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INVESTMENT OPPORTUNITIES FOR AN ALASKAN GENERAL STOCK OWNERSHIP COMPANY

A REPORT TO THE ALASKA STATE LEGISLATURE

"this is crap" 2-20-80/11:45

Sam is also disappointed with this report as is Gerry Gauche

212-285-5659 Bob Gerard of Dillon Reed investment Bankers would do free work on this as would other invest. Bankers E.F. Hutton, Smith Barney

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CHAPTER ONE

OVERVIEW OF THE ECONOMY

Alaska is a state of nearly 600,000 square miles, having an area of approximately 20% of the continental United States. Some two-thirds of the population of 400,000+ is concentrated in cities of Anchorage, Fairbanks and Juneau. Potentially, the Alaskan economy could develop rapidly in future years. A much greater population can theoretically be supported at high living standards as the State's resources are more fully utilized.

Available land resources are large in relation to the population. Production of large exportable surpluses of primary products has traditionally been a feature of the economy. Exports of crude petroleum, fish and other marine products, and forest products provide the greater part of Alaska's overseas earnings.

Overseas influences can therefore have an important bearing on some aspects of the Alaskan economy. Substantial variation in world prices of primary products, for example, can have a significant effect not only on the level of internal income, but also on Alaska's ability to finance imports.

The expansion of secondary industry in Alaska would reduce the influence of external conditions on the economy. The importance of a better balance in the economy was also demonstrated by the problems that developed with the completion of TransAlaska Pipeline System (TAPS).

Population and Work Force

During the years since statehood, Alaska's population growth has been, on the whole, relatively rapid. The period since 1959 has just about doubled the population. Natural increase above the national average was generally responsible for the growth, except for the heavy in-migration during the pipeline period. The impact of immigration

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has been greater than is indicated by the contribution to total numbers. The in-migration of young adults has helped reduce the average age to well below the national average. Less than 3% of Alaska's population is older than 65. This change in the age structure of the population results in a more rapid growth of the total work force and very high participation rates.

The size of the labor force has a seasonal pattern, with summer employment approximately 10% above the annual average, and winter well below the average. A significant number of the additional summer workers are temporaries from the lower 48. Seasonality has been declining steadily in recent years.

Employment amd Markets

Even adjusting for the distortion produced by the trans-Alaska pipeline, civilian employment has been growing in Alaska well above the expansion of population. The government sector continues to be the largest employer, but has declined from 40% of non-agricultural wage-and-salary employment in 1960 to an estimated 33% in 1979.

The growth of the population and work force has been associated with an expansion in the market demand for goods and services of almost every kind. Apart from increase in prices, two factors have operated to raise expenditure on goods and services -- the above average growth in population, and an increase in average real incomes. The growth in total expenditure on goods and services has meant that economies of larger scale operation have become more rapidly available to existing businesses, and, in addition, it has made possible the establishment of new businesses for which the market was previously too small.

There is every reason to believe that opportunities for expansion into new industries and new products will continue to offer themselves as the population increases. Furthermore, the increasing diversification of the industrial and service structure inevitably fosters further expansion. Newly established industries create demands for supplies of parts and materials. In other fields, the establishment of one industry may result in raw materials becoming available for the establishment of others. Instances of this are the Alpetco refinery in Valdez and the Pacific Alaska LNG plant in Nikiski.

Similarly the expansion of the economy makes possible the provision of services which would be impractical in a smaller market. Replacement of mail order facilities with full service stores have developed extensively in this way, while the establishment of Alaska offices where previously served from the lower 48 reflects the growth in the financial structure of the economy.

Employment is often cyclical in Alaska. Construction of the oil pipeline increased total employment by perhaps 60,000 over three years. The completion produced a substantial decrease in employment as can be seen in the table below.

Non-Agricultural Wage & Salary Employment

	Annual Average 1976	% of Total	Annual Average 1979 Est.	% of Total
Mining	3,965	2.3	5,519	3.4
Contract Construction	30,233	17.4	10,510	6.4
Manufacturing	10,331	6.0	11,189	6.8
Trans., Communications & Public Utilities	15,704	9.1	16,445	10.0
Wholesale Trade	6,098	3.5	5,678	3.5
Retail Trade	21,466	12.4	23,541	14.3
Finance, Insurance & Real Estate	7,102	4.1	8,039	4.9
Services	27,633	15.9	27,803	16.9
Government	49,670	28.6	54,424	33.2
Miscellaneous	1,297	.7	957	.6
Total	173,499	100.0	164,107	100.0

Source: The Alaska Economic Information and Reporting System, Quarterly Report, October 1979.

Those large projects with a large construction component will probably continue to produce substantial swings in total employment. Because of in-migration of temporary

Charge

residents for construction jobs and a larger economic and employment base, future projects should not have as dramatic an impact as TAPS.

Availability of Labor

The availability of labor, both generally and in particular categories, and the terms and conditions that govern employment are of critical interest to businessmen and others contemplating investment.

At the end of 1979 the Alaskan work force numbered about 165,000, or about 40% of the population. Only one out of fifteen workers in Alaska is engaged in manufacturing while three out of every ten work for state, federal or local government. Although comparisons are not altogether reliable, the industrial composition of the Alaskan work force is now broadly comparable with the rest of the United States except for manufacturing where one out of four workers in the lower 48 are engaged in some form of manufacturing activity.

Wages paid are considerably higher than average wages for the United States as a whole, as is the cost of living. Average wages (excluding construction) adjusted for the cost of living difference in terms of consumer buying power, is only moderately above the figures from California, Oregon and Washington.

Prevailing wage rates in Alaska will be an adverse factor to any industry which requires large amounts of labor, unless offset by other advantages. The small employment base is also an inhibiting factor because of the shortage of specialized skills needed for many new businesses.

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CHAPTER TWO

THE MAJOR SECTORS

This chapter presents summaries of our views on Alaska's principal economic sectors not covered separately. For some sectors, our conclusions on possible AGSOC participation are preliminary and should be studied in depth by AGSOC's management over a period of time. Also, times do change and what is appropriate or desirable today may be altered in a relatively short period of years.

Forest Products

Although a major industry in Alaska, forest products may not be significant to to AGSOC. This is not due so much from a lack of investment potential, but from the effectiveness of private enterprise, and the plans of the village and native corporations. These groups may have preempted the field although some joint ventures could be possible.

Finance, Insurance and Real Estate

The fastest growing major segment of the State's economy seems well served by existing institutions and generally is not capital intensive.

Wholesale and Retail Trade

Traditionally, the second largest employer is the State with growth reflecting population expansion, higher personal incomes and inflation. Potential exists for AGSOC leasing activities, but direct investment is unlikely.

Mining

The mining and processing of minerals has been a declining sector of the Alaskan economy in postwar years since 1946. This is in the face of very substantial mineral resources. Alaska contains large reserves of copper, coal, iron ore, molybdenum,

Change

uranium, nickel, mercury, limestone and others. Overall, these resources provide a broad basis for an expanding minerals activity within the State.

Because of the size of the State, many areas have, as yet, received little detailed attention. However, as new discoveries are unlikely to be fortuitous — unlike most of those made in the past — success with probably call for the outlay of considerable sums, both for prospecting and exploration, as well as for development to the production stage. In the past, out-of-state capital has played an important role in mineral development and there is good reason to suppose that this will be true of the future also. Mining costs in Alaska are higher than those in the lower 48, largely because of the remote location of many deposits, high labor and transportation costs.

Higher world prices for many minerals, particularly in the last 18 months, will probably stimulate renewed exploration in Alaska. A doubling of prices relative to expenses obviously does wonders for anticipated profit margins and return on investment calculations.

We anticipate that AGSOC will find a number of investment or leasing opportunities in the minerals area. Some of the more promising appear to be:

Iron ore reduction or pelletizing plants.

Additional mine-mouth electric generating facilities at Nanana coalfield.

Copper smelting.

Transportation facilities, including coal railroad cars for Beluga coalfield.

Electric generating facilities for a number of reduction or smelting plants currently under consideration.

Tourism

Even with a lack of sufficient accommodations and transportation to many areas, the number of tourists to Alaska is growing at an above average rate. Vistor-related activities already employe an estimated 8,000 people within the State. The State

Division of Tourism estimates that the number of tourists per year will expand at a 13% compounded annual rate over the next ten years. Because of higher costs, tourist expenditures could reach $500 million annually by 1990, compared with $100 million as recently as 1976.

In order to make Alaska more attractive as a tourist destination, infrastructure facilities will need to be expanded. This should include construction of additional tourist accommodations, construction of access roads and further development of recreation facilities in remote areas. In order to reduce seasonality, additional ski areas would seem desirable.

We are unclear as to AGSOC's exact participation within the industry. Investment opportunities will undoubtedly develop and should be analyzed on a case-by-case basis.

Utilities and Communications

In Alaska, this area is far more heavily government owned and operated than in the lower 48. Employment is about 5,000 state-wide and the various activities consume large amounts of capital. We believe AGSOC participation will probably be centered in the leasing of specialized electric generating equipment covered in other chapters, and not as a prime operator of utility or communication systems.

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CHAPTER THREE

TRANS ALASKA PIPELINE SYSTEM

In the last year and a half, there has been much discussion and publicity of an AGSOC purchase of British Petroleum's interest in TAPS. Because of its large size in relation to the Alaskan economy, careful consideration must be given to TAPS as a potential investment opportunity. Various pipeline owners in TAPS have expressed publicly or privately that they would be willing to sell their interests. Although no sales or transfers have been made, some smaller owners have declined to participate in current TAPS expansion programs.

BP's interest in TAPS is valued at $1.2 to $1.5 billion depending on certain assumptions used in the valuation. Most of BP's investment is debt financed, since their current debt level is about $1 billion.

The British Petroleum Company Limited transferred its leases on the North Slope to Standard Oil of Ohio in January of 1970. BP then invested in the Alaska Pipeline because Sohio was under financial pressures and could not handle its full share of the first expansion. Since BP now had substantial ownership of Sohio, BP worked out a partnership basis with Sohio to fund expansion of the pipeline.

BP Company Ltd. established BP Pipelines, Inc. as the vehicle to hold their assets in TAPS. BP Pipelines, Inc. and Sohio Pipelines Company then entered into a partnership for financing of their respective shares in TAPS.

BP Pipelines, Inc. is headquartered in San Francisco and holds the assets of the pipeline as its only operating asset. As a common carrier, the company is subject to FERC regulation. Direct operating expense is over $6 million per year. About one third of direct expense is fuel to run pump stations, another third are costs associated with rate hearings, and over $1 million is insurance on the pipeline assets. The remainder of the operation can operate at a budget of less than $1 million per year.

AGSOC, were it to replace BP Pipelines, would incur the same expenses with adjustments for its level of participation in rate hearings and shareholder record keeping and reporting expense.

BP Financial Projections

1A, 1B, 2A, 2B, 3A+3B

The analysis summarized in Tables ~~1, 2, and 3,~~ show potential projections for BP Pipelines interest in TAPS. (1C, 1D, 2C, 2D, 3C+3D show similar situation for AGSOC ownership) A key assumption used in this analysis is a 1.2 million barrels per day capacity for TAPS. Analysis was made at three tariffs. The FERC set tariff of $4.68 per barrel, the sought tariff at $6.35, and a mid-range tariff at $5.50. Depreciation schedules used for tax and reporting purposes are those schedules used by BP Pipelines in its FERC hearings report. The principal payments and amortizations are shown on the schedule in Table 4. The interest rate used for purposes of this review is the 9.4% interest rate, which is the imbedded interest rate on the total loans outstanding for BP Pipelines. The dismantling, direct expense, and Alyeska expense used are those figures which factor in the 1978 reported figures and 1979 Alyeska's optimistic budget. A tax rate of 50% was applied, ignoring tax loss carry forwards or investment tax credits.

rates set for normal corp. not AGSOC

? table 6 @ 10%

?

The results of this analysis demonstrates that under a low tariff, (i.e., $4.68) net before taxes will be approximately $60 million per year for BP Pipelines. This profit will reduce yearly until a tariff increase or a capacity expansion occurs. Income taxes may take up to half of that $60 million pre-tax figure, especially after use of loss carry forwards and investment tax credits.

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A mid-range tariff of $5.50 produces higher profits, approximately $100 to $120 million, decreasing thereafter.

A $6.35 tariff will produce revenues of over $400 million which are currently the revenues used in the 1978 and 1979 BP Pipeline reports. Net before tax income would be in excess of $150 million and cash flow would be higher, depending upon tax

?

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consequences. However, cash flow declines after 1979 due to the buildup in principal payments. When, and if, FERC sets a lower tariff, the revenues will also decrease with corresponding decreases in cash flow and pre-tax net.

Added ¶ on AGSOC, Tables 1,2,3 - distribution

Table 1A

BP PIPELINES

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	? INCOME TAX	? NET INCOME	? ~~CITIZEN SHAREHOLDERS INCOME~~
		$	$	$	$	$	$	$	~~ACTUAL $~~
1979	64062	4.68	299810	74000	104735	61580	29748	29747	0 59495
1980	64062	4.68	299810	79180	104735	61580	27158	27157	0 54315
1981	64062	4.68	299810	84723	102347	61580	25580	25580	0 51160
1982	64062	4.68	299810	90654	97647	61580	24965	24964	0
1983	64062	4.68	299810	96999	92938	61580	24147	24146	0
1984	64062	4.68	299810	103788	80671	61580	26886	26885	0
1985	64062	4.68	299810	111053	75961	61580	25608	25608	0
1986	64062	4.68	299810	118827	70961	61580	24221	24221	0
1987	64062	4.68	299810	127145	65950	61580	22568	22567	0
1988	64062	4.68	299810	136045	60950	61580	20618	20617	0
1989	64062	4.68	299810	145568	55939	61580	18362	18361	0
1990	64062	4.68	299810	155758	50939	61580	15767	15766	0
1991	64062	4.68	299810	166661	45928	61580	12821	12820	0
1992	64062	4.68	299810	178327	40918	61580	9493	9492	0
1993	64062	4.68	299810	190810	35908	61580	5756	5756	0
1994	64062	4.68	299810	204167	32289	61580	887	887	0
1995	64062	4.68	299810	218458	30080	61580	-5153	-5155	0
1996	64062	4.68	299810	233750	27871	61580	-11695	-11696	0
1997	64062	4.68	299810	250112	25662	61580	-18771	-18773	0
1998	64062	4.68	299810	267620	23453	61580	-26421	-26422	0
1999	64062	4.68	299810	286354	21366	61580	-34744	-34746	0
2000	64062	4.68	299810	306399	20154	61580	-44161	-44162	0
2001	64062	4.68	299810	327847	17616	61580	-53616	-53617	0
2002	64062	4.68	299810	350797	16779	61580	-64672	-64674	0

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200 ~~POPULATION RATE: 000~~ ~~POPULATION: 1~~

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Table 1B

BP PIPELINES

CASH FLOW

($000)

YEAR	REVENUES	90% NET INCOME	? ~~TOTAL SHAREHOLDER DISTRIBUTION~~ 1400	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	? NET CASH FLOW	? CUMULATIVE CASH FLOW	
	$	$	$	$	$	$	$	$	
1979	299810	~~29747~~ 53545.5	0 133.86	61580	7500	0	98827	98827	113575
1980	299810	~~27157~~ 48884	0 122.21	61580	8025	25400	71362	170189	
1981	299810	~~25580~~ 46044	0 115.11	61580	8587	50000	45747	215936	
1982	299810	24964	0	61580	9188	50100	45632	261568	
1983	299810	24146	0	61580	9831	130500	-34943	226625	
1984	299810	26885	0	61580	10519	50100	48884	275509	
1985	299810	25608	0	61580	11255	53200	45243	320752	
1986	299810	24221	0	61580	12043	53300	44544	365296	
1987	299810	22567	0	61580	12886	53200	43833	409129	
1988	299810	20617	0	61580	13788	53300	42685	451814	
1989	299810	18361	0	61580	14753	53200	41494	493308	
1990	299810	15766	0	61580	15786	53300	39832	533140	
1991	299810	12820	0	61580	16891	53300	37991	571131	
1992	299810	9492	0	61580	18073	53300	35845	606976	
>1993	299810	5756	0	61580	19338	38500	48174	655150	
1994	299810	887	0	61580	20692	23500	59659	714809	
1995	299810	-5155	0	61580	22140	23500	55065	769874	
1996	299810	-11696	0	61580	23690	23500	50074	819948	
1997	299810	-18773	0	61580	25348	23500	44655	864603	
1998	299810	-26422	0	61580	27122	22200	40080	904683	
1999	299810	-34746	0	61580	29021	12900	42955	947638	
2000	299810	-44162	0	61580	31052	27000	21470	969108	
2001	299810	-53617	0	61580	33226	8900	32289	1001397	
2002	299810	-64674	0	61580	35552	8900	23558	1024955	

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200 ~~POPULATION RATE: 000~~ ~~POPULATION: 1~~

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

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Table 2A

BP PIPELINES

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX ?	NET INCOME ?	~~[illegible] INCOME~~ ?
		$	$	$	$	$	$	$	$
1979	64062	5.50	352341	74000	104735	61580	56013	56013	0
1980	64062	5.50	352341	79180	104735	61580	53423	53423	0
1981	64062	5.50	352341	84723	102347	61580	51846	51845	0
1982	64062	5.50	352341	90654	97647	61580	51230	51230	0
1983	64062	5.50	352341	96999	92938	61580	50412	50412	0
1984	64062	5.50	352341	103788	80671	61580	53151	53151	0
1985	64062	5.50	352341	111053	75961	61580	51874	51873	0
1986	64062	5.50	352341	118827	70961	61580	50487	50486	0
1987	64062	5.50	352341	127145	65950	61580	48833	48833	0
1988	64062	5.50	352341	136045	60950	61580	46883	46883	0
1989	64062	5.50	352341	145568	55939	61580	44627	44627	0
1990	64062	5.50	352341	155758	50939	61580	42032	42032	0
1991	64062	5.50	352341	166661	45928	61580	39086	39086	0
1992	64062	5.50	352341	178327	40918	61580	35758	35758	0
1993	64062	5.50	352341	190810	35908	61580	32022	32021	0
1994	64062	5.50	352341	204167	32289	61580	27153	27152	0
1995	64062	5.50	352341	218458	30080	61580	21112	21111	0
1996	64062	5.50	352341	233750	27871	61580	14570	14570	0
1997	64062	5.50	352341	250112	25662	61580	7494	7493	0
1998	64062	5.50	352341	267620	23453	61580	-155	-157	0
1999	64062	5.50	352341	286354	21366	61580	-8479	-8480	0
2000	64062	5.50	352341	306399	20154	61580	-17895	-17897	0
2001	64062	5.50	352341	327847	17616	61580	-27350	-27352	0
2002	64062	5.50	352341	350797	16779	61580	-38407	-38408	0

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200 ~~POPULATION RATE: 000~~ ~~POPULATION: 1~~

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Added Tableau AG 80C 1C & 1D

Table 2B

BP PIPELINES

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	? [redacted]	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	? NET CASH FLOW	? CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	352341	56013	0	61580	7500	0	125093	125093
1980	352341	53423	0	61580	8025	25400	97628	222721
1981	352341	51845	0	61580	8587	50000	72012	294733
1982	352341	51230	0	61580	9188	50100	71898	366631
1983	352341	50412	0	61580	9831	130500	-8677	357954
1984	352341	53151	0	61580	10519	50100	75150	433104
1985	352341	51873	0	61580	11255	53200	71508	504612
1986	352341	50486	0	61580	12043	53300	70809	575421
1987	352341	48833	0	61580	12886	53200	70099	645520
1988	352341	46883	0	61580	13788	53300	68951	714471
1989	352341	44627	0	61580	14753	53200	67760	782231
1990	352341	42032	0	61580	15786	53300	66098	848329
1991	352341	39086	0	61580	16891	53300	64257	912586
1992	352341	35758	0	61580	18073	53300	62111	974697
1993	352341	32021	0	61580	19338	38500	74439	1049136
1994	352341	27152	0	61580	20692	23500	85924	1135060
1995	352341	21111	0	61580	22140	23500	81331	1216391
1996	352341	14570	0	61580	23690	23500	76340	1292731
1997	352341	7493	0	61580	25348	23500	70921	1363652
1998	352341	-157	0	61580	27122	22200	66345	1429997
1999	352341	-8480	0	61580	29021	12900	69221	1499218
2000	352341	-17897	0	61580	31052	27000	47735	1546953
2001	352341	-27352	0	61580	33226	8900	58554	1605507
2002	352341	-38408	0	61580	35552	8900	49824	1655331

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200 [redacted]

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Added new Tables on AGSOC 2C + 2D

Table 3A

BP PIPELINES

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX ?	NET INCOME ?
		$	$	$	$	$	$	$
1979	64062	6.35	406794	74000	104735	61580	83240	83239
1980	64062	6.35	406794	79180	104735	61580	80650	80649
1981	64062	6.35	406794	84723	102347	61580	79072	79072
1982	64062	6.35	406794	90654	97647	61580	78457	78456
1983	64062	6.35	406794	96999	92938	61580	77639	77638
1984	64062	6.35	406794	103788	80671	61580	80378	80377
1985	64062	6.35	406794	111053	75961	61580	79100	79100
1986	64062	6.35	406794	118827	70961	61580	77713	77713
1987	64062	6.35	406794	127145	65950	61580	76060	76059
1988	64062	6.35	406794	136045	60950	61580	74110	74109
1989	64062	6.35	406794	145568	55939	61580	71854	71853
1990	64062	6.35	406794	155758	50939	61580	69259	69258
1991	64062	6.35	406794	166661	45928	61580	66313	66312
1992	64062	6.35	406794	178327	40918	61580	62985	62984
1993	64062	6.35	406794	190810	35908	61580	59248	59248
1994	64062	6.35	406794	204167	32289	61580	54379	54379
1995	64062	6.35	406794	218458	30080	61580	48338	48338
1996	64062	6.35	406794	233750	27871	61580	41797	41796
1997	64062	6.35	406794	250112	25662	61580	34720	34720
1998	64062	6.35	406794	267620	23453	61580	27071	27070
1999	64062	6.35	406794	286354	21366	61580	18747	18747
2000	64062	6.35	406794	306399	20154	61580	9331	9330
2001	64062	6.35	406794	327847	17616	61580	-124	-125
2002	64062	6.35	406794	350797	16779	61580	-11180	-11182

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200 [redacted]

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

0

Table 3B

BP PIPELINES

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	? ~~TOTAL~~ ~~[illegible]~~	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	? NET CASH FLOW	? CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	406794	83239	~~0~~	61580	7500	0	152319	152319
1980	406794	80649	~~0~~	61580	8025	25400	124854	277173
1981	406794	79072	~~0~~	61580	8587	50000	99239	376412
1982	406794	78456	~~0~~	61580	9188	50100	99124	475536
1983	406794	77638	~~0~~	61580	9831	130500	18549	494085
1984	406794	80377	~~0~~	61580	10519	50100	102376	596461
1985	406794	79100	~~0~~	61580	11255	53200	98735	695196
1986	406794	77713	~~0~~	61580	12043	53300	98036	793232
1987	406794	76059	~~0~~	61580	12886	53200	97325	890557
1988	406794	74109	~~0~~	61580	13788	53300	96177	986734
1989	406794	71853	~~0~~	61580	14753	53200	94986	1081720
1990	406794	69258	~~0~~	61580	15786	53300	93324	1175044
1991	406794	66312	~~0~~	61580	16891	53300	91483	1266527
1992	406794	62984	~~0~~	61580	18073	53300	89337	1355864
1993	406794	59248	~~0~~	61580	19338	38500	101666	1457530
1994	406794	54379	~~0~~	61580	20692	23500	113151	1570681
1995	406794	48338	~~0~~	61580	22140	23500	108558	1679239
1996	406794	41796	~~0~~	61580	23690	23500	103566	1782805
1997	406794	34720	~~0~~	61580	25348	23500	98148	1880953
1998	406794	27070	~~0~~	61580	27122	22200	93572	1974525
1999	406794	18747	~~0~~	61580	29021	12900	96448	2070973
2000	406794	9330	~~0~~	61580	31052	27000	74962	2145935
2001	406794	-125	~~0~~	61580	33226	8900	85781	2231716
2002	406794	-11182	~~0~~	61580	35552	8900	77050	2308766

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200 ~~POPULATION RATE: 000~~ ~~POPULATION: 1~~

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Add new Table 1 AGSOC 3C + 3D

TABLE 4

TRANS-ALASKA PIPELINE

FINANCE REPAYMENTS

(BP SHARE)

DATE	$m
1979	0
1980	25.4
1981	50.0
1982	50.1
1983	130.5
1984	50.1
1985	53.2
1986	53.3
1987	53.2
1988	53.3
1989	53.2
1990	53.3
1991	53.3
1992	53.3
1993	38.5
1994	23.5
1995	23.5
1996	23.5
1997	23.5
1998	22.2
1999	12.9
2000	27.0
2001	8.9
2002	8.9
2003	8.9
2004	8.9
2005	8.9
2006	8.9
2007	134.0

BP Loan Agreements and Guarantees

BP Pipelines has three classes of loans outstanding, as summarized in Table 5. Each loan would be assumable in a transfer of interest in TAPS. However, BP would not be relieved as a guarantor without approval of a majority or all of the note-holders.

In essence, all of the note agreements use as security notes issued by BP Pipelines, Inc., and in turn those notes are secured by a guarantee or a note issued by BP LTD. Thus the security interest in the notes are not an interest in the pipeline per se, but are backed up by guaranteed notes from the pipelines' company and/or British Petroleum. ~~The TAPS owners are not allowed to assign their interest in relation to the TAPS agreement.~~

Trade for lease tracts

Public Indentures

Under the terms of both public indentures, the company to whom BP Pipelines sells or assigns its interest in TAPS may assume payments of the loans as of the original schedules on the indentures. However, such payments or assumptions would not eliminate British Petroleum, the obligor of the notes, without a comparable guarantor.

Any repayment schedules on these notes prior to normal redemption dates would have to be in the same proportions for both Standard Oil of Ohio and AGSOC. However, BP may be able to prepay their guarantee to the capital company without the capital company having to redeem any notes prior to the normal redemption schedule. If AGSOC or Standard Oil of Ohio wanted to prepay in different proportions, however, there would be a disproportionate amount due under the terms of the note for future debt outstanding. In all likelihood, the 1983 note with the 8-5/8% interest would not be prepaid prior to redemption date unless the AGSOC were to pay cash for the sale.

The 8-5/8% indenture requires a principal payment in 1983 for BP of $80.5 million. In any other year the payment schedule for all notes outstanding have total principal payments of $53 million or less except for the year 1983 and the year 2007.

how would this effect AGSOC cash flow?

Thus, in summary as regards the 1983 Public issue, AGSOC could either pay cash for the system and finance it through debt or assume payments of this indenture with the principal due in 1983.

On a cash sale for TAPS, a section of the Note Agreement states that the net proceeds of the sale (for at least fair value as determined by the Board of BP Pipelines) be applied in an amount in cash equal to the proceeds of such sale, to the retirement of the guaranteed note.

How does all of this relate to its relative significance to the states economy and that of a maximum return to stockholders? also how might AGSOC expect FERC to react to AGSOC's unique tax status in establishing a rate and the impact of such on return to stockholders?

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the impact of such on return to stockholders?

TABLE 5

BP PIPELINE NOTES

Principal Amounts

		Principal $MM
PUBLIC ISSUE	9-3/4% DUE 1999	80.5
PUBLIC ISSUE	8-5/8% DUE 1983	80.5
PRIVATE PLACEMENT	10-5/8% DUE 1993	262.6
PRIVATE PLACEMENT	10-5/8% DUE 1998	300.9
PRIVATE PLACEMENT	9-3/4% DUE 1993	116.8
PRIVATE PLACEMENT	9-3/4% DUE 1998	44.1
VALDEZ BONDS	6 % DUE 2007	112.7
VALDEZ BONDS	6.05 % DUE 2007	101.4
	TOTAL	$1,099.6

Public Issue Debenture Due 1999

Under the terms of this note and the other public issue, in order to separate Sohio and BP in the prepayment schedules and obligations, a 66-2/3% majority of the holders of the notes must have approved such changes. No such changes would extend the maturity or reduce the interest rate. Otherwise, redemptions for Sohio and BP would have to be made in the same proportions and at the same time. The normal redemption schedules on these notes begin in June 1980 and increase by approximately $3 million in 1985, continuing until 1999. The earlier principal amounts are approximately $1 million for the BP share. In the BP Pipelines note purchase agreement on this public issue, BP Pipelines would be able to transfer property under a sale, provided that the successor corporation observe all the terms and covenants of the indenture, or BP may receive as of the previous note the net proceeds of the sale at the fair value of the sale and such proceeds be applied to retirements of the note or held for such.

Since these notes are higher interest (9-3/4%) than the previous notes and have due dates ranging from 1980 to 1999, there may be an advantage for the AGSOC to pay this portion in cash directly to BP, rather than assume the obligations of the note. The benefits would be substantial under the terms when AGSOC could borrow at a lower interest rate and possibly a longer payback period.

The major problem with remaining under the terms of the note would be in the event that Sohio or AGSOC wanted a different repayment schedule than that provided for under the note indenture. Such a modification would require a 66-2/3% majority vote of the bond holders. This may not be an impossible task.

Valdez, Series A Bonds

The Valdez Series A bonds are 6% municipal bonds with a total principal amount of $112.7 million for BP's share. The final due date for these bonds is the year 2007; however, mandatory sinking fund redemptions commence on July 1, 1998 up through 2006 of approximately $5 million per year. The remainder will be due in the year 2007.

These bonds are based on a lease and sublease basis and are revenue bonds. Leases are from the Lessor BP Pipelines, Inc. to the City of Valdez and a sublease in return from the City of Valdez to BP Pipelines, Inc. Under the terms of the sublease agreement, the Lessor or BP Pipelines may sell its assets providing that the receiving corporation is an Alaskan corporation and unconditionally assumes the due and punctual performance of the obligations under the lease and sublease agreement. At that point the Lessor will have no further obligations under the lease. The subrents under the lease back to BP Pipelines is 32.2% of principal premium or interest on the total revenue bonds and related expenses.

The BP guarantee on the Valdez bonds is an unconditional guarantee for full payment of 32.2% of the principal and premium and interest when due. However, there is no cross guarantee from BP on any default on the Sohio guarantee. Contrary to other bonds and notes, it does not appear that BP has to redeem in the same proportion in prepayments as Sohio in terms of their respective 68/32% ratio. Thus if BP were to prepay or redeem at a quicker rate, they would, in effect, receive credit for their share of the prepayments and not be required to cross pay any of Sohio's notes when due. It also appears that a sale of the assets of the pipeline does not release British Petroleum under the guarantee agreement.

Under the redemption or prepayment clauses, the redemption price has a penalty of 3% in 1987 and 1988 going down to 1/2 of 1% in 1993.

Redemption is at principal amount after 1993. Any proposed change in the guarantee agreement as it would affect the elimination of BP or Sohio would require the consent of 100% of the bond holders.

Valdez Series B Bonds

The Valdez Series B bonds are 6.05% revenue bonds due the year 2007 and are again governed by a lease/sublease agreement between the City of Valdez and BP Pipelines and the guarantee agreement by British Petroleum Company Limited. The terms are similar to the Series A bonds with no cross guarantee by Sohio or BP for the other share, and prepayments again treated separately and credited to each subleesee's account. If BP Pipelines were to sell its interest in TAPS assets, then BP Pipelines, Inc. would be relieved from obligations under the lease/sublease agreements. However, the BP guarantee, as in the Series A, bonds is not affected by any sale or disposition of assets. Thus BP would always remain as the guarantor. The mandatory sinking fund redemptions of the Series B bonds begin in 1998 and ends in 2006, at an amount approximately $4 million per year. Prepayment penalties start with a 3% penalty in 1987/1988, going down to 1/2 of 1% in 1992, and at principal amount after 1993. The balance would be due in the year 2007. The amount of these bonds for BP Pipelines is $101.4 million.

Private Placement Issue

The first private placement issues were 10-5/8% notes due January 1993 and 1998 for a total BP share of $563.5 million. Mandatory repayments are 1.96% quarterly or approximately 8% yearly of the 1993 notes and 1.41% quarterly or slightly over 5-1/2% annually for the 1998 notes. These repayments begin in 1980. Beginning in 1987, BP and Sohio, if they jointly agree to do so, may double the above percentages. Otherwise, there is a prepayment premium beginning in 1987 ranging from 3-1/2%, reducing annually to zero in 1992 for the 1993 notes, and 3-1/2% reducing annually to zero in 1995 for the 1998 notes.

Under the agreement, BP Pipelines may sell its assets to AGSOC providing that AGSOC assumes all of the BP Pipelines' obligations. However, no sale can be made if the book value of BP Pipelines' share in TAPS becomes less than $855 million or the through-put capacity becomes less than 142,560 barrels per day. This restriction is equivalent to a through-put capacity of less than 900,000 barrels per day for the total TAPS system.

Any sale must be for cash and must conform to the TAPS amended agreements. The notes at the 10-5/8% interest rate are $262,591,000 for the 1993 notes and $300,909,000 for the 1998 notes. The prepayments, therefore, on the 1993 notes are approximately $17 million per year. The option of doubling these prepayments only upon agreement with Sohio would, in effect, double those above values.

An alternative to the sale for cash is a sale for or to a corporation whose only assets are the interest in TAPS.

That corporation would be bound by the terms and conditions of the private placement note agreement. BP's guarantee is unconditional and would not be affected by sale to AGSOC. According to the note agreement, BP will not permit any sale of stock in BP Pipelines except to BP or a wholly-owned subsidiary of BP.

The guarantees are not cross guarantees and BP is not responsible for Sohio's debt under the terms of these agreements.

The terms and agreements of the 9-3/4% notes are similar to the 10-5/8% notes. The 1993 notes carry a prepayment schedule of approximately $9 million per year. The total of these notes is $116,886,000. For the 1998 notes (principal amount $44,114,000), the prepayments would amount to approximately $2-1/2 million per year. The option to double these prepayments would require the consent of Sohio to double theirs in an equal and proportionate share. Other than those changes, the note agreements are similar to the 10-5/8% interest notes.

AGSOC Investment in TAPS

? The major issues at stake in the projections of AGSOC interest in TAPS are the rate hearings at FERC and valuating and financing of ownership. One of the major risks in buying part of TAPS is the actual tariff to be set by FERC. A low tariff would make operations marginally profitable.

why not shown in Tables 1, 2+3

The expected methodology for setting the tariff is to set a valuation for the

Make Change

pipeline and thereby for each owner's share, and to apply a rate of return on that valuation. The tariff calculation would entail adding the rate of return in dollars to the operating costs to arrive at revenue needed. A tariff is then set. The first phase hearings will set a valuation formula, which in all likelihood will be the actual cost of the pipeline. There may be some other factors entering into the cost values, such as interest used during construction. There probably will not be an allowance for return on equity during construction. The actual percentage rate of return can range from 9 to 20%.

One of the assumptions in the financial analysis used in this report is that the tariff does not decrease in the future at constant capacity. This will most likely be the case, since operating expenses will increase with inflationary pressures probably at least at a rate of 7% per year. Although the value of the pipeline may be reduced due to depreciation, the result of a ~~decreased~~ decrease in valuation should not be as large as the increase in inflationary pressures on the operating expenses of the system. Thus, the tariff need not be reduced through a constant formula imposed by FERC. As capacity expands, a lower tariff may produce the same rate of return. However, there may be requirements for an increase in the tariff if through-put drops in the future.

One of the major issues at the FERC hearings is whether or not the actual cost on the books for constructing TAPS is, and should be, included in the valuation of the pipeline. The factor for not including all historic costs would be mismanagement during construction. Phase II of the hearings will address this issue, and might possibly result in a reduction in valuation due to the unwarranted increase in costs.

Although current rates are in effect at the operator's requested levels, there is the possibility that carriers would have to refund revenues if permanent rates are set by FERC at a level lower than the current rates.

The most critical inputs to the financial projections for AGSOC are valuation of purchase price, tariff rate, and interest rate. Other inputs such as inflation rate, operating expenses, Alyeska or indirect, have a much smaller effect on the overall viability of an AGSOC investment.

The most critical factor in the feasibility of a TAPS investment is the tariff rate selected by the FERC hearings. A 2% change in tariff rate would cause at least a 10% change in dividends to shareholders and a 50% change in available cash flow at the end of a 20-year period.

At this stage AGSOC would have little effect in influencing the tariff to be selected by FERC at the hearings.

There are two possibilities in this regard. One is to become an interested party in the current hearings since (a) AGSOC is identified as a possible investor in TAPS, and (b) AGSOC's tax structure as it regards federal income taxes would be significantly different than the other TAPS owners. An initial reading from FERC would eliminate the uncertainty. The second possibility would be for a full hearing on the valuation of the purchase price between AGSOC and BP to be held after the tariff rate has been decided by the FERC hearings. An estimate on when a tariff might be approved is mid 1980.

The second most critical variable in financial projections for AGSOC is the purchase price of an interest in the pipeline. A 2% reduction in purchase price would amount to a greater than 5% change in dividends to shareholders and approximately a quarter point ~~20%~~ difference in cash flow at the end of a 20-year period. For comparison purposes, a very easy to get 3% change if recapitalized fully 3% change in the interest rate would result in a change in the shareholder dividends and net cash flow approximately equal to a 2% change in purchase price. For example, a $20 million change in the purchase price would have approximately the same effect as a 1/4 of 1% change in the interest rate on the debt for a 100% debt-financed purchase. Contrary to the influence AGSOC may have on a finally set tariff rate, AGSOC will have a great deal to say on the purchase price and a significant amount of influence on the interest rate for new debt.

? return to stockholders

Other variables which affect the financial projections are a decrease in Alyeska operating expenses. A 1% decrease in expense would produce approximately a 1% change in shareholder dividends and a slightly higher change in cash flow. The real problems with the expense side of the picture is that inflation would seriously affect operating expenses in a 10-to 20-year period, and tariffs or revenues wouldn't increase as rapidly as operating costs in a heavy inflationary period. A change in the form of principal payments and/or depreciation schedules again has some affect on the overall financial projections for AGSOC, but these effects have not proved to be significant in relation to other variables.

?

A summary of financial project ions for AGSOC are shown in Table 6. The financial estimates for AGSOC have the following assumptions built into the income and cash flow projections: i) Under a 1.6 billion barrel per day capacity, delivery would be 85,429,000 barrels per year. ii) The operating expenses for AGSOC would be a sum of the Alyeska expenses at a 15.84% rate for the BP share, and direct expenses which were estimated to be equal to the estimated expense currently projected for BP Pipelines. (Note that the direct expenses for AGSOC staffing may be less than the staff expenses of BP Pipelines in terms of management and operations of AGSOC. However, the major expense which will impact AGSOC which is not incurred by BP Pipelines would be the administrative cost in shareholder reporting. Rough estimates of that cost would be approximately $2.00 per shareholder on an annual basis, with extra cost for setting up the program and probably a more extensive annual reporting procedure. Thus the direct costs of AGSOC would be approximately equal to the present direct costs of BP Pipelines, assuming the TAPS investment is carrying all of the AGSOC's operating expenses.)

Interest is applied to year end balance after that year's principal payments have been deducted. The principal payments are assumed to be deducted at the end of the year. The depreciation and amortization would be on a straight line basis or an

for how long

S.L. for 20 yrs

accelerated basis, depending on the circumstances of the schedule. Income tax is assumed to be zero, presuming that AGSOC elects to be non-taxed and distributes 90% or more of income to the shareholders. ? max. return to stockholders

Added ¶ re: cash flow and dividend years and alternatives for continued distributions etc.

TABLE 6

BP rate is 9.4% / page 9

? ? ? what years total accumulated Taxable negative

$ Tariff	Pipeline Capacity MM b/d	AGSOC Purchase Price ($000)	Imbedded Interest Rate	First Year Citizen Distribution Pre-Tax	Number of Years Income Stream	($000) Cash Balance 24 Years
4.68	1.6	1,600,000	10%	155	14 yrs	-111,088
5.00	1.6	1,600,000	10%	216	16	158,504
5.00	1.6	1,500,000	10%	238	17	346,226
5.25	1.6	1,450,000	10%	335	21	612,585
5.50	1.6	1,600,000	10%	334	21	668,317
5.50	1.6	1,500,000	10%	366	22	699,443
5.50	1.6	1,600,000	7%	441	22	733,717
6.35	1.6	1,600,000	10%	496	24	898,341

The citizens income is based upon a 90% distribution. This dividend would be prior to the income tax withholding. Note that a figure above $133 would result in a net check to the shareholder for over $100, after a 25% tax withholding rate. The principal payments would be deducted from the cash flow, leaving a yearly net cash flow and a cumulative cash flow for a 24 year period. Added strategies for AGSOC re: negative cash flow

? what is this with the neg. Balance

Under an expanded capacity system, additional investment would be required in TAPS. Estimates in 1977 dollars indicate an investment of over $650 million to increase capacity to 1.6 million b/d and over a billion to go to 2 million b/d. Thus, in 1980 dollars, the investment for a 15.84% share may range between $100 to $150 million, increasing with any delays. Our assumptions under this capacity show beginning full year flow in 1982. The AGSOC purchase price in Table 6 reflects the additional investment to increase capacity.

Under a $4.68 tariff for the 1.6 million barrel per day capacity, a 15 year income stream with an individual shareholder distribution of about $150 would occur with a $1.6 billion valuation and a 10% imbedded interest cost (see Table 6). However, at such a capacity, cash flow would cause serious problems if, in fact, capacity were to drop after the first 10 or 15 years. At a $5.00 tariff, and a value of 1.5 billion to 1.6 billion, shareholder distribution would range from $200 to $300, depending upon the interest rate. At this tariff, a 15 year income stream with steady volume flow in the pipeline would keep a positive cash flow throughout the 25-year period. However, if the flow were to drop below 1.6 billion barrels, there would be problems after a 10- or 15-year period.

At a $6.35 tariff under the expanded capacity line, AGSOC could distribute between $400 and $500 for each shareholder for a number of years.

Current flow capacity has been raised to about 1.4 million barrels per day and shall approach 1.5 million barrels per day by the end of 1980. Most of the higher flow capacity has been achieved through use of a special chemical additive, without construction of new pump stations, although new pump stations are being completed.

To date, only Arco, Exxon, and BP are participating in the capital expansions, and BP's share should increase to a 16.8% ownership of TAPS by the end of 1980.

We have previously discussed the possible AGSOC investments in the British Petroleum share of TAPS. However, there are alternative investment opportunities in TAPS through acquisition of pipeline interests of other companies. Prior to the 1979 and 1980 expansion programs, Mobil held a 5% interest in TAPS, and Union and Phillips each held a 1.66% interest (or about one-tenth the size of the BP interest). Since Mobil, Union, and Phillips have so far declined to participate in TAPS expansion, their respective shares have dropped to about 4.3% for Mobil, and 1.4% for Union and Phillips.

If AGSOC were to purchase a 1.5% interest in TAPS at an assumed price of $125 million, the pro-forma would be as follows under current tariffs:

(000)

Net Income	$17,900	
Depreciation & Reserves	7,000	
Principal Payments	(2,000)	
Net Cash Flow	22,900	
Stockholder Distribution	16,100	@ 90%/400,000 shareholders = $32.23 dividend/yr
Cash Surplus	$ 6,900	

Such a pro-forma is for the first few years and will change considerably as principal payments increase or as oil flow changes. With initial cash reserves, AGSOC can invest in other TAPS interests. As oil reserves change, or as pipeline expansion continues, AGSOC can participate in expansion not committed by other owners.

CHAPTER FOUR

ALASKAN GAS PIPELINE

Although there is much discussion about state and federal financing in the Alaskan gas pipeline, an opportunity may exist for AGSOC ownership in the Alaskan section of the proposed gas pipeline. Although current partnership agreements are in existence for ownership of the Alaska Highway gas pipeline, no definitive financing arrangements are set. Thus, flexibility in ownership and financing allows for new concepts in private and public investment in the line.

The Alaska Highway Gas Pipeline venture is still somewhat speculative. Risks arise from the marginal economics in the market for gas which must carry high transportation costs and uncertainities of cost overruns, engineering or regulatory problems, or interruption of gas production. Although there is much discussion in public and private circles about these problems, they are, in essence, not unlike the risks in construction and operation of TAPS.

Because of the high transportation costs of gas through the pipeline to Eastern or Western leg markets, Alaskan gas prices may be double the existing gas prices of present production in those markets. Transportation costs of 2 to 3 dollars per mcf are within current estimates of pipeline system costs. Transportation costs alone are therefore equal to current gas prices in the markets to be served. Once wellhead prices are added, total costs far exceed current prices.

Although analysis of costs appears to be a negative factor in the gas pipeline project, these same concerns faced TAPS in its initial history. Many factors will come into play to drive the end price of gas to levels which can eventually support the Alaskan Highway Pipeline costs. Rapidly escalating oil prices -- spurred even more by the so-called windfall profits tax -- will create more demand for natural gas at higher price

9

levels. Furthermore, a gradual decrease in U.S. dependence on foreign oil imports will create more internal demand for natural gas as a substitute for oil in long-term energy planning. Thus, even though there appears to be a glut in gas supplies, and a cost difference between Alaskan gas energy and other currently available sources, these conditions are essentially temporary and should not be a deterrent to consideration of investments in the gas pipeline project.

Although the overall cost for the gas pipeline is around $14 billion, the 730 mile Alaskan section will cost about $2 billion in today's dollars. With a debt-to-equity ratio of 75%/25%, and an overall rate of return of 16% based on current debt costs, a pro-forma operating statement of the Alaskan pipeline would be as follows: in P form

16% Return on Rate Base (Excluding Interest)	$320,000,000	@ 16% w/2 Billion investment
Depreciation	125,000,000	
Debt Service 75% debt	(191,000,000)	180 million interest 11 " principal 191
Taxes - AGSOC	-0-	
Net Cash Flow	254,000,000	126 million = 90% of income
Potential Net Profit - Available For Dividends	321 - interest $140,000,000	
? Net Retained Cash Flow After Distribution (Assume 90% Stockholder Distribution)	@ 90% = 126,000,000 /400,000 = $315. / shareholder ~~128,000,000~~	= 10% + depreciation

(Thus, with an AGSOC investment of $500 million of equity money, the net available retained cash flow would be over $100 million per year in early years, and over $100 million could be distributed to the stockholders.) ~~If AGSOC and the Permanent Fund were in a joint venture to raise the $500 million equity, the Permanent Fund may be reimbursed over a five- to ten-year period and still have an equity interest in the operations.~~

?

what about 10 share limit does it not apply to Perm. Fund?

Added P on gas conditioning plant, indicated as possible investment

CHAPTER FIVE

TRANSPORTATION

Overview and Conclusion

The unique importance of public (common carrier) passenger and cargo transportation to the State of Alaska and its citizens provides substantive philosophical rationale for AGSOC to consider transportation investments. Our review at this stage is more conceptual than specific, even though we cite some individual companies as examples and for background informational purposes. We are categorically excluding public sector transportation activities such as Alaska's land and marine highways and general cargo port facilities.

Transportation investments can be accomplished in at least two ways -- acquisition of an operating entity and by leasing long life major capital assets (railroad locomotives and rolling stock, commercial aircraft, ocean barges, freighters, bulk carriers, etc.) to existing transportation companies serving the state. Since equipment leasing is discussed in another chapter, this section will concentrate on opportunities for direct investment in operating companies.

Certain transportation sectors are highly fractured. In Alaska this circumstance is found in intrastate trucking and air taxi services. These type companies tend to be small, have high failure rates, and erratic operating records. For these reasons, we do not generally view intrastate motor carriers and local service airlines as appealing investment candidates.

By definition, transportation is cyclical, leveraged, labor and capital intensive, and regulated. Accordingly, unusual discipline must be exercised in the traditional investment criteria of quality and depth of management, financial strength, operating records, competitive position, return on invested capital, etc. We also generally favor existing businesses with documented histories and prospects rather than start-up situations, unless these new ventures can achieve near immediate profitability as in the case of a new mine-to-port railroad or slurry pipeline.

Based on our initial survey, the number of Alaskan oriented sufficiently large transportation investments are quite limited in number. Further, their capital intensive, cyclical nature makes transport companies inherently more risky than some of the other target industries that AGSOC is considering.

The AGSOC, when created, may want to direct its initial investment selection process in other areas unless appropriate transportation investments can be identified.

Air Transportation

Scheduled air and cargo passenger carriers within Alaska and between Alaska and the lower 48 are Alaska Airlines, Wien Air Alaska, Northwest, Western Airlines and Flying Tiger Line (cargo only). Alaska and Wien are truly indigenous to the state in their history, service orientation and route structure, and their recent operating records are the most indicative barometers of the growth of Alaskan air services.

Alaska Airlines

Alaska is the larger of the two companies. Its Boeing 727 airplanes serve about 40 points in Alaska, and Seattle, Portland and San Francisco. The company's common stock is traded on the American and Pacific Coast Stock Exchanges.

Alaska Airlines
Operating Highlights
(000's)

Year	Revenues: Passenger	Revenues: Cargo and Mail	Revenues: Total	Operating Income	Net Income
1978	$72,392	$7,241	$84,246	$8,671	$7,231
1977	63,537	6,679	76,518	8,064	3,414
1976	57,359	5,729	69,475	7,448	7,631
1975	52,274	6,482	66,620	6,428	6,111

Source: Moody's Transportation Manual

Wien Air Alaska

Wien has an approximate 11,000 mile route structure serving 150 points within Alaska, Whitehorse, Yukon Territory and Seattle with Boeing 737 and Fairchild turbo-prop aircraft. Following a recent tender offer and treasury stock purchase, about 55% of its common stock is owned by a subsidiary of Household Finance Corp. and 25% by Alaska Northwest Properties, Inc., a spin-off from Alaska Airlines. In November, Alaska Northwest Properties was reportedly holding discussions with Alaska native corporations about buying its interest.

Wien Air Alaska
Operating Highlights
(000's)

Year	Revenues: Passenger	Revenues: Cargo	Revenues: Mail	Revenues: Total	Operating Income	Net Income
1978	$34,134	$12,505	$10,770	$62,495	$3,538	$ 482
1977	29,900	10,641	10,469	55,769	195	(742)
1976	37,593	13,462	9,549	62,708	6,092	2,421
1975	31,336	12,835	8,828	55,991	7,191	3,676

Source: Moody's Transportation Manual

Maritime

The principal general cargo common carrier ocean transportation between Alaska and the lower 48 (Seattle-Tacoma) is provided by Sea-Land, Alaska Hydro-Train, and Totem Ocean Trailer Express (TOTE). Sea-Land and TOTE provide at least bi-weekly sailings between Seattle and Anchorage in medium size cellular container and RO-RO vessels, respectively. Alaska Hydro-Train is a rail car barge service operating between Seattle and Whittier.

There are additional specialized and contract maritime operators between the lower 48 and Alaska, although their number has diminished since the completion of TAPS. The Merchant Marine Act of 1920 (Jones Act) requires that maritime trade between U.S. states be conducted in U.S. built vessels. There is, of course, a great cargo imbalance northbound since only two of Alaska's major export commodities — lumber and fish products — can be carried in liner type services.

There is no ocean passenger service per se to Alaska other than the state ferry system, although the Inside Passage and panhandle ports have become very popular summer destinations for cruise ships. (The investment in and development of Alaskan tourist facilities by the AGSOC is discussed elsewhere in this report.) Most, if not all, of the Alaska cruise ships are foreign owned, built and manned, providing them with a prohibitive economic advantage over a U.S. operation.

In the maritime sector, Kelso & Co. believes that TOTE may warrant further investigation as an AGSOC investment candidate. TOTE, which began service in September, 1975, is a subsidiary of Sun Shipbuilding (Sun Company) and leases its two RO-RO ships from Sun. The original sponsors of TOTE tried unsuccessfully to raise start-up financing in the private capital market during the difficult period of the 1974-75 recession. While TOTE's financial performance reportedly has been marginal, the company has steadily gained market share and now carries over 55% (vis-a-vis Sea-Land) of the Seattle-Anchorage ocean borne general cargo.*

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* Because of the participants' ownership structure and the Federal Maritime Commission's non-disclosure policy, Kelso has been unable to expeditiously obtain cargo statistics and financial data on the Alaska-Seattle marine trade route and operators.

Motor Carrier

Without having conducted a specific survey and analysis, we have earlier stated our philosophical aversion to investments in small intrastate truckers even though Alaska's transport infrastructure may be deficient in motor carriage services.

On the other hand, there is an Alaska-lower 48 trucker — Lynden Transport, Inc. — which has a strong market position, solid operating history and sound balance sheet could be a prime AGSOC investment candidate. Kelso & Co. has not had any discussions on this subject with Lynden management and principal stockholders, although Lynden has in recent years been buying into its treasury a sizeable portion of its publicly held shares.

Lynden is a common carrier of freight between Washington state and Alaska by highway and water (TOTE), a milk hauler in Washington, Idaho, Oregon and Alaska, a motor freight operator in western and northwestern Canada, an Alaskan intrastate special and general commodities carrier, and an air freight forwarder to and from Alaska. The company is the largest highway carrier within Alaska and between Alaska and the Pacific Northwest. A subsidiary conducts construction, gravel, and coal operations.

Lynden's 1978 revenue profile was (000's):

U.S. Transportation	$28,107
Canadian Transportation	2,745
Construction, etc.	1,538
Total Revenues	$32,390

Change

Lynden Transport, Inc.
Operating Highlights
(000's)

	Revenues						
Year	Freight	Mail	Milk	Constr-uction	Total	Operating Income	Net Income
1978	$23,880	$4,385	$2,587	$1,538	$32,390	$1,741	$ 648
1977	17,569	4,362	2,302	853	25,086	1,003	419
1976	20,552	4,087	1,978	863	27,481	1,722	1,131
1975	21,384	3,421	1,831	---	26,636	3,646	1,540
1974	11,647	3,010	1,783	---	16,441	1,813	888

Source: 1978 Annual Report to Shareholders and 10-K; Moody's Transportation Manual.

Railroad

Alaska is served by two railroads — the Alaska Railroad (ARR) and the White Pass & Yukon (WP & YR).

We dismiss the WP & YR as an AGSOC investment because it serves only one Alaska city (Skagway), is Canadian owned, and essentially provides a transshipping mode for the Yukon territory's booming mining industries. Neither is WP & YR a logical equipment leasing candidate since it is a narrow gauge line.

From a political and public interest standpoint the federally-owned Alaska Railroad would be a most reasonable AGSOC investment candiate. Kelso & Co. has reviewed the railroad's operating and financial record and the plethora of consultant and government studies that have been prepared on the ARR in recent years. We have concluded that the Alaska Railroad is intrinsically unprofitable under its present route structure, commodity mix and labor agreements, particularly since it does not now have to bear the financial burden of debt service and income taxes. The railroad was quite profitable during TAPS construction and would probably earn money during the gas pipeline construction. However, unusual or abnormal events are heavily discounted in the fundamental investment decision making processes.

Alaska Railroad
Operating Highlights
(000's)

Period	Rev. Tons	Ton* Miles	Total Revenues	Total Expenses	Gain (Loss) After Depreciation
11 Mos. to 8/31/79	N/A	N/A	$22,875	$28,933	($6,058)
Sept. FY 1978	2,178	330.0	29,091	33,625	(4,534)
Sept. FY 1977	2,305	404.0	35,022	35,982	(960)
TQ 1976	N/A	N/A	10,051	11,164	(1,113)
June FY 1976	2,188	529.9	53,678	49,597	4,081
June FY 1975	1,862	475.9	42,287	37,079	5,807

* In millions
N/A -- Not Available
TQ — Transitional Quarter
Source: Alaska Railroad Financial Statements

Beyond the railroad's desultory financial record and outlook, there are several other structural and political problems that are collectively very dissuasive:

a) The prevelant perception of the railroad as a "public utility." This problem has become manifest in at least two areas — the requirement of the railroad to provide passenger service at a loss and the difficulty in implementing fair market value rental rates on the ARR's commercial and industrial properties.

b) The non-commercial orientation of management as cited in the 1978 GAO report.

c) The difficulties of segregating under private ownership data processing, purchasing and other management functions now handled through U.S. government agencies.

d) The requirement for large capital outlays on the railroad property and for equipment in the event of a sharp traffic pickup. Between 1975 and 1978, $37 million was expended for much needed roadbed, bridge and tunnel improvements, and purchase of new locomotives and rolling stock which program has upgraded the ARR to an "excellent...light density single track railroad."*

e) The dispute over certain railroad property ownership rites between the railroad and Federal-State Land Use Planning Commission.

There are long range plans for extending the railroad to the lower 48 via British Columbia. If Alaska's extensive mineral deposits of copper and steam coal are eventually developed, new rail lines may be constructed to serve these mines. The financing requirements for such railroads will be considerable and the AGSOC would be a vehicle for providing some of this imbedded capital on a basis that could be fully compensatory to the trust.

In conclusion, Kelso & Co. believes that direct AGSOC investment in Alaska's existing railroads is not desirable, but long-term (finance) leases of equipment could be considered.

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*Railway Age, April 9, 1979, p. 29. Underlining by Kelso.

CHAPTER SIX

FISHERIES

Fishery products represent a major industry for Alaska. In addition to the value of the commercial catch, fish processing represents about half of the state's manufacturing employment. A series of recent studies indicate that the best opportunity for expansion of the Alaskan fishing industry lies in bottomfishing.

Although Alaska's waters are highly productive, Alaska's bottomfish industry is not fully utilized, especially by domestic fishing interests. The extension of U.S. territorial waters to 200 miles will give Alaska fisherman better access to the supply which in the past have been taken by foreign trawlers. An opportunity exists for a major expansion of the Alaska fishing industry with significant economic benefits. It is estimated that full development of Alaska fisheries can add almost 30,000 in employment and impact trade balances of one billion dollars by 1990.

One of the impediments to expansion is the lack of access to private capital for vessels and processing facilities. Programs are now available for government-guaranteed loans for vessel construction or conversion, and tax deferred programs are available for harvesting and processing vessels. However, the major inhibition to development of fisheries is the absence of associated processing facilities.

AGSOC, through its favorable tax treatment, would provide a current effective tax deferral program for a processing plant. Coupled with a processing plant, the AGSOC could provide cold storage facilities and service facilities for fishing fleets. These areas are capital intensive components of establishing fisheries, yet are areas in which direct government involvement is not recommended. In addition, since the capital requirements are much higher than those for vessel purchase (except for catcher processors or floating processor plants), private development of these plants and service facilities is slow

Many indirect benefits will fall from an AGSOC program in Fisheries. The project will receive wide publicity and promote public sector attention to developing the infrastructure necessary to fisheries, especially in harbor facilities. Additionally, such publicized entrance in fishing could stimulate private and independent fishing vessel construction and conversion to bottomfishing.

A recent publication of the U.S. Department of Commerce indicates investments for Alaskan groundfish development by 1990 as follows:

Harvesting Vessels	$ 185,000,000
Processing Facilities	$1,990,000,000
Public Facilities	$ 527,000,000

AGSOC participation in the vessels could be through leasing operations as discussed further. However, there appears to be some private development efforts for catcher-processors in Alaska by Energy Resources Company of America (ERCA), and through government guaranteed financing, capital investment may not be too restricted.

Major investments are required for the processing facilities. Except for the catcher-processors, United States efforts in major off-shore processing ships are unsuccessful and undeveloped. Thus, in the near term, the fishing industry must develop through shore-based processing plants.

New plant investments would range from $3,000,000 to $4,000,000 for processing facilities in Ketchikan, Sitka, Seward, and Homer, $15,000,000 for Kodiak, and $40,000,000 for Dutch Harbor. Return on investments based on normal operations and 1979 level of prices would range from 3% to 20% per year with varying assumptions.

An example of processing plant economics is shown in Table 7.

TABLE 7

AGSOC Processing Plant - Small Size

	? ~~(000)~~
Revenue	
(11,000,000 lbs @ $.90/lb average all species)	$9,900,000
Cost of Fish 11,261,904.76 lbs waste	
22,261,904. lb (@ $.21/lb average all species) X 22,261,904. lb =	4,675,000
Shipping Costs	1,225,000
Labor	1,270,000
Sales, G & A	1,200,000
Maintenance and Utilities	330,000
Depreciation	250,000
Interest (100% financed at 11% interest) for fixed assets	385,000
Land and Dock Lease	50,000
Total	$9,385,000
Income Before Taxes	$ 515,000

The projections in Table 7 assume that AGSOC has 100% financing for all fixed assets in the plant. In addition, it assumes that AGSOC leases land, dock, and access roads from a government entity on fair market value lease rates. It also assumes that AGSOC maintains and operates interim storage units, but not shipping containers. Furthermore, the processing plant site shares facilities with vessel refueling and servicing operations at the dock. Those operations are to be run independently.

Based on a continuous level of operation for five years, AGSOC would have a retained cash flow of $100,000 per year or $500,000. It would have retired about 1/3 of its debt and have a net long-term debt of $2,250,000. If net earnings before tax were to increase at a rate of 10% per year (based on a semi-successful fishery development) the AGSOC processing plant would have a fair market value of over $3,500,000 and AGSOC could sell the facility to a private party and have a net cash profit of over $1,500,000.

An alternative to an AGSOC operating division running the processing plant would be to lease the plant to an existing fish processing business or to have a management company run the plant. The net result would be an eventual sale of the plant to the operator after a five- or ten-year period. For AGSOC to make a fair return, sale should be set at fair market value or pre-set on an option basis, assuming a reasonable profit growth and a price/earnings ratio.

Vessels

The development of Alaskan fisheries requires major investments by the private sector in harvesting and processing vessels for bottomfish. Investments range from approximately $1,000,000 for an 85-foot trawler to about $12,000,000 for a 250-foot catcher-processor. On the other hand, conversion of existing shrimpers or crabbers for bottomfish can range from $50,000 to $500,000.

Recent financing programs, such as the Fishing Vessel Obligation Guarantee program administered by the National Oceanic and Atmospheric Administration (NOAA), provide a loan guarantee of up to 87-1/2% of vessel construction or reconstruction. In addition, the Capital Construction Fund allows deferral of federal taxation of vessel income when that income is used for investments in new vessels.

Although efforts are underway on the part of some Alaskan businesses to promote harvesting under these programs, other fishing interests and independent fishermen find it difficult to gain access to this capital. It is at this point where an AGSOC leasing operation has a role.

For example, an 85-foot vessel with a capital cost of $1,000,000 can earn over

$100,000 in income and maintain $150,000 per year in payments for the vessel. Based on a 10% annual interest rate and a 15-year amortized loan, the AGSOC would have an annual payment of $129,000 and could net over $20,000 per vessel per year on a leasing program. Additionally, as vessels become more expensive and fisheries develop profitable operations, lease revenues may increase and substantial residual values on vessels would contribute to AGSOC capital accumulation.

Since some estimates of new fishing vessel requirements in Alaska over the next 10 years approximate 200, or a value of almost $200,000,000, an AGSOC leasing operation has a large market potential. If AGSOC were to lease 25% of the requirements over the next 10 years, its net lease revenue would reach a maximum of $1,000,000 per year profit excluding a buildup of residual value worth.

CHAPTER SEVEN

LEASING

Leveraged leasing could offer some favorable tax advantages for AGSOC. Additionally, an AGSOC leasing program could stimulate many segments of the Alaskan economy which are currently restricted by lack of capital.

Although leasing is an alternative source of financing capital equipment, it offers advantages to both sides of the relationship. Both have some tax advantages, and although the leasing company assumes more risk, the lessee grants compensation for its diminished risk in higher rental payments.

There are many variables in the structure of a lease so that a single financial model would not cover all cases. However, for illustrative purposes, the following example shows the advantages to AGSOC:

> Suppose a company were to lease a $1,000,000 piece of equipment through AGSOC. If this equipment had a 20-year life, possible lease payments (under today's high interest rates) might be as high as $175,000 per year or higher if a short-term lease were executed. On the other hand, AGSOC's principal and interest payment could be under $150,000 per year. Thus AGSOC could achieve a cash flow spread of at least 2-1/2% of the equipment value per year, and under certain conditions this could be as much as 5%. However, the significant tax factors which would benefit AGSOC and its stockholders would be the investment tax credit and depreciation. In the first year of the investment, 10% of the value of the equipment could be claimed as a tax credit. Under the Federal legislation, Subchapter U to the Internal Revenue Code, this would be passed through directly to AGSOC's shareholders. The distribution of profits could be controlled by the

? do these benefits not also apply to all other potential AGSOC investments, if so why wasn't it stated elsewhere?

depreciation schedule used so that up to the full value of the positive cash flow could be retained by AGSOC without tax penalty. This reserve could be used to offset future cash requirements or for new investment.

A major attractiveness of leasing for AGSOC is that it could borrow nearly 100% of the purchase price of certain investments. Our recent discussions with major banks, indicate that the banks would loan to AGSOC at favorable rates, assuming a reasonable AGSOC capitalization. Additionally, for large investments, most institutions will provide necessary expertise in structuring the lease and managing the asset through the lease term.

If AGSOC were to operate a leasing company serving different industries with different products, the company would need marketing support and other administrative, legal, and clerical services. The level of the support required would approach 5% of the total revenues received by the company.

A sample pro-forma of a leveraged leasing company with $100,000,000 of equipment on lease is as follows:

Revenues	$24,000,000	
Operating Expenses explain	1,200,000	
Interest Expense @what %	11,000,000	
Depreciation @what rate	8,333,000	
Total	$20,533,000	@90% = 3,120,300.–
Net Profit	$ 3,467,000	/ by 400,000 = $7.80 dividend

The above pro-forma would be applicable to the first few years of operation. After that time, interest expense may decline considerably, or alternatively, more equipment can be placed on lease because of cash flow buildups from depreciation. Thus, income can increase with interest expense decreasing producing larger profit margins. The risk associated with this business would fall in the residual value or marketability of the

Option Sale re-lease

equipment leased as the lease term expires or if the lessee defaults.

Leasing is a competitive business. Initially, we investigated AGSOC leasing aircraft to Alaska Air Lines, for example. However, Alaska Air Lines has multiple proposals for such leases and at much more favorable rates than could be offered by AGSOC. The reasons for strong competition, especially in aircraft, are the favorable tax advantages (increasing for those in higher than 50% tax brackets) and high resale residual values for aircraft after the initial lease terms. Many lessors will therefore sacrifice short-term cash flow for current tax benefits and long-term profits. The best opportunities for AGSOC would seem to be areas of leasing where lease competition is not so high, e.g., for leasing to start-up business ventures, and in other situations where financing sources are difficult to obtain.

Potentially, leasing may be applicable to many sections of the Alaskan economy. Some of the more promising are summarized below.

Motel and Hotel

Over time there should be opportunities in sale and leasebacks of motel/hotel sites and structures. This industry offers more favorable opportunities for AGSOC leasing since there are more favorable tax credits available in motel/hotel leasing than for other forms of commercial real estate.

Fishing

Currently, there are investment opportunities in Alaska for both processing vessels and on-shore processing plants. The vessels offer good opportunities since interim financing during construction would not be as big a handicap as construction of new plants. Leasing of fishing vessels, or sale and leaseback of converted fishing vessels, also offer opportunities in the fishing industry.

Hard Rock Minerals

There will be potential for leasing mining equipment as mining develops within the State.

Oil and Gas

In gas pipeline construction, leasing opportunities will exist in rolling stock used during construction. There also are opportunities for leasing drilling rigs or LNG storage tanks. The high value of storage tanks is attractive for an AGSOC investment.

Petrochemicals Gas Conditioning Plant?

The development of a petrochemical industry using Alaskan resources has stimulated much interest in parts of Alaska. Construction financing is not an attractive leasing opportunity, but certain installed equipment may offer possibilities.

Agriculture

Agricultural equipment offers some lease opportunities although AGSOC might not want to compete in the financing for the leasing of relatively low value equipment.

Electric Power not expanded upon because of time & money

Potential for the leasing of prefabricated plants exists in Alaska. Major users of electric power or new hydroelectric plants may have financing difficulties. AGSOC may be able to lease a full plant to potential operators.

Alaska Railroad

The railroad is covered in the Chapter on Transportation. There is a potential lease opportunity in freight cars, locomotives and other equipment. As in the airline industry, rail car leasing is competitive with many participants.

CHAPTER EIGHT

SOURCES AND COSTS OF CAPITAL FUNDS

SOURCES OF CAPITAL

Problems of raising capital and rationing it among competing investment projects are common to all business corporations. The long-run profitability of the enterprise hinges on the solution of these two problems. Knowledge of sources and costs of capital is needed for both.

Good management of corporate capital views as quite separate these two problems: (1) sourcing (acquisition) of capital funds and (2) rationing (investment) of that capital. Rationing capital among investment proposals should be on merit, independent of source or cost of funds for that particular project. Investable funds of AGSOC should be treated as a common pool, not as separate compartments. Similarly, the problem of acquiring capital should be solved independently of its rationing and also on the basis of merit (the comparative costs and risks of alternative patterns of sourcing).

The first part of this chapter surveys, for decision-making purposes, the various sources of capital for AGSOC; the second part examines ways of estimating the cost of capital obtained from major sources.

The supply of capital for corporate investment comes ultimately from the savings of individuals, corporations, and governments. As to immediate sources, a corporation normally has two choices: use its own savings (internal) or tap the savings of others (external).

Internal Sources

The main internal source of corporate savings is the generation of cash from operations. Corporate savings is the act of not paying out all profits in dividends. Stockholders benefit from saving and internal investment of the corporation's after-tax cash generation when the rate of return on the investment is higher than the corporation's cost of capital. This is approximately the opportunity cost of capital to its stockholders, because the corporation usually has the option of buying its own stock.

Gross cash earnings generated by operations constitute a common pool of future funds from which dividends will be paid and new investments financed. This pool should have corporate-wide availability for capital expenditures. When each division is restricted to the reinvestment of its depreciation charges regardless of the productivity of its investment proposals, the separability of sourcing and rationing of capital funds is abrogated, and one of the major advantages of the diversified firm is destroyed.

When AGSOC elects to take advantage of the special provisions of Subchapter U, the corporation itself will be exempt from all federal income taxes but must distribute 90% of its earnings to shareholders. Thus, except for the remaining 10%, the use of retained earnings as a source of funds will not be available to AGSOC.

External Sources - Debt Capital

As external sources there are two ways for AGSOC to get savings from outsiders: borrow (debt capital) or partner (equity capital). Debt capital can be arbitrarily classified as either short-term or long-term.

Short-Term Debt

Short-term debt of AGSOC can be of two sorts. The first is inadvertent borrowing which is a cultural by-product of normal operations. Mostly it is caused by lags between the time a service is performed and the time it is customary to pay for it. The second sort of short-term borrowing is quite deliberate. The main source for most companies is the commerical bank. A line of credit is usually established, which sets a maximum amount of borrowing which the company may draw down as its needs dictate.

Long-Term Debt

Drawing the dividing line arbitrarily at one year, we classify intermediate-term debt capital as long-term. The term loan is a typical instrument. Its source may be a commercial bank, an insurance company, or a trust fund. Term loans result from direct negotiations between borrower and lender. Thus, they are privately placed as contrasted with public sale through the money market.

For longest term borrowing, the usual loan contract is a bond. It may be placed privately by direct sale to a large financial institution or sold to the public, usually through an investment banker.

Long-term debt can be subclassified in three ways:

(1) Nature of security (mortgage versus debenture bonds).

(2) Directness of the obligation (direct debt versus off-balance sheet financing).

(3) Degree of participation (pure debt versus contingency debt).

These three bases of classification overlap.

Nature of Security

Borrowings may be secured by pledging specific assets (mortgage bonds) or secured only by the corporation's general credit (debenture bonds). The basic security for the debt of any corporation is, however, its uncommitted cash generating ability. A bank does not want to run a coal mine. Sale of a pledged asset is only a resort of desperation. The relevant economic measure of the debt-carrying ability of a corporation is not the balance sheet, but the future generation of cash from operations, which can be derived from forecasted income statements.

Directness of Debt

In addition to direct debt, a corporation can borrow indirectly by a variety of devices such as long-term leases, sale-and-lease-backs, oil payments and royalty arrangements, and through-put agreements. Regardless of legal status or accounting treatment, these forms of indirect obligation are the economic equivalent of direct debt. They are contractual obligations to make periodic payments for the use of capital and to repay principal under specified conditions. These forms of off-balance-sheet borrowing have attractions. They can be (1) tailored precisely to the borrower's needs as to amount and timing, (2) negotiated privately, and (3) left off the balance sheet. The price of these conveniences is usually a slightly higher interest cost.

Participation

Some debt has partnership features (for example, convertibles and income bonds). Convertible bonds are a cross between debt and equity financing. The bond holder has an option to convert his debt claim into shares of common stock at a predetermined price, which is equivalent to a long-term call on equity. The requirement in the Federal Enabling Law limiting the transfer of common stock to individuals who own no more than ten shares of stock probably will prohibit the effective use of convertible debt by AGSOC. (Revenue Act of 1978, Section 1391(a)(4)(D)(iii).) It is theoretically possible to design a convertible bond indenture that would require immediate sale of the stock received upon conversion back to AGSOC at fair market value.

Quasi-equity features are less clear, but nevertheless are present in most indirect debt (for example, lease-backs and oil royalties). Most lease-backs and oil-payment and oil-royalty arrangements give the lender options and residual values that have some attributes of equity.

Joint bonds are obligations issued jointly by two or more corporations, and are their joint and several obligations. Thus, the Louisville & Nashville and the Southern Railway collateral trust bonds were secured by the stock of the "Monon" Railroad, owned in equal parts by the two guarantors. These two roads were each liable for one-half of the principal and interest, and fulfillment of all other obligations imposed by the indenture under which the bonds were issued. Should either company have defaulted on any of its obligations under the indenture, the deposited stock belonging to the defaulting company was to become the property of the other company, which thenceforth was liable in severalty upon all the covenants contained in the bonds.

Joint bonds have been issued also by states and municipalities. The bonds of the Authority of the Port of New York are in effect a joint obligation of the states of New York and New Jersey. Joint bonds offer the potential of cooperative ventures by AGSOC, the Permanent Fund, Native Corporations and others.

External Sources - Equity Capital

Equity capital raised externally is of two types: (1) preferred stock, which is a kind of preferential, but limited partnership, and (2) common stock, which is full partnership.

Preferred Stock

Dividends of preferred stock come ahead of common, but are limited in amount. They are, however, not a contractual obligation and hence are not deductible as an expense for corporate income tax. Since the Federal Enabling Law limits General Stock Ownership Corporations to one class of stock, AGSOC cannot have preferred stock in its capitalization (Section 1391(a)(4)(A)).

Common Stock

Common stock is the economic equivalent of full partnership in the earnings and assets of the corporation. Dividends are discretionary, (although a Subchapter "U" GSOC has a strong incentive to pay out 90% of earnings) and common stockholders get only the residual left after other payments.

THE COST OF CAPITAL

All resources command a price for their use. Capital is no exception. Management's task is to blend the various capital sources available to achieve the lowest long-run cost for the Company's total requirements. This overall combined cost is the weighted average of the market cost of the major kinds of corporate capital: debt, preferred stock, and common equity. Capital from internal and indirect hard-to-measure sources should be assigned the cost of its alternative direct source. The alternative for lease debt is direct borrowing for an equivalent term. The alternative for internal cash generation, whether labeled "earnings plowback" or "depreciation," is flotation of common stock.

The Cost of AGSOC Debt Capital

That debt capital as a cost is undebatable. The use of money borrowed from outsiders has a price. This price is established by market forces and is knowable with considerable precision. This price the company must pay.

The price of debt capital fluctuates with changes in supply and demand. At any time, the price differs depending on (1) the credit-worthiness of the borrower, (2) the duration and other terms of the loan, (3) the type of lending institution, and (4) the section of the country. The debt-cost range is wide, from 36% for trade credit if cash discounts are passed, down to prime rate and below. The underlying causes of this wide disparity in the price of debt money are differences in risks and in costs of administration and collection. These two forces sometimes are opposed. For a short-term loan, the risk is less but the costs of launching and administration are proportionately higher. Other features affect the cost structure of debt capital; for example, privacy has a price. Off-balance-sheet borrowing commands higher prices in the marketplace, and corporate private placements cost somewhat more than equivalent public debt.

Market imperfections distort the structure. Ignorance has a price. The astute borrower will try to borrow at the lowest rung of the debt-cost ladder that his credit worthiness will permit. The competent lender will seek as comfortable a cushion of compensation for his risk differential as knowledge will warrant and competition permit. Because of the newness of the federal legislation (1978), AGSOC will be in somewhat unique position as a new borrower. Alaskan banks will be generally familiar with the situation and able to handle short-term AGSOC debt requirements. There are approximately 100 U.S. commerical banks with a legal lending limit over $10,000,000. Because of geography or other considerations, we have identified 25 of these banks for possible consideration in term loan borrowings. With a reasonable capital structure, AGSOC should be essentially a prime rate customer for the commercial banks.

what 25

In addition, there are 107 foreign banks with offices in the United States, largely in the Eastern portion of the country. However, 9 foreign banks have offices in San Francisco and 6 in Los Angeles. Many of these banks provide services and loan terms other than those offered by U.S. commercial banks and should be considered a potential source of funds.

The true cost of debt capital is often higher than its nominal cost. The disparity is produced by many devices. Discounting (deducting interest in advance) increases true interest rate, as does the requirement of minimum balances, because they pare down the amount really available to the lender. Charges for investigation, servicing, and insurance can also raise the effective cost of debt.

The historical outlay cost of debt capital is easy to measure. It is indicated by the market yield to maturity on the company's debt securities, adjusted for costs of flotation and deflated for corporate income taxes. AGSOC might expect to pay an average of 14% in present money markets for a balanced package of short-term debt, term loans and long-term (15 year) insurance company private placements. The private placement area is dominated by 50 large insurance companies. Except for the very largest insurance companies, the average participation by these companies in a private placement financing is from $3,000,000 to $10,000,000 each.

The Cost of Equity Capital

In a market economy, any resource which is scarce, relative to the demand for it, commands a price — however difficult it may be to measure that price. This is true even though reimbursement for the suppliers of equity capital is a residual; that is, what is left after more tangible costs of operations, including interest on debt, are satisfied. In the long run, equity capital is not a discretionary cost. The fact that the rewards are residual does not, as some think, mean that common stock capital is costless. In the long run, equity capital has a market price which is determined by investors' alternatives. Although owners of equity capital assume the ultimate risk by accepting as their compensation what is left, they have in most companies the option of selling at some price. They will not reinvest or long leave their capital in any corporation which does not offer reasonable prospects of returns as high as those promised by alternative investments.

Looking into the future, the AGSOC investments made today must be capable of earning enough in the future to cover all costs, including the costs of equity capital, as well as providing for recovery of the capital invested during the economic life of the project. Only thus can AGSOC maintain its financial integrity over the long term. For this reason, the policy of investment selection should establish investment standards which are based on the price it may pay for capital — the combined cost of equity and debt capital — to assure that no investment will be taken on today which will knowingly be incapable of earning the cost of capital in the future.

CHAPTER NINE

INVESTMENT POLICY

Corporate Intent

Investment policy is a subject closely related to the AGSOC Board of Directors. The primary function of the Board is to set policy. It may be up to the AGSOC senior investment officer to initiate policy and recommend changes in policy. The final decision, however, is the responsibility of the Board of Directors. There are three types of policy decisions that are basic: (1) determining the philosophy of investment, (2) estimating basic industry and economic trends and determining the best way to take advantage of them, and (3) dove-tailing corporate needs and future plans with investment philosophy.

* return to stockholder basic to all 3

On the philosophy of investment, it is up to the Board to decide in no uncertain terms whether it wishes staff to pursue a conservative, long-term investment program with emphasis on stability and income, or whether it wishes to place primary emphasis on total income (current income plus appreciation), rapid turnover, venture equity, and opportunistic types of investment.

The second type of policy, an estimate of industry and economic outlooks, provides opportunity for the staff to practice their utmost persuasion, but nevertheless it still should be the function of the Board to have the final word with clearly stated guidelines. Finally, the corporate needs of AGSOC must be injected into the equation. Of immediate consideration is the cash flow, dividend policy, and the nature of reserve adjustments. Of longer term consideration are corporate plans for the future.

?

Availability of Investment Funds

Except for very large projects which will require separate financing, normal investment policy will be heavily influenced by the AGSOC capital structure. The chapter on Sources and Cost of Capital Funds indicated a ready availability of debt funds to AGSOC presuming a satisfactory equity base. The experience of British Columbia Resources Investment Corporation suggests that considerable success might be possible in the sale of additional participation from the public. (See Appendix A.)

Below is one potential scenario out of many possibilities for development of the AGSOC equity base.*

A. Distribution of One Initial Common Share

400,000 eligible residents, 348,000 elect to participate shares distributed (assumption is same 87% as achieved by British Columbia Resources).

B. Sale of Convertible Debenture to Residents

17,400 Alaskans purchase nine $100 principal amount, 8% Convertible Debentures. Each $100 debenture is convertible into one share of AGSOC common stock, thus keeping within the 10-share maximum as provided under Federal GSOC legislation. Proceeds to AGSOC would be $15,600,000. (Assumption is that 5% of the 348,000 Alaskans receiving initial shares will purchase the full offered allocation of debentures.) For comparison purposes, 6.5% of the British Columbians that received five free shares purchased at least 100 or more additional shares for proceeds of $487,500,000. An additional 2.0% purchased less than 100 additional shares.

