Alaska Corporate Income Tax Primer

Who Pays the Alaska Corporate Net Income Tax

A **Corporation** that is **doing business in Alaska**

"Corporation" Includes

- An entity organized as a corporation that is not an S-Corporation, generally referred to as a C-corporation
- A corporation electing S-corporation status
- A Limited Liability Company (LLC) that elects C-corporate status for tax purposes

Exemptions

- S-corporations generally do not pay tax at the corporate level, their income or loss is passed through to the individual shareholders where it is taxed. This income is not subject to tax under Alaska law.

Doing Business in Alaska - Nexus

- Direct business activity of a corporation

- Indirect business activity:
  - By a partnership in which a corporation has an interest
  - By an LLC wholly owned by a corporation (single member LLC)
  - By an LLC electing partnership status (in which a corporation is a member)

Federal & Alaska Taxation of Business Entities and Owners

	C-Corporation	S-Corporation	Partnership	LLC (Mult. Members)	LLC (Single Member)	Sole Proprietor
Federal Income Tax Status	Taxed directly at corporate rates.	Generally not taxed at corporate level. Income assigned to shareholders who pay tax in corporate income.	Not taxed at entity level. Income assigned to partners who pay tax on partnership income.	Elective, either C-corporation status or pass through status as a partnership or S-corporation.	Ignored for tax purposes, all income and activity attributed to owner.	Individual proprietor is taxed directly
Entities' Alaska Tax Status	Same as Federal	Same as Federal	Same as Federal	Same as Federal	Same as Federal	Same as federal
Subject to AK CIT?	Yes	No (rare exceptions apply)	No	*Maybe*	*Maybe*	No
Owners subject to AK CIT due to entities income or activity	*No*	No, all are individuals	Corporate partners – Yes Individual partners - No	Corporate members – Yes Individual members - No	Corporate owner – Yes Individual owner - No	No
Federal Taxation of Distribution	Dividends subject to tax, corporate shareholders can exclude all or part of dividend income	Distributions are tax free to the extent of previously taxed earnings	Distributions are tax free to the extent of partners basis	Controlled by tax status.	Ignored	Ignored
Alaska Taxation of Distributions from Income	Dividends received by corporate taxpayers are subject to tax, corporate shareholders can exclude all or part of dividend income	N/A	Distributions are tax free to the extent of partners basis	Controlled by tax status.	Ignored	N/A
Federal Taxation of Compensation to Owners/Employees	Corporate deduction / Individual is taxed on income. Double taxation avoided.	Deduction against pass through income / Individual is taxed on income. Double taxation avoided.	Deduction against pass through income / Individual is taxed on income. Double taxation avoided.	LLC deduction / Individual is taxed on income.	N/A	N/A
Alaska Taxation of Compensation to Owners/Employees	Corporate deduction / Individual is not taxed. Income in the form of compensation is not taxed.	Corporate deduction / Individual is not taxed. Income in the form of compensation is not taxed.	Partnership deduction / Individual is not taxed. Income in the form of compensation is not taxed.	LLC deduction / Individual is not taxed. Income in the form of compensation is not taxed.	N/A	N/A

Alaska Department of Revenue
Tax Division
Non-Petroleum Corporation Income Tax Liabilities by Sector[1]

Business Activity	%	Preliminary FY 2003 Tax Liability	%	FY 2002 Tax Liability	%	FY 2001 Tax Liability	%	FY 2000 Tax Liability	%	FY 1999 Tax Liability	%	FY 1998 Tax Liability
Airlines	0%	426,889	1%	2,145,349	1%	1,829,425	1%	2,705,322	0%	1,157,714	1%	1,735,467
Construction	1%	1,413,593	1%	1,935,919	1%	1,357,780	1%	1,673,615	1%	1,638,376	1%	2,050,289
Finance	3%	8,326,531	3%	8,994,254	3%	3,690,786	5%	10,636,659	3%	10,161,632	3%	9,170,326
Fish[2]	1%	1,743,738	1%	2,077,476	2%	3,039,414	1%	1,966,142	0%	1,359,905	1%	1,483,496
Manufacturing[3]	0%	1,166,218	1%	1,727,297	1%	1,755,109	1%	1,782,218	1%	3,081,797	1%	3,784,507
Mining[4]	0%	31,030	0%	18,665	0%	285,815	0%	75,900	0%	398,435	0%	246,792
Oil and Gas[5]	84%	216,146,150	87%	290,496,501	71%	102,873,464	74%	159,031,727	83%	243,494,814	82%	240,554,444
Real Estate	0%	1,213,492	0%	539,347	1%	1,525,122	1%	1,427,584	1%	1,745,832	0%	1,330,113
Retail	4%	9,449,539	2%	6,319,374	3%	4,601,219	3%	6,067,087	2%	5,040,997	2%	5,241,579
Services[6]	4%	9,420,749	2%	8,186,279	6%	8,704,506	4%	9,481,634	4%	11,118,228	3%	7,657,407
Transportation[7]	1%	2,768,424	1%	3,548,633	2%	2,828,536	1%	3,120,394	1%	3,669,637	1%	3,157,115
Utility & Comm.	0%	708,840	1%	2,782,964	5%	7,373,389	4%	9,172,989	2%	6,241,187	3%	9,178,023
Wholesale	2%	5,061,710	2%	5,823,224	3%	4,359,367	3%	5,670,993	2%	4,571,731	2%	4,999,215
Other Sectors[8]	0%	515,607	0%	540,349	0%	568,676	1%	1,164,398	0%	1,310,741	1%	2,841,659
Total[9]	100%	**$258,392,510**	100%	**$335,135,630**	100%	**$144,792,609**	100%	**$213,976,662**	100%	**$294,991,025**	100%	**$293,430,432**

[1] Reporting a tax liability on an original corporate income tax return. Liabilities may differ from amounts remitted by the taxpayer during the fiscal year due to timing differences resulting from estimated tax payments, credits and final payment of taxes. Based upon information provided on tax returns as interpreted by DOR. Prior years have been updated for consistency purposes.

[2] Includes fish processors that are usually classified under manufacturing.

[3] Fish processing, and wood products manufacturing included under fisheries and forestry sectors.

[4] Does not include oil and gas extraction.

[5] Only includes liabilities from companies that filed as oil and gas corporations.

[6] Includes oil and gas services.

[7] Airline transportation is included in its own sector above.

[8] Forestry and insurance sectors combined for confidentiality reasons.

[9] In FY 1999, total general corporation income tax liabilities were updated and, consequently, do not match the liabilities shown in our annual reports.

Alaska Corporate Income Tax Primer

Wholly Alaska Business

A corporation doing business in Alaska, but not in any other state is taxed on its federal taxable income subject to state modifications.

Alaska Taxable Income		Tax Rate		Alaska Tax
$ 500.00	X	1%	=	$ 5.00

Multi-state Business

A corporation doing business in Alaska and in one or more other states must apportion its total income to Alaska

Apportionment of Income

Total Income		Apportionment Factor		Alaska Taxable Income		Tax Rate		Alaska Tax
$ 1,000.00	X	50%	=	$ 500.00	X	1%	=	$ 5.00

Apportionable Income

Generally, the combined federal taxable income of the taxpayer, affiliated corporations, and their share of the income of pass through entities owned by the group.

Factors

Oil & Gas Corporations - Modified Apportionment

	Alaska	Everywhere	Factor
Sales	20,000	100,000	20%
Property	50,000	100,000	50%
Extraction	400,000	500,000	80%
Apportionment Factor = Average			**50%**

Other Corporations - Standard Three Factor

	Alaska		Everywhere	Factor
Sales	75,000	/	100,000	75%
Property	50,000	/	100,000	50%
Payroll	125,000	/	500,000	25%
Apportionment Factor = Average				**50%**

STATE APPORTIONMENT OF CORPORATE INCOME

(Formulas for tax year 2004 -- as of January 1, 2004)

ALABAMA *	3 Factor	NEBRASKA	Sales
ALASKA *	3 Factor	NEVADA	No State Income Tax
ARIZONA *	Double wtd. sales	NEW HAMPSHIRE	Double wtd. Sales
ARKANSAS *	Double wtd. sales	NEW JERSEY (1)	Double wtd. Sales
CALIFORNIA *	Double wtd. sales	NEW MEXICO *	Double wtd. sales
COLORADO *	3 Factor/Sales & Property	NEW YORK	Double wtd sales
CONNECTICUT	Double wtd. sales/Sales	NORTH CAROLINA *	Double wtd. sales
DELAWARE	3 Factor	NORTH DAKOTA *	3 Factor
FLORIDA	Double wtd. sales	OHIO *	60% Sales, 20% Property & Payroll
GEORGIA	Double wtd. sales		
HAWAII *	3 Factor	OKLAHOMA	3 Factor
IDAHO *	Double wtd. sales	OREGON *	80% Sales, 10% Property & Payroll
ILLINOIS *	Sales		
INDIANA	Double wtd. sales	PENNSYLVANIA *	Triple wtd. sales
IOWA	Sales	RHODE ISLAND (2)	40% Sales, 30% Property & Payroll
KANSAS *	3 Factor		
KENTUCKY *	Double wtd. sales	SOUTH CAROLINA	Double wtd. sales/Sales
LOUISIANA	Double wtd. sales	SOUTH DAKOTA	No State Income Tax
MAINE *	Double wtd. sales	TENNESSEE *	Double wtd. sales
MARYLAND	Double wtd. sales	TEXAS	Sales
MASSACHUSETTS	Double wtd. sales/Sales	UTAH *	3 Factor
MICHIGAN	90% Sales, 5% Property & Payroll	VERMONT	3 Factor
		VIRGINIA	Double wtd. sales
MINNESOTA	75% Sales,12.5% Property, and 12.5% Payroll	WASHINGTON	No State Income Tax
		WEST VIRGINIA *	Double wtd. sales
MISSISSIPPI	Accounting/3 Factor	WISCONSIN *	Double wtd. sales
MISSOURI *	3 Factor/sales	WYOMING	No State Income Tax
MONTANA *	3 Factor	DIST. OF COLUMBI	3 Factor

Source: Compiled by FTA from various sources.
Note: The formulas listed are for general manufacturing businesses. Some industries have special formula different than those reported.
* State has adopted substantial portions of the UDITPA.
(1) A 3-factor formula is used for corporations not subject to the corporation business franchise tax.
(2) For tax years beginning after 2004, apportionment formula will be double weighted sales.

Oil & Gas CIT Factor Analysis
Impact of Factors Based on Average Revenue for FY98-FY03

Based on 2002 Returns

Average Factors	Current Law	Double Weight Extraction	Eliminate Sales Factor	Single Factor Extraction	Single Factor Property	Single Factor Sales
Extraction	16.3%	32.6%	16.3%	16.3%	0.0%	0.0%
Property	5.3%	5.3%	5.3%	0.0%	5.3%	0.0%
Sales	0.2%	0.2%	0.0%	0.0%	0.0%	0.2%
Average Factor*	7.3%	9.5%	10.8%	16.3%	5.3%	0.2%
Projected Revenue**	$ 209	$ 229	$ 290	$ 329	$ 251	$ 7
Change - Revenue $		$ 20	$ 81	$ 120	$ 42	$ (202)
Change - Percent		9.8%	38.6%	57.5%	20.3%	-96.7%

* Average factors are not weighted by apportionable income, the change in the average factor does not generate a corresponding change in revenues.

** Revenue based on adjusting factors of individual returns filed by the industry.

Summary of Estimated Revenue Impacts of Tax Changes Based on FY98-FY03 Receipts

Action	Total $ millions	O&G	Other
Change corporate rate by 1% of taxable income	27.0	21.0	6.0
Eliminate federal credits	10.0	9.6	0.4
Allow enhanced oil recovery (EOR) credit for Alaska projects	(6.2)	(6.2)	
Tax net capital gain at ordinary rates	2.0	1.6	0.4
Restrict NOL usage to carryforwards (short term benefit)	2.0		2.0
Tax S-Corporations under AK CIT	29.4		29.4
Tax Partnerships under AK CIT	16.6		16.6
Tax Proprietorships under AK CIT	29.6		29.6
Tax Cruise Ship income under AK CIT*	6.8		6.8

* Very rough estimate from extrapolated data. Approximates head tax of $8.50 per passenger.

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RANGE OF STATE CORPORATE INCOME TAX RATES

(For tax year 2004 -- as of January 1, 2004)

State	Tax Rates	Tax Brackets		# of Brackets	Bank Tax Rates	Federal Tax Deductible
ALABAMA	6.5	----Flat Rate----		1	6.5	*
ALASKA	1.0 - 9.4	10,000	90,000	10	1.0 - 9.4	
ARIZONA	6.968 (b)	----Flat Rate----		1	6.968	
ARKANSAS	1.0 - 6.5	3,000	100,000	6	1.0 - 6.5	
CALIFORNIA	8.84 (c)	----Flat Rate----		1	10.84 (c)	
COLORADO	4.63	----Flat Rate----		1	4.63	
CONNECTICUT	7.5 (d)	----Flat Rate----		1	7.5 (d)	
DELAWARE	8.7	----Flat Rate----		1	8.7-1.7 (e)	
FLORIDA	5.5 (f)	----Flat Rate----		1	5.5 (f)	
GEORGIA	6.0	----Flat Rate----		1	6.0	
HAWAII	4.4 - 6.4 (g)	25,000	100,000	3	7.92 (g)	
IDAHO	7.6 (h)	----Flat Rate----		1	7.6 (h)	
ILLINOIS	7.3 (i)	----Flat Rate----		1	7.3 (i)	
INDIANA	8.5	----Flat Rate----		1	8.5	
IOWA	6.0 - 12.0	25,000	250,000	4	5.0	* (k)
KANSAS	4.0 (l)	----Flat Rate----		1	2.25 (l)	
KENTUCKY	4.0 - 8.25	25,000	250,000	5	--- (a)	
LOUISIANA	4.0 - 8.0	25,000	200,000	5	--- (a)	*
MAINE	3.5 - 8.93 (m)	25,000	250,000	4	1.0	
MARYLAND	7.0	----Flat Rate----		1	7.0	
MASSACHUSETTS	9.5 (n)	----Flat Rate----		1	10.5 (n)	
MINNESOTA	9.8 (o)	----Flat Rate----		1	9.8 (o)	
MISSISSIPPI	3.0 - 5.0	5,000	10,000	3	3.0 - 5.0	
MISSOURI	6.25	----Flat Rate----		1	7.0	* (k)
MONTANA	6.75 (p)	----Flat Rate----		1	6.75 (p)	
NEBRASKA	5.58 - 7.81	50,000		2	--- (a)	
NEW HAMPSHIRE	8.5 (q)	----Flat Rate----		1	8.5 (q)	
NEW JERSEY	9.0 (r)	----Flat Rate----		1	9 (r)	
NEW MEXICO	4.8 - 7.6	500,000	1 million	3	4.8 - 7.6	
NEW YORK	7.5 (s)	----Flat Rate----		1	7.5 (s)	
NORTH CAROLINA	6.9 (t)	----Flat Rate----		1	6.9 (t)	
NORTH DAKOTA	3.0 - 10.5	3,000	50,000	6	7 (b)	*
OHIO	5.1 - 8.5 (u)	50,000		2	--- (u)	
OKLAHOMA	6.0	----Flat Rate----		1	6.0	
OREGON	6.6 (b)	----Flat Rate----		1	6.6 (b)	
PENNSYLVANIA	9.99	----Flat Rate----		1	--- (a)	
RHODE ISLAND	9.0 (b)	----Flat Rate----		1	9.0 (v)	
SOUTH CAROLINA	5.0	----Flat Rate----		1	4.5 (w)	
SOUTH DAKOTA	---				6.0-0.25% (b)	
TENNESSEE	6.5	----Flat Rate----		1	6.5	
UTAH	5.0 (b)	----Flat Rate----			5.0 (b)	
VERMONT	7.0 - 9.75 (b)	10,000	250,000	4	7.0 - 9.75 (b)	
VIRGINIA	6.0	----Flat Rate----		1	6.0 (x)	
WEST VIRGINIA	9.0	----Flat Rate----		1	9.0	
WISCONSIN	7.9	----Flat Rate----		1	7.9	
DIST. OF COLUMBIA	9.975 (y)	----Flat Rate----			9.975 (y)	

Source: Compiled by FTA from various sources

Note: Michigan imposes a single business tax (sometimes described as a business activities tax or value added tax) of 1.9% on the sum of federal taxable income of the business, compensation paid to employees, dividends, interest, royalties paid and other items.

