ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

446 SCOMM12: OIL & GAS TAXATION & PIPELINE 1972-77

SOHIO EXAMPLE

TABLE B

If all of Sohio's business were in Alaska and all of its income were represented by the box below, all of its income would be taxed at 9.4% under present law.

ALASKA

100% of Income	X	9.4%

Since a substantial part of Sohio's business will be in Alaska and a substantial part of it will be elsewhere, the present law of Alaska taxes the part of it that is attributable to Alaska at 9.4% and the other states tax the part attributable to them at their rates of taxation. Using the allocation from Part I of Table A:

ALASKA			ALL OTHER STATES		
28% of Income	X	9.4%	72% of Income	X	Other States Tax Rates

Alaska would receive 9.4% of the Company's Alaska income. While this might represent 2.5% to 3.0% of the company's total income, these lower percentages are not very meaningful, except that they reflect the fact that when a company does business in more than one state, each of the states will generally tax the share of the income attributable to that state.

BOOK INCOME PROBLEMS UNION

EXAMPLE II

ALASKA H.B. 322
USING HIGHER OF BOOK OR TAXABLE INCOME
TAXES RECOVERY OF CAPITAL

Alaska House Bill No. 322 proposes to base Alaska taxable income on the higher of taxable income as defined in AS 43.20.011(e) (adjusted federal taxable income), or book net income determined without regard to any taxes on, or measured by, net income.

Since the tax is based on the <u>higher</u> of taxable income or book net income before income taxes, it appears that all Alaska oil and gas producers (including native corporations) will effectively be prevented from fully recovering their capital investment for Alaska income tax purposes and will therefore be taxed on phantom income. Consider the attached simplified example which clearly shows that only $76,000 of a $100,000 capital expenditure would be recovered through the depreciation deduction allowed by the proposed law. The taxpayer would lose as a tax deduction 24% of the cost of a capital expenditure necessary to produce income and would be taxed on $24,000 of <u>non</u>-existent income.

EXAMPLE: Company X is in the business of producing oil and gas. It owns machinery which it purchased for $100,000 on January 1, 19A, for use in its producing operations. Production income is $50,000 per year and the machinery has an expected useful life of five years. Depreciation and income using tax and book methods are as follows:

	Tax			Books		
Year	Revenue	Depreciation (DDB/SYD)	Taxable Income	Revenue	Depreciation (S/L)	Net Income
19A	$50,000	$40,000	$10,000	$50,000	$20,000	$30,000
19B	50,000	24,000	26,000	50,000	20,000	30,000
19C	50,000	18,000	32,000	50,000	20,000	30,000
19D	50,000	12,000	38,000	50,000	20,000	30,000
19E	50,000	6,000	44,000	50,000	20,000	30,000
	Total	$100,000	$150,000		$100,000	$150,000

Since the Alaska bill requires that the higher of taxable income or book income before taxes be used as the tax base, the Alaska income and related depreciation for each year are as follows:

Year	Tax/Books	Depreciation	Alaska Taxable Income
19A	Books	$20,000	$30,000
19B	Books	20,000	30,000
19C	Tax	18,000	32,000
19D	Tax	12,000	38,000
19E	Tax	6,000	44,000
	Total	$76,000	$174,000
Real Net Income			150,000
Phantom Net Income subjec to 9.4% tax			$ 24,000

EXTRACTION FACTOR PROBLEMS UNION

EXAMPLE I

Corr Conn

ALASKA H.B. 322
USING EXTRACTION FACTOR ATTRIBUTES ONE-THIRD
OF NON-PRODUCING INCOME TO PRODUCING OPERATION

Alaska House Bill No. 322 proposed to substitute an extraction factor for the sales factor in the Alaska apportionment formula. This substitution can result in an attribution of as much as one-third of all "downstream" income (i.e., income from transportation, refining, marketing, etc.) or non-producing income to Alaska, and can cause this one-third "overlap" of downstream income to be taxed twice. Consider the following simplified example:

Assume that a producer of oil and gas in Alaska with upstream operations wants to expand into California with downstream operations. Sales, payroll, and property would be as shown below. Further assume that all production is in Alaska.

			Existing Law Apportionment Factors	
	Alaska	California	Alaska	California
Sales	$50,000	$50,000	50/100 = .5	50/100 = .5
Payroll	$20,000	$20,000	20/40 = .5	20/40 = .5
Property	$30,000	$30,000	30/60 = .5	30/60 = .5
			1.5 ÷ 3 = .5	1.5 ÷ 3 = .5

Assuming taxable income of $40,000, each state would have taxable income attributed to it of $20,000 ($40,000 x .5 apportionment factor) under the uniform form[illegible] and there is no overlapping taxation.

AGO 531178

Now assume that an extraction factor is substituted for the sales factor in Alaska, while all other amounts remain the same:

Alaska

	Data	Apportionment Factors
Extraction	10,000 Units	10/10 = 1.0
Payroll	$20,000	20/40 = .5
Property	$30,000	20/60 = .5
		2.0 ÷ 3 = .66667

This will have no effect on the California apportionment factor which remains at .5 since California still abides by the uniform rules. Since total taxable income is still $40,000, Alaska has attributed income of $26,667 ($40,000 x .66667), while California's attributed income remains at $20,000. Thus, substitution of an extraction factor results in the attribution of one-third of the California downstream income to Alaska, and a $6,667 "overlap" of income which is taxed twice. In effect, the Alaska producer would be paying one-third more income tax on his California operations than would his competitors in that state. This added burden could even block his expansion plans completely.

BOOK INCOME PROBLEMS INDUSTRY

Can the Oil and Gas Corporate Franchise Tax Proposal by the Administration of the State of Alaska result in duplicative taxation?

A. Proposed Law
The law would define net income as the higher of (1) taxable income for federal income tax purposes or (2) net income reported to a company's shareholders without regard to any tax on net income.

B. Illustrative Case
Assume a company invests $2,000 in a project having a life of 5 years. The company elects to write off the $2,000 for federal income tax purposes using the so called sum-of-the-years-digits (SOYD)*/ method of rapid depreciation. For its financial reporting purposes the company writes off the investment in equal amounts each year of its life.

Results would be as follows using the indicated revenues and expenses:

		Year 1	Year 2	Year 3	Year 4	Year 5	Total
1.	Revenue	$1,000	$1,000	$1,000	$1,000	$1,000	$5,000
2.	Expenses	200	200	200	200	200	1,000
3.	Net	800	800	800	800	800	4,000
4.	Tax Depreciation	666	534	400	266	134	2,000
5.	Federal Taxable	134	266	400	534	666	2,000
6.	Financial Depreciation	400	400	400	400	400	2,000
7.	Financial Income, Before Tax	400	400	400	400	400	2,000
8.	Taxable by Alaska	400	400	400	534	666	2,400

C. Results
The amount subject to federal taxes over the life of the project is $2,000, and the financial net income before tax is also $2,000. However, the amount subject to Alaskan taxes would be $2,400, or 20% more than the amount subject to federal taxes. Effectively then the 9.4% tax rate would be 11.28%.

*/ Under the SOYD method a project with a 5 year life would have depreciation equal to the following percents of the total investment for each year, respectively: 33.3%, 26.7%, 20.0%, 13.3% and 6.7%.

SCOMM

#12:8

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

EXECON
3/16/77
BEGIN RUN

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

AGO 531182

EXICON DATA RECORD IMAGES

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202, 2*.73/
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450, 1, 4*0, 1969,900,2*0, 1977,-225/
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    CASE TYPE= ROUTINE, CASE NUMBER -          500
    MID-YEAR DISCOUNTING          - YES
    DEPLETION KEY                 -   0
    CALCULATING ECO LIMIT         -  NO
    BOOK ECONOMICS                -  NO

    ZONES                         -   4
    COMMODITIES                   -   2
    POTENTIAL LIFE, YEARS         -  38
    YEAR 1969 FACTORS
     INTEREST             WORKING-   1.0000
                          NET    -   0.8750
                          COST   -   1.0000
                          EXPENSE-   1.0000
     OVERHEAD
      INVESTMENT(INCL.D.H.CST)-   0.0
      DIRECT OPNG EXPENSE     -   0.0
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PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 ZONE PRODUCTION SCHEDULES (GROSS VALUES)

YEAR		ZONE 1		ZONE 2		ZONE 3	
PRO- JECT	CAL- ENDAR	MAIN PROD OIL MBBL /YR	ASSOC PROD	MAIN PROD GAS BCF/YR	ASSOC PROD	MAIN PROD AD [illegible] MBBLS/YR	ASSOC PROD
1	1969	0.0	0.0	0.0	0.0	0.0	0.0
2	1970	0.0	0.0	0.0	0.0	0.0	0.0
3	1971	0.0	0.0	0.0	0.0	0.0	0.0
4	1972	0.0	0.0	0.0	0.0	0.0	0.0
5	1973	0.0	0.0	0.0	0.0	0.0	0.0
6	1974	0.0	0.0	0.0	0.0	10.000	0.0
7	1975	0.0	0.0	0.0	0.0	26.000	0.0
8	1976	0.0	0.0	0.0	0.0	273.000	0.0
9	1977	146.000	0.0	0.0	0.0	313.000	0.0
10	1978	438.000	0.0	0.0	0.0	64.000	0.0
11	1979	438.000	0.0	0.0	0.0	67.000	0.0
12	1980	573.000	0.0	0.0	0.0	71.000	0.0
13	1981	573.000	0.0	0.0	0.0	79.000	0.0
14	1982	573.000	0.0	0.0	0.0	84.000	0.0
15	1983	573.000	0.0	0.730	0.0	88.000	0.0
16	1984	573.000	0.0	0.730	0.0	87.000	0.0
17	1985	573.000	0.0	0.730	0.0	83.000	0.0
18	1986	548.000	0.0	0.730	0.0	73.000	0.0
19	1987	521.000	0.0	0.730	0.0	64.000	0.0
20	1988	460.000	0.0	0.730	0.0	56.000	0.0
21	1989	394.000	0.0	0.730	0.0	50.000	0.0
22	1990	336.000	0.0	0.730	0.0	47.000	0.0
23	1991	262.000	0.0	0.730	0.0	43.000	0.0
24	1992	204.000	0.0	0.730	0.0	40.000	0.0
25	1993	159.000	0.0	0.730	0.0	37.000	0.0
26	1994	124.000	0.0	0.730	0.0	34.000	0.0
27	1995	97.000	0.0	0.730	0.0	30.000	0.0
28	1996	91.000	0.0	0.730	0.0	27.000	0.0
29	1997	82.000	0.0	0.730	0.0	24.000	0.0
30	1998	74.000	0.0	0.730	0.0	21.000	0.0
31	1999	66.000	0.0	0.730	0.0	18.000	0.0
32	2000	60.000	0.0	0.730	0.0	15.000	0.0
33	2001	54.000	0.0	0.730	0.0	12.000	0.0
34	2002	48.000	0.0	0.730	0.0	9.000	0.0
35	2003	43.000	0.0	0.730	0.0	6.000	0.0
36	2004	39.000	0.0	0.730	0.0	3.000	0.0
37	2005	35.000	0.0	0.730	0.0	3.000	0.0
38	2006	0.0	0.0	0.730	0.0	0.0	0.0
TOTALS		8157.00	0.0	17.52	0.0	1857.00	0.0

YEAR	ZONE 4 MAIN PROD	ASSOC PROD

PRO- JECT	CAL- ENDAR	INC TAX MDOLS/YR	
1	1969	0.0	0.0
2	1970	0.0	0.0
3	1971	0.0	0.0
4	1972	0.0	0.0
5	1973	0.0	0.0
6	1974	0.0	0.0
7	1975	0.0	0.0
8	1976	0.0	0.0
9	1977	31.100	0.0
10	1978	43.000	0.0
11	1979	47.900	0.0
12	1980	57.900	0.0
13	1981	67.400	0.0
14	1982	76.400	0.0
15	1983	86.900	0.0
16	1984	95.800	0.0
17	1985	103.700	0.0
18	1986	106.200	0.0
19	1987	108.000	0.0
20	1988	109.000	0.0
21	1989	109.000	0.0
22	1990	109.000	0.0
23	1991	109.000	0.0
24	1992	109.000	0.0
25	1993	109.000	0.0
26	1994	109.000	0.0
27	1995	109.000	0.0
28	1996	106.000	0.0
29	1997	103.000	0.0
30	1998	100.000	0.0
31	1999	95.000	0.0
32	2000	90.000	0.0
33	2001	85.000	0.0
34	2002	80.000	0.0
35	2003	75.000	0.0
36	2004	70.000	0.0
37	2005	65.000	0.0
38	2006	60.000	0.0
	TOTALS	2625.40	0.0