? or a fraction of one share

fractional purchases allows future purchases up to 10 full shares

* The sample scenario is in technical conflict, but probably not in legislative intent conflict with the Federal Enabling Law which limits ownership to individuals. It could be argued that the Permanent Fund represents a group of individuals or the law could be changed.

C. Purchase by Permanent Fund

Permanent Fund purchases 200,000 common shares at $100 per share and 200,000 of the same 8% Convertible Debentures sold to individual Alaskans. Combined proceeds to AGSOC would be $40,000,000.

After the above steps, an AGSOC pro-forma balance sheet is shown.

Assets		Liabilities and Stockholders' Equity	
Current Assets		Current Liabilities	-0-
Cash and Temporary Investments	$55,600,000	Long-Term Debt	
		Convertible 8% Subordinated Debentures	$35,600,000
Investment and Other Assets	-0-	Stockholders' Equity	
		Common Stock, issued 548,000 shares*	$20,000,000
Total Assets	$55,600,000	Total Liabilities and Stockholders' Equity	$55,600,000

Under the above scenario, the 8% Convertible Subordinated Debentures would be junior to all other debt, providing AGSOC considerable borrowing capacity. Presuming a combination of additional debt totaling $44,400,000 at an average interest rate of 14%, AGSOC would have available funds for investment of some $100 million. A 20% return on invested funds before taxes (approximately the average in recent years from Textron, Inc., a comparable company in many ways) would produce the following pro forma income

Ha Ha. and who will be Alaskan G. Wm. Miller

*356,600 shares of additional common stock reserved for conversion of the 8% Convertible Debentures.

statement.

0 = 1 billion Dollar investment

Profit Before Interest and Taxes*	$20,000,000
Less Interest Charges	9,064,000
Profit Before Taxes*	$10,936,000
Dividends at 90%	9,842,400
To Retained Earnings at 10%	1,093,600
Dividends Per Common Share (548,000 Shares Outstanding)	$17.96

Since income would be larger in this situation from dividends ($17.96 versus $8.00 in interest), residents would tend to convert the convertible debentures into shares of common stock. Based on full conversion of the debentures, the income statement would appear as follows:

Profit Before Interest and Taxes*	$20,000,000
Less Interest Charges	6,216,000
Profit Before Taxes*	$13,784,000
Dividends at 90%	12,405,600
To Retained Earnings at 10%	1,378,400
Dividends Per Common Share (904,000 Shares Outstanding)	$13.72

This scenario represents a relatively small scale GSOC with assets of about 10% of the total of the Native Corporations. The $100 million figure was selected to allow easy multiplication to higher levels of size.

*No taxes due if Subchapter U GSOC.

CHAPTER TEN

CONCLUSION

Alaska has expanded significantly in recent years. It is a State of youth and vitality, and full of opportunity for the enterprising. The pace of development anticipated in Alaska is such that the need for capital is great, and openings exist for new enterprises. Technological development also continues to create additional opportunities for investment. As a result of our work, we see no difficulty in finding adequate investment opportunities even for a large size AGSOC over a period of time. Except for transfers of ownership situations such as TAPS, nearly all of the anticipated investment opportunities should meet a number of Alaska's principal economic goals. Presumably, AGSOC, owned and managed within Alaska, will be sensitive to the needs of employment, economic diversification, reduction of seasonality and other State goals.

Interviews with insurance companies, banks, and others demonstrate considerable interest in participation in AGSOC debt financing. In the beginning each potential source of funds will carefully analyze the AGSOC capitalization, management and business plan prior to making firm commitments. Such analysis will importantly impact the terms, cost and conditions imposed by the lender. Such factors will significantly influence the investment performance of AGSOC.

Added FP explaining summary table & statement of impact of management

? Risk of Failure in table does

(+) = ~~high probability of failure~~ ~~or does~~

(-)

(+) good results; I guess is not failure
or
(-) negative; I guess is low probability of failure

APPENDIX A

A CASE STUDY: BRITISH COLUMBIA RESOURCES INVESTMENT CORPORATION

British Columbia Resources Investment Corporation was initially conceived to be a vehicle to return to the private sector certain investments which were owned by the Province of British Columbia under their socialistic regime. The Government wanted to avoid the conflicts which can arise where it had regulatory authority over the forest products industry, for example, and yet had a direct holding in some pulp, lumber and plywood companies. In addition, the Government felt the process could provide a mechanism to raise some badly needed equity capital and would at the same time enable its citizens, who were watching their savings being eroded by inflation, to participate directly and individually in resource ownership.

BCRIC was patterned after the Canada Development Corporation and the Alberta Energy Company. After enacting legislation, the Government appointed five prominent British Columbians to be the founding incorporators of the company and its initial directors. They had one common and very significant characteristic; they are all chief executive offices of their own highly successful B.C. headquartered public company, and their companies do not compete with any BCRIC investments.

The company then acquired their initial investments from the Province for a promissory note of $151,000,000. The selection of investments (only from the Province's holdings) and the valuation of these investments was through a process audit by the Canadian investment firms of McCloud Young, A. E. Ames, Pemberton, and Richardson. BCRIC selected only good companies from the many Province holdings.

In order to give the ownership to the people, the Government agreed to exchange the $151,000,000 promissory note in full settlement for 15,000,000 common shares. Of those 15,000,000 shares, they offered to give 12,000,000 away, or five each, to each of the eligible residents. At the same time as applications were to be received for free shares, BCRIC would accept subscriptions for further shares at $6.00 each, to be issued from the treasury, to a maximum of 5,000 shares for eligible person. Book value before dilution was over $10.00 per share. Bearer shares were to be used in order to save the corporation the expense of registering potentially 2.4 million shareholders. In order to have registered shares and be a voting shareholder, one had to purchase a minimum of 95 shares, to be added to the five free ones in order to qualify. Bearer shares could be traded just as registered shares, and the stock exchanges agreed to reduce the trading block to five shares. In order to cut down on shareholder costs, only registered owners received mailed notices. Annual and interim shareholder reports for bearer shares are distributed by delivery of 250 copies to each branch of a financial institution to be placed on counters for pickup. Shareholder service costs are estimated at $1.50 per year for registered holders.

The distribution was an awesome and expensive undertaking. Because it involved a potential distribution to 2.4 million people, it required the utilization of all the financial institutions in the Province. Without the full participation of those institutions, involving some 1,300 individual locations, the job could not have been accomplished. Each branch of these institutions agreed to accept applications upon presentation of two forms of identification. The computer operations of BCRIC then sorted to avoid duplications.

The distribution and the sale resulted in 83% of the eligible population, or 2,000,000 people, applying for their free shares and 130,000 individuals applying to buy 100 or more shares, yielding gross proceeds of $487,500,000. Incidentally, another 40,000 people purchased extra shares, but not in sufficient number to be qualified for registration. In total, BCRIC has now 96,500,000 issued shares; the total cost of distributing <u>all</u> shares was $15,000,000 or approximately 3% of proceeds to the company.

The response surprised everybody involved in the process. There were a number of factors that produced such astounding results. First, the Canadian stock market was buoyant and a lot of people were interested in the market generally, with gas and oil interest particularly strong. (The inclusion of the gas and oil leases in BCRIC assets added appeal.) Second, people in British Columbia have pride in their Province, and they responded very positively to the concept of a totally B.C. operated and directed company in the resource field. Third, was the Premier's own personal support of the issue. Fourth, the Board of Directors had great provincial credibility. Fifth, the general momentum that the issue developed as people read about it, talked about it, and listened to the advice of professionals as well as their friends and neighbors. They felt it was attractively priced. And finally, of course, there was an element of straight speculation by people anticipating a fast, profitable turn.

Between late June and August 7th, when trading was to commence, there was deliberation on the question of the appropriateness of the company declaring its intention to provide assistance in the maintenance of an orderly market, should it be required. The issue was not underwritten. However, the Board had the courage of their conviction in the principles of a free market, and elected not to provide support. While that decision did take courage, it was also reinforced by the belief that the large majority of the original purchasers were long-term investors and not short-term speculators. Now that shares are traded on the Vancouver and Toronto Exchange, anybody across Canada can buy shares. (There is no holding period for the free or purchased shares.) In 1979, some 24,000,000 shares were traded (about 20% of the total).

BCRIC has been successful in keeping its image as a private company rather than a quasi-public body. It states its responsibilities only to shareholders and not to the Province. It has freedom to invest in companies outside of the Province.

Selection of new investments will be concentrated in the area of natural resources. BCRIC feels no restraint on its investment objectives through other companies, the government, or any social responsibility other than such responsibility any private company may hold. BCRIC intends to be an operating company rather than just a holding company. Its initial and current holdings are:

> 81% of Canadian Cellulose, a public company and a major pulp and lumber producer in the Province.
>
> 100% of two medium-sized lumber producers, Kootenay Forest Products and Plateau Mills, the former also a producer of sheathing plywood.
>
> 10% of the shares of Westcoast Transmission, a natural gas pipeline company controlled by Pacific Gas & Electric Company.
>
> A license to explore for gas and oil on some 2.3 million acres of public land in northeastern British Columbia.

BCRIC has a present equity capitalization of over $600,000,000 through the offer and the initial holdings. In addition, it can borrow to put its total asset holdings over a billion. It currently generates about $30,000,000 in earnings on a sales volume of $300,000,000 through its present holdings. Its interest earnings on the cash proceeds of the issue are yielding over $1,000,000 a week or over 11%; however, in order to stimulate growth, their policy is not to distribute dividends for three to five years.

BCRIC feels that one of the benefits of wide citizen ownership is that employees of its companies see themselves as working for themselves and other citizens as owners rather than unknown shareholders or the government. BCRIC feels that many labor problems will be averted through this concept.

APPENDIX B

FEDERAL ENABLING LAW

REVENUE ACT OF 1978 [1]

(H.R. 13511)

ENACTING TITLE VI, INTERNAL REVENUE CODE OF 1954, AS AMENDED

GENERAL STOCK OWNERSHIP CORPORATIONS

NOTE: Numbers in parenthesis above the text refer to the explanatory annotations immediately following the text of the legislation.

Sec. 601. ESTABLISHMENT AND TAXATION OF GENERAL STOCK OWNERSHIP CORPORATIONS AND THEIR SHAREHOLDERS.

(a) IN GENERAL - Chapter 1 [2] (relating to normal taxes and surtaxes) is amended by adding at the end thereof the following new subchapter:

"Subchapter U [3] - General Stock Ownership Corporations

"Sec. 1391. Definitions.
"Sec. 1392. Election by general stock ownership corporation.
"Sec. 1393. Corporation taxable income taxed to shareholders.
"Sec. 1394. Rules applicable to distributions of electing general stock ownership corporations.
"Sec. 1395. Adjustments to basis of stock of shareholders.
"Sec. 1396. Minimum distribution.
"Sec. 1397. Special rules applicable to earnings and profits of an electing general stock ownership plan.

"Sec. 1391. DEFINITIONS.

"(a) GENERAL STOCK OWNERSHIP CORPORATION. - For purposes of this subchapter, the term 'general stock ownership corporation' (hereinafter referred to as a 'GSOC') means a domestic [4] corporation which -

"(1) is not a member of an affiliated group (as defined in section 1504), [5] and

"(2) is chartered and organized after December 31, 1978, and before January 1, 1984;[6]

"(3) is chartered by an act of a State legislature[7] or as a result of a State-wide referendum;

"(4) has a charter providing -

"(A) for the issuance of only 1 class of stock,

"(B) for the issuance of shares only to eligible individuals[8] (as defined in subsection (c));

"(C) for the issuance of at least one share to each eligible individual,[9] unless each eligible individual elects within one year after the date of issuance not to receive such share;

"(D) that no share of stock shall be transferable -

"(i) by a shareholder other than by will or the laws of descent and distribution until after the expiration of 5 years from the date such stock is issued by the GSOC except where the shareholder ceases to be a resident of the State;[10]

"(ii) to any person other than a resident individual of the chartering State;[11]

"(iii) to any individual who, after the transfer, would own more than 10 shares of the GSOC;[12]

"(E) that such corporation shall qualify as a GSOC under the Internal Revenue Code;[13]

"(5) is empowered to invest in properties (but not in properties acquired by it or for its benefit through the right of eminent domain.[14]

For purposes of this subsection, section 1504

(a) shall be applied by substituting '20 percent' for '80 percent' wherever it appears.

"(b) ELECTING GSOC. - For purposes of this subchapter, the term 'electing GSOC' means a GSOC which files an election under section 1392 which, under section 1392, is in effect for such taxable year.[15]

"(c) ELIGIBLE INDIVIDUALS. - For purposes of subsection (a), the term 'eligible individual' means an individual who is, as of a date specified in the State's enabling legislation for the GSOC, a resident of the chartering State and who remains a resident of such State between that date and the date of issuance.[16]

"(d) TREATED AS PRIVATE CORPORATION. - For purposes of this title, a GSOC shall be treated as a private corporation and not as a governmental unit.[17]

"(e) STUDY OF GENERAL STOCK OWNERSHIP CORPORATIONS. - The staff of the Joint Committee on Taxation shall prepare a report on the operation and effects of this subchapter relating to GSOC's. An interim report shall be filed within two years after the first GSOC is formed and a final report shall be filed by September 30, 1983.

"Sec. 1392. ELECTION BY GSOC.

"(a) ELIGIBILITY. - Except as provided in section 1393, any GSOC may elect, in accordance with the provisions of this section, not to be subject to the taxes imposed by this chapter.[18]

"(b) EFFECT. - If a GSOC makes an election under subsection (a) then -

"(1) with respect to the taxable years of the GSOC for which such election is in effect, such corporation shall not be subject to the taxes imposed by this chapter and, with respect to such taxable years and all succeding taxable years, the provisions of section 1396 shall apply to such GSOC,[19] and

"(2) with respect to each such taxable year, the provisions of section 1393, 1394, and 1395 shall apply to the shareholders of such GSOC.[20]

"(c) WHERE AND HOW MADE. - An election under subsection (a) may be made by a GSOC at such time and in such manner as the Secretary shall prescribe by regulations.

"(d) YEARS FOR WHICH EFFECTIVE. - An election under subsection (a) shall be effective for the taxable year of the GSOC for which it is made and for all succeeding taxable years of the GSOC, unless it is terminated under subsection (f).

"(e) TAXABLE YEAR. - The taxable year of a GSOC shall end on October 31 unless the Secretary consents to a different taxable year.".[21]

"(f) TERMINATION. - The election of a GSOC under subsection (a) shall terminate for any taxable year during which it ceases to be a GSOC and for all succeeding taxable years.[22] The election of a GSOC under subsection (a) may be terminated at any other time with the consent of the Secretary, effective for the first taxable year with respect to which the Secretary consents and for all succeeding taxable years.[23]

"Sec. 1393. TAXABLE INCOME TAXED TO SHAREHOLDERS.

"(a) GENERAL RULE. - The taxable income of an electing GSOC for any taxable year shall be included in the gross income of the shareholders of such GSOC in the manner and to the extent set forth in this subsection.[24]

"(1) AMOUNT INCLUDED IN GROSS INCOME. - Each shareholder of an electing GSOC on any day of a taxable year of such GSOC shall include in his gross income for the taxable year with or within which the taxable year of the GSOC ends the amount he would have received if, on each day of such taxable year, there had been distributed pro rata to its shareholders by such GSOC an amount equal to the taxable income of the GSOC for its taxable year divided by the number of days in the GSOC's taxable year.[25]

"(2) TAXABLE INCOME DEFINED. - For purposes of this section, the term 'taxable income' of a GSOC shall be determined without regard to the deductions allowed by part VIII of subchapter B (other than deductions allowed by section 248, relating to organizational expenditures).[26]

"(b) SPECIAL RULE FOR INVESTMENT CREDIT.[27] - The investment credit of an electing GSOC for any taxable year shall be allowed as a credit to the shareholders of such corporation in the manner and to the extent set forth in this subsection.

"(1) CREDIT. - There shall be apportioned among the shareholders a credit equal to the amount each shareholder would have received if, on each day of such taxable year, there had been distributed pro rata to the shareholders the electing GSOC's net investment credit divided by the number of days in the GSOC's taxable year.

"(2) NET INVESTMENT CREDIT. - For purposes of this paragraph the term 'net investment credit' means the investment credit of the electing GSOC for its taxable year less any tax from recomputing a prior year's investment credit in accordance with section 47.

"(3) RECAPTURE. - There shall be apportioned among the shareholders of a GSOC, in the manner described in paragraph (1), an additional tax equal to the excess of any tax resulting from recomputing a prior year's investment credit in accordance with section 47 over the investment credit of the GSOC for it's taxable year.

"Sec. 1394. RULES APPLICABLE TO DISTRIBUTIONS OF AN ELECTING GSOC'S[28]

"(a) SHAREHOLDER INCOME ACCOUNT. - An electing GSOC shall establish and maintain a shareholder income account[29] which account shall be -

"(1) increased at the close of the GSOC's taxable year by an amount equal to the GSOC's taxable income for such year,[30] and

"(2) Decreased, but not below zero, on the first day of the GSOC's taxable year by the amount of any GSOC distribution to the shareholders of such GSOC made or treated as made during the prior taxable year.[31]

"(b) TAXATION OF DISTRIBUTION. - Distributions by an electing GSOC shall be treated as -

"(1) a distribution of previously taxed income to the extent such distribution does not exceed the balance of the shareholder income account as of the close of the taxable year of the GSOC,[32] and

"(2) a distribution to which section 301(a) applies but only to the extent such distribution exceeds the balance of the shareholder income account as of the close of the taxable year of the GSOC.[33]

"(c) DISTRIBUTIONS NOT TREATED AS A DIVIDEND. - Any amounts includible in the gross income of any individual by reason of ownership of stock in a GSOC shall not be considered as a dividend for purposes of section 116.[34]

"(d) REGULATIONS. - The Secretary shall have authority to prescribe by regulation, rules for treatment of distribution in respect of shares of stock of the GSOC that have been transferred during the taxable year."[35]

"Sec. 1395. ADJUSTMENT TO BASIS OF STOCK OF SHAREHOLDERS.[36]

"The basis of a shareholder's stock in an electing GSOC shall be increased by the amount includible in the gross income of such shareholder under section 1393, but only to the extent to which such amount is actually included in the gross income of such shareholder.

"Sec. 1396. MINIMUM DISTRIBUTIONS.

"(a) GENERAL RULE. - A GSOC shall distribute at least 90 percent of its taxable income for any taxable year by January 31 following the close of such taxable year.[37] Any distribution made on or before

January 31 shall be treated as made as of the close of the preceding taxable year.

"(b) IMPOSITION OF TAX IN CASE OF FAILURE TO MAKE MINIMUM DISTRIBUTION.(38) - If a GSOC fails to make the minimum distribution requirements described in subsection (a), there is hereby imposed on the GSOC a tax equal to 20 percent of the excess of the amount required to be distributed over the amount actually distributed.

"Sec. 1397. SPECIAL RULES APPLICABLE TO AN ELECTING GSOC.(39)

"(a) GENERAL RULE. - The current earnings and profits of an electing GSOC as of the close of its taxable year shall not include the amount of taxable income for such year which is required to be included in the gross income of the shareholders of such GSOC under section 1393(a).(40)

"(b) SPECIAL RULE FOR AUDIT ADJUSTMENTS.(41) -

"(1) TAXABLE INCOME. - Taxable income of an electing GSOC shall, in the year of final determination, be increased or decreased, as the case might be, by any adjustment to taxable income for a prior taxable year.

"(2) INVESTMENT CREDIT. - The investment credit of an electing GSOC shall, in the year of final determination, be increased or decreased, as the case might be, by any adjustment to the net investment credit for a prior taxable year.

"(3) METHOD OF MAKING ADJUSTMENTS. - An electing GSOC shall include in gross income for the year of an adjustment the amount described in paragraph (1) and shall take into account the adjustment described in paragraph (2), and shall be liable for payment of interest in the amount that would have been payable by the GSOC under section 6601 (relating to interest on underpayment, nonpayment or extensions of time for payment, of tax) or receivable by the GSOC under section 6611 (relating to interest on overpayments) if such GSOC had been a corporation other than an electing GSOC.

(b) TECHNICAL AMENDMENTS. -

(1) NET OPERATING LOSS DEDUCTION.(42) - Paragraph (1) of section 172(b) (relating to net operating loss carrybacks and carryovers) is amended by adding at the end thereof the following new subparagraph:

"(H) In the case of an electing GSOC which has a net operating loss for any taxable year such loss shall not be a net operating loss carryback to any taxable year preceding the year of such loss, but shall be a net operating loss carryover to each of the 10 taxable years following the year of such loss."

(2) INCOME TAX COLLECTED AT SOURCE.[43] - Section 3402 (relating to income collected at source) is amended by adding at the end thereof the following new subsection:

"(r) EXTENSION OF WITHHOLDINGS TO GSOC DISTRIBUTIONS. -

"(1) GENERAL RULE. - An electing GSOC making any distribution to its shareholders shall deduct and withhold from such payment a tax in an amount equal to 25 percent of such payment.

"(2) COORDINATION WITH OTHER SECTIONS. - For purposes of sections 3403 and 3404 and for purposes of so much of subtitle F (except section 7205) as relates to this chapter, distributions of an electing GSOC to any shareholder which are subject to withholding shall be treated as if they were wages paid by an employer to an employee."

(3) ADJUSTMENTS TO BASIS.[44] - Section 1016(a) (relating to adjustments of basis) is amended by redesignating pargraph (23) as (22) and by inserting after paragraph (20) the following new paragraph:

"(21) to the extent provided in section 1395 in the case of stock of shareholders of a general stock ownership corporation (as defined in section 1391) which makes the election provided by section 1392; and".

(4) RETURN OF GENERAL STOCK OWNERSHIP CORPORATION.[45] - Subpart A of part III of subchapter A of Chapter 61 (relating to information returns) is amended by adding at the end thereof the following new section:

"Sec. 6039B. RETURN OF GENERAL STOCK OWNERSHIP CORPORATION.

"Every general stock ownership corporation (as defined in section 1391) which makes the election provided by section 1392 shall make a return for each taxable year, stating specifically the items of its gross income and the deductions allowable by subtitle A, the amount of investment credit or additional tax, as the case may be, the names and addresses of all persons owning stock in the corporation at any time during the taxable year, the number of shares of stock owned by each shareholder at all times during the taxable year, the amount of money and other property distributed by the corporation during the taxable year to each shareholder, the date of each such distribution, and such other information, for the purpose of carrying out the provisions of subchapter U of chapter 1, as the Secretary may by regulation prescribe. Any return filed pursuant to this section shall, for purposes of chapter 66 (relating to limitations), be treated as a return filed by the corporation under section 6012.[46] Every GSOC shall file an annual report with the Secretary summarizing its operations for such year."[47]

(c) CLERICAL AMENDMENTS.[48] -

(1) The table of subchapters for chapter 1 is amended by adding at the end thereof the following:

"SUBCHAPTER U. - General stock ownership plans."

(2) The table of sections for subpart A of part III of subchapter A of chapter 61 is amended by adding at the end thereof the following:

"Sec. 6039B. Return of general stock ownership corporation."

(d) EFFECTIVE DATE.[49] - The amendments made by this section shall apply with respect to corporations chartered after December 31, 1978, and before January 1, 1984.

1. The Revenue Bill of 1978 was passed by the Congress of the United States on October 14, 1978, and signed into law by President Carter on November 6, 1978. The General Stock Ownership Corporation provisions were included as a Senate amendment to that Bill (H.R. 13511) and appear in the legislation as Title VI.

2. The Internal Revenue Code is organized into chapters, subchapters, sections, and subsections. Chapter 1 of the Internal Revenue Code deals generally with the income tax provisions of the Federal law covering both personal and corporate taxes.

3. The Revenue Act of 1978 amends Chapter 1 of the Internal Revenue Code to add a new subchapter designated as Subchapter U. This subchapter, containing seven sections (Sections 1391-1397), sets forth the Federal tax law regarding General Stock Ownership Corporations.

4. A domestic corporation is a corporation which is organized under the laws of the United States or a state thereof.

5. The Internal Revenue Code, Section 1504, defines an affiliated group for purposes of determining which corporations are eligible to file consolidated returns. Generally, an affiliated group is formed when one corporation acquires 80% or more of the voting stock of one or more other corporations. The 80% or more definition in Section 1504 is to be read as 20% or more for purposes of the GSOC legislation.

Since GSOC stock may not be owned by a corporation or other non-individual, the limitation on membership in affiliated groups applies only to ownership by the GSOC of stock in other corporations. The GSOC, in order to avoid being a member of an affiliated group, may not own 20% or more of the stock in another corporation. Failure to comply with this requirement would appear to jeopardize the special tax treatment available to the GSOC under Federal law.

This limitation was included in the GSOC provisions in order to prevent the GSOC from becoming a holding company for other corporations' stock. Because of the special nature of the GSOC tax advantages this limitation is not particularly significant. The elimination of corporate income taxes for the GSOC may not be extended to corporations owned by the GSOC. Therefore, any subsidiary corporation would be fully subject to the Federal income tax, and dividends paid by such a corporation to the GSOC would be net of Federal taxes. The special tax advantage of the GSOC in eliminating the Federal corporate income tax would therefore be defeated by significant ownership of subsidiary corporations.

6. In keeping with the experimental nature of the General Stock Ownership Corporation legislation, a five year period was provided during which such corporations may be formed. Any corporation not formed within the dates set forth in the Act

will not be eligible for treatment under Federal tax law as a General Stock Ownership Corporation. However, any corporation formed and qualifying under these provisions during the five year period will continue to receive the special tax treatment provided GSOCs indefinitely. There is no limitation on the tax advantages once a corporation is established within the designated time frame.

7. The term charter is used in its broadest sense and means that the corporation must have a special grant of powers from either the State Legislature or a statewide referendum. It would not appear to be acceptable for a state to generally authorize the creation of GSOCs. But, it also does not appear necessary for a state to adopt into the law the actual Articles of Incorporation for the GSOC. Indeed, it may be unacceptable for a Legislature to enact the Articles of Incorporation into law and subsequently allow the stockholders of the corporation to amend the Articles. Amendment of the Articles of Incorporation in such a case would appear to effectively amend the statutes of the authorizing state and this would seem to be an unconstitutional delegation of the power of a State Legislature. Conversely, if the Articles of Incorporation could not be amended by its stockholders, it would not appear to be a private business corporation as Congress contemplates by this law.

8. Eligible individual is defined in Section 1391(c) and will be further discussed in Footnote 16 below.

9. At least one share of stock in the General Stock Ownership Corporation must be issued to each eligible individual unless that individual elects within the first year of ownership not to receive the stock. This language does not appear to preclude charging a purchase price for the stock, but in such an event would seem to require that some accommodation be made for those eligible individuals who are not in a position or who are unwilling to pay for the stock. Generally, the drafters of the legislation contemplated the simple distribution of the stock without charge to eligible individuals, with corporate operations and purchases thereafter financed initially through debt instruments only. This would enable the stockholders to build an equity in the stock through amortization of debt with the earnings of corporate investments.

10. In order to qualify as a General Stock Ownership Corporation, the transfer of corporate stock must be restricted during the first five years following its issuance. Since it was contemplated that stockholders in a General Stock Ownership Corporation would be limited to the residents of the authorizing state, an exception is provided so that if an individual ceases to be a resident or dies during the first five years, his stock may be sold or transferred.

The five year transfer restriction was included in order to give shareholders a period of time during which to become familiar with the benefits of stock ownership. It is hoped that during the first five years of corporate operations the GSOC would be in a position to distribute dividends, giving its shareholders some experience with the income generating capabilities of capital and giving those interested in the formation of these particular corporations an opportunity to study the reactions of shareholders to this new type of investment.

In order to discourage shareholders from emigrating in order to sell their stock prior to the end of the five year period, it may be necessary to provide for some controlled purchase price. This could be done in the form of an option on the part of the corporation to repurchase stock from an individual emigrating from the authorizing state at a value below either the fair market value or income stream valuation approach. Such a repurchase would be consistent with the private capital nature of the GSOC stock and could return to the shareholder his book equity. Book equity valuation for purposes of a mandatory repurchase during the five year nontransferability period might be appropriate in that this represents the shareholder's share of cash invested in acquiring the asset. This is the case because the distribution of stock was cost free to the shareholder and his only investment at the time of sale will be in the form of what would otherwise be cash distributions applied to the repayment of the debt incurred to buy the underlying assets. Thus the shareholder is paying for his capital out of the income it produces.

In the event that a shareholder whose shares are repurchased at book value has incurred tax liability in excess of his distributions of cash from the corporation, his basis in the stock will be increased accordingly and he will receive a capital loss deduction for the difference between the book value purchase price and his adjusted basis. This loss deduction will offset his future additional income from the GSOC, insuring that he remains whole once the transaction is concluded if the assets purchased by the GSOC have thrown off in income their purchase costs and necessary interest.

11. Transfers of GSOC stock may not be made to individuals who are not "residents" of the authorizing state. This limitation is designed to assure that the GSOC, which must begin life as a corporation owned by the residents of a single state, either continues to be owned by those residents or, if they are permitted to take it out of state and cease to be residents, they must at or before their death transfer their GSOC stock to a qualified resident. Thus, while a holder of GSOC stock may sell or otherwise dispose of his stock, he may not do so to a corporation, trust, partnership, or other artificial person nor to any individual who is not a resident of the authorizing state.

12. This limitation on transfers was included in order to assure that great concentrations of GSOC stock do not develop. The GSOC was conceived as a means of broadening capital ownership and thereby spreading more widely the income benefits from capital. This transfer limitation implements these goals.

13. The requirements of Section 1391(4)(A)-(E) are limitations which must be included in both the GSOC authorizing legislation adopted by the State Legislature and the Articles of Incorporation for the GSOC. The limitation set forth in (E) simply makes it clear that both the authorizing Legislature and the incorporators of the General Stock Ownership Corporation intend to qualify under the provisions of Subchapter U of the Internal Revenue Code.

14. There are generally no limitations on the types of investments which GSOCs may undertake. However, because of the unique relationship between GSOCs and the authorizing State Legislatures, certain members of Congress felt it necessary to clarify that GSOCs may not be used as vehicles through which ownership of existing capital assets can be transferred from one group to another through the exercise of the state's powers of eminent domain. Therefore, this limitation was added to prevent the power of state condemnation from being used to transfer unwillingly ownership of an existing business to a General Stock Ownership Corporation. This language does not preclude the condemnation of a pipeline right of way or the purchase by a General Stock Ownership Corporation of an asset a component of which is acquired by the sellers through condemnation. It is designed only to preclude the direct condemnation of existing business assets and a resale thereof to the GSOC.

15. The General Stock Ownership Corporation, in order to avail itself of the special tax treatment provided under Subchapter U, must file an election with the Secretary of the Treasury under the terms of Section 1392, discussed below at Footnote 18.

16. Eligible individuals are those individuals to whom stock must be issued under the provisions of Section 1391(a)(4)(B). Stock must be issued to individuals who are, as of a specific date set forth in the state's GSOC enabling legislation, residents of the state and who remain residents of the state until the date the stock is actually issued. The statutory language with respect to a specific date was included to allow a State Legislature to select a date certain upon which residency could be determined. It was contemplated that such a date might be one prior to the date of the enabling legislation in order to assure that a flood of immigrants to the state would not be encouraged.

The term resident may be defined by the State Legislature for purposes of the GSOC legislation in any constitutional and acceptable manner. The term resident itself is a legal term of uncertain meaning, the definition of which varies with the use. For purposes of general stock ownership legislation it may be appropriate to use a definition of resident which equates that term with the legal term of "domiciliary". This would give a definition of resident dependent not only upon present mailing address or physical location within the state, but intent, however evidenced, to establish and maintain primary geographical living situs within the State of Alaska.

17. The GSOC is to be treated as a private corporation and therefore is not eligible to issue securities or levy taxes as a governmental unit or municipal corporation.

18. To take advantage of the special provisions of Subchapter U, the General Stock Ownership Corporation must file an election under the provisions of Section 1392. The election is to be made at the time and in the manner described by the Secretary of the Treasury. Section 1392(b) is effective for the taxable year of the GSOC for which it is filed and for all later taxable years unless the election is terminated.

19. If the GSOC makes an election under Section 1392, the GSOC corporation itself is exempt from all the income taxes imposed by Chapter 1 of the Internal Revenue Code for the year in which the election is made and all following years until the election is terminated. The GSOC is, however, subject to the limitations of Section 1396 which requires minimum distributions of GSOC income and imposes a penalty tax in the event of a failure to distribute income in accordance with Section 1396 requirements.

20. While the electing GSOC is exempt from Federal income tax, the income of the corporation is taxed to the shareholders under Sections 1393, 1394 and 1395. These sections set out the rules under which the shareholders are attributed the income of the General Stock Ownership Corportion, provide for tax treatment of GSOC distributions, and establish rules for determining the basis of a shareholder's stock.

21. In order to assure that significant deferral of income does not occur, the General Stock Ownership Corporation is required to operate on a taxable year ending on October 31st. This allows the corporation sufficient time to determine its taxable income for the year and to provide that information to the shareholders prior to the April 15th regular filing deadline for shareholders' returns.

22. It appears that under the Federal legislation there is at least one event which could involuntarily terminate the special tax status of the General Stock Ownership Corporation, and that event would be membership in an affiliated group which is prohibited under the terms of Section 1391(a)(1). Depending on interpretations of the general law, other events might involuntarily terminate the special status of the GSOC, such as a revocation by the State Legislature of a corporation's charter or amendments to the Articles of Incorporation which remove the conditions required by Section 1391(4) and (5).

23. The election of the General Stock Ownership Corporation to qualify under Subchapter U may be terminated at any time with the consent of the Secretary of the Treasury. Voluntary termination of GSOC status under Subchapter U might be sought in the event that a General Stock Ownership Corporation were to incur taxable income, perhaps from recapture on the sale of an asset, substantially in excess of cash available for distribution. At

this point the Board of Directors might elect to terminate GSOC status so that the taxable income of the corporation did not flow through to the shareholders, but remained, under the normal rules of corporate taxation, with the corporation. While it is not expected that such an event is likely to occur, it was felt that an option should be provided to allow voluntary termination of elections.

24. This provision makes it clear that the income of the General Stock Ownership Corporation is to be taxed directly to the shareholders.

25. If an individual is a shareholder of a General Stock Ownership Corporation at any point during the GSOC's taxable year, that individual will be attributed a share of the corporation's income for that taxable year. The income must be included in the return of the shareholder for the shareholder's tax year during which the GSOC year ends. Thus, if an individual is a shareholder of a GSOC at any time during the corporation's fiscal year beginning on November 1, 1980, and ending on October 31, 1981, the shareholder would be required to include his share of GSOC income on his personal return for calendar year 1981.

If an individual is a shareholder of a General Stock Ownership Corporation throughout the entire taxable year of the corporation, his share of GSOC income is determined by dividing the total amount of GSOC income for the year by the number of shares of stock outstanding and then multiplying this per share earnings figure by the number of shares owned by the shareholder. If, however, the shareholder should dispose of his stock during the corporation's taxable year, he will be attributed income from the corporation on the basis of the number of days during the corporation's taxable year during which he was a shareholder. The per share income of the corporation for the entire year would be divided by 365 to determine the per share daily earnings of the corporation and this amount would be multiplied by the number of days during the year which the shareholder owned his stock. The product of this formula would give the earnings attributable to shareholder's part year ownership interest and this amount would be included in the shareholder's taxable year during which the GSOC year ends.

26. The term taxable income is a clearly defined term for the purposes of the Internal Revenue Code. The taxable income of the General Stock Ownership Corporation is to be determined under the normal rules for corporations, although the General Stock Ownership Corporation is not required to pay tax on this income. The General Stock Ownership Corporation is not allowed to deduct those items normally allowed to corporations under Part 8 of Subchapter B. These deductions include the dividend received deduction, the foreign corporation dividend received deduction, public utilities dividends deduction, and other minor tax deductions. The General Stock Ownership Corporation is allowed to deduct the organizational expenses allowed by Section 248 under

Part 8 of Subchapter B of the Internal Revenue Code. Section 248 provides an option to corporations to deduct organizational expenses over a period of not less than sixty months.

27. The Internal Revenue Code allows a tax credit equal to 10% of the purchase price of certain types of new and used property. This 10% credit is a dollar for dollar offset against taxes due rather than a deduction from gross income in arriving at taxable income. The property eligible for the investment tax credit is generally depreciable tangible personal property, excluding buildings and structural components, used by an individual or corporation engaged in a trade or business and having a useful life of at least three years. The investment tax credit may be taken on the taxpayer's return during the year in which the taxpayer places such an asset into use in his trade or business. In the event that the taxpayer disposes of an asset on which he has taken an investment tax credit prior to the required seven year holding period, he is subject to recapture by the Federal Government of all or a portion of the investment tax credit in the form of additional tax liability. The sections of the Internal Revenue Code applicable to investment tax credits and investment tax credit recapture include Sections 38, 46, 47, and 48.

The 10% investment tax credit is not allowed to a General Stock Ownership Corporation. This is unimportant, however, since the General Stock Ownership Corporation has no tax liability and therefore could not avail itself of the tax credit in any event. Section 1393(b) provides that the investment tax credit to which a General Stock Ownership Corporation would be entitled if it were taxable shall flow through to the shareholders in much the same manner as income. The investment tax credit and any recapture of investment tax credit generated by the sale of corporate assets will be netted at the corporate level. If there is a net investment tax credit, that amount will be prorated to the shareholders in the same manner as income. If there is a net investment tax credit recapture, this amount will be prorated as well, but will be characterized as additional tax liability to the shareholders. It is not expected that the corporation will operate in such a way as to generate any significant amount of net investment credit recapture.

28. Distributions of corporate income are normally taxed as ordinary income to the extent that they constitute dividends paid out of the earnings of the corporation. Distributions in excess of the accumulated earnings of the corporation are treated as a reduction in the shareholder's basis in his stock and to the extent they exceed the shareholder's basis are taxed at capital gains rates. Additional rules are necessary for distributions from General Stock Ownership Corporations since the distributions do not bear direct relationship to the amount of tax which the shareholders may pay. The rules of Section 1394 are designed to indicate whether a distribution of cash from a General Stock Ownership Corporation is a distribution of

income which has already been taxed to the shareholders, a distribution of capital reducing the shareholder's basis in his shares, or a capital gain.

29. The shareholder income account is simply a bookkeeping entry of the corporation designed to keep track of the relationship between taxable income of the GSOC attributed to the shareholders and cash distributions by the GSOC to its shareholders.

30. The shareholder income account is increased at the close of each GSOC taxable year by an amount equal to the GSOC's taxable income in order to indicate the total amount of taxable income which has been attributed to the shareholders and is taxable to them.

31. The shareholder income account is decreased to a minimum balance of zero at the beginning of each GSOC taxable year by the amount of distributions made to the shareholders from the GSOC during the prior year. Thus the account which has been increased by the amount of GSOC taxable income for the prior year is immediately decreased by the amount of distributions made from the GSOC during the same year. Any balance remaining in the GSOC income account after these entries have been made will show the amount of GSOC income in excess of cash distributions on which the GSOC shareholders have paid tax. A General Stock Ownership Corporation is required by Section 1396 to distribute at least 90% of its taxable income for any taxable year ending October 31st by January 31st of the following year. Any distribution made on or before January 31st is to be treated as if it were made as of the close of the preceding taxable year ending October 31st. This means that distributions made within three months of the close of the GSOC's taxable year will be treated as made during the preceding taxable year for purposes of the shareholder income account.

32. To the extent that distributions of the General Stock Ownership Corporation do not exceed the amount in the shareholder income account as of the close of the taxable year (the taxable income of the GSOC for the current year and any taxable income in excess of the distributions from prior years), the distribution will be treated as a distribution of income which has already been taxed to the shareholders and therefore will come to the shareholders tax free.

33. If the distribution should exceed the balance of the shareholder income account, the account would be netted out at zero and distributions in excess of the account would be dealt with under Section 301(a) of the Internal Revenue Code. Section 301 provides that distributions which are not a dividend within the meaning of Code Section 316 (which such GSOC distributions would not be) are treated first as a reduction of the shareholder's basis in his stock and, to the extent the distribution exceeds the shareholder's basis, the distribution is treated as a capital gain. Distributions which are treated as a capital gain will

either be treated as a short term or long term capital gain depending on the time period during which the shareholder has owned his stock.

34. Section 116 of the Internal Revenue Code provides a $100.00 exclusion for individuals receiving dividends on corporate stock. This provision is a simplified way of eliminating the double taxation of dividends for the recipients of small dividend amounts. Since the double taxation of dividends has been completely eliminated for all shareholders in a General Stock Ownership Corporation, it was felt that this additional tax concession was unnecessary. Therefore, the income attributable to an individual taxpayer from a General Stock Ownership Corporation is not eligible for the $100.00 dividend exclusion provided by Section 116.

35. Distributions from the General Stock Ownership Corporation of cash or other property may not directly parallel the tax liability of the respective owners of stock in a situation where a sale of stock occurred during the taxable year. It was felt appropriate to provide the Secretary of the Treasury with regulatory authority to determine the best means of adjusting the relative tax statuses of the seller and buyer and to establish rules for the allocation of distribution rights between the two parties.

36. Generally, in a conventional corporation, the basis of a shareholder in his corporate stock equals the price paid for that stock. Upon a sale of the stock, the shareholder determines his taxable gain by deducting his basis from the sale's proceeds. It is this amount which is referred to in the tax laws as a capital gain. The shareholder in a General Stock Ownership Corporation which distributes its stock free of charge to the shareholders will have a basis in his stock at the time of receipt equal to zero. In the event that distribution of the stock should result in a tax liability to the shareholder because the Internal Revenue Service has imputed income to him from the receipt of stock, the shareholder would receive a basis in the stock equal to the value at which the stock is assessed for purposes of Federal income taxation.

Section 1395 provides a special rule for determining the basis of stock in General Stock Ownership Corporations. Assuming that no income is imputed to the shareholder upon receipt of his shares, he will have a zero basis in the stock at the time of receipt. The basis in his stock will then be increased for the amount of GSOC income which is attributed to him for tax purposes. This means that as he pays tax on General Stock Ownership Corporation income the basis in his stock will increase. The basis will be decreased for distributions from the General Stock Ownership Corporation reflecting the shareholder's receipt of income on which he has paid tax. In the normal course of events, a General Stock Ownership Corporation shareholder will have a basis in his stock which reflects the difference between the income of the corporation on which he has been taxed less the cash distributions which he has received from the corporation. If the corporation distributes all of its taxable income, the shareholder will continue to have a zero basis in his stock and the entire proceeds of any sale thereof will be treated for tax purposes as a capital gain.

37. In order to assure that the shareholders of the General Stock Ownership Corporation have cash on hand sufficient to cover the tax liability generated by the income attributed to them from the General Stock Ownership Corporation, the corporation is required to distribute to its shareholders at least 90% of its taxable income for the year ending October 31st on or before the following January 31st. This distribution would normally allow the shareholders to have cash on hand to pay their personal taxes for the year ending December 31st on the following April 15th when those taxes become due.

38. In order to insure that the General Stock Ownership Corporation makes the distributions required by Section 1396, a penalty is provided for failure to do so. This penalty is an additional tax (deductible by the General Stock Ownership Corporation) equal to 20% of the amount which the GSOC failed to distribute on a timely basis. Thus, if the General Stock Ownership Corporation had taxable income for the year of $100.00 and distributed only $80.00 by January 31st of the following year, it would fail to comply with the requirements of Section 1396. Section 1396 requires a 90% distribution of taxable income and would have required the corporation to distribute $90.00 to its shareholders by January 31st of the following year rather than $80.00. A 20% tax would be levied on the difference between the amount which should have been distributed ($90.00) and the amount which was in fact distributed ($80.00). Thus, the tax would be 20% of $10.00 or $2.00.

39. Section 1397 sets forth special rules applicable to a General Stock Ownership Corporation and a number of technical amendments to other sections of the Internal Revenue Code necessary to the operation of the GSOC provisions.

40. Earnings and profits is a technical term under the Internal Revenue Code and is composed essentially of the undistributed retained earnings of the corporation. Current earnings and profits are determined on an annual basis and if undistributed are added to earnings and profits generally. Distributions by a corporation are treated as dividends and taxed as ordinary income to the extent of a corporation's earnings and profits. Therefore, it is important in dealing with a General Stock Ownership Corporation, whose income is taxed to the shareholders, to assure that income which is so taxed is not included in earnings or profits. This general rule sets forth that position and assures that current earnings and profits for a General Stock Ownership Corporation do not include income of the corporation which is taxed to its shareholders.

41. When the Internal Revenue Service audits a taxpayer, it may find that an overpayment to the government has been made by the taxpayer or that the taxpayer owes additional taxes to the government. It may be several years before an audit of a taxpayer is completed and a final determination of his tax status for a particular year is determined. Normally an adjustment is made in the taxpayer's tax liability for the year being audited and that adjustment is paid by the taxpayer or the government in the year in which the audit is completed.

In the case of a General Stock Ownership Corporation, audit adjustments are treated in a modified manner. Since the shareholders of the General Stock Ownership Corporation are taxed directly on the income of the corporation, any error in the corporation's tax status for a particular year will be reflected on the individual returns of each shareholder. It would be very clumsy and complicated to adjust the tax status of each GSOC shareholder for such an error. If audit adjustments were handled in this manner, it might well happen that hundreds of thousands of shareholders would find themselves being audited by the Internal Revenue Service because of the tax treatment of a particular item by the General Stock Ownership Corporation. To avoid this result, audit adjustments for General Stock Ownership Corporations are to be made at the corporate level and reflected in the income of the corporation for the year in which a final determination of the tax audit is completed. This means that if the General Stock Ownership Corporation understated its income for a particular year due to the error in the tax treatment of a particular item, the adjustment for that error would be made in the year of the final determination and the corporation would have additional income in that year as a result of the adjustment. In addition, the corporation may be liable for interest payments and penalties which will be computed in the normal manner under Section 6601 of the Code. In the event that the General Stock Ownership Corporation overstated its income and therefore the shareholders had tax liability in excess of the correct amount, adjustments would be made in the form of a reduction to the current year General Stock Ownership Corporation income and a cash payment by the government equal to the interest due on overpayments under Internal Revenue Code Section 6611.

42. This provision amends the net operating loss deduction provisions of Section 172(b) to provide for a ten year carryover of net operating losses for General Stock Ownership Corporations. This means that if the General Stock Ownership Corporation for any year should incur a net operating loss (total deductible costs of operation in excess of the current year's income) the corporation can carry this loss omer and use it as a deduction against future years' income for a period of ten years from the year in which the loss was incurred.

43. Section 3402 of the Internal Revenue Code provides for the withholding of taxes by employers directly from employees' paychecks. In order to assure that the shareholders of a General

Stock Ownership Corporation are not attributed income on which they are unable to pay the tax, the GSOC is required to withhold from each cash distribution to its shareholders an amount equal to 25% of the cash payment. This amount will be paid to the Federal Government and be credited to the shareholders as an advance payment of the tax due. This provision creates a new Section 3402(r) which sets forth the general rule on withholding and ties the GSOC withholding provisions into the general rules dealing with withholding on wages. Of particular note is the provision in Section 3402(n) which provides an exemption from the withholding provisions for individuals who have filed a withholding exemption certificate with the General Stock Ownership Corporation certifying that the shareholder incurred no tax liability for the preceding taxable year and anticipates that he will incur no tax liability for the current year.

44. This provision simply cross-references the basic provisions for the General Stock Ownership Corporation set forth in Section 1395 back into the general basis provisions in the capital gains sections of the Code at Section 1016(a).

45. This provision sets forth requirements for an information return to be filed by the General Stock Ownership Corporation with the Internal Revenue Service. This return is an information return only as the GSOC itself is exempt from Federal income taxes. The information on the return must include a statement of the General Stock Ownership Corporation's income for the year, investment credits, the names and addresses of the shareholders, the number of shares owned by each, the amount of GSOC distributions to each shareholder, the date of each distribution, and any other information which the Secretary of the Treasury may prescribe by regulation.

46. For purposes of the statute of limitations on income tax audits and crimes, the return of a General Stock Ownership Corporation is to be treated as a return filed under Code Section 6012, which sets forth who must file income tax returns. Other procedural provisions of the Internal Revenue Code are tied into Code Section 6012 so that the General Stock Ownership Corporation will be covered by the normal rules regarding filing requirements, audits and the rights of taxpayers.

47. In addition to filing an annual information return with the Internal Revenue Service, the General Stock Ownership Corporation is required to file its annual report with the Secretary of the Treasury. It is contemplated that this annual report would be significantly more detailed than a normal corporate annual report and would address such questions as the effect of the GSOC on distributions of income and wealth, the level of transfer payments made or required, the social and demographic profiles of GSOC shareholders, the level of economic understanding of GSOC shareholders, and possible beneficial revisions of General Stock Ownership Corporation legislation.

48. This provision simply amends the index and tables of the Internal Revenue Code to provide for the inclusion of Subchapter U.

49. The operative dates for Subchapter U are set forth in this provision which makes it clear that the Subchapter U changes apply to corporations formed within the December 31, 1978 - January 1, 1984 time frame. It is clear from the language in this provision that the tax benefits of Subchapter U will continue after January 1, 1984, for any corporation formed within this time frame and continuing to comply with the provisions of Subchapter U.

INVESTMENT OPPORTUNITIES FOR AN ALASKAN GENERAL STOCK OWNERSHIP COMPANY

A REPORT TO THE ALASKA STATE LEGISLATURE

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CHAPTER ONE

OVERVIEW OF THE ECONOMY

Alaska is a state of nearly 600,000 square miles, having an area of approximately 20% of the continental United States. Some two-thirds of the population of 400,000+ is concentrated in cities of Anchorage, Fairbanks and Juneau. Potentially, the Alaskan economy could develop rapidly in future years. A much greater population can theoretically be supported at high living standards as the State's resources are more fully utilized.

Available land resources are large in relation to the population. Production of large exportable surpluses of primary products has traditionally been a feature of the economy. Exports of crude petroleum, fish and other marine products, and forest products provide the greater part of Alaska's overseas earnings.

Overseas influences can therefore have an important bearing on some aspects of the Alaskan economy. Substantial variation in world prices of primary products, for example, can have a significant effect not only on the level of internal income, but also on Alaska's ability to finance imports.

The expansion of secondary industry in Alaska would reduce the influence of external conditions on the economy. The importance of a better balance in the economy was also demonstrated by the problems that developed with the completion of TransAlaska Pipeline System (TAPS).

Population and Work Force

During the years since statehood, Alaska's population growth has been, on the whole, relatively rapid. The period since 1959 has just about doubled the population. Natural increase above the national average was generally responsible for the growth, except for the heavy in-migration during the pipeline period. The impact of immigration has been greater than is indicated by the contribution to total numbers. The in-migration of young adults has helped reduce the average age to well below the national average. Less than 3% of Alaska's population is older than 65. This change in the age structure of the population results in a more rapid growth of the total work force and very high participation rates.

The size of the labor force has a seasonal pattern, with summer employment approximately 10% above the annual average, and winter well below the average. A significant number of the additional summer workers are temporaries from the lower 48. Seasonality has been declining steadily in recent years.

Employment amd Markets

Even adjusting for the distortion produced by the trans-Alaska pipeline, civilian employment has been growing in Alaska well above the expansion of population. The government sector continues to be the largest employer, but has declined from 40% of non-agricultural wage-and-salary employment in 1960 to an estimated 33% in 1979.

The growth of the population and work force has been associated with an expansion in the market demand for goods and services of almost every kind. Apart from increase in prices, two factors have operated to raise expenditure on goods and services — the above average growth in population, and an increase in average real incomes. The growth in total expenditure on goods and services has meant that economies of larger scale operation have become more rapidly available to existing businesses, and, in addition, it has made possible the establishment of new businesses for which the market was previously too small.

There is every reason to believe that opportunities for expansion into new industries and new products will continue to offer themselves as the population increases. Furthermore, the increasing diversification of the industrial and service structure inevitably fosters further expansion. Newly established industries create demands for supplies of parts and materials. In other fields, the establishment of one industry may result in raw materials becoming available for the establishment of others. Instances of this are the Alpetco refinery in Valdez and the Pacific Alaska LNG plant in Nikiski.

Similarly the expansion of the economy makes possible the provision of services which would be impractical in a smaller market. Replacement of mail order facilities with full service stores have developed extensively in this way, while the establishment of Alaska offices where previously served from the lower 48 reflects the growth in the financial structure of the economy.

Employment is often cyclical in Alaska. Construction of the oil pipeline increased total employment by perhaps 60,000 over three years. The completion produced a substantial decrease in employment as can be seen in the table below.

Non-Agricultural Wage & Salary Employment

	Annual Average 1976	% of Total	Annual Average 1979 Est.	% of Total
Mining	3,965	2.3	5,519	3.4
Contract Construction	30,233	17.4	10,510	6.4
Manufacturing	10,331	6.0	11,189	6.8
Trans., Communications & Public Utilities	15,704	9.1	16,445	10.0
Wholesale Trade	6,098	3.5	5,678	3.5
Retail Trade	21,466	12.4	23,541	14.3
Finance, Insurance & Real Estate	7,102	4.1	8,039	4.9
Services	27,633	15.9	27,803	16.9
Government	49,670	28.6	54,424	33.2
Miscellaneous	1,297	.7	957	.6
Total	173,499	100.0	164,107	100.0

Source: The Alaska Economic Information and Reporting System, Quarterly Report, October 1979.

Those large projects with a large construction component will probably continue to produce substantial swings in total employment. Because of in-migration of temporary residents for construction jobs and a larger economic and employment base, future projects should not have as dramatic an impact as TAPS.

Availability of Labor

The availability of labor, both generally and in particular categories, and the terms and conditions that govern employment are of critical interest to businessmen and others contemplating investment.

At the end of 1979 the Alaskan work force numbered about 165,000, or about 40% of the population. Only one out of fifteen workers in Alaska is engaged in manufacturing while three out of every ten work for state, federal or local government. Although comparisons are not altogether reliable, the industrial composition of the Alaskan work force is now broadly comparable with the rest of the United States except for manufacturing where one out of four workers in the lower 48 are engaged in some form of manufacturing activity.

Wages paid are considerably higher than average wages for the United States as a whole, as is the cost of living. Average wages (excluding construction) adjusted for the cost of living difference in terms of consumer buying power, are only moderately above the figures from California, Oregon and Washington.

Prevailing wage rates in Alaska will be an adverse factor to any industry which requires large amounts of labor, unless offset by other advantages. The small employment base is also an inhibiting factor because of the shortage of specialized skills needed for many new businesses.

CHAPTER TWO

THE MAJOR SECTORS

This chapter presents summaries of our views on Alaska's principal economic sectors not covered separately. For some sectors, our conclusions on possible AGSOC participation are preliminary and should be studied in depth by AGSOC's management over a period of time. Also, times do change and what is appropriate or desirable today may be altered in a relatively short period of years.

Forest Products

Although a major industry in Alaska, forest products may not be significant to AGSOC. This is not due so much to a lack of investment potential, but to the effectiveness of private enterprise, and the plans of the village and native corporations. These groups may have preempted the field although some joint ventures could be possible.

Finance, Insurance and Real Estate

The fastest growing major segment of the State's economy seems well served by existing institutions and generally is not capital intensive.

Wholesale and Retail Trade

Traditionally, the second largest employer is the State with growth reflecting population expansion, higher personal incomes and inflation. Potential exists for AGSOC leasing activities, but direct investment is unlikely.

Mining

The mining and processing of minerals has been a declining sector of the Alaskan economy in postwar years since 1946. This is in the face of very substantial mineral resources. Alaska contains large reserves of copper, coal, iron ore, molybdenum, uranium, nickel, mercury, limestone and others. Overall, these resources provide a broad basis for an expanding minerals activity within the State.

Because of the size of the State, many areas have, as yet, received little detailed attention. However, as new discoveries are unlikely to be fortuitous — unlike most of those made in the past — success with probably call for the outlay of considerable sums, both for prospecting and exploration, as well as for development to the production stage. In the past, out-of-state capital has played an important role in mineral development and there is good reason to suppose that this will be true of the future also. Mining costs in Alaska are higher than those in the lower 48, largely because of the remote location of many deposits, high labor and transportation costs.

Higher world prices for many minerals, particularly in the last 18 months, will probably stimulate renewed exploration in Alaska. A doubling of prices relative to expenses obviously does wonders for anticipated profit margins and return on investment calculations.

We anticipate that AGSOC will find a number of investment or leasing opportunities in the minerals area. Some of the more promising appear to be:

Iron ore reduction or pelletizing plants.

Additional mine-mouth electric generating facilities at Nanana coalfield.

Copper smelting.

Transportation facilities, including coal railroad cars for Beluga coalfield.

Electric generating facilities for a number of reduction or smelting plants currently under consideration.

Tourism

Even with a lack of sufficient accommodations and transportation to many areas, the number of tourists to Alaska is growing at an above average rate. Visitor-related activities already employ an estimated 8,000 people within the State. The State Division

Division of Tourism estimates that the number of tourists per year will expand at a 13% compounded annual rate over the next ten years. Because of higher costs, tourist expenditures could reach $500 million annually by 1990, compared with $100 million as recently as 1976.

In order to make Alaska more attractive as a tourist destination, infrastructure facilities will need to be expanded. This should include construction of additional tourist accommodations, construction of access roads and further development of recreation facilities in remote areas. In order to reduce seasonality, additional ski areas would seem desirable.

We are unclear as to AGSOC's exact participation within the industry. Investment opportunities will undoubtedly develop and should be analyzed on a case-by-case basis.

Utilities and Communications

In Alaska, this area is far more heavily government owned and operated than in the lower 48. Employment is about 5,000 state-wide and the various activities consume large amounts of capital. We believe AGSOC participation will probably be centered in the leasing of specialized electric generating equipment covered in other chapters, and not as a prime operator of utility or communication systems.

CHAPTER THREE

TRANS ALASKA PIPELINE SYSTEM

In the last year and a half, there has been much discussion and publicity of an AGSOC purchase of British Petroleum's interest in TAPS. Because of its large size in relation to the Alaskan economy, careful consideration must be given to TAPS as a potential investment opportunity. Various pipeline owners in TAPS have expressed publicly or privately that they would be willing to sell their interests. Although no sales or transfers have been made, some smaller owners have declined to participate in current TAPS expansion programs.

BP's interest in TAPS is valued at $1.2 to $1.5 billion depending on certain assumptions used in the valuation. Most of BP's investment is debt financed, since their current debt level is about $1 billion.

The British Petroleum Company Limited transferred its leases on the North Slope to Standard Oil of Ohio in January of 1970. BP then invested in the Alaska Pipeline because Sohio was under financial pressures and could not handle its full share of the first expansion. Since BP now had substantial ownership of Sohio, BP worked out a partnership basis with Sohio to fund expansion of the pipeline.

BP Company Ltd. established BP Pipelines, Inc. as the vehicle to hold their assets in TAPS. BP Pipelines, Inc. and Sohio Pipelines Company then entered into a partnership for financing of their respective shares in TAPS.

BP Pipelines, Inc. is headquartered in San Francisco and holds the assets of the pipeline as its only operating asset. As a common carrier, the company is subject to FERC regulation. Direct operating expense is over $6 million per year. About one third of direct expense is fuel to run pump stations, another third is costs associated with rate hearings, and over $1 million is insurance on the pipeline assets. The remainder of the operation can operate at a budget of less than $1 million per year.

AGSOC, were it to replace BP Pipelines, would incur the same expenses with adjustments for its level of participation in rate hearings and shareholder record keeping and reporting expense.

BP Financial Projections

The analysis summarized in Tables 1A, 1B, 2A, 2B, 3A, and 3B, show potential projections for BP Pipelines interest in TAPS. (Corresponding Tables 1C, 1D, 2C, 2D, 3C and 3D show similar situations for AGSOC ownership as discussed later.) A key assumption used in this analysis is a 1.2 million barrels per day capacity for TAPS. Analysis was made at three tariffs. The FERC set tariff of $4.68 per barrel, the sought tariff at $6.35, and a mid-range tariff at $5.50. Depreciation schedules used for tax and reporting purposes are those schedules used by BP Pipelines in its FERC hearings report. The principal payments and amortizations are shown on the schedule in Table 4. The interest rate used for purposes of this review is the 9.4% interest rate, which is the imbedded interest rate on the total loans outstanding for BP Pipelines. The dismantling, direct expense, and Alyeska expense used are those figures which factor in the 1978 reported figures and 1979 Alyeska's optimistic budget. A tax rate of 50% was applied, ignoring tax loss carry forwards or investment tax credits.

The results of this analysis demonstrates that under a low tariff, (i.e., $4.68) net before taxes will be approximately $60 million per year for BP Pipelines. This profit will reduce yearly until a tariff increase or a capacity expansion occurs. Income taxes may take up to half of that $60 million pre-tax figure, especially after use of loss carry forwards and investment tax credits.

A mid-range tariff of $5.50 produces higher profits, approximately $100 to $120 million, decreasing thereafter.

A $6.35 tariff will produce revenues of over $400 million which are currently the revenues used in the 1978 and 1979 BP Pipeline reports. Net before tax income would be in excess of $150 million and cash flow would be higher, depending upon tax consequences. However, cash flow declines after 1979 due to the buildup in principal payments. When, and if, FERC sets a lower tariff, the revenues will also decrease with corresponding decreases in cash flow and pre-tax net.

Since AGSOC ownership would change depreciation schedules, tax rates and cash flows, the corresponding Tables 1, 2 and 3, show the effects of various tariffs on AGSOC income and shareholder distributions. For all tariffs except a $6.35 tariff, cash distributions available for shareholders terminate after ten years or so without tariff increases; however, since operating expenses continue to increase, there is substantiation for tariff increases, especially if new oil reserves are not discovered.

Table 1A

BP PIPELINES

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME
		$	$	$	$	$	$	$
1979	64062	4.68	299810	74000	104735	61580	29748	29747
1980	64062	4.68	299810	79180	104735	61580	27158	27157
1981	64062	4.68	299810	84723	102347	61580	25580	25580
1982	64062	4.68	299810	90654	97647	61580	24965	24964
1983	64062	4.68	299810	96999	92938	61580	24147	24146
1984	64062	4.68	299810	103788	80671	61580	26886	26885
1985	64062	4.68	299810	111053	75961	61580	25608	25608
1986	64062	4.68	299810	118827	70961	61580	24221	24221
1987	64062	4.68	299810	127145	65950	61580	22568	22567
1988	64062	4.68	299810	136045	60950	61580	20618	20617
1989	64062	4.68	299810	145568	55939	61580	18362	18361
1990	64062	4.68	299810	155758	50939	61580	15767	15766
1991	64062	4.68	299810	166661	45928	61580	12821	12820
1992	64062	4.68	299810	178327	40918	61580	9493	9492
1993	64062	4.68	299810	190810	35908	61580	5756	5756
1994	64062	4.68	299810	204167	32289	61580	887	887
1995	64062	4.68	299810	218458	30080	61580	-5153	-5155
1996	64062	4.68	299810	233750	27871	61580	-11695	-11696
1997	64062	4.68	299810	250112	25662	61580	-18771	-18773
1998	64062	4.68	299810	267620	23453	61580	-26421	-26422
1999	64062	4.68	299810	286354	21366	61580	-34744	-34746
2000	64062	4.68	299810	306399	20154	61580	-44161	-44162
2001	64062	4.68	299810	327847	17616	61580	-53616	-53617
2002	64062	4.68	299810	350797	16779	61580	-64672	-64674

INTEREST RATE: 940   TAX RATE: 500   INFLATION RATE: 070

PIPELINE VALUE: 1114200

ALYESKA EXPENSE: 60000   DIRECT EXPENSE: 6500

Table 1B

BP PIPELINES

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$
1979	299810	29747	61580	7500	0	98027	98027
1980	299810	27157	61580	8025	25400	71362	170189
1981	299810	25580	61580	8587	50000	45747	215936
1982	299810	24964	61580	9188	50100	45632	261568
1983	299810	24146	61580	9831	130500	-34943	226625
1984	299810	26885	61580	10519	50100	48884	275509
1985	299810	25608	61580	11255	53200	45243	320752
1986	299810	24221	61580	12043	53300	44544	365296
1987	299810	22567	61580	12886	53200	43833	409129
1988	299810	20617	61580	13788	53300	42685	451814
1989	299810	18361	61580	14753	53200	41494	493308
1990	299810	15766	61580	15786	53300	39832	533140
1991	299810	12820	61580	16891	53300	37991	571131
1992	299810	9492	61580	18073	53300	35845	606976
1993	299810	5756	61580	19338	38500	48174	655150
1994	299810	887	61580	20692	23500	59659	714809
1995	299810	-5155	61580	22140	23500	55065	769874
1996	299810	-11696	61580	23690	23500	50074	819948
1997	299810	-18773	61580	25348	23500	44655	864603
1998	299810	-26422	61580	27122	22200	40080	904683
1999	299810	-34746	61580	29021	12900	42955	947638
2000	299810	-44162	61580	31052	27000	21470	969108
2001	299810	-53617	61580	33226	8900	32289	1001397
2002	299810	-64674	61580	35552	8900	23558	1024955

INTEREST RATE: 940   TAX RATE: 500   INFLATION RATE: 070

PIPELINE VALUE: 1114200

ALYESKA EXPENSE: 60000   DIRECT EXPENSE: 6500

Table 1C

AGSOC

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.68	299810	78400	130000	54167	0	37243	82
1980	64062	4.68	299810	83888	124583	54167	0	37172	82
1981	64062	4.68	299810	89760	119167	54167	0	36716	81
1982	64062	4.68	299810	96043	113750	54167	0	35850	79
1983	64062	4.68	299810	102766	108333	54167	0	34544	76
1984	64062	4.68	299810	109960	102917	54167	0	32766	72
1985	64062	4.68	299810	117658	97500	54167	0	30485	67
1986	64062	4.68	299810	125894	92083	54167	0	27666	61
1987	64062	4.68	299810	134707	86666	54167	0	24270	53
1988	64062	4.68	299810	144137	81250	54167	0	20256	45
1989	64062	4.68	299810	154226	75833	54167	0	15584	34
1990	64062	4.68	299810	165022	70416	54167	0	10205	22
1991	64062	4.68	299810	176573	65000	54167	0	4070	9
1992	64062	4.68	299810	188933	59583	54167	0	-2873	0
1993	64062	4.68	299810	202158	54166	54167	0	-10681	0
1994	64062	4.68	299810	216309	48750	54167	0	-19416	0
1995	64062	4.68	299810	231451	43333	54167	0	-29141	0
1996	64062	4.68	299810	247652	37916	54167	0	-39925	0
1997	64062	4.68	299810	264987	32499	54167	0	-51843	0
1998	64062	4.68	299810	283537	27083	54167	0	-64977	0
1999	64062	4.68	299810	303384	21666	54167	0	-79407	0
2000	64062	4.68	299810	324621	16249	54167	0	-95227	0
2001	64062	4.68	299810	347345	10833	54167	0	-112535	0
2002	64062	4.68	299810	371659	5416	54167	0	-131432	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Table 1D

AGSOC

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	37243	33519	54167	7400	54167	11124	11124
1980	299810	37172	33455	54167	7918	54167	11635	22759
1981	299810	36716	33044	54167	8472	54167	12144	34903
1982	299810	35850	32265	54167	9065	54167	12650	47553
1983	299810	34544	31090	54167	9700	54167	13154	60707
1984	299810	32766	29489	54167	10379	54167	13656	74363
1985	299810	30485	27437	54167	11106	54167	14154	88517
1986	299810	27666	24899	54167	11883	54167	14650	103167
1987	299810	24270	21843	54167	12715	54167	15142	118309
1988	299810	20256	18230	54167	13605	54167	15631	133940
1989	299810	15584	14026	54167	14557	54167	16115	150055
1990	299810	10205	9185	54167	15576	54167	16596	166651
1991	299810	4070	3663	54167	16666	54167	17073	183724
1992	299810	-2873	0	54167	17833	54167	14960	198684
1993	299810	-10681	0	54167	19081	54167	8400	207084
1994	299810	-19416	0	54167	20417	54167	1001	208085
1995	299810	-29141	0	54167	21846	54167	-7295	200790
1996	299810	-39925	0	54167	23375	54167	-16550	184240
1997	299810	-51843	0	54167	25011	54167	-26832	157408
1998	299810	-64977	0	54167	26762	54167	-38215	119193
1999	299810	-79407	0	54167	28635	54167	-50772	68421
2000	299810	-95227	0	54167	30639	54167	-64588	3833
2001	299810	-112535	0	54167	32784	54167	-79751	-75918
2002	299810	-131432	0	54167	35079	54167	-96353	-172271

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Table 2A

BP PIPELINES

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME
		$	$	$	$	$	$	$
1979	64062	5.50	352341	74000	104735	61580	56013	56013
1980	64062	5.50	352341	79180	104735	61580	53423	53423
1981	64062	5.50	352341	84723	102347	61580	51846	51845
1982	64062	5.50	352341	90654	97647	61580	51230	51230
1983	64062	5.50	352341	96999	92938	61580	50412	50412
1984	64062	5.50	352341	103788	80671	61580	53151	53151
1985	64062	5.50	352341	111053	75961	61580	51874	51873
1986	64062	5.50	352341	118827	70961	61580	50487	50486
1987	64062	5.50	352341	127145	65950	61580	48833	48833
1988	64062	5.50	352341	136045	60950	61580	46883	46883
1989	64062	5.50	352341	145568	55939	61580	44627	44627
1990	64062	5.50	352341	155758	50939	61580	42032	42032
1991	64062	5.50	352341	166661	45928	61580	39086	39086
1992	64062	5.50	352341	178327	40918	61580	35758	35758
1993	64062	5.50	352341	190810	35908	61580	32022	32021
1994	64062	5.50	352341	204167	32289	61580	27153	27152
1995	64062	5.50	352341	218458	30080	61580	21112	21111
1996	64062	5.50	352341	233750	27871	61580	14570	14570
1997	64062	5.50	352341	250112	25662	61580	7494	7493
1998	64062	5.50	352341	267620	23453	61580	-155	-157
1999	64062	5.50	352341	286354	21366	61580	-8479	-8480
2000	64062	5.50	352341	306399	20154	61580	-17895	-17897
2001	64062	5.50	352341	327847	17616	61580	-27350	-27352
2002	64062	5.50	352341	350797	16779	61580	-38407	-38408

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Table 2B

BP PIPELINES

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$
1979	352341	56013	61580	7500	0	125093	125093
1980	352341	53423	61580	8025	25400	97628	222721
1981	352341	51845	61580	8587	50000	72012	294733
1982	352341	51230	61580	9188	50100	71898	366631
1983	352341	50412	61580	9831	130500	-8677	357954
1984	352341	53151	61580	10519	50100	75150	433104
1985	352341	51873	61580	11255	53200	71508	504612
1986	352341	50486	61580	12043	53300	70809	575421
1987	352341	48833	61580	12886	53200	70099	645520
1988	352341	46883	61580	13788	53300	68951	714471
1989	352341	44627	61580	14753	53200	67760	782231
1990	352341	42032	61580	15786	53300	66098	848329
1991	352341	39086	61580	16891	53300	64257	912586
1992	352341	35758	61580	18073	53300	62111	974697
1993	352341	32021	61580	19338	38500	74439	1049136
1994	352341	27152	61580	20692	23500	85924	1135060
1995	352341	21111	61580	22140	23500	81331	1216391
1996	352341	14570	61580	23690	23500	76340	1292731
1997	352341	7493	61580	25348	23500	70921	1363652
1998	352341	-157	61580	27122	22200	66345	1429997
1999	352341	-8480	61580	29021	12900	69221	1499218
2000	352341	-17897	61580	31052	27000	47735	1546953
2001	352341	-27352	61580	33226	8900	58554	1605507
2002	352341	-38408	61580	35552	8900	49824	1655331

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Table 2C

AGSOC

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.50	352341	78400	130000	54167	0	89774	199
1980	64062	5.50	352341	83888	130000	54167	0	84286	187
1981	64062	5.50	352341	89760	127460	54167	0	80954	179
1982	64062	5.50	352341	96043	122460	54167	0	79671	177
1983	64062	5.50	352341	102766	117450	54167	0	77958	173
1984	64062	5.50	352341	109960	104400	54167	0	83814	186
1985	64062	5.50	352341	117658	99390	54167	0	81126	180
1986	64062	5.50	352341	125894	94070	54167	0	78210	173
1987	64062	5.50	352341	134707	85630	54167	0	77837	172
1988	64062	5.50	352341	144137	80310	54167	0	73727	163
1989	64062	5.50	352341	154226	74980	54167	0	68968	153
1990	64062	5.50	352341	165022	69660	54167	0	63492	141
1991	64062	5.50	352341	176573	64330	54167	0	57271	127
1992	64062	5.50	352341	188933	55890	54167	0	53351	118
1993	64062	5.50	352341	202158	50560	54167	0	45456	101
1994	64062	5.50	352341	216309	46710	54167	0	35155	78
1995	64062	5.50	352341	231451	41260	54167	0	25463	56
1996	64062	5.50	352341	247652	38910	54167	0	11612	25
1997	64062	5.50	352341	264987	33460	54167	0	-273	0
1998	64062	5.50	352341	283537	31110	54167	0	-16473	0
1999	64062	5.50	352341	303384	25790	54167	0	-31000	0
2000	64062	5.50	352341	324621	24500	54167	0	-50947	0
2001	64062	5.50	352341	347345	21800	54167	0	-70971	0
2002	64062	5.50	352341	371659	17710	54167	0	-91195	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Table 2D

AGSOC

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	352341	89774	80797	54167	7400	0	70544	70544
1980	352341	84286	75857	54167	7918	25400	45114	115658
1981	352341	80954	72859	54167	8472	50000	20734	136392
1982	352341	79671	71704	54167	9065	50100	21099	157491
1983	352341	77958	70162	54167	9700	130500	-58837	98654
1984	352341	83814	75433	54167	10379	50100	22827	121481
1985	352341	81126	73013	54167	11106	53200	20186	141667
1986	352341	78210	70389	54167	11883	84400	-10529	131138
1987	352341	77837	70053	54167	12715	53200	21466	152604
1988	352341	73727	66354	54167	13605	53300	21845	174449
1989	352341	68968	62071	54167	14557	53200	22421	196870
1990	352341	63492	57143	54167	15576	53300	22792	219662
1991	352341	57271	51544	54167	16666	84400	-7840	211822
1992	352341	53351	48016	54167	17833	53300	24035	235857
1993	352341	45456	40910	54167	19081	38500	39294	275151
1994	352341	35155	31640	54167	20417	54500	23599	298750
1995	352341	25463	22917	54167	21846	23500	55059	353809
1996	352341	11612	10451	54167	23375	54500	24203	378012
1997	352341	-273	0	54167	25011	23500	55405	433417
1998	352341	-16473	0	54167	26762	53200	11256	444673
1999	352341	-31000	0	54167	28635	12900	38902	483575
2000	352341	-50947	0	54167	30639	27000	6859	490434
2001	352341	-70971	0	54167	32784	40900	-24920	465514
2002	352341	-91195	0	54167	35079	170000	-171949	293565

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1300000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

Table 3A

BP PIPELINES

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME
		$	$	$	$	$	$	$
1979	64062	6.35	406794	74000	104735	61580	83240	83239
1980	64062	6.35	406794	79180	104735	61580	80650	80649
1981	64062	6.35	406794	84723	102347	61580	79072	79072
1982	64062	6.35	406794	90654	97647	61580	78457	78456
1983	64062	6.35	406794	96999	92938	61580	77639	77638
1984	64062	6.35	406794	103788	80671	61580	80378	80377
1985	64062	6.35	406794	111053	75961	61580	79100	79100
1986	64062	6.35	406794	118827	70961	61580	77713	77713
1987	64062	6.35	406794	127145	65950	61580	76060	76059
1988	64062	6.35	406794	136045	60950	61580	74110	74109
1989	64062	6.35	406794	145568	55939	61580	71854	71853
1990	64062	6.35	406794	155758	50939	61580	69259	69258
1991	64062	6.35	406794	166661	45928	61580	66313	66312
1992	64062	6.35	406794	178327	40918	61580	62985	62984
1993	64062	6.35	406794	190810	35908	61580	59248	59248
1994	64062	6.35	406794	204167	32289	61580	54379	54379
1995	64062	6.35	406794	218458	30080	61580	48338	48338
1996	64062	6.35	406794	233750	27871	61580	41797	41796
1997	64062	6.35	406794	250112	25662	61580	34720	34720
1998	64062	6.35	406794	267620	23453	61580	27071	27070
1999	64062	6.35	406794	286354	21366	61580	18747	18747
2000	64062	6.35	406794	306399	20154	61580	9331	9330
2001	64062	6.35	406794	327847	17616	61580	-124	-125
2002	64062	6.35	406794	350797	16779	61580	-11180	-11182

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Table 3B

BP PIPELINES

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$
1979	406794	83239	61580	7500	0	152319	152319
1980	406794	80649	61580	8025	25400	124854	277173
1981	406794	79072	61580	8587	50000	99239	376412
1982	406794	78456	61580	9188	50100	99124	475536
1983	406794	77638	61580	9831	130500	18549	494085
1984	406794	80377	61580	10519	50100	102376	596461
1985	406794	79100	61580	11255	53200	98735	695196
1986	406794	77713	61580	12043	53300	98036	793232
1987	406794	76059	61580	12886	53200	97325	890557
1988	406794	74109	61580	13788	53300	96177	986734
1989	406794	71853	61580	14753	53200	94986	1081720
1990	406794	69258	61580	15786	53300	93324	1175044
1991	406794	66312	61580	16891	53300	91483	1266527
1992	406794	62984	61580	18073	53300	89337	1355864
1993	406794	59248	61580	19338	38500	101666	1457530
1994	406794	54379	61580	20692	23500	113151	1570681
1995	406794	48338	61580	22140	23500	108558	1679239
1996	406794	41796	61580	23690	23500	103566	1782805
1997	406794	34720	61580	25348	23500	98148	1880953
1998	406794	27070	61580	27122	22200	93572	1974525
1999	406794	18747	61580	29021	12900	96448	2070973
2000	406794	9330	61580	31052	27000	74962	2145935
2001	406794	-125	61580	33226	8900	85781	2231716
2002	406794	-11182	61580	35552	8900	77050	2308766

INTEREST RATE: 940 TAX RATE: 500 INFLATION RATE: 070

PIPELINE VALUE: 1114200

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Table 3C

AGSOC

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	6.35	406794	73700	130000	54167	0	148927	330
1980	64062	6.35	406794	78859	124583	54167	0	149185	331
1981	64062	6.35	406794	84379	119167	54167	0	149081	331
1982	64062	6.35	406794	90286	113750	54167	0	148591	330
1983	64062	6.35	406794	96606	108333	54167	0	147688	328
1984	64062	6.35	406794	103368	102917	54167	0	146342	325
1985	64062	6.35	406794	110605	97500	54167	0	144522	321
1986	64062	6.35	406794	118347	92083	54167	0	142197	315
1987	64062	6.35	406794	126631	86666	54167	0	139330	309
1988	64062	6.35	406794	135495	81250	54167	0	135882	301
1989	64062	6.35	406794	144979	75833	54167	0	131815	292
1990	64062	6.35	406794	155128	70416	54167	0	127083	282
1991	64062	6.35	406794	165986	65000	54167	0	121641	270
1992	64062	6.35	406794	177605	59583	54167	0	115439	256
1993	64062	6.35	406794	190037	54166	54167	0	108424	240
1994	64062	6.35	406794	203340	48750	54167	0	100537	223
1995	64062	6.35	406794	217574	43333	54167	0	91720	203
1996	64062	6.35	406794	232804	37916	54167	0	81907	182
1997	64062	6.35	406794	249100	32499	54167	0	71028	157
1998	64062	6.35	406794	266538	27083	54167	0	59006	131
1999	64062	6.35	406794	285195	21666	54167	0	45766	101
2000	64062	6.35	406794	305159	16249	54167	0	31219	69
2001	64062	6.35	406794	326520	10833	54167	0	15274	33
2002	64062	6.35	406794	349377	5416	54167	0	-2166	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6300

AGSOC

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	406794	148927	134034	54167	7400	54167	22293	22293
1980	406794	149185	134267	54167	7918	54167	22836	45129
1981	406794	149081	134173	54167	8472	54167	23380	68509
1982	406794	148591	133732	54167	9065	54167	23924	92433
1983	406794	147688	132919	54167	9700	54167	24469	116902
1984	406794	146342	131708	54167	10379	54167	25013	141915
1985	406794	144522	130070	54167	11106	54167	25558	167473
1986	406794	142197	127977	54167	11883	54167	26103	193576
1987	406794	139330	125397	54167	12715	54167	26648	220224
1988	406794	135882	122294	54167	13605	54167	27193	247417
1989	406794	131815	118634	54167	14557	54167	27738	275155
1990	406794	127083	114375	54167	15576	54167	28284	303439
1991	406794	121641	109477	54167	16666	54167	28830	332269
1992	406794	115439	103895	54167	17833	54167	29377	361646
1993	406794	108424	97582	54167	19081	54167	29923	391569
1994	406794	100537	90483	54167	20417	54167	30471	422040
1995	406794	91720	82548	54167	21846	54167	31018	453058
1996	406794	81907	73716	54167	23375	54167	31566	484624
1997	406794	71028	63925	54167	25011	54167	32114	516738
1998	406794	59006	53105	54167	26762	54167	32663	549401
1999	406794	45766	41189	54167	28635	54167	33212	582613
2000	406794	31219	28097	54167	30639	54167	33761	616374
2001	406794	15274	13747	54167	32784	54167	34311	650685
2002	406794	-2166	0	54167	35079	54167	32913	683598

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1300000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 60000   DIRECT EXPENSE: 6300

TABLE 4
TRANS-ALASKA PIPELINE

FINANCE REPAYMENTS

(BP SHARE)

DATE	$m
1979	0
1980	25.4
1981	50.0
1982	50.1
1983	130.5
1984	50.1
1985	53.2
1986	53.3
1987	53.2
1988	53.3
1989	53.2
1990	53.3
1991	53.3
1992	53.3
1993	38.5
1994	23.5
1995	23.5
1996	23.5
1997	23.5
1998	22.2
1999	12.9
2000	27.0
2001	8.9
2002	8.9
2003	8.9
2004	8.9
2005	8.9
2006	8.9
2007	134.0

BP Loan Agreements and Guarantees

BP Pipelines has three classes of loans outstanding, as summarized in Table 5. Each loan would be assumable in a transfer of interest in TAPS. However, BP would not be relieved as a guarantor without approval of a majority or all of the note-holders.

