TESTIMONY BEFORE SENATE RESOURCES COMMITTEE 1977-1978 (NOTEBOOK)

Mary Singelton - ARCO

except for '74

Sole purpose of taxation - to fund budgets
needs of State as determ. by leg

Seim '69

O&D has spent 12 B dev. the field
& building TAPS
Has paid 2 B in royalties, bonuses
+ taxes & all kinds

9,000 corp. (profit types)
- fed. income tax 36,000
ind - - 200 M

Fish
Timber
Hard rock mining

Sales Tax
Property Tax - State
Severance Tax -

Cook Inlet - negative until a couple yrs ago
2% of total revenues for State
Marginal field - Royalties
Employment

Sustaining role - other dimensions
other developments

4/24/78

Marc Singletary

Petro-chemical – marginal

Gas line – Gas conditioning plant –
1 Bil

Arco, et al not interested in financing

Taken only 1 factor in investment climate

Crawford Thomas
8½ yrs. City Council & Calif. Tax Bd
Non-unitary for another
Unitary, for 1 purpose

Legal difficulty in changing from multi-state part act

Income earned – multi state tax act
Entire tax owed in income tax

Changes in multi-state tax act must be through tax administrator.

"Separate accounting is dead"
– according to Crawford Thomas

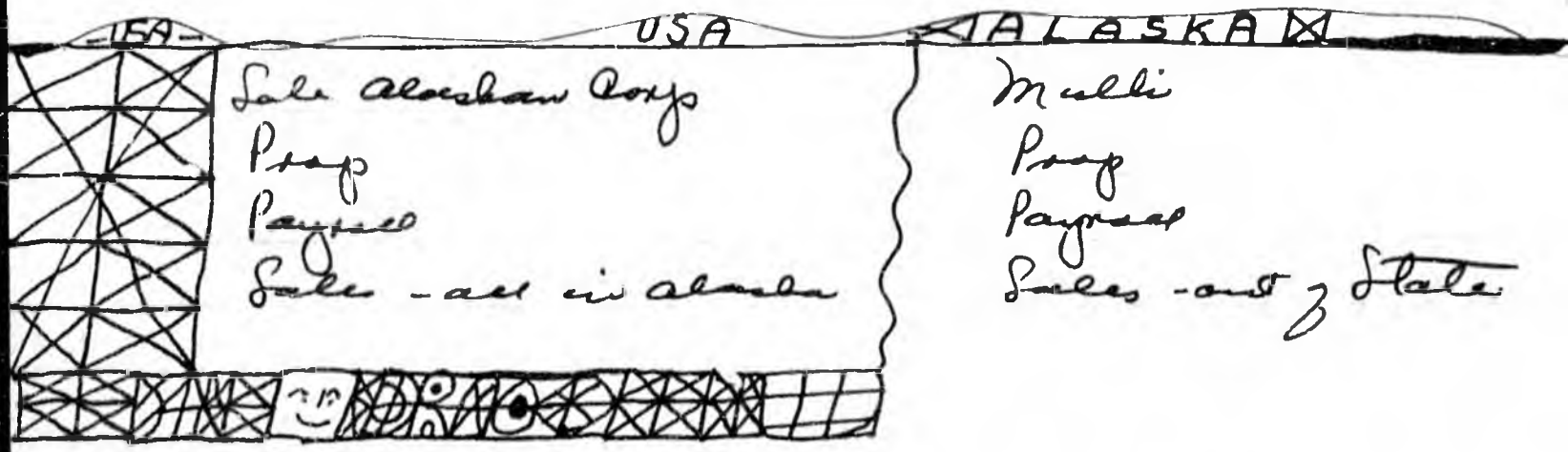
2/24/78

Local 9.4 Prof. Gary Boren
O & G lawer? St. Louis, ~~University~~ no
Wash. University of law
Intangible drilling cost
if not new - taken as a capitalized asset

Property - Payroll - Sales
on on
PRUDHOE BAY | ALASKA
accountaweights to Sales

Multi - State Tax Pact

Reorganize Multi - State rather than new method



Unitary Theory - one business
formula

Questions

Administration of Separate Accounting

Kust p. 34 "In practice separate accounting is impossible to administer and determine"

Lipton "[Hale] Pedrick stands as a monument by Hale"
"Now, its been said that this separate accounting is impossible to administer.... As I mentioned before there are two states that actually utilize separate accounting, if they can do it, we can be done, it can be."

Equity of the Situation

Lennon p. 1 The current method ... "provides equality amongst taxpayers"

Lipton "I put it to you that you cannot through your present income tax statute get an equitable burden of income taxation upon the companies operating here in Alaska, not through the apportionment method." Cites ex. in Anderson report of 4 major producers each with greatly different tax liabilities."

Revenues

Lennon p. 2 Separate Accounting "would free Alaska out of the multistate tax compact, would create tremendous audit problems for the Dept of Revenue, and might even result in a net revenue loss to the state." Why? Not explained any other further in his paper.

Not profit interest
Amerada Hess?

Growth report – Harry Dimas

"Treating us differently"
want to be treated like any other
corp. in the State of Alaska

Points in the ICC case
Olivers wants to FN to get in also

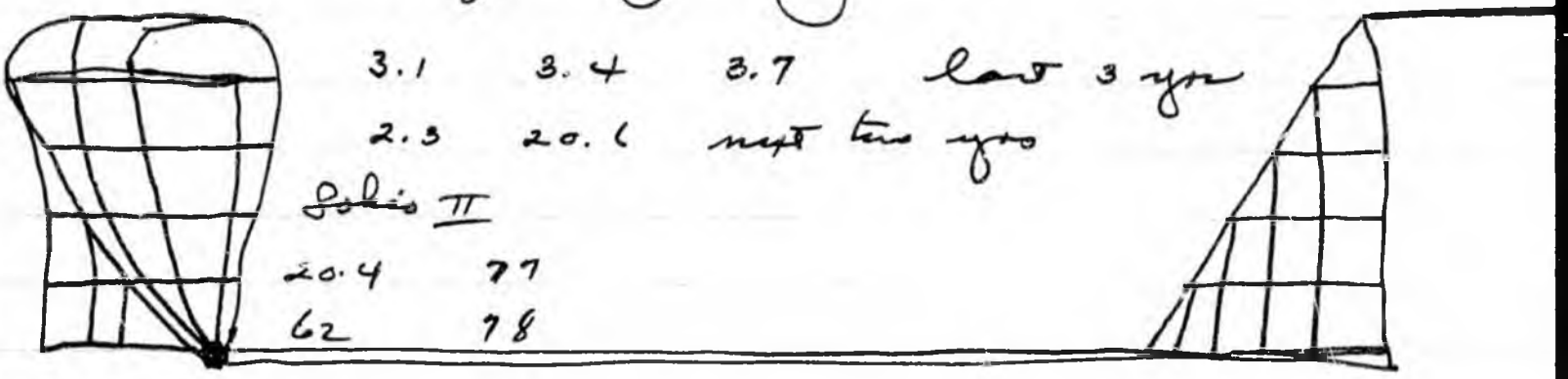
Texaco	6.40
Paddy-Sea	2.00
PanCan	1.00
	9.40

Devries normal business exp tax
jurisdiction

Jobs
Husky
Chevron
Texaco
Union
Amoco
4 or 5 others

Trying to borrow – tax jurisdiction making it different

Sterling Gallagher



Seeking to raise money – severance tax
income tax – traditional

John Messenger

Study – in Hannibal on 12 States

Same approx – ~~trades~~ Broader study

Oliver Leavitt

Timber tariffs much higher than anticipated

Gathering charges – sent in court

Need oil co. expertise to discover & develop
getting oil out of their own difficult

70,000 natives to share 70%

Reduction in value of native lands

Poor business climate

Harold Pomeroy – Kauai
"unconscious profit" – Thru take more
US News & World Report
collision course with inadvertency
viability in the future
Be careful about taking more
than industry to be able to go deeper
& ~~further~~ farther

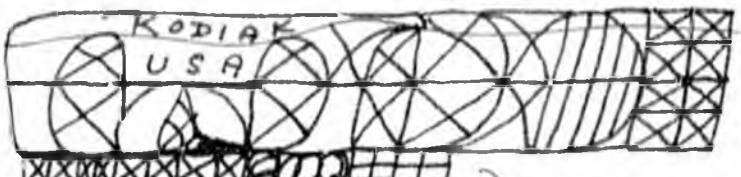
of 2x/98

Robert L. Moore
Arthur Andersen & Co.

(1) ~ ~ CI
(2) ~ ~ ~ ~ PB ~ ~ x8
(3) ~ ~ ~ ~ ~ ~

(1) Cook Inlet, Gas production,
Lisborne, Kapanich Fields

Gas - no price
cost & pipeline
Kapanich & Lisborne - undeveloped



What is actually net income
Moore - Source & income is a legal question

Legality & Bills

17. Amoco Production Co. v. Armhold, 213 Kan. 636, 518 P. 2d 453 (1974); Superior Oil Co. v. Franchise Tax Board, 60 Cal. 2d 406, 386 P. 2d 33 (1963); Honolulu Oil Corp v. Franchise Tax Board, 60 Cal 2d 416, 386 P. 2d 40 (1963).

18. Pierce, "The Uniform Division of Income for Tax purposes Act," 37 TAXES 747, 780 (1957).

19. Final Report, Committee on Tax Situs and Allocation, National Tax Association, 1951, published at pp. 456 et seq, Proceedings of the Forty-Fourth Annual Conference.

20. Interstate Taxation Act, Volume 2, p. 1767 (report of hearings on the Willis bill, H.R. 11798, 1966).

21. Hellerstein, "Allocation and Nexus in State Taxation of Interstate Business," 20 Tax Law Review 259, 275-276 (1965).

22. Congressional Record, Oct. 4, 1977, p. S16238.

23. 43 U.S.C.A. § 1333

24. Legal Ruling No. 366, CCH Cal. Tax Rptr. ¶205-026; Legal Ruling No. 396, op. cit. ¶205-519.

25. Tradesmans Nat. Bank v. Oklahoma Tax Comm., 309 U.S. 560(1940)

26. Complete Auto Transit Inc. v. Brady, _____ U.S. _____, 51 L. Ed. 2d 326 (1977)

27. See, e.g., remarks of Sen. Kennedy in Congressional Record, July 1, 1977, p. S11416

28. See, e.g., Note, "Multinational Corporations and Income Allocation Under Section 482 of the Internal Revenue Code," 89 Harv. L.R. 1202 (1976) in which the federal approach is unfavorably compared to the unitary approach used by California, Oregon, and Alaska.

29. Donald M. Drake Co. v. Dept. of Revenue, 236 Or. 26, 500 P. 2d 1041 (1972); Amoco Production Co. v. Armhold, fn. 6, supra

30. See cases cited at fn. 17, supra

TESTIMONY

OF

GARY I. BOREN

BEFORE THE

SENATE RESOURCES COMMITTEE

OF THE

ALASKA STATE LEGISLATURE

TESTIMONY

MADAM CHAIRMAN AND MEMBERS OF THE COMMITTEE:

I AM GARY BOREN, PROFESSOR OF LAW AT WASHINGTON UNIVERSITY, IN ST. LOUIS, MISSOURI. I AM HERE ON BEHALF OF THE ALASKA OIL AND GAS ASSOCIATION, FOR WHICH I PREPARED A STUDY ON PROPOSED CHANGES IN THE MANNER IN WHICH THE STATE OF ALASKA TAXES THE INCOME OF CORPORATIONS THAT PRODUCE OIL AND GAS IN THE STATE. I UNDERSTAND THAT COPIES OF THAT STUDY HAVE BEEN MADE AVAILABLE TO THE MEMBERS OF THIS COMMITTEE.

I HAVE BEEN INTERESTED IN THE PROBLEMS OF STATE TAXATION OF CORPORATE INCOME FOR SOME TIME, AND HAVE WRITTEN A SERIES OF THREE ARTICLES ON THE SUBJECT, WHICH HAVE BEEN PUBLISHED IN VARIOUS LEGAL JOURNALS. THESE ARTICLES DEAL WITH THE WAY IN WHICH THE STATES DIVIDE THE INCOME OF A CORPORATION TO DETERMINE THE AMOUNT EACH STATE MAY TAX. IT IS THESE ARTICLES THAT PROVIDE MY QUALIFICATIONS FOR SPEAKING HERE ON THAT SUBJECT TODAY.

THE PROPOSAL WHICH THIS COMMITTEE IS NOW CONSIDERING WOULD CHANGE DRASTICALLY THE METHOD CURRENTLY IN USE IN ALASKA AND WHICH IS IN USE IN THE OVERWHELMING NUMBER OF OTHER STATES THAT TAX CORPORATE INCOME. IT IS THEREFORE APPROPRIATE TO INVESTIGATE THE MERITS OF THE REASONS GIVEN BY THOSE WHO ARE DISSATISFIED

WITH THE PRESENT SYSTEM. THE ULTIMATE CONCERN FOR THIS COMMITTEE AND THE LEGISLATURE IS WHETHER ALASKA IS GETTING ITS FAIR SHARE OF THE INCOME OF THE TAXPAYERS THAT PRODUCE OIL AND GAS IN THIS STATE. THOSE WHO BELIEVE THAT ALASKA IS NOT QUESTION THE VALIDITY OF BOTH OF THE COMPONENT PARTS OF THE SYSTEM NOW IN USE AS IT APPLIES TO THE OIL AND GAS INDUSTRY. THEY ATTACK THE METHOD OF DETERMINING THE TOTAL INCOME OF A TAXPAYER, AND THEY ALSO ATTACK THE METHOD BY WHICH ALASKA DETERMINES THE PORTION OF THE TOTAL INCOME THAT THE STATE MAY TAX.

THE UNDERLYING CLAIM OF THE PROPONANTS OF THE BILL BEFORE YOU AND OF THE BILL THAT PASSED THE HOUSE IS THAT LOCAL TAXPAYERS ARE PAYING A 9.4% EFFECTIVE RATE ON THEIR INCOME WHILE THE OIL AND GAS PRODUCERS PAY A SUBSTANTIALLY LOWER EFFECTIVE RATE ON THEIR INCOME. THAT IS A SERIOUS CHARGE, BUT AN INVESTIGATION OF THE REASONS FORWARDED TO BACK UP THAT CLAIM DEMONSTRATES THAT THE CHARGE IS UNFOUNDED. LOCAL TAXPAYERS DO NOT PAY A HIGHER EFFECTIVE RATE THAN THE OIL AND GAS INDUSTRY.

THOSE WHO PROPOSE A CHANGE RECOGNIZE, AS THEY MUST, THAT ALASKA MAY NOT TAX THE TOTAL INCOME OF A CORPORATION THAT HAS OPERATIONS IN OTHER STATES AND COUNTRIES. THE CONSTITUTION OF THE UNITED STATES PERMITS A STATE ONLY TO TAX THAT PORTION OF THE TOTAL INCOME THAT IS ATTRIBUTABLE TO THAT STATE. IF A CORPORATION HAS $100 OF INCOME FROM WORLDWIDE OPERATIONS, ALASKA MAY NOT APPLY ITS 9.4% RATE TO THAT TOTAL INCOME. THE PORTION OF

INCOME ATTRIBUTABLE TO ALASKA MUST FIRST BE DETERMINED. IT IS THE WAY IN WHICH THAT PORTION IS DETERMINED THAT IS IN DISPUTE.

THE METHOD CURRENTLY IN USE IN ALASKA BEGINS GENERALLY WITH THE TOTAL INCOME OF A CORPORATION AS REPORTED FOR PURPOSES OF THE FEDERAL INCOME TAX. THAT INCOME IS THEN DIVIDED BY A MATHEMATICAL FORMULA TO DETERMINE THE AMOUNT OF INCOME ATTRIBUTABLE TO ALASKA. THE FORMULA CONSISTS OF THREE FRACTIONS, THAT ARE CALLED FACTORS. THESE FRACTIONS ARE THE PROPORTIONS OF PROPERTY IN ALASKA TO PROPERTY WORLDWIDE, THE PROPORTIONS OF PAYROLL IN ALASKA TO PAYROLL WORLDWIDE, AND THE PROPORTION OF SALES IN ALASKA TO SALES WORLDWIDE. THE FRACTIONS ARE AVERAGED, AND THE AVERAGE FRACTION IS APPLIED TO TOTAL INCOME TO DETERMINE INCOME THAT MAY BE TAXED BY ALASKA. THIS INCOME IS THEN MULTIPLIED BY THE ALASKA TAX RATE TO GET THE AMOUNT OF TAX THAT IS PAID.

I WOULD LIKE TO DISCUSS FIRST THE TAXABLE BASE, FEDERAL TAXABLE INCOME. THE PROPOSAL BEFORE THE COMMITTEE WOULD DO AWAY WITH THIS AS THE WAY IN WHICH COMPUTATION OF THE INCOME FROM OIL AND GAS PRODUCTION AND PIPELINE TRANSPORTATION IN ALASKA BEGINS. THE OBJECTION MADE TO FEDERAL TAXABLE INCOME AS A STARTING POINT IS THAT IT IS "ERODED," FOR OIL AND GAS PRODUCERS; THAT IS, THAT IT DOES NOT REFLECT TRUE TOTAL INCOME FOR THESE TAXPAYERS. THE ARGUMENTS THAT HAVE BEEN MADE FOR THIS POSITION RELATE TO TWO ITEMS; THE IMMEDIATE DEDUCTION FOR INTANGIBLE DRILLING AND DEVELOPMENT COSTS, AN ITEM PECULIAR TO OIL AND GAS

PRODUCERS (ALTHOUGH THE MINING INDUSTRY GETS A SIMILAR IMMEDIATE DEDUCTION); AND THE CREDIT FOR FOREIGN TAXES PAID, AN ITEM AVAILABLE TO MULTINATIONALS UNDER THE FEDERAL INCOME TAX. TO THE EXTENT THAT OTHER ITEMS THAT AFFECT FEDERAL INCOME TAXES AND THROUGH ADOPTION OF THE FEDERAL SYSTEM ALSO AFFECT ALASKA TAXES ARE CONSIDERED EROSIONS, THE BENEFITS OF THOSE EROSIONS ARE SHARED BY ALL ALASKAN TAXPAYERS. THESE ITEMS, USUALLY DEDUCTIONS, THEN DO NOT AFFECT THE RELATIVE TAX BURDEN OF THE OIL AND GAS PRODUCERS AS COMPARED TO OTHER ALASKA TAXPAYERS.

THE DEDUCTION FOR INTANGIBLE DRILLING AND DEVELOPMENT EXPENDITURES PERMITS A TAXPAYER TO TAKE A CURRENT DEDUCTION FOR AN AMOUNT THAT WOULD OTHERWISE BE DEDUCTED OVER A PERIOD OF TIME. IF A CURRENT DEDUCTION WERE NOT PERMITTED, THE TAXPAYER WOULD CAPITALIZE THESE AMOUNTS AS PART OF THE COST OF THE OIL, AND WOULD RECOVER THESE AMOUNTS AS DEDUCTIONS WHEN THE OIL WAS LIFTED FROM THE GROUND AND SOLD. FOR EXAMPLE, IF A TAXPAYER INCURS $10 OF INTANGIBLE DRILLING AND DEVELOPMENT COSTS IN DRILLING A WELL, AND THE OIL IS PRODUCED IN EQUAL AMOUNTS OVER A 10 YEAR PERIOD, THE ALTERNATIVES ARE THESE. THE TAXPAYER MAY TAKE THE $10 AS A DEDUCTION IMMEDIATELY UNDER FEDERAL LAW. IF IT DID NOT, THE ALTERNATIVE FOR THE TAXPAYER WOULD BE TO TAKE A $1 DEDUCTION FOR EACH OF THE 10 YEARS OF PRODUCTION. THE TOTAL DEDUCTION IS THE SAME. TAKING THE DEDUCTION IMMEDIATELY MEANS THAT IT CANNOT BE TAKEN LATER. THE RESULT OF THE CURRENT DEDUCTION IS THAT THE STATE WILL GET ITS TAXES LATER THAN IT OTHERWISE WOULD. BUT THE STATE WILL GET THOSE TAXES.

THE AVAILABILITY OF THE CREDIT FOR FOREIGN TAXES PAID BY MULTINATIONALS APPEARS TO BE THE BASIS FOR THE POSITION TAKEN BY CONGRESSMAN VANIK OF OHIO THAT THE FEDERAL GOVERNMENT IS NOT GETTING ITS TOTAL TAXES FROM MULTINATIONAL CORPORATIONS. USING THE VANIK POSITION AS A STARTING POINT, IT HAS BEEN ARGUED THAT IF THE FEDERAL GOVERNMENT ISN'T GETTING ITS FAIR SHARE, THE STATE OF ALASKA, WHICH USES FEDERAL TAXABLE INCOME AS A STARTING POINT, MUST ALSO NOT BE GETTING ITS FAIR SHARE. REFUTATION OF THIS ARGUMENT REQUIRES AN EXPLANATION OF HOW THE FEDERAL CREDIT WORKS, AND INDEED JUST WHAT A CREDIT IS.

A CREDIT AGAINST TAXES COMES IN AT THE END OF THE PROCESS AFTER THE AMOUNT OF TAX IS DETERMINED. IT IS NOT TAKEN INTO ACCOUNT IN DETERMINING THE AMOUNT OF TAXABLE INCOME THE WAY A DEDUCTION IS. A TAXPAYER STARTS WITH ITS TOTAL TAXABLE RECEIPTS, REDUCES THAT AMOUNT BY THE PERMITTED DEDUCTIONS AND GETS ITS TAXABLE INCOME. TAXABLE INCOME IS MULTIPLIED BY THE APPROPRIATE RATE TO GET THE AMOUNT OF TAX DUE. THAT AMOUNT OF TAX IS THEN REDUCED DIRECTLY BY THE AMOUNT OF THE CREDIT ALLOWED. TO EMPHASIZE THE POINT, THE CREDIT FOR FOREIGN TAXES PAID IS NOT TAKEN INTO ACCOUNT IN COMPUTING THE AMOUNT OF FEDERAL TAXABLE INCOME -- THE CREDIT COMES INTO PLAY ONLY AFTER TAXABLE INCOME HAS BEEN DETERMINED. FOR EXAMPLE, ASSUME A MULTINATIONAL TAXPAYER WITH $150 OF WORLDWIDE RECEIPTS AND $50 OF DEDUCTIBLE EXPENSES. THE TAXPAYER HAS $100 OF TAXABLE INCOME. ASSUMING A FEDERAL INCOME TAX RATE OF 48%, THE TAX ON THE $100 IS $48.

IF THE TAXPAYER HAS PAID FOREIGN INCOME TAXES OF $25, IT IS PERMITTED TO REDUCE ITS TAXES OWED TO THE UNITED STATES BY THAT AMOUNT. THE RESULT WOULD BE THAT THE TAXPAYER WOULD ONLY PAY THE UNITED STATES $23. IT IS THAT $23 OF TAXES PAID IN RELATION TO THE $100 OF TAXABLE INCOME THAT GIVES RISE TO THE POSITION THAT THE FEDERAL GOVERNMENT IS NOT GETTING ITS FAIR SHARE OF THE TAXES FROM THESE TAXPAYERS.

THERE ARE REASONS FOR THE EXISTENCE OF THE FOREIGN TAX CREDIT. BUT THE ARGUMENTS FOR AND AGAINST IT ARE ABSOLUTELY IRRELEVANT TO THE QUESTION OF WHETHER FEDERAL TAXABLE INCOME IS AN APPROPRIATE STARTING POINT FOR COMPUTING ALASKA INCOME TAXES. THAT IS BECAUSE THE CREDIT DOES NOT ENTER INTO THE COMPUTATIONS OF ALASKA TAXABLE INCOME IN ANY WAY. ALASKA APPLIES ITS FORMULA TO FEDERAL TAXABLE INCOME BEFORE THE CREDIT IS TAKEN INTO ACCOUNT FOR FEDERAL PURPOSES. IN TERMS OF THE EXAMPLE GIVEN PREVIOUSLY, ALASKA STARTS WITH THE $100 OF TOTAL TAXABLE INCOME. IT DOES NOT REDUCE THAT INCOME BY THE CREDIT. NOR DOES IT GIVE ANY CREDIT OF ITS OWN FOR FOREIGN TAXES PAID. THE $25 OF FOREIGN INCOME TAXES PAID IS NEVER TAKEN INTO ACCOUNT BY ALASKA. ALASKA DOES NOT EVEN PERMIT IT TO BE TAKEN AS A DEDUCTION FROM INCOME. THUS, THOSE WHO ARGUE THAT BECAUSE THE FEDERAL GOVERNMENT IS GETTING LESS THAN HALF THE APPROPRIATE TAXES IN THE ABOVE EXAMPLE, THE STATE OF ALASKA MUST BE GETTING LESS THAN HALF OF THE 9.4% IT SHOULD GET, ARE SIMPLY IGNORING THE ABSOLUTE IRRELEVANCE OF THE FOREIGN TAX CREDIT TO ALASKA TAXES.

I AM NOT HERE TO TELL THIS COMMITTEE THAT THE FEDERAL METHOD FOR DETERMINING TAXABLE INCOME IS PERFECTION ITSELF. OF COURSE IT IS NOT. THE SYSTEM HAS SHORTCOMINGS AND IS THE SUBJECT OF CONSTANT DEBATE, AND OF CHANGE. I AM ONLY SAYING THAT THE SYSTEM IN USE DOES NOT PLACE THE OIL AND GAS MULTINATIONALS IN A FAVORED POSITION IN COMPARISON TO THOSE CORPORATIONS IN ALASKA THAT ENGAGE IN OTHER KINDS OF OPERATIONS.

THE SECOND OBJECTION TO THE WAY IN WHICH ALASKA DETERMINES THE AMOUNT OF INCOME IT MAY TAX RELATES TO THE FORMULA USED TO DIVIDE INCOME. THAT OBJECTION IS DIRECTLY REFLECTED IN THE BILL UNDER CONSIDERATION BY THIS COMMITTEE. IT WOULD SUBSTITUTE SEPARATE ACCOUNTING FOR THE USE OF A FORMULA AS THE PRINCIPAL METHOD BY WHICH INCOME IS ATTRIBUTED TO ALASKA FOR THE OIL AND GAS INDUSTRY. THE BILL THUS INDICATES A MISTRUST OF THE FORMULA AS APPROPRIATE TO THE TASK OF DIVIDING THE INCOME OF OIL AND GAS PRODUCERS.

WHAT IS A FORMULA AND WHY HAVE ITS VIRTUES WON SO MUCH ACCEPTANCE FOR THAT DEVICE? THE THEORY OF THE FORMULA IS THAT THE TOTAL INCOME OF A TAXPAYER WHOSE BUSINESS CROSSES STATE LINES IS THE RESULT OF THE CONTRIBUTION OF ACTIVITIES OR ITEMS IN ALL THE STATES THAT HAVE A CONNECTION TO THE INCOME. THE INCOME PRODUCED IN ANY ONE STATE IS MEASURED BY THE PROPORTIONS THAT THE ITEMS OCCURRING IN THAT STATE BEAR TO THE TOTAL OF THOSE ITEMS FOUND EVERYWHERE.

OF THE THREE FACTORS THAT MAKE UP THE FORMULA, PROPERTY, PAYROLL, AND SALES, TWO APPEAR TO BE NONCONTROVERSIAL. NO DISSATISFACTION HAS BEEN EXPRESSED WITH THE AMOUNTS OF PROPERTY AND PAYROLL THAT THE FORMULA USES. THE HIGH COSTS OF THESE ITEMS IN ALASKA MEANS THAT PAYROLL AND PROPERTY IN ALASKA ARE RELATIVELY HIGHER THAN IN MOST OTHER JURISDICTIONS. THE PRIMARY REASON FOR MISTRUST OF THE FORMULA AS IT APPLIES TO OIL AND GAS PRODUCERS IS THE SALES FACTOR. THE OBJECTION TO THE SALES FACTOR IS THAT IT THROWS INCOME OUT OF ALASKA INTO OTHER STATES, BECAUSE RELATIVELY SMALL AMOUNTS OF OIL AND GAS ARE CONSUMED IN ALASKA.

THE SALES FACTOR, OF COURSE, DOES NOT OCCUR IN ISOLATION. IT IS BALANCED BY THE PROPERTY AND PAYROLL FACTORS. THAT BALANCING IS INTENTIONAL. THE RESULT IS THAT NO ONE FACTOR HAS TOO LARGE AN INFLUENCE ON THE RESULT. THE HIGH CONCENTRATIONS OF PROPERTY AND PAYROLL IN THE PRODUCING STATES ARE COUNTERWEIGHTS TO THE INFLUENCE OF THE SALES FACTOR. FROM THE STANDPOINT OF THE MARKET STATES, THE SALES FACTOR BALANCES THE CONCENTRATIONS OF PAYROLL AND PROPERTY THAT OCCUR IN THE PRODUCING STATES. BY AVERAGING THE THREE FACTORS, DISTORTION CAUSED BY ANY ONE IS AVOIDED. BUT THE QUESTION IS RAISED AS TO WHETHER IT IS APPROPRIATE TO HAVE A SALES FACTOR IN ANY EVENT.

THE SALES FACTOR IS USED BY ALL STATES THAT HAVE AN APPORTIONMENT FORMULA WITH THE EXCEPTION OF WEST VIRGINIA. THE SALES FACTOR IS IN SUCH WIDESPREAD USE BECAUSE IT IS GENERALLY AGREED THAT IT IS SUCH

THE MARKET STATES, THE PLACE WHERE AN ITEM IS CONSUMED, HAVE A CLAIM TO A PORTION OF THE INCOME. THE EXISTENCE OF MARKETS IN OTHER STATES CLEARLY CONTRIBUTES TO THE INCOME DERIVED FROM OIL AND GAS OPERATIONS IN ALASKA. CONSIDER HOW MUCH INCOME THERE WOULD BE TO TAX IF ALL OF THE OIL AND GAS PRODUCED IN ALASKA HAD TO BE CONSUMED IN ALASKA FOR LACK OF ANY OTHER MARKET.

THE CONTRIBUTION OF THE MARKET TO TOTAL INCOME THAT IS REFLECTED BY INCLUDING A SALES FACTOR IN THE APPORTIONMENT FORMULA IS RECOGNIZED BY OTHER PRODUCING AND MANUFACTURING STATES. NOR HAS ANY SUFFICIENT REASON BEEN FORWARDED WHY A FORMULA DOES NOT WORK FOR THE OIL AND GAS INDUSTRY. IT HAS BEEN SAID THAT THE STATE OF ALASKA IS UNIQUE BECAUSE OF THE EXTENT TO WHICH IT MUST RELY ON THE OIL AND GAS INDUSTRY FOR ITS TAX BASE. IF THAT IS TRUE, IT NEVERTHELESS DOES NOT CHANGE THE AMOUNT OF INCOME OF THE OIL AND GAS PRODUCERS THAT HAS ITS SOURCE IN ALASKA. AND ONE MAY QUESTION THE PREMISE. MICHIGAN, WHICH IS HEAVILY DEPENDENT ON THE AUTOMOBILE INDUSTRY, DOES NOT SINGLE IT OUT FOR A SPECIAL, MORE BURDENSOME, TREATMENT. THE STATE OF ALASKA, OF COURSE, IS NOT BOUND BY WHAT OTHER STATES DO. BUT BEFORE DEPARTING FROM A SYSTEM THAT HAS BEEN ADOPTED IN SO MANY OTHER JURISDICTIONS, THE LEGISLATURE MIGHT WELL CONSIDER THAT THE USE OF THE FORMULA IN OTHER STATES MAY INDICATE THAT THERE ARE GOOD REASONS FOR RETAINING THE FORMULA IN ALASKA.

ANOTHER OBJECTION TO THE FORMULA NOW IN USE THAT HAS BEEN FORWARDED BY THOSE WHO SEEK A CHANGE, IS THAT SOME OTHER METHOD WOULD PRODUCE MORE TAXES FOR ALASKA. THAT IS TRUE. INDEED, IN ESSENCE, THE BILL BEFORE YOU IS A TAX INCREASE ON THE OIL AND GAS INDUSTRY. BUT IT IS NOT RESPONSIVE TO THE QUESTION AS TO WHETHER THE CURRENT SYSTEM, OR THE ALTERNATIVE PROPOSED, GIVES ALASKA ITS FAIR SHARE OF TAXES. IF, AS I AM TRYING TO SHOW, THE CURRENT SYSTEM IS FAIR, AN INCREASE IN INCOME TAXES, IF THAT IS WHAT THE LEGISLATURE WANTS DONE, OUGHT TO BE BORNE BY ALL CORPORATE INCOME TAXPAYERS.

I SHOULD LIKE TO TURN NOW TO THE MERITS OF THE ALTERNATIVE SYSTEM EMBODIED IN THE BILL BEING CONSIDERED BY THIS COMMITTEE. THE ARGUMENT MADE TO SUPPORT THAT BILL IS THAT SEPARATE ACCOUNTING, (OR THE VARIATION OF IT CONTAINED IN THE BILL), IS A MORE ACCURATE WAY OF DETERMINING THE INCOME ATTRIBUTABLE TO ALASKA THAN IS THE USE OF AN ARBITRARY FORMULA. THE ACCURACY CLAIMED FOR SEPARATE ACCOUNTING IS DEEMED TO BE SELF-APPARENT. THE DEVICE CONSIDERS WHAT ACTUALLY GOES ON IN THE STATE IN COMPUTING THE AMOUNT OF INCOME THE STATE SHOULD TAX. THAT IS THE REASON SEPARATE ACCOUNTING WAS FIRST USED. AND SEPARATE ACCOUNTING IS STILL USED, BUT IN A SUBSTANTIALLY DIMINISHED DEGREE.

YOU HAVE HEARD IN PRIOR TESTIMONY ABOUT THE CONSIDERABLE ADMINISTRATIVE DIFFICULTIES CONNECTED WITH SEPARATE ACCOUNTING. IT REQUIRES THE MAINTENANCE BY TAXPAYERS OF EXTENSIVE RECORDS [illegible]

NOT NEEDED FOR OTHER PURPOSES. AUDITS BY THE STATE WOULD BE MORE TIME CONSUMING AND HENCE MORE EXPENSIVE. THE BILL BEFORE YOU ATTEMPTS TO LIMIT THESE DIFFICULTIES, ALTHOUGH MANY REMAIN. IF THESE WERE THE ONLY REASONS AGAINST THE USE OF SEPARATE ACCOUNTING THE LEGISLATURE, AFTER WEIGHING THE EXTENT OF THE ADMINISTRATIVE BURDEN, MIGHT, OR MIGHT NOT, DECIDE THAT THE ACCURACY WAS WORTH THE TROUBLE. THAT WOULD BE FOR THE LEGISLATURE TO DETERMINE. BUT I WOULD LIKE TO DISCUSS THE UNDERLYING CLAIM, THE CLAIM THAT SEPARATE ACCOUNTING IS ACCURATE.

THE VIEW OF MOST OF THOSE WHO HAVE STUDIED THE ISSUE IS THAT SEPARATE ACCOUNTING IS NOT ACCURATE FOR BUSINESSES WHOSE OPERATIONS CROSS STATE LINES. BY FOCUSING ON WHAT GOES ON IN ONE STATE, IT IGNORES WHAT HAPPENS ELSEWHERE. BY CONSTRUCTING AN ARTIFICIAL BUSINESS THAT OPERATES ONLY IN ONE STATE, SEPARATE ACCOUNTING DISREGARDS THE REALITY OF THE BUSINESS BEING TAXED.

THE BILL BEFORE THIS COMMITTEE RECOGNIZES THIS LIMITATION. IT DOES NOT CALL FOR A COMPLETE SEPARATE ACCOUNTING. ONLY INCOME FROM OIL AND GAS PRODUCTION AND PIPELINE TRANSPORTATION IN ALASKA IS ACCOUNTED FOR SEPARATELY. ALL OTHER INCOME IS SUBJECTED TO FORMULARY APPORTIONMENT, AND THIS INCLUDES THE INCOME DERIVED FROM OIL AND GAS PRODUCTION AND PIPELINE TRANSPORTATION IN OTHER JURISDICTIONS. A TRUE SEPARATE ACCOUNTING WOULD NOT TAX PRODUCTION INCOME OUTSIDE ALASKA, NOR SEEK TO REACH ANY OTHER INCOME FROM OPERATIONS OUTSIDE ALASKA. THE

WORKINGS OF THIS BILL CAN ONLY LEAD TO THE SAME INCOME BEING TAXED TWICE, AND IN AN AMOUNT IN EXCESS OF THE DOUBLE TAXATION UNDER A TRUE SEPARATE ACCOUNTING. THAT REALITY ONLY UNDERSCORES THE UNDERLYING NATURE OF THE BILL. IT IS SIMPLY A WAY TO GET MORE TAX DOLLARS FROM THE OIL AND GAS PRODUCERS. IT IS NOT A REFORM.

THE ARTIFICIAL PROVISIONS OF THE BILL THAT CAUSE THE GREATEST DIFFICULTIES ARE THE WAY IN WHICH GROSS INCOME IS DETERMINED AND THE LIMIT ON THE DEDUCTIONS THAT ARE ALLOWED. TO USE PRODUCTION AS AN EXAMPLE, GROSS INCOME IS DETERMINED TO BE THE VALUE OF THE OIL AND GAS PRODUCED AS ESTABLISHED FOR PURPOSES OF THE SEVERANCE TAX. WITHOUT REFERENCE TO THE QUESTION WHETHER THAT VALUE IS ACCURATE AS A VALUE, I WOULD LIKE TO POINT OUT THAT THE BILL CONFUSES VALUE FOR PURPOSES OF A PROPERTY OR A SEVERANCE TAX WITH THE ISSUE OF THE SOURCES OF INCOME, WHICH IS THE QUESTION TO BE CONSIDERED IN DIVIDING INCOME AMONG THE STATES.

THE CONTRIBUTION OF OTHER STATES TO THE VALUE OF PROPERTY IS IRRELEVANT IN A PROPERTY TAX OR A SEVERANCE TAX. THOSE OTHER STATES CANNOT TAX THOSE VALUES. ONLY THE STATE IN WHICH THE PROPERTY IS LOCATED OR FROM WHOSE GROUND IT WAS SEVERED MAY DO SO. THE CONTRIBUTION OF OTHER STATES TO VALUE MAKE ALL THE DIFFERENCE IN AN INCOME TAX, BECAUSE THAT VALUE IS TRANSFORMED TO INCOME TO WHICH THOSE OTHER STATES HAVE A CLAIM. THE VALUE OF OIL AND GAS IN ALASKA IS INCREASED BECAUSE THE OIL AND GAS

WILL BE TRANSPORTED TO, AND EVENTUALLY SOLD IN, OTHER STATES. A PROPERTY TAX OR A SEVERANCE TAX IS STATIC. THE QUESTION IS VALUE IN ONE STATE AT ONE POINT IN TIME. AN INCOME TAX IS THE RESULT OF TRANSACTIONS, WHICH HERE CROSS STATE LINES.

BECAUSE OTHER STATES AGREE THAT THE USE OF A FORMULA IS APPROPRIATE FOR THE OIL AND GAS INDUSTRY, THEY WILL BE TAXING THE SAME VALUES ALASKA TAXES. IF THE PRESENT SYSTEM WERE WRONG, THERE EXISTS A MECHANISM FOR SOLVING ALASKA'S PERCEIVED PROBLEM WITHOUT SUBJECTING THE OIL AND GAS INDUSTRY TO MULTIPLE TAXATION. ALASKA IS A MEMBER OF THE MULTISTATE TAX COMPACT. THE ALASKA COMMISSIONER OF REVENUE IS AN OFFICER OF THE MULTISTATE TAX COMMISSION. HE, ON HIS OWN INITIATIVE, OR PERHAPS AT THE DIRECTION OF THE LEGISLATURE, COULD WORK WITHIN THAT BODY FOR THE ADOPTION OF UNIFORM REGULATIONS EMBODYING A NEW SYSTEM. ALASKA COULD PRESENT ITS POSITION ON THE APPROPRIATE METHOD OF DIVIDING INCOME OF OIL AND GAS PRODUCERS AND HAVE IT EVALUATED BY A GROUP COMPOSED OF THE TAX ADMINISTRATORS OF OTHER STATES. AND I RECOMMEND THAT PROCEDURE TO HIM.

THE ARTIFICIALITYOF THE BILL IS ALSO EVIDENCED BY ITS TREATMENT OF DEDUCTIONS. ONLY DIRECT EXPENSES OF EXPLORATION AND PRODUCTION, AND A LIMITED AMOUNT OF INTEREST EXPENSE ARE PERMITTED AS DEDUCTIONS FROM OIL AND GAS PRODUCTION INCOME AS DETERMINED FOR ALASKA. ALL OVERHEAD AND OTHER INDIRECT EXPENSES ARE DISALLOWED. THERE ARE, NEVERTHELESS, ACTUAL COSTS WITH A RELATIONSHIP TO

THE PRODUCTION OF OIL IN ALASKA. AGAIN, THE BILL RECOGNIZES INTERNALLY THE ARTIFICIAL NATURE OF THESE LIMITS. THOSE DEDUCTIONS DISALLOWED MAY BE TAKEN INTO ACCOUNT IN COMPUTING THE INCOME FROM OTHER OPERATIONS, AND THE NET INCOME FROM THESE COMPUTATIONS ARE SUBJECTED TO THE SPECIAL APPORTIONMENT FORMULA IN THE BILL. THE RESULT OF THIS IS THAT OVERHEAD AND OTHER INDIRECT EXPENSES RELATING TO PRODUCTION INCOME ARE ATTRIBUTED TO OTHER OPERATIONS THAT TAKE PLACE OUTSIDE THE STATE. ONLY A SMALL PROPORTION OF THOSE THAT WOULD OTHERWISE REDUCE INCOME IN ALASKA END UP AS EFFECTIVE DEDUCTIONS. WHAT YOU THEN WOULD HAVE IS SOMETHING PART WAY BETWEEN AN INCOME TAX AND A GROSS RECEIPTS TAX -- NEITHER FISH NOR FOWL -- BUT AT INCOME TAX RATES THAT FAR EXCEED RATES UNDER A GROSS RECEIPTS TAX.

I HOPE THAT I HAVE BEEN ABLE TO DEMONSTRATE FOR YOU THAT THE OIL AND GAS INDUSTRY IS NOT PAYING INCOME TAXES AT A LOWER EFFECTIVE RATE THAN LOCAL TAXPAYERS PAY, AND THAT THE ALTERNATIVE PROPOSED CREATES INEQUITY RATHER THAN ABOLISHING IT. BEFORE CLOSING, I WOULD LIKE TO RAISE BRIEFLY SOME OTHER ISSUES CONNECTED WITH THE BILL.

BEYOND THE INACCURACIES THAT RESULT FROM THE USE OF SEPARATE ACCOUNTING, THE BILL RAISES SEVERAL LEGAL QUESTIONS. THE UNITED STATES SUPREME COURT HAS RECENTLY RECOGNIZED THAT TAXES TAILORED FOR SPECIAL INDUSTRIES MAY VIOLATE THE COMMERCE CLAUSE. THE

VERY MAGNITUDE OF THE INCREASE IN TAXES OVER WHAT WOULD HAVE BEEN OWING IN A PRIOR YEAR HAS BEEN CONSIDERED OF SIGNIFICANCE BY THAT COURT IN DECIDING A QUESTION OF APPORTIONMENT UNDER A TAX ON THE ROLLING STOCK OF A RAILROAD. QUESTIONS HAVE ALSO BEEN RAISED ABOUT THE ABILITY OF THE STATE OF ALASKA TO CONTINUE ITS MEMBERSHIP IN THE MULTISTATE TAX COMMISSION. I WOULD NOT PRESUME TO ADVISE YOU ON HOW ANY OF THOSE QUESTIONS WOULD BE DECIDED. I CAN ONLY SAY THAT THE PROBLEMS ARE REAL ONES. THE UNCERTAINTIES THAT THEY RAISE ARE CERTAINLY APPROPRIATE FOR THE LEGISLATURE TO CONSIDER IN THE PROCESS OF REACHING A DECISION ON THIS BILL.

THE BILL BEFORE THIS COMMITTEE HAS A FLAW THAT GOES BEYOND THE INTERNAL DEFECTS OF THE PROPOSAL. THE BILL IS A STEP AWAY FROM THE GOAL OF UNIFORMITY THAT PROMPTED THE ENACTMENT OF THE UNIFORM DIVISION OF INCOME ACT AND THE ADOPTION OF THE MULTI-STATE TAX COMPACT BY THE STATE OF ALASKA. THE LEGISLATURE MAY DECIDE THAT UNIFORMITY WITH THE LAWS OF OTHER STATES, AND THE BENEFITS TO THE STATE AND TO TAXPAYERS THAT UNIFORMITY PROVIDES MUST BE SUBORDINATED TO OTHER INTERESTS OF THE STATE OF ALASKA. BUT THE BENEFITS OF UNIFORMITY DO DESERVE TO BE WEIGHED IN THE DECISION MAKING PROCESS. IN THAT BALANCE THE DIFFICULTIES OF SEPARATE ACCOUNTING, ITS INACCURACIES, AND THE DEFECTS OF THE BILL BEFORE THIS COMMITTEE, INCLUDING THE LEGAL QUESTIONS IT RAISES ALSO DESERVE CONSIDERATION. THE PRESENT SYSTEM OF DIVIDING CORPORATE INCOME HAS SERVED ALASKA WELL UP TO THIS POINT. ITS CONTINUED USE WOULD SERVE ALASKA WELL IN THE FUTURE.

GARY I. BOREN

Biographical Information

Education:

Bachelor of Arts, University of California, Los Angeles - 1957

Bachelor of Laws, University of California, Los Angeles - 1961

Member of the Order of the Coif
Note and Comment Editor, U.C.L.A. Law Review

Professional:

Professor of Law and Director of the Graduate Tax Program, Washington University School of Law, St. Louis, Missouri

Assistant Professor - 1967-1971
Associate Professor - 1971-1975
Professor - 1975-Present

Private practice, Los Angeles, California - 1961-1967

Member State Bar of California

Major Publications:

Equitable Apportionment: Administrative Discretion and Uniformity in the Division of Corporate Income for State Tax Purposes
49 So. Cal. L. Rev. 991 (1976)

Specific Allocation of Corporate Income in California: Some Problems in the Uniform Division of Income for Tax Purposes
30 TAX. L. REV. 607 (1975)

Separate Accounting in California and Uniformity in Apportioning Corporate Income
18 U.C.L.A. L. REV. 478 (1971)

Courses Taught:

*State and Local Taxation
*Federal Income Taxation
*Federal and Estate Gift Taxation
*Seminar in Tax Policy and Current Legislation
Seminar in Advanced Tax Research
Natural Resources

*Courses taught currently

STATEMENT

OF THE DOW CHEMICAL COMPANY

For the Hearing Conducted by the

Alaska Senate Resources Committee

Juneau, Alaska

March 18, 1977

By J. H. Davidson
Technical Advisor
Dow Chemical U.S.A.
Midland, Michigan

J.H. DAVIDSON

Mr. Chairman,

My name is John Davidson and I am a Technical Advisor in the Agricultural Products Department of Dow Chemical U.S.A. Since graduation from Michigan State University in 1937, I have been employed by Dow working in the area of research and development with agricultural chemicals, among them formulations of 2,4,5-trichlorophenoxyacetic acid (2,4,5-T) and 2,4-dichlorophenoxyacetic acid (2,4-D) which you are discussing today.

This statement expressing the position of The Dow Chemical Company regarding 2,4,5-T and 2,4-D concerns the registered uses for 2,4,5-T as given on the ESTERON 245 and ESTERON 99 Concentrate labels, copies of each are attached. These labels are registered by the United States Environmental Protection Agency as EPA Registration No. 464-205-AA and No. 464-201-AA.

The Dow Chemical Company believes that the federal EPA registration adequately covers the requirements for safe use of 2,4,5-T and 2,4-D and may be summarized in the following statements:

1. The 2,4,5-T and 2,4-D herbicide products presently registered comply with the provisions of the Federal Insecticide, Fungicide and Rodenticide Act as amended.

2. 2,4,5-T and 2,4-D herbicides will perform their intended function without unreasonable adverse effects on the environment.

3. When used in accordance with widespread and commonly recognized practice, 2,4,5-T and 2,4-D will not cause unreasonable adverse effects on the environment as defined by the Federal Insecticide, Fungicide and Rodenticide Act as amended.

4. The registrations of 2,4,5-T and 2,4-D containing herbicides should not be cancelled or any classification changed.

The prohibition of 2,4,5-T used around the home, recreation areas, on lakes, ponds and ditch banks is frequently cited as a reason for severely restricting its use in other areas. Clarification of this point by relating some of the background information may be of help.

Shortly before EPA became operative in April of 1970 a joint announcement by the Secretaries of Agriculture, Interior and Health Education and Welfare was issued suspending the use of 2,4,5-T around the home, recreation areas, on lakes, ponds, ditch banks and food crops. This was prompted primarily because 2,4,5-T was under investigation as an ingredient in a defoliant used in the Vietnam War. An objection was filed regarding suspension of 2,4,5-T on food crops but not for the use of 2,4,5-T around homes, recreation areas, on lakes, ponds, and ditch banks. At the time, these uses of 2,4,5-T were not considered important, and the benefits to be derived from questioning the suspension order apparently did not outweigh even the costs of opposing such an action. In addition, alternative and reasonably acceptable herbicides were available. Despite extensive investigation, no evidence has been developed that there is any hazard from the use of 2,4,5-T around the home, recreation areas, on lakes, ponds, ditch banks and food crops.

A brief discussion on the use of phenoxy herbicides is presented in the report entitled "Phenoxy Herbicides" recently prepared by the Council for Agricultural Science and Technology. A copy of this report is attached. The authors of this report are recognized experts in their respective fields. Several paragraphs from this report are pertinent to the issues covered in this statement and will be quoted here.

From the Summary.

The phenoxy herbicides are predominantly toxic to green plants and are much less toxic to mammals, birds, fish, reptiles, shellfish, insects, worms, fungi and bacteria. When properly used, they do not occur in soils and water at levels harmful to animals and microorganisms. They do not concentrate in food chains and do not persist from year to year in croplands. They are detectable only rarely in food and then only in insignificant amounts.

A highly poisonous kind of dioxin called TCDD is an unavoidable contaminant in commercial supplies of 2,4,5-T and silvex. The amount present in currently produced formulations of 2,4,5-T and silvex is not enough to alter the toxicological properties of these preparations or to endanger human health or to affect plants or animals in the environment.

The phenoxy herbicides are widely used because they are more efficient and usually less hazardous and less injurious to the environment than alternative methods. Use of these chemicals is estimated to reduce the cost of production of the crops on which they are used by about 5% and to reduce overall agricultural production costs in the United States by about 1%. Uses in forests and nonagricultural situations provide additional savings. If the phenoxys were no longer available, the cost of food, forest products, electric power, transportation and governmental services would be higher. These costs would be borne by consumers.

From the Residue Section, p. 17.

Residues of the phenoxy herbicides leached into the soil are bound to some extent by soil particles and are held in the upper part of the soil. They do not leach into water tables and contaminate wells and springs, nor do they move significantly into streams or to adjacent areas from surface runoff. However, wind or water erosion that carries major quantities of soil would also transport herbicide residues if any were present. The diluting effect of the soil is such that levels of the phenoxy herbicide in the root zone of plants are extremely low. Normally the levels are not sufficient to injure green plants or to affect non-green organisms such as bacteria, fungi, worms, insects and rodents.

The phenoxys are, without exception, subject to decomposition by various microorganisms that are universally present in soils. When applied to soils at typical agricultural rates, 2,4-D is usually decomposed in one to four weeks. MCPA requires about six weeks and 2,4,5-T about three months for essentially complete destruction. Silvex degradation is slightly slower than that of 2,4,5-T. Thus the phenoxy herbicides do not build up in the soil, and treatments can be applied to croplands year after without accumulation.

From the Dioxin Section, p. 19.

TCDD sprayed into waters rapidly disappears, evidently due to vapor distillation into the atmosphere and to decomposition by sunlight provided the waters contain small amounts of organic compounds. It is known that TCDD can bioaccumulate in algae, snails and fish. This property is of no practical interest, however, since there is no

substantial supply of the chemical in the environment subject to accumulation. Analyses reveal that accumulation in food-chain organisms is not a problem. Measurable levels of TCDD have not been found in herring gulls, sea lions, eagles, cormorants, butterfish, eels, chain pickerels and large bodies of fresh and salt water. It has not been possible to detect TCDD in American supplies of food and feed and in fish meal.

In order to assure appropriate quality assurance of 2,4,5-T herbicides as produced by The Dow Chemical Company certain analyses are made on each lot of product produced. In addition to certain routine analyses on 2,4,5-T and silvex an examination of each lot is made to assure compliance with the recommendation on 2,3,7,8-tetrachlorodibenzo-p-dioxin (TCDD).

In the "Report of the Advisory Committee on 2,4,5-T to the Administrator of the Environmental Protection Agency" submitted in May of 1971, recommendations were included regarding quality control of the manufactured product. These included a limit of 0.1 ppm TCDD in all future production and the surveillance by the EPA of products on the market. The Dow Chemical Company analyzes each lot of product containing 2,4,5-T to be certain that it complies with this recommendation. To the best of my knowledge, EPA inspectors periodically collect samples from dealer shelves and retainer samples from the manufacturer for purposes of determining compliance with this recommendation.

In June of 1974 the United States Environmental Protection Agency withdrew the formal hearing on 2,4,5-T due to lack of data. Prior to this withdrawal several conferences were held by experts from United States Environmental Protection Agency, United States Department of Agriculture, Food and Drug Administration, Environmental Defense Fund, Dow and

others in which studies on toxicology, analytical methodology and environmental samples were discussed in detail. As a result of the information presented at these meetings and supplied in the preparation for the public hearing, the United States Environmental Protection Agency withdrew the intent to hold hearings on 2,4,5-T, silvex and herbicides potentially containing 2,3,7,8-tetrachlorodibenzo-p-dioxin and withdrew its cancellation of the registration of 2,4,5-T in rice fields, the only food crop use of significance. This notice of withdrawal was printed in the Federal Register, Vol. 39, No. 126, June 28, 1974. A copy is attached.

Registration requirements of the United States Environmental Protection Agency include information to support the safe use of these products when used according to label instructions. This safety information applies to humans, wildlife and livestock.

The U.S. Environmental Protection Agency has established the following maximum contaminant levels for the organic chemicals 2,4-D and silvex in community water systems:

2,4-D	0.1 milligrams per liter (ppm)
silvex	0.01 milligrams per liter (ppm)

See attached Federal Register December 24, 1975, p. 59571.

Formulations of 2,4,5-T and 2,4-D are registered for sale in all states and in all provinces of Canada.

We therefore oppose any additional restrictions on the use of 2,4-D or 2,4,5-T.

Respectfully submitted,

J. H. Davidson
Dow Chemical U.S.A.
Midland, Michigan

2,4,5-TRICHLOROPHENOXYACETIC ACID AND HERBICIDES POTENTIALLY CONTAINING TETRACHLORODIOXIN

Withdrawal of Cancellation and Withdrawal of Intent to Hold Hearings

Please take notice that pursuant to the authority vested in me by sections 6(b)(1) and 6(b)(2) of the Federal Insecticide, Fungicide and Rodenticide Act, as amended, I hereby withdraw the order of cancellation of 2,4,5-Trichlorophenoxyacetic Acid (2,4,5-T) only insofar as it relates to rice dated August 6, 1971 (36 FR 14777, August 11, 1971) and I further withdraw (1) the notice of intent to hold hearing on all registered uses of 2,4,5-T dated July 19, 1973 (38 FR 19859–60, July 24, 1973) and (2) the notice of intent to hold hearing on all registered uses of herbicides derived from 2,4,5 Trichlorophenol, including Silvex and Erbon, dated May 10, 1974 (39 FR 17466, May 16, 1974). All suspensions of uses of 2,4,5-T remain in effect, and all cancellations of uses of 2,4,5-T for which a hearing was not requested similarly remain in effect. See also USDA–PRD, PR 70–11, April 20, 1970 and USDA–PRD, PR 70–13, May 1, 1970.

Accordingly, I hereby withdraw the proceedings initiated by the aforementioned Order and Notices (FIFRA Consolidated Docket No. 295) and the new proceeding (FIFRA Docket No. 302) initiated by the Notice dated May 10, 1974 (39 FR 17466, May 16, 1974).

I take these actions for the reasons given in the statement which accompanies this notice and without prejudice to the issuance of such orders or notices in the future if such issuance is warranted in the judgment of the appropriate officials of this Agency.

Dated: June 24, 1974.

JOHN QUARLES,
Acting Administrator.

[FR Doc.74–14920 Filed 6–27–74;8:45 am]

2,4,5-TRICHLOROPHENOXYACETIC ACID AND HERBICIDES POTENTIALLY CONTAINING TETRACHLORODIOXIN

Residue Monitoring Program

Concern over the use of 2,4,5-Trichlorophenoxyacetic Acid (2,4,5-T) in the United States initially arose when 2,4,5-T was used as a defoliant during the Vietnamese War. On August 6, 1971 this agency issued an order reaffirming cancellation of 2,4,5-T on food crops for human consumption (36 FR 14777, August 11, 1971), and on July 19, 1973 the Agency issued a notice of intent to hold hearing on all registered uses of 2,4,5-T (38 FR 19859–60, July 24, 1973) pursuant to section 6(b)(2) of the Federal Insecticide, Fungicide and Rodenticide Act, as amended. A similar section 6(b)(2) notice of intent to hold hearing on all registered herbicides derived from 2,4,5-Trichlorophenol, including Silvex and Erbon, was issued on May 10, 1974 (39 FR 17466, May 16, 1974).

All herbicides derived from 2,4,5-Trichlorophenol, including 2,4,5-T, Silvex and Erbon, have the potential of containing tetrachlorodioxin (TCDD). As study of 2,4,5-T by this Agency continued, concern focused on the contaminant TCDD. By 1973 residue monitoring devices had been developed that appeared capable of monitoring TCDD in parts per trillion (ppt), the degree of sensitivity needed for measurement of TCDD in man and the human food chain. The 1973 notice specifically delayed the hearing on 2,4,5-T until April 1974 "to permit the Agency to complete an environmental and human monitoring project on the presence of the tetrachlorodioxin impurity found in 2,4,5-T and the extent to which the dioxin may adversely affect human and animal health." (38 FR 19860, July 24, 1973). The residue monitoring program was the only means available to determine if TCDD is bioaccumulating in man and the human food chain. Without the answer to the question of bioaccumulation, the danger of TCDD cannot be assessed.

As reported by attorneys of this Agency on March 21, 1974 in FIFRA Consolidated Docket No. 295, methodological problems have delayed the TCDD residue monitoring project. Since that date, the methodological problems have not been solved. Problems at first thought to relate only to human and rice samples now are found to relate to all samples. No date for completion of the TCDD residue monitoring can be given, and in fact, completion of the project by the Agency may be two or more years away.

Under the circumstances, it does not seem appropriate to continue administrative proceedings when the evidence which would largely determine the outcome of those proceedings remains scientifically unavailable. The Agency will continue its TCDD residue monitoring program and will take such further action as it deems appropriate once the results of the monitoring project are available.

Dated: June 24, 1974.

JOHN QUARLES,
Acting Administrator.

[FR Doc.74–14921 Filed 6–27–74;8:45 am]

WEDNESDAY, DECEMBER 24, 1975

VOLUME 40
NUMBER 248

PART IV:

ENVIRONMENTAL PROTECTION AGENCY

WATER PROGRAMS

National Interim Primary Drinking Water Regulations

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER D—WATER PROGRAMS

[FRL 464-7]

PART 141—NATIONAL INTERIM PRIMARY DRINKING WATER REGULATIONS

On March 14, 1975, the Environmental Protection Agency (EPA) proposed National Interim Primary Drinking Water Regulations pursuant to sections 1412, 1414, 1415, and 1450 of the Public Health Service Act ("the Act"), as amended by the Safe Drinking Water Act ("SDWA" Pub. L. 93-523), 40 FR 11990. EPA held public hearings on the proposed regulations in Boston, Chicago, San Francisco, and Washington during the month of April. Several thousand pages of comments on the proposed regulations were received and evaluated. In addition, the Agency has received comments and information on the proposed regulations from the National Drinking Water Advisory Council, the Secretary of Health, Education, and Welfare, and from numerous others during meetings with representatives of State agencies, public interest groups and others.

The regulations deal only with the basic legal requirements. Descriptive material will be provided in a guidance manual for use by public water systems and the States.

The purpose of this preamble to the final regulations is to summarize the most significant changes made in the proposed regulations as a result of comments received and the further consideration of available information. A more detailed discussion of the comments and of changes in the proposed regulations is attached as Appendix A.

Water Systems Covered

The Safe Drinking Water Act applies to each "public water system," which is defined in Section 1401(4) of the Act as "a system for the provision to the public of piped water for human consumption, if such system has at least fifteen service connections or regularly serves at least twenty-five individuals." Privately owned as well as publicly owned systems are covered. Service "to the public" is interpreted by EPA to include factories and private housing developments. (See generally, House Report, pp. 16-17.)

The definition of "public water system" proposed in the Interim Primary Drinking Water Regulations sought to explain the meaning of the statutory reference to "regular" service. It was proposed to interpret this term as including service for as much as three months during the year. Because the proposed definition would have excluded many large campgrounds, lodges, and other public accommodations which serve large numbers of tourists but which are open for slightly less than three months each year, the definition in the final version covers systems serving an average of at least twenty-five individuals at least 60 days out of the year. The use of a minimum number of days rather than months also makes clear that a system may qualify as a public water system even if it is not open every day during a given month.

Once "public water system" has been defined, it is necessary to define the two major types of public water systems—those serving residents and those serving transients or intermittent users. The possible health effects of a contaminant in drinking water in many cases are quite different for a person drinking the water for a long period of time than for a person drinking the water only briefly or intermittently. Different regulatory considerations may in some cases apply to systems which serve residents as opposed to systems which serve transients or intermittent users. Accordingly, § 141.2(e) makes clear that all "public water systems" fall within either the category of "community water systems" or the category of "non-community water systems." To make clear which regulatory requirements apply to which type of system, the category covered is specifically indicated throughout the regulations.

The proposed regulations defined a "community water system" as "a public water system which serves a population of which 70 percent or greater are residents." Reliance in the proposed definition on the percentage of water system users who are residents would result in treating some fairly large resort communities with many year-round residents as non-community systems. Therefore, the definition of "community water system" has been changed to cover any system which serves at least 15 service connections used by year-round residents or serves at least 25 year-round residents.

Small Community Water Systems

Many community water systems in the country are quite small, since it is the intention of the Act to provide basically the same level of health protection to residents of small communities as to residents of large cities, and since a number of advanced water treatment techniques are made feasible only by economies of scale, the cost of compliance with the requirements of the Act may pose a serious problem for many small communities. The regulations seek to recognize the financial problems of small communities by requiring more realistic monitoring for systems serving fewer than 1,000 persons. Variances and exemptions authorized by the Act can also assist in dealing with economic problems of small community systems in appropriate cases, at least temporarily. EPA will provide technical assistance on effective treatment techniques which can be used by small systems.

These methods of dealing with the financial problems of some small community systems may not be sufficient in specific instances to make compliance with all applicable regulatory requirements feasible. EPA is commencing a study of potential problems faced by small community systems in meeting applicable requirements under the Act and these regulations, and, if necessary, will make additional adjustments in the Interim Primary Drinking Water Regulations prior to their effective date.

Non-Community Systems

"Non-community systems" are basically those systems which serve transients. They include hotels, motels, restaurants, campgrounds, service stations, and other public accommodations which have their own water system and which have at least 15 service connections or serve water to a daily average of at least 25 persons. Some schools, factories and churches are also included in this category. It is conservatively estimated that there are over 200,000 non-community water systems in the country. However, it should be recognized that while their number is large, they normally are not the principal source of water for the people they serve.

The regulations as proposed would have applied all maximum contaminant levels to non-community systems as well as to community systems. This approach failed to take into account the fact that the proposed maximum contaminant levels for organic chemicals and most inorganic chemicals were based on the potential health effects of long-term exposure. Those levels are not necessary to protect transients or intermittent users. Therefore, the final regulations provide that maximum contaminant levels for organic chemicals, and for inorganic chemicals other than nitrates, are not applicable to non-community systems. An exception was made for nitrates because they can have an adverse health effect on susceptible infants in a short period of time.

Even without monitoring for organic chemicals or most inorganic chemicals, in the initial stages of implementation of the drinking water regulations, monitoring results from tens of thousands of non-community systems could overwhelm laboratory capabilities and other resources. This could delay effective implementation of the regulations with respect to the community systems which provide the water which Americans drink every day. To avoid this result, non-community systems will be given two years after the effective date of the regulations to commence monitoring. In the meantime, non-community systems which already monitor their water are encouraged to continue to do so, and the States are encouraged to take appropriate measures to test or require monitoring for non-community systems that serve large numbers of people.

Of course, non-community systems which pose a threat to health should be dealt with as quickly as possible. The maximum contaminant levels applicable to non-community water systems therefore will take effect 18 months after promulgation, at the same time as levels applicable to community systems. Inspection and enforcement authority will apply to non-community systems at the same time as to community systems.

Sanitary Surveys

EPA encourages the States to conduct sanitary surveys on a systematic basis,

Sec.
141.22 Turbidity sampling and analytical requirements.
141.23 Inorganic chemical sampling and analytical requirements.
141.24 Organic chemical sampling and analytical requirements.
141.27 Alternative analytical techniques.
141.28 Approved laboratories.
141.29 Monitoring of consecutive public water systems.

Subpart D—Reporting, Public Notification, and Record-keeping

141.31 Reporting requirements.
141.32 Public notification of variances, exemptions, and non-compliance with regulations.
141.33 Record maintenance.

AUTHORITY: Secs. 1412, 1414, 1445, and 1450 of the Public Health Service Act, 88 Stat. 1660 (42 U.S.C. 300g-1, 300g-3, 300j-4, and 300j-9).

Subpart A—General

§ 141.1 Applicability.

This part establishes primary drinking water regulations pursuant to section 1412 of the Public Health Service Act, as amended by the Safe Drinking Water Act (Pub. L. 93-523); and related regulations applicable to public water systems.

§ 141.2 Definitions.

As used in this part, the term:

(a) "Act" means the Public Health Service Act, as amended by the Safe Drinking Water Act, Pub. L. 93-523.

(b) "Contaminant" means any physical, chemical, biological, or radiological substance or matter in water.

(c) "Maximum contaminant level" means the maximum permissible level of a contaminant in water which is delivered to the free flowing outlet of the ultimate user of a public water system, except in the case of turbidity where the maximum permissible level is measured at the point of entry to the distribution system. Contaminants added to the water under circumstances controlled by the user, except those resulting from corrosion of piping and plumbing caused by water quality, are excluded from this definition.

(d) "Person" means an individual, corporation, company, association, partnership, State, municipality, or Federal agency.

(e) "Public water system" means a system for the provision to the public of piped water for human consumption, if such system has at least fifteen service connections or regularly serves an average of at least twenty-five individuals daily at least 60 days out of the year. Such term includes (1) any collection, treatment, storage, and distribution facilities under control of the operator of such system and used primarily in connection with such system, and (2) any collection or pretreatment storage facilities not under such control which are used primarily in connection with such system. A public water system is either a "community water system" or a "non-community water system."

(f) "Community water system" means a public water system which serves at least 15 service connections used by year-round residents or regularly serves at least 25 year-round residents.

(g) "Non-community water system" means a public water system that is not a community water system.

(h) "Sanitary survey" means an on-site review of the water source, facilities, equipment, operation and maintenance of a public water system for the purpose of evaluating the adequacy of such source, facilities, equipment, operation and maintenance for producing and distributing safe drinking water.

(i) "Standard sample" means the aliquot of finished drinking water that is examined for the presence of coliform bacteria.

(j) "State" means the agency of the State government which has jurisdiction over public water systems. During any period when a State does not have primary enforcement responsibility pursuant to Section 1413 of the Act, the term "State" means the Regional Administrator, U.S. Environmental Protection Agency.

(k) "Supplier of water" means any person who owns or operates a public water system.

§ 141.3 Coverage.

This part shall apply to each public water system, unless the public water system meets all of the following conditions:

(a) Consists only of distribution and storage facilities (and does not have any collection and treatment facilities);

(b) Obtains all of its water from, but is not owned or operated by, a public water system to which such regulations apply;

(c) Does not sell water to any person; and

(d) Is not a carrier which conveys passengers in interstate commerce.

§ 141.4 Variances and exemptions.

Variances or exemptions from certain provisions of these regulations may be granted pursuant to Sections 1415 and 1416 of the Act by the entity with primary enforcement responsibility. Provisions under Part 142, *National Interim Primary Drinking Water Regulations Implementation*—subpart E (Variances) and subpart F (Exemptions)—apply where EPA has primary enforcement responsibility.

§ 141.5 Siting requirements.

Before a person may enter into a financial commitment for or initiate construction of a new public water system or increase the capacity of an existing public water system, he shall notify the State and, to the extent practicable, avoid locating part or all of the new or expanded facility at a site which:

(a) Is subject to a significant risk from earthquakes, floods, fires or other disasters which could cause a breakdown of the public water system or a portion thereof; or

(b) Except for intake structures, is within the floodplain of a 100-year flood or is lower than any recorded high tide where appropriate records exist.

The U.S. Environmental Protection Agency will not seek to override land use decisions affecting public water systems siting which are made at the State or local government levels.

§ 141.6 Effective date.

The regulations set forth in this part shall take effect 18 months after the date of promulgation.

Subpart B—Maximum Contaminant Levels

§ 141.11 Maximum contaminant levels for inorganic chemicals.

(a) The maximum contaminant level for nitrate is applicable to both community water systems and non-community water systems. The levels for the other inorganic chemicals apply only to community water systems. Compliance with maximum contaminant levels for inorganic chemicals is calculated pursuant to § 141.23.

(b) The following are the maximum contaminant levels for inorganic chemicals other than fluoride:

Contaminant	*Level, milligrams per liter*
Arsenic	0.05
Barium	1.
Cadmium	0.010
Chromium	0.05
Lead	0.05
Mercury	0.002
Nitrate (as N)	10.
Selenium	0.01
Silver	0.05

(c) When the annual average of the maximum daily air temperatures for the location in which the community water system is situated is the following, the maximum contaminant levels for fluoride are:

Temperature Degrees Fahrenheit	Degrees Celsius	Level, milligrams per liter
53.7 and below	12.0 and below	2.4
53.8 to 58.3	12.1 to 14.6	2.2
58.4 to 63.8	14.7 to 17.6	2.0
63.9 to 70.6	17.7 to 21.4	1.8
70.7 to 79.2	21.5 to 26.2	1.6
79.3 to 90.5	26.3 to 32.5	1.4

§ 141.12 Maximum contaminant levels for organic chemicals.

The following are the maximum contaminant levels for organic chemicals. They apply only to community water systems. Compliance with maximum contaminant levels for organic chemicals is calculated pursuant to § 141.24.

	Level, milligrams per liter
(a) Chlorinated hydrocarbons:	
Endrin (1,2,3,4,10, 10-hexachloro-6,7-epoxy-1,4, 4a,5,6,7,8,8a-octahydro-1,4-endo, endo-5,8 - dimethano naphthalene).	0.0002
Lindane (1,2,3,4,5,6-hexachlorocyclohexane, gamma isomer).	0.004
Methoxychlor (1,1,1-Trichloro-2, 2 - bis [p-methoxyphenyl] ethane).	0.1
Toxaphene ($C_{10}H_{10}Cl_8$-Technical chlorinated camphene, 67-69 percent chlorine).	0.005

(b) Chlorophenoxys:	
2,4-D, (2,4-Dichlorophenoxyacetic acid)	0.1
2,4,5-TP Silvex (2,4,5-Trichlorophenoxypropionic acid)	0.01

§ 141.13 Maximum contaminant levels for turbidity.

The maximum contaminant levels for turbidity are applicable to both community water systems and non-community water systems using surface water sources in whole or in part. The maximum contaminant levels for turbidity in drinking water, measured at a representative entry point(s) to the distribution system, are:

(a) One turbidity unit (TU), as determined by a monthly average pursuant to § 141.22, except that five or fewer turbidity units may be allowed if the supplier of water can demonstrate to the State that the higher turbidity does not do any of the following:

(1) Interfere with disinfection;

(2) Prevent maintenance of an effective disinfectant agent throughout the distribution system; or

(3) Interfere with microbiological determinations.

(b) Five turbidity units based on an average for two consecutive days pursuant to § 141.22.

§ 141.14 Maximum microbiological contaminant levels.

The maximum contaminant levels for coliform bacteria, applicable to community water systems and non-community water systems, are as follows:

(a) When the membrane filter technique pursuant to § 141.21(a) is used, the number of coliform bacteria shall not exceed any of the following:

(1) One per 100 milliliters as the arithmetic mean of all samples examined per month pursuant to § 141.21 (b) or (c);

(2) Four per 100 milliliters in more than one sample when less than 20 are examined per month; or

(3) Four per 100 milliliters in more than five percent of the samples when 20 or more are examined per month.

(b) (1) When the fermentation tube method and 10 milliliter standard portions pursuant to § 141.21(a) are used, coliform bacteria shall not be present in any of the following:

(i) more than 10 percent of the portions in any month pursuant to § 141.21 (b) or (c);

(ii) three or more portions in more than one sample when less than 20 samples are examined per month; or

(iii) three or more portions in more than five percent of the samples when 20 or more samples are examined per month.

(2) When the fermentation tube method and 100 milliliter standard portions pursuant to § 141.21(a) are used, coliform bacteria shall not be present in any of the following:

(i) more than 60 percent of the portions in any month pursuant to § 141.21 (b) or (c);

(ii) five portions in more than one sample when less than five samples are examined per month; or

(iii) five portions in more than 20 percent of the samples when five or more samples are examined per month.

(c) For community or non-community systems that are required to sample at a rate of less than 4 per month, compliance with paragraphs (a), (b)(1), or (b)(2) of this section shall be based upon sampling during a 3 month period, except that, at the discretion of the State, compliance may be based upon sampling during a one-month period.

Subpart C—Monitoring and Analytical Requirements

§ 141.21 Microbiological contaminant sampling and analytical requirements.

(a) Suppliers of water for community water systems and non-community water systems shall analyze for coliform bacteria for the purpose of determining compliance with § 141.14. Analyses shall be conducted in accordance with the analytical recommendations set forth in "Standard Methods for the Examination of Water and Wastewater," American Public Health Association, 13th Edition, pp. 662–688, except that a standard sample size shall be employed. The standard sample used in the membrane filter procedure shall be 100 milliliters. The standard sample used in the 5 tube most probable number (MPN) procedure (fermentation tube method) shall be 5 times the standard portion. The standard portion is either 10 milliliters or 100 milliliters as described in § 141.14 (b) and (c). The samples shall be taken at points which are representative of the conditions within the distribution system.

(b) The supplier of water for a community water system shall take coliform density samples, at regular time intervals, and in number proportionate to the population served by the system. In no event shall the frequency be less than as set forth below:

Population served:	*Minimum number of samples per month*
25 to 1,000	1
1,001 to 2,500	2
2,501 to 3,300	3
3,301 to 4,100	4
4,101 to 4,900	5
4,901 to 5,800	6
5,801 to 6,700	7
6,701 to 7,600	8
7,601 to 8,500	9
8,501 to 9,400	10
9,401 to 10,300	11
10,301 to 11,100	12
11,101 to 12,000	13
12,001 to 12,900	14
12,901 to 13,700	15
13,701 to 14,600	16
14,601 to 15,500	17
15,501 to 16,300	18
16,301 to 17,200	19
17,201 to 18,100	20
18,101 to 18,900	21
18,901 to 19,800	22
19,801 to 20,700	23
20,701 to 21,500	24
21,501 to 22,300	25
22,301 to 23,200	26
23,201 to 24,000	27
24,001 to 24,900	28
24,901 to 25,000	29
25,001 to 28,000	30
28,501 to 33,000	35
33,001 to 37,000	40
37,001 to 41,000	45
41,001 to 46,000	50
46,001 to 50,000	55
50,001 to 54,000	60
54,001 to 59,000	65
59,001 to 64,000	70
64,001 to 70,000	75
70,001 to 76,000	80
76,001 to 83,000	85
83,001 to 90,000	90
90,001 to 96,000	95
96,001 to 111,000	100
111,001 to 130,000	110
130,001 to 160,000	120
160,001 to 190,000	130
190,001 to 220,000	140
220,001 to 250,000	150
250,001 to 290,000	160
290,001 to 320,000	170
320,001 to 360,000	180
360,001 to 410,000	190
410,001 to 450,000	200
450,001 to 500,000	210
500,001 to 550,000	220
550,001 to 600,000	230
600,001 to 660,000	240
660,001 to 720,000	250
720,001 to 780,000	260
780,001 to 840,000	270
840,001 to 910,000	280
910,001 to 970,000	290
970,001 to 1,050,000	300
1,050,001 to 1,140,000	310
1,140,001 to 1,230,000	320
1,230,001 to 1,320,000	330
1,320,001 to 1,420,000	340
1,420,001 to 1,520,000	350
1,520,001 to 1,630,000	360
1,630,001 to 1,730,000	370
1,730,001 to 1,850,000	380
1,850,001 to 1,970,000	390
1,970,001 to 2,060,000	400
2,060,001 to 2,270,000	410
2,270,001 to 2,510,000	420
2,510,001 to 2,750,000	430
2,750,001 to 3,020,000	440
3,020,001 to 3,320,000	450
3,320,001 to 3,620,000	460
3,620,001 to 3,960,000	470
3,960,001 to 4,310,000	480
4,310,001 to 4,690,000	490
4,690,001 or more	500

Based on a history of no coliform bacterial contamination and on a sanitary survey by the State showing the water system to be supplied solely by a protected ground water source and free of sanitary defects, a community water system serving 25 to 1,000 persons, with written permission from the State, may reduce this sampling frequency except that in no case shall it be reduced to less than one per quarter.

(c) The supplier of water for a non-community water system shall sample for coliform bacteria in each calendar quarter during which the system provides water to the public. Such sampling shall begin within two years after the effective date of this part. If the State, on the basis of a sanitary survey, determines that some other frequency is more appropriate, that frequency shall be the frequency required under these regulations. Such frequency shall be confirmed or changed on the basis of subsequent surveys.

(d) (1) When the coliform bacteria in a single sample exceed four per 100 milliliters (§ 141.14(a)), at least two consecutive daily check samples shall be collected and examined from the same sampling point. Additional check samples shall be collected daily, or at a frequency estab-

mental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(2) Barium—Atomic Absorption Method, "Standard Methods for the Examination of Water and Wastewater," 13th Edition, pp. 210–215, or "Methods for Chemical Analysis of Water and Wastes," pp. 97–98, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(3) Cadmium—Atomic Absorption Method, "Standard Methods for the Examination of Water and Wastewater," 13th Edition, pp. 210–215, or "Methods for Chemical Analysis of Water and Wastes," pp. 101–103, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(4) Chromium—Atomic Absorption Method, "Standard Methods for the Examination of Water and Wastewater," 13th Edition, pp. 210–215, or "Methods for Chemical Analysis of Water and Wastes," pp. 105–106, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(5) Lead—Atomic Absorption Method, "Standard Methods for the Examination of Water and Wastewater," 13th Edition, pp. 210–215, or "Methods for Chemical Analysis of Water and Wastes," pp. 112–113, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(6) Mercury—Flameless Atomic Absorption Method, "Methods for Chemical Analysis of Water and Wastes," pp. 118–126, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(7) Nitrate—Brucine Colorimetric Method, "Standard Methods for the Examination of Water and Wastewater," 13th Edition, pp. 461–464, or Cadmium Reduction Method, "Methods for Chemical Analysis of Water and Wastes," pp. 201–206, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(8) Selenium—Atomic Absorption Method, "Methods for Chemical Analysis of Water and Wastes," p. 115, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(9) Silver—Atomic Absorption Method, "Standard Methods for the Examination of Water and Wastewater", 13th Edition, pp. 210–215, or "Methods for Chemical Analysis of Water and Wastes", p. 146, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

(10) Fluoride—Electrode Method, "Standard Methods for the Examination of Water and Wastewater", 13th Edition, pp. 172–174, or "Methods for Chemical Analysis of Water and Wastes," pp. 65–67, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974, or Colorimetric Method with Preliminary Distillation, "Standard Methods for the Examination of Water and Wastewater," 13th Edition, pp. 171–172 and 174–176, or "Methods for Chemical Analysis of Water and Wastes," pp. 59–60, Environmental Protection Agency, Office of Technology Transfer, Washington, D.C. 20460, 1974.

§ 141.24 Organic chemical sampling and analytical requirements.

(a) An analysis of substances for the purpose of determining compliance with § 141.12 shall be made as follows:

(1) For all community water systems utilizing surface water sources, analyses shall be completed within one year following the effective date of this part. Samples analyzed shall be collected during the period of the year designated by the State as the period when contamination by pesticides is most likely to occur. These analyses shall be repeated at intervals specified by the State but in no event less frequently than at three year intervals.

(2) For community water systems utilizing only ground water sources, analyses shall be completed by those systems specified by the State.

(b) If the result of an analysis made pursuant to paragraph (a) of this section indicates that the level of any contaminant listed in § 141.12 exceeds the maximum contaminant level, the supplier of water shall report to the State within 7 days and initiate three additional analyses within one month.

(c) When the average of four analyses made pursuant to paragraph (b) of this section, rounded to the same number of significant figures as the maximum contaminant level for the substance in question, exceeds the maximum contaminant level, the supplier of water shall report to the State pursuant to § 141.31 and give notice to the public pursuant to § 141.32. Monitoring after public notification shall be at a frequency designated by the State and shall continue until the maximum contaminant level has not been exceeded in two successive samples or until a monitoring schedule as a condition to a variance, exemption or enforcement action shall become effective.

(d) For the initial analysis required by paragraph (a) (1) and (2) of this section, data for surface water acquired within one year prior to the effective date of this part and data for ground water acquired within three years prior to the effective date of this part may be substituted at the discretion of the State.

(e) Analyses made to determine compliance with § 141.12(a) shall be made in accordance with "Method for Organochlorine Pesticides in Industrial Effluents," MDQARL, Environmental Protection Agency, Cincinnati, Ohio, November 28, 1973.

(f) Analyses made to determine compliance with § 141.12(b) shall be conducted in accordance with "Methods for Chlorinated Phenoxy Acid Herbicides in Industrial Effluents," MDQARL, Environmental Protection Agency, Cincinnati, Ohio, November 28, 1973.

§ 141.27 Alternative analytical techniques.

With the written permission of the State, concurred in by the Administrator of the U.S. Environmental Protection Agency, an alternative analytical technique may be employed. An alternative technique shall be acceptable only if it is substantially equivalent to the prescribed test in both precision and accuracy as it relates to the determination of compliance with any maximum contaminant level. The use of the alternative analytical technique shall not decrease the frequency of monitoring required by this part.

§ 141.28 Approved laboratories.

For the purpose of determining compliance with § 141.21 through § 141.27, samples may be considered only if they have been analyzed by a laboratory approved by the State except that measurements for turbidity and free chlorine residual may be performed by any person acceptable to the State.

§ 141.29 Monitoring of consecutive public water systems.

When a public water system supplies water to one or more other public water systems, the State may modify the monitoring requirements imposed by this part to the extent that the interconnection of the sysems justifies treating them as a single system for monitoring purposes. Any modified monitoring shall be conducted pursuant to a schedule specified by the State and concurred in by the Administrator of the U.S. Environmental Protection Agency.

Subpart D—Reporting, Public Notification and Record Keeping

§ 141.31 Reporting requirements.

(a) Except where a shorter reporting period is specified in this part, the supplier of water shall report to the State within 40 days following a test, measurement or analysis required to be made by this part, the results of that test, measurement or analysis.

(b) The supplier of water shall report to the State within 48 hours the failure to comply with any primary drinking water regulation (including failure to comply with monitoring requirements) set forth in this part.

(c) The supplier of water is not required to report analytical results to the State in cases where a State laboratory performs the analysis and reports the results to the State office which would normally receive such notification from the supplier.

§ 141.32 Public notification.

(a) If a community water system fails to comply with an applicable maximum contaminant level established in Subpart B, fails to comply with an applicable testing procedure established in Subpart C of this part, is granted a variance or an exemption from an applicable maximum contaminant level, fails to comply with the requirements of any schedule prescribed pursuant to a variance or exemption, or fails to perform any monitoring required pursuant to Section 1445 (a) of the Act, the supplier of water shall notify persons served by the system of the failure or grant by inclusion of a notice in the first set of water bills of the system issued after the failure or grant

veys and the NAS study. CCE was initially used as a means of taste and odor control. As concern over adverse health effects of organic chemicals grew, CCE was turned to as a rough surrogate for organics to be used as a health-based standard rather than as an esthetic standard. Unfortunately, as more is learned about organic chemical pollution of drinking water, CCE looks less and less effective as a surrogate for harmful organics.

The principal difficulty with CCE is that it includes only about one-tenth of the total organic content of the volume of water sampled and it does not measure organic compounds of greatest concern, such as the volatile halomethanes. Thus, a high CCE test result does not necessarily mean that the water tested may pose a hazard to health, and a low CCE test result may be obtained from water with a high level of potentially harmful organic compounds. In short, there is no sound basis of correlation between CCE test results and the level of harmful organic chemicals in the water tested.

To establish a maximum contaminant level under these circumstances would almost certainly do more harm than good. It could give a false sense of security to persons served by systems which are within the established level and a false sense of alarm to persons served by systems which exceed the level. It also would divert resources and attention from efforts to find more effective ways of dealing with the organic chemical problem.

Total organic carbon (TOC) and chemical oxygen demand (COD) are surrogates that have been considered, but they have limitations also. TOC has the advantage of being quicker and cheaper (on a per sample basis) than CCE, but the availability of sensitive instruments for this measurement is questionable. More investigation of the significance of any TOC number as a health effects limit is also needed. COD is easily determined with readily available laboratory equipment, but COD is not limited to organic compounds, and besides a COD number also cannot be adequately related to health significance at this time.

EPA is diverting substantial resources to research into the health effects of specific organic chemicals and groups of organic chemicals. Also, it is expected that the study of the National Academy of Sciences will produce further data on health effects. However, in view of the significance of the potential health problem, it is not enough to wait for this additional health effects data. EPA therefore will undertake to identify one or more surrogate tests for organic chemicals or organic chemical groups, and will also study in depth the presence of specific organic chemicals in drinking water supplies. It is anticipated that this effort will result in the development of an additional MCL or MCL's for organic chemicals by amendment of the Interim Primary Drinking Water Regulations without having to wait for a more complete resolution of the organic chemicals question in the Revised Regulations.

Accordingly, EPA is adopting regulations on organic chemical monitoring, using the authority of Sections 1445 and 1450 of the Act. The regulations require that over 100 selected public water systems serving substantial populations collect samples of raw and treated water for submission to EPA for organics analysis. EPA will analyze the samples for a number of general organic parameters, including CCE, TOC (volatile and non-volatile), NVOC, Total Organic Chlorine (TOCl), ultraviolet absorbancy, and fluorescence. In addition, the water will be analyzed for 21 specific organic compounds. These laboratory analyses will be used to evaluate the extent and nature of organic chemical contamination of drinking water, to evaluate the validity of the general organic parameters as surrogates for measures of harmful organic chemicals, and to determine whether there is an adequate basis for establishing maximum contaminant levels for specific organics or groups of organics.

In addition, EPA is embarking on an intensive research program to find more definitive answers to the following four questions:

1. What are the effects of commonly occurring organic compounds on human health?

2. What analytical procedures should be used to monitor finished drinking water to assure that any primary drinking water regulations dealing with organics are met?

3. Because some of these organic compounds are formed during water treatment, what changes in treatment practices are required to minimize the formation of the compounds in treated water?

4. What treatment technology must be applied to reduce contaminant levels to the concentrations that may be specified in the regulations?

This research will involve health-effects and epidemiological studies, investigations of analytical methodology, and pilot plant and field studies of organic removal unit processes. Some phases of the research are to be completed by this fall, while much of the remainder is to be completed within the next calendar year.

As soon as sufficient information is derived from the monitoring program and related research, primary drinking water regulations will be amended so that the organic chemical problem can be dealt with without delay. The monitoring program will be completed within one year.

During the interim period while satisfactory MCL's for organic contamination in drinking water are being developed, EPA will act in specific cases where appropriate to deal with organic contamination. If the EPA monitoring program reveals serious specific cases of contamination, EPA will work with State and local authorities to identify the source and nature of the problem and to take remedial action. EPA will also aid the States in identifying additional community water supplies that require analysis.

2. Pesticides. Proposed § 141.13 contained MCL's for several organic pesticides. Most of the comments on § 141.13 (out of a total of 100) requested that the MCL's for pesticides either be raised or deleted entirely. There were two requests for inclusion of limits for 2,4,5-T, one request for an organophosphate insecticide limit, one for a limit on dioxin, and requests for limits for aldrin, dieldrin, DDT and chlorine (sic.) Other comments suggested that pesticide limits be restricted to emergencies or spills, or at least only to surface water during periods of pesticide use. There were also requests for research on carcinogenic risk and bioamplification.

These proposed pesticides levels were carefully considered by the Advisory Committee and have been reviewed in light of available data on the health effects of these pesticides and their incidence in drinking water supplies. The levels established are adequately supported by the authorities cited in the Statement of Basis and Purpose.

A limit for 2,4,5-T was tentatively proposed by the Advisory Committee but was deleted from the Committee's final report in 1973 on the grounds that EPA's ban on the use of 2,4,5-T for aquatic uses made a drinking water limit unnecessary. That ban has now been in effect for about five years, and it is highly unlikely that this herbicide exists in drinking water except perhaps in extremely rare cases in trace amounts. EPA is now investigating reports of 2,4,5-T in some waterways in Northern Louisiana, and will reconsider the desirability of an MCL for 2,4,5-T if new data indicate that the pesticide is appearing in drinking water supplies at a significant rate. Dioxin is a minor contaminant of 2,4,5-T, and the same basic considerations apply to it.

The desirability of an MCL for organophosphorus insecticides, which was recommended in 1973 by the Advisory Committee, was carefully considered by EPA. It was decided not to adopt such a level, because although these pesticides would pose a serious health risk if they were present at the consumer's tap, the fact is that there is no evidence that such pesticides reach the consumer's tap. This was discussed in the preamble to the proposed primary drinking water standards, at 40 FR 11992. As noted there, these pesticides reach water sources usually only by accident or indirectly, and their tendency to degrade rapidly apparently has prevented problems which might occur when they do reach drinking water sources. The principal threat from these pesticides is from accidental spills in water sources. The appropriate way to deal with such spills is by emergency action when they occur, not by periodic monitoring which would not catch the problem in time.

With respect to aldrin, dieldrin and DDT, EPA's national survey of the presence of these pesticides in drinking water supplies has not been completed. If the results of that survey indicate that those pesticides are present in a significant number of water supplies, an appropriate amendment of the Interim Primary Drinking Water Regulations will be proposed.

The proposed MCL's for chlordane, heptachlor, and heptachlor epoxide have been deleted because EPA is currently involved in suspension and cancellation hearings for these pesticides. MCL's will be reconsidered at a later date.

Current research on pesticides, including both surveys of their incidence in water supplies and their health effects, will be continued and expanded.

3. Monitoring Requirements. There were over 250 comments on § 141.24, dealing with monitoring for compliance with the MCL's for CCE and pesticides. However, most of these comments were more related to the merits of the MCL's than to the monitoring requirements. The CCE limit has been discussed above, and that discussion will not be repeated here.

A number of comments on § 141.24 suggested that monitoring requirements for pesticides be eliminated, or at least that the responsibility for such monitoring be assumed by EPA or the States rather than by public water system. Concern was expressed over the cost of monitoring for pesticides, and the absence of pesticides in public water systems in some areas.

EPA agrees that regular monitoring for pesticides is not needed for all public water systems using only ground water sources. Pesticides are rarely found in significant levels in ground water. Accordingly, the proposed § 141.24 has been amended to provide that for a system using only ground water, monitoring shall be required only when specified by the entity with primary enforcement responsibility. This will more reasonably limit monitoring for pesticides in systems using only ground water to those instances when the State or EPA has reason to suspect the possibility of contamination.

In the case of surface waters, the greater incidence of these pesticides requires monitoring across-the-board. For all community water systems using surface water sources for all or part of their water, monitoring for pesticides will be required within one year of the effective date of the regulations. This monitoring shall be repeated at intervals specified by the State and in no event less frequently than at three year intervals.

Section 1424 has also been amended to require that samples to be analyzed for pesticides must be collected during a period of the year designated by the entity with pri-

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HERBICIDE

FOR THE CONTROL OF TREES, BRUSH AND BROADLEAF WEEDS

Low-Volatile Brush and Weed Herbicide for
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ACTIVE INGREDIENT:	
2,4,5-Trichlorophenoxyacetic Acid, Propylene Glycol Butyl Ether Esters	69.2%
2,4,5-Trichlorophenoxyacetic Acid Equivalent — 4 Pounds per Gallon	45.0%
INERT INGREDIENTS:	30.8%

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Do Not Ship or Store with Food, Feeds, or Clothing

PRECAUCION AL USUARIO: Si usted no leo ingles, no use este producto hasta que la etiqueta le haya sido explicada ampliamente

TRANSLATION: (TO THE USER: If you cannot read English, do not use this product until the label has been fully explained to you.)

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KEEP OUT OF REACH OF CHILDREN
MAY BE HARMFUL IF SWALLOWED • MAY CAUSE IRRITATION
Avoid Contact with Eyes, Skin and Clothing

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Contains Propylene Glycol Butyl Ether Esters of 2,4,5-T • Acid Equivalent: 4 Pounds per Gallon

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ESTERON 245 herbicide is recommended for industrial vegetation control in forest areas; on right-of-ways, such as communication lines, electrical powerlines, pipelines, highways, and railroads; fence rows; and on rangelands and pastures. This herbicide controls herbaceous and woody plants including such 2,4-D resistant species as—ash, black gum, brambles, groundcherry, hawthorn, horsenettle, maple, mesquite, oak, osageorange, palmetto, poison ivy, prickly pear cactus, redbay, salmonberry, sweetgum, wild blackberry, wild rose, and certain species of Ribes. **Do not apply ESTERON 245 where spray drift may contact nearby 2,4,5-T susceptible crops or other desirable plants or may contaminate water intended for irrigation or domestic purposes. Read and follow all Use Precautions given on this label.**

PREPARING THE SPRAY

Use only diesel oil, No. 1 or No. 2 fuel oil or kerosene where oil is recommended in the spray mixture.

Oil Sprays: Add ESTERON 245 to the required amount of oil in the spray tank or mixing tank and mix thoroughly. This mixture can be made at any time before actual use and no separation will occur. Do not let any water, or oil-water mixture sprays get into the ESTERON 245 or into the finished mixture, as it may form a gel.

Water Sprays: Fill the spray tank about half full with clean water, add the required amount of ESTERON 245 and complete filling the tank. Mix thoroughly and continue agitation while spraying. **Caution: See NOTE in paragraph on Oil-Water Mixture Sprays.**

Oil-Water Mixture Sprays: When vigorous agitation is used, 1 gallon of ESTERON 245 will emulsify up to 10 gallons of oil in 100 gallons of spray mixture. First, premix the ESTERON 245 and oil in a separate container. Do not allow any water or mixtures containing water to get into the ESTERON 245 or the premix. Fill the spray tank about half full with water, then slowly add the premix with continuous agitation and complete filling the tank with water. In the premix is put in the tank without any water, the first water added may form a thick "invert" (water in oil) emulsion which will be hard to break. As an alternate procedure, the oil may be added after the ESTERON 245 is mixed in the water, but highly vigorous mechanical agitation is required and a poor emulsion may be formed. The premix method is preferred.