Similarly, Texas imposes a franchise tax of 4.5% of earned surplus. Nevada, Washington, and Wyoming do not have state corporate income taxes.
(a) Rates listed include the corporate tax rate applied to financial institutions or excise taxes based on income. Some states have other taxes based upon the value of deposits or shares.
(b) Minimum tax is $50 in Arizona, $50 in North Dakota (banks), $10 in Oregon, $250 in Rhode Island, $500 per location in South Dakota (banks), $100 in Utah, $250 in Vermont.
(c) Minimum tax is $800. The tax rate on S-Corporations is 1.5% (3.5% for banks).
(d) Or 3.1 mills per dollar of capital stock and surplus (maximum tax $1 million) or $250.
(e) The marginal rate decreases over 4 brackets ranging from $20 to $650 million in taxable income. Building and loan associations are taxed at a flat 8.7%.
(f) Or 3.3% Alternative Minimum Tax. An exemption of $5,000 is allowed.
(g) Capital gains are taxed at 4%. There is also an alternative tax of 0.5% of gross annual sales.
(h) Minimum tax is $20. An additional tax of $10 is imposed on each return.
(i) Includes a 2.5% personal property replacement tax.
(k) Fifty percent of the federal income tax is deductible.
(l) Plus a surtax of 3.35% (2.125% for banks) taxable income in excess of $50,000 ($25,000).
(m) Or a 27% tax on Federal Alternative Minimum Taxable Income.
(n) Rate includes a 14% surtax, as does the following: an additional tax of $7.00 per $1,000 on taxable tangible property (or net worth allocable to state, for intangible property corporations); minimum tax of $456.
(o) Plus a 5.8% tax on any Alternative Minimum Taxable Income over the base tax.
(p) A 7% tax on taxpayers using water's edge combination. Minimum tax is $50.
(q) Plus a 0.50 percent tax on the enterprise base (total compensation, interest and dividends paid). Business profits tax imposed on both corporations and unincorporated associations.
(r) The rate reported in the table is the corporation business franchise tax rate. The minimum tax is $500. An Alternative Minimum Assessment based on Gross Receipts applies if greater than corporate franchise tax. Corporations not subject to the franchise tax are subject to a 7.25% income tax. Banking and financial corporations are subject to the franchise tax. Corporations with net income under $100,000 are taxed at 6.5%. The tax on S corporations is being phased out through 2007. The tax rate on a New Jersey S corporation that has entire net income not subject to federal corporate income tax in excess of $100,000 will remain at 1.33% for privilege periods ending on or before June 30, 2006. The rate will be 0.67% for privilege periods ending on or after July 1, 2006, but on or before June 30, 2007; and there will be no tax imposed for privilege periods ending on or after July 1, 2007. The tax on S corporation with entire net income not subject to federal corporate income tax of $100,00 or less is eliminated for privilege periods ending on or after July 1, 2007.
(s) Or 1.78 (0.1 for banks) mills per dollar of capital (up to $350,000; or 2.5% of the minimum taxable income; or a minimum of $1,500 to $100 depending on payroll size ($250 for banks); if any of these is greater than the tax computed on net income. An addition tax of 0.9 mills per dollar of subsidiary capital is imposed on corporations. Small corporations with income under $290,000 pay a 7.5% tax on all income.
(t) Financial institutions are also subject to a tax equal to $30 per one million in assets.
(u) Or 4.0 mills time the value of the taxpayer's issued and outstanding share of stock with a maximum payment of $150,000. An additional litter tax is imposed equal to 0.11% on the first $50,000 of taxable income, 0.22% on income over $50,000; or 0.14 mills on net worth.
(v) For banks, the alternative tax is $2.50 per $10,000 of capital stock ($100 minimum).
(w) Savings and Loans are taxed at a 6% rate.
(x) State and national banks subject to the state's franchise tax on net capital is exempt from the income tax.
(y) Minimum tax is $100. Includes surtax.

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Potential Corporate Income Tax
on S-Corporations

Where positive taxable income is:	# Returns	Projected Taxable Income	Projected Revenue	Revenue from Top 100	Revenue from Top 25
< 10,000	629	2,806,257	28,063		
< 20,000	454	6,722,386	89,048		
< 30,000	374	9,287,565	166,427		
< 40,000	255	8,942,698	204,708		
< 50,000	211	9,005,408	239,270		
< 60,000	166	9,150,806	300,048		
< 70,000	135	8,047,575	279,830		
< 80,000	97	6,786,970	271,358		
< 90,000	113	9,022,430	405,219		
Over 90,000	907	329,455,434	27,377,091	14,227,352	7,248,734
Totals	3,341	399,227,529	**29,361,061**	**14,227,352**	**7,248,734**
				48%	25%

Notes:

Revenue based on all entity types that elect treatment as an S Corporation under Internal Revenue Code and Treas Reg 301.7701-1 to -3. 76 entities above are LLC under state law electing S-corp. Projected revenue from LLC = $469,000.

Revenue is stated after apportionment. Factor estimated by applying weighted factor of domestic C corporations for that group, under the assumption that domestic S-corporation would have similar amount of outside business.

Revenue includes all returns with income greater than zero filed within reporting period. Although some returns are for prior years, we have included the revenue under the assumption that the State would not have received the revenue for a late return until filed. Amount does not include net operating losses. 1,880 S corporations had losses. NOL's will cause fluctuation in revenue for any given year. Data is not presently available to estimate the impact of losses carried forward.

Revenue estimate based on returns with an Alaskan address. 989 additional entities file with an address outside Alaska, for which we do not have readily available data. However, we expect $1 - 3 million additional revenue from outside corporations.

Compare Top 25 & 100 S-Corp to C-Corp: Top 25 C-Corp = 93% of corporate revenue. Top 100 C corp = 97% corporate revenue. [Table 5, Tax Division Annual Report FY 02.]. Thus S-Corp income base much broader than C-Corp.

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Potential Tax on S-Corporations
by industrial classification

Industry Group	# of Returns in Top Tier	Projected Taxable Income	Top Tier Potential Revenue
Construction	172	56,149,207	4,600,865
Retail Trade	133	50,037,437	4,176,839
Professional, Scientific & Technical	106	36,026,905	2,966,769
Transportation & Warehousing	59	28,479,712	2,443,453
Health Care & Social Services	101	30,170,737	2,436,089
Finance & Insurance	42	27,353,215	2,404,882
Wholesale Trade	44	20,579,257	1,760,210
Manufacturing	19	16,867,118	1,510,269
Real Estate, Rental & Leasing	43	16,957,625	1,423,737
Other Services	43	1,378,919	1,125,896
Accommodation & Food Services	51	13,348,054	1,052,757
Agriculture, Forestry, Fishing	58	9,803,330	691,833
Administrative & Support	16	7,975,581	686,345
Arts, Entertainment, Recreation	13	4,245,632	347,609
Information	*	505,561	43,563
Utilities	*	1,664,427	152,496
Management of companies	*	-	-
Mining, Oil & Gas	*	-	-
Educational Services	*	-	-
Top Tier Revenue by Industry	907		27,627,554
Estimated apportionment factor			99.0934%
Estimated apportioned revenue, top tier			**27,377,091**

Note:
* Not shown if number of corporations in the top tier is less than 10.

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Potential Corporate Income Tax on Sole Proprietors

Where positive taxable income is:	# Returns	Projected Taxable Income	Projected Revenue
< 10,000	22,716	71,319,681	713,197
< 20,000	5,255	75,295,551	980,411
< 30,000	2,622	64,133,153	1,137,395
< 40,000	1,458	50,533,340	1,146,534
< 50,000	982	43,928,947	1,214,447
< 60,000	684	37,436,650	1,220,199
< 70,000	500	32,326,125	1,212,829
< 80,000	379	28,452,869	1,215,030
< 90,000	275	23,275,791	1,104,821
Over 90,000	1,511	272,952,610	19,673,985
Totals	36,382	699,654,717	**29,618,847**

Notes:

Revenue based on all returns with an AK address that filed Form 1040 Sch C for tax year 2001. Sch C is not necessarily the sole source of income for all returns. Best information available suggests that of the number listed above, 10,993 returns (representing $311,277,856 pre-tax income) have no reported salaries or wages.

Revenue includes all returns with income greater than zero filed within reporting period. Although some returns are for prior years, we have included the revenue under the assumption that the State would not have received the revenue for a late return until filed. Amount does not include net operating losses. 1,584 Sch C businesses had losses. NOL's will cause fluctuation in revenue for any given year. Data is not presently available to estimate the impact of losses carried forward.

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Potential Corporate Income Tax
on Partnerships

Where positive taxable income is:	# Returns	Projected Taxable Income	Projected Revenue
< 10,000	449	1,744,821	17,448
< 20,000	162	2,378,504	31,370
< 30,000	111	2,721,589	48,348
< 40,000	89	3,073,766	69,551
< 50,000	60	2,711,050	75,553
< 60,000	44	2,387,045	77,223
< 70,000	36	2,327,821	87,347
< 80,000	22	1,663,132	71,451
< 90,000	23	1,945,677	92,311
Over 90,000	345	235,236,362	20,746,018
Remove C-corp partners	(16)	(50,938,140)	(4,724,825)
Totals	1,325	205,251,627	**16,591,794**

Notes:

Revenue includes all returns filed from AK with income greater than zero filed within reporting period. Although some returns are for prior years, we have included the revenue under the assumption that the State would not have received the revenue for a late return until filed. Amount does not include net operating losses. 1,295 partnerships had losses. NOL's will cause fluctuation in revenue for any given year. Data is not presently available to estimate the impact of losses carried forward.

Some partnerships have C-corp partners. Under existing corporate tax law, partnership income flows to the corporate partner and is subject to the corporate income tax. A review of the top 100 partnerhsips resulted in an adjustment to remove income that would have been taxed at the corporate level. Data limitations prevents a more definitive adjustment to all income levels.

Commissioner Briefing
Corporate Income Tax Outline
February 2003

Limitations on the State's Power to Tax

"Nexus" is the legal shorthand that refers to the connection that a potential taxpayer has with a state that justifies and enables that state to impose tax. A corporation must have sufficient "nexus" with the state, by virtue of its business activities within the state, in order for a state to impose taxes.

Public Law 86-272 is a federal law that restricts the power of the states to impose income tax. If a business limits its activities in the state to the solicitation of orders for sales of tangible personal property, the business is immune from that state's income tax.

How States Determine Taxable Income for Corporations

Background
Under the Commerce and Due Process Clauses of the Constitution, states can only tax income that is earned within the taxing state. For a corporation that has no affiliated corporations and does business only in one state, the state can tax all of the corporation's income. If the corporation does business (i.e. has nexus) in more than one state, or is a member of group of corporations that collectively does business in more than one state, then the taxing state must determine, in some acceptable manner, the amount of income earned or otherwise attributable to the taxing state. There are two basic methods to assign income to the taxing state - separate accounting and formulary apportionment.

Separate Accounting
This method computes the amount of corporate income attributable to the state based solely upon income realized and expenses incurred within the taxing state. In the early 20th century, this was the favored method by states. However, as multistate corporations became more complex and vertically integrated, states adopted formulas to measure and apportion income. No state currently uses separate accounting as the preferred method of assigning income except in certain circumstances.

States moved to apportionment primarily because separate accounting produced results that were imprecise and arbitrary. Furthermore, separate accounting was extraordinarily difficult to administer for vertically integrated businesses due to the innumerable intercompany transactions between business segments. Under separate accounting, taxpayers have an incentive to overstate expenses and understate income within the taxing jurisdiction. Administrators were faced with complex and litigious audits geared toward scrutinizing intercompany transactions under an arm's length standard. Today, the administration of a broad based corporate income tax on a separate accounting basis would be nearly impossible in terms of the resources required to effectively monitor intercompany transactions.

Formulary Apportionment

In response to the difficulties of administering separate accounting, the states began to devise formulas whereby a portion of the *total* net income of a corporate business could be attributed to the taxing jurisdiction based upon the factors of profitability – that is the business inputs that gave rise to the income.

Early apportionment formulas used only one factor – property. States soon realized this produced distorted results by giving too much weight to manufacturing activity and not enough to the selling activity. Several states expanded the formula to include payroll and sales. The "*three factor formula*" was eventually incorporated into the Uniform Division of Income for Tax Purposes Act ("UDITPA").

19 states have adopted UDITPA as the exclusive or optional method of apportionment, 24 states have adopted UDITPA with some changes or have adopted a similar method.

Alaska adopted UDITPA in 1970 and it appears in AS 43.19.

AS 43.20.065 makes the apportionment provisions of AS 43.19 mandatory for all multistate businesses in Alaska.

The Apportionment Formula

The standard UDITPA formula is the average of the property, payroll and sales factor and is expressed as:

$$\frac{\dfrac{\text{Property in State}}{\text{Property Everywhere}} + \dfrac{\text{Payroll in State}}{\text{Payroll Everywhere}} + \dfrac{\text{Sales in State}}{\text{Sales Everywhere}}}{3}$$

The above formula weights the factors equally. Some states double weight the sales factor and some states use a single sales factor.

The Income Base – "Business Income" of a "Unitary Business"

Before the apportionment formula can be applied, there are two overriding constraints to apportionment.

First, case law has determined that the formula can only be applied to a unitary business. A unitary business, as the name implies, functions as single economic unit. If the business activity within the state is separate and distinct from the rest of the business, then formulary apportionment is inappropriate.

Second, the nature of the income to be apportioned must be considered. Not all income of the unitary business should be apportioned – only *"business income"*. Under the rules of apportionment, business income is the income that bears a reasonably close relationship to the to the central business of the unitary group. *"Non-business income"* is that income that is only remotely connected to the central business. Non-business income is not apportioned, but rather is allocated to the state where the property or business activity is located.

Business income is sometimes referred to as *"apportionable income"* as it is the income to which apportionment factors are applied. Non-business income is often called *"allocable income"*.

AS 43.19 adopts the current UDITPA definition of business income at Article IV, 1(a):

> "Business income" means income arising from transactions and activity in the regular course of the taxpayer's trade or business and includes income from tangible and intangible property if the acquisition, management, and disposition of the property is constitute integral parts of the taxpayer's trade or business operations."

<u>The Combined Report</u>
When determining the extent of unitary business, states disregard the separate legal existence of separately incorporated affiliates. When a group of corporations conduct a single unitary business, states combine the incomes of the separate corporations (eliminating the intercompany transactions within the group) to arrive at the unitary business income subject to apportionment. The apportionment factors are computed in a similar fashion. This process is referred to as *"combination"* and the return filed under this method referred to as the *"combined report" or "combined return"*.

