

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECTS 86 / 2

937 SCOMM32: AK GENERAL STOCK OWNERSHIP CORP. 1979-80 737

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	75058	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	-38300	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

Schedule 25A

ALASKA GSOP

NET INCOME

(\$000)

YEAR	DELIVERY VOLUMES (000 BBL)	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	265505	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	DISHANTLING 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

Schedule 26A

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	148002	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	287
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

(5000)

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	136920	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: 2000

ALASKA GSOP

NET INCOME

(\$000)

YEAR	DELIVERY VOLUMES (000 BRLS)	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

Schedule 27B

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	127170	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

CORRECTION

CORRECTION

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
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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	127170	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	106943	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	37653	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 GSNP

NET INCOME

(\$000)

YEAR	DELIVERY VOLUMES (000 BBL'S)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
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	24405	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 26B

ALASKA GSOP

CASH FLOW

(\$000)

YEAR	REVENUES	NET INCOME	TOTAL SHAREHOLDERS 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	118285	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	32564	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 GSOF

NET INCOME

(\$000)

DELIVERY VOLUMES (000 BBL'S)	TARIFF	REVENUES	OPERATING EXPENSES	INTEREST	DEPRECIATION AND AMORTIZATION	INCOME TAX	NET INCOME	CITIZEN SHAREHOLDER INCOME
1982	85429	469860	92500	112000	66667	0	198693	441
1983	85429	469860	98975	107333	66667	0	196885	437
1984	85429	469860	105904	102667	66667	0	194622	432
1985	85429	469860	113317	98000	66667	0	191876	426
1986	85429	469860	121250	93333	66667	0	188610	419
1987	85429	469860	129738	88667	66667	0	184788	410
1988	85429	469860	138821	84000	66667	0	180372	400
1989	85429	469860	148538	79333	66667	0	175322	389
1990	85429	469860	158937	74666	66667	0	169590	376
1991	85429	469860	170062	70000	66667	0	163131	362
1992	85429	469860	181966	65333	66667	0	155894	346
1993	85429	469860	194704	60666	66667	0	147823	328
1994	85429	469860	208334	56000	66667	0	138859	308
1995	85429	469860	222917	51333	66667	0	128943	286
1996	85429	469860	238521	46666	66667	0	118006	262
1997	85429	469860	255217	42000	66667	0	105976	235
1998	85429	469860	273082	37333	66667	0	92778	206
1999	85429	469860	292198	32666	66667	0	78329	174
2000	85429	469860	312652	28000	66667	0	62541	138
2001	85429	469860	334537	23333	66667	0	45323	100
2002	85429	469860	357954	18666	66667	0	26573	59
2003	85429	469860	383011	14000	66667	0	6182	13
2004	85429	469860	409821	9333	66667	0	-15961	0
2005	85429	469860	438508	4666	66667	0	-39981	0

ACTUAL \$

INTEREST RATE: 700 TAX RATE: 0 INFLATION RATE: 070

PIPELINE VALUE: 1600000 POPULATION RATE: 000 POPULATION: 405

ALYESKA EXPENSE: 75000 DIRECT EXPENSE: 9000

Schedule 29B

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

Schedule 30A

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	133680	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

Schedule 30B

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

Schedule 31A

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	48386	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

Schedule 32A

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	129730	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	179552	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	82060	66667	32896	66667	42015	769572
2003	542474	72797	65517	66667	35199	66667	42479	812051
2004	542474	52653	47300	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

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A Basic Report British Petroleum