AGO 531186

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 PROJECT INTEREST FACTORS (FRACTIONS)

YEAR PRO- JECT	YEAR CAL- ENDAR	PROD/REVNUE W.I.	PROD/REVNUE N.I.	INVEST W.I.	EXPENSE W.I.	CARRY/TRADE OPTION (FRACTIONS) INVEST RECOV- ERY	CARRY/TRADE OPTION (FRACTIONS) MARGIN ALLOC- ATED	PRODUCTION OPTION CUM PROD
1	1969	1.0000	0.8750	1.0000	1.0000			

AGO 531187

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 INVESTMENTS (GROSS VALUES)

CAL-ENDAR YEAR	TYPE INVEST	INVEST CATGY	AMOUNT M$	SER-VICE YEAR	*****SALVAGE***** YEAR	AMOUNT M$	PER-CENT	PCT TAX CREDIT	DEPRECIATION TYPE	LIFE YRS	PCT DCL BAL	INVEST OVHD RATE $/$
1969	TANG-N	DRILL	37.0	1977	0	0.0	0.0	7.0	GDLN			
1970	TANG-N	DRILL	56.0	1977	0	0.0	0.0	7.0	GDLN			
1971	TANG-N	DRILL	76.0	1977	0	0.0	0.0	7.0	GDLN			
1972	TANG-N	DRILL	31.0	1977	0	0.0	0.0	7.0	GDLN			
1973	TANG-N	DRILL	59.0	1977	0	0.0	0.0	7.0	GDLN			
1974	TANG-N	DRILL	227.0	1977	0	0.0	0.0	7.0	GDLN			
1975	TANG-N	DRILL	809.0	1977	0	0.0	0.0	10.0	GDLN			
1976	TANG-N	DRILL	1183.0	1977	0	0.0	0.0	10.0	GDLN			
1977	TANG-N	DRILL	512.0	1977	0	0.0	0.0	7.0	GDLN			
1978	TANG-N	DRILL	377.0	1978	0	0.0	0.0	7.0	GDLN			
1979	TANG-N	DRILL	346.0	1979	0	0.0	0.0	7.0	GDLN			
1980	TANG-N	DRILL	461.0	1980	0	0.0	0.0	7.0	GDLN			
1981	TANG-N	DRILL	670.0	1981	0	0.0	0.0	7.0	GDLN			
1982	TANG-N	DRILL	627.0	1982	0	0.0	0.0	7.0	GDLN			
1983	TANG-N	DRILL	629.0	1983	0	0.0	0.0	7.0	GDLN			
1984	TANG-N	DRILL	497.0	1984	0	0.0	0.0	7.0	GDLN			
1985	TANG-N	DRILL	343.0	1985	0	0.0	0.0	7.0	GDLN			
1986	TANG-N	DRILL	129.0	1986	0	0.0	0.0	7.0	GDLN			
1988	TANG-N	DRILL	300.0	1988	0	0.0	0.0	7.0	GDLN			
1990	TANG-N	DRILL	300.0	1990	0	0.0	0.0	7.0	GDLN			
1991	TANG-N	DRILL	191.0	1991	0	0.0	0.0	7.0	GDLN			
1993	TANG-N	DRILL	81.0	1993	0	0.0	0.0	7.0	GDLN			
1969	INTANG	DRILL	48.0	1977								
1970	INTANG	DRILL	64.0	1977								
1971	INTANG	DRILL	38.0	1977								
1972	INTANG	DRILL	5.0	1977								
1973	INTANG	DRILL	10.0	1977								
1974	INTANG	DRILL	37.0	1977								
1975	INTANG	DRILL	132.0	1977								
1976	INTANG	DRILL	192.0	1977								
1977	INTANG	DRILL	90.0	1977								
1978	INTANG	DRILL	90.0	1978								
1979	INTANG	DRILL	90.0	1979								
1980	INTANG	DRILL	90.0	1980								
1981	INTANG	DRILL	90.0	1981								
1982	INTANG	DRILL	90.0	1982								
1983	INTANG	DRILL	88.0	1983								
1984	INTANG	DRILL	82.0	1984								
1985	INTANG	DRILL	82.0	1985								
1986	INTANG	DRILL	21.0	1986								

TOTAL TANGIBLE (NEW) INVESTMENT	(M$)	7941.0
TOTAL TANGIBLE (USED) INVESTMENT	(M$)	0.0
TOTAL SALVAGE	(M$)	0.0
TOTAL INTANGIBLE INVESTMENT	(M$)	1339.0

PROPERTY PURCHASES/SURRENDERS

CAL-ENDAR YEAR	LEASEHOLD BONUS M$	LEASEHOLD G&G M$	EQUIP-MENT M$
INI-TIAL	0.0	0.0	0.0
1969	900.0	0.0	0.0
1977	-225.0	0.0	0.0

AGO 531189

CASE 500 LOCAL TAXES, TARIFF

AD VALOREM TAX

NONE

PRODUCTION TAX

OIL YEAR	PROD $/$	GAS YEAR	PROD $/$
1969	0.037	1969	0.040
1981	0.047	0	0.0
1982	0.075	0	0.0
1985	0.073	0	0.0
1990	0.070	0	0.0
1995	0.065	0	0.0

* SPECIAL CHARGE SCHEDULE *

OIL/CONDENS. TARIFF	GAS/G.LIQ. SEVERANCE

NONE

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL. ST INC TAX IS APPORTIONED

CASE 500 PRODUCT PRICE SCHEDULE

YEAR PRO-JECT	YEAR CAL-ENDAR	OIL $/BBL	GAS $/MCF	AD VAL $/DOLS	INC TAX $/DOLS
1	1969	6.450	0.852	-1.143	-1.143
10	1978	6.670	0.852	-1.143	-1.143
11	1979	7.280	0.852	-1.143	-1.143
13	1981	7.780	0.852	-1.143	-1.143
17	1985	8.030	0.852	-1.143	-1.143

AGO 531191

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 DIRECT EXPENSE FACTORS

NONE

FIXED AND NON-RECURRING EXPENSE

CALENDAR YEAR	M$
1976	44.0
1977	129.0
1978	133.0
1979	145.0
1980	149.0
1981	240.0
1982	252.0
1983	248.0
1984	261.0
1985	318.0
1986	321.0
1987	319.0
1988	323.0
1989	313.0
1990	308.0
1991	297.0
1992	286.0
1993	280.0
1994	271.0
1995	270.0
1996	235.0
1997	233.0
1998	234.0
1999	232.0
2000	232.0
2001	114.0
2002	111.0
2003	108.0
2004	106.0
2005	104.0
2006	24.0

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 YEARLY ANALYSIS OF NET INCOME AND PRODUCTION

YEAR PRO- JECT	CAL- ENDAR	OIL W.I. PROD MBBL /YR	OIL N.I. PROD MBBL /YR	OIL NET INCOME M$/YR	GAS W.I. PROD MMMCF/YR	GAS N.I. PROD MMMCF/YR	GAS NET INCOME M$/YR
1	1969	0.0	0.0	0.0	0.0	0.0	0.0
2	1970	0.0	0.0	0.0	0.0	0.0	0.0
3	1971	0.0	0.0	0.0	0.0	0.0	0.0
4	1972	0.0	0.0	0.0	0.0	0.0	0.0
5	1973	0.0	0.0	0.0	0.0	0.0	0.0
6	1974	0.0	0.0	0.0	0.0	0.0	0.0
7	1975	0.0	0.0	0.0	0.0	0.0	0.0
8	1976	0.0	0.0	0.0	0.0	0.0	0.0
9	1977	146.0	127.7	824.0	0.0	0.0	0.0
10	1978	438.0	383.2	2556.3	0.0	0.0	0.0
11	1979	438.0	383.2	2790.1	0.0	0.0	0.0
12	1980	573.0	501.4	3650.0	0.0	0.0	0.0
13	1981	573.0	501.4	3900.7	0.0	0.0	0.0
14	1982	573.0	501.4	3900.7	0.0	0.0	0.0
15	1983	573.0	501.4	3900.7	0.7	0.6	544.2
16	1984	573.0	501.4	3900.7	0.7	0.6	544.2
17	1985	573.0	501.4	4020.0	0.7	0.6	544.2
18	1986	548.0	479.5	3850.4	0.7	0.6	544.2
19	1987	521.0	455.9	3660.7	0.7	0.6	544.2
20	1988	460.0	402.5	3232.1	0.7	0.6	544.2
21	1989	394.0	344.7	2768.3	0.7	0.6	544.2
22	1990	336.0	294.0	2360.8	0.7	0.6	544.2
23	1991	262.0	229.2	1840.9	0.7	0.6	544.2
24	1992	204.0	178.5	1433.4	0.7	0.6	544.2
25	1993	159.0	139.1	1117.2	0.7	0.6	544.2
26	1994	124.0	108.5	871.3	0.7	0.6	544.2
27	1995	97.0	84.9	681.5	0.7	0.6	544.2
28	1996	91.0	79.6	639.4	0.7	0.6	544.2
29	1997	82.0	71.7	576.2	0.7	0.6	544.2
30	1998	74.0	64.7	519.9	0.7	0.6	544.2
31	1999	66.0	57.7	463.7	0.7	0.6	544.2
32	2000	60.0	52.5	421.6	0.7	0.6	544.2
33	2001	54.0	47.2	379.4	0.7	0.6	544.2
34	2002	48.0	42.0	337.3	0.7	0.6	544.2
35	2003	43.0	37.6	302.1	0.7	0.6	544.2
36	2004	39.0	34.1	274.0	0.7	0.6	544.2
37	2005	35.0	30.6	245.9	0.7	0.6	544.2
38	2006	0.0	0.0	0.0	0.7	0.6	544.2
TOTALS		8156.9	7137.3	55425.1	17.5	15.3	13061.1

YEAR PRO-	CAL-	AD VAL W.I. PROD	AD VAL N.I. PROD	AD VAL NET INCOME	INC TAX W.I. PROD	INC TAX N.I. PROD	INC TAX NET INCOME	TOTAL INCOME