AS 43.20.065 mandates the use of combined reporting and apportionment.

<u>Separate Reporting</u>
A few states do not require or allow a combined report. These states honor the separate corporate boundaries (and the underlying "separate accounting" used to determine the separate corporation's income). These states still apportion the income of the separate corporation when the corporation does business in more than one state. This method is usually referred to as *"separate reporting"* and taxpayers file *"separate company reports"*.

<u>Tests for Unity</u>
Formulary apportionment is tied to the concept of unity because the inputs to the formula come from only the branches or affiliated corporations that make up the unitary group. That is to say, the income and factors of non-unitary corporations or businesses simply are not part of the formula. Therefore, it is critically important that the extent of the unitary business be defined and with this question there has been considerable litigation that has produced several definitions that should, in theory, produce the same results.

Many courts recite the tests contained in *Butler Bros.* an early California case. There, the court set forth the *"three unities test"*:

1. Unity of ownership (i.e. the enterprise is linked by common ownership, usually the parent company owning a controlling interest in the common stock such that the parent controls the operations of the subsidiary).

2. Unity of operation, as evidenced by central purchasing, advertising, accounting, and management divisions.

3. Unity of use, evidenced by a centralized executive force and general system of operation.

More recently, courts have expressed the unity criteria as functional integration, centralization of management and economies of scale. Regardless of how the tests are expressed, the concept is that there are flows of value within the business segments, the unitary business operates as a single economic unit, and the parts of the enterprise are inextricably linked and dependent upon each other.

The classic example of a unitary business is the fully integrated oil and gas company that explores for oil and gas, produces and refines it, and ultimately sells fuels and other petroluem products to consumers. Each of those activities is dependent upon the other, and each contributes to overall operations of the company.

Alaska's Tax Base – Federal Taxable Income with Modifications

Regardless of whether the income in question is business or non-business income, the states must set out the rules to measure the income. Most states conform to the Internal Revenue Code ("IRC " or "the Code") to some degree.[1] Alaska links itself very closely to the federal statutes by the adoption of most of the Internal Revenue Code.[2]

A major departure from the IRC is that Alaska, like most states, does not allow a deduction for taxes based on or measured by net income. Alaska also does not allow a foreign tax credit.

Worldwide Apportionment

During the 1970's, states applied the apportionment factors to the total worldwide income of the business. Worldwide apportionment was controversial because:

1. Applying property and payroll factors on a worldwide basis can distort the amount of income apportioned to the state in light of vastly different wage rates and property costs in developing countries.
2. It is difficult to convert foreign books and records to a format acceptable to the states.
3. States had difficulty accessing foreign books and records for audit.

Companies domiciled in the UK and Japan were particularly vocal in their criticism of worldwide apportionment. These countries made it clear that states that did not employ

[1] California is a notable exception. California has written its own 'Internal Revenue Code".

[2] See AS 43.20.021.

worldwide apportionment would be favored sites for investment. Also, the U.S. State Department under President Reagan strongly criticized worldwide apportionment.

We should note that the U.S. and its trading partners generally follow separate accounting and treaties when determining taxable income at the national level. For example, the IRC taxes the entire income of a U.S. corporation and addresses potential double taxation by allowing a foreign tax credit. No country has adopted a formulary apportionment method.

<u>Water's Edge Apportionment</u> (AS 43.20.073)
California is the recognized leader in developing multistate apportionment legislation and case law and California has long been aggressive in asserting worldwide apportionment. However, in response to the economic and political pressure, California enacted *"water's edge"* legislation whereby taxpayers may elect to combine only those corporations that do business in the U.S. Other states followed with similar rules. Alaska was one of the final holdouts, enacting water's edge legislation in 1991. Alaska's water's edge combination is not available to oil and gas taxpayers.

<u>History of Oil and Gas Corporate Income Tax</u>
Before 1978, no special rules existed for oil and gas corporations – they filed using worldwide apportionment using the standard three factors of property, payroll .nd sales.

Based upon the belief that the standard factors did not fairly or fully represent the income producing activities and income of oil and gas producers in Alaska, the legislature enacted AS 43.21. This required oil and gas producers and pipeline companies to compute their Alaska taxable income on a separate accounting basis, which greatly increased their tax liabilities. The hallmarks of this statute were:

- Since virtually no oil was actually sold in Alaska, oil produced was considered to be gross income, measured by the value of the oil at the point of production.
- Direct operating costs were deductible.
- General Overhead and Administrative expenses were allocated.

The Alaska oil and gas industry promptly sued the state arguing that AS 43.21 was unconstitutional. Faced with protracted litigation and the potential for huge corporate tax refunds, the legislature looked for alternatives to AS 43.21 and settled upon modifications to standard apportionment effective in 1982.[3] Those provisions are in AS 43.20.072.

<u>Special Apportionment – Oil and Gas Producers and Pipelines</u> (AS 43.20.072)

The highlights of AS 43.20.072 are:

- .072 applies to corporations that produce oil or gas in Alaska or own regulated pipelines in Alaska.
- The apportionable income base is worldwide income with adjustments:

[3] The Alaska Supreme Court ultimately upheld AS 43.21 with a decision issued in 1985.

Cost depletion is mandatory (percentage depletion disallowed).
Intangible drilling costs capitalized (IRC allows partial write-off).
Slower depreciation methods required (Accelerated Cost Recovery not allowed).

- Standard three factor apportionment modified to: Property, Extraction, and Sales (extraction factor replaces payroll factor).
- "Extraction factor" is oil and gas produced in Alaska divided by oil and gas produced worldwide.
- The sales factor includes intercompany tariffs (normally intercompany transactions are eliminated in combination).

Some Important Alaska Court Cases

1. Unity – *Earth Resources*

   The Alaska Supreme Court found that seemingly diverse business enterprises were nonetheless a unitary business. Earth Resources Company (ERC), the parent company, was domiciled in Texas. ERC's subsidiaries owned and operated a refinery in Tennessee, marketed gasoline, transported crude oil, and conducted mining operations. In Alaska, ERC formed Earth Resources Company of Alaska (ERCA) with the intent that ERCA would build and operate a refinery. ERCA had some minority shareholders. At a time when the Alaska refinery had not been built and was not producing revenue, ERC sought to find some source of income. ERCA, with the help of ERC, purchased a local paving company, which was very profitable and contributed most of ERCA's income during the tax years involved.

   The Court found that the companies exhibited sufficient functional integration, centralization of management and economies of scale to support a finding of unity.

2. Business Income and Adoption of the Internal Revenue Code – *OSG Bulkships*

   This case addressed the situation where combination and apportionment rules collide with the sourcing of income provisions of the IRC. The Court set forth the general principle that Alaska's adoption of the IRC and its sourcing rules, take a back seat to the worldwide combination and apportionment provisions (then worldwide) under AS 43.20.065.

   Overseas Shipholding Group (OSG) through its subsidiaries owned and operated a fleet of U.S. and Foreign flagged vessels used in variety of shipping operations worldwide. OSG had organized such that a U.S. corporations owned and operated the domestic vessels and a foreign organized corporation owned and operated the foreign flagged vessels. The U.S. parent corporation through its subsidiaries owned and chartered vessels that entered Alaska waters to transport ANS crude oil.

Under IRC section 883, foreign flagged vessels are exempt from U.S. income tax if the country of registry provides a similar exemption for U.S. vessels. Consequently, OSG did not include the corporations that owned the foreign vessels in its Alaska combined return.

The Court recognized the fundamental difference between the federal source-based tax system and the UDITPA apportionment method. The Court noted that Alaska statutes adopt the IRC unless modified or excepted to by a specific provision in Alaska law. The court viewed IRC section 883 as an income-sourcing rule that was excepted to in the adoption of combination and apportionment at AS 43.20.065, and ruled that the foreign corporations should be included in the combined group.

It is interesting to note that within months of this decision, the Alaska legislature, under heavy lobbying pressure from the cruise ship industry, amended AS 43.20.021(a) to adopt IRC 883. Since most of the vessels in the Alaska cruiseship industry are foreign flagged, currently the industry is effectively exempt from Alaska income tax.

With respect to business income, the Court found that OSG's investment companies generated investment income, not operational income and therefore the income was non-business income and should not have been included in apportionable income.

3. Foreign Income Tax – *Gulf Oil Corporation (1988)*

Gulf Oil Corporation, like many oil companies today, find themselves paying arguably exorbitant income taxes to OPEC countries and other oil producing countries. Audit included these taxes in apportionable income relying on AS 43.20.031(c).

Gulf argued that Alaska should follow the federal rules concerning foreign taxes. Federally, a taxpayer can elect to either deduct the payments in their entirety[4], or a taxpayer can elect to take the tax as a credit. If the taxpayer elects to take a federal credit, the taxpayer must follow the rules of IRC section 901 that restrict the amount of the payment that is creditable. Understandably, the U.S. treasury does not want to subsidize a foreign government's tax take with unlimited foreign tax credits; therefore the 901 regulations start with the presumption that the levy is not an income tax and place the burden on the taxpayer to prove that the levy is an income tax. The 901 regulations provide for a safe harbor calculation that essentially allows a credit equal to what would have been paid to the U.S. federal government rather than the actual tax payment to the foreign government. Gulf

[4] Virtually any payment to the foreign country save for a bribe, is deductible federally as a business expense, so the characterization of a payment as a royalty, production payment, or income tax is irrelevant.

argued that the Alaska tax addback should be the amount available for U.S. credit, not the total amount of income tax paid to the foreign government.

The Court rejected Gulf's logic, first noting AS 43.20.036 (no foreign tax credit) is an Alaska exception to the adoption of the federal 901 regulations – they simply don't apply. The Court also rejected the notion that Alaska should adopt a federal rule that explicitly is intended to make a levy difficult to characterize as an income tax. The adoption of such a rule would foster tax avoidance.

Alaska Department of Revenue - Income and Excise Audit Division
Overview of Alaska Corporation Net Income Tax - AS 43.20
January 14, 2003
By Mark Graber, Audit Manager

Taxpayers
Alaska taxes the net income of all corporations doing business in the state. There are two exceptions. Insurance companies pay an insurance premium tax instead of income tax. Corporations recognized under Subchapter S of the Internal Revenue Code are generally exempt.

Apportionment Determines Alaska Taxable Income
Corporations doing business both within and outside Alaska apportion a part of their total business income to Alaska by a formula. The formula uses an average of certain ratios ("apportionment factors") that reflect income-producing activity in Alaska as compared to activity everywhere. Taxpayers multiply total business income by the apportionment factor to determine Alaska taxable income. Corporations doing business solely in Alaska pay tax on all their income.

Apportionment Formulas - Oil and Gas Extraction v. Payroll
The standard apportionment formula uses property, payroll, and sales. Oil and gas corporations use an extraction factor (oil and gas produced in Alaska vs. everywhere) instead of the payroll factor. Alaska considers the extraction factor a better measure of business activity in Alaska for oil and gas companies, and the extraction factor increases the tax as compared to using the payroll factor.

Business Income - Water's Edge and Worldwide Apportionment
Before 1991, Alaska required all corporations to apportion a part of their worldwide income to Alaska. In 1991, Alaska enacted "water's edge" legislation. Under the water's edge method, taxpayers apportion only U.S. income. This generally lowers the tax. The water's edge rules apply to all corporations except oil and gas producers and pipelines; they continue to apportion a part of worldwide income to Alaska.

Business Income - Special Rules for Oil and Gas.
Alaska uses the Internal Revenue Code with some modifications to determine business income. One major modification is that corporations cannot deduct net income taxes paid. Other rules accelerate tax payments and apply only to oil and gas companies. These rules deal with intangible drilling costs, depletion, and depreciation methods.

Tax Rates
The same graduated tax rate schedule applies to all corporations. The highest rate is 9.4% and applies to taxable income over $90,000.

Corporation Tax Collections - 80% from Oil and Gas
Table 2 of the FY 02 Income and Excise Audit Division Annual Report shows total tax collections from oil and gas companies as compared to all other corporations. During FY

00 through FY 02, the Division collected $848.4 million in corporate income taxes. Oil and gas corporations paid over $679 million - over 80% of the total.

Corporation Tax Collections - the other 20%

Most of Alaska's small businesses pay no corporation tax because they are able to elect Subchapter S status under the Internal Revenue Code. Alaska law exempts S-corporations, but unlike the federal system, does not impose personal income tax on the flow through of corporate profits to shareholders. A main requirement for Subchapter S status is a limited number of shareholders. Publicly traded companies cannot elect Subchapter S status. In FY 02, approximately 14,900 non-oil and gas corporations filed tax returns. 5,800 S-Corporations filed in FY 02 - over one-third have the total non-oil and gas filings.

Most of the non-oil and gas corporate tax revenue comes from large, publicly traded, multistate and multinational corporations. These corporations include the national retail stores, communications providers, seafood processors, airlines, and construction companies.

CORPORATION INCOME TAX
AS 43.20

Description
Alaska levies the corporate net income tax on net income of corporations that have nexus and derive income from sources within Alaska. Corporations compute their tax liability based on federal taxable income with Alaska adjustments.

Alaska uses an apportionment method to determine the portion of income that is taxable in the state. Corporations other than oil and gas apportion their income to Alaska by using a three-factor formula based on sales, property and payroll. Taxpayers determine Alaska taxable income by applying the apportionment factor to the corporation's modified federal taxable income.

Multistate oil and gas corporations apportion income on a worldwide apportionment method. Other multistate corporations apportion income to Alaska under a "water's edge" apportionment method. A corporation engaged in business solely in Alaska computes its tax liability on 100% of its taxable income.

Rate
Corporation tax rates increase from 1% to 9.4% in $10,000 increments of Alaska taxable income. The maximum rate of 9.4% applies to income over $90,000.

Returns
Corporations file returns annually. Tax payments are due two and a half months from the close of the fiscal year. Taxpayers must remit tax payments over $150,000 by wire transfer or electronic funds transfer (EFT). The payment due date may not be extended.

Tax returns are due three and a half months after the close of the fiscal year. Corporations may extend their filing due date by six months.

Example: The filing due date for calendar year corporations is April 15. Corporations may extend their filing due date to October 15. In any case, payment is due March 15.

Corporations make quarterly estimated tax payments based on past activity and the current year's accrued tax liability. Taxpayers must remit estimated payments over $100,000 by wire transfer or electronic funds transfer (EFT).

Exemptions
S-corporations and LLCs are generally exempt from corporation income tax and are treated as partnerships for Alaska tax purposes. Electric and telephone cooperatives, which are required to pay cooperative taxes under AS 10.25, are also exempt.

Credits
Education - Taxpayers who make contributions for educational purposes to accredited Alaska universities or colleges may take a tax credit for 50% of the first $100,000 and 100% of the next $100,000 of contributions. The maximum credit is $150,000 per tax year.

Minerals Exploration Incentive - Taxpayers may take a credit for 100% of eligible costs of exploration activities related to determining existence, location, extent, or quality of a locatable mineral or coal deposit. An approved minerals exploration incentive credit may not exceed $20 million and must be applied within 15 tax years after the taking of the credit is approved. Application of the credit is limited to 50% of the lesser of the taxpayer's mining license tax liability or 50% of the taxpayer's total corporation net income tax liability.

Oil and Gas Exploration Incentive - Taxpayers may take a credit for up to 50% on state land (or 25% on non state lands) of eligible oil and gas exploration costs. An approved oil and gas exploration incentive credit may not exceed $5 million per project and is limited to $30 million per taxpayer. Taxpayers may apply the credit against 100% of corporation net income taxes due.