Joel D. Fischer
Constantine D. Fliakos

January 20, 1978

Price (1/20/78)	Range 1977-1978	Earnings Per Share			P/E Ratio		Yield	Return on Investment
		1976	1977E	1978E	1977E	1978E		
\$15 3/8	16 1/4 - 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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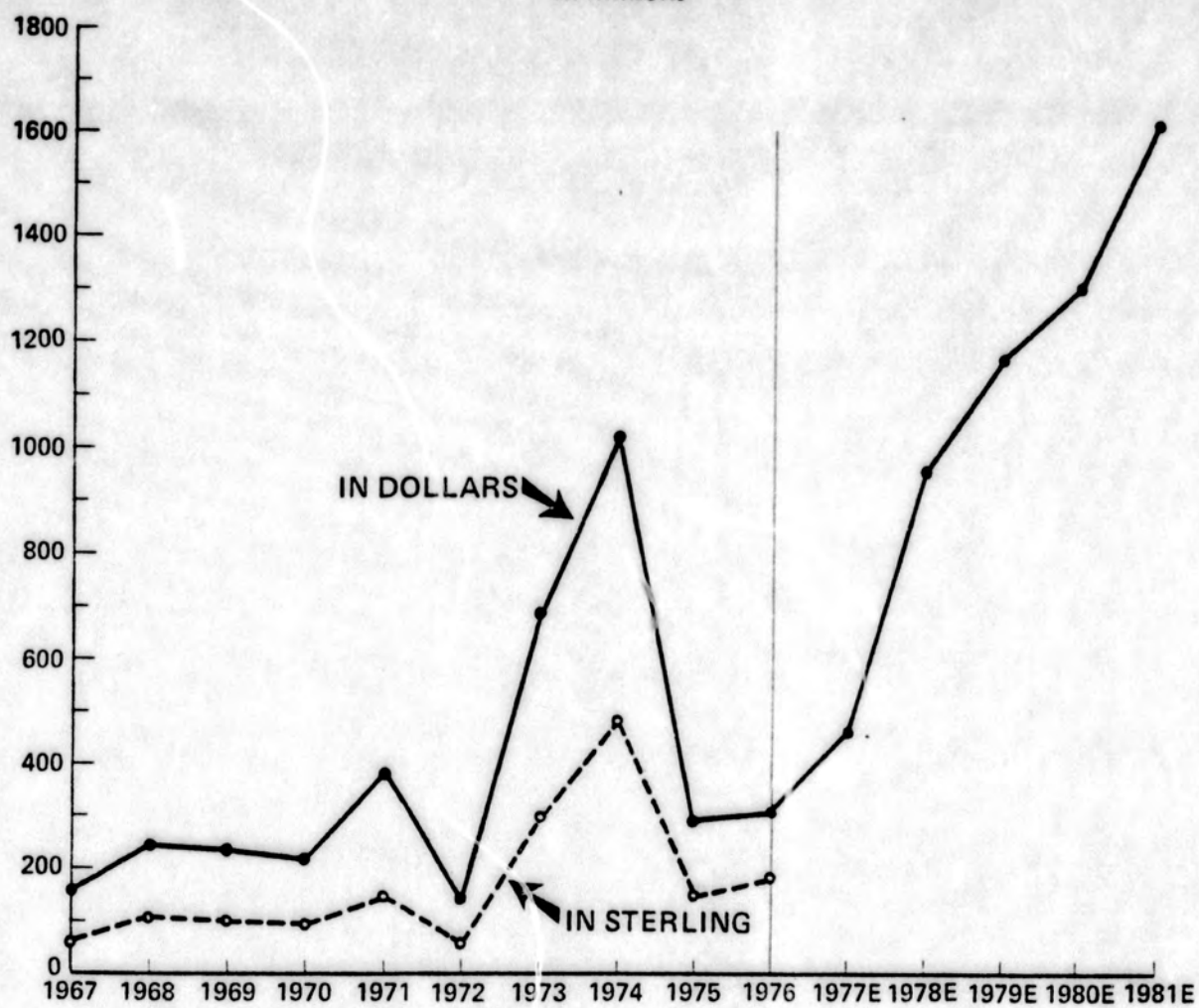
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EARNINGS
In Millions

CHART 1



Note: Earnings are before extraordinary items

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.

BRITISH PETROLEUM
Summary of Earnings
(Dollars in Millions)

TABLE 1

Drexel Burnham Lambert
INCORPORATED

	<u>1975</u>	<u>1976</u>	<u>1977E</u>	<u>1978E</u>	<u>1979E</u>	<u>1980E</u>	<u>1981E</u>
United States	\$25	\$35	\$35	\$300	\$410	\$470	\$710
<u>Foreign</u>							
Petroleum:							
North Sea production	-	\$145	\$440	\$555	\$600	\$635	\$645
Other production	<u>\$190</u>	<u>125</u>	<u>125</u>	<u>130</u>	<u>135</u>	<u>140</u>	<u>140</u>
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
	<u>\$295</u>	<u>\$305</u>	<u>\$465</u>	<u>\$950</u>	<u>\$1,160</u>	<u>\$1,300</u>	<u>\$1,600</u>
EPS	\$0.76	\$0.79	\$1.20	\$2.45	\$3.00	\$3.35	\$4.15

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.