NOTE: ESTERON 245 in water or oil-water sprays forms an emulsion, not a solution, and separation may take place unless sprays are agitated continuously. Mechanical agitation is recommended.

INDUSTRIAL BRUSH AND WEED CONTROL INCLUDING FORESTRY USES

HIGH VOLUME SPRAYS

Foliage Treatment: For control of woody vegetation up to 8 feet tall, apply when foliage is well developed and plants are actively growing. Spraying during prolonged hot, dry weather or after leaves have lost their normal green color and vigor may not give satisfactory control. Use 3 to 4 quarts of ESTERON 245 in 100 gallons of water and apply as a full coverage spray. Usually 100 to 200 gallons per acre will be required, although dense stands of brush may require up to 400 gallons per acre. Completely wet all plant parts including leaves, stems and bark. Poison ivy, some brambles and many broadleaf weeds may be controlled using 2 quarts of ESTERON 245 in 100 gallons of water.

To control grasses as well as broadleaf weeds and woody plants on conifer forest planting sites, ESTERON 245 may be used in a tank mixture with DOWPON* grass herbicide. Consult label directions and precautions for DOWPON to determine recommended use of this product.

Basal Bark Treatment: Brush and small trees can be controlled by spraying the basal parts of brush stems and tree trunks to a height of 12 to 15 inches from the ground line. Use a solution of 3 gallons of ESTERON 245 in 100 gallons (1 pint in 4 gallons) of oil. With certain resistant species, 4 gallons of ESTERON 245 in 100 gallons (1 pint in 3 gallons) of oil, is effective. As only the basal portions of the brush are treated on a spot basis, the total amount sprayed per acre would not be expected to exceed 100 gallons. Knapsack or power equipment may be used, but complete wetting of the indicated area is necessary, particularly at the ground line. This means spraying until run-down or run-off to the ground line is noticeable. Old or rough bark is quites more spray than young or smooth bark. Low pressures are desirable. Apply at any time, including the winter months, except when snow, ice or water prevent spraying to the ground line. Often delayed response and killing can be expected.

Dormant Brush: Treat any time after brush is dormant and most of the foliage has dropped. Spray should be concentrated at the base of stems and in addition, the upper parts of the stems should be broadcast sprayed enough to wet them. Under rootsuckering species such as sumac, persimmon, sassafras and locust, also spray the ground area to control small root suckers that may not be readily visible. Mix 1½ gallons of ESTERON 245 in 100 gallons of oil. Brush of average density and 4 to 6 feet high may take up to 150 gallons of spray mixture per acre.

Stump Treatment: Where growth is more than 6 to 8 feet tall, cut it close to the ground and spray the freshly cut stumps and stubs with 3 gallons of ESTERON 245 in 100 gallons (1 pint in 4 gallons) of oil, mixed thoroughly. For more resistant species, use 4 gallons of ESTERON 245 in 100 gallons (1 pint in 3 gallons) of oil. Wet thoroughly all exposed bark, as well as cut surfaces. This means spraying until run-down or run-off to the ground line is noticeable. Old or rough bark requires more spray volume than young or smooth bark. Apply at any time, including the winter months, except when ice, snow or water prevent spraying to the ground line. Best results are obtained on freshly cut stumps two inches across or larger. Adequate coverage normally requires from 10 to 100 gallons per acre depending on density of stumps and stubs.

"Frill" Treatment: For large trees, make a singlehack girdle or "frill" of overlapping axe cuts completely around the tree as close to the ground as feasible. Spray the frill thoroughly using a mixture of 2 gallons of ESTERON 245 in 100 gallons (½ pint in 3 gallons) of oil.

Spot Foliage Treatment: Use ¼ pint of ESTERON 245 in 3 gallons of water and spray to wet all foliage, shoots, stems and bark without runoff.

LOW VOLUME SPRAYS

Apply low volume sprays containing ESTERON 245 when foliage is well developed and plants are actively growing. For best results on woody species, soil moisture should be sufficient to promote foliar growth. Spraying during prolonged hot, dry weather or after leaves have lost their normal green color and vigor may not give satisfactory control. Apply low volume sprays by air or ground equipment only when spray drift will not be a problem—note use precautions.

Right-of-Ways and Forest Site Preparation

Foliage Treatment: Use 1 to 3 gallons of ESTERON 245 in enough water to make 10 to 30 gallons of total spray per acre. If desired, oil can be added to the spray in accordance with directions for "Oil-Water Mixture Sprays" given under **PREPARING THE SPRAY.**

Use With TORDON 101 Mixture: ESTERON 245 may be used with TORDON® 101 Mixture herbicide in a tank mix combination spray applied by aircraft for improved control of root suckering species and other species often not adequately controlled with 2,4,5-T. Use 1 to 2½ gallons of ESTERON 245 Herbicide plus 1½ to 2½ gallons of TORDON 101 Mixture per acre by diluting with water to a total spray volume of 10 to 30 gallons per acre. Use the higher rates where resistant species such as red maple, sourwood, ash, oaks, hawthorn and cedar are prevalent and especially during unfavorable conditions for plant growth such as drought. Do not add oil or NORBAK® particulating agent to the spray. Aerial applications of the tank mixture should be made only with a helicopter mounted Microfoil applicator or an equipment system providing equivalent drift control.

Read the directions and all the Use Precautions on both labels before using this tank mix.

Note: Do not plant conifer seedlings on treated areas for at least 6 months after applying 2 gallons or more of TORDON 101 per acre in such a tank mix.

Basal Treatment Using Powered Knapsack Sprayer—Mix 1½ to 2 gallons of ESTERON 245 with fuel oil or kerosene to make 20 gallons of total spray solution. Apply with a portable knapsack mistblower to all sides of lower brush stems including the root collar. Good coverage at the root collar is essential for best results. Run mistblower at ¼ to ½ throttle for best spray delivery and coverage. For maximum drift control use a basal nozzle attachment and do not raise nozzle above the horizontal position.

Forest Conifer Release by Air or Ground Sprays

Oil Spray—Apply 2 to 3 quarts of ESTERON 245 in about 10 gallons of oil per acre to control undesired hardwoods in dormant Douglas fir, true fir, hemlock and spruce. Rates higher than 2 quarts may cause conifer injury. Do not use this spray on pines (note section below for pine recommendation). Apply **before** conifer bud break during late dormancy, usually February and March in the northwest. Application of this spray after conifer bud break can injure the conifers.

Water Spray—Apply 2 to 3 quarts of ESTERON 245 in 10 to 15 gallons of water per acre to control hardwood species in conifers including pines. Apply during the summer **after** the conifers cease spring growth and have "hardened off." Rates higher than 2 quarts may cause conifer injury.

Consult your State, Regional or Extension Forester for recommendations to fit local conditions.

RANGELAND AND PASTURES

RANGELAND—AIR APPLICATION FOR BRUSH CONTROL

Consult the Agricultural Experiment Station, your local Extension Service Weed or Range specialist for best time to treat and need for re-treatment in your area. Do not use from early boot to milk stage where grass seed production is desired.

Mesquite: Use 1 pint of ESTERON 245 plus ⅓ to 1 gallon of oil in enough water to make 4 gallons of total spray per acre. Apply 40 to 90 days after first leaves appear.

Sand Shinnery Oak: Use ⅓ to 1 quart of ESTERON 245 plus 1 gallon of oil in enough water to make 4 gallons of total spray per acre.

Post and Blackjack Oaks: Use 2 quarts of ESTERON 245 plus 1 gallon of oil in enough water to make 4 to 6 gallons of total spray per acre.

PASTURE—FOR BROADLEAF WEED CONTROL

Use 1 to 3 quarts of ESTERON 245 per acre by aircraft or ground equipment in the amount of water needed to obtain uniform application. Apply when weeds are in full leaf and after grass is well established. Do not apply on staloniferous grasses such as bent and bermuda or on forage legumes because these can be injured or killed. Do not apply on newly seeded areas, and do not use from early boot to milk stage where grass seed production is desired. **Note:** Do not graze dairy animals on treated areas within 6 weeks after application. Do not graze meat animals on treated areas within 2 weeks of slaughter.

USE PRECAUTIONS

AVOID CONTACT WITH 2,4,5-T SUSCEPTIBLE CROPS AND OTHER DESIRABLE BROADLEAF PLANTS—ESTERON 245 Herbicide is injurious to most broadleaf plants. Therefore, do not apply directly to or otherwise permit even minute amounts to contact cotton, grapes, tobacco, fruit trees, vegetables, flowers, ornamentals or other desirable plants susceptible to 2,4,5-T. Do not use in or near a greenhouse.

DO NOT APPLY IN THE VICINITY OF COTTON, GRAPES, TOBACCO, TOMATOES OR OTHER DESIRABLE 2,4,5-T SUSCEPTIBLE CROPS OR ORNAMENTAL PLANTS.

DO NOT SPRAY WHEN WIND IS BLOWING TOWARDS SUSCEPTIBLE CROPS OR ORNAMENTAL PLANTS

AVOID SPRAY DRIFT—Applications should be made only when there is no hazard from spray drift since very small quantities of the spray, which may not be visible, may severely injure susceptible crops during both growing and dormant periods. Use coarse sprays to minimize drift since, under adverse weather conditions, fine spray droplets may drift a mile or more. The spray thickening agent, NALCO-TROL[1], may be used with this product to aid in reducing spray drift. If used follow all use recommendations and precautions on the product label.

[1] NALCO-TROL—Trademark of NALCO Chemical Company

GROUND EQUIPMENT—With ground equipment, spray drift can be lessened by keeping the spray boom as low as possible; by applying 20 gallons or more of spray per acre; by using no more than 20 pounds spraying pressure with large droplet producing nozzle tips; by spraying when wind velocity is 8 miles per hour or less. Do not apply with hollow cone-type insecticide or other nozzles that produce a fine-droplet spray.

AERIAL APPLICATION—With aircraft, drift can be lessened by applying a coarse spray; by using no more than 20 pounds spray pressure at the nozzles, by using straight stream nozzles directed straight back; by using a spray boom no longer than ¾ the wing span of the aircraft; and by spraying only when wind velocity is less than 6 mph.

DO NOT APPLY BY AIRCRAFT WHEN AN AIR TEMPERATURE INVERSION EXISTS. Such a condition is characterized by little or no wind and with air temperature lower near the ground than at higher levels. The use of a continuous smoke column at or near site of application is suggested to indicate direction and velocity of air movement, and to indicate a temperature inversion by layering of the smoke.

At high temperatures (above 95°F) vapors from this product may injure susceptible plants growing nearby. Do not use in or near a greenhouse. Excessive amounts of this herbicide in the soil may temporarily inhibit seed germination or plant growth.

Do not use around the home, recreation areas or similar sites. Do not use on susceptible grasses, such as bent, except for spot spraying, nor on freshly seeded areas until grass has become well established. (Most legumes are usually damaged or killed).

This product is toxic to fish. Keep out of lakes, streams, and ponds. Do not apply where run-off is likely to occur. Do not contaminate water by cleaning of equipment or disposal of wastes.

Do not contaminate irrigation ditches or water used for irrigation or domestic purposes. This product can be stored in an unheated building but if exposed to subfreezing temperatures, should be warmed to at least 40°F and mixed thoroughly before using. Do not store near fertilizers, seeds, insecticides or fungicides. Do not reuse containers. To avoid injury to desirable plants, do not store, handle or apply other agricultural chemicals with the same containers or equipment used with ESTERON 245 except as specified on this label.

Rinse equipment and containers and dispose of waste by burying in non-crop lands away from water supplies. Containers should be disposed by punching holes in them and burying with waste or follow official local recommendations for container disposal.

Local conditions may affect the use of herbicides. Consult your State Agricultural Experiment Station or Extension Service weed specialist for advice in selecting treatments from this label to best fit local conditions. Be sure that use of this product conforms to all applicable regulations. Apply this product only as specified on this label.

NOTICE: Seller warrants that the product conforms to its chemical description and is reasonably fit for the purposes stated on the label when used in accordance with directions under normal conditions of use, but neither this warranty nor any other warranty of MERCHANTABILITY or FITNESS FOR A PARTICULAR PURPOSE express or implied, extends to the use of this product contrary to label instructions, or under abnormal conditions, or under conditions not reasonably foreseeable to seller, and buyer assumes the risk of any such use.

10586-049-5 P676

THE DOW CHEMICAL COMPANY
AND SUBSIDIARIES
MIDLAND, MICHIGAN 48640, USA ZÜRICH, SWITZERLAND HONG KONG, BCC
CORAL GABLES, FLORIDA 33134, USA SARNIA, ONTARIO, CANADA
* Trademark of THE DOW CHEMICAL COMPANY

DOW

SPECIMEN LABEL
REDUCED TO 75%

ESTERON* 99* CONCENTRATE

LOW-VOLATILE HERBICIDE

CONTAINS PROPYLENE GLYCOL BUTYL ETHER ESTERS OF 2,4-D
2,4-D Acid Equivalent: 4 pounds per gallon

For the Control of Many Broadleaf Weeds, Herbaceous Perennials and Woody Plants Susceptible to 2,4-D in Grass Pastures, Certain Crops and Non-Crop Areas.

ACTIVE INGREDIENT:
2,4-Dichlorophenoxyacetic Acid, Propylene Glycol Butyl Ether Esters 72.8%
INERT INGREDIENTS: 27.2%
2,4-D Acid Equivalent 44.9%—4 pounds per gallon
E.P.A. Registration No. 464-201-AA E.P.A. Est. 464-MI-1

AGRICULTURAL CHEMICAL

Do Not Ship or Store with Food, Feeds, or Clothing

PRECAUCION AL USUARIO: Si usted no lee inglés, no use este producto hasta que la etiqueta le haya sido explicada ampliamente.

TRANSLATION: (TO THE USER: If you cannot read English, do not use this product until the label has been fully explained to you.)

CAUTION

KEEP OUT OF REACH OF CHILDREN
HARMFUL IF SWALLOWED
MAY CAUSE IRRITATION
Avoid Contact with Eyes, Skin and Clothing

18.9 L / 5 GAL

86-1062 PRINTED IN U.S.A. IN APRIL, 1976.
REPLACES SPECIMEN LABEL 86-1062 PRINTED MARCH, 1976.
DISCARD PREVIOUS SPECIMEN LABELS.
REVISIONS INCLUDE: (1) CONTROL OF WILD GARLIC IN STUBBLE GRAIN FIELDS ADDED
(2) FOREST CONIFER RELEASE ADDED
(3) RESTRICTION ON USING CORN FODDER ADDED TO WEED CONTROL IN CORN.

ESTERON® 99® CONCENTRATE

SPECIMEN LABEL
(BACK)
REDUCED TO 75%

WEED LIST

ESTERON 99 Concentrate herbicide is recommended for control of numerous broadleaf weeds and certain 2,4-D susceptible woody plants without injury to most established grasses. Species controlled include the following, plus many others:

beggarticks • bitterweed • blueweed, Texas • broomweed • buckbrush • buckwheat, wild buckwheat, wild • burdock • burhead • carpetweed • catnip • chamisa • chicory • cocklebur • coffeeweed cornflower • coyotebrush • croton • dandelion • docks • dogfennel • elderberry • fanweed galinsoga • garlic, wild • goatsbeard • halogeton • hemp, wild • jewelweed • jimsonweed lambsquarter • loco, bigbend • mallow, Venice • manzanita • marsheider • milkvetch morningglory, annual • mustards • nettles • onion, wild • pennycress • pepperweed, field pigweed • plantains • poorjoe • rabbitbrush • radish, wild • ragweed • rape, wild • redstem sage, coastal • sagebrush, big • sagebrush, sand • salsify • sand shinnery oak • shepherdspurse • sicklepod • smartweed • sneezeweed, bitter • sowthistle, annual • spanishneedles • sumac • sunflower • sweetclover • tansymustard • tansyragwort • thistle, bull thistle, musk • thistle, Russian • tumbleweed • velvetleaf • vervains • vetch • water plantain willow • witchweed • wormwood • yellow rocket • yellow starthistle

USE DIRECTIONS

Apply ESTERON 99 Concentrate as water or oil spray during warm weather when weeds or brush are actively growing. Application under drought conditions often will give poor results. Use low spray pressure to minimize drift. On cropland and along roadsides, do not exceed 20 psi pressure. Apply enough spray volume to provide uniform coverage of weeds and brush, usually 5 to 20 gallons per acre by ground equipment and 3 to 5 gallons by aircraft. Higher gallonage may be used if desired to improve spray coverage. Generally, the lower dosages recommended on this label will be satisfactory for young, succulent growth of sensitive weed species. For less sensitive species and under conditions where control is more difficult, the higher dosages will be needed. For crop uses, do not mix with oil or other adjuvants unless specifically recommended on this label. Deep-rooted perennial weeds such as Canada thistle and field bindweed and many woody plants usually require repeated applications for maximum control. **Do not apply ESTERON 99 Concentrate where spray drift may contact nearby susceptible crops or other desirable plants or may contaminate water for irrigation or domestic use. Read and follow all Use Precautions given on this label.**

NOTE: If there are uncertainties concerning special local use situations or specific crop variety tolerances to 2,4-D, consult your State Agricultural Experiment Station or local Extension Service weed specialists for advice.

TO PREPARE THE SPRAY: (1) Fill the spray tank about half full with water, then add the required amount of ESTERON 99 Concentrate, with agitation, and finally the rest of the water. NOTE: ESTERON 99 Concentrate in water forms an emulsion which tends to separate unless the mixture is kept agitated. (2) If oil is added, first mix the ESTERON 99 Concentrate and the oil and then add this mixture to the water. However, with adequate agitation, the oil can be added after the ESTERON 99 Concentrate is mixed in the water. (3) If straight oil is used, a solution is formed and separation does not occur. Do not allow any water to get into the oil-herbicide mixture to avoid formation of an invert emulsion.

USE IN LIQUID NITROGEN FERTILIZER: ESTERON 99 Concentrate may be combined with liquid nitrogen fertilizer suitable for foliar application to accomplish weeding and feeding of corn, small grains or grass pastures in one operation. Use ESTERON 99 Concentrate in accordance with recommendations for these crops as given on this label. Use liquid fertilizer at rates recommended by supplier or Extension Service Specialist. Fill the spray tank about half full with the liquid fertilizer, then add the ESTERON 99 Concentrate with agitation and complete filling the tank with fertilizer. Apply immediately and continue agitation in the spray tank during application. Application during very cold weather (near freezing) is not advisable. Do not store the spray mixture.

WEED CONTROL IN SMALL GRAINS NOT UNDERSEEDED WITH A LEGUME: NOTE: Do not permit dairy animals or meat animals being finished for slaughter to forage or graze treated grain fields within 2 weeks after treatment.

Spring Wheat and Barley: Apply ½ to 1 pint per acre. Spray when grain is in full tiller stage (usually 4 to 8 inches tall) but before the boot stage and when weeds are small. Do not apply before the tiller stage nor from early boot to the dough stage. Higher rates, up to 2 pints per acre, may be needed to handle difficult weed problems in certain areas such as under dry conditions especially in western areas. **However, do not use unless possible crop injury will be acceptable.**

Winter Wheat and Rye: Apply ½ to ¾ pint per acre in the spring at the full tiller stage but before the early boot stage. For improved control of difficult weeds including wild garlic and wild onion, apply 1 to 2 pints per acre. Since these rates may injure the crop, do not use unless possible crop injury will be acceptable. For the high rates on spring wheat and barley as well as winter wheat and rye consult State Agricultural Experiment Station or Extension Service Weed Specialists for recommendations or suggestions to fit local conditions.

Spring Seeded Oats: Apply ½ pint per acre at the full tiller stage but before the early boot stage. Oats are less tolerant to 2,4-D than wheat or barley and are more likely to suffer some injury.

Fall Seeded Oats (Southern) Grown for Grain: Apply ½ to 1¼ pints per acre after full tillering but before the early boot stage. Some difficult weeds may require higher rates for maximum control but crop injury may result. Do not spray during or immediately following cold weather.

Preharvest Treatment: Apply 1 to 2 pints per acre when grains are in the hard dough stage to control large weeds that may interfere with harvest. Best results will be obtained when soil moisture is sufficient to cause succulent weed growth. **NOTE:** Do not feed treated straw to livestock.

WEED CONTROL IN CORN: Use one of the following three programs: **Preemergence:** Apply 1 to 2 quarts per acre to soil anytime after planting but before corn emerges. Do not use on light sandy soil. **Emergence:** Apply 1 pint per acre just as corn plants are breaking ground. **Postemergence:** After emergence of corn, use ½ pint per acre. Application of ¾ to 1 pint per acre may be needed for maximum control of some weeds but such rates are more likely to injure the corn. If corn is over 8 inches tall, use drop nozzles to keep the spray off the corn foliage as much as possible. Do not apply from the tasseling to dough stage. Do not use with oil, atrazine or other adjuvants. Crop injury is more likely to occur if corn is growing rapidly under high temperature and high soil moisture conditions. To reduce breakage of stalks from temporary brittleness caused by 2,4-D, delay cultivation for 8 to 10 days after treatment. Do not forage or feed corn fodder for 7 days following application. **NOTE:** Hybrids vary in response to 2,4-D and some are easily injured. Spray only varieties known to be tolerant to 2,4-D. Contact seed company or your Agricultural Experiment Station or Extension Service weed specialists for this information.

PREHARVEST CORN TREATMENT: After the hard dough or denting stage, apply 1 to 2 pints per acre by air or ground equipment to suppress perennial weeds, decrease weed seed production, and control tall weeds such as bindweed, cocklebur, dogbane, jimsonweed, ragweed, sunflower, velvetleaf and vines that interfere with harvesting. Do not forage or feed corn fodder for 7 days following application.

CONTROL OF WILD GARLIC IN STUBBLE GRAIN FIELDS: Following the harvest of small grain or corn, wild garlic often produces new fall growth. This should be sprayed with 2 to ½ quarts per acre of ESTERON 99 Concentrate. This is a useful practice as one part of a wild garlic control program. Do not forage for 7 days following application.

WEED CONTROL IN SORGHUM (MILO): Apply ½ pint per acre when sorghum is 5 to 15 inches tall. A higher rate of ¾ to 1 pint per acre may be needed to control some weeds but the chance for crop injury is likewise increased. Do not use with oil. Do not treat before the sorghum is 5 inches tall nor during the boot, flowering or early dough stages. If sorghum is taller than 8 inches, use drop nozzles to keep the spray off the foliage as much as possible. Temporary crop injury may occur under conditions of high soil moisture and high air temperatures. Varieties vary in tolerance to 2,4-D and some hybrids are quite sensitive. Spray only varieties known to be tolerant to 2,4-D. Contact seed company or your Agricultural Experiment Station or Extension Service weed specialists for this information.

GRASS SEED CROPS: Use 1 to 1½ pints per acre in the amount of water required for uniform application by air or ground equipment. Apply to established stands in spring from the tiller to early boot stage. Do not spray in boot stage. New spring seedings may be treated with the lower rate after the grasses have at least five leaves. Perennial weed regrowth may be treated in the fall.

WEED AND BRUSH CONTROL IN RANGELAND AND GRASS PASTURES: NOTE: Do not graze dairy animals on treated areas within 7 days after application. Do not use on bent grass, alfalfa, clover, or other legumes. Do not use on newly seeded areas until grass is well established. Do not use from early boot to milk stage where grass seed production is desired.

Bitterweed, Broomweed, Croton, Docks, Kochia, Marsheider, Musk thistle and Other Broadleaf Weeds: Use 2 quarts of ESTERON 99 Concentrate per acre in the amount of water needed for uniform application. If the weeds are young and growing actively, 1 quart per acre will provide control of some species. Deep-rooted perennial weeds may require repeated treatments in the same year or in subsequent years.

Wild Garlic and Wild Onion: Apply 2 to 3 quarts per acre, making three applications (fall-spring-fall or spring-fall-spring) starting in late fall or early spring.

Weed Control in Newly Sprigged Coastal Bermudagrass: Apply 1 to 2 quarts per acre preemergence and/or postemergence.

Sand Shinnery Oak and Sand Sagebrush: On the oak, use 1 quart in 5 gallons of oil or in 4 gallons of water plus 1 gallon of oil per acre. Apply by aircraft between May 15 and June 15. On the sagebrush, use 1 quart in 3 gallons of oil per acre and apply by aircraft when foliage is fully expanded and the brush is actively growing.

Big Sagebrush and Rabbitbrush: Use 2 to 3 quarts per acre in 2 to 3 gallons of oil or in 3 to 5 gallons of oil-water emulsion spray. For rabbitbrush, the 3 quart rate is usually required. Brush should be leafed out and growing actively when treated. Retreatment may be needed.

Chemise, Manzanita, Buckbrush, Coastal Sage, Coyotebrush and Certain Other Chaparral Species: Use 2 to 3 quarts per acre in 5 to 10 gallons of water. One gallon of fuel oil may be included in the spray mixture for added effectiveness. Make applications by aircraft or ground equipment to obtain uniform spray coverage. For effective control, the brush must be fully leafed out and growing actively when sprayed. Retreatment may be needed.

WOODY PLANT CONTROL IN NON-CROP AREAS: To control species susceptible to 2,4-D in rights-of-way, fencerows, roadsides, and along drainage ditchbanks, spray brush up to 6 to 8 feet tall after spring foliage is well developed, using 3 to 4 quarts of ESTERON 99 Concentrate in 100 gallons of water and wetting all parts of the brush including foliage, stems and bark. This may require up to 400 gallons of spray per acre for adequate coverage of solid stand of brush. Make application in such a way as to prevent drift of the spray off the area being treated. Spraying can be effective at any time up to 3 weeks before frost as long as soil moisture is sufficient for active growth of the brush. Control will be less effective in midsummer during hot dry weather when soil moisture is deficient and plants are not actively growing. Oil or wetting agent may be added to the spray, if needed for increased effectiveness.

FOREST CONIFER RELEASE: After northern conifers jack pine, red pine, black spruce, and white spruce cease growth and "harden off" in late summer, a spray of 1½ to 3 quarts of ESTERON 99 Concentrate in 8 to 25 gallons of water per acre may be applied by air to control certain competing hardwood species such as alder, aspen, birch, hazel and willow. Since this treatment may cause occasional conifer injury, do not use if such injury cannot be tolerated. Consult your regional or extension forester or state herbicide specialist for recommendations to fit local conditions.

WEED CONTROL IN NON-CROP AREAS SUCH AS LAWNS, GOLF COURSES, CEMETERIES, PARKS, AIRFIELDS, ROADSIDES, VACANT LOTS, DRAINAGE DITCH BANKS: Apply 1 to 3 quarts of ESTERON 99 Concentrate per acre in the amount of water needed for uniform application. Usually 2 quarts per acre provides good weed control under average conditions. Treat when weeds are young and growing well. Do not use on golf greens nor on dichondra or other broadleaf herbaceous ground covers. Do not use on creeping grasses such as bent and St. Augustine except for spot treating, nor on newly seeded turf until grass is well established.

Reseeding of treated areas should be delayed following treatment. With spring application, reseed in the fall; with fall application, reseed in the spring.

Legumes are usually damaged or killed so do not treat areas where the legumes are desired. Deep-rooted perennial weeds may require repeated treatments in the same season or in subsequent years.

TULE (BULRUSH) AND OTHER RUSHES: Mix 2 quarts of ESTERON 99 Concentrate and 1 gallon of diesel oil or kerosene, then add this mixture to 100 gallons of water. Spray to wet all foliage (400-800 gallons per acre). Addition of a wetting agent may be advisable. Apply in the spring during flower head emergence. Respray if needed when regrowth is 3 to 5 feet tall.

SPOT TREATMENT: To control broadleaf weeds in small non-cropland areas with a hand sprayer, use ¼ pint of ESTERON 99 Concentrate in 3 gallons of water and spray to thoroughly wet all weed foliage. Keep spray mixture agitated to prevent separation.

STORAGE: May be stored in unheated building.

MISCELLANEOUS USES: Low-Bush Blueberries: Contact Agricultural Sales, The Dow Chemical Company, P.O. Box 1706, Midland, Michigan 48640 for use directions.

USE PRECAUTIONS

AVOID CONTACT WITH 2,4-D SUSCEPTIBLE CROPS AND OTHER DESIRABLE BROADLEAF PLANTS: ESTERON 99 Concentrate herbicide is injurious to most broadleaf plants. Therefore, do not apply directly to or otherwise permit even minute amounts to contact cotton, grapes, tobacco, fruit trees, vegetables, flowers, ornamentals or other desirable plants susceptible to 2,4-D. Do not use in or near a greenhouse.

DO NOT APPLY IN THE VICINITY of COTTON, GRAPES, TOBACCO, TOMATOES OR OTHER DESIRABLE 2,4-D SUSCEPTIBLE CROPS or ORNAMENTAL PLANTS.

DO NOT SPRAY WHEN WIND IS BLOWING TOWARDS SUSCEPTIBLE CROPS OR ORNAMENTAL PLANTS.

AVOID SPRAY DRIFT: Applications should be made only when there is no hazard from spray drift since very small quantities of the spray, which may not be visible, may severely injure susceptible crops during both growing and dormant periods. Use coarse sprays to minimize drift since, under adverse weather conditions, fine spray droplets may drift a mile or more. The spray thickening agent, NALCO-TROL[1] may be used with this product to aid in reducing spray drift. If used follow all use recommendations and precautions on the product label.

[1] NALCO-TROL — Trademark of NALCO Chemical Company

GROUND EQUIPMENT: With ground equipment, spray drift can be lessened by keeping the spray boom as low as possible; by applying 20 gallons or more of spray per acre; by using no more than 20 pounds spraying pressure with large droplet producing nozzle tips; by spraying when wind velocity is low; and by stopping all spraying when wind exceeds 6 to 7 miles per hour. Do not apply with hollow cone-type insecticide or other nozzles that produce a fine-droplet spray.

AERIAL APPLICATION: With aircraft, drift can be lessened by applying a coarse spray; by using no more than 20 pounds spray pressure at the nozzles; by using straight stream nozzles directed straight back; by using a spray boom no longer than ¾ the wing span of the aircraft; and by spraying only when wind velocity is less than 6 mph.

DO NOT APPLY BY AIRCRAFT WHEN AN AIR TEMPERATURE INVERSION EXISTS. Such a condition is characterized by little or no wind and with air temperature lower near the ground than at higher levels. The use of a continuous smoke column at or near site of application is suggested to indicate direction and velocity of air movement, and to indicate a temperature inversion by layering of the smoke.

Violent windstorms may move soil particles. If 2,4-D is on soil particles and they are blown onto susceptible plants, visible symptoms may appear. Serious injury is unlikely. The hazard of movement of 2,4-D on dust is reduced if treated fields are irrigated or if rain occurs shortly after application.

At high temperatures (above 95°F) vapors from this product may injure susceptible plants growing nearby. Do not use in a greenhouse. Excessive amounts of this herbicide in the soil may temporarily inhibit seed germination or plant growth.

This product is toxic to fish. Keep out of lakes, streams, or ponds. Do not apply where runoff is likely to occur. Do not contaminate water by cleaning of equipment, or disposal of wastes. Do not contaminate irrigation ditches or water used for irrigation or domestic purposes.

To avoid injury to desirable plants, do not handle or apply other agricultural chemicals with the same equipment used for ESTERON 99 Concentrate except as specified on this label. This product can be stored in an unheated building but do not store near fertilizers, seeds, insecticides or fungicides. Do not reuse containers. Dispose of empty containers by punching holes in them and burying with waste in non-cropland away from water supplies or follow official local recommendations for container disposal.

Local conditions may affect the use of herbicides. Consult your State Agricultural Experiment Station or Extension Service weed specialists for advice in selecting treatments from this label to best fit local conditions. **Be sure that use of this product conforms to all applicable regulations. Apply this product only as specified on this label.**

MONEY BACK GUARANTEE

ESTERON 99 Concentrate herbicide is guaranteed by The Dow Chemical Company to the full extent of the purchase price:

1. **To give satisfactory control of weed and brush species listed on container when used as recommended.**
2. **To form a suitable spray mixture in any water fit for spray use.**
3. **To store satisfactorily at temperatures as low as −40°F.**

NOTICE: Seller warrants that the product conforms to its chemical description and is reasonably fit for the purposes stated on the label when used in accordance with directions under normal conditions of use, but neither this warranty nor any other warranty of MERCHANTABILITY or FITNESS FOR A PARTICULAR PURPOSE, express or implied, extends to the use of this product contrary to label instructions, or under abnormal conditions, or under conditions not reasonably foreseable to seller, and buyer assumes the risk of any such use.

10586-067-4 8476

When to Use: Apply during June and July when weed tops have emerged sufficiently above the blueberry stems to allow treatment of the weeds and not the blueberry plants. Apply only during the year before the first burn. To use this method of weed control, two-year burns should be extended to three years.

Caution: Do not allow the spray being applied to the cloth-covered drum to be directed onto the blueberries. Do not harvest-rake field during the herbicide treatment year or until a two-year interval thereafter.

MISCELLANEOUS: CONTROL OF WOODY WEEDS IN LOW-BUSH BLUEBERRY FIELDS IN MAINE: How to use: Mount a drum 8 to 10 feet long or some other suitable length, and 1½ to 2 feet in diameter on an axle such as an old hay rake frame. Cover the drum with water absorbent yet tough cloth which will resist rapid wear and tear. Draw the cloth-covered drum across the blueberry field and at the same time spray evenly onto the full length of the top of the cloth-covered drum a spray mixture made by diluting 1 quart of ESTERON 99 Concentrate in 50 gallons of water per acre. Have the drum mounted so that as it revolves on its axis it is high enough to miss most of the low bush blueberry stems, yet low enough to forcibly brush the spray-saturated cloth-covered drum against the higher woody weeds, principally sweet fern, wild cherry and poplar. Keep the cloth wet enough to provide top coverage of the weeds, yet not so wet as to allow runoff of the liquid which could cause injury to the blueberry plants.

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THE PHENOXY HERBICIDES

Council for

Agricultural Science and Technology

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FOREWORD

"The Phenoxy Herbicides" was developed to meet the need for an accurate, objective, and authoritative statement of the properties, uses, and effects of this important class of herbicides and the alternatives to their use. The report was prepared by a task force of seventeen scientists representing the states of Maryland, Alabama, Indiana, Wisconsin, Illinois, Missouri, Arkansas, Texas, Arizona, Oregon, and California. Subject-matter areas of the various scientists included agricultural economics, agricultural engineering, agronomy, botany, forestry, horticulture, pesticide chemistry, plant pathology, plant physiology, range science, toxicology, and weed science. The task force met in Denver from November 20 to 22 to prepare a draft of the report. The draft was subsequently revised by the chairman, returned to members of the task force and others for comment, revised again, edited, and reproduced for distribution.

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SUMMARY

The phenoxy herbicides, 2,4-D, 2,4,5-T, MCPA, silvex and related materials, are selective herbicides widely used in crop production and in the management of forests, ranges and industrial, urban and aquatic sites. These chemicals are related to naturally occurring plant growth regulators. They kill plants by causing malfunctions in growth processes. Broad-leaved plants are generally susceptible to the phenoxy herbicides, whereas most grasses, coniferous trees and certain legumes are relatively resistant.

The phenoxy herbicides are used to control broad-leaved weeds in wheat, barley, rice, oats, rye, corn, grain sorghums and certain legumes. Such uses increase yields, improve product quality and reduce production costs. The phenoxy herbicides are used in forests to suppress unwanted hardwood trees and brush, to reduce competition with conifers already established or to prepare sites for the regeneration of conifers. They are used on grazing lands to control unpalatable and noxious plants and to kill brush and small trees that reduce the productivity of pastures and ranges. 2,4-D and other phenoxys are used in canals, ponds, lakes and waterways to kill floating weeds such as water hyacinth, submerged weeds such as pondweeds, and emergent and shoreline plants such as cattails and willows. Industrial and urban uses include control of brush on utility and transportation rights of way, control of dandelions, plantains and other weeds in turf and suppression of ragweed, poison ivy and other plants of public health importance.

The principal hazard in the use of the phenoxys is to crops and other valuable plants either within the treated area or nearby. Treated crops and forest trees can be injured through accidental overdosing, improper timing of treatments, unusual weather conditions and other causes. Injury to nearby crops and ornamentals can result from drift of droplets or vapors of the spray. Such losses are largely preventable through the use of proper formulations and spray equipment and the exercise of good judgment.

The phenoxy herbicides are predominantly toxic to green plants and are much less toxic to mammals, birds, fish, reptiles, shellfish, insects, worms, fungi and bacteria. When properly used, they do not occur in soils and water at levels harmful to animals and microorganisms. They do not concentrate in food chains and do not persist from year to year in croplands. They are detectable only rarely in food and then only in insignificant amounts.

A highly poisonous kind of dioxin called TCDD is an unavoidable contaminant in commercial supplies of 2,4,5-T and silvex. The amount present in currently produced formulations of 2,4,5-T and silvex is not enough to alter the toxicological properties of these preparations or to endanger human health or to affect plants or animals in the environment.

The phenoxy herbicides are widely used because they are more efficient and usually less hazardous and less injurious to the environment than alternative methods. Use of these chemicals is estimated to reduce the cost of production of the crops on which they are used by about 5% and to reduce overall agricultural production costs in the United States by about 1%. Uses in forests and nonagricul-

tural situations provide additional savings. If the phenoxys were no longer available, the cost of food, forest products, electric power, transportation and governmental services would be higher. These costs would be borne by consumers.

INTRODUCTION

The phenoxy herbicides were discovered over thirty years ago, incidental to research on naturally occurring plant hormones. As the chemical nature of these substances became known, related compounds were synthesized and tested for effects on plant growth. Certain phenoxy acetic acids, including 2,4-D, were found to be plant growth regulators and in due course were discovered independently in the United States and Britain to be active herbicides capable of selectively killing many broad-leaved weeds in cereal grains, grasslands and coniferous forests. Further research led to the commercial use of several phenoxy herbicides, including 2,4-D, 2,4,5-T, MCPA and silvex. These pioneer accomplishments have now expanded into a world-wide effort by industry and public research agencies that has discovered a wide array of useful herbicides, most of which are chemically and functionally unrelated to the phenoxys.

Despite the development of many other herbicides, the phenoxys remain major tools in vegetation management. Although replaced by newer materials in some instances, the phenoxys continue to find additional and expanded uses, such that 2,4-D is currently in critically short supply in world commerce. An important development for the tropical nations has been the recent discovery that a wide range of weeds can be prevented in paddy rice by applying 2,4-D to the water three or four days after transplanting. This and other developments forecast expanded usefulness for 2,4-D and related chemicals in the management of such diverse resources as croplands, forests, ranges, waterways, industrial lands, public utility properties, wildlife habitats, urban parks, athletic fields and landscape plantings.

The phenoxy herbicides are weak acids that are only slightly soluble in water and petroleum oils. Although the acid is the active form, they are normally converted to water-soluble amines or oil-soluble esters for convenience in handling and application. These are mixed with other ingredients, such as solvents, emulsifiers, thickeners, and wetting agents, to make commercial formulations for specific uses. The amine forms are diluted with water and sprayed on foliage or injected undiluted into trees. Esters are sprayed as oil solutions or as emulsions with water. One class of amine salts of the phenoxys is soluble in oil rather than in water. The strength of commercial formulations is expressed in terms of the equivalent content of the parent acid. However, different products are not equally effective even on this basis. Esters generally have greater herbicidal activity than the amine forms but are more expensive. Esters may evaporate from foliage after application, releasing fumes that can move outside the treated area and cause injury to sensitive plants. This hazard can be reduced by the use of low-volatile esters, but these cost more than the high-volatile esters and are less effective as herbicides in some situations. There is no single best formulation for all purposes, and this is reflected in the availability of a wide variety of commercial products for a multitude of uses. Available products include mixtures of phenoxy herbicides and mixtures of these herbicides with unrelated herbicides, fertilizers and other materials.

Many phenoxy acids have herbicidal activity. They form a family of compounds that have similar chemical and biological properties but differ in details that affect their activity on individual plants, their cost and other characteristics. The ones presently used in the United States include 2,4-D, 2,4,5-T, MCPA, silvex, 2,4-DB, MCPB, dichloroprop, mecoprop, 2,4-DEP and erbon. 2,4-D is by far

the predominant compound. It is without equal in cost and effectiveness for routine control of most broad-leaved weeds in the presence of grasses. Other phenoxys find use only where they control weeds resistant to 2,4-D or where crops are less sensitive to them than to 2,4-D. In 1971 the amounts of 2,4-D, 2,4,5-T and silvex produced in the United States were, respectively, 45, 6 and 3 millions pounds, representing over 90 percent of all phenoxy production. MCPA, 2,4-DB, MCPB, dichloroprop and mecoprop have important but limited special uses. 2,4-DEP and erbon are chemicals closely related to 2,4-D and 2,4,5-T that act primarily through the soil. They are not extensively used.

Mixtures of 2,4-D and 2,4,5-T related to commercial brush killers were employed as "defoliants" in the war in Indochina, causing partisans in this conflict to denounce this use as "chemical warfare." It was claimed that, in addition to killing plants, the materials killed people, livestock and wild animals and caused human birth defects. These charges have been exhaustively investigated by scientists and argued emotionally in the press and elsewhere. The evidence is that in Southeast Asia, as elsewhere, these chemicals have little biological activity beyond their great effectiveness as herbicides, and that whatever environmental effects they have result from their action on vegetation. However, it is not the purpose of this report to renew this largely political controversy, but to take note that formulations, rates of application, methods of application and other factors differed greatly from accepted agricultural practice. Conclusions in the one instance, therefore, may not apply in the other.

HERBICIDAL PROPERTIES

The phenoxy herbicides are absorbed by plant foliage, roots and soft stem tissue. When applied as a drench in diesel oil, they can soak through the dry bark of trees and enter living tissues by this means. Once absorbed, the phenoxys move within the plant along the pathways that carry food and water. They tend to accumulate in the actively growing parts of roots and stems. As the herbicide distributes through the plant, the leaves and buds twist and curl, followed by malformed new growth of stems and leaves. Sensitive young plants may die in a few days. Hardy shrubs and trees may succumb only after weeks or months or may survive without evident injury.

The phenoxy herbicides appear to enter in an imperfect and uncontrolled way into the regulation of growth processes normally governed by the natural growth hormones. There is interference with cell division and enlargement, with food utilization and with a wide array of other vital processes. The exact mechanism of these actions is not known, and indeed the exact workings of natural plant growth regulators are equally obscure. Phenoxy herbicides are far more toxic to green plants than to animals because the kinds of materials that have growth regulating activity in plants do not act in the same way in animals.

The phenoxys in addition to their use as herbicides, also find limited use as plant growth regulators for crops. For example, they can be used to control the ripening of bananas. 2,4-D is sprayed on orange trees to increase fruit size and prevent fruit and leaf drop. Silvex is sprayed on apples to enhance coloring and prevent premature fruit drop. Although popularly miscalled "defoliants," the

phenoxys are, in fact, antidefoliants and act at low concentrations to prevent the shedding of leaves and fruit. They enhance blossom retention and increase fruit set. At low concentrations the phenoxys promote the rooting of cuttings and presumably could be used for this purpose in plant propagation. Although these are useful properties, the great toxicity of the phenoxy herbicides to plants limits their employment as purely plant growth regulators. Ordinarily such needs are met by other hormone derivatives that are less active as herbicides and are marketed specifically for plant regulatory purposes.

PRACTICAL USES

The phenoxy herbicides are used in land and water management wherever their particular selective properties coincide with the desired changes in vegetation. The most common uses are suppression of broad-leaved plants in the presence of grasses, conifers or certain legumes. The situations in which management objectives are served by this kind of selectivity are extraordinarily diverse, ranging from essentially wilderness areas to intensive urban horticulture. Each use is governed by the known response to the herbicide of each kind of plant present. Such general rules as "broad-leaved plants are susceptible while grasses and conifers are resistant" have important exceptions, and nothing short of thorough knowledge of the response of each kind of plant under prevailing conditions has made possible the effective use of these chemicals.

Herbicides are most useful when employed in coordination with other practices in vegetation management systems. The aim is to create conditions favorable to the crop, forest trees, range grasses and other preferred species and unfavorable to unwanted plants. The total set of manipulations constitutes the management system in each case. The phenoxy herbicides function in a wide variety of systems ranging from forest and wild-land management and cereal and forage production to industrial land uses. Management objectives are diverse, including primarily the production of food, forest products and other commodities and also the management of fish and game habitats, suppression of allergenic and poisonous plants, maintenance of navigable and recreational waterways and many others.

Cropland

Four-fifths of the total amount of phenoxy herbicides used in the United States is applied to cropland and rangeland. In 1971, 38 million pounds of these chemicals were used on food and feed crops. The principal crops treated are the grains, wheat, corn, barley, oats and rice. The usual treatment is with 2,4-D at a rate of less than one pound per acre.

The small grains are always infested to some extent with annual and perennial weeds that can be controlled by the phenoxy herbicides. If not controlled, these weeds reduce crop yield, interfere with harvesting and reduce grain quality. For example, wild garlic bulblets harvested with the wheat cause a garlic taste in flour milled from the grain, making it virtually worthless. 2,4-D is the principal herbicide used in this country for control of broad-leaved weeds in cereal grains. Approximately 27 million acres of these crops are treated with this compound annually. The recommended rate of application depends on the specific weed problem and crop resistance but generally ranges from 1/4 to 1 pound per acre. Under some conditions,

2,4-D is not adequately selective in the small grains, and it is common practice in such cases to use MCPA instead. Although MCPA is appreciably more expensive than 2,4-D, about 7 millions acres of small grains are treated with it annually. A substantial portion of the U.S. rice acreage also receives 2,4-D, 2,4,5-T or MCPA treatment for control of broad-leaved weeds. 2,4,5-T and silvex are often used in rice in the southern states, where curly indigo and other weeds resistant to 2,4-D and MCPA are widespread.

Few alternative practices are available for control of broad-leaved weeds in cereal grains. Mechanical and hand tillage following planting are hopelessly impractical. Of the other selective herbicides used for special weed problems in small grains, none can be considered as general substitutes for the phenoxys. For example, dicamba can be used to control some annual and perennial broad-leaved weeds in oats and wheat (not barley), but this material does not control weedy mustards and other important weeds. Moreover, dicamba is relatively toxic to small-seeded legumes and thus cannot be used in the central and eastern areas of the United States where small-seeded legumes are commonly intersown with small grains. Bromoxynil controls many annual broad-leaved weeds in small grains, but it is not effective against most perennials and cannot be used in winter grains and where small-seeded legumes are intersown. Present practice in some areas is to combine dicamba or bromoxynil at low rates with 2,4-D or MCPA to broaden the spectrum of weeds controlled. Dinoseb is another alternative herbicide which controls primarily annual broad-leaved weeds in small grains. It is not a translocated herbicide and is thus less effective on perennials than the phenoxys. There are essentially no alternatives to the phenoxy herbicides in rice production.

2,4-D is used to control broad-leaved weeds in corn and sorghum. This use has decreased since the introduction of the triazines and other effective preplant and preemergence herbicides that kill not only broad-leaved plants but weedy grasses as well. However, increased use of these newer herbicides has not been without problems. Deep-rooted perennial weeds are generally resistant to these materials, and their populations increase in the absence of periodic treatments with 2,4-D. Thus, 2,4-D continues to retain a place in corn and sorghum culture, with approximately 20 million acres of these crops being treated with 2,4-D annually. The rate of application ranges from 1/4 to 1/2 pound per acre. Dicamba is a partial alternative to 2,4-D; however, it does not control all of the species controlled by 2,4-D and is best used in mixtures with 2,4-D to extend the spectrum of weeds controlled.

Cultivation supplemented by hoeing is an alternative to 2,4-D in production of corn and sorghum. Indeed, cultivation is still widely practiced with these crops, either alone or in combination with herbicides. However, cultivation cannot remove weeds occurring directly in the crop row. It can provide partial weed control at low cost but must be supplemented with hand work at costs that are presently prohibitive.

MCPB and 2,4-DB can be used for control of broad-leaved weeds in legumes. MCPB and 2,4-DB are not themselves herbicides but are precursors of the herbicides, MCPA and 2,4-D, respectively. They can be safely used to control certain broad-leaved weeds in green peas, soybeans, peanuts and small-seeded forage legumes because these crops have less ability to convert them to MCPA and 2,4-D than do the

weeds. The total amount of MCPB and 2,4-DB used is small, but they make possible the control of certain yield-limiting weeds in important leguminous crops. In most instances, no other herbicide is equally effective for this purpose.

Alternatives to the use of 2,4-DB and MCPB in legumes are limited. Dinoseb can be used as a postemergence treatment on some small-seeded forage legumes, green peas and peanuts for control of broad-leaved annuals, but this material is less effective on perennials and cannot be used on late emerging weeds without risk of crop damage. Chloroxuron and bentazon are possible substitutes for postemergence control of broad-leaved annual weeds in soybeans; however, these herbicides are several times more costly than 2,4-DB. Cultivation after planting continues as a recognized weed control practice in the larger-seeded legumes grown as row crops, but this practice has the limitations described earlier for corn and sorghum.

Phenoxy herbicides are used to control susceptible weeds in such crops as apples, asparagus, blueberries, cranberries, flax, pears, potatoes, strawberries and sugarcane. Each crop has specific requirements for weed control, including in some instances special formulations and unusual methods of application. In orchards and vineyards the herbicide need not be truly selective since it can be applied selectively to the weeds and not to the trees and vines.

The diversity and versatility of the phenoxy herbicides also provide the agriculturist with many options for weed control around the farm in noncrop situations. Such uses are coordinated with preventive and cultural practices, such as proper seedbed preparation, to make up efficient production systems. Post harvest and preplanting tillage followed by careful seedbed preparation can weaken perennial weeds and provide clean ground for the new crops. The purpose of later phenoxy treatments is to control susceptible weeds which begin growth with the crop or later.

An important advantage of having a variety of herbicides and other practices is that it makes possible the alternation and rotation of control measures in successive years. When the same methods are used year after year, special populations of weeds tolerant to the conditions created build up. Rotations to different herbicides or to other crops, each with its particular herbicides and cultural methods, and the use of combinations of herbicides or combinations of herbicides with other methods are the stock-in-trade means of combatting weeds in croplands. Thus the phenoxys are not only production tools in the crops in which they are directly used but also in the crops that are produced in rotation with them.

Pastures and Ranges

Pastures and ranges are lands producing grasses or other forage plants that are harvested by grazing with domesticated animals. Pastures are grazing lands that are intensively managed, often by periodic cultivation, irrigation or rotation with crops. Rangelands are less intensively managed and are often arid or rough lands little altered from their natural state.

The central problem inherent in all grazing lands is the fact that livestock consume forage plants and leave weedy plants untouched and uninjured. The result is that valuable species are suppressed while unpalatable or noxious ones remain

undamaged and free to prosper under reduced competition. Thus, the very nature of grazing is to provide an overwhelming competitive advantage to weedy species. The advantage is so great that, in the absence of proper management, weeds come to predominate in nearly all situations, often to the nearly complete exclusion of forage species.

Weedy vegetation can be held in check to some extent and forage yield maintained by the proper timing and rotation of grazing and by avoiding excessive grazing. Pastures can be plowed and replanted. Ranges can be reseeded or seeded with improved species. Fertilizers can be applied and pests controlled. Such positive measures are useful and necessary for increasing forage production; however, effective management systems must sooner or later face up to the necessity of taking direct destructive action against weeds. Available methods for controlling pasture and range weeds include chemical and mechanical methods and fire.

The phenoxys are the principal herbicides used on grazing lands. Their low cost, high activity, suitability for low-volume application and ability to kill most broadleaved plants, including woody species such as mesquite and sagebrush, without injury to grasses and certain legumes, make them widely useful in pasture and range management. As early as 1951, 500,000 acres of rangelands were treated with 2,4-D and 2,4,5-T. By 1966, over 10 million pounds of phenoxy herbicides, largely 2,4-D, were being applied annually to privately owned pastures and rangelands in the 48 contiguous states, amounting to nearly one-fourth of the total domestic consumption of phenoxy herbicides at that time. In 1971, 7.9 million pounds of phenoxy herbicides were applied to privately owned pastures and rangelands. Again the largest amount used was 2,4-D applied to 6 million acres of land. Slightly less than 1 million pounds of 2,4,5-T was applied to 1.1 million acres of land, much of it for control of mesquite, a task for which this chemical is uniquely adapted.

At present, most of the 2,4-D used on grazing lands is being applied to pastures. Treatment in 1971 amounted to 5 million acres or approximately 5 percent of the present 100 million acres of pastures in the United States. Of the 530 million acres of rangeland, only about 2.1 million acres, amounting to 0.4 percent of the total, are treated with phenoxy herbicides each year. One reason for this difference is that pastures are treated annually and rangelands only every 6 to 10 years. Another factor is that woody plants on rangelands reach levels requiring treatment on only 150 to 200 million acres and are then treated only when returns justify the expenditure. Although treating rangelands with phenoxy herbicides often increases forage production several fold, the land may be so arid or otherwise unproductive that this level of increase is not enough to yield an adequate return on treatments costing as little as $3 per acre.

Alternatives to phenoxy herbicides are more limited on rangelands than on pastures. Economic constraints on rangelands are dictated by the inherently low productivity of these lands. Drastic treatment such as bulldozing, ripping, or rootplowing followed by seeding may cost six times as much as treatment with phenoxy herbicides. These procedures destroy existing forage and disturb the soil, making it susceptible to wind and water erosion. Such alternatives are attractive only on sites with high productive potential that can be revegetated quickly.

Before rangelands were managed as they are now, natural fires apparently were able to reduce brush and coarse weeds to levels that were in balance with forage species. Man has largely eliminated fire, presumably to prevent loss of forage

and to reduce the danger of wildfire. This, in part, accounts for a general increase in weeds on rangelands and suggests a reevaluation of our attitudes toward fire in range management. Fire on range and pasture lands is clearly an alternative to the use of phenoxy herbicides in some situations, particularly for brushlands. The smoke resulting from range or pasture burning, the destructive appearance of the fires, the difficulty of keeping fires from spreading and the hazard to wildlife are factors discouraging the use of burning and leading to the proliferation of laws restricting the employment of fire in range and pasture management.

Forests

Forests cover a full third of the United States, or 750 million acres. Two-thirds of this, 500 million acres, is productive enough to be managed for commercial timber. The remainder is either too low in productivity for timber, or has been withdrawn for other uses such as water yield, grazing, wildlife or recreation.

Three-fifths of the commercial timberland (about 300 million acres) is producing forest products at less than two-thirds of capacity due primarily to competing undesired vegetation. Over 100 million acres of this area is productive land that is supporting virtually no timber despite a history of high-value growth. These are the principal areas on which phenoxy herbicides, mostly 2,4-D, 2,4,5-T and silvex, are being used to help restore a desired forest cover.

The use of phenoxy herbicides in forestry, as elsewhere, is to discriminate between desired and undesired plants. In some cases, defective trees or undesired species have become dominant, whereas in others there are not enough trees to form a stand because of weed, brush or vine competition. In another, and less common, situation forests fail to regenerate because wildlife habitats have become altered in ways that support destructive populations of animals.

Traditional forestry methods emphasize hand-cutting for thinning and culling of forest stands. Such methods may be satisfactory and economically sound, particularly where cut material is utilized. However, high costs and the sheer magnitude of the problem on a nationwide basis make it evident that large-scale forest improvement simply will not be achieved by manual means. Herbicides are being used increasingly as a substitute for hand cutting.

The phenoxy herbicides are used for preparation of sites for tree establishment and release of preferred species from competing woody plants. Herbicides are applied by aircraft, by ground broadcast sprays and by treating individual trees. Rates of herbicide application for both aerial and ground broadcast treatments generally range from 2 to 4 pounds of 2,4,5-T or 2,4-D/2,4,5-T mixture per acre. Broadcast applications for conifer release are based on the greater resistance of the principal conifer species than of hardwoods to the phenoxys. Individual tree injections are made through spaced incisions around the trunk using about one milliliter of 2,4-D per cut. Limited use is also made of basal sprays and stem frills, with phenoxy herbicides being applied in oil solution to the bases of tree trunks or to cuts on the stems. Such treatments have lasting effects and usually need be used only once or twice in a 30- to 80-year forest rotation cycle. Many areas do not develop conditions requiring treatment; others, once initial conditions are corrected, should never need re-treatment if properly managed.

On forest land, as on cropland and rangeland, the phenoxys should be used in concert with other management practices and other herbicides to secure objectives beyond the simple suppression of unwanted plants. There are many alternative pro-

cedures for both timber stand improvement and complete rehabilitation. These employ both chemical and nonchemical procedures, including the option to take no action at all.

Culling and thinning may be accomplished by injecting organic arsenicals, picloram or dicamba. Injection does not expose other trees to the herbicide nor entail significant contamination of the general environment. However, costs generally favor use of the phenoxy herbicides, often by several dollars per acre.

Site preparation may be accomplished with picloram, dicamba and amitrole in place of, or in addition to, the phenoxys. These chemicals are relatively less selective among woody species than the phenoxys, and amitrole also kills grasses. Residues of picloram and dicamba are more persistent and active than are those of phenoxys. They can often be used effectively despite this problem, but at a cost of $10 to $40 per acre more than for site preparation based on the phenoxys. Generally, fewer problems are encountered with phenoxys than with substitutes. The use of other materials is usually warranted only when there is a need to control species resistant to the phenoxys.

Mechanical equipment can be used for forest weed control, but usually at greater cost and hazard. Power saws are more costly to operate in most circumstances than are injectors. Operator hazard from the use of saws is high, both directly from the equipment and indirectly from falling trees. Girdling requires much labor and entails a delay of a year or longer for weed trees to die. Bulldozers may be used to clear land for planting, and rolling choppers can incorporate brush and woody residues into soil. Such extreme methods are costly and disruptive to the soil, and they may lead to erosion and sedimentation in streams.

Fire is an important cultural tool that may be used independently or in conjunction with herbicides and mechanical methods. However, objectionable smoke and the difficulties of fire control restrict the use of fire. Herbicides are often used to desiccate vegetation, so that smoke is reduced, and to allow areas to be burned when adjacent areas are green and low in flammability.

The decision to make no treatment may be justified in some instances; however, such a decision is more often made through neglect rather than through planned action. Alterations to vegetation resulting from past malpractices are not automatically self-repairing. Trees and shrubs present on a site tend to remain dominant unless removed or killed. If forest composition is poor for any reason, it will likely remain poor. If game habitat is poor in such a stand, it will remain poor. Each selective removal of forest products will increase the proportion of undesirable growing stock. The effect of no treatment is therefore likely to persist indefinitely and to perpetuate the degradation of stands conditioned by past and present utilization practices.

Aquatic Habitats

Aquatic vegetation is present in all surface waters of reasonable quality. It is responsible for all food production in water and thus provides the nutritional basis for all aquatic life, ranging from microorganisms to game fish and water fowl. Under certain circumstances there is a buildup of overwhelming masses of aquatic weeds that may clog streams, lakes, reservoirs and canals, causing flooding, inter-

fering with the flow of irrigation and drainage water, restricting navigation, interfering with recreation, and impairing fish and wildlife habitats.

The growth forms of aquatic plants range from single-celled algae to floating mats of such flowering plants as alligatorweed and water hyacinth that completely cover the water surface. Submersed plants, such as the pondweeds, are rooted to the bottom and grow entirely under water. Others, such as cattails and bulrushes, are rooted to the bottom in shallow water and rise above the water surface.

Most of the many desirable attributes of water may be served at one time or another by the judicious use of herbicides. Domestic water reservoirs are often treated on a regular basis with copper salts to suppress algae, and in other situations various chemicals, including phenoxy herbicides, are added to the water or sprayed on floating or emergent vegetation.

2,4-D can be used at rates of 1 to 2 pounds per acre for control of water hyacinth and at rates up to 4 pounds for control of many other floating or emergent species. Alligatorweed is resistant to 2,4-D but may be controlled with silvex. 2,4-D is frequently used in the form of granules or pellets which, after being spread over the water surface, sink to the bottom to kill rooted submersed weeds. Silvex is similarly used to control weeds more resistant to 2,4-D. Both 2,4-D and silvex are put in water in liquid form at 1.5 to 2 ppm or 5 pounds per acre foot of water for control of some weeds. Bulrushes, cattails, water lilies and most shoreline and emergent weeds are controlled with oil-water emulsion of 2,4-D esters at rates of 4 to 6 pounds per acre.

There are some alternatives to phenoxy herbicides for chemical control of aquatic weeds. Diquat can be used to control water hyacinth, water lettuce and duckweed. Acrolein and aromatic solvents are effective for control of submersed weeds, but both are highly toxic to aquatic animals. Endothall, dichlobenil, diquat, and fenac are alternatives to the use of phenoxy herbicides for certain weeds and under some conditions. There are no suitable chemical alternatives to 2,4-D and silvex for control of most shoreline or emergent weeds. Mechanical alternatives include underwater cutters for rooted weeds and swath cutters for floating mats. Dredging, draglining, and underwater dragging of chains and other devices may be used on suitably accessible waterways. The cost of mechanical methods for control of water hyacinth ranges from $150 to $1600 per acre compared with $5 to $60 per acre for treatments with the phenoxy herbicides. Costs of more than $100 per acre may be expected with the use of alternative herbicides.

The most extensive use of phenoxy herbicides in aquatic environments is in the production of rice. In view of the worldwide importance of this most critical food crop, the use in rice culture may eventually become the most important use of these versatile herbicides. The uses in rice and in noncrop aquatic situations have much in common, including the existence of few economical alternative methods.

Industrial Lands

Industrial vegetation management is directed primarily at modifying plant cover so that it does not interfere with industrial operations. Effects on the general environment and on aesthetic values must also be considered. Management actions range from minor tree pruning, for protection of power lines and structures,

to the total suppression of all plants in such installations as railroad tracks, substations and storage yards. Industrial areas requiring total vegetation control are usually treated with soil sterilants rather than phenoxy herbicides. Industrial lands in the United States subject to management of plant cover are in excess of 50 million acres. This total includes nearly 4 million miles of highway, 200,000 miles of railroad and about 2 million miles of overhead electric lines, of which 300,000 miles are high-capacity circuits occupying 4 million acres.

Mos utility, highway and railroad rights-of-way are initially cleared by mechanical means, the cost of clearing in wooded areas varying widely with the nature of the terrain, labor costs and other factors. On power and communication line rights-of-way, subsequent control commonly entails the use of 2,4-D and 2,4,5-T. Newly constructed lines cleared with mechanical equipment often require two herbicide applications in succession to control sprouts; subsequent treatments are needed less frequently, depending upon the agressiveness of invading species. Maintenance operations may involve: (1) selective basal sprays of 2,4,5-T or 2,4-D/2,4,5-T esters at rates of 12 to 16 lb per 100 gallons of oil; (2) foliage or stem-foliage sprays of 2,4,5-T or 2,4-D/2,4,5-T mixtures in water applied with ground equipment at rates of 3 to 4 lb of chemical per 100 gallons of spray mixture; and (3) aircraft applications of 2,4,5-T or 2,4-D/2,4,5-T mixture at rates up to 12 lb per acre, often as invert emulsions or combined with a thickening agent to reduce spray drift. Other treatments include tree injections of the kind used in forests. Silvex and dichloroprop are used as foliage sprays at rates similar to those used with other phenoxy herbicides. These compounds kill certain species not controlled by 2,4-D and 2,4,5-T, but otherwise they affect a more limited spectrum of plants.

The preferred vegetation on highway and utility rights-of-way is usually grass and other short vegetation. The proper management of vegetation on roadsides is important to safety by providing adequate sight distances on curves and at junctions and intersections. Also, tall weeds can cause hazardous snowdrifts. Before the use of phenoxys, mowing, plowing, hand cutting and burning were about the only control methods available. 2,4-D, 2,4,5-T and other herbicides have eliminated the need for plowing, hand cutting and burning and also permit fewer mowings per year. Chemicals are particularly useful on steep slopes, wet areas and areas obstructed by guard rails and other structures and not accessible to mowing machines. The use of phenoxy herbicides on rights-of-way is sometimes restricted by the proximity of desirable vegetation susceptible to herbicide injury.

Alternative measures for utility rights-of-way maintenance include such chemicals as ammonium sulfamate, picloram, amitrole and dicamba. Ammonium sulfamate is effective for control of many woody plants. However, since it must be applied as high-volume sprays, it is not suited to helicopter applications. Ammonium sulfamate appears to be environmentally safe for wildlife and free of residue problems. Ammonium sulfamate kills grass and is thus not suitable for broadcast treatments where ground cover is wanted. Picloram is highly effective on many woody plants and can be applied as foliage sprays or to the soil in granular form. It is relatively persistent in the soil and must be used with due regard for this characteristic. Amitrole, dicamba and other foliar herbicides have important uses in industrial weed control, but unfortunately none of them duplicate the highly useful selectivity pattern of the phenoxy herbicides.

Alternative management systems on most rights-of-way in wooded areas are similar to those used in forestry and include: (1) periodic hand cutting, (2) mowing, and (3) mechanical clearing by plowing or bulldozing. Terrain limitations greatly restrict

the use of ground equipment as replacements for aerial applications which are currently used on more than 2.2 million acres of right-of-way annually.

Urban Lands

Urban vegetation is principally lawn and turf, supplemented with shade trees and shrubbery. The central management effort is directed toward maintaining high-quality, weed-free turf. There are 15 million acres of turf in the United States, of which one-tenth is golf courses and one-third is home lawns.

2,4-D, 2,4,5-T, silvex, MCPA and dichloroprop are used on turf to control dandelions, plantains, garlic, chickweed and other nongrass weeds. This is standard practice by the home owner, greenskeeper and park manager throughout the world. Other herbicides used in turf management include DCPA, benefin, bensulide, arsonates, siduron and others that control crabgrass and certain other annual grasses. DCPA and dicamba are effective also on selected annual grasses and some phenoxy-tolerant broad-leaved weeds. Dicamba is readily absorbed by roots from soil and can injure shrubs and shade trees by this means. The use of alternative herbicides to the exclusion of phenoxy herbicides would greatly reduce the control of broad-leaved weeds critical in turf management.

The phenoxy herbicides are also widely used in public health programs to suppress poison ivy and allergenic plants such as ragweed.

HAZARDS

All chemicals, including ordinary household materials and the common ingredients of foodstuffs, are to some extent hazardous to man and other living things. A chemical may be a fire hazard, stain clothing, cause the floor to be slippery when spilled, or be poisonous and cause illness or death. In the case of poisoning, the hazard is compounded of two variables: the inherent toxicity of the chemical and the degree of exposure to it. High toxicity with little exposure presents low hazard, whereas high exposure to materials that are not highly poisonous may have serious consequences.

The toxicity of the phenoxy herbicides is known with reasonable accuracy on hundreds of species of plants and animals under a variety of conditions. The levels of herbicide present in the environment as a result of normal use and under conditions representing possible misuse are also known for a wide variety of situations. These facts form the basis for the assessment of hazards resulting from the use of the phenoxy herbicides. The scientific data are exhaustive, comprising more than 35,000 scientific papers and technical reports over a 30-year period. The phenoxys are relatively old materials in terms of research and accumulated experience in their use. It is possible not only to assess risks projected on the basis of experimental data but also to confirm or deny these projections on the basis of hazards that have developed or failed to develop from a quarter-century of extensive use throughout the world.

The phenoxy herbicides are powerful plant killers, and the principal hazards from their use accrue from this fact. The hazard is almost entirely to plants. The danger is either from failures in selectivity, leading to injury of the crop or other valuable plants in the treated area, or from spray drift or the movement

of herbicide vapors, leading to injury of plants outside the treated area. There is a preponderance of evidence that the phenoxy herbicides are not significantly hazardous to animal life and microorganisms under normal conditions of use and indeed under conditions of substantial misuse. There may be injury to animals indirectly as a result of the changes in vegetation. This, however, is a consequence of the chosen vegetation management plan and not of the means taken to accomplish it.

Losses to crops due to failures in selectivity can result from overdosing due to mismeasurement of chemicals, poorly calibrated spray equipment, overlapping of spray swaths causing double coverage, and climatic variations that affect crop resistance. Rice, for example, is susceptible to 2,4-D injury at certain stages of growth, and many normally resistant plants are subject to injury during flowering and fruiting. Conifers are less resistant to the phenoxys when in rapid growth. Such injury is widely recognized by farmers and foresters throughout the world, and the means of preventing major losses are well known but, unfortunately, are not always practiced.

Spray Drift

The most serious hazard in the use of the phenoxy herbicides is drift of the chemical to nontarget vegetation during or after application. Phenoxy herbicides are extremely toxic to cotton and grapes. Beans, tomatoes, melons and many ornamental plants are also easily damaged. The hazard is related to the susceptibility of the plants, their stage of development and whether they are actively growing or not. Other factors are the distance from treated areas to susceptible plants, the amount of herbicide applied on a given day and the nature of the herbicide formulation used. The proportion of driftable small drops in the emitted spray and the height of the application (air or by ground) above the surface also affect spray drift. Wind velocity and direction and the degreee of turbulent mixing can greatly increase or decrease downwind transport and deposition of the spray in the susceptible crop area. Air temperature and humidity alter crop response and affect spray evaporation.

The herbicide can move as spray droplets, or it can evaporate and move as vapors. The ester forms of phenoxy herbicides can evaporate from droplets in the air or from plants and other surfaces after spraying. The vapors can then drift in the air to sensitive crops and other susceptible plants outside treated areas. This behavior is mainly a property of the high-volatile esters. Low-volatile esters are essentially free of this hazard except under conditions of very high temperatures and the close proximity of sensitive crops. In such events, the amine salt formulations provide still further protection against the hazard of spray drift.

Drift of herbicides as droplets can be greatly reduced by spraying the material in the form of larger and heavier droplets that tend to settle rapidly in the target area. Droplet size can be increased by using higher spray volume, lower pressures, coarse nozzles, nozzles of special design, or special systems for aircraft that give close control of droplet size. Thickening agents can be added to the spray mixture to cause it to form larger drops rather than fine particles.

Application machines and techniques have improved significantly in the past

few years. It is no longer necessary in hazardous situations to apply phenoxys with equipment and formulations not specifically designed to reduce drift. Although a larger number of smaller drops may be more effective, larger spray drops of 500 to 1500 microns settle rapidly and provide safer and, over the long run, more economical control.

With use of the best available technology, it is routinely possible to deposit 97 to 99 percent of the released spray within ordinary target areas by either aircraft or ground equipment. Although such precision is not without its measure of added cost, in hazardous situations the additional expense is clearly worthwhile. Even more effective means are being developed which will permit use of phenoxy herbicides with significantly less drift than possible with present methods.

In hazardous situations, phenoxy herbicides should be applied only when a positive and firm wind is blowing away from nearby susceptible crops. They should not be applied when a temperature inversion, or a warm layer of air, is overhead under 1500 ft elevation. Absence of wind or an inversion ceiling reduce turbulent mixing or ventilation and promote build-up of small drops and vapor in the air that can drift as a concentrated mass to sensitive crops.

A final means of protecting from drift is to recognize situations that are beyond normal protective measures and not spray at all. When highly susceptible crops such as cotton and grapes are grown within 3 to 5 miles of large-scale spray operations (over 100 acres per day), crop injury may occur despite normal precautions. Several states have regulations that apply to such situations. They forbid use of specified herbicides at certain times of the year and may require special permits for exceptionally hazardous uses, or they may allow application only under regulatory supervision.

It is an important factor in the detection and prevention of drift that the effect of the phenoxys on plants is not insidious. When plants are injured, the symptoms are pronounced and unmistakable, and indeed the symptoms often appear more serious at first than is ultimately the case. The pattern of injured vegetation in relation to the primary treatment is ordinarily such that the source of spray drift is readily apparent.

Toxicity

Toxicity is the degree that a substance is poisonous. It is commonly expressed as the lethal dose, or lethal concentration, to 50 percent of the test animals (LD_{50} or LC_{50}). Dose is usually stated in milligrams of chemical per kilogram of body weight (mg/kg). Concentration is expressed as parts per million (ppm) of toxicant in food, water or air.

The acute oral toxicity of a single dose of the phenoxy herbicides to mammals ranges from 100 mg/kg to 2000 mg/kg, depending upon the test animal and the particular chemical or formulation. The herbicides are absorbed after ingestion, transported via the plasma, concentrated in the kidneys and rapidly eliminated in the urine. For 2,4-D or 2,4,5-T, the acute oral LD_{50} is upwards of 300 mg/kg for rats, mice, guinea pigs, hamsters, rabbits, primates and various livestock and large game animals. This is equivalent to a dose of 3/4 ounce of chemical for a human weighing 164 pounds. The dog has lower capacity to excrete the phenoxys, and as a result these chemicals are about three times more toxic to dogs than to other test animals.

It is known that man excretes the phenoxy herbicides rapidly via the urine.

In long-term feeding trials, test animals tolerate doses of as much as 25 percent to as little as 0.4 percent of the acute oral LD_{50} fed daily on a continuing basis without ill effects. Signs of poisoning include loss of appetite, loss of weight, weakness, lack of coordination, alterations of the liver and other internal organs, and in some instances defective offspring. 2,4,5-T is known to be a teratogen (cause birth defects) when administered at high doses to mice under some circumstances. The same may be true for the other phenoxys as well, since presumably all biologically active chemicals can be shown to have this effect under some conditions of exposure. When gestating animals are poisoned by massive doses of any substance, effects on the developing offspring are inevitable.

The phenoxy herbicides are generally less toxic to birds than to mammals. The acute oral LD_{50} for 2,4-D and 2,4,5-T for poultry, mallards, pheasants, pigeons and quail ranges from 300 to 5000 mg/kg. The LC_{50} for these chemicals in feed for birds is upwards of 2500 ppm and is typically greater than 5000 ppm. The toxicity to fish is highly variable. LC_{50} values range from less than 1 ppm to more than 1000 ppm in water. These values are equivalent to treatments of 10 pounds to 10,000 pounds of phenoxy herbicide per acre in a pond 4 feet deep. Toxicity is largely associated with the ester and oil-soluble amine formulations. The water-soluble amine salts are to all intents nontoxic to fish. Oysters, crabs, mussels and a wide variety of other invertebrates are not directly affected by the phenoxy herbicides applied in lakes, ponds and estuaries for aquatic weed control. The phenoxys are essentially nontoxic to insects and related organisms and are not significantly fungicidal or bactericidal.

Residues

When the phenoxy herbicides are sprayed on vegetation, a residue of the herbicide is deposited on plant foliage, on soil, on fences, poles and structures, and often into surface waters. Of the herbicide deposits on leaves, some is absorbed into the living tissues, often killing the plant. The residue remaining in the tissues of dead plants is largely decomposed as the plant material rots; however, some is released into the soil. The herbicide remaining in surviving plants is broken down over a period of a few days to a few weeks. Forage from pastures and ranges treated with 2,4-D, 2,4,5-T, MCPA or silvex has initial residues in and on the plant material of about 100 ppm per pound of chemical applied per acre. Residues in and on forage rarely exceed 300 ppm, and this only on sparse vegetation from the heaviest allowable rates of use on grazing lands. Forage residues decline with a half-life of one to two weeks. Thus, within two to four weeks, levels have fallen into the range of one-half to one-sixteenth of the initial value.

Since domestic and wild grazing animals tolerate up to 2000 ppm of phenoxy herbicides continuously in feed and larger amounts for short periods, there is no hazard to animals from forage residue even from treatment of ranges and pastures at exaggerated rates. No residues appear in the milk of cows consuming rations containing up to 300 ppm of 2,4-D, MCPA or silvex and up to 30 ppm of 2,4,5-T. Thus residues could possibly appear in milk following grazing in areas treated with practical rates of 2,4,5-T. To guard against this, there are stipulated waiting periods for milking or slaughter of animals grazed on ranges and pastures treated with herbicides.

In monitoring programs, no residues of 2,4-D or silvex were detected by the U.S. Food and Drug Administration in 13,000 samples of milk and 12,000 samples of meat from market channels analyzed for these compounds from 1963 to 1969. Trace amounts of 2,4,5-T were found in several samples. About 12 percent of more than 8,000 samples of meat analyzed by F.D.A. over a three-year period were reported to contain an average of 0.02 ppm of MCPA in the fat. This finding, although of no health significance, is nevertheless perplexing since such residues cannot be experimentally induced in cattle and sheep from continuous feeding at rates up to 500 ppm of MCPA in the ration. Residues of the phenoxy herbicides are also occasionally detectable in plant products used as food, although at levels so low as to be of no medical interest.

Residues of the phenoxy herbicides leached into the soil are bound to some extent by soil particles and are held in the upper part of the soil. They do not leach into water tables and contaminate wells and springs, nor do they move significantly into streams or to adjacent areas from surface runoff. However, wind or water erosion that carries major quantities of soil would also transport herbicide residues if any were present. The diluting effect of the soil is such that levels of the phenoxy herbicide in the root zone of plants are extremely low. Normally the levels are not sufficient to injure green plants or to affect non-green organisms such as bacteria, fungi, worms, insects and rodents.

The phenoxys are, without exception, subject to decomposition by various microorganisms that are universally present in soils. When applied to soils at typical agricultural rates, 2,4-D is usually decomposed in one to four weeks. MCPA requires about six weeks and 2,4,5-T about three months for essentially complete destruction. Silvex degradation is slightly slower than that of 2,4,5-T. Thus the phenoxy herbicides do not build up in the soil, and treatments can be applied to croplands year after year without accumulation.

Detectable residues of the phenoxy herbicides do not appear in surface waters unless the chemicals are directly added to the water or fall there incidental to spraying of rice or shoreline and forest vegetation or unless the chemicals are added as a water treatment for the control of aquatic vegetation. In practice the greatest residues in streams and lakes resulting from range and forest uses are less than 0.1 ppm. The concentration in water from treatment of rice and the spraying of floating and emergent aquatic weeds rarely exceeds 0.1 ppm. Treatments equivalent to several parts per million of 2,4-D are used to control such submersed aquatic weeds as water milfoil. These are added as slow-release granules containing phenoxy esters or water-soluble amines. Rates and application practices are designed to keep water residues below the approved 0.1 ppm level.

Residues in running water are subject to dilution through stream flow, adsorption by bottom mud and decomposition by sunlight. The concentration in streams after forest and shoreline treatments usually falls below detectable levels in a few days. In shallow waters such as rice paddies or stagnant, swampy areas, residues are decomposed by microorganisms and destroyed by sunlight. Residues decline at about the same rate as in soils. The decomposition of the phenoxys is rapid in most waters. The rate is reduced only under conditions of oxygen deficiency.

Dioxin

A dioxin contaminant referred to as TCDD is formed in the manufacture of the

phenol used to make 2,4,5-T and silvex. The presence and significance of this impurity have become known only in recent years. 2,4,5-T formerly contained from 1 to 80 ppm of TCDD, concentrations sufficient to cause skin eruptions called chloracne in industrial workers. Although it has not been feasible to eliminate this contaminant entirely, present production methods are able to reduce the dioxin level to less than 0.1 ppm.

To have reduced to a fraction of one percent of its original content an impurity in a chemical already widely used and recognized as safe to the public would appear to be a sufficient solution of a routine problem. However, as more data were obtained, it became apparent that TCDD is one of the most toxic chemicals known. The hazard posed by the presence of a very very small amount of this very very toxic substance has therefore been of concern. As in other cases, the hazard must be evaluated in terms of toxicity and degree of exposure.

TCDD is toxic to laboratory animals at all stages of life, and it also causes birth defects. The acute oral LD_{50} ranges from 0.0006 mg/kg (0.6 µg/kg) in male guinea pigs to 115 µg/kg in rabbits. Dogs are less sensitive to TCDD than rabbits. Toxicity is about equal in the rabbit whether the compound is ingested or applied to the skin.

The effects are skin damage, liver damage, hemorrhage and reduced ability to cope with disease organisms. Death from a lethal dose is often delayed several weeks. Following ingestion by the rat, TCDD is absorbed from the gut, localized in the liver and fat, and eliminated largely via the feces but to some extent through the urine. A small amount is metabolized to harmless materials. About half of the ingested material is eliminated from the body in the first 17 days.

Birth defects develop when the chemical is administered during the time of pregnancy when foetal organs are forming. The effect is directly upon the developing pup rather than on the genetics of the mother. TCDD is more of a toxicant than a teratogen. It usually causes death rather than a wide range of abnormalities.

TCDD is from 5000 to 500,000 times more toxic to mammals than 2,4,5-T. The content of TCDD in commercial 2,4,5-T is less than one part in ten million. On this basis, a single toxic dose of TCDD would be contained in from 20 to 2,000 toxic doses of 2,4,5-T. Thus, the presence of 0.1 ppm of TCDD in 2,4,5-T does not contribute significantly to the toxicity of herbicidal preparations of 2,4,5-T.

For a person or animal to be poisoned with TCDD without first being poisoned with 2,4,5-T would require the existence of a mechanism in nature that would separate TCDD from 2,4,5-T, concentrate it and make it accessible for consumption in food or feed. Any postulated mechanism must recognize available facts about the environmental fate of dioxin.

The amount of TCDD distributed in the United States in 2,4,5-T is probably no more than eight ounces annually. This material is distributed over approximately five million acres at the rate of about 50 micrograms per acre, an amount equal to an acute lethal dose for a large animal, assuming it to be somewhat more sensitive to TCDD than the most susceptible known test animal. The material falling on the foliage is not absorbed appreciably by plants but gradually disappears from the leaves by decomposition due to the action of sunlight, evaporation into the atmosphere and washing from the leaves into the soil by rainfall. In addition to the

loss by degradation, it should be noted that losses from volatility and washing into the soil serve further to dilute rather than to concentrate the remaining residues.

Once in the soil, residues become firmly bound to soil particles and are not appreciably taken up by plants. The TCDD does not leach downward but remains localized in the surface soil. The concentration at this time is less than one part in 10 trillion, a dilution ratio equivalent to a distance of an inch in 200 million miles (roughly twice the distance to the sun). Microbial degradation then comes into play and decomposes the remaining chemical to basic materials over a period of probably a year or two.

TCDD sprayed into waters rapidly disappears, evidently due to vapor distillation into the atmosphere and to decomposition by sunlight provided the waters contain small amounts of organic compounds. It is known that TCDD can bioaccumulate in algae, snails and fish. This property is of no practical interest, however, since there is no substantial supply of the chemical in the environment subject to accumulation. Analyses reveal that accumulation in food-chain organisms is not a problem. Measurable levels of TCDD have not been found in herring gulls, sea lions, eagles, corcorants, butterfish, eels, chain pickerels and large bodies of fresh and salt water. It has not been possible to detect TCDD in American supplies of food and feed and in fish meal.

TCDD does indeed become set free from 2,4,5-T and silvex in the soil as a result of the more rapid decomposition of the herbicides. However, in the process the dioxin becomes diluted beyond any possibility of doing harm. Evaluating the hazard of TCDD in the environment is largely a problem of comprehending numerical values far removed from common experience. One is at first likely to be so overwhelmed by the enormity of the toxicity of the compound that he fails to comprehend the infinitesimal levels of exposure.

Present evidence indicates that the dioxin contaminant in 2,4,5-T and silvex is a matter of academic rather than practical interest. It is quite literally an academic problem in the sense that many questions remain unanswered about TCDD, and research should be continued until all aspects of the toxicity, occurrence and environmental fate of this chemical are thoroughly understood.

Socioeconomic Factors

The fact that phenoxy herbicides are widely used in cropland agriculture, on rangelands and pasture, on private forests and public forest watersheds, and in a variety of industrial and urban uses is ample evidence that they are efficient inputs into production processes relative to available alternatives. If these herbicides were not relatively efficient and inexpensive, they would not be in use.

There are alternatives to the use of phenoxy herbicides, but each would cost more to achieve the same objective. Alternatives are almost always available in production processes. The relevant questions are (1) how much do the alternatives cost; (2) who would pay the additional cost; and (3) why should the low-cost method be discarded in the first place?

This report has shown that, with proper application and with current standards of production, phenoxy herbicides do not have serious unintentional side effects.

Indeed, where control of weeds or woody plants is advantageous, these herbicides usually have less harmful side effects on the environment than alternative methods of control.

It is clear that reduced use of the phenoxy herbicides on farms would result in increased costs to consumers. Some producers would gain at the expense of others, hired agricultural labor might gain marginally and nonpaid farm family labor would likely lose. There would be both short-run gains and losses followed by long-run gains and losses. The net effect would be loss. The effects of restriction on forest and industrial uses have not been analyzed in detail. However, one effect would surely be increased prices of forest products. Costs to household users would be mostly increased trouble and labor.

The costs of a possible ban on all phenoxy herbicides on agricultural uses have been estimated[1/] in terms of the reduction in net U.S. farm and ranch income that would occur if alternative means of weed control were used to maintain current levels of agricultural output. The estimates were for the late 1960's, but the general conclusions would hold today. While both prices and input costs have risen, cost-price ratios have remained fairly constant. Therefore, results expressed as percentages or ratios should remain reasonably valid.

The estimates show that the costs of alternative weed control measures would total about 1 percent of the farm value of all crops and about 5 percent of the farm value of the crops actually affected. The percentages of the total increase in cost borne by individual crops would be: corn, 37; wheat, 17; rice, 3; other small grains, 10; grain sorghum, 4; pastures, 11; rangelands, 12; and other crops, 6. One cost would be about 20 million more man-hours of labor to maintain production.

If total output were to remain constant, the costs of such a ban would fall mostly on the producers of the affected crops in those areas of the nation where phenoxys had been used. Net farm income would not be reduced as greatly as gross farm income since farmers would naturally make their adjustments in fields and areas where control problems are the least. Consumers would not be affected under the assumption of constant total output. The demand for farm labor would rise, and farm wages could rise -- a gain to labor and a cost to farmers.

Although the assumption of constant output is useful for the purpose of estimating alternative control costs, the actual adjustments would be more complex. With increased production costs, farm output in the affected crops would tend to fall. One would expect a decline of less than 5 percent--probably 2 to 3 percent. Since the products involved are price inelastic, a decline in output would generate a more than proportional increase in price. Total revenue to farmers producing the affected crops would probably rise, and net income to these same farmers probably would fall--but by less than 5 percent. The price of farm labor might rise slightly; the prices of products to users would rise. Since most of the effects would be in feed-grain crops, much of the rise in consumer prices would probably be felt in prices of meat. Cattle feeders and range cattlemen would probably be affected

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1/ ERS and ARS Agricultural Economic Report No. 194, November 1970.

more than the crop producers themselves, since crop producers would be receiving higher crop prices and could make adjustments in their cropping practices and cropping patterns that would aid in maintaining farm income.

Different areas of the county would be affected in different ways. For example, there would be a rather severe income decline in the rice producing region of Louisiana, balanced by net income increases in the rice producing areas of California where growers are less dependent upon phenoxy herbicides.

All short-run adjustments end up as increases in prices of food, lumber, paper, and other commodities to consumers. The long-run effects of banning a particular management technique in crop, range and forest production are difficult to forecast. New technologies are developed to cope with changing situations, and managers shift from one technique to another to meet changing needs and to get the advantages of new ways of doing things. The costs of production using phenoxy herbicides cannot be forecast in comparison with the costs of new technology that might arise in the future.

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STATEMENT OF LARRY DINNEEN
ARCTIC SLOPE REGIONAL CORPORATION
BEFORE THE
SENATE RESOURCES COMMITTEE
STATE OF ALASKA
FEBRUARY 22, 1978

I am not here today to play the numbers game related to the corporate income tax legislation before your Committee. But I have a few points to make, based on my years of experience in developing business ventures in several states and working for the Arctic Slope Regional Corporation (ASRC) in Alaska.

The "bottom line" of my statement is this: the enactment of the separate accounting bill or the franchise bill -- or anything in between -- would be bad for Alaskans. Although the intent of both bills my be simply to extract more dollars out of the major oil corporations in Alaska, the effect will be damaging to ASRC, to some 70,000 Native Alaskans and to the future viability of the economy of the State of Alaska. First, I would like to call your attention to some of the specifics in the proposed legislation.

JUST THE OIL COMPANIES?

It is evident from some of the language in both bills that the intent is to exempt the Native Regional Corporations from the provisions of the bills. I believe that in either case, litigation could prove that Native Regional Corporations would not be exempt. This is especially true with regard to the separate accounting bill as the actual amending language in Section 2 relates directly to "income of any corporation derived in Alaska." Additionally, it appears

deductible costs would not include the costs of the consultants that we have had to hire in Seattle, Washington, D.C. and elsewhere to deal with the myriad of government problems that are facing us . and to ensure that we are getting the most expert advice on our business matters. Since the Committee is addressing the separate accounting bill in particular, we felt that it was important to bring out these two points.

But the major point is that we do not feel that it is in Alaska's interest --and particularly with respect to ASRC and other Native Regional Corporations -- to change the corporate income tax laws affecting the major oil companies or anyone else, particularly at this time in Alaska's history. Even if we were exempted ultimately from the language of the corporate income tax legislation, the effects of raising taxes on the oil industry in Alaska would be directly damaging to ASRC and thousands of other Alaskans. Although I will develop this point further in my testimony, I want to mention now that ASRC and other corporations are engaged in a great deal of contract work for the major oil companies. And, while no one expects the Prudhoe Bay companies to leave the State altogether, there is no doubt but that the amount of exploratory work going on in Alaska could and should be much higher. And with exploratory and development work comes jobs for Native Alaskans in the form of contract work. Yet this is only one important aspect of the tax issue that I would like to call to your attention.

THE BILLION BARREL OIL FIELDS PROBLEM

Last year, Revenue Commissioner Sterling Gallagher spoke about our problem to the Federal Energy Administration officials dealing with North Slope oil pricing in discussing the Lisburne and Kuparuk oil pools:

> "The Lisburne and Kuparuk pools are illustrative of the case for most-likely discoveries on Alaska Native lands selected under the Alaskan Native Claims Settlement Act. It is far more probable that any discoveries on Native lands will be in the 1 to 2 billion-barrel range like Lisburne-Kuparuk, than in the 8 to 10 billion-barrel range like the main Prudhoe pool." 1/

The problem for ASRC is that we need to raise capital in order to find these fields and we need oil company expertise both to find and develop them. But the future is not PRUDHOE-BAY SIZED FIELDS.

Costs in Alaska are extremely high, and there are many other places still left in the world -- including the North Sea -- where drilling operations are more profitable than they have been and especially will be in Alaska. The wellhead value, after subtracting transportation, etc, is only about $3 these days, and with smaller sized fields as the likely prospect for future discoveries, we can not afford to continue raising taxes on the oil industry without directly reducing the likelihood of finding and developing marginal fields. Needless to say, this is of some concern to ASRC in particular, but all 70,000 Natives are also directly affected...

1/ Statement of Commissioner Sterling Gallagher, Department of Revenue, State of Alaska to the Federal Energy Administraion Regarding Alaska North Slope Crude Oil Price and Entitlements Issues, Washington, D.C., March 21, 1977, p. 3.

ALASKA NATIVES: THE LOWERING OF EXPECTATIONS

With the enactment of the Alaska Native Claims Settlement Act, it was hoped that the Alaskan Native might at last be able to have more of what some have called The American Dream. More choices in terms of employment and lifestyle. And a strong economic base from which to build for their children and grandchildren.

But problems with the Federal Government have multiplied, causing long delays in land transfer and incredible costs. The importance of the D2 issue cannot be overstated. The threat to village lifestyles and subsistence living is very great. Yet few seem to realize that the State government is another direct threat.

If either of the corporate income tax bills were to pass, there would be an immediate effect, not only on the oil companies but also on every Native in Alaska. There would be an immediate reduction in the value of Native land to the Natives who have made their selections in large measure for resource value. All Natives are affected because of Section 7(i) of the Act which provides that 70% of the revenues received by an Native Corporation for hard rock minerals or oil and gas discovered on the Corporation's land will be shared with the other Corporations.

Thus, if ASRC cannot get a billion barrel field developed or more fields found, every other Native Corporation and its stockholders will also be adversely affected. Not to mention the adverse affect on the State of Alaska itself over the long term.

THE THIRD ALTERNATIVE

In conclusion, I would like to highlight a number of important points that Milton Lipton made in addressing this Committee on January 25th. First, despite any perceived "deficiency" in Alaska's corporate oil income tax laws, Lipton endorsed the Arthur Andersen study and stated that the figures are "revealing." Lipton also pointed out that the Legislature should note that "the deficiency in your corporate income tax receipts from the oil and gas producing industry is at least and probably more than made up by higher severance and ad valorem taxation which the Legislature has already imposed upon the industry."

Additionally, Lipton took a good bit of time expressing the importance of perceptions. He stated that the impression which the State of Alaska presents "may be even more important in discouraging investment than the fact of the tax burden per se." He spoke also about the dangers of giving the impression of having an "ad hoc taxing policy" which increases taxes year to year "dedicated to the budgetary needs, revenue deficiences, or whatever the case may be." As a businessman, not an economist, I have noted that the perception of Alaska as a good plce to invest is already poor.

And Lipton seriously presented what he called the Third Alternative: not to amend the income tax statute. It seems to me that the two corporate income tax bills may make more dollars and cents for the State in the near term but that it makes much more sense for Alaska at this point to stop changing the oil and gas tax laws.

Prudhoe Bay production will begin to decline in about eight years. Once a new field is discovered in Alaska, it takes about eight years to get it into production. We need much more exploration now and many more discoveries in the future to replace the income from Prudhoe Bay. A tax hike now could mean the loss of far greater revenues in the future for the State from the development of the remaining smaller fields. And we must face the fact that there probably will not be any more Prudhoe Bays in Alaska.

The Native interest in this matter is clearly the value of our land, revenue and jobs. But the importance of the perception of Alaska is important to all Alaskans. With billions of dollars of surplus revenues projected by the State for the future, we do have time. The passage of these bills would not just reduce oil companies' profitability. Either one would be damaging to the economic aspirations of all Alaskans and particularly Alaskan Natives.

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TRANSCRIPT OF TESTIMONY BEFORE

THE SENATE RESOURCES COMMITTEE

OF THE

ALASKA STATE LEGISLATURE

BY

RICHARD M. DONALDSON

VICE PRESIDENT FOR GOVERNMENT AND PUBLIC AFFAIRS

THE STANDARD OIL COMPANY (OHIO)

AT JUNEAU, ALASKA

ON FEBRUARY 10, 1978

CONCERNING PENDING OIL AND GAS INCOME TAX PROPOSALS

I am Dick Donaldson from Sohio and I'm glad to be back here. I should say that a couple of years ago when I first started appearing before this Legislature and indeed this Committee, I expressed the thought that we had come to the State of Alaska as a stranger but really with the hope of being engaged in business here for 25, 50, 100 years--who knows how long. In a sense those words are beginning to become prophetic. It might be worth reporting today that in almost every sense, we are now an Alaskan company. Some of you may have counted up that 75% to 80% of our assets as a whole company are here now, invested in this State, and given our merger with British Petroleum and a combination of those entities at the year's end, we now can say we have 700 plus employees who are residents of the State. Virtually all of our production of oil is here associated with Prudhoe Bay. And even though we have activities in twenty some states in the Lower 48 involving the manufacture, distribution and sales in different businesses, in terms of the lion's share of our business, we are Alaskan. I was also interested, I don't know whether I should say pleased, but interested at least, to see that the U.S. District Court here recently ruled that we are an Alaskan company. That puts the seal on it, if it was ever needed. And though we have not been an Alaskan company for long, we really are now, and personally

I'm kind of glad about it. I feel good about it. We've had a few problems, solved some, and others remain.

