D. Current Profits

Per-barrel North Slope profits for calendar year 1991 by field are displayed in Tables 12-A through 12-G. Table 12-A summarizes all fields and feeder pipelines; Tables 12-B through 12-G break down the summary data for 1991 by producing field. Producers' profits on production and pipelining average $4.77 per barrel, ranging from $5.38 per barrel for Prudhoe Bay oil to $0.60 per barrel for Milne Point oil.

To avoid overstating industry income and profits, Deakin chose conservative numbers when he encountered data discrepancies. According to Deakin, this approach resulted in a probable understatement of revenue and per-barrel profits. For example, Deakin relied on the price the companies reported to the State of Alaska for tax and royalty payments. That price was liable to be lower than the prevailing market prices. Delayed payments to the state in settlement of tax and royalty disputes typially include payments for previous years, confirming higher per-barrel prices than the reported prices on which Deakin relied. (Oil Industry Profitability in Alaska, 1969 through 1987, pp. T-58, T-59).

Deakin's per-barrel profit figures have been re-stated for consistency with this report. Deakin delineated per-barel profits in terms of working interest ownership, excluding royalty barrels; this report spreads revenues, costs (including royalty payments) and profits across total barrels.

CY 1991 North Slope Barrel Profit Analysis (Table 12-A)

North Slope Profit Analysis: ALL FIELDS	/ - - CY 91 ANS Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.35	$17.21	Dept. of Revenue data
2 Quality Adjusted Price			
3 Production / Disposition (Bbls. year / Day)			
a Production (mm bbls. yr. / day) 664.870 / 1.822			DNR 1992 Historical Oil Production (incl. NGL's)
b. Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4 Feeder Pipeline Tariffs	($0.10)	($0.10)	Wghtd. avg. sum of items 4a thru 4g
a Operating & capital costs	($0.04)	($0.04)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	$0.00	$0.00	30% of total DOR property tax
c State income tax (pipelines)	$0.00	$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.01)	($0.01)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.02)	($0.02)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.01)	($0.01)	"
g DR&R allowance	$0.00	$0.00	"
5 TAPS Pipeline Tariff	($3.41)	($3.41)	Sum of items 5a thru 5h
a Operating & capital costs	($1.31)	($1.31)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.65)	($0.65)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.49)	($0.49)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.64)	($0.64)	"
g DR&R allowance	($0.08)	($0.08)	"
h Pumpability Charge			Dept. of Revenue data
6 State Share (Feeder Lines)	($0.01)	($0.01)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.01)	($0.01)	Item 4d
8 Industry Profit (Feeder Lines)	$0.03	$0.03	Sum of items 4e, 4f
9 State Share (TAPS)	($0.25)	($0.25)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.65)	($0.65)	Item 5d
11 Industry Profit (TAPS)	$1.13	$1.13	Sum of items 5e, 5f
12 Tanker to Gulf / West Coast	($3.53)	($1.67)	USFRA data (DOR)
13 Wellhead value	$11.02	$12.64	Sum of items 1, 4, 5, 12
14 State Royalties, Production & Property Taxes	($3.01)	($3.41)	Sum of items 14a thru 14d
a Royalty	($1.30)	($1.50)	Item 13 less field costs * est. field royalty
b Severance tax	($1.31)	($1.51)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	$.054 * .875	
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($3.49)	($3.49)	Sum of items 15a, 15b
a Lifting Costs	($1.19)	($1.19)	Derived from trade publication estimates
b Depletion, Depreciation & Amortization	($2.30)	($2.30)	Derived from trade publication estimates
16 Net Revenue (production)	$4.52	$5.74	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.15)	($0.15)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($1.40)	($1.79)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$2.96	$3.79	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$3.42	$3.82	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$2.06	$2.45	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$4.12	$4.95	Sum of items 8, 11, 19
23 CY 91 Industry Avg. per-barrel ANS Profit		$4.77	

CY 1991 North Slope Barrel Profit Analysis (Table 12-B)

North Slope Profit Analysis: PRUDHOE BAY	/ - - CY 91 Prudhoe Avg. ($/bbl.) - - / Gulf Coast	West Coast	/ Notes
1 Average Price for ANS (Spot)	$18.35	$17.21	Dept. of Revenue data
2 Quality Adjusted Price	$18.68	$17.54	From DOR data
3 Production / Disposition — Bbls. year / Day			
a Production (mm bbls. yr. / day) 486.706 / 1.330			DNR 1992 Historical Oil Production (incl. NGL's)
b. Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff	($3.41)	($3.41)	Sum of items 5a thru 5h
a Operating & capital costs	($1.31)	($1.31)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.65)	($0.65)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.49)	($0.49)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.64)	($0.64)	"
g DR&R allowance	($0.08)	($0.08)	"
h Pumpability Charge	$0.00	$0.00	Dept. of Revenue data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)	($0.25)	($0.25)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.65)	($0.65)	Item 5d
11 Industry Profit (TAPS)	$1.13	$1.13	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.83)	($1.07)	USFRA data (DOR)
13 Wellhead value	$11.44	$13.07	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($3.22)	($3.64)	Sum of items 14a thru 14d
a Royalty	($1.33)	($1.54)	Item 13 less field costs * est. field royalty
b Severance tax	($1.49)	($1.70)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($2.75)	($2.75)	Sum of items 15a, 15b
a Lifting Costs	($0.95)	($0.95)	Salomon Bros., June 25, 1991
b Depletion, Depreciation & Amortization	($1.80)	($1.80)	Salomon Bros., June 25, 1991
16 Net Revenue (production)	$5.47	$6.68	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.15)	($0.15)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($1.71)	($2.09)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$3.61	$4.43	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$3.62	$4.04	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$2.35	$2.74	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$4.74	$5.56	Sum of items 8, 11, 19
23 CY 91 Industry Avg. per-barrel Profit (Prudhoe Bay)		$5.38	

CY 1991 North Slope Barrel Profit Analysis (Table 12-C)

North Slope Profit Analysis: KUPARUK	/--CY 91 Kuparuk Avg. ($/bbl.)--/ Gulf Coast	West Coast	Notes
1 Average Price for ANS (Spot)	$18.35	$17.21	Dept. of Revenue data
2 Quality Adjusted Price	$17.26	$16.12	From DOR data
3 Production / Disposition *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 113.532 / 0.311			DNR 1992 Historical Oil Production (incl. NGL's)
b. Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4 Feeder Pipeline Tariffs	($0.21)	($0.21)	Sum of items 4a thru 4g
a Operating & capital costs	($0.08)	($0.08)	Pro-rated from TAPS estimates
b State & local property tax (pipelines)	($0.01)	($0.01)	Pro-rated from TAPS estimates
c State income tax (pipelines)	($0.01)	($0.01)	Pro-rated from TAPS estimates
d Federal income tax (pipelines)	($0.04)	($0.04)	Pro-rated from TAPS estimates
e After-tax margin	($0.03)	($0.03)	Pro-rated from TAPS estimates
f Recovery of deferred return	($0.04)	($0.04)	Pro-rated from TAPS estimates
g DR&R allowance	$0.00	$0.00	Pro-rated from TAPS estimates
5 TAPS Pipeline Tariff	($3.70)	($3.70)	Sum of items 5e thru 5h
a Operating & capital costs	($1.31)	($1.31)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.65)	($0.65)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.49)	($0.49)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.64)	($0.64)	"
g DR&R allowance	($0.08)	($0.08)	"
h Pumpability Charge	($0.29)	($0.29)	From DOR data
6 State Share (Feeder Lines)	($0.02)	($0.02)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.04)	($0.04)	Item 4d
8 Industry Profit (Feeder Lines)	$0.07	$0.07	Sum of items 4e, 4f
9 State Share (TAPS)	($0.25)	($0.25)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.65)	($0.65)	Item 5d
11 Industry Profit (TAPS)	$1.13	$1.13	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.83)	($1.07)	USFRA data (DOR)
13 Wellhead value	$9.52	$11.15	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.60)	($2.99)	Sum of items 14a thru 14d
a Royalty	($1.13)	($1.34)	Item 13 less field costs * est. field royalty
b Severance tax	($1.07)	($1.25)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($4.95)	($4.95)	Sum of items 15a, 15b
a Lifting Costs	($1.65)	($1.65)	Salomon Bros., June 25, 1991
b Depletion, Depreciation & Amortization	($3.30)	($3.30)	Salomon Bros., June 25, 1991
16 Net Revenue (production)	$1.97	$3.21	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.15)	($0.15)	from DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.58)	($0.98)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$1.23	$2.07	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$3.02	$3.40	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.27	$1.67	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$2.43	$3.27	Sum of items 8, 11, 19
23 CY 91 Industry Avg. per-barrel Profit (Kuparuk)		$3.09	

CY 1991 North Slope Barrel Profit Analysis (Table 12-D)

North Slope Profit Analysis: ENDICOTT	/ - - CY 91 Endicott Avg. ($/bbl) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.35	$17.21	Dept. of Revenue data
2 Quality Adjusted Price	$17.37	$16.23	From DOR data
3 Production / Disposition — Bbls. year / Day			
a Production (mm bbls. yr. / day) 42.530 / 0.116			DNR 1992 Historical Oil Production (incl. NGL's)
b. Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4 Feeder Pipeline Tariffs	($0.71)	($0.71)	Sum of items 4a thru 4g
a Operating & capital costs	($0.29)	($0.29)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.03)	($0.03)	30% of total DOR property tax
c State income tax (pipelines)	($0.01)	($0.01)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.07)	($0.07)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.20)	($0.20)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.08)	($0.08)	"
g DR&R allowance	($0.03)	($0.03)	"
5 TAPS Pipeline Tariff	($3.58)	($3.58)	Sum of items 5a thru 5h
a Operating & capital costs	($1.31)	($1.31)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.65)	($0.65)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.49)	($0.49)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.64)	($0.64)	"
g DR&R allowance	($0.08)	($0.08)	"
h Pumpability Charge	($0.17)	($0.17)	From DOR data
6 State Share (Feeder Lines)	($0.04)	($0.04)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.07)	($0.07)	Item 4d
8 Industry Profit (Feeder Lines)	$0.28	$0.28	Sum of items 4e, 4f
9 State Share (TAPS)	($0.25)	($0.25)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.65)	($0.65)	Item 5d
11 Industry Profit (TAPS)	$1.13	$1.13	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.83)	($1.07)	USFRA data (DOR)
13 Wellhead value	$9.25	$10.88	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.44)	($2.81)	Sum of items 14a thru 14d
a Royalty	($1.26)	($1.49)	Item 13 less field costs * est. field royalty
b Severance tax	($0.78)	($0.92)	Item 13 *.856 * nominal severance* ELF
c Spill Response & Cons. ($.054/bbl*.875)	($0.05)	($0.05)	$.054 * .856
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($5.82)	($5.82)	Sum of items 15a, 15b
a Lifting Costs	($1.94)	($1.94)	Derived from trade data
b Depletion, Depreciation & Amortization	($3.88)	($3.88)	Derived from trade data
16 Net Revenue (production)	$0.99	$2.24	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.15)	($0.15)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.27)	($0.67)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$0.57	$1.41	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.89	$3.26	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$0.98	$1.38	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$1.98	$2.83	Sum of items 8, 11, 19
23 CY 91 Industry Avg. per-barrel Profit (Endicott)		$2.64	

CY 1991 North Slope Barrel Profit Analysis (Table 12-E)

North Slope Profit Analysis: LISBURNE	/ - - CY 91 Lisburne Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.35	$17.21	Dept. of Revenue data
2 Quality Adjusted Price	$19.33	18.19	From DOR data
3 Production / Disposition *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 14.652 / 0.040			DNR 1992 Historical Oil Production (incl. NGL's)
b. Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff	($3.11)	($3.11)	Sum of items 5a thru 5h
a Operating & capital costs	($1.31)	($1.31)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.65)	($0.65)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.49)	($0.49)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.64)	($0.64)	"
g DR&R allowance	($0.08)	($0.08)	"
h Pumpability Charge	$0.30	$0.30	From DOR data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)	($0.25)	($0.25)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.65)	($0.65)	Item 5d
11 Industry Profit (TAPS)	$1.13	$1.13	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.83)	(1.07)	USPRA data (DOR)
13 Wellhead value	$12.39	$14.07	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($1.92)	($2.13)	Sum of items 14a thru 14d
a Royalty	($1.45)	($1.65)	Item 13 less field costs * est. field royalty
b Severance tax	($0.06)	($0.07)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($8.45)	($8.45)	Sum of items 15a, 15b
a Lifting Costs	($2.80)	(2.80)	Salomon Bros. June 25, 1991
b Depletion, Depreciation & Amortization	($5.65)	(5.65)	Salomon Bros. June 25, 1991
16 Net Revenue (production)	$2.03	$3.44	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.15)	($0.15)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.60)	($1.05)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$1.27	$2.23	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.32	$2.53	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.25	$1.70	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$2.40	$3.36	Sum of items 8, 11, 19
23 CY 91 Industry Avg. per-barrel Profit (Lisburne)		$3.15	

CY 1991 North Slope Barrel Profit Analysis (Table 12-F)

North Slope Profit Analysis: MILNE PT.	/ - - CY 91 Milne Pt. Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.35	$17.21	Dept. of Revenue data
2 Quality Adjusted Price	$17.02	$15.88	From DOR data
3 Production / Disposition (Bbls. year / Day)			
a Production (mm bbls. yr. / day) 7.457 / 0.020			DNR 1992 Historical Oil Production (incl. Schrader BL)
b. Volume to East / West Coast (%)	21.93%	78.07%	From DOR data
4 Feeder Pipeline Tariff (Milne Pt. only)	($1.36)	($1.36)	Sum of items 4a thru 4g
a Operating & capital costs	($0.88)	($0.88)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.06)	($0.06)	30% of total DOR property tax
c State income tax (pipelines)	($0.02)	($0.02)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.13)	($0.13)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.16)	($0.16)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.05)	($0.05)	"
g DR&R allowance	($0.06)	($0.06)	"
5 TAPS Pipeline Tariff	($4.00)	($4.00)	Sum of items 5a thru 5h
a Operating & capital costs	($1.31)	($1.31)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pepelines)	($0.65)	($0.65)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.49)	($0.49)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.64)	($0.64)	"
g DR&R allowance	($0.08)	($0.08)	"
h Pumpability Charge	($0.59)	($0.59)	From DOR data
6 State Share (Milne Pt. Feeder Line)	($0.09)	($0.09)	Sum of items 4b, 4c
7 Federal Share (Milne Pt. Feeder Line)	($0.17)	($0.13)	Item 4d
8 Industry Profit (Milne Pt. Feeder Line)	$0.21	$0.21	Sum of items 4e, 4f
9 State Share (TAPS)	($0.25)	($0.25)	Sum of items 5b, 5c (to TAPS owners)
10 Federal Share (TAPS)	($0.65)	($0.65)	Item 5d
11 Industry Profit (TAPS)	$1.13	$1.13	Sum of items 5e, 5f (to TAPS owners)
12 Tanker (to Gulf / West Coast)	($3.83)	($1.07)	USFRA data (DOR)
13 Wellhead value	$7.63	$9.25	Sum of items 2, 4, 5, 12 + ($0.21) Kuparuk Pipe tariff
14 State Royalties, Production & Property Taxes	($1.67)	($2.01)	Sum of items 14a thru 14d
a Royalty	($1.27)	($1.57)	Item 13 less field costs * est. field royalty
b Severance tax	$0.00	($0.03)	Item 13 *.817 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($6.20)	($6.20)	Sum of items 15a, 15b
a Lifting Costs	($2.07)	($2.07)	Derived from trade data
b Depletion, Depreciation & Amortization	($4.13)	($4.13)	Derived from trade data
16 Net Revenue (production)	($0.24)	$1.05	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.15)	($0.15)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	$0.00	($0.29)	West: Est. 32.1% of items 16 + 17; Gulf Coast negative
19 Milne Pt. Profit (production)	($0.39)	$0.61	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.17	$2.50	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$0.82	$1.07	Sum of items 7, 10, 18
22 Total Milne Profit (production + pipeline)	($0.18)	$0.82	Sum of items 8 (Milne Pt. Pipeline only), 19
23 CY 91 Industry Avg. per-barrel Profit (Milne Pt.)		$0.60	

CY 1991 North Slope Barrel Profit Analysis (Table 12-G)

North Slope Profit Analysis: OTHER	/ - - CY 91 Other Revenue Avg. ($/bbl.) - - /		Notes
(Kuparuk Pipeline tariff on Milne Pt. Oil)	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	(n.a.)	(See analysis of Milne Pt. oil)
2 Quality Adjusted Price		(n.a.)	
3 Production / Disposition (Milne Pt.) *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 7.457 / 0.020			
b. Volume to East / West Coast (%)	0.00%	(n.a.)	
4 Feeder Pipeline Tariff (Kuparuk's Milne Pt. oil)	($0.21)	($0.21)	Sum of items 4a thru 4g
a Operating & capital costs	($0.10)	($0.10)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.01)	($0.01)	30% of total DOR property tax
c State income tax (pipelines)	$0.00	$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.03)	($0.03)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.05)	($0.05)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.01)	($0.01)	"
g DR&R allowance	$0.00	$0.00	"
5 TAPS Pipeline Tariff			
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
h Pumpability Charge			
6 State Share (Kuparuk's Milne Pt. oil)	($0.02)	($0.02)	Sum of items 4b, 4c
7 Federal Share (Kuparuk's Milne Pt. oil)	($0.03)	($0.03)	Item 4d
8 Industry Profit (Kuparuk's Milne Pt. oil)	$0.05	$0.05	Sum of items 4e, 4f
9 State Share (TAPS)			
10 Federal Share (TAPS)			
11 Industry Profit (TAPS)			
12 Tanker (to Gulf / West Coast)	____	____	
13 Wellhead value			
14 State Royalties, Production & Property Taxes			
a Royalty			
b Severance tax			
c Spill Response & Conservation Taxes			
d State & local property tax (production)			
15 Production costs			
a Lifting Costs			
b Depletion, Depreciation & Amortization	____	____	
16 Net Revenue (production)			
17 State Income Tax (production)			
18 Federal Income Tax (production)	____	____	
19 Industry Profit (production)			
20 Total State Share (production + pipelines)	$0.02	$0.02	Sum of items 6, 9, 14, 17 (Kuparuk Pipeline only)
21 Total Federal Share (production + pipelines)	$0.03	$0.03	Sum of items 7, 10, 18 (Kuparuk Pipeline only)
22 Total Industry Profit (Kuparuk's Milne Pt. oil)	$0.05	$0.05	Sum of items 8, 11, 19 (Kuparuk Pipeline only)
23 CY 91 Industry Avg. per-barrel Profit (Kup. Pipe / Milne Pt. oil)		$0.05	

One can estimate the North Slope producers' total profits from Alaska operations for 1991 by multiplying the estimated per-barrel profit of $4.77 by the 664.9 million barrels produced during the course of that year; the North Slope producers' total profit on their Alaska operations would be $3,006,000,000 ($3.006 billion). If the North producers were a single corporation — in fact, three companies control over 90% of North Slope production and pipeline profits and work closely together in most aspects of their operations — the North Slope Oil Corporation would have been in a dead heat with Phillips Morris for second place among the most profitable corporations in the United States in 1991.[61]

The following graph shows 1991 North Slope profits in relation to the profits earned by the nation's most profitable corporations for that year.

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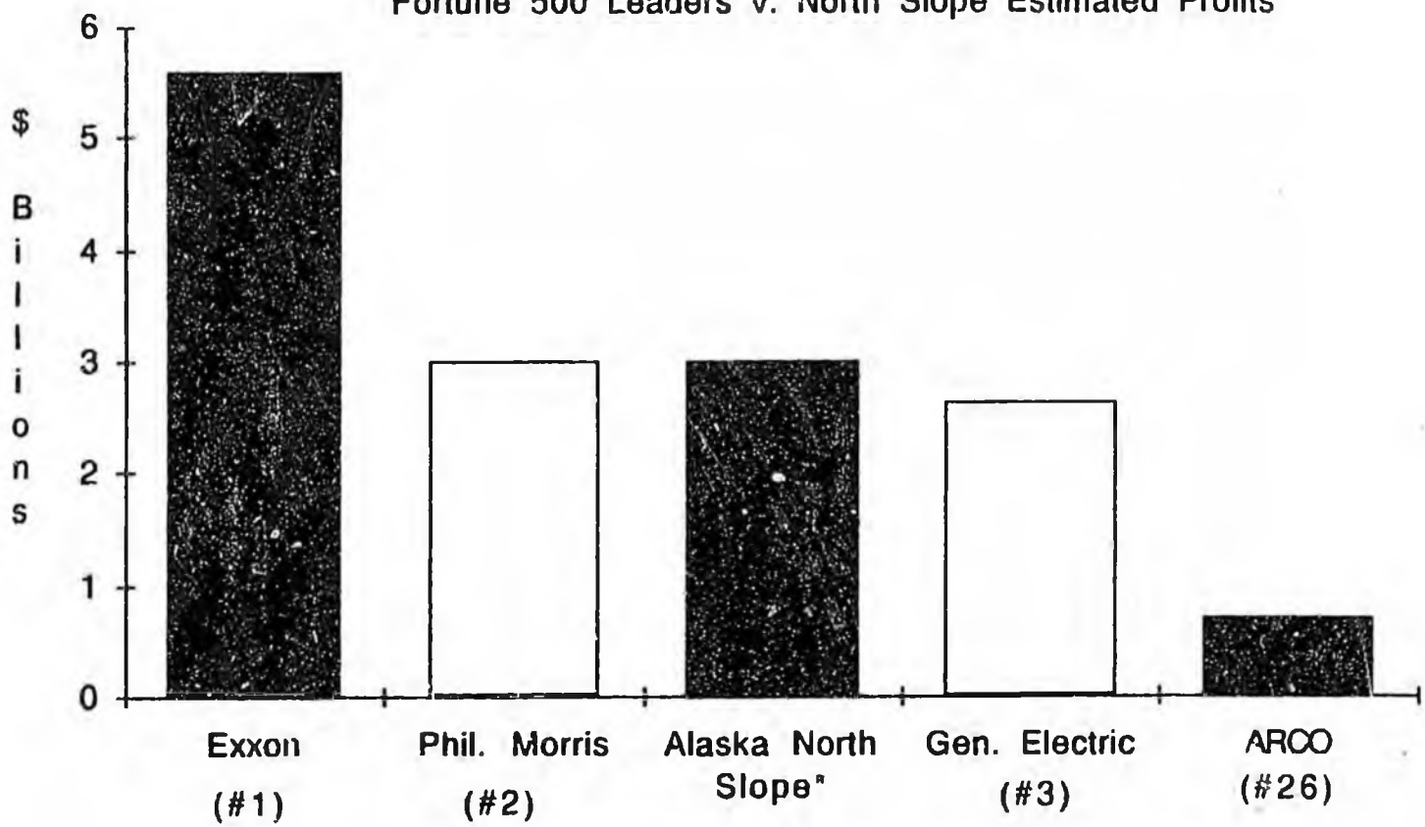
[61] Fortune, April 20, 1992.