Alaska Veterans' Memorial Endowment. This bill provides credits of up to 50 percent for contributions of not more than $100,000 and 75 percent of the next $100,000 in contributions made to the Veterans' Memorial Endowment Fund. Taxpayers may not use a contribution claimed as a credit for more than one tax type. Also, when combined with credits for contributions to qualifying educational institutions, credits may not exceed $150,000. These credits cannot exceed 50 percent of a taxpayer's tax liability.

CORPORATION INCOME TAX

2003 - *Gas Exploration and Development Tax Credit* allows a corporate income credit for 10 percent of qualifying expenditures incurred in exploration and development of natural gas reserves in Alaska, except for the North Slope.

Disposition of Revenue

The Division deposits revenue derived from corporation net income taxes into the General Fund except as noted below.

For oil and gas corporations only, the Division deposits into the Constitutional Budget Reserve fund those revenues received as a result of a tax assessment issued by the Division.

History

The corporation net income tax dates back to 1949 when the territorial legislature enacted the "Alaska Net Income Tax Act". The Act imposed a flat tax of 10% of the corporation's federal income tax liability.

1957 – Tax rate was increased to 18%.

1975 – Original income tax act repealed and an income tax act based on taxable income rather than federal tax liability was enacted. The tax was equal to 5.4% of taxable income with a surtax of 4% based on federal surtax exemptions. For 1975, the federal surtax exemption was $50,000.

1978 – Oil and gas corporations required to calculate taxable income based on a "separate accounting" method requiring the corporations to account for Alaska activity only in determining taxable income (AS 43.21).

1981 – Separate accounting (AS 43.21) was repealed and the modern corporation tax rate structure was adopted (1% - 9.4%). With repeal of AS 43.21, all corporations file returns using worldwide combined reporting and use the same tax rate structure.

1984 – The legislature adopted the special industrial incentive investment tax credit.

1987 – Alaska education credit was authorized.

1991 – Alaska's legislature enacted a bill requiring corporations, except for oil and gas corporations, to calculate taxable income based on the "water's edge" combined reporting method. Oil and gas corporations continue to use the worldwide combined reporting method. Also, the legislature increased the Alaska education credit maximum from $100,000 to $150,000.

1994 – Alaska's legislature authorized the Oil and Gas Exploration Incentive Credit. The legislature limited the credit to $30 million and provided that taxpayers may apply the credit to 100% of corporation taxes due.

1995 – Alaska's legislature authorized the minerals exploration incentive credit. The legislature limited the credit to $20 million and taxpayers may apply it against 50% of corporation taxes due over a 15-year period.

1995 – Alaska's legislature enacted a bill exempting foreign cruise ship and airline companies from tax.

2002 – Alaska Veterans' Memorial Endowment provides credits of up to 50 percent for contributions of not more than $100,000 and 75 percent of the next $100,000 in contributions made to the Veterans' Memorial Endowment Fund. The tax credit provisions will sunset on July 1, 2003.

2002 – The Oil and Gas Exploration Incentive Credit extends the exploration incentive tax credit to June 30, 2007.

2003 – Legislation authorized the Gas Exploration and Development Tax Credit.

FY 2003 Statistics on following page.

CORPORATION INCOME TAX

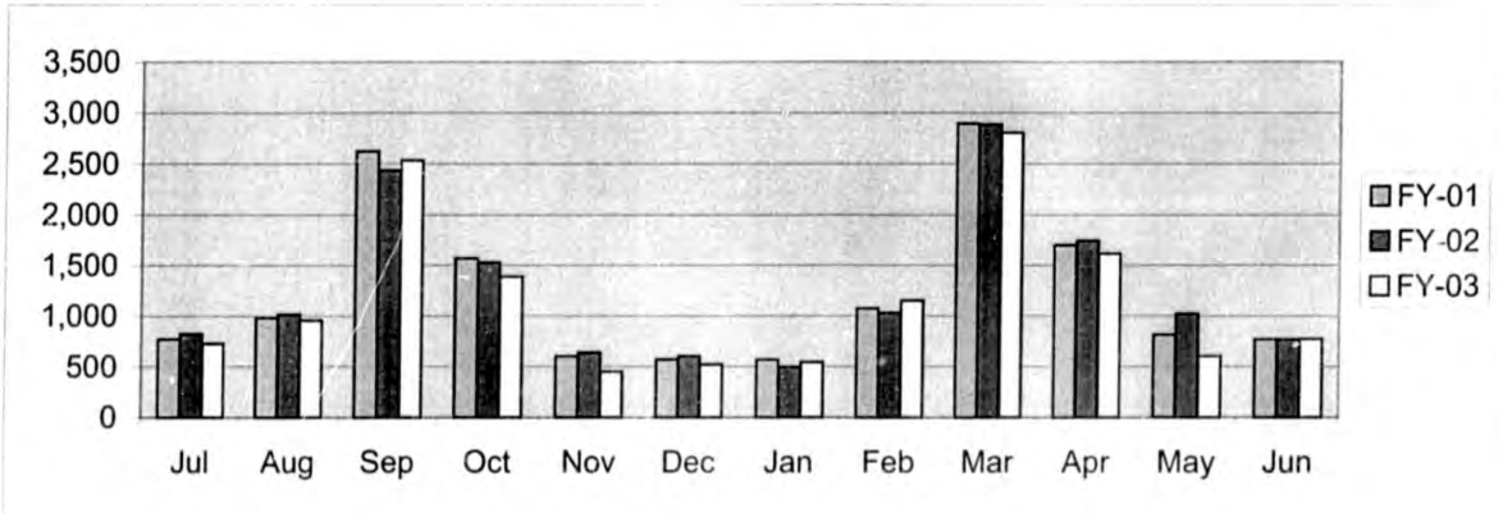
FY 2003 Statistics

Tax Collections – Oil and Gas Corporations	
General Fund	$151,088,300
CBRF	17,221,507
Total	168,309,807
Number of Returns	62
Number of Taxpayers	28
Program Cost	$624,274
Staffing (*full-time equivalent*)	7.7

Tax Collections – Other Corporations	
General Fund	$47,712,454
Number of Returns	14,015
Number of Taxpayers	11,618
Program Cost	$1,108,317
Staffing (*full-time equivalent*)	18.8

Chart 3
Corporations Filing Activity
For Fiscal Years 2001, 2002 and 2003

Number of Returns Filed by Month



Fiscal Year	FY 2003	FY 2002	FY 2001
Total Returns Filed	14,077	14,997	14,940

Detail of FY 2002 Filing Activity

Entity Type	Original	Amended	NOL*	Incomplete	Total
Subchapter C	6,089	655	377	449	7,570
Subchapter S	5,815	37	3	0	5,855
Exempt	138	7	7	0	152
Homeowners Assoc.	437	1	0	0	438
Oil & Gas	23	39	0	0	62
Total	12,502	739	387	449	14,077

*Net operating loss carryback

Table 5
Corporation Tax Liabilities Statistics

Tax liabilities reported on original returns filed in FY03

	Oil and Gas Corporations			Other than Oil and Gas Corporations			All Corporations		
Tax Liability Reported	**# Filers**	**Amount**	**% Total**	**# Filers**	**Amount**	**% Total**	**# Filers**	**Amount**	**% Total**
Above $1 million	6	$212,799,442	98.45%	7	$15,860,374	37.54%	13	$228,659,816	88.49%
$500,000 - $1 million	4	2,626,401	1.22%	9	6,167,428	14.60%	13	$8,793,829	3.40%
$100,000 - $499,999	3	647,462	0.30%	46	11,207,643	26.53%	49	$11,855,105	4.59%
$50,000 - $99,999	1	70,863	0.03%	46	3,216,772	7.61%	47	$3,287,635	1.27%
$10,000 - $49,999	0	0	0.00%	171	4,094,816	9.69%	171	$4,094,816	1.58%
$1,000 - $9,999	1	1,725	0.00%	417	1,445,887	3.42%	418	$1,447,612	0.56%
$100 - $999	1	219	0.00%	560	226,925	0.54%	561	$227,144	0.09%
$1 - $99	1	38	0.00%	904	26,515	0.06%	905	$26,553	0.01%
Zero Tax	6	0	0.00%	10,319	0	0.00%	10,325	$0	0.00%
Total	**23**	**$216,146,150**	**100.00%**	**12,479**	**$42,246,360**	**100.00%**	**12,502**	**$258,392,510**	**100.00%**

Note: Amounts reflect tax liabilities reported on the taxpayer original returns. Liabilities may differ from amounts remitted by the taxpayer during the fiscal year due to timing differences resulting from estimated tax payments, credits and final payment of taxes reported.

Alaska's Petroleum Revenues — An Overview

The Elements of Alaska's Petroleum-Revenue System.

Oil and Gas Production Tax (also called "severance tax") (AS 43.55):

The tax is levied as a percentage of the netback (or wellhead value) in the field, with the exact percentage depending on the "economic limit factor" (ELF) for each field. The netback equals the market price minus transportation costs (tanker, pipeline). In times of very low prices, "floor" rates of 80¢ a barrel and 6.4¢ per Mcf (1,000 cubic feet) become applicable, and these are also adjusted by the ELF.

There are also two conservation surcharges on taxable oil. One is 3¢ a barrel and is always in effect, and the other is 2¢ and operates only when there is less than $50 million in the Oil and Hazardous Substance Release Prevention and Response Fund. The ELF does not apply to either surcharge.

During FY 2003, $588 million in production tax was paid to the state of Alaska, and another $11 million in surcharges.

Royalty (arises from individual oil and gas lease contracts):

The "landowner's share," royalty is not a true tax but a contractual obligation, like rent, that is paid to the landowner for the use of the land. In this case the landowner is the state instead of a private person. If the state elects to take its royalty in value, the royalty payment is based on a netback similar to the severance tax. When the state takes its royalty in kind, it sells the physical oil or gas to a purchaser who receives it at the same point where it is deliverable to the state — namely, the meter into the pipeline.

During FY 2003, $1,278.7 million in oil and gas royalties was paid to the state of Alaska, of which $403.8 million was deposited into the Permanent Fund.

Oil and Gas Property Tax (AS 43.56):

The annual state property tax is 20 mills per dollar (2%) of the assessed value on oil and gas production property and pipelines. Refineries, LNG plants and gas utility pipelines are excluded. This tax is shared with municipalities where the taxable property is located. Each municipality levies its own property tax at the same rate as for other taxable property, and the local tax payment is credited against the tax owed to the state.

During FY 2003, $268.9 million in oil and gas property tax was paid, of which $48.7 million was paid to the state and $220.4 million to municipalities — North Slope Borough, $194.2 million; Valdez, $13.2 million; Kenai Peninsula Borough, $7.7 million; Fa banks North Star Borough, $4.4 million; and Anchorage, $2.8 million. The Matanuska-Susitna Borough and the cities of Whittier and Cordova also received small shares.

Oil and Gas Corporate Income Tax (AS 43.20):

All taxpayers under this tax, not just oil companies, determine their taxable Alaskan income using apportionment, in which an Alaskan "slice" is cut from the whole "pie" of a business's income and taxed by the state. For everyone except oil companies, the pie is their income earned in the United States and the width of their Alaskan slice is based on their in-state percentages of U.S. property, sales and payroll. For oil companies, the pie is their worldwide income and the width of their Alaskan slice is based on their in-state percentages of worldwide property, sales and production. The same rates of tax apply to oil companies' taxable Alaskan income as to all other corporations' taxable Alaskan income.

During FY 2003, oil companies paid $151.1 million in corporate income tax to the state of Alaska. Non-petroleum companies paid $47.7 million.

How the Pieces Fit Together.

Alaska's system of petroleum revenues is like a three-legged stool. Each of the legs is a particular kind of tax that responds differently to changing economic circumstances.

Severance tax and royalty are linked to market prices.

One leg is the state severance tax and royalty, which are linked directly to market prices because both are based on a netback (or wellhead price) equal to the market price minus the cost of getting the production to market. These revenues respond quickly to price and market changes. They increase directly when prices climb or production increases, and fall when prices fall or production declines.

Property tax is less sensitive to market changes.

A second leg is the state property tax on oil and gas production and pipeline property. Like all property taxes, this tax is based on the long-term value of the taxable property, which is much less sensitive to volatile short-term fluctuations in energy prices than production tax and royalty.

Income tax hedges against regional market conditions affecting Alaska, by looking at worldwide business performance.

This third and final leg considers the worldwide income of an oil company's entire business, not just Alaska, and then carves out an Alaskan "slice" of this worldwide income "pie." This worldwide approach allows Alaska to include in the measure of the tax due a portion of a corporation's profits, for example, from a new discovery in the North Sea or South America, as well as to include part of the profits from "downstream" refining and marketing Outside. Even when prices are low and the Alaskan part of the business may only be breaking even, part of the profits being earned elsewhere are attributed to the Alaskan business to calculate the tax.

These three legs aren't equal, of course. The state gets most of its petroleum revenue from the severance tax and royalties. But the petroleum corporate income tax generates significant tax revenues, as does the property tax, and these both tend to have a softening effect when there is volatility in crude oil markets and big swings in severance tax and royalty collections.

A Two-Page History of Alaska's Oil and Gas Taxes.

Alaska enacted its first oil and gas tax — the production tax with a 1% rate — back in Territorial days in 1955 just as federal lands on the Kenai Peninsula were being opened up to oil and gas leasing for the first time. Drilling on those leases led to the discovery of oil at Swanson River in 1957, which proved pivotal in persuading Congress to pass the Alaska Statehood Act the next year. Tidelands and submerged lands in Cook Inlet that Alaska received at Statehood were soon leased, and in late 1965 the first offshore oil field in the Inlet came into production, with three more in 1967. The Fairbanks flood in August 1967 led to the passage of a 3% "Disaster Severance Tax" by a Special Session of the Legislature that fall — the first change in Alaska's petroleum taxes since 1955.

The discovery at Prudhoe Bay was announced in 1968, and on September 10, 1969 additional state lands there and nearby were leased for $900 million in bonuses. The magnitude of these events transformed Alaska, and it began a decade of tinkering with its petroleum taxes trying to tailor them to this supergiant field. Historically, the most important of these tinkerings were:

Oil and Gas Property Tax (current AS 43.56)

> The state property tax was enacted in 1973 as part of a package of legislation passed in a Special Session to end litigation threatening to delay the start of construction of the trans-Alaska pipeline. The provisions for municipalities to tax the same property were a compromise to win their support since they had successfully blocked legislation for a state property tax without municipal-sharing in 1972.

Oil and Gas Reserves Tax (former AS 43.58)

> In 1975 Alaska faced a fiscal emergency because of the delays in starting construction of the trans-Alaska pipeline, and as a result state revenues from Prudhoe Bay had not yet materialized to replace the $900 million from 1969, which was nearly all spent. To fill the gap, the state enacted a temporary two-year tax on oil and gas reserves. This tax succeeded through the cooperation of the North Slope companies paying it, and they cooperated because they could apply their full reserves tax payments as credits against their future production taxes. The tax was collected in 1976 and 1977 and then ceased to operate by its own terms, and it was eventually repealed in 1986 well after all the credits against production taxes had been taken.