TABLE 2

BRITISH PETROLEUM

U.S. and the North Sea

Contribution to Earnings Per Share

	<u>1975</u>	<u>1976</u>	<u>1977E</u>	<u>1978E</u>	<u>1979E</u>	<u>1980E</u>	<u>1981E</u>
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	<u>.70</u>	<u>.32</u>	<u>(.03)</u>	<u>.22</u>	<u>.36</u>	<u>.48</u>	<u>.61</u>
	\$.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	<u>92</u>	<u>41</u>	<u>(3)</u>	<u>9</u>	<u>12</u>	<u>14</u>	<u>15</u>
	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 balances. 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

<u>Thousand Barrels Per Day</u>	<u>1975</u>	<u>1976</u>	<u>1977E</u>	<u>1978E</u>	<u>1979E</u>	<u>1980E</u>	<u>1981E</u>
Forties (96%)	20	180	395	480	480	475	420
Ninian (15%)	--	---	---	5	25	45	50
Buchan (54%)	--	---	---	---	---	---	10
Magnus (100%)	--	---	---	---	---	---	25
	<u>20</u>	<u>180</u>	<u>395</u>	<u>485</u>	<u>505</u>	<u>520</u>	<u>505</u>
Million barrels		65	144	176	184	190	184
Profit margin per barre.	--	\$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.

BRITISH PETROLEUM
North Sea Profitability - Forties Field
(Dollars Per Barrel)

TABLE 4

	<u>Under Current Price</u>	<u>With Price Escalation</u>
<u>PROFIT PER BARREL</u>		
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	<u>(3.30)</u>	<u>(3.90)</u>
Net profit	<u>\$3.05</u>	<u>\$3.60</u>
<u>PETROLEUM REVENUE TAX (PRT)</u>		
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	<u>(0.65)</u>	<u>(0.70)</u>
Taxable base for PRT	\$9.35	\$11.35
PRT @ 45%	\$4.20	\$5.10
<u>CORPORATION TAX</u>		
Wellhead price	\$13.80	\$16.25
Royalty	(1.70)	(2.05)
Operating cost	(0.60)	(0.65)
Depreciation	(0.95)	(0.95)
PRT	<u>(4.20)</u>	<u>(5.10)</u>
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.

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 net profits interest 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, BP's equity in Sohio 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.

BRITISH PETROLEUM
Projected U.S. Earnings
(Millions of Dollars)

TABLE 5

ICC-PREScribed TARIFF

<u>Sources</u>	<u>Current Price Case</u>					<u>Price Escalation Case</u>			
	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>
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 (Percent)	60.0 29.9%	285.0 48.3%	335.0 51.3%	345.0 52.1%	420.0 53.3%	295.0 48.3%	380.0 51.3%	420.0 52.1%	540.0 53.3%
Total	<u>\$35.0</u>	<u>\$288.0</u>	<u>\$365.0</u>	<u>\$392.0</u>	<u>\$565.0</u>	<u>\$298.0</u>	<u>\$410.0</u>	<u>\$467.0</u>	<u>\$710.0</u>

a. Includes ITC.

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BRITISH PETROLEUM
Projected U.S. Earnings
(Millions of Dollars)

TABLE 6

INITIAL TARIFFS SUBMITTED BY THE COMPANIES

<u>Sources</u>	<u>Current Price Case</u>					<u>Price Escalation Case</u>			
	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>
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 (Percent)	60.0 29.9%	260.0 48.3%	315.0 51.3%	340.0 52.1%	405.0 53.3%	280.0 48.3%	370.0 51.3%	405.0 52.1%	535.0 53.3%
Total	<u>\$35.0</u>	<u>\$340.0</u>	<u>\$420.0</u>	<u>\$466.0</u>	<u>\$610.0</u>	<u>\$360.0</u>	<u>\$475.0</u>	<u>\$532.0</u>	<u>\$765.0</u>

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)	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)	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 well-head 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
Benchmark Pipeline Models
(Dollars Per Barrel)

TABLE 8

	Owners'		ICC's	
	<u>Proposed Tariffs</u>		<u>Authorized Tariffs</u>	
	<u>BP</u>	<u>Sohio</u>	<u>BP</u>	<u>Sohio</u>
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	<u>1.452</u>	<u>1.346</u>	<u>0.569</u>	<u>0.574</u>
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
Fourth-Quarter 1977 Pipeline Model
(Dollars Per Barrel)

TABLE 9

	Owners'		ICC's	
	Proposed Tariffs		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.

BRITISH PETROLEUM AND SOHIO
Pipeline Earnings, 1978 Costs
(Dollars Per Barrel)

TABLE 10

	Owners'		ICC's	
	Proposed Tariffs		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
Pipeline Earnings, By Quarter
(Dollars Per Barrel)

TABLE 11

	<u>BP</u>	<u>Sohio</u>
<u>1977</u>		
III Q ^a	\$(2.37)A	\$(2.48)A
IV Q ^b	(0.78)	(1.00) ^c

If Initial Tariffs Remain In Force

<u>1978</u>		
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

<u>1978</u>		
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 retorted 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-1980 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."