Graph 2.

CY 1991 Estimated Profits

Fortune 500 Leaders v. North Slope Estimated Profits



* Principally Exxon, ARCO and BP (BP is not listed in Fortune 500)

Sources: Fortune, April 20, 1992; Table 12-A

The industry's $3 billion profit earned North Slope operations does not include:

==> downstream profits from marine transportation, refining and marketing of North Slope crude oil;

==> the intangible value to the vertically integrated North Slope producers of assuring its refineries a stable supply of crude oil through its North Slope production; and

==> off-book or hidden profits totalling hundreds of millions of dollars from the accumulation of funds such as TAPS DR&R collections.[62]

North Slope'profits for 1991 were impressive, but they were not unusual. ARCO reports after-tax profits for its ARCO Alaska production arm, ARCO Alaska, in its annual report. ARCO Alaska's 1991 income of $413 million, down 41% from 1990's Mid-East crisis high, was 13% below the company's 1987-89 average.[63]

Tables 13A-G and 14A-G present composite and field per-barrel profit estimates for state fiscal year 1992 (FY 92) and calendar year 1992 (CY 92) through September. FY 92 fell into a price trough. Oil prices dropped after the the U.S. bombardment of Iraq in early 1991 and did not rebound for more than a year. Thus FY 92 may be used as a conservative indicator of North Slope oil profits. The average North Slope per-barrel profit for FY 92 dropped to $4.51, down $0.26 per barrel from CY 91. Estimated profits rebounded to an estimated $4.72 for the current calendar year. In addition to indicating the magnitude and the consistent nature of North Slope profits, these tables also serve to demonstrate the subtleties of relationship between price and profitability.

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[62] DR&R pay-outs may have significant affects on future production scenarios (see Hidden Billions: The TAPS DR&R Provision, (op. cit.).

[63] Atlantic Richfield Co., 1991 Annual Report, p. 61. ARCO Alaska's profit is derived almost entirely from its North Slope production; TAPS profits are included with a different subdivision, the ARCO Transportation Co.

FY 1992 North Slope Barrel Profit Analysis (Table 13-A)

yl		/ - - FY 92 ANS Avg. ($/barrel) - - /		Notes
		Gulf Coast	West Coast	
1	Average Price for ANS (Spot)	$17.81	$16.64	Monthly spot averages (DOR)
2	Quality Adjusted Price			
3	Production / Disposition *Bbls. year* *Day*			
	a Production (mm bbls. yr. / day) 654.332 / 1.788			From DOR data (incl. NGL's)
	b Volume to East / West Coast (%)	20.51%	79.49%	From DOR data
4	Feeder Pipeline Tariffs	($0.09)	($0.09)	Wghtd. avg. sum of items 4a thru 4g
	a Operating & capital costs	($0.04)	($0.04)	From Dept. of Law (7/29/92) less 4b
	b State & local property tax (pipelines)	$0.00	$0.00	30% of tot. l DOR property tax
	c State income tax (pipelines)	$0.00	$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
	d Federal income tax (pipelines)	($0.01)	($0.01)	From Dept. of Law (7/29/92) less item 4c
	e After-tax margin	($0.02)	($0.02)	From Dept. of Law (7/29/92)
	f Recovery of deferred return	($0.01)	($0.01)	"
	g DR&R allowance	$0.00	$0.00	"
5	TAPS Pipeline Tariff	($3.44)	($3.44)	Sum of items 5a thru 5h
	a Operating & capital costs	($1.36)	($1.36)	From Dept. of Law (7/29/92) less 5b
	b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
	c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
	d Federal income tax (pipelines)	($0.64)	($0.64)	From Dept. of Law (7/29/92) less item 5c
	e After-tax margin	($0.51)	($0.51)	From Dept. of Law (7/29/92)
	f Recovery of deferred return	($0.61)	($0.61)	"
	g DR&R allowance	($0.07)	($0.07)	"
	h Pumpability Charge			Dept. of Revenue data
6	State Share (Feeder Lines)	($0.01)	($0.01)	Sum of items 4b, 4c
7	Federal Share (Feeder Lines)	($0.01)	($0.01)	Item 4d
8	Industry Profit (Feeder Lines)	$0.03	$0.03	Sum of items 4e, 4f
9	State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10	Federal Share (TAPS)	($0.64)	($0.64)	Item 5d
11	Industry Profit (TAPS)	$1.12	$1.12	Sum of items 5e, 5f
12	Tanker (to Gulf / West Coast)	($3.74)	($1.04)	USFRA data (DOR)
13	Wellhead value	$10.53	$12.06	Sum of items 1, 4, 5, 12
14	State Royalties, Production & Property Taxes	($2.90)	($3.27)	Sum of items 14a thru 14d
	a Royalty	($1.24)	($1.43)	Item 13 less field costs * est. field royalty
	b Severance tax	($1.26)	($1.44)	Item 13 *.875 * nominal severance* ELF
	c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
	d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15	Production costs	($3.49)	($3.49)	Sum of items 15a, 15b
	a Lifting Costs	($1.19)	($1.19)	Derived from trade publication estimates
	b Depletion, Depreciation & Amortization	($2.30)	($2.30)	Derived from trade publication estimates
16	Net Revenue (production)	$4.15	$5.31	Sum of items 13, 14, 15
17	State Income Tax (production)	($0.13)	($0.13)	DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18	Federal Income Tax (production)	($1.29)	($1.66)	Est. 32.1% of items 16 + 17
19	Industry Profit (production)	$2.73	$3.52	Sum of items 16 thru 18
20	Total State Share (production + pipelines)	$3.28	$3.65	Sum of items 6, 9, 14, 17
21	Total Federal Share (production + pipelines)	$1.94	$2.31	Sum of items 7, 10, 18
22	Total Industry Profit (production + pipelines)	$3.88	$4.67	Sum of items 8, 11, 19
23	FY 92 Industry Avg. per-barrel ANS Profit		$4.51	

FY 1992 North Slope Barrel Profit Analysis (Table 13-B)

North Slope Profit Analysis: PRUDHOE BAY	/ - - FY 92 Prudhoe Avg. ($/bbl.) - - /		/ Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$17.81	$16.64	Dept. of Revenue data
2 Quality Adjusted Price	$18.14	$16.97	From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 476.834 / 1.303			From DOR data
b. Volume to East / West Coast (%)	20.51%	79.49%	From DOR data
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff	($3.44)	($3.44)	Sum of items 5a thru 5h
a Operating & capital costs	($1.36)	($1.36)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.64)	($0.64)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.51)	($0.51)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.61)	($0.61)	"
g DR&R allowance	($0.07)	($0.07)	"
h Pumpability Charge	$0.00	$0.00	Dept. of Revenue data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.64)	($0.64)	Item 5d
11 Industry Profit (TAPS)	$1.12	$1.12	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.74)	($1.04)	USFRA data (DOR)
13 Wellhead value	$10.96	$12.49	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($3.10)	($3.50)	Sum of items 14a thru 14d
a Royalty	($1.28)	($1.47)	Item 13 less field costs * est. field royalty
b Severance tax	($1.42)	($1.62)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($2.75)	($2.75)	Sum of items 15a, 15b
a Lifting Costs	($0.95)	($0.95)	Salomon Bros., June 25, 1991
b Depletion, Depreciation & Amortization	($1.80)	($1.80)	Salomon Bros., June 25, 1991
16 Net Revenue (production)	$5.11	$6.25	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.13)	($0.13)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($1.60)	($1.96)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$3.38	$4.15	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$3.48	$3.87	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$2.24	$2.60	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$4.50	$5.27	Sum of items 8, 11, 19
23 FY 92 Industry Avg. per-barrel Profit (Prudhoe Bay)		$5.11	

FY 1992 North Slope Barrel Profit Analysis (Table 13-C)

North Slope Profit Analysis: KUPARUK	/ - - FY 92 Kuparuk Avg. ($/bbl) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$17.81	$16.64	Dept. of Revenue data
2 Quality Adjusted Price	$16.72	$15.55	From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 115.970 / 0.317			From DOR data
b. Volume to East / West Coast (%)	20.51%	79.49%	From DOR data
4 Feeder Pipeline Tariffs	($0.21)	($0.21)	Sum of items 4a thru 4g
a Operating & capital costs	($0.08)	($0.08)	Pro-rated from TAPS estimates
b State & local property tax (pipelines)	($0.01)	($0.01)	Pro-rated from TAPS estimates
c State income tax (pipelines)	($0.01)	($0.01)	Pro-rated from TAPS estimates
d Federal income tax (pipelines)	($0.04)	($0.04)	Pro-rated from TAPS estimates
e After-tax margin	($0.03)	($0.03)	Pro-rated from TAPS estimates
f Recovery of deferred return	($0.04)	($0.04)	Pro-rated from TAPS estimates
g DR&R allowance	$0.00	$0.00	Pro-rated from TAPS estimates
5 TAPS Pipeline Tariff	($3.73)	($3.73)	Sum of items 5a thru 5h
a Operating & capital costs	($1.36)	($1.36)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.64)	($0.64)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.51)	($0.51)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.61)	($0.61)	"
g DR&R allowance	($0.07)	($0.07)	"
h Pumpability Charge	($0.29)	($0.29)	From DOR data
6 State Share (Feeder Lines)	($0.01)	($0.01)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.04)	($0.04)	Item 4d
8 Industry Profit (Feeder Lines)	$0.07	$0.07	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.64)	($0.64)	Item 5d
11 Industry Profit (TAPS)	$1.12	$1.12	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.74)	($1.04)	USFRA data (DOR)
13 Wellhead value	$9.04	$10.57	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.51)	($2.88)	Sum of items 14a thru 14d
a Royalty	($1.08)	($1.27)	Item 13 less field costs * est. field royalty
b Severance tax	($1.03)	($1.21)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($4.95)	($4.95)	Sum of items 15a, 15b
a Lifting Costs	($1.65)	($1.65)	Salomon Bros., June 25, 1991
b Depletion, Depreciation & Amortization	($3.30)	($3.30)	Salomon Bros., June 25, 1991
16 Net Revenue (production)	$1.58	$2.74	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.13)	($0.13)	from DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.47)	($0.84)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$0.99	$1.78	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.90	$3.26	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.15	$1.52	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$2.17	$2.96	Sum of items 8, 11, 19
23 FY 92 Industry Avg. per-barrel Profit (Kuparuk)		$2.80	

FY 1992 North Slope Barrel Profit Analysis (Table 13-D)

North Slope Profit Analysis: ENDICOTT FIELD	/ - - FY 92 Endicott Avg. ($/barrel) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$17.81	$16.64	Dept. of Revenue data
2 Quality Adjusted Price	$16.83	$15.66	From DOR data
3 Production / Disposition (Bbls. year / Day)			
a Production (mm bbls. yr. / day) 40.843 / 0.112			From DOR data
b. Volume to East / West Coast (%)	20.51%	79.49%	From DOR data
4 Feeder Pipeline Tariffs	($0.71)	($0.71)	Sum of items 4a thru 4g
a Operating & capital costs	($0.29)	($0.29)	From Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.03)	($0.03)	30% of total DOR property tax
c State income tax (pipelines)	($0.01)	($0.01)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.07)	($0.07)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.20)	($0.20)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.08)	($0.08)	"
g DR&R allowance	($0.03)	($0.03)	"
5 TAPS Pipeline Tariff	($3.60)	($3.60)	Sum of items 4a thru 4g
a Operating & capital costs	($1.36)	($1.36)	From Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.64)	($0.64)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.51)	($0.51)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.61)	($0.61)	"
g DR&R allowance	($0.07)	($0.07)	"
h Pumpability Charge	($0.17)	($0.17)	From DOR data
6 State Share (Feeder Lines)	($0.04)	($0.04)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.07)	($0.07)	Item 4d
8 Industry Profit (Feeder Lines)	$0.28	$0.25	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.64)	($0.64)	Item 5d
11 Industry Profit TAPS)	$1.12	$1.12	Sum of items 5e, 5f
12 Tanker to Gulf / West Coast)	($3.74)	($1.04)	USFRA data (DOR)
13 Wellhead value	$8.77	$10.30	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.27)	($2.61)	Sum of items 14a thru 14d
a Royalty	($1.19)	($1.41)	Item 13 less field costs * est. field royalty
b Severance tax	($0.68)	($0.80)	Item 13 *.856 * nominal severance* ELF
c Spill Response & Coast. ($.054/bbl*.875)	($0.05)	($0.05)	$.054 * .856
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($5.82)	($5.82)	Sum of items 15a, 15b
a Lifting Costs	($1.94)	($1.94)	Derived from trade data
b Depletion, Depreciation & Amortization	($3.88)	($3.88)	Derived from trade data
16 Net Revenue (production)	$0.68	$1.87	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.12)	($0.12)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.18)	($0.56)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$0.38	$1.19	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.68	$3.02	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$0.89	$1.27	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$1.78	$2.59	Sum of items 8, 11, 19
23 FY 92 Industry Avg. per-barrel Profit (Endicott)		$2.42	

FY 1992 North Slope Barrel Profit Analysis (Table 13E)

North Slope Profit Analysis: LISBURNE	/ - - FY 92 Lisburne Avg. ($/barrel) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$17.81	$15.64	Dept. of Revenue data
2 Quality Adjusted Price	$18.79	17.62	From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 13.359 / 0.037			From DOR data
b. Volume to East / West Coast (%)	20.51%	79.49%	From DOR data
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff	($3.14)	($3.14)	Sum of items 5a thru 5h
a Operating & capital costs	($1.36)	($1.36)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.64)	($0.64)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.51)	($0.51)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.61)	($0.61)	"
g DR&R allowance	($0.07)	($0.07)	"
h Pumpability Charge	$0.30	$0.30	From DOR data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.64)	($0.64)	Item 5d
11 Industry Profit (TAPS)	$1.12	$1.12	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.74)	(1.04)	USFRA data (DOR)
13 Wellhead value	$11.91	$13.44	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($1.80)	($1.99)	Sum of items 14a thru 14d
a Royalty	($1.40)	($1.59)	Item 13 less field costs * est. field royalty
b Severance tax	$0.00	$0.00	Item 13 * 875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($8.45)	($8.45)	Sum of items 15a, 15b
a Lifting Costs	($2.80)	(2.80)	Salomon Bros. June 25, 1991
b Depletion, Depreciation & Amortization	($5.65)	(5.65)	Salomon Bros. June 25, 1991
16 Net Revenue (production)	$1.66	3.00	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.13)	($0.13)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.49)	($0.92)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$1.04	$1.95	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.18	$2.37	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.13	$1.56	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$2.16	$3.07	Sum of items 8, 11, 19
23 FY 92 Industry Avg. per-barrel Profit (Lisburne)		$2.88	

FY 1992 North Slope Barrel Profit Analysis (Table 13-F)

North Slope Profit Analysis: MILNE PT.	/ - - FY 92 Milne Pt. Avg. ($/barrel) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$17.81	$16.64	Dept. of Revenue data
2 Quality Adjusted Price	$16.48	$15.31	From DOR data
3 Production / Disposition (Bbls. year / Day)			
a Production (mm bbls. yr. / day) 7.326 / 0.020			From DOR data
b. Volume to East / West Coast (%)	20.51%	79.49%	From DOR data
4 Feeder Pipeline Tariff (Milne Pt. only)	($1.07)	($1.07)	Sum of items 4a thru 4g
a Operating & capital costs	($0.64)	($0.64)	From Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.05)	($0.05)	30% of total DOR property tax
c State income tax (pipelines)	($0.02)	($0.02)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.11)	($0.11)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.16)	($0.16)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.05)	($0.05)	"
g DR&R allowance	($0.04)	($0.04)	"
5 TAPS Pipeline Tariff	($4.02)	($4.02)	Sum of items 5a thru 5h
a Operating & capital costs	($1.36)	($1.36)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.15)	($0.15)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.64)	($0.64)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.51)	($0.51)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.61)	($0.61)	"
g DR&R allowance	($0.07)	($0.07)	"
h Pumpability Charge	($0.59)	($0.59)	From DOR data
6 State Share (Milne Pt. Feeder Line)	($0.08)	($0.08)	Sum of items 4b, 4c
7 Federal Share (Milne Pt. Feeder Line)	($0.11)	($0.11)	Item 4d
8 Industry Profit (Milne Pt. Feeder Line)	$0.21	$0.21	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.64)	($0.64)	Item 5d
11 Industry Profit (TAPS)	$1.12	$1.12	Sum of items 5e, 5f (to TAPS owners)
12 Tanker (to Gulf / West Coast)	($3.74)	($1.04)	USFRA data (DOR)
13 Wellhead value	$7.44	$8.97	Sum of items 2, 4, 5, 12 + ($0.21) Kuparuk Pipe tariff
14 State Royalties, Production & Property Taxes	($1.65)	($1.93)	Sum of items 14a thru 14d
a Royalty	($1.25)	($1.53)	Item 13 less field costs * est. field royalty
b Severance tax	$0.00	$0.00	Item 13 *.8165 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.04)	($0.04)	$.054 * .8165
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($6.20)	($6.20)	Sum of items 15a, 15b
a Lifting Costs	($2.07)	($2.07)	Derived from trade data
b Depletion, Depreciation & Amortization	($4.13)	($4.13)	Derived from trade data
16 Net Revenue (production)	($0.40)	$0.85	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.12)	($0.12)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	$0.00	($0.24)	West: Est. 32.1% of items 16 + 17; Gulf Coast negative
19 Milne Pt. Profit (production)	($0.52)	$0.50	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.08	$2.36	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$0.75	$0.99	Sum of items 7, 10, 18
22 Total Milne Profit (production + pipeline)	($0.31)	$0.71	Sum of items 8 (Milne Pt. Pipeline only), 19
23 FY 92 Industry Avg. per-barrel Profit (Milne Pt.)		$0.50	

FY 1992 North Slope Barrel Profit Analysis (Table 13-G)

North Slope Profit Analysis: OTHER	/ - - FY 92 Other Revenue, Avg. ($/bbl.) - - /		Notes
(Kuparuk Pipeline tariff on Milne Pt. Oil)	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	(n.a.)	(See analysis of Milne Pt. oil)
2 Quality Adjusted Price		(n.a.)	
3 Production / Disposition (Milne Pt.) *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 7.326 / 0.020			
b. Volume to East / West Coast (%)	0.00%	(n.a.)	
4 Feeder Pipeline Tariff (Kuparuk's Milne Pt. oil)	($0.21)	($0.21)	Sum of items 4a thru 4g
a Operating & capital costs	($0.10)	($0.10)	From Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.01)	($0.01)	30% of total DOR property tax
c State income tax (pipelines)	$0.00	$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.03)	($0.03)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.05)	($0.05)	From Dept. of Law (7/29/92)
f Recovery of deferred return	($0.01)	($0.01)	"
g DR&R allowance	$0.00	$0.00	"
5 TAPS Pipeline Tariff			
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
h Pumpability Charge			
6 State Share (Kuparuk's Milne Pt. oil)	($0.02)	($0.02)	Sum of items 4b, 4c (KPL payment on Milne Pt. oil)
7 Federal Share (Kuparuk's Milne Pt. oil)	($0.03)	($0.03)	Item 4d (KPL payment on Milne Pt. oil)
8 Industry Profit (Kuparuk's Milne Pt. oil)	($0.05)	($0.05)	Sum of items 4e, 4f (KPL profit on Milne Pt. oil)
9 State Share (TAPS)			
10 Federal Share (TAPS)			
11 Industry Profit (TAPS)			
12 Tanker (to Gulf / West Coast)			
13 Wellhead value			
14 State Royalties, Production & Property Taxes			
a Royalty			
b Severance tax			
c Spill Response & Conservation Taxes			
d State & local property tax (production)			
15 Production costs			
a Lifting Costs			
b Depletion., Depreciation & Amortization			
16 Net Revenue (production)			
17 State Income Tax (production)			
18 Federal Income Tax (production)			
19 Industry Profit (production)			
20 Total State Share (production + pipelines)	$0.02	$0.02	Sum of items 6, 9, 14, 17 (Kuparuk Pipeline only)
21 Total Federal Share (production + pipelines)	$0.03	$0.03	Sum of items 8, 10, 18 (Kuparuk Pipeline only)
22 Total Industry Profit (Kuparuk's Milne Pt. oil)	$0.05	$0.05	Sum of items 8, 11, 19 (Kuparuk Pipeline only)
23 FY 92 Industry Avg. per-barrel Profit (Kup. Pipe / Milne Pt. oil)		$0.05	

CY 1992 North Slope Barrel Profit Analysis (Table 14-A)