Your Committee has before it again a possible amendment changing Alaska's corporate income tax as applied to the oil and gas industry. In the last few days you've heard some thought provoking testimony, Milton Lipton's and gentlemen that you've heard this week and this afternoon. My purpose is not to rehash or go through what you already know. Last year, in March, I presented some rather extensive testimony on this subject. If you have interest in it, you'll find on pages 16 thru 23 of that testimony there were some remarks dealing with the legalities of the bills that you now have before the Legislature on income tax. Rather than repeat that, I simply want to call it to your attention and hope that someone will look at it again.

I would like to address what I think probably is the biggest problem in State revenues, and one which so far as I know the State of Alaska has really not begun to grapple with. It's probably one that affects each of us and all of us a lot more than anything else we are doing right now. It's interesting to me that Milton Lipton addressed this when he was here. In fact, he spoke of it several times. I read a

transcript of at least part of his remarks, and I thought I might begin by just picking up a couple of his points which introduce this subject. I have tried very hard not to take it out of context because he really was speaking of Alaska when he was saying this. These were his words:

> "First of all, what you see is a kind of ad hoc taxing policy, increasingly year after year dedicated to the budgetary needs, revenue deficiencies, or whatever the case may be."

And another point he said, and I quote:

> "I think it's true that insofar as the State's budgetary needs or revenue deficiencies always seem to be made up by oil industry taxation, this becomes a disabling and discouraging thing for industry. If it is perceived that this is the way in which the taxation proceeds in Alaska, that if there is a budgetary need or a revenue deficiency that almost without regard to (and there was a blank in the transcript) of taxation or the principle of taxation, the incremental revenue or budgetary needs will come from oil industry taxation. This cannot be a matter of indifference to companies that have their choice of operating any place," etc.

Concurrently in another brief comment and almost to the same effect, he again used the word "perception". That word jumped out of the page at me and I call it specifically to your attention. Mr. Lipton said this:

> "I think this is one of the things the Legislature surely will want to consider, that if the perception is that changes in the tax structure, as it is applied to the oil and gas industry, are regularly taken, largely with the view to budgetary needs or revenue deficiency, and hardly ever with the long view as to what is a reasonable tax regime for the State, then I think it creates impressions which may be even more important in discouraging investment than the fact of the tax burden per se."

Well, my own plain statement of the problem runs like this. I think it might help to etch out what I believe to be the principal facts bearing on it. First, the budgets in the State of Alaska and in local government here have grown steadily, substantially, and almost relentlessly over the last eight or nine years. The State budget itself quadrupled between 1970 and 1976. Likewise, the number of government employees has also grown over this period. The cost of people is the biggest part of any budget, any year, in any government today. Today the State and local government as a category in Alaska is the largest employer.

I don't know but you might want to find out how many of these people working for government here today are now supported by revenues from Alaskan resources have come from the outside. That might be an interesting perspective on

some of your own problems, not that it's good or bad, but you ought to know who is involved and where your resources are going.

A document called, "The Alaska Economic Forecast--1978", which was published on January 20, 1978 by the Institute of Social and Economic Research of the University of Alaska, has focused on State and local government employment in 1977. It reported that the total number of employees by government in the State went from 31,096 people up to 34,370 people. This was an increase last year, 1977, in one year alone, of over 3,200 people. When I read this it struck me: that's half as many people as the whole oil industry has working in the State right now, that much of an increase in one year!

On page nine of this Forecast there is this comment:

> "State and local government sector will again grow in 1978, mainly as a result of a growing state budget. Employment in the State and local government is forecast to rise about 7% over 1977."

Alaska's history, in my judgement, confirms again and again that your government's appetite to spend money is limited only by the amount available to spend, and not always by that. There is no indication that this trend over the last eight or

nine years here will change unless some serious thinking is done about it, and I believe right here in the Legislature. Even if the size of your government could begin to flatten out and not grow too fast, the size of your budgets is still going to grow just to support it in the future.

Thus, the first principal fact bearing on the State's basic problem is size and direction of its government.

The second principal fact is that today most of the cost of this government in Alaska is being funded by the oil industry, and so to speak, the State has gone back to the well a number of times in recent years. If you want to be plain about it, I would have to observe that the State is taxing and spending as if there was no bottom to Prudhoe Bay.

But Prudhoe Bay total production will be half done in eight to nine years and will gradually begin to decline in production as all oil fields do. I'm sure you remember as I do that it took eight or nine years from the time Prudhoe Bay was discovered to put it on stream where it is today. An interesting point: eight or nine years to get here, and eight or nine years of the fat level of production out ahead,

then the income and the production begin to decline. Frankly, if we found another Prudhoe Bay this afternoon, how long would it take to get through the applications, the permits, the approvals, the environmental impact statement, the litigation, some legislation that always seems to follow such projects, the design, the engineering, the drilling and construction, the whole works to put a major new field on stream? Seven, eight, nine, ten years? I don't know. Your numbers are probably just as good as mine.

Some have said it's not likely that another Prudhoe Bay will be found in Alaska. Maybe. It's probably something of a long shot. But even then, the question is when? I think a more realistic view is that there is a lot of resource potential here in oil and gas. There is a very good possibility of finding a number of smaller fields to fully offset that eventual decline of Prudhoe Bay's production. But you know, new fields are not usually found over night or in bunches, just when you may need them for oil production, or just when you may need them for State revenue purposes.

Another fact that bears on this is that it doesn't take very long today to count the drilling rigs that are doing exploratory work in Alaska. People have come here from other

parts of the world to look around and say, you know, this is only a small fraction of the exploratory work you might find going on elsewhere in the world where the resource potential is high.

So, taking these two principal facts, the growth of the State budgets and the present level of exploration here, let me tell you what I think the basic problem is that you face. No, let me say this, I think we both face it, it's a problem that we share.

On one hand you have got a large and growing government with a huge appetite for revenue. On the other hand you have got very little exploration going for you today to feed that appetite eight or nine years out when it's even hungrier, and when the Prudhoe production starts to decline, as it will. Out there is a revenue gap, and I don't believe the State has ever taken a hard look at it. It has always engaged in the wishful thinking that someone will find another Prudhoe Bay, or that somehow things will work out. Put it this way: if the oil industry wasn't here today to tax, you would have to increase the tax burden on all other Alaskan taxpayers, all of them, 200% or 300% just to support the government that you have going right now. It might be interesting to figure

that out. That's the kind of problem you have out ahead of you in this gap that I have been trying to describe, if you don't think about it today.

As a very practical matter, the principal source of the revenues the State will need to support its government and to sustain its economy, to sustain the jobs, the businesses, and the standard of living that most Alaskans enjoy today, will most likely have to come from some continuing, reasonable resource development in the State, and particularly development related to oil and gas. And that brings it back to us, the oil industry, whom you will eventually look to to do this job. You can't live with us, and you can't live without us!

It comes back to a couple of choices. Some will argue, well, let's tax the hell out of them and change the rules back when we've gone too far. I've heard that here occasionally in the last few years, but I think most Alaskans would agree that's a fairly shortsighted policy.

The other choice involves that matter of perception. Remember that word "perception" that Milton Lipton used. How will the companies in our industry perceive that they will be treated if they begin now to risk going out to find new oil and gas reserves in Alaska, whether it is a large one like

Prudhoe Bay or a number of smaller fields. If the size of the government and its budget are out of hand in the years ahead, a company can take very little comfort from the fact that it has an interest only in a small or medium sized field, and not a Prudhoe Bay. Its perception will be that it gets the tax bill, that government is a serious business risk here, and that it had better think seriously before undertaking that kind of risk.

At this point, you might like to consider a couple of other remarks that Milton Lipton made when he was here two weeks ago. He just didn't call the point of perception to your attention. What he also said was this, and again this is a quote:

> "From the first time we appeared before this Legislature to discuss taxes, we did not think from the beginning that your tax policy had to be uniquely constrained by the Cook Inlet experience. We did not think that the tax policy ought to be carried away by the exuberance of Prudhoe Bay. We thought your tax policies should be oriented pointing to a continuing incentive for the development of the potential oil and gas resources of the State."

Another point he had was a one liner, which I thought jumped right off the page:

"Because the industry is important to Alaska, no Legislature can be indifferent to the aggregate tax burden."

And then at several points in his testimony, he spoke about the importance of the continuity, of the stability of tax policy.

In different ways as he spoke to you this year, he was dredging up the points of perception and stability, and was really asking you to think about it because he couldn't decide things for you, nor can we. In this I think Mr. Lipton understands something about the State's needs. I know he understands the industry's needs because that's been the experience of his firm. He also understands the lead time necessary to get resource exploration and development going in the field and finally get production on stream.

The basic problem Alaska must face, its growing government, covering its costs, and keeping the State's economy going to support all the people who don't work for government, ties together the information that you've been receiving in pieces for the last two weeks. It makes clear the relevance of the Arthur Andersen work on total tax burden. Indeed, Mr. Lipton acknowledged the relevance when he said this:

"My first reading of the report suggests that it is a carefully prepared, highly useful document. I think it's been done in a highly professional manner. I think it is correct to say, as they conclude, that the aggregate burden of taxation on the oil and gas industry in Alaska is higher than in any of the other states."

It also shows the relevance of growing State budgets to the State's basic problem, the relevance of the growing numbers of State and local government employees, the relevance of growing State unemployment figures, and the relevance of the declining value in privately owned land with mineral potential as the aggregate tax burden increases.

I have some new information for you which I think you may be interested in. It also has relevance to the State's basic question. There's a man on my staff named Terry Schreiner. He looked into something that we were interested in this last week, and he gave me a brief report. I'd like to just read the summary of it. Terry said:

"I have looked at the drilling expenditures for oil and gas in Alaska for the years preceding Prudhoe Bay compared to more recent years. It shows that, although more money is being spent in Alaska for drilling, Alaska is getting a smaller proportion of the total drilling expenditures expended in the United States in recent years than it did in the years before Prudhoe Bay. For instance, in 1967 drilling expenditures in Alaska were (and I'll just

> round the numbers out, he has the exact figures here) $106 million or 4.62% of the total $2.2 billion spent in the whole United States. In 1976 the drilling expenditures in Alaska were $174 million or 2.34% of the total $7.4 billion spent in the United States. This loss of share of the drilling expenditures occurred in spite of the fact that in 1976, Alaska had drilling expenditures which were locked in because of the requirements of Prudhoe Bay. As a marketer of investment opportunities in oil and gas, Alaska is losing market share to the other states in the United States. The source of these figures are the 1967 and 1976 Joint Association Surveys put out by the American Petroleum Institute."

Terry's point is that your share of the work going on in drilling measured by expenditures ten years ago was a little over 4½% of the whole United States. Today, you are down to less than 2½%. The relevance of that to your basic problem, to your future revenue gap, seems to me fairly apparent.

But matters of relevance are not limited to numbers. I can think of some other people that you might want to invite to appear before your Committee, Madam Chairman, on this matter of perception--Mr. Lipton's word perception. One might be Don Simasko of Simasko Drilling. They are no longer working in Alaska. You might want to find out why, and what his perception is of your situation. The second might be a man named Tennessee Miller, who walked into these halls last year out of the blue, and upset some members of

this Legislature. He rattled a few cages. Now Tennessee Miller and I had never met before. He's a dirt pusher by trade. He builds roads, air strips, work pads and what not for the oil industry. His message last year was that he works when the oil industry works, and he wasn't working. At least three of his spreads were idle, and he didn't like it. Another point of perception.

A third and totally different perspective might come from a man named David Goodman, a managing partner of Morgan Stanley, investment bankers in New York. Mr. Goodman's credentials are obvious. He personally raised $5 billion of the money invested in Prudhoe Bay and TAPS, probably the Guiness indoor and outdoor record. Mr. Goodman has a perspective and a perception on how the investors who have the money needed here to do this work feel now and may feel about the questions that you are wrestling with.

Senator Ted Stevens is another one. I understand he'll be here shortly, I don't know the exact date, I think this coming Tuesday. In December he spoke before the OMAR Petrochemical Symposium in Anchorage, and he talked about this type of development here. One of his remarks was a point of perception which you may want to ask him about when he comes. He said:

> "Alaska's total taxes and royalties are now the highest among energy producing states. We are also, obviously, the most remote. If we want to develop and diversify our economy, we must provide the incentives to be competitive with more accessible states. If we want major capitalization from the private sector, we must provide a return on investment that makes their participation profitable. If we want long term cooperation from the Lower 48, we must provide their economic interests equitable treatment."

Another man that might give you some perception from quite a different quarter is a man who can talk a good deal about the proposed ALCAN Project. That's terribly important to the State of Alaska, and to most of the companies represented by people in this room. Sy Orlofsky is a man who works for Columbia Gas. I think he's a Senior Vice President. He has long experience in the gas industry, buying gas, shipping it and selling it. I first met him when he was a member of the Northwest Gas Project Study Group, and then knew him in the Arctic Gas project which has now been rolled into ALCAN. I think Sy's perception might be interesting to you. He won't tell you that permits will fall out of the sky, and that the money to do that project can be picked off the trees. He can give you about as hardheaded an appraisal as anyone I know of the probabilities and timing of that project that I think is critical to our industry and to the State of Alaska. I don't know that he can come, but I expect that if you extended him

an invitation, he would do it. He's just that kind of a man. His perception on that project could be extremely valuable to this Committee and the Legislature.

Another one is Jess Carr, an interesting man. I've not seen much of him personally, but I heard him speak in Anchorage in October. What he said that day was that jobs and resource development and Alaska's economic health go hand in hand. He raises that point of perception again and perhaps this Legislature might want to get some comments from him about it.

Still another perspective. You have a man named Bob Richards that most of you know. He is one of Alaska's top economists. Bob is always an optimist, but ask him what his 1979 case for Alaska is, first from an optimistic point of view, and then from a worst case point of view, and consider both as a matter of perception. And there are other witnesses you might call.

It seems to me that what you have right here on your Committee's table is this very basic problem that the State hasn't begun to deal with. It's a terrible problem. The appetite of government for revenue, the people's needs to

be met, and a very visible revenue gap out there that can only be met if you go to work today, right now, and try to fill it with the most likely source of revenue based on some reasonable resource development.

All of this sounds pretty negative, but I think that there is a positive side to it as well. The truth is that we need each other, and the sooner we recognize that, the better. Frankly, I would much rather come to Alaska as a partner and not as an opponent.

What can you do? I suggest six things. I have no monopoly on knowledge about the subject, but looking at it from the industry's perception, these are six things that I'd hope would be on somebody's list in the Alaskan government.

First, recognize that since 1968 with the various changes that had been made in the State's tax laws on oil and gas, the State has done a pretty good job of putting itself in a position to pay its bills as far as its government is concerned, and it will be in that position for the next eight, nine or ten years. Its back is not to the wall.

As a footnote to this first point, because there is always the question when you have an income tax bill before you, how does Alaska stack up against other states? If you will take a look at Exhibits II and X in the Arthur Andersen Report, you will see that the total income tax revenues from Prudhoe Bay and the pipeline to the State of Alaska under its own present law exceeds in gross revenues to the State what Prudhoe Bay and the pipeline would pay under the income tax laws of the other seven states compared in the Arthur Andersen Study. Said another way, the income tax law you already have on the books will produce more revenue than the other seven states compared. You've already got the winning combination, if that's the thing that you're worried about. When you are looking at the income tax legislation before you, the question is not tax deficiency and not a better law; it simply comes down to more money and nothing else.

But the first point of the six is to recognize that you can pay your government's bills comfortably, on your own projections, for the next eight or ten years.

The second point is this. Decide for yourself, if you are going to fill your gap by looking to more resource development and sensible development in the State. If that's your

judgement, then try to convince the industry that this type of longer run development is really important to the State from the standpoint of its own revenue position out there eight or ten years from now. Do something to convince the industry that short-term experimentation with your tax laws no longer makes sense. With the history of the last eight or ten years, you've got some persuading to do. I don't say this in an unfriendly way, but recognize that the industry in many ways may be in a "show me" posture. I think you can do it. Again, it's a point that so much needs your attention. That stability is a key if you are going to solve your basic problem.

Third, do the best job you can to manage the size and direction of your State and local government. If you can just hold even, you will have done a lot to help a fairly tough situation that's right out there a few years ahead of you.

Fourth, run your Permanent Fund on a businesslike basis. Draw as much as you can from the experience of private fund management. It's there if you seek it.

Fifth, before extending or implementing new or old regulation of industry, ask yourself, is it necessary? What does it really do for the State?

Sixth and from the standpoint of the majority of Alaskans who work for themselves or for companies here, recognize that a program of continuing resource development will undergird the State's economy for many, many years as it affects these people. You'll also have to recognize that resources can't be found and developed if you can't get to them. The current, and I would characterize it as a "non-leasing policy" in the State of Alaska does not solve this need. You obviously cannot have resource development if you can't get to the acreage. This is so whether it's onshore or offshore. If you set up a simple leasing program, like the gentleman said earlier this afternoon, stick to it, unless there is a very major reason for change. All of these things boil down to stability and make sense all around.

Finally, and this is a personal note, Sohio, and I think probably this is true of all the other companies in our industry working here, has no desire to run the State, not to run your government, and not to pre-empt it, but we sure would like to work here. I think this is consistent with what most of the people in Alaska want too. Your basic problem is there. You've got to face it sooner or later.

It's much better sooner, and I wish you well in that endeavor.

I brought you something that you may or may not want, but it might be useful to you because it deals with the perception point. This week I was in Washington to testify in the proceedings on the pipeline tariff before the Federal Energy Regulatory Commission. The subject of my testimony is a little embarrassing. It is a factual account from which counsel will argue that government at the federal and state level has become a major business risk. What I was asked to do, and what we did from a whole room full of documents that I set up sort of as a library in my department, is to summarize the history that we lived through in the five years that preceded the start-up of construction of the pipeline and a lot of work at Prudhoe Bay, in dealing with government, at the Federal level and here in Alaska, in terms of legislation, in terms of permit negotiation, and in terms of litigation. It is not written to offend anybody. It is a factual account and it occurred to me--this has been filed in Washington, but I have not formally given my testimony--that your Committee and any others that want it in the Legislature, might find that this is a useful reference. Some

members of the Legislature weren't here when a lot of this happened. I think we all need to have some feel of this prologue to wrestle with the basic problem I have been describing. Maybe it's nothing more than a souvenir, but if you'd like it, I offer it for your record and indicate that while it's probably not complete in every detail, it's not a bad summary of that period.

I brought you one other thing that I think I ought to give you because your Committee has dealt with the subject of Coastal Zone Management. Some of you worked very very hard in trying to get a model piece of legislation. I read it, and I thought on the face of the legislation it was a good piece of work. I want to confess to you that one of my other odd jobs in our industry right now is serving on a national committee of the American Petroleum Institute, called the National CZM Steering Committee. We have found that in the 34 states and several territories that are concerned with coastal zone management, government and public interest bodies of various sorts, generally self-appointed, have come up with the idea that they really don't want anything going on on their shoreline. If I had to say what their strategy is, it's this: if they can keep us on the beach, we can't go offshore to find

energy and bring it ashore. It's as simple as that. In some states you have well drawn laws as you have here in Alaska, but they are capable of being distorted one way or another. The purpose of this national committee is straightforward. It says look, national interest requires sensible development of energy. It requires attention to the environment, but you simply cannot lock up the shore. I think that this subject of coastal zone management is germane to your basic problem, since resource development onshore and offshore will have a lot to do with the economic health of Alaska in the years ahead. What I brought to you as another souvenir is a booklet that is just off the press that our national committee developed. In effect it sets forth what I think is a fairly balanced position, the viewpoint on the part of industry that all reasonable uses of coasts have to be considered. Its title is "A Shore for All Purposes". If you can't read all of it because you have so much to read, you'll see that there is an executive summary for legislators and executives inside the cover. I recommend it to you. I only have a few copies, but I just brought these for your Committee because I knew of your past interest.

Thank you very much. If you have questions, I would be happy to answer them.

Question: The first thing I wrote down here in my notes while I was listening to Dick was the point concerning the court decisions. A huge welcome to SOHIO as being an Alaskan citizen.

Answer: Thank you. This is my 49th trip to the 49th State.

Senator Huber: Professor Parkenson had written on it ....on this tax study about governments rising always to meet the available profits. I'm sure that Dick might even have discovered this separately.

Answer: You understand, Senator, I'm not trying to find fault. These are essentially observations. You come to a place and you just see this going on. We've known each other for a few years now, and I'm just telling it as it is.

Senator Huber: I really want to know, Dick, you said that all of the problems that the companies have in dealing with the tax policies, I get from you that it isn't just this jurisdiction, it's many other jurisdictions that the oil companies are in doing this. As the needs for taxes raise, it goes to the most logical places.

Answer: Let me respond to that. As a practical matter, you do see a similarity of problems in other states. There is a difference in Alaska which I will confess to, and that is the velocity of the problem. Decision here is notably faster. I don't mean that again in an offensive way, it just is an accelerating thing here.

Senator Huber: I don't think it is. Your problem seems to be parallel with another one. Your problem of the companies being able to interface with the taxes and how the burden builds. It seems to be like a man quite a few years ago in government stated. You probably want to comment on it. It is interesting that Franklin Delano Roosevelt said that you couldn't win an election in this country without the support of big oil, and you couldn't govern with it. So he was having trouble from that viewpoint; oil companies are having trouble from the viewpoint of being able to operate a business under the government's taxing policies.

Answer: That's why I said half seriously and half kidding, you can't live with us, and you can't live without us. Thank you.

TESTIMONY OF

COMMISSIONER STERLING GALLAGHER

BEFORE THE

RESOURCE COMMITTEE

OF THE

ALASKA STATE SENATE

February 22, 1978

STERLING GALLAGHER

MADAME CHAIRMAN AND MEMBERS OF THE SENATE RESOURCES COMMITTEE:

I WANT TO THANK YOU FOR GIVING ME THIS OPPORTUNITY TO TESTIFY TO YOU ON THIS IMPORTANT ISSUE OF INCOME TAXATION OF THE OIL INDUSTRY.

I HAVE TESTIFIED AT GREAT LENGTH LAST YEAR ON THE SPECIFICS OF THE INCOME TAX BILLS WHICH WERE BEFORE YOUR COMMITTEE, INCLUDING THE GOVERNOR'S FRANCHISE TAX BILL AND THE SEPARATE ACCOUNTING BILL WHICH IS NOW BEFORE YOU.

RATHER THAN REHASHING THOSE POINTS AND ARGUMENTS I WOULD LIKE TO SPEAK TO YOU ON WHAT I BELIEVE IS THE MOST IMPORTANT ISSUE - ESTABLISHING AN EFFECTIVE AND EQUITABLE INCOME TAX SYSTEM FOR THE OIL AND GAS INDUSTRY IN ALASKA.

BY EFFECTIVE, I MEAN A TAX SYSTEM WHICH IS FREE OF THE SPECIAL CORPORATE TAX LOOPHOLES AND WHICH IS ACCURATELY MEASURED BY ACTUAL BUSINESS ACTIVITY AND EARNINGS IN THE

STATE SO THAT EFFECTIVE TAX RATES APPROXIMATE STATUTORY TAX RATES ON INCOME PRODUCED IN THE STATE.

BY EQUITABLE, I MEAN A TAX SYSTEM WHICH PLACES MULTISTATE CORPORATIONS ON A PAR WITH LOCAL CORPORATIONS. THAT IS - MULTISTATE OIL CORPORATIONS MUST SHARE EQUALLY IN THE CORPORATE INCOME TAX PAYMENTS TO THE STATE BASED UPON THEIR EARNINGS AND ACTIVITIES WITHIN THE STATE.

UNTIL AN INCOME TAX SYSTEM WHICH IS BOTH EFFECTIVE AND EQUITABLE IS ADOPTED FOR THE OIL AND GAS INDUSTRY, I BELIEVE WE WILL HAVE TAX INSTABILITY. UNTIL THIS INEQUITY WITH THE INCOME TAX IS DEALT WITH ONCE AND FOR ALL THERE WILL BE CONTINUAL PRESSURE FOR CHANGE, AND IT WILL BE AN ISSUE BEFORE THE LEGISLATURE EVERY SINGLE YEAR UNTIL IT IS RESOLVED.

FOR SEVERAL YEARS NOW, THE LEGISLATURE'S OIL AND GAS CONSULTANTS, WALTER LEVY AND ASSOCIATES HAVE RECOMMENDED A REVAMPING OF THE CORPORATE INCOME TAX AS APPLIED TO THE OIL AND GAS

INDUSTRY. FOR THE LAST THREE YEARS SEVERAL BILLS HAVE BEEN INTRODUCED IN THE LEGISLATURE TO DEAL WITH THE INCOME TAX ISSUE. LAST YEAR BOTH THE DEPARTMENT OF REVENUE AND A SPECIAL SUBCOMMITTEE OF THE LEGISLATIVE COUNCIL MADE EXTENSIVE STUDIES OF ALASKA'S CORPORATE INCOME TAX AS APPLIED TO OIL AND GAS CORPORATIONS AND MADE SPECIFIC RECOMMENDATIONS TO REFORM THE INCOME TAX. I BELIEVE THAT THIS YEAR IS THE TIME TO FINALLY REFORM ALASKA'S CORPORATE INCOME TAX.

AS STATED BY THE DEPARTMENT AND OTHER SOURCES, THE OIL AND GAS INDUSTRY PAYS AN EFFECTIVE ALASKA INCOME TAX RATE OF BETWEEN 2 TO 3 PERCENT ON THEIR ALASKA INCOME. THIS RESULTS FROM TWO FACTORS - A SUBSTANTIALLY ERODED FEDERAL TAX BASE AND AN INAPPROPRIATE APPORTIONMENT FORMULA. THE COMBINATION OF THESE FACTORS THEN RESULT IN MULTISTATE OIL CORPORATIONS PAYING LESS TAX THAN THAT OF LOCAL CORPORATIONS ON THE SAME INCOME EARNED IN THE STATE.

THIS INEFFECTIVENESS OF OUR INCOME TAX IS EASILY DISPLAYED BY SIMPLY EXAMINING THE ACTUAL INCOME TAX PAYMENTS MADE BY

THE OIL INDUSTRY OVER THE PAST FEW YEARS AND LOOKING AT OUR PROJECTIONS OF FUTURE INCOME TAX COLLECTIONS.

FOR EXAMPLE, IT WASN'T UNTIL THE 1973 TAX YEAR THAT CORPORATE INCOME TAX PAYMENTS FROM THE OIL INDUSTRY FINALLY CREPT ABOVE THE $1 MILLION DOLLAR MARK. AND DURING THE LAST 3 YEARS OIL COMPANY INCOME TAX PAYMENTS HAVE TOTALED $2.1 MILLION, $3.7 MILLION AND $4.4 MILLION RESPECTIVELY. IN FACT, TOTAL CORPORATE INCOME TAX PAYMENTS OF THE OIL INDUSTRY FOR THE LAST SEVEN YEARS HAVE BEEN ONLY $13,108,000. THIS REPRESENTS 9.4 PERCENT OF APPROXIMATELY $140,510,000 IN TAXABLE INCOME OVER THE LAST SEVEN YEARS.

TO VIEW THIS TAXABLE INCOME REPORTED BY THE OIL INDUSTRY IN PERSPECTIVE YOU NEED ONLY MULTIPLY LAST YEAR'S OIL PRODUCTION FROM COOK INLET TIMES 50 PERCENT OF ITS AVERAGE WELLHEAD VALUE TO FIND THAT IT EXCEEDS THE TOTAL OIL COMPANY INCOME TAXED BY ALASKA FOR THE LAST SEVEN YEARS. IN FACT THE SEVEN YEARS OF REPORTABLE INCOME REPRESENTS A LITTLE LESS THAN .25 PER BARREL OF THE OIL PRODUCED FROM COOK INLET OVER THE SAME

SEVEN YEAR PERIOD. THESE REPORTED INCOME FIGURES DO NOT I BELIEVE REPRESENT THE NET INCOME EARNED NOR REFLECT THE ACTIVITIES IN ALASKA BY THESE COMPANIES DURING THIS PERIOD.

NOR IS THIS INEQUITABLE SITUATION LIKELY TO CHANGE MUCH IN FUTURE YEARS EVEN AS A RESULT OF THE HIGHER PROFITABLE PRUDHOE BAY PRODUCTION. BASED UPON ACTUAL TAX RETURN INFORMATION WE ARE ONLY ESTIMATING ADDITIONAL CORPORATE INCOME TAX REVENUES AS A RESULT OF PRUDHOE BAY PRODUCTION OVER THE NEXT TWO YEARS OF $2.3 MILLION AND $23.6 MILLION DOLLARS RESPECTIVELY. AGAIN THIS REPRESENTS ONLY A SLIGHT RETURN FROM THE SUBSTANTIAL INCOME EARNED AND ACTIVITIES TAKING PLACE IN THE STATE.

THIS INFORMATION IS IN MARKED CONTRAST TO THE PREDICTIONS OF LIKELY INCOME TAX REVENUES PROVIDED BY THE OIL INDUSTRY AND THEIR CONSULTANTS. FOR EXAMPLE, LAST YEAR IN SOHIO'S SUBMISSION #1, SOHIO ASSUMED CORPORATE INCOME TAX REVENUES TO THE STATE OF ALASKA OF $27.4 MILLION DOLLARS IN 1977 AND

$62 MILLION DOLLARS IN 1978 IF OIL WERE SOLD IN CALIFORNIA FOR $13 PER BARREL.

IN ADDITION, THE ARTHUR ANDERSON STUDY SHOWS ALASKA INCOME TAX REVENUES OF $1,747,100 OVER A 25 YEAR PERIOD OR AN AVERAGE OF $69,884,000 PER YEAR.

THESE REPRESENTATIONS OF INCOME TAX COLLECTIONS JUST DON'T MATCH THE PAST TAX RETURNS OF THE OIL INDUSTRY OR THE LIKELY RETURNS IN THE NEAR FUTURE.

AGAIN LET ME EMPHASIZE THAT WE NEED AN EFFECTIVE CORPORATE INCOME TAX. ONE THAT TRULY REFLECTS THE BUSINESS ACTIVITY AND INCOME EARNED IN THE STATE.

IN RESPONSE TO FACTS OF THE ACTUAL EFFECTIVE INCOME TAX RATES PAID BY THE OIL INDUSTRY YOU HAVE HEARD SUBSTANTIAL TESTIMONY BY THE OIL INDUSTRY CONSULTANTS JUSTIFYING THE RESULT OF LOW EFFECTIVE TAX RATES IN THE NAME OF UNIFORMITY.

I TOO BELIEVE THAT UNIFORMITY IS A LAUDABLE GOAL FOR THE STATES AND THAT IS WHY I AND MY DEPARTMENT ARE ACTIVE PARTICIPANTS IN THE MULTISTATE TAX PROGRAM OF THE MULTISTATE TAX COMMISSION. THIS DOES NOT MEAN, HOWEVER, THAT WE SHOULD BLINDLY MARCH IN LOCK STEP IN THE NAME OF UNIFORMITY AND IGNORE OUR RESPONSIBILITY OF PROVIDING AN EFFECTIVE AND EQUITABLE CORPORATE INCOME TAX SYSTEM. I BELIEVE THAT WE HAVE A DUTY TO INSURE THAT THE CORPORATE INCOME TAX SYSTEM RETURN TO THE STATE, TAX REVENUES WHICH ACCURATELY REFLECT THE BUSINESS ACTIVITY AND INCOME EARNED IN THE STATE EVEN IF THE INCOME IS EARNED BY CORPORATIONS THAT DO BUSINESS THROUGHOUT THE WORLD. THE ACTUAL INCOME TAX REVENUES RECEIVED TO DATE AND PROJECTIONS OF FUTURE INCOME TAX REVENUES DO NOT, I BELIEVE, REFLECT THE SUBSTANTIAL BUSINESS ACTIVITIES AND PROFITS EARNED IN ALASKA IN PAST YEARS AND THE FUTURE BY THESE MULTINATIONAL CORPORATIONS.

I DON'T THINK WE CAN TOLERATE ANY LONGER A CORPORATE INCOME TAX SYSTEM ON THE OIL INDUSTRY WHICH ALLOWS MULTINATIONAL CORPORATIONS TO AVOID TAXES ON SUBSTANTIAL EARNINGS BY TAKING ADVANTAGE OF ALL THE SPECIAL FEDERAL TAX AND ACCOUNTING DEVICES AND BY THE USE OF AN APPORTIONMENT FORMULA WHICH DOES NOT ACCURATELY REFLECT OIL INDUSTRY ACTIVITY IN THE STATE. IN ADDITION, I DON'T THINK WE CAN TOLERATE A SYSTEM WHICH BECAUSE OF THESE LOOPHOLES AND UNREPRESENTATIVE FORMULAS ALLOW LOCAL CORPORATIONS TO PAY HIGHER EFFECTIVE TAX RATES THAN MULTINATIONAL CORPORATIONS FROM LIKE ACTIVITIES.

I THEREFORE ASK FOR YOUR FAVORABLE CONSIDERATION OF AN EFFECTIVE AND EQUITABLE CORPORATE INCOME TAX FOR THE OIL AND GAS INDUSTRY. I BELIEVE THAT THE TAX BILL WHICH WE HAVE PROPOSED MEETS THIS CRITERIA.

THAT BILL WOULD HAVE ELIMINATED ALL THE CORPORATE LOOPHOLES THROUGH THE ADOPTION OF A BOOK INCOME DEFINITION OF TAXABLE INCOME. IT ALSO WOULD HAVE SOLVED THE PROBLEM OF THE

APPORTIONMENT FORMULA BY SUBSTITUTING AN EXTRACTION FACTOR FOR THE SALES FACTOR AND THEREBY PROVIDING A MORE ACCURATE MEASURE OF OIL INDUSTRY ACTIVITY AND INCOME IN THE STATE. I BELIEVE THAT THAT BILL WOULD FOR THE FIRST TIME PROVIDE BOTH AN EFFECTIVE AND EQUITABLE INCOME TAX FOR OIL AND GAS CORPORATIONS.

AS YOU KNOW, HOWEVER, I AM OPPOSED TO THE SPECIFIC BILL THAT IS BEFORE YOU SINCE I BELIEVE THAT IT COULD LEAVE US WITH JUST ANOTHER INEFFECTIVE INCOME TAX. I AM OPPOSED TO THIS BILL BECAUSE IT WOULD ALLOW ONE PART OF A BUSINESS TO CALCULATE ITS OWN TAX LIABILITY BASED UPON SUCH ITEMS AS INTERCOMPANY TRANSPORTATION CHARGES. THUS WE COULD POSSIBLY BE LEFT IN THE SAME SITUATION THAT WE FIND OURSELVES IN TODAY WITH SEVERANCE TAX AND ROYALTY COMPUTATIONS - THAT IS INCOME SUBSTANTIALLY REDUCED BY INFLATED TRANSPORTATION CHARGES.

THEREFORE, I WOULD ASK FOR YOUR FAVORABLE CONSIDERATION FOR THE APPROACH CONTAINED IN THE ORIGINAL HB 322 AND ESTABLISH AN EFFECTIVE INCOME TAX ON THE OIL AND GAS INDUSTRY.

INCOME TAX PAYMENTS
BY OIL AND GAS CORPORATIONS

1970-1976 Taxable Years

47 COMPANIES	1970	1971	1972	1973	1974	1975	1976	TOTAL
			(thousands)					
TOTAL	484,620	587,304	519,598	1,230,100	2,161,053	3,765,285	4,460,019	13,207,979

TESTIMONY OF RICHARD KILGORE
DIRECTOR OF RESEARCH FOR
W.J. LEVY CONSULTANTS

RICHARD KILGORE - I am trying hard not to take it as a reflection of my testimony that every time I testify fewer people seem to show up, but this is a Saturday morning and its not quite like the middle of the week. My opening remarks, if you recall, were, try to present some overview of the various types of taxation on the issues and principals of oil and gas taxation. My second testimony before Senate Resources, and in the afternoon before the two committees, tried to elaborate and sharpen the pros and cons in approaches to income taxation, that is the apportionment verses seperate and direct accounting. Now today, I would like to provide you with our comments on the specifics on the bills before you, and also take the opportunity to address some of the issues raised by other testimony you have heard. And I would like to start again with the income tax. Before I get to the specifics there, I would like to discuss very briefly, some of the broad questions raised by industry spokesmen, in which they say that any deviation from the present three factor proportionate formula raises the potential for double or multiple taxation. I think this point was realsed by every one of the oil campany spokesmen. I want to make it clear that if all states used the three factor proportionate formula only, then the total income of the companies is apportioned to all the states and the sum of the tax basis in the individual states will add up to the corporations total income, and the deviations,

either by different factors such as the (Eathen, Ainsworth approach?) as substituding abstraction or going to book income or going to some sort of seperate accounting approach does tend to work in the direction of raising the tax basis of states that do that and has the tendency of each of the states in their own approach to taxation identifying a tax base which when added up on total would be somewhat more than the total income of the corporatio I think there can be no denying this, taking either of these t o approaches, does raise the potential for double taxation. This is clear, but against this Alaska has to be concerned with how the apportionment works for the State itself, and how, not simply how the system works in broad for the companies and equidy for the companies, but how it works for the State of Alaska and what sort of income is thrown up for the State of Alaska, it can't ignore this either. The State, looking at its own situation, I think in many respects does have a unique situation to look at, in many respects Alaska is unique and the taxation of oil and gas in Alaska in itself is unique. As I don't really have to tell you, oil and gas is far in the way, the largest industry and will be the largest income producing industry in Alaska. Alaska also does not have other industry, much in the way of other industry other than oil and gas it does not have major, it does not have agriculture on any kind of major scale as do other states, so many other states with a broader economic base can afford to have apportionment formulas

which they work well for some industries, not so well though for others and so forth, they tend to more average out than certainly they would for the State of Alaska. Another unique feature of Alaska's situation is its oil and gas industry is largely extractive and transportation ends of the business, Alaska does not have major refineries as do other states such as California, Louisiana, and Texas. It does not have major mardeting because it has limited markets on it because of its limited population, so it does not have major investments in mardeting and alike as other states do. So without refining, without marketing, head offices are not located here and so on, it does not have many of tnese factors which in other states have helped the apportionment formula work for the states. That is where you have all of these other activities, one tends to have larger payrolls, there are larger numbers employed in these other functions tends to apportion income to those states. It does not have major sales within the state and so on. So this also makes Alaska's situation unique and as we have said many times, it tends ti make the three factor a-portionment formula not particulary effective for Alaska. So on the one hand, the industry's argument is certainly a legitimate one and they have every right to be concerned about totential for double taxation and I think, beyond that, the potential that if you adopt this sort of a system that other states may somehow follow you and if this happens to them they more and more run the risk that the sum of the tax basis in all the states exceed their own income and this is a very legitimate concern of theirs. On the other hand, you do have these unique features of the oil and gas industry in Alaska that I have just mentioned. This means that Alaska really has to weigh its own unique

circumstances against the violence done to the principal of uniformity and the potential for double taxation, if you alter your income tax, you must appreciate what you are doing and what you are doing to the companies, you have got to attempt to assess, at least broadly what it really does mean to the company it violates the principal clearly, but what does it mean in terms or dolars and cents of the potential for double taxation in those terms and I think in that respect, some of the questioning of Senator Croft yesterday was along those lines and I think you probably also should pursue this somewhat more. You have to admit what you are doing, it would work in this direction but you have to get some appreciation of exactly what that does to oil companies. And I think in that respect if you are looking at that, I think, it is relevent that the oil industry is not taxed in all states, there are some states that do not have a corporate income tax and I think it is also relevent that the tax rate in other states is often lower than it is in Alaska. So if you are looking at the double taxation issue, I think this is relevent because it bears on how much are they really hurt by this kind of double taxation fort of thing which other approaches imply. And I think you have also been concerned, to some extent, that what you do would set a precedent for other states and, this is a legitimate concern of the industry, I don't know any other situation, at least I can't think of any other situations which what you are doing would immediately trigger something by some other state, but still the potential for that happening is there. So I think its very important for you to appreciate that what is being said is correct, you have your own interest, and if you are going to go this approach, that you appreciate what you are doing and try to get some feel for what it really means to the

companies. Now I would like to move on to some specifics on the bills before you, the income tax bills, and I would like to start with Senate Bill 236, and House Bill 322. This is the so-called corporate franchise tax and it is a modified apportionment formula. Now, here we really don't have comments on the bill itself and the way its drafted, it is, as far as we can see, a well drafted bill, does what it is intended to do, and I think in the respect of this bill the questions we have on the bill really have to do with the effectiveness of the approach and not really the specifics in the bill. It seems to do what it intends to do and the question in mind is, how effective is the approach this bill is attempting to use, so I really won't have any line-by-line comments on that, but I will on H.B. 105, excuse me, S.B. 105, H.B. 145, somehow I seem to have misplaced that one. Yes, Senate Bill 105. I would first like to call attention to, on page 1, line 18, to the intent of this bill, the intent of the bill seems to be, have to do with the determination for tax liability on production and pipeline activities, it addresses itself to these activities and in fact, uses the work "activities", it is not a tax on an entity, its tax on activities, now this approach would presumably differ from a net proceeds approach which taxes income form well or field or this kind of thing. This is presumably looking at these particular activities, that is oil and gas production activities and oil and gas transportation activities. And this is what the intent states, but when I am going to come to later sections and discuss those, I think it looks to us as when you go into the sections of the bill, which involve the calculation of the tax it doesn't really seem to be consistent with the intent to tax activities which is stated in the beginning, and I will ella-

borate on that when I come to it. I would also point out on page 1, line 28, that when it comes to taxing oil and gas transportation, like pipeline, this bill refers only to crude oil or natural gas by pipeline, the wording of the bill very specifically excludes products pipelines in the state and you have a products pipeline coming on soon I believe, I don't know whether this was the intent of the bill, I just want to point it out to you but this particular piece of legislation specifically excludes products pipelines and I question whether this was deliberate or not, I think you ought to consider that. Moving on to page 2, line 24, these are the costs that could be deducted under this bill. It has costs, including the cost of gathering, gathering is used there. Now, the point I want to make on the use of the words "cost of Gathering" is that these costs of gathering may very well be beyond the well head. This is a bill which takes well head value as the income and starts deducting cost, gathering cost may be beyond the well head in which they don't, in this case if they are beyond the well head they do not go to build up the well head value, but in fact, rather serve to reduce the well head value, so in effect if you take this treatment of using gathering costs as a deduction and these gathering costs are beyond the well head, in fact what you are doing seems to be allowing a double deduction, double deduction.

QUESTION- Thinking that the tax is placed at well head, and these are beyond the well head so its a bouble deduction.

KILGORE - It is a double deduction, right, it could be a double deduction, in fact I don't know how it is going to work on Prudhoe Bay, but the gathering could in many areas trump lines that also are the gatherers, it could be in this case that Alyeska pipeline would be the gatherer and you would be taxing them under this bill then you would also be allowing against oil and gas production a gathering

charge or a gathering cost so I think you ought to, this is something that needs to be cleared up, if it is gathering, maybe it should very specifically say, "gathering before the well head" or something of this sort. Your wording should establish some kind of consillience between the value in the producing function and the value of the activities in the transportation function beyond that. My next comments are on page 3, line 1, again we are talking about expences that can be deducted when it talks about lease acquisitions payments on the well head, lease acquisition payments, property taxes paid before the production on the lease holds, so what we are talking about are lease acpuisition payment on the lease holds, now we are going to underscore on the lease hold. Now its not clear to us with this kind of wording whether this is ment to be restrictive so that the deduction for these kinds of costs are restricted to producing lease holds, or is this generally an applicable feature of the law, that is when we use a word on the lease hold does that mean we are confining deduction ofthose costs specifically to income from that lease hold or is it more generally deductable. This sort of problem I think runs all the way through here and this particular section looks to us as if it might be intended to be restricted, that is restrict the income against which these acquisition costs could be written. Especially if you look at this in the content of section 7, a little further below it appears to us that this may be the intent. And that same problem comes up on the same page 3, on line 9, where we have associated with a lease hold, another case we have "field" in this particular wording here and, I think in another section there's the use of the word "property". Now, if these different words are used in here, I think that it ought to be made clear that there

is a intended destinction amongst these various things, I am going to come later, to a more general approach to this, where one really wouldn't really need these kinds of words and this seems to imply to us that there is some destinction between these and therefore, there is some restriction against, restriction on what income various kins of catagories acrossed here can be written off. In general, the wording of this whole section here on deductions really seems to be closer to us to a net proceeds tax than it is what we would call a seperate accounting approach. The wording here would seem to imply that to us if it doesn't mean that I thank the wording ought to be changed, it ought to be very clear against which income you can deduct, your various expences. For example, it is not clear to us in the wording of this bill how a producer who has income, say in Prudhoe Bay, has made another oil discovery and he is in the process of developing that discovery, putting in producing wells and the like, it is not lear under this bill, to us, how he could handle those development costs, would be able to, if he had to capitalize it, could he start writing them off immediately against his Prudhoe Bay income or his other income, or would he have to capitalize those and wait to deduct some sort of, that capitalized cost until he had production from this other new field that he has, so its not clear to us what is really intended in this bill, is it really a seperate accounting approach or is it something closer to a net proceeds. This raises the question of what should be your basic approach. Now if what is intended here is really seperate accounting, under an income tax and not a seperate kind of tax as a net proceeds was, we would think a more appropriate way would be really, to consolidate all the exploration, development and production

revenues and costs anywhere in the State. That is one would take revenues where ever they were from oil production or production of oil and gas in the State, and then be allowed to deduct all expences having to do with the activity of exploring, development, producing oil and gas, and this ould mean allowing the expencing of dry wholes here agains income there or development costs, amortization of development costs as against your income elsewhere, and we think if this is really an income tax approach, this makes more since really than an attempt to narrowly link expenditures with producing income from specific fields, even if you then allow some sort of write-off for losses and so on. We think it makes more since to go a more consolidated approach and it does not appear to us that the working nearly does that. Moving on to page 3, down on line 24, this is where we get into the determination of pipeling transportation income, the first section of this has to do with pipelines that, operating solely in interstate commerce and in this case subject to ICC regulations. Now what the bill sets as taxible income under those situations is 8% comes from, ICC said that one can set tariffs no higher than that level which would result in a 8% return on valuation of the pipeline, thats where this comes from, and seems to be an attempt to get that income. Well, first of all there would appear to be a technical flaw if this is the intention of the bill, to tax from the basis of ICC income. If you may recall, the ICC 8% allowable return on pipeline valuation is 8% after tax, <u>that is after income taxes</u>, after the deduction of all income taxes, including federal income tax, therefore, if this tax were operative and you were taxing at 8% of the valuation of the pipeline, you would be taxing 8% of <u>after tax</u> income, not before tax, and I don't

think that was the intent of this bill. All your other sorts of taxes are always on before tax income, your present tax law starts with taxable income, federal taxable income, well, this is before the deduction of federal income taxes and this is after the deduction of federal income taxes, a very much smaller tax base, and I don't think your intent ever was to tax after the federal income tax was already deducted. So I think this was probably just a technical problem here I don't believe it was really an intent to tax after tax income rather than before tax, and if the intent is to really do this, that is tax assentually on a ICC basis this is what you would obviously have to do I think is to take 8% after tax, add back the federal income tax, gross it up to a pretax concept. Again I think this is just a technical matter, I don't think this was the intent.

SEN. HUBER - I think, I wish Chancy were here, I think it was their intent to tax it after, if that was their intent, would you have any comments that would apply to it?

KILGORE - Well, I don't really know what the prupose of it would be, your general principal of taxation in most cases for corporations taxes in states is to tax on a taxable income basis before deduction of federal income taxes. And it seems to me, you are kind of restricting yourself to roughly half what kind of tax base you normally would try to reach.

SEN. HUBER - If the intent was to tax after, would this have the effact of not allowing it to be put into the base in such a manner that it would decrease the value of the oil? In other words, the value of Alaska's oil would decreace by the transportation charges and the profits on the transportation. They may have been aiming at that particular item.

KILGORE - Sentor Huber, I don't see how it would work that way because no matter, what ever state taxes you impose on the pipeline I don't care whether they are on a before tax, after tax, or property or whatever basis, they are going to be a liable deducation under ICC rule making. Going to a lower base and taxing less will not, it will still be a deduction obviously, it will be a lower deduction, but if thats purely your aim, you can not tax them at all if you want to get the well haired by that, if thats what you really have in mind. I think this is, you can talk to the people who wrote this but I think this is an oversite. This is a technical matter, I want to point it out because I suspect it was not the intent, but we also feel that this method of taxation has problems anyway it is clearly tax on deemed income, it does not look at the actual revenue of the pipeline, it does not look at the individual costs incured by the pipeline, its deed, and it may very well not accord with the income actually earned by the pipeline. That is even if the pipeline, a Alyeska pipeline is setting tariffs in line with ICC rule making trying to get the maximum 8% there is no assurance in any one year that they will in fact earn 8% on valuation obviously, you don't know exactly what your costs are you don't know what the values are going to be and so forth, so what you do is set a tariff which would appear on a projected basis we will try to get your 8% valuation, there is no assurance from year to year that you may in fact earn income greater than 8% of valuation or less than 8% on valuation, there is just no knowg exactly what sort of results you will get, and so certainly the ICC itself does not intend that exactly 8% is earned every quarter every year and so on, its just an impossible thing, it just can't happen, infact if youlook at the ICC records,

you will see thats clearly the case, not every pipeline is earning exactly 8% from year to year. So we think the real problem with taxing on a deed basis an aproach which looks at the actual revenue and expenditures of the pipeline, one of the other whitnesses yeasterday asked if this was in fact legal to do it on a deen basis,we don't know the answer to that but it may very well be legal questions with this, there are also questions with equity, taxing in a dean basis rather than an actual basis.
Sen. Huber- it it possible then that they just intended to use the lower base so it would be effectivly about 4% insteat of 8%, is that possible
Kilgore- thats possible, that would be . .
Sen. Huber - cause I can see what they are trying to get to, if you have to tax these oil pipelines in accordance with persentage of interest, mobile oil pipelines all over the country areall worked into the company and you get that scrambled egg that you can't unscrambly, and I hhink they were problaly willing to take a smaller persentage right off of the interstate Alaska line at a point where tthey would get it ratherthan unscrambling that egg., I think thats the attempt.
KILGOR_- Senator Huber, it is my understanding that out of some underlegisltaion you passed in past session that the companies will be providing you withan accounting of Aleyeska pipeline, unscrambled from the rest of their pipeline oppgrations. That is my recolection, and the pipeline regulatory bill, this is one of the provision and one that was not taken out laterthat the companies will infact provide you withrevenues, costs for Aseyeska pipeline
HUBER- again, this wasn't something that I helped draft, but I believe you to know information is to be provided the mechanisms

in our income tax law for unscrambling it and getting to the income of the pipeline just from Alaska are considered to be unyielding or don't exist. I think that's where the egg scramble is. I think that's what we've got here. It just may help in you telling us how to do it. I wish Chancy was here again, as I say. Is he coming back Madam Chairman?

CHAIRMAN POLAND - No.

SENATOR HUBER - He won't be back this morning. I had counted on him being here, he said he was going to.

CHAIRMAN POLAND - He's at a finance meeting.

SENATOR HUBER - The reason is because the bills that he's talking about now by the subcommittee, Chancy and Greg are the people that can really help us on them, and they should be here.

CHAIRMAN POLAND - Well, don't tell me Senator Huber, tell him.

SENATOR HUBER - Well, I can't tell another Senator what to do, but I'd really counted on him being here. It's too late now. We could have Greg and we'd be getting more information.

CHAIRMAN POLAND - I don't know why Greg isn't here. Let's go on anyway.

RICHARD KILGORE - Well, some of the intent of this section, I think, becomes clearer when you get to later sections about the Alaska Pipeline. I would like to point out though, that this taxing on this basis of inter-state pipeline at the 8% also really doesn't give them much of any incentive, no incentive really to lower their tarrifs if they're really interested in doing it. What is being taxed at that full 8% and you go to a lower tarrif, you don't even get any income tax benefit for doing that, so I'd like to point that out.

SENATOR HUBER - And even if you taxed it at half of that, it would be the same kind of incentive situation.

RICHARD KILGORE - Yeah, there just is no incentive to do that. You're going to pay on that regardless of what you do, unless you go to the other section of the bill that follows a little further on, which appears to be an attempt to strengthen the Alaska Pipeline Commission. That's a section just a little bit further on. Now, we basically wonder whether this is really necessary that one would try to force people through your income tax legislation to accept rules and regulations, and so on, of the Alaska Pipeline Commission through an income tax approach. I think we should also point out that under this

bill if a company, pipeline company, wishes to set tarrifs, say, lower than what would give him 8% on valuation, in fact, he may very well want to set tarrifs along the line established by the Alaska Pipeline Commission, but he may not want to go as far as the section here that says that he has to abide by all the rules and regulations of the Alaska Pipeline Commission. He may not want to go that far, but he may be willing to set tarrifs along the lines that the Alaska Pipeline Commission feels are appropriate, and he'll still be taxed at the 8%. He has to go all the way in order to have his income calculated in another way along the lines of the Alaska Pipeline Commission, and we really question whether this is the proper vehicle for trying to strengthen the Commission. We think there's a question also on the bottom of Page 3, where there's no ICC valuation where companies engage at least partially in intra-state commerce, and then it talks about he can have his taxes assessed on the basis of the Alaska Pipeline Commission assessment of income, and it's not clear to us from the wording here whether, what this means. Does this mean the rules of the Alaska Pipeline Commission as applied to the total operations of this pipeline which is both an inter-state and intra-state commerce, or does it only mean that part of the business of the pipeline which is purely intra-state. I suspect the intent means all. The Alaska Pipeline Commission rules and assessments of income as applied to the total business of the pipeline, but it's not entirely clear to us that this section says that.

As I said before, when you come to Page 4, Line 14 where the election, there is an election, it may very well be that companies are willing to set tarrifs more in line with what Alaskan's deem are appropriate, but still be reluctant to subject themselves to all regulations and so forth, provisions of the Commission. A minor technical problem on Page 4, Line 21, where we're talking about taxation of gas pipelines, this has to do with income along procedures established by the Federal Power Commission. I think it would work out very well to say Federal Power Commission or Assessor because as you may know there are, President Carter has proposed a reorganization of our energy, various energy agencies in the United States, including a Department of Energy which would include in it the Federal Power Commission, so it may very well be subsumed under something else, so I think it should say that. Now, our feeling is that if you're going to go the separate accounting route, I think you ought to consider carefully, rather than these sort of provisions that appear here, a more straightforward kind of separate accounting approach for oil pipelines. As I said before, it is our understanding that all the revenues and costs of the Alyeska Pipeline will be made available to the State, that is they will not be hidden in all the other pipeline operations of the companies in the lower '48, which would hav been the case without your own provisions for them, but you will, it is our understanding, get the information, and it would seem to us a more straight-

forward approach to take these data and assess what the income is of the pipeline. One may want to take the information given and change depreciation rates or something of this sort. You may not want to use the same ones that the ICC does, as would be given to you by the companies, but you would have information to make a straight-forward accounting of the pipeline, if you desire to go the separate accounting route, and if you do, we would urge that you look carefully at that rather than these sorts of provisions here.

On Page 5 we have a section for the determination of income from other activities, that is from activities other than the oil and gas production and transportation, which you dealt with on the separate accounting basis, and what it amounts to is an apportionment formula for the rest of the income. Now, we think that the language here is really not clear either. There is talk about adjustment of factors to take out of the factors, say the payroll, etc., that are involved in the production and transportation section before which are separately accounted. One would take those out it says, but it doesn't really tell you whether they should be taken out of the numerator, or whether they would also be taken out of the denominator of the fractions used in the apportion system. We don't think it's clear. I think you could also raise a question as to what's intended here also, what you're going to do is exclude income that you tax otherwise in this bill before this on production and transportation,

but when you come to apportioning for other activities in Alaska, you appear to leave in the total income that gets apportioned, the total income of the company, you appear to leave in all their other production and transportation activities, so in attempting to get at, say, what refining income is here in the State, you're going to go through an apportionment formula which is also going to produce not only their refining activities elsewhere, but their production and transportation, and so on, and it's not entirely clear to us what exactly you really want to do under these circumstances. Presumably, if a company had no other activities in Alaska, that all their payrolls, properties, etc., were associated purely with the transportation and production functions, these fractions would be zero, and there would be no problem, but as long as there are other people involved in Alaska you would be apportioning, and I think you ought to conisder carefully what it is that you want to, how you want to try to do that.

We have down in Section 15, some provisions that have to do with the Department of Revenue providing estimates of tax costs of various kinds of deductions, and I think our only question there is the way the wording is, it's a very raw statement about the tax costs of various deductions. It would seem to mean you would have to come up with a tax cost of all kinds of categories of costs. I think what is meant is the tax costs of various special kinds of tax accounting. I don't think it really means that they want the tax cost

of such things as just plain operating costs, wages and so forth. I don't think that's the intent of this that one would want the tax cost of deducting payrolls, I mean because noone questions the deduction of payrolls.

CHAIRMAN POLAND - I'm sorry, but we've had a slight emergency, and we're going to take a ten minute break.

(MEETING RESUMED)

RICHARD KILGORE - I've been asked if I wouldn't state again what our problems were with the wording on the bottom of Page 5. This section calls for the Department of Revenue to rpovide a report, and in that report it asks for a report on itemized deductions by category, and the tax cost of these deductions. Now, I suspect what is not meant is all itemized deductions, that is, one would have the tax cost of allowing royalties as an expense, the tax cost of allowing payrolls as an expense. I don't think this is what they have in mind. Normally when you're talking about the tax costs of something, you're talking about what is the cost of treating various items in one way versus another way. That is in the case of intangible drilling costs, allowing them as a straight expense, or do you capitalize and advertise them over time, or if it's percentage depletion, what's the cost of this particular way of accounting, and normally one calculates tax cost for those things, not for

normal kinds of operating costs and so on that one has. I think that this should be defined a little bit more here, and the purpose of doing it too, also, I think should be defined, but I think what is meant is some special accounting procedures and so forth on tax cost of these, not all itemized deductions as is stated here.

Now, turning to Page 6, Line 3, talks about in this report for the Department of Revenue, a summary of each corporate tax return filed which shows income from the production of oil or natural gas, showing the total amount of oil and gas produced by or for each tax payer, the taxable income of the corporation from production as reported in accordance with and so on, and also the pipeline transportation. Now, we feel that this kind of a public report of income tax information could be especially threatening for the companies. We think it raises a lot of questions about laying out in the public record various kinds of information that would normally be considered confidential, and laying this out on the record, we think could have some impact on competitive situation of the industry. What it would do, is probably disclose the specifics of Prudhoe profitability. Everybody has an idea of what Prudhoe Bay profitability is, but this would probably lay it out on the line.

SENATOR HUBER - Is that bad, to have the profitability laid out on the line for once, so that we all know what we're

talking about?

RICHARD KILGORE - Well, I think from the standpoint of the companies, it is bad, and I think they have a ligitimate complaint about this because once this information is out, it's not only available for you people to assess, but it also would effect competitive relationships. That is it would throw up information which say companies in the position of negotiating for the purchase of Prudhoe Bay Oil would know alot about what their competitors' costs and so forth were, and this is the kind of information which is normally not available in those kinds of buying and selling relationships, and I think for those who are in the selling position, this is.....

SENATOR HUBER - Did you say for oil or for lease _____ so that I can relate it.

RICHARD KILGORE - This calls for the whole corporation as such. This would presumably show for any individual company its total profitability on oil and gas production in Alaska, but it's basically EXXON's and Prudhoe Bay's position obviously.

SENATOR HUBER - Richard, I'm trying to be constructive, but I'm having trouble, I can see where more data base being out, if the companies we're talking about between themselves

selling their leases for their property, maybe somebody wants to sell somebody a pig in a poke or something, so the data being out would be detrimental, but I think you said that in selling oil, rather than oil properties, and I wonder about that being it's a completely controlled market, how there would be any legitimate interest there.

RICHARD KILGORE - Well, it may not very well be a completely controlled market, we don't know how FEA, what they're going to do on Prudhoe Bay pricing and so on, but what the FEA does is always set ceiling prices, and there's a question of whether one can realize the ceiling prices. There may very well be a situation where major refineries in California who are not Prudhoe Bay producers will be bargaining for North Slope Crude, and trying to strike a bargain with a North Slope producer, and this price is not fixed, there will be a bargain on some of these prices, and you do something when you introduce information in the public record that the buyer has access to. He knows then more about the economics of the seller.

SENATOR HUBER - The future danger it might cause than, rather than the present because they're so tightly sewed up now.

RICHARD KILGORE - In fact there's a general proposition putting this kind of thing on the record does put out confidential information which is normally not made available in public,

which is internal to companies, and I think it changes the bargaining kind of situation to some extent, it just has to.

SENATOR HUBER - I'm happy to hear, Madam Chairman, that somebody thinks that something may go more than the free market place, because from listening to the radio this morning, I was afraid that everything about energy was going to get further from the free market place until the President comes right into my house and tells me what I can do inside of my home.

RICHARD KILGORE - Anyway, we see problems with making this kind of information available by company. I think, if you want information it might very well be possible for the Department of Revenue to combine information in such a way that wouldn't disclose individual company positions. I don't know, aggregating data by producing areas or something of this sort. I don't know, but giving you information that would be helpful without raising these kinds of disclosure problems. That really concludes my specific comments on this piece of legislation. In sum, I guess, what we're really saying is if you feel you want to go the separate accounting route, that you might very well consider some alternative to this, or some alternative provisions, and in the oil and gas producing area really thinking seriously about consolidation, the consolidated kind of thing where you would consolidate all the revenues

and deduct all costs in the State of Alaska rather than the provisions here, which seem to be closer to a net proceeds, and on the pipeline that you consider again a more simple straight forward direct taxation on the basis of the information that will be coming to the State on the Alyeska Pipeline.

SENATOR HUBER - Madam Chairman, while Dick is still in this 015, this is the area where I questioned industry yesterday, if you remember. Dick on the secrecy of these reports, do you think that Line 28, Page 5, under the 015, one of the things I read into this is I thought that was all inclusive, and maybe it isn't.

RICHARD KILGORE - Would you repeat that again, Senator.

SENATOR HUBER - Page 5, Line 28, under 015. We're talking about public reporting, which you were just talking about a moment ago. I took it to mean itemized deduction by category, and that these returns by category must run all the way through this, so that you aren't disclosing actual returns, but only by category.

RICHARD KILGORE - Well, I did not read it that way Senator Huber. I read this particular part of the report has to do with itemized deductions by category and tax cost, and then

I read on the next page, Line 2 of the next page, also included in the report shall be the summary of each corporate tax return. I didn't read by categories as part of that. These seem to be two separate parts of this report to me.

SENATOR HUBER - Greg was that meant to be in there so that that is by category rather than divolging the summary of an actual individual tax report?

GREG ERICKSON - Mr. Haggert drafted that particular portion of it, and it is my understanding that, subject to correction by him, is that each individual tax report and the summary by category.

SENATOR HUBER - In other words, the way I'm reading category is what you determine it to be? But the category goes over to the next pate too.

UNIDENTIFIED SPEAKER - No. There are two requirements. The intent when it was drafted, was that there be a general summary for all taxpayers under this piece of legislation by category. Then, in part B there would be for each taxpayer a summary of that taxpayer's tax due and paid, and so on, so that it would not be by category it would be by taxpayer in two parts of it.

RICHARD KILGORE - Okay, I would then like to turn to the severance tax. As I said in my general remarks, if you're interested in raising the severance tax, both of these bills that we're going to consider seem to in general follow our guidelines, and has to do with more the specifics of how each one of them works. We'll start with HB 144, SB 103. This bill does several things. One is it moves to lease averaging rather than wells in the calculation, and we think that makes an awful lot of sense from the administrative standpoint, and probably should be done even if you don't raise the severance tax, probably even amending your present severance tax would do that, and would make sense. Page 1, Line 11 of the bill moves the point of tax from the wellhead to a new point of production which is later defined.

SENATOR HUBER - How is this defined?

RICHARD KILGORE - It's defined back on Page 4, line 9, gross value at the point of production means for oil, the value of the oil at the point where it is metered or measured in a condition of pipeline quality on the premises of the lease or property from which it is recovered. So in come cases it would change the point of taxation from the wellhead to somewhere beyond up to a point where it was meter measured and made put in pipeline conditions, so it clearly, and this is pointed out by someone else, moves the point of taxation

and in a sense in certain situations it would tend to tax the transportation and upgrading of the crude oil. That's clearly the case.

SENATOR HUBER - I think it had another reason for being in there. I think it was on account of that Kenai deal to where if they transferred our royalty share portion that went into resale that they were subject to the APUC, and doing it this way, while they pushed their royalty share through our line, they were not subject to our APUC. There was quite a problem on that in Kenai, it happens to be in gas, but we're talking jointly here and I think this was done for the company's benefit.

RICHARD KILGORE - Well, I think also in Cook Inlet, as I understand it, there have been continuing disputes about questions of wellhead and where one taxes, and I think this is all intended to straighten this matter out by legislation. This is where it is, and we don't have to argue about backing out transportation or whatever, this is what they're talking about. This makes administration of it easier, clearly, I think that some of the testimony yesterday it was complained that there would be a cost to the companies in a sense that they wouldn't be taxed on transporting and upgrading. I think that if it's administratively easier and there is a cost, perhaps what you should do here is get a better idea of what you're really talking about in terms of cost and dollars and

cents. What is really the extra costs that companies would bear by doing this, or some idea. I think that's how you would have to assess that. Now lets look at the tax rates in this bill. I think you are all familiar with the fact that it adds higher well brackets and puts in these higher brackets at higher tax rates than exist in the present legislation, and it also lowers the tax rates, both the cents per barrel tax and the percentage tax for lower productivity wells. Now, just to give you a rough idea of what this does, and I'd like to just give you some numbers on how it would seem to us to effect, say, Prudhoe Bay, and then look at the Cook Inlet situation under this bill. All the numbers I'm going to use are ease of comperability for 27 gravity crude oil. Now, in Prudhoe Bay,' and I'm assuming for purposes of this calculation that the wellhead value on Prudhoe Bay is say $7.50 per barrel just as illustriative. Under the present tax for a 5,000 barrel a day well in Prudhoe Bay, and these figures are cents per barrel of gross production not of taxable production, but you still get an idea of the relative increase in the tax. The present tax for 5,000 barrel a day well at $7.50 is 49 and 1/2 cents per barrel of gross production. This tax for the same well, a 5,000 barrel a day well would raise the tax to 68.9 cents. That's about a 37% increase in taxation of a 5,000 barrel a day well in Prudhoe Bay. If you went to a 10,000 barrel a day well, the percentage increase and the tax is greater. As against

about 51 cents at the present time, this tax would raise it to about 80 cents, so on a very productive 10,000 barrel a day well at Prudhoe Bay, the increase there would be about 58%, increased through this tax over what you have today. The effective rate on gross barrels produced would go from about 7.8% on a 10,000 barrel a day well to about 12.2% under the new tax, so this is what it does to Prudhoe Bay, very significant increases. And the percentage as I gave you were really the effective rate on taxable barrels going from 7 8 to 12.2. So you are ending up on the very productive well, you end up with an average effective rate on taxable barrels of just under 12 and 1/2 percent in Louisiana. I think that's what was intended. So that's the impact it has on Cook Inlet, I mean on Prudhoe Bay. Now, lets look at Cook Inlet, and particularly the old oil because we've always been worried about effective taxation of old oil. Now, this bill does retain the cents per barrel feature that exists in the present bill, and it retains the cents per barrel feature with basically the same floor price as you have today. It works out for 27 gravity crude to about $6.10 today. So it retains that, but what it does at the same time is that it does lower the rates of taxation both percentage and the cents per barrel taxes in the lower well brackets, so despite the cents per barrel feature still being in there, it does lower taxes on low productivity wells below what they are today. I'll again give you some examples, and they'll

again be on the same basis as before. 27 gravity crude, and these are figures on a gross barrel basis. At the present time a 100 barrel a day well in Cook Inlet would be on the cents per barrel tax and it would pay 26.6 cents per barrel. This bill on a 100 barrel a day well would eliminate the tax. It would go to zero, and a very substantial gain for a 100 barrel per day well. For a 300 barrel a day well, would also pay under the present tax, 26.6 cents. Under this bill, under our calculations, it would drop that 26.6 to 14.2 cents per barrel. So you have about a 12 and 1/2 cent reduction for a 300 barrel a day well, and if you move up to a 500 barrel a day well, you still get a reduction. Under the present tax it would be 28.7 cents. Under SB 103 it would be 21.2. ' So even for a 500 barrel per day well, you're going down by about 7 and 1/2 cents per barrel, and in fact this new tax as compared with the present lowers the tax up to somewhere wells in the range of 1,000 to 2,000 barrels a day. Somewhere in that range, the new tax gets higher than the old tax, so it does provide very significant relief for low productivity wells.

SENATOR HUBER - Madam Chairman - the figures which we have in the committee they are open to him now, I think, I just wonder when he finishes there. If you have any dispute with those, I think that they confirmed his testimony.

RICHARD KILGORE - Yes Senator, we did do our own homework on this obviously, and we have had a chance to look at what legislative affairs has, and they coincide with what I'm testifying here.

SENATOR HUBER - I was wondering. It would help us a lot to know that they do or don't or if there are differences.

RICHARD KILGORE - No they don't they calculate the same way we do.

Now, so this bill does, I think, meet our objections really to the present taxation of old oil at Cook Inlet which has the high effective rates because of the cents per barrel feature. At least its present operation would reduce the tax substantially for low productivity wells, and we think that's a good feature of this bill. I should point out though, this bill does retain cents per barrel and it does retain escalation of that cents per barrel, so it is possible that under this bill we would again be back in the same problem that we have today. If the escalation manages to raise the cents per barrel tax high enough, we could be back in this problem again of taxing old oil in Cook Inlet at high prices, it's possible. The potential is still in this bill.

SENATOR HUBER - This evades it from present time, and we might have to look at it again in future years if we don't do something with cents per barrel.

RICHARD KILGORE - Yes, it may be back again.

SENATOR HUBER - Well, I'd sure look at it again, Madam Chairman, than I would to have Tom Fink for Governor.

RICHARD KILGORE - I think I was on record the first time I testified as saying that if you do retain a cents per barrel that perhaps what you do is at least consider no further escalation in cents per barrel, and perhaps that could be in this bill too. I don't know. I want to only point out that it could happen again. So that's basically what this tax does. It raises fairly significantly, the tax in Prudhoe Bay, but it does lower the tax considerably on low productivity old oil priced wells in Cook Inlet. It also has a severance tax for gas that is flaired, and a very substantial one, five times the rate. I think before you do this kind of thing and add such a tax, you ought to look very carefully at where gas is being flaired and why. There has been testimony yesterday about safety flairs and so on. I think you ought to look very carefully at what it is that you would be taxing and why the flairing is going on at the present time. Now, if what you're really trying to do is tell companies to find a use for this flaired

gas and find markets for it, I think that at the very least if there is gas being flaired now which you think you could find markets for, therefore you're going to try to compel people through this tax, somebody used the word incentive the other day, but you're compelling them through this tax that at least you ought to provide somebody with a grace period before they would pay this tax. That is, you wouldn't start right away. You would make it clear to them that they had certain time within which to find markets for this. You wouldn't penalize them in the meantime, but if you don't find gas for which it's logical to find markets, that you would say at some point in the future you're going to start paying a tax on this, so you had better get busy and look for markets. I don't think I.....

SENATOR HUBER - I think, Madam Chairman, that we should make sure in there. I think we should find out the required safety flair of no more than a certain amount except during an emergency blowout or something like that. The idea was, as long as it's economically unfeasible to take small amounts of gas and reinject them, the State loses its royalty share on it, and the nation loses the energy strictly because at a given space in time, using if you will excuse me, a cash discounting flow and everything else, that we determine its value and we say it's nothing, and what's nothing is moving down the pike another twenty or thirty years may be all we have, and Prudhoe Bay, in spite of an absolute no

flair restriction has been allowed to flair and everybody knows it. Somehow or other, it does have to be stopped, and if you make it so it isn't economically feasible to flair, then it becomes economically feasible to build a small compressor system for saving.

GEORGE SILIDES - Madam Chairman, I know that the flairing _____ as Huber pointed out, _____ that the flairing of course, and the word allowed is important, they get permission from the State, and we have to do something about the bill, that we don't have competition between the taxing department and the Department of Oil and Gas Conservation. They are the ones that give the permission, and you have to apply and you have to point out that it's being done with safety and so on. I don't think that the bill intended to penalize somebody for entering into a safety feature, and so am I correct Mr. Kilgore?

RICHARD KILGORE - I would assume that that's the intent. You'r not really interested in taxing gas.....

SENATOR HUBER - But that board still has the power and makes the exemptions and has been constantly making the exemptions, and it's a matter of record, both at Prudhoe Bay and elsewhere, they make the exemptions, they're legally made, but the product is gone, the resource is gone, it is flaired, and so at least putting in a fairly stiff recovery there, does at

least give us something off of our severance tax that went up in flair too.

GEORGE SILIDES - Madam Chairman, I might make another comment. I think that in view of the comments being made, we're going to have to look into the legality of being able to tax a safety feature.

SENATOR HUBER - No, we don't tax the safety feature. Let's not get crossways on that. We should put an exemption in here for the safety flair only, and somewhere we need to come up with a figure of what is the amount that may be flaired to date per well or per safety flair. We definitely shouldn't tax them on what is a safety requirement. But there isn't a provision. The gas that's being burned in significant, is not being burned in so called legal actual safety flairs. It's being flaired otherwise by legal permits by the board.

CHAIRMAN POLAND - I think we have to check with the Board as to why they are giving the tax.

SENATOR HUBER - That's why the Governor's bills has it in it. That's why committee's bills has had this for two years, and we should certainly, like Dick says, make sure that we don't tax the necessary safety flairs. I asked yesterday what

was, and they said a million cubic feet. That's a thousand MCF's a day. I'm not sure that that isn't considerably over what's needed to burn there in case, I need a good definition of a safety flair.

RICHARD KILGORE - I think also you might consider if you really feel the gas is being flaired that you don't want to be flaired other than as safety purposes or whatever, that's something you might consider as an alternative just tightening up your regulatory bill and your regulations rather than do it through a taxing approach.

SENATOR HUBER - We've done everything but tar and feather the board.

REPRESENTATIVE OSTERBACK - Madam Chairman, could anybody tell us how much gas they will be flairing at Prudhoe Bay? Anything that burns is energy. We're talking about we're running short of energy. Somebody talked about the railroad. If they took it in there, they could take out about a hundred tanks of gas a day, and they didn't think it would be enough to pack that out with flairing, and that would be an awful lot of energy, but most of us don't really know what this gas is with the flairing, but I know anything that burns is energy, and we're talking we're running out of energy. So I think there should be something done about it. Anything

that you can save as energy, you can sell. There's no problem in that.

RICHARD KILGORE - Well, I agree with you, if what we're really talking about is waste, then I think we should eliminate that. It is energy, and you're absolutely right, and I think you should look very carefully at what's going to happen at Prudhoe Bay, and how your regulatory people will handle it.

SENATOR HUBER - Might we, Madam Chairman, Al brought it up and it's very important. I think that it's understood that they have stopped flairing or are to stop flairing. It was only for that refinery that they flaired at Prudhoe Bay, and they didn't pump it back down the gas well even though they were drawing gas out to run the refinery because it would have cost more money than the gas was worth, so naturally the gas was worth nothing, so it wouldn't cost money to pump it back down into the ground. If it had a value of 20 cents an MCF, it would have been a lot cheaper to pump it back down into the ground, but just so that the record is straight, we aren't really looking for flairing at Prudhoe Bay, but if you will take a look at the Valdez terminal, you will find that we don't flair no more, but we've got three huge oxidizers there, and there's going to be a tremendous amount of energy unless the LPG's that are in that gas and the vapors that are in the gas at Valdez,

unless there's a plant built to recover those and use them which is not in the plan, it is going to effectively flair trillions of BTU's before Valdez is over with. That's because the plant and the tanks will not stand the pressure in the storage.

GEORGE SILIDES - Madam Chairman, I think the point is well made that something's got to be done about defining what is meant by safety gas, what is being wasted, and I think also that the bill had intended to address the bottom of the possible wasting of carbon dioxide. There was a considerable amount in this particular natural gas, and I suppose what we're getting to is that we have to do something about those things, either by definition or by amending the bill. I think this is a point that we're going to have to look into. I don't think we're going to get it solved right here.

SENATOR HUBER - I think they're willing, George, not to flair the carbon dioxide, but I'm not sure if they will get rid of it.

GEORGE SILIDES - It doesn't burn anyway, Senator.

CHAIRMAN POLAND - We'll be checking on this flairing part.

SENATOR HUBER - Well, it's important on both ends. I think that the bill needs to not penalize them, but by all means

should be retained in the bill, and we may of course have to put it in in some other places. I don't think this is going to effect it when it comes to the flairs in Valdez.

RICHARD KILGORE - I'd like to move on the the second severance tax bill, and that's HB 321, SB 238. Now, basically this tax changes the tax rate to 10%, but it also has a cents per barrel feature of 75 cents per barrel, so it has an effective floor price of $7.50, and it also has what _____ for an economic limit factor built into it, and I think Mr. Wilson yesterday did quite a good job explaining how the mechanics of this worked, and he also provided an example for you that I think was probably quite useful. Basically what the bill does is give you the first hundred barrels a day as an allowance for operating costs is what it amounts to, and wells producing more than 100 barrels a day, they pay then an increasing fraction of the 10% for the 75 cent tax is the way it works, and it's a continually increasing thing as well productivity moves above average well productivity moves above loo barrels a day. Very roughly, a 100 barrel a day well would pay no tax under this bill. A 200 barrel a day well would pay about 43% of the tax. It isn't 50% because as you might think by taking 100 to 200 because it's taxable barrels only that count. That is the 200 barrel a day doesn't produce 200 barrels that are entirely income to the company. Twelve and a half percent of those go to the State.

GEORGE SILIDES - Mr. Kilgore, it's 43%.

RICHARD KILGORE - It's 43%, 200 is 43% of either 10% of value or 75 cents a barrel depending on which it is.

GEORGE SILIDES - That's what I wanted you to say.

RICHARD KILGORE - For a 300 barrel a day well it would be 62% of these basic rates and on a 4,000 barrel a day well, it would be up to 89% of this. This is the way it works, and it amounts to a continuous function as against the step schedule that you have in your present legislation. As I said, it amounts to a continuous function and in principal we find it as kind of an appealing concept as against the step schedule. Now the other feature of it is that one can't apply for an economic limit factor greater than 100 barrels per day well average if you can prove it, and what you basically have to prove is that your operating costs that you require, out of pocket operating costs are greater than what you would get with 100 barrels of production per well. You would need more than this to recover your operating costs. Now, there appear to us to be a couple problems with how this actually works. First of all on Page 3 Line.....

SENATOR HUBER - Madam Chairman, I would note that we've got John Messenger here, too. This is the same problem that came

up yesterday in talking with the industries. We might want John to answer some of these.

RICHARD KILGORE - It has to do first of all with how costs are defined, and that starts on Page 3, Line 16, subsection C here, and as was pointed out in testimony yesterday, it is not clear that the cost category specifically allowed here really provide for all the kind of out of pocket expenses that a producer might have, and basically that's the concept that you're trying to get at, whatever is out of pocket expenses, and it's not clear to us that that is the case and some questions were raised yesterday and I think you ought to consider those too, but what I think is more important is that after calculating the costs here, you then have to determine how many barrels are necessary to recover, that is if more than the hundred that you are allowed anyway. Now the problem with it is that the way that the bill was written, you don't take your costs and divide through by the price of oil that you as a producer receive. That is your actual price, if you're an old oil producer and getting $5.00 per barrel, you don't divide through by $5.00 to see how many barrels you need to recover your costs, but you use another deemed price to do this, and the deemed price is acquisition, this is Page 3, Line 29, its acquisition costs CIF at westcoast refineries for imported oil of like quality and then you net this back to Alaska, so you're not doing it on the price you actually

receive, you're doing it on a deemed price that you may not be receiving, and it seems to us this causes problems.

SENATOR HUBER - Could we at this point if it's convenient, I wonder, Sterling isn't here, but John is and this was the question yesterday, I understood from the testimony by the State that as of starting in December or sometime like that that these wells that were in economic trouble shall we say, that these figures that you have put in here talking about _____ price are actually what's happened. They are now being allowed, these higher prices on the producer's share, but not upon the State's royalty share. The argument yesterday, and I think we're right into it again today, is whether we're just talking about a possible deemed price working it back from San Francisco or whether we're truly talking about what they're going to get, and the industry said no this was unfair that wasn't what they were going to get, so we're right at the nitty gritty, and. I think you can help us John.

RICHARD KILGORE - Perhaps, Senator, I'm going to give an example, maybe I ought to do this and then we can talk about it.

SENATOR HUBER - Okay, just so that John, he wasn't here yesterday, so he's alerted. My stand was or what I saw was that you fellows put this in here because that's actually

what the oil companies are getting, and so you were getting right to the nitty gritty, and they said no this is what they might give them, but I understood Sterling to say that this had actually started in December, and I don't think this was in testimony, I believe this was talking in the afterwards that it actually had started in December and the State had been denied that increase, but the producer's share had been allowed, so if that predicates it and as he goes on if you can straighten this out, it will help me a lot.

RICHARD KILGORE - I'd like to just give a little example of what we're talking about here. If we had an operating cost for a well or wells whatever the unit or something, and say $2,800 a day, and these were direct operating expenses defined properly however, and if you didn't get these revenue enough to do this, you would shut down. Now, if one looked at the foreign price and then netted back to Alaska, let's say you came up with $14 just to make the arithmetic easy, you came up with $14. Now in calculating your economic limit factor here, you would divide through by that, and that would give you $2,800 divided by $14 is 200 barrels a day. You're economic limit you could then justify is 200, rather than the 100 which you had presumed. That means you're getting more, but let's say that the producer only gets $5 a barrel for oil because he's receiving the old oil price in Cook Inlet. He doesn't bet $14, he gets $5. Well for him to actually recover the

$2,800 his total expenses at $5 he's actually receiving for his oil, his real economic limit factor is $2,800 divided by $5 or 560 barrels, so that in fact, his limit factor, that is the number of barrels he needs before he's got to shut down, because he doesn't make it out of pocket cost of 560 under this bill it appears to me, he would only get 200. I don't think it really gives you the results that you intend. The result that you intend is to provide relief for marginal wells. It doesn't appear to really serve the intended purpose.

SENATOR HUBER - That's at $5.61?

RICHARD KILGORE - That's at $5.00 even.

SENATOR HUBER - But doesn't this other deal work to raise that?

RICHARD KILGORE - Well, the other thing we're talking about is price relief under FEA regulations. I think that's really something different here. I'm addressing.....

SENATOR HUBER - That's not five dollar oil. You know, if we're talking about his economical limit on the well then we assume it to be $5.00 oil, but he is actually receiving $10.95 for it because it's below a certain economic limit

already established, then we're dealing with something that doesn't exist, and that's what I'm trying to get into this, and I thought that that was why the State had drafted it.

RICHARD KILGORE - Because it assumes that the Federal government will always bail out people, is what you're saying, other than royalty owners.

SENATOR HUBER - My information was, it didn't only assume, it was based on what was happening. Can you clarify that John?

JOHN MESSENGER - Let me just make a couple comments. I guess it's true that one position that we've taken on this bill that our taxes should not be based on the artificial price set by the Federal government, and the Federal government set a price of $5.00. Our position is that we shouldn't be content with the tax based on that artificial price, and that's why, one, we've set the cents per barrel floor, likewise when you're figuring the economic limit factor, again, we say the true economic limit is not how many barrel are produced at the artificial price, but the amount of barrels they would produce using the true value of that oil, pre-market oil. We should insure ourselves that so many cents to so many percent of that pre-market oil because that is our resource and we should get at least that percent out of it. Secondly, is that producers are

reaching their break even point which they will stop producing. There is a procedure by which they can make application to the FEA and get price relief and with that higher price they can produce longer, but the FEA has said that they will give price relief only to the producers, and not to royalty owners, so if a company is reaching its economic limit in Cook Inlet, and they go in for price relief, they are given that price relief. They will raise their price, but they will not raise that price in the terms of the amount of royalties which _____. So, it's two things, one is the tax rate and the economic limit factor should be based upon the true value of the oil, and secondly that producers are protected through FEA regulations, but the State is not.

SENATOR HUBER - Then I guess what he's saying is that if someone's going to shut down the production there, by it being below economic limit on $5.00 oil, the State is advocating that we put the monkey on the fed's back and say you did it, you set an artificial price, we're going to set our tax based on free market price, and if you want to save that resource, save that company, you can turn around and do likewise what's reasonable. I'd say it's what I call putting the monkey on the Fed's back. They caused the problem. I happen to be strongly in agreement with the State's stand on that, and compliment them for it because why should we throw away our royalty share and our

taxing ability because somebody forced an artificial price down our throut, and is forcing that same artificial price down the throat of the oil companies.

RICHARD KILGORE - Look, I'm going to address myself to the question of the artificial price, that's part of what I'm doing here, and I think the Commissioner took issue with earlier testimony I made when I said I thought this was a flaw in the thing, and it certainly was, I thought, a flaw in terms of its purpose of providing relief, and now I do understand why they do this which is another objective, than what appeared to be the intent of the bill, and I'm going to come back to the whole question of the artificial price. It's very clear they did this by design. I'd like to again, as you asked, talk about just very roughly what it does to Prudhoe Bay and then to Cook Inlet, and then discuss the consequences of that. Again, for Prudhoe Bay, looking at 5,000 and 10,000 barrel a day wells at Prudhoe Bay, this bill also raises taxes significantly on those wells as does the other bill, as does HB 321 that we looked at before, excuse me HB 144, that we looked at before, but it does not raise them as sharply as the other tax. If we take a 5,000 barrel a day well, I said that, and I'm not going to run through all the numbers here, I think, but that the other tax for a 5,000 barrel a day well raised the tax about 39% on a 5,000 barrel a day well. This tax would raise it about 29% it appears to us using the presumed hundred

barrel figure. The discrepancy between the two gets larger at very productive wells because of the steep rates near the end of the schedule in the other bill, and for a 10,000 barrel a day well, HB 144 raised it 58%, this would raise it about 27% on the very productive wells, so if it both increased taxes on Prudhoe Bay, clearly the one, HB 144 would increase them significantly.

SENATOR HUBER - That would be effective of what of 5 and 10.

RICHARD KILGORE - Okay, the effective rate would be very close to, on taxable barrels it would be very close to 10%. On 5,000, it would be 9.8% and 9.9% on the 10,000. It approaches 10%.

SENATOR HUBER - Just slightly under ten percent for a total maximum. Or fully 2 and 1/2 percent, a little over 2 and 1/2 percent below Louisiana. Using the Administration's bill.

RICHARD KILGORE - That's correct.

SENATOR HUBER - And it would be right at Louisiana with the other bill.

RICHARD KILGORE - Close to it. That's correct.

Now, let's look at what happens to the Cook Inlet old oil price here. This bill as the other one for a 100 barrel a day well eliminates the tax altogether. It does exactly the same thing, but what we find troublesome is that is you go to 300 barrel a day wells, these are the wells that we're concerned with because of their productivity and the old oil price they have to bare, they get the tax there doesn't go down, but it increases. It goes up from 26.6 cents on gross barrels to 40.6 cents. It goes up by 14 cents a barrel. This tax raises it that much. On a 500 barrel a day well, it raises it by about 13 and 1/2 cents, and on a 1,000 barrel a day well. I'm sorry 14 cents increase on a 300 barrel a day well, 22 cents on a five hundred barrel a day well, and 28 cents on a 1,000 barrel a day well. What I think are particularly disturbing are the increases on the lower productivity wells. A well as low as 300 barrels a day which we already have some concern for because of the effective rate on the old oil thing has actually a fairly substantial increase in its tax burden. As Commissioner Gallagher stated correctly, you get this result because of raising the floor price essentially. You are raising the floor price from $6.10 to $7.50 and you have higher tax rates at the same time, and it's deliberately designed to do this. Now, we really feel that this kind of goes against what we feel are good principals of severance taxation. What you're saying is the producer in Cook Inlet he received a relatively low old oil price established by

the Federal government. This in turn restricts his own profitability, but then the State adds to his burden by taxing him as if he received $7.50, and it seems to us that rather than help his producing situation, this only makes the situation worse. One of the reasons given for doing this is that the Federal government is following an unwise, or I think it was described as a foolish price policy. Now, this may or may not be the case. I'm not willing to pass a judgement on that, but they're, you should know that the Federal government does have reasons for doing this. It's not capricious, they do have reasons. They have concern over the effect. What they're concerned with is this, we've had a fantastic increase in the oil prices outside the United States by the OPEC nations and if one frees the oi., the old oil price, it will go up very, very sharply. It will, perhaps in some cases, close to triple in price and the people are concerned about the consequences of this. Rightly or wrongly, they are concerned about the inflationary impact on consumers. They're concerned about when _____ producers, because these are on old oil wells, wells production which is established at old costs and so on and therefore you have to question whether you want to give them huge increases in the price and windfalls. There is concern over that. So there are reasons, and you can argue one way or another, but there are reasons for this.

SENATOR HUBER - Would it be fair to say that those reasons are exactly on a par with the same reasons for having controlled gas prices as would be in inter-state commerce as well as setting a free-market price. It's the same principal in both cases.

RICHARD KILGORE - As deregulation of natural gas prices. Yes.

SENATOR HUBER - Deregulation of natural gas. Deregulation of petroleum would do the same thing, it would increase the price at the burner or the price at the gas tank as it comes in out of the nozel, but all of the other factors of pro and con are the same.

RICHARD KILGORE - Yes, that's right, and the concern is that if you let it go up to, and I really object to the word free-market price because we're not talking about free-market price, what we're talking about is it goes to a price administered by OPEC. That's what we're talking about going from price administered by the Federal government to a price administered by OPEC. This is by no means a free-market price. It's a market price, but one set by OPEC, and set by political reasons as much as for economic reasons.

SENATOR HUBER - Some of us are referring to free-market price though as to this free-market price that exists that we talk

about what the price would be if OPEC were not controling it. Some of us are talking about a true free-market price

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RICHARD KILGORE - Senator, I don't know what the price would be if OPEC were not controling it.

SENATOR HUBER - We don't know. We have projections just like we do on what Prudhoe Bay is going to cost.

RICHARD KILGORE - One the one hand, if OPEC did not exist one would certainly expect over time that the price would rise at some point in time to the level of alternative energy sources which are quite high in the $20 - $25 range. On the other hand, in the short run, you do have an overhang of surplus productive capacity in the world, and if there were no OPEC, and it were perfectly free market, there's no reason why the price couldn't drop to less than $1.00 per barrel, because that's what costs are in their surplus capacity. If there were truly competitive free market, one would have $1.00 a barrel oil or less because that's what the costs are in the middle east, less than that so but as time went on, and this surplus which overhangs the market now, and which would push it down, gets eaten up and it will, one would then have prices moving off in the other direction. I don't know what the price would be. But anyway, we're talking about not letting the price, the U.S.

government as a matter of policy, not letting it go to a price set outside its own borders by an orgnaization of petroleum exporting companies, and that's what we're talking about. It's the intent apparently of the Congress not to do this because basically the idea is concerned with price impacts, concerned with windfalls, and also that there's no way of assuring that the price that would be set by OPEC is an appropriate price for our internal markets for our own costs and so forth. There's no way of knowing whether they will set a price appropriate to our cost circumstances in the United States or a price that may be very much higher than people think it is now or maybe even a price lower. Not good enough for development of our domestic resources. So this is a matter of national policy and people can quarrel.

SENATOR HUBER - Feable minded or otherwise.....

RICHARD KILGORE - Well, I don't want to characterize it. I'm trying to give you a few of the reasons for doing this, and this is a matter of federal policy. Now, but even if it is a foolish policy, or at least if Alaska views it as one, or the people who did this legislation think it is, I think that you have to ask, if that is the case, still, why do you want to then punish producers for this price policy basically. They already suffer enough from it in terms of the revenues they receive, why do you want to go an

added step and raise their taxes because of this. I don't think it's reasonable to assume that if you do this you will force national policy to change by what you do in the way of taxation here in Alaska. That seems to be reasonable.

GEORGE SILIDES - Madam Chairman, may I ask a question?

In addition to your comment of being unable to force national policy, would you think that this kind of tax is counter-productive?

RICHARD KILGORE - I suppose it's possible, I don't really know the answer to that, but I suppose there are reasons that might want to lead one to that result, and if the FEA has procedures for relief of these kinds of situations , then it sees the State of Alaska in fact imposing higher and higher taxes on such low productivity wells. I don't know. It's not inconceivable that it would enter into their thinking in this matter. Rather than providing relief, it seems that the State of Alaska goes in the other direction in this situation.

SENATOR HUBER - George brought something up here. Isn't this the fact that it effects these 300 barrel wells just because of the total tax maximum that we pay and then how we apply the mechanics of the formula. They could for instance, modify, and the mathematics of it I would have

to find out from somebody else how, so that that point would hit, maybe, more on a five or six hundred barrel a day well and maybe give as much as 10.3% or 10.4% out of Prudhoe Bay instead of an even 10%, and the formula diddled with enough to change that point to where it would be correct. Couldn't that be done?

RICHARD KILGORE - Yes it could be. If you like the basic approach of the continuous formula .....

SENATOR HUBER - Apparently you do, and I do too, and we might consider, and George's question pointed up that we might consider something from being John Messender is here, that they might give us an alternative is that reasonable Madam Chairman?

CHAIRMAN POLAND - Well yes, except today we have Mr. Kilgore with us. He's leaving on a plane and we want to take advantage of this. We can bring this up.

SENATOR HUBER - I have considered this, Madam Chairman, to be a work session with him, and it's more valuable to me, the way we've been conducting it here today, than anything that we've had.

CHAIRMAN POLAND - Well fine. Let's give him a chance to get with it.

RICHARD KILGORE - Okay, we really are concerned with how this aspect works. There are two parts where Alaska is attempting to impose its own view of what the proper price policy should be, that is if they want the OPEC price. It comes on the floor, and it also comes as I said before in this calculation of the economic limit factor again. It enters in two places, and we have serious questions about this and what you really want to do. If the basic intent of the legislation is to provide relief that you don't go off in the other direction simply because you're unhappy with the prices because this throws all the burden on the producer, and then you're going exactly against what you really want to do, and you could have economic consequences to this.

I understand your concern with the prices that you get for your oil, and you'd rather get higher prices than lower prices, and that's fine, but the question is if the price is not set at a level that you think is appropriate then what do you do about it, and I guess, it's just bothersome to us that what you do about it is throw a burden back on a producer here. That's what you're doing about it, and that then goes against what we feel is an appropriate kind of severance tax because then you run into all the kind of economic problems with this gross tax and that's our concern, and we appreciate why you think in terms of floors and why you want to get an adequate value for your oil, and so forth,

and we understand why you do it, it's the consequences.

This tax also raises the tax on natural gas. If you'll recall our testimony before, we were always pointing out to you that if you did this you would have an impact on Alaskan consumers, that would flow through to Alaskan consumers. I noticed that there is another bill which is HB 329, SB 239 which is a residential fuel credit, and I presume that the intent of this is to mitigate to some extent the impact that raising the gas tax would have on Alaska. Consumers - we're not really in a position to know how adequately it does this because this has to do with what fuel bills really are in Anchorage and so on. We really don't have the information to calculate how adequately that does that, but obviously, you are concerned with that aspect to it, and the balance of the increase of course would be assessed against exports. I think that the other thing I should point out is that here you have in this not only an increase in the tax rate from 4% to 10%, but also introduce a floor price here, that is a minimum 6.4% per MCF, which is an effective floor price of 64 cents per MCF, and I think we have the same reservations here about this as you do on the oil side. If you have oil flowing, producers getting less than 64 cents, someone mentioned 42 cents the other day, but less than 64 cents, then you start to raise the effective rate of it, and I think we have the same problems with it here as we would anywhere else, and this

also has a gas flaired feature taxation, but it's only double, not five times, and all my comments on that go for this too.