BRITISH PETROLEUM AND SOHIO
Pipeline Earnings,
1979-1981 Costs and Volumes
(Dollars Per Barrel)

TABLE 12

	Owners'		ICC's	
	Proposed Tariffs		Authorized Tariffs	
	BP	Sohio	BP	Sohio
<u>A. 1979 Costs</u>				
	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
<u>B. 1980 Costs and Volumes</u>				
	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
<u>C. 1981 Costs and Volumes</u>				
	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.

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. 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 long-term-controlled tonnage. 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.

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. 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	1978	1979	1980	1981	Price Escalation Case			
	4th Q					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	1978	1979	1980	1981	Price Escalation Case			
	4th Q					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	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.

TABLE 15

BRITISH PETROLEUM AND SOHIO
Projected Operating Rates in Alaska
(Thousands of Barrels Per Day)

	<u>Production/ Throughput</u>	<u>Share of TAPS Throughput</u>		<u>Sohio's Share of Production</u>	
		<u>BP</u>	<u>Sohio</u>	<u>Gross</u>	<u>Net</u>
<u>1977</u>					
III Q	474/466 ^a	74	155	252	221 ^b
IV Q	725	115	242	385	337
<u>1978</u>					
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	<u>1,100</u>	<u>174</u>	<u>367</u>	<u>585</u>	<u>512</u>
Year	1,012	160	338	538	471
<u>1979</u>					
Year	1,100	174	367	585	512
<u>1980</u>					
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	<u>1,300</u>	<u>206</u>	<u>433</u>	<u>691</u>	<u>605</u>
Year	1,200	190	400	638	558
<u>1981</u>					
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
<u>Contribution^e</u>	\$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
Contribution of Alaska-Integrated
(Millions of Dollars)

TABLE 17

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)

	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>
Crude Oil Production	\$250	\$195	\$190	\$190	\$190	\$195	\$190
Natural Gas	---	5	10	20	30	35	45
Exploration Expense	<u>(60)</u>	<u>(75)</u>	<u>(75)</u>	<u>(80)</u>	<u>(85)</u>	<u>(90)</u>	<u>(95)</u>
	<u>\$190</u>	<u>\$125</u>	<u>\$125</u>	<u>\$130</u>	<u>\$135</u>	<u>\$140</u>	<u>\$140</u>

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 to 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 PETROLEUM

Foreign Crude Oil Production and Supply
Excluding North Sea: Volumes and Profits

	<u>1975</u>	<u>1976</u>	<u>1977E</u>	<u>1978E</u>	<u>1979E</u>	<u>1980E</u>	<u>1981E</u>
<u>Thousand Barrels Per Day</u>							
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
<u>Million Barrels Per Year</u>	1,250	1,225	1,150	1,135	1,105	1,075	1,050
<u>Profit Margin Per Barrel</u>	\$.20	\$.16	\$.16	\$.17	\$.17	\$.18	\$.18
<u>Profits In Millions</u>	\$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)

	<u>1975</u>	<u>1976</u>	<u>1977F</u>	<u>1978F</u>	<u>1979F</u>	<u>1980F</u>	<u>1981E</u>
<u>Crude Supplies</u>							
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
<u>Crude Required for BP Refineries</u>	(1,720)	(1,900)	(1,975)	(2,075)	(2,150)	(2,220)	(2,275)
<u>Other</u>	(20)	(60)	(50)	(50)	(50)	(50)	(50)
	(1,740)	(1,960)	(2,025)	(2,125)	(2,200)	(2,270)	(2,325)
<u>Crude Sales to Third Parties</u>	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

	<u>1975</u>	<u>1976</u>	<u>1977E</u>	<u>1978E</u>	<u>1979E</u>	<u>1980E</u>	<u>1981E</u>
<u>Million Cubic Feet Per Day</u>							
North Sea	165	182	200	190	180	170	165
Other	<u>133</u>	<u>168</u>	<u>225</u>	<u>300</u>	<u>350</u>	<u>425</u>	<u>475</u>
	298	350	425	490	530	595	640
<u>Billion Cubic Feet Per Year</u>	109	128	155	175	195	215	235
<u>Profit Margin Per mcf</u>	---	\$.05	\$.07	\$.11	\$.15	\$.17	\$.19
<u>Profits In Millions</u>	<u>\$--</u>	<u>\$5</u>	<u>\$10</u>	<u>\$20</u>	<u>\$30</u>	<u>\$35</u>	<u>\$45</u>

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 North-western 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.

BRITISH PETROLEUM: Refining Capacities
Outside North America

TABLE 24

	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.

BRITISH PETROLEUM: Refinery Runs
Outside North America

TABLE 25

	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.

BRITISH PETROLEUM: Refined Product Sales
Outside North America

TABLE 26

	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.