Separate Accounting Income Tax (former AS 43.21)

In 1978 the state removed oil companies from the slice-of-the-pie apportionment system that applied to all other taxpayers, and put them under a separate-accounting system to determine the amount of income from their Alaskan businesses. Due to a combination of extremely high oil prices ($40 a barrel) and extremely low operating costs at the start of Prudhoe Bay's productive life, the amount of taxable income — and hence the amount of tax — was considerably higher under separate accounting than it was under apportionment. There was already litigation over separate accounting in Wisconsin and Vermont, and soon suit was filed over Alaska's tax. In 1980 the Wisconsin and Vermont cases were decided by the U.S. Supreme Court, which ruled both times against separate accounting — going so far as to say in one decision that separate accounting is "theoretically incommensurable" with apportionment, which the Court upheld in both cases.

Because taxpayers had wanted separate accounting in those cases, state officials at the time believed the two decisions did not mean Alaska's separate-accounting law was invalid. But they felt the state should not take the risk of keeping separate accounting on the books during the litigation and letting its exposure grow by a billion dollars a year. So in 1981 separate accounting was repealed and replaced with the current version of slice-of-the-pie apportionment, which limited the state's exposure to the $2 billion already collected. The state supreme court upheld the separate-accounting law in 1985, and the U.S. Supreme Court declined to hear an appeal from that decision.

The ELF (Economic Limit Factor)

The ELF is a formula in the production tax that adjusts the tax rate for each field. As originally enacted in 1977, the ELF reduced the tax rate by looking at the percentage of the value of the production that is needed to cover the costs of producing that oil and gas. The more marginal a field is, the higher this percentage becomes and the smaller the ELF gets. The ELF becomes zero, and there is no tax, precisely when the cost percentage reaches 100 percent and the field is breaking even. The effect of the original ELF was to lower tax rates for Cook Inlet oil fields, which were already in decline and beginning to become marginal, while allowing the tax rate for Prudhoe Bay to be increased from about 7.9% to 12 percent.

In 1981 as part of the legislation repealing separate accounting, the ELF was suspended for Prudhoe Bay until it reached its tenth anniversary of production. At the same time the base rate for oil was increased from 12.25% to 15 percent for fields in production for more than five years. The purpose of suspending the ELF and raising the base rate was to offset most of the reduction the state's income tax revenue resulting from the switch from separate accounting back to apportionment. In June 1987 Prudhoe Bay reached its tenth anniversary and its production tax rate went from 15% to about 12.45%, which was still higher than the 11–11½% it had been in 1981 just before the enactment of the suspension.

In 1989 the oil ELF formula was changed to include a new factor, field size. The more a field produces, the bigger its ELF and the higher its tax rate. By the same token, small fields have low tax rates or no tax at all. The purpose of the change was to raise taxes for the state's two largest fields, Prudhoe and Kuparuk, while lowering taxes and to encourage development of smaller fields on the Slope, as well as fields with very thick oil like West Sak.

The present ELF is succeeding on both counts. Since 1989 the state has collected over $2 billion in extra production tax from Prudhoe and Kuparuk because of the new ELF. At the same time, current and planned developments of small nearby fields (so-called satellite fields) will help offset the continuing production decline of those two giant fields, allowing overall North Slope production to remain basically flat over the 2001-2010 decade. The ELF's incentive for developing small fields contributes significantly to the economics of these satellites.

STATE OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

DEPARTMENT OF REVENUE

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March 18, 2004

The Honorable Mike Hawker,
Chair, House Ways and Means Committee
Alaska House of Representatives
Alaska State Legislature
Juneau, Alaska

Dear Representative Hawker:

Dan Dickinson, Director of the Tax Division, asked me to deliver the attached information to you. The information he compiled is the result of testimony before the House Ways and Means Committee on February 25, February 27, and March 3, 2004, and requests of Mr. Dickinson to provide additional information.

Please contact me at 465-2302 if you have further questions, or if you need additional information.

Very truly yours,

Landa Baily

Landa B. Baily
Special Assistant to
Commissioner Corbus

Attachment

Tax Division

Memo

To: Landa Baily

From: Dan E. Dickinson, Director

Date: 3/15/04

Re: House Ways and Means

Chuck Harlamert, Mike Williams and I testified before the House Ways and Means committee on February 25, 27th and March 3 2004. The committee requested and we supplied certain items. This package covers all the outstanding items:

From February 25

A matrix, like that presented in the Sources book, that shows not when the CBRF will be exhausted but when it will hit a balance of 1 billion dollars.

A breakout of elements in out forecast, like that presented for historical data in the Sources book, showing detail.

There was also a request for analysis of the effect of a head tax or sales tax that affected cruise ship passengers on our obligations to respect international commerce. We have no particular single document that presents such an analysis. We have worked closely with the DOL on this and suggest that they be asked to testify on this legal point if the committee wishes to pursue it.

Finally we were asked about material we had put together on alternative taxes in general and corporate taxes specifically , so I have pulled together the various 'think pieces" from our sources book and a briefing paper that was put together last year for the new commissioner.

From March 3

We obtained the following statistics from DCED concerning the number of LLCs in Alaska:
There are 6,031 LLCs organized under Alaska law and 871 organized in other states but registered to do business in Alaska for a total of 6,902.

We were asked to investigate whether any other state had special taxes on freight that would be the equivalent of head taxes on the cruise industry. We could find none.

FALL2003 Revenue Source Book = OIL REVENUE
General Fund Unrestricted Revenue

Pr Sul Sub	Fall2003	Forecast projections ====>										
Ca Cal Category 2	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
UNRESTRICTED REVENUES												
Taxes												
Property	**48.5**	**45.6**	**42.4**	**40.2**	**37.7**	**37.5**	**37.0**	**36.3**	**35.5**	**34.7**	**34.0**	**33.3**
Sales/Use												
Alcoholic Beverage	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7
Tobacco Products	16.3	16.7	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Insurance Premium	42.6	44.7	44.7	44.7	44.7	44.7	44.7	44.7	44.7	44.7	44.7	44.7
Electric and Telephone Cooperative	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Motor Fuel Tax	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
Vehicle Rental Tax	1.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Tire Fee	2.4	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Sale/Use	**117.2**	**125.6**	**125.7**	**125.7**	**125.7**	**125.7**	**125.7**	**125.7**	**125.7**	**125.7**	**125.7**	**125.7**
Income Tax												
Corporate General	49.0	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
Corporate Petroleum	220.0	195.0	179.0	172.0	164.0	157.0	150.0	143.0	135.0	128.0	121.0	113.0
Total Income	**269.0**	**248.7**	**232.7**	**225.7**	**217.7**	**210.7**	**203.7**	**196.7**	**188.7**	**181.7**	**174.7**	**166.7**
Severance												
Oil and Gas Production inc. Exploration Credit	554.2	417.8	321.0	294.1	321.4	317.3	276.5	249.0	222.5	212.2	193.1	181.7
Oil and Gas Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Gas Haz Release	9.4	9.3	9.2	9.1	9.2	9.1	9.1	9.0	9.0	8.8	8.5	8.0
Total Severance Tax	**563.6**	**427.1**	**330.2**	**303.2**	**330.6**	**326.4**	**285.6**	**258.0**	**231.4**	**221.1**	**201.5**	**189.7**
Other Resource Taxes												
Fisheries Business	8.3	10.3	10.3	10.3	10.3	10.3	11.8	11.8	11.8	11.8	11.8	11.8
Fishery Resource Landing	2.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Mining	0.7	1.3	1.3	1.3	1.3	1.3	1.3	1.5	1.7	1.7	1.7	1.7
Total Resources Tax	**11.0**	**14.2**	**14.2**	**14.2**	**14.2**	**14.2**	**15.7**	**15.9**	**16.1**	**16.1**	**16.1**	**16.1**
Other Taxes												
Estate	1.4	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Charitable Gaming	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total Other Tax	**3.9**	**3.2**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**
Total Taxes	**1,013.2**	**864.4**	**747.7**	**711.5**	**728.5**	**717.0**	**670.2**	**635.1**	**599.9**	**581.8**	**554.5**	**534.0**

FALL2003 Revenue Source Book
General Fund Unrestricted Revenue

= OIL REVENUE

Pr Sul Sub	Fall2003	Forecast projections ====>										
Ca Cal Category 2	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Licences and Permits Unrestricted												
Motor Vehicle	43.5	45.9	46.4	46.8	47.3	47.8	48.2	48.7	49.2	49.7	50.2	50.7
Other	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total Licences & Permits	**45.5**	**47.9**	**48.4**	**48.8**	**49.3**	**49.8**	**50.2**	**50.7**	**51.2**	**51.7**	**52.2**	**52.7**
Charges for Services												
Marine Highways	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Total Charges for Services	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**
Fines and Forfeitures	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**	**7.0**
Rents and Resources												
Mineral Bonuses and Rents	12.1	16.1	28.0	16.8	12.4	14.0	14.0	14.0	14.0	14.0	14.0	14.0
NET Oil and Gas Royalties + interest paid	886.5	737.6	609.7	599.2	593.2	584.1	553.5	531.9	506.1	479.3	422.5	400.1
Timber Sales	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
NET Coal Rent and Royalties	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Other Resource Revenue	6.0	6.2	6.2	6.4	6.6	7.1	7.1	7.3	7.5	7.5	7.5	7.5
Total Rents and Royalties	**905.6**	**760.9**	**644.9**	**623.4**	**613.2**	**606.3**	**575.7**	**554.3**	**528.7**	**501.9**	**445.1**	**422.7**
Investment & Interest Revenue	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**
Other Miscellaneous	**21.5**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**	**14.0**
Total General Fund Unrestricted Revenue	**2,022.9**	**1,724.3**	**1,492.1**	**1,434.9**	**1,442.0**	**1,424.2**	**1,347 2**	**1,291.3**	**1,230.9**	**1,186.5**	**1,102.8**	**1,060.5**

Total General Fund Unrestricted Revenue	2,022.9	1,724.3	1,492.1	1,434.9	1,442.0	1,424.2	1,347.2	1,291.3	1,230.9	1,186.5	1,102.8	1,060.5
Total Oil Revenue	1,730.7	1,421.4	1,189.3	1,131.5	1,137.9	1,119.0	1,040.1	983.3	922.0	877.1	792.9	750.1
Total Non-Oil Revenue	292.2	302.9	302.8	303.4	304.1	305.2	307.1	308.0	308.9	309.4	309.9	310.4

Commissioner Briefing
Corporate Income Tax Outline
February 2003

Limitations on the State's Power to Tax

"Nexus" is the legal shorthand that refers to the connection that a potential taxpayer has with a state that justifies and enables that state to impose tax. A corporation must have sufficient "nexus" with the state, by virtue of its business activities within the state, in order for a state to impose taxes.

Public Law 86-272 is a federal law that restricts the power of the states to impose income tax. If a business limits its activities in the state to the solicitation of orders for sales of tangible personal property, the business is immune from that state's income tax.

How States Determine Taxable Income for Corporations

Background
Under the Commerce and Due Process Clauses of the Constitution, states can only tax income that is earned within the taxing state. For a corporation that has no affiliated corporations and does business only in one state, the state can tax all of the corporation's income. If the corporation does business (i.e. has nexus) in more than one state, or is a member of group of corporations that collectively does business in more than one state, then the taxing state must determine, in some acceptable manner, the amount of income earned or otherwise attributable to the taxing state. There are two basic methods to assign income to the taxing state - separate accounting and formulary apportionment.

Separate Accounting
This method computes the amount of corporate income attributable to the state based solely upon income realized and expenses incurred within the taxing state. In the early 20th century, this was the favored method by states. However, as multistate corporations became more complex and vertically integrated, states adopted formulas to measure and apportion income. No state currently uses separate accounting as the preferred method of assigning income except in certain circumstances.

States moved to apportionment primarily because separate accounting produced results that were imprecise and arbitrary. Furthermore, separate accounting was extraordinarily difficult to administer for vertically integrated businesses due to the innumerable intercompany transactions between business segments. Under separate accounting, taxpayers have an incentive to overstate expenses and understate income within the taxing jurisdiction. Administrators were faced with complex and litigious audits geared toward scrutinizing intercompany transactions under an arm's length standard. Today, the administration of a broad based corporate income tax on a separate accounting basis would be nearly impossible in terms of the resources required to effectively monitor intercompany transactions.

Formulary Apportionment

In response to the difficulties of administering separate accounting, the states began to devise formulas whereby a portion of the *total* net income of a corporate business could be attributed to the taxing jurisdiction based upon the factors of profitability – that is the business inputs that gave rise to the income.

Early apportionment formulas used only one factor – property. States soon realized this produced distorted results by giving too much weight to manufacturing activity and not enough to the selling activity. Several states expanded the formula to include payroll and sales. The "*three factor formula*" was eventually incorporated into the Uniform Division of Income for Tax Purposes Act ("UDITPA").

19 states have adopted UDITPA as the exclusive or optional method of apportionment, 24 states have adopted UDITPA with some changes or have adopted a similar method.

Alaska adopted UDITPA in 1970 and it appears in AS 43.19.

AS 43.20.065 makes the apportionment provisions of AS 43.19 mandatory for all multistate businesses in Alaska.

The Apportionment Formula

The standard UDITPA formula is the average of the property, payroll and sales factor and is expressed as:

$$\frac{\frac{\text{Property in State}}{\text{Property Everywhere}} + \frac{\text{Payroll in State}}{\text{Payroll Everywhere}} + \frac{\text{Sales in State}}{\text{Sales Everywhere}}}{3}$$

The above formula weights the factors equally. Some states double weight the sales factor and some states use a single sales factor.

The Income Base – "Business Income" of a "Unitary Business"

Before the apportionment formula can be applied, there are two overriding constraints to apportionment.

First, case law has determined that the formula can only be applied to a unitary business. A unitary business, as the name implies, functions as single economic unit. If the business activity within the state is separate and distinct from the rest of the business, then formulary apportionment is inappropriate.

Second, the nature of the income to be apportioned must be considered. Not all income of the unitary business should be apportioned – only *"business income"*. Under the rules of apportionment, business income is the income that bears a reasonably close relationship to the to the central business of the unitary group. *"Non-business income"* is that income that is only remotely connected to the central business. Non-business income is not apportioned, but rather is allocated to the state where the property or business activity is located.

Business income is sometimes referred to as *"apportionable income"* as it is the income to which apportionment factors are applied. Non-business income is often called *"allocable income"*.

AS 43.19 adopts the current UDITPA definition of business income at Article IV, 1(a):

> "Business income" means income arising from transactions and activity in the regular course of the taxpayer's trade or business and includes income from tangible and intangible property if the acquisition, management, and disposition of the property is constitute integral parts of the taxpayer's trade or business operations."

<u>The Combined Report</u>
When determining the extent of unitary business, states disregard the separate legal existence of separately incorporated affiliates. When a group of corporations conduct a single unitary business, states combine the incomes of the separate corporations (eliminating the intercompany transactions within the group) to arrive at the unitary business income subject to apportionment. The apportionment factors are computed in a similar fashion. This process is referred to as *"combination"* and the return filed under this method referred to as the *"combined report" or "combined return"*.

AS 43.20.065 mandates the use of combined reporting and apportionment.

<u>Separate Reporting</u>
A few states do not require or allow a combined report. These states honor the separate corporate boundaries (and the underlying "separate accounting" used to determine the separate corporation's income). These states still apportion the income of the separate corporation when the corporation does business in more than one state. This method is usually referred to as *"separate reporting"* and taxpayers file "*separate company reports*".

<u>Tests for Unity</u>
Formulary apportionment is tied to the concept of unity because the inputs to the formula come from only the branches or affiliated corporations that make up the unitary group. That is to say, the income and factors of non-unitary corporations or businesses simply are not part of the formula. Therefore, it is critically important that the extent of the unitary business be defined and with this question there has been considerable litigation that has produced several definitions that should, in theory, produce the same results.