SENATOR HUBER - That is in the equalization deal?

RICHARD KILGORE - No, it's in the severance tax, itself. There's a provision.

In the end, I'd like to talk a little bit about this whole question of the overall tax burden and how you assess it, the kind of questions that Senator Rader has been talking about, but I would first just like to make a few comments on the property tax bill, unless there are some other questions here on the severance tax.

CHAIRMAN POLAND - No. I was going to suggest that when you are finished on the bill, and before you kind of wrap up, that we take a five minute break.

RICHARD KILGORE - Okay, shall I just say a few things about the property tax. I have relatively limited comments here. HB 323, SB 237, now, this extends the property tax to some other areas as you know to refineries, gas plants, and also to marine transportation, and L & G liquifaction facilities, and so forth. So it extends the kinds of things that you would tax with your property tax. Now, the only real comments

that we have here are that for each of these areas that you're thinking of proposing a property tax on, you think carefully about where that tax will actually be borne. You're talking about taxing properties for crude oil production that largely obviously is borne by producers. They realize prices in the lower '48 that are set for them, and the tax you impose is a tax which they have to bare in terms of their own profitability, but that's not necessarily the case with each of these other areas that you are extending, and what I think you ought to think about what you are doing, because if you're looking at property taxes on refining in Alaska, we would expect that most of the refining capacity in Alaska for some time to come would be basically capacity oriented to supplying low markets so that the tax that you impose on those refineries presumably would over the long run be borne by Alaskan consumers. You're assessing a tax which goes to the treasury, but eventually that tax would have to be borne by consumers if the refineries are to operate properly. So you have to worry about the incidence of the tax. If you're looking at L & G facilities you have to worry again about the consequences of this and what will happen, and who will actually bare this. Will it be a cost that will simply be passed along because the facilities under an FPC jurisdiction will be passed along as probably may be the case. It's not clear that if it's L & G or export to foreign countries whether this would be the case. Who would bare it, it's not entirely clear.

GEORGE SILIDES - Would it not also have an effect on a decision as to whether to locate in Alaska.

RICHARD KILGORE - Yes, it could under certain circumstances. If it's a cost which basically the person thinking of putting in the facility has to bare himself because he hasn't got an automatic pass along or he can't pass along to Alaskan consumers, or he can't through his regulatory process, pass it along, then surely, it would be one of those tax entering into his decision as to whether to locate in Alaska. Noone can say whether this is the thing that would swing it in the balance, but obviously, it's part of the package of doing business, if it's a higher cost, it could have some effect, yes.

The last one is marine transportation, and there, well there's a question of legality, I guess, but we can't address ourselves to those, but it seems to me you might have some concern about this one too, because you already face a problem where you are concerned with the fact that your oil may have to move to quite distant markets, for example the U. S. gulf and the eastcoast, and you're very much rightly concerned about that long haul and those high transportation costs and what it may do to your wellhead value, and if you go this route of taxing marine transportation, you obviously add to the cost of transportation, I don't know how much would be thrown up by this tax, but you are in principal anyway

adding to the cost of transporting your oil which certainly works in the direction of lowering the value of your oil, so I think that you ought to consider this as well, as I say, in each case consider the consequences, but here you're putting an added cost on transportation and it may be small, but it certainly works in the direction of lowering your wellhead value. Basically that concludes my remarks on the specifics of the bill.

I would like to conclude with a few remarks about this old question of the total tax burden in Alaska. What fair share is, and at what point do you destroy incentives, undermine profitability and the like, and of course Senator Rader has been pressing a number of people for answers to this, but as he himself in asking the question admits, there obviously is no easy answer to this question. If there were, somebody would have given it, and I can't give you an easy answer. A number of things have been suggested, all of which make a certain amount of sense. What kind of activity is there in the State has been suggested. A number of people have suggested looking at the total tax burden in Alaska, relative to other states. I have a few comments on that aspect too. It clearly is important what the total tax burden is on the oil and gas industry, there's just no doubt about that and how it compares with other states. It certainly is not just the absolute amount of dollars being paid or dollars per

barrel of production being paid to the State. What really matters for the economics of the industry for their incentives to go in and so forth really are these aggrigate dollars or dollars per barrel things put into context of the profitability of the operation in the various states. This is what really counts in the end, not just the amount that one pays. If one is paying a high tax, but in a situation where profitability is very large it's one thing, if they're paying perhaps even a lower level of taxation in a situation where profitability is low can be another thing. So, you really have to put it in the context of profitability. This doesn't make it any easier to answer obviously because profitability is elusive and difficult to measure, but certainly one has to put it in this context, not just in the dollars themselves. And the second thought about it is, I think that although some people have said this, that the mix in which you get your taxes out of this total burden to your state and other states is really not irrelevant. Someone suggested that a dollar is a dollar, but this isn't really quite so it seems to me if you're looking at the burden of those dollars on people. If you have taxes that are realtively based or geared closely to income, that is income taxes in kind of a true income tax in a sense that it is directly trying to measure income, it's one thing if you collect it that way as against certain just gross taxes or property taxes and the like, because if you have taxes based on income, they have a different economic impact than gross taxes.

If you have a severance tax, it's not a matter of indifference how it comes. If you're collecting high severance taxes in Alaska because you have wells that are extremely productive and that's the way your tax is structured that's one thing, if you're just doing it flat out on everything that's another. So, that it's not just the total dollars, these dollars have different effects, and that high taxes in one circumstance where they're thrown up out of a total tax package that's more closely geared to income and costs and so forth may be less of a burden than in another case where you have somewhat lower taxes, but their generated by things that have nothing to do with profitability, and you have a low profitability situation, so that I think it isn't strictly the total, it is the mix and the types of taxes that you have also, that also matters, and to the extent that the closer these are geared to income, the better you really are. The second thought I have on this whole question is the State, I'm thinking in terms of the burden of its taxation also has to remember that it has a role not only as a taxing authortiy, but you also in this State, and this is different from other states, most other states anyway, you have also a role as a land owner, you have lots of land and you will have leased that land and you will be leasing more, and you have to realize that the higher and higher you put you. own taxes, this will have some effect on the kinds of terms that you're going to be able to get for your land. No matter how you lease it.

If you lease it on a bonus basis, the higher your taxes, the lower your bonus. If you go on a royalty bidding basis, the higher your taxes, you'll get lower royalty bids out of all that, or if you have a net carried interest or a net profit interest kind of leasing arrangement which you may turn to. Your profit people are willing to give you also _____ part of the taxes.

GEORGE SILIDES - This matter came up before in a different form, and the comment was made by the speaker was that not to be so terribly concerned because the competition in leasing would take care of that matter.

RICHARD KILDGOR - Well what I'm saying is that I think the competition in the leasing is going to reflect your taxation. That is, if you have higher taxes, I would expect in general you will get out of the competitive process when people are bidding for leases on whatever variable they're bidding, whether it be royalty or bonus or whatever, the amount of the tax that they will perceive you will take in the future will effect their bids, and they'll bid competitively and it will be reflected on how much money they're willing to offer you initially, or how much percentage of the thing they're willing to give you and so forth, so that your tax will effect the terms you're able to get on your own land.

REPRESENTATIVE OSTERBACK - I would like to ask a question. We listened to all this testimony, but we never came down yet with how much are we getting for our oil. And another question on leasing, it doesn't seem to make any difference, the bids I say that came out from the State or from outside the three mile limit seem to be about the same value they are bidding into the millions for off-shore leasing. What kind of a deal could you answer that on off-shore leasing? And the taxes, what kind of taxes are they paying? Are we going to get a benefit out of the off-shore leasing taxes?

RICHARD KILGORE - Well, on off-shore leases, where they're on Federal waters, you basically will not get the state severance tax from those barrels or MCF's of gas being produced out _____ there, and basically the tax that that oil in Federal waters will be subjected to is basically just the Federal income taxation, and you will not get severance or other kinds of tax revenues unless one's able to go through some franchise tax kind of thing. I just don't know whether that is legally possible for you to do that, but unless you can think of something ingenious of that sort, basically it will be just federal taxation on that, and the bids that would be received if you had comperable prospects on shore Alaska, lets say off shore but in Alaska waters similar prospects to something over the line in Federal waters, and you put these up for bonus bidding,

presumably what you would get since you have no severance tax on the offshore, you would presumably get higher bonus bids to the federal government, than you in Alaska would get for your exactly comperable prospects. I don't know if that answers the question or not.

REPRESENTATIVE OSTERBACK - One other thing, somebody brought up the other day that since we get 10%, or we pay 10% of the federal tax, I don't know, I know you know more about, would we be getting a share of the federal tax in the amount of 10%?

RICHARD KILGORE - Yes, to the extent you share in federal revenues and so on, yes you do get some share that way. That is correct, but the other thing is that as you know, there is some move afoot in the Congress to provide some sort of sharing of royalties and other income from offshore productions with the coastal states, and I would think that the State of Alaska should push very hard for this kind of thing, and I would also think that in the past this was probably not the kind of thing that the Congress would pass because there were relatively few states which would benefit from that basically Texas, Louisiana and California that would benefit from that kind of thing, that is sharing the revenues, some portion of the royalties and bonuses in the federal waters off their shores, but the situation seems

to be quite different today because we now are talking about exploration along basically the whole eastcoast of the United States, so there are an awful lot more states which potentially could benefit from this and presumably would support such a measure in Congress. There seems to be a lot more support for that kind of thing than before, and perhaps you will get something like this. I think there's a lot of merit in doing this from a national standpoint too, because as you know on the eastcoast there are all kinds of environmental opposition to this drilling and everything and bringing this oil ashore and everybody is up in arms about the environmental problems, well, I would think that if the states including my own where I live, New Jersey, really thought they had the prospect of getting some direct share of the income from oil and gas in federal waters offshore New Jersey, I think they would view the environmental matters somewhat differently, or at least be willing to look much more realistically at them and have greater support for this activity, so I think that this is something that Alaska should be looking for, and maybe it's another way you would be able to benefit, and if you were able to get some benefit, in that way some share of royalties, bonus income and so on from federal waters offshore Alaska, I think the amounts of money, I don't know what the share would be, I think the amounts of money that you would be getting would be very very much larger than any kind of fooling with apportionment factors

in that franchise bill to try to pick up something. We're talking about much larger potential amounts of money I would think.

REPRESENTATIVE OSTERBACK - Talking about the environmental conservation and everything, you're going to get a lot of static from fishermen, _____ coming out that the oil won't take Kachemak Bay for example. Now, Kachemak Bay, only produces about 6 million pounds of shrimp, but you come up towards the chain around Kodiak, what we do, that's just a drop in the bucket, and we're buying that back, so there's going to be a lot of static, say in the Bering Sea, is one of the richest crab, herring, shrimp, and out along the chain, so if there is no revenue for the State, then we're going to kill off our fisheries and there's going to be a lot of static coming from that on the offshore drilling, because you can see what happened in Kachemak Bay, which is just a small little thing, and we're going to pay I don't know how many million dollars to buy that back to save that fishery. And what I'm trying to get across, if we're not going to get no sharing off the offshore, there's going to be a big fight to try to stop it.

RICHARD KILGORE - Absolutely, because then you say what do you need it for, to get nothing whatsoever out of it. I don't want anything I say to be construed that I'm against environmental concerns, they obviously are very real, but

I think what you're saying is correct and this goes for other parts of the country too, if what you're talking about is development of Federal waters, and off your shore with the potential environmental problems from which you will suffer, and you get absolutely no benefit, then what do you need it for. In those circumstances one would take a very extreme, I think, position on viewing the environmental damages. That is, one would say, I don't care if the chances are one in a million, I don't want it because I don't get anything out of it anyway. If there's any chance whatsoever, let's just don't do it, because I don't gain anything anyway, but if you have something to gain from it, I think perhaps people may very well take a more realistic view of what the potential hazards are, what might happen, and with the odds have been happening and so forth, but if people are in the position where they have absolutely nothing to gain, and any possibility of something happening to their environment, that's really going to be against them.

REPRESENTATIVE OSTERBACK - One more, if I may. Take say a barrel of oil is worth what $12.00, $11.00, what? A barrel of fish is worth about $200.00. So what do we want?

RICHARD KILGORE - Sure, if you're going to destroy a valuable industry.....

GEORGE SILIDES - One of the things the administration has put forth through the federal government in my recollection is that, it is just that, and this is why they were hoping to hold off some of the offshore production was to submit a proposition to the Federal government on revenue sharing. I think you are familiar with that, and I think you touched on it. My recollection, and I ask this only for informational purposes as you know, it seems to me that we also suggested a two tier affair. I know you hate everything with two tiers in it, but in that all of the states were able to get a portion of the offshore revenues, so that you gain a broader base of support.

RICHARD KILGORE - Yes, and I think that's a sensible approach to this whole thing too. One can gain broader support where you have some approach as you're saying. Where you have everybody benefits to some extent, but those who are directly effected or so on, get some larger share.

I am saying that you do have this interrelation when you think about how high you put your taxes. There is this interrelation between what your taxing policy will be and how much you are raising taxes, and what you're going to get in terms of economic benefits when you lease lands, and that's very very clear, so to some extent you're taking one area through higher taxes and you give up in another through lower, whatever it is, bonuses and so on. So to some

extent they are offsetting, but of course at the same time you have to appreciate that while this is true on new leases for people under existing lease terms, obviously they can't change their contracts with you if you raise taxes, so if you raise taxes they are hurt. You also through your tax policy, obviously effect the value of lands or the value that one can get out of other landowners in the State, and of course the native corporations are obviously the ones who will be effected to the extent that you raise taxes and they make new arrangements on their lands, they will be effected, and they will get less in the way of.....

SENATOR HUBER - I wanted to just for a moment on that same subject to lead Dick back across the cannon ball range and the mud flats, and back to dry land for a minute on these leasing policies, and you were talking about bonus leasing when we got into this, and isn't it true that the price paid for a bonus lease whether it's offshore or onshore, mud flats or whatever, it is based upon what they're willing to pay for the price to gamble on what may be down there in a huge gamble and if we wanted to minimize what our tax would do on that, the minimum would be no tax, and other than that to have a tax that would have a minimum effect, would be a tax that was a percentage of a net profit, and if you had a percentage of net profit tax, that would be the kind of tax that would provide the minimum for losing money in your bonus, because they would all figure when they were bidding

that there would be no tax on anything that we don't get anything on and it will only be a maximum of this amount of exposure on the net when we do make, and if we don't make, we don't pay.

RICHARD KILGORE - That's correct, but that's assuming of course that the income tax that you have really is taxing what is real kind of income in Alaska. If you are on, as the gentleman from EXXON testified the other day, if you're on an apportionment formula, you may pay income tax anyway.

SENATOR HUBER - I didn't mean to lead you back into the net proceeds tax which you happened to design, but I'm thinking about any fair income tax that would.....

RICHARD KILGORE - The income tax works differently, that's right, in the sense when he factors it in and if it's true income tax, he only pays if he wins, so it does effect what he's willing to pay.

SENATOR HUBER - I just wanted to get it to where we actually, what kind of tax we've heard so much, so many times about how you discourage your front end money in bonus bidding, and in some cases, it's absolute milarkey, you don't do it at all, and there you hardly do any discouragement when you do it on a net profit basis. If you get a portion of that in there in a gross manner, you've got a problem.

RICHARD KILGORE - My only point here was to leave you with the idea that we do have an interrelation between the taxes and what you will get on your lands when you lease them, but you also will effect, of course, the value that other people get from their lands and _____ the native corporations.

Well in the end, this whole question of the relative tax burdens and the effects, and when do you have to_____ incentives, when do you discourage, obviously there are no easy answers as I said at the outset. There are many things you would obviously have to look at, and many of these have been suggested. One would obviously be an economic study of the industry, some of which have been done. Levels of activity would be another indicator of your total tax package, lease bids and so on, comparisons with other states and all these things are things that one would look to and try to assess how far you have gone in your taxation policy.

I think one of the really best safe courses, so one would really know where one is in this whole thing, even after you look at all these sort of measures, one of the best safeguards is probably to try to design taxes in your state that relate reasonably well to profitability. I think you run less of a risk if you do this. If you are able reasonably, or in some fasnion to relate them to profitability, then you're not going to impose a very big tax burden if the industry isn't

very profitable, and if it is very profitable, you tend to throw up higher taxes and you run less of a risk really that you end up imposing on reasonable taxes on people, and this probably in the end is one of your best safeguards to kind of keep those principals in mind which means taxes related either directly related to income or taxes sort of semi-related to income as the step schedule that you have or the continuous schedule as is proposed where you really impose high taxes only in circumstances that weem to indicate high profitability, that is high well productivity which tends to be associated with high profitability, so I think the more that you keep to these kind of principals, the less of a problem you're likely to have in terms of really going too far in your tax burden on the industry.

GEORGE SILIDES - I have questions on two matters which concern most of us. One of them I know particularly concerns Senator Huber also, and if I may I would like to ask them now. One is do you have any comment on wipping out all the industrial incentive taxes in the State.

RICHARD KILGORE - We really don't have a comment on that.

GEORGE SILIDES - And the other one then is something which was discussed back in 1973 when we had a bill before us to own part of the TAAPS line. Now we have some bills in front of us which concern the possibility of again acquiring

an equity interest in gas lines or other lines, and I wonder if you could comment on that, whether your position has changed or what it might be now.

SENATOR HUBER - George, would you _____ bills particularly is for an industrial incentive, or for a state sponsor corporation which would operate on its own under the so called industrial incentive type bonding 100% if you could expand your question .....

GEORGE SILIDES - Senator, yes, I was going to make it into two parts, one is just to get a general statement on the State being an equity owner, and secondly of course we have SB 251 which is Senator Huber's bill actually.

RICHARD KILGORE - I haven't seen the bill itself.

SENATOR HUBER - It establishes an authority Dick, and with all of the powers, 100% of the authority to build the gas line.

RICHARD KILGORE - Well, frankly I would prefer, if you don't mind kind of deferring an answer to this question, and give it a little more thought. I know we have in the past, I guess, generally kind of questioned states being involved in things of this sort, and I don't want to give a general answer.

SENATOR HUBER - I don't want to force it either, but the reason that you might give it some consideration when you go back home is that the bill is not this one that is just an idea of whether we do it next year. This particular bill is an either now or never type of thing because it is designed, the whole purpose of it is to supply the North Slope gas to the lower '48 at an economically feasible price to make the project feasible, so it don't have to be subsidized either by users or the government, and if with the FEA setup and everything is set up with the President's approval and everything, it's an either pass it, so it's a method or else it will not be a factor. It's kind of a forced thing but it's now or never. It's timely.

RICHARD KILGORE - Senator, there are a lot of ramifications and a lot of things to think through on this particular kind of thing. I would prefer rather than just giving it off the top of my head, if we did especially take a look at the bill in itself, think it through carefully, and either come back to you with a written response or on the occasion of our next visit be prepared to respond.

MEETING ADJOURNED.

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LEONARD E. KUST is a partner in the New York law firm of Cadwalader, Wickersham & Taft. He was formerly Vice President and General Tax Counsel of Westinghouse Electric Corporation with which he was associated from 1955 to 1970.

A native of Wisconsin, Mr. Kust is a graduate of the University of Wisconsin and the Harvard Law School. He is a member of the New York and Pennsylvania bars.

He is a past president of the Tax Institute of America, and of the Tax Executives Institute. Mr. Kust has served as Chairman of Governor Scranton's Committee on Tax Administration, Chairman of Task Forces for Governor Shafer's Tax Study and Revision Commission, and was a member of the Advisory Committee of the Commissioner of Internal Revenue. He has served on the Executive Committee of the National Tax Association, as a Director of the Chamber of Commerce of the United States, and as a member of the Taxation Committee. He is a member of the Tax Section of the American Bar Association, a member of the Council of the U.S.A. Branch of the International Fiscal Association, a member of the Advisory Board of Tax Management, and a member of the Advisory Board of the Tax Foundation.

Mr. Kust has written on a wide variety of tax issues, including "State Taxation of Income from Interstate Commerce: New Dimensions of an Old Problem", S.W. L.J. 1 (1960); "State Taxation of Interstate Sales", 46 Va. L. Rev. 1290 (1960); "Federal Tax Reform", the Tax Executive, Vol XIV, April, 1962; "Standards of Conduct for Tax Executives", the Tax Executive, Vol. XIV, July 1962; "A Reappraisal of Taxation of International Business Income", National Tax Association Proceedings, Annual Conference, 1966, p.154; "Alternatives for New Federal Revenues", Tax Review, Tax Foundation, Vol. XXXIV, No. 7, July, 1973.

TESTIMONY BEFORE THE
SENATE RESOURCES COMMITTEE
OF THE
ALASKA STATE LEGISLATURE

By

LEONARD E. KUST

February 10, 1978

Madame Chairman and members of the Committee:

I am LEONARD KUST, partner in the New York City law firm of Cadwalader, Wickersham & Taft. I have been retained by the Alaska Oil and Gas Association (AOGA) to study the present Alaska corporate income tax and the various proposals to change that tax pending before the Alaska Legislature. On December 9, 1977 I presented a 45 page paper to AOGA setting forth my views on these issues. This paper has, I understand, been made available to you and I offer a copy for inclusion in the record of these hearings.

Before I proceed further I think you are entitled to ask whether I have the credentials to presume to give you views which it is worth your time to listen to and consider. I have for this purpose prepared a resume of my past involvement in issues of state taxation of the income of multistate and multinational business. I would like to offer this

resume for the record and hand copies to members of the committee for their perusal, if they wish.

I understand that your major concern and the concern which the various bills under consideration are intended to address is that the current Alaska income tax fails to reach and effectively tax income derived from oil and gas production and transportation activity in Alaska and your concern that oil and gas corporations operating in Alaska are paying to Alaska significantly less than the statutory 9.4% tax rate on their income.

Let me remind you at the outset of what I am sure you are all aware. Under the United States Constitution Alaska cannot impose its tax of 9.4% on the entire income of corporations engaged in business in Alaska and elsewhere. Such a tax would insure multiple taxation by the states in which the corporation does business and be an unconstitutional burden on interstate commerce.

This constitutional limitation conforms with internationally recognized fundamental principles of tax jurisprudence. Where the activities of a business extend over two or more countries or states, all of the income from such business cannot be taxed by each of the countries or states.

Accordingly Alaska can impose a tax only on Alaska source income of corporations which operate in Alaska and elsewhere. Any tax which applies to income earned outside Alaska will not only result in multiple taxation but will also violate both the United States Constitution and the generally accepted principles of tax jurisprudence.

The problem, of course, is in determining the source of income. This is not a new problem. It is a problem which scholars, legislators, and tax administrators have struggled with over the years. In this modern era as corporations have expanded their interests throughout the country and in many cases the world the problem has become more acute. The states from the outset upon enacting corporation net income taxes beginning in 1911 strove to avoid imposing an unconstitutional burden on interstate commerce by taxing only a portion of the income of the interstate business. The development over the years has been in devising and refining the method by which to determine the portion of the total income of a multistate business which should be taxed by each state and the attainment of uniformity in the methods used by different states so as to subject to tax all, but not more than all, of the total income of multistate business.

The system which has developed has two elements:

(i) a tax base measured by a company's worldwide income determined by reference to Federal taxable income and (ii) a method of dividing this base through use of an apportionment formula.

Why a formula approach? Well, the states initially sought to determine the source of income by means of "separate accounting", that is, by constructing an income or loss statement for the activities of the business in the state as if it constituted an independent business dealing at arm's-length with the remainder of the business and the outside world. It was soon evident, however, that separate accounting was not reasonably feasible within the limits of administrative practicability. As a consequence, the so-called "Massachusetts formula" gained early and general acceptance, commencing in the 1920's, among tax administrators and business taxpayers as a reasonable alternative to separate accounting for determining the portion of the total income of multistate business which is taxable in each of the states in which it has activities. The Massachusett's three-factor formula apportions the income of a business to the taxing state on the basis of the average of three fractions:

(1) property within the state over total property,

(2) payroll within the state over total payroll,

and

(3) sales within the state over total sales.

It was recognized at the outset that multiple taxation of multistate business income arises not merely from failure to apportion reasonably but from disparity in methods of apportionment as well, even though each method by itself and applied universally might be reasonable. The National Tax Association began advocating uniformity in the method of apportionment as early as 1919. Ultimately, these and other efforts culminated in the Uniform Division of Income for Tax Purposes Act (UDITPA) adopted by the National Commissioners on Uniform State Laws in 1957. UDITPA incorporated the three-factor formula and, most notably, defined the numerator of the sales fraction, with respect to which the greatest divergence from uniformity had developed, as being sales having their destination, that is, delivered to customers, in the state.

The Multistate Tax Compact, of which Alaska is a member, inaugurated in 1966 to promote uniformity and thereby avert Federal legislation then under consideration to impose uniformity on the states, incorporates UDITPA.

The UDITPA formula is not without its flaws; clearly it is not perfect. Whether, in theory, a better formula can

be developed, I do not know. This particular formula rests on common sense which has survived years of practical application. Most importantly, this formula has been accepted by both taxpayers and state tax administrators.

I want to emphasize the general acceptance of the three factor UDITPA formula. Out of my experience serving as co-chairman in 1969-71 of a committee of state administrators and business representatives seeking to formalize a country-wide uniform system for division of income of multistate and multinational business by a combination of the Multistate Tax Compact and Federal legislation, I can report that there was at no time any disagreement among the state tax administrators and business representatives as to the validity of the three factor formula. It was accepted by all as the bedrock on which any system of uniform division of income must rest.

Out of a total of 44 states and the District of Columbia which impose a corporate net income tax, 40 provide for the three-factor formula, 25 by adoption of UDITPA or the Multistate Tax Compact and 15 by incorporation in their own tax statutes, four of the latter giving greater weight to the sales factor than to the property and payroll factors. Differences in the economies of the states as to whether primarily industrial, or commercial, or agricultural or extractive have not affected the general acceptance of the three-

factor formula as essentially fair and reasonable.

The major concern raised by the proposals under consideration by this Committee , and I will discuss the proposals more specifically in a few moments, is that they would seriously disrupt the uniformity which over the years the states and business have labored to achieve, and which, I believe, is essential to fair and effective taxation by the states of the income of multistate businesses. A few other states have begun to tinker with the formula for their own parochial interests. I deplore such action. If you really believe that the UDITPA formula is not reasonable with respect to the oil and gas industry as a whole, the solution is to proceed under Section 18 of UDITPA on a case by case basis or to approach other states and seek a new uniform method for division of the income of the industry. Unilateral action by Alaska or by any other state would generate multiple taxation and would threaten the framework that has developed for division of income among the states.

But beyond the question of uniformity, I believe that both HB 322 and SCS CSHB 322 and the impetus behind them are based on a fundamental fallacy. They are based on the assumption--and I stress assumption--that the "fair" share of income to be taxed by Alaska is

to be determined by changing the apportionment formula or by statutory "separate accounting" so as to approximate the income based on barrels of production in Alaska times the well-head price less costs and expenses incurred solely in Alaska. This is demonstrably not the "fair" share of income attributable to Alaska. Income is not merely the result of production. The creation of income requires both production and consumption. It is the demand created by the economies of the consumption states that converts the production into income. The consumption states have an undeniably legitimate claim to tax part of the income which is based on this price created by their demand. Would Alaska agree that only the states in which the goods are produced which are sold by Sears in Alaska can tax the income and Alaska cannot? Of course not. As the consumer state in this case it wants to and is entitled to and it does tax a portion of the income from production outside Alaska.

Thus, having read some of the prior testimony, I would take sharp issue with the confident assertion that Alaska's fair share of the income of the oil and gas industry is the well-head price less costs and expenses incurred in Alaska.

I would like to challenge Mr. Lipton and Professor Zeifman to present their arguments to the Multistate Tax Commission or to a meeting of the National Association of Tax Administrators in support of their proposals as appropriate uniform methods to be accepted by all states for division of the income of the oil and gas industry. I think it is reasonable to predict that neither of the proposals would be judged to be a fair and reasonable basis for uniform division of income among the states.

This committee and the Alaska legislature will ultimately decide what course to follow. It is your responsibility and your prerogative but I would like to suggest that your decision should be made against the broader framework which I have presented rather than the narrow perspective urged upon you in support of the proposals under consideration.

THE ZEIFMAN-AINSWORTH PROPOSALS

The proposals of Professors Zeifman and Ainsworth which are incorporated in H.B. 322 are based on these two premises: (i) that Alaska's tax base has been eroded through Federal tax subsidies and incentives which are unrelated to the definition of net income, and (ii) that the UDITPA apportionment formula unfairly reduces the amount of taxable income attributable to Alaska by corporations which export non-renewable petroleum resources from the state. Zeifman and Ainsworth recommend:

1. Adoption of a tax base measured by the greater of book income or Federal taxable income, and
2. Replacement of the destination-oriented sales factor with an "extraction factor".

Furthermore, they propose that these changes apply only to corporations with ordinary gross receipts in excess of $250,000,000, more than 50% of which is derived from production, transportation, refining, manufacturing, processing, distribution or retail sale of oil or gas or products derived from oil and gas.

I believe that Professors Zeifman and Ainsworth are mistaken both as to their premises and their recommended solutions.

The current Alaska income tax base is a corporation's Federal taxable income. That base includes the world-wide income of the corporation - not just United States source income. In determining Federal taxable income, Congress has allowed certain deductions which are not taken into account in determining the corporation's book income. These "tax subsidies", however, are for the most part available to all corporations, including corporations engaged in business solely in Alaska and multinational corporations engaged in various business activities in Alaska. It is unfair to single out the oil industry. If "tax subsidies" are to be eliminated they should be eliminated for all corporations.

Furthermore, with respect to the one Federal "tax subsidy" available solely to the oil and gas industry, a current deduction for intangible drilling costs, it is erroneous to charge that because drilling costs reduce Federal taxable income Alaska in using such income provides an incentive to drilling wells outside Alaska. Federal taxable income reflects not only deductions for the cost of wells drilled outside Alaska but also the income from such wells. It is not a one-way street. Alaska is no more providing an incentive for drilling outside Alaska than other states are providing an incentive for drilling in Alaska.

The Department of Revenue has cited Congressional studies by Congressmen Vanik of Ohio to support the Department's claim that adoption of the Federal tax base by Alaska results in an effective tax rate significantly less than 9.4%. Vanik's study measures Federal income tax due as a percentage of worldwide income. Obviously this comparison will result in an effective U.S. tax rate of less than 48% for companies engaged in foreign operations because the United States provides a credit against its tax on worldwide income for taxes paid to other countries. This is the necessary alternative to taxing only the income earned in the United States. Similarly, measuring taxes due to Alaska as a percentage of a corporation's total worldwide income will result in an effective tax rate of less than 9.4%. Both comparisons are meaningless, since neither the United States nor the State of Alaska intends or reasonably can impose its tax on the worldwide income of taxpayers without a foreign tax credit or without apportionment. It is primarily because of the division of income (by means of a foreign tax credit at the Federal level and formula apportionment at the state level), not determination of the tax base, that the effective rate on worldwide income is significantly less than the statutory rate. If 25% of the worldwide income of a company is earned in Alaska, obviously the effective rate of Alaska tax on worldwide income will be 2.35%.

The suggestion of Professors Zeifman and Ainsworth, which is incorporated in H.B. 322, that book income be used as

a tax base is unique. I am aware of no state with a tax base measured by book income, even as an alternative basis. Book income is an inappropriate tax base. Adoption of such a tax base would in effect delegate determination of income to the company's management and the accounting profession. If Alaska is not prepared to accept management's and their accountants' determination, it will have to develop an audit staff sufficient in size and skill to conduct its own audits. It will not be able to rely on the audit skills and extensive examinations of the Federal government or the Multistate Tax Compact.

Furthermore, book income not only reflects taxable income before tax subsidies but also many accounting and timing differences unrelated to Congressional tax policies, many of which reduce book income in comparision to taxable income. As an example, corporations are often entitled and even required for financial accounting purposes to set up reserves for certain estimated expenses or losses which are not deductible in determining Federal taxable income.

Finally, use of the higher of Federal taxable income or pre-tax book net income as a tax base, as is proposed in H.B. 322, will tax income without reduction for those expenses which are deducted in different years in determining book net income and Federal taxable income. For example, if book income

exceeds Federal taxable income because of current deduction for intangible drilling costs which are deferred for book purposes, and then Federal taxable income in a succeeding year exceeds book income because the deferred intangible drilling costs are then expensed for book purposes, the tax base will be determined without deduction for such costs at any time.

As to substitution of the extraction factor for the sales factor in the apportionment formula, it is my view that the UDITPA formula provides for fair and equitable division of income of oil and gas corporations between Alaska and the rest of the world and fairly reflects the extent of their activity in Alaska as compared to the rest of the world.

The destination sales factor cannot be regarded as allocating Alaska's share of income to other states but more properly as assuring to the market states a fair share of the taxable income base. Without the purchasing power and demand provided by the market states, there would be little if any income of oil and gas companies for Alaska to tax. The sales factor quite properly gives recognition to the contribution by the market states to the creation of the income tax base. Substitution of the extraction factor for the sales factor would ignore the contribution of the market state to the creation of income, just as would an origin-oriented sales factor

which was used for years by heavy manufacturing states for their parochial interest. Use of this factor was so short sighted that it drove business out of these states. States such as New York and Massachusetts have had to retreat so far that they have adopted double-weighted destination sales factors to attempt to convince businesses to stay or to return to their states.

Alaska may dismiss this experience as irrelevant since the oil is in Alaska and the oil business cannot go elsewhere. Only within limits is this so, but in any event Alaska cannot ignore applicable principles of fairness and of cooperative action among the states to avoid multiple taxation. Use of an extraction factor in Alaska when other states use a destination sales factor would obviously result in multiple taxation. Is it proper for Alaska to take deviant action and expect all the other states to conform their apportionment formulas to Alaska's in order to avoid multiple taxation? Is it appropriate for Alaska unilaterally to disrupt the progress the states have cooperatively been making toward uniformity in their apportionment formulas?

Professors Zeifman's and Ainsworth's proposal to replace the destination sales factor of the UDITPA formula with an origin-oriented extraction factor is based primarily on

ADDRESS TO SENATE RESOURCE COMMITTEE

SCSCSHB 322

(An Act Relating to the Alaska Net Income Tax)

Madame Chairman, members of the committee, my name is Oliver Leavitt. I am a resident of Barrow and serve as Director and Treasurer of the Arctic Slope Regional Corporation. I also am priviledged to serve on the Board of the Alaska Federation of Natives.

Two years ago I had the pleasure to appear before this committee and give testimony concerning a package of bills that collectively dealt with increases in existing taxes or imposed new taxes on oil and gas production in the state. At that time we argued against the imposition of new or additional taxes as unnecessary and counter-productive for the state and very harmful to the economic condition of the native regional corporations who had not sufficient time to generate a positive cash flow in connection with natural resource development.

While some may have heeded our testimony in 1976 since the proposals to enact new taxes were not adopted that session; a major increase in the severance tax passed and become law in the second session of the 9th Legislature or last year in 1977.

We are thankful that some of the more revolutionary and

POTENTIALLY DAMAGING TAX PROPOSALS WERE NOT ACTED UPON.

SINCE PASSAGE OF THE SEVERANCE TAX INCREASE LAST YEAR SEVERAL VERY IMPORTANT FACTORS HAVE SURFACED THAT AFFECT THE VALUE OF PRESENT AND PROBABLY FUTURE OIL PRODUCTION FROM THE NORTH SLOPE.

MOST SERIOUS IS THE CURRENT AND PROPOSED PERMANENT TAPS AND TANKER TARIFFS WHICH ARE ALMOST 4.00/BBL GREATER THAN WE ANTICIPATED IN 1976. OF COURSE, THE FINAL TARIFF IS NOT SETTLED BUT IT MOST CERTAINLY WILL BE GREATER THAN WE BELIEVED POSSIBLE AT THE TIME WE CALCULATED THE THEN WELLHEAD VALUE OF CRUDE.

THE OUTCOME OF A PENDING LAWSUIT - STATE OF ALASKA VS. AMARADA HESS CORPORATION, ET. AL. - COULD HAVE VERY SERIOUS ADVERSE AFFECTS ON THE FUTURE OF OIL AND GAS REVENUES THAT MAY BE GENERATED FROM ASRC LANDS - IF THE STATE WERE TO LOSE IN ITS ARGUMENT AGAINST DEDUCTIONS FOR FIELD GATHERING CHARGES.

IF THE TARIFFS AS PROPOSED BY OWNER COMPANIES OF ALYESKA PIPELINE SERVICE COMPANY ARE SUSTAINED AND IF ADDITIONAL CHARGES ARE ALLOWED TO MOVE OIL FROM THE WELLHEAD TO THE CUSTODY TRANSFER POINT, AND AN ADDITIONAL TARIFF TO BRING THE LIKELY SOURCE AREAS FOR ASRC CRUDE TO MARKET VIA TAPS OR SOME OTHER ALTERNATIVE MEANS IS ASSUMED - THE HIGHEST OPEC PRICE TODAY WOULD PROBABLY NET BACK CLOSE TO NOTHING AT THE WELLHEAD. AS YOU ARE AWARE BOTH ROYALTY AND NET PROFITS ARE

CALCULATED FROM WELLHEAD PRICE.

OF COURSE THESE ARE EXTREMES BUT THERE ARE NO ASSURANCES AT THIS TIME THAT CRUDE OIL PRODUCED FROM ASRC LANDS WILL COMMAND A PRICE THAT WILL ADEQUATELY COMPENSATE ASRC FOR EXTRACTION OF ITS RESOURCES.

ONE OF THE MOST SIGNIFICANT AREAS OF POTENTIAL REVENUE FOR ASRC AND HENCE THE OTHER REGIONS THAT WILL SHARE UNDER 7(i) OF ANSCA IS THE NET PROFITS PROVISIONS OF THE VARIOUS AGREEMENTS WE HAVE WITH SEVERAL MAJOR OIL COMPANIES.

THE NET PROFITS INTEREST IS CALCULATED ON THE COMPANY'S PROFIT PER BARREL BEFORE FEDERAL INCOME TAXES BUT AFTER DEDUCTIONS OF ALL OTHER COSTS INCLUDING STATE TAXES. THE LOWER THE PRE TAX (FEDERAL) PROFIT THE LESS THAT ASRC AND THE OTHER REGIONS WILL RECEIVE.

ANOTHER IMPORTANT MATTER WE THINK THE COMMITTEE SHOULD WEIGH IN CONSIDERING THE DIRECT AND INDIRECT IMPACT OF INCREASED TAXES IS THE AFFECT IT WILL HAVE ON FUTURE LAND TRANSACTIONS THAT MAY INVOLVE ASRC LANDS NOT SUBJECT TO ANY PRESENT AGREEMENT.

OF APPROXIMATELY 5 MILLION ACRES TO BE CONVEYED TO ASRC LESS THAN HALF IS SUBJECT TO EXISTING CONTRACTS.

WHILE WE BELIEVE THAT SOME OF THE LANDS UNDER LEASE ARE HIGHLY PROSPECTIVE FOR OIL AND GAS, WE HAVE FOUND NONE YET

AND UNTIL WE DO THERE REMAINS THE CONCERN THAT MAYBE NONE OF THE LANDS BEING EXPLORED HAVE ANY SUBSURFACE VALUE.

THE NECESSITY FOR THE SUBSURFACE RESOURCES TO PAY OFF IN FAVOR OF THE NATIVE REGIONAL CORPORATIONS IS SO OBVIOUS THAT I NEED NOT EVEN BRING IT UP.

WE ARE VERY CONCERNED THAT AN UNSTABLE TAX POLICY THAT CHANGES EACH YEAR WILL BE AN OBSTACLE IN MAKING NEW EXPLORATION CONTRACTS ON THE 50 PERCENT OF ASRC LANDS THAT ARE AVAILABLE FOR NEW DEALS.

IN SUMMARY WE THINK THAT THE UNCERTAINTY OF THE IMPACT OF PERMANENT TARIFFS AND OTHER DEDUCTIONS TO THE WELLHEAD VALUE OF CRUDE OIL AND GAS SHOULD BE ENOUGH OF A CAUTION SIGN TO THE LEGISLATURE TO GET ALL THE FACTS AND SEE WHERE THE STATE AND ALL OF ITS PEOPLE STAND BEFORE HASTILY ADOPTING ADDITIONAL TAXES ON INDUSTRY WHICH GO FAR BEYOND A COMPANY'S POCKET BOOK - THEY WILL AFFECT AN AWFUL LOT OF THE PERMANENT CITIZENS OF THIS STATE.

THANK YOU

MILTON LIPTON TESTIMONY
BEFORE THE JOINT RESOURCES COMMITTEES
January 25, 1978

MILTON LIPTON:

The comments that I would like to offer and then open up to your questions are based upon the draft for a bill that amends the leasing policy of the state. To begin with, I call your attention to a rather unique and I think a very progressive statement of the preamble which says that among the purposes of this is to maximize the state's share from profitable oil and gas production while minimizing revenue from unsuccessful exploration wells and from marginal economic oil and gas production. It is a most unusual approach for a state or a government that is leasing property to take....that is...what you are saying in effect is that you are not trying to maximize your revenues come oil or high water, but that you'll take your revenues from successful oil and gas exploration and you are prepared to forego under certain circumstances optimum revenues that you might have gotten from bonuses paid to the state where the venture was unsuccessful. I would think that the industry would look with great favor upon this as a principle of leasing, and as I said before, it's a most unusual thing to see a government proposing this itself.

A major change which is now being proposed in your leasing policy has to do with bidding methods and on page 4 of the proposed draft bill there are actually eight (8) different bidding methods itemized which would be available to the commissioner and from which he could select in any particular lease sale. The eight different bidding methods break down really into four different bid variables. The first is the very familiar front end bonus bid, and there are three (3) different ways this can be done.

The second is royalty bidding and there are two different ways the commissioner can do that. The third is bidding for a net profit interest to the state out of the proceeds of successful oil and gas exploration development and production. The fourth is bidding on the basis of work obligations, how much a company will commit itself to work obligations. As I said, the bonus bidding is the familiar one which as been used most commonly, I think, almost exclusively here in Alaska in which the blocks which are up for competitive bidding will go to that company that offers to the state the highest bonus, and then the terms of the lease specify certain fixed commitments on the part of the leasing company, in the past, it has been almost universally 12 1/2% royalty. Under this proposed legislation, if the commissioner can solicit competitive bidding on the basis of a front-end bonus but with one of three alternative sets of fixed commitments written into the lease. One is a straight royalty which shall not be less than 12 1/2%. Second is a sliding scale royalty, that is beginning initial production at one level and then moving upward. And the third is a combination of a fixed royalty and a net profit interest to the state where the fixed royalty shall not be less than 12 1/2% of the fixed profit, interest shall not be set by the commissioner at less than 30%. So in effect this deviates from your present practice only insofar as it gives the commissioner a choice of three different elements which he can write into the leases when he opens them up for competitive bidding on the basis of the bonus. The royalty bidding is quite different. Here the two alternatives are that the companies would bid competitively; offering, competing on the basis of a sliding scale royalty which cannot begin at less than 12 1/2% and which carries thereafter a fixed bonus. The bonus is fixed by the commissioner, the companies bid on what kind of a sliding scale royalty they are prepared to offer the state or alternatively there's a fixed bonus and they offer a

fixed royalty. They bid competitively on royalty not a sliding scale royalty, but one says I'll offer 12 1/2%, another one says I'll offer 15%, yet another one says I'll offer 18%..... A few words about royalty, competitive royalty bidding, in previous discussions with committees of this legislature we have argued that royalty bidding is not a preferred form of bidding, except under very exceptional circumstances. If, for example, you have semi-proven acreage where the volume of the oil to be found is reasonably calculable, and the risks are not that great, location of the oil in terms of distance from ports or whatever else is pretty well known because other production is close by, under those circumstances you might have royalty bidding. But under most circumstances we would feel that royalty bidding is not a preferred form of bidding. You remember from our discussion of severance tax that the nature of the royalty or of the severance tax is that it becomes a percentage of gross value. Taken off the top of the gross value without regard to what the profitability of the venture is and when companies don't have to pay a very large bonus, the bonus is fixed at a modest rate, everybody pays the same bonus bids, but competitively on the basis of the royalty there may be a tendency for companies in their exuberance to obtain the lease to push the royalty which they offer the state progressively higher, they don't know what their competitors are going to offer, so they stretch their bid in order to win the lease. And then subsequently it may turn out that this royalty to which they commit themselves and which must be paid on every barrel of production over the entire duration of the lease becomes a very burdensome one; it could lead to earlier abandonment. But this is particularly relevant, what I'm saying now in the context of paragraph "D" at the bottom of page 4, which says regulation shall be established for all bidding methods to allow reduction of royalty to compensate for these increasing costs in the later stages of production decline, to prolong the

economic life of the field. And then it goes on, it says that the commissioner cannot really abate the royalty before at least two years of production have transpired. But, I put it to you, that although discretion on the part of the commissioner to abate royalties is something which you had in your lease a long, long time ago in your leasing bill; although this may be good legislative practive and good administrative practice when fields are beginning to reach the end of their natural life and you would like to encourage the maintenance of production even if it means taking a lesser royalty; to have this in the statute at the time when companies are bidding competitively on the royalty and then there is a temptation to say, well, if we bid too high a royalty, we come running back to the commissioner and we ask for abatement of the royalty So, you put the state, you put the commissioner in a very bad hole and and you have perhaps without intending to, you encouraged the companies to bid not the highest royalty that they think they can afford to pay in light of their exploration expectations, but to over bid because when worse comes to worse they will go running back for abatement of royalty. So I would think that if you are going to maintain this feature in the leasing law which says that in order to encourage the continuation of marginal production there will be the possibility of abating royalty then you certainly, I think, want to consider very, very carefully whether you want to have among the options, under which the commissioner can lease, bidding competitively on royalty. The third alternative or the third form of competitive bidding is bidding a percentage of net profit to the state. What this means in effect is that the companies who are bidding competitively to obtain a lease will say to the state, well, your lease requires us to pay a fixed bonus so we all have to do that and in another version your lease requires us to pay a fixed bonus, plus no less than 12 1/2% royalty whatever the commissioner specifies. Now, each company

bids competitively by saying to the state that after we have paid the bonus and after we pay a royalty of 12 1/2% of gross well head value on every dollar of production, thereafter, each year we convey to the state a percentage of our net profits and the companies bid competitively; the company that commits itself to turning back to the state the largest percentage of net profits is the company that wins the lease. Net profits can be defined, they are not defined in the statute, and I think correctly not so. The commissioner before any lease sale where the bidding component or the bidding variable is net profit, tells all companies who are entering the bidding precisely how net profit will be computed. It does not have to be and, hopefully, will not be the same way net profit is computed for income tax purposes. It is a notional concept of net profit which says you start with this gross value or whatever it is and you subtract certain specified costs everyone knows precisely without too great argument or debate how the accounting will be done in the course of the year and relatively simple accounting can be mandated by the commissioner before the lease sale. We have felt for a long time that the net profit bidding variable is a particularly attractive one, both in the standpoint of industry and for the standpoint of whatever government it is that's putting up acreage for lease. Not necessarily to the exclusion to other possibilities, but under certain circumstances a very attractive approach. What it does is, it removes a great deal of the capital available for exploration from the front-end bonuses so that the money thats available goes to productive work instead of just to front-end bonus. Where there is highly successful exploration the lessor, State of Alaska in this case, can expect to have very, very substantial revenues from the lease quite apart from taxation or anything else. Revenue from the

lease as the percentage of net profits. You might even think of net profit as a royalty based upon net value instead of a royalty based upon gross value. Sometime it's referred to as a net royalty or a net profit carried interest. What it means in effect is that the State of Alaska takes on a very considerable proportion of the risks in the exploration game. It does get a bonus but the bonus is a small bonus fixed by the commissioner as being appropriate to this bidding variable. And it may get, say, a fixed royalty but after that the larger proportion of the income which the state might expect to receieve it would receive only if the lease proves to be a productive lease and how much the state gets depends upon how much oil or gas is found, what the value the oil or gas is, and how profitable the operation. So the state in a sense becomes a partner with the explorer in both the failures and the successes of the venture. But the state does not become a working partner, the state does not become an active partner, the state is not in the oil and gas business. The decision as to whether or not the exploration should take place, the competitive bidding on what the net profit conveyed to the state is... all of these are private decisions by private industry in a competitive environment. Then the final variable, and it is the eighth item among the alternatives available to the commissioner, is bidding on the basis of work commitments. And there in a sense, the commissioner says when the sale is being advertised, that there is going to be a fixed bonus, and there is going to be a stipulated royalty. Now the winner of this lease who is entitled to do the exploration is the company who commits the largest amount of money to exploration process. This kind of bidding, perhaps, would be utilized in very, very difficult environment areas where the state wants to be sure that all potentials of the acreage are really explored, where the costs of exploration may be very, very high and where in the absence of work commitments the companies may be inclined to back out too quickly in terms of the results of one

unsuccessful well or whatever the case might be and the state would like to get the best possible exploration of the prospects within the area put up for lease and therefore says to the companies, we will reduce your bonus commitments, we won't have a bidding on the basis of royalty, but we will allow you to bid on how much you are prepared to commit to the exploration of this acreage which the state is putting up for lease. Well, just a few comments, I've already indicated that I think, that we think, that gross royalty bidding except in rare circumstances, is not the most attractive form of competitive bidding, and particularly not if you are going to allow abatement of royalty under certain circumstances. Bonus bidding, net profit bidding, work bidding, each one a reasonable approach to competitve bidding depending upon the nature of the area which is up for lease; how the state, the commissioner, and his technical staff regard the potentials. So I think that by providing these alternatives, the state is in effect creating a reasonable basis for a leasing policy within Alaska. I wonder, however, whether it is necessary in legislation to itemize all eight possibilities, that is to say, a bonus bid with not less than a 12 1/2% royalty, or a bonus bid with a sliding scale royalty, or a bonus bid with not less than 12 1/2% royalty and not less than 30% net profit. There are many variations which are itemized here, and for example, a bonus bid with not less than 12 1/2% royalty, and not less than 30% net profit is hardly, I would suspect in most areas, is hardly going to get much competition in terms of the bonus. Why not less than 30% net profit? It seems to me that if you lay out in gross terms what the permissable bid variables are, bonus under certain circumstances royalty, perhaps net profit, work commitments, and then leave it to the commissioner as to the combination of variables and the minima for the fixed items he wants to put in there, how far can one anticipate in legislation itself, what combination of fixed commitments

should underlie the selection of a bid variable, like a bonus variable and I would think that perhaps it might be advisable for the legislature to consider presenting to the commissioner a greater option of more bidding variables and perhaps set certain minima, but not itemize them in the details which appear here. Now there is one other aspect of the bidding that I would like to refer to and it is an item that appears on page 9. It says lands which have been offered for lease within the previous five years, but which received no bids at public auction may at the discretion of the commissioner be immediately offered for lease under regulations promulgated in advance upon terms most advantageous to the state including leasing non-competitively. The commissioner shall utilize a sliding scale of royalty based upon such formuli as he determines to be equitable, but need not adhere to the rental schedule in subsection (k) of this act nor to the 57 (indesc.) acres per lease and so on. What I am calling your attention to is the option here avaiable to the commissioner where a lease that is offered for bidding has not been taken up very quickly, to put it back for lease including under noncompetitive circumstances. I think that this could open up some dangerous precedents. Particularly if it's offered too quickly. I mean that the fact that a lease is not taken up in competitive bidding does not mean that there is no oil and gas there, it does not mean that the prospects are not good for oil or gas, it means that given the state of the knowledge at that moment of time, given the way the industry perceives the attractiveness at the moment of time they have'nt been interested in bidding on it.. They had other things that were more attractive, whatever the case might be. But let some time go by before opening this up for leasing again and particularly under competitive conditions again, what may have been learned about the geology of the state in the interim period. The way in which

company perspectives may have changed for a lot different reasons, I don't know what the case may be, I think may lead to the ability to lease under more favorable terms rather than for the state to conclude that nobody wanted our lease, well, we would like to have it explored anyway, lets get it on the market as quickly as possible, even if under noncompetitive circumstances. I would strongly suggest that you hear from the department, as well as from me, and others about why there is a sense of urgency about leasing noncompetitively just because the lease has not been taken up. I pass to other aspects than the terms of bidding and leasing. On page 5, there is a very pregnant one line clause which says the commissioner is authorized to withhold acreage from leasing in a particular lease sale. Now again, for those of you who remember one of the first reports we made for the legislature on leasing policy many, many years ago, one of the things that was discussed was the advisability, under appropriate circumstances, of the state leasing less than the full acreage in which there might be industry interest. Now enough acreage has to be put up for lease so that the companies that win the leases have a reasonable aggregation of acreage to provide for viable production of oil or gas or whatever is discovered. It doesn't necessarily mean that everything within a particular area of prospective interest has to be put up for lease simultaneously, there is good reason particularly if the purpose is to maximize the states share from profitable oil and gas production and minimize revenue from unsuccessful exploration wells and from marginal production for the state to withhold a certain amount of acreage. Now the acreage which was withheld may be condemned as absolutely sterile if the exploration around it finds nothing, (indesc.) the state may have withheld may turn out to be condemned by the industry you will never be able to lease it in which case you will not have gotten any bonus revenue

or whatever the case may be. But on the other hand, if it is successful you may come up with a subsequent lease sale with a net profit bidding for example, which makes it very attractive to the state in terms of the income that they will receive. So I would think that this thing is that the commissioner is not only authorized, but subject only to circumstances which make it undesireable which in case the commissioner has to exercise his judgement, that he should in fact withhold acreage it should be a more positive thing. I wouldn't want to make it binding under all circumstances. discretion must lie (indesc.) some areas where it may not be feasible where whatever acreage is put up really has to encompass the most of the structure which is in interest. If it can be done, I think it would be advisable to do so. The next feature that I would like to touch on briefly has to do with the period of exploration and on page 6 the appropriate paragraph says that an oil and gas lease shall cover a reasonably compact area and be for a period of five years. And there is no provision here for extension of the exploration period except under specific circumstances if production is eminent or a well has to be completed or the property goes into unitization. What under normal circumstances is a 5 year exploration period. I would suggest that there should be provision for at least some reasonable extension of the exploration period particularly in a country as difficult to operate in as the State of Alaska, where the geology, the environment, the climate, the circumstances all make it impossible to conclude an ongoing exploration period precisely within the five years. A whole exploration season may be lost because of a combination of circumstances; because drilling equipment couldn't get out there, or at the end of one season the

seismic work never got completed and one has to wait for the proper time of the year to go back and finish it and one loses a year of exploration. I would think it would be advisable to allow an extension of the exploration period. If in the view of the commissioner, good faith has been exercised by the easing company in the previous 5 years. I think it does no violence to the interest of the state. But there is another very interest feature thats introduced here at the bottom of page 9, paragraph v, the state shall have the right to purchase not to exceed 16 2/3% by volume of the oil and gas produced pursuant to a lease, and it goes on. That is to say, the state is assuring itself that if it chooses, it can have as much as 1/6th of the oil or gas produced on the lease. Now included within that would be the states royalty oil and gas and the volume metric equivalent of whatever the state may get on a net profit share. But if those fall short of 2/3rds of the oil and gas the state has the right to buy at the market value at the field price enough to make up 2/3rds. There is no obligation on the state to do it, the state has the right to do it. I see a tremendous advantage of the state in this, I seen no great diadvantage to the industry in this if exercised judiciously. It could be unattractive to the industry if it is arbitrarily applied and particularly out of small production where the lease holder really needs a substantial volume of oil to provide the economics for his export out of the state for example, and taking away 1/6th of the volume of oil starts cutting things too narrow for him, then I would say that this could be a burden to any company who is undertaking the exploration and who successfully is doing the development. So I would think there ought to be at least some proviso where by the lease holder is protected against simply a determination to take 16 2/3rd

no matter what, and in particularly small areas where the increment if the state gets may matter very little to the state but may matter very much to the producing company. I think some kind of clause should be put in to provide the protection.

That's the sum of the remarks that I think I could make about the special features of this proposed bill and if there are any aspects of it that I touched on or things that I have not chosen to talk to that you would like to address yourself to, I'm at your mercy.

SENATOR POLAND I will ask you one question Mr. Lipton, and that is, have you felt for sometime that our leasing policy needed to be updated or overhauled?

MILTON LIPTON Well, I think that if only to broaden increase, the number of options available for leasing, yes, I think so. I think the traditional front end bonus bidding and there is a lot to be said for it under the proper circumstances, and, but for this to be the sole basis of competitive bidding, I think it places a burden in rank wildcat areas upon the industry which is unnecessary, that you have to put so much money that ought to be used constructively, pay out as a bonus and it puts the state in a position where in many rank wildcat areas what the state gets is miniscule in terms of bonuses compared to what may be the profitability. If you add up the sum total of bonuses received by the state from the producing areas of Prudhoe Bay, it is miniscule bonus income because the companies were bidding on rank wildcat areas at a time when even if they were

successful no one ever knew if it could be developed, tremendous volumes of oil had to be found and if prices had ever stayed at $3.00 per barrel it never woud have been produced you see, under those circumstances obviously the bonuses are very very little. Now, I think there is no great virtue in the state having competition on the basis of front end bonuses when the total amount of bonus income you may get, particularly in the less attractive areas of the state. What seemed to be the less atractive areas of the state will be very very little and may prove to be the most attractive producing areas after they are developed. So that if you minimize the front end bonus under certain circumstances and go to a net profit interest then you have a chance of sharing much more considerably in the profitability of successful ventures and without doing great violence to the incentives of the industry. Because no company is going to bid away such a large share of the net profits that it leaves them without the incentive of very very profitable operations on the remaining shares. Now it is something which I think can be equitable both to the state and to the company. So yes, I do think that the leasing warranted amendment if for no other reason than to introduce a greater variety of bidding variables without going mad with you know giving the commissioner so many options that the poor man will never no on what basis he can make a selection. But I think to introduce several other options is a major step forward.

Q: Senator Huber - Milt, can you tell me from industries viewpoint if we would do any harm to this bill, in particular, or good or otherwise, your comments in regards to us putting an Alaska hire clause into the leasing requiring Alaska hire based not upon our regulatory rights but upon our proprietary contract rights?

Lipton: Senator Huber, you know, you ask me from the standpoint of the industry you really should ask that of the industry, not of me, but I would give you a very quick impression and if you put an Alaska hire clause, in, what it

means to the industry depends really on what you intend by Alaska hire. I mean there, if the industry doesn't have sufficient flexibility to obtain competent people, whatever their origin, then I think it does harm to the industry. But if the way in which it is applied is sufficiently flexible then I suspect not only wouldn't the industry object, but the industry would be delighted. You know, I think the industry would like to make the maximum possible contribution to Alaska hire. But it must be a very difficult thing to administer, I suppose.

Q: Senator Huber - I apologize for asking the industry viewpoint. I was asking basically for the economics of the industries viewpoint.

Lipton - Well, as I said the economics are affected depending upon how this either contributes to, or intereferes with the efficiency of the industries exploration and producing operations.

Q: Senator Huber - I was referring to a particulary in the difference between our regulatory powers as a government and our proprietary rights as a contr ct maker in this particular case.

Lipton - Well Senator Huber, this suggests to me that if you are doing this as part of a contract rather than by regulation, does that mean it's going to be less flexible, because it is in the contract?

Q: Senator Huber - Madame Chairman, Mr. Lipton, the intention is to make it less flexible because we are presently finding that our leases do not contain this and that hiring is not being done from the North Slope from Alaska where it could be done when there is qualified people sitting on the benches. And we want something to get a handle on this, so that it is not going to be struck down by the Supreme Court saying that you cannot make

such a law we want to work on our proprietary rights being that is our oil that we are selling.

Lipton - Senator Huber, I find it very difficult to give you a responsive answer because if you say that there are qualified people sitting up there who are not being hired, now obviously that is bad and if you had it in the lease they would be hired. On the other hand, if the industry may interpret qualified people differently. I don't know it's very very, it's difficult to say. But if the whole idea is to make it a firmer obligation through the lease that is one thing. But if you make it a firmer obligation and there is no flexiblity then I think it could be very difficult.

Q: Senator Huber - Well Madame Chairman, I won't dwell on it but just one more short thing, so that you understand what I am talking about. When the industry on the North Slope makes a deal, with forinstance, a Hawaiian corporation to supply them with the personnel and to do the hiring for them and then the hiring is done in Houston Texas we become concerned when there is qualified Alaskans sittin on the bench. But if we have a handle, a way that we can get a handle on this, using our proprietary rights we should be doing it, or trying to find a way to do it when we know that we can't do it with our regulatory rights and that is why I wanted to get your expertise on this.

Senator Meland - Madame Chairman, I, has Mr. Lipton spoken to any type of questions about all the legislature or are we just talking about (inaudible). Because I did have some questions that were left over from Wednesday, but we can certainly wait on that and talk about this legislation before us.

Senator Poland - Well what we had though we would do is talk about this and when there are no more questions on this we will go to the royalty oil proposals and then throw it open for all types of questions.

Q: Senator Radar - There are many question Madame Chairman. I had two items that I would like to have Dr. Lipton comment on. One of them is the concept of limiting from 500,000 acres to 200,000 acres the amount that any one entity can hold in leased lands and that concept actually appears in several faces in the bill. I assume it is to prevent or to insure a competitive market here so that we don't end up with one company dominating the field. Comment on this and give us your observations on that and what problems and benefits might flow from that.

Lipton - I think there is great virute in limiting acerage holding by an individual company. On the other hand, I have no feel really, for whether 200,000 acres as an amendment to the 500,000 alternative is too little or not. I would strongly urge that in order to acheive the same purpose, that is, I think that two things are of value. Acerage limitation I think could go in there. I don't think it does violence, providing that it is not so narrow that in a sense very soon you start reducing the number of competitors and a company that is successful in a couple of lease sales and then suddenly finds itself barred from further competitive bidding for acerage. You defeat your own purpose if you do that. But I sense that the purpose of the legislature and certainly the interest of the state is that acerage shall not be held. The purpose of winning acerage under a lease is to get on with the business of exploration. And therefore I would suggest that whether there is competive bidding on work obligations is one of the options or not. I think there should be work obligations in every lease. The commissioner should in every lease stipulate minimum, not maximum work obligations. We are not trying to tell the companies how to conduct their exploration activities. But there should be certain minimum work commitments which the companies have to perform in order to hold that lease. Let them get on with the business of exploration. It does no violence to the purpose of the companies, unless they want to get in that bidding and then sit back and wait for

somebody else to do some work or they wanted to be sure they were represented in the area but they had other fish to fry elsewhere in the state or somewhere else. I think you have a five year duration of the lease and I have already suggested that you might be willing to extend it, if the companies really need it and they have been going about their business. On the other hand, there should be minimum work obligations in every lease there. I think also there is a certain virtue in putting a ceiling on the amount of acerage which a given corporate or individual can hold as a result of leasing from the State of Alaska. I certainly would not want you to cut that down so small that you lose the competitive bidding and the third, fourth and the fifth lease sale because one company has already not exhausted it's interest, not even exhausted it's dollars but has exhausted it's ability to hold acerage in the state.

Q: Senator Radar - Would you comment on the provision as to the lessee or permittee conducting any exploration for development or production of oil and gas, the state shall provide the commissioner access to all data obtained from such activities and shall provide copies of such specific data as the commissioner may request. I don't know whether that is intended to change the public disclosure of that information or whether there is still proprietary interests or not but what is your understanding of that provision and your comment? It is on the top of page ten. It starts on the second line.

Lipton - I assume that your statutes prevent public disclosure of this for some minimum period. What is it two years in Alaska. Two years, I think I believe. Two years by statute.

Q: Senator Radar - Cause I take it that the proposal here does not suggest that we alter that proprietary -

Lipton - I would hope not. I would hope not. I think the right to proprietary information for at least two years. For any company operating here considering the amount of money which goes into

exploration. I think that should be protected.

Q: Senator Radar - Well let me ask you this. Would that be true. I assume the reason for your statement is that a company therefore gets the value of it's own work product. But what if the state, for example, should for reasons unknown, at the time of exploration, should withhold in the leasing for a period of three years. Then under those circumstances we would have deprived the company of the value of it's own work product. I don't know how to avoid that but I can see a problem here and perhaps discretion should be available here. Although I am not certain as to the purpose of this particular section or what the discretion or the thrust of the discretion should be. Whether the purpose here basically is to give the state the right to deprive them of the work product, within two years or what?

Lipton - Well I don't know how you can set the period of confidentiality so that it conforms with the amount of, the lapse of time between one lease sale and another lease sale. I mean that is a pretty difficult thing to do. I don't think, see the point is the state has access to this information. It is just that the competitors don't have access to this information. And in that respect there is a certain value in extending the period of confidentiality to a reasonable period of time because the value of the information is not just for another lease sale in exactly the same area. There is an awful lot of information. It becomes valuable because one correlates it with what one knows from other wells elsewhere. One builds up ones geologic and geophyical knowledge as this stuff becomes public. So there is virtue in keeping it confidential for a reasonable length of time. But I don't know, one can't do it for too long a time or you deprive the industry as a whole of what is really basic knowledge necessary for it to advance. So there is some kind of a compromise has to be struck between the virtue of the confidentiality to the company doing the work and how important it is for the whole industry to know more and more about the State of Alaska.

Q: Senator Radar - Well let me ask you. You have suggested in a number of instances descretion in the commissioner. Do you think that in this particular instance that we should provide administrative descretion in perhaps, write in a minimum or maximum or something of that nature. Or do you think the two year -

Lipton - Senator Radar I don't think this is an area where the commissioner ought to have descretion. This is a protection which the legislature is going to give to an exploring company as they are taking the risks in putting it's money in. It depends upon the legislature to know exactly what it's protection is.

Q: Senator Radar - Well what if you wrote in a minimum of two years, an extension of that period of time before it was made public?

Lipton - Senator Radar, I don't know of any place where that exists. That of course doesn't mean that it's a bad idea. I don't know that it exists anywhere else. I am not familiar with it. I think normally two years is pretty ample time. Again I would certainly defer to the judgement of people in the administration you know they have alot more experience with what the circumstances up here in Alaska have been.

Q: Senator Huber - Madame Chairman, I would like to just ask Milton just one thing, one question that was raised here by Senator Radar and I would hope he would concur with me. Milton will you take a look into the matter that Senator Radar brought out to determine in your opinion how our laws stack up on this at this time and give us some kind of a report on it. I think I know and the question I would like to ask you would be if you thought that two years was the best period of time and compare this with our current law and give us another report.

Lipton - Yes. I would be pleased to.

Q: Senator Radar - Madame Chairman, perhaps if I might ask Dr. Lipton, he said he had no particular feel to the 200,000 acre limitation for single holdings. I might ask him if it is possible for you to develop a feel for that. At least give us your best judgementas to whether or not -

Lipton - Yes.

MILTON LIPTON'S COMMENTS ON ROYALTY OIL

Lipton - Obviously you are waiting to see whether and if so what kind of a royalty contract is going to emerge from the Royalty Board itself. In the absence of any specific proposal and certainly, there is very little purpose to comment on the versions of the proposals that were presented early on. They were in preliminary form and a great deal of negotiation has been taking place during the last several months. So all I can talk about is something which has to do with the way in which you would look at a royalty contract if it is presented to you. I think it is germain but not all that direct. First of all just let me say and I guess virtually all those studies that have been done come to pretty much the same conclusion. That if you consider a given facility to process petroleum feedstocks from Alaska, if the facility could be built in Alaska or were to be built closer to the markets, say in the lower 48 states, the identical facility in Alaska will cost more to build. There is very little question about that for alot of reasons. The facility will cost more if it is built here than if it is built there. Secondly, that if you look at the transportation costs, if the facility were in the lower 48 say a refinery, and the crude oil is transported from Alaska to the refining facility below, the transportation cost of moving that crude oil will be substantially less than the transportaion costs of moving the output of the facility in Alaska to the markets. Whether it is petroleum products or whether it is petrochemical fractions. Transportation costs will be very very considerably higher. So that when you contemplate the development of a refining petrochemical complex in Alaska based upon Alaskan feedstocks, one faces immediately this advantageous cost, both in construction and transportation. The basis question which anyone has to address himself to, whether it is someone who wants to contract for the use of the royalty oil or whether it's the legislature looking at his proposal, the basic question is, how do you offset this competitive disadvantage. How do you do it. And I put it to you, there are three ways in which it can be done. One if there

is something unique about the project. That is to say, the people have conjured up, have imagined, have created a concept which somehow is more favorable because it is in Alaska than it would be elsewhere. That is to say, partial use of products here, products going to various destinations elsewhere or a different combination of products, somewhere out of the product mix or out of the technology which creates that product mix you might be able to get an offset. Second of course is if the state gives a subsidy. That is to say there is a cost disadvantage here. Does the state want the other benefits of this kid of industralization, whether it is employment or whether it is a creation of a tax base or the value of the products have been increased, or whatever the reason. Is this a sufficient reason for the state to give a subsidy. The State could offset the competitive disadvantage. The third possibility is that everybody expects that the competitive disadvantage has been taken care of and there is no subsidy required. But in fact it has not been taken care of. That is to say after five years of development and construction and operations begin it suddenly turns out that the competitive disadvantage is still there. One hasn't offset them and then, where does one proceed from there. If the facility is completed the oil storage tanks nearby are beginning to receive Prudhoe Bay royalty oil, operations are about to begin and suddenly one finds out that the marketing of the products is more difficult than had been anticipated. The price obtainable for the product is less than had been anticipated. What is the recourse. Well, I suspect that the people who have undertaken to contract for the roylaty oil have made a very substantial investment will come to the state and say look this is something which is of interest to you. The state suddenly doesn't want a new industry here. To go by the boards what can be done and in a sense not an explicit subsidy but an implicit subsidy is built into the thinking about the project. I take a negative tack here because I start with the premise and unless we are persuaded differently we hold to this premise that here is a competitive disadvantage in this particular environment, looking ahead say to 1982 or 1983 when the products may come on the market, competitive disadvantage operating here in Alaska and therefore I would suggest for the legislature that they look at any contract which is presented

to them with a very very jaudiced eye. Now the environment will be changing and one of the things which we feel you must consider, is whether the environment for contracting for the sale of royalty oil is best at the present time or whether it will prove with the passage of time. That is to say, at the present time you face an over expansion of petrochemical capacity, world wide, in the United States, in Japan, in Europe, incoming capacity for various reasons over the next few years. If you look beyond 83, 84, 85, 86, the world oil environment begins to change . The surpluses of today will begin to be eliminated it will be shortages but it is going to get somewhat tighter and under those circumstances the advantage of an assured flow of feedstocks, royalty oil from the State of Alaska may be much more attractive than it is today where competitive pricing is more important than availability, because crude oil is everywhere available today. Now what I am saying in sum is, that if you look at the contract then with a jaundiced eye the benefits for the state and if there are no benefits for the state you don't even consider the contract. But if the presumed benefits for the state, the hopeful benefits for the state, are still surrounded by an awful lot of questions marks than I would think that you risk very little by saying no, let's postpone this commitment of royalty oil and let's keep looking further for how and when the optimum use of it can be done. Because one is committed you not only are unable to look beyond that to what may be better, but you also as they say face the risk that an implicit subsidy is built in to the operation. I guess my advice is look carefully, exercise vigorious judgement and you probably loose more by being precipitious and saying yes, than you risk by saying hold off and let's wait and see.

Q: Senator Radar - Dr. Lipton the argument has been made that it will take a certain amount of oil to amortize the investment for petrochemical or refining or something else, any kind of a break down process here or a creation of a local industry and if the longer we wait then the less oil we have to amortize that plant and the less feasible it becomes for the industry to enter, the new industry to enter, and the argument then further goes that

if that is the case and if your prediction is correct that a contract now which will really not be producing until perhaps 80 or 83 or perhaps even 85 very near the maximum production of the field, that now is the time to award the contract because of the lead time, to is necessary. If we wait until that market exists that the lead time added on to the market conditions which you predict, is such that we cannot expect Prudhoe Bay to build that industry.

Lipton - If the people, if the group with whom a proposed contract is negotiated and which is layed before are anticipating this by 1983, 84, 85, may very well be that the terms and conditions of the contract presented to you are sufficiently firm that you can look at it even with a jaundiced eye and say this is worth taking our chances on. What I am concerned about is that it will not be as yet. Now I am not suggesting that you wait until 1985, or 86 to commit royalty oil. But what I am saying is with a passage of a year or two years may firm up the judgment or bring forth a more concrete set of terms in a contract. I am not trying to prejudge what reaches you this session, all I am saying is look at it with a jaundiced view. Now if you wait two years you haven't consumed so much of the royalty oil patrimony that there is not enough left and also the, I would hate to think that the limit of the state's availability of it's own natural resources is it's 12 1/2% interest in the established reserves of Prudhoe Bay. The next oil discovery here the state will have access to 16 2/3% of the oil it is in your new leasing bill and there will be other discoveries here, there are already. So it is not as though if you don't do it now you are going to run out of oil in order to support that kind of a project. You wouldn't want to wait until half of Prudhoe Bay has been produced already, I am not suggesting that. But I don't think that a year or two is going to make that much difference in the total availability of the oil.

Q: Senator Huber - Is this the period now when we can ask questions that are not confined directly say to present petroleum royalty

leases or can I ask some questions about gas this time.

Senator Poland - You can. We weren't going to do too much about gas today, but you are certainly welcome to ask Mr. Lipton we will go into the question and anwer period now unless someone else has a specific -

Q: Senator Butrovich - Well, before John gets on to the gas, would it be alright if I could ask Mr. Lipton a couple of questions about this petrochemical bit and you say there a (inaudible) on the market as far as the products that such a plant would produce if there was a plant in Alaska. What do you think would happen if the oil line had gone down the highway as the proposed gas line is going. Do you suppose that all of that oil would be going down to the lower 48 without a petrochemical plant somewhere along the way.

Lipton - Oh yes. I am sure of it. I am sure of it. Yes. There is no great incentive now for the companies that control the other 87 1/2% of the production to put that crude oil into petrochemical facilities. As a matter of fact one of the major producers in Prudhoe Bay has just withdrawn in Texas in construction of a major ethylene operation. There is a lot of surplus capacity around today.

Q: Senator Butrovich - You are in effect saying virtually what the administration is saying, or maybe they are not saying maybe I am just reading their minds, as far as a petrochemical industry in Alaska.

Lipton - What I'm saying is, look, Alaska by all counts is not an obvious place to put a petrochemcial industry. It just isn't an obvious place to put a petrochemical industry. If you start initiating a petrochemical industry in Alaska you do it for a reason.

Now, one reason could be that the feedstocks are cheaper here in Alaska than somewhere else and that overcomes high construction costs and that overcomes high transportation costs. You go where the feedstocks are relatively low in cost. Well that's not true here. The feedstock is not low in cost here. That is the royalty oil is not low cost oil here as compared to what it would cost if it were transported by tanker to a different petrochemical location which is closer to markets and you don't have to pay high cost transportation to move the petrochemical intermediates you see. Alright. There is another reason for bringing a petrochemical industry to Alaska or some other location. That is to say, if there is a shortage of feedstocks and you can put a petrochemical facility in an area where because you put it there you get feedstocks which you couldn't get elsewhere. Then you go that route. That is to say if there is a shortage and the only way I can latch on to 150,000 barrels a day of Alaskan crude oil, I can't get it from the private producers in Prudhoe Bay because they have internal uses for it, it is highly competitive elsewhere. But if I come to Alaska by golly the State of Alaska will commit their royalty oil. Then there is a reason for doing it, that becomes a specific advantage. The access to the feedstock is a very valuable advantage. The trouble is we are not at that point yet. I don't think we are at that point yet. We are at the point now where feedstocks are readily available at highly competitive prices and where is the advantage of Alaska. Alaska is in the wrong place. Alaska will be in the right place when the tightness of crude oil around the world, the tightness of gas liquids around the world makes it very very attractive to negotiate with the State of Alaska and have access to the royalty oil. In other words, your royalty oil has a scarcity value where as today your royalty oil has no scarcity value and as a matter of fact suffers a cost, a price. It's going into a world where people are more concerned about price than they are about availability. When they are less concerned about price and more concerned about availability your royalty oil, your royalty gas, your liquids becomes very much more attractive. Now the question is where is this transition, how long is it going to take before the perception of

the attractiveness of it. I think that people who negotiating here are seeing it already. They are very anxious to tie up the sate's royalty oil, that's why they are here and they are struggling themselves to figure out how can we get assured access to the state's royalty oil that is going to be very valuable in the future and overcome what looked to be alot of these competitive disadvantages now. This is what they are working towards. They see it, that is why they want to be up here. Not because of the cost advantages.

Q: Senator Butrovich - Well, Mr. Lipton, you know we ship automobiles and television sets and everything else from Japan what is the situation forinstance in Japan as far as petrochemicals are concerned? Are the products from petrochemial plants do they have all they need? I hate to display my ignorance but I don't know.

Lipton - No, no. You are asking a question that is very difficult to answer. There are groups here that are trying to build a petrochemcial facility in Alaska who are trying to negotiate firm contracts for the sale of their petrochemicals in Japan. Now, I am going to give you a judgement, it is a judgement based upon our exposure and our experience and how we see things and when they come back with firm contracts from Japan I am going to look very very foolish. But, the way we see the eastern hemisphere petrochemical situation there is a very very substantial surplus. Japan has got a lot of capacity. Not only is there Japanese capacity in Japan but there is Japanese owned capacity or Japanese investment in capacity elsewhere in Southeast Asia. On top of that the Japanese who have always felt that they were at the mercy of foreign oil from other sources. They have no oil production whatsoever there. Virtually all the energy consumed in Japan is imported. Crude oil has got to be imported mostly from the middle east. The natural gas they have is imported as liquified natural gas and they are always worried about the assured availability of their feedstocks. Both the refining (inaudible) petrochemicals.

Now Saudi Arabia, Iraq, Iran are all anxious to develop petrochemical facilities for the same reason that Alaska wants to. But these are government owned operations now with huge oil reserves, and what they are saying is that if you will put your petrochemical facilities in our country you are assured of access to the feedstocks so the Japanese are negotiating with the Shah of Iran to build a big refinery petrochemical complex there. But you know it goes very slowly. It goes very slowly because the high cost of transportation of petrochemical products, intermediates and derivatives to the Japanese markets or the Southeast Asian markets is a stumbling block. This negotiation has been going on for years. What I am saying is that there is this surplus and I think it is going to be very very difficult to get the Japanese today to contract for the initial delivery for products in 1983 and to continue thereafter for 20 years thereafter. It is a devilishly difficult thing to do in this kind of an environment. If it can be done, I think it is magnificant. It is going to be very very difficult to get firm, oh, letters of intent galore. Yes, under proper circumstances competitive prices we shall be pleased under those circumstances to buy this that and the other. The letters of intent but a firm contract take or pay, I doubt it very much.

Q: Senator Butrovich - Madame Chairman, I hear what you are saying Mr. Lipton however, you did say that geography was against us and I couldn't agree more, but I also everything I read on the national economy has balance of trade. You can't read anything because some economist, some expert is saying that we correct the balance of trade all those little figures we look at in the paper every day are not going to include too much. I don't know whether they are right or wrong. We are in a position geographically to do something about balance of trade if it is practical and when you said that we were the victims of geography, that was an understatement. You realize that all traffic south from Alaska is empty traffic and all traffic north is loaded traffic and all raw products generated in Alaska, shipped to the South 48 and then shipped back to Alaska in finished product and

we pay for it. And of course I recognize that we are just talking about a drop in the bucket when we talk about Alaska consumption of those products but nevertheless I am not going to take out of my mind because if in fact there was a market that could take a great percentage of petrochemical products I am sure that the entire economy of our state would benefit. If we in turn didn't have to ship that stuff down south and then ship it back and pay the freight both ways on it which is in effect what we do now and it isn't confined to oil we do it with canned salmon and practically everything else that is generated in Alaska and it doesn't make living in Alaska any easier. We do it by saying that somewhere down the road in 10 years or 15 years we are going to correct it. It really doesn't satisfy me. I would want to hear alot of pro's and con's on the matter before I would be willing to endorse any move by the state to preclude alot more investigating even tho I would like an answer day after tomorrow. I am not convinced(inaudible) possibility. Senator I hope nothing I've said implied that it can't be done or it will not be done. I wasn't when I talked about the changing world on a whole I wasn't saying that you have to wait 10 to 12 years. I do feel though that it would be irresponsible of me to imply that all is right with the world because we would like it to be that way for all Alaska. Everything you've said about the cost of transportation back and forth about the adverse balance of trade the advantage for Alaska in having retained within Alaska some of the products based upon your natural resources and at the same time benefit from the export potential. All these things I think, this is the basis on which people are struggling to put the proper kind of contract together and I appreciate the efforts that are being done. But realistically if I am talking to you I must express what seems to be our evaluation of the circumstances of the time. Also I would caution you that even if you go to a major ethylene operation, in Alaska, you must ask yourself, the consumer of Alaska, the population of Alaska has very little use for ethylene and very little use for propylene. The question really is going

going to be what's the next step of manufacturer and which are the finished products because what your people want are either finished industrial or finished consumer products here. Some of the industrial petrochmecials which can be used in Alaska will cost alot less and some of the consumer products. The question is will you carry the process of transformation far enough in Alaska in order to do good for the Alaskan people. Now all of these things I think are what you want to look at. When you see a contract placed before you. But I think that out of a sense of desire or even a sense of frustration because things have gone so poorly for so long. I think for that reason I don't think one should close his eyes to question marks about a proposal that reaches you. I still think you should look at it very very carefully. On the other hand if you think all of these things are desirable, perhaps a certain amount of subsidization is not unwarranted by the state. That is a decision that you have to make and there may be alot of other benefits that make it well worth while for modest subsidization by the state.

Q: Senate Radar - Along the same line I remember when I first came to Alaska I got a haircut. I don't remember what I paid for it, maybe it was a dollar and a half but I was used to paying fifty cents or something like that. I ask the barber you know, suprised, and there was no sign, well why the high price of haircuts. Well it is the freight. The longer I live here the more truth I appreciate was in that. But we have always thought that forinstance everything, I doubt that there is a single thing in this room that is an Alaskan product. Everything here is shipped in, the only thing in this building that probably wasn't shipped in is the concrete, not even the concrete, the concrete itself was shipped in but there is a lock in sand and gravel in this whole building. And for everything that is shipped up here there is an empty van or capacity or something going back south to get another load. Which means that transportation costs in some sense as we have hoped that if what we were manufacturing here and again I think that

this is part of your statement depends upon the stage of manufacture in which we take it and whether or not we can use what are now empty facilities, in that I take it from what you say that we probably could not use the same type of facilities which brought the materials that made this building, the steel and everything here, I doubt that there is a single Alaska product in the building. Is it your thought that we really can't expect that to significantly change that problem which we are facing(inaudible).

Lipton - No, really all I am saying is that have a look at what is laid before you and see how it goes. Is it really what you want, and if the advantages are there, are there question marks. is there a never never land where you don't know where the state is going to come up on the balance and if that is the case all I am saying is, that I don't think that you risk losing everything if you are very very critical of the first thing that is laid in front of you. That is not the beginning and end of all possibilities for petrochemical development in Alaska. It may very well be Senator Butrovich, that the most advantageous basis for petrochemical operations in Alaska is not feedstocks derived from crude oil, but feedstocks derived from your natural gas. See that is another possibility, but that is a long way down the line. That can be a very long way down the line.

Q: Senator Meland - Senator Poland and to Dr. Lipton and this is probably something that's left over from last Wednesday when we were talking on the franchise tax. During the recess, I think that we had at that time, Senator Butrovich and I were discussing the taxes and not necessarily the tax on oil we were talking about the tax on fish also. I don't know if the friendship between Senator John and I, I know that he knows that I come from a location that has alot of seafood off it's shores and I know Senator John is very fond of seafood. But anyway we got to discussing canned salmon and there was a little song and I promise you Senator Poland that I won't sing the song. I am more of a bar

room singer than I am a courtroom type singer but I did remember some of the words and it went something like this and I scribbled them down and it says "I like humpback salmon little humpback salmon caught by a Sitka fisherman and I forget some of the words, but it still goes like this. I don't want a T-bone steak from a steer that is roped in Texas but give me fish and I don't give a damn if I do pay taxes." Now you know that is 35 years ago when I was singing this song and you know things have changed because we really do give a damn if we pay taxes. The question Dr. Lipton, I come from a small community compared to Anchorage, we are more a rural small town, rather than a large urban type. So it is not unusual that I spent alot of my time on main street talking to the same people day in and day out. The very simple question that you can probably answer it yes or no. But the question they ask me, they say Senator Meland now you are going to go over to Juneau pretty quick and I know you are going to be talking about taxes on the oil companies, can you tell me this, if the legislature sees fit to put an extra burden on the oil companies in taxation will that in turn mean that petroleum products that we buy will be increased to offset the extra taxation sort of thing. Well, the only answer that I can give them is that I don't think the oil companies are particularly benevolent in protecting society, they are to do business and to make money hopefully they do to have thousands and thousands of shareholders that hope that they do make money. Is this the case, we increase taxes but then does the consumer when he is buying his petroleum products eventually pay, that is the question, a very simple question.

Lipton - I will give you a simple answer. It is not complete. The answer is no. The answer is no.

Q: Senator Meland - Could you elaborate a little on that.

Lipton - The taxes paid by the oil and gas industry here in Alaska, advalorem taxes on their hardware, the severence tax on their production, the income tax on the profits they

make here. All of these things represent cost to the industry the same way other costs are. But the price at which that crude oil, which has been taxed by the State of Alaska, can enter a refinery, is not higher because of those taxes. They are cost to the industry, they effect the revenues of the state and the profits of the industry but there is no way in which a company producing crude oil in Alaska can get a higher price for a gallon of gasoline or a higher price for a gallon of number two oil, or a higher price for a barrel of heavy fuel oil, just because he has paid higher taxes here in Alaska. The Alaskan crude oil goes into refineries and has to compete with crude oil from other areas. It has no direct effect upon the prices paid -

Q: Senator Meland - Tell me this then. How do the large corporations and yesterday, we were talking about hundreds of millions of dollars and billions. Now I, with my high school education know that a billion is a thousand million. Am I right? I hope I am. Now of course until I read the Juneau empire I didn't know that a billion minutes ago Christ was still on earth. You know so it is mind boggling to alot of legislators, because most legislators come from all walks of life as you know. The figures that we use when we start talking about hundreds of millions and billions is enough to compound the most brillant minds of industry, commerce, banking or whatever you say. But do you mean to say that over a 25 year life of a field and so that the taxes are increased like a 25 billion or whatever it might be, I forget the figure I didn't, I have enough notes here, but I don't think I wrote that down. But nobody pays, you mean the companies just can drop that and still do business?

Lipton - No. If the burden of taxation is such that it begins to deprive the companies of the profits which are essential for their operations then the product will not be produced. All I am saying is and please don't interpret this as an argument in favor of higher taxation. I am trying to give you a very honest answer to a very straight forward question. Alaskan

taxation on crude oil production here in Alaska, cannot be passed on by the oil companies to their customers because they operate in the competitive environment, anymore than they are able to pass on to the customers of California who buy their gasoline and who buy their deisel oil, who buy their burning oil. They cannot pass on the run up in the cost of building the Alyeska pipeline from an original estimate of 800 million dollars to a final figure of close to, with interest, 10 billion dollars. They cannot recover that from the customers in California, because there are enough people who are willing to sell gasoline to the customers of California processed from crude oil from other areas so that they cannot raise their prices competitively. This is a real cost to the companies. They can't pass this back to the state. They can pass it forward to the consumer. It comes out of what otherwise would have been larger profits. The same thing is true with the taxation here. Now, there is an exception. The exception is your gas taxation. Where there are contracts for the sale of gas to consuming sections of the State of Alaska and those contracts specify that an increase in state taxation shall be passed on to the consumer, than the consumer pays higher prices for the gas. But where you are selling petroleum products in competitive markets where the products can be refined from Alaska crude or California crude or Indonesian crude or Saudi Arab crude you can't get a higher price from the gasoline manufactured from Alaskan crude because it is too much competition on the market.

Q: Senator Meland - But prices generally could rise.

Lipton - If all petroleum prices go up. If all petroleum cost go up, or all crude oil taxes go up, then sure the consumer has to pay more. But the taxes here is Alaska cannot effect gasoline prices in California.

Q: Senator Meland - I think I understand exactly what you are saying. Not just Alaska but generally, and generally in large companies doing business -

Lipton - If Alaska were an isolated entity. That is to say if the oil produced in Alaska were refined in Alaska and were sold in Alaska and you had sufficient capacity to do that and you had high transportation costs from outside then increases in your taxes could be passed on to Alaskan consumers. They pay more for their gasoline. You are going to keep raising the prices only so high as it finally pays to import gasoline from California and put a ceiling on it. But so long as you are operating in this kind of a competitive environment, I must give you that answer.

Q: Senator Meland - Thank you and thank you Senator Poland, sorry I took so much time.

Lipton - That poem was worth everything.

Q: Senator Huber - I can't possibly get the interest of this Committee with my question. So I am in a very non-competitive position shall we say. First I want to start with the where John Radar and Senator Butrovich were and that has to do with the timing of the royalty oil processing to petrochemicals refining in Alaska. As, and I get from you that you say not quite yet. I mean we got time in this area and my concern is that I thought on the oil that it looks like we are at the 11th hour and 55th minute and on the gas maybe we are even closer to the 12th hour. That is what I am worried about because my figures show that Prudhoe Bay will start declining in oil production in less than eight years from now and at that time it would probably be impossible to start a petrochemical or refining complex in the state when Prudhoe Bay field is declining in production. I don't know I think the lead time is some 3 to 5 years or something like that to get the refinery and petrochemical compex built here. Aren't we actually late instead of early? That is the first question. The second one goes into gas.

Lipton - If you say that Prudhoe Bay production is going to

start declining, in what did you say 8 years. I said 8 years because it is a 9.8 billion barrel (inaudible)

Lipton - And you don't think that in the 9th year there will be as much production moving through that pipeline as in the 8th year.

Q: Senator Huber - Yes I think there will but.

Lipton - Why?

Senator Huber - Our production starts declining and we have to drill more wells to hold the production up. The field is beyond it's half way point. Can somebody afford to build the complex after that.

Lipton - Suppose you have three other oil producing fields that are feeding that pipeline before the peak of Prudhoe Bay production is reached. Why is everything uniquely associated with Prudhoe Bay.

Q: Senator Huber - Madame Chairman, is there some indication of that. I noticed on most oil fields on the lower 48 and the rest of the world 4 years or 5 after the discovery is made and the initial amounts of the oil in the pool are announced as proven reserves that there is changes, either downgrades or upgrades. I noticed in Alaska now, where a number of years since 1969, almost 10 and we are still holding at almost no better than 9.8 billion barrels of recoverable oil there. This is quite noticable.

Lipton - Senator Huber having spoken negatively to the response to Senator Butrovich's questions let me be very very positive. There have been other oil discoveries on the North Slope and there are resevoirs in the Prudhoe area for which at the moment there are no immediate production plans. Indeed if it turns out that there is a substantial volume of added production off the North Slope and we always optimistically

assume that from 1980 on the movement of crude oil through the pipeline is going to be on the order of 2 million barrels a day. Because we don't believe that the Prudhoe Bay is the beginning and end of everything. But if there is two million barrels a day moving for a considerable period of time and if as indications now are, a good portion of the incremental portion of the oil is going to be heavy oil, that may lend itself much more advantageously as feedstock to petrochemical operations than using what is coming out of the Prudhoe Bay field at the present time. It may be more advantageous as a basis for feedstock than it is to export at the California markets. What I am saying is that I don't believe that this is really a last gasp for Alaska. Perhaps I am too optimistic, I don't know. But I am not even saying that you forgo at the present time contracts for the sale of royalty oil. All I am saying is be critical. Look at them carefully. Similarily, if use is going to made of your feedstocks from the state's royalty gas that may not come to for wish until 1984 or 1985, but planning is going to have to be done fairly soon. Because pipeline design and everything else which is involved will have to be initiated relatively soon. I am certainly not saying do nothing, just shuffle your feet. What I am saying is be cautious, be cautious. This is not that everything stands or falls on the basis of accepting as it is one particular contract, unless it is clearly advantageous.

Q: Senator Huber - I would like to pursue now, the natural gas. In the light of everything we have talked about on royalty oil, talking about natural gas and it's processing within the state at this time and I would like to revolve around the conditions that exist. The pipeline through Canada approved. The particulars of that being that the Canadians use the pipeline too and I believe that some of the other particulars are that the gas delivered to the lower 48 has to be at the 1,000 B.T.U. per M.C.S. level which is high methane and so forth. Do we have an opportunity in the natural gas to look later or are we going to lose our natural gas liquids and our C_2 faction, our ethene to production in Canada and don't we have a different set of circumstances

here that if we produce it in Alaska which is the United States that we have something towards the balance of trade here. As I understand it that if we send the gas through the pipeline into Canada, to the lower 48, the only thing that the Canadians have to deliver to the lower 48 is gas of the right B.T.U. per 1,000 o M.C.S.

Lipton - No. Not so, not so.

Q: Senator Huber - If then they take out the ethene and the other liquids at that point or whatever it may be, but do we have another chance not to plan our petrochemical industry based upon natural gas now.

Lipton - First a factual statement. The gas that moves through the pipeline, there will be proprietary ownership of that gas. The Canadians can't do anything to that gas unless the owner of that gas agrees to it. There is nothing in the pipeline treaty, there is nothing in the statutes of Canada which permits them, at their option, suddenly to take liquids out of gas owned by someone else. Now if the liquids are valuable the people who own the gas are most apt to strip the liquids out, either in California or in the Great Lakes area, at the end of the pipeline. They will allow the Canadians to do it if the Canadians can give them very very high value for it but it will be more valuable on the U.S. end than it will be in Canada. But that is a minor thing. The real question you've ask I think, and the answer to that is, that yes, there is potential value to Alaska of the liquids contained in the Prudhoe Bay stream. It could be very very valuable and unless you plan for the use of it in advance you may lose the opportunity to hold them here in the state. Now there are two things that are involved. One has to do with the liquids for the entire stream of gas 2 billion cubic feet a day, a very substantial volume of liquids. This the state can encourage the use internally. It can negotiate, but what's of immediate interest, I think, is that in the royalty gas, that this not completely elude the control of the state

and as I had occasion to say previously, there is in the state's royalty gas a volume of liquids perhaps somewhere in the range of 6 or 7 thousand barrels per day out of the state's royalty share of a 2 billion cubic foot per day gas flow. Now that at least the state ought to be exploring. In other words if one can't think big and accomplish that, at the very least one doesn't want to allow everything to escape and the royalty gas is one thing that the state not only ought to be paying attention to, but on that scale I would suspect that it is perfectly feasible. It may be feasible on a large scale and that is something that has to be explored. But if not at least maximum access to the state's royalty gas and if necessary what you put back into the pipeline for export to the lower 48 states is a leaner gas stream with the liquids that are valuable to you extracted, say in Fairbanks.

Q: Senator Huber - One small clarification point and when you are referring to natural gas liquids you are including everything below the C_1 faction, is that right?

Lipton - Yes, but I am not sure that they are all equally valuable. I mean ethane is used one way and propane and butanes are used quite a different way. If there is any natural gasoline that is a different story. Yes. That is what I am referring to.

Q: Senator Huber - I have been afraid that we may lose our ethane by definition because it is a dry gas that normally goes with the methane if it hasn't been extracted for commercial purposes, it's a perfectly suitable type like gas. I just want to make sure we are talking about natural gas. We are all of a sudden defining that. Madame Chairman, I wonder could I just defer to Senator Butrovich for a question.