In essence, all of the note agreements use as security notes issued by BP Pipelines, Inc., and in turn those notes are secured by a guarantee or a note issued by BP LTD. Thus the security interest in the notes is not an interest in the pipeline per se, but is backed up by guaranteed notes from the pipelines' company and/or British Petroleum.

Public Indentures

Under the terms of both public indentures, the company to whom BP Pipelines sells or assigns its interest in TAPS may assume payments of the loans as of the original schedules on the indentures. However, such payments or assumptions would not eliminate British Petroleum, the obligor of the notes, without a comparable guarantor.

Any repayment schedules on these notes prior to normal redemption dates would have to be in the same proportions for both Standard Oil of Ohio and AGSOC. However, BP may be able to prepay their guarantee to the capital company without the capital company having to redeem any notes prior to the normal redemption schedule. If AGSOC or Standard Oil of Ohio wanted to prepay in different proportions, however, there would be a disproportionate amount due under the terms of the note for future debt outstanding. In all likelihood, the 1983 note with the 8-5/8% interest would not be prepaid prior to redemption date unless the AGSOC were to pay cash for the sale.

The 8-5/8% indenture requires a principal payment in 1983 for BP of $80.5 million. In any other year the payment schedule for all notes outstanding has total principal payments of $53 million or less except for the year 1983 and the year 2007.

Thus, in summary as regards the 1983 Public issue, AGSOC could either pay cash for the system and finance it through debt or assume payments of this indenture with the principal due in 1983.

On a cash sale for TAPS, a section of the Note Agreement states that the net proceeds of the sale (for at least fair value as determined by the Board of BP Pipelines) be applied in an amount in cash equal to the proceeds of such sale to the retirement of the guaranteed note.

TABLE 5

BP PIPELINE NOTES

PRINCIPAL AMOUNTS

		$MM
PUBLIC ISSUE	9-3/4% DUE 1999	80.5
PUBLIC ISSUE	8-5/8% DUE 1983	80.5
PRIVATE PLACEMENT	10-5/8% DUE 1993	262.6
PRIVATE PLACEMENT	10-5/8% DUE 1998	300.9
PRIVATE PLACEMENT	9-3/4% DUE 1993	116.8
PRIVATE PLACEMENT	9-3/4% DUE 1998	44.1
VALDEZ BONDS	6 % DUE 2007	112.7
VALDEZ BONDS	6.05 % DUE 2007	101.4
	TOTAL	$1,099.6

Public Issue Debenture Due 1999

Under the terms of this note and the other public issue, in order to separate Sohio and BP in the prepayment schedules and obligations, a 66-2/3% majority of the holders of the notes must have approved such changes. No such changes would extend the maturity or reduce the interest rate. Otherwise, redemptions for Sohio and BP would have to be made in the same proportions and at the same time. The normal redemption schedules on these notes begin in June 1980 and increase by approximately $3 million in 1985, continuing until 1999. The earlier principal amounts are approximately $1 million for the BP share. In the BP Pipelines note purchase agreement on this public issue, BP Pipelines would be able to transfer property under a sale, provided that the successor corporation observe all the terms and covenants of the indenture, or BP may receive as of the previous note the net proceeds of the sale at the fair value of the sale and such proceeds be applied to retirements of the note or held for such.

Since these notes are higher interest (9-3/4%) than the previous notes and have due dates ranging from 1980 to 1999, there may be an advantage for the AGSOC to pay this portion in cash directly to BP, rather than assume the obligations of the note. The benefits would be substantial under the terms when AGSOC could borrow at a lower interest rate and possibly a longer payback period.

The major problem with remaining under the terms of the note would be in the event that Sohio or AGSOC wanted a different repayment schedule than that provided for under the note indenture. Such a modification would require a 66-2/3% majority vote of the bond holders. This may not be an impossible task.

Valdez, Series A Bonds

The Valdez Series A bonds are 6% municipal bonds with a total principal amount of $112.7 million for BP's share. The final due date for these bonds is the year 2007; however, mandatory sinking fund redemptions commence on July 1, 1998 up through 2006 of approximately $5 million per year. The remainder will be due in the year 2007.

These bonds are based on a lease and sublease basis and are revenue bonds. Leases are from the Lessor BP Pipelines, Inc. to the City of Valdez and a sublease in return from the City of Valdez to BP Pipelines, Inc. Under the terms of the sublease agreement, the Lessor or BP Pipelines may sell its assets providing that the receiving corporation is an Alaskan corporation and unconditionally assumes the due and punctual performance of the obligations under the lease and sublease agreement. At that point the Lessor will have no further obligations under the lease. The subrents under the lease back to BP Pipelines is 32.2% of principal premium or interest on the total revenue bonds and related expenses.

The BP guarantee on the Valdez bonds is an unconditional guarantee for full payment of 32.2% of the principal and premium and interest when due. However, there is no cross guarantee from BP on any default on the Sohio guarantee. Contrary to other bonds and notes, it does not appear that BP has to redeem in the same proportion in prepayments as Sohio in terms of their respective 68/32% ratio. Thus if BP were to prepay or redeem at a quicker rate, they would, in effect, receive credit for their share of the prepayments and not be required to cross pay any of Sohio's notes when due. It also appears that a sale of the assets of the pipeline does not release British Petroleum under the guarantee agreement.

Under the redemption or prepayment clauses, the redemption price has a penalty of 3% in 1987 and 1988 going down to 1/2 of 1% in 1993.

Redemption is at principal amount after 1993. Any proposed change in the guarantee agreement as it would affect the elimination of BP or Sohio would require the consent of 100% of the bond holders.

Valdez Series B Bonds

The Valdez Series B bonds are 6.05% revenue bonds due the year 2007 and are again governed by a lease/sublease agreement between the City of Valdez and BP Pipelines and the guarantee agreement by British Petroleum Company Limited. The terms are similar to the Series A bonds with no cross guarantee by Sohio or BP for the other share, and prepayments again treated separately and credited to each sublessee's account. If BP Pipelines were to sell its interest in TAPS assets, then BP Pipelines, Inc. would be relieved from obligations under the lease/sublease agreements. However, the BP guarantee, as in the Series A, bonds is not affected by any sale or disposition of assets. Thus BP would always remain as the guarantor. The mandatory sinking fund redemptions of the Series B bonds begin in 1998 and ends in 2006, at an amount approximately $4 million per year. Prepayment penalties start with a 3% penalty in 1987/1988, going down to 1/2 of 1% in 1992, and at principal amount after 1993. The balance would be due in the year 2007. The amount of these bonds for BP Pipelines is $101.4 million.

Private Placement Issue

The first private placement issues were 10-5/8% notes due January 1993 and 1998 for a total BP share of $563.5 million. Mandatory repayments are 1.96% quarterly or approximately 8% yearly of the 1993 notes and 1.41% quarterly or slightly over 5-1/2% annually for the 1998 notes. These repayments begin in 1980. Beginning in 1987, BP and Sohio, if they jointly agree to do so, may double the above percentages. Otherwise, there is a prepayment premium beginning in 1987 ranging from 3-1/2%, reducing annually to zero in 1992 for the 1993 notes, and 3-1/2% reducing annually to zero in 1995 for the 1998 notes.

Under the agreement, BP Pipelines may sell its assets to AGSOC providing that AGSOC assumes all of the BP Pipelines' obligations. However, no sale can be made if the book value of BP Pipelines' share in TAPS becomes less than $855 million or the through-put capacity becomes less than 142,560 barrels per day. This restriction is equivalent to a through-put capacity of less than 900,000 barrels per day for the total TAPS system.

Any sale must be for cash and must conform to the TAPS amended agreements. The notes at the 10-5/8% interest rate are $262,591,000 for the 1993 notes and $300,909,000 for the 1998 notes. The prepayments, therefore, on the 1993 notes are approximately $17 million per year. The option of doubling these prepayments only upon agreement with Sohio would, in effect, double those above values.

An alternative to the sale for cash is a sale for or to a corporation whose only assets are the interest in TAPS.

That corporation would be bound by the terms and conditions of the private placement note agreement. BP's guarantee is unconditional and would not be affected by sale to AGSOC. According to the note agreement, BP will not permit any sale of stock in BP Pipelines except to BP or a wholly-owned subsidiary of BP.

The guarantees are not cross guarantees and BP is not responsible for Sohio's debt under the terms of these agreements.

The terms and agreements of the 9-3/4% notes are similar to the 10-5/8% notes. The 1993 notes carry a prepayment schedule of approximately $9 million per year. The total of these notes is $116,886,000. For the 1998 notes (principal amount $44,114,000), the prepayments would amount to approximately $2-1/2 million per year. The option to double these prepayments would require the consent of Sohio to double theirs in an equal and proportionate share. Other than those changes, the note agreements are similar to the 10-5/8% interest notes.

AGSOC Investment in TAPS

The major issues at stake in the projections of AGSOC interest in TAPS are the rate hearings at FERC and valuating and financing of ownership. One of the major risks in buying part of TAPS is the actual tariff to be set by FERC. A low tariff would make operations marginally profitable.

The expected methodology for setting the tariff is to set a valuation for the pipeline and thereby for each owner's share, and to apply a rate of return on that valuation. The tariff calculation would entail adding the rate of return in dollars to the operating costs to arrive at revenue needed. A tariff is then set. The first phase hearings will set a valuation formula, which in all likelihood will be the actual cost of the pipeline. There may be some other factors entering into the cost values, such as interest used during construction. There probably will not be an allowance for return on equity during construction. The actual percentage rate of return can range from 9 to 20%.

One of the assumptions in the financial analysis used in this report is that the tariff does not decrease in the future at constant capacity. This will most likely be the case, since operating expenses will increase with inflationary pressures probably at least at a rate of 7% per year. Although the value of the pipeline may be reduced due to depreciation, the result of a decrease in valuation should not be as large as the increase in inflationary pressures on the operating expenses of the system. Thus, the tariff need not be reduced through a constant formula imposed by FERC. As capacity expands, a lower tariff may produce the same rate of return. However, there may be requirements for an increase in the tariff if through-put drops in the future.

One of the major issues at the FERC hearings is whether or not the actual cost on the books for constructing TAPS is, and should be, included in the valuation of the pipeline. The factor for not including all historic costs would be mismanagement during construction. Phase II of the hearings will address this issue, and might possibly result in a reduction in valuation due to the unwarranted increase in costs.

Although current rates are in effect at the operator's requested levels, there is the possibility that carriers would have to refund revenues if permanent rates are set by FERC at a level lower than the current rates.

The most critical inputs to the financial projections for AGSOC are valuation of purchase price, tariff rate, and interest rate. Other inputs such as inflation rate, operating expenses, Alyeska or indirect, have a much smaller effect on the overall viability of an AGSOC investment.

The most critical factor in the feasibility of a TAPS investment is the tariff rate selected by the FERC hearings. A 2% change in tariff rate would cause at least a 10% change in dividends to shareholders and a 50% change in available cash flow at the end of a 20-year period.

At this stage AGSOC would have little effect in influencing the tariff to be selected by FERC at the hearings.

There are two possibilities in this regard. One is to become an interested party in the current hearings since (a) AGSOC is identified as a possible investor in TAPS, and (b) AGSOC's tax structure as it regards federal income taxes would be significantly different than the other TAPS owners. An initial reading from FERC would eliminate the uncertainty. The second possibility would be for a full hearing on the valuation of the purchase price between AGSOC and BP to be held after the tariff rate has been decided by the FERC hearings. An estimate on when a tariff might be approved is mid 1980.

The second most critical variable in financial projections for AGSOC is the purchase price of an interest in the pipeline. A 2% reduction in purchase price would amount to a greater than 5% change in dividends to shareholders and approximately a quarter point difference in cash flow at the end of a 20-year period. For comparison purposes, a 3% change in the interest rate would result in a change in the shareholder dividends and net cash flow approximately equal to a 2% change in purchase price. For example, a $20 million change in the purchase price would have approximately the same effect as a 1/4 of 1% change in the interest rate on the debt for a 100% debt-financed purchase. Contrary to the influence AGSOC may have on a finally set tariff rate, AGSOC will have a great deal to say on the purchase price and a significant amount of influence on the interest rate for new debt.

Other variables which affect the financial projections are a decrease in Alyeska operating expenses. A 1% decrease in expense would produce approximately a 1% change in shareholder dividends and a slightly higher change in cash flow. The real problems with the expense side of the picture is that inflation would seriously affect operating expenses in a 10-to 20-year period, and tariffs or revenues wouldn't increase as rapidly as operating costs in a heavy inflationary period. A change in the form of principal payments and/or depreciation schedules again has some affect on the overall financial projections for AGSOC, but these effects have not proved to be significant in relation to other variables.

A summary of financial project for AGSOC are shown in Table 6. The financial estimates for AGSOC have the following assumptions built into the income and cash flow projections: i) Under a 1.6 billion barrel per day capacity, delivery would be 85,429,000 barrels per year. ii) The operating expenses for AGSOC would be a sum of the Alyeska expenses at a 15.84% rate for the BP share, and direct expenses which were estimated to be equal to the estimated expense currently projected for BP Pipelines. (Note that the direct expenses for AGSOC staffing may be less than the staff expenses of BP Pipelines in terms of management and operations of AGSOC. However, the major expense which will impact AGSOC which is not incurred by BP Pipelines would be the administrative cost in shareholder reporting. Rough estimates of that cost would be approximately $2.00 per shareholder on an annual basis, with extra cost for setting up the program and probably a more extensive annual reporting procedure. Thus the direct costs of AGSOC would be approximately equal to the present direct costs of BP Pipelines, assuming the TAPS investment is carrying all of the AGSOC's operating expenses.)

Interest is applied to year end balance after that year's principal payments have been deducted. The principal payments are assumed to be deducted at the end of the year. The depreciation and amortization would be on a straight line basis or an accelerated basis, depending on the circumstances of the schedule. Income tax is assumed to be zero, presuming that AGSOC elects to be non-taxed and distributes 90% or more of income to the shareholders.

The number of years of income stream in Table 6, refers to the number of consecutive years from date of investment that AGSOC would have income and cash flow to make distributions. For example, at the $4.68 tariff, AGSOC would be able to make distributions through 1994, but would not have reportable income after that date. Prior to the time when income becomes reduced, AGSOC could, in fact, apply for higher tariffs and continue cash distributions indefinitely. Alternatively, oil flow may increase to cover such shortfalls.

TABLE 6

$ Tariff	Pipeline Capacity MM b/d	AGSOC Purchase Price ($000)	Imbedded Interest Rate	First Year Citizen Distribution Pre-Tax	Number of Years Income Stream	($000) Cash Balance 24 Years
4.68	1.6	1,600,000	10%	155	14	-111,088
5.00	1.6	1,600,000	10%	216	16	158,504
5.00	1.6	1,500,000	10%	238	17	346,226
5.25	1.6	1,450,000	10%	335	21	612,585
5.50	1.6	1,600,000	10%	334	21	668,317
5.50	1.6	1,500,000	10%	366	22	699,443
5.50	1.6	1,600,000	7%	441	22	733,717
6.35	1.6	1,600,000	10%	496	24	898,341

The citizens income is based upon a 90% distribution. This dividend would be prior to the income tax withholding. Note that a figure above $133 would result in a net check to the shareholder for over $100, after a 25% tax withholding rate. The principal payments would be deducted from the cash flow, leaving a yearly net cash flow and a cumulative cash flow for a 24-year period. The cash balances shown in Table 6, indicate the cash remaining in AGSOC after a 24-year period. If the cash balance under a constant tariff were to fall negative, the strategies of AGSOC may be to (1) refinance the project assuming adequate oil reserves, (2) apply for periodic tariff increases, (3) purchase TAPS at a lower price or (4) a combination of the above.

Under an expanded capacity system, additional investment would be required in TAPS. Estimates in 1977 dollars indicate an investment of over $650 million to increase capacity to 1.6 million b/d and over a billion to go to 2 million b/d. Thus, in 1980 dollars, the investment for a 15.84% share may range between $100 to $150 million, increasing with any delays. Our assumptions under this capacity show beginning full year flow in 1982. The AGSOC purchase price in Table 6 reflects the additional investment to increase capacity.

Under a $4.68 tariff for the 1.6 million barrel per day capacity, a 15 year income stream with an individual shareholder distribution of about $150 would occur with a $1.6 billion valuation and a 10% imbedded interest cost (see Table 6). However, at such a capacity, cash flow would cause serious problems if, in fact, capacity were to drop after the first 10 or 15 years. At a $5.00 tariff, and a value of 1.5 billion to 1.6 billion, shareholder distribution would range from $200 to $300, depending upon the interest rate. At this tariff, a 15 year income stream with steady volume flow in the pipeline would keep a positive cash flow throughout the 25-year period. However, if the flow were to drop below 1.6 billion barrels, there would be problems after a 10- or 15-year period.

At a $6.35 tariff under the expanded capacity line, AGSOC could distribute between $400 and $500 for each shareholder for a number of years.

Current flow capacity has been raised to about 1.4 million barrels per day and shall approach 1.5 million barrels per day by the end of 1980. Most of the higher flow capacity has been achieved through use of a special chemical additive, without construction of new pump stations, although new pump stations are being completed.

To date, only Arco, Exxon, and BP are participating in the capital expansions, and BP's share should increase to a 16.8% ownership of TAPS by the end of 1980.

We have previously discussed the possible AGSOC investments in the British Petroleum share of TAPS. However, there are alternative investment opportunities in TAPS through acquisition of pipeline interests of other companies. Prior to the 1979 and 1980 expansion programs, Mobil held a 5% interest in TAPS, and Union and Phillips each held a 1.66% interest (or about one-tenth the size of the BP interest). Since Mobil, Union, and Phillips have so far declined to participate in TAPS expansion, their respective shares have dropped to about 4.3% for Mobil, and 1.4% for Union and Phillips.

If AGSOC were to purchase a 1.5% interest in TAPS at an assumed price of $125 million, the pro-forma would be as follows under current tariffs:

(000)

Net Income	$17,900	
Depreciation & Reserves	7,000	
Principal Payments	(2,000)	– 62.5 yrs?
Net Cash Flow	22,900	
Stockholder Distribution	16,100	
Cash Surplus	$ 6,900	

Such a pro-forma is for the first few years and will change considerably as principal payments increase or as oil flow changes. With initial cash reserves, AGSOC can invest in other TAPS interests. As oil reserves change, or as pipeline expansion continues, AGSOC can participate in expansion not committed by other owners.

CHAPTER FOUR

ALASKAN GAS PIPELINE

Although there is much discussion about state and federal financing in the Alaskan gas pipeline, an opportunity may exist for AGSOC ownership in the Alaskan section of the proposed gas pipeline. Although current partnership agreements are in existence for ownership of the Alaska Highway gas pipeline, no definitive financing arrangements are set. Thus, flexibility in ownership and financing allows for new concepts in private and public investment in the line.

The Alaska Highway Gas Pipeline venture is still somewhat speculative. Risks arise from the marginal economics in the market for gas which must carry high transportation costs and uncertainities of cost overruns, engineering or regulatory problems, or interruption of gas production. Although there is much discussion in public and private circles about these problems, they are, in essence, not unlike the risks in construction and operation of TAPS.

Because of the high transportation costs of gas through the pipeline to Eastern or Western leg markets, Alaskan gas prices may be double the existing gas prices of present production in those markets. Transportation costs of 2 to 3 dollars per mcf are within current estimates of pipeline system costs. Transportation costs alone are therefore equal to current gas prices in the markets to be served. Once wellhead prices are added, total costs far exceed current prices.

Although analysis of costs appears to be a negative factor in the gas pipeline project, these same concerns faced TAPS in its initial history. Many factors will come into play to drive the end price of gas to levels which can eventually support the Alaskan Highway Pipeline costs. Rapidly escalating oil prices -- spurred even more by the so-called windfall profits tax -- will create more demand for natural gas at higher price levels. Furthermore, a gradual decrease in U.S. dependence on foreign oil imports will create more internal demand for natural gas as a substitute for oil in long-term energy planning. Thus, even though there appears to be a glut in gas supplies, and a cost difference between Alaskan gas energy and other currently available sources, these conditions are essentially temporary and should not be a deterrent to consideration of investments in the gas pipeline project.

Although the overall cost for the gas pipeline is around $14 billion, the 730 mile Alaskan section will cost about $2 billion in today's dollars. With a debt-to-equity ratio of 75%/25%, and an overall rate of return of 16% based on current debt costs, a pro-forma operating statement of the Alaskan pipeline would be as follows:

Return on Rate Base (Excluding Interest)	$320,000,000
Depreciation	125,000,000
Debt Service	(191,000,000)
Taxes - AGSOC	-0-
Net Cash Flow	254,000,000
Potential Net Profit - Available For Dividends	$140,000,000
Net Retained Cash Flow After Distribution (Assume 90% Stockholder Distribution)	128,000,000

The return on rate base would be 16% of the $2 billion investment and would be net of all operating expenses. To the return of $320 million, adding depreciation and netting debt service of $191 million ($180 million interest and $11 million principal payments) yields the yearly cash flow. Netting interest of $180 million from the total return of $320 million yields the reportable income, 90% of which (or $126 million) is distributed to stockholders. Thus net cash flow remaining in the corporation would be $254 million less

$126 million or $128 million. Thus, with an AGSOC investment of $500 million of equity money, the net available retained cash flow would be over $100 million per year in early years, and over $100 million could be distributed to the stockholders.

A related project, the gas conditioning plant may be an attractive prospect for AGSOC participation. To date, FERC has indicated that the producers must bear the conditioning costs, but this position could change during negotiations for pipeline financing. Guarantees on cost over-runs will be needed from major interests to make the project viable. Until the basic parameters are established, one can only speculate on the possible investment potential of the conditioning plant for AGSOC or the State of Alaska.

CHAPTER FIVE

TRANSPORTATION

Overview and Conclusion

The unique importance of public (common carrier) passenger and cargo transportation to the State of Alaska and its citizens provides substantive philosophical rationale for AGSOC to consider transportation investments. Our review at this stage is more conceptual than specific, even though we cite some individual companies as examples and for background informational purposes. We are categorically excluding public sector transportation activities such as Alaska's land and marine highways and general cargo port facilities.

Transportation investments can be accomplished in at least two ways -- acquisition of an operating entity and by leasing long life major capital assets (railroad locomotives and rolling stock, commercial aircraft, ocean barges, freighters, bulk carriers, etc.) to existing transportation companies serving the state. Since equipment leasing is discussed in another chapter, this section will concentrate on opportunities for direct investment in operating companies.

Certain transportation sectors are highly fractured. In Alaska this circumstance is found in intrastate trucking and air taxi services. These types of companies tend to be small, have high failure rates, and erratic operating records. For these reasons, we do not generally view intrastate motor carriers and local service airlines as appealing investment candidates.

By definition, transportation is cyclical, leveraged, labor and capital intensive, and regulated. Accordingly, unusual discipline must be exercised in the traditional investment criteria of quality and depth of management, financial strength, operating records, competitive position, return on invested capital, etc. We also generally favor existing businesses with documented histories and prospects rather than start-up situations, unless these new ventures can achieve near immediate profitability as in the case of a new mine-to-port railroad or slurry pipeline.

Based on our initial survey, the number of Alaskan oriented sufficiently large transportation investments are quite limited in number. Further, their capital intensive, cyclical nature makes transport companies inherently more risky than some of the other target industries that AGSOC is considering.

The AGSOC, when created, may want to direct its initial investment selection process in other areas unless appropriate transportation investments can be identified.

Air Transportation

Scheduled air and cargo passenger carriers within Alaska and between Alaska and the lower 48 are Alaska Airlines, Wien Air Alaska, Northwest, Western Airlines and Flying Tiger Line (cargo only). Alaska and Wien are truly indigenous to the state in their history, service orientation and route structure, and their recent operating records are the most indicative barometers of the growth of Alaskan air services.

Alaska Airlines

Alaska is the larger of the two companies. Its Boeing 727 airplanes serve about 40 points in Alaska, and Seattle, Portland and San Francisco. The company's common stock is traded on the American and Pacific Coast Stock Exchanges.

Alaska Airlines
Operating Highlights
(000's)

Year	Revenues: Passenger	Revenues: Cargo and Mail	Revenues: Total	Operating Income	Net Income
1978	$72,392	$7,241	$84,246	$8,671	$7,231
1977	63,537	6,679	76,518	8,064	3,414
1976	57,359	5,729	69,475	7,448	7,631
1975	52,274	6,482	66,620	6,428	6,111

Source: Moody's Transportation Manual

Wien Air Alaska

Wien has an approximate 11,000 mile route structure serving 150 points within Alaska, Whitehorse, Yukon Territory and Seattle with Boeing 737 and Fairchild turbo-prop aircraft. Following a recent tender offer and treasury stock purchase, about 55% of its common stock is owned by a subsidiary of Household Finance Corp. and 25% by Alaska Northwest Properties, Inc., a spin-off from Alaska Airlines. In November, Alaska Northwest Properties was reportedly holding discussions with Alaska native corporations about buying its interest.

Wien Air Alaska
Operating Highlights
(000's)

Year	Revenues: Passenger	Revenues: Cargo	Revenues: Mail	Revenues: Total	Operating Income	Net Income
1978	$34,134	$12,505	$10,770	$62,495	$3,538	$ 482
1977	29,900	10,641	10,469	55,769	195	(742)
1976	37,593	13,462	9,549	62,708	6,092	2,421
1975	31,336	12,835	8,828	55,991	7,191	3,676

Source: Moody's Transportation Manual

Maritime

The principal general cargo common carrier ocean transportation between Alaska and the lower 48 (Seattle-Tacoma) is provided by Sea-Land, Alaska Hydro-Train, and Totem Ocean Trailer Express (TOTE). Sea-Land and TOTE provide at least bi-weekly sailings between Seattle and Anchorage in medium size cellular container and RO-RO vessels, respectively. Alaska Hydro-Train is a rail car barge service operating between Seattle and Whittier.

There are additional specialized and contract maritime operators between the lower 48 and Alaska, although their number has diminished since the completion of TAPS. The Merchant Marine Act of 1920 (Jones Act) requires that maritime trade between U.S. states be conducted in U.S. built vessels. There is, of course, a great cargo imbalance northbound since only two of Alaska's major export commodities -- lumber and fish products -- can be carried in liner type services.

There is no ocean passenger service per se to Alaska other than the state ferry system, although the Inside Passage and panhandle ports have become very popular summer destinations for cruise ships. (The investment in and development of Alaskan tourist facilities by the AGSOC is discussed elsewhere in this report.) Most, if not all, of the Alaska cruise ships are foreign owned, built and manned, providing them with a prohibitive economic advantage over a U.S. operation.

In the maritime sector, Kelso & Co. believes that TOTE may warrant further investigation as an AGSOC investment candidate. TOTE, which began service in September, 1975, is a subsidiary of Sun Shipbuilding (Sun Company) and leases its two RO-RO ships from Sun. The original sponsors of TOTE tried unsuccessfully to raise start-up financing in the private capital market during the difficult period of the 1974-75 recession. While TOTE's financial performance reportedly has been marginal, the company has steadily gained market share and now carries over 55% (vis-a-vis Sea-Land) of the Seattle-Anchorage ocean borne general cargo.*

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* Because of the participants' ownership structure and the Federal Maritime Commission's non-disclosure policy, Kelso has been unable to expeditiously obtain cargo statistics and financial data on the Alaska-Seattle marine trade route and operators.

Motor Carrier

Without having conducted a specific survey and analysis, we have earlier stated our philosophical aversion to investments in small intrastate truckers even though Alaska's transport infrastructure may be deficient in motor carriage services.

On the other hand, there is an Alaska-lower 48 trucker -- Lynden Transport, Inc. -- which has a strong market position, solid operating history and sound balance sheet could be a prime AGSOC investment candidate. Kelso & Co. has not had any discussions on this subject with Lynden management and principal stockholders, although Lynden has in recent years been buying into its treasury a sizeable portion of its publicly held shares.

Lynden is a common carrier of freight between Washington state and Alaska by highway and water (TOTE), a milk hauler in Washington, Idaho, Oregon and Alaska, a motor freight operator in western and northwestern Canada, an Alaskan intrastate special and general commodities carrier, and an air freight forwarder to and from Alaska. The company is the largest highway carrier within Alaska and between Alaska and the Pacific Northwest. A subsidiary conducts construction, gravel, and coal operations.

Lynden's 1978 revenue profile was (000's):

U.S. Transportation	$28,107
Canadian Transportation	2,745
Construction, etc.	1,538
Total Revenues	$32,390

Lynden Transport, Inc.
Operating Highlights
(000's)

Year	Revenues: Freight	Mail	Milk	Construction	Total	Operating Income	Net Income
1978	$23,880	$4,385	$2,587	$1,538	$32,390	$1,741	$ 648
1977	17,569	4,362	2,302	853	25,086	1,003	419
1976	20,552	4,087	1,978	863	27,481	1,722	1,131
1975	21,384	3,421	1,831	---	26,636	3,646	1,540
1974	11,647	3,010	1,783	---	16,441	1,813	888

Source: 1978 Annual Report to Shareholders and 10-K; Moody's Transportation Manual.

Railroad

Alaska is served by two railroads -- the Alaska Railroad (ARR) and the White Pass & Yukon (WP & YR).

We dismiss the WP & YR as an AGSOC investment because it serves only one Alaska city (Skagway), is Canadian owned, and essentially provides a transshipping mode for the Yukon territory's booming mining industries. Neither is WP & YR a logical equipment leasing candidate since it is a narrow gauge line.

From a political and public interest standpoint the federally-owned Alaska Railroad would be a most reasonable AGSOC investment candidate. Kelso & Co. has reviewed the railroad's operating and financial record and the plethora of consultant and government studies that have been prepared on the ARR in recent years. We have concluded that the Alaska Railroad is intrinsically unprofitable under its present route structure, commodity mix and labor agreements, particularly since it does not now have to bear the financial burden of debt service and income taxes. The railroad was quite profitable during TAPS construction and would probably earn money during the gas pipeline construction. However, unusual or abnormal events are heavily discounted in the fundamental investment decision making processes.

Alaska Railroad
Operating Highlights
(000's)

Period	Rev. Tons	Ton* Miles	Total Revenues	Total Expenses	Gain (Loss) After Depreciation
11 Mos. to 8/31/79	N/A	N/A	$22,875	$28,933	($6,058)
Sept. FY 1978	2,178	330.0	29,091	33,625	(4,534)
Sept. FY 1977	2,305	404.0	35,022	35,982	(960)
TQ 1976	N/A	N/A	10,051	11,164	(1,113)
June FY 1976	2,188	529.9	53,678	49,597	4,081
June FY 1975	1,862	475.9	42,287	37,079	5,807

* In millions
N/A -- Not Available
TQ -- Transitional Quarter
Source: Alaska Railroad Financial Statements

Beyond the railroad's desultory financial record and outlook, there are several other structural and political problems that are collectively very dissuasive:

a) The prevelant perception of the railroad as a "public utility." This problem has become manifest in at least two areas — the requirement of the railroad to provide passenger service at a loss and the difficulty in implementing fair market value rental rates on the ARR's commercial and industrial properties.

b) The non-commercial orientation of management as cited in the 1978 GAO report.

c) The difficulties of segregating under private ownership data processing, purchasing and other management functions now handled through U.S. government agencies.

d) The requirement for large capital outlays on the railroad property and for equipment in the event of a sharp traffic pickup. Between 1975 and 1978, $37 million was expended for much needed roadbed, bridge and tunnel improvements, and purchase of new locomotives and rolling stock which program has upgraded the ARR to an "excellent...light density single track railroad."*

e) The dispute over certain railroad property ownership rites between the railroad and Federal-State Land Use Planning Commission.

There are long range plans for extending the railroad to the lower 48 via British Columbia. If Alaska's extensive mineral deposits of copper and steam coal are eventually developed, new rail lines may be constructed to serve these mines. The financing requirements for such railroads will be considerable and the AGSOC would be a vehicle for providing some of this imbedded capital on a basis that could be fully compensatory to the trust.

In conclusion, Kelso & Co. believes that direct AGSOC investment in Alaska's existing railroads is not desirable, but long-term (finance) leases of equipment could be considered.

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*Railway Age, April 9, 1979, p. 29. Underlining by Kelso.

CHAPTER SIX

FISHERIES

Fishery products represent a major industry for Alaska. In addition to the value of the commercial catch, fish processing represents about half of the state's manufacturing employment. A series of recent studies indicate that the best opportunity for expansion of the Alaskan fishing industry lies in bottomfishing.

Although Alaska's waters are highly productive, Alaska's bottomfish industry is not fully utilized, especially by domestic fishing interests. The extension of U.S. territorial waters to 200 miles will give Alaska fisherman better access to the supply which in the past have been taken by foreign trawlers. An opportunity exists for a major expansion of the Alaska fishing industry with significant economic benefits. It is estimated that full development of Alaska fisheries can add almost 30,000 in employment and impact trade balances of one billion dollars by 1990.

One of the impediments to expansion is the lack of access to private capital for vessels and processing facilities. Programs are now available for government-guaranteed loans for vessel construction or conversion, and tax deferred programs are available for harvesting and processing vessels. However, the major inhibition to development of fisheries is the absence of associated processing facilities.

AGSOC, through its favorable tax treatment, would provide a current effective tax deferral program for a processing plant. Coupled with a processing plant, the AGSOC could provide cold storage facilities and service facilities for fishing fleets. These areas are capital intensive components of establishing fisheries, yet are areas in which direct government involvement is not recommended. In addition, since the capital requirements are much higher than those for vessel purchase (except for catcher processors or floating processor plants), private development of these plants and service facilities is slow.

Many indirect benefits will fall from an AGSOC program in Fisheries. The project will receive wide publicity and promote public sector attention to developing the infrastructure necessary to fisheries, especially in harbor facilities. Additionally, such publicized entrance in fishing could stimulate private and independent fishing vessel construction and conversion to bottomfishing.

A recent publication of the U.S. Department of Commerce indicates investments for Alaskan groundfish development by 1990 as follows:

Harvesting Vessels	$ 185,000,000
Processing Facilities	$1,990,000,000
Public Facilities	$ 527,000,000

AGSOC participation in the vessels could be through leasing operations as discussed further. However, there appears to be some private development efforts for catcher-processors in Alaska by Energy Resources Company of America (ERCA), and through government guaranteed financing, capital investment may not be too restricted.

Major investments are required for the processing facilities. Except for the catcher-processors, United States efforts in major off-shore processing ships are unsuccessful and undeveloped. Thus, in the near term, the fishing industry must develop through shore-based processing plants.

New plant investments would range from $3,000,000 to $4,000,000 for processing facilities in Ketchikan, Sitka, Seward, and Homer, $15,000,000 for Kodiak, and $40,000,000 for Dutch Harbor. Return on investments based on normal operations and 1979 level of prices would range from 3% to 20% per year with varying assumptions.

An example of processing plant economics is shown in Table 7.

TABLE 7

AGSOC Processing Plant - Small Size

Revenue	
(11,000,000 lbs @ $.90/lb average all species)	$9,900,000
Cost of Fish	
(@ $.21/lb average all species)	4,675,000
Shipping Costs	1,225,000
Labor	1,270,000
Sales, G & A	1,200,000
Maintenance and Utilities	330,000
Depreciation	250,000
Interest (100% financed at 11% interest) for fixed assets	385,000
Land and Dock Lease	50,000
Total	$9,385,000
Income Before Taxes	$ 515,000

The projections in Table 7 assume that AGSOC has 100% financing for all fixed assets in the plant. In addition, it assumes that AGSOC leases land, dock, and access roads from a government entity on fair market value lease rates. It also assumes that AGSOC maintains and operates interim storage units, but not shipping containers. Furthermore, the processing plant site shares facilities with vessel refueling and servicing operations at the dock. Those operations are to be run independently.

Based on a continuous level of operation for five years, AGSOC would have a retained cash flow of $100,000 per year or $500,000. It would have retired about 1/3 of its debt and have a net long-term debt of $2,250,000. If net earnings before tax were to increase at a rate of 10% per year (based on a semi-successful fishery development) the AGSOC processing plant would have a fair market value of over $3,500,000 and AGSOC could sell the facility to a private party and have a net cash profit of over $1,500,000.

An alternative to an AGSOC operating division running the processing plant would be to lease the plant to an existing fish processing business or to have a management company run the plant. The net result would be an eventual sale of the plant to the operator after a five- or ten-year period. For AGSOC to make a fair return, sale should be set at fair market value or pre-set on an option basis, assuming a reasonable profit growth and a price/earnings ratio.

Vessels

The development of Alaskan fisheries requires major investments by the private sector in harvesting and processing vessels for bottomfish. Investments range from approximately $1,000,000 for an 85-foot trawler to about $12,000,000 for a 250-foot catcher-processor. On the other hand, conversion of existing shrimpers or crabbers for bottomfish can range from $50,000 to $500,000.

Recent financing programs, such as the Fishing Vessel Obligation Guarantee program administered by the National Oceanic and Atmospheric Administration (NOAA), provide a loan guarantee of up to 87-1/2% of vessel construction or reconstruction. In addition, the Capital Construction Fund allows deferral of federal taxation of vessel income when that income is used for investments in new vessels.

Although efforts are underway on the part of some Alaskan businesses to promote harvesting under these programs, other fishing interests and independent fishermen find it difficult to gain access to this capital. It is at this point where an AGSOC leasing operation has a role.

For example, an 85-foot vessel with a capital cost of $1,000,000 can earn over

$100,000 in income and maintain $150,000 per year in payments for the vessel. Based on a 10% annual interest rate and a 15-year amortized loan, the AGSOC would have an annual payment of $129,000 and could net over $20,000 per vessel per year on a leasing program. Additionally, as vessels become more expensive and fisheries develop profitable operations, lease revenues may increase and substantial residual values on vessels would contribute to AGSOC capital accumulation.

Since some estimates of new fishing vessel requirements in Alaska over the next 10 years approximate 200, or a value of almost $200,000,000, an AGSOC leasing operation has a large market potential. If AGSOC were to lease 25% of the requirements over the next 10 years, its net lease revenue would reach a maximum of $1,000,000 per year profit excluding a buildup of residual value worth.

CHAPTER SEVEN

LEASING

Leveraged leasing could offer some favorable tax advantages for AGSOC. Additionally, an AGSOC leasing program could stimulate many segments of the Alaskan economy which are currently restricted by lack of capital.

Although leasing is an alternative source of financing capital equipment, it offers advantages to both sides of the relationship. Both have some tax advantages, and although the leasing company assumes more risk, the lessee grants compensation for its diminished risk in higher rental payments.

There are many variables in the structure of a lease so that a single financial model would not cover all cases. However, for illustrative purposes, the following example shows the advantages to AGSOC:

> Suppose a company were to lease a $1,000,000 piece of equipment through AGSOC. If this equipment had a 20-year life, possible lease payments (under today's high interest rates) might be as high as $175,000 per year or higher if a short-term lease were executed. On the other hand, AGSOC's principal and interest payment could be under $150,000 per year. Thus AGSOC could achieve a cash flow spread of at least 2-1/2% of the equipment value per year, and under certain conditions this could be as much as 5%. However, the significant tax factors which would benefit AGSOC and its stockholders would be the investment tax credit and depreciation. In the first year of the investment, 10% of the value of the equipment could be claimed as a tax credit. Under the Federal legislation, Subchapter U to the Internal Revenue Code, this would be passed through directly to AGSOC's shareholders. The distribution of profits could be controlled by the

depreciation schedule used so that up to the full value of the positive cash flow could be retained by AGSOC without tax penalty. This reserve could be used to offset future cash requirements or for new investment.

A major attractiveness of leasing for AGSOC is that it could borrow nearly 100% of the purchase price of certain investments. Our recent discussions with major banks, indicate that the banks would loan to AGSOC at favorable rates, assuming a reasonable AGSOC capitalization. Additionally, for large investments, most institutions will provide necessary expertise in structuring the lease and managing the asset through the lease term.

If AGSOC were to operate a leasing company serving different industries with different products, the company would need marketing support and other administrative, legal, and clerical services. The level of the support required would approach 5% of the total revenues received by the company.

A sample pro-forma of a leveraged leasing company with $100,000,000 of equipment on lease is as follows:

Revenues	$24,000,000
Operating Expenses	1,200,000
Interest Expense	11,000,000
Depreciation	8,333,000
Total	$20,533,000
Net Profit	$ 3,467,000

The above pro-forma would be applicable to the first few years of operation. After that time, interest expense may decline considerably, or alternatively, more equipment can be placed on lease because of cash flow buildups from depreciation. Thus, income can increase with interest expense decreasing producing larger profit margins. The risk associated with this business would fall in the residual value or marketability of the equipment leased as the lease term expires or if the lessee defaults.

Leasing is a competitive business. Initially, we investigated AGSOC leasing aircraft to Alaska Air Lines, for example. However, Alaska Air Lines has multiple proposals for such leases and at much more favorable rates than could be offered by AGSOC. The reasons for strong competition, especially in aircraft, are the favorable tax advantages (increasing for those in higher than 50% tax brackets) and high resale residual values for aircraft after the initial lease terms. Many lessors will therefore sacrifice short-term cash flow for current tax benefits and long-term profits. The best opportunities for AGSOC would seem to be areas of leasing where lease competition is not so high, e.g., for leasing to start-up business ventures, and in other situations where financing sources are difficult to obtain.

Potentially, leasing may be applicable to many sections of the Alaskan economy. Some of the more promising are summarized below.

Motel and Hotel

Over time there should be opportunities in sale and leasebacks of motel/hotel sites and structures. This industry offers more favorable opportunities for AGSOC leasing since there are more favorable tax credits available in motel/hotel leasing than for other forms of commercial real estate.

Fishing

Currently, there are investment opportunities in Alaska for both processing vessels and on-shore processing plants. The vessels offer good opportunities since interim financing during construction would not be as big a handicap as construction of new plants. Leasing of fishing vessels, or sale and leaseback of converted fishing vessels, also offer opportunities in the fishing industry.

Hard Rock Minerals

There will be potential for leasing mining equipment as mining develops within the State.

Oil and Gas

In gas pipeline construction, leasing opportunities will exist in rolling stock used during construction. There also are opportunities for leasing drilling rigs or LNG storage tanks. The high value of storage tanks is attractive for an AGSOC investment.

Petrochemicals

The development of a petrochemical industry using Alaskan resources has stimulated much interest in parts of Alaska. Construction financing is not an attractive leasing opportunity, but certain installed equipment may offer possibilities.

Agriculture

Agricultural equipment offers some lease opportunities although AGSOC might not want to compete in the financing for the leasing of relatively low value equipment.

Electric Power

Potential for the leasing of prefabricated plants exists in Alaska. Major users of electric power or new hydroelectric plants may have financing difficulties. AGSOC may be able to lease a full plant to potential operators.

Alaska Railroad

The railroad is covered in the Chapter on Transportation. There is a potential lease opportunity in freight cars, locomotives and other equipment. As in the airline industry, rail car leasing is competitive with many participants.

CHAPTER EIGHT

SOURCES AND COSTS OF CAPITAL FUNDS

SOURCES OF CAPITAL

Problems of raising capital and rationing it among competing investment projects are common to all business corporations. The long-run profitability of the enterprise hinges on the solution of these two problems. Knowledge of sources and costs of capital is needed for both.

Good management of corporate capital views as quite separate these two problems: (1) sourcing (acquisition) of capital funds and (2) rationing (investment) of that capital. Rationing capital among investment proposals should be on merit, independent of source or cost of funds for that particular project. Investable funds of AGSOC should be treated as a common pool, not as separate compartments. Similarly, the problem of acquiring capital should be solved independently of its rationing and also on the basis of merit (the comparative costs and risks of alternative patterns of sourcing).

The first part of this chapter surveys, for decision-making purposes, the various sources of capital for AGSOC; the second part examines ways of estimating the cost of capital obtained from major sources.

The supply of capital for corporate investment comes ultimately from the savings of individuals, corporations, and governments. As to immediate sources, a corporation normally has two choices: use its own savings (internal) or tap the savings of others (external).

Internal Sources

The main internal source of corporate savings is the generation of cash from operations. Corporate savings is the act of not paying out all profits in dividends. Stockholders benefit from saving and internal investment of the corporation's after-tax cash generation when the rate of return on the investment is higher than the corporation's cost of capital. This is approximately the opportunity cost of capital to its stockholders, because the corporation usually has the option of buying its own stock.

Gross cash earnings generated by operations constitute a common pool of future funds from which dividends will be paid and new investments financed. This pool should have corporate-wide availability for capital expenditures. When each division is restricted to the reinvestment of its depreciation charges regardless of the productivity of its investment proposals, the separability of sourcing and rationing of capital funds is abrogated, and one of the major advantages of the diversified firm is destroyed.

When AGSOC elects to take advantage of the special provisions of Subchapter U, the corporation itself will be exempt from all federal income taxes but must distribute 90% of its earnings to shareholders. Thus, except for the remaining 10%, the use of retained earnings as a source of funds will not be available to AGSOC.

External Sources - Debt Capital

As external sources there are two ways for AGSOC to get savings from outsiders: borrow (debt capital) or partner (equity capital). Debt capital can be arbitrarily classified as either short-term or long-term.

Short-Term Debt.

Short-term debt of AGSOC can be of two sorts. The first is inadvertent borrowing which is a cultural by-product of normal operations. Mostly it is caused by lags between the time a service is performed and the time it is customary to pay for it. The second sort of short-term borrowing is quite deliberate. The main source for most companies is the commercial bank. A line of credit is usually established, which sets a maximum amount of borrowing which the company may draw down as its needs dictate.

Long-Term Debt.

Drawing the dividing line arbitrarily at one year, we classify intermediate-term debt capital as long-term. The term loan is a typical instrument. Its source may be a commercial bank, an insurance company, or a trust fund. Term loans result from direct negotiations between borrower and lender. Thus, they are privately placed as contrasted with public sale through the money market.

For longest term borrowing, the usual loan contract is a bond. It may be placed privately by direct sale to a large financial institution or sold to the public, usually through an investment banker.

Long-term debt can be subclassified in three ways:

(1) Nature of security (mortgage versus debenture bonds).

(2) Directness of the obligation (direct debt versus off-balance sheet financing).

(3) Degree of participation (pure debt versus contingency debt).

These three bases of classification overlap.

Nature of Security

Borrowings may be secured by pledging specific assets (mortgage bonds) or secured only by the corporation's general credit (debenture bonds). The basic security for the debt of any corporation is, however, its uncommitted cash generating ability. A bank does not want to run a coal mine. Sale of a pledged asset is only a resort of desperation. The relevant economic measure of the debt-carrying ability of a corporation is not the balance sheet, but the future generation of cash from operations, which can be derived from forecasted income statements.

Directness of Debt

In addition to direct debt, a corporation can borrow indirectly by a variety of devices such as long-term leases, sale-and-lease-backs, oil payments and royalty arrangements, and through-put agreements. Regardless of legal status or accounting treatment, these forms of indirect obligation are the economic equivalent of direct debt. They are contractual obligations to make periodic payments for the use of capital and to repay principal under specified conditions. These forms of off-balance-sheet borrowing have attractions. They can be (1) tailored precisely to the borrower's needs as to amount and timing, (2) negotiated privately, and (3) left off the balance sheet. The price of these conveniences is usually a slightly higher interest cost.

Participation

Some debt has partnership features (for example, convertibles and income bonds). Convertible bonds are a cross between debt and equity financing. The bond holder has an option to convert his debt claim into shares of common stock at a predetermined price, which is equivalent to a long-term call on equity. The requirement in the Federal Enabling Law limiting the transfer of common stock to individuals who own no more than ten shares of stock probably will prohibit the effective use of convertible debt by AGSOC. (Revenue Act of 1978, Section 1391(a)(4)(D)(iii).) It is theoretically possible to design a convertible bond indenture that would require immediate sale of the stock received upon conversion back to AGSOC at fair market value.

Quasi-equity features are less clear, but nevertheless are present in most indirect debt (for example, lease-backs and oil royalties). Most lease-backs and oil-payment and oil-royalty arrangements give the lender options and residual values that have some attributes of equity.

Joint bonds are obligations issued jointly by two or more corporations, and are their joint and several obligations. Thus, the Louisville & Nashville and the Southern Railway collateral trust bonds were secured by the stock of the "Monon" Railroad, owned in equal parts by the two guarantors. These two roads were each liable for one-half of the principal and interest, and fulfillment of all other obligations imposed by the indenture under which the bonds were issued. Should either company have defaulted on any of its obligations under the indenture, the deposited stock belonging to the defaulting company was to become the property of the other company, which thenceforth was liable in severalty upon all the covenants contained in the bonds.

Joint bonds have been issued also by states and municipalities. The bonds of the Authority of the Port of New York are in effect a joint obligation of the states of New York and New Jersey. Joint bonds offer the potential of cooperative ventures by AGSOC, the Permanent Fund, Native Corporations and others.

External Sources - Equity Capital

Equity capital raised externally is of two types: (1) preferred stock, which is a kind of preferential, but limited partnership, and (2) common stock, which is full partnership.

Preferred Stock

Dividends of preferred stock come ahead of common, but are limited in amount. They are, however, not a contractual obligation and hence are not deductible as an expense for corporate income tax. Since the Federal Enabling Law limits General Stock Ownership Corporations to one class of stock, AGSOC cannot have preferred stock in its capitalization (Section 1391(a)(4)(A)).

Common Stock

Common stock is the economic equivalent of full partnership in the earnings and assets of the corporation. Dividends are discretionary, (although a Subchapter "U" GSOC has a strong incentive to pay out 90% of earnings) and common stockholders get only the residual left after other payments.

THE COST OF CAPITAL

All resources command a price for their use. Capital is no exception. Management's task is to blend the various capital sources available to achieve the lowest long-run cost for the Company's total requirements. This overall combined cost is the weighted average of the market cost of the major kinds of corporate capital: debt, preferred stock, and common equity. Capital from internal and indirect hard-to-measure sources should be assigned the cost of its alternative direct source. The alternative for lease debt is direct borrowing for an equivalent term. The alternative for internal cash generation, whether labeled "earnings plowback" or "depreciation," is flotation of common stock.

The Cost of AGSOC Debt Capital

That debt capital is a cost is undebatable. The use of money borrowed from outsiders has a price. This price is established by market forces and is knowable with considerable precision. This price the company must pay.

The price of debt capital fluctuates with changes in supply and demand. At any time, the price differs depending on (1) the credit-worthiness of the borrower, (2) the duration and other terms of the loan, (3) the type of lending institution, and (4) the section of the country. The debt-cost range is wide, from 36% for trade credit if cash discounts are passed, down to prime rate and below. The underlying causes of this wide disparity in the price of debt money are differences in risks and in costs of administration and collection. These two forces sometimes are opposed. For a short-term loan, the risk is less but the costs of launching and administration are proportionately higher. Other features affect the cost structure of debt capital; for example, privacy has a price. Off-balance-sheet borrowing commands higher prices in the marketplace, and corporate private placements cost somewhat more than equivalent public debt.

Market imperfections distort the structure. Ignorance has a price. The astute borrower will try to borrow at the lowest rung of the debt-cost ladder that his credit worthiness will permit. The competent lender will seek as comfortable a cushion of compensation for his risk differential as knowledge will warrant and competition permit. Because of the newness of the federal legislation (1978), AGSOC will be in somewhat unique position as a new borrower. Alaskan banks will be generally familiar with the situation and able to handle short-term AGSOC debt requirements. There are approximately 100 U.S. commerical banks with a legal lending limit over $10,000,000. Because of geography or other considerations, we have identified 25 of these banks for possible consideration in term loan borrowings. With a reasonable capital structure, AGSOC should be essentially a prime rate customer for the commercial banks.

In addition, there are 107 foreign banks with offices in the United States, largely in the Eastern portion of the country. However, 9 foreign banks have offices in San Francisco and 6 in Los Angeles. Many of these banks provide services and loan terms other than those offered by U.S. commercial banks and should be considered a potential source of funds.

The true cost of debt capital is often higher than its nominal cost. The disparity is produced by many devices. Discounting (deducting interest in advance) increases true interest rate, as does the requirement of minimum balances, because they pare down the amount really available to the lender. Charges for investigation, servicing, and insurance can also raise the effective cost of debt.

The historical outlay cost of debt capital is easy to measure. It is indicated by the market yield to maturity on the company's debt securities, adjusted for costs of flotation and deflated for corporate income taxes. AGSOC might expect to pay an average of 14% in present money markets for a balanced package of short-term debt, term loans and long-term (15 year) insurance company private placements. The private placement area is dominated by 50 large insurance companies. Except for the very largest insurance companies, the average participation by these companies in a private placement financing is from $3,000,000 to $10,000,000 each.

The Cost of Equity Capital

In a market economy, any resource which is scarce, relative to the demand for it, commands a price -- however difficult it may be to measure that price. This is true even though reimbursement for the suppliers of equity capital is a residual; that is, what is left after more tangible costs of operations, including interest on debt, are satisfied. In the long run, equity capital is not a discretionary cost. The fact that the rewards are residual does not, as some think, mean that common stock capital is costless. In the long run, equity capital has a market price which is determined by investors' alternatives. Although owners of equity capital assume the ultimate risk by accepting as their compensation what is left, they have in most companies the option of selling at some price. They will not reinvest or long leave their capital in any corporation which does not offer reasonable prospects of returns as high as those promised by alternative investments.

Looking into the future, the AGSOC investments made today must be capable of earning enough in the future to cover all costs, including the costs of equity capital, as well as providing for recovery of the capital invested during the economic life of the project. Only thus can AGSOC maintain its financial integrity over the long term. For this reason, the policy of investment selection should establish investment standards which are based on the price it may pay for capital -- the combined cost of equity and debt capital -- to assure that no investment will be taken on today which will knowingly be incapable of earning the cost of capital in the future.

CHAPTER NINE

INVESTMENT POLICY

Investment policy is a subject closely related to the AGSOC Board of Directors. The primary function of the Board is to set policy. It may be up to the AGSOC senior investment officer to initiate policy and recommend changes in policy. The final decision, however, is the responsibility of the Board of Directors. There are three types of policy decisions that are basic: (1) determining the philosophy of investment, (2) estimating basic industry and economic trends and determining the best way to take advantage of them, and (3) dove-tailing corporate needs and future plans with investment philosophy.

On the philosophy of investment, it is up to the Board to decide in no uncertain terms whether it wishes staff to pursue a conservative, long-term investment program with emphasis on stability and income, or whether it wishes to place primary emphasis on total income (current income plus appreciation), rapid turnover, venture equity, and opportunistic types of investment.

The second type of policy, an estimate of industry and economic outlooks, provides opportunity for the staff to practice their utmost persuasion, but nevertheless it still should be the function of the Board to have the final word with clearly stated guidelines. Finally, the corporate needs of AGSOC must be injected into the equation. Of immediate consideration is the cash flow, dividend policy, and the nature of reserve adjustments. Of longer term consideration are corporate plans for the future.

Availability of Investment Funds

Except for very large projects which will require separate financing, normal investment policy will be heavily influenced by the AGSOC capital structure. The chapter on Sources and Cost of Capital Funds indicated a ready availability of debt funds to AGSOC presuming a satisfactory equity base. The experience of British Columbia Resources Investment Corporation suggests that considerable success might be possible in the sale of additional participation from the public. (See Appendix A.)

Below is one potential scenario out of many possibilities for development of the AGSOC equity base.*

A. <u>Distribution of One Initial Common Share</u>

400,000 eligible residents, 348,000 shares distributed (assumption is same 87% as achieved by British Columbia Resources).

B. <u>Sale of Convertible Debenture to Residents</u>

17,400 Alaskans purchase nine $100 principal amount, 8% Convertible Debentures. Each $100 debenture is convertible into one share of AGSOC common stock, thus keeping within the 10-share maximum as provided under Federal GSOC legislation. Proceeds to AGSOC would be $15,600,000. (Assumption is that 5% of the 348,000 Alaskans receiving initial shares will purchase the full offered allocation of debentures.) For comparison purposes, 6.5% of the British Columbians that received five free shares purchased at least 100 or more additional shares for proceeds of $487,500,000. An additional 2.0% purchased less than 100 additional shares.

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* The sample scenario is in technical conflict, but probably not in legislative intent conflict with the Federal Enabling Law which limits ownership to individuals. It could be argued that the Permanent Fund represents a group of individuals or the law could be changed.

C. **Purchase by Permanent Fund**

Permanent Fund purchases 200,000 common shares at $100 per share and 200,000 of the same 8% Convertible Debentures sold to individual Alaskans. Combined proceeds to AGSOC would be $40,000,000.

After the above steps, an AGSOC pro-forma balance sheet is shown.

Assets		Liabilities and Stockholders' Equity	
Current Assets		Current Liabilities	-0-
Cash and Temporary Investments	$55,600,000	Long-Term Debt	
		Convertible 8% Subordinated Debentures	$35,600,000
Investment and Other Assets	-0-		
Total Assets	$55,600,000	Stockholders' Equity	
		Common Stock, issued 548,000 shares*	$20,000,000
		Total Liabilities and Stockholders' Equity	$55,600,000

Under the above scenario, the 8% Convertible Subordinated Debentures would be junior to all other debt, providing AGSOC considerable borrowing capacity. Presuming a combination of additional debt totaling $44,400,000 at an average interest rate of 14%, AGSOC would have available funds for investment of some $100 million. A 20% return on invested funds before taxes (approximately the average in recent years from Textron, Inc., a comparable company in many ways) would produce the following pro forma income

***356,600 shares of additional common stock reserved for conversion of the 8% Convertible Debentures.**

statement.

Profit Before Interest and Taxes*	$20,000,000
Less Interest Charges	9,064,000
Profit Before Taxes*	$10,936,000
Dividends at 90%	9,842,400
To Retained Earnings at 10%	1,093,600
Dividends Per Common Share (548,000 Shares Outstanding)	$17.96

Since income would be larger in this situation from dividends ($17.96 versus $8.00 in interest), residents would tend to convert the convertible debentures into shares of common stock. Based on full conversion of the debentures, the income statement would appear as follows:

Profit Before Interest and Taxes*	$20,000,000
Less Interest Charges	6,216,000
Profit Before Taxes*	$13,784,000
Dividends at 90%	12,405,600
To Retained Earnings at 10%	1,378,400
Dividends Per Common Share (904,000 Shares Outstanding)	$13.72

This scenario represents a relatively small scale GSOC with assets of about 10% of the total of the Native Corporations. The $100 million figure was selected to allow easy multiplication to higher levels of size.

*No taxes due if Subchapter U GSOC.

CHAPTER TEN

CONCLUSION

Alaska has expanded significantly in recent years. It is a State of youth and vitality, and full of opportunity for the enterprising. The pace of development anticipated in Alaska is such that the need for capital is great, and openings exist for new enterprises. Technological development also continues to create additional opportunities for investment. As a result of our work, we see no difficulty in finding adequate investment opportunities even for a large size AGSOC over a period of time. Except for transfers of ownership situations such as TAPS, nearly all of the anticipated investment opportunities should meet a number of Alaska's principal economic goals. Presumably, AGSOC, owned and managed within Alaska, will be sensitive to the needs of employment, economic diversification, reduction of seasonality and other State goals.

Interviews with insurance companies, banks, and others demonstrate considerable interest in participation in AGSOC debt financing. In the beginning each potential source of funds will carefully analyze the AGSOC capitalization, management and business plan prior to making firm commitments. Such analysis will importantly impact the terms, cost and conditions imposed by the lender. Such factors will significantly influence the investment performance of AGSOC.

The Summary Table indicates the relative impact of possible investments discussed in this report. A plus (+) sign indicates a positive effect or a high probability of good results, a negative (-) sign indicates a negative effect or low probability, and a zero (0) indicates a relatively small change over existing conditions. Estimated return on investment (ROI) is based on an industry standard debt/equity capitalization for AGSOC. The table reflects current economic and business conditions of Alaska and the lower-48. Long-term investment results will be strongly impacted by the management direction of AGSOC.

SUMMARY TABLE

	Increased Employment	Stimulation Other Investments	Reduction of Economic Cyclicality	Growth Potential	AGSOC ROI Near Term	AGSOC ROI Long Term	Risk of Failure	Interference Private Sector
Forest Products	+	0	-	+	-	+	0	-
Finance	0	+	0	+	0	+	0	-
Insurance	0	0	0	+	0	+	0	-
Real Estate	0	+	-	+	+	+	-	-
Wholesale Trade	0	+	0	-	0	0	0	-
Retail Trade	+	+	0	+	0	+	-	-
Mining	+	0	+	+	-	0	-	0
Tourism	+	+	+	+	-	+	-	+
Utilities	0	0	0	0	+	0	+	0
Communications	0	0	0	0	0	+	0	0
TAPS	0	0	0	0	+	0	0	+
Gas Pipeline	+	+	+	0	-	0	0	+
Gas Conditioning Plant	+	+	+	0	-	0	0	+
Air Transport	0	0	-	+	-	+	-	-
TOTE	0	0	-	0	0	0	0	0
Motor Carrier	0	0	-	+	+	+	-	-
Alaska Railroad	0	0	-	-	-	-	0	+
Fish Processing	+	+	0	+	0	+	0	+
Fishing Vessels	+	+	0	+	0	0	-	+
Leasing	0	+	+	+	+	0	0	0

APPENDIX A

A CASE STUDY: BRITISH COLUMBIA RESOURCES INVESTMENT CORPORATION

British Columbia Resources Investment Corporation was initially conceived to be a vehicle to return to the private sector certain investments which were owned by the Province of British Columbia under their socialistic regime. The Government wanted to avoid the conflicts which can arise where it had regulatory authority over the forest products industry, for example, and yet had a direct holding in some pulp, lumber and plywood companies. In addition, the Government felt the process could provide a mechanism to raise some badly needed equity capital and would at the same time enable its citizens, who were watching their savings being eroded by inflation, to participate directly and individually in resource ownership.

BCRIC was patterned after the Canada Development Corporation and the Alberta Energy Company. After enacting legislation, the Government appointed five prominent British Columbians to be the founding incorporators of the company and its initial directors. They had one common and very significant characteristic; they are all chief executive offices of their own highly successful B.C. headquartered public company, and their companies do not compete with any BCRIC investments.

The company then acquired their initial investments from the Province for a promissory note of $151,000,000. The selection of investments (only from the Province's holdings) and the valuation of these investments was through a process audit by the Canadian investment firms of McCloud Young, A. E. Ames, Pemberton, and Richardson. BCRIC selected only good companies from the many Province holdings.

In order to give the ownership to the people, the Government agreed to exchange the $151,000,000 promissory note in full settlement for 15,000,000 common shares. Of those 15,000,000 shares, they offered to give 12,000,000 away, or five each, to each of the eligible residents. At the same time as applications were to be received for free shares, BCRIC would accept subscriptions for further shares at $6.00 each, to be issued from the treasury, to a maximum of 5,000 shares for eligible person. Book value before dilution was over $10.00 per share. Bearer shares were to be used in order to save the corporation the expense of registering potentially 2.4 million shareholders. In order to have registered shares and be a voting shareholder, one had to purchase a minimum of 95 shares, to be added to the five free ones in order to qualify. Bearer shares could be traded just as registered shares, and the stock exchanges agreed to reduce the trading block to five shares. In order to cut down on shareholder costs, only registered owners received mailed notices. Annual and interim shareholder reports for bearer shares are distributed by delivery of 250 copies to each branch of a financial institution to be placed on counters for pickup. Shareholder service costs are estimated at $1.50 per year for registered holders.

The distribution was an awesome and expensive undertaking. Because it involved a potential distribution to 2.4 million people, it required the utilization of all the financial institutions in the Province. Without the full participation of those institutions, involving some 1,300 individual locations, the job could not have been accomplished. Each branch of these institutions agreed to accept applications upon presentation of two forms of identification. The computer operations of BCRIC then sorted to avoid duplications.

The distribution and the sale resulted in 83% of the eligible population, or 2,000,000 people, applying for their free shares and 130,000 individuals applying to buy 100 or more shares, yielding gross proceeds of $487,500,000. Incidentally, another 40,000 people purchased extra shares, but not in sufficient number to be qualified for registration. In total, BCRIC has now 96,500,000 issued shares; the total cost of distributing <u>all</u> shares was $15,000,000 or approximately 3% of proceeds to the company.

The response surprised everybody involved in the process. There were a number of factors that produced such astounding results. First, the Canadian stock market was buoyant and a lot of people were interested in the market generally, with gas and oil interest particularly strong. (The inclusion of the gas and oil leases in BCRIC assets added appeal.) Second, people in British Columbia have pride in their Province, and they responded very positively to the concept of a totally B.C. operated and directed company in the resource field. Third, the Premier gave his own personal support to the issue. Fourth, the Board of Directors had great provincial credibility. Fifth, a general momentum developed on the issue as people read about it, talked about it, and listened to the advice of professionals as well as their friends and neighbors. They felt it was attractively priced. And finally, of course, there was an element of straight speculation by people anticipating a fast, profitable turn.

Between late June and August 7th, when trading was to commence, there was deliberation on the question of the appropriateness of the company declaring its intention to provide assistance in the maintenance of an orderly market, should it be required. The issue was not underwritten. However, the Board had the courage of their conviction in the principles of a free market, and elected not to provide support. While that decision did take courage, it was also reinforced by the belief that the large majority of the original purchasers were long-term investors and not short-term speculators. Now that shares are traded on the Vancouver and Toronto Exchange, anybody across Canada can buy shares. (There is no holding period for the free or purchased shares.) In 1979, some 24,000,000 shares were traded (about 20% of the total).

BCRIC has been successful in keeping its image as a private company rather than a quasi-public body. It states its responsibilities only to shareholders and not to the Province. It has freedom to invest in companies outside of the Province.

Selection of new investments will be concentrated in the area of natural resources. BCRIC feels no restraint on its investment objectives through other companies, the government, or any social responsibility other than such responsibility any private company may hold. BCRIC intends to be an operating company rather than just a holding company. Its initial and current holdings are:

> 81% of Canadian Cellulose, a public company and a major pulp and lumber producer in the Province.
>
> 100% of two medium-sized lumber producers, Kootenay Forest Products and Plateau Mills, the former also a producer of sheathing plywood.
>
> 10% of the shares of Westcoast Transmission, a natural gas pipeline company controlled by Pacific Gas & Electric Company.
>
> A license to explore for gas and oil on some 2.3 million acres of public land in northeastern British Columbia.

BCRIC has a present equity capitalization of over $600,000,000 through the offer and the initial holdings. In addition, it can borrow to put its total asset holdings over a billion. It currently generates about $30,000,000 in earnings on a sales volume of $300,000,000 through its present holdings. Its interest earnings on the cash proceeds of the issue are yielding over $1,000,000 a week or over 11%; however, in order to stimulate growth, their policy is not to distribute dividends for three to five years.

BCRIC feels that one of the benefits of wide citizen ownership is that employees of its companies see themselves as working for themselves and other citizens as owners rather than unknown shareholders or the government. BCRIC feels that many labor problems will be averted through this concept.

APPENDIX B

FEDERAL ENABLING LAW

REVENUE ACT OF 1978[1]

(H.R. 13511)

ENACTING TITLE VI, INTERNAL REVENUE CODE OF 1954, AS AMENDED

GENERAL STOCK OWNERSHIP CORPORATIONS

NOTE: Numbers in parenthesis above the text refer to the explanatory annotations immediately following the text of the legislation.

Sec. 601. ESTABLISHMENT AND TAXATION OF GENERAL STOCK OWNERSHIP CORPORATIONS AND THEIR SHAREHOLDERS.

(a) IN GENERAL - Chapter 1[2] (relating to normal taxes and surtaxes) is amended by adding at the end thereof the following new subchapter:

"Subchapter U[3] - General Stock Ownership Corporations

"Sec. 1391. Definitions.
"Sec. 1392. Election by general stock ownership corporation.
"Sec. 1393. Corporation taxable income taxed to shareholders.
"Sec. 1394. Rules applicable to distributions of electing general stock ownership corporations.
"Sec. 1395. Adjustments to basis of stock of shareholders.
"Sec. 1396. Minimum distribution.
"Sec. 1397. Special rules applicable to earnings and profits of an electing general stock ownership plan.

"Sec. 1391. DEFINITIONS.

"(a) GENERAL STOCK OWNERSHIP CORPORATION. - For purposes of this subchapter, the term 'general stock ownership corporation' (hereinafter referred to as a 'GSOC') means a domestic[4] corporation which -

"(1) is not a member of an affiliated group (as defined in section 1504),[5] and

"(2) is chartered and organized after December 31, 1978, and before January 1, 1984;[6]

"(3) is chartered by an act of a State legislature[7] or as a result of a State-wide referendum;

"(4) has a charter providing -

"(A) for the issuance of only 1 class of stock,

"(B) for the issuance of shares only to eligible individuals[8] (as defined in subsection (c));

"(C) for the issuance of at least one share to each eligible individual,[9] unless each eligible individual elects within one year after the date of issuance not to receive such share;

"(D) that no share of stock shall be transferable -

"(i) by a shareholder other than by will or the laws of descent and distribution until after the expiration of 5 years from the date such stock is issued by the GSOC except where the shareholder ceases to be a resident of the State;[10]

"(ii) to any person other than a resident individual of the chartering State;[11]

"(iii) to any individual who, after the transfer, would own more than 10 shares of the GSOC;[12]

"(E) that such corporation shall qualify as a GSOC under the Internal Revenue Code;[13]

"(5) is empowered to invest in properties (but not in properties acquired by it or for its benefit through the right of eminent domain.[14]

For purposes of this subsection, section 1504

(a) shall be applied by substituting '20 percent' for '80 percent' wherever it appears.

"(b) ELECTING GSOC. - For purposes of this subchapter, the term 'electing GSOC' means a GSOC which files an election under section 1392 which, under section 1392, is in effect for such taxable year.[15]

"(c) ELIGIBLE INDIVIDUALS. - For purposes of subsection (a), the term 'eligible individual' means an individual who is, as of a date specified in the State's enabling legislation for the GSOC, a resident of the chartering State and who remains a resident of such State between that date and the date of issuance.[16]

"(d) TREATED AS PRIVATE CORPORATION. - For purposes of this title, a GSOC shall be treated as a private corporation and not as a governmental unit.[17]

"(e) STUDY OF GENERAL STOCK OWNERSHIP CORPORATIONS. - The staff of the Joint Committee on Taxation shall prepare a report on the operation and effects of this subchapter relating to GSOC's. An interim report shall be filed within two years after the first GSOC is formed and a final report shall be filed by September 30, 1983.

"Sec. 1392. ELECTION BY GSOC.

"(a) ELIGIBILITY. - Except as provided in section 1393, any GSOC may elect, in accordance with the provisions of this section, not to be subject to the taxes imposed by this chapter.[18]

"(b) EFFECT. - If a GSOC makes an election under subsection (a) then -

"(1) with respect to the taxable years of the GSOC for which such election is in effect, such corporation shall not be subject to the taxes imposed by this chapter and, with respect to such taxable years and all succeding taxable years, the provisions of section 1396 shall apply to such GSOC,[19] and

"(2) with respect to each such taxable year, the provisions of section 1393, 1394, and 1395 shall apply to the shareholders of such GSOC.[20]

"(c) WHERE AND HOW MADE. - An election under subsection (a) may be made by a GSOC at such time and in such manner as the Secretary shall prescribe by regulations.

"(d) YEARS FOR WHICH EFFECTIVE. - An election under subsection (a) shall be effective for the taxable year of the GSOC for which it is made and for all succeeding taxable years of the GSOC, unless it is terminated under subsection (f).

"(e) TAXABLE YEAR. - The taxable year of a GSOC shall end on October 31 unless the Secretary consents to a different taxable year.".[21]

"(f) TERMINATION. - The election of a GSOC under subsection (a) shall terminate for any taxable year during which it ceases to be a GSOC and for all succeeding taxable years.[22] The election of a GSOC under subsection (a) may be terminated at any other time with the consent of the Secretary, effective for the first taxable year with respect to which the Secretary consents and for all succeeding taxable years.[23]

"Sec. 1393. TAXABLE INCOME TAXED TO SHAREHOLDERS.

"(a) GENERAL RULE. - The taxable income of an electing GSOC for any taxable year shall be included in the gross income of the shareholders of such GSOC in the manner and to the extent set forth in this subsection.(24)

"(1) AMOUNT INCLUDED IN GROSS INCOME. - Each shareholder of an electing GSOC on any day of a taxable year of such GSOC shall include in his gross income for the taxable year with or within which the taxable year of the GSOC ends the amount he would have received if, on each day of such taxable year, there had been distributed pro rata to its shareholders by such GSOC an amount equal to the taxable income of the GSOC for its taxable year divided by the number of days in the GSOC's taxable year.(25)

"(2) TAXABLE INCOME DEFINED. - For purposes of this section, the term 'taxable income' of a GSOC shall be determined without regard to the deductions allowed by part VIII of subchapter B (other than deductions allowed by section 248, relating to organizational expenditures).(26)

"(b) SPECIAL RULE FOR INVESTMENT CREDIT.(27) - The investment credit of an electing GSOC for any taxable year shall be allowed as a credit to the shareholders of such corporation in the manner and to the extent set forth in this subsection.

"(1) CREDIT. - There shall be apportioned among the shareholders a credit equal to the amount each shareholder would have received if, on each day of such taxable year, there had been distributed pro rata to the shareholders the electing GSOC's net investment credit divided by the number of days in the GSOC's taxable year.

"(2) NET INVESTMENT CREDIT. - For purposes of this paragraph the term 'net investment credit' means the investment credit of the electing GSOC for its taxable year less any tax from recomputing a prior year's investment credit in accordance with section 47.

"(3) RECAPTURE. - There shall be apportioned among the shareholders of a GSOC, in the manner described in paragraph (1), an additional tax equal to the excess of any tax resulting from recomputing a prior year's investment credit in accordance with section 47 over the investment credit of the GSOC for it's taxable year.

"Sec. 1394. RULES APPLICABLE TO DISTRIBUTIONS OF AN ELECTING GSOC'S[28]

"(a) SHAREHOLDER INCOME ACCOUNT. - An electing GSOC shall establish and maintain a shareholder income account[29] which account shall be -

"(1) increased at the close of the GSOC's taxable year by an amount equal to the GSOC's taxable income for such year,[30] and

"(2) Decreased, but not below zero, on the first day of the GSOC's taxable year by the amount of any GSOC distribution to the shareholders of such GSOC made or treated as made during the prior taxable year.[31]

"(b) TAXATION OF DISTRIBUTION. - Distributions by an electing GSOC shall be treated as -

"(1) a distribution of previously taxed income to the extent such distribution does not exceed the balance of the shareholder income account as of the close of the taxable year of the GSOC,[32] and

"(2) a distribution to which section 301(a) applies but only to the extent such distribution exceeds the balance of the shareholder income account as of the close of the taxable year of the GSOC.[33]

"(c) DISTRIBUTIONS NOT TREATED AS A DIVIDEND. - Any amounts includible in the gross income of any individual by reason of ownership of stock in a GSOC shall not be considered as a dividend for purposes of section 116.[34]

"(d) REGULATIONS. - The Secretary shall have authority to prescribe by regulation, rules for treatment of distribution in respect of shares of stock of the GSOC that have been transferred during the taxable year."[35]

"Sec. 1395. ADJUSTMENT TO BASIS OF STOCK OF SHAREHOLDERS.[36]

"The basis of a shareholder's stock in an electing GSOC shall be increased by the amount includible in the gross income of such shareholder under section 1393, but only to the extent to which such amount is actually included in the gross income of such shareholder.

"Sec. 1396. MINIMUM DISTRIBUTIONS.

"(a) GENERAL RULE. - A GSOC shall distribute at least 90 percent of its taxable income for any taxable year by January 31 following the close of such taxable year.[37] Any distribution made on or before

January 31 shall be treated as made as of the close of the preceding taxable year.

"(b) IMPOSITION OF TAX IN CASE OF FAILURE TO MAKE MINIMUM DISTRIBUTION.[38] - If a GSOC fails to make the minimum distribution requirements described in subsection (a), there is hereby imposed on the GSOC a tax equal to 20 percent of the excess of the amount required to be distributed over the amount actually distributed.

"Sec. 1397. SPECIAL RULES APPLICABLE TO AN ELECTING GSOC.[39]

"(a) GENERAL RULE. - The current earnings and profits of an electing GSOC as of the close of its taxable year shall not include the amount of taxable income for such year which is required to be included in the gross income of the shareholders of such GSOC under section 1393(a).[40]

"(b) SPECIAL RULE FOR AUDIT ADJUSTMENTS.[41] -

"(1) TAXABLE INCOME. - Taxable income of an electing GSOC shall, in the year of final determination, be increased or decreased, as the case might be, by any adjustment to taxable income for a prior taxable year.

"(2) INVESTMENT CREDIT. - The investment credit of an electing GSOC shall, in the year of final determination, be increased or decreased, as the case might be, by any adjustment to the net investment credit for a prior taxable year.

"(3) METHOD OF MAKING ADJUSTMENTS. - An electing GSOC shall include in gross income for the year of an adjustment the amount described in paragraph (1) and shall take into account the adjustment described in paragraph (2), and shall be liable for payment of interest in the amount that would have been payable by the GSOC under section 6601 (relating to interest on underpayment, nonpayment or extensions of time for payment, of tax) or receivable by the GSOC under section 6611 (relating to interest on overpayments) if such GSOC had been a corporation other than an electing GSOC.

(b) TECHNICAL AMENDMENTS. -

(1) NET OPERATING LOSS DEDUCTION.[42] - Paragraph (1) of section 172(b) (relating to net operating loss carrybacks and carryovers) is amended by adding at the end thereof the following new subparagraph:

"(H) In the case of an electing GSOC which has a net operating loss for any taxable year such loss shall not be a net operating loss carryback to any taxable year preceding the year of such loss, but shall be a net operating loss carryover to each of the 10 taxable years following the year of such loss."

(2) INCOME TAX COLLECTED AT SOURCE.(43) - Section 3402 (relating to income collected at source) is amended by adding at the end thereof the following new subsection:

"(r) EXTENSION OF WITHHOLDINGS TO GSOC DISTRIBUTIONS. -

"(1) GENERAL RULE. - An electing GSOC making any distribution to its shareholders shall deduct and withhold from such payment a tax in an amount equal to 25 percent of such payment.

"(2) COORDINATION WITH OTHER SECTIONS. - For purposes of sections 3403 and 3404 and for purposes of so much of subtitle F (except section 7205) as relates to this chapter, distributions of an electing GSOC to any shareholder which are subject to withholding shall be treated as if they were wages paid by an employer to an employee."

(3) ADJUSTMENTS TO BASIS.(44) - Section 1016(a) (relating to adjustments of basis) is amended by redesignating pargraph (23) as (22) and by inserting after paragraph (20) the following new paragraph:

"(21) to the extent provided in section 1395 in the case of stock of shareholders of a general stock ownership corporation (as defined in section 1391) which makes the election provided by section 1392; and".

(4) RETURN OF GENERAL STOCK OWNERSHIP CORPORATION.(45) - Subpart A of part III of subchapter A of Chapter 61 (relating to information returns) is amended by adding at the end thereof the following new section:

"Sec. 6039B. RETURN OF GENERAL STOCK OWNERSHIP CORPORATION.

"Every general stock ownership corporation (as defined in section 1391) which makes the election provided by section 1392 shall make a return for each taxable year, stating specifically the items of its gross income and the deductions allowable by subtitle A, the amount of investment credit or additional tax, as the case may be, the names and addresses of all persons owning stock in the corporation at any time during the taxable year, the number of shares of stock owned by each shareholder at all times during the taxable year, the amount of money and other property distributed by the corporation during the taxable year to each shareholder, the date of each such distribution, and such other information, for the purpose of carrying out the provisions of subchapter U of chapter 1, as the Secretary may by regulation prescribe. Any return filed pursuant to this section shall, for purposes of chapter 66 (relating to limitations), be treated as a return filed by the corporation under section 6012.[46] Every GSOC shall file an annual report with the Secretary summarizing its operations for such year."[47]

(c) CLERICAL AMENDMENTS.[48] -

(1) The table of subchapters for chapter 1 is amended by adding at the end thereof the following:

"SUBCHAPTER U. - General stock ownership plans."