Many courts recite the tests contained in *Butler Bros.* an early California case. There, the court set forth the "*three unities test*":

1. Unity of ownership (i.e. the enterprise is linked by common ownership, usually the parent company owning a controlling interest in the common stock such that the parent controls the operations of the subsidiary).

2. Unity of operation, as evidenced by central purchasing, advertising, accounting, and management divisions.

3. Unity of use, evidenced by a centralized executive force and general system of operation.

More recently, courts have expressed the unity criteria as functional integration, centralization of management and economies of scale. Regardless of how the tests are expressed, the concept is that there are flows of value within the business segments, the unitary business operates as a single economic unit, and the parts of the enterprise are inextricably linked and dependent upon each other.

The classic example of a unitary business is the fully integrated oil and gas company that explores for oil and gas, produces and refines it, and ultimately sells fuels and other petroluem products to consumers. Each of those activities is dependent upon the other, and each contributes to overall operations of the company.

Alaska's Tax Base – Federal Taxable Income with Modifications
Regardless of whether the income in question is business or non-business income, the states must set out the rules to measure the income. Most states conform to the Internal Revenue Code ("IRC " or "the Code") to some degree.[1] Alaska links itself very closely to the federal statutes by the adoption of most of the Internal Revenue Code.[2]

A major departure from the IRC is that Alaska, like most states, does not allow a deduction for taxes based on or measured by net income. Alaska also does not allow a foreign tax credit.

Worldwide Apportionment
During the 1970's, states applied the apportionment factors to the total worldwide income of the business. Worldwide apportionment was controversial because:

1. Applying property and payroll factors on a worldwide basis can distort the amount of income apportioned to the state in light of vastly different wage rates and property costs in developing countries.
2. It is difficult to convert foreign books and records to a format acceptable to the states.
3. States had difficulty accessing foreign books and records for audit.

Companies domiciled in the UK and Japan were particularly vocal in their criticism of worldwide apportionment. These countries made it clear that states that did not employ

[1] California is a notable exception. California has written its own "Internal Revenue Code".
[2] See AS 43.20.021.

worldwide apportionment would be favored sites for investment. Also, the U.S. State Department under President Reagan strongly criticized worldwide apportionment.

We should note that the U.S. and its trading partners generally follow separate accounting and treaties when determining taxable income at the national level. For example, the IRC taxes the entire income of a U.S. corporation and addresses potential double taxation by allowing a foreign tax credit. No country has adopted a formulary apportionment method.

Water's Edge Apportionment (AS 43.20.073)
California is the recognized leader in developing multistate apportionment legislation and case law and California has long been aggressive in asserting worldwide apportionment. However, in response to the economic and political pressure, California enacted *"water's edge"* legislation whereby taxpayers may elect to combine only those corporations that do business in the U.S. Other states followed with similar rules. Alaska was one of the final holdouts, enacting water's edge legislation in 1991. Alaska's water's edge combination is not available to oil and gas taxpayers.

History of Oil and Gas Corporate Income Tax
Before 1978, no special rules existed for oil and gas corporations – they filed using worldwide apportionment using the standard three factors of property, payroll and sales.

Based upon the belief that the standard factors did not fairly or fully represent the income producing activities and income of oil and gas producers in Alaska, the legislature enacted AS 43.21. This required oil and gas producers and pipeline companies to compute their Alaska taxable income on a separate accounting basis, which greatly increased their tax liabilities. The hallmarks of this statute were:

- Since virtually no oil was actually sold in Alaska, oil produced was considered to be gross income, measured by the value of the oil at the point of production.
- Direct operating costs were deductible.
- General Overhead and Administrative expenses were allocated.

The Alaska oil and gas industry promptly sued the state arguing that AS 43.21 was unconstitutional. Faced with protracted litigation and the potential for huge corporate tax refunds, the legislature looked for alternatives to AS 43.21 and settled upon modifications to standard apportionment effective in 1982.[3] Those provisions are in AS 43.20.072.

Special Apportionment – Oil and Gas Producers and Pipelines (AS 43.20.072)

The highlights of AS 43.20.072 are:

- .072 applies to corporations that produce oil or gas in Alaska or own regulated pipelines in Alaska.
- The apportionable income base is worldwide income with adjustments:

[3] The Alaska Supreme Court ultimately upheld AS 43.21 with a decision issued in 1985.

Cost depletion is mandatory (percentage depletion disallowed).
Intangible drilling costs capitalized (IRC allows partial write-off).
Slower depreciation methods required (Accelerated Cost Recovery not allowed).

- Standard three factor apportionment modified to: Property, Extraction, and Sales (extraction factor replaces payroll factor).
- "Extraction factor" is oil and gas produced in Alaska divided by oil and gas produced worldwide.
- The sales factor includes intercompany tariffs (normally intercompany transactions are eliminated in combination).

Some Important Alaska Court Cases

1. <u>Unity – *Earth Resources*</u>
The Alaska Supreme Court found that seemingly diverse business enterprises were nonetheless a unitary business. Earth Resources Company (ERC), the parent company, was domiciled in Texas. ERC's subsidiaries owned and operated a refinery in Tennessee, marketed gasoline, transported crude oil, and conducted mining operations. In Alaska, ERC formed Earth Resources Company of Alaska (ERCA) with the intent that ERCA would build and operate a refinery. ERCA had some minority shareholders. At a time when the Alaska refinery had not been built and was not producing revenue, ERC sought to find some source of income. ERCA, with the help of ERC, purchased a local paving company, which was very profitable and contributed most of ERCA's income during the tax years involved.

   The Court found that the companies exhibited sufficient functional integration, centralization of management and economies of scale to support a finding of unity.

2. <u>Business Income and Adoption of the Internal Revenue Code – *OSG Bulkships*</u>
This case addressed the situation where combination and apportionment rules collide with the sourcing of income provisions of the IRC. The Court set forth the general principle that Alaska's adoption of the IRC and its sourcing rules, take a back seat to the worldwide combination and apportionment provisions (then worldwide) under AS 43.20.065.

   Overseas Shipholding Group (OSG) through its subsidiaries owned and operated a fleet of U.S. and Foreign flagged vessels used in variety of shipping operations worldwide. OSG had organized such that a U.S. corporations owned and operated the domestic vessels and a foreign organized corporation owned and operated the foreign flagged vessels. The U.S. parent corporation through its subsidiaries owned and chartered vessels that entered Alaska waters to transport ANS crude oil.

Under IRC section 883, foreign flagged vessels are exempt from U.S. income tax if the country of registry provides a similar exemption for U.S. vessels. Consequently, OSG did not include the corporations that owned the foreign vessels in its Alaska combined return.

The Court recognized the fundamental difference between the federal source-based tax system and the UDITPA apportionment method. The Court noted that Alaska statutes adopt the IRC unless modified or excepted to by a specific provision in Alaska law. The court viewed IRC section 883 as an income-sourcing rule that was excepted to in the adoption of combination and apportionment at AS 43.20.065, and ruled that the foreign corporations should be included in the combined group.

It is interesting to note that within months of this decision, the Alaska legislature, under heavy lobbying pressure from the cruise ship industry, amended AS 43.20.021(a) to adopt IRC 883. Since most of the vessels in the Alaska cruiseship industry are foreign flagged, currently the industry is effectively exempt from Alaska income tax.

With respect to business income, the Court found that OSG's investment companies generated investment income, not operational income and therefore the income was non-business income and should not have been included in apportionable income.

3. Foreign Income Tax – *Gulf Oil Corporation (1988)*

Gulf Oil Corporation, like many oil companies today, find themselves paying arguably exorbitant income taxes to OPEC countries and other oil producing countries. Audit included these taxes in apportionable income relying on AS 43.20.031(c).

Gulf argued that Alaska should follow the federal rules concerning foreign taxes. Federally, a taxpayer can elect to either deduct the payments in their entirety[4], or a taxpayer can elect to take the tax as a credit. If the taxpayer elects to take a federal credit, the taxpayer must follow the rules of IRC section 901 that restrict the amount of the payment that is creditable. Understandably, the U.S. treasury does not want to subsidize a foreign government's tax take with unlimited foreign tax credits; therefore the 901 regulations start with the presumption that the levy is not an income tax and place the burden on the taxpayer to prove that the levy is an income tax. The 901 regulations provide for a safe harbor calculation that essentially allows a credit equal to what would have been paid to the U.S. federal government rather than the actual tax payment to the foreign government. Gulf

[4] Virtually any payment to the foreign country save for a bribe, is deductible federally as a business expense, so the characterization of a payment as a royalty, production payment, or income tax is irrelevant.

argued that the Alaska tax addback should be the amount available for U.S. credit, not the total amount of income tax paid to the foreign government.

The Court rejected Gulf's logic, first noting AS 43.20.036 (no foreign tax credit) is an Alaska exception to the adoption of the federal 901 regulations – they simply don't apply. The Court also rejected the notion that Alaska should adopt a federal rule that explicitly is intended to make a levy difficult to characterize as an income tax. The adoption of such a rule would foster tax avoidance.

SPRING 2000
REVENUE SOURCES BOOK

Alaska Department of Revenue
Tax Division

April 7, 2000

THE SEAL OF THE STATE OF ALASKA

Tony Knowles, Governor
Wilson L. Condon, Commissioner
Dan E. Dickinson, Director
Charles Logsdon, Chief Petroleum Economist

F. Constitutional Budget Reserve

Minimum Necessary CBRF Borrowing Authorization

What is the minimum authorization for annual borrowing from the CBRF needed for state government to function? The answer is the anticipated difference between Unrestricted General Purpose Revenue and the General Fund budget *plus $300 million*. This $300 million needed for cash flow is repaid at the end of each year.

Why must the authorization be $300 million more than the anticipated deficit? Because of the following:

1. Since 1990, the General Fund has "borrowed" $3.9 billion from the CBRF.
2. The Alaska Constitution requires that whenever the General Fund owes money to the CBRF at the end of a fiscal year, any balance in the General Fund – up to the amount of the outstanding debt – must be transferred to the CBRF.
3. Since the General Fund's debt to the CBRF is so large ($3.9 billion), the entire balance in the General Fund is automatically transferred to the CBRF at the end of each fiscal year, making the General Fund balance $0 on July 1.
4. Given the payroll, invoices, school funding and other payables that the state owes at any point in time, financial management professionals unanimously agree that the state must always have a balance of at least $100 million in the General Fund.
5. The first month of the fiscal year has the highest level of General Fund expenditure of any month because, in addition to meeting the state's normal monthly operating expense, including the foundation payment to school districts, the state must pay a disproportionally large amount of General Fund money to the university, for debt service, for summer construction projects and to municipal governments.
6. Although General Fund expenses are high early in the fiscal year, revenue receipts are delayed, so the General Fund must borrow $300 million in July – both to restore the $100 million balance after the end-of-the-fiscal-year payback to the CBRF on June 30 and to meet immediate needs – regardless of whether oil prices are high or low.
7. If oil prices were high enough during the year to balance the budget – $29 per barrel for FY 2001 – the revenue cash flow still would not catch up with the expenditure cash flow until June 30, the very last day of fiscal year, and the day the General Fund happens to receive its largest amount of cash revenue.
8. The story starts all over again at midnight that night when the General Fund balance must be reduced to zero again to repay the CBRF.

The $300 million is the state's working capital. It is needed to bridge the differences in the day-to-day timing of funds flowing in and out of the General Fund, just like working capital is needed by a company to bridge the differences in the day to day timing of money outflows and inflows.

REVENUE SOURCES
Forecast and Historical Data

SPRING 2002

Alaska Department of Revenue
Tax Division

Tony Knowles, Governor
Wilson L. Condon, Commissioner
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Could Higher Oil Prices Fill the Fiscal Gap?

The short answer is no, not unless you believe in the improbable. Still, that doesn't stop Alaskans from hoping.

A quick study of the numbers, however, shows it certainly is extremely unlikely. Alaska North Slope crude oil would have to fetch higher prices for a longer period than at any time in the pipeline's 25-year history. And not just a little higher for a short time, but a lot higher for a long time.

- **How much is the fiscal gap at high, or low, oil prices?**

At $30 oil, Alaska would still face a half-billion-dollar-a-year fiscal gap over the next 10 years.

At $10 oil, the gap would range between $1 billion and $1.7 billion a year.

Figure 9.
Annual Fiscal Gap at $30/ Barrel Oil

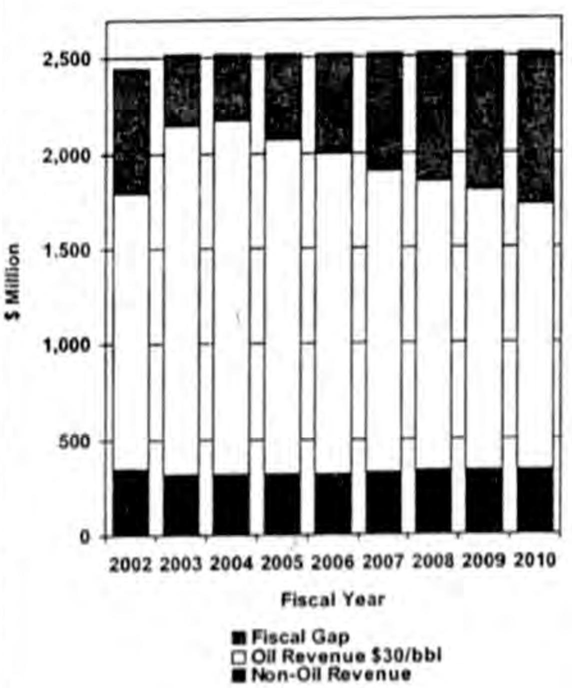
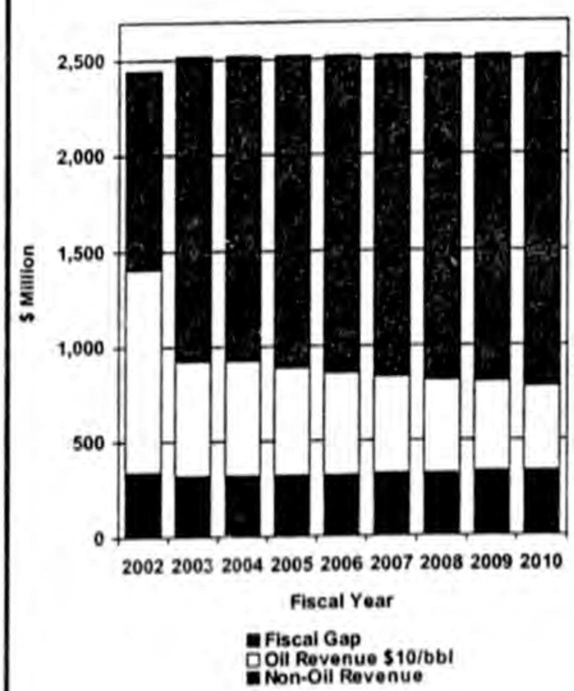


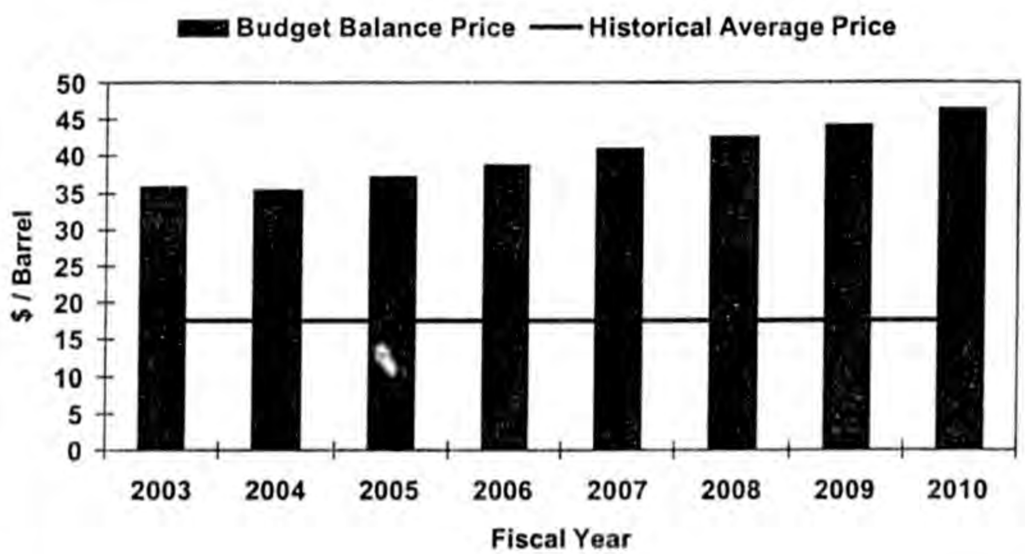
Figure 10.
Annual Fiscal Gap at $10/ Barrel Oil



▪ How high would oil prices have to climb to balance the state budget through the end of the decade?