Q: Senator Butrovich - Mr. Lipton you were saying that the plants would probably be set up in California or some place. Can you tell the Committee or at least tell me what is the royalty cost of moving dry gases compared to wet gases?

Lipton - I couldn't tell you off hand. An awful lot depends upon how tight the capacity of the gas line is. That is one thing I do know. If you have got alot of capacity in the gas line the difference in cost is immaterial. But if you are tight on capacity, the difference I couldn't tell you off hand. I just don't have it with me.

Q: Senator Butrovich - Do you say the difference in cost -

Lipton - If there is capacity in the line.

Q: Senator Butrovich - Well, of course I am speaking only of the line that would carry the gas down the Alcan.

Lipton - What I mean by capacity line is. A pipeline is designed for a certain maximum flow. At any particular time you may not be using the full capacity in other words (inaudible) If you are not running the line at maximum capacity, then I think it makes very little difference on how much or the pumpable liquids you have removed and how much you have left in the line.

Q: Senator Butrovich - I know nothing about that, but I have been lead to believe by other people that there is a great difference in cost in moving liquid gas as compared to dry gas.

Lipton - If you are losing the line of designed capacity, yes. I don't know off hand what the difference is, unfortunately.

Q: Senator Butrovich - Is there any place along the line that we could actually get that information.

Lipton - No problem, I will get in touch with my staff and I'll get you the answer.

Q: Senator Radar - Madame Chairman, I had a question along the same line if I might. We are being suggested, and I think it is the same line. That we should make a decision now on our

gas petrochemical industry so that there can be a design which is the most efficient a 7/8 design or an 8/8 design, a design which accomodates a line which would not operate at full capacity and therefore carry the liquids easily, or a line which would operate at full capacity and therefore more economic line and so on and so forth. It has been suggested at least to me by some people, that the decision to be made, should be made now, if the design of the Canadian pipeline is to begin now. Is that, how do you meet that kind of an argument or that presentation. Just comment on it.

Lipton - I think the immediate problem in design or at least before the design is too frozen is whether or not there are going to be facilities to off-take say a Fairbanks or wherever. This can be built into the design of the pipeline. Thereafter I don't think it is a matter of 7/8 or 8/8, the difference there implies that 12 1/2 % of the natural gas is taken out to be retained in Alaska. Now it is very difficult for me to conceive that Alaska is going to be able to use that full 1/8 of everything of the methane, the ethane, the propane, the butanes and everything else. That to me strikes me as an unlikely thing in view of your energy requirements even in terms of industrialization. What would you use that amount of methane for. Now you may have a methanol operation, that is a different story. Maybe you can conceive of the movement of the utilizing the methane for methanol operation. If this can be done, then sure it is going to effect the whole design of the pipeline, but the other possibility again , which I say that if the maximum can come to forlition at least the state shouldn't lose whatever it can get out of it and that is if you extract the liquids, not necessarily all the liquids you have a major extraction of the liquid component in the natural gas stream and you utilize that productively in the state the propanes, the butanes maybe even some of the methane and then pass on a leaner gas stream for export purposes you'll get the B.T.U. value of whatever you left there, even if you leave some of the ethane in you will get the B.T.U. value of the ethane, you will get the B.T.U. value of the

methane. But you have left for yourself the liquids which are more valuable per M.C.F. or per gallon than the B.T.U. value there and this is what you want to maximize on and that What I am really saying is that if one can design an optimum operation so that all of the state's royalty gas is upgraded in value within the state than that is the ideal case. But if you can acheive the ideal case I wouldn't want you to forgo something less than the ideal case which is that you utilize the higher value of the liquids that can be extracted even if you must sell everything else for B.T.U. value.

Q: Senator Radar - I am sure you said it but I am not sure I heard it. Again we are being asked to make a decision at this time, as soon as possible here, by the Alcan people on a design basis to tell them what we intend to do with what we can take out of that line and use in Alaska for petrochemical or otherwise and as I understand your answer is that we are going to have to tell Alcan or Northwest or whatever they call themselves that until we have a petrochemical industry we can't give you that information and that at this time we don't have one and therefore they will have to design a pipeline to carry what they anticipate to be the production of the Prudhoe Bay field.

Lipton - No. You don't have to have a petrochemical industry. If they're asking you now, how much of that gas are you going to retain in the State of Alaska, I don't think there is any earthly way in which you can answer them today. You have to pursue what the possibilities are for the utilization and if you are talking about taking all of the state's royalty gas. You can take it for several different reasons. One because you can use the B.T.U.'s right in the state that is you just burn it as gas. Or alternatively, that if you break that gas up, the components of the natural gas will have greater value in the state than the B.T.U. value of it. For example propane uses bottle gas to be used for heating, cooking things in the villages in place of a fantastically high price which is paid at the present time. This is very very valuable in the State

of Alaska tremendously valuable. If you could use a methane for a methanol operation for export operations this would increase the value over the pure B.T.U. value if you just let it into the pipeline stream. But you have to know reasonably well what you can use the different components of the natural gas for. Now the maximum, to say we are going to take the full 12 1/2 % of the natural gas and keep it here in Alaska to say that for the pipeline people before you know that you can do it, might put you in a position where later on there is no capacity, although I don't doubt, I don't believe that. 8/8 of 7/8 of what, of what level of gas production, of what level of gas production. The State of Alaska can have some option on capacity as well, you know, it is not that you are going to design it smaller because you are going to take the gas, there may be some prorating of gas. They are not going to design, the first day that gas flows through the pipeline there is not going to be an optimum utilization of the designed capacity. The state ought to have some option on some flexibility on how much of that pipeline capacity it is going to use, but above that what I am saying is that if you can't early on, come to a fixed conclusion as to how all of the gas is going to be used at least you should be planning for the utilization of the liquids out of the royalty gas stream. At the very least and couple that with a certain flexibility as to what can be done later on.

Q: Senator Radar - But how can we get that option. How do we get that option. How do we preserve that option in the future as I don't understand the regulatory scheme and the federal decisions that are being made.

Lipton - Well they really haven't been made. There aren't any. The trouble is there aren't any now they are in the process of being made.

Q: Senator Radar - Yes but aren't those being made in irrespective of this reservation that we are talking about and won't they be made , I have a hard time saying yes, I would like to keep this option open. Unless you are saying that we should

keep it open. I am wondering can we keep it open other than by telling whoever is designing the gasline that we are going to take it off or we are not going to take it off or we just say that we don't know.

Lipton - Well I think one of the things, the way I suppose that it has to proceed is that you discuss a certain flexibility for the state in terms of volumes and you say to the pipeline people that when they go into negotiation over all of the terms and conditions of construction from the regulatory standpoint this is something that has got to be taken into account. I mean after all the state has a tremendous economic interest in this thing and I don't think you can be pushed completely aside.

Q: Senator Radar - Well let me ask you, as I understand an argument you have right now involves taking off oil in Fairbanks and that is that the pipeline was designed to carry the full flow of the production North of Fairbanks, South of Fairbanks and that therefore when they take the gas off in Fairbanks, they should pay the rate of the complete tariff to Valdez because of the fact that the design is there, the pipeline is there, it is going and the lesser, the fuel savings on the pumping they are only carrying a lesser amount is insignificant, as I say that is under litigation. Perhaps you want to comment on that. But secondly, it has been suggested to us that if we don't want to same kind of an argument and pay the full tariff of gas from Fairbanks to Chicago or someplace else whatever you are going to figure to be the terminus that we have to at this time tell the pipeline people whoever they may be the regulatory agencies, that we are going to take it off or else they are going to ask us to share in that cost in that unused capacity or whatever it is if we don't and therefore the time is upon us as Senator Huber says that the argument is being made that we are at the 11th hour if we are to avoid that problem. Perhaps you could consider both of them, maybe they are not problems, I don't know.

Lipton - Let me address myself to the 11th hour first. If you are at the 11th hour, you see, and decisions have to be made

and you are capable of making decisions, you should do it. But one can be at the 11th hour and not be able to make the decision, as the philosopher said there is some questions to which there are no answers. I don't think you can allow yourself to be put in the position where you make a definitive decision when the basis for it isn't there. Let me back up to the crude oil pipeline thing, it is an interesting analogy. I remember very well the long and arduous debates which transpired before this legislature on the subject of the right of way leasing for the pipeline. Now the discussion of the pipeline putting in facilities for the off take of oil for the use in Alaska along that route, that was made very very clear in legislative debate, right down the line. There was never any question that this was the intention and this was made very very clear. So that in a sense the operators of the pipeline were not without prior knowledge of the fact that along the route of the pipeline there would be off take and if they knew no other location along the route where there would be off take the one obvious place was Fairbanks. It might have been elsewhere as well, but Fairbanks was a pretty obvious place. So this was not a matter of all of a sudden they were confronted with a completely unknown thing. Secondly as far as the tariff is concerned the pipeline is not operating at capacity now and it is not a matter of their being deprived of ability to put oil all the way through the pipeline in a sense and the amount of oil which unbalances their system for what is it 12,000 barrels a day being delivered to Fairbanks it doesn't look to me as though this is a, I want to prejudge what is in the administrative process and I am sure it is going to go up in the courts but it would take an awful lot of convincing that the only economical basis upon which they can operate that pipeline is to charge the same tariff from Prudhoe Bay to Fairbanks as they charge from Prudhoe Bay to Valdez. The design of the natural gasline the analogy is well taken and it means that you have to have as much forsight as possible but I don't know how you can presume to give an intelligent and definitive answer in advance. Much as one would like to, how does one do it and therefore I say one has to explore what degree of flexibility

is available to the state in terms of access to capacity and again when we talk about capacity what's going to be the design capacity of the line. Is it going to be 2 billion cubic feet per day or more. It is going to be more than that I think for ultimate deliverability. Now there may be times when the amount of gas which can be delivered into that pipeline, I say at 2 billion cubic feet a day can include or exclude the state's royalty gas, depending upon what the level of production is from the wells. In other words if you have without royalty gas, capacity to move 2 billion cubic feet a day without royalty gas then you could produce over 2 billion cubic feet a day of gas if the well facilities will permit it. You've got flexibility at that end also. I don't think that all of the onus of deterministically should rest just upon Alaska and it's royalty gas decision.

Q: Senator Radar - Well, are you suggesting that we could use our conservation authority as to limiting, or as to setting the level production of the conservation matter to assist our economic determinations here.

Lipton - No. I wasn't suggesting that at all. What I was suggesting is that there may be flexibility in total amount of gas that is available. In that case one of the (inaudible) is involving your designed capacity say from Prudhoe Bay to Fairbanks to perhaps take a somewhat larger than 2 billion cubic feet a day.

Q: Senator Radar - As I understand it you are saying that resevior mechanics would permit perhaps a 20% take off -

Lipton - It doesn't require 20% we are talking about 12 1/2/%.

Q: Senator Radar - Yes but perhaps as high as 20% or more flexibility automatically just as a matter of resevoir engineering.

Lipton - Not necessarily at any moment of time. That is again a matter of production experience. It may not be the same in the

early period. It may be different when you start going to cap gas and so on. The only thing I am saying is that the State should make as many decision as it can. It cannot be coarsed into making decisions without knowledge that is not there. Therefore in the absence of that one shoots for a much flexibility as possible in the negotiations.

Q: Senator Huber - I would like to continue just a little more now on the same line. I guess maybe starting from the back. As of today Mr. DeLong is down from Fairbanks. He gave the Fairbanks delegation copies of the suit that they are now in. I don't want to discuss the merits of that suit but the suit is with SOHIO and it is exactly what we are talking about. Because of prempting what they say is capacity in the line as far as Fairbanks they say that it should pay the same rate all the way through. Now my problem now is that if we get in the same position in the gas line because our indecision or our lack of action becomes procrastinstion aren't we setting up the same identical thing inspite of the fact that we have got a blueprint in front of us. Let me ask a question to show what I mean Madame Chairman. I don't know whether it is of you or Mr. Lipton or who. But Mr. Lipton I certainly would like to comment on it. If we were not procrastinating now and say we can't make the decision at this time what are we doing forinstance to look at Big Delta as the takeoff point for the state's royalty gas and at that point we consider the total use of it because we have the Javerscreek coal field and the two of them can be combined to use the entire methane flow from the manufacture of menthanol. It is a good open area there is no problem with air pollution or anything at this time, lots of air movement in the area and plenty of water, plenty of ground water, plenty of cooling. It would be a very good area for a petrochemical industry. Now, Madame Chairman, if we don't try to look at that in a way to move the product to market, we have an unused Haines pipeline there in and Southeastern certainly needs the economy from that. It is sittin there empty. It could be used just as easily to carry the products

out, liquid products, including methanol. Here is something that looks like it is synergestically available to us and a way to do it if we don't wait, but if we wait until that is planned capacity, has made it so that the gas transportation is going to cost us alot more money than we have decided that our product is forever going to be sent to a foreign country to do it and then sell it back to us or to the lower 48 without getting maximum use or even maximum benefits to the entire country not to mention Alaska. So if we aren't doing that now as (inaudible) unless somebody tells me. Have we got a project down by somebody to look into it. We haven't so when does our indecision, because we can't make a decision now, become procrastination, or is it going to straighten itself out. We need to do something. But what.

Senator Poland - I do know the state is having a study done on the liquids. Beyond that I don't know.

Senator Huber - I am just worried that we are studying it to death. Because if we aren't at the 11th hour and the 55th minute now or the 59th minute I don't know where we are. Mr. DeLong of North Pole Refineries seems to think so. He talked all during the lunch hour to the Fairbanks delegation in regards to this. He isn't just the only one I have told my other people that the Department of Natural Resources has not been interested in talking with us and that included the methanol story now for a number of years. These people come down here and they have spent their money before. They have told me that we are no longer interested in spending money by coming to Alaska and knocking on the door when the Department of Natural Resources will not even listen to what we have to say. They say we have got other plans, we are not interested. Yet if we are truly at the 11th hour or the 11th hour and the 59th minute we got here by our own indecision which is nothing but plain procrastination.

Senator Poland - Mr. Lipton we very much appreciate the time you have been able to spend with us now and to give you something to really work with before you come back to see us in the Spring.

Senator Meland - Madame Chairman could I, before you leave do you want the words to I like humpback salmon, I will give them to you.

Lipton - I would like that very much.

Senator Radar - The tune is even better than the words.

TESTIMONY OF MILTON LIPTON
BEFORE THE HOUSE/SENATE RESOURCES COMMITTEES
January 25, 1978

MILTON LIPTON: Let me just suggest very quickly the kind of topics that I would like to discuss with you and the things I will lay before you briefly before I subject myself to your questioning, because I think the committee is much more interested in addressing the questions to me. But very briefly, there are three things I thought I would discuss with you bearing upon the subject of the income tax legislation which is before you. The first thing is the income tax issue itself, why it is an issue, and what the alternatives are facing the legislature. The second is some discussion of the overall tax burden here in Alaska which is imposed upon the oil and gas industry producers, and then, third, a comparison of the bills that originated in the House and in the Senate, what the pros and cons of each would seem to be, what the implications of each are.

Well, then, on the subject of why the issue of amending the income tax, it seems to me that, by now, after years of discussion, there is rather general agreement that the present method by which the State of Alaska's corporate income tax is administered with respect to the oil and gas industry is deficient. I say generally agreement. We, of course, as consultants to the legislature have been saying this for some time. I believe that in the last session, when the submission on taxation was made by Sohio, it appeared as we have said before, that approximately 25% of the income from Prudhoe Bay operations, as estimated first by ourselves, then by Sohio, approximately 25% was actually allocated to the State of Alaska by the present method of apportionment. Now there is before you a submission on a comparative state tax burden study by Arthur Andersen.

I will say more about that in the context of the total burden of taxation. But it's interesting that in their own analysis, using their assumptions, that the net income from TAPS and Prudhoe Bay of the four companies that comprise the largest percentage participation, in both the producing operations and the transportation operations, over 25 years, according to their assumptions, and the assumptions are carefully spelled out, they estimate that the net income from production and TAPS transportation will aggregate about 37 billion dollars over the 25 years. Their own estimate of the income allocated to the State of Alaska by the present apportionment formula under your present income tax law, would be 16 billion dollars. That is to say, less than 50% of the income which they estimate to be generated in Alaska, would actually be allocated to Alaska. If you applied your income tax rate to their estimate of income generated by Prudhoe Bay production and TAPS transportation, the aggregate taxation that would accrue to Alaska would have been $3.5 billion dollars over 25 years. Under the allocation system they estimate that there will actually be paid to the state about $1.5 billion. So the deficiency, then, in the income tax statute as it is now applied to oil and gas, comes to about $2 billion dollars by their estimate. This is why I say there is now fairly general agreement that the application of the apportionment formula to an oil and gas producing industry in Alaska under the conditions that obtain here in Alaska results in this kind of a deficiency.

Now, there are alternatives which can be taken. One alternative is the approach that is embodied in the bill passed by the lower house here, which essentially redefines corporate income, which has to be allocated among the states....Alaska, and changes the apportionment

formula. This is one possible approach, and it is designed to yield higher corporate income tax payments from the oil and gas industry. A second approach is that of the bill that was before this committee of the Senate in the last session, and this involves separate accounting of oil and gas producing and transportation operations in Alaska to arrive at the income generated by those activities in Alaska to which there would be applied your regular, statutory corporate income tax... I'll return later on to discuss these two alternatives.

But there is a third alternative, and this alternative is that the Legislature may decide not to amend the income tax statute. This, in fact, is urged upon you by the industry, and the industry's position, I believe, is that the aggregate tax burden in Alaska is already the highest among the major oil producing states in the United States. By inference, this says that the deficiency in the income tax statute in the allocation of income to you, the deficiency in your corporate income tax receipts from the oil and gas producing industry is at least and probably more than made up by higher severance and ad valorem taxation which the Legislature has already imposed upon the industry. Now, this is not without relevance, I believe. It says something about the revenues that Alaska is already receiving; it has economic implications for the companies making up the oil industry both in Alaska and outside of Alaska, and therefore for the kind of decisions that they will be making. So I believe that there is a relevance for the Legislature in looking at it, and looking at it carefully, what the aggregate tax burden is, how it is built up, and what the implications are, and so I turn to that now.

I had this study by Arthur Andersen and Company only as long as it took me to fly from New York here; it's 12 hours from airport to airport so I had a fair amount of time to read this and other material, but I read it once and I must say that it all made the 12-hour trip pass very very quickly. What I say now about the study, I say tentatively but my first reading of the report suggests that it is a carefully prepared, highly useful document. I think it's been done in a highly profe sional manner and I don't believe that there is a real quarrel with what Arthur Andersen has done in any respect. One has to be careful in interpreting what the implications are, and I want to discuss those with you, but so far, insofar as they spell out what their assumptions are and how they built up their model, I think it is correct to say, as they conclude, that the aggregate burden of taxation on the oil and gas industry in Alaska is higher than in any of the other states. What does that mean? First of all, it's higher as measured by the technique used by Arthur Andersen; that is to say, they apply the statutes of other states to Alaska and to selected oil and gas operations in Alaska, that is to say to the Prudhoe Bay producing field with the model they constructed and the profitability of the Prudhoe Bay field for Sohio, British Petroleum, Exxon, and ARCO, and they applied it to TAPS and they measured what the presumed tax liability would be for these four participants for this Prudhoe Bay and TAPS operation and they said "What would have been the liability of those companies if in fact the California statutes applied here in Alaska, the Louisiana statutes applied here in Alaska, or the Texas statutes applied here in Alaska?" and their conclusion from one of their models, the simplest of the models, was that if the burden of taxation in Alaska

is 100%, then the California tax regime would lead to tax liability that would be 92% of Alaska's, eight percentage point difference; Louisiana's 85% of Alaska's. Well, absent Alaska, you get some interesting differentiations among the other states. If Alaska's not in the picture, California would be the highest, and Louisiana would have a tax burden only 93% of Alaska's, so there is always somebody who is at the top and there's a range of differentiation among them, but nonetheless I think the figures are revealing. More importantly, however, I think it raises several questions which you the Legislature must answer. The questions are easy to phrase; you must answer the questions. From the standpoint of a state perspective, oil and gas operations in Alaska differ very significantly from those in California, Louisiana, and Texas. First of all, oil operations in Alaska are very highly concentrated in production - production of oil and gas - and the transportation of oil and gas within the state, transportation related to the actual production. Highly concentrated in this respect. California, Louisiana, Texas have oil operations which are very much in balance. Production in each of the states, major producing states, but refining in all those states, major refining states, marketing, consumption of petroleum products in each of those states, all integrated operations of the companies operating there. So that, in effect, the way in which the taxation as applied to their industries is a reflection of the fact they have all aspects of oil industry operations reasonably balanced within their state. Secondly, each of these states has highly diversified economic and industrial activity. California, a major oil producing state, has important agricultural industries, important industrial activities, and important trade, service, and financial activities associated with all of that. Texas the same thing, an important

agricultural state, an important industrial state. Louisiana the same. What I'm saying, in effect, is that Alaska, or California, or Texas, or Louisiana, any state, conceives of its tax regime, what kind of taxes it levies, how it taxes various industries, and which specific tax it selects for different industries, especially extractive industries, must be related to the economic and industrial makeup of the state itself, and to say that Alaska has the highest burden of taxation is meaningful, but it must also be viewed in the context of what the economic and industrial composition of Alaska is also, and to say that the burden of taxation is to Louisiana taxes one of Alaska would be somewhat less is not to say the Louisiana legislators would have that complex of oil industry taxation if Louisiana looked like Alaska, or if California looked like Alaska. But these are questions which you yourself must judge, that the burden of taxation is meaningful, but it must also be construed and appreciated in the context of what the economic and industrial structure of your state is. Now, from the standpoint of the industry, whether the tax is unduly burdensome or not is not solely determined by whether the Alaskan taxes are higher than California's or Louisiana's or Texas', but whether they are so onerous that they militate against investment, particularly investment in exploration and development, and I put it to you that so far, there is in fact no indication that that's the case. Now, the Andersen study is uniquely oriented, as I said, to one aspect of oil and gas operations in Alaska, albeit the most important one at the present time, that is to say the Prudhoe Bay production and TAPS transportation, and I think their conclusions are highly relevant and I think meaningful in that respect. I would like to lay before you something which we had said from the first time we appeared before this Legislature to discuss taxes.

We did not think from the beginning that your tax policies had to be uniquely constrained by the Cook Inlet experience. We did not think that your tax policy ought to be carried away by the exhube nce of Prudhoe Bay. We thought your tax policies should be oriented pointing to a continuing incentive for the development of the potential oil and gas resources of the state. Now, what the Legislature has done over these years is to consider three different types of taxation imposed upon the oil industry which have different implications...For example, you have amended your severance tax over time. Now we've always said that one of the characteristics of the severance tax is that it's an impost on the gross revenue achieved from a producing operation, on the gross revenue, therefore it is not sensitive to the profitability of production, to differences in producing fields, and for that reason there has to be an almost natural ceiling of how much of the gross revenue you take away in the form of a severance tax before you start interfering with the incentives of industry to develop marginal fields. But this Legislature has also, in its wisdom, taken that into account, so that for some time now, you have had a severance tax which is graduated, and in a sense differentiates in the burden of severance taxation between fields which may have the same gross revenue but which have one of the highest peak rates of severance taxation among the oil producing states of the United States, one of the peak rates, that's the peak rate only for those producing operations where well producibility is very high. You have a uniquely low severance tax rate for those producing operations whose well productivity is very low; as a matter of fact you have what I believe no other states have, which is a complete abatement of severance taxation for marginal production in this state.

So that if you apply other states' taxation measures including severance taxation to what is the optimum circumstances of producibility at the present time in Alaska, wells that are producing on the average between 5 - 7,000 barrels a day, you turn out to be comparatively high, but if you carry this out for marginal operations in Cook Inlet excepting only insofar as the cents per barrel aggregates the problem that we talk about in a different context, you don't have onerously high severance taxes compared to other states. The income tax we've always suggested to you is the least onerous form of taxation insofar as it affects investment decisions by industry, because it doesn't impinge upon the margins. The income tax liability only goes up when profitability goes up. So there are qualifications to the way in which one must regard the simple statement that the total burden of taxation here in Alaska is already the highest. It is the highest if you compute it with the most productive operations in the state; it would not be so if you looked elsewhere. Nonetheless, I think it's true that insofar as the state's budgetary needs or revenue deficiencies are always seem to be made up by oil industry taxation, this becomes a disabling and discouraging thing for investment. If it is perceived that this is the way in which the taxation proceeds in Alaska, that if there is a budgetary need or a revenue deficiency that almost with regard to the continuity of taxation or the principle of taxation, the incremental revenue or budgetary needs will come from oil industry taxation. This can not be a matter of indifference to companies that have their choice of operating one place to another. And, if too frequently changes in taxation are dictated only by budgetary needs or revenue deficiencies, without regard for continuity in the tax regime of the state, then I think it can be disabling.

Now, nothing I said here should imply that Alaska ought to go ahead and amend its income tax. But neither does any of the evidence that I've seen that's placed before the legislature convincingly militate against review of the income tax, particularly if you choose seriously to consider amendment to the income tax which tries to offset the existing deficiency in your statute. If you do that, and you do it clearly in the context of the longer run tax treatment of the industry; for example, if it conduces to greater stability in your severance and ad valorem tax policy; that is to say if you amend the income tax to bring your income tax revenues more nearly into line with the actual income generated from oil and gas operations within the state, and if this, in the mind of the Legislature, is not just an addition to the aggregate load of tax revenues from oil and gas operations over the next 25 years, but is conducive to greater stability, that is to say otherwise it militates against what might have been alternatively increases in the cents per barrel tax, for example, then I think it could be a feature not only which increases the revenue for the state, but probably is more conducive and more constructive for the industry as a whole in terms of their ability to project the tax regime under which they operate. What I'm addressing myself to here now is not so much an aggregate increase over all the tax revenues from the oil industry - this is something you must decide, whether it's required, whether it should come - but the suggested amendments to the income tax as a constructive change in the overall panoply, the whole series of taxes which you impose on the oil industry.

Before I discuss the two specific bills before you, let me just say that, repeat an argument that you've heard, that any deviation from the commonly utilized apportionment formula will lead, for the companies

operating up here, to some form or another of double taxation; that is to say that they will be taxed on income earned up here in Alaska or apportioned to Alaska, and that if a formula or separate accounting is used that differs from what other states do, then in fact, one place or another, the companies will be paying taxation to two states on the same margin of oil and gas operation. It is cited, I'm sure you've seen this figure, that of the 44 states that have corporate income taxes, 40 use the formula. But of the 40, four of those 40 have themselves, in the infinite wisdom of their own legislatures, altered the formula. It's not the common formula that's used by all of them, 4 have altered the formula, New York, Florida, Massachusetts, Wisconsin, use sales as one of the factors in the formula, you know the property factor, the payroll factor. These four states still use the sales factor, but they've increased the weight of the sales factor to more than one-third, for reasons that their own legislatures considered to be appropriate to their own states, as I'll have occasion to mention, Oklahoma and Indiana use separate accounting for oil producing operations in their states under specified circumstances. And then in many of the states the definition of income which then is going to be apportioned by formula, differs from state to state. So there are variations already; there really isn't this unique uniformity which say that if Alaska deviates, it is outside of the fold. And as I said before, where there are these deviations, the selection of separate accounting, or in so many of these states, differences in the burden of taxation because California uses ad valorem taxation, has no severance tax, other states where they have severance taxes would not allow ad valorem tax, other states have combinations of them, some states don't even have corporate

income taxes. Where these differences occur obviously there are differences which are related to the economic and industrial structure of the state. I would like you to consider the things we're now going to say about income taxation in the context of the specific problem which you face here in Alaska, that you have a disproportionate amount of all oil and gas activity, largely focused on one function, which is the production of oil and gas and the related function of the pipeline transportation.

First, on the senate bill on separate accounting. What I'm going to try to do, again, is briefly discuss what I feel are the plusses and minuses, the advantages and disadvantages of the alternative approaches and you will bear with me if I'm repeating things which you have heard before. The issue has come up many times.....I would say that a major advantage of separate accounting is that it provides a direct determination of the income generated in Alaska by oil and gas producing operations. This is the function of separate accounting - to give you an independent estimate, independent determination, independent judgement, which means that when you tax that income under your corporate income statute, you are taxing the income which by definition, by calculation and by reporting has been generated by activities of the industry here in Alaska. This I say is a major attraction, advantage, a plus of separate accounting. I think there's another advantage for the state, not only in terms of the income tax itself; I think it provides meaningful data on the profitability of industry's producing and transportation operations here in the state which would be helpful and useful to the Legislature in its review of all oil and gas taxation. You would know something about this particular industry which is so important in your state and its profitability against which you can

review every aspect of taxation, not only the fact that you apply your income tax rates directly to income generated in the state. On the other hand, this is the negative aspect of it, I suppose. There are administrative difficulties. The administrative difficulties begin, of course, I think the greatest ones are probably the determination of expenses, the deductions, and depreciation, and the difficulties become particularly acute when the expenses or the expenditures represent transactions within a major corporation, that is to say, purchases by an Alaskan affiliate from an out-of-state affiliate which are the prices involved, the costs involved are they (IA) Why the problem of administration? It is said that companies can fool around with their tax returns when costs in Alaska are not actually out-of-pocket costs but payments due to other corporations. I have to assume, I don't know whether the Legislature agrees with it, I would have to assume that the personnel both of oil companies reporting tax accounts to the state of Alaska and the personnel of the revenue service here in Alaska auditing those accounts are all honorable gentlemen. I wouldn't assume that there's going to be malfeasance in the actual reporting. But the problem is more likely to be that where regulations laid down by the revenue department allow discretion on the part of the reporting company, they will, within the range of discretion permitted by the regulation, always choose those figures, those numbers, which minimize their tax burden in Alaska. Obviously they will do that. The question then is, to what extent can your regulations narrow the range of discretion and at least roll up a reasonable allocation of costs to the revenue and the gross profits generated here in Alaska. So far as TAPS is concerned, this is not a special problem here in Alaska, because TAPS is going to be

regulated elsewhere and the costs, their depreciation and the determination of profit of TAPS for better or for worse will fall under the jurisdiction of both the Federal government and the Alaska Pipeline Commission. But in any event, I would put it to you, that if the formula as now applied only yields 25% of the Sohio estimated..... only allocates 25% of taxable income to the State of Alaska, there is such a margin of advantage to be gained than improving upon the form of state corporate income taxation, that there could be considerable leeway for discretionary movements of costs back and forth before you are really disadvantaged; that is to say I believe that the administration can adequately be done and the margin of discretion not so great but that you would still have a major net advantage to the state. Now, it's been said that this separate accounting is impossible to administer. I've heard said that as a matter of fact there are representations and...(IA) before you that the quotation is impossible to administer and determine. As I mentioned before, there are two states that actually utilize separate accounting. For better or for worse, it can be done, it can be. There are problems there, but there can be adequate administration not too complicated and range of discretion may not be something you can entirely avoid, but within the range of advantage to the state. There's a second area, problem area of administration, however, that's worth very careful attention on your part and that's how do you arrive at the value of the oil before you start deducting the costs, depreciation charges, to arrive at the profit for a producing operation. How do you arrive at the value of the oil as the basis for calculating income? Well, you do it already. It has to be done now for purposes of royalty and production tax calculations. So for better or for worse,

you do have a valuation of your oil at the wellhead for which you can derive, through separate accounting, an estimate of the producing profits, the producing income. But what if the value of the oil at the wellhead is depressed by low prices obtained for your oil at the refineries in the lower 48 states to which it goes. What if that happens? If the price obtained in California, or in Texas or Louisiana, if these are depressed prices, then your wellhead values are also depressed, for royalty purposes, for severance tax purposes, and they will also be depressed for income tax purposes. Why depressed? U.S. regulations, which may depress, so long as we have price control, which may depress the netback value. California's surpluses would require higher transportation costs to move it to the Gulf. A lot of things can interfere with your obtaining as high a value as you think might be warranted at the Prudhoe Bay point of production. What can the state do about it? But the basic concept is whether you want to accept that or not. That is to say, if Alaska's income tax revenues are going to be related to the profitablility of production, and if the reality of operations are such that somehow the wellhead values are depressed by adverse marketing circumstances, whether it's by U.S. government fiat which sets price controls or whether it's California surpluses or whatever, this is a fact of life. Now, the separate accounting technique does in fact expose you to the uncertainties of the value of the oil produced. If the value of the oil produced in the future improves through a combination of circumstances including the virtual elimination of U.S. government price controls over the years ahead, increase in world oil prices, increasing tightness in world oil balances sometime in the 1980's, all these will work to the improvement in the value of your oil in its

markets, and also at the wellhead, and it will improve the profitability of the producing operation and this will be reflected in your corporate income tax revenues if you apply your statutory rate to a separate accounting of profitability. At a point in time when, as today, the value of a good portion of your oil is depressed by circumstances beyond the control either of the companies or the State of Alaska, this would give you lower corporate income tax revenues from separate accounting than would otherwise be the case. But now lower revenues than you would get under your present apportionment formula.

One of the arguments, one of the criteria which has always been stipulated as an important principle of taxation by the industry and I think considered by the Legislature also, is how equitable is the burden of taxation among taxpayers, how equitable is it among tax payers? I put it to you that you cannot through your present income tax statute get an equitable burden of income taxation upon the companies operating here in Alaska, not through the apportionment formula. You can get equitable burden of taxation through separate accounting, because in effect what you say is that we will tax each company 9.4% on what, on that company's profits or income generated here in Alaska, Under your present statute, the burden of corporate income taxation is very inequitable here in Alaska, very much so. Industry hasn't said much about it, but it is so and the best evidence of that is in the Andersen report itself, where again they have for the four major participants in Prudhoe Bay and in TAPS calculated both the profitability, the income of those four companies, according to their model, and what the tax liability of those four companies would be, it leads to some very astonishing results. For example, the Andersen estimates of Exxon and ARCO's profits from their parallel participations in Prudhoe Bay and in TAPS, is over

25 years of operation, 343. The tax liability, if it were proportionate to equities of these companies, they have the same equity, the tax liability would be $343 million over the 25 years, Exxon, $343 million, ARCO, $343 million. Applying the income tax liability under your present statutes, Andersen estimates that Exxon will pay $530 million taxes in the state of Alaska. ARCO will pay $208 million to the State of Alaska. Both with the same income from the producing and transportation operations, but with a tax liability that differs over 25 years by as much as $300 million. This is a corporate income tax statute that you have which not only is deficient in raising the corporate income tax revenue for the state proportionate to the profits generated in the state, but which produces an inequity such as this between two taxpayers who in Prudhoe Bay and TAPS would actually be earning approximately the same profitability on their operations.

Turning to the house bill, and I'm going to compare the two, one against the other in just a moment. If you turn to the house bill, there are three interesting, three features, which depart from the present statute. The first one is a change in the definition of the corporation's income which is going to be allocated. The second is a change in the formula which takes care of the allocation. And the third is a change in the definition of what goes into the formula which is at least by inference intended to bring with the tax regime of Alaska or expose to Alaska corporate income taxation a portion of the profitability of oil companies operating in the Federal offshore areas but serviced from Alaskan (IA). The change in the definition of corporate income that's going to be allocated is a simple one. It says in the bill that the income to which the apportionment formula will be applied will be either

book income as reported to stockholders by the corporation that's operating here in Alaska, that is to say its world-wide income as reported say in its annual report to stockholders certified by its own public accountants, or taxable income as reported to the Federal government or federal income taxation, whichever is the larger. There can be several reasons for moving from your present base of allocation to book or to federal. One is whether or not the Legislature believes that the definition of taxable income as laid down by the Federal government is the definition you want to accept. You heard the arguments in the last session of the Legislature that the Federal government, in defining taxable income for oil and gas operations, provides a whole series of possible tax advantages which in effect tend to reduce the taxable income on which the Federal tax is computed and you use that and reduce the taxable income which is allocated to Alaska. Well, this is a question for the Legislature to decide, whether or not the Federal concept of expensing of intangibles, which is probably the most important one, or accelerated depreciation, or whatever is involved should enter into tax base or into taxable income or not. These things could be changed, that is the basis of your present statute, if you want to say that companies can't expense intangibles, that they'll have to capitalize and depreciate intangibles for purposes of Alaskan computation. But the other reason, which I think is a more pragmatic one, is just taking one or the other, whichever is higher, gives you a higher base upon which to make your allocation. Very pragmatically, what it does is it increases the income of the corporation in the eyes of the revenue department of Alaska when it starts applying its allocation. It's just it would yield a higher total income for apportionment. Now, the change in the formula for apportionment involves the

elimination of the sales factor and its replacement by an extraction factor. As you've all heard, the sale factor militates against the apportionment of income to Alaska because the bulk of the oil and later on the gas produced in Alaska will not be sold in Alaska so you have relatively low sales in proportion to the profitability of the producing operation. And so you have small sales factor, and by averaging process, you have a small apportionment factor as a whole. If you substitute for sales extraction, you will then be taking into account the volume of oil produced here in Alaska in proportion to the corporation's total production of oil and gas.

Now, it looks on the face of it as though this approach is a cleaner approach from an administrative standpoint. Book value, as determined by the corporation, book income as determined by the corporation, without any reference to the Federal taxation or the Alaskan taxation or anything else. They're reporting what they think is the approporiate income to their stockholders, the State of Alaska takes that and, since most corporations will almost inevitably, not always, but most often show higher book income than Federal taxable income, it's a safe bet that if you have your choice of the best of either one from year to year, you're going to be increasing the whole thing. And you keep the formula except you change one factor. But I put it to you that I don't chink that the administration of either the income base or the formula is really as simple or clear cut as it seems. First of all, if we choose either book value or Federal tax--book income or Federal tax income, whichever is higher each year, this would be determined by your revenue department and it means looking behind the figures to a certain extent, there will be variations from year to year, back and forth adjustments, I submit there are a lot of difficulties which may

be involved. It will have to be monitored. I don't mean to exaggerate the difficulties, but neither do I think we should exaggerate the simplicity of administration. The extraction factor can cause very, very serious doubt. The volume of oil and gas produced in Alaska on a (I.A.) basis is probably fairly easy to estimate company by company. You go to the world-wide production of oil and gas by these companies, you are moving outside the regime of the U.S. and you're looking at oil production and increasing the gas production under institutional and governmental arrangements which not only vary fantastically from country to country, but are in a process of change over time. For example, if you went back 10 years when virtually all the production of major internationally integrated companies was under concessions, it was very easy to compute what their gross production of oil was and what their net production of oil was after a royalty sale. But now, concessions are increasingly disappearing, so the concept of equity oil is disappearing. You have production under work contracts, profit-sharing contracts, production-sharing contracts, joint-venture contracts, and the way the company is compensated, whether it be in dollars or in oil, and the definition of whether that oil is owned by the company or is lifted by the company in behalf of the national oil corporation and moved into international trade on behalf of the national corporation, these are fantastically difficult things to disentangle. And I suspect that when it comes to getting the denominator of this factor in your apportionment formula, oil and gas production in Alaska as a fraction of world-wide oil and gas production, there can be many difficulties. And the problems will have to be resolved, not just once, but almost year after year is the circumstances of operations in the different

companies in the world, the Middle East, and in the Far East, and in Latin America, and in Europe. The answer is that you've got a pragmatic approach in the house bill that I agree would...all of the revenue department calculations, would yield higher tax revenue; I suspect that you really don't know how much more it would yield. You don't know how much more because the effect of the change in the definition of taxable income and the change in the formula can only be obtained if you go back in history. If you look over the last 5 years, you know what the difference would have been in those past 5 years, but it's very difficult to know what it would have been over the next 5 years or the next 10 years. You've got a pragmatic approach which says we are raising the taxable income which we're going to allocate, we're going to improve the allocation formula, pragmatically we're pretty sure that is's going to yield higher income tax revenues from Alaska.

Now the third feature is the bringing into the numerator of the formula the property, payrolls, and extraction, the appropriate offshore figures if in a sense the servicing is from an Alaskan base, and if there is not obligation to another state, which says in effect that Alaska will have allocated to it a portion of the unitary corporate income world-wide allocated to Alaska, not only in proportion to the property paid on the extraction from the State of Alaska itself but also from Federal offshore areas which are proximate to Alaska and served from Alaskan bases. This is a straightforward concept the legalities of which I leave to the lawyers. You must decided in your wisdom whether or not you want to attempt this or not.

Well, I've tried to touch on the highlights of these alternatives. Now let me simplify by making the comparison and telling you what in my judgment are the most relevant differences between them.

First off, either one of them, if adopted by the Legislature, would increase substantially the state's corporate income tax revenue. Either one of them. I think there's an available estimate by how much the separate accounting would. I don't think one can get quite that close in the other case, in the case of the House Bill, but either one would increase substantially the state's income from the corporate income tax. Both of them, I think, involve complications of administration. I don't think either of them involve administrative complexities so great that that should be the reason for the Legislature to say, "No, we won't adopt the House Bill," or "No, we won't adopt the Senate Bill." There are administrative complications, but I don't believe that these are complications so great that that should be the decisive consideration in the mind of the Legislature. The revenue department could administer either one of them, and whatever the complications may be, there will be certain uncertainties and there will be costs of administration, but there could be an adequate degree of administration, I think, of either one of these bills. I don't think the choice between either one should rest upon administrative difficulty - you shouldn't reject them for administrative difficulty, accept one or the other because of less administrative difficulty.

The big advantage of separate accounting, as I said before, its unique advantage, is that it addresses itself directly to the income generated in Alaska. This is an important feature of the bill, and I think there's an advantage for the State of Alaska in taxing the income that is generated here and measured directly here. As I said, not only is the basis of your income tax, but also because it gives you a fix on the circumstances of the industry with respect to all forms of taxation.

Now the industry may fear that this leads inevitably to higher taxation in all directions. I submit that's not necessarily so. There are times when your direct approximation of industry profitability may cause this or successive Legislatures to go slowly on oil industry taxation when you have the realities in front of you. The purpose is not to get higher taxation, but it gives you a direct fix on what the profitability of the industry's operations are. In contrast, and this is a very important feature of the House Bill, and also of your present law incidentally, it largely, it largely isolates the income taxed in Alaska, and hence the Alaskan corporate income tax revenues, from what happens in Alaska. In other words, you're getting your share of the corporation's world-wide income. Now, if Alaskan profits go up, okay, their world-wide profits go up, but you get a very small share of that factor. But if Alaskan profits go down, therefore the corporation's world-wide profits go down, but not by a very big percentage, and what you get allocated to Alaska is what you get in your income tax revenues, is largely isolated from the impact of adverse events here in Alaska. Now, your present statute does that also, because you work with, again, with Federal taxable income allocated by formula, and in the House Bill, you work with book income as reported to stockholders, a change in the formula. You largely isolate your income tax revenue from what specifically happens to the profitability of Alaskan operations, because you're taking a share of world-wide, and you're taking it by a fixed formula. What happens in Alaska doesn't have that effect on the world-wide operation of many of these companies. Now, is this a plus or a minus in the eyes of the Legislature? That's for you to decide. From the standpoint of revenue, it isolates you. From the standpoint of a form of oil and gas industry taxation which has the least effect upon decision making, upon marginal

operation, and so on, the closer you get to true income when you tax it, the better you are off. But you sumit yourself to certain uncertainties. You take the plusses when profitability is higher, you suffer the minuses when profitability goes down, or does not go up as high as you would have liked it to have gone up, where your budget estimates anticipated it would go up. Separate accounting gives you your revenues on the direct taxation of the income generated here, or the estimate of it given the vagaries of all administration accounting. The feature of the House Bill is it largely isolates you from the specifics of Alaska's oil and gas profitability and the income generated directly here in Alaska. And of course the third distinction is that the House Bill could bring taxable income and income tax revenues to Alaska indirectly from off-shore operations, indirectly insofar as the offshore operations proximate to Alaska raise the total earnings of the corporation. and your formula is improved by getting their property and payrolls and production off-shore into your apportionment formula. It could give you indirectly both taxable income and income tax revenues from those operations. Again, the Legislature must decide whether this, from a standpoint of revenue, is attractive to the state of Alaska from the standpoint of relations with other states and with the Federal government, and attempt to extend the range of taxation of Alaska, whether this is something you prefer to do or not to do, but this again is a legislative choice.

Now, what I try to do in summary, as you consider these two bill, is to make these four points. One - either one of them will raise quite substantially the income tax revenue from the companies operating here in Alaska in production and transportation. The feature that stands out in separate accounting is it gives you a direct fix on the income generated by operations within the state. And that of course, I think, is of value

to the Legislature quite above the tax, knowing that. The feature of the House Bill is that it isolates you from the uncertainties of the income generated directly here in Alaska, gives you a share through apportionment, or through allocation, of the corporation operating here, a share of that corporations world-wide income. A fourth feature of the House Bill does not attempt to extend the jurisdiction of the Alaskan corporate tax regime to the offshore areas by a change in the numerator of three factors of your apportionment formula.

I've exhausted that particular material I wanted to call to your attention, and I hope I haven't exhausted your attention span. Now I'll place myself at your mercy and whatever questions you have.

QJESTIONS AND ANSWERS OF MILTON LIPTON

BEFORE THE HOUSE/SENATE RESOURCES COMMITTEES

January 25, 1978

Q. POLAND: I'm going to lead off with the first one, and it has nothing to do with income tax, because it's an issue that I know is going to come before us this session and that is the floor, cents per barrel.

LIPTON: The legislative history cents per barrel was introduced simultaneously with the step schedule of severence taxation at the last moment at the time when the legislature was most concerned that unanticipatedly high pipeline tariffs would depress wellhead values, resulting in lesser income than the state would like to put into its budget over I think it was a 2-year period when projections were being made in the cents per barrel being produced. Let me just say that from the revenue standpoint, it's a tremendous problem to the projections that the State has to make from time to time and what seek and what it's going to get from oil and gas operations. The establishment of the floor, it gives you assurance that whatever happens, this is the least that you're going to get. But it also says something that you don't say in any other aspect of your severence tax legislation, namely that the State abstracts itself from the realities of the environemnt in which the oil companies are operating, that come hell or high water, whether the industry, for whatever reason. is

able or not able to get the wellhead value on which the State's percent of wellhead value tax is calculated, the State would get at least that. It's clearcut as a revenue measure. It denies the principle of taxation which is built into the percent value. It says that the higher the producibility of the wells, the greater will be the tax imposed, percent of that gets higher; as your producibility goes down it gets lower. But let me just give you some facts on how it's operating today, the cents per barrel. Now the example that I'm going to give you is based upon restricted production because of the pipeline problem up at Prudhoe Bay, and we have used by our calculations what you're using, the assumption that average production per well is 5,000 barrels per day. This is under conditions of restricted production. Now, there are two cases which we've taken in order to illustrate the way in which it operates. We've taken what I would call a "best netback" case, which in effect is a close approximation to where a company such as ARCO would be producing, out of it's share of 5,000 barrel per day wells, and marketing it's oil in California, so that it gets a relatively favorable netback; that is to say when you're finished selling your oil at over $13/barrel to refineries in California, you pay your ocean transportation and your pipeline costs, you come up with a wellhead value of something slightly over $6.52. Now, under those circumstances, the severence tax liability of a company such as ARCO operating under those circumstances, is about the same whether they pay cents per barrel or percent of wellhead value. It comes out to around 62.6 or 62.7¢ per barrel. This is what they would pay in severence tax to the State of Alaska on the basis of it's production from the 5,000 barrel/day well. And that works out to about 9.6% of wellhead value, in either case; that is to say the break-even point, the point of indifference whether you're percent of wellhead value or cents per barrel is around, the break-even point is very close to $6.50,

and so they would paying 62.6-62.7¢, and that's about 9.6% of wellhead value. Now if you take the opposite extreme, take a comapny such as SOHIO, which is producing and selling it's oil in the most distant market, the US Gulf Coast, and you deduct very high ocean transportation costs, including trans-shipment to get through the Panama Canal, and you deduct it's pipeline tariff, and all of these are based upon the company's own pipeline tariffs, which they are in effect charging at the present time, then you get a netback value of something under $3.80. Over $6.50 to less than $3.80. So far as these two companies are concerned, these are realities of life. The one company, able to get it's oil at a good price in California with relatively low transportation costs having a netback of over $6.50; the other is equally a fact of life, the inability to market all of it's production with a very substantial volume of oil, a significant proportion of it's total, having to incur high transportation costs to the U.S. Gulf, and then netting back less than $3.80. It will pay exactly the same severence tax, 62.7¢. It will pay the same severence tax because the cents per barrel floor is operative. It will pay the same severence tax. That severence tax is 16.5% of it's wellhead value, which is actually higher because it's on a cents/barrel basis then the top of your range in your severence tax bill, which is 12.25% is escalating value % of wellhead value. So here you have the contrast between the implications for the State of Alaska and the implications for the producing companies. For the State of Alaska, the floor, the cents/barrel, provides guaranteed income a part, and the devil take the economic circumstances under which the company is operating, whereas, in the companies, they in effect, have to commit themselves to the severence tax liability, despite the fact it becomes a very large proportion of their wellhead value. I pointed this out

previously in the case of Cook Inlet, where the problem was not the ability to dispose of the oil with differences in netback values, where the problem was a distinction between upper tier oil and lower tier oil imposed upon the producers in Cook Inlet by the administration of price ceilings by the federal government, where your cents/barrel floor became very very onerous some of the particularly low profit operations in Cook Inlet, simply because the cents/barrel was an exaction from them for the purposes of your revenue, but became a very large percentage of what the value of their oil was at the wellhead by virute of federal tax regulations. Now, this is a dichotomy, you know, this is a dilemna that one can't get away with. If the state wants underpinning in terms of it's severence tax revenues and opts to do this by cents/barrel route, it inevitably is going to involve inequities and tax burdens upon certain producers either because of federal controls on the process they're allowed to sell it on, or because of the economic facts of life that only a certain proportation if the production has to go to a distant market at a relatively high cost themselves; which to a very considerable extent they absorb, although to the extent that it depresses their wellhead values, it affects your royalities, although not your severence tax revenues, so, this is a dilemna which you face, whether or not you will insist upon protection for the state's revenue, and the devil take the economic reality, or whether you go the other route. Now I suspect that there's always a compromise in the way in which these things are determined upon in the course of amending your regulation, and it certainly, I would think that the cents/barrel which you adopted in the last session of the legislature, that is to say the particular amendment to the severence tax bill which you enacted last session, was designed under normal circumstances not to impose onerous

cents/barrel taxation upon the company, that is, you had anticipated that a $6.50 wellhead value will obtain for most of the production on the North Slope, in which case the cents per barrel really is not onerous, because the companies were paying on a percent of wellhead value. So if your cents/barrel is geared to hurt a company only if the wellhead value falls below $6.50, and you don't anticipate it falling below $6.50. Oh, this was a kind of compromise, protection against what might go wrong. Well, a lot of things went wrong. Among the things that went wrong were things that were partly beyond control of the company. Namely the adverse economics of disposing of the Prudhoe Bay production beyond California. One of the other things that went wrong, not necessarily wrong but went counter to the expectations of the Legislature, was that the pipeline tariff posted by the companies and now applicable pending adjudication by the Department of Energy, the successor to the ICC, is a very high pipeline tariff. This tends to reduce the wellhead value. So partly the companies have in effect shifted wellhead value down, because of the profit of the pipeline, but partly it has to do with economic circumstances, the ability to market at a good market, the prices in California are not that different than in Gulf Coast, for competitive reasons, but that's a different story. Basically, the price that they have to compete against is not much different in California than in the Gulf of Mexico. The big difference is the difference in transportation costs and there is a difference of $2.50 in transportation costs gross, and probably somewhere between 70 - 80¢ net after taxes out of pocket to the companies to go all the way to the US Gulf Coast.

Q: Sumner: I believe that I heard you say this morning that if we keep foremost in

of mind the subject of future investment incentives in Alaska that we're going to have to weigh very carefully, even though we may want to restructure the tax structure here in Alaska, but as it relates to the aggregate of the total taxes that are being paid, I got an impression that you thought maybe we ought to think cautiously of how much we might increase in aggregate the taxes that are paid as it concerns the future investment incentives.

Lipton: I think that's right. I think that no industry can be indifferent and because the industry is important to Alaska, no legislature can be indifferent to the aggregate tax burden. I think that's quite a different thing from simply being overwhelmed by a statistic which says this industry is already paying, given our assumptions, somewhat, 5% more, five percentage points more than we would be paying in California. There's a shadow area between where tax burdens or expected tax burdens suddenly are going to affect industry investment incentives, particularly in the area of exploration. One thing you know, that the exploration dollar does not go automatically where the tax burden is least. The exploration dollar tends to go where the exploration prospects are best. You can surely shift it somewhere in this gray, shadowy area, where the tax burden get so overwhelming, or if there is somewhere the perception, and I think this is one of the things the Legislature surely will want to consider, that if the perception is that changes in the tax structure, as it is applied to the oil and gas industry, are regularly taken, largely with the view to budgetary needs or revenue deficiency, and hardly ever with the long view as to what is a reasonable tax regime for the state, then I think it creates impressions which may be even more important in discouraging investment than the fact of the tax burden per se. And this is why I think in all of our discussions with the legislature, we've

tried to emphasize that a balanced tax structure, in which each of the three elements, which are the income tax, the severence tax, and the ad valorem tax, have to be weighed somehow by a different criteria because they have different effects on the industry, but if it's balanced and if there's a concept of continuity over time, that under those circumstances we have not yet seen this legislature placing such extravagant burdens on the industry that if they had sufficient confidence in, you know, the trend over the future, that this would not discourage investment.

Q: Sumner: What is your guess to the liklihood of depressed oil prices in Alaska to resolve the oil activity throughout the rest of the world. Right now in terms of the efforts to increase or step-up production in many areas of the world and the West Coast surplus to some degree, do you see that as building on itself?

LIPTON: No. I don't think that there's anything in the nature of oil exploration world-wide. One has to have an incentive, and two, has to have a purpose. The incentive is the hoped-for profitability of the relatively high foreign oil prices. The purpose is to try to create the reserves, the expanded reserves that will meet world oil requirements in the future. If I may digress for just a moment, we're living in a strange circumstance. The productive capacity in the world today is considerably larger than world oil requirements. The reserves of the world today are really not very great compared to what future demand is going to be. We're facing a temporary surplus of collective capacity but a long run deficiency in the reserve base for oil, so the exploration is going to go on. I don't think there's any adverse effect on Alaska. I think the long run opportunities for marketing Alaskan oil in North America at prices that are attractive from the standpoint of the profitability

of exploration ventures, from the standpoint of the state's share of the economic value, the prospects down the line are terrific, and if the geologists of the company see the opportunities here, the exploration money will come.

Q: Sumner: I'm trying to determine what period of years might be involved in your projection there and weigh that against what is scheduled to be the peak production years, Prudhoe Bay for instances, which is right now of course one of the largest reserves in the state. You know, if it's ten years down the road, we won't be competitive, or we will have marketed the major part of this oil from that reserve. So does the long term picture look like three years, four years before improved or upturned pricing structure.

LIPTON: I don't think your prospects are all that adverse even at the present time. You're suffering a temporary disadvantage by virtue of several things, one, price control and two, the fact that your production is surplus to the ability or the willingness of California refiners to take that amount of your oil, and this will become aggravated next year when the production goes up substantially and the demand for all crude oil in California refineries is not going to be large, so that a larger portion of your oil is going to move beyond, but there will be in the interim, there'll be improvement in both world and US oil prices, world oil prices because of the level detemined by OPEC and US oil prices under whatever compromise on energy policy evolves.

Q: SUMNER: On the near and the long term?

Q: HUBER: Milton, would you go further into the relationship between cents/barrel in relation to vertically intergrated companies allocation to expenses and profits, sales, processing, production, transportation, such as possibly what would be the difference in situations with BP?SOHIO for instance if they have decided to take not the maximum in the transportation but to take

a minimum from the pipeline transportation and maximize their production profits.

LIPTON: Well, Senator Huber, you pick a difficult example. British Petroleum has a direct participation in the pipeline, so whatever the after-tax profitability of the pipeline operations are, for its undivided share of tax it accrues 100% of the profitability. Now, whatever the effect will be upon the wellhead value at Prudhoe Bay, therefore on the tax liabilities of Prudhoe Bay producers, therefore on the after-tax profits of Prudhoe Bay producers, affect British Petroleum only through it's partial ownership of SOHIO. What the net effect would be, I would assume without doing a great deal of number work, British Petroleum looks at 100% interest on the one hand and less than 100% interest through SOHIO's participation in Prudhoe Bay, would in a sense place greater weight on it's 100% equity which is the pipeline participation than on it's indirect participation in Prudhoe Bay. But you see, neither this company nor any other company has complete flexibility in how they operate. The tariff that British Petroleum set TAPS car set on the same basis as all the other operating companies; that is to say they chose to calculate a tariff based upon the old ICC 8% rate-making modified by the 7% consent decree with Department of Justice, and so they all use the same principles, they've got approximately the same tariffs depending upon their debt proportions and so on. British Petroleum behaved exactly the same way, and obviously, if it did behave the same way as the other companies, it was thinking in terms of what seemed, from their assumptions, to be an appropriate policy. I really don't know that there's so much difference among the companies. The other part of your question is a meaningful one. If you have integrated operations, and if in fact the

tax exposure of profits earned in one place or one function is different, in other words, if you earn the profits here you pay more taxes, therefore you like to have the profit somewhere else. If you earn the profits in production, you pay higher taxes, therefore you like to have the profits in transportation. This is true of any company that has the possibility of shifting through transferring pricing the profitability from production to (IA). But the companies don't have freedom here in terms of the pipeline. . . The issue of the pipeline tariff really I think should be divorced from the taxing policy of the legislature, at least at this moment in time because it's now at issue. First of all in the courts and certain legal respect, and more importantly, it's at issue before the Economic Regulatory Administration, Department of Energy, which is looking into both things, both what the capital base is for the de.. nation of tariffs, and two, what the proper rate of return ought to be. And this is now in adjudiction. And your own Alaska Pipeline Commission is seized with the issue of the tariff between Prudhoe Bay and Fairbanks. It's going through it's own administrative process, and if it turns out that in fact, the administrative decision upheld in the courts is that the pipeline tariff is too high you will get higher wellhead values and (IA) the companies whatever their predilection will be low side of profitibility and tax exposure, are going to have to follow suit.

Q: HUBER: I can recall the arguments when we put in the cents per barrel, and it was to protect the state, if I remember right, through revenues even if the oil would fall to zero wellhead value, and even if the allowed transportation should be extremely high. Coupled with that was the figures given to us many times that most oil pipelines were allowed to 8% maximum but the history of the ICC shows that they weren't, the prices were such that they weren't taking only 5%, 6%, 4.5%

of these figures and many others several times showed that most of ICC-controlled pipelines were not charging that maximum amount. Here we have the situtation that you brought up, SOHIO is paying 12.25% effectively because of the floor

LIPTON: (INTERRUPTS) (16.5)

Q: (continues) you said 16.5% effective, and yet every one of them is change and it seems like they have decided that the Alaska pipeline that the old proportion will be used, they will go for the maximum they can and I'd hate to see what it would be if we didn't have the lid of 8%. It looks like you've got a whole new ball game here.

LIPTON: Senator Huber, I think I do recall your reference to the past.

We have been rather vocal on this subject of ICC tariff regulations and pointed out the history of two things, one, that the 8% rate making rule was a monstrous rate-making rule because it had been adopted in an economic environment which no longer existed and the ICC for unfathomable reasons has never gone back and reviewed the 8% and the rate-making rule, and because of that, we raised the whole question of the effect upon netback values, wellhead values, and we strongly supported the establishment of the Alaska Pipeline Commission, which gives you your own avenue of administrative regulation. But you know, an interesting thing happened. All of a sudden the ICC came alive, and the ICC said that that old 8% rate-making rule is no good. We're going to go to a 10% rule. But you know the 10% rule yields much lower tariffs than the old 8% rule. The 8% rule was 8% after tax and after recovery of interest on total valuation. The 10% rule, and there's nothing magic about it, and I suspect that in the course of time the review of the whole issue will nmodify that too, but the whole point of the 10% rate-making rule is not to give a higher rate of return. What is said in effect was the 10% shall be the total return to capital; that is to say your interest charges,

which are such a fantastically large thing have to be covered by that 10% return of your capital, and this led to ICC-proposed tariffs which were $1.50 or so on the average below what the companies have posted. Now I suspect that the change in attitude of the ICC did not arise of a vaccum. It was a reflection of a long discussion on the implications of the rates that had taken place before your legislature over many years and argumentation over what the appropriate rates of return should be, what the appropriate rate base should be, and what the resulting tariff would be, and I think that at this stage of the game, from the standpoint of Alaska, not from the standpoint of the companies, there is reason to anticipate at least that there will be very very serious review of these pipeline rates. Now if it turns out that after all administrative review and after all judicial review, that the company tariffs stand, where are we left then? What's the judgement then? That everybody's wrong? The companies are wrong? The Department of Energy io wrong? The courts which uphold them are wrong? The Alaska Pipeline Commission hasn't been able to do anything. I doubt that that's the case. But if all of that does transpire, what then is the implication? Maybe the tariffs are not of out line. If it's done through all process, I don't think that's going to be the result. I think the strength of the Alaskan position is in everything which has transpired over the last few years, including the arguments about the rate base, the arguments about the rate of return, and everything else, I think this, I strongly believe that this is a judgment, a personal judgment, that you will have substantially lower tariffs on TAPS than were promulgated by the companies themselves.

LIPTON TESTIMONY

Q: HUBER: Just one final follow-up. It is within our responsibility, purvue as legislators for the State of Alaska's people to determine at what point do you say this is what we would do in fairness, or do you say if it isn't economically feasible to produce this oil at this time because of transportation problems, federal rules that are in many cases arbitrary assumptions, maybe we shouldn't get rid of this depletable well at this time. The cents per barrel tends to do that, what I'm talking about, rather than removing it entirely, or move the cents/barrel down to where we could bring more fairness to the companies as you say, what do we do with ...

LIPTON: Senator Huber, if you're talking about revenue per se, it's a persuasive argument. If the function is to provide an underpinning to state revenues, the cents/barrel does it. Now, the other question is what are the implications when you choose to buttress or underpin state revenues by doing this? First of all, what you see is a kind of ad hoc taxing policy, increasingly year after year dedicated to our budgetary needs, revenue deficiencies, or whatever the case may be. There are circumstances which may militate in that direction, if it's necessary, if the state faces a crisis. But you must always ask yourself, is this to be the principle of taxation that you'll follow in every legislative session, or are you willing to say that the state has an economic interest which is represented by, first of all, it's royalty claim in the lease, secondly by principles of taxation which have been evolved over sessions, and only under extreme situations do you start intruding unique revenue problems as the basis for change in the tax liability in one year or the next year or the third year. I have no argument against the necessity of doing so from time to time, when abnormal circumstances intrude. I do think that it

causes, the question is asked of me so many times, including just this session, where do you start adversely affecting corporate investment decisions, and I said thenand I still feel that you could with the burden of taxation do it, but more likely, the kind of changes in the burden of taxation really won't have that much effect, but if there is a perception that tax policy always is detemined with a kind of a unique view toward the budgetary exigencies and the revenue deficiencies of the moment, and there seems to eb no continually over time, that would have a very adverse effect.

Q: HUBER: By possibly reducing the floor, and I do hope that in some cases this might be a viable suggestion. I just can't get it with our responsibility that floor of 62.5 ¢ a barrel, for Alaskan oil now at least that's the floor on severence tax, and I can't see how that could be effective now when this same oil it's competing with throughout the world, other countries like Arabia, are taking $10.00 a barrel, we're taking too much at 62.5¢. I just wonder if we're making our discussions in the right range. We shouldn't be making off somewhere halfway in between somewhere instead of down below the bottom one.

LIPTON: I'll give you a very quick answer to that. Saudi Arabia in effect takes more than $10 a barrel for their oil. But let's assume that you'll be satisfied with a modest $10/barrel taxation on your oil. You take $10/barrel for your oil and the oil has to be sold in L.A in competition with Saudi Arabian oil, or $13/barrel. Now you have left $3/barrel to pay your transportation costs from L.A. to Valdez, never mind the profit on the pipeline, your pipeline costs from Valdez up to PrudhoeBay, the costs of producing the oil. $3 won't do that. That's why you can't get $10 for your oil and Saudi Arabia can

get $10 for it's oil. Furthermore, you are not a Saudi Arabia in Alaska. Let me be presumptious for a moment in addressing the Alaska Legislature. You are not a United States in Alaska either. You're living as part of a nation which also has a tax regime. The United States has all forms of taxation upon oil and gas operations, including your oil and gas operations here in Alaska. The United States has a policy with respect to development of energy resources, the pricing of energy resources, they may be unattractive in Alaska. They are largely tax regimes attractive to the oil companies, the price and policies are attractive to the, but never the less, it is our national policy and it seems to me that the State of Alaska in its perception of how it treats the oil industry, must do so as part of the United States talking about an oil industry which is also part of the United States.

Q: HUBER: It just seems like we've got about a 20 to 1 difference there, and I hate to get working below the one figure in figuring where we should come out when I have a feeling it's somewhere between the 1 and the 20 instead of below the zero line, below the 1 line. And I just can't relate it.

LIPTON: A, Senator here, let me put it this way. There are companies operating here in Alaska who are operating in the Middle East, and earning in the range from .15¢ to .21¢ a barrel for their producing operations. And it's a bonanza to them. A fantastic bonanza, ever so much profitable than any operation in Alaska. If they earn as a margin of after tax profit in Alaska $2 a barrel we couldn't come close to the profit ability of middle east operations. Look at the fantastic difference in investment that's involved. What's of interest is not just how many cents per barrel we take away after cost and taxes, but how much of an investment of that is necessary to do it. There's a tremendous difference. I'm not addressing myself again to the fact the industry could not

stand any increase in taxation here or it's too high now. This is a very difficult thing to arrive at and this is a thing the legislature always has to balance. But I don't think, this is my only point, I don't think that the criterian the legislature should use in deciding whether the taxes are too high, or whether in fact they should raise taxes on the oil industry here. That they should look at the government take or the taxation in foreign producing countries. It's completely irrelevent.

Q: HUBER: Could you tell us better and more direct how should Alaska get it's honest, true, fair share both as a property owner and as a taxing entity if we don't use comparative means. That I think is the level we set up.

LIPTON: You're comparing yourselves with other tax jurisdictions which are also state states in the United States. I mean this is one of the reasonable comparisons. And you look at one form of taxation which is a corporate income tax and try to get what is a, well, you've got a corporate income tax rate. The problem is that that rate is going to apply to too low an estimate income. You can correct that if you choose. You have a severence tax which has evolved over time, I think in a very healthy direction. You have increased the ceiling percent of well head value over time not to any onerous letters compared to other states. You reduced it at the other end. You tried to provide not only for the state's revenue under optimum circumstances, but for protection of larger industry operations under adverse circumstances. You loaded on ad valorem taxes at a very considerable extent, and you did that under the exigencies I think it's quite understandable that, in your judgement revenue needs which anticipated the flow of revenues. You chose an avenue which was to tax before profits were being generated. It happens alot of times. But I think this is the basis upon which you judge. You look first at the total tax burden, then you look at the individual parts, and how are

they in terms of the revenue for the state and what are the economic implications for the companies that have to operate under those taxes. Certainly you've never subscribed here to the opinion that you're aggregate taxation, or that individual aspects of taxation were so onerous that in a sense they are discouraging operations here is Alaska. There's no evidence that operations here in Alaska are discouraged. If there's been a lag in exploratory drilling there certainly hasn't been because of the tax regime. It's because of the problems of leasing, land selection.

Q: REP. MILLER: Just real quick, and I'm curious, name a few states that use separate accounting.

LIPTON: Louisiana and Oklahoma

Q: REP. OSTERBACK: Talking about the oil. Have you done any figuring on the gas? That's the next thing that's going to face us in our Committee, the well-head price on gas. Have you done anything on that.

LIPTON: No. This is a wide open subject, and I have nothing but pity for those individuals who must now wrestle with the problem of not only what, what the well-head price of Prudhoe Bay gas can be. Second, Question, what the well-head price of gas ought to be. Can be, ought to be, and third, is how to get at those things. This is an awesome problem. Just let me say that I think this is one thing which is again to the thinking of the legislature. We always said that your oil is a price taker. That is to say, the price at which your oil can be disposed of in the refining centers of the lower 48 states can never be determined by Alaska, the state of Alaska or Alaskan producers. You're price takers you've got to move into the refineries in competition with other forms of oil. Which is why any increase in real costs that are incurred, for example, the ultimate cost of the pipeline, they come out of the ultimate profitability of Alaskan operations and they come out of the state revenue. There's no way of getting away from that. This

is not quite true in the case of gas. In the case of gas things which happen here in Alaska have influenced what the price of that gas will be when it's delivered to lower 48 markets. For example, severence taxes can be passed on. Increases in cost can be passed on. The reason is that the barrel of oil that reaches the California refinery has to be refined in competition with a barrel of oil from somewhere else. And MCF gas which reaches the Great Lakes area from Alaska doesn't have the market and competition with the MCF of gas which comes up from Texas, or off shore Louisiana, because you've got rolled in pricing which is involved at different stages of the game. Both in the transmission pricing and the distribution gas companies. Now how that's going to be resolved over future years, it has to be resolved before the new gas pipeline is finally going to be brought before us. But it is quite possible that the well-head price of gas on the North Slope will turn out to be higher on the BTU basis than the well-head value of the oil. It's quite possible. In which case the utilization of that gas in Alaska may not be so effective. If that's the way it works out. Although the utilization of the liquids may be very attractive, but that's a different story. I'm sorry but this is kind of a long winded answer, but the answer is basically I don't know what the price is going to be, but there's a difference between the way the price of gas can be determined and the way the price of oil can be determined.

Q: BUTROVICH: At what point in time and has the Prudhoe Bay oil been felt by the National Energy picture?

LIPTON: On sure. I mean there's no two ways about it. You've got 800,000 barrels a day of American oil being produced here which would increase our imports by 800,000 barrels a day if we didn't have.

If you ask how important is that 800,000 barrels a day or 1.2 million barrels a day which hopefully you'll reach next year, or 2 million barrels a day that you may reach by 1980. It's very difficult to judge how important that is from the standpoint of national balances. You would just hate like hell not to have it.

Q: BUTROVICH: I was going to ask you if that is good. The overall effect.

LIPTON: I don't think there's any argument on the part of the producing companies that have to pay your taxes and the part of the State of Alaska that have revenues, and the part of the United States as a whole, which has the benefit of that oil, no question about it.

Q: BUTROVICH: Suppose it hadn't gone on stream until July 1, 1979.

LIPTON: We're importing more oil now. The interim volumes of oil would be available in 1979 and thereafter. I don't think it would be the decisive factor in the national interest. I don't think it would have a very major impact upon the companies, and probably the state of Alaska. The companies' cash flow in the state of Alaska is revenue, you know.

Q: BUTROVICH: Would you elaborate a little about the companies cash flow, I'm not that concerned about the state's revenues.

LIPTON: There's no question that from the standpoint of operating companies the invested proceeds over time there is in the best of circumstances a very considerable lag between the time the investment starts and the time the investment is completed the first production, the first pipeline really begins and then build up your revenues thereafter. The companies have to pay out the money for a long period of years and incur interest costs over the whole interim. The duration between outlay and income, let us say the cash flow, is a very vital consideration, no question about it. Which is one of the reasons

that in almost all instances the companies would look for the most expeditious possible development of a resource the earliest possible production. The cash flow is, you said something interesting about the workers of other companies than the government because the government

Q: BUTKOVICH: Pardon me. I didn't mean to say I was more concerned with the companies. I was more concerned with what effect it would have on the companies that's what I wanted to elaborate on. I'm more concerned about the state.

LIPTON: Yes. But your point, I was going to suggest that your comment really is a very meaningful comment in another context. For a profit making company the timing of it's outlays and it's income and it's cash flow, is extremely important to the continuity of it's operations because the dollar that's spent out can't be reemployed until it's returned in so for a company that would like to expand and continue to grandise it's profits. Cash flow is what provides the dynamics of it's operation. But for most governments the cost of waiting for income is really not as terrible as it is for companies. The cost of waiting if you have to put a discount factor or interest factor is bound to be lower for government, because for governments the governments are looking to a continous lead for revenues over the future. Now nobody wants to defer revenue too long, but the dollar of revenue deferred which becomes a dollar of revenue earned is going to play it's role in the budgetary balance wherever it takes place. The viability of government is not dependent upon the timing of cash flow really so much as it is for a profit making organization. That's one of the reasons, again we're talking about taxes. If you built a foreign producing operations, one of the forms that has

recently evolved is a production sharing contract. And you have a company that operates as a producer for a government oil entity and the nature of the production sharing contract is that the company will recover out of early production all of it's operating costs and what barrels of oil recover it's operating costs and relatively will quickly get enough barrels of oil to recover it's whole capital investment. Now after that shares go in increasing proportions say to government. For the company the amount that it's willing in negotiations to give to a foreign government will be the greater. The earlier the foreign government allows that company to get enough barrels of oil to recover it's costs. In other words, they will split more number of the government the earlier they can get back to themselves, because the cash flow is so important to them and the governments which recognize that are willing to do it, because they feel that the cash flow to the government is always going to be valuable in terms of their budgetary balances.

Q: RADAR: Mr. Lipton, the failure of Arthur Andersen to take into consideration the Cook Inlet production, is that considering amount of production. Does that significantly alter their conclusions here.

LIPTON: First of all I was not critical of Arthur Andersen for not doing this. They did what they were asked to do.

Q: RADAR: Yes, we are talking about a statewide policy here and ranking. What I'm saying is the failure of their application only to Prudhoe . . . What effect do you think it would have had, had they included Cook Inlet?

LIPTON: Senator, if all you did was to expand Cook Arthur Andersen model to include Cook Inlet as it is today, an extrapolation of the remaining reserves into a production profile for for Cook Inlet and apply the whole thing you'd have very little effect on the sum total. Because we're talking about close to 10 billion barrels of oil in Prudhoe Bay we're talking very

limited reserves, you know production now out of Cook Inlet is around 120,000 barrels a day which is projected with a (IA) overtime. Now I don't, the specific answer to your question is if the model had been designed to include all oil producing operations, all oil reserve discovered and available for development and production as they now exist in Alaska the effect upon the ranking would be very very small.

Q: RADAR: Would it be as much as 1%, maybe bringing 1 from 92 - 93 or something in that range?

LIPTON: I don't know. The answer is two-fold. The effect depends on two things. First of all upon the relative volumes. Now we know what that is. The relative volumes are overwhelmingly in the Prudhoe Bay direction. Plus the pipeline which is so much profitability and taxation involved in the pipeline. However, some of the greatest advantages the state gives under it's tax regime are given to Cook Inlet. I would not think it would make as much as 1 percentage point difference in the ranking producers.

Q: RADAR: In the future when we're in full production instead of limited production because of problems with the pipeline, full production Alaskan wells will move into higher bracket and Alaskan rating or ranking actually as compared to the next closest state would be further apart as the fields grow older and the fields produce less and less. Alaska's ranking would be closer to Louisianias' for example.

LIPTON: I'm not sure that I get the thrust of your question, and that is to say as you increase your production for example, if next year you average 7,000 barrels a day for a Prudhoe Bay well your cents per barrel goes up to 64.8¢. So your cents per barrel tax goes up. The chances are that your

average well-head value if the tariff remains the same will go down. The average well-head will go down, because a larger volume of the Prudhoe Bay production next year is going to have to move to the Gulf Coast and net back even lower. So if you're looking one year ahead then the incidence of taxation in Alaska will look worse than today. If the study were made just for one year, remember Arthur Andersen study is based upon a projection of 25 years. So if you are just doing it for next year as compared to this it will look less favorable. They've already done this for 25 years. That shouldn't have any effect upon their (IA) but let me just say something else. That if your tax regime remains as it is, abstract what may change, you have only to project reasonable increases in the well-head value because of what is happening to world oil prices and what's happening to government prices. Reasonable increases in well-head value and suddenly the tax burden becomes proportionately lower here in Alaska. Because increase in the value of the oil will go to a very considerable extent to the companies themselves. That is to say what's going to be the increase in the tax burden as the value of the oil goes up. Your ad valorem taxation really isn't going to increase very much. Your severence taxation will increase a little bit as you go through cents per barrel into percent of well-head value and by god, your state income tax revenue will hardly increase at all. Because you are under a formula an allocation formula. So as production increases in the future and as the value of Prudhoe oil goes up in the future the burden, the relative burden of Alaska taxation as things now stand becomes less.

Q: RADAR: I'm interested in your observation as to the statement we the federal government is going to expect Alaska to participate in the financing of an Alcan pipeline and the federal government in no circumstance is going to participate. I don't know that, and I understand that some federal people

will be up here in a couple of weeks to talk about that very thing. I'm a little bit uneasy as to what our posture is and what our maneuvering room is against what their maneuvering room is.

LIPTON: I recently returned form Alberta, Edmundton, where we are also consultants. The question of financing the gas line of course has been raised in Alberta as well as in the State of Alaska. I find it of double interest because while the pipelines were competing for authorization the promotors were very hush hush about requiring outside financing and everything. Once the competition was over and the realities begin to emerge and one begins to worry about who's going to do the financing and whether the province of Alberta should take an equity interest or whether the State of Alaska should lend money or whether the State of Alaska should in a sense guarantee the bonds so the rate of interest will be lower. I don't know how many different roles the state of Alaska can be cast. It's already been, with respect to the oil and gas industry, cast in the role of a soverign power. It's already cast in a role of a land owner, and now it's going to be cast in the role of a money lender. I just don't know the answer. This comes down in the end to very pragmatic consideration. What are the realities of financing as they are presented to you? What is the state's interest in pursuing this? How far should the state go?

Q: RADAR: What do you think promoted the Federal government to take the position that it was reasonable for the state to finance or participate in the financing but unreasonable for the federal government to participate.

LIPTON: That's what they said to the city of New York.

Q: RADAR: New York was asking for something, we're not asking for anything.

LIPTON: No. They're saying that these are problems internal to Alaska and we should not take the responsibility for it. That is a bad analogy. But this a subject

one can address themselves to a lot better after one knows what the real circumstances are. I don't know that the Federal government in the end will not play in some kind of a role in the financing of the gas line. An awful lot depends on the extent in which the federal government wants (1) the gasline built by a certain date, (2) is convinced that private financing either is not available, which is unlikely, but is available at onerous interest rates. Therefore what role should the government, any government whether it federal, state or provincial. I think it is a little too early because so far I suspect that what we are hearing are the protestations of the party of the first part. That is to say the people who are involved in the financing.

Q: RADAR: When do you expect when the federal government will reach an agreement on the price, set a price, April - May?

LIPTON: This Spring or early this Summer I would suspect it has to be done. Even if the least optimistic time schedule or authorization, financing, construction, design and construction of the gas line has been met, the pricing policy is basic to almost any other decision that can be made.

Q: RADAR: Well if they expect the state to participate, again I'm thinking about our session and our opportunity to address this problem. Do you think we are likely to have before us the facts that it takes to intelligently address this problem if we were to adjourn in June, what's your best estimate on that?

LIPTON: I would doubt very much if you'll have all the facts, but I think you may have, the first thing I think you have to listen to more than anything else is just what the facts along this line are going to be, what are now the alternatives to the companies involved in the construction line. How do they see their own alternatives. What is the Federal Government realistically thinking about. I don't think the Federal Government is

actually asking the state of Alaska to undertake any of the responsiblity, I'm sure of that at all. The Federal Government may be simply saying to the people building this pipeline, "Look, you go ahead. These are the authorizations - these are the rules of the game. Now you go where can in terms of equity in terms of debt capital and in terms of the government entities that are involved. Really, which is basically the state of Alaska, the Province of Alberta, the Federal government of Canada to a certain extent, even the problems of British Columbia. I doubt if you'll have all the facts, but you'll probably have alot more."

SUMMARY OF MILTON LIPTON TESTIMONY
BEFORE THE SENATE RESOURCES COMMITTEE
January 25, 1978

Prepared by REED STOOPS
Senate Resources Staff Assistant

Tax Deficiency

Milton Lipton initiated his presentation by illustrating a deficiency in Alaska's present corporate income tax statutes. According to the Andersen Report, the total net income accruing to the four major oil companies over a 25 year period from Prudhoe Bay production and TAPS transportation will be $37 billion. Current methods of apportionment would only subject $16 billion to state income tax. At a taxation rate of 9.4% that means $1.5 billion in income tax revenues under current law as opposed to $3.5 billion if the entire net profits were subject to state income tax.

Alternative Approaches

Three alternative approaches to correct the "deficiency" discussed were the oil and gas corporate franchise tax (CS HB 322) which redefines corporate income and changes the apportionment formula, a method of "separate accounting" (SCS CS HB 322) for the oil and gas industry, and maintenance of the status quo.

Andersen Report

He then offered the following comments on the Arthur Andersen Report, a comparative state tax burden study, prepared at the request of the Alaska Oil and Gas Association:

(1) The report is highly professional, accurate, and conclusions relevant "as measured by the technique used...". The Alaska tax burden is higher than the other seven states analyzed, but only as the tax law relates to Prudhoe Bay.

(2) The other states used in the comparison are different from Alaska in that the industry here is concentrated heavily in production and transportion and we lack the economic and industrial diversity present in the other states.

(3) Whether or not the tax is "unduly burdensome" to the industry is not solely determined by relative rates of taxation, but by whether the tax structure "militates against investment." "...so far, there is in fact no indication that this is the case."

Severance Tax

The income tax also should be placed in perspective amongst other types of taxation imposed by the state. The severance tax, applied to gross revenues from oil production, under current law is graduated and differentiates between fields with the same gross revenue but different producing characteristics. Therefore, Alaska has a high peak tax on highly productive wells, but also a uniquely low tax rate on marginal wells. As Prudhoe wells produce on the average of 5-7,000 barrels a day, the tax rate is high. On Cook Inlet, the tax rate is relatively low.

Continuity of Tax Policy

He notes that the income tax is the least "onerous" to the industry as it effects investments. But the state should guard against creating a perception that its tax policies on oil and gas are subject to continual change as our budgetary needs change. Continuity of the tax regime is very important to investment decisions by the industry. Therefore any change in the income tax should be done only in the context of a long term policy which creates greater stability in Alaska's severance and ad valorem tax policy.

Apportionment Deviation

Before comparing the House and Senate approaches, Lipton briefly discussed the argument that deviation from the current method of apportionment will lead to inequities or double taxation. Of 44 states with corporate income taxes, 4 already use variations of the standard apportionment formula, and 2 use forms of separate accounting. These deviations relate to differences in the economic and industrial structure of the states, as is true in Alaska.

Senate version (SCS CS HB 322)

Advantages

Separate Accounting

(1) Gives Alaska a direct determination of income generated by oil and gas operations by taking only revenue generated in state.

(2) Gives the state data on profitability of the industry useful in future review of oil and gas taxation policies.

(3) Will increase revenue to the state, especially where wellhead prices increase (Note: this may be an advantage or disadvantage with respect to the House version. Revenues may also decrease if wellhead prices decrease.)

(4) Should create greater equity amongst oil and gas taxpayers operating in Alaska, (Note: Andersen Report shows differing tax liabilities between Exxon and ARCO based on comparable revenues.).

Disadvantages

(1) Administration difficulties
  (a) determination of expenses allows for discretion by industry

  (b) determination of base value of oil before deductions. problems may be created by depressed prices caused by price control, marketability, etc.

House version (CS HB 322)

Advantages

(1) Changes definition of corporate income to include either book income (income reported to stockholder) or Federal taxable income, whichever is higher. Gives the state a higher base upon which to tax.

Redefinition of Apportionment

(2) Substitutes an extraction factor for the sales destination factor in the apportionment formula - will increase revenue to the state as a production factor is much higher than a sales factor in Alaska.

(3) Incorporates OCS into the formula when it is served by a land base in Alaska. (Note: possible legal complications).

(4) Revenues are somewhat isolated from conditions in Alaska as the tax is based partially on world-wide performance of the industry. (This may be an advantage or disadvantage depending upon future wellhead prices).

Disadvantages

(1) Administrative difficulties

(a) hard to ascertain world-wide production of oil when complex foreign contracts exist

(b) verification of book and federal taxable income reported by industry.

Major points in conclusion:

Summary Points

Either bill would increase the state's corporate income tax revenue.

Both bills involve administrative difficulties, but neither is insurmountable.

Separate accounting provides "a direct fix on income generated by operations within the state" and has value beyond the tax.

The House version isolates Alaska from uncertainties of income generated only in Alaska by sharing to a degree in world-wide profits. It also attempts to extend tax jurisdiction to Outer Continental Shelf development.

Question and answer session follows (refer to page 24)

TESTIMONY OF

HERMAN LOEB

DIRECTOR OF EXPLORATION ENVIRONMENTAL AFFAIRS

PENNZOIL COMPANY

STATE CAPITOL - STATE OF ALASKA

JUNEAU, ALASKA

February 10, 1978

Members of the Senate Resources Committee: My name is Herman Loeb. I am the Director of Exploration Environmental Affairs for the Pennzoil Company. I live in Houston, Texas.

At the very beginning, let me state that my remarks will not deal with the intricacies of your tax laws or pending legislation except in the most general sense. Instead, I would like to touch on Pennzoil's approach to exploration and factors that influence the spending of exploration dollars by the Company, and most particularly in the State of Alaska. The tax structure of the State is a vital part of this package and will influence the focus of exploration efforts of any company, large or small.

The Pennzoil Company is primarily a natural resources domestic exploration and production company. We are no stranger to the State of Alaska. We drilled two wildcats in 1967 and 1968 in the Lower Cook Inlet on State leases (Strichikoff Area), and in 1969 opened an exploration office in Anchorage. I have a personal stake in this dialogue because in 1969 I had the assignment of establishing the exploration office in Anchorage. We built a home, the whole bit, and were fortunate enough to be able to stay in the State until 1973.

As a working geologist, I rapidly became aware of the tremendous potential for oil & gas in the State. The number of undrilled, unexplored sedimentary basins was and still is unbelievable. I had worked older known geological areas in West Texas, the Rocky Mountains, South Texas, and South Louisiana where the idea of an undrilled basin was unheard of and didn't exist.

Pennzoil was not alone in its awareness of this oil & gas potential in the State. Many smaller exploration-minded companies

and independents were ready to move their people to Anchorage. This Committee knows the next verse---it is simply as it was--- the "land freeze". First, Udall, then Hickel, then Morton. Spice that with passage of the Native Claims Act, approval of the pipeline, and the eventual State selection process and you add up to almost a decade of problems. These factors made it impossible for the smaller companies to buy leases, drill wells, or operate.

Some with plans to come North delayed that decision and never came. We came early, but to my extreme personal regret, we left early also in 1973. My family and I hated to leave, but there was no place to make Pennzoil dollars multiply and no sound reason for management to keep an office in Anchorage.

Let me state at this point that there is extreme competition in the industry. We have been busy and successful in operations in the OCS in the Gulf of Mexico. We acquired our first leases in 1970, and to date we have production with our partners that produces approximately 70,000 BOPD and 1 billion cu. ft. of gas per day. We bid with major companies and against them. We like it--we think we can make a "better mouse trap" and we can play the exploration game. However, we must know the rules. It's impossible when the rules change and the tax structure is an integral, important part of the pre-game plan.

Elements of risk are vital in our shop when top management decisions as where to put its people and spend its revenue dollars are made. There is an inherent risk every time we drill a well; first, if we can drill the hole; then if we are fortunate enough to encounter hydrocarbons in commercial quantities; and finally, if we can complete successfully. The calculation of risks and the

overall evaluation of these factors are the heart of any successful exploration effort. The regional geology, the reservoirs, costs to operate, access to locations, availability of suppliers and material, competition both internal and external, and taxes comprise some of the key elements. A stable predictable tax system is necessary to properly evaluate rates of payout and capital requirements.

The most positive approach to a possible remedy to some of the State's revenue needs is to encourage additional exploration. The State could utilize another Prudhoe Bay. You need the smaller companies such as Pennzoil, as well as the larger companies, to drill some of your unexplored sedimentary basins.

The industry exploration dollars are going to be spent in areas where oil & gas leases are available, where lease schedules and terms are clearly defined, and where the elements of risk conducive to ascertainable planning for capital, equipment, and manpower are positive and most of all where a fair, equitable tax climate prevails. These factors we hope will be considered in your approach to tax legislation.

In closing, the industry will initially tend to go where it's wanted, and a stable, fair tax program would undoubtedly provide an impetus to further exploration in the State.

Again, we appreciate the opportunity for comment.

Statement of David S. Mace
Sohio Petroleum Company
before the
Senate Resources Committee
Alaska State Legislature
May 22, 1978

Statement of David S. Mace
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before the
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PART III: ARTICLES ON LEASING

1. M.I.T. Professor John W. Devanney III, "How to Bid for Offshore Rights," Technology Review, February 1976, p. 44.

2. "Alberta Canada: Exploratory Drilling Incentive System," The Landman, March 1978, pp. 18-20.

3. Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977:

   - Gregg K. Erickson, "Work Commitment Bidding"
   - Dale R. Jordan, "Petroleum Leasing in British Columbia"
   - Walter J. Mead, "Cash Bonus Bidding for Mineral Resources"
   - Arlon R. Tussing, "The Role of Public Enterprise"

Statement of David S. Mace
Sohio Petroleum Company
before the
Senate Resources Committee
Alaska State Legislature
May 22, 1978

As Assistant General Manager, I am pleased to have the opportunity to present the views of Sohio Petroleum Company, a Division of Sohio Natural Resources Company, with respect to the House-passed version of H.B. 854.

We strongly feel that the oil and gas leasing bill merits thoughtful study, as its implementation will determine the State's ability to conduct an effective leasing program in the future. Since the industry's ability and willingness to participate in future lease sales will be determined by the manner in which future administrations administer the State's leasing bill, it is vitally important that the provisions contained therein give clear guidance to the Department of Natural Resources (DNR).

Although the House has significantly improved the bill as originally introduced, we feel that there are key provisions that should be further amended. Additionally, we strongly believe that further consideration should be given to the exclusion of several of the proposed bidding methods and to the general concept of experimentation in Alaska's leasing program.

Prior to describing the specific problems we see in H.B. 854, I should like to outline for you why we feel that Alaska should, particularly at this time, pay close attention to energy policy development in general and its leasing program in particular. To put it in a nutshell, world supplies of conventional oil and gas have shrunk and are narrowing rather quickly; the chances of finding another Prudhoe Bay-sized field--anywhere in the U.S.--are next to zero. Thus policy decisions affecting oil and gas are crucial if Alaska is to find and develop her remaining petroleum resources, thereby strengthening the future economic outlook for all Alaskans and the political/economic outlook for the United States.

PART I: AT THE CROSSROADS

THE IMPORTANCE OF OIL AND GAS POLICY DECISIONS

Global Prospects

The Workshop on Alternative Energy Strategies (WAES), a two-year international energy and economic project, directed by the Massachusetts Institute of Technology, recently released their final report which indicated that:

(1) All energy resources and conservation measures must be developed vigorously to meet total projected demand in the period 1985 - 2000; and

(2) Energy policy decisions made now will be the critical determinants as to whether or not sufficient incremental supplies will be available to meet demand in the years ahead.

In other words; according to the WAES Report:

> The years up to 1985 are critical ones...We are...on the threshhold of a critical decision period. We cannot afford to waste the years immediately ahead if we are to have any large-scale energy options available before the end of the century. The time for decisive action is now. 1/

In this environment, the importance of the Federal and State petroleum leasing programs affecting Alaska cannot and must not be underestimated. Whether or not Alaska's oil and gas resources can and will be developed will be an important factor not only for Alaska but also for the United States as a determinant in the future global energy, economic and political balance. The critical nature of energy decision-making at this time is further underscored by the following conclusions stated in the WAES Report:

1/ ENERGY:GLOBAL PROSPECTS, 1985-2000, Report of the Workshop on Alternative Energy Strategies, M.I.T. Professor Carroll L. Wilson, Project Director McGraw-Hill Book Company, San Francisco, 1977.

(1) The supply of oil will fail to meet increasing demand before the year 2000, most probably between 1985 and 1995...(p.3)

(2) Demand for energy will continue to grow even if governments adopt vigorous policies to conserve energy...(p. 4)

(3) The continued growth of energy demand requires that energy resources be developed with the utmost vigor...(p.4)

(4) Even if there are no governmental constraints on oil production, oil supply will meet demand only under the most optimistic assumptions about gross additions to reserves...(p.145)

(5) Possible constraints on oil production by members of OPEC are likely to cause oil supply to peak at the latest some-time around 1990 although lower production limits could bring this date forward into the early 1980's...(p.145)

(6) All the effort put into oil exploration around the world over the past one hundred years has only yielded 240 large oil fields...(p.123)

(7) With only a small chance of either discovering a new Middle East or discoveries in the Middle East as large as in the past, the past rate of genuine new discoveries can only be achieved if a large number of smaller producing areas are found. (p.122)

(8) Given lead times of 5-10 years or more for many projects, failure to make necessary near-term commitments or to resolve a variety of current restraints on production, or to develop future supplies may foreclose some options for 1985. (p.265)

(9) Failure to recognize the importance and validity of these findings and to take appropriate and timely action will almost certainly result in a world different from the one on which these projections have been based. (p.5)

(10) Failure to act could lead to substantially higher energy prices as the supply/demand imbalance becomes more apparent with the consequent frustration of the aspirations of the less developed countries. The major political and social difficulties that might arise could cause energy to become a focus for confrontation and conflict. (p.5)

(11) The longer the world delays facing this issue the more serious the outcome will be. Even with prompt action the margin between success and failure in the 1985-2000 period is slim. Time has become one of the most precious of our resources. (p.5) 2/ (Emphasis added)

2/ Ibid., pages as indicated above.

Another important point in the Report relates to the size of future oil fields. Worldwide, over 30,000 oil fields have been discovered, but about 75 percent of the oil lies within 240 large fields, each with over 500 million barrels of recoverable reserves. 3/

Out of the tens of thousands of producing oil fields in North America, there are only five fields that have recoverable reserves of more than 500 million barrels (Prudhoe Bay, which is new; and Elk Hills and Wilmington in California, and East Texas and Yates in Texas, all of which are old fields). Despite a great deal of exploration in North America, there has been no recent discoveries of fields more than 500 million barrels, except Prudhoe Bay. In other words, the probabilities of finding large new fields on the order of Prudhoe Bay has significantly diminished, not only globally, but also in the United States.

The WAES Report also makes clear that in certain environments, such as the North Sea, a 500 million barrel field is at the economic margin. 4/ Because of the particularly harsh environment in Alaska's North Slope, and elsewhere in the unexplored part of the State, a field that may contain even more than 500 million barrels of oil could be right on the edge of economic viability in Alaska, given the uniquely high costs and transportation difficulties.

While all of the above has critical implications both for the United States and Alaska, there are yet another set of reasons why we believe that the designing of the future oil and gas leasing program in Alaska deserves serious and careful consideration.

3/ Ibid., p. 123

4/ Ibid.

Alaskan Petroleum Outlook

In a sense, the State of Alaska is facing on a smaller scale some of the same problems described earlier on a global scale. Whereas world oil production may begin to decline in about seven years, Prudhoe Bay will begin to decline within the decade. This fact has important implications to all Alaskans and, in view of the revenue needs of the State, it would appear to be critically important for the State to ensure and encourage a steady, strong and ongoing oil and gas development program in Alaska. But the historic rate of genuine new discoveries can only be achieved worldwide if a large number of small producing areas are found. Likewise, the future of petroleum discoveries in Alaska will most probably involve smaller fields which will be more costly to develop.