North Slope Profit Analysis: ALL FIELDS	/ - - CY 92 ANS Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.10	$17.42	Jan.-Sept. spot average (DOR)
2 Quality Adjusted Price			
3 Production / Disposition *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 636.8156 / 1.740			DOR actuals thru August, then Spr. 92 forecast incl. NGLs
b. Volume to East / West Coast (%)	18.70%	81.30%	From DOR data
4 Feeder Pipeline Tariffs	($0.10)	($0.10)	Wghtd. avg. sum of items 4a thru 4g
a Operating & capital costs	($0.04)	($0.04)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	$0.00	$0.00	30% of total DOR property tax
c State income tax (pipelines)	$0.00	$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.01)	($0.01)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.02)	($0.02)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.01)	($0.01)	"
g DR&R allowance	$0.00	$0.00	"
5 TAPS Pipeline Tariff	($3.46)	($3.46)	Sum of items 5a thru 5h
a Operating & capital costs	($1.41)	($1.41)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.16)	($0.16)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.63)	($0.63)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.53)	($0.53)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.58)	($0.58)	"
g DR&R allowance	($0.06)	($0.06)	"
h Pumpability Charge			Dept. of Revenue data
6 State Share (Feeder Lines)	($0.01)	($0.01)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.01)	($0.01)	Item 4d
8 Industry Profit (Feeder Lines)	$0.03	$0.03	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.63)	($0.63)	Item 5d
11 Industry Profit (TAPS)	$1.11	$1.11	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.76)	($1.05)	USFRA data (DOR) thru June
13 Wellhead Value	$10.79	$12.81	Sum of items 1, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.96)	($3.46)	Sum of items 14a thru 14d
a Royalty	($1.27)	($1.52)	Item 13 less field costs * est. field royalty
b Severance tax	($1.28)	($1.52)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($3.65)	($3.65)	Sum of items 15a, 15b
a Lifting Costs	($1.24)	($1.24)	Derived from trade publication estimates
b Depletion, Depreciation & Amortization	($2.41)	($2.41)	Derived from trade publication estimates
16 Net Revenue (production)	$4.17	$5.70	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.14)	($0.14)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($1.29)	($1.78)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$2.74	$3.77	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$3.36	$3.85	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.94	$2.43	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$3.88	$4.92	Sum of items 8, 11, 19
23 CY 92 Industry Avg. per-barrel ANS Profit		$4.72	

CY 1992 North Slope Barrel Profit Analysis (Table 14-B)

North Slope Profit Analysis: PRUDHOE BAY	/ - - CY 92 Prudhoe Avg. ($/bbl.) - - /		/ Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$19.35	$17.21	DOR Spr. 92 revenue forecast mid-case (pp. 17-18)
2 Quality Adjusted Price	$18.68	$17.54	From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 459.330 / 1.255			DOR actuals thru August, then Spr. 92 forecast; incl. NGL's
b. Volume to East / West Coast (%)	18.70%	81.30%	From DOR data
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff	($3.46)	($3.46)	Sum of items 5a thru 5h
a Operating & capital costs	($1.41)	($1.41)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.16)	($0.16)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.63)	($0.63)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.53)	($0.53)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.58)	($0.58)	"
g DR&R allowance	($0.06)	($0.06)	"
h Pumpability Charge	$0.00	$0.00	Dept. of Revenue data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.63)	($0.63)	Item 5d
11 Industry Profit (TAPS)	$1.11	$1.11	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.76)	($1.05)	USFRA data (DOR) thru June
13 Wellhead value	$11.22	$13.24	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($3.17)	($3.69)	Sum of items 14a thru 14d
a Royalty	($1.32)	($1.58)	Item 13 less field costs * est. field royalty
b Severance tax	($1.44)	($1.70)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total property tax (from DOR data)
15 Production costs	($2.87)	($2.87)	Sum of items 15a, 15b
a Lifting Costs	($0.99)	($0.99)	Salomon Bros (June 25, 1991) * inflation
b Depletion, Depreciation & Amortization	($1.88)	($1.88)	Salomon Bros (June 25, 1991) * inflation
16 Net Revenue (production)	$5.18	$6.69	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.14)	($0.14)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($1.62)	($2.10)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$3.42	$4.44	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$3.56	$4.07	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$2.25	$2.73	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$4.53	$5.55	Sum of items 8, 11, 19
23 CY 92 Industry Avg. per-barrel Profit (Prudhoe Bay)		$5.36	

CY 1992 North Slope Barrel Profit Analysis (Table 14-C)

North Slope Profit Analysis: KUPARUK	/ - - CY 92 Kuparuk Avg. ($/bbl.) - - / Gulf Coast	West Coast	Notes
1 Average Price for ANS (Spot)	$18.10	$17.42	Jan.-Sept. spot average (DOR)
2 Quality Adjusted Price	$17.01	$16.33	From DOR data
3 Production / Disposition *Bbls. year / Day*			
a Production (mm bbls. yr. / day) 116.071 / 0.317			DOR actuals thru August, then Sps. 92 forecast
b. Volume to East / West Coast (%)	18.70%	81.30%	From DOR data
4 Feeder Pipeline Tariffs	($0.21)	($0.21)	Sum of items 4a thru 4g
a Operating & capital costs	($0.09)	($0.09)	Pro-rated from TAPS estimates
b State & local property tax (pipelines)	($0.01)	($0.01)	Pro-rated from TAPS estimates
c State income tax (pipelines)	($0.01)	($0.01)	Pro-rated from TAPS estimates
d Federal income tax (pipelines)	($0.04)	($0.04)	Pro-rated from TAPS estimates
e After-tax margin	($0.03)	($0.03)	Pro-rated from TAPS estimates
f Recovery of deferred return	($0.04)	($0.04)	Pro-rated from TAPS estimates
g DR&R allowance	$0.00	$0.00	Pro-rated from TAPS estimates
5 TAPS Pipeline Tariff	($3.75)	($3.75)	Sum of items 5a thru 5h
a Operating & capital costs	($1.41)	($1.41)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.16)	($0.16)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.63)	($0.63)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.53)	($0.53)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.58)	($0.58)	*
g DR&R allowance	($0.06)	($0.06)	*
h Pumpability Charge	($0.29)	($0.29)	From DOR data
6 State Share (Feeder Lines)	($0.01)	($0.01)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.04)	($0.04)	Item 4d
8 Industry Profit (Feeder Lines)	$0.07	$0.07	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.63)	($0.63)	Item 5d
11 Industry Profit (TAPS)	$1.11	$1.11	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.76)	($1.05)	USFRA data (DOR) thru June
13 Wellhead value	$9.30	$11.32	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.58)	($3.06)	Sum of items 14a thru 14d
a Royalty	($1.10)	($1.36)	Item 13 less field costs * est. field royalty
b Severance tax	($1.06)	($1.30)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total property tax (from DOR data)
15 Production costs	($5.16)	($5.16)	Sum of items 15a, 15b
a Lifting Costs	($1.72)	($1.72)	Salomon Bros (June 25, 1991) * inflation
b Depletion, Depreciation & Amortization	($3.44)	($3.44)	Salomon Bros (June 25, 1991) * inflation
16 Net Revenue (production)	$1.56	$3.09	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.14)	($0.14)	from DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.45)	($0.95)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$0.96	$2.01	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.98	$3.46	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.12	$1.62	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$2.14	$3.18	Sum of items 8, 11, 19
23 CY 92 Industry Avg. per-barrel Profit (Kuparuk)		$2.99	

CY 1992 North Slope Barrel Profit Analysis (Table 14-D)

North Slope Profit Analysis: ENDICOTT	/ - - CY 92 Endicott Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.10	$17.42	Jan.-Sept. spot average (DOR)
2 Quality Adjusted Price	$17.12	$16.44	From DOR data
3 Production / Disposition *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 40.620 / 0.111			DOR actuals thru August, then Spr. 92 forecast
b. Volume to East / West Coast (%)	18.70%	81.30%	From DOR data
4 Feeder Pipeline Tariffs	($0.71)	($0.71)	Sum of items 4a thru 4g
a Operating & capital costs	($0.29)	($0.29)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.03)	($0.03)	30% of total DOR property tax
c State income tax (pipelines)	($0.01)	($0.01)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.07)	($0.07)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.20)	($0.20)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.08)	($0.08)	"
g DR&R allowance	($0.03)	($0.03)	"
5 TAPS Pipeline Tariff	($3.63)	($3.63)	Sum of items 5a thru 5h
a Operating & capital costs	($1.41)	($1.41)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.16)	($0.16)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.63)	($0.63)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.53)	($0.53)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.58)	($0.58)	"
g DR&R allowance	($0.06)	($0.06)	"
h Pumpability Charge	($0.17)	($0.17)	From DOR data
6 State Share (Feeder Lines)	($0.04)	($0.04)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)	($0.07)	($0.07)	Item 4d
8 Industry Profit (Feeder Lines)	$0.28	$0.28	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.63)	($0.63)	Item 5d
11 Industry Profit (TAPS)	$1.11	$1.11	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.76)	($1.05)	USFRA data (DOR) thru June
13 Wellhead value	$9.03	$11.05	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($2.35)	($2.80)	Sum of items 14a thru 14d
a Royalty	($1.22)	($1.52)	Item 13 less field costs * est. field royalty
b Severance tax	($0.71)	($0.87)	Item 13 *.856 * nominal severance* ELF
c Spill Response & Cons. ($.054/bbl*.875)	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($6.07)	($6.07)	Sum of items 15a, 15b
a Lifting Costs	($2.02)	($2.02)	(1991 costs derived from trade data) * inflation
b Depletion, Depreciation & Amortization	($4.05)	($4.05)	(1991 costs derived from trade data) * inflation
16 Net Revenue (production)	$0.61	$2.13	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.14)	($0.14)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.15)	($0.65)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$0.32	$1.38	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.78	$3.23	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$0.85	$1.35	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$1.71	$2.78	Sum of items 8, 11, 19
23 CY 92 Industry Avg. per-barrel Profit (Endicott)		$2.58	

CY 1992 North Slope Barrel Profit Analysis (Table 14-E)

North Slope Profit Analysis: LISBURNE	/ - - CY 92 Lisburne Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.10	$17.42	Jan.-Sept. spot average (DOR)
2 Quality Adjusted Price	$19.08	18.40	From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 13.124 / 0.036			DOR actuals thru August, then Spr. 92 forecast
b. Volume to East / West Coast (%)	18.70%	81.30%	From DOR data
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff	($3.16)	($3.16)	Sum of items 5a thru 5h
a Operating & capital costs	($1.41)	($1.41)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.16)	($0.16)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.63)	($0.63)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.53)	($0.53)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.58)	($0.58)	"
g DR&R allowance	($0.06)	($0.06)	"
h Pumpability Charge	$0.30	$0.30	From DOR data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.63)	($0.63)	Item 5d
11 Industry Profit (TAPS)	$1.11	$1.11	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)	($3.76)	(1.05)	USFRA data (DOR) thru June
13 Wellhead value	$12.17	$14.19	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes	($1.84)	($2.09)	Sum of items 14a thru 14d
a Royalty	($1.42)	($1.68)	Item 13 less field costs * est. field royalty
b Severance tax	($0.01)	($0.01)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.05)	($0.05)	$.054 * .875
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($8.80)	($8.80)	Sum of items 15a, 15b
a Lifting Costs	($2.92)	(2.92)	Salomon Bros (June 25, 1991) * inflation
b Depletion, Depreciation & Amortization	($5.89)	(5.89)	Salomon Bros (June 25, 1991) * inflation
16 Net Revenue (production)	$1.52	$3.29	Sum of items 13, 14, 15
17 State Income Tax (production)	($0.14)	($0.14)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	($0.44)	($1.01)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)	$0.94	$2.14	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.22	$2.48	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$1.07	$1.64	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)	$2.05	$3.25	Sum of items 8, 11, 19
23 CY 92 Industry Avg. per-barrel Profit (Lisburne)		$3.02	

CY 1992 North Slope Barrel Profit Analysis (Table 14-E)

North Slope Profit Analysis: MILNE PT.	/ - - CY 92 Milne Pt. Avg. ($/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$18.10	$17.42	Jan.-Sept. spot average (DOR)
2 Quality Adjusted Price	$16.77	$16.09	From DOR data
3 Production / Disposition (Bbls. year / Day)			
a Production (mm bbls. yr. / day) 7.671 / 0.021			DOR actuals thru Aug., then Spr. 92 forecast; incl. Schr. Bl.
b. Volume to East / West Coast (%)	18.70%	81.30%	From DOR data
4 Feeder Pipeline Tariff (Milne Pt. only)	($0.77)	($0.77)	Sum of items 4a thru 4g
a Operating & capital costs	($0.40)	($0.40)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.04)	($0.04)	30% of total DOR property tax
c State income tax (pipelines)	($0.01)	($0.01)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.10)	($0.10)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.16)	($0.16)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.05)	($0.05)	"
g DR&R allowance	$0.01	($0.01)	"
5 TAPS Pipeline Tariff	($4.05)	($4.05)	Sum of items 5a thru 5h
a Operating & capital costs	($1.41)	($1.41)	Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)	($0.16)	($0.16)	30% of total DOR property tax
c State income tax (pipelines)	($0.09)	($0.09)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.63)	($0.63)	Dept. of Law (7/29/92) less item 5c
e After-tax margin	($0.53)	($0.53)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.58)	($0.58)	"
g DR&R allowance	($0.06)	($0.06)	"
h Pumpability Charge	($0.59)	($0.59)	From DOR data
6 State Share (Milne Pt. Feeder Line)	($0.06)	($0.06)	Sum of items 4b, 4c
7 Federal Share (Milne Pt. Feeder Line)	($0.13)	($0.10)	Item 4d
8 Industry Profit (Milne Pt. Feeder Line)	$0.21	$0.21	Sum of items 4e, 4f
9 State Share (TAPS)	($0.24)	($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)	($0.63)	($0.63)	Item 5d
11 Industry Profit (TAPS)	$1.11	$1.11	Sum of items 5e, 5f (to TAPS owners)
12 Tanker (to Gulf / West Coast)	($3.76)	($1.05)	USFRA data (DOR) thru June
13 Wellhead value	$7.99	$10.01	Sum of items 2, 4, 5, 12 + ($0.21) Kuparuk Pipe tariff
14 State Royalties, Production & Property Taxes	($1.74)	($2.11)	Sum of items 14a thru 14d
a Royalty	($1.33)	($1.71)	Item 13 less field costs * est. field royalty
b Severance tax	$0.00	$0.00	Item 13 *.8165 * nominal severance* ELF
c Spill Response & Conservation Taxes	($0.04)	($0.04)	$.054 * .8165
d State & local property tax (production)	($0.36)	($0.36)	70% of total DOR property tax
15 Production costs	($6.46)	($6.46)	Sum of items 15a, 15b
a Lifting Costs	($2.15)	($2.15)	(1991 costs derived from trade data) * inflation
b Depletion, Depreciation & Amortization	($4.31)	($4.31)	(1991 costs derived from trade data) * inflation
16 Net Revenue (production)	($0.21)	$1.44	Sum of items 13, 14, 15
17 State Income Tax (production)	$0.00	($0.14)	From DOR Spr. 92 forecast (p. 38) less items 4c, 5c
18 Federal Income Tax (production)	$0.00	($0.42)	West: Est. 32.1% of items 16 + 17; Gulf Coast negative
19 Milne Pt. Profit (production)	($0.21)	$0.88	Sum of items 16 thru 18
20 Total State Share (production + pipelines)	$2.05	$2.56	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)	$0.77	$1.14	Sum of items 7, 10, 18
22 Total Milne Profit (production + pipelines)	$0.00	$1.09	Sum of items 8 (Milne Pt. Pipeline only), 19
23 CY 92 Industry Avg. per-barrel Profit (Milne Pt.)		$0.89	

CY 1992 North Slope Barrel Profit Analysis (Table 14-G)

North Slope Profit Analysis: OTHER	/ - - CY 92 Other Revenue Avg. ($/bbl.) - - /		Notes
(Kuparuk Pipeline tariff on Milne Pt. Oil)	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	(n.a.)	(See analysis of Milne Pt. oil)
2 Quality Adjusted Price		(n.a.)	
3 Production / Disposition (Milne Pt *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 7.671 / 0.021			
b. Volume to East / West Coast (%)	0.00%	(n.a.)	
4 Feeder Pipeline Tariff (Kuparuk's Milne Pt. oil)	($0.21)	($0.21)	Sum of items 4a thru 4g
a Operating & capital costs	($0.10)	($0.10)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)	($0.01)	($0.01)	30% of total DOR property tax
c State income tax (pipelines)	$0.00	$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)	($0.03)	($0.03)	Dept. of Law (7/29/92) less item 4c
e After-tax margin	($0.05)	($0.05)	Dept. of Law (7/29/92)
f Recovery of deferred return	($0.01)	($0.01)	*
g DR&R allowance	$0.00	$0.00	*
5 TAPS Pipeline Tariff			
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
h Pumpability Charge			
6 State Share (Kuparuk's Milne Pt. oil)	($0.02)	($0.02)	Sum of items 4b, 4c
7 Federal Share (Kuparuk's Milne Pt. oil)	($0.03)	($0.03)	Item 4d
8 Industry Profit (Kuparuk's Milne Pt. oil)	$0.05	$0.05	Sum of items 4e, 4f
9 State Share (TAPS)			
10 Federal Share (TAPS)			
11 Industry Profit (TAPS)			
12 Tanker (to Gulf / West Coast)			
13 Wellhead value			
14 State Royalties, Production & Property Taxes			
a Royalty			
b Severance tax			
c Spill Response & Conservation Taxes			
d State & local property tax (production)			
15 Production costs			
a Lifting Costs			
b Depletion, Depreciation & Amortization			
16 Net Revenue (production)			
17 State Income Tax (production)			
18 Federal Income Tax (production)			
19 Industry Profit (production)			
20 Total State Share (production + pipelines)	$0.02	$0.02	Sum of items 6, 9, 14, 17 (Kuparuk Pipeline only)
21 Total Federal Share (production + pipelines)	$0.03	$0.03	Sum of items 7, 10, 18 (Kuparuk Pipeline only)
22 Total Industry Profit (Kuparuk's Milne Pt. oil)	$0.05	$0.05	Sum of items 8, 11, 19 (Kuparuk Pipeline only)
23 CY 92 Industry Avg. per-barrel Profit (Kup. Pipe / Milne Pt. oil)		$0.05	

The field profitability model enables one to focus on the economics of the less profitable North Slope endeavors, as well as the vastly lucrative Prudhoe Bay. For understanding North Slope development issues this may be useful. In this regard, Milne Point warrants particular attention. Four factors reducing Milne Point's profitability have already been identified: (1) Milne Point oil is relatively heavy and therefore less valuable than other North Slope crude oils currently in production (line 2); (2) Milne Point volume is small and production costs are relatively high (line 3); (3) Milne Point oil bears the highest feeder line tariffs of all North Slope crude oils (lines 4, 13); and (4) the Milne Point owners do not share ownership in TAPS and therefore do not earn profits on the TAPS shipping fee (line 22).

The fourth point is particularly important to understand Milne Point's bottom line: If Milne Point owners had a share in TAPS, that field's CY 91 West Coast profit of $0.82 per barrel would have been augmented by a TAPS profit of $1.13. Instead, that $1.13 goes to the TAPS owners, who are producing from fields that are already more profitable than Milne Point. [64]

For FY 92, Milne Point's estimated profit dropped only $0.11 per barrel from the CY 91 average. During the same period, Prudhoe Bay's estimated profit dropped $0.28 per barrel. And for CY 92, Milne Point's estimated profit is up $0.38 from FY 92, an increase of $0.27 per barrel from CY 91. Thus Milne Point is well ahead of its CY 91 level, while Prudhoe Bay has yet to return to that level. These figures are shown in Graph 3.

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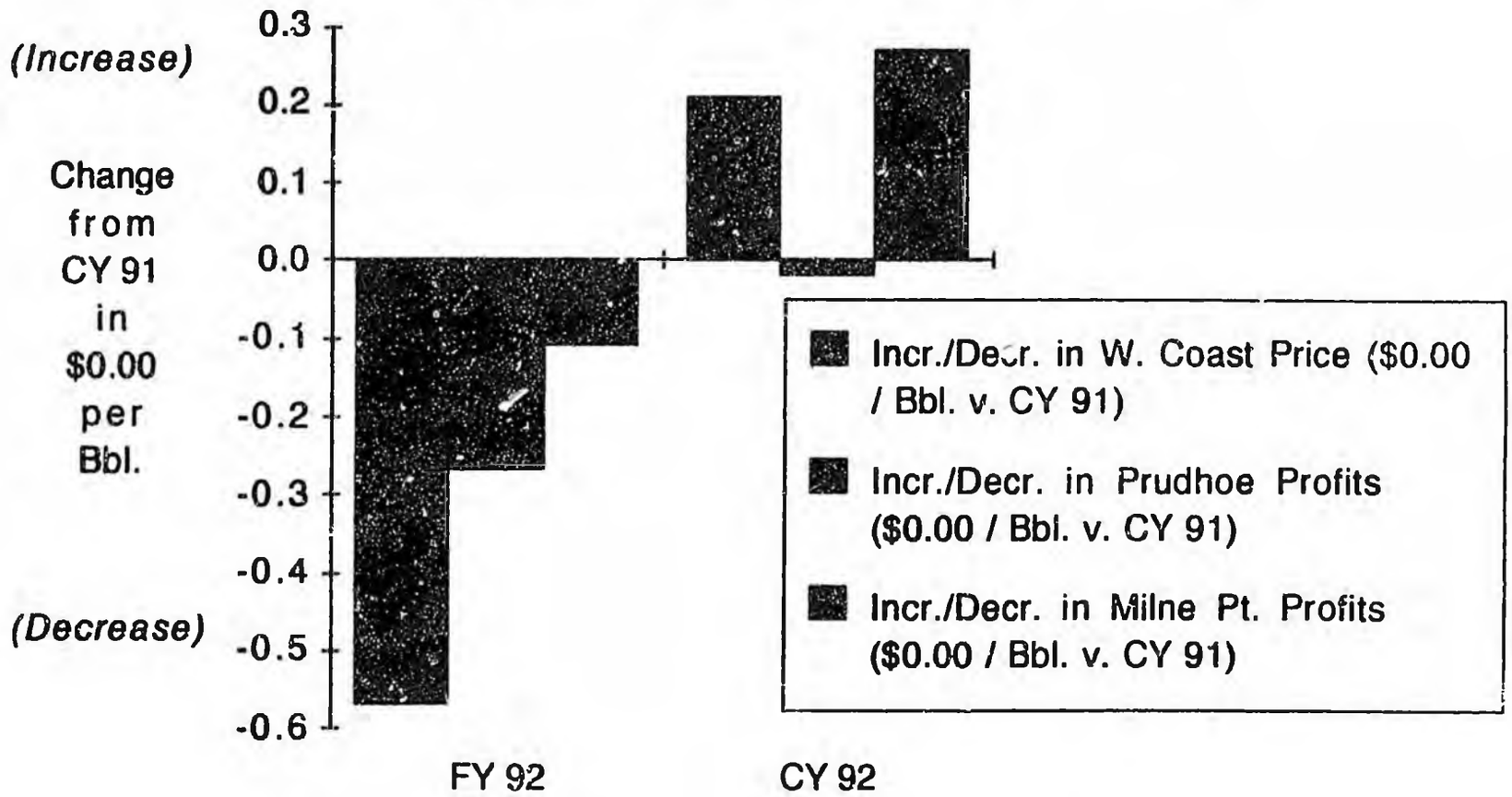
[64] Milne Point oil is marketed on the West Coast; only BP ships to the Gulf. For this reason, the West Coast figure should be regarded as a more realistic calculation of Milne Point income than the weighted average. The negative result shown for Gulf Coast disposition of Milne Point oil is only theoretical. Milne Point oil also bears a higher royalty rate than other fields. Even though Milne pays less than more profitable fields in combined royalty and severance payments due to its lower wellhead value and the operation of the ELF, a relatively high percentage of economic rent that goes to the state compared to that of other production. The model therefore suggests that some form of rate relief for Milne Point — from the state and/or from the TAPS and Kuparuk pipeline owners — may be warranted.