(2) The table of sections for subpart A of part III of subchapter A of chapter 61 is amended by adding at the end thereof the following:

"Sec. 6039B. Return of general stock ownership corporation."

(d) EFFECTIVE DATE.[49] - The amendments made by this section shall apply with respect to corporations chartered after December 31, 1978, and before January 1, 1984.

1. The Revenue Bill of 1978 was passed by the Congress of the United States on October 14, 1978, and signed into law by President Carter on November 6, 1978. The General Stock Ownership Corporation provisions were included as a Senate amendment to that Bill (H.R. 13511) and appear in the legislation as Title VI.

2. The Internal Revenue Code is organized into chapters, subchapters, sections, and subsections. Chapter 1 of the Internal Revenue Code deals generally with the income tax provisions of the Federal law covering both personal and corporate taxes.

3. The Revenue Act of 1978 amends Chapter 1 of the Internal Revenue Code to add a new subchapter designated as Subchapter U. This subchapter, containing seven sections (Sections 1391-1397), sets forth the Federal tax law regarding General Stock Ownership Corporations.

4. A domestic corporation is a corporation which is organized under the laws of the United States or a state thereof.

5. The Internal Revenue Code, Section 1504, defines an affiliated group for purposes of determining which corporations are eligible to file consolidated returns. Generally, an affiliated group is formed when one corporation acquires 80% or more of the voting stock of one or more other corporations. The 80% or more definition in Section 1504 is to be read as 20% or more for purposes of the GSOC legislation.

Since GSOC stock may not be owned by a corporation or other non-individual, the limitation on membership in affiliated groups applies only to ownership by the GSOC of stock in other corporations. The GSOC, in order to avoid being a member of an affiliated group, may not own 20% or more of the stock in another corporation. Failure to comply with this requirement would appear to jeopardize the special tax treatment available to the GSOC under Federal law.

This limitation was included in the GSOC provisions in order to prevent the GSOC from becoming a holding company for other corporations' stock. Because of the special nature of the GSOC tax advantages this limitation is not particularly significant. The elimination of corporate income taxes for the GSOC may not be extended to corporations owned by the GSOC. Therefore, any subsidiary corporation would be fully subject to the Federal income tax, and dividends paid by such a corporation to the GSOC would be net of Federal taxes. The special tax advantage of the GSOC in eliminating the Federal corporate income tax would therefore be defeated by significant ownership of subsidiary corporations.

6. In keeping with the experimental nature of the General Stock Ownership Corporation legislation, a five year period was provided during which such corporations may be formed. Any corporation not formed within the dates set forth in the Act

will not be eligible for treatment under Federal tax law as a General Stock Ownership Corporation. However, any corporation formed and qualifying under these provisions during the five year period will continue to receive the special tax treatment provided GSOCs indefinitely. There is no limitation on the tax advantages once a corporation is established within the designated time frame.

7. The term charter is used in its broadest sense and means that the corporation must have a special grant of powers from either the State Legislature or a statewide referendum. It would not appear to be acceptable for a state to generally authorize the creation of GSOCs. But, it also does not appear necessary for a state to adopt into the law the actual Articles of Incorporation for the GSOC. Indeed, it may be unacceptable for a Legislature to enact the Articles of Incorporation into law and subsequently allow the stockholders of the corporation to amend the Articles. Amendment of the Articles of Incorporation in such a case would appear to effectively amend the statutes of the authorizing state and this would seem to be an unconstitutional delegation of the power of a State Legislature. Conversely, if the Articles of Incorporation could not be amended by its stockholders, it would not appear to be a private business corporation as Congress contemplates by this law.

8. Eligible individual is defined in Section 1391(c) and will be further discussed in Footnote 16 below.

9. At least one share of stock in the General Stock Ownership Corporation must be issued to each eligible individual unless that individual elects within the first year of ownership not to receive the stock. This language does not appear to preclude charging a purchase price for the stock, but in such an event would seem to require that some accommodation be made for those eligible individuals who are not in a position or who are unwilling to pay for the stock. Generally, the drafters of the legislation contemplated the simple distribution of the stock without charge to eligible individuals, with corporate operations and purchases thereafter financed initially through debt instruments only. This would enable the stockholders to build an equity in the stock through amortization of debt with the earnings of corporate investments.

10. In order to qualify as a General Stock Ownership Corporation, the transfer of corporate stock must be restricted during the first five years following its issuance. Since it was contemplated that stockholders in a General Stock Ownership Corporation would be limited to the residents of the authorizing state, an exception is provided so that if an individual ceases to be a resident or dies during the first five years, his stock may be sold or transferred.

The five year transfer restriction was included in order to give shareholders a period of time during which to become familiar with the benefits of stock ownership. It is hoped that during the first five years of corporate operations the GSOC would be in a position to distribute dividends, giving its shareholders some experience with the income generating capabilities of capital and giving those interested in the formation of these particular corporations an opportunity to study the reactions of shareholders to this new type of investment.

In order to discourage shareholders from emigrating in order to sell their stock prior to the end of the five year period, it may be necessary to provide for some controlled purchase price. This could be done in the form of an option on the part of the corporation to repurchase stock from an individual emigrating from the authorizing state at a value below either the fair market value or income stream valuation approach. Such a repurchase would be consistent with the private capital nature of the GSOC stock and could return to the shareholder his book equity. Book equity valuation for purposes of a mandatory repurchase during the five year nontransferability period might be appropriate in that this represents the shareholder's share of cash invested in acquiring the asset. This is the case because the distribution of stock was cost free to the shareholder and his only investment at the time of sale will be in the form of what would otherwise be cash distributions applied to the repayment of the debt incurred to buy the underlying assets. Thus the shareholder is paying for his capital out of the income it produces.

In the event that a shareholder whose shares are repurchased at book value has incurred tax liability in excess of his distributions of cash from the corporation, his basis in the stock will be increased accordingly and he will receive a capital loss deduction for the difference between the book value purchase price and his adjusted basis. This loss deduction will offset his future additional income from the GSOC, insuring that he remains whole once the transaction is concluded if the assets purchased by the GSOC have thrown off in income their purchase costs and necessary interest.

11. Transfers of GSOC stock may not be made to individuals who are not "residents" of the authorizing state. This limitation is designed to assure that the GSOC, which must begin life as a corporation owned by the residents of a single state, either continues to be owned by those residents or, if they are permitted to take it out of state and cease to be residents, they must at or before their death transfer their GSOC stock to a qualified resident. Thus, while a holder of GSOC stock may sell or otherwise dispose of his stock, he may not do so to a corporation, trust, partnership, or other artificial person nor to any individual who is not a resident of the authorizing state.

12. This limitation on transfers was included in order to assure that great concentrations of GSOC stock do not develop. The GSOC was conceived as a means of broadening capital ownership and thereby spreading more widely the income benefits from capital. This transfer limitation implements these goals.

13. The requirements of Section 1391(4)(A)-(E) are limitations which must be included in both the GSOC authorizing legislation adopted by the State Legislature and the Articles of Incorporation for the GSOC. The limitation set forth in (E) simply makes it clear that both the authorizing Legislature and the incorporators of the General Stock Ownership Corporation intend to qualify under the provisions of Subchapter U of the Internal Revenue Code.

14. There are generally no limitations on the types of investments which GSOCs may undertake. However, because of the unique relationship between GSOCs and the authorizing State Legislatures, certain members of Congress felt it necessary to clarify that GSOCs may not be used as vehicles through which ownership of existing capital assets can be transferred from one group to another through the exercise of the state's powers of eminent domain. Therefore, this limitation was added to prevent the power of state condemnation from being used to transfer unwillingly ownership of an existing business to a General Stock Ownership Corporation. This language does not preclude the condemnation of a pipeline right of way or the purchase by a General Stock Ownership Corporation of an asset a component of which is acquired by the sellers through condemnation. It is designed only to preclude the direct condemnation of existing business assets and a resale thereof to the GSOC.

15. The General Stock Ownership Corporation, in order to avail itself of the special tax treatment provided under Subchapter U, must file an election with the Secretary of the Treasury under the terms of Section 1392, discussed below at Footnote 18.

16. Eligible individuals are those individuals to whom stock must be issued under the provisions of Section 1391(a)(4)(B). Stock must be issued to individuals who are, as of a specific date set forth in the state's GSOC enabling legislation, residents of the state and who remain residents of the state until the date the stock is actually issued. The statutory language with respect to a specific date was included to allow a State Legislature to select a date certain upon which residency could be determined. It was contemplated that such a date might be one prior to the date of the enabling legislation in order to assure that a flood of immigrants to the state would not be encouraged.

The term resident may be defined by the State Legislature for purposes of the GSOC legislation in any constitutional and acceptable manner. The term resident itself is a legal term of uncertain meaning, the definition of which varies with the use. For purposes of general stock ownership legislation it may be appropriate to use a definition of resident which equates that term with the legal term of "domiciliary". This would give a definition of resident dependent not only upon present mailing address or physical location within the state, but intent, however evidenced, to establish and maintain primary geographical living situs within the State of Alaska.

17. The GSOC is to be treated as a private corporation and therefore is not eligible to issue securities or levy taxes as a governmental unit or municipal corporation.

18. To take advantage of the special provisions of Subchapter U, the General Stock Ownership Corporation must file an election under the provisions of Section 1392. The election is to be made at the time and in the manner described by the Secretary of the Treasury. Section 1392(b) is effective for the taxable year of the GSOC for which it is filed and for all later taxable years unless the election is terminated.

19. If the GSOC makes an election under Section 1392, the GSOC corporation itself is exempt from all the income taxes imposed by Chapter 1 of the Internal Revenue Code for the year in which the election is made and all following years until the election is terminated. The GSOC is, however, subject to the limitations of Section 1396 which requires minimum distributions of GSOC income and imposes a penalty tax in the event of a failure to distribute income in accordance with Section 1396 requirements.

20. While the electing GSOC is exempt from Federal income tax, the income of the corporation is taxed to the shareholders under Sections 1393, 1394 and 1395. These sections set out the rules under which the shareholders are attributed the income of the General Stock Ownership Corportion, provide for tax treatment of GSOC distributions, and establish rules for determining the basis of a shareholder's stock.

21. In order to assure that significant deferral of income does not occur, the General Stock Ownership Corporation is required to operate on a taxable year ending on October 31st. This allows the corporation sufficient time to determine its taxable income for the year and to provide that information to the shareholders prior to the April 15th regular filing deadline for shareholders' returns.

22. It appears that under the Federal legislation there is at least one event which could involuntarily terminate the special tax status of the General Stock Ownership Corporation, and that event would be membership in an affiliated group which is prohibited under the terms of Section 1391(a)(1). Depending on interpretations of the general law, other events might involuntarily terminate the special status of the GSOC, such as a revocation by the State Legislature of a corporation's charter or amendments to the Articles of Incorporation which remove the conditions required by Section 1391(4) and (5).

23. The election of the General Stock Ownership Corporation to qualify under Subchapter U may be terminated at any time with the consent of the Secretary of the Treasury. Voluntary termination of GSOC status under Subchapter U might be sought in the event that a General Stock Ownership Corporation were to incur taxable income, perhaps from recapture on the sale of an asset, substantially in excess of cash available for distribution. At

this point the Board of Directors might elect to terminate GSOC status so that the taxable income of the corporation did not flow through to the shareholders, but remained, under the normal rules of corporate taxation, with the corporation. While it is not expected that such an event is likely to occur, it was felt that an option should be provided to allow voluntary termination of elections.

24. This provision makes it clear that the income of the General Stock Ownership Corporation is to be taxed directly to the shareholders.

25. If an individual is a shareholder of a General Stock Ownership Corporation at any point during the GSOC's taxable year, that individual will be attributed a share of the corporation's income for that taxable year. The income must be included in the return of the shareholder for the shareholder's tax year during which the GSOC year ends. Thus, if an individual is a shareholder of a GSOC at any time during the corporation's fiscal year beginning on November 1, 1980, and ending on October 31, 1981, the shareholder would be required to include his share of GSOC income on his personal return for calendar year 1981.

If an individual is a shareholder of a General Stock Ownership Corporation throughout the entire taxable year of the corporation, his share of GSOC income is determined by dividing the total amount of GSOC income for the year by the number of shares of stock outstanding and then multiplying this per share earnings figure by the number of shares owned by the shareholder. If, however, the shareholder should dispose of his stock during the corporation's taxable year, he will be attributed income from the corporation on the basis of the number of days during the corporation's taxable year during which he was a shareholder. The per share income of the corporation for the entire year would be divided by 365 to determine the per share daily earnings of the corporation and this amount would be multiplied by the number of days during the year which the shareholder owned his stock. The product of this formula would give the earnings attributable to shareholder's part year ownership interest and this amount would be included in the shareholder's taxable year during which the GSOC year ends.

26. The term taxable income is a clearly defined term for the purposes of the Internal Revenue Code. The taxable income of the General Stock Ownership Corporation is to be determined under the normal rules for corporations, although the General Stock Ownership Corporation is not required to pay tax on this income. The General Stock Ownership Corporation is not allowed to deduct those items normally allowed to corporations under Part 8 of Subchapter B. These deductions include the dividend received deduction, the foreign corporation dividend received deduction, public utilities dividends deduction, and other minor tax deductions. The General Stock Ownership Corporation is allowed to deduct the organizational expenses allowed by Section 248 under

Part 8 of Subchapter B of the Internal Revenue Code. Section 248 provides an option to corporations to deduct organizational expenses over a period of not less than sixty months.

27. The Internal Revenue Code allows a tax credit equal to 10% of the purchase price of certain types of new and used property. This 10% credit is a dollar for dollar offset against taxes due rather than a deduction from gross income in arriving at taxable income. The property eligible for the investment tax credit is generally depreciable tangible personal property, excluding buildings and structural components, used by an individual or corporation engaged in a trade or business and having a useful life of at least three years. The investment tax credit may be taken on the taxpayer's return during the year in which the taxpayer places such an asset into use in his trade or business. In the event that the taxpayer disposes of an asset on which he has taken an investment tax credit prior to the required seven year holding period, he is subject to recapture by the Federal Government of all or a portion of the investment tax credit in the form of additional tax liability. The sections of the Internal Revenue Code applicable to investment tax credits and investment tax credit recapture include Sections 38, 46, 47, and 48.

The 10% investment tax credit is not allowed to a General Stock Ownership Corporation. This is unimportant, however, since the General Stock Ownership Corporation has no tax liability and therefore could not avail itself of the tax credit in any event. Section 1393(b) provides that the investment tax credit to which a General Stock Ownership Corporation would be entitled if it were taxable shall flow through to the shareholders in much the same manner as income. The investment tax credit and any recapture of investment tax credit generated by the sale of corporate assets will be netted at the corporate level. If there is a net investment tax credit, that amount will be prorated to the shareholders in the same manner as income. If there is a net investment tax credit recapture, this amount will be prorated as well, but will be characterized as additional tax liability to the shareholders. It is not expected that the corporation will operate in such a way as to generate any significant amount of net investment credit recapture.

28. Distributions of corporate income are normally taxed as ordinary income to the extent that they constitute dividends paid out of the earnings of the corporation. Distributions in excess of the accumulated earnings of the corporation are treated as a reduction in the shareholder's basis in his stock and to the extent they exceed the shareholder's basis are taxed at capital gains rates. Additional rules are necessary for distributions from General Stock Ownership Corporations since the distributions do not bear direct relationship to the amount of tax which the shareholders may pay. The rules of Section 1394 are designed to indicate whether a distribution of cash from a General Stock Ownership Corporation is a distribution of

income which has already been taxed to the shareholders, a distribution of capital reducing the shareholder's basis in his shares, or a capital gain.

29. The shareholder income account is simply a bookkeeping entry of the corporation designed to keep track of the relationship between taxable income of the GSOC attributed to the shareholders and cash distributions by the GSOC to its shareholders.

30. The shareholder income account is increased at the close of each GSOC taxable year by an amount equal to the GSOC's taxable income in order to indicate the total amount of taxable income which has been attributed to the shareholders and is taxable to them.

31. The shareholder income account is decreased to a minimum balance of zero at the beginning of each GSOC taxable year by the amount of distributions made to the shareholders from the GSOC during the prior year. Thus the account which has been increased by the amount of GSOC taxable income for the prior year is immediately decreased by the amount of distributions made from the GSOC during the same year. Any balance remaining in the GSOC income account after these entries have been made will show the amount of GSOC income in excess of cash distributions on which the GSOC shareholders have paid tax. A General Stock Ownership Corporation is required by Section 1396 to distribute at least 90% of its taxable income for any taxable year ending October 31st by January 31st of the following year. Any distribution made on or before January 31st is to be treated as if it were made as of the close of the preceding taxable year ending October 31st. This means that distributions made within three months of the close of the GSOC's taxable year will be treated as made during the preceding taxable year for purposes of the shareholder income account.

32. To the extent that distributions of the General Stock Ownership Corporation do not exceed the amount in the shareholder income account as of the close of the taxable year (the taxable income of the GSOC for the current year and any taxable income in excess of the distributions from prior years), the distribution will be treated as a distribution of income which has already been taxed to the shareholders and therefore will come to the shareholders tax free.

33. If the distribution should exceed the balance of the shareholder income account, the account would be netted out at zero and distributions in excess of the account would be dealt with under Section 301(a) of the Internal Revenue Code. Section 301 provides that distributions which are not a dividend within the meaning of Code Section 316 (which such GSOC distributions would not be) are treated first as a reduction of the shareholder's basis in his stock and, to the extent the distribution exceeds the shareholder's basis, the distribution is treated as a capital gain. Distributions which are treated as a capital gain will

either be treated as a short term or long term capital gain depending on the time period during which the shareholder has owned his stock.

34. Section 116 of the Internal Revenue Code provides a $100.00 exclusion for individuals receiving dividends on corporate stock. This provision is a simplified way of eliminating the double taxation of dividends for the recipients of small dividend amounts. Since the double taxation of dividends has been completely eliminated for all shareholders in a General Stock Ownership Corporation, it was felt that this additional tax concession was unnecessary. Therefore, the income attributable to an individual taxpayer from a General Stock Ownership Corporation is not eligible for the $100.00 dividend exclusion provided by Section 116.

35. Distributions from the General Stock Ownership Corporation of cash or other property may not directly parallel the tax liability of the respective owners of stock in a situation where a sale of stock occurred during the taxable year. It was felt appropriate to provide the Secretary of the Treasury with regulatory authority to determine the best means of adjusting the relative tax statuses of the seller and buyer and to establish rules for the allocation of distribution rights between the two parties.

36. Generally, in a conventional corporation, the basis of a shareholder in his corporate stock equals the price paid for that stock. Upon a sale of the stock, the shareholder determines his taxable gain by deducting his basis from the sale's proceeds. It is this amount which is referred to in the tax laws as a capital gain. The shareholder in a General Stock Ownership Corporation which distributes its stock free of charge to the shareholders will have a basis in his stock at the time of receipt equal to zero. In the event that distribution of the stock should result in a tax liability to the shareholder because the Internal Revenue Service has imputed income to him from the receipt of stock, the shareholder would receive a basis in the stock equal to the value at which the stock is assessed for purposes of Federal income taxation.

Section 1395 provides a special rule for determining the basis of stock in General Stock Ownership Corporations. Assuming that no income is imputed to the shareholder upon receipt of his shares, he will have a zero basis in the stock at the time of receipt. The basis in his stock will then be increased for the amount of GSOC income which is attributed to him for tax purposes. This means that as he pays tax on General Stock Ownership Corporation income the basis in his stock will increase. The basis will be decreased for distributions from the General Stock Ownership Corporation reflecting the shareholder's receipt of income on which he has paid tax. In the normal course of events, a General Stock Ownership Corporation shareholder will have a basis in his stock which reflects the difference between the income of the corporation on which he has been taxed less the cash distributions which he has received from the corporation. If the corporation distributes all of its taxable income, the shareholder will continue to have a zero basis in his stock and the entire proceeds of any sale thereof will be treated for tax purposes as a capital gain.

37. In order to assure that the shareholders of the General Stock Ownership Corporation have cash on hand sufficient to cover the tax liability generated by the income attributed to them from the General Stock Ownership Corporation, the corporation is required to distribute to its shareholders at least 90% of its taxable income for the year ending October 31st on or before the following January 31st. This distribution would normally allow the shareholders to have cash on hand to pay their personal taxes for the year ending December 31st on the following April 15th when those taxes become due.

38. In order to insure that the General Stock Ownership Corporation makes the distributions required by Section 1396, a penalty is provided for failure to do so. This penalty is an additional tax (deductible by the General Stock Ownership Corporation) equal to 20% of the amount which the GSOC failed to distribute on a timely basis. Thus, if the General Stock Ownership Corporation had taxable income for the year of $100.00 and distributed only $80.00 by January 31st of the following year, it would fail to comply with the requirements of Section 1396. Section 1396 requires a 90% distribution of taxable income and would have required the corporation to distribute $90.00 to its shareholders by January 31st of the following year rather than $80.00. A 20% tax would be levied on the difference between the amount which should have been distributed ($90.00) and the amount which was in fact distributed ($80.00). Thus, the tax would be 20% of $10.00 or $2.00.

39. Section 1397 sets forth special rules applicable to a General Stock Ownership Corporation and a number of technical amendments to other sections of the Internal Revenue Code necessary to the operation of the GSOC provisions.

40. Earnings and profits is a technical term under the Internal Revenue Code and is composed essentially of the undistributed retained earnings of the corporation. Current earnings and profits are determined on an annual basis and if undistributed are added to earnings and profits generally. Distributions by a corporation are treated as dividends and taxed as ordinary income to the extent of a corporation's earnings and profits. Therefore, it is important in dealing with a General Stock Ownership Corporation, whose income is taxed to the shareholders, to assure that income which is so taxed is not included in earnings or profits. This general rule sets forth that position and assures that current earnings and profits for a General Stock Ownership Corporation do not include income of the corporation which is taxed to its shareholders.

41. When the Internal Revenue Service audits a taxpayer, it may find that an overpayment to the government has been made by the taxpayer or that the taxpayer owes additional taxes to the government. It may be several years before an audit of a taxpayer is completed and a final determination of his tax status for a particular year is determined. Normally an adjustment is made in the taxpayer's tax liability for the year being audited and that adjustment is paid by the taxpayer or the government in the year in which the audit is completed.

In the case of a General Stock Ownership Corporation, audit adjustments are treated in a modified manner. Since the shareholders of the General Stock Ownership Corporation are taxed directly on the income of the corporation, any error in the corporation's tax status for a particular year will be reflected on the individual returns of each shareholder. It would be very clumsy and complicated to adjust the tax status of each GSOC shareholder for such an error. If audit adjustments were handled in this manner, it might well happen that hundreds of thousands of shareholders would find themselves being audited by the Internal Revenue Service because of the tax treatment of a particular item by the General Stock Ownership Corporation. To avoid this result, audit adjustments for General Stock Ownership Corporations are to be made at the corporate level and reflected in the income of the corporation for the year in which a final determination of the tax audit is completed. This means that if the General Stock Ownership Corporation understated its income for a particular year due to the error in the tax treatment of a particular item, the adjustment for that error would be made in the year of the final determination and the corporation would have additional income in that year as a result of the adjustment. In addition, the corporation may be liable for interest payments and penalties which will be computed in the normal manner under Section 6601 of the Code. In the event that the General Stock Ownership Corporation overstated its income and therefore the shareholders had tax liability in excess of the correct amount, adjustments would be made in the form of a reduction to the current year General Stock Ownership Corporation income and a cash payment by the government equal to the interest due on overpayments under Internal Revenue Code Section 6611.

42. This provision amends the net operating loss deduction provisions of Section 172(b) to provide for a ten year carryover of net operating losses for General Stock Ownership Corporations. This means that if the General Stock Ownership Corporation for any year should incur a net operating loss (total deductible costs of operation in excess of the current year's income) the corporation can carry this loss omer and use it as a deduction against future years' income for a period of ten years from the year in which the loss was incurred.

43. Section 3402 of the Internal Revenue Code provides for the withholding of taxes by employers directly from employees' paychecks. In order to assure that the shareholders of a General

Stock Ownership Corporation are not attributed income on which they are unable to pay the tax, the GSOC is required to withhold from each cash distribution to its shareholders an amount equal to 25% of the cash payment. This amount will be paid to the Federal Government and be credited to the shareholders as an advance payment of the tax due. This provision creates a new Section 3402(r) which sets forth the general rule on withholding and ties the GSOC withholding provisions into the general rules dealing with withholding on wages. Of particular note is the provision in Section 3402(n) which provides an exemption from the withholding provisions for individuals who have filed a withholding exemption certificate with the General Stock Ownership Corporation certifying that the shareholder incurred no tax liability for the preceding taxable year and anticipates that he will incur no tax liability for the current year.

44. This provision simply cross-references the basic provisions for the General Stock Ownership Corporation set forth in Section 1395 back into the general basis provisions in the capital gains sections of the Code at Section 1016(a).

45. This provision sets forth requirements for an information return to be filed by the General Stock Ownership Corporation with the Internal Revenue Service. This return is an information return only as the GSOC itself is exempt from Federal income taxes. The information on the return must include a statement of the General Stock Ownership Corporation's income for the year, investment credits, the names and addresses of the shareholders, the number of shares owned by each, the amount of GSOC distributions to each shareholder, the date of each distribution, and any other information which the Secretary of the Treasury may prescribe by regulation.

46. For purposes of the statute of limitations on income tax audits and crimes, the return of a General Stock Ownership Corporation is to be treated as a return filed under Code Section 6012, which sets forth who must file income tax returns. Other procedural provisions of the Internal Revenue Code are tied into Code Section 6012 so that the General Stock Ownership Corporation will be covered by the normal rules regarding filing requirements, audits and the rights of taxpayers.

47. In addition to filing an annual information return with the Internal Revenue Service, the General Stock Ownership Corporation is required to file its annual report with the Secretary of the Treasury. It is contemplated that this annual report would be significantly more detailed than a normal corporate annual report and would address such questions as the effect of the GSOC on distributions of income and wealth, the level of transfer payments made or required, the social and demographic profiles of GSOC shareholders, the level of economic understanding of GSOC shareholders, and possible beneficial revisions of General Stock Ownership Corporation legislation.

48. This provision simply amends the index and tables of the Internal Revenue Code to provide for the inclusion of Subchapter U.

49. The operative dates for Subchapter U are set forth in this provision which makes it clear that the Subchapter U changes apply to corporations formed within the December 31, 1978 - January 1, 1984 time frame. It is clear from the language in this provision that the tax benefits of Subchapter U will continue after January 1, 1984, for any corporation formed within this time frame and continuing to comply with the provisions of Subchapter U.

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

KELSO & CO.
. INCORPORATED
INVESTMENT BANKERS
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December 7, 1978

CHAPTER I

EXECUTIVE SUMMARY

In this report we present a review of British Petroleum's position as it relates to their interest in TAPS. British Petroleum on a consolidated basis has debt outstanding of approximately 1.1 to 1.2 billion dollars representing their loans to finance the Alaskan Pipeline. That portion of their long-term debt represents in the order of 1/3 of their total long-term debt although the pipeline generates revenues and profits of less than 5% and in some cases significantly less than 5% of BP's overall operation.

British Petroleum's current operations (see BP 3rd Quarter tab) are significantly enhanced through the recent increase in net production from Sohio's Prudhoe Bay properties. A reduction in BP's debt position and an increase in their ownership of Sohio might be one of the primary objections for BP to divest itself of its' direct interest in the pipeline and retain a significant indirect interest through Sohio.

Other factors influencing an interest in divesting in the pipeline are most likely the risks in the current FERC rate investigation hearings. There is considerable risk that FERC will establish a low tariff for pipeline owners to increase

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well head values of oil. Such an action would enhance Sohio's operations, but have a negative impact on BP's interest in the pipeline without a corresponding oil interest. (See Prehearing FERC Briefs tab.) In addition current oil producers are considering an increase in the capacity of the pipeline either to 1.6 million barrels per day or 2 million barrel per day through put. The additional investment required by the owners may be over $1 billion for such increase in capacity. That would suggest that if BP were to retain its interest in the pipeline an additional investment of $100 to $200 million may be required on their part.

Other unknowns in the BP position are the estimates for the amount of additional reserves which may flow through the pipeline in the mid to late 1980's when oil production from the Prudhoe Bay field may begin to decline. In such a case pipeline owners would have a reduction in the through put and, therefore, a reduction in revenues. In the longer term, new oil reserves have been predicted for Northern Alaska and may provide an offset. There are enough uncertainties in the near future that some of the pipeline owners may desire divestiture at this time.

It has been publicly stated that a number of pipeline owners wish to sell their interests in TAPS. Sohio and BP have generally been considered as two of those owners. It has also been rumored around Washington, D. C. that the Alaskan GSOP is exploring the purchase of not only BP's interest in the pipeline but the Arco interest as well. It is also public knowledge through the testimony at the FERC hearings that several owners have tried to sell their interest in TAPS, but could not find buyers even at a discounted figure. Phillips was one of these companies. Furthermore, many companies who have an interest in the pipeline have declined to increase their share on a pro rata basis in the proposed expansion to the 1.6 million barrels per day.

Valuation of BP Interest in the Pipeline

In general BP wishes to sell their interest in TAPS to eliminate debt from their balance sheet and receive cash for their equity investment. In round numbers the total value on BP's TAPS investment range from 1.3 to 1.5 billion dollars. Current debt outstanding is approximately $1.1 billion and the true equity interest may be as low as $200 million or as high as $400 million. A complete sale may cause a readjustment in BP's financing arrangements through their loan agreements, but initial indications from BP are that a full cash sale for the equity and the debt portion may be a solution to a change in ownership in TAPS. The alternative would be to have the new owner assume the debt of BP Pipelines, Inc. and pay cash for the equity share.

A complete description of the loan agreements with amortization schedules and guarantees are included in this report. In summary the major problems in assuming the debt would be a number of clauses which indicate that the BP's share or the new owner for the BP share must prepay in the same ratio as Sohio and at the same time for their proportionate debt in the pipeline. Other than that restriction, a transer of interest in TAPS does not appear to be a difficult problem. Additional research is still necessary, but there appears to be agreement that the loan requirements do not impose major restrictions on transferring of an interest in TAPS. In addition BP recognizes and seems comfortable with the fact that they would still remain a guarantor on the debt, but if the State of Alaska is also a guarantor of the Alaskan GSOP debt then BP is not overly concerned with their guarantee.

<u>GSOP Financial Position</u> - (See Summary Table IV - 1)

A thorough analysis has been prepared showing estimated cash flows for the Alaskan GSOP if they were to purchase an interest in TAPS. At a $4.68 tariff which is the FERC interim tariff, the GSOP under a 1.5 billion dollar price and 10% interest rate or assumption of the BP debt, would have an initial distribution well under $100 to shareholders. In addition cash flow would be negative after ten years or so. The only feasible situation at a low tariff would be a $1.3 billion price and a 7% overall interest rate producing an initial shareholder distribution slightly over $150.00. As the tariff increases to $5.00 or $5.50, a $200 distribution per share holder in the first year is likely especially at a $1.3 billion purchase price. At the $6.35

tariff, shareholder income is somewhat under $400 even at a low valuation purchase price.

Under an expanded pipeline to the 1.6 billion barrels per day level, at tariffs of approximately $5.50 which is midrange between the owners' requested tariff and the FERC interim tariff, shareholder distribution may reach over $400 in the first few years and significant cash flow would be available for future expansion or for shareholder distribution throughout the range of a 20 year period.

Remaining Steps

The remaining steps to be taken in achieving a transfer of BP's interest would be a determination of value which BP would agree to. In addition agreement with Sohio on its shipping arrangements with the new owner of BP's share of the pipeline, determination of the Sohio position as it regards partnership with the Alaskan GSOP and the existing loan agreements. Furthermore, decisions will have to be made on whether the GSOP should and can raise capital through revenue bonds or general obligation bonds also whether to pay cash to BP or have the GSOP assume BP's notes are additional decisions for the future. These two alternatives would dictate the price that would be reasonable to the GSOP in order to achieve significant distributions and cash flow for the early years.

SUMMARY OF MEETING

The meetings in.....were attended by..... In the first meeting .....discussed the hearings at FERC (OR 78-1) and the two phases, (1) the valuation and the rate of return phase and (2) a depreciation schedule, tear down, and cost overrun phase. .....statement that the TAPS owners will forever be involved in a rate case of some type may be well founded. The OR 78-1 rate investigation will probably not conclude until late 1980 or beyond. After that time, anyone protesting the established rate may file for a new hearing.

One of the subjects discussed was the financial reporting for the pipelines. .....was not too open as regards these issues, but did admit that the dismantling expense was strictly an internal cash flow expense and that no funded reserve was set up for the final expense.

Alyeska does submit a monthly budget report which includes summaries of their expenses. One point admitted by.....but not to be made public was that the Alyeska operating expenses for 1979 might be approximately $350 million versus a $420 million budget for 1978. This reduction is due to a reduction in personnel and expenses that were basically start-up costs for the pipeline. .....at one time was going to provide us with a 1979 budget, but declined to do so after checking with superiors. Prior to final agreements we may wish to see these budgets. However, we must recognize the sensitivity of having these budgets distributed in view of the current FERC hearings.

Much of the budget for the Alyeska operating expense is due to the use of outside contractors especially for maintenance at the Valdez terminals and the service roads along the pipeline. Pipeline taxes in the form of ad valorem taxes total approximately $167 million per year or almost half of the Alyeska budget.

.....also stated at our second meeting that as of now BP Pipelines has not used any investment tax credit and, therefore, would not be liable for any recapture of investment tax credits upon sale of the system. In addition.....cautioned us as to the tax treatment in setting tariff rates which might be substantially different for the GSOP. The GSOP tariff, based on no income tax liability could be set at far less than other carrier tariffs at least in theory.

SUMMARY OF MEETING

The meetings in.....were attended by..... .....will be present in the meetings in.....on.....

The purpose of the meeting was to discuss the technical considerations in achieving a transfer of interest of the BP share of TAPS to the Alaska GSOP. There were some generalized discussions during lunch which will be summarized first and detailed discussions after lunch on the mechanics of the BP debt agreements and the effect these agreements would have on the transfer of ownership in TAPS.

GENERAL DISCUSSIONS

During the luncheon meeting prior to the more formal detail discussions, the general topics of discussion were the timing for formation of an Alaskan GSOP and when a transfer of interest of TAPS might take place. There was a question from British Petroleum as to whether the State of Alaska would in effect be able to raise the revenue and pass the debt onto the Alaskan GSOP or whether the GSOP would be able to raise a significant amount of cash to affect a sale from British Petroleum to the GSOP. In general British Petroleum stated that a sale of their interest in TAPS would have to be affected by British Petroleum eliminating all of its debt for the TAPS project from their balance sheet and in addition be compensated for their equity investment in the pipeline. There were no specific numbers discussed at these meetings other than the general figures surrounding the debt outstanding on the note agreement. In addition to the interest of BP in effecting a sale, BP was inquiring as to whether or not the Kelso consultants along with any state committees were investigating other investment opportunities for the GSOP. It was understood that the purchase of British Petroleum's share or another oil company share in the pipeline would be highly considered for the Alaska GSOP's first investment avenue. A further topic of interest to British Petroleum was "who is the client of the Kelso Company for this report." It was discussed that the client was part of the State legislature and not particularly the state government itself; and that there would be a differentiation between the State and the GSOP for our work and the negotiations with British Petroleum.

BP stated that, according to the loan agreements, it cannot actively seek a buyer. We mentioned that it is on public record at the FERC hearings that many owners, including BP wish to sell their ownership interest. We confirmed that we would not state that BP is actively shopping their TAPS interest.

We discussed in general the expansion possibilities on the pipeline. Discussions for expansion are underway at the owner's meetings. BP or the GSOP rights during expansion are detailed in the TAPS agreements. First expansion would be to 1.6 mm bbls/day and then to 2 million.

These thoughts cover the general issues discussed prior to the detailed discussions at the meeting regarding the loan agreements.

SPECIFIC ISSUES DISCUSSED WITH BRITISH PETROLEUM

Some preliminary issues were discussed concerning the purchase of fuel for the pump stations by British Petroleum Pipelines. Natural gas is used for the first four pump stations. British Petroleum purchases through Sohio. This purchase agreement is terminable at the sale of British Petroleum's interest in the pipeline. The gas flows through a parallel gas line to the pipeline. The tariff for this gas is the tariff set by the FERC at the rate hearings. British Petroleum Pipeline uses approximately 100,000 MCF per month of natural gas. The remainder of the oil used for the other pump stations are from topping plants at each pump station. This oil is not paid for by British Petroleum. It is essentially part of the oil retrieved from the pipeline and does not come out of the pipeline owner's share of the oil or of the tariff.

A question was brought up by us as to the change in the amount of reserves now stated at the FERC hearings to be 9.1 billion barrels. The old reserve was 9.6 billion barrels. It was not known by.....or the BP people why the reserve estimate was changed however,.....from BP stated that the number to be used for planning purposes should be 9.1 billion and that that would now be a good number.

The major subject of the meetings were the problems that would be encountered in transferring ownership interest in TAPS as it would regard the various debt issues that Sohio and BP have issued through the capital company jointly owned by Sohio and BP. There are two public issues, two private placements and two issues of the Valdez bonds. It was a general conclusion of the BP people that the biggest problems would be encountered in the private placement issues and the biggest problem of all would be to get BP out as the obligor position in regard to the debts.

Any transfer of interest in the TAPS line as far as the private placements are concerned would require a 50% or a majority of the lenders' agreement. A full elimination of BP on the loan would require a 100% agreement; that is thought to be impossible to obtain. BP did not see any real opposition to a transfer of interest if the State of Alaska were to be a guarantor on the loans to the Alaskan GSOP.

One of the requirements that BP clean its balance sheet from the debt is to keep the level of the BP guarantee far down the line. For example, BP would have to dispose of the asset involved and not be the prime guarantor on the loan. If the State of Alaska were to guarantee the loan for the GSOP, BP would be in a comfortable position to eliminate these debts from their balance sheet. There is another problem with BP as to the amount of loans it carries through the Sohio Company and how that may appear on the balance sheet. There are new British accounting standards labeled FSAB-14 which would allow them to eliminate reference to the BP/ Sohio investment joint debts on their balance sheet.

BP sees as one of the biggest problems the elimination of the BP/Sohio proportionate interest in the debt agreements. That appears to be the most significant obstacle to overcome in transferring interest in TAPS.

As it stands now BP and Sohio have to make payments, both prepayments and future payments in the same ratio as ownership in the capital company. In order to change this ratio a majority of the lenders would have to agree to a change in that clause of the contract. This occurs in Article IV in the Private Placement agreements. In the Public Agreements it appears in Section IV of the Note Purchase Agreement. It is the general feeling that these problems would all be overcome by raising all capital initially and paying BP in cash upon transfer of the assets. The problems occur when the new owner of TAPS would assume the obligations of BP on the debt agreements. Under this condition there is a BP/Sohio or

Sohio/GSOP relationship which forces proportionate payments. There has been general discussions during the meetings that it may not be in the best interest of the GSOP to be a partner with Sohio on these capital agreements and on the other hand it might not be in the best interest of Sohio (BP really) to be in partners with the GSOP on these agreements.

Under the Valdez loans Sohio and BP remain liable for the 68/32% share regardless of the amount of prepayment. This 68/32% share would be on the remaining liability.

BP stressed that the equity portion of their investment would have to be paid in cash and that a note for payment to occur at some future time would not be acceptable to BP for the purchase. This really would cause BP problems in consents on agreements and other aspects for transfer of ownership in TAPS. BP saw no problem in extending time periods for closing of a deal in regards to consent of other owners and waiving their preemptive rights to a sale.

On page 65 of the Public Issue Agreement, it is noted that 2/3rds of the holders of the debt would have to agree as to what price would be acceptable for the lenders to get out of such agreement. Under the Public Issue the GSOP can take all obligations; however, BP would remain a guarantor.

Under the Private Placement consent of 50% of the lenders as stated before would be required to transfer ownership.

The best way for BP to achieve a sale would be cash up front for the Private Placement portions. This would amount to approximately $700 million with a possible discount for the purchase through the Private Placement portion. This kind of a deal would also solve any problems with Sohio. The buyers must assume all obligations under any cash however.

On the Valdez side, the problem in assuming the BP obligations would be the relationship between GSOP and Sohio. Any change in this relationship stated on the agreements would require a majority of the holders of the bonds to approve. This may be a very difficult situation since as of now we do not know who owns the majority of the bonds. However, we may be able to obtain a list of the original purchasers of these bonds and may get some clues from this. Naturally the problem with these prepayments would be the fact that Sohio and the GSOP may not be in the same position at the same time to make these prepayments.

This is a general summary of the specific problems discussed at the meeting. The details of the bond issues and the agreements were provided with summaries attached for our review. We would have access to.....for questions based on our review of these agreements.

SUMMARY OF PREHEARING BRIEFS IN TAPS CASE

The following is a summary of prehearing briefs filed during December 1977 and January 1978 in Phase I of the Trans Alaska Pipeline System rate investigation (OR78-1).

This investigation was instituted on 6/28/77 when the Interstate Commerce Commission suspended initial rates filed by the TAPS carriers in May and June 1977 for the seven-month statutory period and prescribed interim rates which it would accept during the suspension period. The initial rates — which ranged from $6.04 to $6.44 per barrel — were protested by the State of Alaska, the Arctic Slope Regional Corp., the Department of Justice, and the ICC's Bureau of Investigation and Enforcement. The interim rates prescribed by the ICC ranged from $4.68 to $5.10/bbl., or from $1.13 to $1.59 lower than the initial rates filed by the respective companies. Several of the TAPS carriers appealed the 6/28/77 order to the Fifth Circuit which upheld the ICC's action. Subsequently, however, the Supreme Court granted requests to stay the ICC's suspension of the proposed initial rates, conditioned upon agreement of the petitioners to keep separate accounts of amounts collected thereunder and to refund any portion ultimately determined to be unlawful. The Supreme Court also granted petitions for writ of certiorari to review the ICC's suspension action.

Meanwhile, the Energy Co. of Alaska — which has built a new refinery at North Pole near Fairbanks, Alaska and receives crude oil shipments through TAPS — filed protests against in-transit rules filed by five of the TAPS carriers as part of their interstate tariffs. Issues raised by these protests are consolidated in Phase I of this case.

Following a prehearing conference in August 1977, an ICC Administrative Law Judge adopted a request by the Department of Justice and the State of Alaska to phase the proceeding. Phase I will deal with questions of appropriate rate base, rate of return, treatment of taxes, and method of calculating total revenues. For the purposes of Phase I, amounts claimed by Respondents for construction or operating costs, depreciation charges, and removal costs will not be challenged. Phase II will consider the prudency of the TAPS expenditures, depreciation charges, removal costs, and all other issues not adjudicated in Phase I.

The TAPS proceeding was shifted on 10/1/77 to the new Federal Energy Regulatory Commission which, under the Department of Energy Organization Act, was assigned the ICC's responsibilities for oil pipeline rates and valuations.

Evidence was served by Respondents in Phase I on 11/30/77. Prehearing briefs were filed by the Protestants (and the Department of Energy as an intervener) in December and by the Respondents at the end of January. Hearings will commence for cross-examination on 2/7/78.

The prehearing briefs highlight the differences in positions of the protestant and respondent parties. Except for Energy Co. of Alaska which is concerned only with in-transit tariff provisions, the other protestants — State of Alaska, Arctic Slope Regional Corp., Department of Justice, and the FERC Staff (successor here to the ICC Bureau of Investigation and Enforcement) — all concur in recommending a net original cost rate base and determination of a rate of return applicable to such a rate base, and in contending that the FERC is not bound by previous ICC methodology in any way. While none of the protestant parties made any specific recommendation as to rate of return level, Alaska, Arctic Slope and the Justice Department urged that TAPS — as a transportation monopoly with an assured supply and market demand — involves "minimal relevant risks" for equity investors and is "at least as attractive an investment opportunity as public utilities and natural gas pipelines." These parties further recommend consideration of flow through treatment of liberalized depreciation tax benefits and the investment tax credit. By contrast, the TAPS carriers (Respondents) contend that adherence to an ICC-type valuation rate base is required both by law and public policy considerations, that the unusual risks of the TAPS project justify a rate of return on a valuation rate base of 20%, and that any departure from normalization of accelerated depreciation tax benefits would be contrary to Congressional intent and regulatory practice.

Department of Justice, State of Alaska and Arctic Slope Regional Corporation

A joint prehearing brief filed by the Justice Department, State of Alaska and Arctic Slope Regional Corporation (Protestants) on 12/15/77 urged rejection of a valuation rate base determined according to past ICC methodology, adoption instead of a net original cost rate base, determination of a reasonable rate of return on a net original cost rate base -- treating TAPS equity investment as no more risky than that in public utilities or natural gas pipelines, and consideration of flowthrough of tax benefits flowing from accelerated depreciation.

Initially, the Protestants urged that TAPS be regulated as a distinct entity separate from other pipeline interests of the eight owners. TAPS is a new pipeline and represents an enormous investment relative to other pipelines, the Protestants stated. Moreover, "whatever the competitive environment in the Lower 48 States, it is clear that the magnitude of the investment, the economics of a 48-inch pipeline and its unique location makes the TAPS transportation system a classical natural monopoly and, quite possibly, a legal one as well." Therefore, "it would be singularly inappropriate to treat the owner companies' interests in TAPS as segments of their overall pipeline interests."

The Protestants argued that use of a valuation rate base -- including an element of reproduction cost new -- is neither legally required nor economically justified. The concept of including reproduction cost in the rate base, the brief noted, stems from a Supreme Court decision in 1898 (Smyth v. Ames) holding that regulated entities were entitled to earn a fair return on the "fair value" of property dedicated to public service. At that time, reproduction cost was considered to provide greater certainty regarding property valuation than the inflated values reflected in company accounts. During the ensuing 50 years, however, reproduction cost came under increasing attack as a reliable measure of value and was effectively rejected by the Supreme Court in 1944 (FPC v. Hope Natural Gas Co.). Since that time, the Protestants observed, most state and federal regulatory agencies (including the FCC and the former FPC) have rejected the use of any element of reproduction cost in the rate base and have adopted an original cost less depreciation or similar standard.

Moreover, the Protestants emphasized, while Section 19(a) of the Interstate Commerce Act requires the Commission to value property owned or used by every common carrier oil pipeline subject to its jurisdiction and to consider the cost of reproduction new (and the cost of reproduction new less depreciation) in making such valuation, nothing in that provision prohibits the Commission from finding some other basis of value -- such as net original cost -- to be more appropriate for ratemaking purposes. Nor, the Protestants added, is there anything in the Department of Energy Organization Act which requires the FERC to follow the ICC regulatory methodology. Rather, the legislative history of that Act makes clear that the FERC "is free to make any changes that it deems appropriate in the ICC method of regulating oil pipelines."

Economically, the Protestants added, an ICC valuation rate base reflecting reproduction cost leads to arbitrary and irrational results because (1) the so-called "condition percent" factor used to determine reproduction cost less depreciation — which factor represents an estimate of physical depreciation based on an approximation of the average useful life span of property of a certain class -- does not conform with the straight line method used to estimate annual depreciation expense for rate-making purposes, ignores the basic purpose of depreciation (to reflect the rate and extent of capital recovery) and could result in a return being paid on capital that had long been recouped by investors; (2) addition of a 6% "going concern value" before consideration of land, rights-of-way and working capital -- intended to reflect the difference in value between an operative and an inoperative pipeline — bears no apparent relation to any element of value and is completely unjustified; and (3) inflation becomes incorporated in the rate base, thereby preventing meaningful comparisons between oil pipeline rates of return and those experienced by other regulated and unregulated industries.

By contrast, the Protestants continued, a net original cost rate base suffers from none of the above deficiencies. "It is readily and verifiably ascertainable and provides a basis for comparability necessary to assess the appropriate rate of return in light of the risks of the enterprise."

With respect to rate of return, the Protestants declared that overall return allowances up to 20% requested by the TAPS carriers on a valuation rate base are "excessive" and inconsistent with the standards set by the Supreme Court in the Hope and Bluefield cases, i.e., that the rate of return permitted a regulated entity should be commensurate with "returns on investments in other enterprises having comparable risls" and no greater than that necessary to attract capital to the enterprise. While making no specific recommendation at this time, the Protestants said the TAPS carriers are entitled to a reasonable rate of return on an original cost rate base commensurate with the "real" risks of the enterprise. In assessing the nature of such risk, the Protestants took the position that the bulk of the TAPS equity investment is subject to only "minimal relevant risks and uncertainties" and that TAPS "is at least as attractive an investment opportunity as public utilities and natural gas pipelines or, indeed, as integrated oil companies." Specifically, the Protestants noted, the TAPS line represents a monopoly over the transportation of North Slope oil, a market for this oil is assured, and there is little danger of insufficient oil volumes to permit recoupment of invested capital. While the carriers stress the difficulties and uncertainties of constructing and operating a pipeline in Alaska, the Protestants added, these uncertainties related only to ultimate construction and operational costs and "afforded no major risk to the TAPS investor." Hence, they "are irrelevant to an appropriate rate of return analysis."

In short, "despite the logistic, geotechnic and climatic challenges which characterized the project, the risk to the TAPS equity investment was minimal. The enterprise enjoys a transportation monopoly of a commodity whose supply and market demand are assured. Furthermore, it possesses -- for risk analysis purposes — all of the relevant characteristics of a public utility or natural gas pipeline."

The Protestants further recommended that the FERC reject the carriers' proposal to use their parent company capital structures for purposes of determining an appropriate rate of return, and that it instead employ either the actual investment in TAPS or alternatively a hypothetical capitalization reflecting the financial and business risks of TAPS.

In the event a valuation rate base is adopted, the Protestants said the rate of return level must be adjusted downward in order to preclude "double counting" of inflation factors.

Turning to the treatment of taxes, the Protestants noted the magnitude of tax-related expenses to overall costs reflected in the initially filed TAPS tariffs — ranging from 20% (ARCO) to 25% (Phillips) — thereby demonstrating the importance of this issue. Again, the Protestants made no specific recommendation at this time but said the Commission is free to consider alternative methods. Specifically (1) the Commission may require flowthrough of the tax benefits resulting from the use of accelerated depreciation; 1/ (2) assuming normalization, the related deferred tax account should either be deducted from the rate base or included as part of the capital structure at a zero rate of return; (3) the net economic cost to the carriers of property on which the investment tax credit is taken should be reflected in the rate base; and (4) carriers which chose to deduct interest during construction should be required to subtract such accounts from the rate base.

The Protestants' brief also stressed the Commission's responsibility to carry out the national energy goals set forth in the Department of Energy Organization Act, including the goal of fostering and assuring competition among persons engaged in the energy supply industries. This goal "is particularly meaningful in the case of TAPS because excessive rates can have a direct effect upon the competitive development of North Slope crude oil reserves." Specifically, given the inverse relationship between the wellhead price of North Slope oil and the level of the TAPS tariff, "excessive TAPS rates would not only deter potential non-TAPS owner development of the North Slope, because of an artificially low wellhead value, but would also create a disincentive for TAPS owner development except in proportion to pipeline ownership interests." If pipeline rates are excessive, the Protestants explained, it would be uneconomical, or at least less economical, for an oil company without a TAPS pipeline affiliate to invest in the Prudhoe Bay Field because that oil company "would not be assured that excessive pipeline earnings stemming from the shipment of its crude oil would ultimately be returned in the form of pipeline company dividends." The same disincentive would apply to an oil company which has a TAPS affiliate but proposed to develop a share of North Slope production substantially greater than its percentage ownership of TAPS because of the necessity to ship much of its oil over another company's share of the pipeline, "thus surrendering an amount equal to the excessive pipeline profits." It therefore follows that "unless all oil companies with substantial ownership interest in TAPS' subsidiaries are willing to participate in further development, pro rata with their share of TAPS, such oil companies might be deterred from aggressively developing North Slope oil reserves. Such a result would be contrary to National Energy and Competition Policies."

In conclusion, the Protestants concluded that the Commission has full authority to issue an interim rate order, with a refund condition, following the conclusion of hearings in Phase I and before a resolution of the issues in Phase II. In support, the Protestants cited an interim rate order issued by the FPC in 1960 — ultimately affirmed by the Supreme Court (FPC v. Tennessee Gas Transmission Co., 375 U.S. 145) — which required immediate refunds of amounts collected by Tennessee prior to the interim order and made the interim rates subject to further refund depending on the Commission's final determination of just and reasonable rates.

1/ The brief noted that the former FPC adopted normalization of deferred taxes for electric and gas utilities in an effort to provide improved cash flow and ameliorate the poor financial condition of these industries. However, the brief stressed, this rationale does not apply to the oil pipeline industry which, "judged by any standard, is in excellent financial health," nor to TAPS, "an enterprise whose need for additional cash flow to finance expansion is minimal."

FERC Staff

The FERC Staff brief, filed 12/30/77, recommended adoption of a net original cost rate base, and determination of all other issues — including rate of return, interest during construction and federal income taxes — consistent with that rate base.

The FERC Staff contended that a net original cost rate base should be adopted for the TAPS carriers because it (1) rests on relatively accurate figures, (2) entails a "much less expensive and time consuming" computation than a valuation standard; (3) "reduces administrative problems by speeding the disposition of cases and permitting greater precision in the writing of decisions"; and (4) is used by the great majority of state and federal jurisdictions, including the FERC. The Staff further declared that the FERC is under no statutory or judicial obligation to employ a valuation rate base. While Congress intended the valuation process set forth in Section 19(a) of the Interstate Commerce Act to produce information that might be necessary in later proceedings covering such matters as rates, bankruptcy, finance, taxation and others, the Staff stated, Congress did not require the use of such valuation for rate base. In short, "valuations are informational only and achieve a greater level of significance only when offered in evidence in proceedings; they have little other importance in and of themselves." Had the ICC believed it was statutorily bound to use a valuation formula for rate base, Staff added, it would not have instituted the Ex Parte 308 investigation.

Staff next stressed the relationship between a fair rate of return and the type of rate base to which it is applied. Specifically, a fair rate of return on a net original cost rate base must be adjusted downward if applied to a valuation rate base. Otherwise, the result would be to provide double coverage of inflation in both the rate base (through inclusion of a reproduction cost element) and rate of return.

In further connection with a fair rate of return, the FERC Staff contended that (1) interest on long-term debt is part of the return element and hence should not be treated as an above-the-line operating expense; (2) management inefficiencies during the construction period should not be reflected either as part of the rate base or fair rate of return; and (3) the capital structure should be compatible with the treatment of interest-during-construction capitalized in the rate base as well as with the treatment of interest in the determination of income taxes. As to this last point, the Staff said the TAPS carriers are totally inconsistent. Specifically, Staff explained, the oil company parents of the TAPS carriers have assigned high debt ratios to each of their subsidiaries for capitalization of interest-during-construction. However, the parent companies in most cases either obtained the financing themselves and later created a subsidiary pipeline company, or simply lent their credit to the subsidiary to obtain financing in the form of a parent guaranty of the subsidiary's debt. Parent companies obtaining financing in their own names, Staff continued, implicitly pledged that the equity on their books would be subject to a contingent liability upon default on the loans, while those companies lending their credit in the form of debt guarantees also created only contingent liabilities upon default of the loans by the subsidiaries. Therefore, in now seeking compensation on behalf of their parent companies who bear these contingent responsibilities as if the contingencies are capitalized, "the carriers ignore the fact that their parents were not required to raise equity equivalent to the sums financed by the debt investors. If the parents are entitled to a return on 100% equity, they cannot at the same time book up to 94% debt in their subsidiaries and capitalize over $1 billion in interest-during-construction."

The Staff added that the carriers followed several different methods of computing interest-during-construction, and that most of these methods appear to violate ICC accounting regulations prohibiting accrual of any allowance for equity funds used during construction. In short, "interest during construction may have been inflated beyond a reasonable level" by the TAPS carriers.

In regard to income taxes, Staff said a first question is whether income taxes for ratemaking purposes should be calculated on the basis of (1) each carrier as an independent entity, (2) the consolidated tax return of each of the parent oil companies, or (3) TAPS as one independent entity. Whatever alternative is chosen, Staff said, must be compatible with the treatment of other issues (e.g., capital structure, flowthrough versus normalization of liberalized depreciation tax benefits, interest-during-construction, and the investment tax credit).

A second question, Staff added, is whether to adopt normalization or flow-through treatment for liberalized depreciation tax benefits, investment tax credits, and other interperiod timing differences which result from the use of different treatment for book and tax purposes. "The selection of normalization or flow through should be made on an issue-by-issue basis to assure that total revenue requirements are developed on a reasonable and consistent basis; that tax benefits are not lost due to specific IRS rulings; that the selection is consistent with prior options taken by the parent oil companies; and that the tax burden comports with the present and future tax obligation and is fairly distributed to present and future customers." In the event of normalized treatment, Staff added that accumulated deferred tax reserves should either be deducted from the rate base or included in the capital structure at zero cost.

Finally, Staff indicated its intent to inquire into the need for cash working capital allowances by the TAPS carriers; the basis for accruing depreciation reserves (straight line or unit of production); the need for an annual expense and associated reserve for removal costs supposedly applicable at the end of the service life of the pipeline; the validity of including various overheads and intercompany charges in capitalized investment; and the inclusion of any startup expenses in the projected cost of service. Staff said some of these issues will be involved in Phase II as to particular cost levels, but it may be possible in Phase I to develop a means for making appropriate adjustments should that later become necessary.

Department of Energy

The Department of Energy -- which intervened to assist the FERC in arriving at "just and reasonable" tariffs for TAPS -- said its principal interest is the apportionment of the delivered cost of Alaskan North Slope (ANS) oil between wellhead prices and transportation charges in such a way as to (1) compensate the owners of TAPS for their investment expenses and risks "only to the extent required by law"; and (2) provide the greatest possible incentive to produce existing reserves, discover and produce new reserves, as well as promote competition among ANS producers.

The transfer to FERC of the ICC's authority over oil pipelines and the FPC's authority over natural gas pipelines, the DOE asserted, demonstrates a Congressional intent that the FERC "develop a coherent national policy with respect to the establishment of tariffs for energy-related pipelines which takes into account the national energy interest." This case provides "an opportunity to incorporate standards of transportation system regulation that are simultaneously fair to the owners of TAPS and consistent with the needs and goals of the country. In balancing these considerations, DOE believes that the national economic interest and national energy policy to reduce national reliance on imported oil militate in favor of minimum tariffs consistent with the costs and risks prudently incurred by the pipeline owners."

Establishment of TAPS tariffs at levels higher than the lowest reasonable level, DOE added, would be likely to diminish incentives to produce and discover maximum ANS reserves, reduce the total flow of ANS oil to the Lower 48 States, aggravate the nation's dependence on imported foreign oil, and entail "negative implications" for domestic employment, growth, tax revenues and stability.

Based on the above principles, DOE supports adoption of an original cost rate base, a rate of return "as low as possible without being confiscatory," flow through tax treatment, and disallowance of any imprudent costs in the rate base or as an operating expense.

The DOE also stressed that the FERC is not obligated to follow prior ICC precedents and policy in determining just and reasonable tariffs. Rather, the FERC is free "to regulate oil pipelines and to establish new standards for determination of what constitutes just and reasonable tariffs, unfettered by prior ICC policy decisions . . . ."

Energy Co. of Alaska

Energy Co. of Alaska (ECA) -- which operates a newly constructed refinery at North Pole, Alaska located 14 miles from Fairbanks and three miles from TAPS -- protested "in-transit" rules filed by five of the TAPS carriers 1/ as part of their interstate tariffs. These in-transit rules, in the case of each carrier, permit the withdrawal from TAPS of oil originating at Prudhoe Bay, and the return of part or all of the withdrawn oil to TAPS for transportation to Valdez and loading on vessels. However, ECA declared, all of the rules are sufficiently unclear and ambiguous that they appear to apply the carriers' interstate rates for shipments from Prudhoe Bay to Valdez to purely intrastate shipments which are withdrawn at North Pole and never redelivered to TAPS. For example, ECA noted, Exxon Pipeline's proposed in-transit provision specifies that the "applicable rate from the initial point of origin of the shipment to Valdez, Alaska shall be paid upon withdrawal of such Petroleum from the System or in advance thereof . . . ." Similar provisions are contained in the tariffs of other carriers. On their face, ECA declared, these transit rules purport to apply to North Slope oil refined at North Pole since that oil is withdrawn from TAPS at an established delivery point, and a portion of the withdrawn oil is returned to the pipeline carriers for delivery to Valdez. 2/ To remove the resultant ambiguity and uncertainty, ECA urged that the in-transit rules be modified to make clear that the respective carriers' rates from the point of origin to Valdez apply only to those volumes withdrawn which are designated by the shipper for reforwarding and not to volumes withdrawn which represent intrastate shipments solely within the State of Alaska.

1/ The five companies are ARCO Pipeline Co., BP Pipelines, Inc., Exxon Pipeline Co., Sohio Pipeline Co., and Union Alaska Pipeline Co. Additionally, Exxon, Sohio, ARCO and Union have filed tariffs with the Alaska Pipeline Commission (APC) requesting that the identical rates and identical governing rules contained in the FERC tariffs be approved for the intrastate movement of oil via TAPS. These filings have been suspended temporarily by the APC.

2/ ECA made clear that it does not object to application of the pipeline companies' interstate rates to the return oil, which will be moved via TAPS to Valdez for delivery to destinations outside Alaska, but only to application of these rates to oil processed at the refinery into other products for distribution around Fairbanks and elsewhere in Alaska's interior.

ECA contended that the movement of crude oil by TAPS from Prudhoe Bay to the North Pole refinery is clearly an intrastate movement and not subject to the Interstate Commerce Act or FERC jurisdiction. Moreover, ECA continued, no jurisdiction can be asserted over these purely intrastate shipments on the basis of any "commingling" doctrine. Cases relevant to "commingling" (e.g., FPC v. Amerada Petroleum Corp., 379 U.S. 687, and California v. Lo-Vaca Gathering Co., 379 U.S. 366) have all concerned natural gas pipelines and are not applicable to oil pipelines, ECA declared. Even assuming that these cases had some bearing on the jurisdiction of the Alaska Pipeline Commission to fix rates for the movement of oil from Prudhoe Bay to North Pole, ECA added, they do not give the FERC jurisdiction over such movements since the Supreme Court specifically left open the question of whether separate nonjurisdictional transactions might occur in spite of original commingling. "The instant case clearly presents that so-called nonjurisdictional transaction [since] a precise amount of crude oil . . . is delivered to the North Pole refinery for use solely within the State of Alaska. While the molecular identification of this crude oil is destroyed as a result of commingling with oil destined for Valdez, this is not a sufficient basis for concluding that it is no longer in intrastate commerce."

In addition, ECA argued that the carriers' apparent attempt to impose their interstate rates on intrastate shipments to the North Pole refinery through the device of in-transit rules represents a "perversion" of the transit privilege. The "extraordinary legal fiction" of transit, ECA stated, has generally developed as the right of a shipper to stop at an intermediate point and change the form or substance of the commodity shipped, and thereafter to reship the commodity so changed to a point of final destination, with the total charge for transportation not exceeding the level which would have pertained if the commodity had been shipped directly from point of origin to final destination. In other words, transit "implies a through movement from a specific origin via a transit point to a specific destination." However, ECA declared, this concept has no applicability to petroleum withdrawn from TAPS at North Pole and never reforwarded to TAPS. Therefore, the in-transit device may not be used to exact a through, interstate rate for a movement solely in intrastate commerce.

Finally, ECA contended, even assuming that the pipeline companies' in-transit rules did govern volumes of oil shipped to the North Pole refinery and not reforwarded, application of the entire interstate rates from Prudhoe Bay to Valdez to these shipments would be unreasonable because of the difference in distance of transportation, i.e., the distance from Prudhoe Bay to the North Pole refinery is 340 miles less than from Prudhoe Bay to Valdez. Also, any such application would destroy the advantage of the refinery's geographic proximity to the Prudhoe Bay field and, in turn, deprive the refinery's Alaskan customers of the benefits of lower energy prices.

TAPS Respondents

A joint prehearing brief filed by the Respondents on 1/27/78 set forth the following positions on the major issues: 1/ (1) a valuation rate base is required both by statute and sound public policy; (2) determination of an appropriate rate of return must give consideration to the unusually large risks involved in construction and operation of the TAPS project and, to the extent capital structure is taken into account, must regard all investment as 100% equity; (3) normalized treatment must be accorded to accelerated depreciation tax benefits and the investment tax credit; and

1/ Several individual TAPS carriers also submitted supplemental prehearing briefs amplifying arguments in the joint brief, addressing certain issues in greater detail (e.g., treatment of costs of dismantling TAPS at the end of its economic life and restoring the right-of-way), and describing issues or evidence relating to specific companies.

(4) the Commission should approve both the in-transit rules filed by certain of the TAPS carriers, as well as intermediate rate rules which authorize uniform rates by each carrier for all shipments through TAPS irrespective of distance the oil is transported.

Initially, the Respondents' brief stressed that the transfer of the ICC's ratemaking and valuation authority to FERC under the Department of Energy Organization Act does not change the substantive rules governing oil pipelines. The Senate Committee report on the DOE bill, for example, made clear that, in the interest of regulatory continuity, no substantive changes were proposed in the existing method of regulation under the Interstate Commerce Act. Similarly, the Conference Report on this bill stated that the precedents and procedures established by the ICC, until changed in accordance with law, "will continue to apply to actions taken by the [FERC] in this area, to the extent they would be applicable under the ICC." Therefore, the brief declared, "to impose radical changes in ratemaking methodology during a ratemaking proceeding comprising less than all pipelines in the industry would be completely out of line with past ICC practice and with the clearly stated Congressional intent that 'the transferred ICC regulatory functions . . . will be fully and completely exercised by the new Commission with a maximum degree of continuity and consistency.'"

The brief further emphasized the differences between regulation of oil pipelines and gas pipelines due to fundamental differences between the two industries. While natural gas pipelines in general enjoy an effective monopoly, mainly serve franchised utilities under firm long-term contracts, and purchase gas under long-term commitments, oil pipelines do not own the products they carry, cannot as common carriers enter into long-term contracts which guarantee access by customers, and face unrestricted entry by competitors. "Because of these greater risks, oil pipelines are not generally viewed as attractive investments by independent investors." Also, the brief continued, an oil pipeline project of efficient size is often too expensive for any one company to finance, and a joint venture must be used to obtain the economies of scale. In the case of TAPS, the brief stated, the form of joint venture is that of an undivided interest pipeline, in which the owners are treated as independent entities for ratemaking purposes, operate as separate common carriers in accepting tenders, file separate tariffs, and compete with each other for shipments. The claim of the Justice Department, State of Alaska and the Arctic Slope Regional Corporation that TAPS is a "natural monopoly in which prices are unrestrained by competition," the brief declared, totally ignores the legal status of undivided interest pipelines. "There is as much competition as there would be if eight competing pipelines had been built side-by-side."

Turning to the specific issues involved in Phase I, the Respondents contended that use of a valuation rate base is both mandated by statute and required by policy considerations. The ICC has historically used valuations determined under Section 19(a) of the Interstate Commerce Act for rate base purposes, the brief stated, and the legislative history of Section 19(a) plainly supports that use. Moreover, Congress expressly excluded oil pipelines from regulatory changes enacted for railroads in 1976 and also stressed the need for continuity in oil pipeline regulation in enacting the DOE bill in 1977. Therefore, "the FERC is dealing with an administrative practice which has its roots in the history of the statute and which has received Congressional endorsement. These factors restrict an agency's discretion to change its practices."

Even if the FERC had authority to abandon use of a valuation rate base, the Respondents added, "such action would be a blow to this country's energy program, since it could seriously impede further construction of much-needed oil pipelines." A change in methodology would not only be "grievously unfair" to the TAPS owners who invested billions of dollars in a project declared by Congress to be in the national interest "in the legitimate expectation that the accepted, traditional method of calculating rates would continue to apply," but also would generate the kind of regulatory uncertainty which inhibits further industry development. The Respondents also rejected any suggestion that the current method of pipeline ratemaking has resulted in unduly high rates tending to restrict entry by independent oil producers into exploration and development of oil resources. The allegation has no significance here since "there are, in fact, nonaffiliated shippers and producers on the North Slope as well as at least one pipeline carrier which has no direct or indirect ownership of production, and traffic from the shippers is now moving via that pipeline and via the pipelines of other TAPS owners."

Further, the Respondents asserted, use of a valuation rate base, by factoring in reproduction costs, protects rates from inflationary erosion. The inflation problem is especially severe for oil pipelines which, unlike utilities continually undergoing new construction, are "generally one-shot commitments of capital." Moreover, the Respondents added, a rate base which reflects inflation experienced in the past is not "double counting" of inflation. This is because the inflation incorporated in a rate of return based on an opportunity cost of capital reflects only expected "future inflation," not that which has already occurred.

The Respondents summed up the valuation approach as follows: "It works. An entire industry has grown up in reliance on this approach. Shippers have received, and consumers have benefitted from, low stable rates. The twin problems of inflationary erosion and loss of investor confidence, which have plagued most regulated industries, have not been a source of difficulty for oil pipelines. Radical surgery on a successful regulatory scheme is both uncalled for and unwise."

Additionally, the brief declared, this case is not the proper proceeding in which to revise valuation methodology. Questions raised by the Protestants regarding the allowance for going-concern value and use of a conditioned percent to measure property depreciation are clearly outside the scope of the issues defined in a pretrial order issued 8/16/77. "The purpose of this proceeding is to examine the tariffs filed by respondents, not to investigate every theoretical question which can be raised relating to oil pipeline ratemaking," and the Commission "should not endorse attempts to sidetrack the proceeding into an academic exercise in ratemaking theory."

With respect to rate of return, the brief stressed that several factors must be considered in addition to the standards set forth by the Supreme Court in the Bluefield case (i.e., the return must correspond to that offered by investments of comparable risk and must be sufficient to attract new capital). First, the brief asserted, since the FERC lacks authority to set wellhead prices for crude oil, any profits or losses at the wellhead are outside the scope of this hearing. Second, the pipeline carriers must be allowed a rate of return adequate to compensate them for the risks they have taken. Otherwise, investment in future expansions will be discouraged, and "future projects (such as the Alaskan gas pipeline) will find financing more difficult, perhaps impossible, because investors will be unsure of receiving a fair return." Were the FERC to adopt DOE's recommendation to set the rate of return at the constitutional minimum of nonconfiscation, "TAPS may be not only the largest pipeline in history, but also the last major pipeline to be built with private funds."

Third, the Respondents stated, investment in the TAPS project should be recognized as the equivalent of a 100% equity investment. In order to obtain any debt funding, the brief explained, the parents of the pipeline companies were required not only to provide an equity investment, but also to guarantee the debt of the pipeline company and thus bear the entire business and financial risk of the enterprise. "If TAPS fails, the investors will be liable for the entire loss. If TAPS succeeds, the investors should be allowed the opportunity to earn a return on the entire investment consistent with the risk they have taken by pledging their assets. Accordingly, if for any reason this Commission deems it necessary to consider capital structure for rate of return determinations, the various ownership interests in TAPS should properly be considered to have a capital structure of 100% equity."

The brief emphasized the unusually large risks involved in the TAPS project, as well as the need to evaluate these risks as of the time investment decisions were made. Some of the protestants, the brief noted, argue that only prospective risks (i.e., those risks remaining after the pipeline has been built and placed in operation) should be considered in determining an appropriate rate of return, and that the construction phase uncertainties are irrelevant because the owners are fully compensated in the rate base for all costs actually incurred. This contention, the brief said, is equivalent to arguing that an investor in the drilling of an oil well that later proved to be successful incurred no cognizable risk of failure because the uncertainties existing at the time of drilling never materialized. "The law is well-settled that investors are entitled to recover for the risks reasonably perceived at the outset, whether or not such risks actually materialize or are eventually overcome."

The Respondents summarized eight categories of risks associated with the TAPS project: (1) licensing and permit requirements — leading to risks and problems created by unprecedented government involvement in the project; (2) construction and technical risks stemming from the necessity to use and develop an entirely new and untried technology; (3) environmental risks created by unprecedented environmental restraints placed on TAPS; (4) weather and terrain causing frequent and severe problems; (5) capital intensiveness and throughput dependence — because TAPS is such a capital intensive enterprise, returns are highly sensitive to slight changes in throughput; (6) economic risks entailed by problems of marketing North Slope oil, such as current difficulties in arranging for the necessary additional pipeline capacity required in the Lower 48 States for movement of oil beyond the West Coast; (7) common carrier risks — requiring TAPS owners to provide space to all shippers, including intermediate shippers "who may take advantage of unreasonably low intrastate rates"; and (8) political risks, including a "broad spectrum" of possible regulatory actions by various federal and state agencies. Given these risks, the brief stated, there is no basis for Protestants' claim that an investment in TAPS "was as attractive, from the standpoint of safety, as an equity investment in a public utility."

In short, the brief declared, the enormous risks inherent in TAPS require inclusion of a premium in the rate of return. Raymond Gary of Morgan Stanley has concluded that a 20% return on TAPS valuation, or 6%-7% above that required for lower risk pipelines in the Continental United States, should be regarded as the minimum appropriate return. "Because of the limitations on return imposed by the Consent Decree, however, the tariffs filed by the carriers actually provide a much lower return than the carriers are entitled to as fair compensation for the risks they have assumed."

In regard to tax expenses, the Respondents opposed any flow through of tax benefits from accelerated depreciation. Rather, the brief declared, normalization is the only proper treatment from the standpoint of accounting practice, regulatory policy and legislative intent. While both the former FPC and the ICC required flow through of accelerated tax depreciation at one time, the brief noted, each agency subsequently abandoned the flow through approach and approved normalization. Also, the brief observed, the assumption underlying the FPC's adoption of flow through treatment, i.e., that tax savings from accelerated depreciation were "permanent," could never apply to TAPS — whatever its merits otherwise — since the depreciable tax base of each of the TAPS owners can be expected to decline, not to remain stable or grow.

Similarly, the Respondents stated, any flow through of the investment tax credit would be clearly contrary to the intent of Congress. Section 203(e) of the 1964 Revenue Act specifically prohibits federal regulatory agencies from flowing through any portion of the investment tax credit realized by regulated companies except certain "public utilities," which were not defined to include oil pipelines. Nor, the Respondents added, is there any reason to deduct investment tax credits from the rate base, as certain Protestants have suggested. Since oil pipelines are not public utilities, inclusion of these amounts in the rate base is required by Section 203(e). Failure to do so would violate the statutory ban on reducing cost of service, since it would "accomplish a similar result by any other method."

Finally, with respect to filed in-transit rules of certain TAPS carriers protested by Energy Co. of Alaska, the brief cited various ICC and court decisions in support of its position that the FERC has jurisdiction over in-transit shipments of oil from Prudhoe Bay to Valdez with removal and reinjection at North Pole and that the in-transit provisions are entirely proper. Moreover, contrary to ECA's allegation, "the scope of the tariffs in quite clear. Obviously, the tariffs filed with FERC apply only to shipments which are subject to FERC jurisdiction. The issue raised by ECA concerns shipments from Prudhoe Bay to ECA's North Pole refinery of oil which is refined there and <u>not</u> returned to TAPS (non-return oil). If, as ECA maintains, these shipments are not part of interstate commerce, it is quite clear that the FERC tariff cannot apply to the shipments. On the other hand, it is arguable that these shipments are part of interstate commerce. On almost identical facts, and under similar statutory language, gas sales have been held to be interstate and subject to FPC jurisdiction. . . . These cases establish the rule that 'the mixing of intrastate gas with a substantial portion of interstate gas in one commingled stream gave the Commission jurisdiction at the outset over the whole transaction.' Under this rule, the entire shipment to ECA would be subject to FERC jurisdiction."

Also, the Respondents added, the FERC has a clear obligation to pass on the intermediate rate rules set forth in the TAPS owners' tariffs. These rules result in the assessment of uniform rates by each carrier for all shipments through TAPS irrespective of the distance the oil is transported. "A uniform rate for intermediate shipments equal to the through rate simply charges that shipper for the capacity he uses, either by physically occupying the space or preventing its use by others. Consequently, the carriers must be allowed to collect the full through rate to compensate them for the revenue they could have obtained from shipments. The only alternative would be to increase the rates for through shippers in order to provide the carriers with just compensation."

Furthermore, the brief observed, the North Pole refinery owes its existence to a pipeline built to serve through shipments and also benefits from the economies of scale made possible by the large through shipments. Hence, "it is fair for ECA to bear its share of the total cost of the pipeline."

(FOR THE BRITISH PETROLEUM COMPANY LIMITED, LONDON)

FOR IMMEDIATE RELEASE **November 30, 1978**

THIRD QUARTER RESULTS

Income before extraordinary items compared with previous periods:-

	1978 $m	1977 (restated)* $m
July-September	170	119
January-September	578	623

*See Note 1 to the Group Income Statement

COMMENTS

The income before extraordinary items for the third quarter of 1978 is $170 million (£85.6 million) giving a total for the first nine months of $578 million (£292 million). This compares with $119 million (£60.1 million) for the corresponding quarter of 1977 and a total of $623 million (£314.4 million) for January/September 1977, a period which benefited substantially from stock appreciation in the first half of that year. The 1978 income figures are after a charge for UK Corporation Tax of $70 million (£35.4 million) in the quarter and $228 million (£115 million) for the nine months.

BP group sales (excluding Sohio) of crude oil, products and chemicals of 3.5 million barrels per day for the quarter are 140 thousand barrels per day or 4.3 percent higher than the second quarter of this year and 80 thousand barrels per day higher than the third quarter in 1977. In both cases the increase is largely attributable to additional sales of crude oil rather than products. Details of group sales including Sohio are shown below.

The Group Income Statement, as detailed in Note 2, includes the results of Sohio on a consolidated basis with effect from January 1, 1978. The BP Group interest in Sohio throughout the third quarter was 51.2 percent but increased to 52.2 percent on October 15, when sustainable net production from Sohio's Prudhoe Bay properties exceeded 550,000 barrels per day. The BP share of Sohio's profits, included in the consolidation, was $78 million (£39.2 million) in the third quarter reflecting the substantial contribution from the investment in the development of production in Alaska.

Production from the Forties Field averaged in excess of 500,000 barrels per day in the third quarter and, whilst price levels expressed in dollars were maintained, income has been reduced by the weakening of the dollar. In Europe trading conditions overall have held the improvement foreseen when the half-year results were announced and there has been a substantial rise in spot prices for light distillates which has improved refiners' margins. Chemicals sales volumes are virtually unchanged but over-capacity in Europe and imports from the USA have further depressed margins and results continue to be disappointing.

The reported income in sterling is extremely sensitive to movements in exchange rates and to the complex reaction these movements have on trading conditions. This applies particularly to the US dollar which is the main currency in which oil is traded. In the third quarter the rate for the US dollar against sterling fell by 12¢ against a 3¢ reduction in the corresponding period of 1977. The effect of this fall on the translation of income from operations in the USA and dollar cash balances in UK companies held to meet dollar commitments is estimated to have reduced reported income by $85 million (£43 million) in the third quarter of 1978. This compares to a reduction of $14 million (£7 million) in the corresponding quarter of 1977.

Income before extraordinary items for the period January/September 1978 per unit of ordinary stock is $1.49 (75.38p) compared with $1.61 (81.21p) for the same period in 1977.

D.A.G. Sarre
Secretary

GROUP SALES

	July-September 1978	July-September 1977 (restated)*	January-September 1978	January-September 1977 (restated)*	Year 1977
Thousands of barrels per day					
BP excluding Sohio					
Crude oil	1,640	1,510	1,520	1,460	1,520
Products/Chemicals	1,860	1,910	1,930	1,950	1,990
	3,500	3,420	3,450	3,410	
Sohio:					
Crude oil	390	-	290	-	-
Products/Chemicals	380	-	430	-	-
	770		720		
Total	4,270	3,420	4,170	3,410	3,510
Millions of tons					
Coal	2.5	-	5.4	0.1	0.2
Millions of cubic feet per day					
Natural gas	256	258	393	345	360

*See Note 1 to the Group Income Statement

Note:

1. Results reported are in conformity with the results which will be furnished to the Securities and Exchange Commission under Form 6-K. The British Petroleum Company Limited is not required to file Form 10-Q.

Investment analyst contact - Christopher Stevenson - 399-0615

THE BRITISH PETROLEUM COMPANY LIMITED

GROUP INCOME STATEMENT

Year 1977 $ million		July-September 1978	July-September 1977 (Restated)*	January-September 1978	January-September 1977 (Restated)*
		$ million			
29,130	Sales proceeds	8,643	7,262	25,313	21,484
5,375	Deduct: Customs duties and sales taxes	1,663	1,410	4,659	3,993
23,755	Net sales proceeds	6,980	5,852	20,654	17,491
516	Other income	151	102	450	337
24,271		7,131	5,954	21,104	17,828
16,923	Cost of sales, including freight, processing and manufacturing	4,858	4,214	14,179	12,419
2,007	Distribution, selling, administrative and other expenses	685	484	2,049	1,434
601	Depreciation and amounts provided	316	144	885	453
411	Interest and financing costs	222	110	707	301
19,942		6,081	4,952	17,820	14,607
4,329	Income before taxation	1,050	1,002	3,284	3,221
2,697	Overseas taxation	548	673	1,718	1,984
1,632	Income after overseas taxation	502	329	1,566	1,237
921	UK taxation (Note 3)	259	213	783	611
711	Income after taxation	243	116	783	626
2	Minority shareholders' interest	73	(3)	205	3
709	Income before extraordinary items	170	119	578	623
107	Extraordinary items	-	-	-	-
602	Net income of the group	170	119	578	623

*See Note 1 to Group Income Statement.