As previously noted, the possibility of finding another Prudhoe Bay-sized field in Alaska--or anywhere--is extremely remote. Further, because of the very high costs of operating in much of Alaska, the size of a discovery must be larger here than it need be in other states to make the project economic. Even the Lisburne and Kuparuk oil pools, which according to State estimate range in potential from one to two billion barrels, may be marginally economic and typical of many future oil and/or gas finds in Alaska. All this tends to suggest that Alaska needs to pay closer attention to the development of her resource policy than a state like Louisiana, for example.

Some have argued that Alaska might be better off 'sitting on' her potential oil and gas resources and waiting for the world oil price to rise even further. Dr. Arlon Tussing, an Alaskan economist advisor to the Senate Energy Committee, considers this attitude, "simplistic" and "naive".

In real terms, world oil prices may stabilize as a result of a prolonged period of relatively low economic growth which would result in lower growth rates for energy consumption than is generally projected. Additionally, as global attention is increasingly focused on energy, the drive to conserve energy and to develop heavier oils, such as Athabascan tar sands, Rocky Mountain oil shale and Orinoco tar belt--and substitutes for conventional oil and gas--will increase. Again, to quote Dr. Tussing, "if you choose to 'sit on' your oil and the decision was wrong, the resultant imbalances could be serious."

A final serious consideration for Alaska relates to a realistic assessment of the future revenue needs of the State. Projections indicate that Alaska's revenue problems in future years require a significant expansion of petroleum exploration and development activity now so that new sources of revenue will be available as Prudhoe Bay declines. This is an especially critical consideration in view of the long lead times involved in exploration and production in the frontier areas of Alaska. In some areas, it can take a decade to find, prove up and begin to develop a field, and transportation problems can be enormously complex, causing further delays.

Implications

Being at the economic/energy crossroads globally -- and in Alaska -- would seem to suggest that it is of vital importance to the State to (1) carefully delineate its goals with respect to a new oil and gas leasing bill and (2) ensure that the proposed legislation, in its implementation, will achieve the desired goals outlined in the legislation. With this in mind, I would like to address some of the specific, critical problems we foresee if H.B. 854 were to be implemented in its current version. Additional, I would like to present some of the experts' views with respect to several broad issues raised by the draft legislation.

PART II: CRITICAL CONCERNS WITH H.B. 854

Bidding Methods - Experimentation

No one knows how beneficial experimentation in bidding methods will be. The U. S. Government tried royalty bidding on ten tracts in an October 1974 lease sale with questionable results. It appears that neither the industry participants nor government officials found the experiment to be particularly successful.

According to The Oil and Gas Journal, "operators say they doubt royalty bidding will ever surface again except in areas where production is almost certain or possibly in drainage-tract sales. Development of wildcat acreage can prove too costly on a royalty bid basis, despite the absence of high front-end expenditures normally budgeted under the traditional bonus-bid system." 5/

Similarly, Energy Secretary Schlesinger appeared to be disenchanted with the royalty bidding experience in Louisiana in that, in a letter to Interior Department Secretary Andrus, Schlesinger apparently stated that the Department of Energy has reservations about the effectiveness of the royalty method based on past experience in the Gulf of Mexico. It appears in fact that Schlesinger raised the same objections to the royalty system as had been raised by industry and formerly by officials in the Department of Interior, i.e., that royalty bidding leads to early abandonment of leases because declining production eventually makes the lease unprofitable under a high royalty arrangement.

5/ Mike Long, "Royalty-bidding experiment turns sour," Oil and Gas Journal, May 2, 1977, p.3[illegible].

Significantly, the Department of Energy and the Interior Department are considering the formation of a task force of experts to help analyze pros and cons of the various systems being proposed in the Federal legislation (which were largely copied in H.B. 854). Apparently, there is considerable disagreement between the two agencies as to the merit of the sliding scale royalty systems used in the last two lease sales, as well as to the efficacy of using other bidding methods. A key problem in forming a task force seems to be a dearth of real experts, however, in that few governments have undertaken experiments in bidding practices long enough or in a manner similar enough as that envisioned in the proposed Federal and State legislation, and to paraphrase Dr. Arlon Tussing's comments: scholarly, empirical analysis of the different bidding systems appears to be 'remarkably skimpy.'

One source document appears to be quite useful, however. Published by the British Columbia Institute for Economic Policy Analysis, Mineral Leasing as an Instrument of Public Policy, contains articles by an international and interdisciplinary group of economists, mining engineers, businessmen and industry consultants. In an introductory section, Dr. Mason Gaffney describes the report as "an outstanding contribution to a rapidly growing field of study."

Our greatest concern with the proposed legislation is reflected in many of the articles in the British Columbia Institute's report. The publication cites significant problems with many of the bidding systems proposed in H.B. 854. Since each new system is so experimental, the likelihood of the Alaska's experiments not succeeding is high. An additional concern is that it would be years before the success or lack of success with a given system can be determined.

An example of our concern relates to the use of royalty bidding. Dr. Arlon Tussing, Dr. Walter Meade and others (including now Energy Secretary Schlesinger) have raised objections to royalty bidding for a variety of reasons. In the Report, Professor Hayne E. Leland, University of California at Berkeley, echoes some of their concerns and ours:

> "Competitive bidding theory makes clear that undesirable consequences may follow from royalty or profit share bidding. If there are no bonus payments required, speculative bidding may lead to extremely high royalties or profit shares being bid, with development occuring only in the most favorable circumstances. This happens because firms have little or nothing to lose by bidding high and then failing to explore or develop..." 6/ (Emphasis added)

Gregg Erickson, a well-known Alaskan economist, in his article on "Work Commitment Bidding," suggests that the problems associated with royalty bidding are well known:

> "The problems created by royalty bidding, principally the premature shutdown effect and the potential for speculator induced misallocation of leases, have been well discussed in the literature. More importantly, they are well understood by persons influencing both public and private mineral resource policies". 7/ (Emphasis added)

Yet, it is not clear to us that royalty bidding problems are well understood by the officials who will guide the Department of Natural Resources in leasing decisions in the next few critical years or in the future.

A specific example of why we are concerned relates to the material prepared by the Department of Natural Resources to accompany H.B. 854, entitled "Two Views on Bidding Strategies." Not only are the numerous problems and dangers of royalty bidding (cited by Meade, Erickson and others in the University of British Columbia Report) not even mentioned,

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6/ Hayne Leland, "Comment," British Columbia Institute Report, p.60

7/ Gregg Erickson, "Work Commitment Bidding," Ibid., p.61.

but also, after three short descriptive phrases under the heading "Royalty Bid-Fixed Bonus," the Department of Natural Resources, with no further comment, analysis, or explanation, simply states: "The Beaufort Sale is an ideal candidate for a royalty bidding scheme." (Emphasis added)

We view such remarks by the State Administration with concern. As indicated previously, many who have taken the time to study the various proposed bidding methods in depth list extensive problems with various schemes for royalty bidding (see also Part 3) and, would hesitate to use royalty bidding schemes of any sort except in drainage sales or where there are known, proven reserves (as mentioned above in the Leland citation). The Beaufort Sea is believed to have a high potential for discovery, but, as in the Gulf of Alaska, the drilling of wells may result in no discoveries, or discoveries of marginal fields. No discoveries - with royalty bidding - means no income for the State of Alaska. And, as royalty bidding adds risk for the State, another quote from Leland is perhaps appropriate here:

> "Note that if the lessor is such that leasing forms a substantial fraction of its revenue (for example the State of Alaska), it may not be optimal to transfer risk from firms to the lessor. Thus, lease contracts which might be appropriate to the federal government may not be appropriate for regional governments". 8/ (Emphasis added)

Future administrations working with the proposed leasing statutes may have multiple choices of bidding methods available to them. We feel it important to stress that we concur both with Mason Gaffney and Gregg Erickson as to where the burden of justification of such decisions should lie, i.e., with those who would change the current system of cash bonus bidding. In this regard, we believe we are safe in assuming that Gregg Erickson's

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8/ Leland, op cit., p.60.

statement below with respect to the work commitment bidding system would apply to any new proposed bidding system:

> "The adoption of a work commitment bidding system implies a judgment that existing institutions for private exploration of public resources result in a suboptimal rate of resource development.
>
> Any argument for the adoption of such a system must first establish that this is in fact the case..." 9/

Similarly, though in a more general way, Mason Gaffney warns:

> "To serve his citizens best, the statesman should...resist the temptation to use his power to manipulate and control...on the too easy presumption that the market has no rationale or normative value of its own. Generations of economists have established that it has, and governments seeking to improve on it need face a certain burden of proof." 10/

One final point: The effects of the cash bonus bidding method, though not perfect, have been rigorously scrutinized, with over 20 years of experience as a basis for analysis. And, according to Professor Mead's extensive studies related to the results of 35 oil and gas lease sales during the period November 1954 to May 29, 1974, bonus bidding with a fixed royalty is effective:

> "On the basis of this evidence, we conclude that competitive bidding for oil and gas leases is sufficiently strong to protect the public interest in obtaining competitive values for its oil and gas resources. This conclusion is further supported by evidence presented above indicating an increase in the average number of bidders and a substantial increase in the average price bid per acre for oil and gas leases". 11/

Thus, it is our judgment that, although in certain, special circumstances, changes in the bidding approach may be advantagous to the State, several factors should be remembered. First, the State currently depends on the petroleum production, some for 70 percent of its revenue, most of which is from a field that will begin to decline in about seven years. New exploration in Alaska is vitally needed.

9/ Erickson, op cit., p.75.

10/ Gaffney, op cit., p.3.

11/ Mead, op cit., p.55.

Second, although oil companies by the nature of their business deal daily in risk and uncertainty, there is no question but that, to the extent the State can reduce uncertainty and foster confidence with regard to the use of new bidding systems, oil and gas exploration will be encouraged.

Third, because the new systems are experimental, we would suggest that the burden of proof for adopting a new system for any lease sale be placed on the Department of Natural Resources because the use of any new system involves greater risks and uncertainty not only for the companies but also for the State.

Lease Terms (a) and (z)

As currently proposed in H.B. 854 the lease stipulations include a normal lease life of five years duration; leases can only be prolonged to ten years in areas where environmental conditions severely restrict operations. It is our understanding from testimony given to the House Resources Committee by personnel of DNR that severely restrictive environmental conditions are interpreted to include moving ice zones in the Beaufort Sea, but not onshore conditions on the North Slope. As this latter area can only be explored by winter operations, a five year lease would only allow 1-2/3 years of exploration time. From a practical standpoint this is not sufficient, and such a restriction would make it physically impossible for an operator to explore a reasonable number of leases.

The cost of exploratory wells in environmentally difficult areas of Alaska, both onshore and offshore, can now be expected to exceed 10 million dollars and sometimes reach 20 million dollars per well. With such large amounts of money involved, exploratory wells are high risk ventures which must be very carefully planned to obtain the greatest return, not only in oil and gas discovered, but also in geological data obtained. Consequently, a company's exploratory program on Alaskan leases must be systematic and careful and can no longer follow the philosophy of "wildcatting." Such a logical approach cannot be rushed in its implementation, and the restriction of leases to a five year term would inevitably result in many leases not receiving the exploratory attention they might deserve. They would be relinquished without having been drilled, and would therefore diminish in value due to their apparent unimportance to the lessee with consequent loss to the State.

To counteract this situation, and allow operators to assess the true value of their landholdings, we are proposing that the normal term of a lease should be ten years, except in those areas where the Commissioner determines that environmental and economic restrictions on operations are not a factor. Since many of the future lease sales will be in hostile environmental areas, it is in the State's interest, we feel, to ensure that sufficient time is permitted for a proper evaluation of the lease areas.

Furthermore, we feel that the bill should specify that, prior to the lease sale, in the tract terms, the State will provide specific information related to provision (z), i.e., the percentages of oil and gas that the State intends to require for in-state use. Otherwise, it becomes impossible realistically to bid on the proposed tracts.

Joint Bidding - Its Effect on Competition (y)

Much has been said in recent years about the competitiveness or lack of competition in oil and gas exploration and development. Concern has risen particularly with respect to joint ventures in general and joint bidding in particular. Although the formation of joint venture groups for lease sale bidding facilitates ease of entry in high-risk ventures, and allows producers to spread their financial investments in an effort to minimize overall risks, the sheer numbers of joint ventures have been interpreted by some as 'fostering something other than competition'.

The two theories about the nature of joint bidding in Federal lease sales (collusive vs. risk-sharing purposes) have been tested by University of North Carolina Professor Edward Erickson and M.I.T. Professor Robert Spann. As they reported in testimony before the U.S. Senate Commerce Committee, the observed patterns of bidding partnerships are most consistent with the hypothesis that joint bidding is a means of risk-sharing, not collusion. 12/ Among the ways in which competition might be fostered rather than reduced by joint arrangements are the following:

Because risks are shared, the cost of capital per unit of supply increment is less, so that entry barriers are lowered in high risk ventures;

Because of joint agreements, smaller independents can and do form independent and successful groups for bidding purposes in Federal lease sales, as evidenced by data on successful bidders in the June 1973 Federal lease sale;

12/ In their study of the 1972 and 1973 Federal offshore lease sales, Erickson and Spann found that membership of bidding groups varies from year to year; market shares for members fluctuate from one year to the next; the most frequent bidding group is a combination of majors and smaller firms, but majors bid alone, as do smaller firms; single firm bids are frequently made by the largest firms, but other firms are also successful single firm bidders, and bidding groups which contain a large number of firms are predominantly composed of smaller firms. They also conclude that the incidence of joint bidding increased as the size of the firm decreased; there was a heavy incidence of joint bidding partnerships between unlike firms; smaller firms use joint bidding ventures as a vehicle for entry into offshore activity. "Competition in the Field Markets for New Natural Gas Supplies," Statement before the Senate Commerce Committee, November 8, 1973.

Because of the number of large and small producer combinations and the frequency with which new groups are formed with different members, producers are able to become involved in many projects so that competition is spread through many projects.

Since joint operating agreements also expressly provide for separate marketing of production from joint ventures, it would appear safe to conclude that risk-sharing through joint ventures need not make competition less intense. By facilitating ease of entry, joint ventures by domestic petroleum companies may indeed make competition more intense. 13/

The work of Professor Mead tends to underscore the findings of Erickson and Spann:

> "The most conclusive test of the workability of cash bonus bidding based on the United States record of OCS oil and gas lease sales is in terms of the rate of return on capital earned by the successful bidders. An analysis has been made on 184 offshore Louisiana oil and gas tracts leased in 1954 and 1955. Precise data are available on bonus payments, rental payments, oil and gas royalty payments, and production of oil and gas during the period from 1954 through 1967. Cost estimates were made for exploration, well drilling and equipment, and operation. Annual cost and annual wellhead values were discounted to obtain a net internal rate of return. The calculations indicate that these early OCS leases generated a 7.5 per cent before tax rate of return to the lessees. Given the fact that oil companies pay relative low U.S. income tax rates, the after tax rate of return would be only modestly lower than the 7.5 per cent before tax rate of return. This net yield clearly does not reflect monopoly power; it shows an excessive degree of competition". 14/ (Emphasis added).

In fact, two studies conducted under the auspices of the United States Geological Survey (both authored jointly by Dougherty of the University of Southern California and Lorenz of the U.S.G.S.) have indicated that the restriction of joint-bidding has failed to achieve its objectives in Federal OCS lease sales.

13/ In the last analysis, if the formation of such groups constituted monopoly power, one would expect to see some results where such groups are formed, e.g., a non-random bid price pattern in Federal lease sales.

14/ Mead, op. cit., p.55.

Major conclusions were:

1. The ban of joint-bidding by major oil companies may in fact have acted to broaden the overall influence of major companies in a given sale. The percentage of all bids and the number of bids per lease in which a major oil company was involved actually increased, which in turn may have increased the total amount of acreage in which major companies participated during this period.

2. When the U.S.G.S studies compared solo bids to joint-bids on given tracts, it was concluded that the joint-bidders tended to go after more highly sought-after leases and that they tended to bid higher on the average than sole-bidding competitors.

From a practical standpoint, allowing joint-bidding has important advantages to the State as well as to the industry, in terms of overall economic efficiency, environmental effects of exploration activity, and flexibility.

For example: Often, a given company may have a great deal of geologic and geophysical data in an area, but for one reason or another does not have the cash on hand to fully utilize its data in a competitive-bonus sale. In this kind of situation, it would make sense to join with another company that has the necessary investment capital and does not have the data.

If the two were unable to combine in partnership, a situation could develop where one company had to duplicate seismic and geologic information already held by the other company. Ironically, a situation would then develop where overall competition in the sale would be reduced, because one company with cash reserves would have expended part of its funds in gaining data, while the other company with information would be limited in participation

because of its cash limitations. Also, there would be the obvious environmental effect of the increased seismic and other activity, including, possibly, the drilling of wells, that would go along with the need to gain additional data.

In view of all of the above, it is very doubtful that joint bidding will adversely affect competition, and it is more likely to enhance competition and result in financial advantages to the State as well as oil companies. In this instance, the Federal Governments stance on restricting joint bidding appears to be counter-productive, and it is not in the State of Alaska's best interest to follow that lead.

Minimum Work Commitments (h)

The current language of H.B. 854 permits the Commissioner to impose a minimum work commitment on a lessee. The only reasons we can deduce for including the provision is to overcome the problems inherent in royalty and net profit bidding procedures. Both these methods inadvertently encourage a lessee to sit on a lease as long as possible without carrying out any work, because the lessee has no meaningful financial involvement in the lease. Consequently, under royalty or net profit bidding, the leaseholder will tend to prefer to 'sit on' the lease in the hope that neighboring leaseholders will, by their efforts, help indicate the true potential of the lease. Conversely, minumum work commitments are not necessary on leases won with a cash bonus bid because the lessee has an obvious financial incentive to produce a profit from his cash investment in the lease as soon as possible.

No responsible bidding company will bid on a lease which it thinks is devoid of prospects unless the bidding method imposes no appeciable risk or financial outlay to the company. Under these circumstances, i.e., when royalty or net profit bidding are used, the company has an inducement to try to obtain the acreage because of the slim chance that its assessment of the poor potential of the land is wrong. To prevent the company from doing nothing with this lease, the Commissioner has to impose a work commitment on it. But if the lessee views the lease prospects as negligible, the lessee will expend money for exploration only up to the amount equal to the work commitment imposed by the State.

The question arises: is this result in the State's best interest? Instead of obtaining maximum exploration on tracts with maximum potential,

the State, under royalty and net profits bidding, will encourage, through work commitments, capital outlays on tracts with minimum potential. And the capital outlays will most likely be a waste of dollars, producing no ultimate gain for the State.

If the cash bonus bidding system is not utilized on a particular lease, however, the level of fixed cash bonus imposed with the bidding system chosen can be made sufficiently large to ensure adequate and prompt exploration. Thus, we recommend that (h) be deleted from H.B. 854.

Data Acquisition by the State

While we understand the State's desire to know more about the potential oil and gas resources underlying State lands, we would reiterate what we and other companies have previously stated: obtaining more data from the companies does not necessarily put the State in a better position to evaluate potential resources. In fact the opposite could be true; government officials, looking at company data, might well understate the potential value of proposed lease acreage because of the general conservative nature of a government compared with, for example, the daringness of one Company geologist willing to stake his professional career on his interpretation of exploratory data. It could also be argued that the very nature of a large government agency makes it easier to hide errors of judgment whereas the company which decides to "go" on a project can hold specific employees more accountable for errors of judgment. But the most important fact to remember is that regardless of how much data the State may obtain, the State will never know what it does or does not have unless the State drills.

Since you may not wish to simply take a company's word for it, the following quotation is presented to underscore the importance of drilling as a means of obtaining useful information and to highlight the relative lack of usefulness of data without drilling. This excerpt is from the writings of an acknowledged expert in leasing policy, Professor Walter Meade, University of Southern California at Santa Barbara:

> "...while the technology for oil exploration prior to the drilling has been advanced in the last century, exploration is still subject to extemely high risk. Drilling is the only definitive test to determine the presence of oil or gas. Thus, bonus bids must be submitted by bidders and accepted or rejected by the government when neither the buyer nor the seller knows whether and in what quantities oil is present..." 15/ (Emphasis added)

15/ Mead, op. cit., p.51.

It would seem obvious, therefore, that if the companies -- with all their data and experience -- don't know at the time of a lease sale whether they've just spent millions for the right to put millions more into drilling potentially dry holes, then the government, with the same data, could hardly be better off. And having all the data of all the companies doesn't necessarily lower the risk of error for the government in that the view supported by most of the data of most of the companies (data that might suggest that "Tract 20" is worthless, for example) could be wrong.

Because more is not necessarily better in the exploration data game, many companies do in fact view data acquisition by the government as the first step which will inevitably lead -- and naturally extend to -- the establishment of government drilling corporations. And, as previously noted, Dr. Arlon Tussing does not view "governmental ownership of producing operations" as "the most effective way of accomplishing the social ends for which it is currently being advocated..." 16/

Additionally, Dale R. Jordan details some of the more severe problems of esblishing government drilling corporations:

> "...This article's purpose is not to examine the political repercussions that might occur when dry holes are drilled with public funds; however, we should examine some of the practical considerations involved in the operation of a public company which has an almost exclusive area within which to explore as a result of discouraging the private sector. For the government to discourage both the existing explorer and the entry of any new ones and to expect the public corporation to be able to fill this void suggests that the government is saying, "if the private companies do it, so can we."

16/ M. Crommelin and A. Thompson, "Introduction," Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977, p.xvi.

Now remember that the private companies comprise all the oil and gas explorers working in the province and those contemplating doing so, given the right opportunities. All these companies have geological staffs, many of who will be geologists who devote most of their time over a considerable number of years entirely to the study of British Columbia's geology. The public corporation could not expect to have such an extensive source of expertise as that available in the free enterprise system. And so the public corporation would suffer from a reduction in the number of ideas generated.

It is not unusual in oil and gas exploration, with its inherent problem of scientific interpretation and evaluation of geological prospects, to find that one company will acquire a block of land, will explore it, and perhaps even drill on it before deciding the search is unsuccessful. The company will then return the land to its owner, the Crown. This does not mean that there are not any commercial hydrocarbons underlying this land; but rather that that particular company was unable to find them. To find these hydrocarbon deposits, a second, a third, or a fourth company should acquire this land, and, if this is done often enough, the hydrocarbon will be encountered, and production will follow. The problem with the public company being the only explorer in the province is that, unless it is fortunate enough to make the initial discovery, it is very doubtful whether there would be enough enthusiasm to have a second, third or perhaps even a fourth try at that particular prospect, with the result that the discovery would not be made. This is surely the worst thing that could happen and is probably the most damning argument against a public corporation moving into an area with an almost exclusive right to explore. 17/

17/ Dale R. Jordon, "Petroleum Leasing in British Columbia," Ibid., pp. 252-253

SUMMARY AND CONCLUSIONS

In summary, we would offer these observations and conclusions:

1. H.B.854, as currently drafted, would create a State leasing system containing many experimental procedures that are new and untried in Alaska. This may not be in the State's interest, because unusual leasing systems could lead to delays in petroleum development that could have serious consequences on future State revenues and Alaska's contribution toward U.S. energy needs.

2. The State's future revenue problems should not be underestimated. The State of Alaska may face an extremely serious revenue situation in the late 1980's as oil production from the Prudhoe Bay field begins to decline. The long lead-times needed to find and develop new Alaskan oil discoveries would indicate that exploration must expand rapidly on State lands to provide needed petroleum revenues for the future.

3. Alternative bidding systems proposed in H.B. 854, although also proposed in OCS legislation now pending in Congress, have not had extensive use in the U.S., nor in very many other places in the world. Experience with royalty bidding in Federal OCS sales has apparently been dissappointing, and the Federal government is giving serious attention to the use of alternate bidding systems.

4. The majority of academic literature that we have been able to find supports the thesis that the traditional bidding methods have worked well in the leasing of public lands for petroleum development. Academic experts also seem to agree that alternative bidding systems present serious problems, except when used in certain special situations.

5. The bill must be clarified where judgmental factors in its administration are critical to the success of the leasing program. The life span of a lease in years must be compatible with the extreme environmental and economic constraints placed on exploration activity in Alaska. To underestimate those constraints will result in unacceptably short lease terms, with a consequent reduction in exploratory work carried out on the leases. A decrease in exploration leads directly to a reduction in discoveries, production and State revenues.

6. Section (2) needs to be clarified in that, as currently drafted, the financing of exploration ventures based on a commitment of future production, would be impossible.

7. Work commitments are not as effective as higher bonus bids in encouraging prompt exploration of worthwhile leases, as work commitments, particularly in conjunction with royalty bidding schemes, work against the State's best interests in developing promising acreage.

PART III: ARTICLES ON LEASING

1. M.I.T. Professor John W. Devanney III, "How to Bid for Offshore Rights," Technology Review, February 1976, p. 44.

2. "Alberta, Canada: Exploratory Drilling Incentive System," The Landman, March 1978, pp. 18-20.

3. Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977:

   - Gregg K. Erickson, "Work Commitment Bidding"
   - Dale R. Jordan, "Petroleum Leasing in British Columbia"
   - Walter J. Mead, "Cash Bonus Bidding for Mineral Resources"
   - Arlon R. Tussing, "The Role of Public Enterprise"

How to Bid for Offshore Rights

Several systems have been proposed to replace the present "bonus-bid" method of assigning leases on offshore oil prospects to developers. Of these, Professor John W. Devanney III of M.I.T. opts for "percentage-of-excess-profits" bids (*see p. 42*). Other proposed arrangements include work obligation permits and various forms of royalty bidding.

The Work Obligation Permit Plan

Under the work obligation permit plan, developers would submit exploratory and provisional drilling plans for a given tract. The government would choose the developer with the most aggressive, best-considered plan, and the developer would then be responsible for agreed-upon amounts of royalties and/or lease rentals. Under this system, used currently by the Norwegians and the British in the North Sea, the great bulk of any economic rent would be transferred to the developer, and a portion of this rent would be returned to the public in the form of corporate income taxes. Of the possible methods reviewed here, this is clearly the most favorable to the developer.

Administering this method to maximize national income depends on the skill and honesty of administrators. There are temptations for prospective developers to submit work plans which represent over-development of the resource so they will be judged the most aggressive, and administrators will have to be wise enough to recognize such over-development and refuse it. The decisions to be made in choosing the "best" work plan are necessarily judgemental, and they are an open invitation to the influence of special interests and even to corruption.

But beyond the possibilities of incompetency or corruption which may result in loss of national income is the basic fact that most of the economic rent goes to the developer. Professor Devanney concludes that work obligation permitting is clearly not desirable, from a nondeveloper point of view. Indeed, as soon as it became clear that economic rent was associated with North Sea oil, the British and Norwegians moved away from this practice.

Royalty Bidding

Royalty bidding involves competitive bidding on a share of the actual gross revenues — generally a percentage of market value — associated with the resource. This method has long been used in state sales of rights, and the federal government experimented with it in the Gulf of Mexico in 1974.

Compared with bonus bidding, royalty bidding transfers some of the risk prior to exploratory drilling from the developer to the public. This helps maintain competition among bidders, for large amounts of up-front capital are not necessary, and the need for large bidding combines disappears.

However, there are other problems. While the method could theoretically give most of the revenues from offshore oil to the public, it could also reduce the total size of the offshore oil pie. This is because the royalty bid, unlike the bonus bid, affects the developer's marginal expenses. For instance, if a developer overestimates production from a certain tract, he will freeze himself into a royalty bid that makes it unprofitable for him to develop the smaller, and thus more expensive, oil find that is actually made. He will refuse to develop it, and the national income will suffer. This risk may especially affect secondary and tertiary production from a tract; such oil will be more expensive than primary oil but still less costly than foreign crude.

Proponents of royalty bidding offer two possible resolutions of this dilemma — re-leasing and renegotiation. The former proposes that if a developer decides not to produce a tract he must turn it back to the government, with all equipment intact, and the government may lease the tract anew, presumably to a different developer at a lower royalty. This would discourage expensive techniques to enhance oil recovery, because the original leaseholder may choose merely to take out the flush production before releasing a tract back to the government. This will be costly to the public, since processes for secondary and tertiary recovery of oil must begin early in a field's life to be most effective. There is also the possibility of excessive administrative costs associated with the negotiations necessary for re-leasing.

Advocates of renegotiation propose that if a developer feels he cannot develop a field at his bid royalty, he should be able to present his evidence to the regulatory body which should be empowered to grant him a decrease if it finds his presentation viable. The obvious problems here are in the regulatory body's verification of the developer's data. The capital-intensiveness of offshore oil makes any estimate extremely sensitive to the cost of capital, and that information is often confidential.

Other potential problems introduced by renegotiation include temptations for developers to "goldplate" a project since additional expenses could come off the royalty — i.e., out of the public's pocket. A developer might deliberately bid high initially in order to obtain a tract, anticipating that he will renegotiate later; and he might go through a whole series of renegotiations as his costs for enhanced recovery techniques begin to appear.

Some have suggested a compromise between bonus bidding and royalty bidding, in which developers would enter a "high" fixed royalty plus a bonus bid of up-front payments. This would decrease the size of bonus bids and aid competition, say its advocates. Unfortunately, this presents the same can of worms as straight royalty bidding.

Installment bonus bidding has also been suggested. This means a developer would pay his bonus in three installments — immediately, after three years, and after five years. He could surrender the lease before the last two payments if things failed to work out. But this presents the same pie-reducing problems as royalty bidding; if a developer originally bid $600 million and after exploratory drilling found oil worth only $350 million, he would abandon the tract rather than pay the final installments even though national income would be increased by $350 million if the find were developed.

There are advantages, however, in installment bonus bidding. There is an automatic re-leasing provision, which could assure that tracts were re-opened for development; and the marginal costs of the oil are not affected, which means that the developer has incentives to invest early in enhanced recovery.

However, the massive amounts of up-front money involved in even a one-third installment payment of a bonus bid will probably still frighten away many bidders. And many bidders would increase their total bonus bids considerably, knowing that they could thus avoid paying additional installments.

ALBERTA, CANADA

Exploratory Drilling Incentive System

A report from Alberta Energy and Natural Resources states the exploratory drilling incentive principles adopted for wells spudded between Jan. 1, 1978 and March 31, 1981 were announced by the government last fall and will be defined in detail in the Exploratory Drilling Incentive Regulation, 1978 when it is issued in the near future.

This regulation, however, may not be available to industry prior to the commencement of the drilling activity it affects. Accordingly, the essential details respecting the forthcoming program are described herewith.

The department expects that the principles and details outlined here will be incorporated, without a change in meaning, into the 1978 Regulation. If, however, such a change does occur, the 1978 Regulation would, of course, take precedence.

(1) Commencement Date of the Forthcoming Program

As previously indicated, an incentive exploratory well in good standing will be

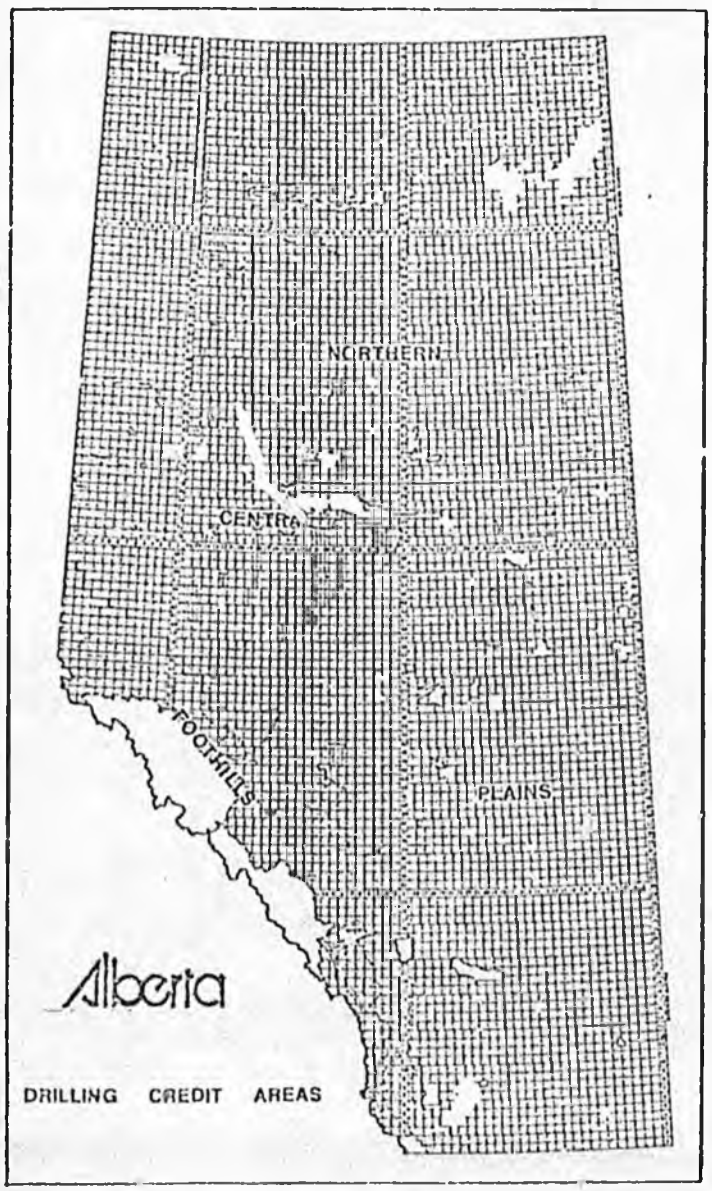


Figure 1

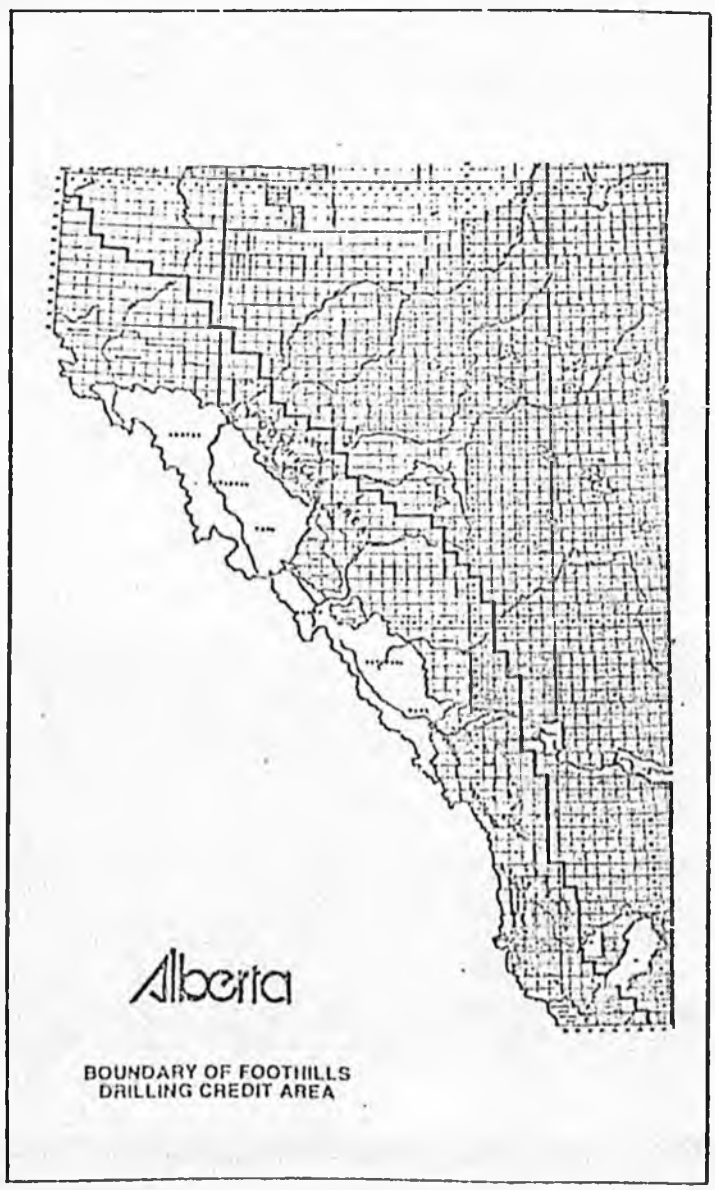


Figure 2

subject to the 1978 Regulation if it commences drilling on or after Jan. 1, 1978. This provision will not be affected if the licensing or certification date is before 1978.

(2) Drilling Credit Areas

Figure 1 shows the drilling credit areas as they will be defined under the 1978 Regulation. The Plains and Foothills Areas have not been changed. The subsisting Northern Area, however has been divided into the new Central and Northern Areas shown by the illustration. The boundary between the two new areas was defined by the Department on the basis of well cost data and topographic and access considerations.

Figure 2 is provided for the convenience of industry to depict the irregular eastern boundary of the Foothills Area. A similar map was issued by the Board in 1974.

(3) Drilling Credit Schedules

Drilling credits under the 1978 Regulation will be determined from Schedules F

SCHEDULE F

Applicable to the Class A Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978

The Class A interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that

(i) has not been duplicated by a drilled and abandoned well within one and one-half miles

(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and

(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class A interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.

	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
Depth, Feet	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot
2,000	0	20	0	30	0	40
3,000	20,000	18	30,000	25	40,000	35
4,000	38,000	18	55,000	25	75,000	40
5,000	56,000	20	80,000	25	115,000	35
6,000	76,000	24	105,000	35	150,000	35
7,000	100,000	30	140,000	40	185,000	50
8,000	130,000	40	180,000	50	235,000	65
9,000	170,000	55	230,000	70	300,000	80
10,000	225,000	75	300,000	90	380,000	100
11,000	300,000	100	390,000	110	480,000	120
12,000	400,000	110	500,000	160	600,000	180
13,000	510,000	160	660,000	200	780,000	210
14,000	670,000	210	860,000	240	990,000	260
15,000	880,000	280	1,100,000	350	1,250,000	350
16,000	1,160,000	340	1,450,000	400	1,600,000	425
17,000	1,500,000	500	1,850,000	550	2,025,000	575
18,000	2,000,000	500	2,400,000	550	2,600,000	575

Figure 3

SCHEDULE G

Applicable to the Class B Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978

The Class B interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that

(i) has been duplicated by a drilled and abandoned well within one and one-half miles.

(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and

(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class B interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.

	Basic for Credit Plains Area		Basic for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
Depth, Feet	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot
2,000	0	15	0	20	0	28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	59,000	19	86,000	24
6,000	57,000	18	74,000	26	110,000	30
7,000	75,000	25	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	380,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,800,000	400	1,930,000	420

Figure 4

and G *(Figures 3 and 4)*. The schedules reflect the government's decision to exclude the upper 2,000 feet from the forthcoming program, and to increase the credits for qualifying wells deeper than about 3,500 feet. For wells greater than 5,000 feet in depth, the increase is between approximately 25 and 45 percent, the difference being justified by the Department's comprehensive well cost study. An exception applies to the new Northern Area, for which credit increases at certain depths exceed 45 percent to correspond with Foothills credits.

(4) Royalty Exemptions

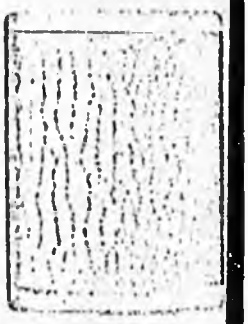
(4.1) Eligibility

Crude oil or gas production must originate from a Class A or Class B interval to qualify for a royalty exemption. Production from any source shallower than 2,000 feet will thus not qualify for royalty exemption under the 1978 Regulation. An exception to the foregoing exclusion is found under the following circumstances: If conventional crude oil is produced from a source shallower than 2,000 feet in the new Northern Area, and if the 2,000-foot interval would have qualified as Class A or Class B footage pursuant to the 1974 Regulations, the crude oil production will be eligible for the normal royalty exemption applicable to deeper production.

(4.2) Duration

The royalty exemptions authorized under the 1978 Regulation will apply to the initial 60 crude oil-producing months or the initial 12 gas-producing months at the well, commencing with the first month in which the crude oil or gas would otherwise be subject to royalty payment.

Additional details concerning these and other principles relating to the forthcoming program will be specified in the 1978 Regulation. If any questions arise after the 1978 Regulation is studied, they may be referred to J. R. Pow or F. Phillips of the Energy Resources Conservation Board, if they pertain to the certification of a well or the determination of its Class A or Class B interval, or to C. R. Smith or E. Saldanha of the Department, if they are concerned with establishing credit or granting royalty exemption. □



Work Commitment Bidding

GREGG K. ERICKSON

One result of the growing concern in the United States over energy matters has been an increased attention to public policies governing the development of Outer Continental Shelf (OCS) oil and gas resources. The institutional structure under which all such development has thus far taken place was established in 1953 by the Outer Continental Shelf Lands Act.[1] This unamended statute provides the Secretary of the Interior with authority to sell oil and gas leases to the public on the basis of cash or royalty bids offered at sealed bid auctions.

The practice of the United States government since the first such sale in 1954 has been to offer relatively small quantities of offshore acreage on an irregular basis, soliciting always cash rather than royalty rate bids. In recent years, the rate at which acreage has moved to market has been accelerating. However, the average per acre bonus received by the government has also increased, partially reflecting worldwide supply conditions. The fact that bids are received in sealed envelopes has resulted in the winning bid being two, three, or several times the amount of the next highest bid.

Among criticisms of present policy is the assertion that this method of lease allocation diverts undesirably large amounts of *front-end money* into the coffers of the government landowner, money that could, would, and should otherwise be used for development of the resource itself.[2] One possible remedy would involve implementation of the existing statutory authority to substitute royalty rate bids, with fixed and presumably low cash bonuses. The problems created by royalty bidding, principally the premature shutdown effect and the potential for speculator induced misallocation of leases, have been well discussed in the literature. More importantly, they are well understood by persons influencing both public and private mineral resource management policies.[3]

An alternative proposed remedy to this same perceived problem is less well understood. Based in part on the method of lease allocation used in the offshore areas of the United Kingdom, it would allocate exploitation rights to the firm that would commit itself to spending the greatest sum in developing the resource. Sealed bids would be solicited as under the present system, but instead of cash the bid variable would be the *work commitment*. Proponents of this system claim that it will divert money the government

landowner would otherwise receive via bonuses into exploration and development expenditures.[4] These additional increments of expenditure, it is further suggested, will increase future production to such an extent that the government landowner will be able to recoup the foregone bonus income in the form of the consequentially increased royalty and tax revenue. Ancillary benefits in the form of employment, resource self-sufficiency, and improved trade balances are also sometimes claimed or alluded to.

To an economist these arguments may not seem too persuasive. Nevertheless, no one appears to have devoted much effort to analyzing the economic implications of such a system, and certainly not in a form that would be comprehensive to the nonéconomist policy maker.[5] This is unfortunate not only because of the substantial public and private interests involved; the system has significant implications for minerals other than petroleum and in places other than the United States OCS. The purpose here is to provide such an analysis.

EVALUATION OF WORK COMMITMENT BIDDING

In evaluating something new the first step is usually to establish a standard against which it can be measured. In this context, the system of competitive cash bidding has long attracted economists concerned with the problem of natural resource allocation, not only as an ideal against which the performance of other systems might be measured, but as a practical and proven technique for bringing resources into productive employment.

Under an idealized competitive cash bidding arrangement, bidders determine the amount they can afford to offer for a mineral lease by a very simple process: they subtract their expected costs of extraction from their expected revenues. The resulting residual is the maximum the prospective bidder can offer for the tract without buying himself an expected loss. Competition, of course, implies that multiple firms will be preparing bids on each tract.

Assuming no uncertainty about the amount of oil to be found or the price that oil will eventually bring, and disregarding the time value of money, the firm with the lowest expected costs of extraction will be capable of submitting the highest, and thus the winning, bid. This is good from society's standpoint, since it means that the resource will be developed with the minimum expenditure of scarce goods and services. The resource's contribution to economic welfare will be greater than it would have been had the tract been awarded to any of the other, less efficient bidders.

Under a work commitment system each prospective bidder will be asking himself: What is the maximum amount I can promise to spend on the development of this tract and still expect to break even? Since any cash bonus

that would have been offered to acquire a tract under the traditional system is no longer necessary, the amount of that bonus may clearly be diverted to the work commitment without raising costs beyond the breakeven point. What is not quite so obvious, however, is that the amount a bidder will promise to spend under the commitment system will exceed the sum of the cash bonus and the amount that he would have allocated to development of the tract under the cash bonus system.

This follows from the fact that any additional increment of expenditure can almost always be spent in a way that will bring about some increase in output from the tract and a corresponding increase in revenue.

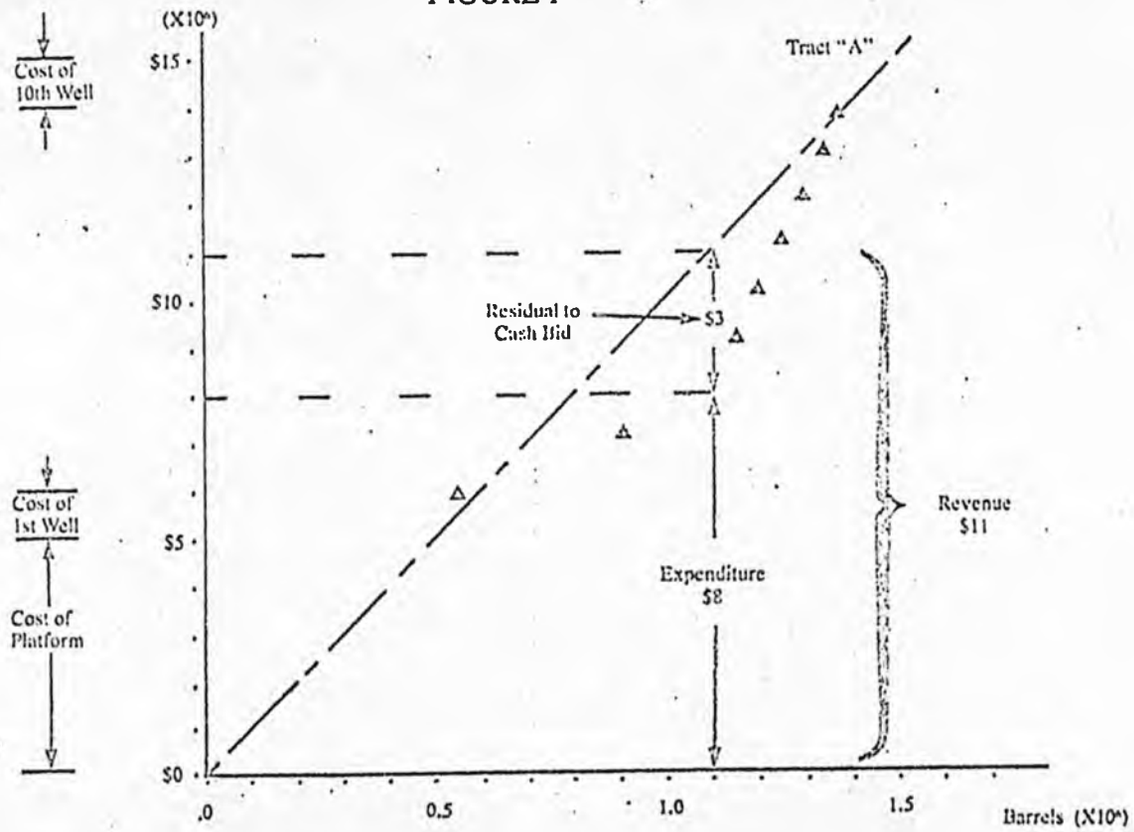
This is most easily demonstrated with a numerical example. Let us assume that a prospective bidder, in determining how much of a cash bonus he can offer for an oil and gas lease on a hypothetical tract A, has calculated the relationship between expenditures on development of the tract and expected production, and that the results of his calculations appear as plotted in Figure 1.

The vertical axis in this graph (and those that follow) measures dollars expended in the tract's development, dollars that we assume will be spent for construction of a platform and the drilling from it of wells. The horizontal scale measures the output that results from that expenditure, denominated in millions of barrels of oil. The relationship between those barrels of output and the revenue they bring their producer (at an assumed price of $10 per barrel) is shown, through appropriate choice of scales, by the dashed 45° straight line running upward to the right. By this means, the vertical scale can be used to show the value of output as well as the cost of production.

In Figure 1, the point closest to the origin indicates that with one platform and one well this operator would expend $6 million (vertical scale) producing an output of 550,000 barrels of oil, worth $5.5 million (determined by the intersection of the 45° line with a line drawn vertically from .55 million barrels). Moving upward and to the right, each subsequent point reflects seriatum the increases in expenditures and output resulting from the drilling of additional wells.

The general shape of the curve defined by these points is characteristic of situations where one major input to the productive process (in this case land) is held constant, while other inputs (in this case wells) are varied. The output curve originates at the lower left hand corner, but it rises vertically at first because the initial input of investment is unproductive: a platform and oil well costs a certain amount, and an expenditure of anything less than that threshold amount produces no oil. The cost of subsequent wells is assumed to be $1 million, no matter how many wells are drilled, creating a curve that looks like a staircase where each increment of cost (representing a new well) creates a new step. The fact that the staircase steepens as we move

FIGURE 1


(X10⁶)
$15
$10
$5
$0
Cost of 10th Well
Cost of 1st Well
Cost of Platform
Tract "A"
Residual to Cash Bid
$3
Expenditure $8
Revenue $11
.0
0.5
1.0
1.5
Barrels (X10⁶)

to the right is a reflection of the diminishing returns, in terms of oil produced, to each additional well drilled into the fixed geographic area encompassed by the lease.

Naturally the prospective bidder will be looking for the point on this output curve that puts his costs as far below the 45° line (his output-revenue function) as possible. As shown in Figure 1, the maximum cash bid this operator could afford to make on tract A (and still expect to break even) is $3 million, which—if he is the winner—would require him to drill three wells.

Consider now the situation this bidder would face were a work commitment bidding system adopted. The question that now confronts him is: How much can I spend (or how many wells can I drill) on tract A and still break even? The answer is clearly $14 million (representing nine wells), indicated on the right side of Figure 2 by the output curve for tract A.

If the bidder wins tract A under a work commitment system, his oil output will be 1.4 million barrels (Figure 2) as compared to the 1.1 million barrels (Figure 1) that he would have produced had he won the tract in a cash bonus sale.

If the success of a mineral resource management policy is measured by the physical quantities of the mineral educed from the earth, the work commitment bidding is clearly superior. A resource's contribution to economic welfare, however, is not its total output (whether measured in dollars or physical quantities) but is the residual left over when the costs of all inputs to the productive process (other than the resource itself) are subtracted from the value of the outputs. In the case of tract A this residual is maximized at $3 million, when the value of the inputs is $8 million. As the input expenditure is increased above this optimum point, the residual—the resource's potential contribution to economic welfare—is gradually dissipated until, at the point where the value of inputs reaches $14 million, there is no more residual left to be dissipated.

In this particular example, the increase in output that would result from a switch to work commitment bidding ($3 million) happens to equal the amount of the residual. This coincides with the fact that the expenditure of each additional $1 million above $8 million (three wells) contributes exactly $500,000 to revenue. If the incremental contribution of the fourth and succeeding wells were greater, for example $750,000, the slope of the output curve traced by these points would be flatter, as shown by the squares in Figure 3, and the increase in production from a switch to commitment bidding would be much greater. To put it another way, it would take twice as large an increase in expenditure to dissipate the $3 million residual.

FIGURE 2

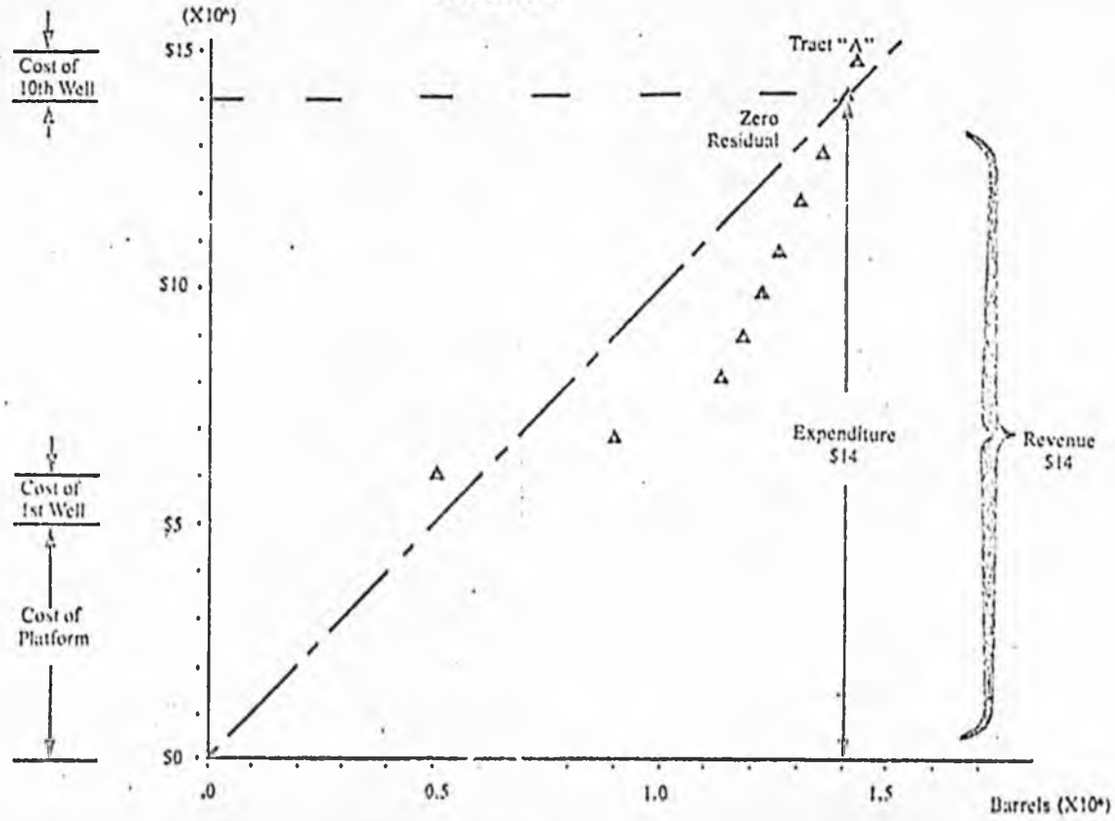
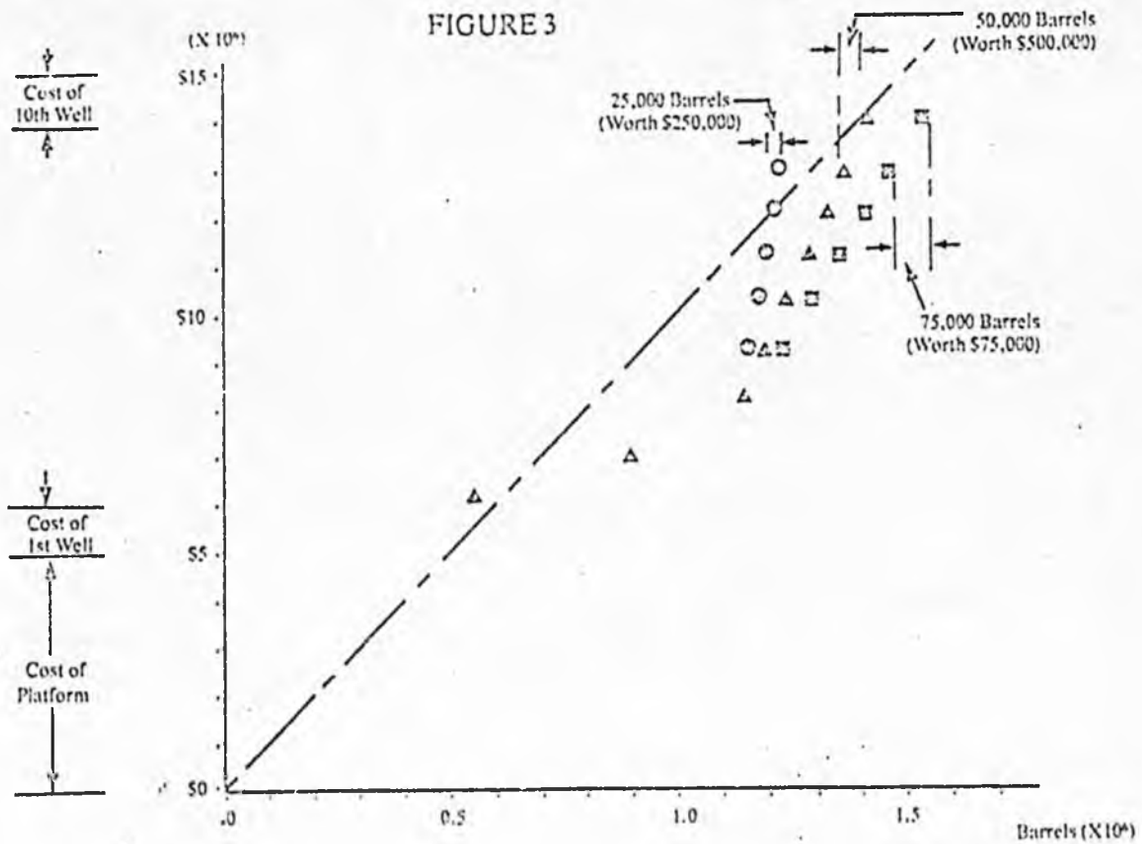

(X10⁶)
$15
$10
$5
$0
Cost of 10th Well
Cost of 1st Well
Cost of Platform
Tract "A"
Zero Residual
Expenditure $14
Revenue $14
.0
0.5
1.0
1.5
Barrels (X10⁶)

FIGURE 3


($ X 10⁶)
$15
$10
$5
$0
Cost of 10th Well
Cost of 1st Well
Cost of Platform
50,000 Barrels (Worth $500,000)
25,000 Barrels (Worth $250,000)
75,000 Barrels (Worth $75,000)
.0
0.5
1.0
1.5
Barrels (X10⁶)

On the other hand, a smaller incremental contribution to output and revenue by the fourth and succeeding wells (for example, an increase of only $250,000 in revenue for each $1 million well) would trace a steeper curve such as the one defined by the circles in Figure 3. The addition to revenue would clearly be less than the $3 million residual sacrificed to obtain it, which is another way of saying that the increase in production would be worth less than the bonus bid sacrificed to obtain it.

TRANSFERABILITY OF COMMITMENTS

Clearly the previously discussed simple work commitment bidding system results in more intensive development of the tract to which it is applied. Clear also is the fact that this effect is dependent on the characteristics of the tract to which it is applied, and in particular on the efficiency with which the successive increments of additional expenditures required under the commitment can be put to work to increase output.

One way to increase this efficiency is to allow an operator who assumes a work commitment in the course of acquiring a particular tract to fulfil that commitment through expenditures on a different tract or tracts.

For example, assume that a bidder has acquired both tract A and tract B as shown in Figure 4. If the work commitment assumed in order to acquire a tract must be fulfilled on that same tract, then his maximum commitment on A (Figure 2) is $14 million; and on B (as indicated in Figure 4 by the dashed lines) it is $8 million. Total output from the two tracts will be 2.2 million barrels.

TABLE 1

WORK COMMITMENT BIDDING

	Output (bbl's)	Revenue ($)	Expenditure ($)	Residual ($)
Tract A	1.4	14	14	0
Tract B	0.8	8	8	0
	2.2	22	22	0

Note: All figures in millions

If the operator is allowed to bid on the two tracts jointly or is otherwise permitted to shift a commitment made to acquire one to the other, then his total work commitment will rise to $24 million, with a corresponding increase in output. As shown in Figure 4, this is possible by operating tract A at the point on the output curve which produces the greatest residual and by transfering that residual, as an internal subsidy, to tract B, where, as indicated by the flatter slope of the output curve, it can be utilized more efficiently. The numbers are summarized in Table 2.

FIGURE 4

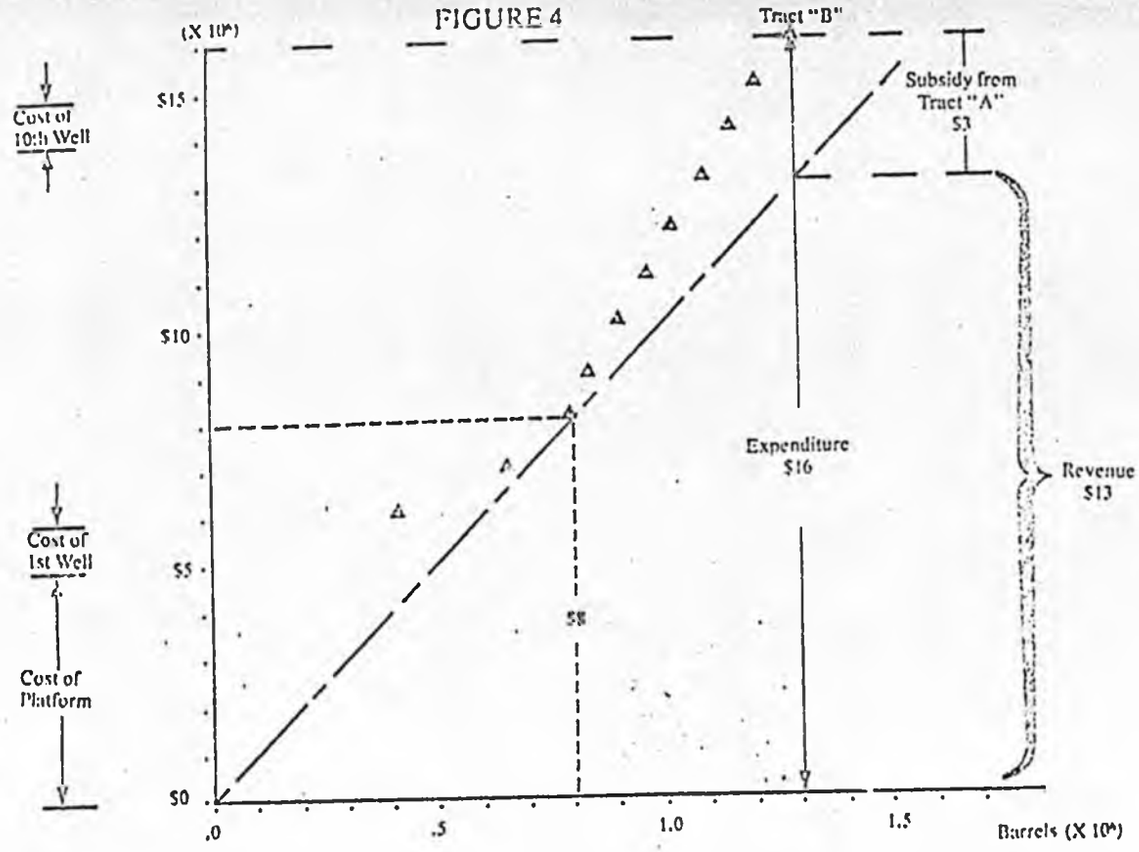

(X 10³)
Tract "B"
Subsidy from Tract "A" $3
$15
$10
$5
$0
Cost of 10th Well
Cost of 1st Well
Cost of Platform
Expenditure $16
Revenue $13
$8
.0
.5
1.0
1.5
Barrels (X 10⁶)

TABLE 2

WORK COMMITMENT BIDDING
(Internal Subsidy Allowed)

	Output (bbl's)	Revenue ($)	Expenditure ($)	Residual ($)
Tract A	1.1	11	8	3
Tract B	1.3	13	16	(3)
	2.4	24	24	0

Note: All figures in millions

EXTENT OF DEVELOPMENT

In the above examples work commitment bidding has been shown to result in a more intensive development of tracts than would be obtained under cash bidding arrangements. If commitment transfers are permitted among tracts, such a system will also bring about more extensive development.

Consider the output curve of tract C in Figure 5. Tract C is clearly something of a "dog," because there is no point at which the output function crosses the 45° "breakeven" line. Under cash bidding, tract C would elicit no interest at all; even if given away free, it would not be developed.

Under a work commitment system, however, tract C may very well be acquired and drilled. Assume that a firm has already acquired tracts A and B as a package with a work commitment of $24 million and that neither tract has yet been drilled. The firm is now offered tract C. How much of a work commitment can the firm offer for it?

The firm had previously planned to use the $3 million residual generated on tract A to internally subsidize tract B. If tract C is added to the inventory, the firm could apply to C $1.5 million of the internal subsidy that would have otherwise gone to tract B and thereby make the development of tract C a feasible proposition. The calculation is shown in Table 3.

TABLE 3

WORK COMMITMENT BIDDING
(Internal Subsidy Allowed)

	Output (bbl's)	Revenue ($)	Expenditure ($)	Residual ($)
Tract A	1.10	11.0	8.0	3.0
Tract B	1.05	10.5	12.0	(1.5)
Tract C	0.75	7.5	9.0	(1.5)
	2.90	29.0	29.0	0

Note: All figures in millions

commitments indicates that the last dollar of subsidy transferred is producing only 33 cents worth of additional oil, it may very well be that another source of oil development—for example, tar sand or oil shale—could be found that would give a better return.[6]

THE TIME FACTOR

To simplify the discussion of the work commitment system, the time dimension of both expenditures and income has thus far been ignored. Since a dollar in hand today is worth more than the promise of a dollar tomorrow, it has been assumed that all bidders have used a discounting mechanism to take account of the time value of money. Thus, they would reduce all amounts of both expenditure and income streams to their *present value*, that is, the lump sum that the bidder would be willing to receive or give in exchange for the specified income or expenditure stream.

If a work commitment system is to be implemented, it will be necessary to take careful account of the fact that a commitment fulfilled in the next year will have a very different impact on output from one of the same amount fulfilled ten years hence.

If the public is going to give up its bonus income to subsidize output, the time when that subsidy takes effect will presumably make some difference. Of course, some arbitrary time limit could be established for the fulfilment of commitments exactly as the United States government sets the five-year term on the OCS oil and gas leases it sells. If free exchanges of commitments are allowed, anyone who wished to distribute expenditures over a time frame incompatible with his commitments could simply enter the market and adjust his inventory of commitments accordingly.

Another way of handling the problem would be simply to apply some appropriate interest rate to every commitment assumed and specify that the amount of expenditure required under that commitment must increase by the amount of the compound interest accumulated in the period between the assumption of the commitment and its fulfilment.

CONCLUSION

The adoption of a work commitment bidding system implies a judgment that existing institutions for private exploitation of public resources result in a suboptimal rate of resource development.

Any argument for the adoption of such a system must first establish that this is in fact the case. Secondly, it must prove that the work commitment approach is the least costly method of achieving the desired higher rate of exploitation.[7]

FIGURE 6

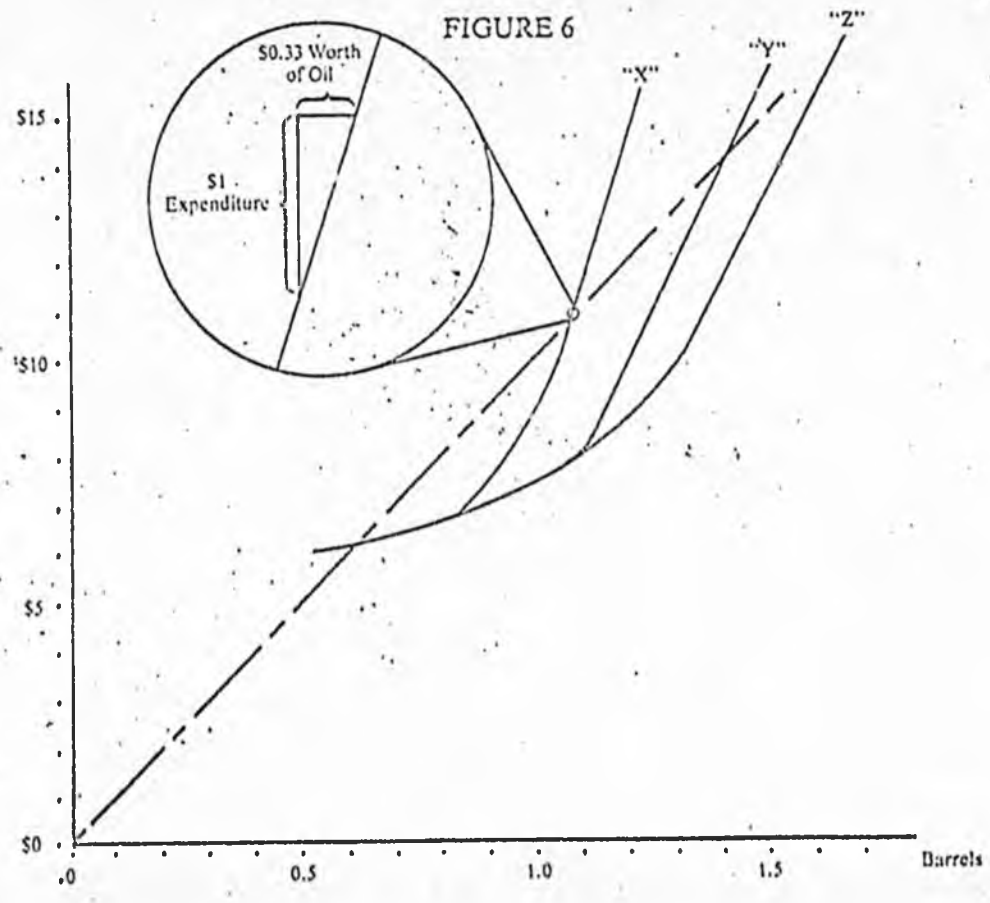
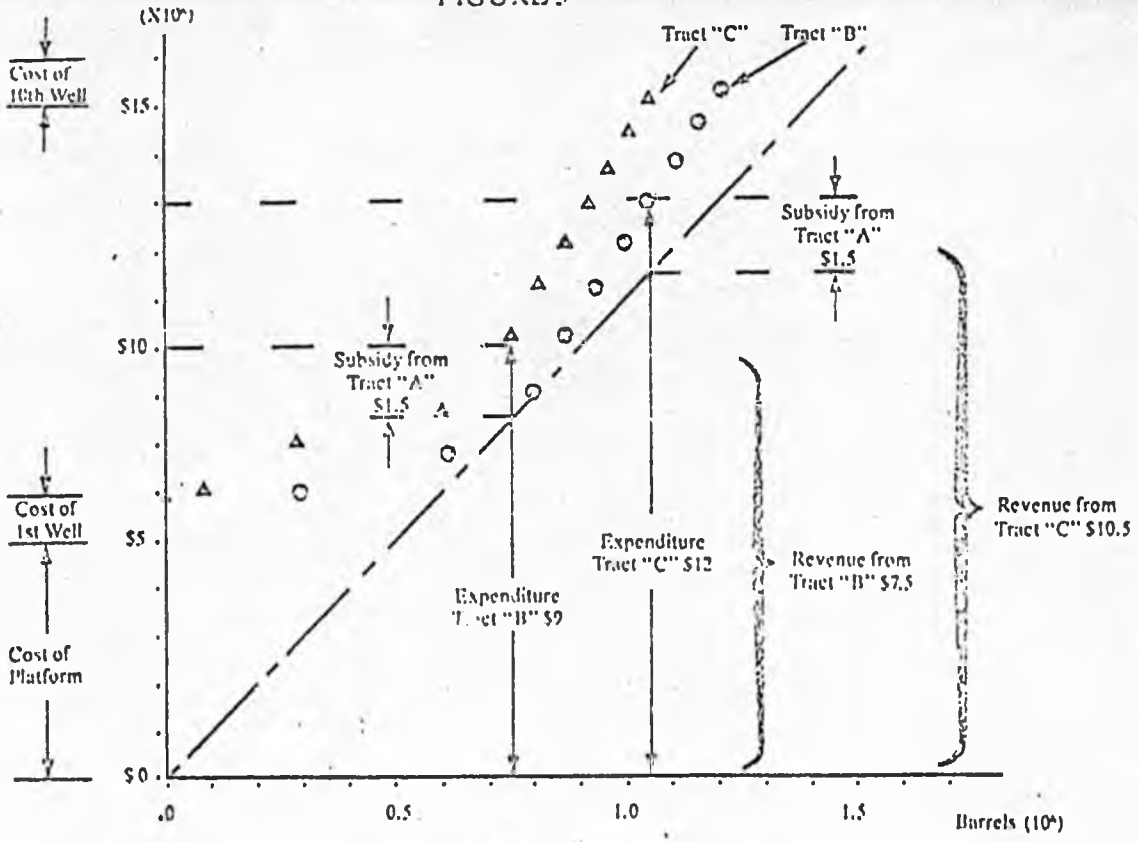


FIGURE 5


(10^6)
Tract "C"
Tract "B"
Cost of 10th Well
$15
Subsidy from Tract "A" $1.5
$10
Subsidy from Tract "A" $1.5
Cost of 1st Well
$5
Expenditure Tract "C" $12
Revenue from Tract "B" $7.5
Revenue from Tract "C" $10.5
Expenditure Tract "B" $9
Cost of Platform
$0
.0
0.5
1.0
1.5
Barrels (10^6)

Development of the three-tra package under the work commitment system will be feasible with a tot xpenditure of $29 million. Since he has already been committed to spe ag $24 million of this, in the course of acquiring tracts A and B, the ma imum commitment bid this operator can afford to make on tract C is $5 million.

Besides illustrating the mechanism through which commitment bidding induces more extensive resource development, the tract C example also indicates how the system (with interna subsidies allowed) may work to the advantage of the firms that can acquire the most tracts. Theoretically, a newcomer with no existing inventory of tracts would be unable to make any commitment bid on tract C.

A way of evading this problem would be to make the commitments transferable. This would allow operator Jones to legally assume the obligations to which operator Smith has committed himself in the course of acquiring tracts from the government. Presumably, operator Smith would pay Jones for the favour.

The prospective bidders in these examples have been endowed with the ability to foresee accurately and precisely the output curve associated with every tract. In practice this is not the case. If there is any characteristic that sets the exploration phase of the petroleum and mineral industries apart from other businesses, it is the everyday uncertainty with which its participants must learn to cope. It is perfectly possible, for example, that Smith might acquire tract C with a work commitment bid of $14 million on the mistaken belief that its output curve is that of tract A. After building a platform and drilling the first four wells, the true shape of the curve—and the firm's predicament—would reveal itself. The required $14 million expenditure applied to tract C would leave Smith with a net loss of about $4 million. If he could somehow shed $5 million of the $14 million commitment, Smith would be able to operate the tract with only four wells already drilled and thereby cut his losses to the more acceptable level of $1.5 million. Smith would be willing to pay up to $2.5 million in cash to unload the $6 million obligation, since that is the amount of his maximum additional loss if he can't get rid of it.

Any other operator who is facing or expects to face an output curve with a flatter slope than that faced by Smith will be able to make a mutually beneficial deal with him, since, for the other party, an additional expenditure of $5 million will bring in more than the maximum $2.5 million that Smith will be willing to pay.

Besides putting the small firm in a better position to compete and mitigating the problems of uncertainty for all firms, large and small, a system which allowed the free exchange of work commitments would have the further and more important advantage of maximizing the overall

efficiency with which work commitments are utilized. To the extent to which such a market was effective in bringing potential commitment offerers together with potential commitment takers, it would ensure that everyone would be operating at a point where a small increase in expenditure by one operator would produce no more and no less additional revenue than would the same increase applied to any other operator.

A minor but interesting benefit of a market in commitments would be the information it would provide concerning the efficiency with which the work commitment system is eliciting additional output.

This can be understood by applying the concept of the output curve (hitherto used in relation to individual tracts) to the entire universe of tracts being offered under the commitment bidding system. By combining all such tracts and treating them as a single entity, an overall output curve similar to Figure 6 can be drawn. Just as in the case of an individual tract, the point where the curve dips farthest below the 45° breakeven line will be the optimum operating point, the point which results in the resource's largest contribution to economic welfare. The distance between the breakeven line and the output curve at that point is the measure of that contribution, and it is equal to the income that would come to the government landowner were a competitive bidding system utilized. It is this residual—the difference between total revenues and total costs—that the public will be sacrificing to subsidize output.

The efficiency with which the subsidy provided by the work commitment system works to increase output will be a function of the output curve's shape to the right of the point where bonus income would be maximized. Three hypothetical configurations for this part of the curve are shown, and the difference this shape makes to the level of additional output educed by the sacrifice of the residual can be seen. The significance of the price at which commitments change hands will be determined by the slope of the output curve at the point where it intersects the 45° breakeven line. Curves Y and Z both cross at an angle which indicates that, at that point, $1 of expenditure produces $0.50 worth of additional output. In either situation the market price for assumption of a $1 million commitment would be $500,000. Curve X, however, crosses the line at a steeper slope (as shown in the inset), indicating that $1 of expenditure will produce $0.33 worth of additional output. If curve Z accurately represents the overall output curve, the market price for the assumption of a $1 million work commitment will be about $333,000.

From a policy standpoint these numbers, whatever they may be, have considerable significance since they can be used to compare the efficiency of the work commitment system in eliciting additional output with whatever other alternative policies may be available. For example, if the market for

In comparing various alternative ways of achieving higher output against the work commitment system, some important features of that system are certain to stand out. First, and probably most significant, is the simple fact that the work commitment system results in a subsidy. As such, the criteria for its evaluation should be no less stringent than those applied to a direct appropriation of public funds or a tax concession adopted for the same purpose.

Secondly, the cost of the subsidy conferred under the work commitment approach is impossible to determine *a priori* and difficult of determination after the fact. If there exists a "right" level of subsidy it will be mostly a matter of luck if the foregone public revenue happens to equal that amount. For similar reasons, the benefits of the subsidy in terms of the total increase in output, development, or whatever, are not amenable to accurate quantification. As a consequence, it is doubly difficult to evaluate the system's relative efficiency.

Finally, a properly designed work commitment system allocates the uncertain amount of the subsidy in a fashion that tends to squeeze the maximum additional output from every dollar of subsidy. It does this more or less automatically. This characteristic means that the transfer of resources occasioned by the subsidy needs no affirmative action on the part of policy makers—as does a direct appropriation of public funds—in order to be continued. This fact, however, combined with the intrinsic uncertainty concerning the subsidy's magnitude makes it easier for vested interests to perpetuate such a subsidy long after any real justification for it has passed.

Notes

1. *U.S. Statutes at Large*, vol. 67, p.345. Public Law 212 (August 7, 1953).
2. For an exposition of the conventional industry wisdom on this point, see "Terms for North Sea Oil," in *Petroleum Press Service* 40 (1973): 122-24.
3. In recent testimony before the Senate Interior Committee, industry representatives were unanimous in their opposition to royalty rate bidding. *Outer Continental Shelf Oil and Gas Developments, Hearings Before the Subcommittee on Minerals, Materials, and Fuels of the Committee on Interior and Insular Affairs* (United States Senate, 93rd Congress, Second Session: May 6,7,8,10,1974).

4. Arguments for the work commitment system are expounded in detail in I. White, D. Kash et al., *North Sea Oil and Gas: Implications for Future United States Development* (Norman: University of Oklahoma Press, 1973).

5. Kenneth Dam has touched on some of these matters, however, in "Oil and Gas Licensing in the North Sea", *Journal of Law and Economics* 8(October 1965) and "Pricing of North Sea Gas in Britain," *Journal of Law and Economics* 13 (April 1970). Dam recognizes the subsidy for what it is and concludes that it is unjustified.

6. If it is determined that only a portion of the residual should be applied as a subsidy, this could be accomplished by offering only a portion of the tracts on the commitments bid basis, but allowing the fulfilment of a commitment on any tract acquired from the government. Since the reduction in the subsidy will move the operating point to the left on the output curve (Figure 5) to a point at which its slope is flatter, the result will be a higher assumption price for commitments. The commonsense explanation is that the optimum amount of total expenditure will be reduced only slightly; but that acreage over which commitments that can be fulfilled by that expenditure will be reduced relatively more. Another alternative would be to combine the work commitment system with a royalty, net profits share, or other form of deferred rent collection. This is in fact the arrangement pertaining in the North Sea sector. If the government takes a very high net profit share, the amount of the subsidy will be substantially reduced.

7. There are certain circumstances where a work commitment system could result in no more extensive or intensive development. This would be the case if the commitment were devoted to an activity not contributing to output. For example, if a government awarded a mineral concession to the operator who promised to build the largest smelter, no increase in mine output would result (unless the location of the smelter made lower grade ores profitable to mine).

Petroleum Leasing in British Columbia

DALE R. JORDAN

FACTORS AFFECTING THE LEVEL OF EXPLORATION

From data published by the provincial department of mines and petroleum resources, it would seem that exploratory drilling in British Columbia in 1974 was in a static position and may even have been declining. There was a 22 per cent drop in the number of exploratory wells drilled in 1973 compared with 1972, and a corresponding drop in the footage drilled. This decline in activity appeared to be continuing into 1974, with drilling down 10 per cent in the first seven months. This apparent decline in exploration for oil and gas in British Columbia came at a time when the demand for oil and gas was high. Prices for oil and gas had increased dramatically, and considerable concern was being expressed over national self-sufficiency in all forms of energy supplies. By comparison, exploration activity in Alberta showed the opposite pattern. In Alberta, exploratory drilling in 1973 increased 50 per cent over 1972. Statistics published by the Daily Oil Bulletin showed that during the first several months of 1974 there was a further increase over the same period in 1973.

What caused the static or possible decline of exploratory drilling in British Columbia at this particular period of strong demand and high price? There are several answers, and formulated theoretical solutions must be viewed in the light of political judgment where governments demand a greater share of resource revenues. Certainly, the federal budget proposals in the spring of 1974 discouraged exploration for oil and gas in Canada; however, it would seem that provincial government policies were largely responsible for any discouragement felt by the oil and gas explorer.

In this article I attempt to set out some of the basic causes that contributed to the 1974 situation in British Columbia. These causes are identified and any suggested solutions are offered in the realization that there is a danger of oversimplifying complex problems and the possible effects of implementing partial solutions.

For any analysis to be meaningful, a proper perspective must be maintained. One of the overriding factors influencing the oil and gas explorer's decision making is the number of geological prospects. In British Columbia, the potential hydrocarbon-bearing portion is thought to be

restricted to the northeast part of the province. The western boundary of this 51,000 square miles is the Rocky Mountains. In 1974, an estimated 37 per cent of the oil and 18 per cent of the gas in this area had been found, leaving an estimated 0.82 billion barrels of oil and 47.56 trillion cubic feet of gas still to be discovered. Although there was considerable potential still remaining for the oil and gas explorer, the area was small compared to Alberta and Saskatchewan, and it was much smaller than the vast geological potential north of the 60th parallel.

Another factor that depressed the enthusiasm of the explorer was the apparent lack of multizone prospects. Drilling a well to test only one potential horizon increases the risk factor significantly.

Before leaving the subject of the province's hydrocarbon potential, it should be remembered that several basins existed, both offshore and in the interior, containing substantial deposits of sedimentary rock that have not been explored to any great extent. Generally, the known geology in these basins discouraged any extensive exploration. Possibly, the very expensive exploration needed in the basins required special consideration before their potential could be fully realized. This special consideration might take the form of a reduced royalty on any hydrocarbon discovered, or of a joint participation scheme whereby the British Columbia government might share in the risks involved.

Another factor to be taken into account by the oil and gas explorer when selecting his areas of interest is the access to those tracts that he feels have hydrocarbon potential. Again, British Columbia was at a disadvantage in 1974 when compared with Alberta and Saskatchewan. Access to this already restricted basin area was affected by muskeg conditions over much of the plains and by deep river valleys in the foothills. These conditions involve greater expense in conducting exploratory work, and the oil and gas explorer would often be confined to only a four-month work year, because of such terrestrial conditions. The problem of limited access presents a very real constraint on attracting the oil and gas explorer and is relevant when considering any changes in land tenure and revenue sharing.

Another important parameter in any deliberation affecting oil and gas exploration is the availability of funds for exploration.

As a general rule, funds generated from production are used to finance exploration. It seems that the risk factor employed by financial institutions effectively discourages the use of debt capital as a source of exploration funds. It is not uncommon to read that an oil and gas producer has arranged for a substantial loan, but this will nearly always be for a specific purpose related to the development of a new reservoir of oil or gas. The discovery of this reservoir would have been funded out of the company's cash flow.

When an oil or gas explorer's cash flow comes from production outside any particular province, then for money for exploration to flow into that province, that jurisidiction must have a framework of leasing and revenue sharing that can favourably compete with other areas also requiring exploration.

It would seem that cash flows from Canadian production will continue to be a major source of exploration funds. In the case of the integrated companies (those having refinery capacity), this will be true under almost any condition short of expropriation.

However, within this framework these funds will generally gravitate to where they can expect the greatest return. It may not be enough for a province to show that it will ensure that the successful explorer will receive a reasonable rate of return. It may well be that the successful criterion for increasing the level of exploratory drilling will be a division of revenues such that the oil and gas explorer will have a sufficient cash flow for an active exploration programme, as compared with other jurisidictions. The explorers who have a cash flow generated from production and the flexibility to determine the best place to reinvest these funds have the responsibility of ensuring that they can go to where they can expect to return the greatest profit.

The ability of the producer to channel cash flow from one jurisdiction to another depends largely upon the particular laws in force where the oil or gas is being produced. The provinces of Alberta and Saskatchewan tend to attempt to discourage the outward flow of funds generated from production in their particular provinces. In both provinces, this discouragement took the form of a high royalty, coupled with a drilling incentive programme, designed to encourage continued exploration.

In Saskatchewan, the mineral tax and the royalty surcharge took away from the producer all of the recent price increases and, in fact, returned to the producer a smaller amount per barrel than he was receiving prior to the price increases. As an inducement to continued exploration in Saskatchewan, an incentive programme was developed, whereby the producer was allowed to retain an additional 30¢ for every barrel produced, providing this money was used for drilling wells, for waterflood projects, research, and other specified purposes in Saskatchewan. This incentive had not been in effect long enough in 1974 to permit a complete analysis of its performance; however, it was really restricted to only those companies that already had production in Saskatchewan. A review of these companies shows that the producers with the majority of the production were the so-called Majors, which raised the question as to whether or not these Majors were prepared to continue to explore in Saskatchewan under any conditions. It is more probable that the exploration philosophy of the

Majors directed that they use their exploration funds searching for high reserve reservoirs (which generally means exploring outside Saskatchewan).

To encourage explorers who do not have production in Saskatchewan, the government provided an incentive credit of about 30 per cent of the costs of drilling exploration wells. This credit could then be used to reduce any royalty or mineral tax obligations that may accrue.

In Alberta, in 1974, there was also an incentive programme for exploration drilling. This incentive took the form of a credit which could be subsequently used to satisfy most of the cash obligations that may arise by virtue of the royalty obligation, rental payments and mineral taxes, and could also be used to purchase oil and gas leases. Credits established in Saskatchewan could not be used to purchase leases. The formula which determined the amount of credit that could be established for any particular exploration well was predicated upon the area of the province in which the well was located and the depth of the well. This formula was expected to return to the explorer by way of credit approximately one-third of his drilling costs.

The principal producers of crude oil in Alberta were much the same as in Saskatchewan—they were the Majors in the oil and gas industry. Again, as in Saskatchewan, it would seem that the interest of the Majors in continuing to explore in Alberta had become blunted, not because of any particular rules, but more through the apparent lack of sufficient high reserve potential which this type of company must search for.

In Alberta, in 1974 the royalty was structured to increase not only when the production increased but also when the price increased. Alberta had also adopted a new oil/old oil concept, whereby royalties were considerably reduced on what was termed new oil, which, of course, had the affect of increasing the producer's cash flow and encouraging the development expenditures. This old/new concept applied as well in the case of natural gas. Saskatchewan also had provision for a reduction in its mineral tax and royalty surcharge for new oil. This reduction was gradually phased out after a few years. Alberta, in 1974, had the lowest rate of royalty on oil and gas, received the highest price for its natural gas and had a price for crude oil equivalent to the other provinces, all of which means that in Alberta the producer of oil and gas received a higher rate of return and, consequently, had more money available to him for exploration purposes than the producer in Saskatchewan or British Columbia.

While the incentive programme adopted in Alberta and Saskatchewan offered encouragement to drill exploration wells, any analysis of the performance of a similar programme which might be suggested for the province of British Columbia must be coupled with the consideration of a lower royalty and subsequent higher cash flows to the producer.

This type of incentive can only be effective if the producer is also offered a return on his development expenditures that is competitive with other jurisdictions into which the oil and gas explorer is free to go.

Another source of money for drilling exploratory wells previously used in North America has been the drilling fund. The drilling fund usually takes the form of buying a number of shares in a limited partnership. The attraction to the investor apart from the possibility of participating in oil and gas discoveries, is the income tax feature in the United States which permits all intangible drilling expenses to be written off in the year that expenditures were made. This can be done without qualifying under any principal business rules, as prevails in Canada. It is this principal business rule that has to the present time precluded the tapping of a similar source of exploration funds in Canada.

It is estimated that between 250 and 400 million dollars are generated annually through the sale of shares in drilling funds in the United States. The United States government, in an attempt to encourage further exploration within its own borders, has chosen to reduce the amount that can be written off against income for income tax purposes when the funds are spent outside the United States. This move precipitated the drying up of exploration funds in Canada which previously came from this source.

Over the past few years other extractive industries, particularly mining, have been channelling considerable amounts of their cash flows into oil and gas exploration. These endeavours have usually taken the form of funding a subsidiary company. The continuation of this type of fund for the purposes of exploring for oil and gas will depend upon the success of the subsidiary companies and also upon the influence that mining taxes will have upon the parent companies' cash flows.

A few years ago it was quite popular for large United States gas utility companies to provide exploration funds on the basis that they would have first call on any gas produced and exported for sale to the United States. This source of exploration funds has also dried up almost completely as a result of decisions by the National Energy Board concerning the exporting of gas and, as a result of rulings by the Federal Power Commission in the United States, which have not allowed these utility companies to include these expenditures in their rate base. The Federal Power Commission looks upon this type of exploratory funding as a mortgage loan, rather than as a prepayment for gas, as the utility companies would prefer.

THE LEASING SYSTEM

The 1974 system of leasing in British Columbia will now be reviewed, and I will attempt to analyse its effectiveness in relation to the relatively small

hydrocarbon potential area, lack of access, difficult terrain, and exploration funds generally coming from cash flows.

The system of granting oil and gas rights on crown lands in British Columbia invoved in 1974 an exploration grant called a "permit," a subsidiary exploration grant called a "drilling reservation," and a development grant called a "lease."

Permits, which can involve upwards of 100,000 acres, could only be acquired through a competitive cash bidding system at sales which were usually held four times a year.

The permits were classified from A to D, depending upon their accessibility and the terrain conditions. The class D permits were for offshore areas. One purpose for classifying permits was to allow them, where the working conditions were difficult, to have a longer life than was otherwise provided.

Permit classification also determined the minimum amount of work the permit owner was obligated to spend in any year. These minimum work obligations were more stringent for the Class A permit, where access and terrain problems were minimal. The significance of this particular requirement was lost because, in order to conduct an equivalent amount of exploration, particularly drilling, the costs involved in the offshore areas far exceed those which would be expended on a class A type permit. The sections of the Petroleum and Natural Gas Act that governed the permit work obligations did not specify any specific exploration programme, but only that a certain amount of money be spent during each term of the permit. This obligation to spend money in exploring on a permit could be satisfied by grouping several permits together, so that expenditures incurred in exploring on any one permit would satisfy the work obligation of the grouped permits. This grouping provision is important because it allowed an explorer to acquire large tracts of land for a short period in order to conduct extensive geophysical exploration.

This obligation to spend money on exploring on a permit could also be satisfied by paying the money to the British Columbia Crown. This would seem to be about as negative a provision as one could imagine, assuming, of course, that the government of British Columbia was interested in ensuring that the companies holding permits were the ones prepared to actively explore. If the removal of this system would give rise to problems, as in the case of an explorer unable to work a permit through no fault of his own, then a far better system would be to provide a means where work obligations could be accumulated and satisfied in the following year.

Permits were valid for one year and could be renewed annually, for a period ranging from five to eight years, providing the company was not in default.

When a permit holder had expended the minimum amount of money exploring on a permit or group of permits or had paid the money to the government, he was entitled to convert the permit into leases. To do this the permit holder had to relinquish 50 per cent of the land back to the Crown. Land selected for conversion into leases could not be in a consolidated block, but had to be in a number of leases, which had to corner one another, or be separated by at least two units—approximately one mile. The maximum size of the lease was six units—approximately three miles square.

This system of exploratory permit and subsequent conversion of half of the land to lease on a chequerboard fashion was similar to that used in Saskatchewan and part of Alberta. The system probably had its beginning in Alberta. It was designed to ensure that when crude oil was discovered, the Crown would be returned some prospective areas which were subsequently sold. This system worked reasonably well, particularly in Alberta, where some substantial discoveries of crude oil were made during the existence of the exploration agreement. Unfortunately, in the vast number of cases a discovery was not made, and the chequerboard pattern for leases led to fragmentation of rights throughout the area formerly comprising the permit. This effect tended to discourage other explorers from entering the area, and this system of selecting leases also prompted the need for the drilling reservation, which generally covered that 50 per cent of the land returned to the Crown.

Seemingly, in those parts of the province having relatively easy terrestrial access and where the potential hydrocarbon-bearing formations were not too deep, this system of chequerboard leasing may be satisfactory. However, in areas where access is a major cost and where deep expensive drilling is required, it tended to discourage anyone other than the holder of the 50 per cent leases from entering the area to explore. Certainly in offshore areas where seabed drilling cost is many times greater than land drilling, this system of lease selection is most unsatisfactory.

Leases granted on crown land in British Columbia in 1974 had a primary term of ten years, renewable for further ten-year periods if particular circumstances existed which generally related to production.

The acquisition of leases in British Columbia was handled in 1974 in two separate ways. First was the way previously mentioned, which was the result of having a permit and then earning the right to acquire leases of 50 per cent of the land. The second was through the competitive cash bidding at one of the quarterly sales held by the British Columbia Crown.

There was no obligation at that time on the part of the lessee to drill a well during the initial term of the lease. A 1974 amendment to the Petroleum and Natural Gas Act, however, permitted the minister to forward a notice to

drill when he considered that development of the lease was not active enough. This amendment seemed to suggest that before the minister would consider sending a notice, there would, in fact, have been a discovery made on the lease. Thus, in sending the notice, the minister was merely requiring development drilling. It seemed most unlikely that the wording of this section would be interpreted such that the minister could require exploratory drilling on existing leases.

There was an apparent trend to shorten the term of leases, with Saskatchewan granting only five-year primary terms. However, in British Columbia the term of 10 years was not excessive when one considers the short period of four to five months when work can be done in the area of hydrocarbon potential. This is quite different from most of the areas in Alberta and Saskatchewan, where drilling and other geophysical operations can be conducted all the year round.

The government of British Columbia appeared to feel that a large number of leases were held by companies not particularly active in exploring in the province and that something should be done to discourage these holdings, so that lands could be offered to others who were prepared to explore. These feelings may have promoted some of the 1974 changes in the Petroleum and Natural Gas Act, whereby the rental on leases was increased from one dollar an acre to two dollars an acre. The effect of this change seemed likely to be the return to the Crown of some acreage which, under the previous rental of one dollar an acre per year, would have been retained by the lessee. However, one must assume that for the most part relinquished leases would be the least attractive, and leases with potential, even though the lessee was not prepared to conduct any immediate exploration programme, would be retained, and the two dollars an acre would be paid. The greatest effect that this rental of two dollars an acre per year seemed likely to have was to deter other explorers from entering the province. It is one thing to create a system designed to discourage excess holdings by companies not prepared to explore immediately, and quite another thing to expect these same rules to promote the entry of new companies and increase exploration activities.

The royalties on crude oil in British Columbia were essentially the highest in Canada in 1974. The rate was 40 per cent for a well producing 1,000 barrels a month and further escalated to about 58 per cent when the monthly production reached 10,000 barrels. It would seem that this royalty level, which directly affected the producer's cash flow, could only act as a deterrent to increasing the level of exploration in British Columbia much beyond its historical pattern of about fifty to sixty exploration wells a year. Other changes that may be made in regulations designed to encourage greater exploration activity will never perform to their full potential until

the producer's return is comparable with what he can obtain in other jurisdictions.