Graph 3.

Change in Price, Estimated Prudhoe and Milne Pt. Profits
(CY 91 v. FY 92 and CY 92)



The Prudhoe Bay results are easily explained: The Prudhoe decrease of $0.27 per barrel in FY 92 represents 47 percent of the $0.57 drop in price. With the industry picking up about 45 percent of the economic rent, if all other factors held constant one would expect the producer to gain or lose that percentage of the change in the price of oil. Although the price of oil has rebounded during the current calendar year, the per-barrel profitability model reflects modest increases in Prudhoe production costs and pipeline tariffs that nibble lightly at Prudhoe's profit margin. Nevertheless, if prices hold steady to year's end, once again in CY 92 North Slope total profits will match those of all but a handful of the most profitable corporations in the nation.

But there's a bit of a mystery about the Milne Point figures. Why didn't the $0.57 drop in the FY 92 average price per-barrel price send Milne Point profits plunging? The primary reason Milne Point suffered a much smaller drop in profits than Prudhoe Bay is that a reduction of $0.58 per barrel in the Milne Point feeder line tariff for CY 92 propped up Milne Point's wellhead value. These reductions resulted from the terms of a settlement in litigation over that tariff. A high feeder-line tariff reduces the wellhead price and production profits. For any given field, the argument over the correct feeder line tariff is a bit unreal; because the producer also owns the feeder line, that tariff is simply a cash transfer from one arm of the company to another. In comparing two fields, however, the field with the more expensive feeder line will produce at a penalty equal to the difference in respective feeder line costs. Milne Point's increasing profit during CY 92 demonstrates the critical importance of feeder line tariffs to marginally profitable fields.

A second noteworthy factor is that the ELF keeps Milne Point's severance tax down when the price of oil drops, reducing the price drop's assault on Milne Point's modest profitability. Note that in the model analysis Milne Point is paying a small severence tax in CY 92 but paid none at FY 92's lower prices. The effect of the ELF, also apparent at Lisburne, would be more visible if we were dealing with fluctuating monthly prices instead of 12-month averages.

E. Future Profits

We turn now to assess future North Slope profits. For this analysis we will use the Department of Revenue's Spring 1992 mid-case forecast scenario for FY 2000. That forecast calls for 971,000 barrels per day — slightly more than half current production rates but about 100,000 barrels per day less than the Department of Natural Resources

April 1992 forecast. One reason for the discrepancy in state forecasts is the absence of West Sak from the Department of Revenue's forecast, discussed above.[65]

Assumptions concerning two variables in the model are especially critical to future profitability: prices (line 1) and production costs (line 15). In July, OPEC Secretary General Subroto told an Anchorage conference that OPEC projections for the 1990's "assume a real price of $21.00 per barrel for OPEC's basket of seven crudes."[66] The head of the Energy Studies Department in the OPEC Secretariat painted a slightly more optimistic picture. He said that OPEC planners think in terms of prices rising from $18.00 to $25.00 by 2000, with an increase of 3% annually after the year 2000.[67] The ANS West Coast spot price typically runs $0.50 to $2.00 below the OPEC basket. Therefore, if OPEC attains its $21.00 target, ANS prices should run at $19.00 per barrel on the West Coast through 2000. A $25.00 per-barrel OPEC price at the end of the century would translate to about $23.00 per barrel for ANS on the West Coast.

The Department of Revenue's Spring 1992 forecast is more conservative than the views of the OPEC officials. DOR's mid-case scenario places ANS in the year 2000 at approximately $19.54 in 1992 dollars. During the next century's first decade, instead of the 3% real annual increase in oil prices price predicted by OPEC researchers, the state forecast price barely exceeds inflation.[68] Those who deal with oil prices are divided as to

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[65] The lower DOR forecast is used for two reasons. First, the aggregate data will match the lower of the two state forecasts, producing a conservative result. Secondly, the Department of Law provided pipeline tariff data for ' is report keyed to the Department of Revenue forecast. The tariff model is sensitive to pipeline throughput and the data could not be converted to DNR figures.

From a policy standpoint state resource managers and the public they serve suffer from having divergent forecasts, neither of which are ready to be used with the pipeline data from the agency responsible for pipelines. In 1990, an international consultant retained by the Legislature and the Department of Revenue observed:

> "A striking feature of the Alaskan oil and gas scene is the lack of coordination between different government agencies .... It has been clear to the consultant through various contacts with representatives of the state government that there is an absence of an exchange of information and ideas on a constructive basis."

Dr. H. Motamen Scobie, "Financial and Other Aspects of Oil Industry Activities and Investment" (prepared for the International Oil Tax Comparison Study Group of the Alaska State Legislature and Department of Revenue, April 1990), p. 40.

[66] Subroto, "The Role of OPEC in the 1990s" (Conference on Energy Issues for the 1990s; University of Alaska Anchorage School of Business and Organization of Petroleum Exporting Countries, July 23-24, 1992), p. 2.

[67] S.A. Al-Fathi, "Current and Future Prospects for Oil" (Conference on Energy Issues for the 1990s; University of Alaska Anchorage School of Business and Organization of Petroleum Exporting Countries, July 23-24, 1992), pp. 11-12.

[68] Spring 1992 Revenue Sources Book, p. 34. (Mid-range 2000 price of $26.95 was converted to 1992 dollars using the inflation forecast in the same table.)

what the future holds. This paper will not rush in where economic wizards tread with fear. In the absence of a crystal ball that enables us to predict the future of oil prices, we will use the more conservative Department of Revenue forecast.[69]

With regard to production costs (line 15), the tables for the year 2000 contain the following adjustments to the current lifting costs used in Tables 12 through 14:

Prudhoe:	(1991 Salomon) x 5% per-year real increase (i.e., inflation plus 5%)
Kuparuk:	(1991 Salomon) x 2
Endicott:	(1991 Salomon x EG&G factor) x 2
Lisburne:	(1991 Salomon) x 5% per-year real increase (i.e., inflation plus 5%)
Milne Pt.:	(1991 Salomon x EG&G factor) x 2.

For the year 2000, DD&A costs are assumed to remain constant. Again, this is believed to be a conservative approach.[70]

These assumptions for FY 2000 are put into the per-barrel profitability model in Tables 15-A through 15-G. The model produces an estimated average profit of $5.34 for each of the 355.4 million barrels forecasted by the Department of Revenue for FY 2000.

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[69] For an excellent statement of the reasons against a pessimistic forecast, see: David Raeume, "A changed world alters oil's future," Anchorage Daily News, Oct. 4, 1992, p. C-1.

[70] DD&A costs were held constant for three reasons: (1) North Slope depreciation schedules typically have been accelerated or front-end loaded, resulting in greater depreciation during early years of production; (2) steadily increasing production forecast totals have made it possible to defray capital costs over a larger number of barrels; and (3) the forecast for FY 2000 is converted to 1992, inflation-adjusted dollars.

FY 2000 North Slope Barrel Profit Analysis (Table 15 - A)

North Slope Profit Analysis: ALL FIELDS	/ - - FY 2000 ANS Avg. (1992$/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	$19.54	From DOR Spr. 92 revenue forecast mid-case (pp. 17-18)
2 Quality Adjusted Price			
3 Production / Disposition (Bbl/t. year / Day)			
a Production (mm bbls. yr. / day) 355.386 / 0.971			DOR Spr. 92 revenue forecast mid-case (p. 47)
b. Volume to East / West Coast (%)	0.00%	100.00%	
4 Feeder Pipeline Tariffs		($0.06)	Wghtd. avg. sum of items 4a thru 4g
a Operating & capital costs		($0.03)	From Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)		$0.00	30% of total DOR property tax
c State income tax (pipelines)		$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.01)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin		($0.01)	From Dept. of Law (7/29/92)
f Recovery of deferred return		$0.00	*
g DR&R allowance		$0.00	*
5 TAPS Pipeline Tariff		($2.74)	Sum of items 5a thru 5h
a Operating & capital costs		($1.39)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)		($0.18)	30% of total DOR property tax
c State income tax (pipelines)		($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.40)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin		($0.58)	From Dept. of Law (7/29/92)
f Recovery of deferred return		($0.12)	*
g DR&R allowance		($0.01)	*
h Pumpability Charge			From Dept. of Revenue data
6 State Share (Feeder Lines)		($0.01)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)		($0.01)	Item 4d
8 Industry Profit (Feeder Lines)		$0.02	Sum of items 4e, 4f
9 State Share (TAPS)		($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)		($0.40)	Item 5d
11 Industry Profit (TAPS)		$0.70	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)		($1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13 Wellhead value		$15.30	Sum of items 1, 4, 5, 12
14 State Royalties, Production & Property Taxes		($3.87)	Sum of items 14a thru 14d
a Royalty		($1.84)	Item 13 less field costs * est. field royalty
b Severance tax		($1.57)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes		($0.03)	$.054 * .875 * deflator
d State & local property tax (production)		($0.43)	70% of total DOR property tax
15 Production costs		($4.45)	Sum of items 15a, 15b
a Lifting Costs		($1.95)	Adj. from trade publication estimates
b Depletion, Depreciation & Amortization		($2.49)	Adj. from trade publication estimates
16 Net Revenue (production)		$6.98	Sum of items 13, 14, 15
17 State Income Tax (production)		($0.18)	From DOR data less items 4c, 5c
18 Federal Income Tax (production)		($2.18)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)		$4.62	Sum of items 16 thru 18
20 Total State Share (production + pipelines)		$4.30	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)		$2.59	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)		$5.34	Sum of items 8, 11, 19
23 FY 2000 Industry Avg. per-barrel ANS Profit		$5.34	

FY 2000 North Slope Barrel Profit Analysis (Table 15 -B)

North Slope Profit Analysis: PRUDHOE BAY FIELD - - FY 2000 Prudhoe Avg. (1992 $/bbl.) - - -			Gulf Coast	West Coast	Notes
1	Average Price for ANS (Spot)		$0.00	$19.54	From DOR Spr. 92 revenue forecast mid-case (pp. 17-15)
2	Quality Adjusted Price			$19.87	From DOR data
3	Production / Disposition	*Bbls. year* *Day*			
	a Production (mm bbls. yr. / day)	242.292 / 0.662			DOR Spr. 92 forecast (incl. NGL's)
	b. Volume to East / West Coast (%)		0.00%	100.00%	
4	Feeder Pipeline Tariffs				None
	a Operating & capital costs				
	b State & local property tax (pipelines)				
	c State income tax (pipelines)				
	d Federal income tax (pipelines)				
	e After-tax margin				
	f Recovery of deferred return				
	g DR&R allowance				
5	TAPS Pipeline Tariff			($2.74)	Sum of items 5a thru 5h
	a Operating & capital costs			($1.39)	From Dept. of Law (7/29/92) less 5b
	b State & local property tax (pipelines)			($0.18)	30% of total DOR property tax
	c State income tax (pipelines)			($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
	d Federal income tax (pipelines)			($0.40)	From Dept. of Law (7/29/92) less item 5c
	e After-tax margin			($0.58)	From Dept. of Law (7/29/92)
	f Recovery of deferred return			($0.12)	"
	g DR&R allowance			($0.01)	"
	h Pumpability Charge			$0.00	From Dept. of Revenue data
6	State Share (Feeder Lines)				Sum of items 4b, 4c
7	Federal Share (Feeder Lines)				Item 4d
8	Industry Profit (Feeder Lines)				Sum of items 4e, 4f
9	State Share (TAPS)			($0.24)	Sum of items 5b, 5c
10	Federal Share (TAPS)			($0.40)	Item 5d
11	Industry Profit (TAPS)			$0.70	Sum of items 5e, 5f
12	Tanker (to Gulf / West Coast)			($1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13	Wellhead value			$15.70	Sum of items 2, 4, 5, 12
14	State Royalties, Production & Property Taxes			($4.29)	Sum of items 14a thru 14d
	a Royalty			($1.87)	Item 13 less field costs * est. field royalty
	b Severance tax			($1.95)	Item 13 *.875 * nominal severance* ELF
	c Spill Response & Conservation Taxes			($0.03)	$.054 * .875 * deflator
	d State & local property tax (production)			($0.43)	70% of total DOR property tax
15	Production costs			($3.20)	Sum of items 15a, 15b
	a Lifting Costs			($1.40)	Salomon Bros. 1991 estimate with 5% p/a (real) increase
	b Depletion., Depreciation & Amortization			($1.80)	Salomon Bros. 1991 estimate
16	Net Revenue (production)			$8.20	Sum of items 13, 14, 15
17	State Income Tax (production)			($0.18)	From DOR data less items 4c, 5c
18	Federal Income Tax (production)			($2.58)	Est. 32.1% of items 16 + 17
19	Industry Profit (production)			$5.45	Sum of items 16 thru 18
20	Total State Share (production + pipelines)			$4.71	Sum of items 6, 9, 14, 17
21	Total Federal Share (production + pipelines)			$2.98	Sum of items 7, 10, 18
22	Total Industry Profit (production + pipelines)			$6.15	Sum of items 8, 11, 19
23	FY 2000 Industry Avg. per-barrel Profit (Prudhoe Bay)			$6.15	

FY 2000 North Slope Barrel Profit Analysis (Table 15 - C)

North Slope Profit Analysis: KUPARUK	/ - - FY 2000 Kuparuk Avg. (1992 $/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	$19.54	From DOR Spr. 92 revenue forecast mid-case (pp. 17-18)
2 Quality Adjusted Price		$18.45	From DOR data
3 Production / Disposition *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 61.854 / 0.169			DOR Spr. 92 revenue forecast mid-case (p. 47)
b. Volume to East / West Coast (%)	0.00%	100.00%	
4 Feeder Pipeline Tariffs		($0.21)	Sum of items 4a thru 4g
a Operating & capital costs		($0.11)	Pro-rated from TAPS estimates
b State & local property tax (pipelines)		($0.01)	Pro-rated from TAPS estimates
c State income tax (pipelines)		$0.00	Pro-rated from TAPS estimates
d Federal income tax (pipelines)		($0.03)	Pro-rated from TAPS estimates
e After-tax margin		($0.04)	Pro-rated from TAPS estimates
f Recovery of deferred return		($0.01)	Pro-rated from TAPS estimates
g DR&R allowance		$0.00	Pro-rated from TAPS estimates
5 TAPS Pipeline Tariff		($3.03)	Sum of items 5a thru 5h
a Operating & capital costs		($1.39)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)		($0.18)	30% of total DOR property tax
c State income tax (pipelines)		($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.40)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin		($0.58)	From Dept. of Law (7/29/92)
f Recovery of deferred return		($0.12)	"
g DR&R allowance		($0.01)	"
h Pumpability Charge		($0.29)	From Dept. of Revenue data
6 State Share (Feeder Lines)		($0.02)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)		($0.03)	Item 4d
8 Industry Profit (Feeder Lines)		$0.05	Sum of items 4e, 4f
9 State Share (TAPS)		($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)		($0.40)	Item 5d
11 Industry Profit (TAPS)		$0.70	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)		($1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13 Wellhead value		$13.78	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes		($2.95)	Sum of items 14a thru 14d
a Royalty		($1.67)	Item 13 less field costs * est. field royalty
b Severance tax		($0.81)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes		($0.03)	$.054 * .875 * deflator
d State & local property tax (production)		($0.43)	70% of total DOR property tax
15 Production costs		($6.60)	Sum of items 15a, 15b
a Lifting Costs		($3.30)	Salomon Bros. June 1991 est. * 2
b Depletion, Depreciation & Amortization		($3.30)	Salomon Bros. June 1991 est.
16 Net Revenue (production)		$4.23	Sum of items 13, 14, 15
17 State Income Tax (production)		($0.18)	From DOR data less items 4c, 5c
18 Federal Income Tax (production)		($1.30)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)		$2.75	Sum of items 16 thru 18
20 Total State Share (production + pipelines)		$3.39	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)		$1.73	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)		$3.51	Sum of items 8, 11, 19
23 FY 2000 Industry Avg. per-barrel Profit (Kuparuk)		$3.51	

FY 2000 North Slope Barrel Profit Analysis (Table 15 - D)

North Slope Profit Analysis: ENDICOTT FIELD / - - FY 2000 Endicott Avg. (1992 $/bbl.) - - /			Gulf Coast	West Coast	Notes
1	Average Price for ANS (Spot)		$0.00	$19.54	From DOR Spr. 92 revenue forecast mid-case (pp. 17-18)
2	Quality Adjusted Price			$18.56	From DOR data
3	Production / Disposition	*Bbls. year* / *Day*			
	a Production (mm bbls. yr. / day)	13.176 / 0.036			DOR Spr. 92 revenue forecast mid-case (p. 47)
	b. Volume to East / West Coast (%)		0.00%	100.00%	
4	Feeder Pipeline Tariffs			($0.52)	Sum of items 4a thru 4g
	a Operating & capital costs			($0.20)	From Dept. of Law (7/29/92) less 4b
	b State & local property tax (pipelines)			($0.04)	30% of total DOR property tax
	c State income tax (pipelines)			($0.01)	4d * (eff. state tax rate / eff. fed. tax rate)
	d Federal income tax (pipelines)			($0.05)	From Dept. of Law (7/29/92) less item 4c
	e After-tax margin			($0.15)	From Dept. of Law (7/29/92)
	f Recovery of deferred return			($0.06)	"
	g DR&R allowance			($0.02)	"
5	TAPS Pipeline Tariff			($2.91)	Sum of items 5a thru 5h
	a Operating & capital costs			($1.39)	Dept. of Law (7/29/92) less 5b
	b State & local property tax (pipelines)			($0.18)	30% of total DOR property tax
	c State income tax (pipelines)			($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
	d Federal income tax (pipelines)			($0.40)	Dept. of Law (7/29/92) less item 5c
	e After-tax margin			($0.58)	Dept. of Law (7/29/92)
	f Recovery of deferred return			($0.12)	"
	g DR&R allowance			($0.01)	"
	h Pumpability Charge			($0.17)	From Dept. of Revenue data
6	State Share (Feeder Lines)			($0.04)	Sum of items 4b, 4c
7	Federal Share (Feeder Lines)			($0.05)	Item 4d
8	Industry Profit (Feeder Lines)			$0.21	Sum of items 4e, 4f
9	State Share (TAPS)			($0.24)	Sum of items 5b, 5c
10	Federal Share (TAPS)			($0.40)	Item 5d
11	Industry Profit (TAPS)			$0.70	Sum of items 5e, 5f
12	Tanker (to Gulf / West Coast)			($1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13	Wellhead value			$13.69	Sum of items 2, 4, 5, 12
14	State Royalties, Production & Property Taxes			($2.50)	Sum of items 14a thru 14d
	a Royalty			($1.90)	Item 13 less field costs * est. field royalty
	b Severance tax			($0.12)	Item 13 *.856 * nominal severance* ELF
	c Spill Response & Cons. ($.054/bbl*.875)			($0.03)	$.054 * .856 * deflator
	d State & local property tax (production)			($0.43)	70% of total DOR property tax
15	Production costs			($7.76)	Sum of items 15a, 15b
	a Lifting Costs			($3.88)	1992 estimate (derived from 1991 trade sources) * 2
	b Depletion, Depreciation & Amortization			($3.88)	Derived from 1991 trade estimates
16	Net Revenue (production)			$3.43	Sum of items 13, 14, 15
17	State Income Tax (production)			($0.18)	From DOR data less items 4c, 5c
18	Federal Income Tax (production)			($1.04)	Est. 32.1% of items 16 + 17
19	Industry Profit (production)			$2.21	Sum of items 16 thru 18
20	Total State Share (production + pipelines)			$2.96	Sum of items 6, 9, 14, 17
21	Total Federal Share (production + pipelines)			$1.49	Sum of items 7, 10, 18
22	Total Industry Profit (production + pipelines)			$3.12	Sum of items 8, 11, 19
23	FY 2000 Industry Avg. per-barrel Profit (Endicott)			$3.12	

FY 2000 North Slope Barrel Profit Analysis (Table 15 - E)

North Slope Profit Analysis: LISBURNE	/ - - FY 2000 Lisburne Avg. (1992 $/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	$19.54	From DOR Spr. 92 revenue forecast mid-case (pp. 17-18)
2 Quality Adjusted Price		20.52	From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 32.208 / 0.088			DOR Spr. 92 forecast (p. 47); mid-case; incl. Pt. McIntyre
b. Volume to East / West Coast (%)	0.00%	100.00%	
4 Feeder Pipeline Tariffs			None
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
5 TAPS Pipeline Tariff		($2.44)	Sum of items 5a thru 5h
a Operating & capital costs		($1.39)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)		($0.18)	30% of total DOR property tax
c State income tax (pipelines)		($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.40)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin		($0.58)	From Dept. of Law (7/29/92)
f Recovery of deferred return		($0.12)	"
g DR&R allowance		($0.01)	"
h Pumpability Charge		$0.30	From Dept. of Revenue data
6 State Share (Feeder Lines)			Sum of items 4b, 4c
7 Federal Share (Feeder Lines)			Item 4d
8 Industry Profit (Feeder Lines)			Sum of items 4e, 4f
9 State Share (TAPS)		($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)		($0.40)	Item 5d
11 Industry Profit (TAPS)		$0.70	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)		(1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13 Wellhead value		$16.65	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes		($3.14)	Sum of items 14a thru 14d
a Royalty		($1.99)	Item 13 less field costs * est. field royalty
b Severance tax		($0.69)	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes		($0.03)	$.054 * .875 * deflator
d State & local property tax (production)		($0.43)	70% of total DOR property tax
15 Production costs		($8.45)	Sum of items 15a, 15b
a Lifting Costs		(2.80)	Salomon Bros. 1991 est. for 1992 with 5% p/a (real) increa
b Depletion, Depreciation & Amortization		(5.65)	Salomon Bros. 1992 estimate
16 Net Revenue (production)		$5.05	Sum of items 13, 14, 15
17 State Income Tax (production)		($0.18)	From DOR data less items 4c, 5c
18 Federal Income Tax (production)		($1.56)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)		$3.31	Sum of items 16 thru 18
20 Total State Share (production + pipelines)		$3.56	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)		$1.97	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)		$4.01	Sum of items 8, 11, 19
23 FY 2000 Industry Avg. per-barrel Profit (Lisburne)		$4.01	