N.B. All conversions from sterling have been made at the September 30, 1978 exchange rate of £1 = $1.98. (See Note 4.)

Notes on Group Income Statement are attached.

November 30, 1978

NOTES

1. The comparative figures for July-September and January-September 1977 have been restated to reflect the change in the group's method of accounting for deferred taxation introduced at the end of 1977. The effect on income before extraordinary items is an increase from $87 million to $119 million and from $416 million to $623 million for July-September and January-September respectively.

2. During the second quarter of 1978 sustainable net production from Sohio's Prudhoe Bay properties exceeded 450,000 barrels per day, thereby increasing the group's interest in Sohio to over 50%. Sohio's results as adjusted to comply with the group's accounting policies have been fully consolidated from January 1, 1978. The comparative figures for 1977 included the group's share of Sohio's published results on an equity accounting basis under the headings 'Other Income' and 'Overseas Taxation'.

   Net sales proceeds and income before extraordinary items are analysed between Sohio and the remainder of the group as follows:

	July-September		January-September		Year
	1978	1977	1978	1977	1977
	$m	$m	$m	$m	$m
Net sales proceeds:					
-BP excluding Sohio	5,662	5,852	16,909	17,491	23,755
-Sohio (100%)	1,318	-	3,745	-	-
Total	6,980	5,852	20,654	17,491	23,755
Income before extraordinary items:					
-BP excluding Sohio	92	109	383	591	651
-Sohio (BP group interest)*	78	10	195	32	58
Total	170	119	578	623	709

   * The weighted average interests for the relevant periods were:

July-September		January-September		Year
1978	1977	1978	1977	1977
%	%	%	%	%
51.2	27.0	46.8	26.3	29.4

3. Due to the uncertainties in computing the charge for UK taxation for a period of less than a year, the amount shown represents the best estimate for the period.

The UK taxation charge of $783 million for the period January-September 1978 is made up as follows:

	$m
Corporate tax at 52%	970
Overseas tax relief	(742)
	228
Petroleum revenue tax	555
	783

4. Figures shown in this US Dollar edition have been translated from the sterling figures at the September 30, 1978 exchange rate of $1.98 = £1 and it should not be construed as a representation that the amounts of the pound sterling accounts represent, or have been or could be converted into, US dollars at this or any other rate.

5. Quarterly figures are unaudited.

6. This statement is prepared under accounting principles generally accepted in the UK.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

DOCKET NO. OR78-1

TRANS ALASKA PIPELINE SYSTEM

(Formerly I&S 9164, et al)

PREPARED REBUTTAL TESTIMONY

OF

PAUL H. JONES

Q. Please state your name and address.

A. I am Paul H. Jones. My business address is 255 California Street, San Francisco, California.

Q. By whom are you employed and in what capacity?

A. I am the Coordinator of Rates and Regulator Affairs for BP Pipelines Inc. on whose behalf I testified earlier in the proceeding. (TR. 5100 _et seq_.)

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the results of operations that have occurred since my initial exhibits were prepared, including an updated estimate of the results for the calendar year 1978.

Q. Have you prepared, or have you had prepared under your direction, exhibits and schedules in support of your prepared testimony?

A. Yes. Submitted with my prepared testimony are 5 exhibits. They are as follows:

Exhibit ____ (PHJ-1), Restated Financial Data for the Tariff Suspension Period (August 1, 1977 to January 29, 1978)

Schedule 1 - Restated Summary of Operations and Rates of Return

Schedule 2 - Restated Operating Revenues

Schedule 3 - Operation, Maintenance and General Expenses

Exhibit ____ (PHJ-2), Estimated Financial Data for the Calendar Year 1978

Schedule 1 - Restated Summary of Operations and Rates of Return

Schedule 2 - Estimated Operating Revenues

Schedule 3 - Estimated Operation, Maintenance and General Expenses

Schedule 4 - Estimated Dismantling costs

Exhibit ____ (PHJ-3), Estimated Financial Data for the 17 Months Ending December 31, 1978

Schedule 1 - Summary of Operations and Rates of Return

Schedule 2 - Estimated Operations, Maintenance and General Expenses

Schedule 3 - Estimated Dismantling Costs

Exhibit ____ (PHJ-4), Estimated Property Costs, Working

Capital and Depreciation Expense

Schedule 1 - Estimated Balances of Carrier Property Accounts and Related Depreciation Expense for Various Periods

Schedule 2 - Estimated Working Capital

Exhibit ____ (PHJ-5), Extract from Alyeska Monthly Status Report, July 1977

Q. What periods of time are represented in your rebuttal exhibits?

A. My exhibits show the results of operations for three different time periods. They are (1) the tariff suspension period, August 1, 1977 through January 29, 1978; (2) the calendar year 1978; and, (3) the 17-month period from August 1, 1977 through December 31, 1978.

Q. Describe and explain Exhibit ___ (PHJ-1), Schedule 1, entitled Restated Summary of Operations and Rates of Return for the Tariff Suspension Period.

A. Exhibit ___ (PHJ-1), Schedule 1, shows revenues and expenses for the tariff suspension period, August 1, 1977 to January 29, 1978. The delivery volumes shown are actual volumes for which revenues were recorded in that period. Operating revenues are taken from Schedule 2 of this Exhibit; Operation, Maintenance and General Expenses, Line 3 are from Schedule [illegible] and Depreciation and Amortization Expense on Line 4 was taken from Exhibit ___ (PHJ-4), Schedule 1. There are no income taxes calculated, because the operating result for this period is a loss of \$40,005,000.

Q. What rates of return resulted in this period?

A. Using the revised valuation amount of \$1,595,898,000, taken from Exhibit ________ (KAB-120), p.6, the rates of return on an annualized basis are: (1) 2.07% for Net Operating Income before Income Taxes and Interest, as shown on Line 12; (2) 2.07% for Net Operating Income after Income Taxes, as shown on Line 13 and (3) a negative 5.03% for Net Carrier Income, as shown on Line 14.

Q. Describe and explain Exhibit _____(PHJ-1), Schedule 2 entitled Restated Operating Revenues for the Tariff Suspension Period.

A. This Schedule shows the rate per barrel, revenue volumes and revenue amounts, in Columns (b), (c) and (d) respectively. Lines 1, 2 and 3 show the rates, volumes and revenues that were actually experienced during the suspension period. Line 6 shows the revenue reduction adjustment to place the amount of the refund, paid in July, 1978, back into the suspension period to which it applied. Line 4 identifies the incidental revenues received during this period. Line 7 shows total restated operating revenues of \$91,534,000.

Q. Describe and explain Exhibit ____ (PHJ-1), Schedule 3.

A. Exhibit ____ (PHJ-1), Schedule 3 is entitled Operation, Maintenance and General Expenses for the Tariff Suspension Period. This Schedule displays, by ICC account number, the operation, maintenance and general expenses for the period from August 1, 1977 to January 29, 1978. Separate amounts are shown for BP Pipelines' 15.84% share of Alyeska's expenses and its own expenses in Columns (c) and (d), respectively. These are the actual costs incurred during that period, except that the expenses for the month of January were reduced by multiplying by a fraction of 29 days over 31 days.

Q. Describe and explain Exhibit ____ (PHJ-2), Schedule 1, entitled Summary of Operations and Rates of Return for the Calendar Year of 1978.

A. The amounts in Schedule 1 of Exhibit ____ (PHJ-2), are comprised of actual amounts, except as noted below, through August 31, 1978, and estimated amounts for the months of September through December, 1978. Operating revenues were taken from Schedule 2 of this Exhibit. The Operation, Maintenance and General Expenses are taken from Schedule 3. Depreciation is from Exhibit ____ (PHJ-4), Schedule 1. The details of Dismantling Costs are shown in Schedule 4 of this Exhibit. Interest expense, shown on Line 9, has been reduced by the $588,000 of interest paid on the tariff refund. Income taxes, on Line 7, were computed at the composite state and Federal tax rate of 53.205772%. The resulting Net Carrier Income, shown on Line 10, is $62,492,000. The rates of return shown on Lines 12, 13 and 14 were computed in the same manner as in Exhibit ____ (PHJ-1), Schedule 1.

Q. Describe and explain Schedule 2 of Exhibit ____ (PHJ-2).

A. Exhibit ____ (PHJ-2), Schedule 2 is entitled Estimated Operating Revenues for the Calendar Year 1978. On Line 1 are the actual delivery volumes and revenues recorded in the period from January 1 through August 31, 1978. This revenue amount is net of the tariff refund (exclusive of interest) paid in July, 1978. Line 2 shows estimated delivery volumes for the period from September 1 through December 31, 1978. The estimated volume of 22,077,000 barrels represents 15.84% of estimated system capacity of 1.19 MMB/D at a 96% time efficiency factor. Revenue for this period was computed at the rate of $6.35 per barrel. On Line 3 is the adjustment to add back the 1977 portion of the refund to show the results as if the ICC-ordered rate had remained in effect for the entire suspension period. This has the effect of increasing revenues by $10,816,000. On Lines 5 and 6 are the minor amounts of other operating revenues that have been or are expected to be received during 1978.

Q. Describe and explain Exhibit ____ (PHJ-2), Schedule 3, entitled Estimated Operation, Maintenance and General Expenses for the Calendar Year 1978.

A. In Columns (c) and (d), respectively, are shown BP Pipelines' 15.84% share of Alyeska's expenses and its own direct expenses for the period. Column (e) is the sum of Columns (c) and (d). The portions of these expenses which are estimated were taken from the latest information available on projected operation, maintenance and general expenses for the balance of 1978.

Q. Describe and explain Exhibit ____ (PHJ-2), Schedule 4, entitled Estimated Dismantling Costs For the Calendar Year 1978.

A. This Schedule shows the calculation of the accrual for dismantling costs for the year 1978. The accrual through June 30, 1978, Lines 1 through 9, is on the basis of total estimated dismantling costs in 1977 dollars of $1,049 million and actual throughputs. The accrual for the last six months of 1978, Lines 10 through 18, is on the basis of total estimated dismantling costs in 1978 dollars of $1,122 and estimated throughputs. The inflation factor is 7%. The total accrual, shown at Line 19, is $7,387,000.

Q. Describe and explain Exhibit ____ (PHJ-3), Schedule 1.

A. Exhibit ____ (PHJ-3), Schedule 1, is entitled Summary of Operations and Rates of Return For The 17 Months Ending December 31, 1978. Essentially, the amounts shown in this schedule include actual revenues and expenses, except where noted below, through August 31, 1978 and estimated amounts for the period from September 1 thru December 31, 1978. Operation, Maintenance and General Expenses are taken from Schedule 2 of this Exhibit. Depreciation and Amortization Expense is the sum of columns E and F of Exhibit _____ (PHJ-4), Schedule 1. Dismantling Costs are detailed in Schedule 3 of this Exhibit. Interest expense has been reduced by $588,000 to eliminate the interest paid on the tariff refund. Income taxes were computed at the composite state and Federal income tax rate of 53.205772%. The rates of return, shown on Lines 12, 13 and 14, were computed in the same manner as in Exhibit ___ (PHJ-1), Schedule 1. Because returns are derived from 17 months of operation and the valuation is applicable to an annual period of 12 months it is necessary to apply the fraction 12/17 to each ratio to convert the 17-month results to annual rates.

Q. Describe and explain Exhibit ______ (PHJ-3), Schedule 2, entitled Estimated Operation, Maintenance and General Expenses for the 17 Months Ending December 31, 1978.

A. Exhibit ______ (PHJ-3), Schedule 2, shows the combined actual and estimated expenses for the period indicated, separated between BP Pipelines' 15.84% share of Alyeska's expenses and its own direct expenses, in Columns (c) and (d), respectively. The amounts in Column (e) are the sums of Columns (c) and (d). The estimated amounts included in this Schedule are based upon the most recent information available.

Q. Please describe and explain Exhibit _____ (PHJ-3), Schedule 3.

A. This Schedule is entitled Estimated Dismantling Costs For the 17 Months Ending December 31, 1978. It shows the actual and estimated accruals for the cost of dismantling the pipeline and restoring the environment. The amount calculated in this Schedule for the period from August 1, 1977 through June 30, 1978 is based upon actual volumes and the total estimated dismantling cost, expressed in 1977 dollars, of $1,049 million; for the period after June 30, 1978, it is based upon actual and estimated volumes and a total estimated dismantling cost, expressed in 1978 dollars, of $1,122 million, based upon an inflation factor of 7%. The total accrual shown on Line 15 is $9,237,000.

Q. Describe and explain Exhibit ____ (PHJ-4), Schedule 1.

A. This Schedule is entitled Estimated Balances of Carrier Property Accounts and Related Depreciation Expense. It shows in Columns (a) and (b), respectively, the ICC account number and description. In Columns (c) and (d) are shown the balances of the Carrier Property Accounts at December 31, 1977 and December 31, 1978 (estimated), respectively. In Columns (e) (f) and (g), are the amounts of depreciation expense calculated for the periods indicated. The Carrier Property Account Balances were taken from Exhibit ____ (KAB-106). The calculations of each of the depreciation expense amounts are described in footnotes 2, 3, and 4 at the bottom of the Schedule.

Q. Describe and explain Exhibit ___ (PHJ-4), Schedule 2, entitled Estimated Working Capital.

A. The estimated working capital requirement is comprised of 15 days estimated cash operating expenses, which totals $2,916,000, as shown on Line 3 and $5,131,000 for materials and supplies, as shown on Line 4. The total working capital requirement, Line 5, is $8,047,000.

Q. Mr. Muldoon, in his exhibits, has used July 1, 1977, referred to as the "oil in" date, for the commencement of operations and has adjusted the cost of five carriers, including BP, to reflect this date in lieu of the July 31, 1977 "oil out" date. Do you agree with that adjustment?

A. No. The majority of the carriers, including BP, capitalized interest and overheads during construction through July 31, 1977. Muldoon adjusted these figures based on his belief that the entire line was serviceable on July 1, 1977. Thus he deducted one month's normalized interest and operating costs from the companies' rate bases. Muldoon'premise for this deduction is simply wrong. The line was not serviceable at that time.

On the one hand, Muldoon embraces standard regulatory practices as the appropriate guidelines to be used in his testimony. But his treatment of the timing of amounts capitalized is not consistent with standard regulatory procedures applicable to accrual of such amounts.

Q. What are the regulatory conventions for determining when capitalization of interest during construction must cease?

A. Generally, regulatory agency instructions provide that an allowance for funds used during construction, taxes and overheads may be capitalized until a facility is ready for service. Public utility regulation permits funds committed to a regulated industry to earn a reasonable rate of return from time of commitment until such dollars are returned to the investor. During construction, owners may capitalize interest at an imputed earning rate, frequently referred to as Allowance for Funds Used During Construction ("AFUDC"). Owners may also capitalize taxes and administrative and general expenses associated with the construction project.

The accepted practice among regulatory agencies in determining the termination of AFUDC calls for a reasonable period of testing the system to insure it is capable of providing reliable service for the purpose for which investment was made. Only after the property has been tested and found ready for service must capitalization of construction allowances, taxes and overheads terminate. Examples of the standard regulatory practices are set out below.

a. The FPC's Uniform System of Accounts for natural gas companies provides:

> The equipment accounts shall include the necessary costs of testing or running a plant or part thereof during an experimental or test period prior to becoming available for service. The utility shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of thirty days. (CFR, Part 201, Chapter 1, p. 133, para 9D)

b. Similar language is contained in the Uniform System of Accounts for electric companies which says:

> 9D. The equipment accounts shall include the necessary costs of testing or running a plant or parts thereof during an experimental or test period prior to such plant becoming ready for or placed in service. The

> utility shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of 120 days for nuclear plant and a period of 90 days for all other plant. Such particulars shall include a detailed operational and downtime log showing days of production, gross killowatts generated by hourly increments, types, and period of outages by hours with explanation thereof, beginning with outages by hours with explanation thereof, beginning with the first date the equipment was either tested or synchronized on the line to the end of the test period. (CFR, Part 101, Title 18, p. 294, para. 9D)

c. Accounting Release Number AR-5 (revised) states that "Capitalization of interest stops when the facilities <u>have been tested</u> and are placed in or ready for service" (emphasis added).

d. Lastly, in Pennsylvania Water and Power Company, 8 FPC 4, (1949) the FPC made this observation (at pp. 43-44):

> The Commission has stated in previous opinions that the determination of the date upon which the capitalization of interest and taxes during construction should cease is not controlled by artificial rules, is not a matter of formula, but is a matter of reasonable judgment based on a construction of all the pertinent facts. It is true that reasonable time should be allowed for test periods and trials, the correction of defects and adjustments, and time for the plant to become sufficiently completed to be responsibly reliable for service for the purpose for which it was intended .

The foregoing illustrate the conventional regulatory approach to termination of AFUDC accruals and the capitalization of other costs. And what they demonstrate is that before the property in question can be viewed as in service it must be tested and shown to be reasonably reliable for the service intended. Muldoon agreed that the foregoing summaries were a fair statement of the criteria used in determining the time period for capitalization of interest and taxes. Significantly, his adjustment does not comport with this standard.

Q. How would you relate those ratemaking conventions to the TAPS situation?

A. I think it's quite clear that the physical completion of construction, about June 20, 1977, when oil was first injected into the line, did not represent the time for termination of capitalized costs. The month of July was a month of testing and extensive correction of defects. The first day of uninterrupted service did not occur until August 5, 1977, and the pipeline did not in fact reach the capacity for which it was designed until March, 1978. However, a delivery of oil was commenced on July 31 and completed on August 1, 1977, and BP has concluded that it would be reasonable to terminate capitalizing construction costs on July 31, 1977.

Q. Please describe the activities that transpired in July, 1977.

A. Exhibit _____ (PHJ-5), which is an extract from Alyeska's July, 1977 Status Report, presents the chronology of start-up activities between June 20, and July 31, 1977. There were numerous shutdowns of the system to correct deficiencies in its mechanical integrity as the line fill operation progressed. The most notable one was the interruption caused by the explosion and fire at Pump Station 8 which shut the pipeline down for 10 days. Alyeska and government personnel walked the pipeline during this period looking for leaks. There was a shutdown as late as July 27, ordered by the Department of Transportation officials, due to "last minute weld problems" in Valdez Terminal piping; final approval to deliver oil into the terminal was not obtained from the Office of Pipeline Safety until July 28. Testing of the ballast water treatment plant was not completed until July 30. These facts confirm that the period was merely a testing period. It is clear that the total system was not ready for reliable service until the end of July. Furthermore, even though the piping was hydrostatically tested, welds extensively X-rayed, fluids circulated in closed systems of the pump stations and numerous other testing programs undertaken to simulate operations before the actual oil flow commenced, the real and final test of the system was not completed until oil was in the entire line and moving smoothly through a synchronized system. Those company managements which concluded that the system was not ready for service until it had met that final test, were exercising sound judgment. Consequently, we found it reasonable to conclude that we had the option, under sound regulatory precedent, to select July 31, 1977 as the proper date for terminating capitalization of taxes, AFUDC and overheads.

Q. Mr. Werner attributed to BP Pipelines an average balance for deferred taxes of over $140 million for the 1978 test year. What do you estimate will be the actual deferred tax balance for BP Pipelines for the year 1978?

A. BP Pipelines had no deferred taxes as of December 31, 1977. As shown on Exhibit ____(PHJ-2), Schedule 1, we estimate income taxes for the year 1978 to be $71 million. Therefore, the average balance of deferred taxes for 1978 should not exceed $35.5 million.

VERIFICATION

CITY AND COUNTY OF SAN FRANCISCO: ss

PAUL H. JONES, being duly sworn, deposes and says that he has read the foregoing statement, knows the contents thereof, and that the same are true as stated.

Paul H. Jones

Paul H. Jones

Subcribed and sworn to before me this 27th day of October, 1978

OFFICIAL SEAL
LUCY PERDICHIZZI
NOTARY PUBLIC - CALIFORNIA
CITY AND COUNTY OF SAN FRANCISCO
My Commission Expires July 28, 1982

Lucy Perdichizzi

Notary Public

Exhibit ____ (PHJ-1)

Schedule 1

BP PIPELINES INC.
Restated Summary of Operations and Rates of Return 1/
For the Tariff Suspension Period 2/
($000)

Line No.	Description (a)	Amount (b)
1.	Delivery Volumes (M Barrels)	19,584
2.	Operating Revenues (Schedule 2)	$ 91,534
	Operating Expenses	
3.	Operation, Maintenance and General Expenses (Schedule 3)	42,185
4.	Depreciation and Amortization	30,558
5.	Dismantling Costs	2,326
6.	Net Operating Income before Income Taxes and Interest	$ 16,465
7.	Income Taxes 3/	-
8.	Net Operating Income After Income Taxes	$ 16,465
9.	Interest Expense	56,470
10.	Net Carrier Income	$(40,005)
11.	Valuation 4/	$1,595,895
	Rates of Return on Valuation	
12.	Net Operating Income before Income Taxes and Interest (Line 6 ÷ Line 11) x 365/182	2.07%
13.	Net Operating Income after Income Taxes (Line 8 ÷ Line 11) x 365/182	2.07%
14.	Net Carrier Income (Line 10 ÷ Line 11) x 365/182	(5.03%)

Notes: 1/ Restated to include the reduction for the suspension period portion of the tariff refund ($16,546) paid in July, 1978
2/ August 1, 1977 to January 29, 1978
3/ Composite State and Federal Income Taxes (Line 6-Line 9) X 53.25772%
4/ See Exhibit ____ (KAB-120)

Exhibit_____(PHJ-1)

Schedule 2

BP PIPELINES INC.
Restated Operating Revenues
For the Tariff Suspension Period 1/

Line No.	Description (a)	Rate per Barrel (b)	Revenue Volumes (M Barrels) (c)	Amount ($000) (d)
	Volumes and Revenues Charged			
1.	August 1 - Oct. 20, 1977	$ 4.68	9,641	$ 45,120
2.	October 21, 1977 - January 29, 1978	$ 6.35	9,908	62,916
3.	Subtotal			$108,036
4.	Incidental Revenues			44
5.	Total Revenues before Adjustment			$108,080
	Adjustment For Refund			
6.	Revenue Volumes, October 21, 1977- January 29, 1978	$(1.67)	9,908	(16,546)
7.	Total Restated Operating Revenues			$ 91,534

1/ August 1, 1977 to January 29, 1978, restated to include the reduction for the suspension period portion of the tariff refund paid in July, 1978.

Exhibit ___ (PHJ- 1)
Schedule 3

BP PIPELINES INC.
Operation, Maintenance and General Expenses
For the Tariff Suspension Period 1/
($000)

Line No.	ICC Account Number	ICC Account Description	Alyeska Expenses (15.84%)	Direct Expenses	Total
	(a)	(b)	(c)	(d)	(e)
		Operation			
1	300	Salaries and wages	$ 1,955	$ -	$ 1,955
2	310	Supplies and expenses	2,036	-	2,036
3	320	Outside services	8,504	-	8,504
4	330	Operating fuel and power	3,577	515	4,092
5		Total Operation Expense	$ 16,072	$ 515	$ 16,587
		Maintenance			
6	400	Salaries and wages	$ 553	$ -	$ 553
7	410	Supplies and expenses	2,224	-	2,224
8	420	Outside services	3,866	-	3,866
9	430	Maintenance materials	762	-	762
10		Total Maintenance Expense	$ 7,405	$ -	$ 7,405
		General			
11	500	Salaries and wages	$ 2,574	$ 302	$ 2,876
12	510	Supplies and expenses	613	99	712
13	520	Outside services	1,464	677	2,141
14	530	Rentals	1,000	50	1,050
15	550	Pensions and benefits	446	(176)	270
16	560	Insurance	373	339	712
17	570	Casualty and other losses	39	-	39
18	580	Pipeline taxes	10,388	5	10,393
19		Total General Expense	$ 16,897	$ 1,296	$ 18,193
20		Total Operation, Maintenance and General Expenses	$ 40,374	$ 1,811	$ 42,185

Notes:

1/ August 1, 1977 to January 29, 1978.

Exhibit_____(PHJ-2)
Schedule 1

BP PIPELINES INC.
Summary of Operations and Rates of Return
For the Calendar Year 1978 1/
($000)

Line No.	Description (a)	Amount (b)
1	Delivery Volumes (M Barrels)	61,729
2	Operating Revenues (Schedule 2)	$ 383,738
	Operating Expenses	
3	Operation, Maintenance and General Expenses (Schedule 3)	70,950
4	Depreciation and Amortization (Exhibit___(PHJ-4), Schedule 1)	61,580
5	Dismantling Costs (Schedule 4)	7,387
6	Net Operating Income before Income Taxes and Interest	$ 243,821
7	Income Taxes 2/	71,055
8	Net Operating Income After Income Taxes	$ 172,766
9	Interest Expense	110,274
10	Net Carrier Income	$ 62,492
11	Valuation 3/	$1,595,895
	Rates of Return on Valuation	
12	Net Operating Income before Income Taxes and Interest (Line 6 ÷ Line 11)	15.28%
13	Net Operating Income after Income Taxes (Line 8 ÷ Line 11)	10.83%
14	Net Carrier Income (Line 10 ÷ Line 11)	3.92%

Notes:

1/ Restated to eliminate the 1977 portion of the tariff refund ($10,816) and the interest paid on the tariff refund ($588).
2/ Composite State and Federal Income Taxes (Line 6-Line 9) X 53.205772%.
3/ See Exhibit_____(KAB- 120), page 6.

Exhibit_____(PHJ-2)
Schedule 2

BP PIPELINES INC.
Estimated Operating Revenues 1/
For the Calendar Year 1978

		Revenue Volumes (M Barrels)	Amount ($000)
	Trunk Revenues		
1.	Actual Deliveries - January 1, - August 31, 1978	39,652	$ 232,637
2.	Estimated Deliveries - September 1, - December 31, 1978	22,077	140,189
3.	Adjustment to Eliminate 1977 portion of refund	-	10,816
4.	Total Trunk Revenues - Restated		$ 383,642
5.	Demurrage Revenue		2
6.	Incidental Revenue		94
7.	Total Operating Revenue		$ 383,738

Notes:

1/ Restated to eliminate the 1977 portion of the tariff refund paid in July, 1978.

Exhibit ____(PHJ-2)
Schedule 3

BP PIPELINES INC.
Estimated Operation, Maintenance and General Expenses
For the Calendar Year 1978
($000)

Line No.	ICC Account Number (a)	ICC Account Description (b)	Alyeska Expenses (15.84%) (c)	Direct Expenses (d)	Total (e)
		Operation			
1	300	Salaries and wages	$ 3,436	$ -	$ 3,436
2	310	Supplies and expenses	3,546	-	3,546
3	320	Outside services	7,117	-	7,117
4	330	Operating fuel and power	4,282	1,847	6,129
5		Total Operation Expense	$ 18,381	$ 1,847	$ 20,228
		Maintenance			
6	400	Salaries and wages	$ 1,194	$ -	$ 1,194
7	410	Supplies and expenses	2,099	-	2,099
8	420	Outside services	4,311	-	4,311
9	430	Maintenance materials	541	-	541
10		Total Maintenance Expense	$ 8,145	$ -	$ 8,145
		General			
11	500	Salaries and wages	$ 3,301	$ 524	$ 3,825
12	510	Supplies and expenses	638	274	912
13	520	Outside services	2,659	1,851	4,510
14	530	Rentals	1,391	84	1,475
15	550	Pensions and benefits	1,267	94	1,361
16	560	Insurance	1,860	1,255	3,115
17	570	Casualty and other losses	342	-	342
18	580	Pipeline taxes	26,693	344	27,037
19		Total General Expenses	$ 38,151	$ 4,426	$ 42,577
20		Total Operation, Maintenance and General Expenses	$ 64,677	$ 6,273	$ 70,950

Exhibit ____ (PHJ-2)
Schedule 4

BP PIPELINES INC.
Estimated Dismantling Costs
For the Calendar Year 1978
($000)

Line No.	Description (a)		Amount (b)
	Actual Accrual - January 1, - June 30, 1978		
	Based on:		
1	Estimated total cost in 1977 dollars ($1,049 million x 15.84%)	$ 166,162	
2	Less accrual to 12-31-77	1,850	
3	Balance to be accrued	$ 164,312	
4	Estimated Prudhoe Bay reserves	9,107,394 MBbls.	
5	Less deliveries to TAPS to 12-31-77	101,372 MBbls.	
6	Remaining reserves	9,006,022 MBbls.	
7	Prudhoe Bay deliveries January-June, 1978	178,006 MBbls.	
8	178006 MBbls.		$ 3,248
9	9006022 MBbls. x $164,312		
	Estimated Accrual-July 1-December 31, 1978		
	Based on:		
10	Estimated total cost in 1978 dollars ($1,122 Million x 15.84%) 1/	$ 177,725	
11	Less: Accrual to 6-30-78	5,098	
12	Balance to be accrued	$ 172,627	
13	Estimated Prudhoe Bay reserve	9,107,394 MBbls.	
14	Less deliveries to TAPS to 6-30-78	279,378 MBbls.	
15	Remaining reserves	8,828,016 MBbls.	
16	Prudhoe Bay deliveries in July 1 - December 31, 1978	211,691 MBbls.	
17	211691 MBbls		$ 4,139
18	8828016 MBbls x $ 172,627		
19	Total		$ 7,387

Note:

1/ $1,049 x 107% = $1,122

Exhibit_____(PHJ-3)

Schedule 1

BP PIPELINES INC.
Summary of Operations and Rates of Return 1/
For the 17 Months Ending December 31, 1978
($000)

Line No.	Description (a)	Amount (b)
1	Delivery Volumes (M Barrels)	77,847
2	Operating Revenue	$ 459,216 4/
	Operating Expenses	
3	Operation, Maintenance and General Expenses (Schedule 2)	105,792
4	Depreciation and Amortization (Exhibit____(PHJ-4,Schedule 1)	87,114
5	Dismantling Costs (Schedule 3)	9,237
6	Net Operating Income Before Income Taxes and Interest	$ 257,073
7	Income Taxes 2/	52,838
8	Net Operating Income After Income Taxes	$ 204,235
9	Interest Expense	157,763
10	Net Carrier Income	$ 46,472
11	Valuation 3/	$1,595,895
	Rates Of Return On Valuation	
12	Net Operating Income before Income Taxes and Interest (Line 6 ÷ Line 11) x 12/17	11.37%
13	Net Operating Income after Income Taxes (Line 8 ÷ Line 11) x 12/17	9.03%
14	Net Carrier Income (Line 10 ÷ Line 11) x 12/17	2.06%

Notes:

1/ Restated to eliminate interest paid on the Tariff Refund ($588)

2/ Composite State and Federal Income Taxes (Line 6-Line 9) X 53.205772%

3/ See Exhibit_____(KAB- 120), page 6.

4/ Comprised of Trunk Revenue ($459,076) and Incidental Revenue ($140)

Exhibit ___ (PHJ-3)
Schedule 2

BP PIPELINES INC.
Estimated Operation, Maintenance and General Expenses
For the 17 Months Ending December 31, 1978
($000)

Line No.	ICC Account Number (a)	ICC Account Description (b)	Alyeska Expenses (15.84%) (c)	Direct Expenses (d)	Total (e)
		Operation			
1	300	Salaries and wages	$ 5,019	$ -	$ 5,019
2	310	Supplies and expenses	5,301	-	5,301
3	320	Outside services	13,944	-	13,944
4	330	Operating fuel and power	7,298	2,286	9,584
5		Total Operation Expense	$ 31,562	$ 2,286	$ 33,848
		Maintenance			
6	400	Salaries and wages	$ 1,673	$ -	$ 1,673
7	410	Supplies and expenses	4,166	-	4,166
8	420	Outside services	7,140	-	7,140
9	430	Maintenance materials	1,237	-	1,237
10		Total Maintenance Expense	$ 14,216	$ -	$ 14,216
		General			
11	500	Salaries and wages	$ 6,622	$ 786	$ 7,408
12	510	Supplies and expenses	1,168	361	1,529
13	520	Outside services	3,645	2,540	6,185
14	530	Rentals	2,411	124	2,535
15	550	Pensions and benefits	585	(62)	523
16	560	Insurance	2,192	1,540	3,732
17	570	Casualty and other losses	358	-	358
18	580	Pipeline taxes	35,114	344	35,458
19		Total General Expense	$ 52,095	$ 5,633	$ 57,728
20		Total Operation, Maintenance and General Expenses	$ 97,873	$ 7,919	$105,792

Exhibit ___ (PHJ-3)
Schedule 3

BP PIPELINES INC.
Estimated Dismantling Costs
For the 17 Months Ending December 31, 1978
($000)

Line No.	Description (a)		Amount (b)
	Actual Accrual - August 1, 1977 through June 30, 1978.		
	Based on:		
1	Estimated total dismantling cost in 1977 dollars ($1,049 million x 15.84%)	$ 166,162	
2	Estimated Prudhoe Bay reserves	9,107,394 MBbls.	
3	Prudhoe Bay deliveries July, 1977-June, 1978	279,378 MBbls.	
4 5	$\frac{279,378 \text{MBbls.}}{9107394 \text{ MBbls.}}$ x $166,162 =		$ 5,097
	Estimated Accrual - July 1 - December 31, 1978		
	Based on:		
6	Estimated total dismantling cost in 1978 dollars ($1,122 million x 15.84%) 1/	$ 177,725	
7	Less accrual to 6-30-78	5,098	
8	Balance to be accrued	$ 172,627	
9	Estimated Prudhoe Bay reserves	9,107,394 MBbls.	
10	Less deliveries to TAPS to 6-30-78	279,378 MBbls.	
11	Remaining reserves	8,828,016 MBbls.	
12	Estimated Prudhoe Bay deliveries July 1-December 31, 1978	211,691 MBbls.	
13 14	$\frac{211691 \text{ MBbls.}}{8828016 \text{ MBbls.}}$ x 172,627		4,140
15	Total Accrual		$ 9,237

Note:

1/ $1,049 x 107% = $1,122

Exhibit ____ (MJ-4)
Schedule 1

BP PIPELINES INC.
Estimated Balances of Carrier Property Accounts and Related Depreciation Expense
($000)

Line No.	Account No. (a)	Account Description (b)	Carrier Property Account Balances: Dec. 31, 1977 (c)	Carrier Property Account Balances: Estimated Dec. 31, 1978 (d)	Depreciation Expense 1/: Aug. 1, - Dec. 31, 1977 (e) 2/	Depreciation Expense 1/: 1978 (f) 3/	Depreciation Expense 1/: Aug. 1, 1977 Jan 29, 1978 (g) 4/
1	151	Land	$ 2,791	$ 2,793	$ -	$ -	$ -
2	152	Rights of Way	145	145	2	6	3
3	153	Line Pipe	32,449	32,450	541	1,298	647
4	154	Line Pipe Fittings	7,573	8,136	126	314	151
5	155	Pipeline Construction	1,006,885	1,008,092	16,781	40,300	20,083
6	156	Buildings	63,989	65,899	1,066	2,598	1,276
7	157	Boilers	2,516	2,639	42	103	50
8	158	Pumping Equipment	12,918	13,301	215	524	258
9	159	Machine Tools and Machinery	13	27	1	2	1
10	160	Other Station Equipment	90,259	91,993	1,504	3,645	1,800
11	161	Oil Tanks	6,581	7,019	110	272	131
12	162	Delivery Facilities	266,272	266,276	4,438	10,651	5,311
13	163	Communication Systems	555	649	23	60	28
14	164	Office Furniture & Equipment	185	384	8	28	9
15	165	Vehicles & Other Work Equipment	8,113	9,672	677	1,779	810
16	Total		$1,501,249	$1,509,475	$ 25,531	$ 61,580	$ 30,558

Notes: 1/ Based on the following annual rates:

Accounts 152 thru 158 and 160 thru 162	4%
Accounts 159, 163 and 164	10%
Account 165	20%

2/ Col. c x Rate x 5/12

3/ (Col. c + Col. d) ÷ 2 x Rate

4/ Col. c x Rate x 182/365

Exhibit____(PHJ-4)
Schedule 2

BP PIPELINES INC.
Estimated Working Capital
($000)

Line No.	Description (a)	Amount (b)
1	Estimated Cash Operating Expenses - 1978 (Exhibit____(PHJ-2), Schedule 3, Column (e) Line 20)	$ 70,950
2	Average Daily Cash Requirements (Line 1 ÷ 365)	$ 194.4
3	Cash Working Capital (Line 2 X 15 Days)	$ 2,916
4	Materials and Supplies	5,131 1/
5	Total Working Capital	$ 8,047

Note:

1/ 15.84% of Alyeska materials and supplies at 12-31-77.

ALYESKA MONTHLY STATUS REPORT

JULY 1977

I. OPERATIONS DIVISION

A. HIGHLIGHTS

- The three outstanding events of the month were:

  - The fire at Pump Station 8, which destroyed the pump and turbine rooms at this station and resulted in one fatality.

  - The completion of line fill on July 28.

  - The loading of the first ship which commenced on July 31 and was completed on August 1 when the ship, the ARCO JUNEAU, sailed for Cherry Point with 824,803 barrels of North Slope crude.

- The significant events of the startup are listed more or less completely in the following narrative:

June 17 - The nitrogen stored in the 48" mainline was released down line thus depressuring the producers' lines permitting them to begin filling these 34" lines.

June 18 - PS 1 began filling tankage.

June 19 - Press Conference at Prudhoe Bay facilities. Received permission from DOI to start line fill.

June 20 - 10:06 started line fill by launching a scraper from PS 1.

June 27 - Gas line to Pump Station 4 damaged by restoration crew removing "temporary" road to a material site. The gas line was incorrectly installed at this location having been buried only 30" below the temporary roadway surface, thus being above the permanent grade.

- Recognition picketing started at all Southern P/L district work locations.

June 29 - Pump Station 1 meters in service.

June 30 - Wax scraper launched from PS 1.

July 4 - Nitrogen, originally scheduled for delivery to PS 10 but rerouted to PS 8 due to union pickets, was injected into the pipeline to top up the nitrogen buffer between air and crude oil. Inadvertently, liquid nitrogen was injected when the wrong tank truck connection was used. This resulted in a mainline pipe failure due to brittle fracture as the cryogenic liquid "puddled" in a sag bind in the station piping.

July 7 - The line was restarted after repairs to the sag bend which required the cut out of a factory elbow. Fit up problems included the correction of poor pipe lineup in the original installation.

- Valdez construction effectively stopped by a sickout of union workers in sympathy with recognitional picketing.

- Pump Station 12 relief tank roof buckled when relief valves opened on power failure causing the mainline to discharge 15 psi air into this tank at a rate in excess of vent capacity. The air pressure was the result of holding "back pressure" on the mainline to slow pig travel in slack line sections. The fact that relief valve flows could exceed tank venting capacity had not been anticipated and the control "circuit board" which holds relief valves stationary on power failure was faulty and being repaired at the time.

July 8 - Pump Station 8 suffered an explosion and fire shortly after starting a mainline pump. The basic cause was opening a 26" suction strainer without properly isolating it. The isolation procedure includes locking out the suction valve and failure to do so permitted this valve to be opened remotely resulting in a massive hydrocarbon discharge. The crude oil ignited from one of several possible sources; the most likely being falling roof hardware including lighting fixtures.

July 18 - Restarted line filling after receiving DOI clearance. Prior to this clearance Alyeska had:

- Blinded off all mainline branches to the pump room at PS 8.
- Reinspected all mainline piping and valving in PS 8.
- Rehydrotested PS 8 piping with crude oil.
- Conducted retraining of operating technicians at all pump stations in equipment isolation and work permit procedures.
- Conducted a Vice Presidential safety inspection of all pump stations and Valdez to confirm retraining and establish that lines of authority were clearly stated and well understood.

July 19 - Contractor backfilling check valve number 7 accidentally damaged a small 1 1/2" vent connection causing an oil leak and forcing a line shutdown. The large front end loader "hooked" the vent valve with its bucket tooth. This check valve was not backfilled earlier because it was necessary to inspect it for small leaks after line pressure was on it. (The check valve had been opened after hydrotesting the pipeline section.)

This incident also highlights the need for tighter work procedures for contractors and the need for smaller equipment better suited to maintenance rather than construction.

July 20 - Pipeline again shut down due to indications of an oil leak. This one was a false alarm when Pump Station 1 lost speed on a mainline pump due to faulty governor operation and LEFMs showed increased flow instead of the actual decrease.

July 21 - Pump Station 9 commercial power supply failed repeatedly. Switched to backup supply from solar units added as a startup change.

July 27 - Pipeline shutdown due to "last minute weld problems" in Valdez Terminal piping brought to light by DOT audit.

July 28 - DOT agrees to pipeline restart and use of full encirclement repair of two terminal welds if repairs in progress are unsuccessful. Line restarted and oil brought into terminal at 23:02 hours. Welds completed at about 22:30 hours and later given clearance by DOT et al. These welds were not in the initial oil path but were in manifolds where isolation for cut out and hot work would be nearly impossible.

July 30 - Deballasting ARCO JUNEAU.

July 31 - Ballast Water Treating Facilities started up. Treated water about 2 ppm oil in water vs. specification of 8 ppm maximum.

- Started loading ARCO JUNEAU with crude oil. Oil temperature 50° F. and no indication of any wax problem.

August 1 - Completed ship loading and sailed the ARCO JUNEAU at 19:00 hours.

KELSO & CO.
INCORPORATED
INVESTMENT BANKERS

GREENSBORO, N.C. SAN FRANCISCO LOS ANGELES

REVENUE BILL OF 1978

(H. R. 13511)

TITLE VI

GENERAL STOCK OWNERSHIP CORPORATIONS

Sec. 601. ESTABLISHMENT AND TAXATION OF GENERAL STOCK OWNERSHIP CORPORATIONS AND THEIR SHAREHOLDERS

(a) IN GENERAL. - Chapter 1 (relating to normal taxes and surtaxes) is amended by adding at the end thereof the following new subchapter:

"Subchapter U - General Stock Ownership Corporations

"Sec. 1391. DEFINITIONS.

"(a) GENERAL STOCK OWNERSHIP CORPORATION. - For purposes of this subchapter, the term 'general stock ownership corporation' (hereinafter referred to as a 'GSOC') means a domestic corporation which -

"(1) is not a member of an affiliated group (as defined in section 1504), and

"(2) is chartered and organized after December 31, 1978, and before January 1, 1984;

"(3) is chartered by an act of a State legislature or as a result of a State-wide referendum;

"(4) has a charter providing -

"(A) for the issuance of only 1 class of stock,

"(B) for the issuance of shares only to eligible individuals (as defined in subsection (c));

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"(C) for the issuance of at least one share to each eligible individual, unless such eligible individual elects within one year after the date of issuance not to receive such share;

"(D) that no share of stock shall be transferable -

"(i) by a shareholder other than by will or the laws of descent and distribution until after the expiration of 5 years from the date such stock is issued by the GSOC except where the shareholder ceases to be a resident of the State;

"(ii) to any person other than a resident individual of the chartering State;

"(iii) to any individual who, after the transfer, would own more than 10 shares of the GSOC;

"(E) that such corporation shall qualify as a GSOC under the Internal Revenue Code;

"(5) is empowered to invest in properties (but not in properties acquired by it or for its benefit through the right of eminent domain).

For purposes of this subsection, section 1504 (a) shall be applied by substituting '20 percent' for '80 percent' wherever it appears.

"(b) ELECTING GSOC. - For purposes of this subchapter, the term 'electing GSOC' means a GSOC which files an election under section 1392 which, under section 1392, is in effect for such taxable year.

"(c) ELIGIBLE INDIVIDUALS. - For purposes of subsection (a), the term 'eligible individual' means an individual who is, as of a date specified in the State's enabling legislation for the GSOC, a resident of the chartering State and who remains a resident of such State between that date and the date of issuance.

"(d) TREATED AS PRIVATE CORPORATIONS. - For purposes of this title, a GSOC shall be treated as a private corporation and not as a governmental unit.

"(e) STUDY OF GENERAL STOCK OWNERSHIP CORPORATIONS. - The staff of the Joint Committee on Taxation shall prepare a report on the operation and effects of this subchapter relating to GSOC's. An interim report shall be filed within two years after the first GSOC is formed and a final report shall be filed by September 30, 1983.

"Sec. 1392. ELECTION BY GSOC.

"(a) ELIGIBILITY.- Except as provided in section 1393, any GSOC may elect, in accordance with the provisions of this section, not to be subject to the taxes imposed by this chapter.

"(b) EFFECT. - If a GSOC makes an election under subsection (a) then -

"(1) with respect to the taxable years of the GSOC for which such election is in effect, such corporation shall not be subject to the taxes imposed by this chapter and, with respect to such taxable years and all succeeding taxable years, the provisions of section 1396 shall apply to such GSOC, and

"(2) with respect to each such taxable year, the provisions of section 1393, 1394, and 1395 shall apply to the shareholders of such GSOC.

"(c) WHERE AND HOW MADE. - An election under subsection (a) may be made by a GSOC at such time and in such manner as the Secretary shall prescribe by regulations.

"(d) YEARS FOR WHICH EFFECTIVE - An election under subsection (a) shall be effective for the taxable year of the GSOC for which it is made and for all succeeding taxable years of the GSOC, unless it is terminated under subsection (f).

"(e) TAXABLE YEAR. - The taxable year of a GSOC shall end on October 31 unless the Secretary consents to a different taxable year.".

"(f) TERMINATION. - The election of a GSOC under subsection (a) shall terminate for any taxable year during which it ceases to be a GSOC and for all succeeding taxable years. The election of a GSOC under subsection (a) may be terminated at any other time with the consent of the Secretary, effective for the first taxable year with respect to which the Secretary consents and for all succeeding taxable years.

"Sec. 1393. TAXABLE INCOME TAXED TO SHAREHOLDERS.

"(a) GENERAL RULE. - The taxable income of an electing GSOC for any taxable year shall be included in the gross income of the shareholders of such GSOC in the manner and to the extent set forth in this subsection.

"(1) AMOUNT INCLUDED IN GROSS INCOME. - Each shareholder of an electing GSOC on any day of a taxable year of such GSOC shall include in his gross income for the taxable year with or within which the taxable year of the GSOC ends the amount he would have received if, on each day of such taxable year, there had been distributed pro rata to its shareholders by such GSOC an amount equal to the taxable income of the GSOC for its taxable year divided by the number of days in the GSOC's taxable year.

"(2) TAXABLE INCOME DEFINED. - For purposes of this section, the term 'taxable income' of a GSOC shall be determined without regard to the deductions allowed by part VIII of subchapter B (other than deductions allowed by section 248, relating to organizational expenditures).

"(b) SPECIAL RULE FOR INVESTMENT CREDIT. - The investment credit of an electing GSOC for any taxable year shall be allowed as a credit to the shareholders of such corporation in the manner and to the extent set forth in this subsection.

"(1) CREDIT. - There shall be apportioned among the shareholders a credit equal to the amount each shareholder would have received if, on each day of such taxable year, there had been distributed pro rata to the shareholders the electing GSOC's net investment credit divided by the number of days in the GSOC's taxable year.

"(2) NET INVESTMENT CREDIT. - For purposes of this paragraph the term 'net investment credit' means the investment credit of the electing GSOC for its taxable year less any tax from recomputing a prior year's investment credit in accordance with section 47.

"(3) RECAPTURE. - There shall be apportioned among the shareholders of a GSOC, in the manner described in paragraph (1), an additional tax equal to the excess of any tax resulting from recomputing a prior year's investment credit, in accordance with section 47 over the investment credit of the GSOC for it's taxable year.

"Sec. 1394. RULES APPLICABLE TO DISTRIBUTIONS OF AN ELECTING GSOC'S.

"(a) SHAREHOLDER INCOME ACCOUNT. - An electing GSOC shall establish and maintain a shareholder income account which account shall be -

"(1) increased at the close of the GSOC's taxable year by an amount equal to the GSOC's taxable income for such year, and

"(2) Decreased, but not below zero, on the first day of the GSOC's taxable year by the amount of any GSOC distribution to the shareholders of such GSOC made or treated as made during the prior taxable year.

"(b) TAXATION OF DISTRIBUTIONS. - Distributions by an electing GSOC shall be treated as -

"(1) a distribution of previously taxed income to the extent such distribution does not exceed the balance of the shareholder income account as of the close of the taxable year of the GSOC, and

"(2) a distribution to which section 301(a) applies but only to the extent such distribution exceeds the balance of the shareholder income account as of the close of the taxable year of the GSOC.

"(c) DISTRIBUTIONS NOT TREATED AS A DIVIDENT. - Any amounts includible in the gross income of any individual by reason of ownership of stock in a GSOC shall not be considered as a dividend for purposes of section 116.

"(d) REGULATIONS. - The Secretary shall have authority to prescribe by regulation, rules for treatment of distributions in respect of shares of stock of the GSOC that have been transferred during the taxable year.".

"Sec. 1395. ADJUSTMENT TO BASIS OF STOCK OF SHAREHOLDERS.

"The basis of a shareholder's stock in an electing GSOC shall be increased by the amount includible in the gross income of such shareholder under section 1393, but only to the extent to which such amount is actually included in the gross income of such shareholder.

"Sec. 1396. MINIMUM DISTRIBUTIONS.

"(a) GENERAL RULE. - A GSOC shall distribute at least 90 percent of its taxable income for any taxable year by January 31 following the close of such taxable year. Any distribution made on or before January 31 shall be treated as made as of the close of the preceding taxable year.

"(b) IMPOSITION OF TAX IN CASE OF FAILURE TO MAKE MINIMUM DISTRIBUTION. - If a GSOC fails to make the minimum distribution requirements described in subsection (a), there is hereby imposed on the GSOC a tax equal to 20 percent of the excess of the amount required to be distributed over the amount actually distributed.

"Sec. 1397. SPECIAL RULES APPLICABLE TO AN ELECTING GSOC.

"(a) GENERAL RULE. - The current earnings and profits of an electing GSOC as of the close of its taxable year shall not include for such year which is required to be included in the gross income of the shareholders of such GSOC under section 1393(a).

"(b) SPECIAL RULE FOR AUDIT ADJUSTMENTS. -

"(1) TAXABLE INCOME. - Taxable income of an electing GSOC shall, in the year of final determination, be increased or decreased, as the case might be, by any adjustment to taxable income for a prior taxable year.

"(2) INVESTMENT CREDIT. - The investment credit of an electing GSOC shall, in the year of final determination, be increased or decreased, as the case might be, by any adjustment to the net investment credit for a prior taxable year.

"(3) METHOD OF MAKING ADJUSTMENTS. - An electing GSOC shall include in gross income for the year of an adjustment the amount described in paragraph (1) and shall take into account the adjustment described in paragraph (2), and shall be liable for payment of interest in the amount that would have been payable by the GSOC under section 6601 (relating to interest on underpayment, nonpayment or extensions of time for payment, of tax) or receivable by the GSOC under section 6611 (relating to interest on overpayments) if such GSOC had been a corporation other than an electing GSOC."

(b) TECHNICAL AMENDMENTS. -

(1) NET OPERATING LOSS DEDUCTION. - Paragraph (1) of section 172(b) (relating to net operating loss carrybacks and carryovers) is amended by adding at the end thereof the following new subparagraph:

"(H) In the case of an electing GSOC which has a net operating loss for any taxable year such loss shall not be a net operating loss carryback to any taxable year preceding the year of such loss, but shall be a net operating loss carryover to each of the 10 taxable years following the year of such loss."

(2) INCOME TAX COLLECTED AT SOURCE. - Section 3202 (relating to income collected at source) is amended by adding at the end thereof the following new subsection:

"(r) EXTENSION OF WITHHOLDINGS TO GSOC DISTRIBUTIONS. -

"(1) GENERAL RULE. - An electing GSOC making any distribution to its shareholders shall deduct and withhold from such payment a tax in an amount equal to 25 percent of such payment.

"(2) COORDINATION WITH OTHER SECTIONS. - For purposes of sections 3403 and 3404 and for purposes of so much of subtitle F (except section 7205) as relates to this chapter, distributions of an electing GSOC to any shareholder which are subject to withholding shall be treated as if they were wages paid by an employer to an employee."

(3) ADJUSTMENTS TO BASIS. - Section 1016 (a) (relating to adjustments of basis) is amended by redesignating paragraph (23) as (22) and by inserting after paragraph (20) the following new paragraph:

"(21) to the extent provided in section 1395 in the case of stock of shareholders of a general stock ownership corporation (as defined in section 1391) which makes the election provided by section 1392; and".

(4) RETURN OF GENERAL STOCK OWNERSHIP CORPORATION. - Subpart A of part III of subchapter A of Chapter 61 (relating to information returns) is amended by adding at the end thereof the following new section:

"Sec. 6039B. RETURN OF GENERAL STOCK OWNERSHIP CORPORATION.

"Every general stock ownership corporation (as defined in section 1391) which makes the election provided by section 1392 shall make a return for each taxable year, stating specifically the items of its gross income and the deductions allowable by subtitle A, the amount of investment credit or additional tax, as the case may be, the names and addresses of all persons owning stock in the corporation at any time during the taxable year, the number of shares of stock owned by each shareholder at all times during the taxable year, the amount of money and other property distributed by the corporation during the taxable year to each shareholder, the date of each such distribution, and such other information, for the purpose of carrying out the provisions of subchapter U of chapter 1, as the Secretary may by regulation prescribe. Any return filed pursuant to this section shall, for purposes of chapter 66 (relating to limitations), be treated as a return filed by the corporation under section 6012. Every GSOC shall file an annual report with the Secretary summarizing its operations for such year."

(c) CLERICAL AMENDMENTS. -

(1) The table of subchapters for chapter 1 is amended by adding at the end thereof the following:

"SUBCHAPTER U. - General stock ownership plans."

(2) The table of sections for subpart A of part III of subchapter A of chapter 61 is amended by adding at the end thereof the following:

"Sec. 6039B. Return of general stock ownership corporation."

(d) EFFECTIVE DATE. - The amendments made by this section shall apply with respect to corporations chartered after December 31, 1978, and before January 1, 1984.

REVENUE ACT OF 1978

Report of the Committee on Finance

United States Senate

H.R. 13511

J. General Stock Ownership Corporations

(Sec. 201 of the bill)

Present law

Under present law, there are no special provisions relating to the establishment of a private corporation for the benefit of the residents of a State.

Reasons for change

The committee believes that many citizens should have a greater ownership stake in the private enterprise system, and that this would lead to better understanding of the system and would encourage individuals to invest in other business enterprises. Also, in the case of individuals now receiving various forms of transfer payments from Federal, State, or local governments, the receipt of dividend income from a General Stock Ownership Corporation (GSOC) would, to some extent, reduce the need for such payments. The committee believes that an experimental program permitting States to form such private corporations for the benefit of their citizens may enable the Congress to study a method of replacing tran fer payments with dividend income.

Explanation of provisions

General.—Under the committee bill, a State would be authorized to establish a GSOC for the benefit of its citizens. It is anticipated that the GSOC would be authorized to borrow money to acquire business enterprises. The cash flow from the operation of the business would be used to pay the loan, and the corporate revenues would be distributed to the GSOC shareholders (i.e., the citizens of the State).

Definition of GSOC.—The bill provides that a corporation must meet certain statutory tests in order to be treated as a GSOC. First, the corporation must be chartered by an official act of the State legislature or by a State-wide referendum. Second, the GSOC's corporate charter must provide for the issuance of all authorized shares to eligible individuals provided that at least one share is issued to each eligible individual, and such eligible individual does not elect within one year after the date of issuance not to receive such share, and provides for certain restrictions on the transferability of the share. The transfer restriction must provide that the share cannot be transferred until the earliest to occur of (1) the expiration of 5 years from issuance, (2) death or (3) failure to meet the State's residency requirements. In no event may shares of stock of a GSOC be transferred to nonresidents. Also, an individual may not acquire more than 9 shares by purchase. Third, the charter must provide that the GSOC is empowered to invest in properties (not including properties acquired by it or for its benefit through the right of eminent domain). Fourth, the GSOC may not be affiliated with any other corporation. Fifth, the GSOC must be organized after December 31, 1978, and before January 1, 1984. An eligible individual is any individual who is a resident of the chartering State as of the date specified in the corporate charter. A State may define a resident for purposes of its GSOC so long as such definition is consistent with constitutional principles.

Election.—A GSOC must make an election to obtain the special statutory treatment provided for by the amendment. The election is effective for the taxable year for which it is made on a timely filed tax return. The manner in which the election is to be made would be determined by regulations. The election once made is irrevocable unless terminated with the consent of the Secretary of the Treasury.

Effect of election.—The effect of the election would be to exempt the corporation from Federal income taxation. Instead, the shareholders of the GSOC would report their proportionate part of the GSOC's taxable income on their Federal individual income tax returns.

Treated as a private corporation.—A GSOC would be treated as a private corporation.

Computation of GSOC income.—The GSOC would compute its taxable income in the same manner as a regular corporation with certain modifications. The GSOC would not be eligible for a dividends received deduction nor any tax credits.

Net operating loss deduction.—The shareholders of a GSOC would not be eligible to report any portion of a GSOC net operating loss on their individual income tax return. Instead, the GSOC would be entitled to a 10-year carryover of any net operating losses.

Investment tax credit and recapture of investment tax credit.—Under the bill, shareholders of the GSOC would be entitled to their pro-rata share of the GSOC's investment tax credit. The shareholders would also be personally responsible for any recapture of such investment tax credit. Neither the corporation nor its shareholders would be entitled to the foreign tax credit.

Taxation of shareholders.—Under the bill, each shareholder would include in his gross income his daily prorated portion of the GSOC's taxable income. Such income would be included in the shareholder's gross income for the taxable year in which or with which the GSOC's taxable year ends. The income in the hands of the shareholder would be treated as ordinary income and would not be eligible for either the partial dividend exclusion (sec. 116) or the maximum tax of earned income.

Shareholders would increase the tax basis of shares of stock in the GSOC to the extent they reported income from the GSOC. Distributions from the GSOC out of such previously taxed income would decrease the tax basis of such shares.

Taxation of GSOC distribution.—Under the bill, distributions from a GSOC's taxable income previously taxed to a shareholder would be treated as a tax-free distribution. Any distribution in excess of such previously taxed income would be taxed in the same manner as a distribution from a regular corporation (sec. 301(c)).

Audit adjustments and amended tax returns.—Any audit adjustment resulting from an Internal Revenue Service determination would be reflected in the GSOC's taxable year in which such adjustment is made (and not the taxable year to which it relates). The amount of such adjustment would be subject to an interest charge in an amount computed as though the income had been taxed to a nonelecting corporation.

Reporting requirements.—Under the bill, a GSOC would be required to file a Federal income tax return and a computer-coded data showing information reported to each of its shareholders. The corporate tax return would be required to meet the same timing requirements as a regular corporation. In addition, a GSOC would be required to give each shareholder a Form 1099. The Form 1099 would report (1) the shareholder's pro rata income for the taxable year, (2) tax-free distributions for the year, (3) the tax treatment of other distributions, and (4) the amount of any investment tax credit and recapture thereof for such year, and (5) any amounts withheld for Federal income tax purposes.

Distribution requirements.—A GSOC would be required to distribute 90 percent of its taxable income to its shareholders by January 31 of the next succeeding year. To the extent a GSOC fails to meet this distribution requirement, a tax equal to 20 percent of the deficiency (i.e., the difference between the required distribution and the actual distribution) would be imposed on the GSOC. The amount of such tax would be allowed as a deduction to the GSOC for the year in which it is paid.

Withholding requirements.—The bill requires the GSOC to withhold an amount equal to 25 percent of every distribution made to its shareholders. The amount of such withholding would be allowed as a refundable credit to the shareholder. The Treasury would be authorized to issue regulations providing a certification procedure for individuals who are nontaxpayers under which they may be exempted from the withholding requirement.

Studies.—It is expected that a study would be made of the effect GSOC's have on competition with regular private corporations. It is also anticipated that a study would be made of the GSOC as a form of full corporate integration.

Taxable year end of GSOC.—The bill requires a GSOC to adopt a taxable year end of October 31. It is anticipated that most GSOC's would elect an October 31 year end. This would enable them to close their books and meet their shareholder reporting requirements by January 31 of the next succeeding year.

Effective date

The provision applies to corporations chartered and organized after December 31, 1978.

Revenue effect

The revenue cost of the proposal is expected to be negligible during the next few years. However, the long-run cost could be substantial.

TABLE IV - 1

Schedule #	$ Tariff	Pipeline Capacity MM b/d	GSOP Purchase Price ($000)	Imbedded Interest Rate	First Year Citizen Distribution Pre-Tax	Number of Years Income Stream	($000) Cash Balance 24 Years	Comments
1	4.68	1.2	1,500,000	10%	19	8	-374,669	High Alyeska Budget
2	4.68	1.2	1,500,000	10%	31	11	-139,081	Low Alyeska Budget
3	4.68	1.2	1,500,000	7%	119	13	-181,876	High Alyeska Budget
4	4.68	1.2	1,500,000	7%	131	15	14,351	Low Alyeska Budget
5	4.68	1.2	1,300,000	10%	82	12	-172,271	
6	4.68	1.2	1,300,000	7%	169	15	- 45,513	
7	4.90	1.2	1,500,000	10%	51	12	-176,008	
8	4.90	1.2	1,500,000	7%	151	15	- 26,148	
9	4.90	1.2	1,300,000	10%	114	14	- 12,085	
10	5.00	1.2	1,500,000	10%	65	13	- 97,237	High Alyeska Budget
11	5.00	1.2	1,500,000	10%	76	15	86,689	Low Alyeska Budget
12	5.00	1.2	1,364,000	10%	118	15	220,273	
13	5.25	1.2	1,364,000	10%	153	16	370,113	$250 MM Premium Due
14	5.25	1.2	1,364,000	10%	153	10	560,581	All Principal Value Due
15	5.50	1.2	1,364,000	10%	189	19	378,643	
16	5.50	1.2	1,300,000	10%	199	18	328,685	Straight Line Principal Payments
17	5.50	1.2	1,300,000	10%	199	18	293,565	BP Amortization Schedule
18	5.50	1.2	1,300,000	7%	286	19	399,370	
19	6.35	1.2	1,300,000	10%	330	23	683,598	
20	6.35	1.2	1,500,000	7%	367	22	688,282	

TABLE IV - 2

Schedule #	$ Tariff	Pipeline Capacity MM b/d	GSOP Purchase Price ($000)	Imbedded Interest Rate	First Year Citizen Distribution Pre-Tax	Number of Years Income Stream	($000) Cash Balance 24 Years
21	4.68	1.6	1,600,000	10%	155	14	-111,088
22	4.68	1.6	1,450,000	7%	323	18	382,786
23	5.00	1.6	1,600,000	10%	216	16	158,504
24	5.00	1.6	1,500,000	10%	238	17	346,226
25	5.00	1.6	1,600,000	7%	323	17	266,675
26	5.25	1.6	1,450,000	10%	335	21	612,585
27	5.50	1.6	1,600,000	10%	334	21	668,317
28	5.50	1.6	1,500,000	10%	366	22	699,443
29	5.50	1.6	1,600,000	7%	441	22	733,717
30	5.50	1.6	1,500,000	7%	443	20	605,230
31	5.50	1.6	1,450,000	7%	478	22	774,273
32	6.35	1.6	1,600,000	10%	496	24	898,341

Schedule 1A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.68	299810	78400	150000	62500	0	8910	19
1980	64062	4.68	299810	83888	143750	62500	0	9672	21
1981	64062	4.68	299810	89760	137500	62500	0	10050	22
1982	64062	4.68	299810	96043	131250	62500	0	10017	22
1983	64062	4.68	299810	102766	125000	62500	0	9544	21
1984	64062	4.68	299810	109960	118750	62500	0	8600	19
1985	64062	4.68	299810	117658	112500	62500	0	7152	15
1986	64062	4.68	299810	125894	106250	62500	0	5166	11
1987	64062	4.68	299810	134707	100000	62500	0	2603	5
1988	64062	4.68	299810	144137	93750	62500	0	-577	0
1989	64062	4.68	299810	154226	87500	62500	0	-4416	0
1990	64062	4.68	299810	165022	81250	62500	0	-8962	0
1991	64062	4.68	299810	176573	75000	62500	0	-14263	0
1992	64062	4.68	299810	188933	68750	62500	0	-20373	0
1993	64062	4.68	299810	202158	62500	62500	0	-27348	0
1994	64062	4.68	299810	216309	56250	62500	0	-35249	0
1995	64062	4.68	299810	231451	50000	62500	0	-44141	0
1996	64062	4.68	299810	247652	43750	62500	0	-54092	0
1997	64062	4.68	299810	264987	37500	62500	0	-65177	0
1998	64062	4.68	299810	283537	31250	62500	0	-77477	0
1999	64062	4.68	299810	303384	25000	62500	0	-91074	0
2000	64062	4.68	299810	324621	18750	62500	0	-106061	0
2001	64062	4.68	299810	347345	12500	62500	0	-122535	0
2002	64062	4.68	299810	371659	6250	62500	0	-140599	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	8910	8019	62500	7400	62500	8291	8291
1980	299810	9672	8705	62500	7918	62500	8885	17176
1981	299810	10050	9045	62500	8472	62500	9477	26653
1982	299810	10017	9015	62500	9065	62500	10067	36720
1983	299810	9544	8590	62500	9700	62500	10654	47374
1984	299810	8600	7740	62500	10379	62500	11239	58613
1985	299810	7152	6437	62500	11106	62500	11821	70434
1986	299810	5166	4649	62500	11883	62500	12400	82834
1987	299810	2603	2343	62500	12715	62500	12975	95809
1988	299810	-577	0	62500	13605	62500	13028	108837
1989	299810	-4416	0	62500	14557	62500	10141	118978
1990	299810	-8962	0	62500	15576	62500	6614	125592
1991	299810	-14263	0	62500	16666	62500	2403	127995
1992	299810	-20373	0	62500	17833	62500	-2540	125455
1993	299810	-27348	0	62500	19081	62500	-8267	117188
1994	299810	-35249	0	62500	20417	62500	-14832	102356
1995	299810	-44141	0	62500	21846	62500	-22295	80061
1996	299810	-54092	0	62500	23375	62500	-30717	49344
1997	299810	-65177	0	62500	25011	62500	-40166	9178
1998	299810	-77477	0	62500	26762	62500	-50715	-41537
1999	299810	-91074	0	62500	28635	62500	-62439	-103976
2000	299810	-106061	0	62500	30639	62500	-75422	-179398
2001	299810	-122535	0	62500	32784	62500	-89751	-269149
2002	299810	-140599	0	62500	35079	62500	-105520	-374669

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1500000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

Schedule 2A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.68	299810	73100	150000	62500	0	14210	31
1980	64062	4.68	299810	78217	143750	62500	0	15343	34
1981	64062	4.68	299810	83692	137500	62500	0	16118	35
1982	64062	4.68	299810	89550	131250	62500	0	16510	36
1983	64062	4.68	299810	95819	125000	62500	0	16491	36
1984	64062	4.68	299810	102526	118750	62500	0	16034	35
1985	64062	4.68	299810	109704	112500	62500	0	15106	33
1986	64062	4.68	299810	117383	106250	62500	0	13677	30
1987	64062	4.68	299810	125600	100000	62500	0	11710	26
1988	64062	4.68	299810	134392	93750	62500	0	9168	20
1989	64062	4.68	299810	143799	87500	62500	0	6011	13
1990	64062	4.68	299810	153865	81250	62500	0	2195	4
1991	64062	4.68	299810	164635	75000	62500	0	-2325	0
1992	64062	4.68	299810	176160	68750	62500	0	-7600	0
1993	64062	4.68	299810	188491	62500	62500	0	-13681	0
1994	64062	4.68	299810	201685	56250	62500	0	-20625	0
1995	64062	4.68	299810	215803	50000	62500	0	-28493	0
1996	64062	4.68	299810	230909	43750	62500	0	-37349	0
1997	64062	4.68	299810	247072	37500	62500	0	-47262	0
1998	64062	4.68	299810	264368	31250	62500	0	-58308	0
1999	64062	4.68	299810	282873	25000	62500	0	-70563	0
2000	64062	4.68	299810	302674	18750	62500	0	-84114	0
2001	64062	4.68	299810	323861	12500	62500	0	-99051	0
2002	64062	4.68	299810	346531	6250	62500	0	-115471	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 59400 DIRECT EXPENSE: 6300

Schedule 2B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	14210	12789	62500	7400	62500	8821	8821
1980	299810	15343	13809	62500	7918	62500	9452	18273
1981	299810	16118	14506	62500	8472	62500	10084	28357
1982	299810	16510	14859	62500	9065	62500	10716	39073
1983	299810	16491	14842	62500	9700	62500	11349	50422
1984	299810	16034	14431	62500	10379	62500	11982	62404
1985	299810	15106	13595	62500	11106	62500	12617	75021
1986	299810	13677	12309	62500	11883	62500	13251	88272
1987	299810	11710	10539	62500	12715	62500	13886	102158
1988	299810	9168	8251	62500	13605	62500	14522	116680
1989	299810	6011	5410	62500	14557	62500	15158	131838
1990	299810	2195	1976	62500	15576	62500	15795	147633
1991	299810	-2325	0	62500	16666	62500	14341	161974
1992	299810	-7600	0	62500	17833	62500	10233	172207
1993	299810	-13681	0	62500	19081	62500	5400	177607
1994	299810	-20625	0	62500	20417	62500	-208	177399
1995	299810	-28493	0	62500	21846	62500	-6647	170752
1996	299810	-37349	0	62500	23375	62500	-13974	156778
1997	299810	-47262	0	62500	25011	62500	-22251	134527
1998	299810	-58308	0	62500	26762	62500	-31546	102981
1999	299810	-70563	0	62500	28635	62500	-41928	61053
2000	299810	-84114	0	62500	30639	62500	-53475	7578
2001	299810	-99051	0	62500	32784	62500	-66267	-58689
2002	299810	-115471	0	62500	35079	62500	-80392	-139081

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1500000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 59400   DIRECT EXPENSE: 6300

Schedule 3B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	53910	48519	62500	7400	62500	12791	12791
1980	299810	52797	47517	62500	7918	62500	13198	25989
1981	299810	51300	46170	62500	8472	62500	13602	39591
1982	299810	49392	44453	62500	9065	62500	14004	53595
1983	299810	47044	42340	62500	9700	62500	14404	67999
1984	299810	44225	39803	62500	10379	62500	14801	82800
1985	299810	40902	36812	62500	11106	62500	15196	97996
1986	299810	37041	33337	62500	11883	62500	15587	113583
1987	299810	32603	29343	62500	12715	62500	15975	129558
1988	299810	27548	24793	62500	13605	62500	16360	145918
1989	299810	21834	19651	62500	14557	62500	16740	162658
1990	299810	15413	13872	62500	15576	62500	17117	179775
1991	299810	8237	7413	62500	16666	62500	17490	197265
1992	299810	252	227	62500	17833	62500	17858	215123
1993	299810	-8598	0	62500	19081	62500	10483	225606
1994	299810	-18374	0	62500	20417	62500	2043	227649
1995	299810	-29141	0	62500	21846	62500	-7295	220354
1996	299810	-40967	0	62500	23375	62500	-17592	202762
1997	299810	-53927	0	62500	25011	62500	-28916	173846
1998	299810	-68102	0	62500	26762	62500	-41340	132506
1999	299810	-83574	0	62500	28635	62500	-54939	77567
2000	299810	-100436	0	62500	30639	62500	-69797	7770
2001	299810	-118785	0	62500	32784	62500	-86001	-78231
2002	299810	-138724	0	62500	35079	62500	-103645	-181876

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 4A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.68	299810	73100	105000	62500	0	59210	131
1980	64062	4.68	299810	78217	100625	62500	0	58468	129
1981	64062	4.68	299810	83692	96250	62500	0	57368	127
1982	64062	4.68	299810	89550	91875	62500	0	55885	124
1983	64062	4.68	299810	95819	87500	62500	0	53991	119
1984	64062	4.68	299810	102526	83125	62500	0	51659	114
1985	64062	4.68	299810	109704	78750	62500	0	48856	108
1986	64062	4.68	299810	117383	74375	62500	0	45552	101
1987	64062	4.68	299810	125600	70000	62500	0	41710	92
1988	64062	4.68	299810	134392	65625	62500	0	37293	82
1989	64062	4.68	299810	143799	61250	62500	0	32261	71
1990	64062	4.68	299810	153865	56875	62500	0	26570	59
1991	64062	4.68	299810	164635	52500	62500	0	20175	44
1992	64062	4.68	299810	176160	48125	62500	0	13025	28
1993	64062	4.68	299810	188491	43750	62500	0	5069	11
1994	64062	4.68	299810	201685	39375	62500	0	-3750	0
1995	64062	4.68	299810	215803	35000	62500	0	-13493	0
1996	64062	4.68	299810	230909	30625	62500	0	-24224	0
1997	64062	4.68	299810	247072	26250	62500	0	-36012	0
1998	64062	4.68	299810	264368	21875	62500	0	-48933	0
1999	64062	4.68	299810	282873	17500	62500	0	-63063	0
2000	64062	4.68	299810	302674	13125	62500	0	-78489	0
2001	64062	4.68	299810	323861	8750	62500	0	-95301	0
2002	64062	4.68	299810	346531	4375	62500	0	-113596	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 59400 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	59210	53289	62500	7400	62500	13321	13321
1980	299810	58468	52621	62500	7918	62500	13765	27086
1981	299810	57368	51631	62500	8472	62500	14209	41295
1982	299810	55885	50297	62500	9065	62500	14653	55948
1983	299810	53991	48592	62500	9700	62500	15099	71047
1984	299810	51659	46493	62500	10379	62500	15545	86592
1985	299810	48856	43970	62500	11106	62500	15992	102584
1986	299810	45552	40997	62500	11883	62500	16438	119022
1987	299810	41710	37539	62500	12715	62500	16886	135908
1988	299810	37293	33564	62500	13605	62500	17334	153242
1989	299810	32261	29035	62500	14557	62500	17783	171025
1990	299810	26570	23913	62500	15576	62500	18233	189258
1991	299810	20175	18158	62500	16666	62500	18683	207941
1992	299810	13025	11723	62500	17833	62500	19135	227076
1993	299810	5069	4562	62500	19081	62500	19588	246664
1994	299810	-3750	0	62500	20417	62500	16667	263331
1995	299810	-13493	0	62500	21846	62500	8353	271684
1996	299810	-24224	0	62500	23375	62500	-849	270835
1997	299810	-36012	0	62500	25011	62500	-11001	259834
1998	299810	-48933	0	62500	26762	62500	-22171	237663
1999	299810	-63063	0	62500	28635	62500	-34428	203235
2000	299810	-78489	0	62500	30639	62500	-47850	155385
2001	299810	-95301	0	62500	32784	62500	-62517	92868
2002	299810	-113596	0	62500	35079	62500	-78517	14351

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 59400 DIRECT EXPENSE: 6300

Schedule 5A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.68	299810	78400	130000	54167	0	37243	82
1980	64062	4.68	299810	83888	124583	54167	0	37172	82
1981	64062	4.68	299810	89760	119167	54167	0	36716	81
1982	64062	4.68	299810	96043	113750	54167	0	35850	79
1983	64062	4.68	299810	102766	108333	54167	0	34544	76
1984	64062	4.68	299810	109960	102917	54167	0	32766	72
1985	64062	4.68	299810	117658	97500	54167	0	30485	67
1986	64062	4.68	299810	125894	92083	54167	0	27666	61
1987	64062	4.68	299810	134707	86666	54167	0	24270	53
1988	64062	4.68	299810	144137	81250	54167	0	20256	45
1989	64062	4.68	299810	154226	75833	54167	0	15584	34
1990	64062	4.68	299810	165022	70416	54167	0	10205	22
1991	64062	4.68	299810	176573	65000	54167	0	4070	9
1992	64062	4.68	299810	188933	59583	54167	0	-2873	0
1993	64062	4.68	299810	202158	54166	54167	0	-10681	0
1994	64062	4.68	299810	216309	48750	54167	0	-19416	0
1995	64062	4.68	299810	231451	43333	54167	0	-29141	0
1996	64062	4.68	299810	247652	37916	54167	0	-39925	0
1997	64062	4.68	299810	264987	32499	54167	0	-51843	0
1998	64062	4.68	299810	283537	27083	54167	0	-64977	0
1999	64062	4.68	299810	303384	21666	54167	0	-79407	0
2000	64062	4.68	299810	324621	16249	54167	0	-95227	0
2001	64062	4.68	299810	347345	10833	54167	0	-112535	0
2002	64062	4.68	299810	371659	5416	54167	0	-131432	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1300000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	37243	33519	54167	7400	54167	11124	11124
1980	299810	37172	33455	54167	7918	54167	11635	22759
1981	299810	36716	33044	54167	8472	54167	12144	34903
1982	299810	35850	32265	54167	9065	54167	12650	47553
1983	299810	34544	31090	54167	9700	54167	13154	60707
1984	299810	32766	29489	54167	10379	54167	13656	74363
1985	299810	30485	27437	54167	11106	54167	14154	88517
1986	299810	27666	24899	54167	11883	54167	14650	103167
1987	299810	24270	21843	54167	12715	54167	15142	118309
1988	299810	20256	18230	54167	13605	54167	15631	133940
1989	299810	15584	14026	54167	14557	54167	16115	150055
1990	299810	10205	9185	54167	15576	54167	16596	166651
1991	299810	4070	3663	54167	16666	54167	17073	183724
1992	299810	-2873	0	54167	17833	54167	14960	198684
1993	299810	-10681	0	54167	19081	54167	8400	207084
1994	299810	-19416	0	54167	20417	54167	1001	208085
1995	299810	-29141	0	54167	21846	54167	-7295	200790
1996	299810	-39925	0	54167	23375	54167	-16550	184240
1997	299810	-51843	0	54167	25011	54167	-26832	157408
1998	299810	-64977	0	54167	26762	54167	-38215	119193
1999	299810	-79407	0	54167	28635	54167	-50772	68421
2000	299810	-95227	0	54167	30639	54167	-64588	3833
2001	299810	-112535	0	54167	32784	54167	-79751	-75918
2002	299810	-131432	0	54167	35079	54167	-96353	-172271

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 6A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.68	299810	78400	91000	54167	0	76243	169
1980	64062	4.68	299810	83888	87208	54167	0	74547	165
1981	64062	4.68	299810	89760	83417	54167	0	72466	161
1982	64062	4.68	299810	96043	79625	54167	0	69975	155
1983	64062	4.68	299810	102766	75833	54167	0	67044	148
1984	64062	4.68	299810	109960	72042	54167	0	63641	141
1985	64062	4.68	299810	117658	68250	54167	0	59735	132
1986	64062	4.68	299810	125894	64458	54167	0	55291	122
1987	64062	4.68	299810	134707	60666	54167	0	50270	111
1988	64062	4.68	299810	144137	56875	54167	0	44631	99
1989	64062	4.68	299810	154226	53083	54167	0	38334	85
1990	64062	4.68	299810	165022	49291	54167	0	31330	69
1991	64062	4.68	299810	176573	45500	54167	0	23570	52
1992	64062	4.68	299810	188933	41708	54167	0	15002	33
1993	64062	4.68	299810	202158	37916	54167	0	5569	12
1994	64062	4.68	299810	216309	34125	54167	0	-4791	0
1995	64062	4.68	299810	231451	30333	54167	0	-16141	0
1996	64062	4.68	299810	247652	26541	54167	0	-28550	0
1997	64062	4.68	299810	264987	22750	54167	0	-42094	0
1998	64062	4.68	299810	283537	18958	54167	0	-56852	0
1999	64062	4.68	299810	303384	15166	54167	0	-72907	0
2000	64062	4.68	299810	324621	11375	54167	0	-90353	0
2001	64062	4.68	299810	347345	7583	54167	0	-109285	0
2002	64062	4.68	299810	371659	3791	54167	0	-129807	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 6B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	299810	76243	68619	54167	7400	54167	15024	15024
1980	299810	74547	67092	54167	7918	54167	15373	30397
1981	299810	72466	65219	54167	8472	54167	15719	46116
1982	299810	69975	62978	54167	9065	54167	16062	62178
1983	299810	67044	60340	54167	9700	54167	16404	78582
1984	299810	63641	57277	54167	10379	54167	16743	95325
1985	299810	59735	53762	54167	11106	54167	17079	112404
1986	299810	55291	49762	54167	11883	54167	17412	129816
1987	299810	50270	45243	54167	12715	54167	17742	147558
1988	299810	44631	40168	54167	13605	54167	18068	165626
1989	299810	38334	34501	54167	14557	54167	18390	184016
1990	299810	31330	28197	54167	15576	54167	18709	202725
1991	299810	23570	21213	54167	16666	54167	19023	221748
1992	299810	15002	13502	54167	17833	54167	19333	241081
1993	299810	5569	5012	54167	19081	54167	19638	260719
1994	299810	-4791	0	54167	20417	54167	15626	276345
1995	299810	-16141	0	54167	21846	54167	5705	282050
1996	299810	-28550	0	54167	23375	54167	-5175	276875
1997	299810	-42094	0	54167	25011	54167	-17083	259792
1998	299810	-56852	0	54167	26762	54167	-30090	229702
1999	299810	-72907	0	54167	28635	54167	-44272	185430
2000	299810	-90353	0	54167	30639	54167	-59714	125716
2001	299810	-109285	0	54167	32784	54167	-76501	49215
2002	299810	-129807	0	54167	35079	54167	-94728	-45513