GOVERNMENT OPTIONS

We can now examine the options available to the British Columbia government in 1974. First, the government could maintain the existing regulations without change; or they could have stricter enforcement of the rules, further reducing cash flows to the producer, making it more difficult to operate; and thirdly, they could make changes designed to encourage greater exploration activity in the province. In each of these options it is assumed that some accommodation could be made between the provincial and federal authorities with regard to the revenue-sharing aspect. If it could not, then it would seem almost certain that exploration activity would decline, not only in British Columbia but also in the rest of Canada, and that even significant changes in the regulations would fail to act as an effective inducement to continued exploration.

In the first instance, if the government were to resist changes to its rules and to continue the existing level of royalty, it could expect to receive about the same amount of exploratory drilling as there has been in the past. This is evident from the sale in August 1974, where some 7.2 million dollars was paid for the right to acquire oil and gas permits, drilling reservations, and leases. This was certainly an indication that the oil industry was not prepared to write British Columbia off because of its high royalties and rather stringent regulations. There are several reasons for this. Companies have enjoyed a general increase in their cash flow, and in 1974 enough cash flow was available to pursue exploration in a province where the rates of royalty would reduce their return on invested capital as compared to other jurisdictions—for example, Alberta or the United States. The intensive competitiveness in the oil and gas industry distinguishes it from all other industries. Companies that have invested a great deal of time and money developing the geological potential of a particular area and have found that it fits their exploration parameters are prepared to offer a good deal of bonus money when this land becomes available through a competitive sale. Also, because a number of years usually elapses between acquiring an exploration permit and the development of and production from any discoveries, the economic climate may change such that what at one time is not attractive may become economic at the time of production.

If the government of British Columbia wished to discourage continued exploration by the existing oil and gas explorers and to discourage entry by newcomers, they could most effectively do this by again raising the rates of royalty and making the tenure of agreements shorter than they were. This

type of action would cause the companies exploring in the province and those contemplating doing so to restrain their activities; exploration would then stagnate.

Presumably, such action by the British Columbia government would not occur without consideration of these consequences and the recognition that a different vehicle should enter the void left by the existing explorers. This could take the form of a public company, such as the British Columbia Petroleum Corporation; alternatively, the government might feel that, given time, the major oil and gas producers, the fully integrated companies, may finish their exploration for high-reserve reservoirs in other parts of Canada and be prepared to return to British Columbia to look for the remaining reserves which they may need to supply their refineries.

To give any support to this latter proposition, one would have to presuppose that the exploration presently being carried on by the Majors in Canada in the Northwest Territories, in the Arctic Islands, and in the offshore areas of eastern Canada will be unsuccessful and that they will have to lower their sights, accept a lesser prospect, and return. This is very difficult to support, considering the successes already achieved in the Northwest Territories, particularly in the Delta, and in the Arctic Islands. Also, there is a vast geological potential remaining as assessed against the very few wells that have been drilled.

The supposition that a provincial public corporation could enter the exploration field and its endeavours be more beneficial to the province than the present system raises many questions about the corporation's practical efficiency and about the possible political repercussions. This article's purpose is not to examine the political repercussions that might occur when dry holes are drilled with public funds; however, we should examine some of the practical considerations involved in the operation of a public company which has an almost exclusive area within which to explore as a result of discouraging the private sector. For the government to discourage both the existing explorer and the entry of any new ones and to expect the public corporation to be able to fill this void suggests that the government is saying, "If the private companies do it, so can we." Now remember that the private companies comprise all the oil and gas explorers working in the province and those contemplating doing so, given the right opportunities. All these companies have geological staffs, many of whom will be geologists who devote most of their time over a considerable number of years entirely to the study of British Columbia's geology. The public corporation could not expect to have such an extensive source of expertise as that available in the free enterprise system. And so the public corporation would suffer from a reduction in the number of ideas generated.

It is not unusual in oil and gas exploration, with its inherent problem of

scientific interpretation and evaluation of geological prospects, to find that one company will acquire a block of land, will explore it, and perhaps even drill on it before deciding the search is unsuccessful. The company will then return the land to its owner, the Crown. This does not mean that there are not any commercial hydrocarbons underlying this land; but rather that that particular company was unable to find them. To find these hydrocarbon deposits, a second, a third, or a fourth company should acquire this land, and, if this is done often enough, the hydrocarbon will be encountered, and production will follow. The problem with the public company being the only explorer in the province is that, unless it is fortunate enough to make the initial discovery, it is very doubtful whether there would be enough enthusiasm to have a second, third, or perhaps even a fourth try at that particular prospect, with the result that the discovery would not be made. This is surely the worst thing that could happen and is probably the most damning argument against a public corporation moving into an area with an almost exclusive right to explore.[1]

If the British Columbia government wishes to increase the level of exploration in the province and so lead, hopefully, to a greater number of discoveries and a better position of self-sufficiency in their own requirements, there are several measures which could be taken to promote such a situation.

The first step that can and must be taken is to increase the cash flow to the producer and to assure the newcomer that if he makes a commercial discovery, he will receive a sufficient return to expand his exploration endeavours in the province. This action should take the form of restructuring the royalty on oil and probably renegotiating the contracts on gas existing between the producer and British Columbia Petroleum Corporation. The 1974 royalty rate on oil was determined by production at the wellhead, with the price not being a factor at all. This means that if the price paid to the producer for a barrel of crude oil should decrease from the present level, then the producer will suffer a decrease in his cash flow, thus his future available financing to continue exploration endeavours in British Columbia will be diminished. A preferred structure on royalty would take into account the possibility of a rising and falling price for the product so that the producer, out of whose cash flows exploratory drilling is carried out, would be the last one to suffer in the case of a decrease in price for both oil or gas. Probably this might best be accomplished by the producer selling his crude oil to the British Columbia Petroleum Corporation in the way gas is sold, but with a better pricing adjustment mechanism than that which exists with the gas contracts.

Another measure that should be taken would be a redesigning of the exploration agreement. This could be done to ensure that the holder could

only earn leases after he had conducted actual work on the permit or in the area within reasonable proximity, and that his earnings would be restricted to a consolidated block rather than come from a sprinkling of leases throughout the permit area. This feature alone would help to ensure exploration, because the permit holder must be satisfied that he is getting, at least in his mind, the right half of the permit under lease.

The manner of acquiring oil and gas rights should be reviewed. As mentioned previously, the only method of acquiring an exploration permit under the present rule is through a competitive cash bidding system usually held on a quarterly basis. There are probably several instances where an oil and gas explorer would have been quite prepared to drill wells in British Columbia if he could have acquired the land for a minimal amount rather than having to use money he would put into exploration to purchase land through the cash bidding system. The rentals and fees charged should be the same as in Alberta, if only to appear competitive in this particular area.

CONCLUSION

The exploration for oil and gas in British Columbia cannot be considered in isolation. The proportion of the reserves of oil and gas remaining to be discovered will depend upon the number of exploration dollars allocated to the task. British Columbia's competitive position for these exploration dollars will depend in large measure on its royalty and land tenure policies.

Cash Bonus Bidding for Mineral Resources

WALTER J. MEAD

Mineral leasing policy alternatives arise out of the fact that governments own mineral resources but, in general, do not engage in mineral resource recovery and processing. Hence, a need arises to transfer publicly owned resources to private enterprise at a price which will reflect the "fair market value" of the resource. The following analysis will, first, explore the problems to be solved by a bidding policy and, second, evaluate the cash bonus method of bidding for mineral leases.

THE PROBLEMS TO BE SOLVED

There are three problems which must be solved by any leasing system. First, the leasing system must as objectively as possible determine who or what firm is to be given the right to exploit publicly owned mineral resources. Second, a price must be determined which the lessee is to pay to the government for the right to recover mineral resoures held in trust for its citizens. Third, assuming that a nation wishes to economize on the use of its scarce resources and to maximize the standard of living of its citizens over time, the leasing system must result in an efficient method of production.

As a prerequisite to a discussion of mineral leasing alternatives there should be a clear statement of the goal(s) to be achieved. It is probably true that economists as a group have a preference for a single goal, declaring it to be one of economic efficiency. Natural resources available to any economy are scarce by definition. Achieving the highest possible standard of living requires that scarce resources be utilized with a maximum of efficiency. If resources are sold at a price below their true value, then the products into which they are converted may also be underpriced. If demand elasticities are less than zero, then the flow of resources into products and the flow of products within the current period will be excessive. Present overconsumption of products and resources will be at the expense of future consumption.

One way of achieving maximum economic efficiency is to price all resources at their "fair market value." Such pricing allows a government the opportunity of capturing the economic rent. Resources should be sold

for the difference between future revenues and costs, appropriately discounted to their present value. The economic principle relating prices, costs, and money flows at different points in time in order to estimate present value (PV) is shown in the following formulation:

$$PV = \sum_{i=0}^{n} \frac{P_iQ_i - C_i}{(1+r)^i}$$

P_iQ_i is the value of the gross income flow at different points in time, C_i represents associated costs, and r represents the interest rate at which future money flows are discounted to the present. The formula clearly shows that higher future prices will increase present values while higher future costs will lower present values. Further, the greater the uncertainty and risk associated with production, the smaller will be present value. Firms utilize some variation of this present value formula in calculating their individual bids. Estimates of the quantity of minerals recoverable from a given tract will, of course, vary widely from firm to firm.

If mineral leases are sold for less than the fair market value as indicated in the above formula, then resources may be used at an excessively rapid rate, and the public, as owners of the resource, will fail to receive their full economic rent. On the other hand, if mineral resources are sold at prices in excess of the fair market value then, in the long run, some operators will be forced out of business. Use of such mineral resources in the present period will be at a suboptimal rate and the public owners will receive more than their normal economic rents.

In the past, Canada apparently has transferred some of its mineral and timber resources through various negotiated transactions rather than by utilizing the auction market approach. Similarly, other foreign governments have traditionally taken the negotiated sale approach in entering into long term oil concessions.

There are major problems involved in the negotiated approach. The correct present value of natural resources is extremely difficult to ascertain. There is no objective test in advance of ultimate production that can indicate the precise present value of mineral resources. By their nature they must first be discovered. Their presence, quantity, and quality are in doubt. With the government as the seller, negotiating with a single buyer, traditional problems of bilateral monopoly are encountered. The seller is interested in maximizing price, while the buyer is interested in minimizing price. Given this uncertainty plus opposing objectives, the civil servant is placed in a difficult position.

A visitor to Canada is reluctant to criticize Canadian experience which has circumvented the market place. Fortunately there is abundant experience within the United States to indicate the shortcomings of the negotiated approach to pricing. We may formulate two general laws which

seem to govern when prices are determined or may be influenced by administrative judgement. First, the buyer will always complain. If the buyer believes that market prices can be reduced by protesting that they are too high, then complaints based on the argument that the operator cannot make a "fair profit" because prices are set too high could be endless. In the timber context, there are two cases where elaborate reports have been written protesting the high price of timber. One, presented by the Simpson Timber Company, protested against the high price of stumpage set by the United States forest service for the Shelton Sustained Yield Unit Agreement. Timber, in this case, is not sold at auction; its price is determined by the United States forest service. In the second case, the Edward Hines Lumber Company protested against the high cost of timber for its southeastern Oregon lumber mill. The timber was sold at an auction where competition was so weak that, in effect, it was sold at the administratively determined minimum price. By protesting, the company apparently felt that minimum prices could be reduced. In this instance, local community help was solicited on the grounds that if the company failed to make a fair profit, it would be forced to curtail operations. Under auction market procedures the government is relatively free from constant complaint and protest, because it is the impersonal market that determines the price rather than a civil servant. Under auction bidding procedures the buyers themselves set the price in competition with one another.

A second general law is that, where prices are set through administration, the government will always set prices short of the fair market value. A bureaucracy will rarely choose the path that makes its position unpleasant. Low prices are believed to generate less criticism and complaint than high prices. Where there is no auction market to test administrative judgement concerning the fair market value, we have no means to prove the second law. Sales of timber in the United States offer an opportunity to test the administratively determined price. Timber is sold by the forest service on the basis of an appraised fair market value, which becomes the minimum price acceptable to the government. Auction bidding begins at this price. In the four years from 1959 through 1962, competitive bidding for timber in the United States Douglas fir region produced an average high bid price that exceeded the forest service statement of fair market value (the appraised price) by 46 per cent.[1] In this case, the interests of the public were protected, at least in part, by reasonably effective competition. In the absence of this competitive check it is quite likely that the appraised prices would have been even lower. The shortcomings of the negotiated approach should lead to auction bidding wherever competition is possible.

CASH BONUS BIDDING

Before bidding can take place, a decision must be made between oral and

sealed bidding. Bidding in either form may start with a stated or unstated minimum acceptable price. In the case of timber sales in the United States, the minimum acceptable price is given by the appraised price, and most timber auctions are conducted under oral auction procedures. On the other hand, in the case of oil and gas leases conducted by the federal government in the United States, the minimum acceptable price is not published, and bidding is normally by sealed bidding procedures. The government retains the right to "reject any and all bids." After bids have been received, it determines whether or not the high bid was adequate.

The factors important in choosing between oral and sealed bidding methods are as follows:

a. Of prime importance is the extent of competition. If competition is weak, then sealed bidding with its element of uncertainty makes collusive arrangements more difficult to enforce. Under sealed bidding rules there is no second chance to bid at any given sale. In contrast, under oral bidding procedures, a collusive arrangement can be policed by the participants during bidding. Further, there is always doubt about how many bidders may appear at a given sale. In oral bidding where only one bidder is present, he will bid the minimum; whereas, in sealed bidding a bidder would probably offer an amount which he believes will win the sale under conditions of more than one bidder.
b. In the timber industry where fixed investments in milling facilities normally exist prior to sales, the buyer needs a means of ensuring access to specific raw materials and specific locations. Oral auction procedures provide this means through the opportunity to cast reaction bids. In contrast, in oil and gas bidding fixed investments are made after winning a sale, hence there is less need to protect one's position through the opportunity to react to the bids of others.
c. Where the severed resource is relatively immobile, as in the case of timber, it is of greater importance that a specific nearby sale be obtained; therefore the oral auction procedures are more appropriate. In the case of oil and gas, the severed resource is highly mobile, so obtaining a specific sale is of less importance. In this case sealed bidding is not disadvantageous.
d. Where the resource to be auctioned is not homogeneous, it may be necessary for a firm to obtain a specific sale. Where this is true, the opportunity to make more than one bid to protect one's need for a specific type of resource may be of great importance. Only oral bidding facilitates this subsequent bidding opportunity.
e. Financial planning often requires that a firm carefully limit its financial exposure. Where this is necessary, oral bidding offers greater control over a total resource financial commitment. In the case of sealed bidding,

firms may be unexpectedly successful and in the process win more sales than were desired or can be successfully financed. On the other hand, a firm's sealed bidding may be totally unsuccessful so that it becomes undercommitted. This shortcoming of sealed bidding may be corrected where resources may be freely transferred among interested buyers. This procedure is normally followed in the case of oil and gas leasing in the United States.

f. Oral bidding requires more on-the-spot decision making than does sealed bidding; therefore, oral bidding requires that a higher level of executive talent be present at the moment of the auction. In contrast, decisions made on the basis of a sealed bid offer no opportunity for subsequent action on the auction floor; therefore, the presence of expensive executive talent is not necessary.

g. The "free rider" is a problem for serious bidders under oral bidding conditions. A serious bidder will carefully examine the potential productivity of a proposed lease sale. This may, as in the case of minerals, require large investments. Under oral bidding conditions, a "free rider" can observe who is bidding, then, if he is confident that they have done their homework, he can continue to outbid them until they reach their maximum and he will win the sale. His purchase is therefore based on someone else's calculations and he, in turn, has saved the cost of the pre-exploration appraisal. Sealed bidding does not offer the free rider the same opportunity.

Once a decision has been made in favour of oral or sealed bidding, then a choice must be made on the object of bidding. A cash bonus bid is one alternative. Additional alternative bidding objects are shown in Table 1.[1]

Bonus bidding is the standard procedure used by the United States government in all of its Outer Continental Shelf (OCS) programmes. Using the present value formula given earlier, potential bidders presumably estimate the present value of the probable mineral recoverable from a tract of land. The formula provides for adequate recovery of capital and compensation for risk, uncertainty, and profit.

One strong advantage that can be claimed on behalf of a bonus system relative to royalty bidding is that it requires a lump sum payment and correspondingly modest royalty payments. Because royalty payments are due on each barrel of oil or unit of natural gas produced (or other mineral), such charges become part of the marginal cost. At the margin of production this is a transfer cost rather than a real social cost. Royalty bidding thus leads to premature abandonment of an oil or gas well. To the extent that royalty payments are required in addition to the cash bonus, there will be premature abandonment of the lease.

The disadvantages of bonus bidding are numerous. First, while the

technology for oil exploration prior to drilling has been advanced in the last century, exploration is still subject to extremely high risk. Drilling is the only definitive test to determine the presence of oil or gas. Thus, bonus bids must be submitted by bidders and accepted or rejected by the government when neither the buyer nor the seller knows whether and in what quantities oil is present. This places the seller in a position of accepting millions of dollars for nothing but the right to spend several more millions drilling potentially dry holes. In cases in which a rich oil field is found, returns to the lessee will be and must be very high.

Second, under current procedures a bonus must be paid when the bid is submitted. When the bonus bid is large, it will represent a very heavy cash drain to the bidder far in advance of any revenue which may be generated from the oil or gas produced from the lease. This significant *front-end loading* of capital costs effectively excludes a small operator from winning leases as a solo bidder, creating an additional barrier to entry into the oil and gas production market. To overcome this entry barrier, firms commonly form joint ventures and bid jointly for a lease.

Third, because the bonus is calculated on a present value basis, the government is forced to accept discount rates used by private enterprise. If private enterprise discount rates are unreasonably high from a social standpoint, then bonus payments to the government will be correspondingly low.

Possible variations of the bonus bidding form are shown in Table 1. The present United States system includes fixed royalty requirements (typically 12½ per cent or 16⅔ per cent of wellhead value). However, a bonus bid might be paired with a sliding scale royalty requirement, permitting the royalty rate to be reduced as a field declines in productivity. As the point of economic abandonment is approached, the royalty rate might be reduced substantially or even eliminated. This procedure would, in turn, eliminate a marginal cost of production that is not a real social cost, and it would permit continued production from a field until the real marginal costs equaled the marginal value of production. This is the optimum point for well abandonment from an economic point of view. If at the time that a bonus bid was submitted all bidders understood that the royalty rate would be reduced to zero under the conditions specified above, the present value of the lease would be increased by an amount equal to the present value of reduced future royalty payments. Thus a tradeoff would be effected from royalty payments to bonus payments. The principal impediment to a sliding scale lies in the difficulty of clearly identifying various points at which royalty rates would be reduced. The lessee would have an economic incentive to manage his production in such a way that minimization of royalty payments would be an operating objective, rather than economic efficiency.

TABLE I

ALTERNATIVE BIDDING FORMS

Bonus Bidding
- a. with a fixed royalty requirement
- b. with a sliding scale royalty requirement
- c. without a royalty
- d. with or without a rental payment
- e. with a profit share
- f. with delayed bonus payments

Royalty Bidding
- a. flat (nonvariable) royalty
- b. sliding scale royalty
- c. with a fixed bonus requirement or no bonus

Profit Share Bidding
- a. net profit or gross profit
- b. with fixed bonus requirement or no bonus
- c. with a royalty requirement or no royalty

Combination of Bonus and Royalty Bidding

Bidding on the Work Programme

The royalty problem, together with the administrative problem of reducing royalty rates under a sliding scale, might be avoided entirely by using a bonus bid without a royalty payment. However, this procedure would simply magnify all three of the problems associated with bonus bidding listed above.

Present procedures in the United States include modest rental charges payable between the points of sale and production. When production begins, rental payments cease and royalty payments take over. Rental payments in OCS oil and gas lease income are insignificant. In 1972, they amounted to 0.3 per cent of total revenue from such leases.[1] The rental requirement apparently was introduced to motivate the lessees toward early production. If they were of significant size, this result would in fact occur, because rents cease when production begins.

To overcome the front-end-loading problem, provision might be made for delayed payment of the bonus. The problem that would follow from this procedure is that in some cases where no minerals were found, lessees would elect a bankruptcy route. In this event, an unfair bidding situation would be created. Responsible firms in business on a perpetual basis would not follow a bankruptcy procedure and would, therefore, be at a bidding disadvantage with respect to others that contemplated bankruptcy in the event of a "dry hole."

A bill currently pending before the United States Congress provides for a 55 per cent fixed share of net profits in lieu of the existing fixed royalty payment accompanying the bonus bid. The winner would still be

determined on the basis of a cash bonus. A profit share payment would avoid the above problems associated with royalty payments. As a given lease approaches exhaustion and its point of economic abandonment, profits would also approach zero and payments would decline proportionately to zero. If the profit share was calculated on the basis of net accounting profits including fixed costs, then the profit share payment would decline to zero prior to the point of economic abandonment. The latter point is reached only when marginal cost (not total costs) equals the marginal revenue. There is nothing wrong with this system providing both parties understand how it works and bidders understand it at the time they submit their bonus bids. The proposed 55 per cent profit share is high and is likely to lead to inefficient operations. A profit share payment is approximately the same as an income tax on each well and is additional to the existing income tax. When the profit share payment is added to the existing income tax, a large part of the penalty for wasteful operations will have been shifted from the operator to the government. While a bonus bid paired with a fixed profit share payment has merit, a 55 per cent profit share added to normal income taxes is inappropriately high from an economic point of view.[4]

Some data are available to permit a partial evaluation of the effectiveness of bonus bidding with a fixed royalty. The United States experience with OCS bidding provides a record of thirty-five oil and gas lease sales during the period November 1954 to 29 May 1974. In addition, three sulphur lease sales and two salt lease sales have been conducted on the OCS. The record may be evaluated in terms of the number of bidders competing for each sale, the conditions of entry of new firms, the record of joint bidding, the extent of concentration among winning firms, the trend in price bid per acre, the resale record of tracts where the initial bid was refused by the seller, and the rate of return earned by the winning bidders. Data pertaining to OCS bidding as follows:

a. For oil and gas lease sales there has been an average of 3.6 bidders competing for each tract receiving bids. The trend from 1954 to date has been one of increasing bidder activity. From 1954 to 1966 the average number of bidders per tract was 2.7. From 1967 to date the average increased to 3.9. From the seller's point of view, even more bidders would be preferred. Given the fact of relatively few bidders, sealed bidding procedures would appear to be more appropriate than oral auction.
b. Entry into the oil and gas auction markets appears to be relatively free. In the first 1954 federal lease offshore from Louisiana, 199 tracts were offered. Ninety-seven of these tracts received 327 bids from 22

different firms, some of which bid in joint bidding combinations. From 1954 to 28 March 1974, an additional 110 firms won tracts as solo bidders or joint bidders with 1 or more other firms. Thus, in addition to the unsuccessful bidders who also perform a competitive function in the bidding process, there were 132 separate firms participating as winning bidders in thirty-three OCS lease sales.[5]

c. Entry by relatively small firms into OCS lease sale bidding is facilitated through joint bidding. Joint bidding by two or more firms each unable to bid solo has the effect of increasing competition. On the other hand, when two or more large firms fully able to bid separately combine to submit a single bid, the effect may be to reduce the number of competitors. However, if through joint bidding, even among large firms, a combination of, say, four firms bids more than four times as frequently as the individuals would have bid solo, then the effect of joint bidding can again be procompetitive.

d. The record shows some tendency toward concentrating winning OCS bids in relatively few hands; however, the extent of concentration also appears to be declining over time. For the nineteen oil and gas OCS lease sales which took place from 1954 through 1966, the eight largest buyers, sale by sale, purchased 85.5 per cent of the tracts. In the fourteen sales from 1967 to 28 March 1974, the percentage of total tracts purchased by the eight largest buyers declined to 62.0.[6]

Using the 184 leases issued in the 1954 and 1955 Louisiana oil and gas lease sales, a multiple regression analysis tested the proposition that firm size was positively related to the high bid by tract as the dependent variable. If large firms are able to outbid smaller firms, then one would expect a positive relationship. The regression analysis revealed no significant relationship between size class of firm (the eight big firms versus all others) and the amount of the winning bid. The same regression equation revealed that the high bid was also independent of whether firms bid jointly or solo. Further, the most significant independent variable related to high bid was number of bidders; the greater the number of bidders competing for any given tract, the higher will be the resulting winning bid. The total value of oil and gas production accumulated through 1967 was also positively related to the high bid. As one would expect the number of acres in the tract leased is also related to the high bid. Estimated water depth as a proxy for development cost was not significantly related to the high bid.[7]

e. Data on the average price bid per acre indicates that with the passage of time the effective high bid per acre has increased substantially. For the entire period 1954 through to 28 March 1974, the average high bid per acre amounted to $1,257.50. For the 1954-1966 period the average was

$301.71 per acre. This increased more than sevenfold to $2,219.90 per acre for the period beginning in 1967. This increase is only partially accounted for by higher crude oil prices. The average price of crude oil increased from $2.89/bbl. in the earlier period, to $3.69/bbl. in the later period. Even this increase would be offset by an unknown decrease in the probability of finding oil, and by increased costs of exploration and production.

f. Lease sales through 1 October 1964 show that of the 1,377 tracts receiving bids, seventy-eight high bid offers were rejected by the government. Subsequently, 26 of these tracts were reoffered and leases awarded. For these 26 tracts, the initial rejected high bid average amounted to $42.41 per acre. The subsequently accepted high bid on resale averaged $411.38. Thus, where bids were found to be inadequate and subsequently reoffered, competition increased bonus payments on these rejected tracts nearly tenfold.

g. The most conclusive test of the workability of cash bonus bidding based on the United States record of OCS oil and gas lease sales is in terms of the rate of return on capital earned by the successful bidders. An analysis has been made of 184 offshore Louisiana oil and gas tracts leased in 1954 and 1955. Precise data are available on bonus payments, rental payments, oil and gas royalty payments, and production of oil and gas during the period from 1954 through 1967. Cost estimates were made for exploration, well drilling and equipment, and operation. Annual cost and annual wellhead values were discounted to obtain a net internal rate of return. The calculations indicate that these early OCS leases generated a 7.5 per cent before tax rate of return to the lessees.[8] Given the fact that oil companies pay relatively low U.S. income tax rates, the after tax rate of return would be only modestly lower than the 7.5 per cent before tax rate of return. This net yield clearly does not reflect monopoly power; it shows an excessive degree of competition.

On the basis of this evidence we conclude that competitive bidding for oil and gas leases is sufficiently strong to protect the public interest in obtaining competitive values for its oil and gas resources. This conclusion is further supported by evidence presented above indicating an increase in the average number of bidders and a substantial increase in the average price bid per acre for oil and gas leases.

CONCLUSIONS

This article has examined the problems to be solved by any leasing system used to transfer publicly owned mineral resources to private firms for processing. The cash bonus bidding system has been used extensively in

the United States, particularly in the leasing of OCS mineral resources. That record has been examined in some detail. While cash bonus bidding embodies problems which have been identified, it also appears to be an economically efficient method of resource conveyance. The United States record indicates that competition has been effective, if not overly effective, in permitting the government to capture the full economic rent. In addition, bonus bidding avoids a major problem of a popular alternative, that of royalty bidding. It appears to be far superior to a negotiated approach in solving the three critical problems of resource leasing: selecting the operator, determining a fair market value, and creating a climate for efficient mineral resource recovery.

Notes

1. W. J. Mead and T.E. Hamilton, *Competition for Federal Timber in the Pacific Northwest—An Analysis of Forest Service and Bureau of Land Management Timber Sales* (U.S.D.A., Forest Service Research Paper PNW-64, 1968), p. 4.
2. For a more thorough discussion of the economic issues involved in oral auctions and sealed bidding, see W.J. Mead, "Natural Resource Disposal Policy-Oral Auctions versus Sealed Bids," *Natural Resources Journal* 7 (April 1967): 194-224.
3. U.S. Department of the Interior, Geological Survey, *Outer Continental Shelf Statistics* (June 1973), p. 43.
4. For a more thorough discussion of this point, see W.J. Mead, Testimony Presented before the United States Senate, Committee on Interior and Insular Affairs, Hearings 7 May 1974.
5. The data presented above from the OCS bidding record are from Susan M. Wilcox, "Entry and Joint Venture Bidding in the Offshore Petroleum Industry," (Ph.D. diss., University of California, Santa Barbara, 1975), p. 66.
6. Ibid.
7. The multiple regression equation is as follows:

$$Y = -9.5809 - \underset{(0.1513)}{0.2279}X_1 + \underset{(0.0111)}{0.0229}X_2 + \underset{(0.1701)}{0.1383}X_3 + \underset{(0.0544)}{0.1235}X_4 + \underset{(0.0253)}{0.408}X_5 + \underset{(0.0235)}{0.0357}X_6$$

where Y is the high bid and the unit of measure is $100,000, X_1 is the size class of the high bidder coded as 10 for instances where the high bidder is one of the big firms and as zero for all other firms, X_2 is the total value of all oil and gas production accumulated up to the end of 1967 and the unit of measure is $100,000, X_3 is the corporate structure of the high bidder coded as 10 for a joint venture and zero for a single firms, X_4 is the number of acres with a unit of measure in 100 acres, X_5 is the number of bidders per sale multiplied by 10, and X_6 is the estimated water depth. This equation accounts for 62 per cent of the total

variability in the high bonus bid. The standard error of estimate is shown in parentheses: see Nossaman-Waters, *Study of the Outer Continental Shelf Lands of the United States*, vol. 1(1968), p. 553.

8. Ibid., p. 56.

The Role of Public Enterprise

ARLON R. TUSSING

My remarks are, firstly, about the role of governmental enterprise generally and, secondly, about some of the considerations involved in using governmental enterprise to foster greater control by the citizens of Canada and British Columbia over their own mineral industries. My view is that governmental ownership of producing operations is not generally the most effective way of accomplishing the social ends for which it is currently being advocated in these industries. Nevertheless, I have a few suggestions how some of the major disadvantages of public enterprise with respect to efficiency and responsibility might be overcome.

Government owned enterprises in the English-speaking countries have seldom owed their existence to an anticapitalist ideology. It is, in fact, hard to detect any systematic difference in motive, organization, or operation between the national, state and provincial, or municipal enterprises established during the incumbency of labour, socialist, and agrarian radical parties and those implemented by Tories of various names and complexions.

Despite the vast amount of existing governmental enterprise today in capitalist countries, and despite the importance of socialist movements and socialist thought in the history of modern civilization, the scholarly literature on public enterprise is remarkably skimpy. Rigorous comparisons —theoretical or empirical—of the economic performance of governmental and private enterprises in the same industry are, to the extent I can determine, nonexistent.

GOVERNMENT OWNERSHIP

The case for government ownership of undeveloped land and natural resource stocks rests on a broader base than that for government ownership of producing enterprises. The intrinsic value of any resource in its natural state is the difference between the value of goods that can be produced from it and the cost (in terms of labour, capital, materials, and organization) required to produce those goods. The size of this residual is not the product

of any person's labour or enterprise; most of the economic value of an *in situ* resource and its appreciation over time result from such diffuse causes as the increase in population, the general advance of technology, the decline in real transport costs, or directly from governmental outlays on roads or geological mapping. On these grounds, it has become almost an axiom of distributive justice (however commonly violated) that the intrinsic value of natural resources should not be privately appropriated.

Other classical grounds for government ownership of natural resources are the desire to control external costs or capture external benefits of their exploitation, and the expected divergence of private capital costs from the social rate of time preference, which is said to result in too rapid (or too slow) development of the resource. I am skeptical about the universal applicability of the last of these arguments; who, indeed, knows what society's true discount rate should be, and why are politicians and civil servants expected to be more sensitive to it than to entrepreneurs? This reservation notwithstanding, I believe that a presumption in favour of government ownership of undeveloped land and resources is generally justified.

Turning to productive enterprise, however, there are three main economic rationales for government ownership in a capitalist society. First is the use of the state to establish or maintain productive activity that would not be profitable as private enterprise, but whose external benefits are deemed to justify a subsidy out of the public exchequer. A subsidy does not, of course, require state ownership, because either private or governmental enterprise could enjoy that subsidy. In either case, support could take the direct form of providing capital or operating expenses from the Treasury or the indirect form of tax exemptions and the use of public resources at less than their cost of fair market value. State ownership, however, may well make a subsidy more palatable to the public, because it does not conspicuously enrich (or appear to enrich) a few private entrepreneurs.

Within the category of public ownership as a vehicle for subsidization are the numerous instances of private enterprise socialized because of chronic insolvency or imminent liquidation, including the Canadian National Railways, most of the British Labour Party's nationalizations after World War II, and the recent takeover of rail passenger transportation by the United States government.

In other cases, the motive for government ownership has been the creation of "public goods," products (or by products) of an enterprise whose value a private owner could not expect to recover by market pricing. Examples of such externalities are flood control by hydropower projects and the promotion of literacy and national unification by the postal system.

Military necessity has been another justification for producing goods in state enterprises which might not meet the test of the private market.

Nineteenth-century America had government lead mines and arsenals and plantations for naval stores; the processing of nuclear fuels now remains a governmental activity on security grounds. Many public transportation and communications ventures were begun as defence projects in Alaska, the Yukon, and British Columbia: examples are the ALCAN highway and the White Alice communications system.

Second among the rationales for public enterprise is the perceived inability of private business, because of the great size or risk of the venture in question, to assemble sufficient capital. This tradition in North America began with state ventures in canal and rail development in the early nineteenth century, then extended to river control and irrigation projects, and continues into the present in enterprises like COMSAT and Panarctic Oils. In many of these cases, the proposed activity was expected to be self-sufficient in the long run, on the basis of the revenues from its product or service, but state initiative was seen as necessary to take advantage of scale economies or to overcome high risk threshholds.

The third circumstance seen to justify government ownership is possession by an enterprise of monopoly power and/or exceptionally rich natural resources, either of which can produce substantial "unearned profits" or rents. Government ownership is one means either of preventing monopoly exploitation of consumers (or monopsony exploitation of workers and sellers) or of collecting for the public treasury monopoly profits or resource rents that would otherwise be captured by the private owners.

Government takeover of profitable businesses has been rare in the English-speaking world. There have been a few instances of ideologically motivated nationalization, but it is instructive to note that these have often been reversed, as in the cases of the iron and steel industry in Britain and, more recently, the grain trade in India. The remaining cases have principally been those of utilities—grain elevators, street railways, water, electrical or telephone systems—which had a monopoly ("natural" or otherwise) in a local service area. In the last category it is often hard to distinguish between the instances where government took over to prevent private exploitation of monopoly power and those in which government saw a monopoly as an opportunity to exploit an assured source of revenue for itself.

There are, of course, a variety of cases which overlap two or all three of these categories. Economic development of a poor or sparsely settled region is often advanced as a justification for public enterprise in transport, communications, or electrical power. In these instances the premise is often that the region lacks capital or capital markets and only the state can mobilize resources on the desired scale. At the same time, the project is seen to encourage growth by its ability to widen markets or otherwise cut costs for commodity producing sectors of the regional economy. Once estab-

(including the National Energy Board) who place the highest priority on national self-sufficiency in one or another mineral resource tend to advance policies that *deter* investment, on the grounds that the beneficiary of current development tends to be the export market, at the cost of future diminished Canadian self-reliance. In this country, moreover, balance of payment effects are often used as part of a case *against* mineral development for export rather than in favour of it. In a world of floating exchange rates, however, one might question whether there is any relevance at all to the balance of payments problem in its usual sense. Finally, the impacts upon environmental quality and the dispersion of population are more likely to be regarded as external *costs* of mining than as *benefits* that justify the government's promotion of mining ventures that otherwise would not be self-supporting.

It is hard to make a respectable case that mining (including oil and gas production) creates beneficial *externalities* for the surrounding community, as distinct from the net value of the minerals produced, or the factor payments (wages, profit, rents, and taxes) which make up that value. The current Canadian interest in state enterprise in the mineral industries does not seem, in summary, to be a result of the belief that they are inevitably unprofitable under private enterprise. On the contrary, it rests in part upon the notion that mineral extraction can indeed be very profitable, and that unearned profits (rents) ought to be controlled and disbursed in socially approved ways. This attitude is sometimes experienced as a concern whether the people of the nation or of the province, who are the nominal owners of its natural resources, are receiving as high a return for the products of their land as they might. One issue is, in short, whether the state is effectively maximizing its revenues from disposal of minerals.

Where effective capital markets exist together with a large enough number of potential operators to create workable competition for resource rights, the government (as landlord and/or sovereign) is more likely to maximize its revenues if it does *not* engage in production. This conclusion does not presume that particular government owned entities are necessarily less enterprising and less effective in cost control than profit motivated private corporations. There may well be a bias against efficiency in most forms of state enterprise, if only because their owners (the public) and managers do not have a clearly defined standard of performance as private managers have in the imperative to maximize the present worth of their firms. But more importantly, by operating a productive enterprise in the extractive industries, the government loses the ability it would otherwise have as landowner to exploit the competition among potential private operators.

At oil and gas lease auctions in the United States, for example, the bid prices on a single tract may vary by a factor of two, ten, or even one

lished, moreover, such an enterprise may have a monopoly status, with the power to abuse or exploit that status, and seem thereby to demand public control or ownership.

Many governmental enterprises (and regulated utilities, which they resemble in important respects) combine subsidies for some activities with appropriation of monopoly rents or resource rents from others. A common practice in both regulated private firms and government enterprise in transportation, communications, and utilities is *cross-subsidization*, in which monopoly profits earned from one area, line of business, or class of customers are dissipated in subsidizing others that are deemed to be socially meritorious. Thus, airline and railroad tariffs on heavily travelled route segments typically exceed cost (including a "fair" return), while service on lower density segments is provided at a loss. Hydroprojects in the Western United States typically subsidize users of irrigation water from revenues earned by water sales to municipalities and industry and by sales of electric power. In Alaska, revenues from both state and federal timber sales are sacrificed to support otherwise uneconomic lumber and pulp mills.

Turning to the mineral industries of Western Canada, there is little evidence that suggests they need to be subsidized by formation of a public corporation or otherwise. The province of British Columbia does not have, for example, a great but decaying industry upon which the community depends both for energy and employment, as the British had in the coal mines of the 1940's.

The British Columbia-Yukon Chamber of Mines may occasionally assert that each mining job generates seven additional jobs in supporting industries, but there is no respectable analytical foundation for such a claim. Even if the extractive industries had such an employment multiplier, it does not necessarily follow that job creation *per se* is a benefit that deserves subsidization from the public purse, much less the creation of a government enterprise. New employment opportunities are a *net* benefit to the existing community only to the extent that they are filled by residents who would otherwise be unemployed or working at more poorly paid jobs. In an "open economy" like that of British Columbia or Alaska, there is no predictable relationship between local job creation and local unemployment, because new employment opportunity attracts immigrants who tend to offset the employment gain. Even if the new jobs directly created were reserved for long-time residents, displacement of residents from old to new jobs and their replacement by nonresidents can be expected to make overall unemployment rates relatively unresponsive to employment growth.[1]

National self-sufficiency in minerals and the earning or retention of foreign exchange are sometimes claimed as external benefits of mining that justify preferential treatment. In Canada, paradoxically, some of those

hundred. These variations reflect widely differing geological evaluations of the tract, exploration strategies, and capital and other costs. Thus each tract tends to be won by the bidder with the *most favourable combination of capital cost and expectations* among all the bidders regarding future product prices, the particular tract's recoverable reserves, and their development and lifting costs. The landlord (state or private) who operates on his own land, however, would have only one management team, one exploration strategy, one team of geologists and engineers, and one supply function for capital. Only by rare accident would the landlord's *actual* performance over the average of all his properties tend to be better than the *expectations* of the most optimistic bidder. If, therefore, he were to lease each tract to the highest bidder among the competing operators, he might anticipate receiving a greater net revenue on each property than he could expect from developing the property himself.

The foregoing prediction is implicitly supported by empirical studies of United States Outer Continental Shelf leasing by Walter Mead and others, who show that successful bidders on the average earn a discounted cash flow rate of return on lease acquisition costs substantially less than the oil industry's average rate of return on capital (see Mead's article, "Cash Bonus Bidding for Mineral Resources," contained in this volume).

The effective use of competition to optimize revenues does not dictate the use of a cash bonus bidding system for *all* minerals or even for petroleum under every circumstance. The degree of knowledge or uncertainty regarding the volume and value of minerals present and their cost of extraction, the relative weight of fixed and variable costs in total extraction costs, the number of potential competitors, and the relative preferences of the government and private operators for certain present income versus uncertain future income are all appropriate considerations in the choice of leasing or disposal systems and taxes on the mineral industries. These questions have been discussed elsewhere,[3] and other articles in this volume give close attention to the relative merits of location, leasing, and sale as systems for disposing of minerals; to royalties and severance taxes, and whether they should be reckoned on gross value or net profits; to bidding on cash bonuses, deferred bonuses, gross or net royalty rates; to the use of acreage rentals; to the optimum size and configuration of tracts; to the amount of geological information the landlord ought to obtain and publish before opening land for lease or disposal; and to the duration of the primary term of a lease or permit, its terms for renewal, and so on.

In summary, state enterprise in the business of developing and producing minerals is surely *one* way to capture and redistribute resource rents, but it is unlikely to be as effective a device for maximizing those rents as the combination of a leasing system that takes full advantage of competition

among private firms (considering the technology and institutional characteristics of each branch of the mining industry) and an appropriate tax system.

The most powerful cases for public enterprise in developing regions (like much of Western Canada and the Territories) relate to transport facilities which create external economies for other economic sectors, including mining. In these instances, both the first motive for socialization (the desire to subsidize) and the second (the need to overcome barriers of scale and risk) may justify investment by the government on projects into which private enterprise will not venture. Neither of these motives, however, creates a case for state enterprise in mineral extraction. Capital and enterprise for mineral exploration and development are plentiful and mobile. Specialized technical inputs, such as geophysical surveys, drilling, and heavy construction can be purchased on contract in a highly competitive market (so that great petroleum and mining companies carry out very few of these activities themselves). Capital sums in the hundreds of millions, or even billions of dollars can be mobilized privately, even without government guarantees, for projects like the Trans-Alaska pipeline, in remote regions.

Development of minerals, like the collection of revenues from their development, is likely to be more rapid and more efficient if it utilizes the diversity of skills, techniques, enterprise, and access to capital in the private economy and the competition between firms differently endowed in these respects. Nationalization or municipalization of producing operations, in my view, has an inevitable price—both in state revenues and in social efficiency—the payment of which must be justified on other grounds.

The hard core of Canadian interest in public enterprise today seems to stem not from a perceived shortage of capital and entrepreneurship (much less an ideological opposition to capitalistic enterprise as such), but from a perceived surplus of foreign capital and entrepreneurship. The problem, it seems, is to assure that mineral development (and, presumptively, related activities like oil refining or oil and gas transportation) are under the control of Canadians or the people of British Columbia, rather than great multinational (read United States) corporations.

It is probably not politic of me as an American to ask what practical difference the nationality of a company's owners or management makes as long as it is subject to the same laws (and obeys them) and pays its proper share of taxes. Foreign companies in Canada have often been berated for not paying enough taxes, but it was after all a *Canadian* decision, reflecting a long-standing Canadian developmental philosophy that the extractive industries should remain largely untaxed. The satisfactions and grievances of Americans regarding the major oil companies apply in the same way to

Mobil and Texaco, which are domestically controlled, as they do to Shell and Sohio, which are foreign controlled. I am afraid I don't see how any more in the way of real resources for Canadians could be squeezed from a government owned business than could be squeezed from American or Canadian owned private enterprise under a well designed leasing and tax system. Nevertheless, one billion American dollars invested in Canada is more conspicuous than one billion Canadian dollars invested in the United States, and the nationality of your managers and stockholders obviously does make a difference to many Canadians. (I must confess, also, that some Americans become hysterical about the very idea of the Arabs or Persians taking over United States businesses.)

Government enterprise is one way to "nationalize" the mineral industries, but it is not, of course, the *only* possible way to foster Canadian equity and enterprise. Stricter nationality criteria could well be applied to holders of claims and leases or of permits to build pipelines, concentrating plants, and refineries. Such policies raise the further question, however, whether there is in fact enough private equity capital and enterprise in Canada to effectively take the place of foreign equity and enterprise. This is an empirical question to which I do not have an answer. If the answer is negative, consideration must be given to the fact that establishing a government enterprise does not *create* any new Canadian resources. It only uses tax money or potential resource revenues to bid capital and talent away from some other employment in Canada. The cost of Canadianization (either by restrictive licensing of private industry or by government enterprise) may be minimal, however, if preferences for nationals result in bidding home significant amounts of Canadian capital and Canadian talent which would otherwise be employed in other countries. (Presumably the net effects of even these moves would have to take into consideration remittances that would otherwise flow back to Canada from investments abroad.)

Government capital need not be regarded strictly as a *substitute* for private capital, Canadian or foreign. In North America during the first half of the nineteenth century, and in almost every country at one time or another, state companies were used as a vehicle to *attract* foreign debt or equity capital, usually British, to ventures they would not otherwise consider. A government owned (or guaranteed) railroad company was often naively regarded by Lombard Street as a safe investment, while the promotions of unknown overseas entrepreneurs were viewed with little regard in the world's principal money market.

The use of government participation is still a major instrument for encouraging foreign investment in developing areas. Joint ventures between American, European, or Japanese private companies and governmental entities of the host country are common in almost all the extractive

industries and in many countries at different levels of economic development. Canada has at least one government enterprise created largely with this function in mind, Quebec's SOQUEM, whose activity consists mainly of joint ventures in mineral exploration with private companies. Petro Canada also *seems* to be interested in this kind of approach.

In addition to being a means by which domestic enterprise becomes a trustworthy borrower (or partner) of foreign capital, state enterprise can also be a means of offsetting a shortage of domestic equity and entrepreneurship. In this role, it has one advantage over promotion of domestic private enterprise through nationality restrictions on investment, management or licences: it avoids the spectre of open discrimination, which could lead to retaliation and might otherwise undermine trade and investment relationships that are beneficial to Canada. The nearly open border allows this country to draw on a much larger pool of capital, technology, and talent than it would with policies fostering autarky. Although this openness is a major element in the ambiguity and insecurity of Canada's national identity, its economic benefits to Canada are relatively greater than they are to the United States. (That is, its impact on the size of the resource pool available to Canada is greater than on the size of the pool available to the United States.) It is therefore a circumstance to be modified only carefully and selectively. Establishing a provincial oil company is one way of containing the side effects of a move in the direction of autarky in a single industry. Such a move might, in fact, limit these side effects even in the industry in question. Suppose the best candidate for executive officer for a British Columbia based oil company were a Texan; there might well be fewer misgivings about hiring him to work for the province than about his heading a subsidiary of an American private firm.

I will conclude this article with some suggestions for the structure and policy of public corporations in the mineral industry, suggestions aimed at combining some of the best features of government and private enterprise, rather than their worst.

First, before establishing a governmental enterprise, be clear what its purpose is to be, what the incentive for the management to accomplish that purpose will be, and, quite rigorously, what will be the measure of the enterprise's success. (I owe this first and most vital point to Milton Moore's critique of the draft of this article.)

Second, do not set up a monopoly. There is no surer formula for inefficiency and social irresponsibility. Economies of scale do exist in mining and petroleum exploration, but they are very small when compared to some other industries or relative to the opportunities for development in an area the size of British Columbia. In petroleum refining, the minimum efficient size of a refinery is probably about the size of the British Columbia

market for petroleum products, but if a new government owned refinery needs a monopoly or protectionist legislation to be profitable, it will almost certainly be a serious burden on consumers. Industries in which scale economies are narrow and where ingenuity and intuition are still crucial, as in mineral exploration or onshore oil and gas production, are probably not the most appropriate candidates for nationalization; but where it is determined to establish a state enterprise, consideration might be given to the establishment of more than one competing public enterprise.

Third, do not clothe the corporation in sovereign immunities. Such immunity can be, and often is, a cover for inefficiency, irresponsibility, and even lawlessness. The corporation should be suable; it should pay taxes or their equivalent (federal, provincial, and local); and it should be subject to environmental and safety laws and regulations and, above all, subject to the bankruptcy laws. Its operations should not be protected by any version of an official secrets act. There is no good reason why the directors, officers, and employees should be excused from the same civil and criminal liability for their actions to which their counterparts in private enterprise are subject.

I would urge hesitation even in providing guarantees for the corporation's debt. A public mining or oil corporation will be pursuing a line of business in which private enterprise regularly borrows money without such guarantees. The more intense scrutiny of bankers and underwriters toward a corporation whose debt must stand on its own merit might well save the corporation's owners—the public—more money than the small interest differential associated with government guarantees.

Fourth, give the public and the corporation's officers and staff a material interest in its success and its efficiency. The government need not hold all the shares but only a controlling interest, not necessarily even a majority. One block of shares (enough to elect at least one director) can be held in trust for the company's employees and voted by them. The remainder of the shares would be offered to the public; they would be voted by their owners and publicly traded. Not only would this provision broaden interest and participation in management, but the market price of publicly traded shares would be a continuing indicator of management performance and of the value of the government's equity. I see no compelling reason to restrict share ownership to residents; it might in fact be useful to encourage minority participation by major oil companies or mining companies. A residence requirement for shareholders, however, would reinforce symbolically the corporation's identity as a national or provincial instrument, and would, of course, limit remittance of dividends abroad.

Fifth, the corporation's policies should be responsive to public policy but not bend to every political wind. I would suggest that only a minority of the

government directors serve at the pleasure of the Cabinet and be regarded as spokesmen for its policies. The remaining directors representing the government's equity would be chosen indirectly for long and staggered terms.

Sixth, the corporation should be under pressure to pay dividends. A majority of the shares (and directors) should represent parties who have a material interest that the corporation *not* retain, reinvest, or dissipate all its earnings: private shareholders, the employees, and the members who serve at the pleasure of the Cabinet (who would presumably be responsive to the fiscal interest of the government). The influence of this group will be a constant corrective to tendencies of management, inside directors, and permanent directors toward complacency, empire building, pyramid building, or gold plating.

Seventh, maintain a clear distinction between the corporation and the government as landowner. The public enterprise should obtain resource rights on crown lands only in competition with other prospective operators. The corporation should not receive a concealed (and indeterminate) subsidy by access to resources at no charge or at a lower price than a competitor might offer. If it must have a preferent right, let it be at most a right to match the highest bidder.

A preferent right on the best offshore leases is a feature of the federal oil and gas corporation (FOGCO), proposed recently in the United States Congress. In view of the prices oil companies have been recently willing to spend in these lease sales, such a preference would guarantee that FOGCO would appear profitable, however incompetent its management, and that the federal treasury would lose billions of dollars in lease revenues.

Eighth, take advantage of the division of labour and competition. The corporation should not attempt to do for itself the things that even the greatest oil and mining companies contract out to others, such as seismic surveying, core drilling, well drilling, well logging, and construction. There is virtually no chance that a state corporation could improve on the performance of private firms in these exceedingly competitive areas.

In summary, I am generally skeptical of the case for public enterprise in the minerals industry but hopeful that such enterprises could be established free of many of their usual shortcomings, providing some thought is given to their purpose, organization, and standards of performance.

Notes

1. In a study aimed at projecting the employment impact of the Trans-Alaska pipeline, we found that *unemployment* in individual labour market areas was almost totally insensitive to the level of *employment*; that is, on a *net* basis, at least, new jobs in Alaska's petroleum and wood products industries and government were entirely filled by immigrants. [Arlon R. Tussing; George W. Rogers; and Victor Fischer, with Richard Nogg and Gregg Erickson, *The Alaska Pipeline Report: Alaska's Economy and Gas Industry Development and Impact of Building and Operating the Trans-Alaska Pipeline*, Institute of Social, Economic and Government Research Report no. 31 (Fairbanks: University of Alaska, 1971)].
2. Arlon R. Tussing and Gregg K. Erickson, *Mining and Public Policy in Alaska* (Fairbanks: Institute of Social, Economic and Government Research, University of Alaska, 1969).

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March 2, 1978

Ms. Kay Poland, Chairman
Senate Committee on Resources
Pouch V
State Capitol
Juneau, Alaska 99811

Dear Ms. Poland:

Enclosed are written copies of my testimony of February 24, 1978, to the Senate Committee on Resources.

Thank you for giving me the opportunity to testify before the Committee on February 8 and February 24.

A question raised by Senator Croft with respect to the income to be earned by the various companies after production and transportation of crude oil to the lower-48 states was not answered correctly. This crude oil merely supplants foreign crude oil and thus refining, marketing, etc., income as reported in the companies' 1976 financial statements and used in our study will be unchanged.

Very truly yours,

ARTHUR ANDERSEN & CO.

By Robert L. Moore
Robert L. Moore

Encl.

SENATE RESOURCES COMMITTEE

TESTIMONY OF ROBERT L. MOORE

FEBRUARY 24, 1978

My name is Robert L. Moore and I am a tax partner with Arthur Andersen & Co., Houston, Texas. The purpose of my testimony today is to respond to the testimony, questions, or comments of others (particularly the Alaska Department of Revenue's testimony and memorandum of February 22, 1978) concerning the Prudhoe Bay Field and Trans-Alaska Pipeline System Comparative State Tax Burden Study, dated January 16, 1978.

The three principal topics I shall address may be categorized as follows--(1) the scope and methodology of the Arthur Andersen & Co. study (study),(2) a study assuming the Prudhoe Bay Field (Prudhoe Bay) and Trans-Alaska Pipeline System (TAPS) were moved to each of the seven states in the study, and (3) a study of Alaska oil and gas tax laws assuming they were applied to each of the other seven states' facts.

SCOPE AND METHODOLOGY OF ARTHUR ANDERSEN & CO. STUDY

Cook Inlet area-

In my testimony presented February 8, 1978, the question of Cook Inlet's inclusion in the study was discussed. What was said then, and repeated now, was that Cook Inlet oil and gas is not a significant contributor to taxes under any states' system when compared to Prudhoe Bay and TAPS. The reasons are (1) the reserves, production, investment, net income, etc., i.e., facts used in measuring tax

burden, attributable to the Cook Inlet area, even though significant in and of themselves, are not significant when compared to those of Prudhoe Bay oil and TAPS, and (2) it is not clear what the relative tax burdens would be on Cook Inlet. Milton Lipton testified January 25, 1978, before this and the House Resource Committee (see page 44-45 of transcript of his testimony) that Cook Inlet was presently producing about 120,000 barrels a day, only about one-tenth of Prudhoe Bay's production. In addition, the Cook Inlet has been producing for about 17 years and does not have the remaining life of Prudhoe Bay nor does it have the net-income-producing capacity of Prudhoe Bay and TAPS.

With respect to tax computations, all significant state taxes must be included. To compare only Alaska severance tax to other states' severance tax is only part of the picture. Alaska severance tax is progressive vis-a-vis volume of production per well and thus, according to the Legislative Affairs Agency's January 31, 1978 memorandum, Alaska severance tax in Cook Inlet would rank only fourth among the states assessing a severance tax. Yet, other taxes are also progressive in nature--California assesses ad valorem tax on reserves (35-40% of total California taxes in the study), but only to the extent such tax exceeds the ad valorem tax on production hardware (even in Prudhoe Bay, the study found that such tax would be eliminated in the 13th (noninflated) and 14th (inflated) years). Thus, it is reasonable to assume that California would assess no or only a nominal reserves tax in the Cook Inlet area.

In addition, ad valorem tax on reserves and/or field hardware for New Mexico and Oklahoma, two states which would assess higher severance tax on Cook Inlet than Alaska according to the Legislative Affairs Agency's January 31, 1978 memorandum, are a small fraction (7% and 24%, respectively) of Alaska's ad valorem tax on such property. Louisiana, the third state which would assess more severance tax than Alaska according to that memorandum, would assess ad valorem tax of only about two-thirds of Alaska's.

In summary, any change in direction in the relative rankings of the states is uncertain but in any case would appear to be nominal. Mr. Lipton's testimony (page 45 of transcript) that the change in rankings, had Cook Inlet been added, would be less than one percent is probably accurate.

Pre-1977 tax burdens-

Obviously one must begin and end somewhere in preparing projections or studies such as this. We began with 1977--the year in which production began, the year the new Alaska severance tax was put into effect, and the year immediately preceding the year in which the proposals for income tax change were to be effective. We ended the study 25 years later when the bulk of proven reserves will have been produced.

However, even if years before 1977 were considered and additional sales or use tax of the other seven states were included, using the Department of Revenue's estimates the increase in tax would result in only a minor change (2.6 to 4.1 percent of Alaska's non-inflated tax) in the relative ranking of the states.

Also discussed in the Department of Revenue's memorandum is California ad valorem tax on reserves and production hardware. California assesses tax on reserves before production, but two limiting factors are apparent--(1) the value of reserves would be discounted substantially (30-40 percent before pipeline construction and 25-30 percent during construction) when they have no deliverability, and (2) as noted above, the reserves tax is not applied if the hardware tax exceeds it in amount. Consequently, the California reserves tax will probably not yield any significant increase in taxes, and possibly none at all.

Ad valorem tax on production hardware is generally assessed before production in the various states, but Alaska's overall tax rate (considering valuation, assessment rate, and tax rate) is higher than all states other than California.

Thus, with respect to pre-1977 tax burdens, it may be concluded that, had these taxes been considered, California would be closer to Alaska, but there would be little change in the ranking of the other states.

Other possibly productive areas-

Gas production from Prudhoe Bay was considered at the time of preparing the study, but data on gas was regarded as too speculative to yield meaningful tax results. Questions of cost of the pipeline and price of gas are still unresolved and probably will remain so for some time to come. The time for making meaningful projections with respect to gas production, transporation and sales in order to determine tax burden should be done at some time in the future when

more reliable data is available. These observations also hold true for the Kuparuk and Lisburne fields.

Moreover, since the severance tax is the primary source of Alaska's tax revenues (almost 50 percent) and since its rate (at the higher of 10% of wellhead value or 6.4¢/MCF) times the Economic Limit Factor (ELF) will probably be the highest (or among the highest) of the states, it does not appear that a significant impact on relative state rankings would occur if and when gas is considered. The gas severance tax rates are:

Alaska	10% or 6.4¢/MCF X ELF
California	None
Louisiana	7¢/MCF
New Mexico	4.69% + 5¢/MCF
Kansas	None
Wyoming	4.0%
Oklahoma	7.0%
Texas	7.5%

Assuming ELF is 80% (it was approximately 84.0% for oil in the study), at $1.00/MCF value of gas at the wellhead, Alaska's severance tax will exceed all except New Mexico's, a low-tax state. At a higher wellhead price (above $1.52/MCF), the Alaska severance tax will exceed all states' severance tax--even New Mexico's. At 75¢ or 50¢/MCF gas price, only Louisiana's and New Mexico's severance taxes exceed Alaska's. Also note that the Carter Administration has proposed a $1.75/MCF wellhead price for domestic interstate gas and that

intrastate gas is selling for about $2.00/MCF presently.

Alaska severance tax computations-

The annual versus 25-year computation yields only $82 million less tax, i.e., less than 1% of total tax attributable to Alaska.

Income tax calculations-

Timing differences-

Alaska's relative income tax burden has not been overstated. No timing differences, e.g., accelerated depreciation, deduction of intangible drilling costs, etc., were taken into account because over the 25-year period all or substantially all such timing differences will reverse for Alaska, United States, and worldwide. For example, the current deduction of intangible drilling costs will reduce income tax for year 1, but will result in higher income tax for following years. Consequently, no attempt was made to compute income tax based on such timing differences.

In addition, because of such timing differences (and 1977 being only a partial production year), the comparison of expected tax collections for a particular year, e.g., 1977 or 1978, with the study's total Alaska income tax divided by 25 is an incomplete analysis.

Apportionment to Alaska-

Worldwide income for each company for 1976 was added to the study's calculations of "Net income from Prudhoe Bay Field and TAPS (A + B)" to arrive at total income, which was apportioned to Alaska on Exhibit VIII(a) Noninflated (and Exhibit XVI(a) Inflated) pursuant to Alaska's apportionment formula. There is no misapplication

of Alaska income tax law. The calculation of Alaska income tax in the study is correct as computed.

Effective tax rates-

It has been asserted that the Alaska effective income tax rate using calculations of income and tax in the study is significantly less than Alaska's 9.4 percent statutory tax rate. To the contrary, Exhibit VIII(a) Noninflated (and Exhibit XVI(a) Inflated) portrays only the amount of income added to all other business of the various owners. It does not address itself to, or make a determination of, the question of source of income which is a determination made by law, not accounting. Such exhibits do not hold or determine that the income is Alaska income.

MOVE PRUDHOE BAY FIELD AND TAPS TO OTHER STATES

The prospect of moving Prudhoe Bay and TAPS to the other states was considered at the time of preparing the study and rejected because it was a departure from facts necessary to get a valid comparison, i.e., speculation would be necessary with respect to (1) price of oil; (2) costs and period of development and production; (3) costs and period of pipeline construction, etc. So many assumptions would have to be made that results could possibly vary depending on which, among reasonably supportable assumptions, were used.

For example, would domestic oil prices be used, and, if so, would "old" or "new" prices be applicable? What would Prudhoe Bay development cost be if it were located in, say, Texas? Would an oil pipeline

be necessary? How much would TAPS cost if it were located in, say, California? When would the field development and pipeline construction have been completed had it been located in, say, Kansas? What would operating expenses attributable to production be?

As a consequence, we do not believe that any such computation may be used as even a check on calculations dealing with existing facts and laws.

APPLY ALASKA TAX LAWS TO OTHER STATES' FACTS

The possibility of applying Alaska's tax laws to the other states' facts was also considered at the time of preparing the study and rejected because (1) it would be a departure from Alaska facts and (2) the job would be very time-consuming (and therefore expensive) in order for it to be done completely and properly. The approach taken is direct and to the point. It deals with existing facts and applies existing laws to such facts. To test the results of the study against different facts seems to be an extraneous exercise.

In addition, an enormous amount of data must be reviewed, assembled, and converted to meaningful tax data in order for ad valorem, severance, and income tax to be computed. Each of these states has thousands of wells and leases and thousands of owners. For example, to determine Alaska income tax for each state, it is necessary to know gross income and expenses for each state (all properties and all fields) which would be added to worldwide income (of all such companies, individuals, etc., operating in the state). To determine Louisiana or Oklahoma income tax, gross income and expense by well is necessary in order

to determine the depletion allowance. To determine Alaska severance tax, knowledge of all wells with more than 300 barrels/day production in each state is necessary. The job could probably be done by using estimates and total figures, but probably would not yield results close enough to actual facts that they would be a good test of the calculations made.

Lastly, at least with respect to the Alaska severance tax, a departure from Alaska facts may produce distorted results. Such tax is designed for high-volume (in excess of 300 barrels/day) wells, a generally required fact for Alaska operations, whereas low-volume wells can be and are operated profitably in the other seven states. Since the other states use a flat-rate severance tax, i.e., no adjustment is made for production volumes, low and high-volume profitable wells can be accommodated by such states' severance taxes, whereas the opposite (Alaska severance tax on other states' wells) is not true with respect to low-volume wells.

STATEMENT

OF

BRISTOL BAY NATIVE CORPORATION

February 9, 1978

Madam Chairman, my name is Donald F. Nielsen, a shareholder and Vice President of Bristol Bay Native Corporation.

We are opposed to S.B. 236 or any other proposal to establish an oil and gas corporate franchise tax. Under the terms of our agreement with a major oil company, if oil or gas is produced on our lands, we will share in the production and would become a producing oil company. The market for our production would be outside of Alaska. The figure in excess of $250,000,000 gross receipts may be of some protection in the immediate future; however, there is no assurance that if such a proposed bill becomes law that this figure could not be adjusted downward to fit any given corporation, nor does it take into account any future price increases.

As an Alaskan corporation, we do not feel we should be required to keep separate accounts and pay any different tax than any other normal Alaska corporation. Also, we feel the proposed franchise tax, if passed, could later be applied to other industires such as mining, all of which tends to discourage major investments and financing of any type of investments in Alaska. The same reasoning applies to any burdensome tax policies that that effect Alaska's investment climate. Thank you.

CITIES SERVICE MINERALS CORPORATION
A SUBSIDIARY OF CITIES SERVICE COMPANY
1016 WEST SIXTH AVENUE
ANCHORAGE, ALASKA 99501

DON STEVENS, PH.D.
DISTRICT GEOLOGIST

(907) 272-9441

March 17, 1977

Mr. Bill Bishop
Bristol Bay Native Corp.
445 East 5th Avenue
Anchorage, AK 99501

Dear Bill:

Mr. Ranspot and I want to thank you and the Bristol Bay Native Corporation staff for the courtesies extended during our meeting last week. We found our review of the Bear Creek Mining Data to be most interesting and, in fact, these data exceeded our expectations. Bear Creek Mining has done an excellent job in its investigation of porphyry type targets.

As I mentioned on the phone, we have had to decline entering into an exploration agreement with Bristol Bay Native Corporation for a number of reasons in spite of the excellent mineral potential indicated by the data reviewed.

Certainly one important reason for being very hesitant to engage in new minerals exploration programs has been the Hammond administration's attitude toward mining taxes. Not only are attempts being made to adversely change the present mining license tax but several comments by the administration have indicated that an additional severance tax bill is going to be introduced in the next session of the legislature. One needs only to look at what has happened to taxes on oil and gas production in the last ten years to believe that the same thing will happen to the mining industry. With the high capital costs and the high infrastructure costs in mine development in Alaska a high tax burden will simply eliminate any chance for development of a mining industry.

The attractiveness of possible mining operations on native corporation land is being outweighed by the ever more burdensome tax policies generated in Juneau.

Sincerely,

Donald L. Stevens

DLS:bh

CHARTS USED IN SUPPORT OF

TESTIMONY

BY:

W. Monte Taylor
Alaska Operations Manager
Exxon Company, U.S.A.
Anchorage, Alaska

To The

State of Alaska
Senate Resources Committee
February 10, 1978

KEY DISCUSSION TOPICS

- Continued development of its natural resources is important to Alaska.
- A reasonable tax climate is important to continued natural resources development.
- By any measure, the oil industry is already paying more than its equitable share of the operating costs of the State of Alaska.
- Any increase in taxes would be counterproductive to the state's best interests.

TAXATION FAIRNESS

Method of Measurements

Compensate for cost of state services.

Equity among taxpayers.

Comparison with other states.

Status of Oil Industry

Industry pays 67% of tax income. Does not require services approaching that level.

Industry pays more taxes as a percent of income than any other Alaska business.

Alaska has the highest tax burden of any of the major oil producing states.

TESTIMONY OF

W. MONTE TAYLOR

BEFORE SENATE RESOURCES COMMITTEE

FEBRUARY 10, 1978

JUNEAU, ALASKA

I am Monte Taylor, Alaska Operations Manager for Exxon Company, U.S.A. My purpose today will be to comment on the overall implications of the bill being considered by this committee. Exxon presented detailed testimony to this committee last year on this bill and other proposed tax legislation and I do not intend to repeat that prior testimony except to update and highlight some of the key points. I have distributed a handout package that will help illustrate some of the key points of my testimony. The first page outlines the areas that I would like to discuss. These are:

1. Continued development of Alaska's vast natural resources, including oil and gas, is important to the state, both as a direct revenue source and as a source of direct and indirect employment opportunities.

2. With Alaska's high operating and investment costs which are related to its location and harsh environment, a reasonable tax climate is an important factor in attracting future investments.

3. By any measure, the oil and gas industry is paying more than its equitable share of the cost of state government and will continue to do so under existing tax laws.

4. Any increase in taxes at the present time will act as a further disincentive to future development and will be conterproductive to Alaska's best interests.

I would like to discuss each of these points in more detail.

CONTINUED DEVELOPMENT IS IMPORTANT TO ALASKA

As most of you know, the USGS has predicted that up to 40% of the future potential for oil discovery in the United States is in Alaska and the offshore waters of the state. Also, there is remarkably large potential in coal, and in various other minerals as well as timber and fish. As has been correctly pointed out by the state and some of the media, Prudhoe Bay will not last forever. I believe it is extremely short-sighted to attempt to have the state's future be dependent on one major oil field. The obvious solution is to develop additional oil fields and our other resources. This, after all, is critical to the creation of future jobs in Alaska and an expanding economy for all Alaskans. The Trans-Alaska Pipeline is an extremely important asset to this state because it provides an outlet for potential future discoveries of oil on the North Slope that might not otherwise be economic to develop in this high-cost area. I also believe it is obvious that Alaska should make every effort to take advantage of its natural resource wealth in planning for the future.

I believe that most Alaskans and most of our legislators strongly support continued, orderly development of our natural resources.

A REASONABLE TAX CLIMATE IS IMPORTANT TO CONTINUED NATURAL RESOURCE DEVELOPMENT

Next I'd like to discuss the importance of a reasonable tax climate if the state is to attract the natural resource and other investments which will bring more jobs and a healthy future economy to Alaska. Aside from the presence of natural resources and their availability for exploration and development, the most important factors impacting investment decisions are operating and investment costs and the degree of uncertainty that exists in predicting future costs and revenues.

Higher Costs, whatever their source, have a significant impact on investment decisions. Higher costs for any business mean that higher revenues are needed to make an adequate return on investment. If the business cannot reasonably anticipate the necessary higher revenues, the investment won't be made. Taxes are, of course, one of the costs and higher taxes obviously translate into higher overall costs.

Alaska already has the highest operating and investment costs of any state due to its location and harsh environment. Any increase in oil industry taxes at this time will, of course, add to these already higher costs, thereby further increasing Alaska's cost disadvantage relative to other states.

Uncertainty about the future is another problem that a businessman faces in making investment decisions -- uncertainty about future volumes, future prices, future revenues, future costs, and future regulations. The more uncertainties that exist, the more difficult the investment decision and the less likely that the investment will be made. An objective of businessmen, therefore, is to limit the number of areas of uncertainty. In this regard the tax burden is normally a relatively predictable item. In most cases businessmen are able to predict a state's tax burdens with only limited uncertainty. This is possible

because the taxing jurisdictions in most states have adopted a broad policy and philosophy which contains two essential elements. First, that tax s should be increased only to meet budgetary needs. Secondly, that the tax burden placed on any group of taxpayers (i.e. business, industry, individuals, ect.) should be fair and equitable when compared to other groups.

A state which raises taxes during periods of current and forecast general fund surpluses and/or enacts frequent tax increases on one or more special groups of taxpayers cannot help but raise a caution flag for people who are considering investments. Those investors who are part of the special target groups will be concerned that the trend will continue. Those investors who may not be a part of the special target group will no doubt wonder whether they will be a special target in the future.

The difficult decision that this committee and the legislature faces in deciding whether to increase oil industry taxes in 1978 lies in their answer to a couple of key questions:

First, what is the current general fund balance and what is the balance forecast for the future based on predicted revenues and expenditures under current tax laws? Stated another way, does the state need to increase taxes now to cover forecast expenditures?

Facts to help you come to grips with this question are, I believe, readily available. Several long-range projections of state revenues and expenditures by the staffs of the administration and the legislature, the most recent of which was published in August, 1977 by the Legislative Affairs Agency, indicate very large general fund balances will accumulate in the future. The answer given by these studies is that new taxes are not needed. Therefore, I believe the most investors would view a decision to increase the overall level of taxes as an unfavorable signal -- a signal that I believe could hurt development of

natural resources and jobs in Alaska.

Since some legislators want to increase state revenue by taxation, even though available studies indicate sufficient revenue will be available to provide the needs of government, we believe it is appropriate to examine the tax burden borne by various taxpayers. Thus, the second question is: "Are the burdens borne by various taxpayer groups fair and equitable, or should some adjustments be made to reduce some burdens and increase others?"

I'd like to concentrate the rest of my remarks on information that may shed light on the second question dealing with fair tax burdens among taxpayers or more specifically, "Is the oil industry equitably taxed under today's tax laws?"

OIL INDUSTRY PAYING MORE THAN ITS EQUITABLE SHARE

Taxation fairness is a subjective term that means different things to different people, but I would like to discuss every reasonable measure of taxation fairness that I can think of or that has been discussed previously. The next chart lists these various measures and gives brief comments about the status of the industry's tax picture relative to that term.

The first and most obvious measure is, does the industry compensate the state for the services it requires and receives. With the industry funding 67% of the tax revenue, surely there is no argument that the industry requires services even approaching that level.

The second measure I listed was equity among taxpayers. It is obvious that the oil and gas industry pays more in total dollars than any other Alaskan industry. A search of the tax laws also reveals that with the special severance and state ad valorem tax, added to the corporate income tax and other taxes common

to all businesses, the petroleum industry taxes as a percentage of income are higher than those on any other Alaskan business. The highest special tax on other businesses is a 7% special net income tax on mining with an allowance for percentage depletion, which is, of course, considerably less than the severance tax of 11.4% of revenue, not to mention the ad valorem tax.

The third method of comparison is with other states having similar businesses and, of course, you have already heard that Alaska has the highest oil tax burden of any of the major oil-producing states. Interestingly, Alaska's current income tax on the industry is also the highest.

AN INCREASE WOULD BE COUNTERPRODUCTIVE

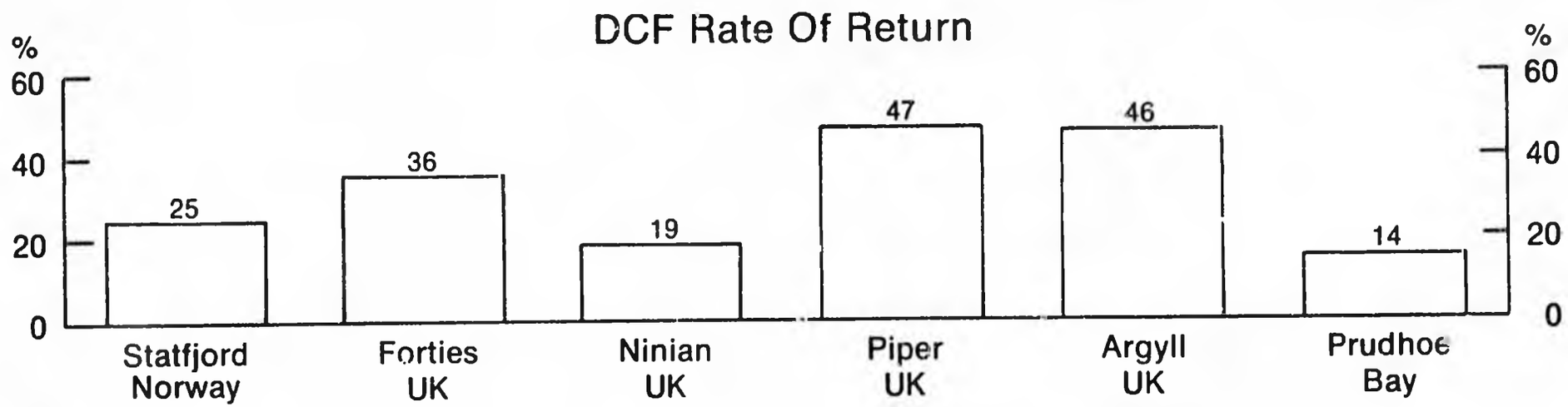
I believe that a careful study of the available facts will lead to the conclusions that 1) no new taxes of any type involving any group are needed, 2) that the petroleum industry by any measure is paying more than its equitable share of the state's tax burden, and 3) an increase in taxes on Alaska's most important industry would be counterproductive to the interest of Alaska. Alaska cannot afford the complacency suggested by some of waiting until some future date to consider developing its resources. Even with the advantages incurred by the existence of the TAPS pipeline, a new oil field on the North Slope of Alaska would take 7 to 9 years to develop and come on production. By about that time, Prudhoe Bay oil production will start to decline and state revenues from the oil production of that field will diminish. Hopefully, there will be a gas line by then; however, as you know there are many problems to be solved before that will happen.

The future of Alaska is dependent on development of its resources. If the tax structure, the unpredictability of future taxes, the high costs, or the lack of land keep just one oil field from being developed, it will result in the loss of many jobs for Alaskans, the loss of revenue to the state, a potential for underutilization of the Trans-Alaskan Pipeline, and less oil for the nation.

Exxon plans to be a part of the Alaskan business community for many, many years to come, not only as an owner of substantial assets related to current operations but, hopefully, as a developer of new oil and gas reserves which can help Alaska and which can help our nation reduce its dependence on foreign oil imports. We believe that many other businesses want to be a part of Alaska's future. But we believe, and hope you agree, that to make a fair and reasonable return on future Alaska investments, we need a stable business climate and a predictable tax system based on need, fairness, and equity.

Monte Taylor

Prudhoe Bay — North Sea Comparison



UNITED KINGDOM PETROLEUM TAXES

A. Corporation Tax Rate of 52%

B. Petroleum Revenue Tax (Calculated on an individual field basis)

1. 45% Rate

2. Deductible Against Corporation Tax

3. Not Effective Until After 175% Recovery of Capital Expenditures

4. First 20 000 B/D From Each Field is Exempt (Up to a Maximum of 73 Million Barrels)

20,000 per day for 10 yrs

5. Not Effective in Any Year Unless Adjusted Profits in That Year Exceed 30% of Capital Expenditures Accumulated Over the Life of the Field

6. Even if Adjusted Profits in a Year Exceed 30% of Capital Expenditures Accumulated Over the Life of the Field, the PRT From a Field is Limited to 80% of Such Excess

C. Corporate Income Tax Allows Immediate Recovery of Capital Investments

BEFORE THE SENATE RESOURCES COMMITTEE

TESTIMONY OF

CRAWFORD H. THOMAS

SCS for CS for HB 322

February 24, 1978

Madame Chairman and Members of the Senate Resources Committee:

My name is Crawford Thomas. I live in Sacramento, California. I have had a long association with state income taxation. I am now retired. Until my retirement in early 1974, I was Chief Counsel of the California Franchise Tax Board for eight and one-half years. The Franchise Tax Board administers the income tax in California.

I commenced working for the Board as an attorney in 1940. My entire time while I was associated with the Board was devoted to legal and administrative problems of state income taxation.

I estimate that about one-half of my time was spent on matters involving the taxation of the income of multistate businesses and the apportionment of such income.

I started my career in taxation at the time when the unitary concept, which you have heard discussed at some length, was first being seriously applied, although the concept had been recognized for some time. I participated in the extension of the unitary concept from its application to a single corporation to its

application to parent and subsidiaries, to foreign subsidiaries and, finally, to the so-called world-wide combinations. I understand that your state now uses essentially the system as is in effect in California.

I was heavily involved for several years in opposition to federal intervention in state income taxation, through the Willis bill and its successor bills.

I was involved with the Uniform Division of Income for Tax Purposes Act, from the time it was first being seriously considered by the states. I supervised the drafting of regulations under this act, which later became the basis of the regulations adopted by the Multistate Tax Commission. Alaska was one of the first states to adopt the Uniform Law for dividing income.

I was involved with the Multistate Tax Compact from the very birth of the Compact idea.

Some substantial portion of my time was spent reviewing and analyzing proposed tax legislation in the California legislature. A prime reason for this review was to spot problems in proposed bills. I have reviewed the bill before you and I have found what I believe to be some major problems. I would like to discuss these problems.

Under your present Alaska law and your administrative practice, an integrated oil business is treated as a unitary business and its Alaska income is determined to be that percentage of its total income, as determined by use of the standard apportionment formula of property, payroll and sales.

This method of apportionment is set forth in the Multistate Tax Compact which Alaska has adopted as its law.

This Compact has a higher status than an ordinary state law. It is a solemn covenant entered into by Alaska and some 18 other states, guaranteeing that taxpayers will be taxed in accordance with the terms of this Compact.

This bill does not amend the Multistate Tax Compact contained in your present law.

I doubt that having adopted the Compact, a state could unilaterally amend it, without violating the Compact and eliminating Alaska as a Compact state.

This bill starts out by saying that, notwithstanding the present law which provides that income shall be apportioned as provided in the Compact, the income of oil and gas production or transportation companies derived from Alaska shall be determined by separate accounting under the provisions of Sec. 18 of Article IV of the Compact.

I shall return to this Section 18 in a moment and at some length.

This bill thus segregates unitary oil and gas producing or transporting companies from other unitary companies and says oil and gas companies, alone, must use a separate accounting procedure. It thus treats these companies as conducting businesses in Alaska entirely separate and distinct from the rest of their world-wide completely integrated businesses.

Now, having totally discarded the unitary concept and use of the uniform formula for computing Alaska production or transporation income, the bill completely reverses itself and considers the out of state income, less the Alaska income, to be unitary income and apportions this by use of a two factor formula which uses only th property and payroll factors.

This treatment of a business as non-unitary for one purpose and unitary for another is completely inconsistent.

We now come to a very major problem, one that I believe has not been sufficiently called to your attention.

If my analysis is correct, then enactment of this bill will not change the present method of apportionment of oil companies. The reason is that in enacting the Compact you also enacted Article III, Section 1 of the Compact. This section provides

that a taxpayer may elect to apportion its income either under the state law, or under Article IV of the Compact which is the uniform apportionment law. By enacting and entering into the Compact, Alaska guarantees this option to its taxpayers to use the formula of property, payroll and sales.

If this bill is enacted as law, an oil company would have a very strong legal argument that it could exercise its option not to report under this law, but to report under the Compact and use the uniform apportionment formula rather than the method used in this bill.

I can find nothing in anything presented to you denying that this would be so.

This bill apparently seeks to eliminate the taxpayer's option by attempting to use Article IV, Section 18, of the Compact to force oil companies to apportion their income by separate accounting.

You will recall that Section 18 states that if the uniform formula does not fairly represent the extent of the taxpayer's business activity in the state, the tax administrator may require the use of separate accounting or a change in the formula.

Leaving aside for the moment the fact that under this bill the legislature and not the tax administrator is making the deter-

mination, I think we should look at this Section 18 in some depth.

Two years before Alaska adopted the Uniform Act for division of income now contained in the Compact, Professor Pierce of the University of Michigan, the drafter of the Uniform Act, published his article (35 Taxes 747 (1957)) stating that Section 18 should be employed sparingly and only to avoid situations which were unusual and where use of the uniform formula would create constitutional problems.

In other words, it was to take care of unforeseen situations unknown at the time the Act was drafted.

My personal knowledge, gained at meetings with state representatives to discuss the Uniform Act, is that the states were very wary of this section. It was felt that unless Section 18 was strictly interpreted, the Uniform Act could not achieve uniformity and could be rendered meaningless.

This strict interpretation has also been the interpretation of the states, including Alaska, forming the Multistate Tax Commission and entering into the Compact.

This strict interpretation is set forth in Regulation IV-18 of the regulations issued by the Multistate Tax Commission.

The first paragraph of the regulation merely restates the text of Section 18. The second paragraph is very important. I do not believe it has been brought to your attention.

That paragraph states:

> "Article IV, Sec. 18 permits a departure from the allocation and apportionment provisions of Article IV only in limited and specific cases."

Here, the attempt in the bill before you is not to apply it to limited and specific cases, but to an entire industry.

The paragraph of the regulation continues to read:

> "Article IV, Sec. 18 may be invoked only in specific cases where unusual fact situations (which ordinarily will be unique and nonrecurring) produce incongruous results under the apportionment provisions contained in Article IV."

There is nothing unusual about the fact situation concerning oil companies. Oil companies are not unusual. They have been around for years. For the same reason, it is not a "unique" situation as referred to in the regulation.

It is not nonrecurring, it is a permanent situation.

The results are not incongruous, that is, unfit or inappropriate. To the contrary, they are fit and appropriate for a unitary business. About 95% of the other states, including Alaska, so hold, as does the great weight of legal authority in this country.

Getting back to Section 18, it specifically says that the tax administrator shall make the determination to use a different method of apportionment. It does not give this authority to a legislature.

As the section is to be used only in specific and unusual cases, this is not only a sound requirement but a vital one.

Only the tax administrator is in a position to investigate specific cases, and only he can make a determination that the case falls within the intent of the section and the regulations.

The Oregon Supreme Court has twice decided that the burden of proof is on the party seeking to invoke Section 18, whether the party be the taxpayer or the State. (Donald M. Drake Co. v. Dept. of Revenue, 236 Ore. 26,500 P2d 1041; Coca-Cola Co. v. Dept. of Revenue, ___ Ore. __,___ P2d ____).

This major problem, as I see it, is that under the present facts, the administrator would have a very difficult time

meeting the burden of proof. The legislature could not. It would not only not be a party to the proceeding, but a mere legislative declaration that the formula does not fairly represent the extent of the business activities in the state is not proof.

The next major problem is that even if the proper party invoked Section 18, or if Alaska withdrew from the Compact and enacted a law requiring oil companies to allocate income by separate accounting, your revenue department, in either instance, would encounter extreme legal difficulties in putting the law into effect and enforcing it.

As others have testified at great length, the great weight of legal authority in this country is that integrated multistate companies such as these are unitary businesses.

I am not aware that you have been given any testimony or information that such companies are not unitary.

As others have also testified, if a business is unitary, the use of the formula is required to determine the income to be apportioned to the state.

I am not aware that you have been given any testimony or information that this is not so. Your revenue department has

consistently taken the position that this concept is correct. The department's position is a matter of public record.

The only support I have seen for the use of the separate accounting method comes from your consultant, Milton Lipton. Mr. Lipton has simply stated a conclusion that there is a deficiency in the present income tax structure and that separate accounting is the way to cure the deficiency, as it will produce more revenue from the oil companies. Mr. Lipton has avoided the vital question of whether the separate accounting method may, in fact, be used.

In the face of the problems I have just outlined, plus those matters addressed by such undisputed experts in their fields as Mr. Kust, Mr. Warren, and Professor Boren in their papers and testimony, it would seem to me that this committee should need more than the mere unsupported conclusion of Mr. Lipton that use of separate accounting rests on a firm legal foundation.

I am aware of Alaska's situation, that the oil is being extracted and revenues from this source will decline unless new fields are developed.

I am also aware that oil is a wasting asset and that Alaska may not have a highly diversified tax base.

If litigation should result from enactment of this bill, I think that a court would have no choice but to simply focus only on the question of whether the method used to determine income attributes to Alaska her share of the unitary income. I do not believe other matters should or would be considered by the court.

From the available material I have reviewed, it appears to me that Alaska's tax burden on oil companies is as high as that imposed by other states.

I am convinced that these companies are paying an effective rate of tax of 9.4%. They are paying a tax of 9.4% upon that portion of their income properly apportioned to Alaska.

For example, if the ABC Oil Company's total net income is $10 million and 10%, or $1 million, is apportioned to Alaska by the formula, then the ABC Company pays a tax of $94,000, or exactly 9.4% of its Alaska income.

To say, for example, that the effective rate of tax is only 4.7%, requires the assumption that $2 million rather than $1 million is the amount of income derived from Alaska sources.

Those that so argue rest their assumption upon the conclusion that Alaska income must be determined by a separate accounting method.

All the testimony you have received shows that such conclusion has no foundation and nothing has been offered in its support.

In going over these matters, I have several times noted the comment that Alaska is not taxing the value of the oil extracted. Such statements misconceive the purpose and function of an income tax. An income tax is not intended to tax the value of oil produced within a state or anything else produced therein.

It is intended to tax that portion of the income of the entire taxpayer entity properly apportioned to the state.

Using an income tax to tax the value of oil produced is simply using the wrong vehicle on the wrong road.

Crawford H. Thomas
1902 12th Avenue
Sacramento, California 95818
(916) 443-5071

Age:	67
Education:	University of California University of California Hastings College of Law, LL.B. 1937
Experience:	Admitted to Califrnia Bar 1937
1937-1940	Associate attorney, Shelton, Gray & McWilliams, San Francisco. Corporation probate and tax law practice.
1940-1942	Junior and Assistant Tax Counsel, Office of Franchise Tax Commissioner, Sacramento. Legal work in connection with administration of Franchise Tax Act, Corporation Income Tax Act and Personal Income Tax Act.
1942-1946	Military service, including ordnance procurement, contract renegotiation and price redetermination, St. Louis Ordnance District. Legal Officer, Military Government, Japan.
1947-1965	Associate Tax Counsel, Franchise Tax Board. Experience in this position is outlined below.
1965-1973	Chief Counsel, Franchise Tax Board. Experience in this position is also outlined below.

Thirty years of my entire legal career has consisted in working with state franchise or income taxation. I commenced work with the Franchise Tax Commissioner in the year of the landmark decision in Butler Bros. v. McColgan, and have, so to speak, grown up with the unitary concept. I participated in the extension of this concept to parent and subsidiary corporations and use of the combined return, world wide combinations, and through all of the developments of the doctrine to its present form and use.

I have handled protested cases and hundreds of appeals involving every facet of this question, participated in all the California legislation, and assisted the attorney general in the preparation in all of the California court cases affirming or extending this doctrine. I estimate that close to a major portion of my time was spent on matters involving the unitary business.

In the eight and one half year period in which I was Chief Counsel of the Franchise Tax Board, I supervised all protests, appeals, litigation and legislation involving the unitary business. I participated in many studies and conferences with industry groups, including the oil industry. I was heavily involved in studies of, and opposition to, attempts by Congress to have federal intervention in the state tax field via the Willis bill and its successor bills. I participated in or supervised California's involvement in the affairs of the Multistate Tax Compact and Commission.

I have made many appearances before legislative committees, the Willis Committee, conferences of state tax administrators and tax executives, chambers of commerce and other groups concerned with state taxation.

My experience has given me an in depth knowledge of the problems faced by the state tax administrator and his legal counsel in the interpretation and enforcement of the unitary concept.

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TESTIMONY

PRESENTED TO

ALASKA SENATE COMMITTEE ON NATURAL RESOURCES

JUNEAU, ALASKA

FEBRUARY 10, 1978

WILLIAM VAN ALEN, DISTRICT MANAGER

PLACD OIL COMPANY

ANCHORAGE, ALASKA

My name is Bill Van Alen and I am Alaska District Manager for Placid Oil Company. My family and I are 18-year residents of Alaska. I talk to you today both for myself and for my employer, Placid Oil Company, who has been in the energy and metallic materials exploration business in Alaska since opening our Anchorage office in 1966.

Placid Oil Company's main office is in Dallas, Texas, and we operate our energy minerals exploration programs in a number of areas in the lower 48; in Canada; and in the North Sea. We have conducted petroleum exploration activities in varying degrees throughout most of Alaska. Placid operated and participated in exploratory drilling projects in the Cook Inlet Basin, but none of the wells drilled on our leases so far have encountered commercial production. It was on the North Slope that Placid Oil Company, in joint partnership with Marathon, Getty, Amerada-Hess, Hunt, and Louisiana Land and Exploration Company, through the drilling of an 11,400 foot well, extended the defined limits of Prudhoe Bay Oil Reservoir.

That particular business venture in which we engaged contributed to an increase in America's petroleum energy reserves. Madam and Gentlemen, we must do everything we can to perpetuate similar searches for energy reserves in Alaska. I respectfully

advise you that proposed further increases in Alaska's corporate income taxes serve as a deterrent for continuing such searches. Alaska must do what it can to encourage energy mineral exploration, not discourage it. Things such as the discovery royalty are needed to encourage exploration. Why, for example, cancel the effect of a discovering company's reduced royalty by subsequently raising that company's income taxes?

It is Alaska's obligation to the nation to assure that a steady, orderly exploration program by industry be conducted in Alaska. It is critical that lands be made available for exploration and for permit procedures to not become so burdensome that they inhibit exploration. Thirdly, and the matter that should be of your concern in reviewing CSHB 322, the economic factors forecasted over the long term must be favorable. This includes the income tax picture. Predictions of perpetual increases in state taxes do not exactly encourage companies to engage in exploration programs in the state. Perpetually increasing income taxes and production taxes has the effect of discouraging energy businesses from investing in Alaska. How can a businessman effectively relate his initial investment to future income when encumbered with the prospect of an ever-increasing tax burden?

In oil operations, one undesirable aspect of having too heavy a tax load might be to reduce expenditures for secondary recovery procedures, thereby reducing total potential output from a

particular field. Reservoir characteristics commonly indicate that secondary recovery facilities should be installed early in the life of a field, but operators might be reluctant to make the financial outlays for their installation should the operator's future income picture be clouded by expectation of excessive taxes.

A steady, broad-based, continuous exploration program in the State would contribute toward reducing unemployment, which I understand is presently at about 13% of the total workforce in Alaska. Successful exploration projects would result in creating further employment possibilities for filling the jobs needed for developing the reserves. Accordingly, an indirect effect of tax increases on energy producers would be non-reduction of employment.

In order for me to obtain funds for exploration by Placid in Alaska, the projects have to compete with comparable projects available from other parts of the country. How, for instance, can I expect my company to participate in a project in Alaska when a project of equal geologic merit in Texas would incur only 60% of the taxes over the life of the field that the company would have to pay out of production from the Alaska project. The increase in income taxes proposed by SB 105 accordingly would induce a restraint on exploration in Alaska.

It is the obligation of the State of Alaska to do its part in contributing to easing America's negative balance of international trade. The key way for Americans to work toward reducing the amount of money we spend for petroleum coming from overseas is to maintain continuous exploration and production of domestic petroleum reserves. Alaska must encourage such sustained exploration in the 49th state. Imposing higher income taxes on companies working in Alaska has the opposite effect and restricts continuous exploration.

All in all, I sincerely urge you to incorporate a more global perspective in your thinking on CSHB 322. In so doing, I'm sure you will conclude that it would not be in Alaska's best interest to increase my company's income taxes any more.

I applaud each of you for your diligent work on Alaska's behalf here in the capital. Thank you sincerely for your attention.

William Van Alen

February 10, 1978

JOHN S. WARREN

Biographical information

Education:

Bachelor of Science in Law, University of Minnesota - 1943

Bachelor of Laws, University of California, Hastings College of Law - 1950

Professional:

Loeb and Loeb, Los Angeles, California - 1957 to present (partner 1960 to present)

Government positions:

Associate Tax Counsel, California Franchise Tax Board - 1951-1957

Consultant, California Department of Finance - 1962

Consultant, California Legislature, Senate Fact Finding Committee on Revenue and Taxation - 1964

Memberships:

State Bar of California

Committee on Taxation (1958-1962)
Committee on Property Sales and Local Taxes (1975-)
Chairman, Subcommittee on Occasional Sales (1976-)

Los Angeles County Bar Association, Tax Section:

Committee on Federal and California Death and Gift Taxes

American Bar Association, Section of Taxation, Committee on State and Local Taxes:

Subcommittee on Non-Federal Solutions to Interstate Tax Problems (1974)
Subcommittee on Important Developments (1975)
Vice Chairman, Subcommittee on Corporation Net Income Taxes (1976)

Articles:

"Sales of Depreciated Properties to Related Entities," 1959 Southern California Tax Institute

"The Unitary Concept in the Allocation of Income," 12 Hastings Law Journal 42 (with Frank M. Keesling)

"Selected Problems in California Corporation Taxes," 1962 Southern California Tax Institute 939

"Income Taxation of Testamentary Trusts,"
23 Journal of Taxation 278

"California Franchise Tax Allocation of Income of Unitary Business,"
1966 Southern California Tax Institute 529

"California's Uniform Division of Income for Tax Purposes Act,"
15 U.C.L.A. Law Review 156 (with Frank M. Keesling)

"Reform Act Changes in Pension and Profit Sharing Plans,"
1971 Southern California Tax Institute 137

Lecturer:

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EXECUTIVE SUMMARY OF POSITION PAPER

ON ALASKA OIL AND GAS TAXATION

By John Warren

Alaska's existing corporation income tax meets all of the generally recognized criteria of a modern and efficient state corporation income tax. It is simple and inexpensive to comply with and enforce, it provides equality among taxpayers, and it contains rules for the allocation of income that provide the best possible assurance against overtaxation or undertaxation of multi-state businesses. The several bills which the Legislature has had under consideration (H.B. 145 and 322, S.B. 105 and 202) are all changes for the worse as far as meeting these criteria is concerned.