JECT	ENDAR	MDOLS/YR	MDOLS/YR	M$/YR	MDOLS/YR	MDOLS/YR	M$/YR	M$/YR
1	1969	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	1970	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	1971	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	1972	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	1973	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	1974	10.0	8.7	-10.0	0.0	0.0	0.0	0.0
7	1975	26.0	22.7	-26.0	0.0	0.0	0.0	-10.0
8	1976	273.0	238.9	-273.0	0.0	0.0	0.0	-26.0
9	1977	313.0	273.9	-313.0	31.1	27.2	-31.1	-273.0
10	1978	64.0	56.0	-64.9	43.0	37.6	-43.0	479.8
11	1979	67.0	58.6	-67.0	47.9	41.9	-47.9	2449.3
12	1980	71.0	62.1	-71.0	57.9	50.7	-57.9	2675.1
13	1981	79.0	69.1	-79.0	67.4	59.0	-67.4	3521.1
14	1982	84.0	73.5	-84.0	76.4	66.8	-76.4	3754.3
15	1983	88.0	77.0	-88.0	86.9	76.0	-86.9	3740.3
16	1984	87.0	76.1	-87.0	95.8	83.8	-95.8	4270.0
17	1985	83.0	72.6	-83.0	103.7	90.7	-103.7	4262.1
18	1986	73.0	63.9	-73.0	106.3	93.0	-106.3	4383.5
19	1987	64.0	56.0	-64.0	108.0	94.5	-108.0	4215.3
20	1988	56.0	49.0	-56.0	109.0	95.4	-109.0	4032.9
21	1989	50.0	43.7	-50.0	109.0	95.4	-109.0	3611.3
22	1990	47.0	41.1	-47.0	109.0	95.4	-109.0	3153.5
23	1991	43.0	37.6	-43.0	109.0	95.4	-109.0	2749.0
24	1992	40.0	35.0	-40.0	109.0	95.4	-109.0	2233.1
25	1993	37.0	32.4	-37.0	109.0	95.4	-109.0	1828.6
26	1994	34.0	29.7	-34.0	109.0	95.4	-109.0	1515.4
27	1995	30.0	26.2	-30.0	109.0	95.4	-109.0	1272.5
28	1996	27.0	23.6	-27.0	109.0	95.4	-109.0	1086.7
29	1997	24.0	21.0	-24.0	106.0	92.7	-106.0	1050.6
30	1998	21.0	18.4	-21.0	103.0	90.1	-103.0	993.4
31	1999	18.0	15.7	-16.0	100.0	87.5	-100.0	943.1
32	2000	15.0	13.1	-15.0	95.0	83.1	-95.0	894.9
33	2001	12.0	10.5	-12.0	90.0	78.7	-90.0	860.8
34	2002	9.0	7.9	-9.0	85.0	74.4	-85.0	826.6
35	2003	6.0	5.2	-6.0	80.0	70.0	-80.0	792.5
36	2004	3.0	2.6	-3.0	75.0	65.6	-75.0	765.3
37	2005	3.0	2.6	-3.0	70.0	61.2	-70.0	745.2
38	2006	0.0	0.0	0.0	65.0	56.9	-65.0	722.1
					60.0	52.5	-60.0	484.2
TOTALS		1857.0	1624.9	-1857.2	2625.4	2297.2	-2625.7	64003.3

AGO 531194

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BRL, ST INC TAX IS APPORTIONED

CASE 500 YEARLY ANALYSIS OF NET EXPENSES

YEAR PRO-JECT	YEAR CAL-ENDAR	DIRECT EXPENSE M$/YR	ESCA-LATION RATE FACTOR	ESCA-LATED DIRECT EXPENSE M$/YR	PROD/ ~~AD VAL.~~ TAXES, ~~TARIFF~~ M$/YR	INDIRECT EXPENSE M$/YR	TOTAL EXPENSE M$/YR
8	1976	44.0	1.000	44.0	0.0	0.0	44.0
9	1977	129.0	1.000	129.0	30.9	0.0	159.9
10	1978	133.0	1.000	133.0	95.9	0.0	228.9
11	1979	145.0	1.000	145.0	104.6	0.0	249.6
12	1980	149.0	1.000	149.0	136.9	0.0	285.9
13	1981	240.0	1.000	240.0	184.9	0.0	424.9
14	1982	252.0	1.000	252.0	292.6	0.0	544.6
15	1983	248.0	1.000	248.0	314.3	0.0	562.3
16	1984	261.0	1.000	261.0	314.3	0.0	575.3
17	1985	318.0	1.000	318.0	315.7	0.0	633.7
18	1986	321.0	1.000	321.0	302.8	0.0	623.8
19	1987	319.0	1.000	319.0	289.0	0.0	608.0
20	1988	323.0	1.000	323.0	257.7	0.0	580.7
21	1989	312.0	1.000	313.0	223.9	0.0	536.9
22	1990	308.0	1.000	308.0	187.0	0.0	495.0
23	1991	297.0	1.000	297.0	150.6	0.0	447.6
24	1992	286.0	1.000	286.0	122.1	0.0	408.1
25	1993	280.0	1.000	280.0	100.0	0.0	380.0
26	1994	271.0	1.000	271.0	82.8	0.0	353.8
27	1995	270.0	1.000	270.0	66.1	0.0	336.1
28	1996	235.0	1.000	235.0	63.3	0.0	298.3
29	1997	233.0	1.000	233.0	59.2	0.0	292.2
30	1998	234.0	1.000	234.0	55.6	0.0	289.6
31	1999	232.0	1.000	232.0	51.9	0.0	283.9
32	2000	232.0	1.000	232.0	49.2	0.0	281.2
33	2001	114.0	1.000	114.0	46.4	0.0	160.4
34	2002	111.0	1.000	111.0	43.7	0.0	154.7
35	2003	108.0	1.000	108.0	41.4	0.0	149.4
36	2004	106.0	1.000	106.0	39.6	0.0	145.6
37	2005	104.0	1.000	104.0	37.8	0.0	141.8
38	2006	24.0	1.000	24.0	21.8	0.0	45.8
TOTALS		6639.9		6639.9	4081.8	0.0	10721.8

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 YEARLY ANALYSIS OF INVESTMENTS AND SALVAGE (NET VALUES)

YEAR PRO- JECT	YEAR CAL- ENDAR	TANG M$	INTANG M$	SALVG M$
0	1968	0.0	0.0	
1	1969	37.0	48.0	0.0
2	1970	56.0	64.0	0.0
3	1971	76.0	38.0	0.0
4	1972	31.0	5.0	0.0
5	1973	59.0	10.0	0.0
6	1974	227.0	37.0	0.0
7	1975	809.0	132.0	0.0
8	1976	1183.0	192.0	0.0
9	1977	512.0	90.0	0.0
10	1978	377.0	90.0	0.0
11	1979	346.0	90.0	0.0
12	1980	461.0	90.0	0.0
13	1981	670.0	90.0	0.0
14	1982	627.0	90.0	0.0
15	1983	629.0	88.0	0.0
16	1984	497.0	82.0	0.0
17	1985	343.0	82.0	0.0
18	1986	129.0	21.0	0.0
20	1988	300.0	0.0	0.0
22	1990	300.0	0.0	0.0
23	1991	191.0	0.0	0.0
25	1993	81.0	0.0	0.0
TOTALS		7941.0	1339.0	0.0

CASE 500 YEARLY ANALYSIS OF DEPLETION ALLOWANCE

YEAR PRO-JECT	CAL-ENDAR	COST DPLTN M$/YR	STATUTORY DEPLETION 0.500*INCOME FOR LIMI-TATION M$/YR	PERCENT M$/YR	ALLOW DPLTN M$/YR	
1	1969	0.0	0.0	0.0	0.0	G
2	1970	0.0	0.0	0.0	0.0	G
3	1971	0.0	0.0	0.0	0.0	G
4	1972	0.0	0.0	0.0	0.0	G
5	1973	0.0	0.0	0.0	0.0	G
6	1974	0.0	0.0	0.0	0.0	G
7	1975	0.0	0.0	0.0	0.0	G
8	1976	0.0	0.0	0.0	0.0	G
9	1977	12.1	0.0	0.0	12.1	C
10	1978	36.2	0.0	0.0	36.2	C
11	1979	36.2	0.0	0.0	36.2	C
12	1980	47.4	0.0	0.0	47.4	C
13	1981	47.4	0.0	0.0	47.4	C
14	1982	47.4	0.0	0.0	47.4	C
15	1983	47.4	0.0	0.0	47.4	C
16	1984	47.4	0.0	0.0	47.4	C
17	1985	47.4	0.0	0.0	47.4	C
18	1986	45.3	0.0	0.0	45.3	C
19	1987	43.1	0.0	0.0	43.1	C
20	1988	38.1	0.0	0.0	38.1	C
21	1989	32.6	0.0	0.0	32.6	C
22	1990	27.8	0.0	0.0	27.8	C
23	1991	21.7	0.0	0.0	21.7	C
24	1992	16.9	0.0	0.0	16.9	C
25	1993	13.2	0.0	0.0	13.2	C
26	1994	10.3	0.0	0.0	10.3	C
27	1995	8.0	0.0	0.0	8.0	C
28	1996	7.5	0.0	0.0	7.5	C
29	1997	6.8	0.0	0.0	6.8	C
30	1998	6.1	0.0	0.0	6.1	C
31	1999	5.5	0.0	0.0	5.5	C
32	2000	5.0	0.0	0.0	5.0	C
33	2001	4.5	0.0	0.0	4.5	C
34	2002	4.0	0.0	0.0	4.0	C
35	2003	3.6	0.0	0.0	3.6	C
36	2004	3.2	0.0	0.0	3.2	C
37	2005	2.9	0.0	0.0	2.9	C
38	2006	0.0	0.0	0.0	0.0	G

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500

YEARLY ANALYSIS OF INCOME TAX

YEAR PRO-JECT	YEAR CAL-ENDAR	NET INCOME M$/YR	TOTAL EXPENSE M$/YR	DEPREC M$/YR	DEPLETION ALLOW M$/YR		INTANG INVEST M$/YR	TAX CREDIT M$/YR	INCOME TAX M$/YR
0	1968		0.0				0.0		0.0
1	1969	0.0	0.0	0.0	0.0	G	48.0	0.0	-23.0
2	1970	0.0	0.0	0.0	0.0	G	64.0	0.0	-30.7
3	1971	0.0	0.0	0.0	0.0	G	38.0	0.0	-18.2
4	1972	0.0	0.0	0.0	0.0	G	5.0	0.0	-2.4
5	1973	0.0	0.0	0.0	0.0	G	10.0	0.0	-4.8
6	1974	-10.0	0.0	0.0	0.0	G	37.0	0.0	-22.6
7	1975	-26.0	0.0	0.0	0.0	G	132.0	0.0	-75.8
8	1976	-273.0	44.0	0.0	0.0	G	192.0	0.0	-244.3
9	1977	479.8	159.9	271.8	12.1	C	315.0	269.1	-403.0
10	1978	2449.3	228.9	528.5	36.2	C	90.0	26.4	725.1
11	1979	2675.1	249.6	516.3	36.2	C	90.0	24.2	831.6
12	1980	3521.1	285.5	530.5	47.4	C	90.0	32.3	1200.1
13	1981	3754.3	424.9	567.3	47.4	C	90.0	46.9	1213.0
14	1982	3740.3	544.6	607.8	47.4	C	90.0	43.9	1132.3
15	1983	4270.0	562.3	633.5	47.4	C	88.0	44.0	1300.6
16	1984	4262.1	575.3	638.4	47.4	C	82.0	34.8	1366.3
17	1985	4383.5	633.7	610.1	47.4	C	82.0	24.0	1421.0
18	1986	4215.3	623.6	544.6	45.3	C	21.0	9.0	1421.6
19	1987	4032.9	608.0	447.9	43.1	C	0.0	0.0	1408.3
20	1988	3611.3	580.7	368.8	38.1	C	0.0	21.0	1238.4
21	1989	3153.5	536.9	308.2	32.6	C	0.0	0.0	1092.4
22	1990	2749.0	495.0	270.4	27.8	C	0.0	21.0	917.8
22	1991	2233.1	447.6	253.1	21.7	C	0.0	13.4	711.7
24	1992	1828.6	408.1	209.2	16.9	C	0.0	0.0	573.3
25	1993	1515.4	380.0	165.0	13.2	C	0.0	5.7	453.8
26	1994	1272.5	353.8	130.8	10.3	C	0.0	0.0	373.3
27	1995	1086.7	336.1	98.0	8.0	C	0.0	0.0	309.4
28	1996	1050.6	298.3	74.3	7.5	C	0.0	0.0	321.8
29	1997	993.4	292.2	56.9	6.8	C	0.0	0.0	306.0
30	1998	943.1	289.6	42.9	6.1	C	0.0	0.0	290.2
31	1999	894.9	283.9	30.0	5.5	C	0.0	0.0	276.3
32	2000	860.8	281.2	19.2	5.0	C	0.0	0.0	266.6
33	2001	826.6	160.4	10.7	4.5	C	0.0	0.0	312.5
34	2002	792.5	154.7	4.4	4.0	C	0.0	0.0	302.1
35	2003	765.3	149.4	1.8	3.6	C	0.0	0.0	293.1
36	2004	745.2	145.6	0.6	3.2	C	0.0	0.0	286.0
37	2005	722.1	141.8	0.0	2.9	C	0.0	0.0	277.2
38	2006	464.2	45.8	0.0	0.0	G	0.0	0.0	210.5
TOTALS		64003.3	10721.8	7941.0	675.0		1564.0	615.6	20073.0