FY 2000 North Slope Barrel Profit Analysis (Table 15 - F)

North Slope Profit Analysis: MILNE PT.	/ - - FY 2000 Milne Pt. Avg. (1992 $/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	$19.54	From DOR Spr. 92 revenue forecast mid-case (pp. 17-18)
2 Quality Adjusted Price		$18.21	From DOR data
3 Production / Disposition (Bbls. year / Day)			
a Production (mm bbls. yr. / day) 2.928 / 0.008			DOR Spr. 92 forecast (no Schrader Bluffs)
b Volume to East / West Coast (%)	0.00%	100.00%	
4 Feeder Pipeline Tariff (Milne Pt. only)		($0.75)	Sum of items 4a thru 4g
a Operating & capital costs		($0.46)	From Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)		($0.05)	30% of total DOR property tax
c State income tax (pipelines)		($0.01)	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.05)	From Dept. of Law (7/29/92) less item 4c
e After-tax margin		($0.12)	From Dept. of Law (7/29/92)
f Recovery of deferred return		($0.04)	"
g DR&R allowance		($0.03)	"
5 TAPS Pipeline Tariff		($3.32)	Sum of items 5a thru 5h
a Operating & capital costs		($1.39)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)		($0.18)	30% of total DOR property tax
c State income tax (pipelines)		($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.40)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin		($0.58)	From Dept. of Law (7/29/92)
f Recovery of deferred return		($0.12)	"
g DR&R allowance		($0.01)	"
h Pumpability Charge		($0.59)	From Dept. of Revenue data
6 State Share (Milne Pt. Feeder Line)		($0.07)	Sum of items 4b, 4c
7 Federal Share (Milne Pt. Feeder Line)		($0.05)	Item 4d
8 Industry Profit (Milne Pt. Feeder Line)		$0.16	Sum of items 4e, 4f
9 State Share (TAPS)		($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)		($0.40)	Item 5d
11 Industry Profit (TAPS)		$0.70	Sum of items 5e, 5f (to TAPS owners)
12 Tanker (to Gulf / West Coast)		($1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13 Wellhead value		$12.49	Sum of items 2, 4, 5, 12 + ($0.21) Kuparuk Pipeline tariff
14 State Royalties, Production & Property Taxes		($2.64)	Sum of items 14a thru 14d
a Royalty		($2.17)	Item 13 less field costs * est. field royalty
b Severance tax		$0.00	Item 13 *.817 * nominal severance* ELF
c Spill Response & Conservation Taxes		($0.03)	$.054 * .817 * deflator
d State & local property tax (production)		($0.43)	70% of total DOR property tax
15 Production costs		($7.19)	Sum of items 15a, 15b
c Lifting Costs		($3.06)	1991 estimate (from trade data) with 5% p/a real increase
b Depletion, Depreciation & Amortization		($4.13)	1991 estimate (from trade data)
16 Net Revenue (production)		$2.66	Sum of items 13, 14, 15
17 State Income Tax (production)		($0.18)	From DOR data less items 4c, 5c
18 Federal Income Tax (production)		($0.80)	Est. 32.1% of items 16 + 17
19 Milne Pt. Profit (production)		$1.69	Sum of items 16 thru 18
20 Total State Share (production + pipelines)		$3.12	Sum of items 6, 9, 14, 17 (excludes Kuparuk Pipeline)
21 Total Federal Share (production + pipelines)		$1.25	Sum of items 7, 10, 18 (excludes Kuparuk Pipeline)
22 Total Milne Profit (production + pipeline)		$1.84	Sum of items 8 (Milne Pt. Pipeline only), 19
23 FY 2000 Industry Avg. per-barrel Profit (Milne Pt.)		$1.84	

FY 2000 North Slope Barrel Profit Analysis (Table 1 - G)

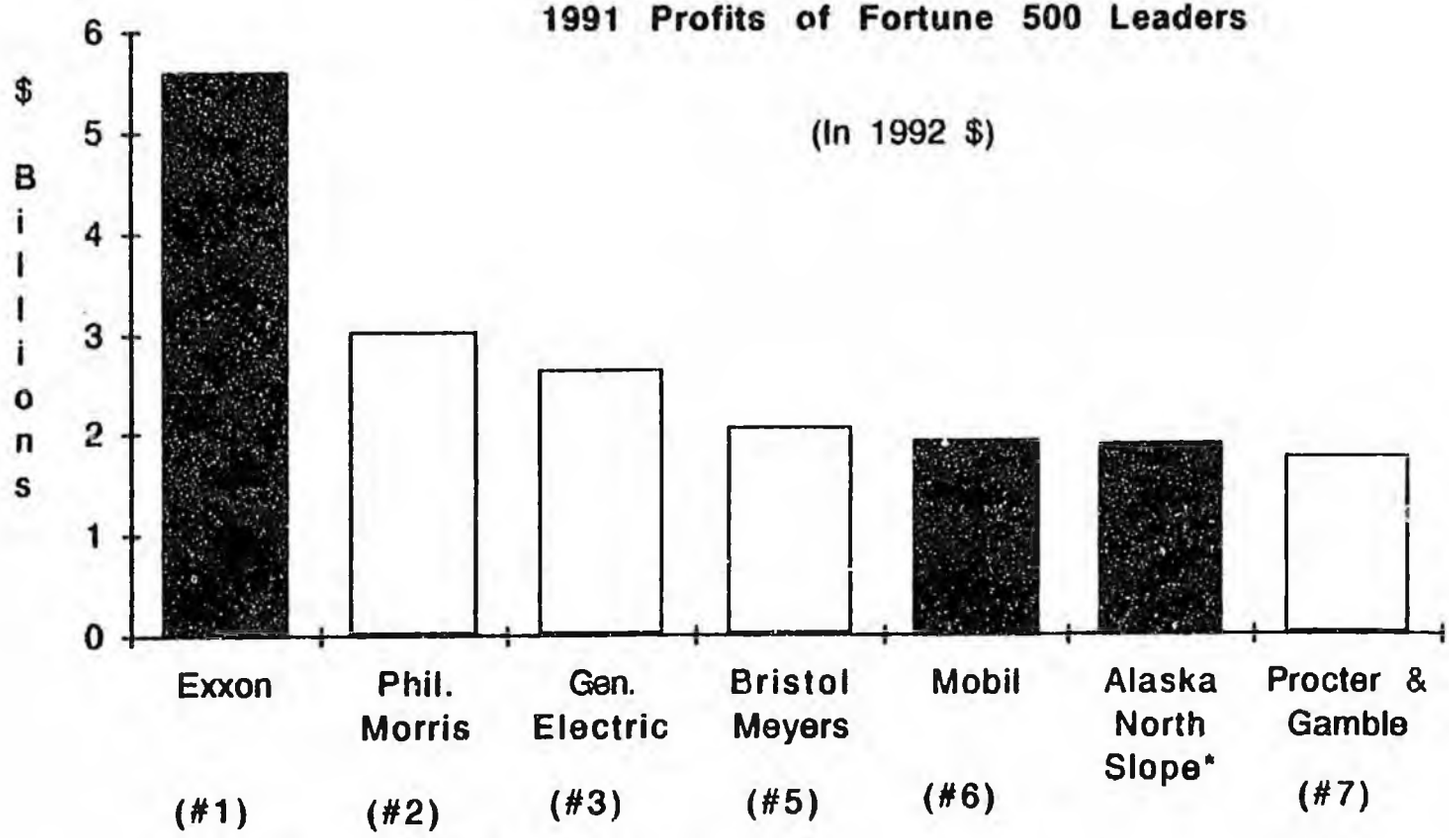
North Slope Profit Analysis: OTHER	/ -- FY 2000 Other Revenue Avg. (1992 $/bbl.) -- / Gulf Coast	West Coast	Notes
(Kuparuk Pipeline tariff on Milne Pt. Oil)			
1 Average Price for ANS (Spot)	$0.00	(n.a.)	(See analysis of Milne Pt. oil)
2 Quality Adjusted Price		(n.a.)	
3 Production / Disposition (Milne Pt.) *Bbls. year* / *Day*			
a Production (mm bbls. yr. / day) 2.928 / 0.008			
b. Volume to East / West Coast (%)	0.00%	(n.a.)	
4 Feeder Pipeline Tariff (Kuparuk's Milne Pt. oil)		($0.21)	Sum of items 4a thru 4g
a Operating & capital costs		($0.10)	Dept. of Law (7/29/92) less 4b
b State & local property tax (pipelines)		($0.01)	30% of total DOR property tax
c State income tax (pipelines)		$0.00	4d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.03)	Dept. of Law (7/29/92) less item 4c
e After-tax margin		($0.05)	Dept. of Law (7/29/92)
f Recovery of deferred return		($0.01)	"
g DR&R allowance		$0.00	"
5 TAPS Pipeline Tariff			
a Operating & capital costs			
b State & local property tax (pipelines)			
c State income tax (pipelines)			
d Federal income tax (pipelines)			
e After-tax margin			
f Recovery of deferred return			
g DR&R allowance			
h Pumpability Charge			
6 State Share (Kuparuk's Milne Pt. oil)		($0.02)	Sum of items 4b, 4c
7 Federal Share (Kuparuk's Milne Pt. oil)		($0.03)	Item 4d
8 Industry Profit (Kuparuk's Milne Pt. oil)		$0.05	Sum of items 4e, 4f
9 State Share (TAPS)			
10 Federal Share (TAPS)			
11 Industry Profit (TAPS)			
12 Tanker (to Gulf / West Coast)			
13 Wellhead value			
14 State Royalties, Production & Property Taxes			
a Royalty			
b Severance tax			
c Spill Response & Conservation Taxes			
d State & local property tax (production)			
15 Production costs			
a Lifting Costs			
b Depletion, Depreciation & Amortization			
16 Net Revenue (production)			
17 State Income Tax (production)			
18 Federal Income Tax (production)			
19 Industry Profit (production)			
20 Total State Share (production + pipelines)		$0.02	Sum of items 6, 9,14, 17 (Kuparuk Pipeline only)
21 Total Federal Share (production + pipelines)		$0.03	Sum of items 7, 10, 18 (Kuparuk Pipeline only)
22 Total Industry Profit (Kuparuk's Milne Pt. oil)		$0.05	Sum of items 8, 11, 19 (Kuparuk Pipeline only)
23 FY 00 Industry Avg. per-barrel Profit (Kuparuk Pipe: Milne Pt. oil)		$0.05	

These per-barrel earnings generate total FY 2000 production and pipeline profit of $1,897,700,000 ($1.897 billion) for the North Slope producers. The FY 2000 North Slope profit estimate generated by the per-barrel profitability model represent a reduction of nearly 40% percent from 1991. Nevertheless, when compared to the nation's corporate profit leaders in 1991, estimated North Slope net income for FY 2000 is on a par with the net income of the seventh most profitable corporation in the nation in 1991. The following graph depicts this comparison.

Graph 4.

Estimated FY 2000 North Slope Profits
v.
1991 Profits of Fortune 500 Leaders

(In 1992 $)



* Principally Exxon, ARCO and BP

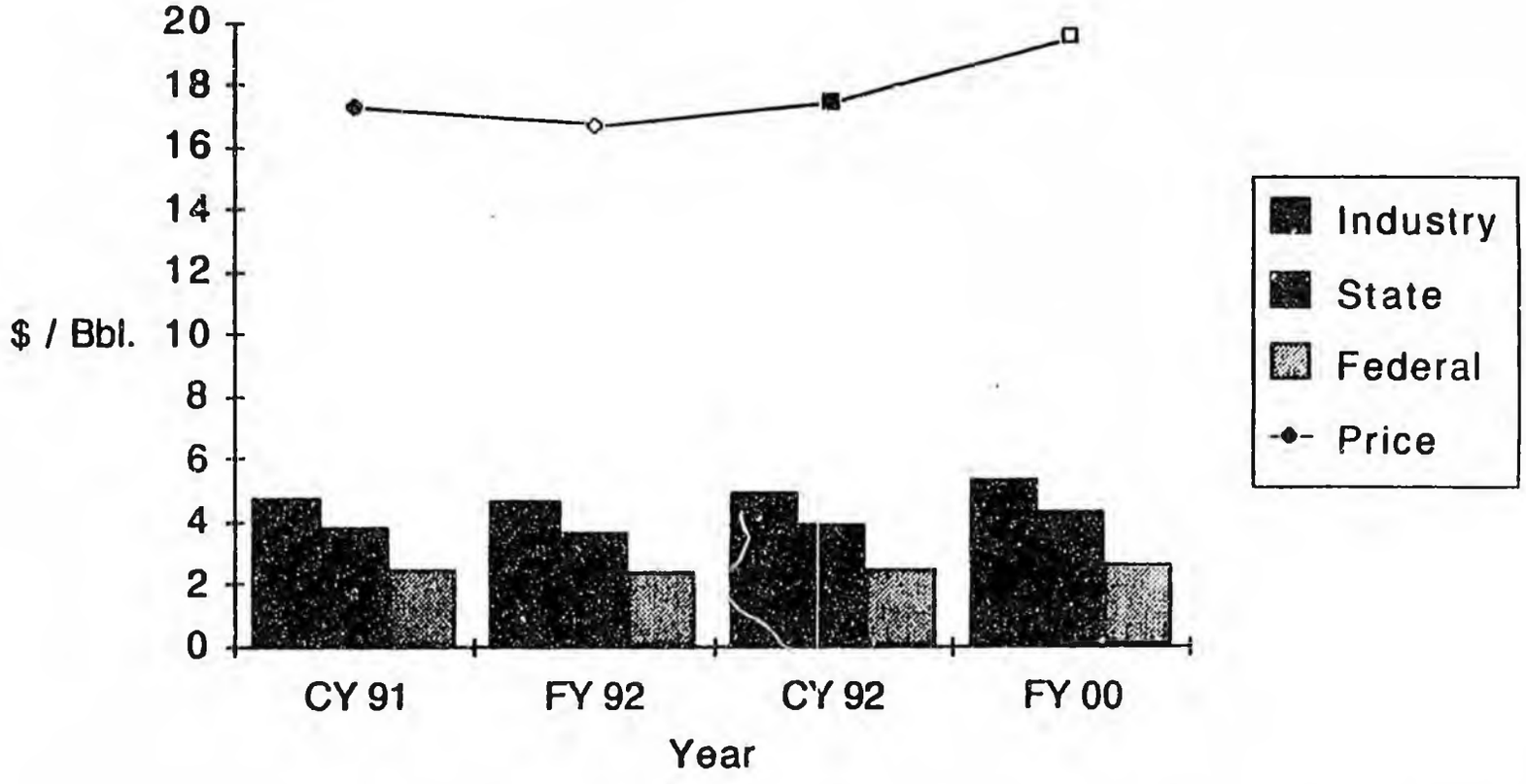
Sources: Fortune, April 20, 1992; Table 15-A

The model indicates that the North Slope is likely to continue to generate handsome profits, even in the face of relatively conservative projections that include: (1) a relatively modest rise in prices, (2) increases lifting costs sharply in opposition to the current trends, (3) exclusion of West Sak, despite industry statements of its plans to produce West Sak as Kuparuk facilities become available.

The following graph summarizes the division of economic rents for the years analyzed in tables 12 through 15.

Graph 5.

West Coast ANS Prices and Economic Rents
CY 91 - FY 2000 (Selected Years)



	CY 1991 ($17.21 / Bbl.)	FY 1992 ($16.64 / Bbl.)	CY 1992 ($17.42 / Bbl.)	FY 2000 ($19.54 / Bbl.) *(in 1992 $)*
Industry Share	$4.77 (43.2%)	$4.67 (43.9%)	$4.92 (43.9%)	$5.34 (43.7%)
State Share	$3.82 (34.6%)	$3.65 (34.3%)	$3.85 (34.4%)	$4.30 (35.2%)
Federal Share	$2.45 (22.1%)	$2.31 (21.7%)	$2.43 (21.7%)	$2.59 (21.2%)

Source: Tables 12-A, 13-A, 14-A, 15-A

The per-barrel profitability model omits West Sak in order to link accurately the pipeline tariff model from the Department of Law with the Spring 1992 production forecast by the Department of Revenue, which omitted West Sak. Nevertheless, it is possible to use the model to take a rough look at West Sak profitability. For this comparison to Table 15, we will use the quality differential provided by the Department of Revenue at line 2, pipeline tariffs from Kuparuk at lines 4 and 5 and production costs from Milne Point at line 15.[71]

[71] The major North Slope operators were contacted but declined to provide cost information for this report. Public policy makers who wish to understand North Slope production potential, production costs and trends should insist on better public information.

FY 2000 North Slope Barrel Profit Analysis (Table 16)

North Slope Profit Analysis: WEST SAK	/ - - FY 2000 W. Sak Avg. (1992 $/bbl.) - - /		Notes
	Gulf Coast	West Coast	
1 Average Price for ANS (Spot)	$0.00	$19.54	From DNR Apr. 92 production forecast. (pp. 4-5)
2 Quality Adjusted Price			From DOR data
3 Production / Disposition *Bbls. year* *Day*			
a Production (mm bbls. yr. / day) 9.125 / 0.025			DOR Spr. 92 revenue forecast mid-case (p. 47)
b. Volume to East / West Coast (%)	0.00%	100.00%	
4 Feeder Pipeline Tariffs		($0.21)	Sum of items 4a thru 4g
a Operating & capital costs		($0.11)	Pro-rated from TAPS estimates
b State & local property tax (pipelines)		($0.01)	Pro-rated from TAPS estimates
c State income tax (pipelines)		$0.00	Pro-rated from TAPS estimates
d Federal income tax (pipelines)		($0.03)	Pro-rated from TAPS estimates
e After-tax margin		($0.04)	Pro-rated from TAPS estimates
f Recovery of deferred return		($0.01)	Pro-rated from TAPS estimates
g DR&R allowance		$0.00	Pro-rated from TAPS estimates
5 TAPS Pipeline Tariff		($3.62)	Sum of items 5a thru 5h
a Operating & capital costs		($1.39)	From Dept. of Law (7/29/92) less 5b
b State & local property tax (pipelines)		($0.18)	30% of total DOR property tax
c State income tax (pipelines)		($0.06)	5d * (eff. state tax rate / eff. fed. tax rate)
d Federal income tax (pipelines)		($0.40)	From Dept. of Law (7/29/92) less item 5c
e After-tax margin		($0.58)	From Dept. of Law (7/29/92)
f Recovery of deferred return		($0.12)	"
g DR&R allowance		($0.01)	"
h Pumpability Charge		($0.88)	From Dept. of Revenue data
6 State Share (Feeder Lines)		($0.02)	Sum of items 4b, 4c
7 Federal Share (Feeder Lines)		($0.03)	Item 4d
8 Industry Profit (Feeder Lines)		$0.05	Sum of items 4e, 4f
9 State Share (TAPS)		($0.24)	Sum of items 5b, 5c
10 Federal Share (TAPS)		($0.40)	Item 5d
11 Industry Profit (TAPS)		$0.70	Sum of items 5e, 5f
12 Tanker (to Gulf / West Coast)		($1.44)	From DOR Spr. 92 forecast mid-case (p. 18)
13 Wellhead value		$11.58	Sum of items 2, 4, 5, 12
14 State Royalties, Production & Property Taxes		($1.82)	Sum of items 14a thru 14d
a Royalty		($1.36)	Item 13 less field costs * est. field royalty
b Severance tax		$0.00	Item 13 *.875 * nominal severance* ELF
c Spill Response & Conservation Taxes		($0.03)	$.054 * .875 * deflator
d State & local property tax (production)		($0.43)	70% of total DOR property tax
15 Production costs		($7.19)	Sum of items 15a, 15b (from Milne Pt.)
a Lifting Costs		($3.06)	1991 M.P est. (from trade data) with 5% p/a real increase
b Depletion, Depreciation & Amortization		($4.13)	1991 M.P. est. (from trade data)
16 Net Revenue (production)		$2.56	Sum of items 13, 14, 15
17 State Income Tax (production)		($0.18)	From DOR data less items 4c, 5c
18 Federal Income Tax (production)		($0.76)	Est. 32.1% of items 16 + 17
19 Industry Profit (production)		$1.62	Sum of items 16 thru 18
20 Total State Share (production + pipelines)		$2.26	Sum of items 6, 9, 14, 17
21 Total Federal Share (production + pipelines)		$1.20	Sum of items 7, 10, 18
22 Total Industry Profit (production + pipelines)		$2.37	Sum of items 8, 11, 19
23 FY 2000 Industry Avg. per-barrel Profit (W. Sak)		**$2.37**	

The results shown in Table 16 assume that West Sak production replaces Kuparuk barrels. In fact, Kuparuk processing facilities can process in excess of 320,000 barrels per day; they are doing so now. If Kuparuk is at 169,000 barrels per day in FY 2000, West Sak could produce at 150,000 barrels per day while sharing the Kuparuk facilities with the forecasted Kuparuk production.