If the Alaska tax base for oil companies were to become the greater of book income or federal taxable income (H.B. 322), the Department of Revenue auditors could no longer rely on federal audits. Rather, they would have to verify two sets of figures for each company. Because the financial accounting rules for determination of book income allow some leeway, the Department would have to adopt regulations to prevent manipulation of book income for tax avoidance purposes and to assure equality

among taxpayers. Furthermore, because income or expenses are often reportable in different years under federal income tax rules than they are under financial accounting rules, intricate adjustments would be necessary to avoid including the same item in the tax base for two years.

The changing of the formula for apportionment of income by substituting an origin sales factor ("extraction factor") for the destination sales factor used by most states (H.B. 322) will force Alaska to withdraw from the Multistate Tax Compact and will deprive the state of the benefits of the joint audit program of the Multistate Tax Commission. More importantly, the use of the extraction factor cannot be justified under the generally accepted principles for apportionment of the income of a unitary business.

Determining Alaska tax liabilities on the basis of separate accounting (H.B. 145, S.B. 105, and H.B. 322 as amended in the Senate) is an even more drastic departure from generally accepted principles of proper state tax policy. It would force Alaska out of the Multistate Tax Compact, would create horrendous audit problems for the Department of Revenue, and might even result in a net revenue loss to the state.

The analytical approaches of the Department of

Revenue and the several consultants who have been advising the Legislature leave much to be desired. They have created the impression that Alaska does not get as much tax revenue from the oil companies as it should because the present tax structure does not attribute to Alaska the net income actually earned in Alaska. They then attempt to persuade the state to turn its back on all of the principles of state taxation and multistate business that have been hammered out over the last century — principles that have been widely endorsed by the courts, by tax administrators of other states, and by tax scholars — and to adopt instead one of several new proposals. They have no difficulty in showing that these proposals would increase Alaska's tax collections, but they fail completely to show that they will come any closer to the ideal of taxing the "net income actually earned in Alaska," no more and no less. Alaska would be ill advised to warp its tax structure away from the tried and true principles simply to collect more taxes from one type of business.

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POSITION PAPER ON ALASKA OIL AND GAS TAXATION

By John S. Warren

I. THE PRESENT ALASKA CORPORATION INCOME TAX

The criteria of a modern and efficient state corporation income tax are that it should be simple and inexpensive to comply with and enforce, it should provide equality among taxpayers, and it should contain rules for the allocation of income that will provide the best possible assurance against overtaxation or undertaxation of multistate business. The present Alaska corporation income tax scores high on all of these points.

Because Alaska uses a tax base which is federal taxable income with only a few adjustments, the Alaska return is easy for the taxpayer to prepare and easy for the Department of Revenue to audit. By requiring taxpayers to report federal audit changes,[1] and by having an agreement for reciprocal exchange of information with the federal government, Alaska gains the benefit of the audit effort of the U.S. Internal Revenue Service free of

charge. In addition, Alaska has effectively shifted to the federal government the burden of adjudicating disputes over the make-up of the tax base.

The Alaska legislature has shown admirable restraint in creating special classes of taxpayers. Highway construction contractors[2] and halibut fishers[3] have been granted preferential treatment, and banks and savings and loan associations[4] and insurance companies[5] have been made subject to other taxes in lieu of the corporation income tax. With these minor exceptions, corporations are treated equally under the pr law.

In the area of allocation of income, Alaska has adopted the same set of rules that has been adopted by 27 of the 45 states (including District of Columbia) that impose taxes on or measured by corporate net income, namely, the rules set forth in the Uniform Division of Income for Tax Purposes Act (UDITPA) and in the Multistate Tax Compact. The UDITPA and Compact rules provide for the apportionment of business income by a formula consisting of the factors of property, payroll, and sales, and this formula is also used by a number of the states that have not actually adopted UDITPA or the Compact.

UDITPA and the Compact represent a major effort to solve, by interstate cooperation, the problem of lack of uniformity in state taxation of multistate business, and Alaska is to be commended for joining in this effort. The extent of Alaska's enthusiasm for the Compact is demonstrated by the fact that its Commissioner of Revenue sits as Treasurer of the Multistate Tax Commission, the body which administers the Compact.

II. THE ZEIFMAN AND AINSWORTH PROPOSALS

Professors Jerome M. Zeifman and Kenneth G. Ainsworth, as consultants to the Alaska Department of Revenue, have criticized the present corporation income tax as it applies to the petroleum industry and have recommended two significant changes. They contend that the present system of taxing the income of oil companies is deficient because the tax base (federal taxable income) is too small and the UDITPA apportionment formula does not assign enough of the tax base to Alaska. They recommend that the tax base for oil companies be equal to the greater of book income or federal taxable income and that the sales factor in the apportionment formula for oil companies be changed from a destination

theory to an origin theory.

A. Effect on Alaska's Membership in the Multistate Tax Compact

The first point to note about the Zeifman and Ainsworth proposals is that they are incompatible with Alaska's continued membership in the Multistate Tax Compact. Article III of the Compact provides that any taxpayer subject to a tax on or measured by net income under the laws of a party state must be given the election to apportion and allocate his income under the rules set forth in Article IV (which are the UDITPA rules). The only exceptions are for financial organizations and public utilities, and it has been held that oil companies are not excludable.[6] The sales factor set forth in Article IV is a destination factor. Therefore, if Alaska subjects oil companies to a tax on or measured by net income and requires them to use an origin sales factor, Alaska will be in breach of the Compact.

Of course Alaska can consider withdrawing from the Compact before enacting the Zeifman and Ainsworth proposals, but this would deprive Alaska of the benefits of the joint audit program of the Multistate Tax Commission.

B. Use of Book Income as the Tax Base

Enacument of Professors Zeifman and Ainsworth's proposal that book income be used as the tax base for oil companies would be a giant step backward from the goal of uniformity, would create inequality among taxpayers similarly situated, would increase the state's audit burden, and would raise questions of constitutionality. Furthermore, their criticism of federal taxable income as the tax base betrays a lack of understanding of the unitary business concept.

(1) The Analytical Error

Professors Zeifman and Ainsworth are correct in saying that by using federal taxable income as the tax base, Alaska accedes to the judgment of Congress regarding tax incentives for industrial expansion; but they are wrong in contending that although it may be all right for Alaska to bear the burden of tax incentives for expansion within the state, it is unfair for it to bear any burden for expansion outside the state. Under the unitary business concept, which is a cornerstone of all modern state tax systems, including Alaska's, an integrated multistate business is looked upon as a single unit, and

each state in which the business is carried on is entitled to tax a portion of the whole. Whatever happens at any place where the business is carried on affects the business everywhere. For example, if an airline serves Alaska, the Western states, Hawaii, and Mexico and if one of its airliners crashes in Mexico, the loss is borne by the entire business, and the resulting tax deduction reduces the tax base in Alaska and everywhere else. Similarly, if an oil company that is active in Alaska and elsewhere makes a major discovery in Brazil, the unitary concept would entitle Alaska to share in the increased tax base that would result from the Brazilian production.

Zeifman and Ainsworth say that Alaska should not go along with Congress in enacting tax incentives to motivate exploration in Brazil, but only to motivate exploration in Alaska. This makes no more sense than to say that the airline should not be allowed to reduce its tax base by loss deductions for crashes in Mexico, but only for crashes in Alaska. The point is that although a case might be made for not allowing any deduction whatsoever for casualty losses or exploration expenses, it is fallacious to argue that Alaska is victimized when its tax base is reduced by such events occurring outside

Alaska. That argument is the equivalent of saying that Alaska accepts the unitary business concept on the income side but rejects it on the deduction side.

(2) The Retreat from Uniformity

Alaska's rejection of federal taxable income in favor of book income would run counter to the trend toward uniformity which Alaska has so far supported. This may be shown by quoting what Professors Zeifman and Ainsworth and others wrote in 1965:

> "Any serious proposals for uniformity of State income tax bases must take into account the fact that the Internal Revenue Code dominates all income taxation in the United States and is a major force in the Nation's business life. Federal tax laws already provide the common frame of reference around which State laws tend to be built and taxpayers tend to regard compliance with Federal definitions of the tax base as byproducts of compliance with Federal definitions. As a result uniformity of State laws can best be achieved through closer conformity of State and Federal definitions.
>
> "The Committee does not recommend that conformity be required to the extent that the States are precluded from formulating their own tax policies. However, it does recommend that each State be required to use, as a starting point for the computation of taxable income, the figure which is reported

to the Federal Government under the Internal Revenue Code."[7]

This recommendation was reached after a long and intensive study of state taxation of interstate commerce, and although the bill embodying the recommedation was not passed by Congress because of state resistance to federal intervention in this area, the statement still stands as a cogent comment on one aspect of the uniformity problem.

(3) The Increased Compliance and Enforcement Burdens

In 1964 Zeifman and Ainsworth, et al., singled out Alaska for special praise in its use of federal taxable income as it exists from time to time and with a minimum of state adjustments. They wrote:

> "Alaska's income tax statute illustrates the simplicity with which the requirements of a moving-base state can be presented. In that State, the taxpayer, having mastered the problems of his Federal return, can quickly determine from the Alaska statute the manner in which it departs from the Federal base. If the taxpayer refers only to the return, his task is even simpler, since Alaska makes only two slight adjustments. These adjustments require the taxpayer to add back Alaska income taxes and contributions to non-Alaska charities.

> The figures for Alaska income taxes and contributions to non-Alaskan charities are readily available both from the taxpayer's Alaska return and the schedules required in support of the Federal return."[8]

Now Zeifman and Ainsworth would have Alaska abandon this commendably simple approach and require one class of taxpayers to use as its tax base the greater of book income or federal taxable income. They state that book income is a readily available figure because it is reported to stockholders and to the Securities and Exchange Commission, but then they suggest that Alaska will want to prescribe its own specific requirements for the determination of book figures. The compliance burden created by this proposal could probably be coped with by the tax departments of the major oil companies, but one wonders whether the Department of Revenue is prepared for what would surely be a greatly increased administrative burden.

To begin with, H.B. 322, the bill incorporating the Zeifman and Ainsworth proposals, (prior to the Senate amendment in full), puts upon the Department the burden of issuing and enforcing regulations for the determination of net income where book income is for some reason unsatisfactory.

Since the recommendation is that the tax base for oil companies be book income or federal taxable income, whichever is greater, the Department of Revenue auditors will have to verify two sets of figures for each taxpayer and then will have to make a determination as to whether book income satisfies the Department's regulations. Furthermore, intricate adjustments will have to be worked out to avoid taxing the same income twice. For example, book income may be higher than federal taxable income in one year because of accelerated depreciation taken on the federal return, and then federal taxable income may be higher than book income in a later year because of recapture of the depreciation under the federal tax rules. Conversely, federal taxable income may be higher than book income in one year because of prepaid income which must be reported in the year of receipt under the federal tax rules, and then book income may be higher than federal taxable income in a later year when the prepaid income is earned and becomes reportable for financial statement purposes. Many more such examples could be cited. Fairness would demand that adjustments be made in all such cases to prevent the same item from being included in the tax base for two years. Failure to allow such adjustments could create such arbitrary and

capricious differences in the relative tax burdens of taxpayers that a serious question of denial of equal protection of the law would arise. Although singling out oil companies for special tax treatment might provide a "reasonable classification" defense to an attack based on the equal protection clause, the defense will break down if the special tax treatment creates discrimination among taxpayers within the class.

Finally, it should be noted that although Zeifman and Ainsworth seem to think that their book income approach could be accommodated into the joint audit program of the Multistate Tax Commission, they have overlooked the fact that their other recommendation of changing to an origin sales factor will require Alaska to leave the Compact altogether. Even if Alaska does not voluntarily withdraw from the Compact and is not expelled by action of the Commission, any oil company could force the issue into court by refusing to submit to a joint audit in which Alaska is participating.

(4) The Due Process Question

It appears that under the Zeifman and Ainsworth proposals the income taxable by Alaska will be determined by applying the three-factor apportionment formula to total book income. Thus they would ignore the distinction between business and nonbusiness income that is made by UDITPA. Under UDITPA (and likewise under the Compact

and current Alaska law) only business income is to be apportioned by formula, and nonbusiness income is to be allocated according to specific rules as to situs.

"Business income" is defined as "income arising from transactions and activity in the regular course of the taxpayer's trade or business, and includes income from tangible and intangible property if the acquisition, management, and disposition of the property constitute integral parts of the taxpayer's regular trade or business operations."[9] All other income is "nonbusiness income."[10] Probably all major oil companies include some income on their financial statements that would be nonbusiness income, such as dividends, interest, rents, and royalties produced by tangible or intangible property that is not an integral part of their regular business. Under the UDITPA rules such nonbusiness income would be allocated to the commercial domicile of the corporation (dividends and interest), or to the situs of the property (rents), or to the place where the property is utilized (patent or copyright royalties).[11] But if Alaska requires oil companies to apportion their entire book income by formula, some of this nonbusiness income will be taxed by Alaska.

Under the due process clause of the United States Constitution, a state may tax the income of a foreign corporation only to the extent that the income is derived from or attributable to sources within the state.[12] In the case of a multistate unitary business, it is fair to say that the business income is derived from all of the states in which the business is carried on, and it is appropriate to determine the portion attributable to each state by a formula.[13] But if nonbusiness income is included in the base to which the apportionment formula is applied, then one or more of the states may be taxing income which has no connection with activities or property in that state; and this is a violation of due process.[14]

The Willis Subcommittee's proposed bill (H.R. 11798, 89th Congress) would also have obliterated the distinction between business and nonbusiness income and required total income to be apportioned by formula. A number of well-qualified witnesses testified that this would be unconstitutional. It is possible that the courts would uphold Congress' power to waive due process in furtherance of the commerce clause, but a state could not do this on its own.

C. Use of an Origin - Oriented Sales Factor ("Extraction Factor").

The Department of Revenue has noted some concern that "the present income tax structure does not return to the State of Alaska 9.4 percent of the net income actually earned in Alaska,"[15] and it has found that the fault lies mainly with the destination sales factor which "completely fails to measure the value of oil produced within [the State]."[16] There are evident flaws in this analysis. In the first place, no oil company earns net income simply by pumping oil out of the ground in Alaska. Income is earned only by the full process of producing, transporting, refining, and marketing the oil. Moreover, the proper point of inquiry is not whether the apportionment formula attributes to Alaska an amount of net income that is proportional to the value of the oil produced in the state, but rather whether it attributes to the state an amount of net income that is proportional to the activity of producing, transporting, refining, and marketing in Alaska as compared to that activity everywhere.

The Department feels that the uniform formula with a destination-oriented sales factor works well for

general mercantile business but not so well for the oil business. The courts of other states have held, however, that there is no inherent difference between the oil business and other businesses that justifies departure from the standard apportionment practices.[17]

As previously noted, the great preponderance of states imposing taxes on or measured by net income use a three-factor apportionment formula consisting of property, payroll, and sales. Although there has been some diversity in the construction of the sales factor, the predominant trend in the last fifteen years has been towards the destination test. This is the rule of UDITPA and the Multistate Tax Compact.

The rationale of the destination theory has been well stated by Prof. Pierce, the chief draftsman of UDITPA, in commenting on the deliberations of the National Conference of Commissioners on Uniform State Laws:

> "Manufacturing states probably would prefer a system attributing sales to the place from which goods are shipped in every case. However, the national conference was of the opinion that such a system would merely duplicate the property and payroll factors which emphasize the the activity of the manufacturing state, so that there would tend to be a

> duplication by such a sales factor. Moreover, it is believed that the contribution of the consumer states toward the production of the income should be recognized by attributing the sales to those states."[18]

The preference for a destination sales factor, and the accompanying "throwback" rule to avoid allocating sales to a place without jurisdiction to tax, did not originate with the NCCUSL. In 1951, a committee of the National Tax Association (a joint government-business association formed in the early 1900's) had settled upon this rule as the most appropriate for uniform use, saying:

> "The purpose of the sales factor is to serve as a balance against other factors, such as property and payroll, and to give recognition to the efforts of a taxpayer in obtaining customers and markets. Allocation of sales to the state where possession of the goods is physically delivered to the purchaser (common carriers being considered as agents of the seller for this purpose) would be most workable, from the standpoint of both taxpayer and administrator."[19]

In 1965 when the Willis Subcommittee recommended abolition of the sales factor and enactment by Congress of a compulsory two-factor formula of property and payroll, there was a clamor of opposition by the states and by business representatives. Of course, many

of the objectors had a bias, but the comments of two neutral observers may be noted. The American Institute of Certified Public Accountants Ad Hoc Committee on State Taxation of Interstate Commerce stated:

> "We do not favor the provisions of the bill which prevent a State from using a gross receipts factor if it chooses to do so. We believe it untenable to argue that an integrated manufacturing and selling organization does not realize any of its income from its sales operations. The use of a gross receipts factor in the apportionment formula will result in a more equitable division of income between the various States."[20]

Professor Hellerstein, a prolific writer in the field, after first criticizing the Willis Subcommittee's statistical data on the effects of abolition of the sales factor, went on to criticize the theories of the abolitionists as follows:

> "Consequently, the rigid doctrine espoused by Professor Harriss and Professor Studenski that income is to be taxed only where services are rendered or property producing income is used is simply out of line with the philosophy of taxation widely in vogue in this country and abroad. Instead, under our tax systems, we have long recognized that the nexus between a State and a taxpayer or a transaction which warrant income taxation includes a whole gamut of legal and economic

relationships, benefits and protections, and encompasses virtually every step in the economic process, from the creation of goods to their conversion into dollars in the market place.

"Wise tax policy must be selective in the steps in the economic process to be used as a basis for tax. But in making a judgment as to fiscal policy in our huckster dominated society - from Madison Avenue to Main Street in every town and hamlet, with the radios and television sets blaring forth wares in every home, with an expenditure of $10 billion or more a year on advertising - one ought not have to argue long the importance of the marketplace in the economic process. Consequently, the claim of the market State to a segment of the income of the interstate vendor, without regard to services rendered or property used in the State, seems to me to be eminently justified.

"Finally, the use of a receipts factor with the sales destination test commends itself on a pragmatic basis. The States in which manufacturing and warehousing take place, the States in which executive, accounting, and administrative personnel carry on their functions, obtain a heavy weighting in multifactor apportionment formulas through the property and payroll factors, and, therefore, there is apportioned to such States a substantial part of existing income measures. If the market State is to share to any significant extent in income tax revenues, the sales factor and the destination test afford a workable means to achieve that result. Moreover, that test sets up a standard not easily

> avoided under a properly drafted formula, a fact of no little significance in this area."[21]

Although the interest of Congress in this area has subsided somewhat since the days of the Willis Subcommittee, bills to impose uniform requirements on state apportionment practices continue to be introduced from time to time. The most recent is S. 2173 introduced by Senator Mathias on October 4, 1977. It is interesting to note that it prescribes a three-factor formula with destination as the test for the sales factor. In his explanation of the bill Senator Mathias said:

> "The bill assigns sales by destination in a State as the simplest, most equitable attribution procedure. It gives due weight to the role of the market in the overall production of income or capital and is one that many businesses and States have learned to live with and prefer."[22]

Senator Mathias had been a member of the Willis Subcommittee. The fact that he has switched from advocating abolition of the sales factor to advocating that all states be required to offer a fomula with a destination sales factor is a further indication of the growing consensus that a fair apportionment formula must include

a destination sales factor.

D. Substitution of Privilege Tax for Direct Net Income Tax

Zeifman and Ainsworth propose that the new tax on oil companies be a privilege tax measured by net income rather than a direct net income tax. They say this would tend to strengthen the state's position in court cases involving apportionment disputes, but they cite no authority for this supposition. The only specific point they make is that it could have special significance in enabling Alaska to tax income relating to economic activities on the outer continental shelf which might otherwise be exempt from the present direct tax. However, the federal pre-emption of the outer continental shelf seems absolute. The Submerged Lands Act states flatly that "State taxation laws shall not apply to the outer Continental Shelf."[23] California has determined that its corporation franchise tax measured by net income cannot extend to the outer continental shelf, thus drilling platforms located in California offshore areas that are part of the outer shelf cannot be included in the numerator of the property factor.[24] It seems quite

clear, therefore, that an attempt by Alaska to include outer shelf properties in the property and extraction factors is doomed to failure regardless of whether the tax is a privilege tax or a direct income tax.

There is another reason, not disclosed by Zelfman and Ainsworth, why their proposed tax has to be a privilege tax measured by net income. If an oil company receives federal bond interest it will be included in book income. The states are not permitted to levy a tax directly on the income from obligations of the United States, but it has been held that such income may be included in the measure of a franchise or privilege tax.[25] More recently, however, the U.S. Supreme Court has swept away the long-observed distinction between direct income taxes and privilege taxes insofar as application to interstate commerce is concerned,[26] and perhaps the states can no longer rely on the distinction as it relates to federal bond interest. The eventual result may be that a state tax on or measured by book income including federal bond interest will be impermissible.

III. DETERMINATION OF ALASKA OIL AND GAS INCOME BY SEPARATE ACCOUNTING

Bills have been introduced in the Alaska Legislature (H.B. 145, and S.B. 105, and also H.B. 322 as amended in the Senate) that would take a new approach to the determination of oil and case production income and pipeline transportation income that is to be taxable in Alaska. Oil and gas production income would be the wellhead value of oil and gas produced in Alaska less certain costs attributable to Alaska operations, and pipeline income would be the sum of the amount reported to the ICC under the category "net balance transferred from income" plus federal and Alaska income taxes paid. The net amount would be taxable at the 9.4 percent rate. Oil companies would continue to be subject to the regular income tax which in their case would be computed by deducting from the tax base the amount of income taxable as above and then apportioning the remainder by a two-factor formula of property and payroll, with property and payroll related to Alaska production and pipeline transportation activity excluded from the numerators and denominators of those factors.

This new approach is basically a separate accounting approach. That is, instead of treating the total business of an oil company as a unitary whole, it

would regard the company as being engaged in two separate businesses, with oil and gas production and pipeline transportation in Alaska looked upon as one business and all other activity carried on in Alaska and elsewhere (including oil and gas production and pipeline transportation carried on elsewhere) looked upon as another business. Thus the approach is based on a fiction, for it is an irrefutable fact that these activities are not separate but are integral parts of a single unitary business.

Separate accounting is now generally considered an archaic and outmoded approach to state taxation of multistate business. Almost without exception, the U.S. Supreme Court and the highest courts of the states have rejected it as inferior to the unitary concept with formula apportionment. The states have learned that if separate accounting is the rule, they will often collect only such amount of taxes from business corporations as the corporations choose to give them. This is because any separate accounting system is replete with opportunities for taxpayer manipulation.

The main reason why the separate accounting method so often fails to produce acceptable results is

that it is dependent upon transfer pricing, i.e., if there is a flow of goods and services among the various states and countries in which the business is conducted (and among the various affiliated corporations engaged in the enterprise), then prices must be placed on all goods and services transferred in and out of the segment of the business within the taxing state. Theoretically, the separate accounting method might work satisfactorily if it could be assured that all such transfer prices were on an arm's length basis, but such assurance always proves elusive.

The sponsors of the Alaska proposal may think they have solved this problem by pricing the crude oil itself at the wellhead value, a figure which can be objectively determined and is beyond taxpayer manipulation. On the deduction side, however, there is fertile ground for the growth of administrative problems. Direct operating costs are deductible, but many of these costs may be incurred in transactions with segments of the business (or affiliated corporations) operating outside the state, and the Department will have to examine every such transaction to assure that no more than an arm's length charge was made to the Alaska operation. Indirect

costs and overhead are not deductible, but it is easy to visualize interminable arguments as to what is a deductible direct cost and what is a nondeductible indirect cost. Depreciation of capital assets is deductible, but it is quite likely that capital assets used in Alaska will be acquired from other segments of the business, and the transfer pricing problem will arise again.

Advocates of separate accounting often cite the fact that the federal government uses it in the taxation of multinational businesses. If a U.S. corporation conducts its foreign operations through foreign subsidiary corporations, its U.S. tax liability is computed only with respect to its own operations, and the income of its foreign subsidiaries generally is not taxable until it is repatriated as dividends to the parent. The Internal Revenue Service tries to cope with the transfer pricing problem by making adjustments under the authority of § 482 of the Internal Revenue Code. This approach has been highly criticized both by politicians[27] and by academicians.[28] Alaska itself has rejected the federal approach in favor of world-wide combination for purposes of its regular income tax.

Like the Zeifman and Ainsworth proposals, the separate account proposals may very well be a breach of the Multistate Tax Compact. The author of S.B. 105 has attempted to give it legitimacy by reciting that the Legislature is making a determination under § 18 of Article IV of the Compact that separate accounting is a better way of allocating oil and gas production income and pipeline transportation income. That section (also § 18 of UDITPA) allows variances from the standard three-factor formula, on motion of either the taxpayer or the state, if the standard method does not fairly represent the extent of the taxpayer's business activity in the state, and separate accounting is mentioned as one of the variations that may be used "if reasonable." Those courts which have considered § 18 have held that the one who invokes the section must bear the burden of proving that the standard method is unsatisfactory and that the proposed variance is more reasonable.[29]

Legislative declarations are not proof, and it appears that Alaska would be hard pressed to make its case. In the first place there are several court decisions that the standard method does produce a reasonable

result for oil companies. Furthermore, if separate accounting is appropriate for Alaska, why is it not also appropriate for every other place where the taxpayer has oil and gas production activity or pipeline transportation activity? If a company has production in Alaska and in California, how can Alaska justify taxing separately the Alaska production income and at the same time leaving the California production income in the tax base to which the apportionment formula is applied in determining the company's regular Alaska income tax?

Unless Alaska can provide convincing answers to such questions, the chances of this new tax scheme surviving litigation seem rather slim.

The foregoing comments are also applicable to S.B. 202 which enacts an "oil and gas net proceeds tax," with the net proceeds to be determined by separate accounting. Although the preamble calls the tax an "ad valorem tax," it would fall within the definition of an "income tax" in § 4 of Article II of the Multistate Tax Compact and would violate the Compact for the same reasons given above with respect to S.B. 105.

III. APPLICATION OF THE VANIK THEORY TO ALASKA TAXES

Each year for the past several years Congressman Vanik has published a study purporting to show the effective federal income tax rate applicable to the nation's major corporations. Briefly stated, Mr. Vanik's technique is to compute the amount of the federal income tax paid by each such corporation as a percentage of that corporation's net income for financial statement purposes. He includes in the total net income figure 100% of the income of subsidiaries (foreign and domestic) in which the corporation owns an interest of more than 50% and the corporation's equity interest in the income of subsidiaries in which it owns an interest of 50% or less. Foreign income taxes are taken as a deduction.

Zeifman and Ainsworth have cited the Vanik study for 1975 in support of their contention that the federal tax base has been unduly eroded by "tax expenditures" and is no longer worthy of use by Alaska for the taxation of oil companies. The Department of Revenue has gone on to convert the Vanik results into Alaska results. The Department takes Vanik's finding that certain oil companies paid an effective

federal tax rate ranging from 1.8% to 35.6% and converts this into effective Alaska tax rates of from .28% to 5% for the same companies. The precise method by which the Department accomplished the conversion has not been disclosed, but for purposes of this discussion it will be assumed that it was done by applying to Vanik's effective federal rates the ratio which the Alaska statutory rate (9.4%) bears to the federal statutory rate (48%).

There are a number of criticisms that can be made of the Vanik approach in the federal context, but even if it is accepted as gospel truth in that context, the extension of it to Alaska is totally undependable.

As previously noted, the federal approach to the taxation of multinational businesses is essentially a separate accounting approach. The foreign operations of multinationals are in large part carried on through foreign subsidiaries, and foreign subsidiaries are not combined with the parent for federal income tax purposes. Alaska, however, does require the inclusion of foreign subsidiaries in a combined report and then applies the apportionment formula to the combined net income. Mr. Vanik also combines them in his approach.

It is erroneous, therefore, to assume that Alaska taxes paid will be in the same proportion to Alaska net income as federal taxes paid bear to Vanik's reconstructed federal net income. A large part of the discrepancy which Vanik finds between federal statutory and effective rates for multinationals must be attributable to the separate accounting method that the federal government uses and the combined method which Vanik uses. Since Alaska also uses the combined method, the discrepancy between Alaska statutory and effective rates should be considerably smaller when properly calculated.

Another aspect of the difference between the federal approach and the Alaska approach to the taxation of multinational corporations has to do with the allowance of credits for foreign taxes. This is pertinent if and to the extent that a U.S.-based multinational corporation conducts foreign operations itself rather than through foreign subsidiary corporations. U.S. corporations are subject to federal income tax on their world-wide income and not just on the income from U.S. sources, as would be the case if the federal government used the formula apportionment approach. Therefore, to avoid the foreign-source income being subjected to duuble taxation, the

federal system allows such a corporation to reduce its federal income tax by the amount of foreign income taxes paid. By contrast, in Alaska and all of the other states inposing income taxes, the double taxation problem is met by taxing the corporation only on its income from sources within the state as determined by formula apportionment. Therefore, states such as Alaska do not, and should not, allow credits for foreign taxes.

Once again, the unreliability of trying to convert Vanik's federal figures and Alaska's figures is apparent. The allowance of foreign tax credits must account for a significant part of the discrepancy which Vanik finds between federal statutory and effective rates, but that is a condition which does not exist in the Alaska tax system.

FOOTNOTES

1. § 43.20.030(d), Alaska Statutes

2. § 19.40.040 AS.

3. § 43.20.031(b)(1) AS.

4. §§ 43.20.031, 43.70.020, 43.70.030 AS.

5. § 21.09.210 AS.

6. Amoco Production Co. v. Arnhold, 213 Kan. 636, 518 P. 2d 453 (1974).

7. Report of Special Subcommittee on State Taxation of Interstate Commerce of the House Committee on the Judiciary (89th Congress) Vol. 4, Part VI, Ch. 39, p. 34. Zeifman and Ainsworth were prominent members of the subcommittee staff, and Zeifman ultimately became the chief counsel. The subcommittee was popularly known as the "Willis Subcommittee" and will hereinafter be so identified.

8. Willis Subcommittee Report, Vol. 1, Part II, Ch. 8, p. 273.

9. § 1(a), UDITPA; § 43.20.170(1) AS.

10. § 1(e), UDITPA; § 43.20.150(5), AS.

11. §§ 4 - 8, UDITPA

12. Shaffer v. Carter, 252 U.S. 37, 52-53 (1919).

13. Underwood Typewriter Co. v. Chamberlain, 254 U.S. 113 (1920).

14. Connecticut General Life Ins. Co. v. Johnson 303 U.S. 77 (1937)

15. Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement, February 1977, pp V-1 (hereinafter referred to as the "Department Report").

16. Department Report, p. V-18

the ground that the extraction factor would generate more tax revenues than the sales factor. Apportionment formulas are not intended to be vehicles to generate tax revenues but are designed to divide income among the states fairly and uniformly so as to avoid multiple taxation.

Finally as to the proposed new tax base and apportionment formula in H.B. 322, the singling out of the oil and gas industry and of companies within the industry having receipts of more than $250,000,000 may well be unconstitutional.

SEPARATE ACCOUNTING -- SENATE CS FOR CS FOR HOUSE BILL 322

I understand that the other major proposal before this Committee is adoption of a tax based upon principles of separate accounting. The declared purpose of this bill is to tax oil and gas production and pipeline transportation income in Alaska by means of a statutory separate accounting, while retaining formula apportionment (as modified) to apportion all other income.

Conceptually, separate accounting constructs an income or loss statement for the activities of a corporation in the state as if it conducted an independent oil and gas production or transportation business solely within Alaska and assumes that all dealings by the business with other

aspects of its business and with the outside world are at arm's-length. I am sure it is an attractive concept to try to isolate the Alaskan income by what purports to be a rational procedure rather than the fixed formula. But let me suggest, as your Department of Revenue has strongly argued, that this approach is doomed to failure. Perhaps with small localized businesses the concept is workable. But to apply this concept to large integrated multinational oil and gas corporations ignores the unitary nature of their operations. Each element of a corporation contributes to the overall net profit of the business. You simply cannot ignore the contribution of out-of-state activity to the creation of income in Alaska and how will separate accounting deal with this?

Separate accounting, in practice, is impossible to administer and determine. I fail to see how a concept which proved to be unworkable in the 1920's, when business was relatively simple, can be expected to work in today's era of complex multistate and multinational business of which the oil companies are a preeminent example. The apportionment formula was resorted to because separate accounting could not be administered.

The current proposal attempts to avoid some of the inherent problems of separate accounting by arbitrarily defining net income. Allocation of overhead expenses is "solved"

by simply denying a deduction for such costs. Pricing differences are "solved" by using as gross income the value of the oil and gas produced as determined for purposes of the production tax. And inadvertently, I assume, the proposal results in a double allocation of production income to Alaska, first by allocating production income in Alaska under the statutory separate accounting formula and then allocating to Alaska a portion of the production income outside Alaska under the two-factor apportionment formula. This is clearly a duplication.

Such duplication can be eliminated only by determining production income by separate accounting both in Alaska and outside Alaska and eliminating both, not just Alaskan production income, from the base subjected to the two-factor apportionment formula.

Accordingly, the current proposal does not by definition even approach theoretical separate accounting, and is at least as arbitrary, if not more so, than formula apportionment. It is, indeed another kind of statutory formula.

The proposal has major infirmities. It purports to be an application of separate accounting but it is not and it incorporates a "double dip" allocation of production income to Alaska. It represents a sharp deviation from uniformity and as such would constitute a major disruption of the common consensus underlying the system of state taxation of interstate business income. Separate accounting defined by legislative fiat and applied by one state to a whole industry in order to increase the state's share of the total income

over that resulting from the three-factor formula necessarily results in multiple taxation because income which is fully taxed by the one state is also apportioned by formula to other states. Such deviant action, particularly when it is directed at one industry, may well be unconstitutional.

Moreover, Alaska must ask itself again whether it is appropriate for it to take unilateral action which will disrupt the progress toward uniformity in the division of income among the states which is essential to avoidance of multiple taxation.

THE MULTISTATE TAX COMPACT

Alaska's continuing membership in the Multistate Tax Compact and the administrative benefits derived from such membership may not be tenable if either of the proposals under consideration are adopted. The courts may find such proposals to be in conflict with the Compact and as a result may hold that Alaska has in effect withdrawn from the Compact or that the Compact remains in effect but enactment of the proposals is ineffective to prevent taxpayers from applying the UDITPA formula under the provisions of the Compact. It will take years of litigation to clarify these issues which will cast doubt on what the applicable law is for taxing the income of the oil and gas industry.

CONCLUSION

The United States Supreme Court presently is considering the constitutionality of Iowa's single-factor sales formula. I cannot predict the Court's decision, nor can I

predict to what extent a state may tamper with the uniform formula without violating constitutional principles. Perhaps the Court is ill suited to act as final arbiter as to whether one method of apportionment is fairer or more reasonable than another. But I suspect that with the nearly nationwide acceptance of UDITPA, the Court will show less tolerance of deviant formulas which result in multiple taxation. In any event years of litigation as to the constitutional validity of either of the proposals if enacted as well as their compatibility with the Multistate Tax Compact must be anticipated.

Great progress has been made in recent years in adopting uniform apportionment methods. Part of the drive for voluntary uniformity has obviously been the desire of both states and taxpayers to avoid Federal intervention. As long as states strive toward uniformity as a goal of fair taxation, Congress will be hesitant to act. If the drive for uniformity falters through unilateral action by states asserting their currently perceived self-interest without restraint and the Supreme Court declines to prescribe a uniform formula, Congress will be constrained to exercise its constitutional responsibility to protect interstate commerce by prescribing a Federal standard of uniformity in the division of multistate business income.

Alaska has been in the forefront of the drive for uniformity. By the collective judgment reflected in the

development and general acceptance of the three-factor formula, Alaska's net income tax fairly and effectively reaches its proportionate share of the income of multinational oil and gas corporations doing business within the state. The proposed changes are designed to produce higher revenue, not a fairer division of multistate income, and they would be destructive of the cooperative effort among the states in developing a uniform approach to the division of multistate business income among them.

Madame Chairman and members of the Committee, I want to reemphasize in conclusion that changing the present formula for determining the portion of the worldwide income of oil and gas companies which is taxable in Alaska is not an appropriate way to increase revenues. If Alaska is to act responsibly it cannot ignore the interests of its sister states and in the long run its own interests in maintaining uniformity in the division of multistate business income among the states. If Alaska believes that the apportionment formula is not fair and reasonable as it applies to oil companies, the proper action to take is under Article 18 of UDITPA or through the Multistate Tax Compact or other cooperative state machinery to persuade other states of a different uniform approach, not unilateral legislation which is destructive of uniformity.

SUMMARY

INCOME TAXATION OF MULTISTATE CORPORATIONS ENGAGED IN OIL AND GAS PRODUCTION AND TRANSPORTATION IN ALASKA

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I. PRINCIPLES OF TAX JURISPRUDENCE

Where the activities of a business extend over two or more states, all of the income from such business cannot reasonably be taxed by each of the states. The whole development of the law regarding state taxation of multistate business income rests on this manifest and undisputed principle. Similarly, international tax jurisprudence and tax treaties are grounded on this basic principle with respect to national taxation of multinational business income.

Under the Constitution and within our federal system, this principle has been implemented by Supreme Court decisions under the commerce and due process clauses and through the voluntary and mutually compatible actions of state legislatures and tax administrators.

The effort has been to avoid multiple taxation of the income of a multistate business through the taxing by each state in which the business has activities of only a portion of the income, determined by some reasonable method of apportionment. The system which has developed has two basic elements: (i) a tax base measured by a company's worldwide income determined by Federal taxable income and (ii) a method of dividing this base through use of an apportionment formula.

The Massachusetts, or three-factor, formula apportions the income of a multistate business to the taxing state on the basis of the average of three fractions: (1) property within the state over total property, (2) payroll within the state over total payroll, and (3) sales within the state over total sales.

It was recognized at the outset that multiple taxation of multistate business income arises not merely from failure to apportion reasonably but from disparity in methods of apportionment as well, even though each method by itself and applied universally might be reasonable. The National Tax Association began advocating uniformity in the method of apportionment as early as 1919. Ultimately, these and other efforts culminated in the Uniform Division of Income for Tax Purposes Act (UDITPA) adopted by the National Commissioners on Uniform State Laws in 1957. UDITPA incorporated the three-factor formula and, most notably, defined the numerator of the sales fraction, with respect to which the greatest divergence from uniformity had developed, as being sales having their destination, that is, delivered to customers, in the state.

The Multistate Tax Compact, inaugurated in 1966 to promote uniformity and thereby avert Federal legislation then under consideration to impose uniformity on the states, incorporates UDITPA.

Out of a total of 44 states and the District of Columbia which impose a corporate net income tax, 40 provide for the three-factor formula, 25 by adoption of UDITPA or the Multistate Tax Compact and 15 by incorporation in their own tax statutes, four of the latter giving greater weight to the sales factor than to the property and payroll factors. Differences in the economies of the states as to whether primarily industrial, or commercial, or agricultural or extractive have not affected the general acceptance of the three-factor formula as essentially fair and reasonable.

II. ALASKA INCOME TAX--PRESENT STRUCTURE AND APPLICATION TO THE OIL AND GAS PRODUCTION AND TRANSPORTATION INDUSTRIES.

Alaska has adopted both UDITPA and the Multistate Tax Compact and determines taxable income by reference to the Federal tax base. No distinction is made between the oil and gas industry and other industries engaged in the production and sale of tangible personal property. Since this is essentially the same treatment which is accorded to the oil and gas industry by all of the states imposing a corporate income tax, Alaska suffers no disadvantage in comparison with other states. Accordingly, there does not appear to be justification for change and departure from uniformity. The burden of proof should rest on those who advocate departure.

III. THE ZEIFMAN-AINSWORTH REPORT

The Zeifman-Ainsworth Report contends that Alaska's tax base has been eroded through Federal tax subsidies and incentives which are unrelated to the definition of net income but which are provided solely to accomplish certain economic and social goals, and that the UDITPA apportionment formula reduces the amount of taxable income attributable to Alaska by corporations which export non-renewable petroleum resources from the state.

Zeifman and Ainsworth's recommendations which have been endorsed by the Department of Revenue and incorporated in H.B. 322 are:

1. Adoption of a tax base measured by the greater of book income or Federal taxable income.
2. Replacement of the destination-oriented sales factor with an "extraction factor" -- the ratio of oil and gas energy units produced in Alaska to total oil and gas energy units produced everywhere.

These changes would apply only to corporations with ordinary gross receipts in excess of $250,000,000 more than 50% of which is derived from production, transportation,

refining, manufacturing, processing, distribution of retail sale of oil or gas or products derived from oil and gas.

The "tax subsidies" cited by Zeifman and Ainsworth are for the most part available to all corporations. It is unfair and perhaps unconstitutional to single out the oil industry.

Furthermore, with respect to the one Federal "tax subsidy" allowed to the oil and gas industries, a current deduction for intangible drilling costs, Alaska does not, as Zeifman and Ainsworth claim, provide an incentive to drill wells outside Alaska. Federal taxable income reflects not only deductions for the cost of wells drilled throughout the world but also the income from such wells. It is not a one-way street. Alaska is no more providing an incentive for drilling outside Alaska than other states are providing an incentive for drilling in Alaska. Denial of this current deduction in Alaska, however, could reduce the incentive to drill wells in Alaska.

Congressman Vanik's computations of "effective taxable income" do not support the view that the adoption of the Federal tax base by Alaska automatically causes Alaska's "effective tax rate" to be less than 9.4%, by something comparable to the difference between the statutory 48% rate and the Vanik "effective U.S. tax rate on

worldwide income". Congressman Vanik's approach of measuring Federal income tax due as a percentage of worldwide income is patently incorrect because the United States, recognizing the principles of international tax jurisprudence, provides a credit against its tax on worldwide income for taxes paid to other countries. Alaska does not provide a credit but imposes its tax rate of 9.4% on a corporation's worldwide income apportioned to Alaska. Obviously after apportionment (or after the foreign tax credit at the Federal level) the amount of Alaskan tax as a percentage of worldwide income will be less than 9.4% (or the Federal tax will be less than 48%).

Book income is an inappropriate tax base. It will greatly increase the administrative and audit costs and burdens of both the oil companies and the Department of Revenue. Furthermore, book income not only reflects taxable income before tax subsidies but also many timing differences unrelated to Congressional tax policies. Use of the higher of Federal taxable income or book income as a tax base would tax income twice to the extent of such timing differences.

The UDITPA apportionment formula provides for fair and equitable division of income of oil and gas corporations between Alaska and the rest of the world and fairly reflects the extent of their activity in Alaska as compared to the rest of the world. The destination sales factor properly

gives recognition to the contribution of the market states to the creation of income. Without the demand and purchasing power of the market states, the value of Alaska's oil and gas would be less and the income tax base of oil and gas companies would be smaller. The extraction factor ignores the contribution of the market state and creates multiple taxation, since nearly every other state uses a destination oriented sales factor.

The extraction factor has been proposed not to make Alaska's apportionment formula "fairer" in terms of reasonable sharing of the income tax base with other states, but to generate more tax revenue. Apportionment formulas are not intended to be vehicles to generate tax revenue but to divide income among the states fairly and uniformly so as to avoid multiple taxation.

IV. SEPARATE ACCOUNTING--S.B. 105

The declared purpose of the "net proceeds" tax is to tax production and pipeline transportation income in Alaska by means of a statutory separate accounting, while retaining formula apportionment (as modified) to apportion all other income.

Conceptually, separate accounting constructs an income or loss statement for the activities of the business in the state as if they constituted an independent business

dealing at arm's-length with the remainder of the business and the outside world. In practice separate accounting is impossible to administer and determine. Separate accounting requires that hypothetical prices be established for goods and services between affiliated companies. Separate accounting must effectively contend with efforts of companies to shift income among divisions, affiliates and states and must devise some reasonable way to attribute overhead expenses to the various business locations and activities of the taxpayer, no doubt by means of an apportionment formula, thereby abandoning to that extent its initial purpose of avoiding the apportionment formula. Furthermore, separate accounting requires maintenance of records needed in the effort to determine geographic income--records which serve no other business function.

S.B. 105 handles the problem of allocating overhead expenses by simply denying a deduction for such costs. Pricing difficulties are "solved" by using as gross income the value of oil and gas produced as determined for purposes of the production tax.

Thus, the proposed net proceeds tax would not by definition apply separate accounting even though it purports to do so.

The proposed net proceeds tax has major infirmities. It purports to be an application of separate accounting but it is not. It represents a sharp deviation

from uniformity and as such would constitute a major disruption of the common consensus underlying the system of state taxation of interstate business income. Separate accounting applied by one state to a whole industry in order to increase its share of tne total income over that resulting from the three-factor formula necessarily results in multiple taxation because income which is fully taxed by one state is also apportioned by formula to other states.

V. THE MULTISTATE TAX COMPACT

Alaska's continuing membership in the Multistate Tax Compact and the administrative benefits derived from such membership may not be tenable if either the Zeifman-Ainsworth proposals or S.B. 105 were adopted. The courts may find such proposals to be in conflict with the Compact and as a result may further hold that Alaska has in effect withdrawn from the Compact or that the Compact remains in effect but enactment of the proposals is ineffective to prevent taxpayers from applying the UDITPA formula under the provisions of the Compact.

VI. UNIFORMITY, COMITY AND ENLIGHTENED SELF-INTEREST

Great progress has been made in recent years in adopting uniform allocation methods. Part of the drive for voluntary uniformity has obviously been the desire of both

states and taxpayers to avoid Federal intervention. As long as states strive toward uniformity as a goal of fair taxation, Congress will be hesitant to act. If the drive for uniformity falters through independent action by states asserting their currently perceived self-interest without restraint, Congress will be constrained to exercise its constitutional responsibility to protect interstate commerce by prescribing a Federal standard of uniformity.

Alaska has been in the forefront of the drive for uniformity. By the collective judgment reflected in the development and general acceptance of the three-factor formula, Alaska's net income tax fairly and effectively reaches its proportionate share of the income of multinational oil and gas corporations doing business within the state. The proposed changes would be destructive of community and comity among the states in dealing reasonably with state taxation of multistate business and are parochially designed to increase tax revenues without regard to the general principles of tax jurisprudence for division of interstate business income adhered to by other states.

A NEW VENTURE IN FEDERALISM— TOWARD A SOLUTION TO STATE TAXATION OF MULTISTATE BUSINESS †

Leonard E. Kust *

I. Introduction

My title—"A New Venture in Federalism" possibly conjures up something far more exciting than my subject. But the obdurate problems involved in state taxation of interstate business require new perspectives and some venturesomeness in statecraft and I will stand by my title, trusting that my subject will at least be challenging if not exactly exciting.

New initiatives are needed to break the sterile impasse with which we have been confronted. All proffered solutions have been rejected.

The present impasse is, of course, part of the historic confrontation between state and national government in a federal system. The problems of state taxation of multistate business arise naturally from a nationwide economy functioning within a federal system. Solutions, on the other hand, necessarily impair in some measure the autonomy of the states.

In spite of this historic context, we must not permit an overweening emphasis on the conflict between "states' rights" and "national supremacy" deflect us from the search for a reasonable accommodation.

Reviewing the history of the controversy, I believe we have passed well beyond a simplistic confrontation between state and national government.

Ever since Chief Justice Marshall in *Brown v. Maryland* [1] declared the obvious, it has remained persuasive that state taxation can impede interstate commerce in violation of the Constitution. Yet as some 300 decisions of the Supreme Court [2] since attest, the judicial process is not a satisfactory

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†This article is based on a talk delivered by Mr. Kust at the TEI Annual Conference in New York City.

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[1] 25 U.S. (12 Wheat.) 419 (1827)

[2] *Northwestern States Portland Cement Co. v. Minnesota*, 380 U.S. 450 at 457, 458 (1959).

instrument for reconciling the sovereign power of states to impose taxes to the needs of a national economy contemplated by the commerce clause of the Constitution.

Recognizing that the taxing power is the most jealously guarded power of sovereignty, it is unfortunate indeed that the first full scale and considered attempt of Congress to exercise its constitutional power to regulate state taxation of interstate commerce should have unnecessarily exacerbated the inherent conflict between state and national government.

Yet H.R. 11798, the result in 1965 of five years of prepatory work by the Subcommittee of the House Judiciary Committee, could not have been better calculated to alarm the states and give credence to a claim of invasion of "states' rights." The drastic departure from prevailing state practice in presenting a two-factor apportionment formula for income taxes and the provision for substantial federal administration provided a momentum for state resistance which has since blocked any reasonable action.

Withdrawal by Congress since to consideration of such modest and really inadequate measures as the Rodino Bill (H.R. 7906) has convinced everyone, I believe, that no undue invasion of "states' rights" is threatened. Reasonable restraints on state taxing power in the interest of freer interstate commerce is now largely accepted on all sides. The quarrel is over what is reasonable and how it should be implemented.

Against this background, let me give you my appraisal of where matters stand and what the prospects are.

II. Possible Solutions in Process

There are presently in process several initiatives in varying degree of implementation and with varying promise of providing reasonable solutions to the problems of state taxation of multistate business.

A. *Uniform Acts.* Since 1890 the National Conference of Commissioners on Uniform State Laws has promoted uniformity in state legislation on subjects where diversity of treatment is an interstate evil.

A National Tax Association Committee issued a report in 1919 urging States to utilize a simple uniform tax on income and in 1921 set forth the model acts which had been drafted pursuant to the 1919 study. Although the NTA persisted in its advocacy of a uniform law, nothing concrete ensued until

1957 when the present Uniform Division of Income for Tax Purposes Act, referred to by the acronym UDITPA, was drafted and approved by the National Commissioners on Uniform State Laws and was in the same year endorsed by the American Bar Association.[3]

After years of standing as the only solution being advocated with respect to the problems of state taxation of interstate business, no sooner had the proposal begun go be implemented than it began to be viewed as inadequate. The Supreme Court decisions in the *Stockham Valve* and *Northwestern Cement* cases[4] in 1959 centered attention on the question of jurisdiction. UDITPA does not deal with jurisdiction. Mr. Justice Frankfurter in his dissent in the forementioned cases urged Congress to act. The business community organized an urgent demand on Congress and Congress, though it had never theretofore recognized any obligation or power in the area, promptly enacted Public Law 86-272 in 1959 delimiting the power of states to impose an income tax on interstate business corporations and calling on the House Judiciary and Senate Finance Committees to make a thorough study and recommend legislation with respect to all of the problems involved, including apportionment of income. When the Supreme Court decided the *Scripto* case[5] in 1960, the impact of sales and use taxes on interstate commerce was by amendment of P.L. 86-272 added to the investigation.[6]

Overtaken by these developments UDITPA has languished. Although efforts continue to have it enacted by state legislatures and some progress continues, the uniform act is now generally viewed as guidance and as a prototype for incorporation in other broader solutions.

But aside from the roll of events, does UDITPA deserve its apparent fate? I believe it has served a laudable and perhaps indispensable purpose in crystallizing thinking about the standards to be incorporated in a uniform apportionment formula, but both its scope and its approach are, I think, clearly inadequate to the needs.

Uniform acts are rarely adopted by all states. Only 25 states and the District of Columbia have adopted UDITPA.[7]

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[3] H.Rep. 1480, 88th Cong., 2d Sess., Vol. 1, pp. 129, et seq. (Willis Subcommittee Report)

[4] *Supra*, 358 U.S. 450 (1959).

[5] *Scripto, Inc. v. Carson*, 362 U.S. 207(1960).

[6] P.L. 87-17; H.Rep. 1480, supra, p. 9.

[7] Alabama, Alaska, Arkansas, California, Colorado, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Missouri, Montana, Nebraska, New Mexico, North Dakota, New Hampshire, Oklahoma, Oregon, South Carolina, Washington, North Carolina, Utah, Virginia.

Usually some deviating amendments are made by state legislatures, as has happened with respect to UDITPA. Some lack of uniformity may be tolerable with respect to other uniform laws, but with respect to UDITPA deviation means a potential duplication of tax burden.

Moreover, as already noted, UDITPA does not deal with jurisdiction. It does not deal with he determination of the income base; it does not deal with the treatment of related taxpayers; and it does not deal with taxes other than the income tax. Finally, the uniform law approach cannot provide machinery for uniform administrative and judicial interpretation which can over time create wide diversity.

I think we can conclude that the uniform law approach will not serve to solve the problems of state taxation of multistate business.

B. *Federal Legislation.* Congressional action and the prospect of additional Congressional action have drained the uniform act approach of vitality. But while federal legislation has distinct advantages over uniform laws, what are the real prospects for effective federal legislation and how would it be implemented?

The prospects are at best uncertain. After its disastrous first proposal for Congressional action incorporated in H.R. 11798, the House Judiciary Subcommittee offered a drastically truncated measure directed primarily to small business. It has been twice passed by the House in spite of adamant opposition by state tax administrators. Now known as the Rodino Bill (H.R. 7906) and pending before the Senate Finance Committee, it is in threat of becoming a casualty a second time as time is running out in this Session of Congress.

Why after so many years and so much effort and such clear need is Congressional action again about to abort?

There is a complex of reasons. There is still a residue of resistance based on the notion that any action represents Congressional interference with states' rights. There is disagreement between business and state tax administrators; there is disagreement among business groups; there is disagreement among tax administrators; and there is reluctance on the part of Congress, particularly the Senate Finance Committee on which all these disagreements have come to bear, to act as arbiter and impose a solution. My reading of the mood of the Finance Committee is quite

frankly that it is waiting for the contending parties to compose their differences.

Overhanging the troubled attempts to solve the problems through federal legislation are some nagging questions if we are to enlarge the narrow scope of the Rodino Bill. How far can the scope be broadened and made effective without provision for administrative and judicial interpretation in a manner which will preserve uniformity? Is federal administration avoidable and if not how can present state opposition be overcome? Is a multistate tax compact an alternative to federal legislation?

C. *The Multistate Tax Compact.* The Multistate Tax Compact was conceived in 1966, and has been promoted as an alternative to federal legislation. It incorporates UDITPA, it provides some sales and use tax standards, it provides for advisory administrative regulations and it provides an arbitration procedure. It is thus clearly superior to the uniform law approach. But it still suffers from some of the defects of a uniform act and encounters some special problems of its own.

In 4 years the Compact has been adopted by only 20 states [8] and has been adopted by none of the major Eastern seaboard industrial states. It has succeeded in getting associate membership from 13 states, including important industrial states, but clearly the prospect of getting broad enough participation to make the compact a self-sufficient solution to the problems of state taxation of multistate business is doubtful.

Moreover, the Compact does not deal with the issues of jurisdiction and its provisions for administrative interpretation are weak. It has no provisions for judicial review. While the contrary is argued, it may well be invalid without Congressional consent. Its enlargement and amendment to meet changing needs would involve cumbersome individual member state legislative approval and if Congressional consent is required, repeated Congressional approval. Facing all of these problems and the present reluctance of additional states to adopt it, the Compact approach also appears unlikely to provide an adequate solution to state taxation of multistate business. It has, nevertheless, served as a rallying point for state tax administrators in their effort to forestall federal legislation, and they have had bills introduced to give Congressional assent to the Compact.

[8] Multistate Tax Newsletter No. 22, July, 1970.

III. AN INNOVATION IN STATECRAFT—FEDERAL LEGISLATION ADMINISTERED UNDER A MULTISTATE COMPACT.

All of the apparently available avenues to solution of the problems of state taxation of interstate business seem to be seriously flawed. How, then, do we proceed?

Obviously some innovative, reconciling initiative is needed. Fortunately this initiative nas been launched, not as a self-conscious exercise in creative statecraft, but intuitively, forced by the logic of the circumstances. It has emerged from the chrysalis of pressure for solution through federal legislation and the counterpressure for solution through a multistate compact. Neither pressure or solution appears sufficient in itself, but an amalgamation of the two approaches may well be the reconciling, innovative answer.

The Bill drafted by the Ad Hoc Committee on Taxation of Interstate Business offers such an answer. I had the privilege of serving as Co-Chairman of this Committee. As you know, the Committee was a volunteer and self-appointed group of state tax administrators and business representatives who subscribed to the view that reconciliation of the positions of business and state tax administrators was necessary and were willing to devote effort to that end.

While palpable hostility between the business and state representatives at the outset threatened the joint enterprise, this gradually gave way to respectful regard for opposing views. Total reconciliation was not achieved but a wide area of accord was defined and, remarkably, from the beginning there was consensus that the solutions to the problems of multistate taxation of interstate business should be implemented through a merger of the compact approach with federal legislation.

I am convinced that, consciously or unconsciously, this was genuinely innovative and regardless of the fact that the Committee's recommendations were not unanimous or whether we individually, on study and reflection, agree with all the details of the Committee's proposals, the larger thrust of the Committee's effort is sound and offers the best and most hopeful solution to the problems of state taxation of multistate business.

A. *The Ad Hoc Committee Proposal.* A brief description of the main provisions of the Ad Hoc Committee's proposal will, I trust, serve to justify this conviction. The fundamental, creative conception is, of course, the merger of the multi-

state tax compact approach and the federal legislation approach.

Under this conception, federal legislation would provide jurisdictional standards, a uniform apportionment formula for income and capital stock taxes, standards for consolidation or combination of affiliated corporations for income tax purposes, standards for sales and use taxes, and procedures for the settlement of disputes, with the Multistate Tax Compact providing the means for administration of the federal legislation.

Such a structure would provide flexibility for adjustment and evolution to improve the system for taxation of interstate business. With the Multistate Tax Compact providing only the administrative machinery under which the States would act cooperatively to administer federal standards, and not itself containing substantive standards, there should be little or no need for future amendments of the Compact. This is desirable since, as already noted, amendment of an interstate compact involves procedures which it would be difficult to make responsive to changing needs and developing thinking with respect to standards for taxation of interstate business. On the other hand, with the Multistate Tax Commission under the Compact acting as the administrative agency it could implement and modify, within the limits of permissible administrative interpretation, the legislative standards under federal law, and when the need for changes exceeded the bounds of permissible administrative interpretation the Commission could seek amendments to the federal legislation, a far more responsive procedure than amendment of an interstate compact. Moreover, under the Committee structure of the Multistate Tax Compact any proposal for amendment of the federal legislation will have been preceded by extensive discussions between state administrators and business representatives and will presumably, therefore, be presented to Congress with a substantial consensus of support.

Time does not permit discussion of the specifics of the standards to be provided by federal legislation or the specifics of the powers of administration delegated to the Multistate Tax Commission. Some are freighted with controversy and the Committee sought to limit itself only to the most pressing problems rather than to deal with all the problems that might arise in the areas which were included in its proposal. The Committee deemed it more important to take an initial step, but a sound one, which would lay the groundwork for perfecting amendments as experience pointed the way.

While the Committee conceived its approach under the compulsion of existential pressures, unaware of historical precedents and unsure of its constitutional propriety, its conception, one finds on research, is not wholly unprecedented and is, with little doubt, wholly constitutional, the latter having been confirmed by competent outside legal counsel during the course of the Committee's deliberations.

B. *Precedents.* In a landmark article in 1925,[9] Mr. Justice Frankfurter, then Professor of Law at Harvard Law School, and James Landis, then his research associate and later Dean of the Law School, analyzed the compact clause of the Constitution and urged a more imaginative use of this clause in dealing with problems requiring interstate adjustments within our federal system. They cited this approach as preservative of the legal autonomy of the states rather than reducing them to departments or mere administrative divisions of the central government. Although acknowledging that the compact cluase had its origin in the boundary disputes pending at the time the Constitution was framed and adopted, they traced its gradual application in other areas and argued that the pressure of modern interstate problems has revealed the rich potentialities of the device. They specifically called attention to its usefulness with respect to interstate conflicts in taxation. The following quotation sounds remarkably current:

> ". . . no one can scan the flood of cases dealing with 'jurisdiction' to tax, rules for apportionment and the like, without realizing that the opportunities for taxation open to the States against common resources might find a more economic and more effective solution through negotiation than through litigation. At all events, in view of the growing burden upon time and feelings, as well as the cost in money due to the conflicts and confusion arising from the administration of independent systems of State taxation, the possibilities of amelioration and economy realizable through an alert use of the Compact Cluase call for more intensive study, as part of a disciplined attack upon the entire tax problem."

This early recognition of the usefulness of the compact clause in interstate taxation has been validated by time, but as we have learned a simple resort to the compact clause is not enough. A more alert and imaginative use is needed. The Ad Hoc Committee's proposal for federal legislation of uniform standards administered under a multistate compact is such a use.

[9] Frankfurter & Landis, THE COMPACT CLAUSE OF THE CONSTITUTION—A STUDY IN INTERSTATE ADJUSTMENTS, 34 Yale Law Journal 685 (1925).

But even this conception is not wholly unprecedented. In an article in 1936,[10] Professor Stevens of Cornell Law School proposed the adoption of uniform corporation laws through a combination of federal legislation and an interstate compact. He suggested federal legislation authorizing an interstate compact to set up an interstate commission on corporation law which would draft and approve uniform corporation law provisions for adoption by member states. But more critically for our purposes, he also suggested that in order to make the compact approach effective the federal legislation should prohibit the conduct of interstate commerce by corporations not formed under an act embodying the uniform law. He had no doubt as to the constitutionality of such a combination of federal regulation of interstate commerce with an interstate compact.[11]

Similarly, there also appears to be ample authority under several Supreme Court decisions[12] to support the administrative and judicial appeal procedures envisioned by the Ad Hoc Committee proposal.

IV. INTERNATIONAL IMPLICATIONS OF THE AD HOC COMMITTEE'S PROPOSAL.

There is more than a federal and interstate dimension to the Ad Hoc Committee's proposal which heightens my interest. The parallel between our interstate problems and the problems of international taxation of multinational business is inescapable. If we can resolve through federal legislation and a multistate compact the problem of interstate taxation, why should not this serve as a prototype for resolution of the problems of international taxation of multinational business through a multilateral treaty? The obstacles may seem insurmountable but the power of the example will be there and and as pressure for solutions mounts with the accelerating growth of multinational business, international machinery may well be implemented to parallel our example. It is clearly in the interest of business not only to solve our domestic problems but to grasp the opportunity through a successful domestic solution to provide a compelling international

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[10] Stevens, UNIFORM CORPORATION LAWS THROUGH INTERSTATE COMPACTS AND FEDERAL LEGISLATION, 34 Michigan Law Rev. 1063 (1936)

[11] See also Holcombe, THE STATES AS AGENTS OF THE NATION, 3 SELECTED ESSAYS ON CONSTITUTIONAL LAW, 1187 (1938).

[12] *Petty v. Tennessee-Missouri Bridge Comm.*, 359 U.S. 275 (1959); *Parden v. Terminal Railway of the Alabama State Docks Department*, 377 U.S. 184 (1964); *Tobin v. U.S.*, 306 F (2) 270 (D.C. Cir. 1962), Cert. den., 371 U.S. 902 (1963).

example. The time may not be so far off when a burgeoning multinational business will require new initiatives to deal with the international implications, including taxes. The impending seriousness of this is attested in the recent testimony on multinational corporations last December and May before the Subcommittee on Foreign Economic Policy of the Joint Economic Committee.

V. PLEA FOR STATESMANSHIP.

I am convinced that nothing less than a new venture in federalism such as the merger of the Multistate Tax Compact and federal legislation will resolve the differences between business and state tax administrators over solutions to the problems of state taxation of interstate business. To me this venture beckons as a challenge to statecraft. It calls for a kind of statesmanship that has not always been abundantly present in the debates on the subject heretofore. But I am optimistic. The not uncommon history of apparently intractible controversies is that they pass from unyielding hostility to grudging recognition of merit in opposing views and gradually to reconciling compromise. I think the multistate business tax controversy is running this course and we may well be entering the last stage of reconciling compromise.

But an acceptable issue out of our difficulties is by no means assured. One must plead for dedication to making our federal system work and for some sustained statesmanship on the part of both tax administrators and business representatives.

I have dealt only with the larger issues but there are specifics which must be incorporated in any solution and my experience on the Ad Hoc Committee makes it only too clear that unyielding adherence to a preferred view with respect to important specifics can destroy the promise of the joint venture.

Aside from its central conception, the genius of the Ad Hoc Committee's proposal, if it merits so laudatory a description, is its spirit of accommodation. There is danger that it may not be considered in the same spirit by contending business groups and state tax administrators now reviewing it.

I do not mean to suggest that the Ad Hoc Committee's proposal must be accepted intact or all will fall. But in seeking adjustments in the proposal let us not rekindle the old hostilities and resume the old intransigent stands.

I question whethe. either of the opposing views in the major specific controversies, such as over use tax jurisdiction and the consolidation of related companies, can wholly prevail. And if we persist in unyielding disagreement, the opportunity for creative statecraft may irrevocably pass, risking to unpredictable future pressures the fashioning of perhaps some drastic solution.

State Taxation of Interstate Business--An Obdurate Issue†

LEONARD E. KUST*

If you are familiar with my past involvement in efforts to resolve the problems and the conflicts in state taxation of interstate business or have yourself been involved as long as I, you will surely agree if I begin by observing that time passes but does not heal . This is not only an observation but a plea for reconciliation to nullify the observation.

A simple roll call of the events of the past 16 years quickly delineates the problems, the conflicts, the fruitless efforts at solutions and the present confusion.

The central problem is inherent in our federal system, the success of which depends on a reasonable accommodation between the soverign powers of the states and the national interest as defined in the Constitution. Specifically with respect to interstate business, the powers of the states to tax such business is subject to the national interest in promoting an open economy as embodied in the commerce clause.

In spite of the clear power of Congress to implement the

† Based on a paper presented at the TEI-Loyola-Tulane-LSUNO State and Local Tax Course, January, 1973.

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commerce clause in this area and the plea addressed by members of the Supreme Court in several cases to Congress to act, the task of accommodating the power of states to tax interstate business to the national interest was left to the fragmentary and uncoordinated process of case by case decisions by the courts.

Finally, in 1957 the National Commissioners on Uniform State Laws adopted the Uniform Division of Income for Tax Purposes Act (UDITPA), and therewith began 16 years of history which almost at once rendered this pioneering effort inadequate if not largely irrelevant. UDITPA had not been adopted by any state when the Supreme Court decisions in the *Stockham Valves* and *Northwestern Cement* cases in 1959 (358 U.S. 450) centered attention on the question of minimum connection as a basis for jurisdiction and UDITPA does not deal with jurisdiction. Prior to those decisions, a foreign corporation engaged solely in interstate activity in a state that had been held not to be subject to a tax measured by net income imposed by such state on the privilege of doing business therein (*Spector Motor Service v. O'Connor*, 340 U.S. 602 (1951)). Under those decisions, however, a tax imposed directly on the net income of such a business was permissible "provided the levy is not discriminatory and is properly apportioned to local activities within the taxing State forming sufficient nexus to support the same" (358 U.S. 450 (1959) at 452).

Alarmed by the exposure to state taxation of income from interstate commerce and the uncertainty of the minimum nexus in the absence of which protection still existed, the business community quickly prevailed upon Congress to take action and within seven months P.L. 86-272 was enacted denying to a state the power to impose a net income tax on an interstate business if the only activity within such state was solicitation. Recognizing that more comprehensive legislation required careful consideration, Congress in P.L. 86-272 called on the House Judiciary and the Senate Finance Committees to make a thorough study and to recommend legislation with respect to all of the problems involved, including apportionment of income. When the Supreme Court decided the *Scripto* case in 1960 (362 U.S. 207), the impact of sales and use tax collection on interstate commerce was added to the investigation.

Against this setting let me simply recall the intervening events in the droning drama that comes to no end and leaves us where we are today. The mere recital without elaboration

conjures up vividly the conflicts and contending views and leaves space to identify the areas of substantial consensus as well as the areas of conflict and to appraise the possibilities of reconciliation and prospective action.

The list of events following P.L. 86-272, unhappily, begins with the legislative proposal, based on the disastrously misconceived conclusions of an elaborate four-year long study by the Willis Subcommittee and embodied in H.R. 11798, which persuaded few but alarmed many, particularly the state tax administrators. This was followed by the drastically truncated measure directed primarily to small business, beginning as the Willis Bill and continuing as the Rodino Bill, which, although thrice enacted by the House has died in three successive sessions of Congress but arises, Phoenix-like, to be introduced again. There is the Multistate Tax Compact promoted by state tax administrators as the alternative to federal legislation. There is the *National Bellas Hess* case (386 U.S. 753 (1967)). There is the unredeemed promise of Senate Finance Committee hearings. There are the first Ad Hoc Committee proposal, the Multistate Tax Commission "Plan", the second Ad Hoc Committee proposal and the Council of State Chambers' COST proposal. There are the competing legislative bills embracing, besides the Rodino Bill (H.R. 1538), the Ribicoff-Mathias Bill (S. 317), the Talcott-Tunney Bill (H.R. 4267), the two Magnuson Bills (S. 1883 and S. 3333) and the Mathias Bill (S. 4080). And, finally, there are the court decisions interpreting P.L. 86-272, the most notable of which are the *Smith, Kline & French* (241 Ore. 50, 403 P. 2d 375 (1965)), *Clairol* (57 N.J. 199, 270 A. 2d 702 (1970) appeal dismissed, 402 U.S. 902 (1971)) and *Heublein* (Dec. 18, 1972) cases, the last of which was just decided last December 18th by the Supreme Court.

There has been plenty of movement; the question is whether it has been forward. The portent of these tangled events is not easy to read. But let us try to devine some meaning from the confused history and venture some views as to where it will or at least should lead.

General Areas of Consensus

The recitation of the recent history of state taxation of interstate business reflects mostly conflict and competing views but there are substantial areas of consensus. It is important not to lose sight of this, for if the differences are to be composed, we shall have to build on the areas of consensus.

There is substantial agreement that there should be a uni-

form formula for the division of interstate business income among the states and that the collection of sales and use taxes by interstate business should be governed by uniform standards.

Although the agreement is less general, it is also broadly agreed that there should be uniform minimum jurisdictional standards for the imposition of an income tax and for the collection of a use tax by interstate business and possibly also for the imposition of capital and gross receipts taxes on such business.

There is accordingly substantial agreement as to the basic elements of needed action. But there is not the same agreement as to means for translating the agreed on general concepts into the needed action nor as to the specifics of such action; indeed, there are some means and some specifics as to which there is only stalemated and unyielding disagreement.

General Areas of Conflict

Having identified the general areas of substantial agreement, let us identify the conflicts as to general concepts that hold little promise of resolution and then consider the specifics with respect to which there is substantial agreement or with respect to which conflict has frustrated the achievement of progress.

First of all, the Rodino Bill, limited to small business and providing a "business location" jurisdictional standard and a two-factor apportionment formula for income has only limited support from business and has been adamantly opposed by the states. It has had the general support of the business community in the past only as a basis of action by the House to permit corrective and enlarging amendments in the Senate. But this has become a worn and tired formula and one wonders whether it will be repeated in this session of Congress.

It seems equally clear that the Multistate Tax Compact cannot carry the day as a self-sufficient solution. Its legal status without Congressional approval remains untested and with business opposition to it as the whole solution, it is unlikely that it will be sufficiently accepted by the large industrial states to work effectively.

It is less clear but probably also true that federal legislation alone, without giving to the states a continuing lead role by way of a modified Multistate Tax Compact, has little chance of being enacted because of state opposition.

This seems to leave only one promising course of action, but

we will deal with this later, turning first to the specific areas of agreement or conflict.

Specific Areas of Agreement or Conflict

Jurisdiction

The problem of the minimum connection required to justify imposition of tax on an interstate business remains as one of the most difficult problems in the accommodation of state and local governments' power to tax to the national interest in an open economy. It is not just a question of equality between in-state and out-of-state business but a question of the deterrence to out-of-state business when the connection with a state or locality is too thin to justify compliance with state and local tax laws by the out-of-state business. This is, of course, primarily a problem of small, expanding business. But this is at the heart of a growing national economy and the encouragement of economic competition. It is also evident that the burden of compliance arises primarily from disparate rules for the determination of income, the apportionment of income, and the obligation to collect use taxes. If the rules were uniform among the states, jurisdictional protection from any state in which there are customers might well prove to be unnecessary, at least with respect to state level taxes.

The proliferation of the imposition of income and use taxes by local governments, however, is another matter. This can be as burdensome to large business as to small, considering that there are some 80,000 local governments. With respect to such taxes, there should be a substantial minimum connection with the taxing jurisdiction.

In spite of the fact that concern about jurisdictional overreach by the states initiated the recent history and remains the prime concern of small business, there has developed far more agreement than may at first be evident.

With respect to income taxes, the Ad Hoc Committee proposal, introduced in the last session of Congress by Senator Magnuson as S. 3333, and the Multistate Tax Commission Plan, both accept P.L. 86-272 as sufficient while the Rodino Bill, the Ribicoff-Mathias Bill and the COST proposal, introduced at the end of the last session of Congress by Senator Mathias as S. 4080, embrace a "business location" concept. But on close examination, how much difference is there between P.L. 86-272 and "business location?" The latter is a more precise and elaborate definition but solicitation by an employee in the state would alone be sufficient in certain circumstances to confer jurisdiction except as solicitation is

rendered insufficient by incorporation of the language of P.L. 86-272 in the definition of "location of an employee." Thus, the minimum connection in both comes to the same thing and by virtue of the same language except for the additional exclusion under the business location standard of installation or repair incidental to an interstate sale, which is important but not a likely matter of critical disagreement.

With respect to the power of state and local governments to impose the obligation on interstate business to collect sales or use taxes, there is substantial agreement in all of the proposals and bills except the Rodino and Ribicoff Bills. The latter bills would impose the business location standard modified only by regular household deliveries. All the other bills and proposals would codify the *Scripto* and *National Bellas Hess* case law extending the jurisdictional reach of states to cover regular solicitation in the state by an employee or representative *(Scripto)*, but not solicitation solely by mail, radio or television *(National Bellas Hess)*. The jurisdiction of local governments, however, would extend beyond the business location test only to regular household deliveries under the Ad Hoc Committee bill, the Multistate Tax Commission Plan and the COST bill, as under the Rodino and Ribicoff Bills.

Thus, again, except for lingering small business interest in the higher state level limitation in the Rodino Bill, there is general agreement as to sales and use tax jurisdiction. It would appear that the far greatest importance of effective limitation of potentially 80,000 local governments requiring collection of their separate sales and use taxes will persuade small business to join in the general consensus.

The Sales Factor

There is no significant controversey with respect to the use or definition of the property and payroll factors of the income apportionment formula. All the conflict centers on the sales factor, first as to whether it should be used and second as to its content. The Rodino and Ribicoff Bills continue to incorporate the two factor formula, omitting sales, which first appeared in H.R. 11798. However, the momentum of support for the two factor formula is waning and was never sufficient to overcome the adamant state opposition. All the other pending proposals employ a three factor formula, including a sales factor on a destination basis.

But disagreement persists with respect to the so-called "throwback" rule, under which sales to customers in a state lacking jurisdiction to tax the seller are assigned to the state of origin. UDITPA, the Multistate Tax Compact and the

Multistate Tax Commission's Plan all incorporate the "throwback" rule. The Ad Hoc Committee Bill (S. 3333) modifies the rule by making it inapplicable to export sales, other than to the U.S. Government, and the COST bill eliminates the "throwback" rule completely.

There is more theoretical fervor than there is practical significance in the disagreement and an accommodation along the lines of the Ad Hoc Committee proposal should be acceptable.

Dividends

There is substantial agreement that the business/nonbusiness income distinction embodied in UDITPA should be avoided and that all income should be apportioned under the formula, with the exception of dividends with respect to which there is strong disagreement.

The Multistate Tax Commission in its regulations and in its Plan would include dividends in apportionable income. The Ad Hoc Committee bill would eliminate from the tax base dividends from 80% owned affiliates and would allocate all other dividends to the commercial domicile of the recipient. The COST bill follows the Ad Hoc proposal but reduces ownership of affiliates to 50%.

The general practice among the states is not to tax intercorporate dividends, but a few states vigorously disagree. It would seem that the taxation of inter-corporate dividends is undoubted double taxation which should certainly not be extended beyond the 15% included in income under the Internal Revenue Code.

The treatment of dividends clearly is one of the most sensitive and important remaining controversies. Failure to resolve it may well stand in the way of the needed accommodation.

Combined or Consolidated Returns.

The treatment of dividends is a sensitive and important issue but the combination or consolidation of related corporations where one is subject to the jurisdiction of the state but the other is not is the more notorious and apparently irreconcilable controversy. Arcane distinctions are drawn between combination and consolidation but for brevity we shall use consolidation as comprehensive.

The storm center of the controversy is the premise, aside from a common ownership, on which consolidation should rest. There are strong advocates of the "unitary business" doctrine among state tax administrators but most administra-

tors appear to be indifferent. On the other hand, business generally strongly adheres to the view that consolidation should be imposed by states only if there has been non-arm's length dealing between the related companies.

Reflecting the controversy, the Ribicoff Bill prohibits consolidation and substitutes reallocation in accordance with the principles of Section 482 of the Internal Revenue Code. The first Ad Hoc Committee bill employed a series of rebuttable presumptions permitting or forbidding consolidation of 80% affiliates, keyed to the volume of intercompany transactions. The Multistate Tax Commission Plan would permit either the state or the taxpayer to elect to consolidate with all 80% affiliates and this was adopted in the second Ad Hoc Committee proposal with the exclusion, however, of affiliates substantially all of the income of which is from foreign sources. The COST bill, on the other hand, permits consolidation only if the state establishes non-arm's length dealing or if the taxpayer establishes that clear reflection of income requires it.

The disparities in the proposals are obviously wide and fundamental but, curiously, the resolution of the conflict may not be as remote as it appears, as I shall explain presently.

Regulations and Appellate Procedures

There are two other specifics over which there is no express general agreement: regulations and appellate procedures. The Multistate Tax Compact provides for the formulation by the Commission of purely advisory regulations while the first Ad Hoc Committee proposal would have conferred on the Multistate Tax Commission the power to promulgate mandatory regulations on nonmembers as well as members of the compact. The second Ad Hoc Committee proposal retreated to advisory regulations which would be adopted only by the action of all states, whether or not members of the compact, and which would not be binding on a state if it took positive administrative action within 180 days rejecting the regulation. None of the other bills or proposals, other than the first Magnuson consent bill, endorse the Multistate Tax Compact or provide for regulations.

With respect to appeals the Multistate Tax Compact provides for arbitration, the first Ad Hoc Committee proposal provided for an appellate procedure within the Multistate Tax Commission from which there was an appeal to the Federal Courts of Appeal, but the second Ad Hoc Committee proposal abandoned all appellate procedure, leaving the resolution of controversies to present state administrative and judicial remedies. The COST proposal does not provide for any ad-

ministrative procedures but would confer jurisdiction on the Court of Claims to review *de novo* final state administrative determinations involving application of the federal legislation.

These are interesting proposals and alternatives for regulations and appeals but they do not represent crucial differences that cannot be dealt with in the context of general agreement with respect to the rest of the legislative package.

The Need for Reconciliation

Having traversed the sixteen years of recent history, where do we stand today? It is my reading of the mood of Congress, particularly of the Finance Committee, that it is waiting for the contending parties to compose their differences. The Congress does not intend to act as arbiter and unless state administrators and business are prepared to give substantial support to one of the existing proposals or a new accommodation it will not act. This is now more likely than ever to be true since Congress will be preoccupied with its constitutional confrontation with the executive. Therefore, unless the past 16 years of effort, contention and substantial accommodation are to come to naught, a final effort to resolve remaining differences must be made.

A Solution to Resolve the Remaining Conflicts

Since neither Federal legislation alone nor the Multistate Tax Compact alone seem capable of commanding sufficient support to provide a solution, the Ad Hoc Committee conception of a combination of the two with appropriate modifications provides the only real promise of reconciliation. It makes sense and deserves support. I do not, however, foreclose; indeed, I encourage, the substitution of a new and broader accord between business and tax administrators, if one can be forged. There is promise of this in the discussions under progress between COST and the Executive Committee of the National Association of Tax Administrators (NATA). One can only hope that the promise will come to an early fruition, since the remaining differences are no longer really so very great, except for some partisans who continue to insist on their own special interest or point of view.

With respect to jurisdiction the existing proposals are not substantively very different with respect to income taxes, and although I would prefer the business location test to simple continuation of P.L. 86-272, I think we should recognize that the business location test would not have resolved beforehand the litigation in the *Clairol* and *Heublein* cases with respect to

the meaning of solicitation under P.L. 86-272. With respect to sales and use tax collection, I believe small business should yield to the more general consensus as to state jurisdiction in order to achieve limitations on the potentially far more burdensome obligation of collecting local government taxes.

The treatment of dividends and consolidation of related companies are the two remaining significant obstacles to general consensus. Again it seems to me that the Ad Hoc Committee proposals are reasonable accommodations. I do not like the elective consolidation by either the state or the taxpayer, since it lacks any rationale except expediency, but it seems to be the only solution that can possibly achieve substantial support from both states and business. The proposal originated with the Multistate Tax Commission Plan and therefore has state support and despite the COST bill's adherence to the arm's-length standard, I have reason to believe that the business community can and would accept the dual elective standard, if affiliates, substantially all of the income of which is from foreign sources, are excluded.

A final effort at accommodation must be made and it must be made during this session of Congress or I fear that all reasonable hope of useful action to bring order and balance into the chaos of state and local taxation of interstate business will be spent, perhaps irrevocably.

An Optimistic Outlook

But I remain optimistic. The not uncommon history of apparently intractable controversies is that they pass from unyielding hostility to grudging recognition of merit in opposing views and gradually to reconciling compromise.

But an acceptable issue out of our difficulties is by no means assured. One must plead for statesmanship on the part of both tax administrators and business representatives. The Ad Hoc Committee conception of a combination of federal legislative standards and the Multistate Tax Compact is a new venture in federalism and, perhaps with some further adjustment, deserves support.. But any other solution with substantial backing by business and state tax administrators, such as the developing COST-NATA accord, deserves encouragement and support. If we persist in unyielding disagreement, the opportunity for creative statecraft may irretrievably pass, risking to unpredictable future pressures the fashioning of perhaps some drastic solution.

Robert Richards

ALASKA ECONOMICS

Alaska's oil and gas tax—one of the highest burdens in the country

Government is the largest sector of Alaska's economy, and the petroleum industry is the major contributor to state government revenue. Let us look at the relationship between these two important sectors:

Government remains the largest employer in Alaska, providing over one-third of all the jobs and about one-quarter of the gross state product. This huge public sector, which at the state and local levels has exhibited strong growth, has been the major factor underlying the stability of the Alaska economy.

The state of Alaska fiscal year 1978 budget provides for total operating expenditures of $1 billion. This represents a 13 percent increase over the level of fiscal year 1977—considerably slower than the 19 percent increase of the previous year.

The state budget has become increasingly dependent on the petroleum industry for its funding. More than one-half of the state's total unrestricted general fund revenue came from petroleum firms in fiscal year 1977. State estimates of fiscal year 1978 petroleum taxes and revenues range from $672 million to $742 million, depending on the wellhead value for North Slope production. These petroleum figures jump to between $856 million and $1.4 billion by 1980. Based on the state's estimated "medium case," the petroleum industry will contribute approximately three-fourths of total state revenue in 1978 and in 1979.

In November, 1976, Alaska voters passed a constitutional amendment creating a Permanent Fund to hold at least one-quarter of all mineral lease rentals, royalties, royalty sale proceeds, federal mineral revenue sharing payments, and bonuses. The Permanent Fund, by law, must be used only for income-producing investments, and the income is to go into the general fund. Depending on the wellhead value, contributions from Prudhoe Bay and Cook Inlet petroleum production at the 25 percent rate to the Permanent Fund could range between $81 million and $94 million in fiscal year 1978, $90 million to $136 million in fiscal year 1979, and $96 million to $173 million in fiscal year 1980.



An aerial view of a pipe storage yard at Valdez showing some of the 48-inch steel pipe used in construction of the Trans Alaska oil pipeline. The state budget has become increasingly dependent on the petroleum industry for its funding. *Alyeska Pipeline Service Co. photo*

It is expected that the 1978 session of the Alaska legislature will enact legislation establishing the investment policies and objectives and the management structure and procedures of the Permanent Fund.

Alaska's oil and gas tax structure also impose one of the highest burdens in the

country, well in excess of the state's requirements to fund its needs. The petroleum industry pays to the state a multiplicity of taxes, including severance taxes, regulation and conservation taxes, exploration, production and pipeline transportation property taxes, as well as motor fuel taxes and corporate income taxes. These taxes are in addition to royalty, bonus and rental payments. In mid-1977 severance tax rates on petroleum production were legislated higher by about one-half for oil and more than double for gas. As the laws now stand, both severance taxes and royalty payments will net the state about one-quarter of the gross value of production at Prudhoe Bay.

Additionally, Alaska has imposed a $30 million Coastal Protection Fund for oil spills in state waters, an item which is being litigated. There is also a $1-to-$10-per gallon state spill penalties law to protect anadromous streams, estuaries and public lands. On top of state taxes, as the oil is loaded into tankers at Valdez, the owners must pay five cents per-barrel into a federal $100 million Trans-Alaska Pipeline Liability Fund. Considering the small petroleum industry permanent work force in Alaska of about 5,000, this capital intensive industry is a corporate citizen which contributes considerably more public revenue than the burden it imposes on public services.

Accompanying heavy taxation, future pre-leasing requirements by state government may require competing petroleum firms to submit confidential seismic and geological data to the state. Additionally, proposed changes in leasing procedures could result in final tract selections being announced only a half-year in advance of each sale.

Another major issue is the tariff charged by the pipeline owners for the service of moving Prudhoe Bay crude oil to Valdez. The tariff is one of the costs deducted from the price of the oil in calculating the field value upon which state royalty payments and severance taxes are based. The owners have proposed an interim tariff ranging from $6.04 to $6.44 on interstate oil, but the Interstate Commerce Commission (ICC) suggested interim charges from $4.68 to $5.10. However, the Supreme Court stayed the ICC tariff order, and the originally filed tariffs became effective on Oct. 20, 1977. Similarly, the Alaska Pipeline Commission is in the process of determining tariffs for intrastate oil.

Considering the already high operating and production costs associated with Alaska's remote location and severe climate, the Alaska state regulatory and tax burden now looms another impediment to development in the 49th state. □

Robert Richards is Executive Vice President of Alaska Pacific Bank and leading economist in the state of Alaska.

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SI N UP SHEET

HEARINGS ON SCS/CS HB 322 - OIL AND GAS CORPORATE FRANCHISE TAX

WEDNESDAY, FEB. 8

DONALD NIELSEN
BRISTOL BAY NATIVE CORP

LEONARD KUST
CONSULTANT, ALASKA OIL & GAS ASSN.

BOB MOORE
CONSULTANT, ARTHUR ANDERSON

FRIDAY, FEB. 10

COMMISSIONER GALLAGHER
DEPT. OF REVENUE

MONTE TAYLOR
EXXON

DICK DONALDSON
SOHIO

JOHN WARREN
CONSULTANT, ALASKA OIL & GAS ASSN

HERMAN LOEB
PENNZOIL

BILL VAN ALEN
H.L. HUNT

EXHIBIT

Reproduced from Congressional Budget Office, Budget Option for Fiscal Year 1977: A Report to the Senate and House Committees on the Budget.

TAX EXPENDITURE ESTIMATES, BY FUNCTION[a]

[Millions of dollars, fiscal years]

Function	Corporations					Individuals				
	1977	1978	1979	1980	1981	1977	1978	1979	1980	1981
National defense (050):										
Exclusion of benefits and allowances to armed forces personnel	.....	.....	.....	.....	.....	650	650	650	650	650
Exclusion of military disability pensions	.....	.....	.....	.....	.....	90	100	110	120	130
International affairs (150):										
Exclusion of income earned abroad by U.S. citizens	.....	.....	.....	.....	.....	160	175	195	205	220
Exclusion of gross-up on dividends of LDC corporations	55	55	55	55	55	.....	.....	.....	.....	.....
Deferral of income of domestic international sales corporations (DISC)	1,420	1,460	1,495	1,580	1,735	.....	.....	.....	.....	.....
Deferral of income of controlled foreign corporations	365	365	365	365	365	.....	.....	.....	.....	.....
Special rate for Western Hemisphere trade corporations	50	50	50	50	50	.....	.....	.....	.....	.....
Natural resources, environment and energy (300):										
Exclusion of interest on state and local government pollution control bonds	170	220	265	300	330	75	100	125	145	160
Expensing of exploration and development costs	840	1,045	1,285	1,540	1,850	195	245	305	365	435
Excess of percentage over cost depletion	1,020	1,015	1,110	1,215	1,325	575	625	640	670	695
Pollution control: 5-year amortization	15	5	.....	.....	.....	.....	.....	.....	.....	.....
Capital gains treatment of royalties on coal and iron ore	20	20	25	25	30	50	60	65	75	85
Capital gains treatment of certain timber income	165	175	190	200	215	65	70	75	80	85
Agriculture (350):										
Expensing of certain capital outlays	115	120	130	135	150	360	370	380	390	400
Capital gains treatment of certain income	40	40	45	50	50	565	655	705	760	820
Cooperatives: deductibility of noncash patronage dividends and certain other items	455	485	520	555	595	.....	.....	.....	.....	.....
Commerce and transportation (400):										
Exemption of credit unions	135	145	155	165	175	.....	.....	.....	.....	.....
Corporate surtax exemption	6,185	6,745	7,300	7,865	8,455	.....	.....	.....	.....	.....
Deferral of tax on shipping companies	130	155	180	205	230	.....	.....	.....	.....	.....
Railroad rolling stock: 5-year amortization	10	5	.....	.....	.....	.....	.....	.....	.....	.....
Financial institutions: excess bad debt reserves	570	635	730	900	1,060	.....	.....	.....	.....	.....
Deductibility of nonbusiness state gasoline taxes	.....	.....	.....	.....	.....	600	665	735	815	910
Depreciation on rental housing in excess of straight line	125	135	145	155	170	455	480	510	545	580
Depreciation on buildings (other than rental housing) in excess of straight line	280	300	325	350	375	215	235	250	275	300

See footnote at end of table.

*Source: Staffs of the Treasury Department & the Joint Committee on Internal Revenue Taxation.

TAX EXPENDITURE ESTIMATES, BY FUNCTION[a]—continued

[Millions of dollars, fiscal years]

Function	Corporations					Individuals				
	1977	1978	1979	1980	1981	1977	1978	1979	1980	1981
Expensing of research and development expenditures	695	725	755	785	815	.....	.....	.....	.....	.....
Capital gains: Corporate (other than farming and timber)	900	1,015	1,090	1,170	1,260	.....	.....	.....	.....	.....
Investment credit	7,585	8,045	8,480	8,890	9,310	1,530	1,635	1,750	1,870	1,995
Asset depreciation range	1,630	1,825	2,000	2,095	2,135	175	195	220	230	235
Dividend exclusion	.....	.....	.....	.....	.....	350	370	385	405	425
Capital gains: Individual (other than farming or timber)	.....	.....	.....	.....	.....	6,225	7,360	7,905	8,490	9,145
Capital gains at death	.....	.....	.....	.....	.....	7,280	8,120	9,015	10,005	11,105
Deferral of capital gains on home sales	.....	.....	.....	.....	.....	890	935	980	1,030	1,080
Deductibility of mortgage interest on owner-occupied homes	.....	.....	.....	.....	.....	4,710	5,225	5,800	6,440	7,150
Deductibility of property tax on owner-occupied homes	.....	.....	.....	.....	.....	3,825	4,245	4,710	5,230	5,805
Deductibility of interest on consumer credit	.....	.....	.....	.....	.....	1,075	1,195	1,325	1,475	1,635
Exclusion of interest on state and local industrial development bonds	195	235	270	315	355	90	110	130	150	170
Excess 1st year depreciation	165	180	200	220	240	85	95	105	115	130
Expensing of construction period interest and taxes	1,065	1,110	1,150	1,190	1,230	570	595	620	645	670
Credit for purchase of new home	.....	.....	.....	.....	.....	100	.....	.....	.....	.....
Community and regional development (450):										
Housing rehabilitation: 5-year amortization	25	20	15	10	10	40	25	15	15	15
Education, training, employment, and social services (500):										
Exclusion of scholarships and fellowships	.....	.....	.....	.....	.....	220	235	245	255	270
Parental personal exemption for student age 19 and over	.....	.....	.....	.....	.....	715	735	760	780	805
Deductibility of charitable contributions (education)	280	325	355	390	430	500	555	610	670	735
Deductibility of child and dependent care expenses	.....	.....	.....	.....	.....	420	460	510	560	615
Child care facilities: 5-year amortization	5	5	.....	.....	.....	.....	.....	.....	.....	.....
Credit for employing AFDC recipients and public assistance recipients under work incentive program	10	10	10	10	10	.....	.....	.....	.....	.....
Deductibility of charitable contributions (social services)	352	402	446	489	536	3,124	3,468	3,847	4,274	4,740
Health (550):										
Exclusion of employer contributions to medical insurance premiums and medical care	.....	.....	.....	.....	.....	4,225	4,730	5,300	5,935	6,650
Deductibility of medical expenses	.....	.....	.....	.....	.....	2,095	2,325	2,580	2,865	3,175
Deductibility of charitable contributions (health)	173	198	219	241	264	831	922	1,023	1,136	1,260

See footnote at end of table.

TAX EXPENDITURE ESTIMATES, BY FUNCTION[a]—continued

[Millions of dollars, fiscal years]

Function	Corporations					Individuals				
	1977	1978	1979	1980	1981	1977	1978	1979	1980	1981
Income security (600):										
Exclusion of social security benefits:										
Disability insurance benefits						370	415	470	525	595
OASI benefits for aged						3,525	3,965	4,460	5,020	5,645
Benefits for dependents and survivors						565	635	715	805	905
Exclusion of railroad retirement system benefits						200	215	230	245	260
Exclusion of unemployment insurance benefits						2,855	2,655	2,470	2,295	2,135
Exclusion of workmen's compensation benefits						640	705	775	855	940
Exclusion of public assistance benefits						130	145	165	185	210
Exclusion of special benefits for disabled coal miners						50	50	50	50	50
Exclusion of sick pay						350	370	385	405	425
Net exclusion of pension contributions and earnings:										
Employer plans						6,475	7,120	7,835	8,620	9,480
Plans for self-employed and others						965	1,065	1,180	1,300	1,440
Exclusion of other employee benefits:										
Premiums on group term life insurance						895	965	1,050	1,135	1,230
Premiums on accident and accidental death insurance						60	65	70	80	85
Income of trusts to finance supplementary unemployment benefits						5	5	5	5	5
Meals and lodging						305	320	335	350	365
Exclusion of capital gains on home sales if over 65						50	55	60	65	70
Excess of percentage standard deduction over minimum standard deduction						1,560	1,635	1,720	1,805	1,895
Additional exemption for the blind						25	25	25	25	25
Additional exemption for over 65						1,220	1,280	1,340	1,410	1,480
Retirement income credit						110	100	90	80	70
Earned income credit: nonrefundable portion						280	270	255	245	235
Earned income credit: refundable portion						1,110	1,065	1,025	985	945
Exclusion of interest on life insurance savings						1,855	2,025	2,210	2,410	2,625
Deductibility of casualty losses						330	355	380	405	430
Maximum tax on earned income						505	580	670	770	885
Veterans' benefits and services (700):										
Exclusion of veterans' disability compensation						595	595	595	595	595
Exclusion of veterans' pensions						30	30	30	30	30
Exclusion of GI bill benefits						280	265	255	240	230

See footnote at end of table.

Ken Kluck
Houston Oil
and Minerals

Regrets testimony
Wed (10-15 min.)
Friday

Per Bill
Hopkins