(PROPERTY SURRENDER AMOUNTS ARE INCLUDED IN THE INTANGIBLE INVESTMENT VALUES)

AGO 531198

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500

YEARLY ANALYSIS OF NET CASH FLOW

YEAR PRO-JECT	YEAR CAL-ENDAR	NET INCOME M$/YR	TOTAL EXPENSE M$/YR	INTANG INVEST M$/YR	TANG INVEST (-)SLVG M$/YR	LEASE -HOLD INVEST M$/YR	FED INCOME TAX M$/YR	NET CASH FLOW M$/YR	CUM CASH FLOW M$/YR
1	1969	0.0	0.0	48.0	37.0	900.0	-23.0	-962.0	-962.0
2	1970	0.0	0.0	64.0	56.0	0.0	-30.7	-89.3	-1051.2
3	1971	0.0	0.0	38.0	76.0	0.0	-18.2	-95.8	-1147.0
4	1972	0.0	0.0	5.0	31.0	0.0	-2.4	-33.6	-1180.6
5	1973	0.0	0.0	10.0	59.0	0.0	-4.8	-64.2	-1244.8
6	1974	-10.0	0.0	37.0	227.0	0.0	-22.6	-251.4	-1496.2
7	1975	-26.0	0.0	132.0	609.0	0.0	-75.8	-891.2	-2387.4
8	1976	-273.0	44.0	192.0	1183.0	0.0	-244.3	-1447.7	-3835.1
9	1977	479.8	159.9	90.0	512.0	0.0	-403.0	120.9	-3714.2
10	1978	2449.3	228.9	90.0	377.0	0.0	725.1	1028.3	-2685.9
11	1979	2675.1	249.6	90.0	346.0	0.0	831.6	1157.9	-1528.0
12	1980	3521.1	285.9	90.0	461.0	0.0	1200.1	1484.2	-43.8
13	1981	3754.3	474.9	90.0	670.0	0.0	1213.0	1356.4	1312.6
14	1982	3740.3	544.6	90.0	627.0	0.0	1132.3	1346.4	2659.0
15	1983	4270.0	562.3	88.0	629.0	0.0	1366.6	1624.1	4283.1
16	1984	4262.1	575.3	82.0	497.0	0.0	1366.3	1741.4	6024.5
17	1985	4383.5	633.7	82.0	343.0	0.0	1421.0	1903.9	7928.4
18	1986	4215.3	623.8	21.0	129.0	0.0	1421.6	2019.8	9948.2
19	1987	4032.9	608.0	0.0	0.0	0.0	1408.2	2016.6	11964.8
20	1988	3611.3	580.7	0.0	300.0	0.0	1238.4	1492.2	13457.0
21	1989	3153.5	536.9	0.0	0.0	0.0	1092.4	1524.3	14981.3
22	1990	2749.0	495.0	0.0	300.0	0.0	917.8	1036.2	16017.5
23	1991	2233.1	447.6	0.0	191.0	0.0	711.7	882.7	16900.2
24	1992	1828.6	408.1	0.0	0.0	0.0	573.3	847.2	17747.4
25	1993	1515.4	380.0	0.0	81.0	0.0	453.8	600.6	18347.9
26	1994	1272.5	353.8	0.0	0.0	0.0	373.3	545.4	18893.4
27	1995	1086.7	336.1	0.0	0.0	0.0	309.4	441.2	19334.6
28	1996	1050.6	298.3	0.0	0.0	0.0	321.8	430.5	19765.1
29	1997	993.4	292.2	0.0	0.0	0.0	306.0	395.1	20160.2
30	1998	943.1	289.6	0.0	0.0	0.0	290.2	363.4	20523.6
31	1999	894.9	283.9	0.0	0.0	0.0	276.3	334.7	20858.3
32	2000	860.8	281.2	0.0	0.0	0.0	266.6	313.0	21171.3
33	2001	826.6	160.4	0.0	0.0	0.0	312.5	353.7	21525.0
34	2002	792.5	154.7	0.0	0.0	0.0	302.1	335.7	21860.7
35	2003	765.3	149.4	0.0	0.0	0.0	293.1	322.9	22183.6
36	2004	745.2	145.6	0.0	0.0	0.0	286.0	313.7	22497.2
37	2005	722.1	141.8	0.0	0.0	0.0	277.2	303.2	22800.4
38	2006	484.2	45.8	0.0	0.0	0.0	210.5	228.0	23028.4
TOTALS		64003.3	10721.8	1339.0	7941.0	900.0	20073.0	23028.4	

AGO 531199

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500

PRESENT VALUE PROFILE

DISCOUNT RATE PERCENT	PRESENT VALUE PROFIT-M$	DISCOUNT RATE PERCENT	PRESENT VALUE PROFIT-M$
0.	23026.4	1.	18631.0
2.	15112.9	3.	12260.9
4.	9987.8	5.	8121.1
6.	6593.0	7.	5337.9
8.	4301.4	9.	3442.5
10.	2728.1	12.	1633.3
14.	863.2	15.	566.8
16.	516.7	18.	-73.5
20.	-353.1	30.	-921.7
40.	-995.5	50.	-962.8
60.	-911.8	70.	-863.1
80.	-821.0	90.	-785.1
100.	-754.3		

INVESTMENT YARDSTICKS

PAYOUT PERIOD = 12.03 YEARS

INVESTOR'S RATE OF RETURN = 17.57 PERCENT

RATIO, UNDISCOUNTED PROFIT TO INITIAL INVESTMENT (BFIT)=0.0

PVP AT 25.00 PERCENT =-753.025 PVPI NOT CALCULATED

AGO 531200

PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 ABBREVIATED RESULT TABLE

PROJECT INITIATION DATE = 1/69
DATE OF FIRST PRODUCTION = 1/74

PRODUCTION/REVENUE

	W.I. PROD	N.I. PROD	N.I. REVENUE M$
OIL (MBO)	8156.9	7137.3	55425.1
GAS (BCF)	17.520	15.330	13061.090
AD VAL (MDOLS)	1857.0	1624.9	-1857.2
INC TAX (MDOLS)	2625.4	2297.2	-2625.7

SUMMARY RESULTS (M$)

TOTAL INCOME	TOTAL EXPENSE	TOTAL INVEST	TOTAL TAX	NET INCOME
64003.3	10721.8	10179.9	20073.0	23028.4

INVESTMENT YARDSTICKS

PAYOUT PERIOD = 12.03 YEARS

INVESTOR'S RATE OF RETURN = 17.57 PERCENT

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PRUDHOE BAY -- PUBLIC DATA, $8.03 PER BBL, ST INC TAX IS APPORTIONED

CASE 500 SUMMARY RESULT TABLE

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INC TAX (MDOLS)	2625.4	2297.2	-2625.7

PROJECT INTEREST FACTORS (FRACTIONS)

YEAR PRO- JECT	CAL- ENDAR	PROD/REVNUE W.I.	PROD/REVNUE N.I.	INVEST W.I.	EXPENSE W.I.
1	1969	1.0000	0.6750	1.0000	1.0000

SUMMARY ECONOMICS (M$)

REVENUE	64003.3
INVESTMENT	
TANGIBLE	7941.0
INTANGIBLE	1339.0
LEASEHOLD	900.0
DRY HOLE	0.0
SALVAGE	0.0
TOTAL	10179.9
EXPENSE	
DIRECT	6639.9
PROD/AD VALOREM, TAXES, TARIFF	4081.8
INDIRECT	0.0
TOTAL	10721.8
BFIT PROFIT	43101.6
INCOME TAX	20073.0
NET PROFIT	23028.4

INVESTMENT YARDSTICKS

PAYOUT PERIOD = 12.03 YEARS

INVESTOR'S RATE OF RETURN = 17.57 PERCENT

RATIO, UNDISCOUNTED PROFIT TO INITIAL INVESTMENT (BFIT)=0.0

PVP AT 25.00 PERCENT =-753.025 PVPI NOT CALCULATED

AGO 531202

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EXXON 1977

calculations

PRUDHOE BAY PROJECT ECONOMICS

GENERATED FROM PUBLICLY AVAILABLE DATA

NORTH SLOPE ECONOMICS CONSTRUCTED FROM PUBLICLY AVAILABLE DATA
MAJOR SOURCES OF DATA AND DATA ITEMS

A. Data Sources:

1. Field Economics

   a. Future production rates, investments, operating costs and oil wellhead prices: State of Alaska's reserves tax study, February 9, 1976, with all data deescalated to 1976 dollars.

   b. Gas prices: Price at pipeline inlet of $1.46/MMBtu from February 1977 advance submission to Canadian NEB by Mr. Radford Shantz, Foster Associates. Cost of Service expense for gas gathering-conditioning of $0.75/MMBtu is based on producer testimony that the cost of service would be about 1/3 of combined gathering-conditioning-transportation costs of service.

   c. Historical investments:
      Sohio/BP Trans Alaska Pipeline Finance, Inc. Prospectus, December 4, 1974;
      The Standard Oil Company (Ohio) Prospectus, December 2, 1976;
      City of Valdez, Alaska, % Marine Revenue Bonds (ARCO Pipe Line Company Project) Preliminary Official Statement, January 27, 1977.

2. TAPS Economics

   a. Total cost: Alyeska announcements.

   b. TAPS will be a regulated concern. Tariffs allowed under ICC rules result in DCF returns from 12 to 14%.

3. Tanker Economics: Consultant reports to FEA, November 1976 (Mortada Study).

   10% Return on Investment

NORTH SLOPE ECONOMICS CONSTRUCTED FROM PUBLICLY AVAILABLE DATA
MAJOR SOURCES OF DATA AND DATA ITEMS (Continued)

B. Major Data Items:

1. Tanker Investment: $1,760MM

2. TAPS Investment - for 1.2 MMB/D: $7,700MM
   - for 1.6 MMB/D: $8,375MM

3. Field Investment - initial: $3,610MM
   - ultimate: $9,280MM

4. Oil Production - Reserves: 8.2 Billion Bbl
   - Peak Rate: 1.6 MMB/D

5. Gas Sales - First Year: 1983
   - Rate: 2.0 Bcf/D

6. Wellhead Prices - Oil: 1978 $6.67
   1980 $7.28
   1985 $8.03
   Average $7.77/Bbl

   Gas: All Years $0.852/Mcf ($0.071/MMBtu) (Separator Outlet)

C. Integrated DCF Rate of Return: 14.5%

AGO 531205

PUBLIC DATA CASE

INTEGRATED RATE OF RETURN

(Investment Weighting Technique)

	Investment MM$	DCF Rate of Return*
Field & Bonus	10,180	17.6
TAPS	8,375	12.0
Tankers	1,760	10.0
Total	20,315	14.5

* Total Capital Employed Basis

PUBLIC DATA CASE
DIVISION OF PRUDHOE BAY FIELD LEVEL INCOME

		1976 Outlook MM$	1976 Outlook %	1969 Outlook %
Wellhead Value (8/8):	Oil	63,343		
	Gas	14,927		
	Total	78,270		
Field Investments		-9,280		
Field Operating Costs		-6,640		
Field Level Income		62,350		
State:	Royalty	9,784		
	Bonus	900		
	Production Tax	4,082		
	Ad Valorem Tax	1,857		
	Income Tax	2,626		
	Total	19,249	31	23
Federal Government		20,073	32	25
Oil Companies		23,028	37	52
		62,350	100	100

PUBLIC DATA CASE
WELLHEAD PRICES
1967 CONSTANT DOLLAR BASIS
$/Bbl

Year	Wellhead Price Used In Reserves Tax Study	Reference Price Escalation (a)	Constant Dollar Wellhead Price (a)
1976			
1977	7.58	1.13	6.45
1978	8.52	0.72	6.67
1979	10.00	0.87	7.28
1980	10.42	0.42	7.28
1981	11.35	0.43	7.78
1982	11.35	-0-	7.78
1983	11.35	-0-	7.78
1984	11.35	-0-	7.78
1985	12.05	0.45	8.03

(a) Reference price of $11.28/Bbl on West Coast.