The production and shipping of 150,000 barrels per day from West Sak additional to the DOR forecast would increase industry profits by about $200 million. Immediately visible is $130 million: $2.37 per-barrel x 54,750,000 barrels = $129,757,500. In addition, West Sak shipments would reduce the TAPS tariff for all barrels produced — including those produced from West Sak. Precise calculation of the TAPS tariff reduction per barrel due to increased production is beyond the scope of this paper, but it is reasonable to assume the tariff reduction would match the percentage increase in total TAPS shipments. If West Sak increased forecasted production of 971,000 barrels per day by 150,000 barels, this would be approximately 15% of the $2.74 tariff, or $0.40 per barrel. The per-barrel profitability model indicates that this amount would be divided amont the producers, the state and the federal government as follows:

State share (35.2%)	$0.14
Federal share (21.2%)	$0.08
Industry share (43.7%)	$0.18

The industry's $0.18 per barrel would add approximately $63 million to the $1.897 billion all-field estimated industry profit for FY 2000 shown in Tables 15-A. The same savings from increased production would apply to the West Sak barrels, increasing the profitability shown in Table 16 for West Sak by the same $0.18 per barrel. That's another $9.8 million. If producing costs are $7.19 per barrel, the expenditure necessary to produce $200 million in profit appears to be something on the order of $400 million. That's an after-tax return of $0.50 per dollar.

While these numbers are only rough approximations, they demonstrate why West Sak will probably be produced unless something better comes along. One other factor lends strength to the case for West Sak production: After nearly two decades of North Slope surplus, California is forecasted to be crude-short again in 1996. Its refineries have learned to deal with heavy oils like that of West Sak. Where other refineries in the world cannot process heavy oil, California refineries have had to deal with heavy oils for decades. In short, California is a ready made market for West Sak oil.

One of the reasons the Department of Revenue's economic forecasters view West Sak dimly is that their model excludes TAPS profits from calculations of whether a field can produce profitably. The Department of Revenue's future scenario fails twice in this regard. First, in deciding whether a field is economically viable, the department's model fails to take into account the TAPS profit on West Sak — which produces $0.70 of the $2.37 per barrel estimated West Sak profit shown in Table 16. Second, the DOR approach apparently ignores the $0.18 per barrel gain on all North Slope barrels resulting from reduced TAPS tariffs due to West Sak's increased production. North Slope producers will view any North Slope development decision as a package that includes Alaska pipeline shipping costs and profits. Any disussion of Alaska operations that overlooks profits of this magnitude should be regarded as irrelevant from an Alaska policy perspective.[72]

The TAPS tariff significantly affects many North Slope development questions. For example, to the TAPS owners, prospective TAPS profits far outweigh the benefits of drilling incentive credits. Likewise, the costs of pipelining greatly exceed potential benefits from such credits for the prospective developer who is not invested in existing North Slope pipelines. In this regard, in 1990 one of the consultants with the International Tax Comparison Study Group reported to the Alaska State Legislature and the Department of Revenue that Great Britain had recently shifted from placing development in the hands of the major companies to encouraging development by small independents. "[P]erhaps there are some lessons to be learnt from the UK," the consultant noted.[73]

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[72] The Alaska Department of Revenue's modelling decision to exclude TAPS profits from the consideration of whether a field can operate profitably may make sense in the case of a hypothetic field — discovered or undiscovered — whose owners have no share in TAPS. But this convention does not reflect economic realities when the model excludes identifiable profits from a field whose owners are known to have a major interest in TAPS.

[73] "Financial and Other Aspects of Oil Industry Activities and Investment" [op. cit.], p. 42.

IV. Recent Developments

In the preceding chapters two aspects of North Slope oil development have been quantified: continued increases in forecasted future production and estimated profits from Alaska operations that rival the top-earning corporations in the United States. In this chapter we turn to three recent developments whose implications for North Slope development warrant consideration. These are: (A) Prospects for developing the Arctic National Wildlife Refuge; (B) consideration of the effects of potential natural gas sales on North Slope production; and (C) the implications of recent discoveries by Conoco (Badami) and ARCO (Kuvlum).

A. Prospects for Developing the Arctic National Wildlife Refuge

In November 1991 the U.S. Senate declined to consider a proposal that the Arctic National Wildlife Refuge be opened to exploration and that funds from Arctic Refuge leasing underwrite a broad range of energy programs. The architect of that plan, Senator Bennett Johnston of Louisiana, acknowledged that no more than 45 of his colleagues supported opening the Aarctic Refuge to exploration and withdrew the proposal. The industry subsequently drew back, putting the state of Alaska at the forefront of promoting development of this province.[74] The model developed in this report for North Slope profitability highlights two aspects of the economics of Arctic Refuge development that make the state's continued efforts in Arctic Refuge somewhat surprising:

(1) Because the Arctic Refuge is on federal land, there is no direct state royalty on Arctic Refuge production. Instead, the state will receive a yet undetermined portion of federal royalties through revenue sharing.

(2) The high price of a feeder line from the Arctic Refuge to TAPS will place a penalty on Arctic Refuge oil that will reduce both the royalty share and the state's severance tax.[75]

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[74] See: "Hickel seeks ANWR delay: Gov. sas it may be wise to hold vote after election," Fairbanks Daily News-Miner, Feb. 3, 1992, p. 1; "Oil lobby abndons ANWR," Anchorage Daily News, April 15, 1992, p. B-1.

[75] A 1986 study for the federal government indicates tariff sensitivity to throughput assumptions. That report estimated a pipeline from the western Arctic Refuge would bear a tariff of $2.00 per barrel for a field producing 1 billion barrels; for a 200 million barrel field, the tariff would be $9.00 per barrel. Costs would double for a field in the eastern region. (John S. Young and William S. Houser, Economics of Oil & Gas Production from ANWR for the Determination of Minimum Economic Field Size [Bureau of Land

Due to the many uncertainties — field size. cost of feeder lines, timing of development, etc. — even if oil were discovered in the Arctic Refuge, modelling Arctic Refuge profits would be beyond the scope of this project. However, per-barrel profitability analysis does make possible a rough comparison can be made between the state's share of an Arctic Refuge barrel and that of an equivalent barrel near Prudhoe Bay on state lands.

Table 17.

State Shares: Near-Prudhoe Barrel v. Arctic Refuge Barrel

	Near-Prudhoe Barrel	Arctic Refuge
Barrel		
Market Price (at refinery)	$20.00	$20.00
Less:		
Arctic Refuge Pipeline Tariff (1986 DOR est.)	---	(5.50)
TAPS tariff	(4.00)	(4.00)
Tanker Cost	(1.00)	(1.00)
Effective Tax and Royalty Basis	$15.00	$9.50
State Share:		
(est. 12.5% royalty, 12.5% severance = 25%) . . .	$3.75	
or		
(est. 6.25% roy.+ 12.5% sev. = 18.75% + est. $0.30 feeder line property tax) *		$2.08
Loss to state from industry investment in Arctic Refuge instead of near-Prudhoe development	($3.75 - $2.08 = $1.67 per barrel)	

* Assumed 50-50 state-federal split of a 12.5% federal royalty.

Table 17 indicates that the state loses more than $1.50 per barrel on the industry's gamble on Arctic Refuge development, compared to state returns on development near Prudhoe. Development near Prudhoe Bay would also be more valuable to the state for another reason. Production in the vicinity of Prudhoe is likely to generate state revenue years before development of as yet-undiscovered oil in the Arctic Refuge.

Management, Alaska State Office, Division of Mineral Resources, 1986], pp. 29, 32, 34). The Alaska Department of Revenue estimated a 1 billion barrel field 125 miles from TAPS would bear a tariff of $5.50 per barrel (Vincent D. Wright, "Potential State Revenue from the Arctic National Wildlife Reserve" [memorandum to Governor Bill Sheffield], May 15, 1986, p. 1).

Why doesn't the high cost of a long arctic feeder line extinguish the industry's interest in this province altogether? From a theoretical standpoint, four reasons for continued industry interest in the Arctic Refuge can be identified: (1) Discovery of a super-giant field could make Arctic Refuge production highly profitable for the industry, even in the face of high feeder line costs — just as Prudhoe Bay 's size enabled the industry to build TAPS; (2) the possibility of sharply rising prices could make Arctic Refuge production profitable; (3) from the producer's standpoint, the necessity of a high-cost feeder guarantees some profit, even in relatively low-price scenarios; and (4) as Table 17 indicates, the state will absorb a disproportionate share of the reduced value of Arctic Refuge production, compared to development in provinces on state land nearer Prudhoe Bay. All four reasons underscore that Arctic Refuge exploration is a gamble whose principal benefactor may be the industry, not the state.

Finally, there is the TAPS factor. For the TAPS owners guaranteed TAPS profits, continued income from retained DR&R holdings and the deferring of DR&R outlays further strengthen the case for Arctic Refuge development.[76] It should be noted that all three TAPS factors apply equally to development near Prudhoe Bay, as well as to the Arctic Refuge.

B. Implications of Recent Discoveries by Conoco (Badami) and ARCO (Kuvlum)

In 1991 Conoco's Badami well hit oil in near-shore state waters in Mikkelson Bay, about 40 miles from Pump Station 1 and 25 miles from the Endicott Pipeline. The strike, at 4,250 barrels of oil per day, has not yet been determined to be commercially viable.[77] A feeder pipe linkup would be about twice the length of the Milne Point pipeline; to that tariff would be added the Endicott tariff. Because these tariffs would be spread across all barrels produced at Badami, field size will be crucial to determining whether the feeder line tariff will prohibit development. Once again the discoverer, Conoco, does not have an interest in TAPS or other producing fields, with the exception of its Milne Point production. The major TAPS owners therefore stand to share in the benefits of Badami production in continued production at other fields and lower TAPS tariffs. Badami is on state land and

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[76] Estimated anual income from past DR&R collections exceeds $400 million per year; estimated DR&R outlays associated with pipeline shutdown in the year 2011 are approximately $4.5 billion (nominal $) between 2010 and 2015 (Hidden Billions: The TAPS DR&R Provision [op. cit.], pp. 21-26).

[77] Bert Tarrant, "The Elephant Hunters," Anchorage Times, March 22, 1992, p. D-3.

would therefore produce both severance and royalty — if there's anything left after the pipeline tariffs.

ARCO's recent discovery at Kuvlum is reported to be light oil flowing at 3,400 barrels per day. The location is 25 miles east of Badami and 15 miles off shore, in 110 feet of water. The possibility Badami and Union's 1985 discovery at Hammerhead could share freeder line costs increases the likelihood of development. In that event, 60 miles of the pipeline to the Arctic National Wildlife Refuge will be in place. Once again, don't start counting chickens just yet. The prospect of bringing oil through the shifting pack ice to shore is formidable — it has never been done before — and ARCO estimates it will need one to two billion barrels to produce Kuvlum. Until further delineation of both strikes is completed, it is too soon to know whether development is likely. Since Kuvlum is off-shore in federal waters, the state would not collect severance; any income from Kuvlum production would come through revenue sharing.[78]

There's another 300 million barrels of high quality oil sitting right where Kuvlum would come to shore. It's the condensate associated with natural gas discovered by Exxon at Flaxman Island. Flaxman gas, in turn, would be produced and marketed only in conjunction with a major gas sale at Prudhoe Bay.[79]

While the uncertainties are enormous, this possibility exists — at least in theory: If Kuvlum and Badami turn out to be major fields and if a major North Slope gas sale moves forward, the addition of Flaxman's condensate would be a third major oil field in that region, possibly reducing feeder line costs in this region to levels at which the oil in the region would be competetive on the world market. The building of a pipeline 60 miles east from Prudhoe Bay would, in turn, increase the attractiveness of any discovery in the Arctic Refuge by reducing the economic penalties of a stand-alone feeder line from the Arctic Refuge.

C. Effects of Potential Natural Gas Sales on Prudhoe Bay Production

Continued interest in a major sale of North Slope natural gas has focused attention on the question of how gas sales will affect Prudhoe oil production. Information bearing

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[78] Frederick Rose, "Arco Oil Find in Beaufort Sea is Likely To Renew Debate Over Wildlife Refuge," Wall Street Journal, Oct. 15, 1992, p. A-3; Kim Fararo and Hal Bernton, "Arco makes Arctic strike," Anchorage Daily News, Oct. 15, 1992, p. A-1.

[79] Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity? (op. cit.), p. 3-38.

on this question was developed in a hearing held by the Alaska Oil & Gas Conservation Commission in November-December 1991 on the Prudhoe operators' request to lower field pressure requirements. The problem is that gas production will eventually cause the loss of oil at Prudhoe Bay. At what point will the prospect of long-term revenues from gas — say in 2025 — outweigh the loss of oil revenue from Prudhoe Bay in 2015? The upshot of a hearing on this subject before the Alaska Legislature last January was this: The Oil and Gas Conservation Commission, on the basis of its earlier hearing, feels that effects of a natural gas sale can best be analyzed after a proposal is made. In the commission's view, there are too many economic uncertainties to warrant the time and expense of modelling before there is a concrete proposal.[80]

The Oil & Gas Conservation Commission's wait-and-see position on gas line development makes sense. The inherent uncertainties of long-range forecasting mean that tomorrow's model has a greater likelihood of producing meaningful results than today's. However, the Commission's strategy assumes that state knowledge and organization are adequate to handle this complex question when it becomes ripe for consideration. However, several problems identified in this report indicate that the state resource managers might consider reorganizing themselves to define issues and make recommendations on development policy decisions in a timely manner.[81]

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[80] House Finance and House Oil and Gas Committee, Hearing on Prudhoe Bay reservoir Development and Management," Jan. 23, 1992. See also: Alaska Oil & Gas Conservation Commission Hearing on Petition to Amend Conservation Order No. 195 Rule 2 and Approve Significant Expansion of Prudhoe Bay Unit Miscible Gas Project, Nov. 18-20, Dec. 20, 1991, resulting in Order No. 290, Feb. 21, 1992

[81] Production forecasts provide one indication that the state may not be capable of reviewing and making informed policy decisions on North Slope development in a timely manner. The state's consistent upward revision of its forecasts is an indication that public bureaucracy may lag industry's in its understanding of the issues at hand. The Department of Revenue's removal of West Sak from its Spring 1992 forecasts provides a further warning that state agencies may be in a poor position to assimilate and interpret new information when the time comes to judge the economic effects of a major gas sale. Finally, the state's failure to apprehend significant problems imbedded in pipeline tariffs — for example, the give-away in the TAPS DR&R provision — provides an additional indication of problems in resource policy management.

Although detailed discussion of the possible institutional corrections to the problems mentioned here is beyond the scope of this report, some suggested remedies will be briefly mentioned:

Poor inter-agency coordination was "striking" to at least one member of the International Oil Tax Comparison Study Group of the Alaska State Legislature and Department of Revenue (Dr. H. Motamen Scobie; see note 65, above). Better inter-agency coordination can be effected by creation of an oil and gas subcabinet wthin the administration. One way the Legislature can insure that state policy makers are handling oil and gas matters in an appropriately even-handed and far-sighted manner would be to establish direct legislative oversight of key oil and gas policy issues by the Legislative Budget and Audit Committee staff. A third institutional fix would be to transfer pipeline tariff responsibilities from the Deapartment of Law to a line agency — the Department of Revenue or Department of Natural Resources. (The transfer of this executive responsibility is the only recommendation that requires statutory action.)

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

OIL AND HAZARDOUS SUBSTANCE RELEASE RESPONSE FUND

FISCAL YEAR 1992 ANNUAL REPORT

January 21, 1993

OIL AND HAZARDOUS SUBSTANCE RELEASE RESPONSE FUND
FISCAL YEAR 1992 ANNUAL REPORT

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OIL AND HAZARDOUS SUBSTANCE RELEASE RESPONSE FUND

FISCAL YEAR 1992 ANNUAL REPORT

Section I. INTRODUCTION

The Oil and Hazardous Substance Release Response Fund, generally referred to as the "Response Fund", was created by the Legislature in 1986 to provide adequate funding for the State to investigate, respond and cleanup spills of oil and hazardous substances. Each year, the Department of Environmental Conservation (DEC), the Response Fund administrator, is required to submit a report to the Legislature providing information on Response Fund expenditures, costs recovered, DEC response activities, projected expenditures, and any other information considered significant by the Commissioner (AS 46.08.060).

Section II provides an update of the Department's response to an internal management audit of the Response Fund. The audit was conducted in May 1991 and provided recommendations to improve DEC's management of the Response Fund. During FY92 a number of steps were taken to resolve specific audit issues. Actions taken during FY93 are described here.

Alaska response capability; are we better off this year? Section III offers an assessment of Alaska's ability to prevent and respond to hazardous substances incidents. Section IV provides information on FY92 Response Fund allocations. Response Funded activities are described in Section V.

Section II. RESPONSE FUND MANAGEMENT AUDIT UPDATE

Since the release of the May 1991 audit report, DEC has and continues to take action to improve management of the Response Fund. The conditions described in the audit report, and corrective actions taken by DEC are outlined below.

USE OF THE FUND BY OTHER AGENCIES

Audit issue:

By statute, DEC is the State's designated Response Fund administrator (AS 46.08.010). However, DEC does not have full management and accounting control over Response Funds directly appropriated to other State agencies by the Legislature. There are no requirements to provide DEC with Response Fund accounting information from agencies receiving direct Response Fund appropriations. DEC can only manage, account, and report on Response Fund appropriations made directly to DEC.

Actions Taken by DEC:

DEC has developed and incorporated standard reporting requirements into FY92 Reimbursable Service Agreements (RSAs) between DEC and other agencies that use the Response Fund.

It is clear that the use of RSAs to manage the transfer of Response Funds between agencies has contributed to the difficulty in obtaining information about the expenditures and obligations incurred in this fund. DEC, the Department of Administration-Division of Finance, the Office of Management and Budget and Legislative Finance staff are currently investigating other options to provide reasonable internal controls and reporting while eliminating the reporting difficulties caused by use of RSAs. Recommendations should be available within ninety days.

CLARIFICATION OF DEC ROLES

Audit Issue:

There is no single manager of the Response Fund.

Actions Taken by DEC:

The Assistant Commissioner is the designated Response Fund Manager.
The Director of SPAR serves as Assistant Response Fund Manager providing policy guidance and direction. A second Assistant Response Fund Manager within the Division of Information and Administrative Services is responsible for procedures, internal fiscal

control and Response Fund accounting reports.

COST RECOVERY

Audit Issue:

Full cost recovery on the majority of incidents does not occur.

Actions Taken by DEC:

Procedures for cost recovery by DEC's regional office response staff are being developed the Division of Information and Administrative Services. Draft procedures are expected to be available within ninety days.

EQUIPMENT POLICY AND PROCEDURES

Audit Issue:

The condition, location, and current value of equipment purchased with Response Funds cannot be accurately documented.

Action Taken by DEC:

It is clear that because of inconsistencies in coding equipment purchases on the State Division of General Services and Supply special fund equipment database, it is not possible to determine the current value of all Response Fund purchased equipment.

The Department has established a response gear inventory database program to track and maintain condition and location summaries of all the Department's growing spill response equipment inventory.

Departments that have inventory lists tracking equipment purchased with response fund dollars are as follows:

Department of Environmental Conservation	$ 597,424
Department of Natural Resources	72,335
Department of Administration, Div. Telecommunications	60,324
Department of Fish and Game	991,825
Department of Transportation/Public Facilities	14,678
Department of Military and Veterans Affairs	950,076

Section III. ALASKA RESPONSE CAPABILITY -- "Are we better off this year?"

Progress continues in State programs designed to prevent and respond to hazardous substances incidents. The State Master Oil and Hazardous Substance Discharge Prevention and Contingency Plan (State Master Plan) has been given approval by the State Emergency Response Commission (SERC) and is now effective. All State agencies are obligated to coordinate their responses to emergency hazardous substance incidents as part of the State's Incident Command System (ICS) under the direction of the State On Scene Coordinator (SOSC). During the next year, State agencies will be developing standard operating procedures to describe the procedures to be followed during specific activities related to incident response.

Recently, the Department of Environmental Conservation (DEC) established four programs related to spill prevention and response programs to focus efforts towards improving the State's ability to prevent and respond to incidents. The four program are: (a) Government Preparedness and Response, (b) Contaminated Sites Remediation, (c) Underground Storage Tanks, and (d) Industry Preparedness. These programs are developed and managed by the Director of the Division of Spill Prevention and Response (SPAR) and implemented throughout the State under the direction of the Regional Administrators/SOSCs. Appendix D describes the goals, background, issues, major features, and benefits of these programs.

The Government Preparedness and Response program has several projects that contribute to ensuring the State and local communities have planned for and are equipped to meet the challenges of responses to hazardous substance releases. These projects are: (a) State and Regional Master Planning, (b) SERC and Local Emergency Planning Committee (LEPC) coordination, and (c) Hazardous Substance Response Preparedness.

The State and Regional Master planning process is evolving into a joint effort with the Federal Government. Agreement in concept has been reached among State and Federal agencies charged with preparing contingency plans for government resources. The Alaska Regional Response Team (ARRT) has also approved the concept. The State and Federal government contingency planners will be working together to develop one contingency plan which will be used by all agencies to coordinate responses to hazardous substance releases. This joint plan will be developed from the bottom -- up! Local plans developed by LEPCs will make up Regional plans which will also serve as Area Plans under the National Contingency Plan. The Regional/Area Plans will then be combined to form annexes to the overall Federal and State Contingency (Master) Plan for Alaska. This plan will be approved by the SERC and the ARRT and jointly exercised.

Many LEPCs have been formed and are preparing local community emergency response plans based on hazards analyses. Significant progress has been made

through increased communications, quarterly workshops which coincide with quarterly SERC meetings, and sustainable levels of State funding. There is a need to develop regulations governing the operations of the SERC, especially as it interacts with LEPCs, and to clarify the roles of local governments and LEPCs. For those areas of the State where interest or capability to form LEPCs is insufficient, the State will be developing one Local Emergency Planning District (LEPD) and provide the resources to address problems in those areas. Funding levels for LEPCs for planning purposes should remain constant; however, many LEPCs are requesting additional funds to purchase response equipment to improve the local capability to respond to incidents they are identifying through their local planning process. Funds for this latter purpose may not be forthcoming because these needs are outside of the scope of LEPCs and should be addressed through State depots. See Appendix E for the status of LEPDs and LEPCs as of December 31, 1992.