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 7A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.90	313904	78400	150000	62500	0	23004	51
1980	64062	4.90	313904	83888	143750	62500	0	23766	52
1981	64062	4.90	313904	89760	137500	62500	0	24144	53
1982	64062	4.90	313904	96043	131250	62500	0	24111	53
1983	64062	4.90	313904	102766	125000	62500	0	23638	52
1984	64062	4.90	313904	109960	118750	62500	0	22694	50
1985	64062	4.90	313904	117658	112500	62500	0	21246	47
1986	64062	4.90	313904	125894	106250	62500	0	19260	42
1987	64062	4.90	313904	134707	100000	62500	0	16697	37
1988	64062	4.90	313904	144137	93750	62500	0	13517	30
1989	64062	4.90	313904	154226	87500	62500	0	9678	21
1990	64062	4.90	313904	165022	81250	62500	0	5132	11
1991	64062	4.90	313904	176573	75000	62500	0	-169	0
1992	64062	4.90	313904	188933	68750	62500	0	-6279	0
1993	64062	4.90	313904	202158	62500	62500	0	-13254	0
1994	64062	4.90	313904	216309	56250	62500	0	-21155	0
1995	64062	4.90	313904	231451	50000	62500	0	-30047	0
1996	64062	4.90	313904	247652	43750	62500	0	-39998	0
1997	64062	4.90	313904	264987	37500	62500	0	-51083	0
1998	64062	4.90	313904	283537	31250	62500	0	-63383	0
1999	64062	4.90	313904	303384	25000	62500	0	-76980	0
2000	64062	4.90	313904	324621	18750	62500	0	-91967	0
2001	64062	4.90	313904	347345	12500	62500	0	-108441	0
2002	64062	4.90	313904	371659	6250	62500	0	-126505	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	313904	23004	20704	62500	7400	62500	9700	9700
1980	313904	23766	21389	62500	7918	62500	10295	19995
1981	313904	24144	21730	62500	8472	62500	10886	30881
1982	313904	24111	21700	62500	9065	62500	11476	42357
1983	313904	23638	21274	62500	9700	62500	12064	54421
1984	313904	22694	20425	62500	10379	62500	12648	67069
1985	313904	21246	19121	62500	11106	62500	13231	80300
1986	313904	19260	17334	62500	11883	62500	13809	94109
1987	313904	16697	15027	62500	12715	62500	14385	108494
1988	313904	13517	12165	62500	13605	62500	14957	123451
1989	313904	9678	8710	62500	14557	62500	15525	138976
1990	313904	5132	4619	62500	15576	62500	16089	155065
1991	313904	-169	0	62500	16666	62500	16497	171562
1992	313904	-6279	0	62500	17833	62500	11554	183116
1993	313904	-13254	0	62500	19081	62500	5827	188943
1994	313904	-21155	0	62500	20417	62500	-738	188205
1995	313904	-30047	0	62500	21846	62500	-8201	180004
1996	313904	-39998	0	62500	23375	62500	-16623	163381
1997	313904	-51083	0	62500	25011	62500	-26072	137309
1998	313904	-63383	0	62500	26762	62500	-36621	100688
1999	313904	-76980	0	62500	28635	62500	-48345	52343
2000	313904	-91967	0	62500	30639	62500	-61328	-8985
2001	313904	-108441	0	62500	32784	62500	-75657	-84642
2002	313904	-126505	0	62500	35079	62500	-91426	-176068

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule [illegible]A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	4.90	313904	78400	105000	62500	0	68004	151
1980	64062	4.90	313904	83888	100625	62500	0	66891	148
1981	64062	4.90	313904	89760	96250	62500	0	65394	145
1982	64062	4.90	313904	96043	91875	62500	0	63486	141
1983	64062	4.90	313904	102766	87500	62500	0	61138	135
1984	64062	4.90	313904	109960	83125	62500	0	58319	129
1985	64062	4.90	313904	117658	78750	62500	0	54996	122
1986	64062	4.90	313904	125894	74375	62500	0	51135	113
1987	64062	4.90	313904	134707	70000	62500	0	46697	103
1988	64062	4.90	313904	144137	65625	62500	0	41642	92
1989	64062	4.90	313904	154226	61250	62500	0	35928	79
1990	64062	4.90	313904	165022	56875	62500	0	29507	65
1991	64062	4.90	313904	176573	52500	62500	0	22331	49
1992	64062	4.90	313904	188933	48125	62500	0	14346	31
1993	64062	4.90	313904	202158	43750	62500	0	5496	12
1994	64062	4.90	313904	216309	39375	62500	0	-4280	0
1995	64062	4.90	313904	231451	35000	62500	0	-15047	0
1996	64062	4.90	313904	247652	30625	62500	0	-26873	0
1997	64062	4.90	313904	264987	26250	62500	0	-39833	0
1998	64062	4.90	313904	283537	21875	62500	0	-54008	0
1999	64062	4.90	313904	303384	17500	62500	0	-69480	0
2000	64062	4.90	313904	324621	13125	62500	0	-86342	0
2001	64062	4.90	313904	347345	8750	62500	0	-104691	0
2002	64062	4.90	313904	371659	4375	62500	0	-124630	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 8B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	313904	68004	61204	62500	7400	62500	14200	14200
1980	313904	66891	60202	62500	7918	62500	14607	28807
1981	313904	65394	58855	62500	8472	62500	15011	43818
1982	313904	63486	57137	62500	9065	62500	15414	59232
1983	313904	61138	55024	62500	9700	62500	15814	75046
1984	313904	58319	52487	62500	10379	62500	16211	91257
1985	313904	54996	49496	62500	11106	62500	16606	107863
1986	313904	51135	46022	62500	11883	62500	16996	124859
1987	313904	46697	42027	62500	12715	62500	17385	142244
1988	313904	41642	37478	62500	13605	62500	17769	160013
1989	313904	35928	32335	62500	14557	62500	18150	178163
1990	313904	29507	26556	62500	15576	62500	18527	196690
1991	313904	22331	20098	62500	16666	62500	18899	215589
1992	313904	14346	12911	62500	17833	62500	19268	234857
1993	313904	5496	4946	62500	19081	62500	19631	254488
1994	313904	-4280	0	62500	20417	62500	16137	270625
1995	313904	-15047	0	62500	21846	62500	6799	277424
1996	313904	-26873	0	62500	23375	62500	-3498	273926
1997	313904	-39833	0	62500	25011	62500	-14822	259104
1998	313904	-54008	0	62500	26762	62500	-27246	231858
1999	313904	-69480	0	62500	28635	62500	-40845	191013
2000	313904	-86342	0	62500	30639	62500	-55703	135310
2001	313904	-104691	0	62500	32784	62500	-71907	63403
2002	313904	-124630	0	62500	35079	62500	-89551	-26148

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 9A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF $	REVENUES $	OPERATING EXPENSES $	INTEREST $	DEPRECIATION AND AMORTIZATION $	INCOME TAX $	NET INCOME $	CITIZEN SHAREHOLDER INCOME ACTUAL $
1979	64062	4.90	313904	78400	130000	54167	0	51337	114
1980	64062	4.90	313904	83888	124583	54167	0	51266	113
1981	64062	4.90	313904	89760	119167	54167	0	50810	112
1982	64062	4.90	313904	96043	113750	54167	0	49944	110
1983	64062	4.90	313904	102766	108333	54167	0	48638	108
1984	64062	4.90	313904	109960	102917	54167	0	46860	104
1985	64062	4.90	313904	117658	97500	54167	0	44579	99
1986	64062	4.90	313904	125894	92083	54167	0	41760	92
1987	64062	4.90	313904	134707	86666	54167	0	38364	85
1988	64062	4.90	313904	144137	81250	54167	0	34350	76
1989	64062	4.90	313904	154226	75833	54167	0	29678	65
1990	64062	4.90	313904	165022	70416	54167	0	24299	53
1991	64062	4.90	313904	176573	65000	54167	0	18164	40
1992	64062	4.90	313904	188933	59583	54167	0	11221	24
1993	64062	4.90	313904	202158	54166	54167	0	3413	7
1994	64062	4.90	313904	216309	48750	54167	0	-5322	0
1995	64062	4.90	313904	231451	43333	54167	0	-15047	0
1996	64062	4.90	313904	247652	37916	54167	0	-25831	0
1997	64062	4.90	313904	264987	32499	54167	0	-37749	0
1998	64062	4.90	313904	283537	27083	54167	0	-50883	0
1999	64062	4.90	313904	303384	21666	54167	0	-65313	0
2000	64062	4.90	313904	324621	16249	54167	0	-81133	0
2001	64062	4.90	313904	347345	10833	54167	0	-98441	0
2002	64062	4.90	313904	371659	5416	54167	0	-117338	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

Schedule 9B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	313904	51337	46203	54167	7400	54167	12534	12534
1980	313904	51266	46139	54167	7918	54167	13045	25579
1981	313904	50810	45729	54167	8472	54167	13553	39132
1982	313904	49944	44950	54167	9065	54167	14059	53191
1983	313904	48638	43774	54167	9700	54167	14564	67755
1984	313904	46860	42174	54167	10379	54167	15065	82820
1985	313904	44579	40121	54167	11106	54167	15564	98384
1986	313904	41760	37584	54167	11883	54167	16059	114443
1987	313904	38364	34528	54167	12715	54167	16551	130994
1988	313904	34350	30915	54167	13605	54167	17040	148034
1989	313904	29678	26710	54167	14557	54167	17525	165559
1990	313904	24299	21869	54167	15576	54167	18006	183565
1991	313904	18164	16348	54167	16666	54167	18482	202047
1992	313904	11221	10099	54167	17833	54167	18955	221002
1993	313904	3413	3072	54167	19081	54167	19422	240424
1994	313904	-5322	0	54167	20417	54167	15095	255519
1995	313904	-15047	0	54167	21846	54167	6799	262318
1996	313904	-25831	0	54167	23375	54167	-2456	259862
1997	313904	-37749	0	54167	25011	54167	-12738	247124
1998	313904	-50883	0	54167	26762	54167	-24121	223003
1999	313904	-65313	0	54167	28635	54167	-36678	186325
2000	313904	-81133	0	54167	30639	54167	-50494	135831
2001	313904	-98441	0	54167	32784	54167	-65657	70174
2002	313904	-117338	0	54167	35079	54167	-82259	-12085

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1300000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

Schedule 10A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.00	320310	78400	150000	62500	0	29410	65
1980	64062	5.00	320310	83888	143750	62500	0	30172	67
1981	64062	5.00	320310	89760	137500	62500	0	30550	67
1982	64062	5.00	320310	96043	131250	62500	0	30517	67
1983	64062	5.00	320310	102766	125000	62500	0	30044	66
1984	64062	5.00	320310	109960	118750	62500	0	29100	64
1985	64062	5.00	320310	117658	112500	62500	0	27652	61
1986	64062	5.00	320310	125894	106250	62500	0	25666	57
1987	64062	5.00	320310	134707	100000	62500	0	23103	51
1988	64062	5.00	320310	144137	93750	62500	0	19923	44
1989	64062	5.00	320310	154226	87500	62500	0	16004	35
1990	64062	5.00	320310	165022	81250	62500	0	11538	25
1991	64062	5.00	320310	176573	75000	62500	0	6237	13
1992	64062	5.00	320310	188933	68750	62500	0	127	0
1993	64062	5.00	320310	202158	62500	62500	0	-6848	0
1994	64062	5.00	320310	216309	56250	62500	0	-14749	0
1995	64062	5.00	320310	231451	50000	62500	0	-23641	0
1996	64062	5.00	320310	247652	43750	62500	0	-33592	0
1997	64062	5.00	320310	264987	37500	62500	0	-44677	0
1998	64062	5.00	320310	283537	31250	62500	0	-56977	0
1999	64062	5.00	320310	303384	25000	62500	0	-70574	0
2000	64062	5.00	320310	324621	18750	62500	0	-85561	0
2001	64062	5.00	320310	347345	12500	62500	0	-102035	0
2002	64062	5.00	320310	371659	6250	62500	0	-120099	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	320310	29410	26469	62500	7400	62500	10341	10341
1980	320310	30172	27155	62500	7918	62500	10935	21276
1981	320310	30550	27495	62500	8472	62500	11527	32803
1982	320310	30517	27465	62500	9065	62500	12117	44920
1983	320310	30044	27040	62500	9700	62500	12704	57624
1984	320310	29100	26190	62500	10379	62500	13289	70913
1985	320310	27652	24887	62500	11106	62500	13871	84784
1986	320310	25666	23099	62500	11883	62500	14450	99234
1987	320310	23103	20793	62500	12715	62500	15025	114259
1988	320310	19923	17931	62500	13605	62500	15597	129856
1989	320310	16084	14476	62500	14557	62500	16165	146021
1990	320310	11538	10384	62500	15576	62500	16730	162751
1991	320310	6237	5613	62500	16666	62500	17290	180041
1992	320310	127	114	62500	17833	62500	17846	197887
1993	320310	-6848	0	62500	19081	62500	12233	210120
1994	320310	-14749	0	62500	20417	62500	5668	215788
1995	320310	-23641	0	62500	21846	62500	-1795	213993
1996	320310	-33592	0	62500	23375	62500	-10217	203776
1997	320310	-44677	0	62500	25011	62500	-19666	184110
1998	320310	-56977	0	62500	26762	62500	-30215	153895
1999	320310	-70574	0	62500	28635	62500	-41939	111956
2000	320310	-85561	0	62500	30639	62500	-54922	57034
2001	320310	-102035	0	62500	32784	62500	-69251	-12217
2002	320310	-120099	0	62500	35079	62500	-85020	-97237

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1500000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.00	320310	73400	150000	62500	0	34410	76
1980	64062	5.00	320310	78538	143750	62500	0	35522	78
1981	64062	5.00	320310	84036	137500	62500	0	36274	80
1982	64062	5.00	320310	89919	131250	62500	0	36641	81
1983	64062	5.00	320310	96214	125000	62500	0	36596	81
1984	64062	5.00	320310	102949	118750	62500	0	36111	80
1985	64062	5.00	320310	110156	112500	62500	0	35154	78
1986	64062	5.00	320310	117867	106250	62500	0	33693	74
1987	64062	5.00	320310	126118	100000	62500	0	31692	70
1988	64062	5.00	320310	134946	93750	62500	0	29114	64
1989	64062	5.00	320310	144392	87500	62500	0	25918	57
1990	64062	5.00	320310	154500	81250	62500	0	22060	49
1991	64062	5.00	320310	165314	75000	62500	0	17496	38
1992	64062	5.00	320310	176886	68750	62500	0	12174	27
1993	64062	5.00	320310	189268	62500	62500	0	6042	13
1994	64062	5.00	320310	202517	56250	62500	0	-957	0
1995	64062	5.00	320310	216693	50000	62500	0	-8883	0
1996	64062	5.00	320310	231861	43750	62500	0	-17801	0
1997	64062	5.00	320310	248091	37500	62500	0	-27781	0
1998	64062	5.00	320310	265458	31250	62500	0	-38898	0
1999	64062	5.00	320310	284040	25000	62500	0	-51230	0
2000	64062	5.00	320310	303923	18750	62500	0	-64863	0
2001	64062	5.00	320310	325198	12500	62500	0	-79888	0
2002	64062	5.00	320310	347962	6250	62500	0	-96402	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1500000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 59700   DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	320310	34410	30969	62500	7400	62500	10841	10841
1980	320310	35522	31970	62500	7918	62500	11470	22311
1981	320310	36274	32647	62500	8472	62500	12099	34410
1982	320310	36641	32977	62500	9065	62500	12729	47139
1983	320310	36596	32936	62500	9700	62500	13360	60499
1984	320310	36111	32500	62500	10379	62500	13990	74489
1985	320310	35154	31639	62500	11106	62500	14621	89110
1986	320310	33693	30324	62500	11883	62500	15252	104362
1987	320310	31692	28523	62500	12715	62500	15884	120246
1988	320310	29114	26203	62500	13605	62500	16516	136762
1989	320310	25918	23326	62500	14557	62500	17149	153911
1990	320310	22060	19854	62500	15576	62500	17782	171693
1991	320310	17496	15746	62500	16666	62500	18416	190109
1992	320310	12174	10957	62500	17833	62500	19050	209159
1993	320310	6042	5438	62500	19081	62500	19685	228844
1994	320310	-957	0	62500	20417	62500	19460	248304
1995	320310	-8883	0	62500	21846	62500	12963	261267
1996	320310	-17801	0	62500	23375	62500	5574	266841
1997	320310	-27781	0	62500	25011	62500	-2770	264071
1998	320310	-38898	0	62500	26762	62500	-12136	251935
1999	320310	-51230	0	62500	28635	62500	-22595	229340
2000	320310	-64863	0	62500	30639	62500	-34224	195116
2001	320310	-79888	0	62500	32784	62500	-47104	148012
2002	320310	-96402	0	62500	35079	62500	-61323	86689

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 59700 DIRECT EXPENSE: 6300

Schedule 12A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.00	320310	73900	136400	56833	0	53177	118
1980	64062	5.00	320310	79073	136400	56833	0	48004	106
1981	64062	5.00	320310	84608	133860	56833	0	45009	100
1982	64062	5.00	320310	90531	128860	56833	0	44086	97
1983	64062	5.00	320310	96868	123850	56833	0	42759	95
1984	64062	5.00	320310	103648	110800	56833	0	49029	108
1985	64062	5.00	320310	110904	105790	56833	0	46783	103
1986	64062	5.00	320310	118667	100470	56833	0	44340	98
1987	64062	5.00	320310	126974	95140	56833	0	41363	91
1988	64062	5.00	320310	135862	89820	56833	0	37795	83
1989	64062	5.00	320310	145372	84490	56833	0	33615	74
1990	64062	5.00	320310	155548	79170	56833	0	28759	63
1991	64062	5.00	320310	166436	73840	56833	0	23201	51
1992	64062	5.00	320310	178087	68510	56833	0	16880	37
1993	64062	5.00	320310	190553	63180	56833	0	9744	21
1994	64062	5.00	320310	203892	59330	56833	0	255	0
1995	64062	5.00	320310	218164	56980	56833	0	-11667	0
1996	64062	5.00	320310	233435	54630	56833	0	-24588	0
1997	64062	5.00	320310	249775	52280	56833	0	-38578	0
1998	64062	5.00	320310	267260	49930.	56833	0	-53713	0
1999	64062	5.00	320310	285968	47710	56833	0	-70201	0
2000	64062	5.00	320310	305986	46420	56833	0	-88929	0
2001	64062	5.00	320310	327405	43720	56833	0	-107648	0
2002	64062	5.00	320310	350324	42830	56833	0	-129677	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1364000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

Schedule 12B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	320310	53177	47859	56833	7400	0	69551	69551
1980	320310	48004	43204	56833	7918	25400	44151	113702
1981	320310	45009	40508	56833	8472	50000	19806	133508
1982	320310	44086	39677	56833	9065	50100	20207	153715
1983	320310	42759	38483	56833	9700	130500	-59691	94024
1984	320310	49029	44126	56833	10379	50100	22015	116039
1985	320310	46783	42105	56833	11106	53200	19417	135456
1986	320310	44340	39906	56833	11883	53300	19850	155306
1987	320310	41363	37227	56833	12715	53200	20484	175790
1988	320310	37795	34016	56833	13605	53300	20917	196707
1989	320310	33615	30254	56833	14557	53200	21551	218258
1990	320310	28759	25883	56833	15576	53300	21985	240243
1991	320310	23201	20881	56833	16666	53300	22519	262762
1992	320310	16880	15192	56833	17833	53300	23054	285816
1993	320310	9744	8770	56833	19081	38500	38388	324204
1994	320310	255	230	56833	20417	23500	53775	377979
1995	320310	-11667	0	56833	21846	23500	43512	421491
1996	320310	-24588	0	56833	23375	23500	32120	453611
1997	320310	-38578	0	56833	25011	23500	19766	473377
1998	320310	-53713	0	56833	26762	22200	7682	481059
1999	320310	-70201	0	56833	28635	12900	2367	483426
2000	320310	-88929	0	56833	30639	27000	-28457	454969
2001	320310	-107648	0	56833	32784	8900	-26931	428038
2002	320310	-129677	0	56833	35079	170000	-207765	220273

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1364000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.25	336326	73900	136400	56833	0	69193	153
1980	64062	5.25	336326	79073	136400	56833	0	64020	142
1981	64062	5.25	336326	84608	133860	56833	0	61025	135
1982	64062	5.25	336326	90531	128860	56833	0	60102	133
1983	64062	5.25	336326	96868	123850	56833	0	58775	130
1984	64062	5.25	336326	103648	110800	56833	0	65045	144
1985	64062	5.25	336326	110904	105790	56833	0	62799	139
1986	64062	5.25	336326	118667	100470	56833	0	60356	134
1987	64062	5.25	336326	126974	95140	56833	0	57379	127
1988	64062	5.25	336326	135862	89820	56833	0	53811	119
1989	64062	5.25	336326	145372	84490	56833	0	49631	110
1990	64062	5.25	336326	155548	79170	56833	0	44775	99
1991	64062	5.25	336326	166436	73840	56833	0	39217	87
1992	64062	5.25	336326	178087	68510	56833	0	32896	73
1993	64062	5.25	336326	190553	63180	56833	0	25760	57
1994	64062	5.25	336326	203892	59330	56833	0	16271	36
1995	64062	5.25	336326	218164	56980	56833	0	4349	9
1996	64062	5.25	336326	233435	54630	56833	0	-8572	0
1997	64062	5.25	336326	249775	52280	56833	0	-22562	0
1998	64062	5.25	336326	267260	49930	56833	0	-37697	0
1999	64062	5.25	336326	285968	47710	56833	0	-54185	0
2000	64062	5.25	336326	305986	46420	56833	0	-72913	0
2001	64062	5.25	336326	327405	43720	56833	0	-91632	0
2002	64062	5.25	336326	350324	42830	56833	0	-113661	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1364000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	336326	69193	62274	56833	7400	0	71152	71152
1980	336326	64020	57618	56833	7918	25400	45753	116905
1981	336326	61025	54923	56833	8472	50000	21407	138312
1982	336326	60102	54092	56833	9065	50100	21808	160120
1983	336326	58775	52898	56833	9700	130500	-58090	102030
1984	336326	65045	58541	56833	10379	50100	23616	125646
1985	336326	62799	56519	56833	11106	53200	21019	146665
1986	336326	60356	54320	56833	11883	53300	21452	168117
1987	336326	57379	51641	56833	12715	53200	22086	190203
1988	336326	53811	48430	56833	13605	53300	22519	212722
1989	336326	49631	44668	56833	14557	53200	23153	235875
1990	336326	44775	40298	56833	15576	53300	23586	259461
1991	336326	39217	35295	56833	16666	53300	24121	283582
1992	336326	32896	29606	56833	17833	53300	24656	308238
1993	336326	25760	23184	56833	19081	38500	39990	348228
1994	336326	16271	14644	56833	20417	23500	55377	403605
1995	336326	4349	3914	56833	21846	23500	55614	459219
1996	336326	-8572	0	56833	23375	23500	48136	507355
1997	336326	-22562	0	56833	25011	23500	35782	543137
1998	336326	-37697	0	56833	26762	22200	23698	566835
1999	336326	-54185	0	56833	28635	12900	18383	585218
2000	336326	-72913	0	56833	30639	27000	-12441	572777
2001	336326	-91632	0	56833	32784	8900	-10915	561862
2002	336326	-113661	0	56833	35079	170000	-191749	370113

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1364000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.25	336326	73900	136400	56833	0	69193	153
1980	64062	5.25	336326	79073	136400	56833	0	64020	142
1981	64062	5.25	336326	84608	136400	56833	0	58485	129
1982	64062	5.25	336326	90531	136400	56833	0	52562	116
1983	64062	5.25	336326	96868	136400	56833	0	46225	102
1984	64062	5.25	336326	103648	136400	56833	0	39445	87
1985	64062	5.25	336326	110904	136400	56833	0	32189	71
1986	64062	5.25	336326	118667	136400	56833	0	24426	54
1987	64062	5.25	336326	126974	136400	56833	0	16119	35
1988	64062	5.25	336326	135862	136400	56833	0	7231	16
1989	64062	5.25	336326	145372	136400	56833	0	-2279	0
1990	64062	5.25	336326	155548	136400	56833	0	-12455	0
1991	64062	5.25	336326	166436	136400	56833	0	-23343	0
1992	64062	5.25	336326	178087	136400	56833	0	-34994	0
1993	64062	5.25	336326	190553	136400	56833	0	-47460	0
1994	64062	5.25	336326	203892	136400	56833	0	-60799	0
1995	64062	5.25	336326	218164	136400	56833	0	-75071	0
1996	64062	5.25	336326	233435	136400	56833	0	-90342	0
1997	64062	5.25	336326	249775	136400	56833	0	-106682	0
1998	64062	5.25	336326	267260	136400	56833	0	-124167	0
1999	64062	5.25	336326	285968	136400	56833	0	-142875	0
2000	64062	5.25	336326	305986	136400	56833	0	-162893	0
2001	64062	5.25	336326	327405	136400	56833	0	-184312	0
2002	64062	5.25	336326	350324	136400	56833	0	-207231	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1364000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 60000   DIRECT EXPENSE: 6500

Schedule 14B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	336326	69193	62274	56833	7400	0	71152	71152
1980	336326	64020	57618	56833	7918	0	71153	142305
1981	336326	58485	52637	56833	8472	0	71153	213458
1982	336326	52562	47306	56833	9065	0	71154	284612
1983	336326	46225	41603	56833	9700	0	71155	355767
1984	336326	39445	35501	56833	10379	0	71156	426923
1985	336326	32189	28970	56833	11106	0	71158	498081
1986	336326	24426	21983	56833	11883	0	71159	569240
1987	336326	16119	14507	56833	12715	0	71160	640400
1988	336326	7231	6508	56833	13605	0	71161	711561
1989	336326	-2279	0	56833	14557	0	69111	780672
1990	336326	-12455	0	56833	15576	0	59954	840626
1991	336326	-23343	0	56833	16666	0	50156	890782
1992	336326	-34994	0	56833	17833	0	39672	930454
1993	336326	-47460	0	56833	19081	0	28454	958908
1994	336326	-60799	0	56833	20417	0	16451	975359
1995	336326	-75071	0	56833	21846	0	3608	978967
1996	336326	-90342	0	56833	23375	0	-10134	968833
1997	336326	-106682	0	56833	25011	0	-24838	943995
1998	336326	-124167	0	56833	26762	0	-40572	903423
1999	336326	-142875	0	56833	28635	0	-57407	846016
2000	336326	-162893	0	56833	30639	0	-75421	770595
2001	336326	-184312	0	56833	32784	0	-94695	675900
2002	336326	-207231	0	56833	35079	0	-115319	560581

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1364000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT-EXPENSE: 6500

Schedule 15 \

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.50	352341	74000	136400	56833	0	85108	187
1980	64062	5.50	352341	79180	136400	56833	0	79928	177
1981	64062	5.50	352341	84723	133860	56833	0	76925	170
1982	64062	5.50	352341	90654	128860	56833	0	75994	168
1983	64062	5.50	352341	96999	123850	56833	0	74659	165
1984	64062	5.50	352341	103788	110800	56833	0	80920	179
1985	64062	5.50	352341	111053	105790	56833	0	78665	174
1986	64062	5.50	352341	118827	96970	56833	0	79711	177
1987	64062	5.50	352341	127145	91640	56833	0	76723	170
1988	64062	5.50	352341	136045	86320	56833	0	73143	162
1989	64062	5.50	352341	145568	80990	56833	0	68950	153
1990	64062	5.50	352341	155758	75670	56833	0	64080	142
1991	64062	5.50	352341	166661	66840	56833	0	62007	137
1992	64062	5.50	352341	178327	58010	56833	0	59171	131
1993	64062	5.50	352341	190810	52680	56833	0	52018	115
1994	64062	5.50	352341	204167	45330	56833	0	46011	102
1995	64062	5.50	352341	218458	42980	56833	0	34070	75
1996	64062	5.50	352341	233750	40630	56833	0	21128	46
1997	64062	5.50	352341	250112	38280	56833	0	7116	15
1998	64062	5.50	352341	267620	35930	56833	0	-8042	0
1999	64062	5.50	352341	286354	30210	56833	0	-21056	0
2000	64062	5.50	352341	306399	25420	56833	0	-36311	0
2001	64062	5.50	352341	327847	19220	56833	0	-51559	0
2002	64062	5.50	352341	350797	18330	56833	0	-73619	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1364000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 60000   DIRECT EXPENSE: 6500

Schedule 15B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	352341	85108	76597	56833	7500	0	72844	72844
1980	352341	79928	71935	56833	8025	25400	47451	120295
1981	352341	76925	69233	56833	8587	50000	23112	143407
1982	352341	75994	68395	56833	9188	50100	23520	166927
1983	352341	74659	67193	56833	9831	130500	-56370	110557
1984	352341	80920	72828	56833	10519	50100	25344	135901
1985	352341	78665	70799	56833	11255	88200	-12246	123655
1986	352341	79711	71740	56833	12043	53300	23547	147202
1987	352341	76723	69051	56833	12886	53200	24191	171393
1988	352341	73143	65829	56833	13788	53300	24635	196028
1989	352341	68950	62055	56833	14753	53200	25281	221309
1990	352341	64080	57672	56833	15786	88300	-9273	212036
1991	352341	62007	55806	56833	16891	88300	-8375	203661
1992	352341	59171	53254	56833	18073	53300	27523	231184
1993	352341	52018	46816	56833	19338	73500	7873	239057
1994	352341	46011	41410	56833	20692	23500	58626	297683
1995	352341	34070	30663	56833	22140	23500	58880	356563
1996	352341	21128	19015	56833	23690	23500	59136	415699
1997	352341	7116	6404	56833	25348	23500	59393	475092
1998	352341	-8042	0	56833	27122	57200	18713	493805
1999	352341	-21056	0	56833	29021	47900	16898	510703
2000	352341	-36311	0	56833	31052	62000	-10426	500277
2001	352341	-51559	0	56833	33226	8900	29600	529877
2002	352341	-73619	0	56833	35552	170000	-151234	378643

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1364000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6500

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.50	352341	78400	130000	54167	0	89774	199
1980	64062	5.50	352341	83888	124583	54167	0	89703	199
1981	64062	5.50	352341	89760	119167	54167	0	89247	198
1982	64062	5.50	352341	96043	113750	54167	0	88381	196
1983	64062	5.50	352341	102766	108333	54167	0	87075	193
1984	64062	5.50	352341	109960	102917	54167	0	85297	189
1985	64062	5.50	352341	117658	97500	54167	0	83016	184
1986	64062	5.50	352341	125894	92083	54167	0	80197	178
1987	64062	5.50	352341	134707	86666	54167	0	76801	170
1988	64062	5.50	352341	144137	81250	54167	0	72787	161
1989	64062	5.50	352341	154226	75833	54167	0	68115	151
1990	64062	5.50	352341	165022	70416	54167	0	62736	139
1991	64062	5.50	352341	176573	65000	54167	0	56601	125
1992	64062	5.50	352341	188933	59583	54167	0	49658	110
1993	64062	5.50	352341	202158	54166	54167	0	41850	93
1994	64062	5.50	352341	216309	48750	54167	0	33115	73
1995	64062	5.50	352341	231451	43333	54167	0	23390	51
1996	64062	5.50	352341	247652	37916	54167	0	12606	28
1997	64062	5.50	352341	264987	32499	54167	0	688	1
1998	64062	5.50	352341	283537	27083	54167	0	-12446	0
1999	64062	5.50	352341	303384	21666	54167	0	-26876	0
2000	64062	5.50	352341	324621	16249	54167	0	-42696	0
2001	64062	5.50	352341	347345	10833	54167	0	-60004	0
2002	64062	5.50	352341	371659	5416	54167	0	-78901	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1300000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET-- INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	352341	89774	80797	54167	7400	54167	16377	16377
1980	352341	89703	80733	54167	7918	54167	16888	33265
1981	352341	89247	80322	54167	8472	54167	17397	50662
1982	352341	88381	79543	54167	9065	54167	17903	68565
1983	352341	87075	78368	54167	9700	54167	18407	86972
1984	352341	85297	76767	54167	10379	54167	18909	105881
1985	352341	83016	74714	54167	11106	54167	19408	125289
1986	352341	80197	72177	54167	11883	54167	19903	145192
1987	352341	76801	69121	54167	12715	54167	20395	165587
1988	352341	72787	65508	54167	13605	54167	20884	186471
1989	352341	68115	61304	54167	14557	54167	21368	207839
1990	352341	62736	56462	54167	15576	54167	21850	229689
1991	352341	56601	50941	54167	16666	54167	22326	252015
1992	352341	49658	44692	54167	17833	54167	22799	274814
1993	352341	41850	37665	54167	19081	54167	23266	298080
1994	352341	33115	29804	54167	20417	54167	23728	321808
1995	352341	23390	21051	54167	21846	54167	24185	345993
1996	352341	12606	11345	54167	23375	54167	24636	370629
1997	352341	688	619	54167	25011	54167	25080	395709
1998	352341	-12446	0	54167	26762	54167	14316	410025
1999	352341	-26876	0	54167	28635	54167	1759	411784
2000	352341	-42696	0	54167	30639	54167	-12057	399727
2001	352341	-60004	0	54167	32784	54167	-27220	372507
2002	352341	-78901	0	54167	35079	54167	-43822	328685

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.50	352341	78400	130000	54167	0	89774	199
1980	64062	5.50	352341	83888	130000	54167	0	84286	187
1981	64062	5.50	352341	89760	127460	54167	0	80954	179
1982	64062	5.50	352341	96043	122460	54167	0	79671	177
1983	64062	5.50	352341	102766	117450	54167	0	77958	173
1984	64062	5.50	352341	109960	104400	54167	0	83814	186
1985	64062	5.50	352341	117658	99390	54167	0	81126	180
1986	64062	5.50	352341	125894	94070	54167	0	78210	173
1987	64062	5.50	352341	134707	85630	54167	0	77837	172
1988	64062	5.50	352341	144137	80310	54167	0	73727	163
1989	64062	5.50	352341	154226	74980	54167	0	68968	153
1990	64062	5.50	352341	165022	69660	54167	0	63492	141
1991	64062	5.50	352341	176573	64330	54167	0	57271	127
1992	64062	5.50	352341	188933	55890	54167	0	53351	118
1993	64062	5.50	352341	202158	50560	54167	0	45456	101
1994	64062	5.50	352341	216309	46710	54167	0	35155	78
1995	64062	5.50	352341	231451	41260	54167	0	25463	56
1996	64062	5.50	352341	247652	38910	54167	0	11612	25
1997	64062	5.50	352341	264987	33460	54167	0	-273	0
1998	64062	5.50	352341	283537	31110	54167	0	-16473	0
1999	64062	5.50	352341	303384	25790	54167	0	-31000	0
2000	64062	5.50	352341	324621	24500	54167	0	-50947	0
2001	64062	5.50	352341	347345	21800	54167	0	-70971	0
2002	64062	5.50	352341	371659	17710	54167	0	-91195	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	352341	89774	80797	54167	7400	0	70544	70544
1980	352341	84286	75857	54167	7918	25400	45114	115658
1981	352341	80954	72859	54167	8472	50000	20734	136392
1982	352341	79671	71704	54167	9065	50100	21099	157491
1983	352341	77958	70162	54167	9700	130500	-58837	98654
1984	352341	83814	75433	54167	10379	50100	22827	121481
1985	352341	81126	73013	54167	11106	53200	20186	141667
1986	352341	78210	70389	54167	11883	84400	-10529	131138
1987	352341	77837	70053	54167	12715	53200	21466	152604
1988	352341	73727	66354	54167	13605	53300	21845	174449
1989	352341	68968	62071	54167	14557	53200	22421	196870
1990	352341	63492	57143	54167	15576	53300	22792	219662
1991	352341	57271	51544	54167	16666	84400	-7840	211822
1992	352341	53351	48016	54167	17833	53300	24035	235857
1993	352341	45456	40910	54167	19081	38500	39294	275151
1994	352341	35155	31640	54167	20417	54500	23599	298750
1995	352341	25463	22917	54167	21846	23500	55059	353809
1996	352341	11612	10451	54167	23375	54500	24203	378012
1997	352341	-273	0	54167	25011	23500	55405	433417
1998	352341	-16473	0	54167	26762	53200	11256	444673
1999	352341	-31000	0	54167	28635	12900	38902	483575
2000	352341	-50947	0	54167	30639	27000	6859	490434
2001	352341	-70971	0	54167	32784	40900	-24920	465514
2002	352341	-91195	0	54167	35079	170000	-171949	293565

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1300000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 64700   DIRECT EXPENSE: 6300

Schedule 10A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	5.50	352341	78400	91000	54167	0	128774	286
1980	64062	5.50	352341	83888	87208	54167	0	127078	282
1981	64062	5.50	352341	89760	83417	54167	0	124997	277
1982	64062	5.50	352341	96043	79625	54167	0	122506	272
1983	64062	5.50	352341	102766	75833	54167	0	119575	265
1984	64062	5.50	352341	109960	72042	54167	0	116172	258
1985	64062	5.50	352341	117658	68250	54167	0	112266	249
1986	64062	5.50	352341	125894	64458	54167	0	107822	239
1987	64062	5.50	352341	134707	60666	54167	0	102801	228
1988	64062	5.50	352341	144137	56875	54167	0	97162	215
1989	64062	5.50	352341	154226	53083	54167	0	90865	201
1990	64062	5.50	352341	165022	49291	54167	0	83861	186
1991	64062.	5.50	352341	176573	45500	54167	0	76101	169
1992	64062	5.50	352341	188933	41708	54167	0	67533	150
1993	64062	5.50	352341	202158	37916	54167	0	58100	129
1994	64062	5.50	352341	216309	34125	54167	0	47740	106
1995	64062	5.50	352341	231451	30333	54167	0	36390	80
1996	64062	5.50	352341	247652	26541	54167	0	23981	53
1997	64062	5.50	352341	264987	22750	54167	0	10437	23
1998	64062	5.50	352341	283537	18958	54167	0	-4321	0
1999	64062	5.50	352341	303384	15166	54167	0	-20376	0
2000	64062	5.50	352341	324621	11375	54167	0	-37822	0
2001	64062	5.50	352341	347345	7583	54167	0	-56754	0
2002	64062	5.50	352341	371659	3791	54167	0	-77276	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	352341	128774	115897	54167	7400	54167	20277	20277
1980	352341	127078	114370	54167	7918	54167	20626	40903
1981	352341	124997	112497	54167	8472	54167	20972	61875
1982	352341	122506	110255	54167	9065	54167	21316	83191
1983	352341	119575	107618	54167	9700	54167	21657	104848
1984	352341	116172	104555	54167	10379	54167	21996	126844
1985	352341	112266	101039	54167	11106	54167	22333	149177
1986	352341	107822	97040	54167	11883	54167	22665	171842
1987	352341	102801	92521	54167	12715	54167	22995	194837
1988	352341	97162	87446	54167	13605	54167	23321	218158
1989	352341	90865	81779	54167	14557	54167	23643	241801
1990	352341	83861	75475	54167	15576	54167	23962	265763
1991	352341	76101	68491	54167	16666	54167	24276	290039
1992	352341	67533	60780	54167	17833	54167	24586	314625
1993	352341	58100	52290	54167	19081	54167	24891	339516
1994	352341	47740	42966	54167	20417	54167	25191	364707
1995	352341	36390	32751	54167	21846	54167	25485	390192
1996	352341	23981	21583	54167	23375	54167	25773	415965
1997	352341	10437	9393	54167	25011	54167	26055	442020
1998	352341	-4321	0	54167	26762	54167	22441	464461
1999	352341	-20376	0	54167	28635	54167	8259	472720
2000	352341	-37822	0	54167	30639	54167	-7183	465537
2001	352341	-56754	0	54167	32784	54167	-23970	441567
2002	352341	-77276	0	54167	35079	54167	-42197	399370

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 64700 DIRECT EXPENSE: 6300

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	6.35	406794	73700	130000	54167	0	148927	330
1980	64062	6.35	406794	78859	124583	54167	0	149185	331
1981	64062	6.35	406794	84379	119167	54167	0	149081	331
1982	64062	6.35	406794	90286	113750	54167	0	148591	330
1983	64062	6.35	406794	96606	108333	54167	0	147688	328
1984	64062	6.35	406794	103368	102917	54167	0	146342	325
1985	64062	6.35	406794	110605	97500	54167	0	144522	321
1986	64062	6.35	406794	118347	92083	54167	0	142197	315
1987	64062	6.35	406794	126631	86666	54167	0	139330	309
1988	64062	6.35	406794	135495	81250	54167	0	135882	301
1989	64062	6.35	406794	144979	75833	54167	0	131815	292
1990	64062	6.35	406794	155128	70416	54167	0	127083	282
1991	64062	6.35	406794	165986	65000	54167	0	121641	270
1992	64062	6.35	406794	177605	59583	54167	0	115439	256
1993	64062	6.35	406794	190037	54166	54167	0	108424	240
1994	64062	6.35	406794	203340	48750	54167	0	100537	223
1995	64062	6.35	406794	217574	43333	54167	0	91720	203
1996	64062	6.35	406794	232804	37916	54167	0	81907	182
1997	64062	6.35	406794	249100	32499	54167	0	71028	157
1998	64062	6.35	406794	266538	27083	54167	0	59006	131
1999	64062	6.35	406794	285195	21666	54167	0	45766	101
2000	64062	6.35	406794	305159	16249	54167	0	31219	69
2001	64062	6.35	406794	326520	10833	54167	0	15274	33
2002	64062	6.35	406794	349377	5416	54167	0	-2166	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	406794	148927	134034	54167	7400	54167	22293	22293
1980	406794	149185	134267	54167	7918	54167	22836	45129
1981	406794	149081	134173	54167	8472	54167	23380	68509
1982	406794	148591	133732	54167	9065	54167	23924	92433
1983	406794	147688	132919	54167	9700	54167	24469	116902
1984	406794	146342	131708	54167	10379	54167	25013	141915
1985	406794	144522	130070	54167	11106	54167	25558	167473
1986	406794	142197	127977	54167	11883	54167	26103	193576
1987	406794	139330	125397	54167	12715	54167	26648	220224
1988	406794	135882	122294	54167	13605	54167	27193	247417
1989	406794	131815	118634	54167	14557	54167	27738	275155
1990	406794	127083	114375	54167	15576	54167	28284	303439
1991	406794	121641	109477	54167	16666	54167	28830	332269
1992	406794	115439	103895	54167	17833	54167	29377	361646
1993	406794	108424	97582	54167	19081	54167	29923	391569
1994	406794	100537	90483	54167	20417	54167	30471	422040
1995	406794	91720	82548	54167	21846	54167	31018	453058
1996	406794	81907	73716	54167	23375	54167	31566	484624
1997	406794	71028	63925	54167	25011	54167	32114	516738
1998	406794	59006	53105	54167	26762	54167	32663	549401
1999	406794	45766	41189	54167	28635	54167	33212	582613
2000	406794	31219	28097	54167	30639	54167	33761	616374
2001	406794	15274	13747	54167	32784	54167	34311	650685
2002	406794	-2166.	0	54167	35079	54167	32913	683598

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1300000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6300

Schedule 20A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1979	64062	6.35	406794	73700	105000	62500	0	165594	367
1980	64062	6.35	406794	78859	100625	62500	0	164810	366
1981	64062	6.35	406794	84379	96250	62500	0	163665	363
1982	64062	6.35	406794	90286	91875	62500	0	162133	360
1983	64062	6.35	406794	96606	87500	62500	0	160188	355
1984	64062	6.35	406794	103368	83125	62500	0	157801	350
1985	64062	6.35	406794	110605	78750	62500	0	154939	344
1986	64062	6.35	406794	118347	74375	62500	0	151572	336
1987	64062	6.35	406794	126631	70000	62500	0	147663	328
1988	64062	6.35	406794	135495	65625	62500	0	143174	318
1989	64062	6.35	406794	144979	61250	62500	0	138065	306
1990	64062	6.35	406794	155128	56875	62500	0	132291	293
1991	64062	6.35	406794	165986	52500	62500	0	125808	279
1992	64062	6.35	406794	177605	48125	62500	0	118564	263
1993	64062	6.35	406794	190037	43750	62500	0	110507	245
1994	64062	6.35	406794	203340	39375	62500	0	101579	225
1995	64062	6.35	406794	217574	35000	62500	0	91720	203
1996	64062	6.35	406794	232804	30625	62500	0	80865	179
1997	64062	6.35	406794	249100	26250	62500	0	68944	153
1998	64062	6.35	406794	266538	21875	62500	0	55881	124
1999	64062	6.35	406794	285195	17500	62500	0	41599	92
2000	64062	6.35	406794	305159	13125	62500	0	26010	57
2001	64062	6.35	406794	326520	8750	62500	0	9024	20
2002	64062	6.35	406794	349377	4375	62500	0	-9458	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6300

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1979	406794	165594	149035	62500	7400	62500	23959	23959
1980	406794	164810	148329	62500	7918	62500	24399	48358
1981	406794	163665	147299	62500	8472	62500	24838	73196
1982	406794	162133	145920	62500	9065	62500	25278	98474
1983	406794	160188	144169	62500	9700	62500	25719	124193
1984	406794	157801	142021	62500	10379	62500	26159	150352
1985	406794	154939	139445	62500	11106	62500	26600	176952
1986	406794	151572	136415	62500	11883	62500	27040	203992
1987	406794	147663	132897	62500	12715	62500	27481	231473
1988	406794	143174	128857	62500	13605	62500	27922	259395
1989	406794	138065	124259	62500	14557	62500	28363	287758
1990	406794	132291	119062	62500	15576	62500	28805	316563
1991	406794	125808	113227	62500	16666	62500	29247	345810
1992	406794	118564	106708	62500	17833	62500	29689	375499
1993	406794	110507	99456	62500	19081	62500	30132	405631
1994	406794	101579	91421	62500	20417	62500	30575	436206
1995	406794	91720	82548	62500	21846	62500	31018	467224
1996	406794	80865	72779	62500	23375	62500	31461	498685
1997	406794	68944	62050	62500	25011	62500	31905	530590
1998	406794	55881	50293	62500	26762	62500	32350	562940
1999	406794	41599	37439	62500	28635	62500	32795	595735
2000	406794	26010	23409	62500	30639	62500	33240	628975
2001	406794	9024	8122	62500	32784	62500	33686	662661
2002	406794	-9458	0	62500	35079	62500	25621	688282

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 60000 DIRECT EXPENSE: 6300

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	4.68	399808	103000	160000	66670	0	70138	155
1983	85429	4.68	399808	110210	153333	66670	0	69595	154
1984	85429	4.68	399808	117925	146666	66670	0	68547	152
1985	85429	4.68	399808	126179	139999	66670	0	66960	148
1986	85429	4.68	399808	135012	133332	66670	0	64794	143
1987	85429	4.68	399808	144463	126665	66670	0	62010	137
1988	85429	4.68	399808	154576	119998	66670	0	58564	130
1989	85429	4.68	399808	165395	113331	66670	0	54412	120
1990	85429	4.68	399808	176973	106664	66670	0	49501	110
1991	85429	4.68	399808	189360	99997	66670	0	43781	97
1992	85429	4.68	399808	202615	93330	66670	0	37193	82
1993	85429	4.68	399808	216797	86663	66670	0	29678	65
1994	85429	4.68	399808	231973	79996	66670	0	21169	47
1995	85429	4.68	399808	248211	73329	66670	0	11598	25
1996	85429	4.68	399808	265585	66662	66670	0	891	1
1997	85429	4.68	399808	284175	59995	66670	0	-11032	0
1998	85429	4.68	399808	304067	53328	66670	0	-24257	0
1999	85429	4.68	399808	325352	46661	66670	0	-38875	0
2000	85429	4.68	399808	348127	39994	66670	0	-54983	0
2001	85429	4.68	399808	372495	33327	66670	0	-72684	0
2002	85429	4.68	399808	398569	26660	66670	0	-92091	0
2003	85429	4.68	399808	426469	19993	66670	0	-113324	0
2004	85429	4.68	399808	456321	13326	66670	0	-136509	0
2005	85429	4.68	399808	488264	6659	66670	0	-161785	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	399808	70138	63124	66670	9000	66670	16014	16014
1983	399808	69595	62636	66670	9630	66670	16589	32603
1984	399808	68547	61692	66670	10304	66670	17159	49762
1985	399808	66960	60264	66670	11025	66670	17721	67483
1986	399808	64794	58315	66670	11797	66670	18276	85759
1987	399808	62010	55809	66670	12623	66670	18824	104583
1988	399808	58564	52708	66670	13507	66670	19363	123946
1989	399808	54412	48971	66670	14452	66670	19893	143839
1990	399808	49501	44551	66670	15464	66670	20414	164253
1991	399808	43781	39403	66670	16546	66670	20924	185177
1992	399808	37193	33474	66670	17704	66670	21423	206600
1993	399808	29678	26710	66670	18943	66670	21911	228511
1994	399808	21169	19052	66670	20269	66670	22386	250897
1995	399808	11598	10438	66670	21688	66670	22848	273745
1996	399808	891	802	66670	23206	66670	23295	297040
1997	399808	-11032	0	66670	24830	66670	13798	310838
1998	399808	-24257	0	66670	26568	66670	2311	313149
1999	399808	-38875	0	66670	28428	66670	-10447	302702
2000	399808	-54983	0	66670	30418	66670	-24565	278137
2001	399808	-72684	0	66670	32547	66670	-40137	238000
2002	399808	-92091	0	66670	34825	66670	-57266	180734
2003	399808	-113324	0	66670	37263	66670	-76061	104673
2004	399808	-136509	0	66670	39871	66670	-96638	8035
2005	399808	-161785	0	66670	42662	66670	-119123	-111088

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	4.68	399808	92500	101500	60417	0	145391	323
1983	85429	4.68	399808	98975	97271	60417	0	143145	318
1984	85429	4.68	399808	105904	93042	60417	0	140445	312
1985	85429	4.68	399808	113317	88812	60417	0	137262	305
1986	85429	4.68	399808	121250	84583	60417	0	133558	296
1987	85429	4.68	399808	129738	80354	60417	0	129299	287
1988	85429	4.68	399808	138821	76125	60417	0	124445	276
1989	85429	4.68	399808	148538	71896	60417	0	118957	264
1990	85429	4.68	399808	158937	67666	60417	0	112788	250
1991	85429	4.68	399808	170062	63437	60417	0	105892	235
1992	85429	4.68	399808	181966	59208	60417	0	98217	218
1993	85429	4.68	399808	194704	54979	60417	0	89708	199
1994	85429	4.68	399808	208334	50750	60417	0	80307	178
1995	85429	4.68	399808	222917	46521	60417	0	69953	155
1996	85429	4.68	399808	238521	42291	60417	0	58579	130
1997	85429	4.68	399808	255217	38062	60417	0	46112	102
1998	85429	4.68	399808	273082	33833	60417	0	32476	72
1999	85429	4.68	399808	292198	29604	60417	0	17589	39
2000	85429	4.68	399808	312652	25375	60417	0	1364	3
2001	85429	4.68	399808	334537	21145	60417	0	-16291	0
2002	85429	4.68	399808	357954	16916	60417	0	-35479	0
2003	85429	4.68	399808	383011	12687	60417	0	-56307	0
2004	85429	4.68	399808	409821	8458	60417	0	-78888	0
2005	85429	4.68	399808	438508	4229	60417	0	-103346	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1450000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	399808	145391	130852	60417	8500	60417	23039	23039
1983	399808	143145	128831	60417	9095	60417	23409	46448
1984	399808	140445	126401	60417	9732	60417	23776	70224
1985	399808	137262	123536	60417	10413	60417	24139	94363
1986	399808	133558	120202	60417	11142	60417	24498	118861
1987	399808	129299	116369	60417	11922	60417	24852	143713
1988	399808	124445	112001	60417	12757	60417	25201	168914
1989	399808	118957	107061	60417	13650	60417	25546	194460
1990	399808	112788	101509	60417	14606	60417	25885	220345
1991	399808	105892	95303	60417	15628	60417	26217	246562
1992	399808	98217	88395	60417	16722	60417	26544	273106
1993	399808	89708	80737	60417	17893	60417	26864	299970
1994	399808	80307	72276	60417	19146	60417	27177	327147
1995	399808	69953	62958	60417	20486	60417	27481	354628
1996	399808	58579	52721	60417	21920	60417	27778	382406
1997	399808	46112	41501	60417	23454	60417	28065	410471
1998	399808	32476	29228	60417	25096	60417	28344	438815
1999	399808	17589	15830	60417	26853	60417	28612	467427
2000	399808	1364	1228	60417	28733	60417	28869	496296
2001	399808	-16291	0	60417	30744	60417	14453	510749
2002	399808	-35479	0	60417	32896	60417	-2583	508166
2003	399808	-56307	0	60417	35199	60417	-21108	487058
2004	399808	-78888	0	60417	37663	60417	-41225	445833
2005	399808	-103346	0	60417	40299	60417	-63047	382786

INTEREST RATE: 700   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1450000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 75000   DIRECT EXPENSE: 9000

Schedule 23A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.00	427145	103000	160000	66670	0	97475	216
1983	85429	5.00	427145	110210	153333	66670	0	96932	215
1984	85429	5.00	427145	117925	146666	66670	0	95884	213
1985	85429	5.00	427145	126179	139999	66670	0	94297	209
1986	85429	5.00	427145	135012	133332	66670	0	92131	204
1987	85429	5.00	427145	144463	126665	66670	0	89347	198
1988	85429	5.00	427145	154576	119998	66670	0	85901	190
1989	85429	5.00	427145	165395	113331	66670	0	81749	181
1990	85429	5.00	427145	176973	106664	66670	0	76838	170
1991	85429	5.00	427145	189360	99997	66670	0	71118	158
1992	85429	5.00	427145	202615	93330	66670	0	64530	143
1993	85429	5.00	427145	216797	86663	66670	0	57015	126
1994	85429	5.00	427145	231973	79996	66670	0	48506	107
1995	85429	5.00	427145	248211	73329	66670	0	38935	86
1996	85429	5.00	427145	265585	66662	66670	0	28228	62
1997	85429	5.00	427145	284175	59995	66670	0	16305	36
1998	85429	5.00	427145	304067	53328	66670	0	3080	6
1999	85429	5.00	427145	325352	46661	66670	0	-11538	0
2000	85429	5.00	427145	348127	39994	66670	0	-27646	0
2001	85429	5.00	427145	372495	33327	66670	0	-45347	0
2002	85429	5.00	427145	398569	26660	66670	0	-64754	0
2003	85429	5.00	427145	426469	19993	66670	0	-85987	0
2004	85429	5.00	427145	456321	13326	66670	0	-109172	0
2005	85429	5.00	427145	488264	6659	66670	0	-134448	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	427145	97475	87728	66670	9000	66670	18747	18747
1983	427145	96932	87239	66670	9630	66670	19323	38070
1984	427145	95884	86296	66670	10304	66670	19892	57962
1985	427145	94297	84867	66670	11025	66670	20455	78417
1986	427145	92131	82918	66670	11797	66670	21010	99427
1987	427145	89347	80412	66670	12623	66670	21558	120985
1988	427145	85901	77311	66670	13507	66670	22097	143082
1989	427145	81749	73574	66670	14452	66670	22627	165709
1990	427145	76838	69154	66670	15464	66670	23148	188857
1991	427145	71118	64006	66670	16546	66670	23658	212515
1992	427145	64530	58077	66670	17704	66670	24157	236672
1993	427145	57015	51314	66670	18943	66670	24644	261316
1994	427145	48506	43655	66670	20269	66670	25120	286436
1995	427145	38935	35042	66670	21688	66670	25581	312017
1996	427145	28228	25405	66670	23206	66670	26029	338046
1997	427145	16305	14675	66670	24830	66670	26460	364506
1998	427145	3080	2772	66670	26568	66670	26876	391382
1999	427145	-11538	0	66670	28428	66670	16890	408272
2000	427145	-27646	0	66670	30418	66670	2772	411044
2001	427145	-45347	0	66670	32547	66670	-12800	398244
2002	427145	-64754	0	66670	34825	66670	-29929	368315
2003	427145	-85987	0	66670	37263	66670	-48724	319591
2004	427145	-109172	0	66670	39871	66670	-69301	250290
2005	427145	-134448	0	66670	42662	66670	-91786	158504

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

Schedule 24A

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.00	427145	103000	150000	66670	0	107475	238
1983	85429	5.00	427145	110210	144990	66670	0	105275	233
1984	85429	5.00	427145	117925	131940	66670	0	110610	245
1985	85429	5.00	427145	126179	126930	66670	0	107366	238
1986	85429	5.00	427145	135012	116110	66670	0	109353	243
1987	85429	5.00	427145	144463	110790	66670	0	105222	233
1988	85429	5.00	427145	154576	105460	66670	0	100439	223
1989	85429	5.00	427145	165395	100130	66670	0	94950	211
1990	85429	5.00	427145	176973	94810	66670	0	88692	197
1991	85429	5.00	427145	189360	83980	66670	0	87135	193
1992	85429	5.00	427145	202615	73150	66670	0	84710	188
1993	85429	5.00	427145	216797	67820	66670	0	75858	168
1994	85429	5.00	427145	231973	58470	66670	0	70032	155
1995	85429	5.00	427145	248211	56120	66670	0	56144	124
1996	85429	5.00	427145	265585	53770	66670	0	41120	91
1997	85429	5.00	427145	284175	51420	66670	0	24880	55
1998	85429	5.00	427145	304067	49070	66670	0	7338	16
1999	85429	5.00	427145	325352	41350	66670	0	-6227	0
2000	85429	5.00	427145	348127	34560	66670	0	-22212	0
2001	85429	5.00	427145	372495	26360	66670	0	-38380	0
2002	85429	5.00	427145	398569	25470	66670	0	-63564	0
2003	85429	5.00	427145	426469	24580	66670	0	-90574	0
2004	85429	5.00	427145	456321	23690	66670	0	-119536	0
2005	85429	5.00	427145	488264	22800	66670	0	-150589	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

Schedule 24B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	427145	107475	96728	66670	9000	50100	36317	36317
1983	427145	105275	94748	66670	9630	130500	-43673	-7356
1984	427145	110610	99549	66670	10304	50100	37935	30579
1985	427145	107366	96629	66670	11025	108200	-19768	10811
1986	427145	109353	98418	66670	11797	53200	36202	47013
1987	427145	105222	94700	66670	12623	53300	36515	83528
1988	427145	100439	90395	66670	13507	53300	36921	120449
1989	427145	94950	85455	66670	14452	53200	37417	157866
1990	427145	88692	79823	66670	15464	108300	-17297	140569
1991	427145	87135	78422	66670	16546	108300	-16371	124198
1992	427145	84710	76239	66670	17704	53300	39545	163743
1993	427145	75858	68272	66670	18943	93500	-301	163442
1994	427145	70032	63029	66670	20269	23500	70442	233884
1995	427145	56144	50530	66670	21688	23500	70472	304356
1996	427145	41120	37008	66670	23206	23500	70488	374844
1997	427145	24880	22392	66670	24830	23500	70488	445332
1998	427145	7338	6604	66670	26568	77200	16772	462104
1999	427145	-6227	0	66670	28428	67900	20971	483075
2000	427145	-22212	0	66670	30418	82000	-7124	475951
2001	427145	-38380	0	66670	32547	8900	51937	527888
2002	427145	-63564	0	66670	34825	8900	29031	556919
2003	427145	-90574	0	66670	37263	8900	4459	561378
2004	427145	-119536	0	66670	39871	8900	-21895	539483
2005	427145	-150589	0	66670	42662	152000	-193257	346226

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.00	427145	103000	112000	66670	0	145475	323
1983	85429	5.00	427145	110210	107333	66670	0	142932	317
1984	85429	5.00	427145	117925	102666	66670	0	139884	310
1985	85429	5.00	427145	126179	97999	66670	0	136297	302
1986	85429	5.00	427145	135012	93332	66670	0	132131	293
1987	85429	5.00	427145	144463	88666	66670	0	127346	282
1988	85429	5.00	427145	154576	83999	66670	0	121900	270
1989	85429	5.00	427145	165395	79332	66670	0	115748	257
1990	85429	5.00	427145	176973	74665	66670	0	108837	241
1991	85429	5.00	427145	189360	69998	66670	0	101117	224
1992	85429	5.00	427145	202615	65331	66670	0	92529	205
1993	85429	5.00	427145	216797	60664	66670	0	83014	184
1994	85429	5.00	427145	231973	55997	66670	0	72505	161
1995	85429	5.00	427145	248211	51330	66670	0	60934	135
1996	85429	5.00	427145	265585	46663	66670	0	48227	107
1997	85429	5.00	427145	284175	41997	66670	0	34303	76
1998	85429	5.00	427145	304067	37330	66670	0	19078	42
1999	85429	5.00	427145	325352	32663	66670	0	2460	5
2000	85429	5.00	427145	348127	27996	66670	0	-15648	0
2001	85429	5.00	427145	372495	23329	66670	0	-35349	0
2002	85429	5.00	427145	398569	18662	66670	0	-56756	0
2003	85429	5.00	427145	426469	13995	66670	0	-79989	0
2004	85429	5.00	427145	456321	9328	66670	0	-105174	0
2005	85429	5.00	427145	488264	4661	66670	0	-132450	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	427145	145475	130928	66670	9000	66670	23547	23547
1983	427145	142932	128639	66670	9630	66670	23923	47470
1984	427145	139884	125896	66670	10304	66670	24292	71762
1985	427145	136297	122667	66670	11025	66670	24655	96417
1986	427145	132131	118918	66670	11797	66670	25010	121427
1987	427145	127346	114611	66670	12623	66670	25358	146785
1988	427145	121900	109710	66670	13507	66670	25697	172482
1989	427145	115748	104173	66670	14452	66670	26027	198509
1990	427145	108837	97953	66670	15464	66670	26348	224857
1991	427145	101117	91005	66670	16546	66670	26658	251515
1992	427145	92529	83276	66670	17704	66670	26957	278472
1993	427145	83014	74713	66670	18943	66670	27244	305716
1994	427145	72505	65255	66670	20269	66670	27519	333235
1995	427145	60934	54841	66670	21688	66670	27781	361016
1996	427145	48227	43404	66670	23206	66670	28029	389045
1997	427145	34303	30873	66670	24830	66670	28260	417305
1998	427145	19078	17170	66670	26568	66670	28476	445781
1999	427145	2460	2214	66670	28428	66670	28674	474455
2000	427145	-15648	0	66670	30418	66670	14770	489225
2001	427145	-35349	0	66670	32547	66670	-2802	486423
2002	427145	-56756	0	66670	34825	66670	-21931	464492
2003	427145	-79989	0	66670	37263	66670	-42726	421766
2004	427145	-105174	0	66670	39871	66670	-65303	356463
2005	427145	-132450	0	66670	42662	66670	-89788	266675

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.25	448502	92500	145000	60147	0	150855	335
1983	85429	5.25	448502	98975	138985	60147	0	150395	334
1984	85429	5.25	448502	105904	132971	60147	0	149480	332
1985	85429	5.25	448502	113317	126956	60147	0	148082	329
1986	85429	5.25	448502	121250	120941	60147	0	146164	324
1987	85429	5.25	448502	129738	114927	60147	0	143690	319
1988	85429	5.25	448502	138821	108912	60147	0	140622	312
1989	85429	5.25	448502	148538	102897	60147	0	136920	304
1990	85429	5.25	448502	158937	96882	60147	0	132536	294
1991	85429	5.25	448502	170062	90868	60147	0	127425	283
1992	85429	5.25	448502	181966	84853	60147	0	121536	270
1993	85429	5.25	448502	194704	78838	60147	0	114813	255
1994	85429	5.25	448502	208334	72824	60147	0	107197	238
1995	85429	5.25	448502	222917	66809	60147	0	98629	219
1996	85429	5.25	448502	238521	60794	60147	0	89040	197
1997	85429	5.25	448502	255217	54780	60147	0	78358	174
1998	85429	5.25	448502	273082	48765	60147	0	66508	147
1999	85429	5.25	448502	292198	42750	60147	0	53407	118
2000	85429	5.25	448502	312652	36735	60147	0	38968	86
2001	85429	5.25	448502	334537	30721	60147	0	23097	51
2002	85429	5.25	448502	357954	24706	60147	0	5695	12
2003	85429	5.25	448502	383011	18691	60147	0	-13347	0
2004	85429	5.25	448502	409821	12677	60147	0	-34143	0
2005	85429	5.25	448502	438508	6662	60147	0	-56815	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1450000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 75000   DIRECT EXPENSE: 9000

Schedule 26B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	448502	150855	135770	60147	8500	60147	23585	23585
1983	448502	150395	135356	60147	9095	60147	24134	47719
1984	448502	149480	134532	60147	9732	60147	24680	72399
1985	448502	148082	133274	60147	10413	60147	25221	97620
1986	448502	146164	131548	60147	11142	60147	25758	123378
1987	448502	143690	129321	60147	11922	60147	26291	149669
1988	448502	140622	126560	60147	12757	60147	26819	176488
1989	448502	136720	123228	60147	13650	60147	27342	203830
1990	448502	132536	119282	60147	14606	60147	27860	231690
1991	448502	127425	114683	60147	15628	60147	28370	260060
1992	448502	121536	109382	60147	16722	60147	28876	288936
1993	448502	114813	103332	60147	17893	60147	29374	318310
1994	448502	107197	96477	60147	19146	60147	29866	348176
1995	448502	98629	88766	60147	20486	60147	30349	378525
1996	448502	89040	80136	60147	21920	60147	30824	409349
1997	448502	78358	70522	60147	23454	60147	31290	440639
1998	448502	66508	59857	60147	25096	60147	31747	472386
1999	448502	53407	48066	60147	26853	60147	32194	504580
2000	448502	38968	35071	60147	28733	60147	32630	537210
2001	448502	23097	20787	60147	30744	60147	33054	570264
2002	448502	5695	5126	60147	32896	60147	33465	603729
2003	448502	-13347	0	60147	35199	60147	21852	625581
2004	448502	-34143	0	60147	37663	60147	3520	629101
2005	448502	-56815	0	60147	40299	60147	-16516	612585

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1450000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.50	469860	92500	160000	66667	0	150693	334
1983	85429	5.50	469860	98975	153333	66667	0	150885	335
1984	85429	5.50	469860	105904	146667	66667	0	150622	334
1985	85429	5.50	469860	113317	140000	66667	0	149876	333
1986	85429	5.50	469860	121250	133333	66667	0	148610	330
1987	85429	5.50	469860	129738	126667	66667	0	146788	326
1988	85429	5.50	469860	138821	120000	66667	0	144372	320
1989	85429	5.50	469860	148538	113333	66667	0	141322	314
1990	85429	5.50	469860	158937	106666	66667	0	137590	305
1991	85429	5.50	469860	170062	100000	66667	0	133131	295
1992	85429	5.50	469860	181966	93333	66667	0	127894	284
1993	85429	5.50	469860	194704	86666	66667	0	121823	270
1994	85429	5.50	469860	208334	80000	66667	0	114859	255
1995	85429	5.50	469860	222917	73333	66667	0	106943	237
1996	85429	5.50	469860	238521	66666	66667	0	98006	217
1997	85429	5.50	469860	255217	60000	66667	0	87976	195
1998	85429	5.50	469860	273082	53333	66667	0	76778	170
1999	85429	5.50	469860	292198	46666	66667	0	64329	142
2000	85429	5.50	469860	312652	39999	66667	0	50542	112
2001	85429	5.50	469860	334537	33333	66667	0	35323	78
2002	85429	5.50	469860	357954	26666	66667	0	18573	41
2003	85429	5.50	469860	383011	19999	66667	0	183	0
2004	85429	5.50	469860	409821	13333	66667	0	-19961	0
2005	85429	5.50	469860	438508	6666	66667	0	-41981	0

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1600000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 75000   DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	469860	150693	135624	66667	8500	66667	23569	23569
1983	469860	150885	135797	66667	9095	66667	24183	47752
1984	469860	150622	135560	66667	9732	66667	24794	72546
1985	469860	149876	134888	66667	10413	66667	25401	97947
1986	469860	148610	133749	66667	11142	66667	26003	123950
1987	469860	146788	132109	66667	11922	66667	26601	150551
1988	469860	144372	129935	66667	12757	66667	27194	177745
1989	469860	141322	127190	66667	13650	66667	27782	205527
1990	469860	137590	123831	66667	14606	66667	28365	233892
1991	469860	133131	119818	66667	15628	66667	28941	262833
1992	469860	127894	115105	66667	16722	66667	29511	292344
1993	469860	121823	109641	66667	17893	66667	30075	322419
1994	469860	114859	103373	66667	19146	66667	30632	353051
1995	469860	106743	96247	66667	20486	66667	31180	384231
1996	469860	98006	88205	66667	21920	66667	31721	415952
1997	469860	87976	79178	66667	23454	66667	32252	448204
1998	469860	76778	69100	66667	25096	66667	32774	480978
1999	469860	64329	57896	66667	26853	66667	33286	514264
2000	469860	50542	45488	66667	28733	66667	33787	548051
2001	469860	35323	31791	66667	30744	66667	34276	582327
2002	469860	18573	16716	66667	32896	66667	34753	617080
2003	469860	183	165	66667	35199	66667	35217	652297
2004	469860	-19961	0	66667	37663	66667	17702	669999
2005	469860	-41981	0	66667	40299	66667	-1682	668317

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.50	469860	92500	150000	62500	0	164860	366
1983	85429	5.50	469860	98975	143750	62500	0	164635	365
1984	85429	5.50	469860	105904	137500	62500	0	163956	364
1985	85429	5.50	469860	113317	131250	62500	0	162793	361
1986	85429	5.50	469860	121250	125000	62500	0	161110	358
1987	85429	5.50	469860	129738	118750	62500	0	158872	353
1988	85429	5.50	469860	138821	112500	62500	0	156039	346
1989	85429	5.50	469860	148538	106250	62500	0	152572	339
1990	85429	5.50	469860	158937	100000	62500	0	148423	329
1991	85429	5.50	469860	170062	93750	62500	0	143548	318
1992	85429	5.50	469860	181966	87500	62500	0	137894	306
1993	85429	5.50	469860	194704	81250	62500	0	131406	292
1994	85429	5.50	469860	208334	75000	62500	0	124026	275
1995	85429	5.50	469860	222917	68750	62500	0	115693	257
1996	85429	5.50	469860	238521	62500	62500	0	106339	236
1997	85429	5.50	469860	255217	56250	62500	0	95893	213
1998	85429	5.50	469860	273082	50000	62500	0	84278	187
1999	85429	5.50	469860	292198	43750	62500	0	71412	158
2000	85429	5.50	469860	312652	37500	62500	0	57208	127
2001	85429	5.50	469860	334537	31250	62500	0	41573	92
2002	85429	5.50	469860	357954	25000	62500	0	24406	54
2003	85429	5.50	469860	383011	18750	62500	0	5599	12
2004	85429	5.50	469860	409821	12500	62500	0	-14961	0
2005	85429	5.50	469860	438508	6250	62500	0	-37398	0

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

Schedule 28B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	469860	164860	148374	62500	8500	62500	24986	24986
1983	469860	164635	148172	62500	9095	62500	25558	50544
1984	469860	163956	147560	62500	9732	62500	26128	76672
1985	469860	162793	146514	62500	10413	62500	26692	103364
1986	469860	161110	144999	62500	11142	62500	27253	130617
1987	469860	158872	142985	62500	11922	62500	27809	158426
1988	469860	156039	140435	62500	12757	62500	28361	186787
1989	469860	152572	137315	62500	13650	62500	28907	215694
1990	469860	148423	133581	62500	14606	62500	29448	245142
1991	469860	143548	129193	62500	15628	62500	29983	275125
1992	469860	137894	124105	62500	16722	62500	30511	305636
1993	469860	131406	118265	62500	17893	62500	31034	336670
1994	469860	124026	111623	62500	19146	62500	31549	368219
1995	469860	115693	104124	62500	20486	62500	32055	400274
1996	469860	106339	95705	62500	21920	62500	32554	432828
1997	469860	95893	86304	62500	23454	62500	33043	465871
1998	469860	84278	75850	62500	25096	62500	33524	499395
1999	469860	71412	64271	62500	26853	62500	33994	533389
2000	469860	57208	51487	62500	28733	62500	34454	567843
2001	469860	41573	37416	62500	30744	62500	34901	602744
2002	469860	24406	21965	62500	32896	62500	35337	638081
2003	469860	5599	5039	62500	35199	62500	35759	673840
2004	469860	-14961	0	62500	37663	62500	22702	696542
2005	469860	-37398	0	62500	40299	62500	2901	699443

INTEREST RATE: 1000   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1500000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 75000   DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.50	469860	92500	112000	66667	0	198693	441
1983	85429	5.50	469860	98975	107333	66667	0	196885	437
1984	85429	5.50	469860	105904	102667	66667	0	194622	432
1985	85429	5.50	469860	113317	98000	66667	0	191876	426
1986	85429	5.50	469860	121250	93333	66667	0	188610	419
1987	85429	5.50	469860	129738	88667	66667	0	184788	410
1988	85429	5.50	469860	138821	84000	66667	0	180372	400
1989	85429	5.50	469860	148538	79333	66667	0	175322	389
1990	85429	5.50	469860	158937	74666	66667	0	169590	376
1991	85429	5.50	469860	170062	70000	66667	0	163131	362
1992	85429	5.50	469860	181966	65333	66667	0	155894	346
1993	85429	5.50	469860	194704	60666	66667	0	147823	328
1994	85429	5.50	469860	208334	56000	66667	0	138859	308
1995	85429	5.50	469860	222917	51333	66667	0	128943	286
1996	85429	5.50	469860	238521	46666	66667	0	118006	262
1997	85429	5.50	469860	255217	42000	66667	0	105976	235
1998	85429	5.50	469860	273082	37333	66667	0	92778	206
1999	85429	5.50	469860	292198	32666	66667	0	78329	174
2000	85429	5.50	469860	312652	28000	66667	0	62541	138
2001	85429	5.50	469860	334537	23333	66667	0	45323	100
2002	85429	5.50	469860	357954	18666	66667	0	26573	59
2003	85429	5.50	469860	383011	14000	66667	0	6182	13
2004	85429	5.50	469860	409821	9333	66667	0	-15961	0
2005	85429	5.50	469860	438508	4666	66667	0	-39981	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	469860	198693	178824	66667	8500	66667	28369	28369
1983	469860	196885	177197	66667	9095	66667	28783	57152
1984	469860	194622	175160	66667	9732	66667	29194	86346
1985	469860	191876	172688	66667	10413	66667	29601	115947
1986	469860	188610	169749	66667	11142	66667	30003	145950
1987	469860	184788	166309	66667	11922	66667	30401	176351
1988	469860	180372	162335	66667	12757	66667	30794	207145
1989	469860	175322	157790	66667	13650	66667	31182	238327
1990	469860	169590	152631	66667	14606	66667	31565	269892
1991	469860	163131	146818	66667	15628	66667	31941	301833
1992	469860	155894	140305	66667	16722	66667	32311	334144
1993	469860	147823	133041	66667	17893	66667	32675	366819
1994	469860	138859	124973	66667	19146	66667	33032	399851
1995	469860	128943	116049	66667	20486	66667	33380	433231
1996	469860	118006	106205	66667	21920	66667	33721	466952
1997	469860	105976	95378	66667	23454	66667	34052	501004
1998	469860	92778	83500	66667	25096	66667	34374	535378
1999	469860	78329	70496	66667	26853	66667	34686	570064
2000	469860	62541	56287	66667	28733	66667	34987	605051
2001	469860	45323	40791	66667	30744	66667	35276	640327
2002	469860	26573	23916	66667	32896	66667	35553	675880
2003	469860	6182	5564	66667	35199	66667	35817	711697
2004	469860	-15961	0	66667	37663	66667	21702	733399
2005	469860	-39981	0	66667	40299	66667	318	733717

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.50	469860	103000	105000	62500	0	199360	443
1983	85429	5.50	469860	110210	100625	62500	0	196525	436
1984	85429	5.50	469860	117925	96250	62500	0	193185	429
1985	85429	5.50	469860	126179	91875	62500	0	189306	420
1986	85429	5.50	469860	135012	87500	62500	0	184848	410
1987	85429	5.50	469860	144463	83125	62500	0	179772	399
1988	85429	5.50	469860	154576	78750	62500	0	174034	386
1989	85429	5.50	469860	165395	74375	62500	0	167590	372
1990	85429	5.50	469860	176973	70000	62500	0	160387	356
1991	85429	5.50	469860	189360	65625	62500	0	152375	338
1992	85429	5.50	469860	202615	61250	62500	0	143495	318
1993	85429	5.50	469860	216797	56875	62500	0	133688	297
1994	85429	5.50	469860	231973	52500	62500	0	122887	273
1995	85429	5.50	469860	248211	48125	62500	0	111024	246
1996	85429	5.50	469860	265585	43750	62500	0	98025	217
1997	85429	5.50	469860	284175	39375	62500	0	83810	186
1998	85429	5.50	469860	304067	35000	62500	0	68293	151
1999	85429	5.50	469860	325352	30625	62500	0	51383	114
2000	85429	5.50	469860	348127	26250	62500	0	32983	73
2001	85429	5.50	469860	372495	21875	62500	0	12990	28
2002	85429	5.50	469860	398569	17500	62500	0	-8709	0
2003	85429	5.50	469860	426469	13125	62500	0	-32234	0
2004	85429	5.50	469860	456321	8750	62500	0	-57711	0
2005	85429	5.50	469860	488264	4375	62500	0	-85279	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	469860	199360	179424	62500	9000	62500	28936	28936
1983	469860	196525	176873	62500	9630	62500	29282	58218
1984	469860	193185	173867	62500	10304	62500	29622	87840
1985	469860	189306	170375	62500	11025	62500	29956	117796
1986	469860	184848	166363	62500	11797	62500	30282	148078
1987	469860	179772	161795	62500	12623	62500	30600	178678
1988	469860	174034	156631	62500	13507	62500	30910	209588
1989	469860	167590	150831	62500	14452	62500	31211	240799
1990	469860	160387	144348	62500	15464	62500	31503	272302
1991	469860	152375	137138	62500	16546	62500	31783	304085
1992	469860	143495	129146	62500	17704	62500	32053	336138
1993	469860	133688	120319	62500	18943	62500	32312	368450
1994	469860	122887	110598	62500	20269	62500	32558	401008
1995	469860	111024	99922	62500	21688	62500	32790	433798
1996	469860	98025	88223	62500	23206	62500	33008	466806
1997	469860	83810	75429	62500	24830	62500	33211	500017
1998	469860	68293	61464	62500	26568	62500	33397	533414
1999	469860	51383	46245	62500	28428	62500	33566	566980
2000	469860	32983	29685	62500	30418	62500	33716	600696
2001	469860	12990	11691	62500	32547	62500	33846	634542
2002	469860	-8709	0	62500	34825	62500	26116	660658
2003	469860	-32234	0	62500	37263	62500	5029	665687
2004	469860	-57711	0	62500	39871	62500	-17840	647847
2005	469860	-85279	0	62500	42662	62500	-42617	605230

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1500000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 85000 DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	5.50	469860	92500	101500	60417	0	215443	478
1983	85429	5.50	469860	98975	97271	60417	0	213197	473
1984	85429	5.50	469860	105904	93042	60417	0	210497	467
1985	85429	5.50	469860	113317	88812	60417	0	207314	460
1986	85429	5.50	469860	121250	84583	60417	0	203610	452
1987	85429	5.50	469860	129738	80354	60417	0	199351	443
1988	85429	5.50	469860	138821	76125	60417	0	194497	432
1989	85429	5.50	469860	148538	71896	60417	0	189009	420
1990	85429	5.50	469860	158937	67666	60417	0	182840	406
1991	85429	5.50	469860	170062	63437	60417	0	175944	390
1992	85429	5.50	469860	181966	59208	60417	0	168269	373
1993	85429	5.50	469860	194704	54979	60417	0	159760	355
1994	85429	5.50	469860	208334	50750	60417	0	150359	334
1995	85429	5.50	469860	222917	46521	60417	0	140005	311
1996	85429	5.50	469860	238521	42291	60417	0	128631	285
1997	85429	5.50	469860	255217	38062	60417	0	116164	258
1998	85429	5.50	469860	273082	33833	60417	0	102528	227
1999	85429	5.50	469860	292198	29604	60417	0	87641	194
2000	85429	5.50	469860	312652	25375	60417	0	71416	158
2001	85429	5.50	469860	334537	21145	60417	0	53761	119
2002	85429	5.50	469860	357954	16916	60417	0	34573	76
2003	85429	5.50	469860	383011	12687	60417	0	13745	30
2004	85429	5.50	469860	409821	8458	60417	0	-8836	0
2005	85429	5.50	469860	438508	4229	60417	0	-33294	0

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1450000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	469860	215443	193899	60417	8500	60417	30044	30044
1983	469860	213197	191877	60417	9095	60417	30415	60459
1984	469860	210497	189447	60417	9732	60417	30782	91241
1985	469860	207314	186583	60417	10413	60417	31144	122385
1986	469860	203610	183249	60417	11142	60417	31503	153888
1987	469860	199351	179416	60417	11922	60417	31857	185745
1988	469860	194497	175047	60417	12757	60417	32207	217952
1989	469860	189009	170108	60417	13650	60417	32551	250503
1990	469860	182840	164556	60417	14606	60417	32890	283393
1991	469860	175944	158350	60417	15628	60417	33222	316615
1992	469860	168269	151442	60417	16722	60417	33549	350164
1993	469860	159760	143784	60417	17893	60417	33869	384033
1994	469860	150359	135323	60417	19146	60417	34182	418215
1995	469860	140005	126005	60417	20486	60417	34486	452701
1996	469860	128631	115768	60417	21920	60417	34783	487484
1997	469860	116164	104548	60417	23454	60417	35070	522554
1998	469860	102528	92275	60417	25096	60417	35349	557903
1999	469860	87641	78877	60417	26853	60417	35617	593520
2000	469860	71416	64274	60417	28733	60417	35875	629395
2001	469860	53761	48385	60417	30744	60417	36120	665515
2002	469860	34573	31116	60417	32896	60417	36353	701868
2003	469860	13745	12371	60417	35199	60417	36573	738441
2004	469860	-8836	0	60417	37663	60417	28827	767268
2005	469860	-33294	0	60417	40299	60417	7005	774273

INTEREST RATE: 700   TAX RATE: 0   INFLATION RATE: 070

PIPELINE VALUE: 1450000   POPULATION RATE: 000   POPULATION: 405

ALYESKA EXPENSE: 75000   DIRECT EXPENSE: 9000

ALASKA GSOP

NET INCOME

($000)

YEAR	DELIVERY VOLUMES (000 BBLS)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
		$	$	$	$	$	$	$	ACTUAL $
1982	85429	6.35	542474	92500	160000	66667	0	223307	496
1983	85429	6.35	542474	98975	153333	66667	0	223499	496
1984	85429	6.35	542474	105904	146667	66667	0	223236	496
1985	85429	6.35	542474	113317	140000	66667	0	222490	494
1986	85429	6.35	542474	121250	133333	66667	0	221224	491
1987	85429	6.35	542474	129738	126667	66667	0	219402	487
1988	85429	6.35	542474	138821	120000	66667	0	216986	482
1989	85429	6.35	542474	148538	113333	66667	0	213936	475
1990	85429	6.35	542474	158937	106666	66667	0	210204	467
1991	85429	6.35	542474	170062	100000	66667	0	205745	457
1992	85429	6.35	542474	181966	93333	66667	0	200508	445
1993	85429	6.35	542474	194704	86666	66667	0	194437	432
1994	85429	6.35	542474	208334	80000	66667	0	187473	416
1995	85429	6.35	542474	222917	73333	66667	0	179557	399
1996	85429	6.35	542474	238521	66666	66667	0	170620	379
1997	85429	6.35	542474	255217	60000	66667	0	160590	356
1998	85429	6.35	542474	273082	53333	66667	0	149392	331
1999	85429	6.35	542474	292198	46666	66667	0	136943	304
2000	85429	6.35	542474	312652	39999	66667	0	123156	273
2001	85429	6.35	542474	334537	33333	66667	0	107937	239
2002	85429	6.35	542474	357954	26666	66667	0	91187	202
2003	85429	6.35	542474	383011	19999	66667	0	72797	161
2004	85429	6.35	542474	409821	13333	66667	0	52653	117
2005	85429	6.35	542474	438508	6666	66667	0	30633	68

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

Schedule 32B

ALASKA GSOP

CASH FLOW

($000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDER DISTRIBUTION	DEPRECIATION AND AMORTIZATION	DISMANTLING RESERVE	PRINCIPAL PAYMENTS	NET CASH FLOW	CUMULATIVE CASH FLOW
	$	$	$	$	$	$	$	$
1982	542474	223307	200976	66667	8500	66667	30831	30831
1983	542474	223499	201149	66667	9095	66667	31445	62276
1984	542474	223236	200912	66667	9732	66667	32056	94332
1985	542474	222490	200241	66667	10413	66667	32662	126994
1986	542474	221224	199102	66667	11142	66667	33264	160258
1987	542474	219402	197462	66667	11922	66667	33862	194120
1988	542474	216986	195287	66667	12757	66667	34456	228576
1989	542474	213936	192542	66667	13650	66667	35044	263620
1990	542474	210204	189184	66667	14606	66667	35626	299246
1991	542474	205745	185171	66667	15628	66667	36202	335448
1992	542474	200508	180457	66667	16722	66667	36773	372221
1993	542474	194437	174993	66667	17893	66667	37337	409558
1994	542474	187473	168726	66667	19146	66667	37893	447451
1995	542474	179557	161601	66667	20486	66667	38442	485893
1996	542474	170620	153558	66667	21920	66667	38982	524875
1997	542474	160590	144531	66667	23454	66667	39513	564388
1998	542474	149392	134453	66667	25096	66667	40035	604423
1999	542474	136943	123249	66667	26853	66667	40547	644970
2000	542474	123156	110840	66667	28733	66667	41049	686019
2001	542474	107937	97143	66667	30744	66667	41538	727557
2002	542474	91187	82068	66667	32896	66667	42015	769572
2003	542474	72797	65517	66667	35199	66667	42479	812051
2004	542474	52653	47388	66667	37663	66667	42928	854979
2005	542474	30633	27570	66667	40299	66667	43362	898341

INTEREST RATE: 1000 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

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

A Basic Report

British Petroleum

Joel D. Fischer
Constantine D. Fliakos

January 20, 1978

Price (1/20/78)	Range 1977-1978	Earnings Per Share 1976	1977E	1978E	P/E Ratio 1977E	1978E	Yield	Return on Investment
$15 3/8	16¾ - 13 3/8	$0.79	$1.20	$2.45	12.8	6.3	2.3%	6.3%

POINT OF VIEW

The strong earnings surge that we foresee for BP--an annual rise of more than 35% in the five years between 1976 and 1981--and the prospect for the relaxation of prevailing U.K. government restrictions on corporate dividends, make BP a very attractive investment, in our opinion. Moreover, last year's successful sale of a large portion of the company's shares owned by the British government has removed a major uncertainty weighing on the stock.