GAS SALES

Price = \$0.71/MMBtu

Initiation Date = 1983 (Technical Considerations, Prudhoe Bay Operating Plan, October, 1976)

Gas Sales Rate - 2.0 Bcf/D (Reserves Tax Study)

Reserves - 25.4 Tcf (De Golyer and Mac Naughton)

Since Reserves Tax Study only goes to 2006, will produce 2.0 X 365 X 10^{-3} X 24Yrs = 17.5 Tcf of 1200 Btu hydrocarbon gas.

GAS VALUE

Value at Pipe Line Inlet = \$1.46/MMBtu. Radford Schantz, Foster Associates Advance testimony filed w/Can. NEB 2/77.

Cost of service expense for gas conditioning based on producer evidence presented to FPC = \$0.75/MMBtu.

Wellhead price = \$1.46 - 0.75 = \$0.71/MMBtu (Sep. Outlet) or 0.852/Mcf at 1200Btu/cu. ft.

Note: Pritchard & Abbot include gas sales expenses but no revenue as the gas is not subject to the reserves tax.

PUBLIC DATA CASE
FIELD EXPENSES; PRODUCTION TAX ON OIL
MM$

Year	Reserves Tax Study Escalated Op. Expenses	Escalation Factor	Constant 1976 Dollar Expenses	Gross Prod'n MM Bbl	No. Producing Wells	B/D/Well	Gross Oil Prod'n Tax %	Well-head Price $/B	MM$ Gross Prod'n Tax Value	Net Prod'n Tax Value	Net Prod'n Tax %	Alternate Price Case: Well-head Price $/B	Alternate Price Case: MM$ Gross Prod'n Tax Value	Alternate Price Case: Net Prod'n Tax Value	Alternate Price Case: Net Prod'n Tax %
1976	44	1.000	44												
77	138	1.070	129	146	166	5000	7.5	6.45	61.8	30.9	3.75	8.17	78.4	39.2	3.75
78	152	1.145	133	438	209	5742	7.5	6.67	191.8	95.9	3.75	8.39	241.2	120.6	3.75
79	178	1.225	145	438	252	4762	7.5	7.28	209.2	104.6	3.75	9.00	258.6	129.3	3.75
1980	195	1.311	149	573	295	5321	7.5	7.28	273.8	136.8	3.75	9.00	338.4	169.2	3.75
81	337	1.403	240	573	313	5015	7.5	7.78	292.5	184.7	4.74	9.50	357.2	339.5	7.13
82	378	1.501	252	573	356	4409	7.5								
83	398	1.606	248	573	399	3934									
84	448	1.718	261	573	441	3560									
85	585	1.838	318	573	481	3264	7.3								
86	590	1.838	321	548	520										
87	586	1.838	319	521	530										
88	594	1.838	323	460	505										
89	575	1.838	313	394	455										
1990	566	1.838	308	336	414	2223	7.0								
91	546	1.838	297	262	376										
92	526	1.838	286	204	316										
93	515	1.838	280	159	265										
94	498	1.838	271	124	212										
95	496	1.838	270	97	170	1560	6.5								
96	432	1.838	235	91	163										
97	438	1.838	233	82	153										
98	430	1.838	234	74	144										
99	427	1.838	232	66	134										
2000	427	1.838	232	60	127	1294	6.3								
01	210	1.838	114	54	119										
02	204	1.838	111	48	110										
03	199	1.838	108	43	103										
04	195	1.838	106	39	97	1100									
05	191	1.838	104	35	95	1000									
06	44	1.838	24												

Reserves Tax Total = $476MM

AGO 531210

PUBLIC DATA CASE
HISTORICAL FIELD CAPITAL EXPENDITURES
MM$

Year	BP/ SOHIO(d)	ARCO(e)	Exxon(f)	Others Est. (a)	Total	IDC & Dry Holes(c)	Tangible
1969	40	nil	nil	45	85	48	37
1970	60	nil	nil	60	120	64	56
1971	60	13	13	28	114	38	76
1972	26	5	5	-	36	5	31
1973	61	4	4	-	69	10	59
1974	134	65	65	-	264	37	227
1975	411	265	265	-	941	132	809
1976					1375 (b)	192	1183
				133	3004	526	2478

(a) World Oil, 12/69, shows 9 completed wells, 9 rigs running, and 2 rigs waiting on freeze-up in addition to ARCO and BP activity. Assume 2 wells per rig as follows with 75% dry holes:

Year	No. Wells	$\overline{M}\$$ Cost Per Well	$\overline{M}\$$ Total Cost	$\overline{M}\$$ Tangible	$\overline{M}\$$ Dry Holes & IDC
1969	9	5	45	3	42
1970	15	4	60	4	56
1971	7	4	28	2	26

(b) Reserves Tax Study

(c) Reserves Tax Study shows 116 producing and 10 injection wells drilled thru 1976. Assume 8 additional (5%) dry holes by Sohio/BP and ARCO. Intangibles and dry holes are then:

$$\$3\overline{M}/\text{Well} \times 70\% \times 176 \text{ successful wells} = \$370\overline{M}$$
$$\$3\overline{M}/\text{Well} \times 100\% \times 8 \text{ dry holes} = 24\overline{M}$$
$$\$394\overline{M}$$

or 14% of the \$2,871$\overline{M}$ spent thru 1976 by Exxon, ARCO and BP/Sohio.

(continued on next page)

(d) Sohio/BP Trans Alaska Pipeline Finance, Inc. Prospectus, December 4, 1974. The Standard Oil Company (Ohio) Prospectus, December 2, 1976.

(e) City of Valdez, Alaska, % Marine Revenue Bonds (ARCO Pipe Line Company Project) Preliminary Official Statement, January 27, 1977.

(f) Assumed identical to ARCO.

PUBLIC DATA CASE
HISTORICAL AND PROJECTED FIELD CAPEX AND AD VAL TAX
1976 CONSTANT DOLLARS
MM$

Year	No. Producing Wells	No. Inject. Wells	No. Wells Drilled	Intang. Drilling Costs (a)	Total Capex With Inflation (b)	Inflation Factor	Total Capex 1976 Dollars (c)	Intang. & Dry Holes	Tangible Invest-ment	Cumulative Tang. Invest-ment	Depreci-ation (d)	Accum. Depr.	Ad Val Tax (e)
1969					85		85	48	37				
1970					120		120	64	56				
71					114		114	38	76				
72					36		36	5	31				
73					69		69	10	59				
74					264		264	37	227	486			10
75					941		941	132	809	1295			26
76	138	10(gas)			1375	1.000	1375	192	1183	2478			273
77	166		43	90	644	1.070	602	90	512	2990			313
78	209		43	90	535	1.145	467	90	377	3367	160	160	64
79	252		43	90	534	1.225	436	90	346	3713	182	342	67
1980	295		43	90	722	1.311	551	90	461	4174	266	608	71
81	313	25(wtr)	43	90	1067	1.403	760	90	670	4844	306	914	79
82	356		43	90	1076	1.501	717	90	627	5471	370	1284	84
83	399		42	88	1151	1.606	717	88	629	6100	436	1720	88
84	441		40	82	995	1.718	579	82	497	6597	510	2230	87
85	481		39	82	781	1.838	425	82	343	6940	577	2807	83
86	520		10	21	276	1.838	150	21	129	7069	602	3409	73
87	530		0		276	1.838	150		150	7219	595	4004	64
88					276	1.838	150		150	7369	552	4556	56
89					276	1.838	150		150	7519	450	5006	50
1990					276	1.838	150		150	7669	335	5341	47
91					200	1.838	109		109	7778	300	5641	43
92					150	1.838	82		82	7860	200	5841	40
93					100	1.838	54		54	7914	200	6041	37
94					50	1.838	27		27	7941	200	6241	34
95											200	6441	30
96+											150/yr		
							9280	1339	7941				

(a) 70% of $3.0MM well cost.
(b) 1976 forward from Reserves Tax Study, 2/76.
(c) Historical not inflated.
(d) Unit of production.
(e) Includes reserves tax of $223MM in 1976 and 253\overline{M}$ in 1977.

AGO 531213

CHASE GROUP OF PETROLEUM COMPANIES (29 in 1975)

		1970	1971	1972	1973	1974	1975	Trendline Growth %/Yr.
Crude Oil Supplies, MB/D		28,862	31,647	33,320	35,223	34,066	28,835	None
Net Income Before Inc. Tax		12,012	15,943	17,417	26,980	49,507	39,640	28
Property, Plant & Equip:	Net	64,550	71,740	75,097	79,613	91,169	99,027	9
	Reserves	53,061	58,562	60,530	64,060	69,219	68,716	
	Total	117,611	130,302	135,627	143,673	160,388	167,743	7

Assumptions for future predictions:

1. Field employees factor is Prudhoe production over worldwide oil supplies times 5. (a)
2. Future growth after accounting for inflation.
    a. Crude oil: 2%/yr.
    b. Net income before taxes: 5%/yr.
    c. Gross P, P & E: 4.0%/yr. thru 1980; 5%/yr. 1980-85; 6%/yr. 1986+.

(a) Recognizes that oil is handled four times (production, transportation, refining, and distribution) and that refining and distribution/marketing are employee intensive steps.

AGO 531214

PUBLIC DATA CASE
FIELD BOOK DEPRECIATION
MM$

Investment Year	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	Total
Investment	2,990	377	346	461	670	627	629	497	343	129	150	
Beginning Reserve (a)	8,157	7,573	7,135	6,562	5,989	5,416	4,843	4,270	3,697	3,149	2,626	
Depreciation:												
1978	160	-	-	-	-	-	-	-	-	-	-	160
1979	160	22	-	-	-	-	-	-	-	-	-	182
1980	210	28	28	-	-	-	-	-	-	-	-	266
1981	210	28	28	40	-	-	-	-	-	-	-	306
1982	210	28	28	40	64	-	-	-	-	-	-	370
1983	210	28	28	40	64	66	-	-	-	-	-	436
1984	210	28	28	40	64	66	74	-	-	-	-	510
1985	210	28	28	40	64	66	74	67	-	-	-	577
1986	201	27	26	38	61	63	71	64	51	-	-	602
1987	191	26	25	37	58	60	68	61	48	21	-	595
1988	169	23	22	32	51	53	60	54	43	19	26	552
1989 (b)												450
1990												335
1991												300
1992												200
1993												200
1994												200
1995												200
1996-2006												150/yr.

a) MM Bbl

b) Simplicity assumptions used past 1989.

PUBLIC DATA CASE
STATE INCOME TAX

	Property Factor (a)			Employees Factor					
	Gross PPE, Bil. $			Crude Oil, MMB/D				Bil. $	
Year	World Wide	P B Field	Gross PPE Factor	World Wide	P B Field	P B Factor	Average 3 Point Factor (b)	World-wide Net Income Before Income Taxes	AK Income Tax (c)
1976	174.4	- (d)	-	29.4	-	-	-	41.6	- (d)
1977	181.4	3.65	0.0201	30.0	0.4	0.0027	.0076	43.6	31.1
1978	188.6	4.18	0.0222	30.6	1.2	0.0078	.0100	45.8	43.0
1979	196.2	4.72	0.0240	31.2	1.2	0.0077	.0106	48.1	47.9
1980	204.0	5.44	0.0267	31.8	1.57	0.0099	.0122	50.5	57.9
1981	212.2	6.51	0.0307	32.4	1.57	0.0097	.0135	53.1	67.4
1982	220.7	7.58	0.0343	33.1	1.57	0.0095	.0146	55.7	76.4
1983	230.0	8.73	0.0380	33.7	1.57	0.0093	.0158	58.5	86.9
1984	238.7	9.73	0.0408	34.4	1.57	0.0091	.0166	61.4	95.8
1985	248.2	10.51	0.0423	35.1	1.57	0.0089	.0171	64.5	103.7
1986	258.2	10.78	0.0418	35.8	1.50	0.0084	.0167	67.7	106.3
1987	271.1	11.06	0.0408	36.5	1.43	0.0078	.0162	71.1	108.3
1988	284.7	11.34	0.0398	37.2	1.26	0.0068	.0155	74.7	108.8
1989	298.9	11.61	0.0388	38.0	1.08	0.0057	.0148	78.4	109.0
1990	313.8	11.89	0.0379	38.8	0.92	0.0047	.0142	82.3	109.8

(a) Under UDITPA rules, property factor is based on original cost.
(b) Sales factor assumed to be zero.
(c) 9.4% rate.
(d) Property factor does not include incomplete construction.