Although we believe North Slope oil production will average slightly above 1 million barrels per day through 2010, the state's declining production tax rate requires a higher price every year just to maintain the same revenues. North Slope oil would have to average $36 a barrel in Fiscal 2003 to balance the budget. The price would have to average $40 a barrel over the next eight years to cover the state budget, but that's just the average. The number gets further out of reach each year. In Fiscal 2010, the price would need to be over $46 a barrel.

Figure 11. Oil Price Necessary to Balance the Budget



▪ If we want to continue using the Budget Reserve Fund to fill the gap, how high would oil prices have to climb to keep the fund alive until the end of the decade?

To reach 2010 with something, anything, in the Budget Reserve Fund would require oil averaging over $33 a barrel for the next eight years — 80% higher the Department of Revenue forecast, 25% higher than U.S. Department of Energy estimates, and 30% higher than this month's high prices driven by the threat of war in the Mideast.

Keep in mind that prices would have to hold fairly steady around the $35 average — the state could not afford a couple of bad years along the way if we wanted to maintain the Budget Reserve Fund and pay our bills. For example, if North Slope oil dipped below $15 for a year or more, as has happened three times since 1989, the Budget Reserve Fund would take such a deep hit that it might hit empty even if prices rebounded the next year.

▪ How likely is it that oil prices will climb high enough to balance the budget in some years, or at least extend the life of the Budget Reserve Fund?

Prices could rise above projections in the short term — maybe even enough to balance the budget for a short time. But it would take a major, sustained global shortage of oil to create the consistent, high oil prices for the long term that could save the Budget Reserve Fund, and such a shortage is extremely unlikely.

Oil is a market-traded commodity, with the forces of supply and demand determining the price. When supply exceeds the demand, which was the world situation earlier this year, prices fall. As oil gets cheaper, demand recovers, which, over time, leads to higher prices as demand builds to match supply. But when demand gets too high, squeezing the supply, prices rise and demand falls back down. Prices eventually come down, too. Oil prices don't just move up and down, they always move up and down. High oil prices also push users to rely more on substitute fuels and conservation, serving as a natural relief valve to cut demand when prices climb too far. Because of how the market works, it is highly unlikely that oil prices could ever stay high enough long enough to solve Alaska's budget problem.

Here are some numbers to consider:

▪ Since a transparent market price for ANS West Coast deliveries emerged in the mid-1980s, Alaska North Slope crude oil delivered to California and Washington refineries has never averaged more than $28 a barrel in a year. As if that was not sobering enough, the price has averaged below $20 a barrel for all but three years since 1988.

▪ The West Coast ANS price has averaged above $30 a barrel in only six months of the past 175 months, and has never reached the $35 a barrel that Alaska would need for the entire year to balance the Fiscal 2003 budget.

▪ Any discussion of the potential for high oil prices would not be complete without looking at the low side of oil prices. Alaska North Slope crude averaged $9.39 a barrel in December 1998, its lowest monthly price ever.

▪ And while North Slope oil has exceeded $30 a barrel on the West Coast six out of the past 179 months, it has fallen below $15 a barrel in 39 of those months.

▪ If OPEC nations wage a price war with non-OPEC producers, and if oil drops to $10 a barrel as it did in late 1998, and if the price stays on the bottom for two years, the Budget Reserve Fund would be empty by November 2003.

Higher — or Lower — Oil Production

Oil production could exceed our forecast, which includes only barrels from fields that are producing or have been discovered. For those that have been discovered, we included production only from those fields we expect to start pumping by 2010.

It is possible, however, that some of the discovered fields could start producing sooner than expected, meaning more production and more revenue to the state. We also expect new oil discoveries on the North Slope, but we do not believe these new fields will begin producing before 2010.

However, these undiscovered fields might also begin producing sooner. We have estimated in this section how much additional production we believe could possibly come from the accelerated development of known reserves and new discoveries.

On the other side of the fiscal coin, it is possible that some of the forecast production from as yet undeveloped fields could be postponed past the expected start-up dates in this forecast. Also, the production rate for developed fields may decline at a faster rate than we project. For every upside there is a downside.

Possible Higher Oil Production

We forecast that "new oil," oil that has been discovered but is not yet flowing through TAPS, will constitute a substantial 10.8% of North Slope production by Fiscal 2005 and 28.2% by Fiscal 2010. Clearly, Alaska is depending on a fair amount of this new oil just to meet our revenue forecast.

But what about undiscovered oil? Oil companies continue to lease new lands and drill exploratory wells in search of reserves, and it is future production from these areas that is harder to predict.

To come up with a credible estimate of potential undiscovered oil that might be produced before 2010, we relied on geological work done by the U.S. Geological Survey and the federal Bureau of Land Management. We then derived an estimate of the North Slope's undiscovered, economically recoverable barrels that could possibly come into production before 2011. We provide in Table 10 our estimate of the potential additional production from these undiscovered reserves over the next decade. These barrels would come from three areas: the National Petroleum Reserve-Alaska (NPRA), the Foothills and the area east of Prudhoe Bay and the Central North Slope. We do not include any production from the Arctic National Wildlife Refuge in this table because even if Congress this year gives the go-ahead for drilling in ANWR, we would not expect to see any production until after 2010.

Table 10. Additional Potential Barrels from Undiscovered Fields
million barrels per day

Fiscal Year	NPRA	Foothills and East of Prudhoe Bay	Central North Slope Satellites	Total
2006	-	-	0.014	0.014
2007	0.040	-	0.028	0.068
2008	0.037	0.034	0.045	0.117
2009	0.035	0.060	0.065	0.159
2010	0.039	0.083	0.082	0.203

If all of the additional undiscovered production were to come online as estimated in Table 10 — 203,000 barrels per day by Fiscal 2010 — the state would receive an estimated $173 million in additional oil and gas tax and royalty payments in Fiscal 2010. That's a little more than 10% of what would be needed to close the budget gap that year. The revenue to the state is held down by the Economic Limit Factor and the lower production tax rate charged on oil flow for the first five years of production from new fields.

This undiscovered new oil could come from:

National Petroleum Reserve-Alaska.
Phillips announced in May of 2001 that it had discovered three separate hydrocarbon accumulations in the NPR-A. Phillips is continuing to do delineation drilling to determine if these discoveries are commercial. The Department of Revenue has developed a risked estimate that these accumulations will yield 325 million barrels of oil, with production starting at 30,000 barrels per day in 2007. However, the NPR-A might yield more oil. First, the area encompassed by the discovered accumulations is comparable to the area overlying the Alpine reservoir, with potential reserves in Alpine's 429 million barrel neighborhood. Second, Phillips and Anadarko continue to explore in other areas of the NPR-A. Phillips drilled the Mitre and Hunter wells four and 12 miles, respectively, away from last year's discovery. Phillips also plans to drill the Puviaq well next year much farther to the west. Anadarko drilled two Altamura wells to the south of the NPR-A discovery. In total Phillips and Anadarko have permitted 34 well locations in the first few years of exploration. Finally, the BLM plans additional lease sales in 2002 and 2004.

Back in 1998, the BLM projected the drilling of 21 exploration wells in the NPR-A leading to the discovery of 600 million barrels of recoverable oil. [1] If the NPR-A yielded 600 million barrels rather than our projected 325 million barrels, these larger reserves would add an additional 35,000 to 40,000 barrels of daily production to our estimated NPR-A production between 2007 and 2010.

Foothills and East of Prudhoe Bay.
The USGS estimates that there are 500 million barrels of technically recoverable reserves in the Central Foothills. [2] We estimate that 300 million barrels of these reserves could be economically recoverable, equating to 83,000 barrels per day by Fiscal 2010.

Central North Slope Satellites and the Beaufort Sea.
The USGS in 1995 estimated perhaps 4.3 billion barrels of technically recoverable, undiscovered oil in the central and eastern coastal regions of the North Slope. The USGS believed this oil would mainly be in the turbidite and Barrow Arch Beaufortian geological plays.[3] The USGS also stated that less than half of this technically recoverable oil would be economically recoverable.[4] Of the estimated 3.6 billion barrels of technically recoverable oil remaining net of post-1995 discoveries, 1.5 billion barrels could be economically recoverable.

(1) See Table IV.A.1.b-7 of the BLM's "Northeast National Petroleum Reserve-Alaska (NPR-A) Integrated Activity Plan/Environmental Impact Statement (IAP/EIS) August 1998.
(2) See USGS Open-File Report 95-75I, "Economics and undiscovered oil and gas accumulations in the 1995 National Assessment of U.S. Oil and Gas Resoruces: Alaska", by Emil Attanasi and Ken Bird at Table 3, Page 37.
(3) USGS[95] Table 3, Page 37.
(4) Of the Eastern Coastal region's 1,632 million barrels of technically recoverable reserves, 39% (638 million barrels) should be economically recoverable. Of the Central Coastal region's 2,002 million barrels of remaining technically recoverable reserves, 45.75% (916 million barrels) should be economically recoverable. The economic recovery factors reflect mid-points between the $18 and $30 cases of USGS[95] Table 3.

Possible Lower Oil Production

The North Slope, like other mature provinces, depends upon production from new fields to offset declines in older fields. In our predictions of oil flow from discovered fields, which already are included in our revenue forecast, we include barrels from anticipated developments in the second half of this decade from Nanuq (2006), Point Thomson (2008), Sourdough (2008), Liberty (2008), Yukon Gold (2009) and Sandpiper (2010).

This table shows our projections for oil production from these fields, totaling 124,000 barrels per day by Fiscal 2010. These fields represent over 40% of the "new oil" included in our revenue forecast for Fiscal 2010. These field developments could be deferred of cancelled. If they are, the state could lose $65 million in FY 2010 — almost 10% of its projected petroleum revenue.

Table 11. Anticipated Production from New Fields This Decade
Thousand Barrels per Day

Fiscal Year	Point Thomson	Sourdough	Yukon Gold	Liberty	Sandpiper	Total
2004	-	-	-	-	-	-
2005	-	-	-	-	-	-
2006	-	-	-	-	-	-
2007	-	-	-	-	-	-
2008	20	10	-	35	-	65
2009	30	15	10	55	-	110
2010	30	15	15	52	12	124

The state faces a more serious loss if the production rate for its developed fields decline at a faster rate than we project. Prudhoe Bay has been in decline since 1988. We forecast that Prudhoe Bay will decline at a slower rate than it did during most of the 1990s, with production falling by an average 5.3% per year between 2001 and 2011. However, the steeper decline rate of 1992 to 1999 could return in 2002 if development drilling is less than we have projected. If the 1992-to-1999 decline rate continues throughout this decade, Prudhoe Bay production would run about 124,000 barrels per day under our forecast for Fiscal 2010. Such a steep production drop could reduce state revenues by an estimated $191 million in 2010.

Alaska Natural Gas Project

It's been more than 18 months since higher natural gas prices across the Lower 48 states reawakened interest in a pipeline to bring natural gas from Alaska's North Slope to Mid-America and California — and hundreds of millions of dollars a year in new revenue to the state treasury. Unfortunately, the same market volatility that pushed prices to record levels in the winter of 2000-2001 also worry producers, pipeline owners and investors, the very sources of the billions of dollars that will be needed to build the gasline.

Over the past 25 years, proposals to move North Slope gas to market — that is, to "commercialize" the stranded resource — have varied between a pipeline to the Lower 48 or one to tidewater, most likely Valdez or Cook Inlet, where the gas would be liquefied and shipped in tankers to Asian markets. High gas prices in the Lower 48 a year ago, coupled with the faltering Japanese economy and abundant gas reserves economically closer to Asia in Indonesia and Australia (without the need for an expensive 800-mile pipeline across the arctic to tidewater), have rekindled interest in the Mid-America pipeline option. Estimates for total project cost, including a gas conditioning plant on the North Slope, 1,800 miles of pipe to the northern end of the North America grid in Alberta, and expansion of existing Lower 48 connections, range from $15 billion to $20 billion.

Proponents have studied the cost of a gasline in varying sizes, moving anywhere from 2 billion cubic feet of gas per day to 4.5 bcf/d. Logically, the larger the project, the lower the unit costs of transporting gas to market, which generally is good news for potential developers and investors. However, the larger the project and the higher the cost, the greater the investment risk. That is the dilemma for moving Alaska gas to market.

Another dilemma is the larger the volume of gas moved to market, the more likely the gas could temporarily oversupply the market and drive down prices. That would mean lower prices not only for gas coming from Alaska, but for all of the gas sold in the Lower 48 states.The cost to producers of lower prices also works against the large Alaska project.

If the risks can be lessened, there is no doubt a gas project would be good for Alaska. For example, a 4.5 bcf/day gasline would generate more than $400 million a year in new state revenue for Alaska if gas prices are at $3 per million Btu in Chicago. But the producers and others will not make their investment decision based on how much the project could earn for the state treasury. Rather, it will be based on the cost of risk and the rate of return for the $20 billion investment. A joint study team comprised of the three major North Slope gas oil and gas producers recently concluded the project is not economic based on their cost estimates and market projections. The Department of Revenue also believes the project would yield a sub-market rate of return under existing market projections. Higher prices, obviously, would improve the economics, but many gas price forecasters do not expect prices to hold much above $3 per million Btu on a consistent basis over the next decade.

The producers, gas pipeline companies and the State of Alaska are working with the state's congressional delegation to reduce the costs and risks associated with the project. There is no question that a gasline would help make up for falling oil production and revenues to the state treasury. And there also is no question that the possibility of a natural gas project deserves a significant amount of state effort to promote and encourage the project.

Broad-Based Taxes

The single largest source of new, non-oil and gas revenue to the state under discussion — other than Permanent Fund earnings — would be a personal income tax or a statewide sales tax. But just how much new revenue would a broad-based tax produce, and what do other states collect, and how do sales and income taxes compare?

Personal Income Tax

What Do Other States Charge?

Of the 50 states, 43 have a personal income tax. Joining Alaska on the list without a tax are Florida, Nevada, South Dakota, Texas, Washington and Wyoming. Of the 43 with a tax, New Hampshire and Tennessee collect taxes on dividends and interest income only.