The sharp growth forecast for earnings will come mainly from two areas:

- The company's strong position in the North Sea is already a major contributor to earnings. It should account for 40% of total earnings in 1981.

- Earnings from the Alaskan North Slope will begin to build this year. We estimate that by 1981, the U.S. will account for 45% of BP's earnings.

We conclude that BP represents an excellent investment value that offers the prospect of an annual rate of return to the investor of more than 20% in the next several years.

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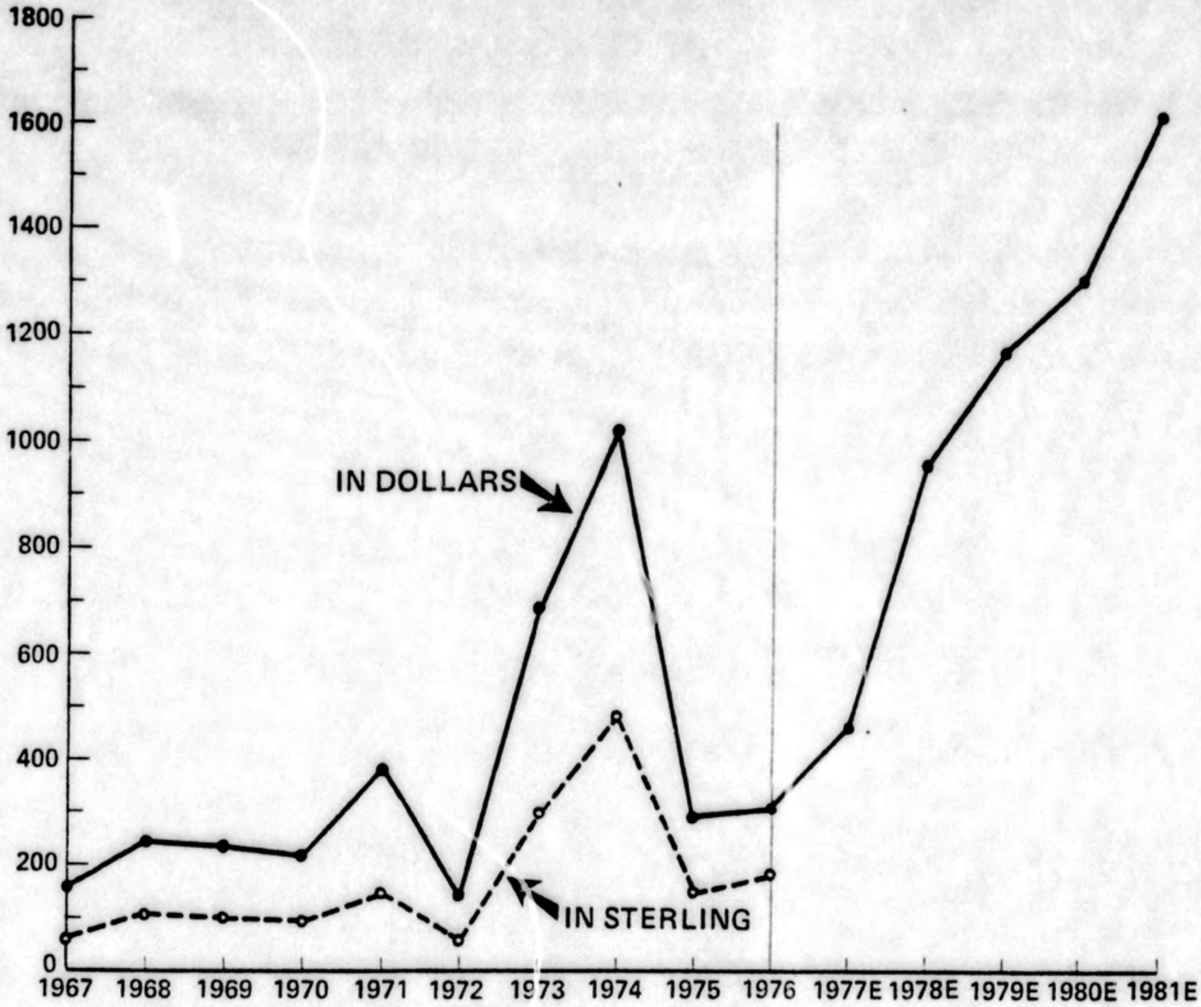
CHART 1

EARNINGS
In Millions



Note: Earnings are before extraordinary items

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SUMMARY OF EARNINGS

We estimate that BP's earnings jumped 50% in 1977 to $465 million from $305 million in 1976 (Table 1). This year, we expect earnings to more than double to $950 million. By 1981, earnings should be around $1.6 billion, which is more than five times the level of earnings in 1976. The annual growth rate between 1976 and 1981 will amount to over 35% a year. On a per share basis, we see earnings rising to $4.15 in 1981 compared with $0.79 in 1976.

The level of earnings that we project for BP will be surpassed only by Exxon and Royal Dutch Petroleum among the international oils, a dramatic change from the present pecking order, which places BP behind any of its major competitors. Two major areas are responsible for the surge in BP's earnings:

- In 1977, the source of the earnings gain was the North Sea. We estimate that profits from that area totalled almost $450 million, compared with less than $150 million in 1976.

- North Sea earnings will continue to expand in the next several years. However, beginning in 1978, the major reason for the earnings surge will be the buildup of production on the North Slope of Alaska. BP's earnings in the U.S., which reflect mainly the buildup of production and transportation of North Slope oil, are expected to jump to $300 million this year, compared with $35 million in 1977, with a further increase to more than $700 million in 1981.

The refining, marketing and transportation business, which has been depressed for the industry overall, has been particularly weak for BP:

- We estimate that in 1976 this segment of the business, including unallocated corporate and other expenses, showed a loss of $135 million. In addition to conditions of excess capacity facing the industry overall, BP has been hurt by the relatively heavy concentration of its business in the especially weak European markets, and a large exposure to residual fuel oil, which has also been an especially depressed product.

- Losses in refining, marketing, and transportation--including unallocated corporate items--widened to an estimated $160 million in 1977. The worsening occurred even though results last year benefited from inventory profits realized in the first half.

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BRITISH PETROLEUM
Summary of Earnings
(Dollars in Millions)

TABLE 1

	1975	1976	1977E	1978E	1979E	1980E	1981E
United States	$25	$35	$35	$300	$410	$470	$710
Foreign							
Petroleum:							
North Sea production	-	$145	$440	$555	$600	$635	$645
Other production	$190	125	125	130	135	140	140
Total	$190	$270	$565	$685	$735	$775	$785
Downstream[a]	(20)	(135)	(160)	(75)	(50)	(25)	-
Chemicals	55	50	40	40	45	50	55
Advance corporation tax credit	-	120	-	-	-	-	-
Other[b]	45	(35)	(15)	-	20	30	50
	$295	$305	$465	$950	$1,160	$1,300	$1,600
EPS	$0.76	$0.79	$1.20	$2.45	$3.00	$3.35	$4.15

2

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

Notes: Historical earnings are translated from the underlying sterling accounts based on the sterling/dollar exchange rate prevailing at the end of each year.

a. The Downstream earnings category includes corporate overhead and other charges and credits which have not been allocated by function.

b. Includes interest income and expense except for TAPS financing which is included with U.S. earnings.

Earnings were also helped from a reversal in last year's accounts of a charge incurred in Australia in previous years.

On the negative side, the following major developments affected last year's results:

- Market conditions in Europe remained weak.

- During a major part of the year, BP's operations were adversely influenced by the two-tier OPEC price structure, because the company's crude oil supplies have been drawn from the higher-priced OPEC countries.

- Finally, BP's results have been adversely affected by the strengthened sterling. The company has apparently incurred large currency losses mainly in the translation into sterling of dollar cash balances held in the U.K. The precise extent of those losses introduces considerable uncertainty in the estimate of last year's earnings.

- Looking ahead, we expect improvement in this segment's earnings. In the first place, it is reasonable to assume that currency fluctuations will have a less severe impact on earnings than in 1977. Indeed, losses may revert to gains should the pound weaken once again. From an operating viewpoint, we expect capacity utilization rates in downstream operations to show gradual improvement in the coming years for the industry overall. Unlike 1977--a year which was saddled by two-tier prices and excess oil supplies--we are looking for an improved supply/demand balance for oil and more stability and firmness in downstream markets. Moreover, the recent OPEC price freeze should be a contributing factor to an improved business climate in downstream markets this year. Finally, BP, in particular, should begin to realize some benefits from efforts to upgrade its refining facilities, streamline its marketing operations, and reduce its tanker exposure.

In the production end of the business, outside the North Sea and the North Slope, we do not expect many changes in the company's outlook. In 1977, margins in crude oil production were affected somewhat by excess crude oil supplies. But even with an improvement in market conditions in coming years, we do not foresee the average after-tax profit margin in crude oil production exceeding $0.18 per barrel.

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TABLE 2

BRITISH PETROLEUM
U.S. and the North Sea
Contribution to Earnings Per Share

	1975	1976	1977E	1978E	1979E	1980E	1981E
U.S.	$.06	$.09	$ .09	$ .79	$1.09	$1.22	$1.87
North Sea	--	.38	1.14	1.44	1.55	1.65	1.67
Other	.70	.32	(.03)	.22	.36	.48	.61
	$.76	$.79	$1.20	$2.45	$3.00	$3.35	$4.15
				SHARE			
U.S.	8%	11%	8%	32%	36%	36%	45%
North Sea	-	48	95	59	52	49	40
Other	92	41	(3)	9	12	14	15
	100%	100%	100%	100%	100%	100%	100%

Source: Drexel Burnham Lambert Incorporated estimates and calculations.

Earnings Sensitivities

Earnings may advance at a faster pace than we are forecasting in our Base Case mainly for the following reasons: a more rapid escalation in OPEC prices, resulting in even higher margins for North Sea and North Slope production; and a more favorable and timely resolution of some of the uncertainties surrounding North Slope oil--such as the TAPS tariff and the timing relating to completion of the California-to-Texas pipeline, as well as the planned expansion of TAPS. On the upside, we would place earnings at $3.75 per share in 1980 and about $4.50 in 1981.

On the downside, a risk which we regard as modest, but, nevertheless, should be recognized, would be that downstream losses will not show the improvement that we are now forecasting, in which case earnings may barely exceed $3 per share in 1980, and will be under $4 in 1981.

On balance, we believe that the odds favor surprises on the upside.

Earnings gains are expected in the natural gas business, but rising exploration expenses should be a negative influence on profits. On balance, we expect after-tax profits in the petroleum exploration and production end of the business to total $125 million in 1977 and to rise to $140 million by 1980/1981.

Chemical profits amounted to about $50 million in 1976. We estimate lower earnings for 1977 because of weak market conditions, particularly in the second half of the year. Profits are seen recovering to $55 million by 1981, reflecting improved business conditions, as well as benefits from expansion plans already under way.

The other category shown in our earnings model of Table 1 includes interest income and expenses and other miscellaneous income. The radical shift in after-tax earnings from a profit of $45 million in 1975 to a loss of $35 million in 1976 chiefly reflects a sharp jump of about $125 million in pretax interest expenses and, to a lesser extent, a reduction in interest income because of lower cash balces. The improvement shown last year, which we see continuing in the coming years, reflects lower levels of interest expense as the company liquidates a portion of the large financial obligations incurred in the development of its North Slope and North Sea interests. Also, the coal business should begin making a contribution to profits, particularly as a result of the recent acquisition of coal interests in Australia.

Earnings Contribution of Major New Areas

The contribution to BP's earnings per share of North Sea production and its growing U.S. interests are summarized in Table 2:

- The North Sea began contributing to earnings in 1976. We estimate that earnings will rise to about $1.65 in 1981 and will account for 40% of total earnings.

- U.S. earnings, mainly because of the North Slope of Alaska, are seen rising to more than $1.85 per share in 1981, which will account for 45% of total profits.

These two new sources of earnings together will be responsible for 85% of BP's total earnings in 1981, which means that in addition to the surge in earnings, their structure will have also changed drastically in the direction of improved quality.

NORTH SEA OIL PRODUCTION

BP's North Sea crude oil production, which began in 1975 from the Forties Field, averaged just under 400,000 barrels a day in 1977, compared with 180,000 barrels a day in 1976. (See Table 3). Overall production from the Forties Field has increased from 400,000 barrels a day in the first nine months of 1977 to 450,000 barrels a day in the fourth quarter. The Forties Field, one of the largest in the North Sea, is estimated to contain remaining recoverable reserves of about 1.6 billion barrels of crude oil. BP has a 96% equity interest in these reserves.

BRITISH PETROLEUM

TABLE 3

North Sea Crude Oil Production and Profits

Thousand Barrels Per Day	1975	1976	1977E	1978E	1979E	1980E	1981E
Forties (96%)	20	180	395	480	480	475	420
Ninian (15%)	--	---	---	5	25	45	50
Buchan (54%)	--	---	---	---	---	---	10
Magnus (100%)	--	---	---	---	---	---	25
	20	180	395	485	505	520	505
Million barrels		65	144	176	184	190	184
Profit margin per barrel	--	$2.25	$3.05	$3.15	$3.25	$3.35	$3.50
Profits in millions	--	$ 145	$440	$555	$600	$635	$645

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

The Ninian Field, where BP's share of oil reserves is estimated at 160 million barrels through its 15% ownership of the field, is expected to come on stream in 1978. Volumes should not amount to much this year, but BP's share of production is expected to exceed 50,000 barrels a day early in the 1980s.

BP's other interests in the United Kingdom include 100% ownership of the Magnus Field, 45% in the Andrew Field, and recently acquired interests in the Buchan, Crawford, and Bruce Fields through "farm-in" arrangements.

The Magnus Field is estimated to have recoverable reserves of 400 million barrels, with peak production estimated at 100,000 barrels a day early in the 1980s. BP also recently announced the early development of the Buchan Field in which it has a 54% interest, while the commercial viability of the Andrews Field is still being assessed. As shown in Table 3, these fields will not be contributing much to production before 1980. As they are brought on stream in the 1980s, however, they should help to offset the decline that will begin in the large Forties Field by that time. A promising new prospect for BP lies in the Norwegian waters, where a discovery has been made on a block which is 57.5% owned by BP. The area is still being appraised.

The estimated profitability per barrel of the Forties Field is shown in Table 4. Our forecast of a profit of $3.05 per barrel is based on a wellhead price of $13.80 and reflects a more-than-adequate allowance for operating costs and depreciation expenses. Conservatism is, we believe, justified in view of the strengthening trend of the pound sterling, which has the effect of raising the dollar equivalent of sterling-denominated costs. We also note that interest costs associated with the development of North Sea production are not reflected in our calculations. These expenses are included with the Other Income category in our Earnings Model.

Our earnings projections beyond 1977 assume that unit profitability for BP's North Sea production will rise to $3.50 by 1981, to reflect the prospects of a continuing rise in prices.

On balance, we expect that BP's profits from North Sea production, excluding interest expense, will rise from $145 million in 1976 to $440 million in 1977 and $645 million in 1980. On a per share basis, North Sea earnings are seen rising from $0.38 in 1976 to about $1.15 in 1977 and should exceed $1.65 in 1981.

Drexel Burnham Lambert Incorporated

BRITISH PETROLEUM TABLE 4

North Sea Profitability - Forties Field
(Dollars Per Barrel)

	Under Current Price	With Price Escalation
PROFIT PER BARREL		
Wellhead price	$13.80	$16.25
Operating cost	(0.60)	(0.65)
Depreciation	(0.95)	(0.95)
Royalty	(1.70)	(2.05)
PRT	(4.20)	(5.10)
Corporation tax	(3.30)	(3.90)
Net profit	$3.05	$3.60
PETROLEUM REVENUE TAX (PRT)		
Wellhead price	$13.80	$16.25
Royalty	(1.70)	(2.05)
Operating cost	(0.60)	(0.65)
175% of capital expenditures	(1.50)	(1.50)
Production allowance	(0.65)	(0.70)
Taxable base for PRT	$9.35	$11.35
PRT @ 45%	$4.20	$5.10
CORPORATION TAX		
Wellhead price	$13.80	$16.25
Royalty	(1.70)	(2.05)
Operating cost	(0.60)	(0.65)
Depreciation	(0.95)	(0.95)
PRT	(4.20)	(5.10)
Taxable base for corporation tax	$6.35	$7.50
Corporation tax @ 52%	$3.30	$3.90

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

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BP IN THE UNITED STATES

Summary of Earnings

BP's principal investments in the United States are an undivided interest of 15.84% in the Trans-Alaskan Pipeline System (TAPS) and its equity in Standard Oil of Ohio (Sohio). A third source of prospective earning power, which should become significant by 1981, is a royalty interest equal to 75% of Sohio's net profits realized from Prudhoe Bay production, net of state royalty, of between 600,000 barrels a day and 1,050,000 barrels a day.

We summarize BP's earnings from these sources in Tables 5 and 6. Our basic projection model (Table 5) is based on the reduced level of pipeline tariffs which were prescribed by the Interstate Commerce Commission (ICC) on June 28, 1977, despite the restoration by Court order--effective last October 21--of the higher tariffs that were initially filed by the owners of TAPS. Fourth-quarter-1977 results were dominated by the higher rates. Higher pipeline tariffs and earnings are associated, of course, with lower earnings from production at the wellhead--for given crude values at Valdez and in the Lower 48. Reduced tariffs yield an opposite effect. Under our controlling tariff assumption, which governs as of the start of 1978, estimated earnings are as follows:

- BP's interest in TAPS showed a loss last year of at least \$25 million. The pipeline makes a modest contribution, about \$3 million, to BP's 1978 earnings. By 1981, this contribution will have risen to \$85 million annually. We note that at BP's initial, higher tariff, these contributions would be \$80 million and \$160 million, respectively. (See Table 6.) Our projections allow for the fillip of BP's currently unutilized investment tax credit (ITC) on TAPS, which now amounts to about \$120 million. BP's share of the capital costs for TAPS, at an initial design capacity of 1,200,000 barrels a day, is approximately \$1.465 billion, including capitalized interest. Like Sohio, BP has financed most of this investment by debt. BP's projected share of the cost of expanding TAPS capacity to 1,500,000-1,600,000 barrels a day is \$107 million, an outlay which will yield \$10.7 million of additional ITC.

- BP's <u>net profits interest</u> in Sohio's net production from Prudhoe Bay, for volumes above 600,000 and up to 1,050,000 barrels a day, will become operative in the latter part of 1980, and will contribute significantly to earnings by 1981. At that time, we estimate that this source should be generating earnings of about $85 million a year under our assumption of modest appreciation in crude prices from 1978 to 1981.

- Finally, <u>BP's equity in Sohio</u> is estimated to have contributed $60 million in 1977. The current-year contribution is estimated at $295 million. By 1981, this contribution is projected at $540 million.

It should also be noted that these earnings reflect the benefit to Sohio's earnings from past, current, and prospective ITC. We estimate that Sohio's benefit from this source amounted to $42 million in 1977, which was only a small portion of its available ITC, including carryforwards, of about $335 million through the close of 1977. An additional $85 million of credits will probably be generated in 1978, and the amounts of available credits will probably remain substantial in 1979, 1980, and 1981 as Sohio invests in a West Coast (Long Beach) crude pipeline to Texas, expansion of TAPS capacity to 1,500,000-1,600,000 barrels a day, further field development at Prudhoe Bay, and established operations in the Lower 48. We expect ITC to be drawn upon heavily in 1978, by perhaps $200 million on our estimate, and in 1979, by $200 million to $220 million.

TABLE 5

BRITISH PETROLEUM
Projected U.S. Earnings
(Millions of Dollars)

ICC-PRESCRIBED TARIFF

Sources	Current Price Case 1977	1978	1979	1980	1981	Price Escalation Case 1978	1979	1980	1981
Equity in TAPS[a]	$(25.0)	$ 3.0	$ 30.0	$ 45.0	$ 85.0	$ 3.0	$ 30.0	$ 45.0	$ 85.0
Net profits interest in Prudhoe Bay production	-	-	-	2.0	60.0	-	-	2.0	85.0
Equity in Sohio's earnings	60.0	285.0	335.0	345.0	420.0	295.0	380.0	420.0	540.0
(Percent)	29.9%	48.3%	51.3%	52.1%	53.3%	48.3%	51.3%	52.1%	53.3%
Total	$35.0	$288.0	$365.0	$392.0	$565.0	$298.0	$410.0	$467.0	$710.0

a. Includes ITC.

TABLE 6

BRITISH PETROLEUM
Projected U.S. Earnings
(Millions of Dollars)

INITIAL TARIFFS SUBMITTED BY THE COMPANIES

Sources	Current Price Case 1977	1978	1979	1980	1981	Price Escalation Case 1978	1979	1980	1981
Equity in TAPS[a]	$(25.0)	$ 80.0	$105.0	$125.0	$160.0	$ 80.0	$105.0	$125.0	$160.0
Net profits interest in Prudhoe Bay production	-	-	-	1.0	45.0	-	-	2.0	70.0
Equity in Sohio's earnings	60.0	260.0	315.0	340.0	405.0	280.0	370.0	405.0	535.0
(Percent)	29.9%	48.3%	51.3%	52.1%	53.3%	48.3%	51.3%	52.1%	53.3%
Total	$35.0	$340.0	$420.0	$466.0	$610.0	$360.0	$475.0	$532.0	$765.0

a. Includes ITC.

Equity in Sohio

BP's equity in Sohio dates back to an agreement reached in 1969 and revised in 1974. As of January 1, 1970, BP transferred to Sohio specific leases on the North Slope, including its acreage in the Prudhoe Bay field, as well as marketing, refining, and transportation assets, which had previously been acquired by a subsidiary of BP from Atlantic Richfield in 1969. In exchange, also as of January 1, 1970, BP acquired 1,000 shares of Sohio special stock.

Those 1,000 shares were initially equivalent to 8,932,000 shares of Sohio common stock. In 1975, BP purchased 1,080,000 common shares of Sohio (of a 2,000,000-share offering) at $68 per share. The special stock plus the common stock purchased in 1975 gave BP an equity of approximately 26% in Sohio before the buildup of Alaskan production.

BP's prospective equity in Sohio will be governed by the maximum rate of sustainable net production, to be achieved by Sohio on or before January 1, 1984. Sustainable net production is defined as the daily average measured over any period of 90 successive days, of crude oil produced and saved which is delivered to pipeline or tanker for refining, sale or exchange, and for use in the United States or Canada, net of Alaska's 12½% royalty interest.

The 1,000 shares of special stock that BP acquired in 1970 will rise in Sohio common-stock equivalent shares according to the schedule shown in Table 7. Note that the increments are triggered by production increments of 50,000 barrels a day. The buildup in BP's prospective equity in the growing number of outstanding Sohio shares--common and common-equivalent--is also shown in Table 7. Relating this schedule to projected net production volumes increases BP's equity in Sohio from an estimated 29.9% in 1977 to 53.3% by 1981.

BP's equity in Sohio reached 37% in late November. On the basis of our assumptions, BP will gain majority control, 50.3% of Sohio, by May 1978. It will achieve 51.3% control in June.

BRITISH PETROLEUM

Equity in Sohio

TABLE 7

Sustainable Net Production (TB/D)	Sohio Common-Stock Equivalence of the 1,000 Special Shares (000)	Sohio Shares Outstanding[a] (000)	BP's Equity Shares[b] (000)	BP's Equity Percent
---	8,932	38,600	10,012	25.9
200	13,806	43,434	14,886	34.3
250	15,740	45,368	16,820	37.0
300	17,866	47,494	18,946	39.9
350	20,218	49,846	21,298	42.7
400	22,830	52,458	23,910	45.6
450	27,894	57,522	28,974	50.4
500	29,034	58,662	30,114	51.3
550	30,222	59,650	31,102	52.1
600	31,460	61,088	32,540	53.3

Year	Sohio Shares Outstanding[a] (000)	BP's Equity Shares[b] (000)	BP's Equity Percent
1977	41,000	12,260	29.9
1978	55,258	26,710	48.3
1979	58,662	30,114	51.3
1980	59,553	31,005	52.1
1981	61,088	32,540	53.3

a. Common and common equivalent.
b. Includes 1,080,000 shares of ordinary common purchased in 1975.

Earnings Sensitivities

In addition to the Basic Earnings Model, we have also calculated the effect that continuation of the pipeline tariffs now in effect--i.e., the initial tariffs filed by the TAPS owners--would have on BP's earnings as opposed to the reduced tariffs authorized last June by the ICC. The Supreme Court may conclude, after pending review, that the ICC acted improperly in suspending the initially proposed tariffs for TAPS. Or, on an eventual review of the substantive issues involved in the rollback of the initial tariffs, the Court may reject the commission's rate-of-return conclusions and cost-findings. (The ICC's initial decision did not modify the owners' cost data; the pending decision by the Federal Energy Regulatory Commission may revise the amount of acceptable capital costs.) In an intermediate case, the Court may accept the commission's rate-of-return criteria but predicate the tariff on higher operating and/or capital costs than the commission's successor stipulates.

As shown in Tables 5 and 6, substitution of the owners' initial rates would:

- increase BP's own pipeline earnings appreciably,
- reduce BP's prospective net profits interest in Sohio's production earnings by a moderate amount, and
- shave the dollar amount of BP's equity in Sohio's integrated earnings.

The net change by 1981 would be an increase of about $55 million in BP's total U.S. earnings, a gain of second-order significance.

Our Basic Earnings Model also reflects the assumption of a 5% annual advance in the price of Saudi Arabian light crude, beginning in mid-1978. As shown in Tables 5 and 6, this moderate escalation assumption is much more critical for Sohio and for BP than the tariff assumption. From BP's standpoint, it more than adequately compensates for the less favorable TAPS-tariff scenario. Such a price hike generates additional earnings for BP of about $145-$155 million by 1981. The two tables also show BP's projected U.S. earnings progression under the conservative assumption of flat OPEC crude prices through 1981.

Longer-Term Prospects

In the 1980s BP, as a result of its equity in Sohio, will benefit from the development of the Prudhoe Bay natural gas reserves. Sohio has an equity of 53.1% in 8.5 trillion cubic feet of solution gas in the main reservoir of the Prudhoe Bay field. (This equity interest is the same as the company's equity in the 9.7 billion barrels of crude oil and condensate reserves.) Sohio also has a 14.8% equity interest in 16.9 trillion cubic feet of gas-cap gas. Its gross reserves, therefore, amount to about 7.0 trillion cubic feet. We doubt whether the gas will begin moving to market before 1983.

ALASKA NORTH SLOPE EARNINGS

Through 1979, BP's earnings from Alaska will derive from two principal sources:

- its own equity in the Trans-Alaska Pipeline System (TAPS),
- its equity in Sohio's profits from production, TAPS, and marine transportation.

By late 1980, BP's net profits interest in Sohio's net production of more than 600,000 barrels per day (up to 1,050 thousand barrels per day) will probably become operative. In all years, BP will, of course, have an equity in Sohio's results generated from the Lower 48.

Some Problems in Estimating North Slope Earnings

At the outset, we must recognize that the period from June 20, 1977, when production began at Prudhoe Bay, through at least mid-1978 is the start-up of an enormous project, which encompasses a number of intricate functions. The start-up problems for the pipeline have been well publicized; some were avoidable, but others were not for a pipeline this long featuring exceptional automation. The future level of pipeline tariffs remains enveloped with uncertainty. So, too, does the delivered cost of foreign crude on the U.S. West and Gulf Coasts, the starting points for earnings calculations.

North Slope crude has come to market at a time when the markets for crude are exceptionally competitive. Prospective purchasers have been studying the processing and yield characteristics of the new supply. Their initial acceptance of the Prudhoe Bay crude has apparently been better than expected, but for some time to come the crude will probably be sold on a relatively short-term basis when sales are to third parties. Most of those sales have recently taken place on a one-month to three-month basis.

During the first few months of operations, tankers were brought to Valdez from the Gulf Coast, the East Coast, and as far away as the Persian Gulf. Tanker transportation charges for early movements have been correspondingly high and "front-loaded" against the wellhead value of the crude in the operators' netback calculations. Wellhead values have been depressed and variable because of transportation costs and because of variations in the monthly mix between oil delivered to the West Coast and long-haul sales to the Gulf Coast. We believe that weighted-average transportation costs will come down during 1978 and 1979 and that average value at the wellhead will rise as the crude finds greater acceptance on the West Coast--although potential West Coast absorption is bounded. An overland transportation system, say by late 1979 or the start of 1980, would increase the value at the wellhead still further.

We note that restoration of the TAPS owners' initial, higher, tariffs as of October 21 further depressed wellhead value at Prudhoe Bay.

The unfortunate explosion at Pump Station 8 on July 8 put an effective constraint on production by limiting available pipeline capacity to about 730,000 barrels per day through early 1978. If the station is repaired by the close of January, as now forecast, nominal pipeline capacity could rise as high as 1,200,000 barrels a day in 30 days. Available capacity would probably be limited to about 1,100,000 barrels a day because of temperature factors, the relative heaviness of the crude, and other constraints on pipeline efficiency. Aggregate production may advance more slowly than capacity for a short period, however, because eligible tanker capacity remains in short supply. Newly constructed U.S.-flag tankers scheduled to enter service by the summer of 1978 could substantially alleviate the shortage.

The size of the surplus on the West Coast created by possible production of 1,100,000 barrels a day will remain a critical determinant of the adequacy of projected tonnage. This surplus may be as high as 425,000-475,000 barrels a day in 1978, 400,000-450,000 barrels a day in 1979 and 1980, and on the order of 700,000-750-000 barrels a day when TAPS capacity reaches 1,500,000 barrels daily. As we observe below, however, such expansion will be predicated upon approval of an overland delivery system from the West Coast. Our estimates of the surplus allow for the new entitlements program for California to restore up to 50,000 barrels a day of recently shut-in heavy crude production.

Our conservative assumption is that Sohio will be able to market 250,000 barrels a day on the West Coast in 1978 and 1979, and 260,000 barrels a day there in 1980 and 1981. We note that the unitization agreement for the Prudhoe Bay field provides for an initial period during which Sohio may underlift, cumulatively, by up to 10 million barrels, after which period the operators may agree to reduce total production to a level that restores basic equities in current output.

Public policy decisions could help to eliminate the surplus in short order, pending completion of an overland pipeline system. Among the range of efficacious policy options are: volumetric import controls, exchanges with Canada, and exports to Japan in exchange for imports East of the Rockies, an option that appears to be precluded by the recent mood of the Congress. Concern over the size of the U.S. trade deficit may well find these options re-examined before very long.

It is important to recognize that the West Coast surplus is increased, from the standpoint of the Prudhoe Bay operators, by their present obligation to market Alaska's royalty oil. Alaska hopes to be in a position to take an important proportion of its royalty claim in kind, for refining, within about four to five years. At that time, the state will assume responsibility for marketing (including marine transportation) a share of current supply. Our projection models assume that Sohio markets all of its gross share of production through 1981.

Cost and Price Parameters Established by Public Policies

The controlling leases in Alaska provide for a state royalty of 12½% of wellhead value. The state severance tax for Prudhoe Bay wells has been established at an effective rate of 11.6%, or not less than $0.76, per net barrel. Alaska imposes an annual ad valorem tax of 2% on the assessed valuation of all exploration, production, and pipeline equipment. During 1976 and 1977, Alaska also imposed a tax on oil reserves, which is creditable against recent and future severance taxes until recovered; this credit is limited to 50 cents per dollar of current severance tax. Sohio's tax payment on reserves was $121.3 million in 1976 and approximately $140 million in 1977. The state income tax rate is 9.4%.

Alaskan crude is classified as upper-tier crude for purposes of federal price controls. Its initial price ceiling of $10.82 a barrel, based on a roughly comparable crude in Montana (from the Cut Bank field), has climbed about 78 cents a barrel through November and at the rate of inflation thereafter, in compliance with current price regulations in the United States. Purchasers of North Slope crude receive the same entitlement treatment as they would for imported crude under the ongoing crude-cost-equalization program. In combination, these two rulings find North Slope crude effectively exempted from price controls. Our working assumption is that the new entitlements penalty, effective January 1, for both North Slope and imported crude refined in California, will be shifted to consumers in that state.

The West Coast sales price for Alaskan crude is governed by the delivered cost of imported crude, adjusted for differences in quality. The resultant wellhead price is, and will probably remain for some years to come, far below the upper-tier ceiling, and that ceiling will continue to move up with the rate of inflation. The wellhead price is governed by the sales price on the West Coast or Gulf Coast, less tanker-transportation charges and pipeline tariff. For the present, operators in Alaska are further reducing the wellhead value for purposes of state royalty claims by a charge incurred in the movement of the oil from the wellhead to Pump Station 1. In Sohio's case, this field charge is 66 cents per barrel.

A federal program of oil-spill insurance has introduced an additional charge of five cents for each barrel leaving the terminal at Valdez (until a fund totaling $100 million is accumulated). This charge, paid by owners of the crude as it is loaded, also reduces the wellhead price. So, too, does an allowance for pipeline volumetric losses, recently six cents per barrel.

The pipeline tariff, which we discuss below, now varies among owners of TAPS; so, too, and even more significantly, does the average tanker cost per barrel moved, reflecting differences in markets supplied (i.e., the mix of West Coast and Gulf Coast sales) and in the composition and cost of tanker fleets. Accordingly, wellhead values vary appreciably from producer to producer (and for a given producer, from month to month). This state of affairs is undoubtedly frustrating for Alaska. Even should prescription of law eventually impose a uniform wellhead value at Prudhoe Bay, economic (netback) wellhead value and production earnings would, nevertheless, continue to vary among operators.

The Pipeline As Profit Center

Until October 20, pipeline operations were governed by tariffs that were appreciably lower than the rates that were originally filed by the owners of TAPS. The Interstate Commerce Commission (ICC) prescribed these rates on June 28, 1977. The rates were to remain in force for seven months, until January 28, 1978, while the commission conducted a comprehensive review of cost, valuation, and rate-of-return criteria. These issues will ultimately be resolved by the Supreme Court. Since creation of the new Department of Energy, responsibility for pipeline rates and for the pending review have been transferred from the ICC to the newly created Federal Energy Regulatory Commission (FERC), a largely autonomous regulatory body within the department.

On October 20, the Supreme Court ruled on a narrower issue. It stayed the ICC decision of June 28, and that stay was continued until the Court decided, on November 28, to hear the TAPS' owners charges that the ICC had acted improperly--departing from its own precedents, which called for hearings, argument, and appeal--in summarily rejecting the rates initially proposed by the owners. Since October 21, the TAPS' owners have been free to reinstate their initial rates, subject to a refund obligation for any portion later found to be excessive. After a hearing, the Supreme Court may continue its stay or find, with the appeals court in New Orleans, that the commission had acted within its authority. In that event, the reduced rates would be reintroduced.

Before long, however, the current process of review by the Supreme Court will become subordinate to the pending completion of a comprehensive analysis and formal investigation of the TAPS tariff structure by the FERC. (Until the FERC completes its investigation, the companies may retain their initially proposed rates, with continued refund obligation.) Interested parties will undoubtedly seek a review of the FERC's decision by the Supreme Court. Accordingly, the tariff issue may not be resolved for another year or two.

For a comprehensive analysis of the far-reaching issues involved in the level of tariffs for TAPS and a review of the cost and profit positions of its eight owners, please see our report on TAPS, "Trans-Alaskan Pipeline System: The Tariff Controversy and Its Manifold Implications," of July 22, 1977.

Table 8 summarizes the pipeline profits of BP and Sohio, based on the cost data they initially submitted. Profits are shown both under the tariffs they initially filed as well as under the tariffs authorized by the ICC. Unit-cost figures and the resulting earnings are predicated on throughput of 1,200,000 barrels per day (438 million barrels per year).

BRITISH PETROLEUM AND SOHIO — TABLE 8

Benchmark Pipeline Models
(Dollars Per Barrel)

	Owners' Proposed Tariffs		ICC's Authorized Tariffs	
	BP	Sohio	BP	Sohio
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	0.933	0.926	0.933	0.926
Depreciation	0.862	0.864	0.862	0.864
Removal costs	0.096	0.096	0.096	0.096
Interest	1.714	1.729	1.714	1.729
Income taxes	1.452	1.346	0.569	0.574
Earnings	$1.293	$1.199	$0.507	$0.511

The above data are reproduced solely because they govern the determination of the initial tariffs submitted by BP and Sohio as well as the reduced tariffs prescribed by the ICC. They are obsolete on a number of counts. Throughput since start-up has been less than expected. Accordingly, unit costs have been greater than anticipated. For throughputs far below the assumed 1,200,000 barrels per day, unit costs have climbed steeply. Even more important, aggregate--and a fortiori unit--operating costs during the troubled start-up period have been appreciably higher than anticipated. Capital costs, too, are proving somewhat different from those anticipated.

We note that most costs (depreciation, removal costs, and interest) are fixed. Among operating costs, system fuel and power costs are semi-variable, as are the various overheads that are included. Significantly, however, fuel and power represent only about 5% of owners' operating costs. Any savings on reduced utilization has been more than offset by the cost of retaining much more of Alyeska's operating personnel than originally contemplated. The ICC (and FERC) includes ad valorem taxes on pipeline property, a fixed cost, among operating costs. At the controlling throughput assumption of 1,200,000 barrels per day, this tax amounts to about 35 cents a barrel; at fourth-quarter throughput of about 725,000 barrels daily, this figure expanded to about 57 cents a barrel.

In recent testimony before the Federal Energy Regulatory Commission (FERC), the pipeline owners and Alyeska submitted revised cost data for 1977, 1978, and for a "normalized 1978," excluding start-up problems and assuming full-year throughput of over 1,100,000 barrels per day. We have carefully examined the new data and have incorporated it in our models of pipeline earnings under alternative tariffs. Table 9, essentially a model of fourth-quarter-1977 results, shows that the increased costs extinguished earnings even at the reinstated initial tariff levels.

BRITISH PETROLEUM AND SOHIO — TABLE 9
Fourth-Quarter 1977 Pipeline Model
(Dollars Per Barrel)

	Owners' Proposed Tariffs		ICC's Authorized Tariffs	
	BP	Sohio	BP	Sohio
	Throughput of 725,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	2.375	2.088	2.375	2.088
Depreciation	1.477	1.477	1.477	1.477
Removal costs	0.165	0.165	0.165	0.165
Interest	2.696	3.100	2.696	3.100
Income taxes	-	-	-	-
Earnings	$(0.363)	$(0.670)	$(2.032)	$(2.130)

To introduce perspective, we show in Table 10 the unit results under up-to-date cost assumptions for the initial tariffs proposed by the companies, as well as for the lower tariffs authorized by the ICC last June. We show these results for throughputs of 750,000, 800,000, 1,000,000, 1,100,000, and 1,200,000 barrels per day.

In a related exercise, we have built up the 1977 and 1978 estimates of pipeline results, quarter by quarter, to take account of the depressing influence of low utilization rates during the first several quarters of operations. Our estimates of pipeline earnings per barrel for 1977 and for 1978 are shown in Table 11.

It is useful to recall that pipeline throughput averaged little more than 300,000 barrels per day in July, when the line was being filled; however, interest costs on pipeline debt were still being capitalized (until July 31). In fact, for both financial and regulatory purposes, all costs incurred in July were capitalized. Throughput averaged about 490,000 barrels per day in August and 700,000 barrels per day in September.

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BRITISH PETROLEUM AND SOHIO

TABLE 10

Pipeline Earnings, 1978 Costs
(Dollars Per Barrel)

	Owners' Proposed Tariffs		ICC's Authorized Tariffs	
	BP	Sohio	BP	Sohio
	Throughput of 1,200,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.113	1.114	1.113	1.114
Depreciation	0.870	0.861	0.870	0.861
Removal costs	0.102	0.102	0.102	0.102
Interest	1.598	1.760	1.598	1.760
Income taxes	1.411	1.228	0.528	0.456
Earnings	$1.256	$1.095	$0.470	$0.407
	Throughput of 1,100,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.215	1.214	1.215	1.214
Depreciation	0.950	0.938	0.950	0.938
Removal costs	0.111	0.111	0.111	0.111
Interest	1.745	1.919	1.745	1.919
Income taxes	1.232	1.046	0.349	0.274
Earnings	$1.097	$0.932	$0.311	$0.244
	Throughput of 1,000,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.338	1.336	1.338	1.336
Depreciation	1.046	1.033	1.046	1.033
Removal costs	0.122	0.122	0.122	0.122
Interest	1.922	2.112	1.922	2.112
Income taxes	1.017	0.823	0.134	0.051
Earnings	$0.905	$0.734	$0.119	$0.046
	Throughput of 800,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.665	1.670	1.665	1.670
Depreciation	1.301	1.291	1.301	1.291
Removal costs	0.152	0.152	0.152	0.152
Interest	2.391	2.640	2.391	2.640
Income taxes	0.445	0.215	-	-
Earnings	$0.396	$0.192	$(0.828)	$(1.053)
	Throughput of 750,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.777	1.782	1.777	1.782
Depreciation	1.388	1.377	1.388	1.377
Removal costs	0.162	0.162	0.162	0.162
Interest	2.551	2.817	2.551	2.817
Income taxes	0.249	0.012	-	-
Earnings	$0.223	$0.010	$(1.197)	$(1.438)

BRITISH PETROLEUM AND SOHIO — TABLE 11

Pipeline Earnings, By Quarter
(Dollars Per Barrel)

	BP	Sohio
1977		
III Q[a]	\$(2.37)A	\$(2.48)A
IV Q[b]	(0.78)	(1.00)[c]
	If Initial Tariffs Remain In Force	
1978		
I Q	\$0.33[d]	\$0.01[c]
II Q	1.60[d]	0.93
III Q	1.60[d]	0.93
IV Q	1.60[d]	0.93
	If ICC-Prescribed Tariffs Reinstated	
1978		
I Q	\$(1.20)	\$(1.44)[c]
II Q	0.46[d]	0.24
III Q	0.46[d]	0.24
IV Q	0.46[d]	0.24

Sources: SEC Forms 10-Q; Drexel Burnham Lambert Incorporated Estimates and Calculations.

a. Arising under ICC-prescribed tariffs; based on reported earnings of pipeline affiliates. Note that costs during July were capitalized.

b. Initial tariffs restored as of October 21.

c. If the depreciation charge per barrel is adjusted to a unit-of-throughput basis, as in Sohio's financial accounts, its loss per barrel is estimated at \$(0.49) in the fourth quarter of 1977. For the first quarter of 1978, this adjustment would yield \$0.21 per barrel on the company's initial tariff, \$(1.02) on the ICC-prescribed tariff. At higher throughput rates, as in subsequent quarters, this adjustment is of much less consequence.

d. Includes carryforward of ITC. On the initial tariff case, this is \$0.103 per barrel in the first quarter of 1978, \$0.507 in subsequent quarters. On the ICC-prescribed tariff case, this is \$0.144 per barrel in the second, third, and fourth quarters of 1978. (Our estimates assume that BP's tax-loss carryforward is amortized over the life of the pipeline, in gear with the amortization of capitalized interest.)

BP's Store of Tax Credits for TAPS

As of the start of pipeline operations, BP had a carryforward of approximately $120 million of ITC and a tax-loss carryforward of approximately $185 million, most of this associated with capitalized interest. By the start of 1978, the tax-loss carryforward had probably risen to at least $210 million, swollen by the TAPS operating loss during the period August through December. BP will earn additional ITC by 1980, on the assumption that it participates in the expansion of TAPS. As noted earlier, we estimate this increment at $10.7 million.

Our TAPS projections for BP assume that its current tax-loss carryforward will be amortized for financial purposes over the life of the pipeline. Capitalized interest will also be amortized over the life of the pipeline. The annual amortization charge for capitalized interest will not give rise to a tax deduction. The amortization of the loss carryforward thus supports the use of the statutory tax rate for financial reporting. (BP may choose to apply the 1977 operating loss against 1978 tax liability.) Our treatment of available ITC is different. We assume that BP works off its ITC dowry at 50% of recognized federal tax liability. Under the reduced tariff case, BP would have unused ITC of $79 million at the close of 1981. Under the retored tariff case, BP's store of ITC would be extinguished during 1981.

Tariff Assumptions for 1979-1981

Our projections of pipeline earnings for the period 1979 through 1981 employ two heroic simplifying assumptions. One is that current tariff levels, as proposed by owners or prescribed last year by the ICC, remain in force. We recognize that cumulative depreciation charges will reduce the measure of capital "used and useful" but posit that this diminution of capital will be offset by (1) the traditional allowance for inflation in the pipeline valuation base and (2) expansion of pipeline capacity to at least 1,500,000 barrels a day by 1981.

Our second powerful assumption is that present equities in the pipeline are maintained upon expansion of the line. This assumption is clearly subject to challenge. Most of Sohio's partners would not be disturbed to see Sohio expand its equity in TAPS to reflect its equity in Prudhoe Bay reserves. How strongly they feel about this will depend on their relative equities in crude and pipeline, the future level of pipeline tariff and earnings, and their share, if any, in future oil discoveries in Northern Alaska. BP's position strikes us as most ambivalent. It participated in the pipeline primarily to assist Sohio during a trying period of financial duress. It may well want out by 1980. However, as the majority owner of Sohio, it would have little desire to embarrass Sohio. From the standpoint of finance, BP has a powerful incentive to facilitate expansion of the pipeline. Realization of its net profits interest in Sohio's production will require expanded throughput capacity. BP's share, at 15.84%, of the $675 million cost of expanding TAPS capacity to 1,600,000 barrels a day would be $107 million, a modest outlay for an annual earnings increment that may amount to between $45 million and $85 million, according to tariff and price assumptions.

Given the wide range of possibilities, we employ our two simplifying assumptions for projection through 1981. (We note, in passing, that the consent of all eight owners of TAPS is required before expansion can be authorized). Table 12 shows potential pipeline earnings at the costs and volumes employed for our 1978-1981 projections. We have raised our second-half-1930 estimate of operating costs by 15 cents a barrel, and added another five cents in 1981, to allow for an increased ad valorem tax and for higher maintenance and overhead associated with a larger system. These are increases in essentially fixed or semivariable costs.

Clearly, in all cases, pipeline results are highly leveraged on fixed charges.

Choice of Pipeline Model

In our analysis, we have selected the "reduced tariff case" as our controlling pipeline assumption. We have done so because our knowledge of regulated industries suggests that the federal courts, including the Supreme Court--the final arbiter, are likely to accept the judgment of the ICC, as articulated in its suspension order of June 28, 1977, that interest expense is an element of return on capital, rather than a cost of service.

The Federal Energy Regulatory Commission (FERC) or the courts may conclude, of course, that a 10% return on valuation is too low, because of project risk or cost-of-capital experience. On the other hand, the FERC may shrink the valuation base to exclude a portion of "cost overruns."

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BRITISH PETROLEUM AND SOHIO

Pipeline Earnings,
1979-1981 Costs and Volumes
(Dollars Per Barrel)

TABLE 12

	Owners' Proposed Tariffs		ICC's Authorized Tariffs	
	BP	Sohio	BP	Sohio
A. 1979 Costs				
	Throughput of 1,100,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.165	1.140	1.165	1.140
Depreciation	0.950	0.942	0.950	0.942
Removal costs	0.111	0.111	0.111	0.111
Interest	1.745	1.904	1.745	1.904
Income taxes	1.258	1.091	0.376	0.319
Earnings	$1.121	$0.972	$0.334	$0.284
B. 1980 Costs and Volumes				
	Throughput of 1,100,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.162	1.137	1.162	1.137
Depreciation	0.947	0.940	0.947	0.940
Removal costs	0.111	0.111	0.111	0.111
Interest	1.740	1.950	1.740	1.950
Income taxes	1.264	1.069	0.381	0.297
Earnings	$1.126	$0.953	$0.340	$0.265
	Throughput of 1,300,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.081	1.137	1.081	1.137
Depreciation	0.833	0.842	0.833	0.842
Removal costs	0.094	0.094	0.094	0.094
Interest	1.601	1.723	1.601	1.723
Income taxes	1.450	1.250	0.567	0.478
Earnings	$1.291	$1.114	$0.505	$0.426
C. 1981 Costs and Volumes				
	Throughput of 1,500,000 Barrels Per Day			
Rate	$6.350	$6.160	$4.681	$4.700
Operating costs	1.051	1.037	1.051	1.037
Depreciation	0.723	0.731	0.723	0.731
Removal costs	0.081	0.081	0.081	0.081
Interest	1.389	1.496	1.389	1.496
Income taxes	1.643	1.489	0.760	0.716
Earnings	$1.463	$1.326	$0.677	$0.639

Prospective decisions about the tariff will have to take into account departures, mainly on the upside, of costs of service from a priori assumptions. Upon exhaustion of the juridical process, the tariff will probably be found somewhere between the "initial levels" and the "reduced levels" we work with.

Production Earnings

Under the rational economics of North Slope oil, production earnings per barrel at Prudhoe Bay derive from a wellhead value that is governed by the sales price of the crude on the West Coast (or Gulf Coast), less tanker cost from Valdez, less the modest charges for oil spill insurance and pipeline volumetric losses, less the TAPS tariff. For the present, Sohio is also deducting, for royalty purposes, a charge of 66 cents a barrel for moving oil from the wellhead to Pump Station 1. This cost appears to be a bit steep. Other operators are making similar, even larger, deductions, and Alaska has filed a lawsuit against the operators, challenging the propriety of netting these field costs against wellhead value. Severance tax is based on the value of the crude at Pump Station 1, a value which we employ as a de facto wellhead price.

Ceteris paribus, for a given sales price, the higher the tariff, the lower the wellhead value--and the lower the production earnings per barrel. We also observe that at the margin, the governmental take on a dollar of production revenue is appreciably higher than on a dollar of pipeline revenue. Nevertheless, Sohio stands to gain from a relatively low tariff in that its equity in production is appreciably larger than its equity in TAPS. Accordingly, the restoration last October of the initially proposed tariffs has provided a mixed bag of plusses and minuses for Sohio and for BP as well.

Sohio has recently been selling its Alaskan crude at an average price of about $13.35 a barrel on the West Coast. This value is based on a delivered cost of $13.75 for Saudi light crude moved to the West Coast, less a discount of 40 cents for quality. The $13.75 incorporates the official sales price of $12.70 for Saudi crude, an import fee of 21 cents, and a charge of 84 cents for transportation. The transportation charge is a normalized cost assumption, based on a Very Large Crude Carrier (VLCC) movement under a 30-month charter. The charge is above spot but below AFRA rates; it is a compromise hammered out between buyer and seller. The recent sales price on the Gulf Coast has been reported at about

$13.40 a barrel; the differential over the West Coast price reflects higher transportation charges from the Persian Gulf, not from Valdez or Los Angeles, and markdowns for quality and competitive pressures. Sohio estimates the more normal Gulf Coast differential over West Coast value at 20 to 25 cents a barrel. Our projection models employ a differential of 15 cents.

<u>We predicate our basic projections of production earnings through 1981 on an annual increase of 5% in F.O.B. price for Saudi Arabian light crude, beginning in mid-1978</u>. We also examine the implications for earnings of an unchanged cost for imported oil. See Tables 13 and 14.

Sohio's tanker costs have been distorted during this initial period of operations by the high cost of moving tankers from remote ports (including Persian Gulf locations) to Valdez for initial loading. We believe that these costs will gradually subside. In its accounting for tankers, Sohio appears to be moving oil from Valdez to the West Coast (i.e., Los Angeles) at a normalized average cost of about 89 cents per barrel. The temporarily swollen marine charges have shown up in the Gulf Coast leg. Charges to the Gulf Coast from Valdez have been reported at $3.47 a barrel through September, $3.61 a barrel in October. These early costs afforded Sohio little if anything in the way of a profit component in 1977. Sohio anticipates an after-tax profit of about 15 cents a barrel on its growing volume of <u>long-term-controlled tonnage</u>. Our models allow for this contribution to begin in 1978.

Marine costs for the Gulf Coast leg in 1978 are expected to decline to $3.00 a barrel by year-end and to average $3.20 for the year. We employ $3.00 a barrel in subsequent years as well. The latter assumption is conservative. It allows for irregular movements to the East Coast, as required, at an incremental cost of 25 cents per barrel.

For buyers of North Slope oil with their own tankers, the sales price at Valdez is net of competitive transportation costs.

<u>The average wellhead value of Sohio's crude for a given pipeline tariff will clearly depend on its mix of West Coast and Gulf Coast sales</u>. The more crude that can be sold on the West Coast, the higher average wellhead value will be. Benefiting from the setback at Pump Station 8, Sohio was able to market about 67% of its recent crude supply, including state royalty oil, on the West Coast, and

STANDARD OIL OF OHIO
Prudhoe Bay Production on Earnings
(Dollars Per Gross Barrel)

TABLE 13

ICC-PRESCRIBED TARIFF

	1977 4th Q	1978	1979	1980	1981	Price Escalation Case 1978	1979	1980	1981
West Coast sales price[a]	$13.35	$13.35	$13.35	$13.35	$13.35	$13.65	$14.30	$15.00	$15.70
Gulf Coast sales price[a]	13.40	13.50	13.50	13.50	13.50	13.80	14.45	15.15	15.85
Tanker cost to West Coast	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Tanker cost to Gulf Coast	3.47	3.20	3.00	1.89[g]	1.89[g]	3.20	3.00	1.89[g]	1.89[g]
Average tanker cost[b]	1.74	2.13	2.10	1.62	1.75	2.13	2.10	1.62	1.75
Oil spill liability fund	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TAPS tariff - Sohio	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.70
Average TAPS cost[c]	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
Pipeline volumetric losses	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Value at Pump Station 1[d]	$6.77	$6.44	$6.48	$6.96	$6.84	$6.74	$7.43	$8.61	$9.19
Royalty[e]	0.76	0.72	0.73	0.79	0.77	0.76	0.85	0.99	1.07
Severance tax[f]	0.69	0.67	0.67	0.71	0.69	0.68	0.75	0.87	0.93
Operating costs	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Ad valorem tax	0.26	0.17	0.19	0.18	0.15	0.17	0.19	0.18	0.15
Depreciation	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
State income tax	0.36	0.35	0.35	0.39	0.38	0.37	0.42	0.51	0.55
Federal income tax	1.69	1.61	1.61	1.78	1.76	1.72	1.94	2.34	2.55
Earnings per barrel	$1.83	$1.74	$1.75	$1.93	$1.91	$1.86	$2.10	$2.54	$2.76

a. Import value adjusted downward for quality.
b. Weighted-average of West Coast and Gulf Coast movements; in late 1977, allows for 20 TB/D sold on East Coast at estimated tanker cost from Valdez of $3.72 a barrel. Beginning in 1980, substitutes pipeline movement (Long Beach to West Texas) for a portion of Gulf Coast movements (300 TB/D in 1980, 400 TB/D in 1981). Assumes 67% of production marketed on West Coast in late 1977, 46% in 1978, 43% in 1979, 41% in 1980, 33% in 1981.
c. Purchased TAPS throughput priced at ICC composite for the eight owners ($4.84 per barrel).
d. Weighted-average of netback values from point of sale.
e. Calculated at 0.125 x (Value at Pump Station 1, less $0.66 a barrel for field costs claimed).
f. Calculated at 0.875 x (0.116 x Value at Pump Station 1) or at 0.875 x minimum severance tax of $0.76 per barrel. Severance tax is payable on net production only.
g. Tanker to Los Angeles plus estimated tariff of $1.00 a barrel from Long Beach to Midland, Texas. Applies to 300 TB/D in 1980, 400 TB/D in 1981. An estimated 78 TB/D in 1980, 137 TB/D in 1981 would continue to move to the Gulf Coast by tanker.

STANDARD OIL OF OHIO
Prudhoe Bay Production Earnings
(Dollars Per Gross Barrel)

TABLE 14

INITIAL TARIFF SUBMITTED BY THE COMPANIES

	1977 4th Q	1978	1979	1980	1981	Price Escalation Case 1978	Price Escalation Case 1979	Price Escalation Case 1980	Price Escalation Case 1981
West Coast sales price[a]	$13.35	$13.35	$13.35	$13.35	$13.35	$13.65	$14.30	$15.00	$15.70
Gulf Coast sales price[a]	13.40	13.50	13.50	13.50	13.50	13.80	14.45	15.15	15.85
Tanker cost to West Coast	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Tanker cost to Gulf Coast	3.47	3.20	3.00	1.89[g]	1.89[g]	3.20	3.00	1.89[g]	1.89[g]
Average tanker cost[b]	1.74	2.13	2.10	1.62	1.75	2.13	2.10	1.62	1.75
Oil spill liability fund	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
TAPS tariff - Sohio	6.16	6.16	6.16	6.16	6.16	6.16	6.16	6.16	6.16
Average TAPS cost[c]	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18
Pipeline volumetric losses	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Value at Pump Station 1[d]	$5.34	$5.01	$5.05	$5.53	$5.41	$5.31	$6.00	$7.18	$7.76
Royalty[e]	0.59	0.54	0.55	0.61	0.59	0.58	0.67	0.82	0.89
Severance tax[f]	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.73	0.79
Operating costs	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Ad valorem tax	0.26	0.17	0.19	0.18	0.15	0.17	0.19	0.18	0.15
Depreciation	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
State income tax	0.25	0.23	0.23	0.27	0.27	0.25	0.31	0.40	0.45
Federal income tax	1.15	1.07	1.07	1.26	1.22	1.18	1.19	1.86	2.06
Earnings per barrel	$1.24	$1.15	$1.16	$1.36	$1.33	$1.28	$1.79	$2.01	$2.24

a. Import value adjusted downward for quality.
b. Weighted-average of West Coast and Gulf Coast movements; in late 1977, allows for 20 TB/D sold on East Coast at estimated tanker cost from Valdez of $3.72 a barrel. Beginning in 1980, substitutes pipeline movement (Long Beach to West Texas) for a portion of Gulf Coast movements (300 TB/D in 1980, 400 TB/D in 1981). Assumes 67% of production marketed on West Coast in late 1977, 46% in 1978, 43% in 1979, 41% in 1980, 33% in 1981.
c. Purchased TAPS throughput priced at ICC composite for the eight owners ($6.21 per barrel).
d. Weighted-average of netback values from point of sale.
e. Calculated at 0.125 x (Value at Pump Station 1, less $0.66 a barrel for field costs claimed).
f. Calculated at 0.875 x (0.116 x Value at Pump Station 1) or at 0.875 x minimum severance tax of $0.76 per barrel. Severance tax is payable on net production only.
g. Tanker to Los Angeles plus estimated tariff of $1.00 a barrel from Long Beach to Midland, Texas. Applies to 300 TB/D in 1980, 400 TB/D in 1981. An estimated 78 TB/D in 1980, 137 TB/D in 1981 would continue to move to the Gulf Coast by tanker.

the balance on the Gulf Coast except for about 20,000 barrels a day moved to the East Coast (Sohio's costly safety valve). As volumes begin to build near term, the West Coast will account for progressively less than half of sales.

By 1980, perhaps by late 1979, one or more pipeline connections from the West Coast to midcontinent refining centers will, hopefully, be in place. We estimate overland transportation cost from Long Beach to Midland, Texas, at $1.00 a barrel (including an after-tax profit of 15 cents). The cost assumption is moderate because the projected line to Midland would incorporate existing facilities. The overland link would appreciably reduce the volume of otherwise required tanker movements via the Panama Canal. Because of production increases anticipated in 1980-1981, tanker deliveries to the Gulf Coast would nevertheless remain important until a Northern Tier pipeline is also in place. As we note below, a significant portion of capacity in a California-to-Texas pipeline may be utilized to move California crude.

As shown in Tables 13 and 14, the substitution of pipeline movement for tankers would markedly improve production earnings per barrel.

Projected Operating Rates

In our projections, we make the simplifying assumption that gross production at Prudhoe Bay equals total pipeline throughput. In fact, production will always be a bit higher than pipeline throughput. The difference is explained in part by fuel requirements for facilities from the wellhead to the terminal at Valdez. The more important claimant upon volume, however, is the marked drop in temperature from Pump Station 1 to Valdez; the loss on this account will contract as throughput rises and the line "heats up."

We note, in passing, that although production began in June, the first sales were made in August. Early operating mishaps extended the lag, but much of it is explained by the time and volumes required for line fill and for accumulating necessary stocks at Valdez. Some ten million barrels of cumulative output were thus absorbed.

We estimate that production and throughput in the fourth quarter of 1977 averaged 725,000 barrels a day. We project the operating rate at 750,000 barrels per day in the first quarter of 1978 and at 1,100,000 barrels a day over the balance of the year. Our estimates assume that Sohio will not have to resort to its option to underlift.

The critical variables for operating rates in 1978 and in subsequent years will be prospective West Coast demand for Alaskan crude, the ability of Sohio in particular to develop reliable outlets, and the expected future supply of eligible tanker capacity.

More on Transportation

The transportation of North Slope crude to Lower-48 markets is requiring an enormous commitment to tankers. The Merchant Marine Act of 1920 (the "Jones Act") stipulates that these tankers must be U.S.-flag vessels, built and registered in the United States, free of federal subsidies, and manned by U.S. crews. The Act also stipulates that the tankers be owned and operated by U.S. citizens. Companies with more than 25% foreign ownership are not considered to be U.S. citizens under the Act. Accordingly, Sohio must charter its Alaskan fleet.

U.S.-flag tankers are and will remain rather scarce, notwithstanding the glut of foreign-flag tankers. Prospective requirements to carry Alaskan oil will rise with output and with the size of the surplus that must be transported from the West Coast via the Panama Canal. These requirements will contract sharply, however, once an overland transportation system becomes available to move oil from the West Coast to markets east of the Rockies. To alleviate the interim shortfall, the Maritime Administration has approved the interim use of U.S.-flag tankers, built with federal subsidies in order to compete in international trade, to carry oil from Valdez to the Pacific side of the Panama Canal. The tankers must be 100,000 dwt or larger.

Sohio will require approximately 1,230,000 tons of eligible tanker capacity to transport its prospective gross share of production from Valdez to the West Coast. At 1,100,000 barrels per day, Sohio's share will amount to 585,000 barrels. As noted earlier, the gross measure of production is important because, for some time to come, Sohio will also be marketing Alaska's royalty interest in its production. If a substantial proportion of the 585,000 barrels per day must be placed on the Gulf Coast, tanker needs will climb more than proportionately. If 250,000 barrels per day can be sold on the West Coast, requiring a long haul for the remaining 335,000 barrels, we estimate that total tanker needs might approximate 2,700,000 tons, including smaller tankers required to transit the Panama Canal.

By mid-1978, Sohio will have eight vessels totaling 1,060,000 tons under long-term charters and an additional three vessels totaling 280,000 tons under a contract of affreightment for three years. (Under affreightment contracts, the owner is committed to capacity, rather than to specific vessels.) Sohio has also chartered 21 additional tankers, aggregating 1,463,000 tons, for periods of one to three years, beginning in 1977 and early 1978. By next August, Sohio will control over 2.8 million tons of capacity.

Sohio's ability to market its projected share of production will depend not only on the West Coast surplus but on volumes placed with purchasers who have eligible tankers under their own control.

The proposed pipeline (PACTEX) from Long Beach, California, to Midland, Texas, may become a reality as complex negotiations with environmental authorities in California approach resolution. Congress may soon approve enabling federal legislation. The line already has the approval of House-Senate energy conferees, Interior Secretary Andrus, the Federal Energy Commission, and the Department of Energy. President Carter has indicated a desire to see TAPS capacity raised above 1,200,000 barrels a day, and output from the Elk Hills Naval Reserve to be expanded as well. Realization of both goals would require an early go-ahead on PACTEX.

The proposed crude line would utilize an existing gas transmission line along much of its route. Capital requirements, excluding capitalized interest during construction and the capitalized value of leased gas pipeline facilities, are estimated at $475 million for 500,000 barrels per day of throughput capacity. Operations could begin 18 to 20 months after the necessary approvals. Once such approvals were obtained, other North Slope operators (e.g., Exxon) would probably take equity interests. The line would also transport Elk Hills crude to midcontinent markets or to strategic storage.

Access to PACTEX will move only a portion of Sohio's potential West Coast surplus in economical fashion. As a supplement to PACTEX, Sohio has joined in the permitting phase of the proposed Kitimat pipeline project. The Kitimat pipeline would carry crude from a terminal at Kitimat, British Columbia, to Edmonton, Alberta. At that point, the line would tie into existing Canadian pipelines serving Canada and U.S. Northern Tier and Midwest states.

We project the operating rate for 1979 at 1,100,000 barrels per day, and for 1981 at 1,500,000 barrels per day. Our 1980 projection assumes completion of the pipeline link to Texas. The second-half 1980 and full-year projections assume expansion of TAPS. Table 15 translates these projections into the equities of BP and Sohio.

BRITISH PETROLEUM AND SOHIO
Projected Operating Rates in Alaska
(Thousands of Barrels Per Day)

TABLE 15

	Production/ Throughput	Share of TAPS Throughput		Sohio's Share of Production	
		BP	Sohio	Gross	Net
1977					
III Q	474/466[a]	74	155	252	221[b]
IV Q	725	115	242	385	337
1978					
I Q	750	119	250	399	349
II Q	1,100	174	367	585	512
III Q	1,100	174	367	585	512
IV Q	1,100	174	367	585	512
Year	1,012	160	338	538	471
1979					
Year	1,100	174	367	585	512
1980					
I Q	1,100	174	367	585	512
II Q	1,100	174	367	585	512
III Q	1,300	206	433	691	605
IV Q	1,300	206	433	691	605
Year	1,200	190	400	638	558
1981					
Year	1,500	238	500	797	697

a. Production will always exceed throughput. The difference arises from system fuel requirements and from pipeline volumetric losses associated with temperature decline. For projection purposes, we recognize but bypass this differential except for a credit on pipeline loss in establishing wellhead value.

b. Sohio's actual sales in the third quarter were approximately 146 TB/D in August, 275 TB/D in September.

Sohio's Earnings

Tables 16 and 17 show the projected buildup of the contribution of Alaskan operations to Sohio's corporate earnings under our alternative tariff and crude-price assumptions. Note that the contribution of Alaskan operations is shown on an integrated basis before interest and income taxes. This approach is consistent with Sohio's financial and tax accounting. It facilitates cash-flow analysis. Equally important, the approach demonstrates how losses on transportation functions help to shelter production earnings from taxation. Federal tax accounting and financial accounting for taxes encompass the results of the company as an entirety. Tax liability does not arise function by function, as otherwise useful functional models might suggest.

The contribution projections are derived from relevant elements of our pipeline and production models. For example, the estimates by year of gross sales revenue are built up from projections of Sohio's gross production, sales prices on the West Coast and Gulf Coast, and the mix of sales between those markets. (The sales price in West Texas, significant beginning in 1980, is assumed to be identical with that on the Gulf Coast.)

The contribution approach points up the extraordinary leverage in Sohio's future results from more intensive use and expansion of TAPS and from savings in transportation costs on substituting PACTEX for sizeable tanker hauls through the Canal. This leverage affords a powerful offset to the drain of BP's net profits interest by 1981.

STANDARD OIL OF OHIO
Contribution of Alaska-Integrated
(Millions of Dollars)

TABLE 16

ICC-PRESCRIBED TARIFFS

	Current Price Case					Price Escalation Case			
	2nd Half 1977	1978	1979	1980	1981	1978	1979	1980	1981
Gross sales revenue	$644.8	$2,639.8	$2,868.9	$3,138.1	$3,913.0	$2,698.7	$3,071.7	$3,523.4	$4,596.6
Purchased TAPS access	93.1	353.3	385.1	421.6	524.7	353.3	385.1	421.6	524.7
Tanker costs[a]	84.0	417.6	448.0	268.1	364.4	417.6	448.0	268.1	364.4
Oil spill fund	2.4	9.8	10.7	11.7	14.5	9.8	10.7	11.7	14.5
Pipeline losses	2.9	11.8	12.8	14.0	17.5	11.8	12.8	14.0	17.5
PACTEX pipeline charges[a]	-	-	-	109.8	146.0	-	-	109.8	146.0
TAPS costs:[b]									
Operating costs[c]	83.5	162.6	152.7	166.5	189.3	162.6	152.7	166.5	189.3
Depreciation	30.5[d]	116.7[d]	126.2	129.9	133.4	116.7[d]	126.2	129.9	133.4
Removal costs	5.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Field costs:									
Royalty	31.8	141.5	155.9	184.5	224.0	149.4	181.5	231.2	311.3
Severance tax	32.7	131.7	143.1	165.8	200.7	133.7	160.1	203.2	270.5
Operating costs	19.3	78.6	85.4	93.4	116.4	78.6	85.4	93.4	116.4
Ad valorem tax	12.5	33.4	40.6	42.0	43.6	33.4	40.6	42.0	43.6
Depreciation	37.6	153.3	166.6	182.1	226.9	153.3	166.6	182.1	226.9
Contribution[e]	$280.7	$1,014.7	$1,127.0	$1,333.9	$1,696.8	$1,063.7	$1,287.2	$1,635.1	$2,223.3

a. Includes earnings return on controlled capacity.
b. Associated with pipeline equity.
c. Includes ad valorem tax.
d. Assumes unit-of-throughput depreciation through first quarter of 1978, straight-line depreciation thereafter. Straight-line accrual for 1977 would be $51.7 million and for all of 1978, $125.7 million.
e. Before interest and income tax.

STANDARD OIL OF OHIO

TABLE 17

Contribution of Alaska-Integrated
(Millions of Dollars)

INITIAL TARIFFS SUBMITTED BY THE COMPANIES

	Current Price Case					Price Escalation Case			
	2nd Half 1977	1978	1979	1980	1981	1978	1979	1980	1981
Gross sales revenue	$644.8	$2,639.8	$2,868.9	$3,138.1	$3,913.0	$2,698.7	$3,071.7	$3,523.4	$4,596.6
Purchased TAPS access	93.1	453.3	494.1	540.9	673.2	453.3	494.1	540.9	673.2
Tanker costs[a]	84.0	417.6	448.0	268.1	364.4	417.6	448.0	268.1	364.4
Oil spill fund	2.4	9.8	10.7	11.7	14.5	9.8	10.7	11.7	14.5
Pipeline losses	2.9	11.8	12.8	14.0	17.5	11.8	12.8	14.0	17.5
PACTEX pipeline charges[a]	-	-	-	109.8	146.0	-	-	109.8	146.0
TAPS costs:[b]									
Operating costs[c]	83.5	162.6	152.7	166.5	189.3	162.6	152.7	166.5	189.3
Depreciation	30.5[d]	116.7[d]	126.2	129.9	133.4	116.7[d]	126.2	129.9	133.4
Removal costs	5.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Field costs:									
Royalty	31.8	106.1	117.4	142.4	171.6	114.0	143.1	191.5	258.9
Severance tax	32.7	131.7	143.1	156.5	194.9	131.7	143.1	170.5	229.8
Operating costs	19.3	78.6	85.4	93.4	116.4	78.6	85.4	93.4	116.4
Ad valorem tax	12.5	33.4	40.6	42.0	43.6	33.4	40.6	42.0	43.6
Depreciation	37.6	153.3	166.6	182.1	226.9	153.3	166.6	182.1	226.9
Contribution[e]	$208.7	$950.1	$1,056.5	$1,265.2	$1,606.5	$1,001.1	$1,233.6	$1,588.2	$2,167.9

a. Includes earnings return on controlled capacity.
b. Associated with pipeline equity.
c. Includes ad valorem tax.
d. Assumes unit-of-throughput depreciation through first quarter of 1978, straight-line depreciation thereafter. Straight-line accrual for 1977 would be $51.7 million and for all of 1978, $125.7 million.
e. Before interest and income tax.

Tables 18 and 19 incorporate the Alaskan estimates into projections of Sohio's corporate net income. Alaskan income tax is based upon the Alaskan integrated contribution less interest on TAPS. The "Lower-48" contribution is the sum of the contributions of Lower-48 production, refining and marketing, coal, and chemicals. Beyond 1977, federal income tax--before ITC--is calculated at the current statutory rate. This is a most conservative assumption.

Note that the contribution of Alaska very quickly dominates corporate results. We regard the "Lower-48" projections as quite conservative also. The perceptible decline from 1977 to 1978 reflects largely the absence of last year's pretax gain of $32 million on sale of production and marketing assets.

Clearly, Sohio's practice in recognizing ITC in its financial results will be a critical factor in its reported earnings for 1978 and 1979.

STANDARD OIL OF OHIO
Earnings Projections
(Millions of Dollars)

TABLE 18

ICC-PRESCRIBED TARIFF

	Current Price Case					Price Escalation Case			
	1977[a]	1978	1979	1980	1981	1978	1979	1980	1981
Contribution[b]									
Alaska (integrated)	\$208.7	\$1,014.7	\$1,127.0	\$1,333.9	\$1,696.8	\$1,063.7	\$1,287.2	\$1,635.1	\$2,223.3
Lower-48	268.0	235.0	245.0	255.0	265.0	235.0	245.0	255.0	265.0
Total	476.7	1,249.7	1,372.0	1,588.9	1,961.8	1,298.7	1,532.2	1,890.1	2,488.3
TAPS interest	115.1	257.1	255.0	268.0	273.0	257.1	255.0	268.0	273.0
Other corp. interest	116.3	198.0	201.0	210.0	194.0	198.0	201.0	210.0	194.0
Alaskan income tax	8.8	71.2	82.0	100.2	133.8	75.8	97.0	128.5	183.3
Federal income tax[c]	82.8	347.2	400.3	485.1	653.3	368.5	470.0	616.1	882.2
Investment tax credit	(42.0)	(200.0)	(200.0)	(100.0)	(100.0)	(200.0)	(220.0)	(100.0)	(100.0)
Embedded tanker profit[d]	-	10.0	15.0	20.0	20.0	10.0	15.0	20.0	20.0
Embedded PACTEX profit[d]	-	-	-	16.5	21.9	-	-	16.5	21.9
Less: BP's net profits interest	-	-	-	1.6	58.4	-	-	2.1	86.8
Corporate net income	\$195.7	\$586.2	\$648.7	\$660.5	\$791.2	\$609.3	\$744.2	\$801.9	\$1,010.9

a. Allows for restoration of initial (higher) tariff as of October 21.
b. Before interest and income tax.
c. Before ITC.
d. After income tax.