Note: After 1990 assume level taxation 1991-95, then decline 3%/yr. as world-wide investment grows.

PUBLIC DATA CASE
TANKERS

Source: The Determination of Equitable Pricing Levels for North Slope Alaskan Crude Oil, November, 1976; Prepared for Office of Regulatory Programs, Federal Energy Administration under Contract No. CR-06-60824-00 (Mortada Study)

1. Required tanker capacity: 4.5 MMDWT assuming West Coast disposition for 2.0 MMB/D.

2. Average vessel size: 115 MDWT.

3. Average cost: $450/DWT plus $40/DWT interest during construction.

4. Roundtrip Valdez - Long Beach = 14.5 days including turn around at both ends of 1.5 days each.

5. Dry docking every two years = 30 days.

6. Weather and repair = 20 days/year.

7. Barrels hauled per year:

   115 MDWT X 6.4 Bbl/Ton = 736 MBbls/trip
   Average operating time = 365 - 15-20 = 330 days/year
   Trips/year = 330 ÷ 14.5 = 22.8
   MMBbls/Year = 22.8 X 736 X 10^{-3} = 16.78 (46 MB/D Avg.)

8. Investment Costs:

Year	Investment for MB/D	No. Vessels Req.	MM DWT	MM$ Investment
1976	828	18	2.07	932
1977	372	8	0.92	414
1978				
1979	370	8	0.92	414
				1760

9. Assumed DCF Return: 10%

STATE OF ALASKA

JAY S. HAMMOND, Governor

DEPARTMENT OF REVENUE

PETROLEUM REVENUE DIVISION

597 W. THIRD AVENUE — ANCHORAGE 99501

February 9, 1976

Mr. R. H. Underwood
Manager, Alaska Taxes
Atlantic Richfield Company
P.O. Box 360
Anchorage, Alaska 99510

Proposed Assessment for Reserves Tax (AS 43.58) on Proven Reserves of Oil in the Prudhoe (Sadlerochit) Oil Pool, North Slope Borough, Alaska

Dear Mr. Underwood:

An appraisal of the market value as of January 1, 1976 of the oil reserves of the Prudhoe (Sadlerochit) Oil Pool has been made for this Division by Pritchard & Abbott, Valuation Engineers of Fort Worth, Texas. This appraisal does not extend to the gas reserves of this reservoir because, in the absence of an initial transmission facility, the gas reserves are exempt from the reserves tax. Enclosed is a copy of the appraisal, which includes a statement of underlying assumptions and a calculation sheet showing how the appraised market value was derived.

Before developing their present projections of capital and operating costs and of the methods by which the pool will be developed, produced and eventually depleted, Pritchard & Abbott engineers have met on several occasions with the proposed unit operators and their partners. During these discussions Pritchard & Abbott indicated their thinking as to their projections, and on some points comments or criticism was offered by the operators. While we found this very useful, I should point out that the projections in the appraisal remain the work of Pritchard & Abbott, and not the operators or their partners.

Pritchard & Abbott have also received well logs and other physical data. The confidentiality of proprietary or statutorily confidential information has been, and will continue to be, strictly maintained. Based on this information, Pritchard & Abbott are preparing a "break out" of the market value by property. While the results of this task are not ready for distribution at this time, I have been informed that properties within the proposed unit that were rendered by Atlantic Richfield Company on behalf of itself and others do not represent more than 39.96 percent of the market value for the entire Prudhoe (Sadlerochit) Oil Pool, or not more than $4,711,000,000. This value includes the value as of January 1, 1976 of any production equipment needed for unit operations that was on those properties on that date. To avoid taxing this production equipment twice, its assessed value for AS 43.56 would be subtracted from the market value of these properties in determining the value of the oil reserves for purposes of the reserves tax.

The reserves tax is unique not only for its temporary nature and its complex system of credits back and forth with the production tax, but also because of its unprecedented magnitude when applied to Prudhoe Bay. Because of this, and to administer the tax fairly and equitably, we are soliciting the review and comments of you, and all other operators and interest-owners in the Prudhoe (Sadlerochit) Oil Pool who wish to make them, before we reach any final decision as to the assessment of the Prudhoe properties. Mr. Gerald D. Heier, State Petroleum Property Assessor, and I will be available at the Division office in Anchorage through February 27, 1976 for discussions about the tax. For the convenience of companies headquartered outside Alaska, Mr. Heier and I will conduct a meeting on Wednesday, March 3, 1976 at the offices of Pritchard & Abbott, 200 Seminary South Building, Fort Worth, Texas, beginning at 9:00 o'clock in the morning (local time). We invite you and any other representatives of Atlantic Richfield Company, or any of the interests on whose behalf you rendered Prudhoe properties, to attend this meeting to discuss the reserves tax. We will remain available in Fort Worth for discussions with smaller groups or individuals through Friday afternoon, March 5, 1976. Written comments received at the Division office in Anchorage by the close of business on March 5, 1976 will also be given full consideration. After that time the record will be closed for our purposes, and we will prepare assessment notices for the reserves tax on the basis of our decisions made in light of this record.

Naturally the provisions for appeals in AS 43.58 and the regulations will remain available to any taxpayer challenging the assessment in his assessment notice.

Please call or write if you have any questions.

Yours very truly,

Thomas K. Williams

Thomas K. Williams
Director
Petroleum Revenue Division
Department of Revenue
State of Alaska

Enclosure

TKW:dh

cc: Mr. Gerald D. Heier, Anchorage

Pritchard & Abbott, Fort Worth, Texas

Exxon Company, U.S.A.

Please hand deliver to Bruce Conner Room 211

February 6, 1976

Mr. Thomas K. Williams, Director
Petroleum Revenue Division
Department of Revenue
State of Alaska
509 West Third Avenue
Anchorage, Alaska 99501

Dear Sir:

The Prudhoe Bay, Sadlerochit Pool has been appraised to determine the market value of remaining oil reserves under unitized conditions. It is my opinion that the market value as of January 1, 1976 is:

$ 11,790,000,000
Eleven Billion Seven Hundred Ninety Million Dollars

In addition to the present worth calculations, I am including a summary of the basic projections used to develope and deplete the oil reserves.

Yours truly,

Malcolm Jarrell, P.E.
Pritchard & Abbott Valuation Engineers

MJ:jr

Enclosures

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AGO 531220

PRUDHOE BAY SADLEROCHIT POOL
PROJECTIONS as of 1-1-76

Development & Depletion

Well Development

The total number of producing wells drilled is based generally on 160 acre spacing per oil well, in the area where the oil column is 200 feet or more. In areas of thinner oil column, the density may vary to 320 acres per well. The magnitude and time frame for well development is,

A. Four (4) rigs continuously working for 12 years,
B. Each rig completes up to ten (10) wells per year,
C. Ten (10) gas injection wells drilled by 1977,
D. Twenty-five (25) water injection wells drilled by 1981,
E. Five hundred thirty (530) producing wells drilled by 1988.

Oil Production

A. Production begins by mid-1977 at an average rate of .8 MMB/D.
B. Production increases to an average rate of 1.2 MMB/D in 1978 & 1979.
C. Production increases to an average rate of 1.57 MMB/D (98% of 1.6 MMB/D) in 1980 & remains constant through 1985.
D. Production decline starts in 1986 and continues through 2005.

Water Production

A. Becomes significant by 1983 and increases to approximately 75% of total fluid production by 1996.
B. Water production in excess of 75% total fluid per well is one basis of plugging wells.

Gas Production

A. Gas/oil production ratio is 730 SCF/Bbl.
B. Shrinkage & fuel consideration is 8% of gross with remaining gas injected through 1980.
C. *Gas sales start in 1981 at a rate of 730 BCF/yr.

Water Injection

A. Source water injection starts in 1981 at a rate of 2250 MB/D and continues through 2000.
    1. Source water requirements based on injection rate of 2250 MB/D minus (-) produced water.
B. Produced water is injected through 2005.

Development & Depletion (cont'd)

Gas Injection

A. Produced gas injected through 1980.
B. *Produced gas sold or used after 1980.

Workovers

A. Begin in 1978 and increase to approximately 20% of the producing wells per year.
B. Plugging operation begins in 1988 and continue through 2006.

*Gas and/or condensate sales is not considered as economic factor in market value calculations.

Expenditures

Capital

A. Capital expenditures for the completion, addition and expansion of production facilities is projected to be approximately 85% of the total through 1985.
B. The average cost to drill & complete a well is $3 MM.

Operating

A.	Basic facility operations	$ 85 MM/yr.
B.	Basic artificial lift facility operation	$ 45 MM/yr.
C.	Well operation	$ 75 M/yr./well
D.	Well workover	$ 400 M/well
E.	Plug & Abandon wells (Net after salvage)	$ 250 M/well
F.	Gas handling & injection	9¢/SMCF
G.	Water handling and injection (1) source	14¢/bbl
	(2) produced	11¢/bbl
H.	Special allowance in 1976 & 1977 for 'start-up' training of personnel, etc.	

*All Capital and Operating expenses is inflated at 7% per year through 1985.

Severence Tax (Production Tax)

A. Based on State of Alaska % formula
i.e., up to 300 B/D/W = 3% of gross wellhead income
next 700 B/D/W = 6% " " " "
next 1000 B/D/W = 8% " " " "

Ad Valorem Tax

A. Estimated tax from A.S. 43.58 (Reserve) + A.S. 43.56 (Property) for 1976 & 1977.
B. Estimated tax from A.S. 43.56 (Property) after 1977.

YEAR	PRICE @ W.H. $/Bbl	NO. OF WELLS PRODUCING	PRODUCTION 8/8 GROSS MM Bbls	INCOME 7/8 GROS MM $
1976		138		
77	7.58	166	146	968
78	8.52	209	438	3265
79	10.00	252	438	3832
80	10.42	295	573	5224
81	11.35	313	573	5691
82	11.35	356	573	5691
83	11.35	399	573	5691
84	11.35	441	573	5691
1985	12.05	481	573	6042
86	No price increase after 1985	520	548	5778
87		530	521	5493
88		505	460	4850
89		455	394	4154
1990		414	336	3543
91		376	262	2762
92		316	204	2151
93		265	159	1676
94		212	124	1307
1995		170	97	1023
96		163	91	959
97		153	82	865
98		144	74	780
99		134	66	696
2000		127	60	633
01		119	54	569
02		110	48	506
03		103	43	453
04		97	39	411
2005		95	35	369
06				
TOTALS			8,157	81,073

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PRUDHOE BAY - SADLEROCHIT POOL
PRESENT WORTH CALCULATIONS
(as of 1-1-76)

EXPENDITURES						
CAPITAL MM $	OPERATING MM $	SEV. TAX MM $	A.V. TAX MM $	TOTAL MM $	INCOME 7/8 NET MM $	P.W. @ 18% MM $
1375	44	1	235	1655	(-1655)	(-1524)
644	138	(73) 37	302	1121	(- 153)	(- 119)
535	152	(248) 124	41	852	2413	1595
534	178	(288) 144	47	903	2929	1641
722	195	(395) 210	54	1181	4043	1920
1057	337	429	63	1896	3795	1527
1076	378	426	78	1958	3733	1273
1151	398	422	93	2064	3627	1048
995	448	418	109	1970	3721	911
781	585	441	119	1926	4116	854
276	590	416	126	1403	4370	769
276	585	393	131	1385	4107	612
276	594	343	135	1348	3502	442
276	575	292	139	1282	2872	307
276	566	247	142	1231	2312	210
200	546	188	144	1078	1684	129
150	526	144	143	963	1188	77
100	515	111	142	868	808	45
50	498	85	141	775	532	25
-0-	496	67	137	700	323	13
	432	62	133	627	332	11
	428	56	126	610	255	7
	430	50	118	598	182	4
	427	44	108	579	117	2
	427	39	96	562	71	1
	210	35	83	328	241	4
	204	31	69	304	202	3
	199	27	55	281	172	2
	195	24	39	258	153	1
	191	21	23	235	134	1
	44		3	47	(- 47)	(- 1)
10,760	11,532	5,328	3,374	30,994	50,079	11,790

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SCOMM

#12:9

RADER

THE DETERMINATION OF EQUITABLE PRICING LEVELS FOR NORTH SLOPE ALASKAN CRUDE OIL

NOVEMBER 1976

Prepared for Office of Regulatory Programs

FEDERAL ENERGY ADMINISTRATION

under Contract No. CR-06-60824-00

This report was prepared under contract to the Federal Energy Administration (FEA) and does not necessarily state or reflect the views, opinions, or policies of the FEA or the Federal Government.