The capability to prevent and respond to crude oil spills has been vastly improved by State legislation and spill prevention and response program activities. However, there is a big gap in the capability to respond to non-crude oil spills and releases of other hazardous substances. This has been particularly evident by the number of chlorine releases experienced throughout the State and the heightened level of awareness of the deadly hazards of uncontrolled chlorine releases. A special task force was recently formed to rapidly increase the State's information base on the threat of chlorine releases, make the population aware of serious risks associated with chlorine releases, take aggressive steps to prevent releases, and eliminate potential sources of emergency releases (such as those at abandoned canneries). During the near future the threat of hazardous materials releases must be weighed against those of oil -- both crude and non-crude. A study on the transportation of non-crude oil indicates there is a glaring gap in the State's capability to respond to such releases in Western Alaska and Southeast. During FY 93, a strategic plan for depots/corps that addresses the State's needs in 1993 and beyond will be developed. This plan will clarify the need for depots and corps and be used as the basis for a nearshore demonstration project funded by the Legislature for FY 93.

DEC has paid considerable attention to crude oil spill contingency planning in its Industry Preparedness program. Oil pollution prevention and control regulations became effective during fiscal year 1992 and the DEC Regional staffs began reviewing revised contingency plans submitted by the oil industry. While crude oil handling and noncrude delivery in the most populated regions of the State have been significantly upgraded, there is increased awareness of the problems with heating oil and gasoline faced by small communities in remote areas of the State. Many of the facilities that serve these areas are dilapidated and will not last much longer. These facilities are not regulated because of their size (below 10,000 barrels), but are increasingly the source of chronic spills, as well as sudden accidental releases. DEC must continue to work with other State and Federal agencies to prevent spills from these facilities. The Alaska Energy Authority has identified $47 million needed to upgrade 236 facilities to

existing codes. A DEC contractor did a separate study of 293 facilities and estimated a minimum of $161 million would be needed to bring them up to prevention standards required of the regulated facilities. It is only a matter of time before these facilities will start to fail in large numbers requiring numerous emergency responses. Many small communities will be in peril, unless proactive measures are taken. DEC currently does not have the resources to dedicate to a project of this nature without significantly reducing its ability to meet its present statutory obligations for hazardous substance spill prevention and response.

During 1992, the initial strategic plan for contaminated sites, Clean 2000 was developed by the Contaminated Sites Remediation staff. The goal is to initiate a systematic process to clean up or control contaminated sites that pose a threat to the public health or the environment. Targets have been set for implementation of program initiatives necessary to ensure that by the year 2000, corrective actions will be underway at all sites which pose an imminent or substantial threat to the public health or the environment. The plan calls for subdividing the list of contaminated sites (presently over 1,500) into action categories ranging from "immediate action/imminent threat" to "no further action/no threat." Existing staff will focus on the enforcement of responsible party cleanup actions at sites considered to pose an imminent or substantial threat to public health or the environment. Sites of lower risk will be placed in a separate category which will be address with an emphasis on voluntary cleanup. A "certified service provider" program is proposed that will shift much of the voluntary compliance work to the private sector with DEC oversight.

Although the Response Fund has not been the funding source for the Underground Storage Tank (UST) program, it is a valuable program that significantly affects pollution prevention and response. Federal regulations require that new underground storage tank installations meet national standards and that tanks already in operation phase-in to meet those standards. Additionally, each facility must show they have some form of financial responsibility in the event of a spill and must follow standard procedures for reporting and cleaning up of oil spills. State law and regulations mirror the federal program, but also established the State Storage Tank Assistance program which offers grants and loans to owners and operators of UST facilities to test, cleanup, upgrade and close their facilities. The process of grant applications has recently been streamlined to expedite grant dollars to the owners/operators for upgrading/closing existing tanks, cleaning up leaking tank sites, and performing tests which will allow them to obtain insurance for financial responsibility requirements. As of December 1, 1992, a total of 523 grants have been encumbered for a total of $5,554,177. There are 510 applications still on file requesting $26,037,766 for which funds of $5,089,056 are currently available. The application sunset for financial assistance is June 30, 1994; however, funding may be made available after that time by the Legislature to provide financial assistance to owners/operators. DEC has been pursuing program delegation from the Environmental Protection Agency (EPA). DEC will be doing an impact analysis of enforcement programs on small facilities and facilities in remote locations

that provide essential public safety services before going forward with program delegation.

In answer to the question posed several pages ago, DEC has continued to make improvements in its programs funded by the Response Fund. There is much more work to do, but we must continue forward progress and make improvements to the State's capability to prevent and respond to hazardous substance incidents.

Section IV. FY92 ALLOCATIONS

DEC was appropriated $28,500,000 in FY 92 from the oil surcharge account and $30,094 from the mitigation account.

DEC	
State and Regional Contingency Planning	$365,900
Spill Prevention, Response, Planning. et. al.	$4,582,000
State Emergency Response Commission	$329,900
Local Emergency Planning Committees	$900,000
Response Office, Depots, and Corps	$2,453,400
Hazardous Substance Spill Technology Review Council	$236,800
Site Investigation, Safety, Cleanup, and Cost Recovery	$3,396,200
Kenai Cleanup Project	$807,000
Exxon Valdez-Spill Cleanup	$3,954,400
Exxon Valdez-Assessment and Restoration	$12,474,400
Exxon Valdez-Litigation	$3,653,100
Arctic Marine Resources Commission	$100,000
Spill Reserve	$12,62[illegible]00
Prince William Sound Regional Citizens' Advisory Council	$175,000
Completion: Non-crude Oil Tanker/Barge Study	$30,000
Other Agency	
Advisory Council/ Transportation of Oil/Hazardous Substances	$239,800
Fund Transfer to Legislative Council	$237,300
Ferries with Oil Spill Response Ability	$500,000
Total Appropriated from Fund	$47,062,600

Tables are provided at the end of this report with additional financial data as follows:

Table 1:	FY92 Expenditures and Obligations
Table 2:	June 30, 1992 Response Fund Balance Sheet
Table 3:	Summary of Funding Sources and Deposits
Table 4:	Mitigation Account Summary
Table 5:	FY93 Allocation Summary
Table 6:	Community Involvement Summary
Table 7:	FY 92 Contractual Payments Exceeding $20,000
Table 8:	FY92 Purchases Exceeding $10,000
Table 9:	DEC Personal Services Expenditures

Section V. FY 92 PROGRAM ACCOMPLISHMENTS

A. State and Regional Contingency Planning

The State Oil and Hazardous Substance Discharge Prevention and Contingency Master Plan relies on the State's Incident Command System for directing State agencies that are responsible for responding to an oil or hazardous substance release. This plan was reviewed by the Emergency Response Committee (ERC) of the State Emergency Response Commission (SERC). The Department extensively revised the ICS described in the Master Plan based on the recommendations of the ERC and an ad hoc ICS Working Group.

$300,000 was allocated to hazards analyses projects undertaken by Local Emergency Planning Committees. Additional hazards studies for areas outside of approved Local Emergency Planning Districts will be conducted during FY 93. When completed, these studies will form the basis for developing regional response plans.

B. Spill Response, Containment, Safety, Cleanup and Cost Recovery

Discharge Prevention and Contingency Plan Review:

AS 46.04.030 requires DEC to review and approve spill prevention and contingency plans for oil terminals, pipelines, tank vessels, barges, and oil and gas exploration and production facilities. The Department routinely reviews each of the approximately 200 plans once every three years. These plans cover approximately 400 individual vessels, barges or facilities. Response funds in this allocation are used for all plan reviews conducted by DEC.

Financial Responsibility:

AS 46.04.040 requires DEC approval of a regulated operation's proof of financial responsibility. Financial Responsibility Program staff reviewed approximately 350 accounts and responded to hundreds of additional requests for technical assistance and other information about the program.

Oil and Hazardous Substance Pollution Control Regulations:

New oil pollution control regulations implementing HB 567 (chapter 191 SLA 1990) became effective in FY92. The regulations describe new contents requirements and planning standards for oil discharge prevention and contingency plans, and the documentation and amounts required for DEC approval of proof of financial responsibility. The new regulations required each operator to submit a revised

prevention and contingency plan to DEC by August 12, 1992. DEC also developed detailed guidelines to accompany the new regulations that facilitate plan preparation and standardize Department review procedures. The guidelines were completed in FY92 and distributed to all planholders.

Inspections and Discharge Exercises:

DEC annually inspects approximately 100 regulated facilities and 100 tank vessels or oil barges. This allocation funds the Department's inspection and spill drill program to verify the effective implementation by industry of their prevention and contingency plans.

Non Catastrophic Response:

Work continued to streamline the administrative procedures by which the State could hire Response Action Contractors to respond on the State's behalf to oil or hazardous substance releases. Investigation began into the feasibility of the State contracting with established Cleanup Cooperatives for additional response capabilities in the event that the State had to take over the management of a large spill release. The Central office, with the support of the Regions, revised and improved the Departments spill notification procedures, establishing the Situation Report (SITREP) form and format. Response staff are being educated on the necessity to share spill information and when to escalate response actions for additional assistance. Safety issues are being stressed to the mid and upper level managers as reminders of the inherent dangers when dispatching personnel to hazardous or unknown situations.

Spill notifications with other State and Federal agencies remained a priority with investigation into the possibility of establishing an electronic link up to the U.S. Coast Guard and the Environmental Protection Agency.

State On Scene Coordinator positions and regional geographic boundary descriptions were defined, eliminating questions on overlapping jurisdictions.

C. State Emergency Response Commission (SERC)

The State Emergency Response Commission (SERC) is responsible for overseeing the development of state and local response plans for oil and hazardous substance releases (AS 46.13.040). The SERC held four quarterly meetings during FY 92.

The first SERC report was completed covering the period 1987-1991. The report contains a brief description of the program, and a comparative analysis of the state [AS 46.13] and federal laws [SARA Title III].

D. Local Emergency Planning Committees (LEPC)

Two new LEPCs were appointed by the SERC during FY 92, bringing the total number of approved LEPCs to twelve.

$600,000 in funding was awarded to Local Emergency Planning Committees and communities forming LEPCs. These funds were used for LEPC formation, LEPC operations, conduction of a hazards analysis, and development of local response plans for oil and hazardous substances.

Two statewide LEPC meetings were held in conjunction with the third and fourth quarter SERC meetings. Approximately fifty representatives from approved LEPCs and Local Emergency Planning Districts which received state funds attended each meeting. The meetings have enhanced communication between program staff and LEPCs, and between the SERC and LEPCs.

Hazards Analysis projects were started for ten Local Emergency Planning Districts. These studies focus on Extremely Hazardous Substances (EHS) as defined in federal law. Local Emergency Planning Committees will use the results in developing local response plans for potential hazardous substance releases. In addition, the results of the studies will provide useful information for policy decisions made by the SERC and DEC related to hazardous substance release prevention and response. The Department will continue the Hazards Analysis project during FY 93 in other areas of the state.

E. Response Office Depots and Corps

The Spill Response Office (SRO) continued a rigorous training regiment in order to become the highly trained oil and hazardous substance spill experts envisioned by the legislature. SRO staff attended numerous advanced and highly technical training courses and spill response drills throughout the United States and Canada. SRO drafted a spill response manual as a cornerstone for training the Department's district and regional response positions. Basic training requirements were established and a database program instituted to track and maintain training records.

SRO safety and training staff conducted numerous refresher and training courses which included an eight hour HAZWOPER refresher course for 130 Department staff, seven state personnel from the Departments of Fish and Game and Natural Resources, and 35 industry personnel associated with Exxon Valdez cleanup activity. Respirator fit test were administered to 133 DEC staff and 30 Fairbanks firefighters. An Incident Command Training (ICS) course was developed and given to 87 DEC personnel. Departmental community involvement training situations included two waste water operators courses given to 55 Kenai Borough personnel detailing safe

handling practices for Chlorine and confined space hazards.

A response gear inventory database program was also established to track and maintain condition and location summaries of all of the Department's growing spill response equipment inventory.

F. Hazardous Substance Spill Technology Review Council

The State Hazardous Substance Spill Technology Review Council (HSSTRC) exists within the SERC, and is responsible for recommending containment and cleanup products and procedures for responding to arctic and subarctic hazardous substance releases (AS 46.13.110). The Council held four formal quarterly meetings and one conference call during FY92. Draft technology protocols were developed and submitted to national and international organizations for public review and comments. An annual report was published by the Council indicating research priorities. During FY92, DEC staff assigned to the HSSTRC obtained membership to and attended the American Society for Testing Materials for F20 Committee on Hazardous Substance and Oil Spill Response meetings. The staff also continues to maintain a vendor/produce database and manages oil and hazardous substance technology information for the HSSTRC and DEC.

G. Contaminated Site Investigation, Safety, Cleanup, and Cost Recovery

The Contaminated Sites Program investigates sites contaminated with oil or hazardous substances and directs cleanup efforts by responsible parties or DEC term contractors. Response Funds are used to hire contractors to investigate and cleanup sites when the responsible party is unable or unwilling to respond. In FY92, DEC had under contract three cleanup contractors and four site assessment contractors. A total of 13 contracts in excess of $1,000 each were issued to these contractors in FY92 for a total expenditure of $394,000.

Five of the 13 contracts were funded from the spill reserve account. These contracts, for a total of $103,400, were for work performed at Benny Benson Lagoon, Aniak Lift Station, Cinnabar Loop, Child's Pad, and Wendell Street cleanup. Each of these sites are described in Appendix A.

Ten other DEC Term Contracts were funded from the contaminated sites non-operating response funds. A description of the site work associated with each of these sites is provided in Appendix B. An eleventh contract, separate from the term contracts, was funded for $77,000 to assess the impact of air pollution from the Alaska Pulp Corporation facility in Sitka. Additional background information on this project can also be found in Appendix B.

FY92 Response Funds were also used to manage and monitor response efforts of

responsible parties. Under this funding, DEC staff provided oversight of over 200 responsible party cleanup actions. The Department of Law was also provided Response Funds for cost recovery and site investigation activities.

The contractual work with Shannon & Wilson to develop a contaminated site database and Alaska Hazard Ranking Model was completed in FY92, with a final payment of $30,100. The final report contained site information and hazard ranking scores for 905 sites. Response Funds were also used for DEC staff to continue the site ranking process in an effort to complete ranking of all the contaminated sites on the database. Additionally, over 400 new sites were added to the list of statewide contaminated sites in FY92.

Other major accomplishments by Contaminated Sites staff funded by Response Funds include: updating guidelines for cleanup of contaminated soils; developing guidance for home heating oil tank owners to address tank leaks; drafting and receiving funding for an Interagency Memorandum of Agreement for cleanup of state-owned contaminated sites; and development of systematic program elements for the Contaminated Sites Program.

H. Kenai Cleanup Project

The purpose of the Kenai Cleanup Project is to implement an intensive effort within the Kenai Peninsula Borough to investigate and cleanup hazardous substances spilled in large part as a result of past industrial practices. Created in May 1988, the project was originally funded out of a separate legislative appropriation obtained through the capital project budget process. Since FY91, the project has been funded through the Response Fund.

FY92 expenditures supported legal assistance to the Kenai Cleanup project from the Department of Law. Response funds were also used by DEC for the cleanup of contaminated sites where the responsible party was not known, unable, or unwilling to respond (Appendix C), and for DEC's oversight of over 100 responsible party cleanups.

I. Exxon Valdez Cleanup

This allocation funded the Department's FY92 cleanup effort in Prince William Sound. During FY92 DEC maintained the Oil Spill Response Center (OSRC) in Anchorage. Reimbursable Service Agreements (RSAs) were issued to other State agencies for either participation or support functions. The Departments of Fish and Game and Natural Resources have specific statute authority requiring their involvement in the cleanup process.

FY92 was the last year of major cleanup activities. The final comprehensive shoreline

monitoring work was completed in late June, science projects were brought to a close with samples sent to laboratories for analysis, and major efforts were centered upon completing reports and making them available to the public. Eleven stations in Prince William Sound were identified as locations for long term monitoring of Exxon Valdez oil spill contaminated sites. The process of classifying all records accumulated during the spill was begun. The OSRC staff worked closely with the Department of Law in providing information for litigation.

RSA#1820019 FY92 Department of Transportation and Public Facilities, M & O Southcentral District

Environmental Conservation leased a building containing a laboratory facility with water, sewer, electricity, trash removal, heat, and snow removal. The RSA amount is $24,000, there were no amendments.

As this was an RSA for space rental and no projects for Exxon Valdez oil spill remediation were involved we did not require a breakdown of the expenditures by the receiving department. It is noted all of the funds were placed in the contractual line. The laboratory was turned back on
June 30 1992.

RSA#1825006 FY92 Department of Military and Veterans Affairs, Division of Emergency Services

Funds were made available in the amount of $5,100 for the final Exxon Valdez closeout activities of the Division. They were intended for repair, shipping, packaging, and storage of equipment issued to Environmental Conservation and related agencies during the oil spill. Emergency Services was able to accomplish these activities without charging against the RSA. A closeout RSA is in process at this time. There were no amendments to this RSA.

RSA#1825007 FY92 Department of Administration, Division of Telecommunications

The Division of Telecommunications used this funding ($71,332--actual expenditures $71,191) to maintain the VHF radio system in Prince William Sound and to close down the system after our response activities were completed. Their support was excellent, we had radio support whenever it was needed. A closeout RSA is in progress.

Personal Services

02N361	Electronic Tech.	$18,000

Contracts > $20.000

Reported in RSA#1821000.

Purchases > $10.000

Reported in RSA#1821000.

RSA#1820018 FY92 University of Alaska Fairbanks, Institute of Northern Engineering

This RSA provided funds ($31,747 payments of $31,747 made) to the University of Alaska to study the presence of hydrocarbons and hydrocarbon-degrading microbes in selected shorelines and shallow subtidal sediments. A determination was to be made to ascertain if the addition of fertilizer would be of continuing benefit to hydrocarbon-degrading microbes. The work was completed timely and the RSA closed.

J. Exxon Valdez Assessment & Restoration

The bulk of the funds for this project were transmitted to the Alaska Department of Fish and Game for distribution to State agencies for projects approved by the Exxon Valdez Trustees. DEC retained a small portion of the funds, Fish and Game utilized the bulk of the funds for its science projects, passing a portion by RSA to the Department of Natural Resources. This is the last year the natural resources damage assessment and restoration efforts will be funded by the Fund, in future years the funding source be the Exxon Civil Settlement monies.

RSA#1820015 FY92 University of Alaska Fairbanks, Institute of Marine Sciences

This RSA provided funds ($14,000--payments of $8416 have been made) to the University of Alaska to conduct a study of sediment grain size. This work is part of a larger project that studies the rate of settling of small sediments and the presence of oil in the water column. The work was completed timely. This RSA will be closed after receipt of a final billing.

RSA#1821000 FY92 Department of Fish & Game, various divisions

This RSA provided the Department of Fish & Game with funds ($11,947,300--payments to date $6,306,190) to participate in the restoration of those portions of Prince William Sound and the Gulf of Alaska affected by the Exxon Valdez oil spill. Some funds were passed on to the Department of Natural Resources via RSA.

Personal Services

See appendix F

Contracts > $20.000

Univ. of Washington	Fisheries study	$ 48,000
Univ. of Calif.-Davis	not stated	162,000
Dept. of Nat. Res.	Restoration work	366,478
Dept. of Nat. Res.	Archaeology	473,246
Dept. of Nat. Res.	Mapping services	583,338
UAF	Subtidal Study # 2	372,800
UAF	Coastal Hab. study	250,000
UAF	Hydrocarbon injury	162,100
UAF	Mammal study	40,800
UAF	Fish analysis	63,882
Woods Hole Inst.	Sample analysis	175,000
NOAA	Sample analysis	100,000
Texas A&M	Sample analysis	55,000
UC-Davis	Sample analysis	157,000
DOL	Litigation mgmt.	645,000
F&G-Comm Fish	M/V Montague	71,250
F&G-Comm Fish	M/V Montague	25,650
UA-SFOS	Pink salmon catches	65,162
UA-Arctic Biol.	River otter injury	121,951
UA-Marine Sci.	Deep water benthos	79,600
Law	Litigation mgmt.	75,000
U.of Arizona	Sample analysis	25,000
Triton Environ.	Incubation exper.	40,000
Dr.Richard Kocan	Herring study	45,000
Dr.Jo Ellen Hose	Herring study	103,800

Purchases > $10.000

Biosonics & HTI	Hydroacoustic equip./ Feasibility study	$150,000
Surveyors Exchange	2 GPS Pathfinders	15,180
Computerland	Computers	23,928
Phoenix Flow Systems	Partec cytometer	55,000
Wildlife Computers	13 satellite depth recorders	52,200
Fortune Marine	Vessel charter	100,000
Ak.Mining/Diving Supp.	Hardbottom inflatable	10,764
Southeast Marine	5 outboard motors	20,000
Jim Faro	Vessel charter	54,000
AK Ship Chandlers	Boat/motor	41,985

RSA#1825025 FY92 University of Alaska Fairbanks, Institute of Arctic Biology

This RSA made available funds ($94,501--payments made $90,302) to determine the numbers of hydrocarbon-oxidizing microorganisms and the oxidation rate potential of sediment samples collected. A final report to be prepared discussing the results. This study was completed and the final report submitted.

K. Exxon Valdez Litigation

RSA#1825008 Department of Law

This RSA made $3,653,100 available to the Department of Law to provide for the services of outside legal counsel necessary to the state to pursue its civil claims against Exxon and Alyeska. There was one amendment reducing the RSA by $500,000. There is a similar RSA for fiscal year 1993. Legal actions are proceeding appropriately.

No RSA monies were expended for personal services or for purchases over $10,000.

Contracts > $20,000

Preston Thorgrimson	Litigation	$1,888,096
Quorum Litigation Serv.	Litigation support	423,969

L. Arctic Marine Resources Commission (AMRC)

The Legislature appropriated $100,000 to fund AMRC through FY 92, with the intent to form a Regional Citizens' Advisory Council for residents of Alaska's Arctic coastal communities. This council would be similar to existing industry-funded councils in Cook Inlet and Prince William Sound organized under the federal Oil Pollution Act of 1990. Absent grant authority, DEC obtained sole-source authority to provide this funding through a contract with AMRC. Contracted services included incorporation and financial organization of AMRC, review of Arctic oil exploration and development issues affecting Alaskans, and efforts to secure federal and industry recognition and support as an Arctic Regional Citizens' Advisory Council.