STANDARD OIL OF OHIO
Earnings Projections
(Millions of Dollars)

TABLE 19

INITIAL TARIFFS SUBMITTED BY THE COMPANIES

	Current Price Case					Price Escalation Case			
	1977[a]	1978	1979	1980	1981	1978	1979	1980	1981
Contribution[b]									
Alaska (integrated)	$208.7	$ 950.1	$1,056.5	$1,265.2	$1,606.5	$1,001.1	$1,233.6	$1,588.2	$2,167.9
Lower-48	268.0	235.0	245.0	255.0	265.0	235.0	245.0	255.0	265.0
Total	476.7	1,185.1	1,301.5	1,520.2	1,871.5	1,236.1	1,478.6	1,843.2	2,432.9
TAPS interest	115.1	257.1	255.0	268.0	273.0	257.1	255.0	268.0	273.0
Other corp. interest	116.3	198.0	201.0	210.0	194.0	198.0	201.0	210.0	194.0
Alaskan income tax	8.8	65.1	75.3	93.7	125.3	69.9	92.0	124.1	178.1
Federal income tax[c]	82.8	319.2	369.7	455.3	614.0	341.3	446.7	595.7	858.1
Investment tax credit	(42.0)	(180.0)	(200.0)	(120.0)	(100.0)	(200.0)	(220.0)	(100.0)	(100.0)
Embedded tanker profit[d]	-	10.0	15.0	20.0	20.0	10.0	15.0	20.0	20.0
Embedded PACTEX profit[d]	-	-	-	16.5	21.9	-	-	16.5	21.9
Less: BP's net profits interest	-	-	-	1.1	42.8	-	-	1.7	70.6
Corporate net income	$195.7	$535.7	$615.5	$648.1	$764.3	$579.8	$718.9	$780.2	$1,001.0

a. Allows for restoration of initial (higher) tariff as of October 21.
b. Before interest and income tax.
c. Before ITC.
d. After income tax.

CRUDE OIL AND NATURAL GAS IN THE FOREIGN AREA EXCLUDING THE NORTH SEA

Summary of Profits

BP's profits from the production and sale of foreign crude oil and natural gas outside the North Sea are summarized in Table 20. Profits of $125 million in 1977 reflect some squeeze in profits margins for crude oil production and sales because of excess supplies. We are forecasting that profits will rise to $140 million in coming years, mainly because of gains from an expanding natural gas business, partly offset by higher expenses for exploration.

TABLE 20

BRITISH PETROLEUM

Foreign Production Profits Excluding North Sea
(In millions)

	1975	1976	1977	1978	1979	1980	1981
Crude Oil Production	$250	$195	$190	$190	$190	$195	$190
Natural Gas	---	5	10	20	30	35	45
Exploration Expense	(60)	(75)	(75)	(80)	(85)	(90)	(95)
	$190	$125	$125	$130	$135	$140	$140

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

Crude Oil Production

BP's supplies of crude oil have fallen substantially in recent years as a result of the nationalization of the company's producing assets in OPEC countries, mainly Kuwait. Oil supplies, which exceeded 4.8 million barrels a day in 1972, will barely exceed 3 million barrels in 1977. Iran is BP's major source of supply, accounting for more than 50% of total volumes.

As shown in Table 21, we expect that BP's volumes will continue to decline over the next several years mainly because of reductions in oil supplies in Iran as the government sells increasing amounts of oil directly to customers outside the traditional outlets of the major oil companies.

Profit margins, which have been held down somewhat in 1977 by particularly weak market conditions, are forecast tc rise to an average of about $0.18 per barrel by 1980. Margins range from more than $0.30 per barrel in Nigeria to $0.15 per barrel in Kuwait.

On balance, production profits are forecast in the $200-million range in each of the next several years.

TABLE 21

BRITISH PET OLEUM
Foreign Crude Oil Production and Supply
Excluding North Sea: Volumes and Profits

	1975	1976	1977E	1978E	1979E	1980E	1981E
Thousand Barrels Per Day							
Iran	1,700	1,760	1,650	1,600	1,550	1,500	1,450
Kuwait	560	480	425	450	450	450	450
Nigeria	480	420	400	400	400	400	400
Abu Dhabi	320	280	250	250	250	250	250
Iraq	140	---	80	80	80	80	80
Other	220	420	350	325	300	275	250
	3,420	3,360	3,155	3,105	3,030	2,955	2,880
Million Barrels Per Year	1,250	1,225	1,150	1,135	1,105	1,075	1,050
Profit Margin Per Barrel	\$.20	\$.16	\$.16	\$.17	\$.17	\$.18	\$.18
Profits In Millions	\$250	\$195	\$190	\$190	\$190	\$195	\$190

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

Crude Oil Sales

BP has traditionally been a large seller of crude oil because its access to crude supplies through its various producing interests has exceeded its refining requirements by a wide margin (Table 22). In 1976, almost 1.6 million barrels a day, or about 45% of BP's total crude supplies were sold to third parties--the major portion under long-term contract with Exxon and Petrofina. Exxon accounted for 24% and Petrofina for 15% of the total volume of crude oil sold in 1976 to purchasers outside BP's own operations. BP's third-party sales volumes will begin to decline as North Sea production plateaus, while other sources of supply from OPEC countries continue to erode. As shown in Table 22, we expect that such crude oil sales will amount to less than 1.1 million barrels a day early in the 1980s, or about 30% of total supplies. As recently as 1973, crude sales totalled 2.4 million barrels a day, accounting for over half the oil supplies available to BP. These trends should not affect the earnings outlook, because in our projections we have not reflected any profits from the sale of crude oil to third parties over and above the margins that we have already allowed for in the production end of the business.

TABLE 22

BRITISH PETROLEUM
Foreign Crude Oil Sales to Third Parties
(Thousand barrels per day)

	1975	1976	1977E	1978E	1979E	1980E	1981E
Crude Supplies							
Excluding North Sea	3,420	3,360	3,155	3,105	3,030	2,955	2,880
North Sea	20	180	395	485	505	520	505
	3,440	3,540	3,550	3,590	3,535	3,475	3,385
Crude Required for BP Refineries	(1,720)	(1,900)	(1,975)	(2,075)	(2,150)	(2,220)	(2,275)
Other	(20)	(60)	(50)	(50)	(50)	(50)	(50)
	(1,740)	(1,960)	(2,025)	(2,125)	(2,200)	(2,270)	(2,325)
Crude Sales to Third Parties	1,700	1,580	1,525	1,465	1,335	1,205	1,060

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

Natural Gas

BP's natural gas business has been relatively small. Natural gas sales amounted to only 350 million cubic feet a day in 1976, revenues totalled $45 million, and profits in that year are estimated at only $5 million (Table 23). Most of the company's natural gas production is from its 100% interest in the West Sole Field, in the southern part of the North Sea. The rest is mainly from BP's 37.5% share in the Kapuni Field in New Zealand, and from Canada.

TABLE 23

BRITISH PETROLEUM
Foreign Natural Gas Sales:
Volumes and Profits

	1975	1976	1977E	1978E	1979E	1980E	1981E
Million Cubic Feet Per Day							
North Sea	165	182	200	190	180	170	165
Other	133	168	225	300	350	425	475
	298	350	425	490	530	595	640
Billion Cubic Feet Per Year	109	128	155	175	195	215	235
Profit Margin Per mcf	---	$.05	$.07	$.11	$.15	$.17	$.19
Profits In Millions	$--	$5	$10	$20	$30	$35	$45

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

BP's natural gas business is expected to expand in the coming years as a result of the company's involvement in the following new projects:

- 18.75% interest in the Maui offshore gas field in New Zealand. The field is estimated to contain recoverable reserves of more than 6 trillion cubic feet, and production start-up is expected late in 1978.

- A 16.3% interest in a liquefied natural gas (LNG) plant on Das Island, offshore Abu Dhabi. First deliveries from the plant, which has a capacity of 550 million cubic feet a day, began in 1977.

- A 20% interest in a LNG project in Nigeria, which is still in the planning stages.

- A 16.7% interest in natural gas discoveries offshore Northwestern Australia, which recently received government approval for development. The discoveries are estimated to contain 15 trillion cubic feet of natural gas reserves.

Overall, BP's share of natural gas developed and undeveloped reserves outside OPEC, in countries such as the U.K., Germany, Australia, New Zealand, and Canada, are estimated to total 6.5 trillion cubic feet, or 16.8 thousand cubic feet per share of common stock outstanding.

DOWNSTREAM OPERATIONS

Summary of Earnings

Downstream operations have been an area of major weakness for BP. We estimate that in 1976 the company lost $135 million in this business, compared with a loss of only $20 million in 1975. The gap widened in 1977 to $160 million. It should be noted, however, that the losses, as we have calculated them, also reflect corporate overhead expenses and other corporate items--such as the impact of currency changes--which we have not allocated by business function. Pension costs, for example, were $50 million higher in 1976 than in 1975, and account for part of the erosion in the results between the two years. And in 1977, because of the strength of the pound sterling, results were affected by currency losses mainly from the translation of dollar cash balances into sterling.

Even if we allow for various extraneous factors that have influenced the results, BP's performance in the downstream business has been at best disappointing. The erosion in performance between 1975 and 1976 reflects the following major factors:

- A worsening situation in the United Kingdom, BP's largest market, and in other European markets outside France and Germany. The cost of crude oil, in dollar terms, rose more than 7% between 1975 and 1976 as a result of a price hike by OPEC in October 1975. In addition to the hike in dollar prices, U.K. refiners incurred even higher crude oil costs in sterling because of the sharp decline--a drop of about 16% between the end of 1975 and 1976--in the value of the pound vis-a-vis the dollar. Crude oil is a dollar-denominated commodity and, therefore, its cost in local currency is affected by currency changes. The rise in the price of refined petroleum products was not adequate to recover these higher costs.

- In France, operations were also affected by the rise in crude oil costs, both in dollars as well as in local currency, but to a lesser extent than in the U.K. Between the end of 1975 and 1976, the value of the franc declined 10%. However, BP experienced better success in France than in the U.K. in recovering the higher crude oil costs in the marketplace.

- BP continued to lose money in Germany in 1976, but the losses moderated from 1975. Unlike the situation in the U.K. and France, the deutsche mark, in relation to the dollar, was stronger in 1976 than in 1975 by about 9%. As a result, crude oil costs, in local currency, did not materially change between 1975 and 1976, because the strengthening of the D-mark was enough to offset the adverse effect of the OPEC price hike.

- BP's 1976 results in Australia reflect an extraordinary after-tax loss of about $10 million, as a result of an adverse Supreme Court judgment against BP Australia on a breach of contract. Since then, the judgment has been reversed, on appeal, in BP's favor, and the reversal has benefited earnings in 1977.

- Refining arrangements in Iran and refining operations in Aden were also a strain on the company's results.

In 1977, there was a combination of positive and negative influences on results. On the positive side, the following factors are noteworthy:

- Inventory profits of $60 million were realized in the first half of the year. BP is on FIFO accounting, and, therefore, earnings benefited from the rise in OPEC prices in the beginning of 1977.

- A reversal in last year's accounts of charges made in previous years for an alleged breach of contract in Australia also influenced after-tax earnings by about $20 million.

Despite these benefits, results last year were hampered by the following major negative factors:

- Market conditions softened in Europe during the year, particularly in Germany. A continuation of market weakness, a boost in OPEC prices during the year, and government regulations in countries such as France, overshadowed the favorable impact that a weakened dollar had on profit margins. As noted earlier, weakness in the dollar tends to lower crude oil costs expressed in local currencies, crude oil being a dollar-denominated commodity.

- The two-tier OPEC price structure penalized BP's performance last year, because 90% of the company's crude supplies came from OPEC countries that adopted a 10% price hike in the first half of the year, while Saudi Arabia, the major producer, settled for only a 5% increase. For the most part, prices of petroleum products did not reflect the full 10% hike. We estimate that the cost under-recovery for BP was at least $50 million.

- Finally, a major strain on last year's results appears to have been currency losses stemming from the translation of dollar cash balances held in the U.K. into a strengthened sterling. Currency losses introduce considerable uncertainty to our earnings estimate for last year because of the sharp rise in the pound's value in relation to the dollar toward the end of the year. In addition to the size of the dollar exposure, critical unknowns are the extent and success of the company's hedging activities. We have estimated the cost at about $75 million.

BP operations have, of course, been affected by the surplus capacity in refining and distribution that has troubled the industry overall in recent years. In 1977, as noted, the two-tier price structure was an added negative influence on BP's results. Nevertheless, even allowing for adverse industry conditions, BP appears to have fared worse than some of its major competitors. Clearly, therefore, unique circumstances in the structure of BP's downstream operations must account for its particularly poor performance. These elements merit some analysis before assessing the outlook.

Accounting Treatment

BP does not follow U.S. accounting principles in the consolidation of the nonsterling accounts of its various affiliates into sterling. In the first place, BP has not adopted the U.S. accounting principles prescribed by FASB No. 8. Quite apart from FASB No. 8, however--which, as we have argued in our previous works relating to Royal Dutch Petroleum is of questionable merit--BP's accounting differs from U.S. practices in the following other important respects:

- Nonsterling fixed assets are translated into sterling at year-end exchange rates rather than at historical rates, which is the practice commonly used in the U.S. Because the pound has weakened over the years versus most other currencies, BP's treatment has had the effect of raising the depreciation charge in its income accounts.

  Accordingly, BP's reported earnings in 1976 were reduced about $65 million. Of that amount, about $30 million can be reasonably ascribed to the depreciation of the company's downstream assets, and, therefore, estimated downstream losses would have been lower by about $30 million if BP's accounting were more consistent with U.S. practices.

A strengthening of the pound versus other currencies would, of course, have the opposite effect.

- In addition to the different way in which BP treats its depreciation account, it also translates the other income accounts of its overseas affiliates differently. Specifically, the translation from nonsterling currencies into sterling is done at year-end exchange rates, in contrast to the practice followed in the U.S. of translating the accounts of affiliates at yearly average exchange rates. Because of the sharp erosion of the pound in 1976 versus most other currencies, this practice has had the effect of inflating the losses incurred by its affiliates outside the U.K.--particularly in Germany--when those losses were consolidated and expressed in sterling.

Geographical Concentration of Refining and Marketing

A geographical analysis of BP's refining capacity reveals that, by far, most of the company's capacity is located in Europe, which has been a particularly weak market in relation to other markets. As shown in Table 24, 86% of BP's capacity outside North America is situated in Europe, compared, for example, with Royal Dutch/Shell, which has only 60% of its capacity in Europe. We chose Royal Dutch/Shell for comparison purposes because it is the strongest company in the foreign downstream business, and, therefore, the comparison serves to highlight probable weaknesses in BP's operations.

BP's relatively large exposure to Europe is also pronounced when considering refinery runs, i.e., crude oil processed through the company's refineries, rather than refining capacities per se. On this basis, Europe accounted for 85% of BP's total crude throughput outside North America, compared with only 59% for Royal Dutch/Shell (Table 25). Nor surprisingly, similar results are obtained if one looks at refined petroleum product sales by area, as shown in Table 26.

TABLE 24

BRITISH PETROLEUM: Refining Capacities
Outside North America

	Thousand Barrels Per Day		Share	
	BP	Royal Dutch/Shell	BP	Royal Dutch/Shell
EUROPE				
U.K.	630	700	25%	16%
France	305	770	12	18
Germany	420	360	17	8
Netherlands	490	530	20	12
Other	290	260	12	6
Total	2,135	2,620	86%	60%
OTHER EASTERN HEMISPHERE				
Japan	--	280	--	6
Australasia	175	165	7	4
Other	170*	790	7	18
Total	345	1,235	14%	28%
OTHER WESTERN HEMISPHERE	---	500	--	12
TOTAL	2,480	4,355	100%	100%

*Note: On May 1, 1977 BP transferred the ownership of its wholly owned refinery in Aden -- with a rated capacity of 150,000 barrels per day -- to the South Yemen Government, and, therefore, has been excluded from the above figures.

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

TABLE 25

BRITISH PETROLEUM: Refinery Runs
Outside North America

	Thousand Barrels Per Day		Share	
	BP	Royal Dutch/Shell	BP	Royal Dutch/Shell
EUROPE				
U.K.	420	415	25%	14%
France	280	465	17	16
Germany	260	260	15	9
Netherlands	260	350	15	12
Other	220	210	13	8
Total	1,440	1,700	85%	59%
OTHER EASTERN HEMISPHERE				
Japan	---	205	--	8
Middle East and Africa	80	100	5	3
Far East and Australasia	160	525	10	18
Total	240	830	15%	29%
OTHER WESTERN HEMISPHERE	---	340	--	12
TOTAL	1,680	2,870	100%	100%

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

TABLE 26

BRITISH PETROLEUM: Refined Product Sales
Outside North America

	Thousand Barrels Per Day		Share	
	BP	Royal Dutch/Shell	BP	Royal Dutch/Shell
EUROPE				
U.K.	300	405	19%	13%
France	280	375	17	12
Germany	280	425	17	14
Other	480	555	30	17
Total	1,340	1,760	83%	56
OTHER EASTERN HEMISPHERE				
Japan	--	415	--	13%
Africa and Middle East	120	615)	7	20)
Asia and Australasia	160	)	10	)
Total	280	1,030	17%	33%
OTHER WESTERN HEMISPHERE	--	355	--	11%
TOTAL	1,620	3,145	100%	100%

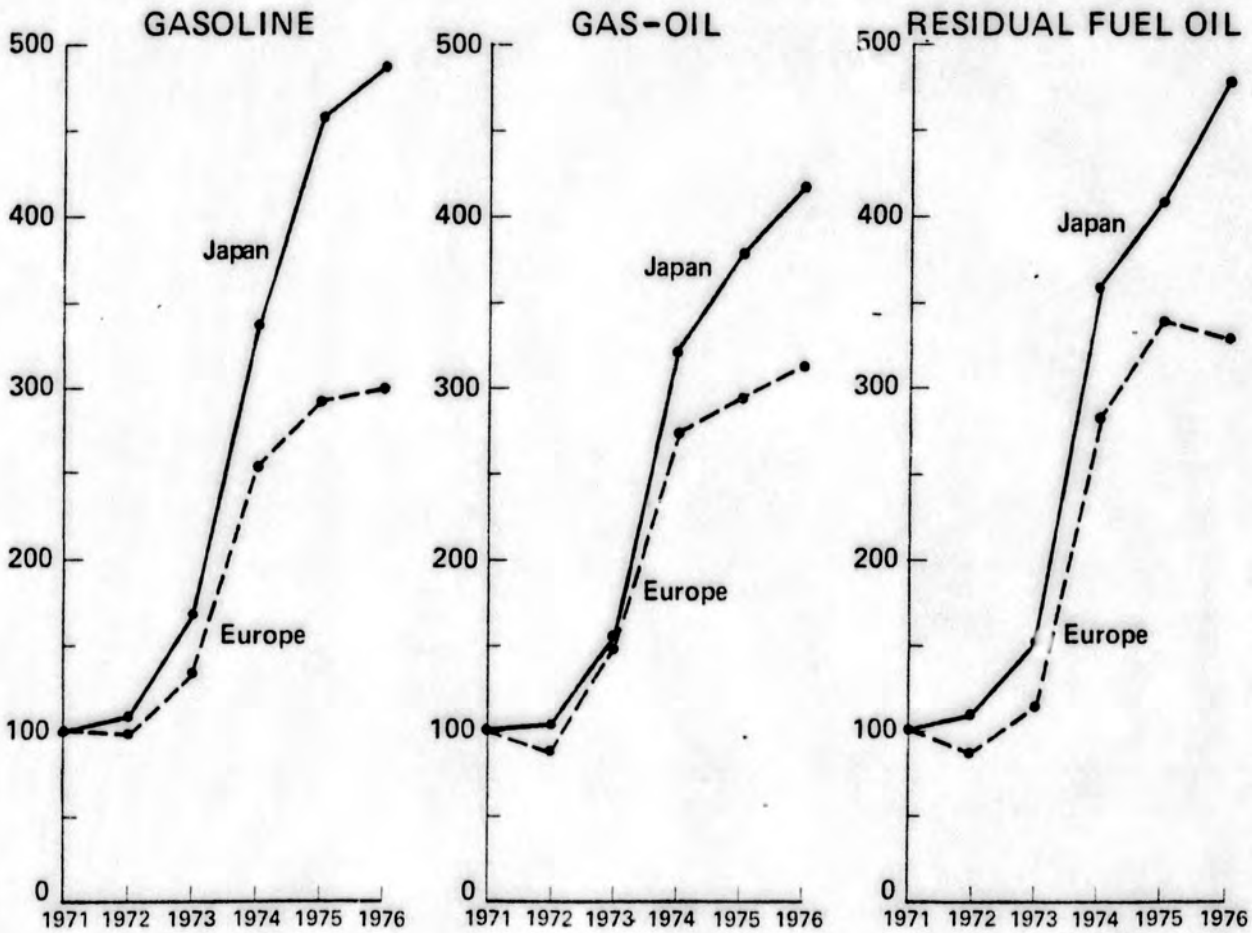
Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

It is apparent, therefore, that BP's operations lack the geographical diversification characteristic of Royal Dutch/Shell's operations. Moreover, the company has concentrated on the European market, which, for the most part, has shown the greatest weakness. As shown in Chart 2, in recent years prices of refined products in Europe have consistently trailed the trend in realizations in other areas, which suggests that the industry has been able to realize higher margins, and, therefore, a better performance outside Europe--an area in which BP's presence is not particularly strong.

CHART 2

REFINED PETROLEUM PRODUCT PRICE TRENDS

(1971 - 100)



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Refining/Marketing Logistical Balance

Within Europe, BP has a major presence in basically four countries: the United Kingdom, France, Germany, and The Netherlands. From a logistical viewpoint, however, BP's refineries, unlike those of Royal Dutch/Shell, are not as well situated in relation to the company's marketing needs. England, for example, accounts for about 25% of BP's refining capacity and also of the total volume of oil that BP refines. Still, the U.K. accounts for only 19% of the company's sales. Viewed another way, BP is in a long refining position in the U.K.--its refinery throughput exceeds sales by about 40%--a situation that necessitates exports of refined petroleum products to other European markets. Such exports must surely be at a competitive cost disadvantage versus petroleum products that are refined locally.

The same is true for the large Dutch/German refining/marketing complex, The Netherlands being a major refining export center, while Germany is a major market for Dutch exports. BP's refining capability in this combined market is far greater than its marketing penetration. By contrast, Royal Dutch/Shell's refining/distribution position in this market is well balanced. Therefore, BP's refinery operations in The Netherlands serve a broader role of balancing its marketing needs in Europe, which again may account for logistical weakness.

Upgrading Capability

Another major weakness of BP in relation to some of its major competitors such as Royal Dutch/Shell is the company's more limited upgrading capability, i.e., the ability to upgrade the heavier ends of the refined barrel into more valuable, lighter products.

Since the oil embargo, the gap in price between the light and heavy ends of the barrel has widened sharply (Chart 3). Based on spot prices in the Rotterdam market, regular gasoline commanded a price premium in 1976 of more than $5 per barrel in relation to residual fuel oil, compared with a premium of only $1 in 1972, the first full year before the embargo. Similarly, the price gap between gas oil and residual fuel oil has widened to $3.30 per barrel from $1.05.

As shown in Table 27, BP's upgrading capability in Europe--consisting of catalytic cracking and re-forming--amounts to only 13% of the company's distillation capacity, compared with 19% for Royal Dutch/Shell. Had we included thermal cracking in our comparisons, Royal Dutch/Shell's superior position would have been even more pronounced.

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CHART 3

PRODUCT PRICE TRENDS IN EUROPE

ROTTERDAM BARGE PRICES
$/BBL

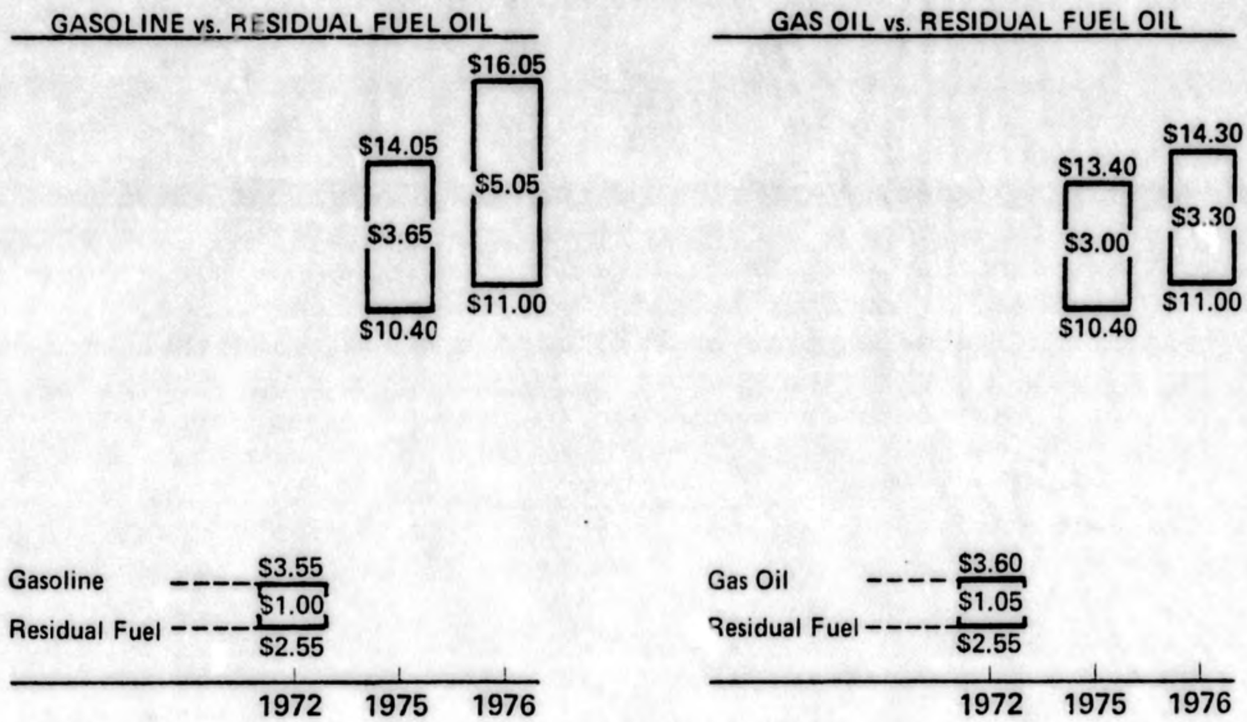


TABLE 27

BRITISH PETROLEUM
Refining Upgrading Capability

	BP Distillation Capacity	BP Cracking and Reforming Capacity	BP Cracking and Reforming as a % of Distillation
EUROPE			
U.K.	630	145	23%
France	305	---	--
Germany	420	45	11
Netherlands	490	20	4
Other	290	70	24
TOTAL	2,135	280	13%

	ROYAL DUTCH/SHELL		
EUROPE			
U.K.	700	160	23%
France	770	130	17
Germany	360	55	15
Netherlands	530	100	19
Other	270	50	19
TOTAL	2,630	495	19%

Note: Capacities are expressed in thousand barrels per day (TBD).

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

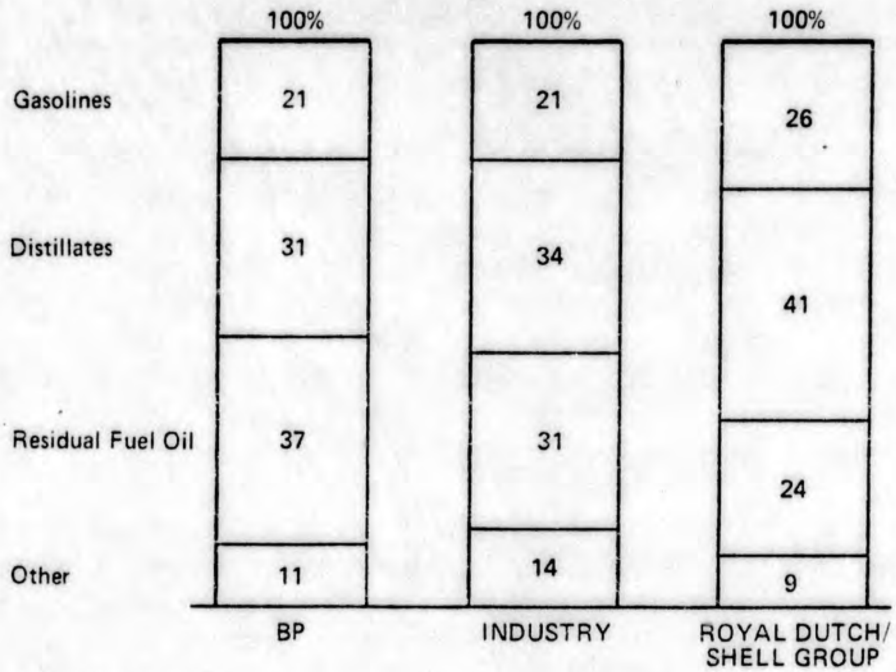
Drexel Burnham Lambert INCORPORATED

BP's relatively limited exposure to the more valuable light products is also indicated on Chart 4, which compares the breakdown of BP's refined petroleum products in Europe with that of Royal Dutch/Shell's. Gasolines, including naphtha, account for about 20% of BP's sales--in line with the industry average--but below Royal Dutch/Shell's share of 26%. But residual fuel oil sales amount to 37% of total volumes for BP versus only 24% for Shell.

CHART 4

REFINED PETROLEUM PRODUCT SALES IN EUROPE

BY MAJOR PRODUCT CATEGORY



Refining in Iran

BP's downstream results have also been adversely affected by the company's commitment to lift refined petroleum products from the Abadan refinery in Iran. The arrangement between Iran and the Iranian consortium of companies, in which BP has a 40% interest, dates back to 1973, when the refinery was nationalized. BP's lifting requirements as a member of the consortium have averaged as much as 120,000 barrels per day. The arrangement has proved to be uneconomic mainly because the oil companies have been given limited flexibility in the type of product to which they are entitled. The consortium's collective lifting arrangements have now been terminated, and BP has negotiated a separate agreement to lift products from the Abadan refinery, presumably under more favorable terms.

Lack of Indigenous Crude Oil Supplies in Germany

In the large German market, which has been depressed for the industry in general, BP's operations are particularly disadvantaged by the lack of domestic petroleum production. Companies such as BP, which lack access to domestic production, have argued strongly that competitors with interest in oil and natural gas production in Germany possess a competitive advantage insofar as production profits can be used to subsidize downstream operations.

The Outlook

We expect BP's downstream performance to improve in the coming years with the prospect that, at the very least, this segment of the business will break even early in the 1980s. We would attribute the improvement to the following factors:

- Although excess capacity in refining and distribution is likely to persist at least through the early 1980s for the industry overall, we would expect utilization rates to improve gradually from recent depressed levels. Market prices for refined petroleum products should reflect this improvement. Nevertheless, we do not as yet expect margins on spot sales to be adequate to recover all fixed costs, let alone yield an attractive return on new investments, at least through the forecast period. We would, however, expect the trend to be an improving one.

- As noted previously, BP's operations have been adversely affected by the limited capability to upgrade the product in its refineries, compared with its major competitors. We expect that this weakness will be alleviated for two reasons:

  - BP is in the process of upgrading some of its refining facilities, particularly in its major refining complex in The Netherlands.

  - The buildup of North Sea production--which is a light crude with low-sulfur content--will enhance the quality of BP's supply.

- In Germany, the government is under persistent pressure to tax excessive profits from domestic production. Companies such as BP and state-controlled Veba, who do not own any domestic production, complain that their marketing position is being undercut by the major competitors who have access to domestic oil supplies. Although we deem it unlikely that Germany will impose punitive taxes in domestic production, short of some increase in the royalty, or a modest increase in tax rates, the debate may result in closer government scrutiny of pricing arrangements within Germany, aimed at restraining the competitive advantage of oil companies with access to domestic crude oil supplies.

- BP has undertaken a program aimed at improving its operating performance, particularly in Germany, through measures such as:

  - Increased concentration on large service stations;

  - Selective selling of smaller unprofitable outlets;

  - Adoption of a more flexible policy in the purchase of crude and products that are more attuned to market conditions and more sensitive to profit opportunities.

- On May 1, 1977 BP transferred the ownership of its wholly owned refinery in Aden to the South Yemen refinery. The refinery is a fairly large one, with a capacity of about 150 thousand barrels per day. Because of the reduced importance of the Suez Canal in oil transportation, however, the refinery's location has not been particularly desirable in recent years. The sale of the refinery, which has not been a profitable one for BP, should also be a factor in the improved performance of BP's downstream business.

- The uneconomic arrangements in Iran involving a commitment to lift refined petroleum products from the Abadan refinery have been renegotiated under more favorable terms to BP.

- BP has reduced its tanker fleet and tonnage materially since the energy crisis of 1973, when the excess capacity in tankers became substantial. Between 1972 and 1976, BP's tonnage--either directly owned or under long-term charter arrangements--has been lowered by about 20% (Table 28). The reduction in the number of vessels has been ever sharper--a decline of 55%. Despite this reduction, however, BP has continued to lose money in its tanker business for the following reasons:

  - BP's committed tonnage before the crisis was extremely large and, therefore, the reduction has been from a high base.

This is in sharp contrast, for example, to Mobil's position--Mobil being perhaps in the best shape among the international major oil companies in terms of tanker coverage. Because Mobil's tanker requirements were relatively uncommitted before the crisis, it has been able to avail itself of surplus conditions in the tanker market by purchasing low-cost resale vessels, by chartering vessels at low rates, or both. As a result, Mobil's marine performance in recent years has benefited more than most of its major competitors.

- In addition to its overcommitted position in tankers overall, BP has had a relatively large portion of chartered tonnage in its fleet. In 1972, 73% of BP's tonnage was under long-term charter, compared with only 60% for Mobil. Although a lot of these relatively high-cost charters have expired since then, high-cost charters continue to make up a sizable portion of BP's coverage.

- As some of BP's costly charters continue to expire, we expect the company's marine performance to improve in the years ahead, even though the tanker glut may persist for some time to come.

TABLE 28

BRITISH PETROLEUM
Foreign Tanker Position

	BP		Mobil		Share BP		Share Mobil	
	1972	1976	1972	1976	1972	1976	1972	1976
Million Deadweight Tons								
Owned	5.3	7.6	2.6	6.3	27%	48%	40%	56%
Long-term charter (over 1 year)	14.2	8.1	3.9	5.0	73	52	60	44
	19.5	15.7	6.5	11.3	100%	100%	100%	100%

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

The moderate improvement in the performance of BP's downstream business that we are forecasting here is predicated, of course, on continuing excess capacity in the downstream business. Should the excess be worked out at a faster pace than we now foresee, BP is quite leveraged and would benefit considerably from any such strength. After all, BP's gross investment in this segment of the business amounts close to $5 billion, which is not much lower than the company's overall capitalization value of about $6 billion. Because of the size of these assets, every percentage point improvement in the return that can potentially be realized on these assets would amount to about $50 million, or more than $0.10 per share.

On the other hand, if evidence suggests that there is only a remote prospect for a reversal of the depressed conditions prevailing in some markets, particularly in Germany, we must question whether a continuing presence in such markets is justified, and we believe that BP's management will, too.

OTHER OPERATIONS

Chemicals

BP's principal chemical activities are mainly in the U.K., and, to a lesser extent, in Germany and France, where BP has presence through a 50% interest in Erdolchemie G.m.b.H. and a 30% interest in Napthtachimie S.A., respectively.

Chemical sales in 1976 totalled $840 million, compared with about $665 million in 1975. (Dollar figures are translations from underlying sterling accounts based on year-end exchange rates in respective years).

Chemical profits, before U.K. taxes, and excluding the chemical activities of Sohio, amounted to $83 million in 1976, compared with $60 million in 1975. These earnings consist of income from direct chemical operations, mainly in the U.K., as well as dividends received from associated companies mainly in Germany and France. Adjusting for U.K. income taxes, we estimate that chemical earnings in 1976 were down moderately from 1975 to about $50 million. After-tax earnings did not change much between the two years, despite a sharp rise in revenues, because a portion of the chemical earnings consists of dividends from associated companies that contribute to BP's profits with a year's lag. As a result, chemical earnings in 1975 were heavily weighted by dividend receipts which, in turn, reflected a strong year for chemicals in 1974. On the other hand, 1976 chemical earnings include lower dividends received in that year because of the weakness in chemicals in 1975.

For 1977, we estimate a further lowering of earnings because of weak business conditions during the second half of the year. The reduction occurred even though BP adopted (in the beginning of 1977) equity accounting for its share of associated chemical operations in Germany. Because of this change, BP's chemical earnings in 1977 benefited from adjustments attributable to the relatively strong performance in chemicals in 1976.

Earnings in the future should benefit from several expansion plants already under way:

- Near Teesside, England, BP has a 50% interest in a new ethylene plant with completion expected in mid-1978. It will increase BP's ethylene capacity to over 2.2 billion pounds a year.

- Also in 1978, completion is expected of a benzene plant in the U.K., with capacity of over 800 million pounds, and a polyethylene plant with a capacity of 140 million pounds.

- Last year, construction began on an acetic acid plant in the U.K. When the plant is completed, BP will have the largest acetic acid capacity--over 900 million pounds--of any other company in Western Europe.

- Finally, expansion plans are under way in Germany, involving a polyethylene plant, and in France, where a polypropylene plant is being built.

Coal

BP is establishing a major presence in coal:

- Last year it acquired a 50% interest in an Australian company, Clotha Development Pty. Ltd., for about $200 million. The acquisition became effective in the beginning of 1977. Current production amounts to 6.4 million tons, 95% of which is metallurgical coal. BP's estimated reserves in Australia, both assigned and unassigned, exceed 775 million tons.

- BP also has a one-third interest in a joint venture in South Africa. Development work is now under way, and production at an annual rate of 3 million tons is expected to begin in 1979.

- Early in 1977, BP acquired extensive coal interests in Canada and announced a major investment program aimed at developing a production capacity of 3 million tons a year of high-quality coking coal. And just recently BP has announced a $45-million development program for the Clarence coal deposits in New South Wales in a joint venture with Oakbridge Ltd. The Clarence mine has estimated reserves of 95 million tons. Plans call for the expansion of production to 2.2 million tons a year from the present level of 880,000 tons.

- In the U.S., BP's coal interests lie, of course, with Sohio. Sohio's Ben Coal Company is the nation's twelfth largest producer of bituminous coal with reserves of over 800 million tons, and production of about 10 million tons.

Proteins and Animal Nutrition

Through acquisition since the beginning of 1975, BP has become a large producer of specialized animal feeds, with annual production of 350,000 tons and sales revenues last year of about $165 million compared with $120 million in 1975.

PROBLEMS IN ACCOUNTING TREATMENT

Earnings in Dollars: What Exchange Rate?

BP is, of course, a U.K. company, and as such it reports its accounts in sterling, in accordance with generally accepted principles in Great Britain. BP presents its figures in dollars as well, but this is done purely for convenience. The dollar amounts provided by the company do not purport to reflect an accurate representation of the company's earnings results. In presenting earnings in dollars, BP follows the practice of translating the underlying sterling accounts into dollars at the exchange rate prevailing at the end of the current reporting period (Table 29). On that basis, BP's 1976 dollar earnings, as presented by the company, are based on an exchange rate of 1£-$1.70, which was the rate prevailing at the end of the year. Similarly, 1975 earnings as well as those for previous years have been adjusted to reflect that exchange rate.

In this report we have adopted the practice of presenting the dollar figures from the underlying sterling accounts using, for translation purposes, the exchange rate prevailing at the end of the period in which the results were initially reported. Therefore, 1976 dollar earnings are based on an exchange rate of 1£-$1.70 prevailing at the end of 1976. But 1975 earnings reflect an exchange rate of 1£-$2.02, which was in effect at the end of 1975. Similarly, 1974 earnings have been translated from the underlying sterling figure using the year-end 1974 exchange rate, and so on.

BRITISH PETROLEUM

Two Methods of Presenting Earnings in Dollars
(Millions)

TABLE 29

	1972	1973	1974	1975	1976	Change 1975	Change 1976
As Reported In Sterling	£ 61	£604	£487	£166	£180	(66%)	8%
In Dollars Based on:							
Year-end 1976 exchange rate (£ = $1.70)	$103	$1,025	$828	$282	$306	(66%)	8%
Exchange rate at the end of each year	$143	$1,401	$1,144	$335	$306	(71%)	(9)%
Note:							
Year-end exchange rate (£ - $)	$2.35	$2.32	$2.35	$2.02	$1.70		

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

We believe that these are the major advantages in our approach:

- Historical results do not require continuing readjustment, depending on the dollar/sterling exchange rate that may prevail in future reporting periods.

- Use of historical year-end exchange rates in deriving dollar figures--which is the translation method we have adopted--provides a more accurate depiction of true operating results. Moreover, it is consistent with the company's practice of translating nonsterling earnings into sterling in the first place.

Earnings in Sterling: Different Accounting Principles

In addition to problems stemming from the presentation of dollar figures, issues of more fundamental concern to the American investor are raised by BP's use of accounting principles prescribed in the U.K., but that are not always consistent with U.S. practice. Those differences arise when BP consolidates the nonsterling accounts of its various affiliated companies into sterling. In particular, in accordance with accounting principles generally accepted in the United Kingdom, all assets and liabilities in currencies other than sterling--as is the case with overseas earnings--should be converted into sterling at the rates of exchange that apply at year-end. This practice is at variance with U.S. practices in the following respects:

- Generally accepted accounting principles in the United States would require that fixed assets denominated in currencies other than sterling be translated at historical exchange rates. Because over the years the pound has generally depreciated versus other currencies, BP's practice has had the effect of increasing the value of its assets in sterling terms. Correspondingly, the depreciation charge is higher than it would have been under U.S. principles. Had BP's practice conformed with U.S. accounting, earnings in 1976 would have been higher by about $65 million (Table 30).

- The adoption of FASB No. 8 in the U.S. has introduced the following additional accounting differences in BP's reporting:

  - FASB No. 8 requires that long-term debt be adjusted to applicable year-end rates with the adjustment taken to current income. Although BP uses current rates in the translation of long-term debt, it does not include the changes in the determination of current income. Instead, the gain or loss is reflected in earned surplus.

- A second change introduced by FASB No. 8 requires that inventories be translated at historical rates, in contrast to BP's practice of valuing inventories at end-of-period exchange rates.

- FASB No. 8 has adopted the previous accounting practice of valuing other monetary assets and liabilities at current exchange rates with the adjustments taken into income. Although this is consistent with BP's practice as to the type of exchange rate used, i.e., the year-end exchange rate, it differs in the way the adjustments are reflected into income. In particular, BP does not include in the determination of income exchange fluctuations relating to the restatement of the monetary assets and liabilities of overseas affiliates. Instead, these fluctuations are taken directly to earned surplus, as is the case with long-term debt.

TABLE 30

BRITISH PETROLEUM
Differences in the Translation
of the Depreciation Account

	In Sterling				
	1972	1973	1974	1975	1976
Earnings as reported by BP	£ 61	£604	£487	£166	£180
Reduction in depreciation charge Based on U.S. accounting principles	10	18	24	28	39
	£ 71	£622	£511	£194	£219
	In Dollars*				
Earnings as reported by BP	$143	$1,401	$1,144	$335	$306
Reduction in depreciation charge Based on U.S. accounting principles	24	42	56	57	66
	$167	$1,443	$1,200	$392	$372

*Note: Translated from underlying sterling figures using year-end exchange rates as follows (£=$): $2.35 $2.32 $2.35 $2.02 $1.70

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

As shown in Table 31, had BP conformed with U.S. accounting principles as prescribed by FASB No. 8, earnings in 1976 would have been lowered by $280 million--from earnings of $305 million to only $25 million, because of the pound's devaluation.

In particular, losses from the currency translation of long-term debt would have exceeded $350 million in 1976. The loss would have been offset partly by a gain of $80 million from the translation of inventories sold.

TABLE 31

BRITISH PETROLEUM
Translation Differences Relating to
Long-Term Debt and Inventories

	In Sterling				
	1972	1973	1974	1975	1976
Earnings as reported by BP	£61	£604	£487	£166	£180
Changes to conform with U.S. principles:					
Dollar debts	(16)	(3)	2	(30)	(75)
Other debts	(36)	(26)	(41)	(99)	(137)
	(52)	(29)	(39)	(129)	(212)
Inventory valuation	--	--	--	(9)	47
Total changes	(52)	(29)	(39)	(138)	(165)
Adjusted income/(loss)	£ (9)	£575	£448	£ 28	£ 15
			In Dollars*		
Earnings as reported by BP	$143	$1,401	$1,144	$335	$306
Changes to conform with U.S. principles:					
Dollar debts	(38)	(7)	5	(61)	(127)
Other debts	(84)	(60)	(96)	(200)	(233)
	(122)	(67)	(91)	(261)	(360)
Inventory valuation	---	--	--	(18)	80
Total changes	(122)	(67)	(91)	(279)	(280)
Adjusted income/(loss)	$21	$1,334	$1,053	$ 56	$ 26

*Note: Translated from underlying sterling figures using year-end exchange rates as follows: (£=$)

$2.35	$2.32	$2.35	$2.02	$1.70

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

As we had argued extensively in our Report on Royal Dutch Petroleum dated March 25, 1977, which, unlike BP, has adopted U.S. accounting principles, the requirements of FASB No. 8 are of questionable merit, particularly as they relate to the currency translation of long-term debt. In BP's case, for example, nonsterling debt is generally raised to finance projects, which, in turn, are expected to generate the necessary cash flow to service the debt. It is most unlikely that the outstanding debt will ever have to be paid off in sterling. Consequently, the gains or losses from the translation of debt do not affect cash flow, nor do they jeopardize a company's financial condition. They merely introduce unfortunate fluctuations in reported earnings.

In summary, therefore, the rather bad results obtained when BP's earnings are adjusted to conform to U.S. accounting principles should not, in our opinion, be of concern to the investor because they by no means indicate the company's earning power or financial strength. Indeed, if the strengthening trend of the pound continues, particularly vis-a-vis the dollar, FASB No. 8 may well lead to currency gains if BP's results are adjusted to conform to U.S. accounting principles. Sohio's large debt would confer a windfall.

Conversion of Nonsterling Assets and Liabilities Held in the U.K.

We noted previously that BP, in contrast to accepted accounting principles in the U.S., does not include in the determination of income exchange fluctuations relating to restatement at year-end exchange rates of monetary assets and liabilities of overseas affiliates. The distinction of overseas affiliates is important. In the case of current assets and current liabilities expressed in currencies other than sterling which are not held overseas, but rather in the U.K.--such as, for example, dollar cash balances held by the parent company--the resulting exchange fluctuations are indeed included in the determination of income. This aspect of currency conversion has surfaced as a serious one last year. Because BP has apparently a large dollar exposure, in a business which is basically denominated in dollars, it incurred a sizable currency loss in 1977 as the pound strengthened, particularly toward the end of the year.

Summary

In general, BP has adopted the practice, in line with accepted accounting principles in the U.K., of translating all assets and liabilities, as well as the earnings of overseas affiliates into sterling at year-end exchange rates. This practice differs from accepted principles in the U.S., which require that some balance-sheet and most income accounts of foreign affiliates be translated at historical and average exchange rates.

In addition, there are differences between U.S. and U.K. accounting practices in the treatment of the exchange fluctuations that arise from the restatement of overseas balance-sheet accounts at year-end exchange rates. In the U.K., these fluctuations are taken to earned surplus, while in the U.S. they are included, for the most part, in the determination of current income.

DIVIDEND

BP pays a dividend twice a year: an interim dividend is paid in November of each year, and a final dividend is paid in May of the following year.

U.K. Dividend Controls

BP, like any other U.K.-based company, is subject to U.K. government controls on dividends, which restrict the increase in any year's dividend, including tax credits associated with the Advance Corporation Tax, to a maximum of 10% from the previous year's level. BP's dividend payments in recent years are shown in Table 32.

TABLE 32

BRITISH PETROLEUM
Dividend Payment Per Share
Net of Advance Corporation Tax

	In Pence		
	Interim	Final	Total
1973	4.170	11.000	15.170
1974	5.860	11.000	16.860
1975	6.250	11.740	17.990
1976	6.875	13.112(a)	19.989(a)
1977	6.981	15.121(b)	22.102(b)
	In Dollars		
1973	$.100	$.266	$.366
1974	.137	.256	.393
1975	.128	.213	.341
1976	.111	.225(a)	.336(a)
1977	.129	.280(b)(c)	.409(b)

Note: (a) Initially, the final dividend paid was 12.914 p ($.221), and the total dividend for 1976 was 19.789 p ($.332) in line with the maximum 10% permitted by legislation at that time. An additional payment for 1976 of .198 p ($.004 per share at an exchange rate of $1.85 per pound) was paid last November, to bring the year's payment to the maximum permissible amount, following the reduction in the rate of the Advance Corporation Tax from 35/65ths to 34/66ths.

(b) BP recently made an application to the U.K. Treasury for permission to increase its total dividend for 1977 to 30p ($.55). The application was not granted. BP has expressed its intention to include an increase in the final dividend for 1977, payable in May, sufficient to bring the total increase for 1977 to the maximum 10% permitted currently. This is the amount that has been reflected above. If dividend controls permit, a higher amount will be paid. In fact, BP has announced that it has reserved, for special distribution when and if dividend controls permit, the difference between the 1977 dividends actually paid and those that would have been paid had the U.K. Treasury accepted its application.

(c) Assuming an exchange rate of $1.85 per pound.

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

A critical uncertainty associated with BP, as an investment, relates to the outlook of dividend controls in the U.K. Should present controls restrict annual increases to a maximum of 10%, the growth in BP's dividend will lag considerably behind the expansion in earnings and cash flow, and the stock's yield will remain at low levels, substantially below those of the company's major competitors.

The legislation governing current dividend controls expired on July 31, 1977, but the controls have been extended for one year. BP recently made an application to the U.K. treasury for permission to increase its total dividend for 1977 to 30 pence per share ($.555 per share based on a foreign exchange rate of 1£=$1.85), a level substantially higher than the 22.102 pence ($.409 per share) that is permitted under current regulations. BP's application was not granted because it was not found to meet any of the normal criteria for dividend increases above the permissible limit. Even so, BP has announced that it is the company's intention to include an increase of 10% in the total 1977 dividend, the maximum permitted by current legislation. Moreover, BP has also announced that it will reserve the difference between the 1977 dividends actually paid and those that would have to be paid had the application to the U.K. treasury mentioned above been granted. The amount so reserved will be available for distribution as a special dividend when the removal of dividend controls permits.

<u>Removal, or at least relaxation, of dividend controls is a critical consideration in our favorable assessment of the stock. We believe that such a prospect is becoming increasingly likely in July, when relevant legislation expires</u>.

<u>Advance Corporation Tax (ACT)</u>

Another factor of critical importance to the American investor relates to the outlook for the double-taxation treaty between the U.S. and the U.K., which has been renegotiated recently. The treaty has been approved by the U.K. House of Commons, but has still not been ratified in the U.S. Before we assess the implications of the renegotiated treaty for the American investor, it is important to note that BP, under current U.K. legislation, has to pay an Advance Corporation Tax to the Internal Revenue with respect to dividends paid to shareholders. The dividends shown in Table 32 are net of the Advance Corporation Tax, which is now at a rate of 34/66ths of the net dividend. Shareholders in the U.K. are deemed, for U.K. income tax purposes, as having taxable income equal to the share of the dividend paid, plus the ACT paid by BP to the Internal Revenue. The ACT is allowed as a tax credit to the shareholder, however. Under the existing tax convention between the U.S. and the U.K., the U.S. shareholder, unlike his U.K. counterpart, is deemed as having a taxable income for U.S. income tax purposes equal only to the dividend paid. The ACT is not added back in determining taxable income, nor is the ACT available as a tax credit. Thus, the dividend received for last year by the American shareholders amounted to $0.34 per share, which is net of the ACT, and this amount is also deemed to be the stockholders' taxable income in the U.S. (Table 33).

BRITISH PETROLEUM

Gross and Net Dividend Per Share: 1976

TABLE 33

	In Pence			In Dollars		
	Interim	Final	Total	Interim	Final	Total
Paid Originally						
Gross Dividend	10.577	19.868	30.445	$.170	$.340	$.510
Less: ACT	(3.702)	(6.954)	(10.656)	(.059)	(.119	(.178)
Net Dividend	6.875	12.914	19.789	$.111	$.221	$.332
Additional Payment (a)						
Gross Dividend	--	--	--	--	--	--
Reduced ACT	--	.198	.198	--	$.004	$.004
Net Dividend	--	.198	.198	--	$.004	$.004
Total Payment						
Gross Dividend	10.577	19.868	30.445	$.170	$.340	$.510
Less: ACT	(3.702)	(6.756)	(10.458)	(.059)	.115)	(.174)
Net Dividend	6.875	13.112	19.987	$.111	$.225	$.336

Note: (a) The additional dividend payment was made to reflect a reduction in the ACT from 35/65ths to 34/66ths.

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

The renegotiated tax treaty between the U.S. and the U.K. now pending introduces the following major changes:

- The U.S. shareholder will be entitled to receive, in addition to the net dividend paid by BP, an amount equal to the ACT, which BP pays the U.K. Internal Revenue on such dividends. Thus, under the proposed treaty, the total dividend receipt by the American shareholder for 1976 would have been $0.51 per share, consisting of the $0.34 per share of net dividend paid plus the ACT of $0.17.

- The U.S. shareholder will now be subject to a 15% withholding tax on the total dividend received. For an investor who is in a taxpaying status in the U.S., the withholding tax will, of course, be available as a tax credit against his U.S. tax liability.

The revised U.S./U.K. tax treaty, combined with the prospect of relaxation of dividend controls in the U.K., enhances considerably BP's investment appeal to the U.S. investor. Consider, for example, the prospect that the dividend for 1977, should U.K. dividend controls permit, will amount to $0.555 per share, net of the ACT. This would be the amount received by the American stockholder under the existing U.K./U.S. tax convention, resulting in a dividend yield of 3.6%. Under the renegotiated tax treaty, the ACT would be included in the dividend paid to the American shareholder. Therefore, if the revised U.K./U.S. treaty were in effect, the American shareholder would be eligible for a dividend with respect to 1977 of $0.84 per share, before withholding tax, or a yield of 5.4% (Table 34). Including the 15% withholding tax which will, of course, be available as a tax credit to a taxpaying investor in the U.S., the yield drops to 4.6%.

These dividend calculations are predicated on the relaxation of dividend controls in the U.K. As shown in Table 34, should present regulations be maintained, the 1977 dividend for the American shareholder, under the provisions of the revised U.K./U.S. treaty, would total $0.62 per share.

The Outlook

Because of BP's strong earnings and cash flow expansion in the next several years, we would expect a strong expansion in dividends as well, assuming dividend controls in the U.K. permit, which we believe

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they will. A dividend payout ratio of 30%--with dividends measured on a net basis, i.e., after ACT--is a reasonable expectation, in our opinion. Such a payout ratio would result in a dividend payment to the American investor, under the provisions of the renegotiated U.S./U.K. tax treaty, of about $1.90 per share in 1981, before withholding tax. This dividend payment would consist of a net dividend of $1.25 per share plus the Advance Corporation Tax of $0.65 per share. Based on the current stock price, the yield to the American investor would, therefore, be about 12% in 1981 (Table 35).

TABLE 34

BRITISH PETROLEUM
Dividend Per Share to U.S. Shareholders for 1977
(Based on Provisions of Pending UK/US Tax Treaty)

	Based on Current UK Dividend Controls	Under Relaxed Dividend Controls
In Pence		
Net Dividend	22.102(a)	30.000(a)
Plus ACT	11.386	15.455
Gross Dividend	33.488	45.455
In Dollars(b)		
Net Dividend	$.409(a)	$.555(a)
Plus ACT	.211	.286
Gross Dividend (Amount Received by American Shareholder)	$.620	$.841
Dividend Less 15% Withholding Tax	$.527	$.715
Yield		
Before Withholding Tax	4.0%	5.4%
After Withholding Tax	3.4	4.6

Note: (a) An interim dividend of 6.981 p ($.129) per share has already been declared for the year 1977. BP has expressed the intention of paying a final dividend next year so that the total payment for the year will amount fo 30.0 p per share ($.555), if UK dividend controls permit. If controls are not lifted, BP will pay the maximum permissible under regulations, i.e., 22.102 p per share ($.409).

(b) All currency conversions are at an exchange rate of $1.85 per pound.

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

BRITISH PETROLEUM

Outlook for Dividends

TABLE 35

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	1976	1977E	1978E	1979E	1980E	1981E
Earnings per share	$0.79	$1.20	$2.45	$3.00	$3.35	$4.15
Dividend payout ratio						
After ACT	43%	33%	30%	30%	30%	30%
Dividend per share (without controls)						
After ACT[a]	$0.34	$0.41	$0.74	$0.90	$1.01	$1.25
Before ACT[b]		0.62	1.12	1.36	1.53	1.89
Dividend yield to American investor[b]						
Before withholding tax	2.2%	4.0%	7.2%	8.8%	9.9%	12.2%

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

Note: For the year 1977, the dividend shown above reflects the maximum permissible by present dividend controls in the UK (see Table 34). BP has expressed the intention of paying a final dividend with respect to 1977 so that the total payment for the year will amount to $0.55 per share, instead of the $0.41 per share shown above, if UK dividend controls permit. In that case, the dividend per share before ACT becomes $0.84 and the yield rises to 5.4%.

a. The Advance Corporation Tax has been reduced to 34/66ths of the dividend paid, from 35/65ths, and is assumed to remain at this level through the forecast period.

b. We are assuming enactment of the proposed UK/US tax treaty. Therefore, beginning in 1977, the dividend we show accruing to the American investor is before deduction of ACT.

FINANCIAL CONDITION

BP's financial condition should improve materially in the next several years, in line with the strong expansion of earnings and cash flow that we foresee. The company's debt-to-equity ratio should improve substantially from present high levels. At the same time, BP will gain the financing flexibility to maintain a high level of capital spending and to pay increasing sums of dividends to stockholders, in line with our expectation for relaxation of controls in the U.K.

Cash Flow Analysis

Our projections of cash flows are shown in Table 36. In the analysis, BP's interest in Sohio is accounted for on an equity basis, and, therefore, cash flows are adjusted for the difference between BP's equity income in Sohio and the cash dividends that we expect BP to receive from Sohio.

We estimate that BP should be able to generate an excess cash flow of more than $1.2 billion in 1977 through 1980, which will be available for: (1) payment of dividends, and (2) reduction of debt and cash advances and/or an increase in cash and marketable securities. The outlook is in sharp contrast to the experience of the previous four years, when the company experienced a cash deficit of about $850 million. To finance this deficit as well as dividend payments, BP had to resort to net financing of $1.4 billion in the period 1973-1976.

The projected cash surplus of about $1.2 billion reflects the following trends:

- Cash flow generated from operations is expected to total about $7.7 billion:

  - Net income, in line with our previous analysis, is seen contributing almost $3.9 billion to cash flow in 1977/1980, compared with only $3.2 billion in the previous four years. The latter figure includes an extraordinary gain of about $700 million from the sale of a portion of the company's production interest in Abu Dhabi.

  - Depreciation, including BP's share of TAPS, is expected to total over $2.8 billion.

TABLE 36

BRITISH PETROLEUM
Cash Flow Analysis
(Million dollars)

	Cumulative 1973 - 1976	Cumulative 1977 - 1980
CASH FLOW BEFORE DIVIDENDS AND FINANCING		
Cash Flow From Operations		
Net income (a)	$3,185	$3,875
Depreciation	1,545	2,850
Other, including deferred taxes	375	1,850
Excess of equity income of Sohio over dividends received	(35)	(860)
	$5,070	$7,715
Cash Flow Used For Operations		
Capital spending	($4,580)	($6,500)
Investment in associated companies	(520)	(250)
Working capital requirements (b)	(2,045)	(250)
	($7,145)	($7,000)
Other Cash Flow	$1,230	$ 500
CASH SURPLUS/(DEFICIT) BEFORE DIVIDENDS AND FINANCING	($845)	$1,215
DIVIDENDS	($555)	($1,075)
CASH SURPLUS/(DEFICIT) BEFORE FINANCING	($1,400)	$ 140
FINANCING		
Debt - Increase/(Decrease)	$1,805	
North Sea Advances-Increase/(Decrease)	610	
Cash - (Increase)/Decrease	($1,015)	
	$1,400	($ 140)

Notes: (a) Includes an extraordinary gain of $.7 billion from the sale of assets in Abu Dhabi.
(b) Before changes in cash and marketable securities position which are included in financing.

Translation of historical figures into dollars is at year-end exchange rates as follows ($ - £):

1973	1974	1975	1976
$2.32	$2.35	$2.02	$1.70

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

- Other cash flow, which includes mainly deferred taxes, is expected to approach $1.8 billion. These deferrals reflect, for the most part, the provision of the U.K. tax law which allows for accelerated depreciation in the payment of both the Petroleum Revenue Tax as well as corporate income taxes.

- An offsetting factor to cash generation will be a shortfall of about $850 million in BP's dividend receipts from Sohio, in relation to the company's equity income in Sohio. Dividend payments by Sohio reflect, in turn, a rise in Sohio's dividend payment ratio to less than 30% of net income in 1981, and an average of 26% during the period 1977-1981 (Table 37).

TABLE 37

BRITISH PETROLEUM
Equity Income in Sohio
Versus Dividend Receipts
(Million dollars)

	Equity Income in Sohio	Dividend Receipts	Difference
1977	$ 60	$ 15	$ 45
1978	295	55	240
1979	380	95	285
1980	420	130	290
1981	540	150	390
Total	$1,695	$445	$1,250

Note: Average dividend as a percent of average equity income: 26%
Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

To place the importance of North Sea in perspective, we estimate that in 1977 alone the Forties Field generated a cash flow (net income plus depreciation and deferred taxes) of over $1.4 billion.

- Cash used in operations is expected to total $7.0 billion over the next four years. The amount consists of the following:

- Capital spending of $6.5 billion represents a sharp rise from the $4.6 billion spent in 1972-1976. Moreover, cumulative spending in the last four years has been heavily weighted by large spending programs in 1975 and 1976 associated with TAPS and the development of the Forties Field. Capital spending is enveloped with considerable uncertainty. Over the past year, BP has undertaken an aggressive investment program, which, if pursued, would make our estimates conservative. We believe that BP will have the financing flexibility to finance even higher levels of spending.

- Investments in associated companies are projected to total $250 billion over the forecast period. Such investments have been high in recent years, to a large extent because of currency changes that do not involve cash outlays. The non-cash impact of currency changes is reflected in the other cash flow line of Table 36.

- Finally, working capital requirements, excluding cash and marketable securities, are forecast to rise by $250 million over the next four years, compared with an increase of over $2.0 billion in the previous four years.

• Other cash flow is forecast at $500 million in 1977-1980, compared with over $1.2 billion in 1972-1976. This category includes items such as insurance and unfunded pension provisions, as well as the value of currency changes that do not affect cash flow.

The cash surplus of $1.2 billion that we are projecting will be available to finance much higher dividend payments than in the past, in line with our expectations for liberalization of dividend controls in the U.K. We estimate that the remaining surplus, i.e., after payment of dividends, will total $140 million. This amount will be available for the reduction in outstanding debts and cash advances and/or the buildup of the company's cash position.

It should be emphasized that these cash flow projections do not reflect full cash benefits from BP's equity in Sohio, on the assumption that Sohio's dividend payments will rise to a payout ratio of under 30% within the forecast period. Longer term, as the payout rises toward Sohio's stated objective of 40%, the cash benefits to BP will, of course, increase substantially.

Debt Leverage

As suggested in the analysis above, BP has had to rely extensively on long-term debt financing to meet its financial requirements. As a result, BP's long-term debt at the end of last year amounted to almost $2.6 billion, resulting in a debt ratio (long-term debt as a percent of long-term debt plus shareholders' equity) of over 34.5%. Of course, a portion of this higher debt reflects the decline in value of the pound which has raised the sterling equivalent of debt denominated in nonsterling currencies--mostly U.S. dollars. Since this foreign debt will be repaid out of nonsterling revenues generated outside the U.K., the portion of the outstanding debt attributable to currency changes does not imply any real increase in BP's debt exposure. Accordingly, if we adjust for changes in currency values, the debt ratio declines slightly to under 33%. This is still an excessive level, substantially higher than the experience of the company's major competitors.

BP's debt ratio should be lowered substantially in the coming years, in line with the company's strong earnings and cash flow expansion. Excluding the impact of currency changes, we estimate a decline in the ratio to 23% in 1980, assuming that the excess flow that will be generated over the next four years will be earmarked for a net reduction in the company's North Sea advance proceeds and short-term debt. Long-term debt, therefore, is held constant at about present levels (Table 38).

But even if BP were to embark on a more ambitious investment program than the one that had already been reflected in our calculations--in which the cash surplus that we are projecting may not materialize--such a prospect will not, in our opinion, strain the company's financing flexibility. Because of the sharp buildup in stockholders' equity, BP has considerable leeway in raising new debt money, in addition to refinancing outstanding liabilities, without creating an undue burden on its debt leverage position.

BRITISH PETROLEUM
Debt Leverage
(Million dollars)

TABLE 38

	1976			1980	
	Before Currency Adj.	Currency Adjustment	After Currency Adj.	Before Currency Adj.	After Currency Adj.
	----IN STERLING----				
Long-term debt	£1,512	(£164)	£1,348		
Stockholders' equity	2,858	(80)	2,778		
Total	£4,370	£(244)	£4,126		
	----IN DOLLARS----				
Long-term debt	$2,570	($279)	$2,291	$ 2,570	$ 2,291
Stockholders' equity	4,859	(136)	4,723	7,659	7,523
Total	$7,429	($415)	$7,014	$10,229	$ 9,814
Long-term debt ratio	34.6%		32.7%	25.1%	23.3%

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

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VALUATION

BP's P E multiple of more than 13 times last year's estimated earnings of $1.20 per share is, of course, at a substantial premium in relation to the multiples of the other international oils. However, because of the strong surge of earnings that we foresee, the multiple will drop sharply to 6.5 times this year's earnings and below 4 times projected earnings in 1981. Beginning this year, therefore, BP's price-earnings ratio will decline to levels much more in line with those of its major competitors. Indeed, looking ahead to 1981, BP's multiple will be only slightly higher than the multiple for Royal Dutch Petroleum-- a company that we have been recommending and continue to recommend. Compared with Exxon, on the other hand, BP's multiple based on 1981 earnings reflects a discount of 35% (Table 39).

What is the Stock Worth?

In an attempt to place a value on BP's stock, we use a present-value stock-valuation model consisting of two components:

- The dividend stream over the next few years.
- The terminal stock value at the end of the fourth year.

The model in formula form is expressed by the following equation:

PV = (Present value of stream of dividends) + (Present value of terminal stock price)

$$\frac{D1}{(1+k)} + \frac{D2}{(1+k)^2} + \frac{D3}{(1+k)^3} + \frac{D4}{(1+k)^4} + \frac{P4}{(1+k)^4} \quad \text{(equation 1)}$$

where: PV = Present value of the stock.

D_i = Dividend in ith year, where i = 1,...,4.

k = Discount rate or required rate of return.

P_4 = Stock price at the end of the fourth year.

Derivation of the present value of the stream of dividends is straightforward, given our dividend projections over the next four years. For discount purposes we use a discount rate--which is equivalent to the rate of return required by investors--of 12%. Such a discount rate makes, we believe, an adequate allowance for the risk associated with BP's outlook as we see it. The calculation is shown in Table 40. The present value of the dividend amounts to $4.40 per share.

In arriving at the likely stock price at the end of the fourth year, i.e., in 1981, the analysis is less straightforward. We apply three alternatives:

- One approach is to project a multiple that we then assign to projected earnings. Even though BP's multiple is likely to be penalized by American investors in relation to the U.S.-based international oils, because BP is a foreign-based company that has different accounting principles than those generally accepted in the U.S., nevertheless, an offsetting positive factor to stock valuation should be the sharply improved quality of BP's operating earnings. By 1981, 85% of BP's earnings will be generated from North Sea production and its U.S. interests. For both business and political considerations, these two earnings sources should command a higher multiple than earnings from established producing areas in OPEC countries or earnings from downstream operations.

  By assigning a multiple of 7.5 times to BP's North Slope and North Sea earnings and a multiple of only 4.5 times to the rest of the company's profits, we project a price of over $29 in 1981 (Table 41).

- The terminal stock price can also be derived by determining first the dividend yield that investors are likely to expect in the future from a company like BP. A yield of 6% is, we believe, a reasonable expectation. Therefore, on the basis of this yield and the dividend amount that we have projected for 1981 of $1.90 per share, the implicit stock price at that time becomes $31.5.

- Finally, it can be argued that the stock price in 1981 will reflect the dividend growth rate expected beyond 1981 and the rate of return that will be required by investors at that time. Specifically, the value of the stock is given by the following expression:

PRICE-EARNINGS RATIOS — TABLE 39

	1977	1978	1980	1981
Earnings per share estimate				
BP	$ 1.20	$ 2.45	$ 3.35	$ 4.15
Royal Dutch Petroleum	11.55	12.65	15.25	16.50
Exxon	5.60	6.55	8.00	8.75
Multiple[a]				
BP	13.3	6.5	4.8	3.9
Royal Dutch Petroleum	4.8	4.4	3.7	3.4
Exxon	8.2	7.0	5.8	5.3

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

a. Based on stock prices as follows: BP - $16; Exxon - $46; Royal Dutch - $56.

BRITISH PETROLEUM — TABLE 40

Present Value of Dividend Stream

	Projected Dividend Amount	Present Value at 12%
1978	$1.12	$1.00
1979	1.35	1.08
1980	1.55	1.11
1981	1.90	1.21
	$5.92	$4.40

Source: Drexel Burnham Lambert Incorporated estimates and calculations.

BRITISH PETROLEUM — TABLE 41

Future Stock Price

Earnings Source:	1981 EPS	1981 Multiple	1981 Stock Value
United States and North Sea	$3.54	7.5	$26.6
Other	0.61	4.5	2.7
Total	$4.15	7.1	$29.3

Source: Drexel Burnham Lambert Incorporated estimates and calculations.

$$P_4 = \frac{D_5}{k-g} \quad \text{(equation 2)}$$

where: P_4 = stock price at the end of the fourth year, i.e., in 1981.

D_5 = dividend amount in the fifth year.

g = dividend growth rate after 1981.

k = rate of return that investors will require in 1981.

Following the surge in earnings and dividends that we expect for BP over the next several years, it is reasonable to assume that dividend growth will taper off to a more sustainable, long-term rate of about 6%, compared with the sharp rise of 40% per year that we foresee for the period 1976/1981.

For discount purposes, we would argue again that a 12% discount rate is reasonable. It makes an adequate allowance for the risk inherent in BP's longer-term outlook, assuming that less risky investment alternatives yield 7-8% at that time. Moreover, the rate is consistent with the 6% dividend yield that we have projected for BP in 1981, which, combined with a longer-term growth of 6% after 1981, results in an expected rate of return of 12%.

Substituting these values in equation 2--specifically, D_5 = \$1.90; k = 12%; and g = 6%--we derive a stock price of \$31.5 for 1981.

Based on the three different approaches discussed above, the present value of the future stock price, using a 12% discount rate in computing the present value, ranges from \$18 to \$20.

The estimated value of the stock, which includes both the present value of the future stock price as well as the dividend stream, ranges from \$23 to \$25. Finally, we note that the discounted cash flow rate of return to the present investor implicit in the three different approaches that we have adopted for valuation purposes exceeds 25%. For this exercise we use the present stock price of \$15 1/2 as surrogate for value.

BRITISH PETROLEUM

Value of Stock and Implicit Rate of Return
(Based on Three Different Approaches in
Projecting Future Stock Price)

TABLE 42

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	Alternative A	Alternative B	Alternative C
	Projecting Future Multiple	Projecting Future Dividend Yield	Projecting Longer-Term Sustainable Growth
Present value of dividend stream[a]	$ 4.40	$ 4.40	$ 4.40
Present value of future stock price[a]	18.63	20.03	20.03
Total present value of stock	$23.03	$24.43	$24.43

Source: Drexel Burnham Lambert Incorporated estimates and calculations.
a. Based on a 12% discount rate.

Conclusion

In our opinion, BP has unquestioned investment merit based on longer-term prospects, and on this basis we recommend purchase of the stock. We also caution, however, that last year's fourth quarter may be perceived as a disappointing one by investors because of the potentially large currency losses that may have been incurred toward the end of last year. It should be recognized that such a prospect, on the heels of a disappointing third quarter as well, may be a damper on the stock near term. However, it should not, in our opinion, detract from the company's operating strengths and bright outlook.

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APPENDIX

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MEMBER OF PRINCIPAL STOCK AND COMMODITY EXCHANGES

Appendix A

BRITISH PETROLEUM
Earnings by Quarter
(Millions)

	In Sterling	Exchange Rate (1£ = $) (a)	In Dollars
1975			
1Q	£ 42.2	$2.409	$102
2Q	37.3	2.198	82
3Q	37.8	2.040	77
4Q	27.6		
Year	£144.9	$2.024	$293
1976			
1Q	£ 20.2	$1.916	$ 39
2Q	51.8	1.781	92
3Q	51.9	1.678	87
4Q	55.9		
Year	£179.8	$1.702	$306
1977			
1Q	£ 90.5	$1.720	$156
2Q	75.7	1.720	130
3Q	44.1	1.747	77
4Q	31.9		
Year	£242.2	$1.92	$465

Note: (a) Quarterly earnings are translated into dollars at exchange rates as of the end of each quarter. Annual earnings are converted at year-end exchange rates.

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

Drexel Burnham Lambert Incorporated

APPENDIX B

BRITISH PETROLEUM
Income Statement, By Year
(Millions)

	In Sterling				
	1972	1973	1974	1975	1976
SALES REVENUES & OTHER INCOME					
Sales Revenues (excluding duties & sales taxes)	£2,284	£3,152	£7,810	£7,781	£10,581
Dividends and Interest from Associated Companies	10	8	12	15	14
Other Interest Royalties and Miscellaneous Income	41	86	161	164	174
Total	£2,335	£3,246	£7,983	£7,960	£10,769
COSTS & OTHER DEDUCTIONS					
Cost of Oil, Ocean Freight, and Manufacturing	£1,001	£1,374	£4,798	£5,420	£ 7,634
Distribution, Selling, Adminis. and Other Expenses	437	549	671	719	910
Depreciation and Amounts Provided re Exploration Expenditures in Non-proven Areas	121	136	164	194	266
Interest and Financing Costs	46	58	79	103	176
Income Taxes	669	825	1,771	1,374	1,598
Income Applicable to Minority Int.	2	10	25	4	6
Total	£2,276	£2,952	£7,508	£7,814	£10,590
NET INCOME BEFORE EXTRAORDINARY ITEMS	£ 59	£ 295	£ 475	£ 145	£ 180

	In Dollars				
	1972	1973	1974	1975	1976
SALES REVENUES & OTHER INCOME					
Sales Revenues (excluding duties & sales taxes)	$5,363	$7,322	$18,346	$15,749	$18,009
Dividends and Interest from Associated Companies	23	19	28	30	24
Other Interest Royalties and Miscellaneous Income	96	200	378	332	296
Total	$5,482	$7,541	$18,752	$16,111	$18,329
COSTS & OTHER DEDUCTIONS					
Cost of Oil, Ocean Freight, and Manufacturing	$2,350	$3,192	$11,271	$10,970	$12,993
Distribution, Selling, Adminis. and Other Expenses	1,026	1,275	1,576	1,455	1,549
Depreciation and Amounts Provided re Exploration Expenditures in Non-proven Areas	284	316	385	393	453
Interest and Financing Costs	108	135	186	208	300
Income Taxes	1,571	1,916	4,160	2,781	2,719
Income Applicable to Minority Int.	5	23	59	8	10
Total	$5,344	$6,857	$17,636	$15,816	$18,024
NET INCOME BEFORE EXTRAORDINARY ITEMS	$ 138	$ 685	$ 1,116	$ 294	$ 306

Notes:

--Translation from sterling into dollars is based on the year-end exchange rate as follows: ($ = 1£) $2.348 $2.323 $2.349 $2.024 $ 1.702

--Figures do not add up because of rounding.

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

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APPENDIX C

BRITISH PETROLEUM
Income Tax Detail
(Millions)

	In Sterling				
	1972	1973	1974	1975	1976
Overseas taxes					
Production taxes	£ 647	£ 777	£1,691	£1,313	£ 1,341
Other	12	33	56	10	61
Total	£ 659	£ 810	£1,747	£1,323	£ 1,402
UK taxes					
Corporation tax	---	---	---	55	138
Advance corporation tax	18	25	34	--	(71)
Transitional tax relief	(7)	(10)	(11)	(11)	--
Petroleum revenue tax	---	---	---	8	129
Total	£ 11	£ 15	£ 23	£ 51	£ 197

	In Dollars				
	1972	1973	1974	1975	1976
Overseas taxes					
Production taxes	$1,519	$1,805	$ 3,972	$ 2,658	$ 2,282
Other	28	77	132	20	104
Total	$1,547	$1,882	$ 4,104	$ 2,678	$ 2,386
UK taxes					
Corporation tax	---	---	---	111	235
Advance corporation tax	42	58	80	---	(121)
Transitional tax relief	(16)	(23)	(26)	(22)	---
Petroleum revenue tax	--	--	--	16	220
Total	$ 26	$ 35	$ 54	$ 103	$ 335

Notes:

--Translation from sterling into dollars is based on the year-end exchange rate as follows: ($ = 1£)	$2.348	$2.323	$2.349	$2.024	$1.702

--Figures do not add up because of rounding

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

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BRITISH PETROLEUM

APPENDIX D

Balance Sheet
(Millions)

	In Sterling		In Dollars	
	1975	1976	1975	1976
ASSETS				
Current Assets				
Cash	£ 753	£ 653	$1,524	$1,111
Marketable securities	57	38	115	65
	810	691	1,639	1,176
Receivables	1,678	2,087	3,396	3,552
Inventories	1,427	1,834	2,888	3,121
Total Current Assets	£3,915	£4,611	$7,924	$7,848
Long-Term Receivables	241	232	488	395
Investments				
Sohio	359	439	727	747
Other	293	344	593	585
Total Investments	£ 652	£ 783	$1,320	$1,333
Properties and Operating Assets, Net	2,415	3,149	4,888	5,360
Total Assets	£7,223	£8,775	$14,619	$14,935
LIABILITIES				
Current Liabilities				
Accounts payable	£1,819	£2,230	$ 3,682	$ 3,795
Taxes payable	219	292	443	497
Finance debts due within one year	692	764	1,401	1,300
Dividends payable	46	50	93	85
Total Current Liabilities	£2,775	£3,337	$ 5,617	$ 5,679
Long-Term Debt	993	1,511	2,010	2,572
North Sea Oil Advance Proceeds	326	319	660	543
Non-Current Liabilities	93	249	188	424
Deferred Taxes	121	184	245	313
Insurance Provisions	45	53	91	90
Unfunded Pension Provisions	90	142	182	242
Minority Interest	105	123	212	209
Total Liabilities	£4,547	£5,917	$ 9,204	$10,071
SHAREHOLDERS' EQUITY	£2,676	£2,858	$ 5,416	$ 4,864

Notes:
Translation from sterling into dollars is based on the year-end exchange rates as follows: ($ = 1£) $2.024 $1.702

Source: Published information; Drexel Burnham Lambert Incorporated estimates and calculations.

BRITISH PETROLEUM
Cash Flow Analysis
(Millions)

APPENDIX E

Drexel Burnham Lambert

	In Sterling				In Dollars			
	1973	1974	1975	1976	1973	1974	1975	1976
CASH FLOW GENERATED FROM OPERATIONS								
Income before extraordinary items and UK taxes	Ŀ 310	Ŀ 499	Ŀ 196	Ŀ 377	$ 719	$1,173	$ 396	$ 641
Less: UK taxes	(15)	(23)	(51)	(197)	(35)	(54)	(103)	(335)
	Ŀ 295	Ŀ 476	Ŀ 145	Ŀ 180	$ 684	$1,118	$ 293	$ 306
Extraordinary items	34	11	21	---	79	26	42	---
Sale of part production interest	274	---	---	---	636	--	--	---
Depreciation	136	164	194	266	316	385	392	452
Other items	(16)	26	(37)	229	(37)	61	(75)	389
Total	Ŀ 723	Ŀ 677	Ŀ 323	Ŀ 675	$1,677	$1,591	$ 652	$1,148
CASH FLOW USED FOR OPERATIONS								
Capital expenditures	Ŀ 300	Ŀ 493	Ŀ 669	Ŀ 808	$ 696	$1,159	$1,351	$1,375
Investment in Sohio	16	10	88	80	37	24	178	136
Investment in other associated companies	13	(27)	27	74	30	(63)	55	126
Working capital requirements	221	198	231	353	513	465	467	601
Total	Ŀ 550	Ŀ 674	Ŀ1,015	Ŀ1,315	$1,276	$1,584	$2,050	$2,238
OTHER CASH FLOW								
Book value of assets sold	Ŀ 72	Ŀ 30	Ŀ 33	Ŀ 48	$ 167	$ 71	$ 67	$ 82
Miscellaneous	(11)	70	60	108	(26)	165	121	184
Change in currency values	23	5	50	137	53	12	101	233
Total	Ŀ 84	Ŀ 105	Ŀ 143	Ŀ 293	$ 195	$ 247	$ 289	$ 499
DIVIDENDS	59	66	67	73	137	155	135	124
SURPLUS/(DEFICIT) BEFORE FINANCING	Ŀ 198	Ŀ 42	(Ŀ 616)	(Ŀ 420)	$ 459	$ 99	($1,244)	$ (714)
FINANCING								
Debt increase, net	21	227	317	342	49	533	640	581
Advances	25	126	161	(41)	58	296	325	(70)
Cash & marketable securities (Buildup) Drawdown	(244)	(395)	138	119	(566)	(928)	279	202
Total Financing	(Ŀ198)	(Ŀ 42)	Ŀ 616	Ŀ 420	($ 459)	($ 99)	$1,244	$ 714