TABLE OF CONTENTS

Three field development plans were analyzed.

Case I: Only Prudhoe Oil Pool (consisting of Sadlerochit, Sag River and Shublik formations) is developed. Field is put on production in mid-1977. Production rate reaches 1.5 MMB/D by early 1979 and is held at that rate until mid-1986, and then declines. Gas sales begin in 1983 at 2 BCF/D.

TAPS' capacity expands to 1.5 MMB/D.

Case II: Field development plans include lower reserve estimates of Kuparuk and Lisburne Oil Pools. TAPS' capacity expands to next level of 2 MMB/D.

Prudhoe Oil Pool is produced at 1.6 MMB/D. Contributions of Kuparuk and Lisburne Oil Pools bring production rate to 1.77 MMB/D. Production rate peaks in 1986 and then declines.

Case III: Field development plans include upper reserve estimates of Kuparuk and Lisburne Oil Pools. TAPS' capacity and Prudhoe Oil Pool production rate are unchanged from Case II.

Contribution of Kuparuk and Lisburne Oil Pools brings rate of production to 1.915 MMB/D. Production rate peaks in 1986 and then declines.

Methodology and Results

1. Develop production rate forecast for each case.

2. Estimate investment in field and costs of operation for each development plan.

3. Estimate investment in TAPS and costs of TAPS' operation for 1.2, 1.5 and 2.0 MMB/D capacity.

4. Determine average transhipment costs from Valdez to West Coast ports. Cost of transshipment including terminal handling is 76 ¢/B.

5. Establish ceiling price (in 1976 dollars) at Valdez, based on price of comparable Saudi Arabian crude to West Coast refinery exclusive of entitlements.

	$/B	
Price of Saudi Arabian crude FOB Ras Tanura	11.51	12.66
Transshipment to West Coast	1.33	
Import Fee	.21	
Terminal Handling	.10	
	13.15	
	- .76	
Ceiling price at Valdez	12.39	13.54

6. Compute tariff rate by year for each case. Average tariff rate for first 10 years of pipeline service:

Case I	4.50 $/B
Case II	4.30 $/B
Case III	4.20 $/B

AGO 531229

- Each TAPS owner has different experience with debt-to-equity ratio and interest rates. Each owner may set a different tariff.
- ICC and Justice Department rulings set the ceiling on tariff rate. An owner can set tariff below ceiling, but Justice Department will not knowingly condone destructive competition. This still leaves a wide latitude for each owner to set a different tariff.
- Owner may set the tariff rate annually (unsmoothed) or smooth the rate over several years.

7. Compute total operating costs of TAPS by year for each case to include:
   - Cost of operations (in 1976 dollars)
   - Ad valorem taxes
   - State of Alaska corporate income tax
   - Federal corporate income tax

8. Compute ceiling well head price by year for each case. This is equal to ceiling price at Valdez minus tariff.

   Use well head price to compute total field operating costs, including
   - Cost of operations (in 1976 dollars)
   - Ad valorem tax
   - Royalty and payments to Alaska Native Fund
   - Severance tax
   - State of Alaska corporate income tax
   - Federal corporate income tax

AGO 531230

9. Compute annual gross revenue generated at Valdez at constant 1976 dollars plus revenue for gas sales in the field at 53 ¢/MCF (before conditioning to pipeline quality).

10. Adjust pre-1976 expenditures to 1976 dollars.

By expressing pre-1976 investments and post-1976 investments and revenues in 1976 dollars, the uncertainty associated with forecasting the future rate of inflation is circumvented. The resulting rate of return is referred to as "real rate of return". Price levels thus determined need to be adjusted quarterly to reflect effects of inflation.

11. Compute DCF, after tax, real rate of return on total investment in TAPS and Prudhoe Bay Field using items 7, 8, 9 and 10 above.

12. Analyze sensitivity of rate of return to price at Valdez by changing it by one dollar increments. Repeat items 8 to 11 above.

13. Analyze sensitivity of rate of return to risk multiplier "R", where $R = 1 + .5 (S - 1)$, and S = inverse of success ratio. Multiply total industry's expenditures on North Slope from 1959 until field discovery in 1968 by risk multiplier. The relationship between R and S assumes the unsuccessful exploratory ventures are expensed for federal income tax purposes.

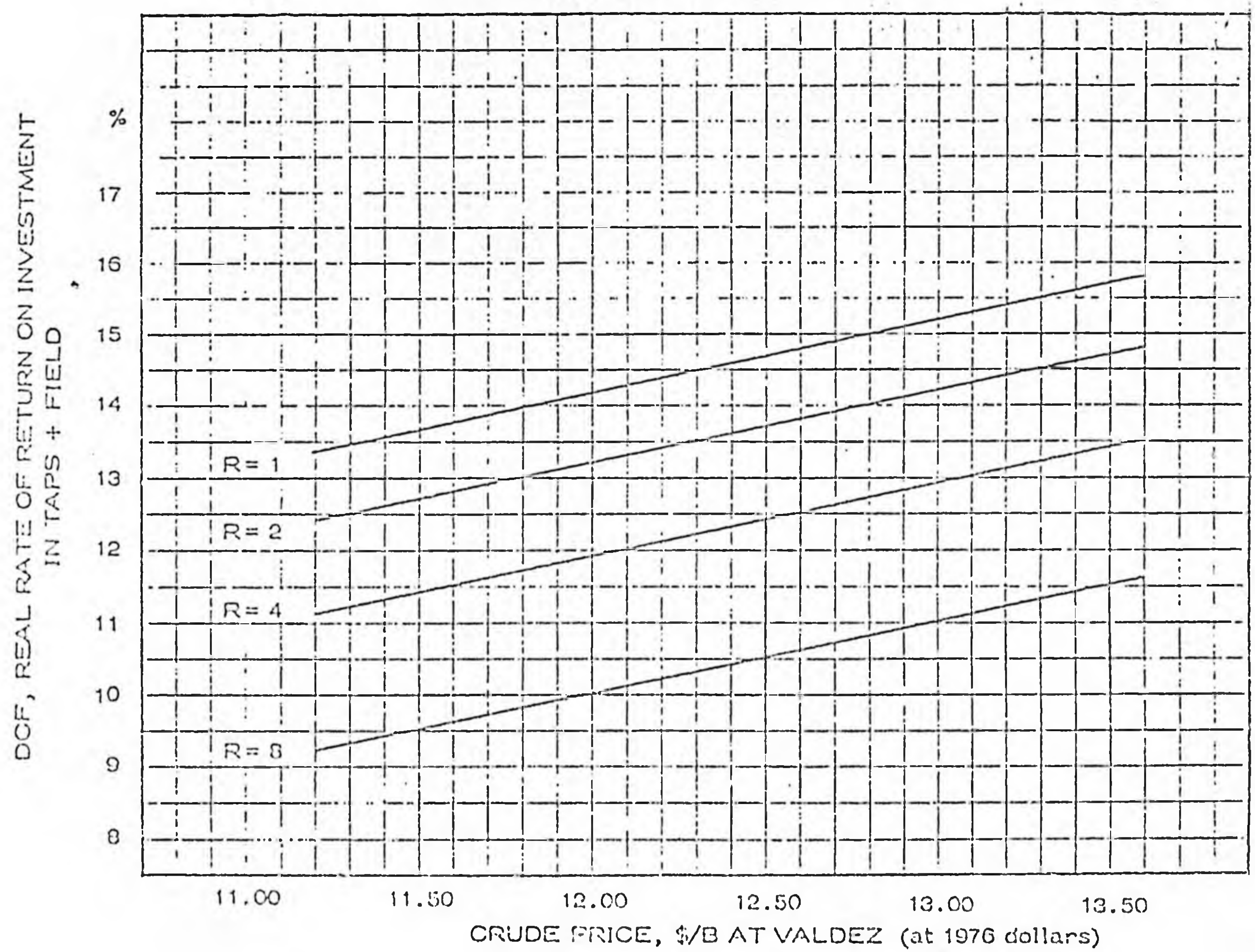
14. Analyze sensitivity of rate of return to uncertainty in tariff determination

15. Analyze sensitivity of rate of return to variation in rate of throughput by comparing rates of return for Cases I, II, and III.

RELATIONSHIP BETWEEN

RATES OF RETURN, RISK MULTIPLIER "R"

AND CRUDE PRICES



AGO 531232

Conclusions

- Rate of return is relatively insensitive to the rate of throughput. The increased cost of developing and operating the speculative and less productive reserves in the Lisburne and Kuparuk Oil Pools is substantially offset by the economy resulting from increasing TAPS' capacity from 1.5 to 2.0 MMB/D.

- The uncertainty in tariff determination has little effect on the rate of return. An increase in tariff shifts the tax obligation to TAPS from the field, and vice versa. Since the field taxable income is more heavily taxed, a lowering of tariff increases the total tax obligation but does not affect the rate of return significantly.

- A change of 1 $/B in the price of crude at Valdez results in a net change in after tax revenue to the owners of 38 ¢/B. It also results in a 1% change in the rate of return.

- The risk multiplier has a dramatic effect on the rate of return. For Case I, with Valdez price of 12.40 $/B:

Risk Multiplier	Rate of Return %
1	14.6
2	13.6
4	12.3
8	10.4

A risk multiplier of 3 to 4.5 (equivalent to success ratio of 1 in 7) is suggested. For this range of risk multiplier and an after tax, DCF, real rate of return of 12%, the price range at Valdez would be

. 11.50 to 12.40 $/B.

Comparable well head price range would be:

Case I	7.00 - 7.90
Case II	7.20 - 8.10
Case III	7.30 - 8.20

Recommendations

- Equitable prices of Prudhoe Bay crude at Valdez fall between 11.50 and 12.40 \$/B (1976 dollars), to be adjusted quarterly for inflation.
- Pricing at Valdez provides a built-in incentive for developing the speculative Kuparuk and Lisburne Oil Pools.
- Pricing at Valdez circumvents the uncertainty in tariff rates.
- Equitable prices of Prudhoe Bay crude at the well head for Case I fall in the range of 7.00 to 7.90 \$/B (1976 dollars), to be adjusted quarterly for inflation.
- This study did not address itself to the implications on pricing of any surplus of crude on the West Coast.

I. Relationship Between Prices at West Coast Ports, Valdez and Well Head

The major components of the total system required to bring the Prudhoe Bay crude to the West Coast refineries are:

1. The Prudhoe Bay Field System
2. The Trans Alaska Pipeline System
3. The Transshipment System which transports the crude from Valdez to West Coast ports.

The price of Prudhoe Bay crude on the West Coast is equal to the price at Valdez plus the cost of transshipment. Similarly, the price at Valdez equals the well head price plus the pipeline tariff.

Cost of Transshipment

The cost of transshipment per barrel is equal to the sum of the operating costs per barrel plus the capital charges per barrel required for depreciating the cost of the tanker over its life after allowing a 10% rate of return on investment. The transshipment cost is very sensitive to tanker size and to the length of the voyage from Valdez to the West Coast port. A detailed analysis and presentation of the costs of transshipment as a function of tanker size and length of voyage is presented in Chapter III.