M. Prince William Sound Regional Citizens' Advisory Council, Ballast Water Treatment Contract

On December 19, 1991, DEC signed the contract for Scientific Studies with the Prince William Sound Regional Citizens Advisory Council (RCAC). The contract authorized RCAC to retain technical experts of its choosing who would review and evaluate three monitoring programs being conducted by DEC at the Alyeska Valdez Marine Terminal. House Bill 75 appropriated a maximum of $175,000 for disbursement by DEC to RCAC for the

performance of the studies.

The three DEC programs under review monitor:

- the influent ballast water to the ballast water treatment facility (BWTF);
- the treated discharge (effluent) from the BWTF;
- sediment hydrocarbon chemistry and sediment toxicity in Port Valdez.

Prior to contract negotiations, RCAC published a Request for Proposals, evaluated responses and contracted with three environmental consulting firms to perform the work. The evaluation of the influent ballast water monitoring program was performed by Beak Consultants, Inc. of Kirkwood, WA and the final report was submitted to RCAC on April 30, 1992. The evaluation of the effluent monitoring program was performed by ISI of Guelph, Ontario, Canada and the final report was submitted to RCAC on August 24, 1992. The evaluation of DEC's toxicity monitoring program was performed by Northwestern Aquatic Sciences of Newport, OR, and the final report was submitted to RCAC on September 16, 1992. Invoices received by DEC to date total $78,884 for the three studies. This total includes RCAC's 10% administrative charges.

RCAC technical staff analyzed the findings and recommendations of the studies and prepared consolidated recommendations to DEC. These recommendations were received by DEC on December 22, 1992. By DEC's receipt of the consolidated recommendations, the December 19, 1991 contract has been fulfilled. DEC will consider RCAC's recommendations and will determine which of the recommendations should be implemented. Decisions on implementation are expected to be made by the end of the first quarter of 1993.

N. Noncrude Tanker Study

As requested by the Legislature, during FY91 DEC surveyed the condition of small (unregulated) noncrude oil terminal facilities with storage capacity between 5,000 and 10,000 barrels. To assist in the survey, a contract was awarded to ECO Engineering, Inc. The report was completed and presented to the Legislature in 1992. The Department utilized an additional $27,000 appropriated for FY 92 to expand this survey by including oil terminals with capacity between 1,000 and 5,000 barrels. A second contract was awarded to ECO Engineering to obtain the data required for this report. A report will be presented to the Legislature at the beginning of the 1993 session.

O. Spill Reserve

In FY92 the spill reserve was used to fund expenditures during the Department's response to releases of hazardous substances which posed an imminent threat to public health,

welfare and safety. A total of $71,383 was expended from the Spill Reserve during FY92. A description of each site on which more than $1,000 was expended can be found in Appendix A.

P. Other Agency Expenditures

The following information was available regarding other agency spending of Response Fund monies through RSAs:

University of Alaska - Research Funding RSA#1820290

Alaska Statute (AS) 46.08.150(3) allows the Oil and Hazardous Substance Response Office to enter into agreements with state and federal government agencies, political subdivisions, the University of Alaska or other entities to conduct research on topics recommended to it by the Hazardous Substance Spill Technology Review Council under AS 46.13.120.

In FY92, a memorandum of agreement was established between the Department and the University of Alaska. The agreement has the intent of expanding cooperative research, using cost effective solutions to environmental problems. A portion of the funding for this agreement is from the Oil and Hazardous Substance Release Response Fund. Use of response funds is limited to research. Each project or proposal should be evaluated with respect to the future economic viability, method and financing of development. The Council will classify projects as "research, development or other". Only those projects classified as research will be further reviewed by the Council.

$100,000 was encumbered in a Reimbursable Service Agreement (RSA) with the University in FY92. No expenditures have been made.

Department of Law RSA#1820025

An encumbrance of $358,000 was made with this RSA to the Department of Law for FY92. The Contaminated Sites Section (DEC) contributed $100,000 from non-operating funds; of this amount, the Kenai Project contributed $40,000 and the Site Investigation Project contributed $60,000. The SPAR Director's Office contributed $8,000 and the remaining $250,000 was from Spill Prevention, Planning and Management.

The funds were primarily used to support legal services required at thirty-five separate cleanup sites. Examples include the Forward Pad Hazardous Substance cleanup on the North Slope, the Skagway Lead Contaminated Cleanup, the Chevron Bulk Plant oil contamination cleanup in Valdez, the Orca Cannery oil contamination cleanup in Cordova, the Marathon/Trading Bay Facility oil contamination cleanup in the Kenai Borough, and the Port of Anchorage contamination assessment.

The funds were also used to a lesser extent to answer policy questions related to strict

liability and lender liability as they apply to hazardous substance releases.

In addition, the funds also provided reimbursement to the Department of Law for normal state legal expenses following the adoption by DEC of the new Oil and Hazardous Substance Pollution Control regulations.

Department of Natural Resources RSA#1820154

The Alaska Department of Natural Resources (DNR) received Response Fund support under an RSA in the amount of $23,900 to perform tasks under two projects, as follows:

Industry Contingency Planning:

DNR began drafting guidelines for review of industry contingency plans. DNR reviewed several industry contingency plans, focusing on oil industry exploration and development projects. Industry contingency plan review also focused on protection or cleanup of historic, archeological or cultural sites. DNR staff participated in meetings of several major planning groups, including the Regional Citizens' Advisory Councils for Cook Inlet and Prince William Sound, and several private cleanup organizations.

State and Regional Contingency Planning:

DNR participated in meetings of the SERC. Staff commented on drafts of the State's master contingency plan. DNR participated in meetings of the State Damage Assessment and Restoration Planning Subcommittee and submitted draft materials to the Department of Law on federal Natural Resources Damage Assessment regulations. DNR monitored activities of the Alaska Regional Response Team and its Response Technology Working Group.

Department of Fish and Game RSA#1825010

The Alaska Department of Fish and Game (ADF&G) received Response Fund monies under an RSA to perform tasks under two projects, as follows:

Industry Contingency Planning:

ADF&G developed internal contingency plan review booklets, reviewed and commented on 29 oil spill contingency plans, monitored the progress of Alyeska activities being conducted under the 1991 Trans-Alaska Pipeline System contingency plan, and made recommendations to DEC regarding implementation of contingency plan improvements. ADF&G participated in six spill response drills to test the provisions of industry contingency plans.

ADF&G participated in major planning forums: the Prince William Sound Steering Committee, Alyeska Pipeline Service Company pipeline committee, Cook Inlet Spill

Prevention and Response Inc. committees, and the Prince William Sound and Cook Inlet Regional Citizen's Advisory Councils. ADF&G represented state interests on the federal Alaska Regional Response Team working groups related to wildlife protection and response technology.

Personal services were paid as follows:

PCN 6102	$20,276
PCN 6061	5,694
PCN 6010	2,365
PCN 6041	15,748
PCN 6064	15,319
PCN 6104	7,955
PCN 6060	6,189
PCN 6048	2,019
PCN 6036	2,096
PCN 6027	977
PCN 6008	1,008
PCN 6138	205
PCN 6136	467
PCN 6110	165
PCN 6007	155
PCN 6087	158
PCN 6128	338
Total	$81,136

State and Regional Contingency Planning:

ADF&G participated in meetings of the SERC and SERC committees. ADF&G commented on drafts of the state master contingency plan and completed the draft environmental sections of the Arctic and Interior regional plans. Staff chaired meetings of the Damage Assessment and Restoration Planning Subcommittee and submitted draft materials to DEC on Natural Resource Damage Assessment (NRDA) issues and tasks necessary to initiate and NRDA program.

Personal services were paid as follows:

PCN 6102	$7,282
PCN 6041	26,480
PCN 6064	8,094
PCN 6048	1,819
PCN 6008	1,837
PCN 6124	545

PCN 6007	252
PCN 6027	292
PCN 6136	224
PCN 6098	263
PCN 6028	159
PCN 6138	132
Total	$47,380

Department of Military and Veterans Affairs RSA#1695000

DEC entered into an Reimbursable Services Agreement (RSA) with the Department of Military and Veterans Affairs, Division of Emergency Services (DES) for $2,000,000 (two million) dollars for FY92 activities associated with development of Oil Spill Response Depots and Corps.

The RSA was later amended to reduce the amount by $300,000.00, providing funding to DEC to conduct a statewide hazards analysis necessary in the decision making process for locating response depots and corps. Before locations for depots can be designated in the State Master Plan, there must be a process accomplished -- "a hazards analysis" -- that identifies the hazards in the State, by areas; identifies vulnerabilities, by areas; and evaluates risks taking into account existing capabilities, by area, to respond to those potential hazards. Once the hazards analyses are done for areas around the State, a statewide database will be formed, a priority ranking developed to identify the areas of greatest need; and depots established to meet those needs.

Of the remaining amount, $1,700,000.00, DES spent or obligated $1,638,870.99 and $61,120.01 lapsed returning to the available balance in the Response Fund.

Personal Services:

Personal Services were paid to DES staff as follows:

PCN 0220	Chief of Logistics	$70,166
PCN 0218	Planner III	55,322
PCN 0112	Storekeeper	45,849
PCN 0185	Haz Mat/Emergency Specialist	50,338
PCN 0219	Accounting Clerk III	35,631
PCN N069	Clerk Typist II	1,706
	ASEA Legal Trust	159
	Total	$259,171

Contracts > $20,000

A contract was issued to Incident Management Associates for development of

Incident Command Systems and associated training. The contract was initially issued for $85,000 and later amended to increase this amount by $14,000 to $99,000.

A contract was issued to SPYDR C-4-1 Management Company for $24,720 to provide the initial high level design for the Advanced Integrated Incident Management System (AIIMS).

Purchases > $10,000

No individual items were purchased with a cost greater than $10,000 other than components of the communications system described below.

Equipment Purchases

With the exception of communications equipment detailed separately, equipment purchases were limited to computer equipment required for data processing and administrative work.

Description	Cost
Macintosh Quadra 950 Computer	$6,839
Tektronix Phaser II Printer	6,576
Apple Mac Color Monitor	3,162
Compaq 386/25E Computer	5,298
Compaq VGA Color Monitor	436
Okidata 390 + Printer (3)	1,198
Compaq Amber Monitor	94
Compaq 386/33L Computer	9,498
Compaq VGA Monochrome Monitor	189
Cabletron 12 Port T-Hub	1,445
Unison Monitor	929
Emerald Disk Drive	3,598
External Modem	171
3270 Emulator Software	439

The following projects were initiated during FY92 using funding provided through this RSA.

Incident Command System Training:

The Incident Command System development and training conducted under the contract with Incident Management Associates provided training in the following concentrations:

Course	Number Trained
Introduction to Incident Command Systems	35
Command Section Training	17
Operations Section Training	19
Planning Sections Training	20
Logistics Section Training	25

Course rosters are available for each class.

Oil and Hazardous Substance First Responder Training:

This project was designed to improve the capability of local first responders to respond to an oil or hazardous substance release and was administered through the Local Emergency Planning Committees (LEPCs). Based on local hazards, LEPCs selected the types of oil and hazardous substance releases their first responders might be confronted with in their immediate areas. To meet the training needs, RSAs were entered into with the University of Alaska - Fairbanks and Southeast, Mining and Petroleum Training Services and Alaska Fire Service Training Services to provide training.

Training was provided that addressed the following specific topics:

First Responder Awareness
First Responder Operations
Haz Mat Technician
Decontamination
Incident Command System (Introduction and Advanced)
Liquid Petroleum Gas

Below is a listing of the number of first responders receiving training and the approximate cost of that training by LEPC:

LEPC	Number Trained	Cost
Fairbanks	450	$52,000
Anchorage	35	16,100
Sitka	90	39,484
Kenai	40	34,289
Juneau	120	38,500
Kodiak	90	21,000
Mat-Su	140	15,008
Ketchikan	90	30,000
Yakutat	4	17,616
NW Arctic	60	18,375

Communications System:

Once completed (December 1993) this package will permit emergency responders to deploy into the field with a complete communications package. They will be able to talk to their home office, send facsimile traffic, communicate via hand held radios with other field staff, aircraft and ships in the area. In addition, field staff will be able to transmit and receive video information while in the field.

Finances supporting this package were obtained from two sources. $800,000 was committed from this RSA and matched with federal dollars. To date, approximately $910,000 has been obligated and the balance will be obligated over the next six to twelve months.

Funds have been obligated for the following:

Description	Cost
VHF Radios (40)	$28,134
Voice/ Facsimile Port Module (16)	18,016
Variable Rate Satellite Modems (4)	31,112
Video Teleconferencing Unit (2)	106,236
Field Video Teleconferencing Unit (2)	50,690
Transportable Antenna System (2)	89,528
Satellite Earth Station Antenna System(2)	191,416
Transportable Earth Station (2)	70,526.00
Satellite Terminal Transceiver (2)	29,100
Modular Satellite Terminal Transceiver (2)	122,100
Hand Held Portable Radios (4)	2,694
Telephones with Deployable Units (96)	26,732
VHF Suitcase Repeaters (4)	38,243
In Focus System Panel and Case (1)	5,683
Personnel and Technical Contracting	100,000

In addition, funds totalling $32,500 were granted to the Alaska Public Radio Network (APRN) to establish a portable satellite uplink. APRN will participate in emergency communications exercises and provide substantive support as may be included in the State Emergency Plan in response to actual emergencies.

State Emergency Response Commission:

A total of $8,781 was spent on State Emergency Response Commission (SERC) activities.

Expenditures were limited to travel and per diem.

Geographic Information System:

A total of $2,285 was spent on items related to Geographic Information Systems (GIS). As noted above, a contract was issued to SPYDR C-4-1 Management Company for $24,720 to provide the initial high level design for the Advanced Integrated Incident Management System (AIIMS). This system is not a GIS.

Department of Administration RSA#1821006

The Department of Administration, Division of Risk Management received $21,554 through an RSA to provide insurance coverage for employees who travel on aircraft charters. This expenditure was a direct result of increased air travel due to the Exxon Valdez Project.

Table 1

FY92 EXPENDITURES AND OBLIGATIONS

CURRENT YEAR AUTHORIZATION	Authorized	Expended	Obligated [Note 1]	Total Expended & Obligated
DEC				
State and Regional Contingency Planning	365.9	197.1	64.1	261.3
Spill Prevention, Response, Planning, et. al.	4,582.0	3,846.2	498.6	4,344.8
State Emergency Response Commission	329.9	257.0	11.5	268.5
Local Emergency Planning Committees	900.0	575.2	324.2	899.4
Response Office, Depots, and Corps	2,453.4	863.6	1,496.8	2,360.4
Hazardous Substance Spill Technology Review Co	236.8	112.4	106.2	218.6
Site Investigation, Safety, Cleanup, and Cost Reco	3,396.2	1,036.5	639.1	1,675.6
Kenai Cleanup Project	807.0	458.0	210.0	667.9
Exxon Valdez-Spill Cleanup	3,954.4	2,337.3	418.9	2,756.1
Exxon Valdez-Assessment and Restoration	12,474.4	6,654.4	3,830.0	10,484.4
Exxon Valdez-Litigation	3,653.1	1,576.9	1,571.4	3,148.3
Arctic Marine Resources Commission	100.0	100.0		100.0
Spill Reserve	12,627.4	71.4	75.3	146.7
Prince William Sound Regional Citizens' Advisory	175.0	57.2	117.8	175.0
Completion: Non-crude Oil Tanker/Barge Study	30.0	29.9		29.9
Other Agency				
Advisory Council/ Transportation of Oil/Hazardous	239.8	120.3		120.3
Fund Transfer to Legislative Council	237.3	237.3		237.3
Ferries with Oil Spill Response Ability	500.0	102.4	157.8	260.2
Subtotal Current Year	47,062.6	18,633.1	9,521.7	28,154.8
PRIOR YEAR AUTHORIZATION				
DEC				
Oil/Hazardous Substance Release Responses		(9.9)		(9.9)
Oil Spill Contingency Plans/Requirements		84.2	15.0	99.2
State & Regional Contingency Plan		26.4	5.0	31.4
Response Office, Depots & Corps		261.5		261.5
Spill Response Drills		105.7		105.7
Spill Response, Containment, et.al.		388.4	71.0	459.4
Exxon Valdez Project		1,123.8	309.4	1,433.2
Kenai Clean-up Project		97.9		97.9
Site Investigation, et.al.		225.9	13.1	239.0
Other Agency				
Oil Spill Contingency Plans/Requirements			59.4	59.4
Natural Resource Damage Assessment		1,358.4		1,358.4
Subtotal Prior Year		3,662.3	472.9	4,135.2
Grand Total FY 92	47,062.6	22,295.4	9,994.6	32,289.9

Note 1: Obligations have been reduced by any overobligated amounts on Reimbursable Services Agreements.

Table 2
OIL & HAZARDOUS SUBSTANCE RELEASE RESPONSE FUND
Balance Sheet
June 30, 1992

		June 30, 1992	June 30, 1991
Assets			
Cash		33,062,827.01	29,433,414.35
Accounts Receivable		2,339,939.90	2,697,387.47
Total Assets		35,402,766.91	32,330,801.82
Liabilities			
Payroll Exceptions		0.00	(13,857.66)
Accrued Payable		1,082,600.16	1,100,824.08
Warrants Outstanding		275,408.17	299,110.37
Total Liabilities		1,358,008.33	1,386,076.79
Fund Balance			
Reserve for Encumbrances		13,911,537.91	10,910,943.35
Reserve for PY Authorizations		1,822,446.72	117,748.29
Reserve for Restricted Revenue	(Note 1)	(5,641,109.99)	0.00
Unreserved		23,951,883.94	19,916,033.39
Total Fund Balance		34,044,758.58	30,944,725.03
Total Liabilities and Fund Equity		35,402,766.91	32,330,801.82

Note 1: The Reserve for Restricted Revenue represents the uncollected revenue estimate balance for Appropriation # 42895-92, which is an RSA between ADEC and the Department of Fish & Game. Both the requesting and the servicing agency's appropriations report to the Oil and Hazardous Substance Release Response Fund.

Table 3
Summary of OHSRRF Funding Sources and Deposits to Oil Surcharge Account
1986-1992
(In Thousands)

Response Fund Source of Funding

Fiscal Year	General Fund Program Receipts	General Fund Mitigation Revenue	Oil Surcharge Revenue	Other General Fund [Note 2]	Total
FY 87		158.7		522.0	680.7
FY 88		304.3		825.0	1,129.3
FY 89	10,000.0	136.5		10,500.0	20,636.5
FY 90	20,000.0	197.6		32,600.0	52,797.6
FY 91		1,696.1	27,000.0		28,696.1
FY 92		30.1	28,500.0		28,530.1
FY 93		1,823.3	27,000.0		28,823.3
Total:	30,000.0	4,346.6	82,500.0	44,447.0	161,293.6

Revenue Collected Oil Surcharge Account

FY 90	26,932.4
FY 91	27,965.2
FY 92	28,669.0
Total:	83,566.6

TABLE 4

FY 92 Mitigation Account Summary
(In Thousands)

Summary of Revenue by Type

Site	Cost Recovery	Penalty	Settlement	Interest	Total
Citigold: Settlement			14.4		14.4
Wendell St.: Settlement			27.7		27.7
SS Noordam: Cost Recovery	16.5				16.5
Sitka Air Monitoring: Interest				8.2	8.2
Tuboscope: Penalty/Fine		5.4			5.4
Unisea Facility: Penalty/Fine		13.2			13.2
M/V Atlantic Seahorse: Penalty/Fine		3.5			3.5
Lorna B/Steelhead: Settlement			29.0		29.0
F/V Skagit Eagle: Penalty/Fine		4.0			4.0
Alaska Pulp Co.: Settlement			7.0		7.0
Exxon: Settlement (Assessment/Litigation)			3,954.0		3,954.0
Poppy Lane: Settlement			275.0		275.0
Chevron Bulk Plant, Valdez: Settlement			100.0		100.0
Benny Benson: Cost Recovery	29.6				29.6
Cominco (Red Dog Mine): Air Pollution Fine		10.0			10.0
Total	46.1	36.1	4,407.1	8.2	4,497.5

TABLE 5

Summary of FY 93 Appropriations

(In Thousands)

Appropriations From the Response Fund	
DEC	
Spill prevention planning and management	6,021.2
State Emergency Response Commission	350.8
Local emergency planning committees	1,200.0
Spill Response Office	1,318.1
Division of Emergency Services/Response Depots and Corps	800.0
Hazards Analysis	177.3
Geographic Information System	689.3
Contaminated Sites Program	3,528.6
Exxon Valdez Litigation	2,968.0
Exxon Valdez Clean-up and Cost Recovery	350.0
Arctic Marine Resources Commission	100.0
Spill Reserve	23,656.7
Nearshore Strike Team Demonstration Projects	1,200.0
Hazardous Substance Spill Technology Review Council	420.0
Extend to FY 93 the FY 92 Allocation for Site Investigation, Safety, Cleanup, and Cost Recovery	1,582.7
OTHER AGENCIES	
Citizens' Oversight Council on Oil and Other Hazardous Substances	237.3
Alaska Marine Highway System Vessel Replacement Fund	7,500.0
Mt. Edgecumbe-Contaminated Site Cleanup (DOE)	430.0
Peninsula Greenhouse, Soldotna-Contaminated Site Cleanup (DNR)	178.0
Forward Pad-Contaminated Site Cleanup (DNR)	490.0
Childs Pad-Contaminated Site Cleanup (DNR)	300.0
Tok River Campground-Contaminated Site Cleanup (DNR)	38.0
Boniface/Northern Lights, DeBarr-Contaminated Site Assessment (DOT/PF)	250.0
DOT/PF Maintenance Station, Soldotna-Contaminated Site Cleanup (DOT/PF)	157.0
Extend to FY 96 the FY 92 Appropriation for Ferries with Oil Spill Response Cabability (DOT/PF)	239.8
Chatham Strait Fish Company, New Chenega-Contaminated Site Cleanup (DCRA)	30.0
Soldotna Fire Training-Contaminated Site Cleanup (UAA)	320.0
Total Appropriated From Fund For FY 1993	54,532.8

Appropriated to Response Fund		
From General Fund	27,000.0	
July 1, 1992 Balance of Mitigation Account Fund	1 823.3	
Total Appropriated to Fund for FY 1993		28,823.3
Unreserved Fund Balance (Table 2)		23,951.9
Total Available to Appropriate		52,775.2