To arrive at a representative transshipment cost to be used for relating the price at Valdez to the price at the West Coast, an average tanker size of 115 MDWT (which is the average size of tanker in the Valdez to West Coast fleet) was used. Furthermore, the length of the voyage was averaged out by arbitrarily assuming that one-third of the Valdez to West Coast crude oil trade goes to Puget Sound and two-thirds to Long Beach.*

Pipeline Tariff

The price of Prudhoe Bay crude at Valdez represents an important point of departure. The pipeline tariff for moving Prudhoe Bay crude from the field to Valdez is computed according to a set of rulings established by the ICC and the Justice Department. The tariff thus calculated represents a ceiling which cannot be exceeded by the owners. The form of ownership of the trans-Alaska pipeline is one of undivided joint interest and permits each owner to post a separate tariff. The owners will probably post different tariffs for several reasons.

1. The actual interest paid on borrowed capital is recognized by the ICC as a component in the tariff computation. Interest charges vary from owner to owner, depending on the interest rate on the pipeline debt, and debt to equity ratio.
2. The ownership in the pipeline is not the same as the ownership in the field reserves.

The Justice Dept. will not knowingly permit destructive competition through tariffs that fail to cover expenses. That still leaves considerable room for variation in the tariffs posted by the different pipeline owners.

For this reason, the price of crude at Valdez and a rate of return based on the combined investment in the field and pipeline system take on an added significance. The trans-Alaska pipeline tariff is computed for the average owner according to the rules and regulations prescribed by the ICC

* This assumption is examined in greater detail on page III-12.

and the Justice Department. The computed tariff is used to arrive at well head price which is the basis for computing:

1. Severance tax
2. State royalty
3. Payments to Alaska Native Fund
4. State and federal corporate income taxes.

II. Rates of Return

The rates of return computed in this study are discounted cash flow, after tax (both state and federal) real rates of return on total investment. Therefore for TAPS, the rate of return computation takes into account the entire capital investment in the pipeline (i.e. not limited to owners' equity). Similarly, therefore, it does not recognize construction interest, which is included in the ICC valuation base for tariff determination.

Predicting the future rate of inflation over the life of the project is subject to a high degree of uncertainty. On the other hand, reasonably reliable predictions can be made of the field producing potential, rates of throughput and operating and investment costs in terms of 1976 dollars. Therefore it is more meaningful to project all future costs and revenues in terms of 1976 dollars and to express all pre-investments also in terms of 1976 dollars. The resulting cash flow yields a real rate of return as distinguished from a nominal rate of return when discounted to determine a zero present worth. The price of oil thus determined is expressed in 1976 dollars and should be adjusted periodically after the fact to reflect the effects of inflation. Table I-1 was used to express pre-1976 investments in 1976 dollars.

Chapter II

QUALITY AND CHARACTERISTICS OF PRUDHOE BAY ALASKAN CRUDE OIL

Introduction

The Prudhoe Bay Field consists of three principal hydrocarbon accumulations. These are the Kuparuk, the Prudhoe and the Lisburne Oil Pools, in order of increasing depth. The Prudhoe Oil Pool is the principal hydrocarbon accumulation in the Prudhoe Bay Field. It ranges in depth from approximately 8,700 feet to 9,300 feet and contains the majority of known proven reserves in the field. The pool is made up of the Sag River, Shublik and Sadlerochit formations. The productive intervals in this pool vary in gross thickness from approximately 20 to 600 feet. The Sadlerochit formation contains most of the reserves in the Prudhoe Oil Pool.

Current development plans focus on the Prudhoe Oil Pool only. To date, no formal plans have been announced by the field operators for the development of the Kuparuk and Lisburne reservoirs. Crude oil from the Prudhoe Oil Pool will be the only crude oil going through the pipeline for the first three years of operation.

Extensive analyses were performed on two crude samples from the Prudhoe Oil Pool. One sample was obtained from ARCO's Sag River State #1 (the Sadlerochit formation) and was analyzed by the Bureau of Mines. The other sample was also a Sadlerochit crude obtained from ARCO's Drill Site #1 and analyzed by ARCO.

Chapter III

TRANSSHIPMENT COSTS BETWEEN VALDEZ AND WEST COAST PORTS

Introduction

The principal market for North Slope Alaskan crude oil will be the West Coast of the United States because export exchange and swap arrangements of domestic crude oil for foreign crudes are barred by law. A number of questions arise about the ability of the West Coast market to absorb the entire production from Prudhoe Bay. Current estimates indicate that in 1978 the West Coast market will have a surplus of 300 to 600 MB/D. The surplus in 1982 may be as high as 600 to 800 MB/D.

The disposition of the surplus crude which will be available in the West Coast market has been analyzed by other studies and falls outside the scope of this assignment.

For the purpose of this study, the principal destination of the Prudhoe Bay Alaskan crude oil will be Puget Sound, San Francisco and the Los Angeles-Long Beach area even though significant amounts of North Slope Alaskan crude oil may find its way to the Gulf Coast.

United States Preference Trade Act

U.S. laws restrict the use of non-U.S. flag vessels in certain trades. For example, pursuant to Section 2 of the Shipping Act of 1916, cargoes transported by sea from one U.S. port to another must be carried in unsubsidized vessels of U.S. registry. These vessels must be owned by U.S. citizens and must have been built in the U.S. Furthermore, the

Merchant Marine Act of 1920 (the Jones Act) requires that cargo transported between domestic ports be in ships built and registered in the U.S. and manned with U.S. crews. The Jones Act further stipulates that companies with more than 25% foreign ownership are not considered to be U.S. companies for purposes of the Act.

Tanker Requirements and Availability

The U.S. tanker capacity which is required to deliver 2 MMB/D of North Slope production will range from 4.5 MMDWT to approximately 6 MMDWT, depending upon the disposition of Alaskan crude oil among the various regions of the U.S. The 4.5 MMDWT assumes that the North Slope production will be shipped to West Coast ports.

Given the dual considerations of economics of scale and port limitations, the preferred tanker sizes for North Slope oil trade are anticipated to range from about 50 MDWT to shallow draft 165 MDWT tankers. Unsubsidized tankers falling within this classification will reach approximately 4.5 MMDWT by 1979-1980. Of the 4.5 MMDWT, 3.2 MMDWT will be owned or controlled by North Slope oil companies who will lease rather than own their tankers for most of the tanker life. The remainder 1.3 MMDWT is owned by independent ship owners. Based on present commitments and tankers on order, enough tanker capacity will be available to transport the North Slope Alaskan crude oil to West Coast ports.

The tanker size distribution of the North Slope oil companies is presented in Table III-1.

Table III-1

TANKER SIZE DISTRIBUTION
FOR
TANKERS OWNED OR CONTROLLED BY
NORTH SLOPE OIL COMPANIES

Number of Tankers	Size of Tankers MDWT	Status	Total Capacity MDWT
2	188	on firm order	376
4	165	on firm order	660
2	150	on firm order	300
1	150	on option	150
1	129	delivered	129
3	120	delivered	360
2	118	on firm order	236
1	118	on short term charter	118
2	81	delivered	162
2	81	on short term charter	162
3	75	delivered	225
4	70	delivered	280
1	52	delivered	52
			3,210
Independent Shipowners			1,300

The average size of tankers in the above distribution is estimated to be 115 MDWT.

Tanker Charter Rates

Tanker charter rates are highly competitive. Prevailing market rates for time and voyage charters are subject to fluctuations from time to time depending on market conditions and supply and demand situation. Although long-term charter rates (usually defined as charters for periods in excess of three years) are also subject to supply and demand, the variations are generally not as extreme as the short-term market rates. Accordingly, the long-term market rates tend to be less volatile. Nevertheless, they also fluctuate from time to time and hence are not suitable as a basis for determining the cost of transshipment. For the purpose of this analysis, the cost of transshipment will be computed by:

- depreciating the cost of the tanker over its useful life after allowing a rate of return on the investment, plus
- the cost of operating the tanker.

Cost of Transshipment from Valdez to West Coast Ports

The cost of transshipment from Valdez to West Coast ports consists of capital charges related to tanker construction plus applicable marine operating costs.

A. Cost of Tanker Construction

The cost of large crude carriers built in American shipyards has risen from around 200 $/DWT in 1970 to over 500 $/DWT on current orders. This cost does not include interest during construction which averages under 10% of the cost of construction.

Tankers which were built before the recent rapid rise in construction costs will have a distinct competitive advantage. The average construction cost for the entire Valdez to West Coast fleet is estimated to be 450 $/DWT plus 40 $/DWT for interest during construction. To arrive at transportation costs in ¢/B, the construction costs are depreciated over the life of the tanker, assuming several rates of return (for sensitivity purposes) and taking into account the length of the voyage between Valdez and various West Coast ports.

The following assumptions were used to compute the annual revenues and hence the capital charges per barrel required to yield various rates of return on the invested capital in tanker construction:

- Investment tax credit = 10%.
- For federal income tax purposes, tanker is depreciated over 14.5 years using double declining balance.
- Tanker life is 25 years.
- Federal income tax is 48%.

The computed capital charges are shown in Tables III-2 and III-3.

Chapter IV

TRANS ALASKA PIPELINE SYSTEM

Basic Facts

The trans-Alaska pipeline is just over 801 miles in length, of which about 375 miles will be buried and the remainder will be elevated. Current plans call for an initial capacity of 600 MB/D when the line is first completed in mid-1977, increasing to an ultimate capacity of 2 MMB/D in three stages. In the first stage, line capacity will be boosted to 1.2 MMB/D by late '77 or early '78. The capacity will be further boosted to 1.5 MMB/D in '79. Boosting the capacity further to 2 MMB/D must be coordinated with the development of speculative reserves (see Field Development Plans). Some estimates indicate that the pipeline via "looping", which employs added pipe and pump stations at various points along the line where the grade requires it, could handle 2.5 MMB/D. The Valdez terminal will have a ship-loading capacity of 80 to 110 MB/H, and can accommodate tankers of 195 MDWT. For a line capacity of 1.2 MMB/D, the storage capacity will be met through 18 tanks with 510 MB capacity each. Four berths will be required for the 1.2 MMB/D throughput, with a fifth berth to be added upon the increase in line capacity.

Trans Alaska Pipeline Ownership

Company	% of line owned
SOHIO Pipe Line Company	33.34
BP Pipelines, Inc.	15.84
ARCO Pipeline Company	21.00
Exxon Pipeline Company	20.00
Mobil Alaska Pipeline Company	5.00
Union Alaska Pipeline Company	1.66
Phillips Petroleum Company	1.66
Amerada Hess Corporation	1.50

TAPS Agreement

Duration of initial team: 30 years

Form of ownership: undivided joint interest

Transfer of ownership:

- permissible for cash
- partners have first purchase rights

Expansion from 1.2 MMB/D to 2.0 MMB/D

- any participant may propose
- other participants may acquire proportionate share or decline
- each partner has option to acquire share for 2 years after expansion

Construction Costs

The estimated costs of pipeline construction for 1.2 MMB/D design capacity is 7.7 billion dollars. This estimate includes the construction costs for the Valdez terminal, the fuel line, pump stations, and pumping plants. The estimated construction costs by year of expenditure and by cost item are shown in Tables IV-1 and IV-2.

Table IV-1

ESTIMATED CONSTRUCTION COSTS OF

TRANS ALASKA PIPELINE SYSTEM

BY YEAR OF EXPENDITURE

(For 1.2 MMB/D Design Capacity)

Year		Expenditures MM$
1969		35
1970		180
1971		109
1972		49
1973		47
1974		857
1975		2,772
1976		2,698
1977		765
1978		188
	Total	7,700

Table IV-2

TRANS ALASKA PIPELINE SYSTEM

CONSTRUCTION COSTS

(MM $)

	Estimated Costs for 1.2 MMB/D (Design Capacity)
1. Alyeska Corporate	940.0
2. Bechtel - General	127.0
3. Pipeline - General	696.1
4. Pipeline Sections	1,353.6
5. Fuel Line	26.1
6. Mainline Pipe & other Permanent Materials	753.1
7. Pipeline & Roads - General	1,696.3
8. Roads - General	20.2
9. Roads	114.0
10. Yukon River Crossing	20.6
11. Fluor	171.2
12. Stations and Terminal - General	.1
13. Stations - General	14.8
14. Pump Stations	618.3
15. Topping Plants	21.1
16. Gate Valves	30.1
17. Mainline Refrigeration	5.0
18. Terminal - General	354.4
19. Terminal	738.0
Total Estimated Construction Costs	$ 7,700.0