Most states use federal adjusted gross income as a starting point to calculate the state income tax, and most also use federal provisions in calculating allowable itemized deductions. In addition:

- 29 states exempt Social Security benefits from taxation.
- 8 states exempt unemployment benefits from taxation.
- 37 states exempt interest earned on their own state and municipal bonds.
- 5 states exempt military pay from taxation.
- 33 states allow a standard deduction for taxpayers (12 use the federal amount).

Most states use a series of brackets to tax different incomes at different rates. Montana has the most tax brackets — 10 — ranging from 2% to 11% of adjusted gross income, with some deductions allowed. Some states have a flat tax — Colorado, Michigan, Massachusetts, Illinois, Indiana and Pennsylvania — ranging from 2.8% of federal taxable income in Pennsylvania to 5.6% of adjusted gross income in Massachusetts.

What are the Options for an Income Tax?

There are three options for the tax base for calculating a personal income tax:

- **Adjusted gross income.** Because the tax base would be the highest of the three options, the tax rate would be the lowest. Adjusted gross income is Line 33 on the federal personal income tax Form 1040, which is an individual's gross income from all sources minus: IRA contributions, student loan interest, Medical Savings Account contributions, moving expenses, one-half of the self-employment tax paid by self-employed individuals, the self-employed health insurance deduction and alimony.

- **Federal taxable income.** This is Line 39 on Form 1040, which is adjusted gross income minus either the standard deduction or all of the itemized deductions allowed under federal law, plus the per-person exemptions allowed under the federal tax code. This requires the state to accept whatever tax deductions are allowed under federal law, although the state also could include its own deductions, credits or other conditions.

- **Federal tax liability**. This is what an individual pays the IRS. Because the tax base would be the lowest of the three options, the actual tax rate would be higher than if the rate were applied to gross income or taxable income. For example, a 2.75% tax on gross income, a 3.8% tax on taxable income, or a 20% tax on federal tax liability would all raise the same amount for the state — about $350 million a year. Another feature of using federal tax liability as the base is that the state tax would be progressive, even with a flat tax rate, meaning the tax rate would increase as an individual's income increased. This also requires the state to accept whatever deductions and credits are allowed under federal law. Federal tax liability is Line 40 on Form 1040 (before several credits under the IRS code), or Line 52 (after Education Tax Credits and Elderly and Disabled Care Credits and others), or Line 52 plus the Earned Income Credit and Additional Child Tax Credit.

How Much Do Alaskans Earn?

IRS data tapes show Alaskans filed 327,510 personal income tax returns for 1999, representing 442,199 taxpayers (114,689 were joint returns). Those returns show:

- Federal adjusted income reported by Alaskans in 1999 totaled $13.2 billion.
- Almost 90% of the tax returns with more than $100,000 in adjusted gross income were joint returns.
- About 7% of returns with less than $20,000 in gross income were joint returns.
- Of the 442,199 taxpayers, 63% reported gross income of under $50,000 and almost 80% reported gross income below $75,000 a year.
- The 10% of taxpayers reporting more than $100,000 a year in gross income represent 33% of total income reported by all Alaskans.
- The 20% earning more than $75,000 represent 50% of total income for Alaskans.

How Much Would the State Raise from an Income Tax?

Several proposals are under discussion in the legislature, but three have garnered most of the attention. The Legislative Fiscal Policy Caucus proposed a 4% flat tax on federal taxable income, which would raise an estimated $360 million a year. The governor proposed a 20% tax on federal tax liability, which would raise about $350 million per year. Representative Bill Hudson proposed a 2.25% tax on adjusted gross income, raising an estimated $285 million per year.

These are approximate numbers for tax rates and how much revenue would be raised. The table assumes a flat tax, for the sake of simplicity in showing potential revenues.

Income Tax Rates and Revenue Projections (1999 IRS Data)

$ Million Revenue	% Adjusted Gross Income	% Federal Taxable Income	% Net Federal Tax Liability
$250	2.00	2.77	13.86
$300	2.38	3.29	16.47
$350	2.75	3.82	19.08
$400	3.13	4.34	21.70

In addition to deciding on the tax base (gross income, taxable income or federal tax liability), the rate schedule (flat tax vs. a variable tax), and exemptions and deductions, the state also would have to consider expectations for audits and enforcement. The stronger the enforcement, the more effective the program, especially with out-of-state residents.

How Much Did Alaskan Raise from its Old Income Tax?

Alaska abolished its personal income tax in 1980. The tax raised $210.4 million in Fiscal 1977, its highest collections ever. The tax was assessed as a percentage of federal taxable income, ranging from 3.5% for income up to $8,000 per year to a high of 14.5% on income in excess of $300,000. In the middle, taxpayers paid 10% of their federal taxable income over $52,000.

If the pre-1980 tax rates were in effect today, Alaskans would pay about $750 million in state personal income taxes. If the tax brackets were adjusted for inflation, that number would be $660 million.

How Much Would Non-Residents Pay, and How Much Would Alaskans Save on Federal Taxes?

An income tax certainly would collect money from non-residents working in Alaska, but there is no way to know exactly how much it would collect. The IRS reports income earned by taxpayers with an Alaska mailing address; it does not report income earned by non-residents working in Alaska. There are no exact numbers for non-resident wages in Alaska, but estimates range from 3% to 10% and the Department of Revenue believes the true number is probably in the middle. At 6% or 7%, an income tax that raised $350 million would collect perhaps $21 million to $22 million a year from non-residents. It is important to remember that most of the non-resident workers who come to Alaska are here for low-paying summer tourism and seafood processing jobs and would not pay much in personal income taxes.

A state personal income tax would be deductible from federal income taxes for Alaskans who itemize. IRS statistics indicate about 25% of Alaska taxpayers itemize their deductions, though most higher-income Alaskans itemize on their federal returns. And since it would be the higher-income Alaskans who would provide most of the state's new income tax revenues, a substantial portion of that tax would be deducted from Alaskans' tax payments to the federal government.

The easiest way to "export" a tax — that is, to shift its cost — is through its deduction against federal tax liability. There is no deduction for state or municipal sales taxes; only income taxes are deductible. A deduction means part of the tax revenue remains in the state instead of going to the federal treasury.

We estimate that Alaskans would recover about 15% of the cost of a state income tax by deducting it from their federal tax bills. For example, if a state income tax generated $350 million a year, almost $53 million would come from the deductibility of the state income tax against federal income taxes. Therefore $275 million of a $350 million income tax would come from pockets of Alaskans, assuming $22 million came from non-residents and $53 million in lower federal taxes.

How Much Would it Cost to Administer an Income Tax?

The department estimates it could cost $6 million in one-time expenses to set up an income tax, including computers, software, printing forms and booklets, launching a public education campaign, and establishing offices. Ongoing expenses for an income tax would be an estimated $6 million to $7 million per year. Assuming $350 million or so per year in tax revenues, that would be within 2% of collections. The cost of collection is similar in other states.

Statewide Sales Tax

What Do Other States Charge?

The only states in the nation without a statewide sales tax are Alaska, Delaware, Montana, New Hampshire and Oregon. The others collect taxes that range from a low of 2.9% in Colorado to 7% in Mississippi and Rhode Island.

- In most states, the cities, counties, transit districts and other taxing authorities add their tax onto the state tax rate, with the states handling collection and enforcement, then disbursing the funds to the municipal agencies.
- State and city sales taxes are collected and administered separately in only a very few locations nationwide. Businesses prefer to deal with a single set of rules and a single taxing authority (reducing compliance costs to businesses).

Because of the cumulative effect of adding local sales taxes to the state tax, many states set a maximum overall rate.

- The highest sales tax rate in the nation is in Oklahoma, where the state reports a combined rate of 9.78% as the highest in the state. Louisiana comes in second, with some jurisdictions charging a combined 9.5% rate.

Most states — 27 of 45 — exempt all or some food purchases from sales taxes, with three additional states charging a lower tax rate on foods.

- All states exempt prescription medicines from sales tax.
- Fewer than 10 states exempt non-prescription medicines from sales tax.

Most states — 27 of 45 — allow businesses to retain a portion of their collections as reimbursement for the expense of collecting the tax for the state. The other 18 states do not allow businesses to retain a percentage of the collections.

- For those states that do allow a "discount" to businesses on their sales tax returns, the rate ranges from 0.5% of the amount collected to as much as 5% for businesses with small tax collections.
- One-third of the states set a maximum on the amount of money a business is allowed to retain.

Of those states with a general statewide sales tax, the tax provides an average 32.3% of overall state general fund revenues.

How Many Alaska Cities and Boroughs Already Have a Sales Tax?

About one-third of Alaskans live in a community — a city or a borough — with a municipal sales tax. The rates for those 200,000-plus Alaskans range from:

- A low of 1% in Tenakee and White Mountain.
- To a high of 7% in Wrangell and 6% in Petersburg, Cordova, Kodiak and Kotzebue.

The 97 cities and boroughs with a sales tax collected about $125 million in Fiscal Year 2001, for an average of more than $600 per capita.

Each municipality has its own list of tax exemptions, limits and rules, such as a cap on the maximum amount of a single purchase subject to a sales tax (to ease the burden on purchasers of big-ticket items such as cars). There is no uniformity across the state. In this aspect, merchants likely would appreciate a state-governed sales tax program, with one set of rules statewide.

The Alaska Municipal League has gone on record opposing a statewide sales tax. The league's members see the sales tax as historically the domain of municipalities in Alaska and do not want to lose control over the tax revenue or administration. Alaska communities with an existing sales tax also fear the economic damage that could be inflicted upon their cities and boroughs if the state were to impose a statewide sales tax on top of municipal taxes.

- For example, Wrangell and Petersburg, at 7% and 6%, respectively, believe merchants in their communities would lose a significant amount of business to out-of-state suppliers if residents were charged an 8%, 9% or 10% combined state/municipal tax.

Most municipalities allow for some form of exemption for senior citizens, though the process varies from city to city.

- For example, Juneau issues tax-exempt cards to seniors and then requires businesses to keep a log of all tax-exempt purchases. Wrangell uses a different approach. It issues seniors a $250-a-year sales tax rebate, rather than requiring businesses to keep a log and enforce the exemption.

Assuming the state controlled collection of the tax, the most efficient method for distributing the local tax back to cities and boroughs would be for the state to determine the local share of the tax revenue and then send payments to the cities and boroughs.

How Much Would the State Raise from a Sales Tax?

The Department of Revenue estimates the state would collect approximately:

- $100 million a year for every 1% in a statewide sales tax on retail goods and services sold in Alaska, assuming no exemptions.
- $70 million a year if foods and medical goods and services were exempted.

Additional exemptions would reduce the tax burden on some residents and, consequently, reduce revenues to the state. Exemptions also could complicate administration of the tax. And, if the state exempted any goods or services already subject to municipal sales taxes, and then imposed its exemptions on municipalities, some cities and boroughs could see a drop in their tax revenues.

Is a Seasonal Sales Tax a Good Idea?

This is hard to judge, but it appears from Juneau's sales tax records that sales are not as heavily weighted to the summer season as many people might expect. Permanent Fund dividends and the Christmas shopping season appear to help keep the volume of sales from leaning too heavily toward a summer surge.

Based solely on Juneau's records, it appears a six-month seasonal tax might not generate much more than 50% to 55% of the year's taxable revenues. And it could be less if local residents shifted their purchases to the no-tax season.

A seasonal sales tax, while intended to grab more tax revenues from summer visitors, could actually harm local businesses, particularly big-ticket merchants that depend on local sales. For example, would a heavy seasonal sales tax deter residents from making purchases locally during the summer season? Would it hurt car dealers, appliance and furniture stores and electronic shops? Would the sales return each fall?

What is the Nationwide Streamlined Sales and Use Tax Agreement?

Businesses nationwide and other states are working hard to win nationwide adoption of a Streamlined Sales and Use Tax Agreement.

> *"It is the purpose of this agreement to simplify and modernize sales and use tax administration in the member states in order to substantially reduce the burden of tax compliance."*

One of the major reasons for the push is to address the issue of lost state and municipal sales tax revenues to mail order and Internet commerce. The growth of mail order and Internet sales is costing states and municipalities billions of dollars a year in lost sales tax revenues. The retail industry has made it clear that it wants to see a set of uniform sales tax rules nationwide as a condition of working with the states to collect sales taxes on interstate commerce. Alaska would not be in compliance with the nationwide effort if it adopted a state sales tax without ordering the same exemptions and rules for municipal sales taxes statewide.

The agreement, which has been adopted by about 20 states, requires:

> *"States to administer any and all sales and use taxes levied by local jurisdictions within the state so that sellers collecting and remitting these taxes will not have to register or file returns with, remit funds to, or be subject to independent audits from local taxing jurisdictions."*

Who Would Pay the Tax?

A sales tax is generally considered to be regressive, meaning that lower-income people, who spend a greater proportion of their income on local goods and services, would pay a larger share of their income in sales taxes when compared to higher-income people. Exemptions for food, medical care and other necessities would reduce but not eliminate this imbalance.

It's hard to say how much of the sales tax would be paid by visitors from out of state, although the Department of Revenue believes it would be in the range of 10% of total tax revenues for a tax in place for the entire year. Visitors spend heavily on gifts, food, lodging and tours, although federal law prohibits a state sales tax on air transportation.

What Other Issues Should be Considered?

In addition to questions of local control, joining the nationwide streamlined sales tax campaign, and the risk of economic damage to communities that already have a heavy sales tax burden, other issues for the state to consider include:

- Taxable vs. non-taxable sales.
  Food (prepared vs. unprepared), medicines (prescription vs. non-prescription), medical care (licensed care only or all care), sales by nonprofit organizations, and sales at vending machines are among the obvious issues.
- Senior citizen tax exemption.
  No exemption, or exempt all purchases by seniors, or issue an annual rebate check? If purchases are exempt, should such tax-exempt purchases be limited?
- An exemption for purchases and/or sales by nonprofit organizations.
- Expectation for audits and enforcement.
  A stronger enforcement and audit program would add to the costs but likely would produce higher revenues to the state.

One other major issue for the state to consider is whether it wants a "use tax" as part of its sales tax. Most states collect a use tax under the same set of statutes as their sales tax. The sales/use tax helps cover sales by nationwide retailers with a nexus (presence) in individual states. For example, if Alaska had a state sales and use tax and if an Alaskan placed a phone order with Eddie Bauer's catalog department, Eddie Bauer would have to collect a sales and use tax on the purchase because it has a store (a presence) in Alaska.

How Much Would it Cost the State to Administer a Sales Tax?

The Department of Revenue estimates it would cost approximately $3 million to $5 million a year to administer a statewide sales tax program, depending on the complexity of the tax, the number of exemptions, and the attention to enforcement and audits. The cost of sales tax programs nationwide average about 1% to 2% of collections. At $3 million to $5 million a year, Alaska would be within that range with a reasonable sales tax that raised $200 million to $250 million per year.

In addition to annual costs, there would be a first-year expense of approximately $2 million to set up the tax program, including programming, offices, public and taxpayer educational programs, publications and tax forms, and a web-based filing system.

Sales Tax vs. Income Tax vs. Budget Cuts vs. Dividends?

Supporters of a graduated-rate income tax say it is progressive, in that it assigns a higher rate to higher-income households, consistent with both ability to pay and the benefits received from public spending. Opponents, however, argue that this penalty for success is unfair and that higher-income households do not receive proportionately higher levels of public services.

A flat income tax is not progressive, unless it is assessed on federal tax liability, in which case it picks up the progressivity (the graduated rates) of federal deductions and tax tables.

Supporters of a sales tax say it is fair in that it taxes everyone at the same rate, but opponents of a sales tax say it is regressive because low-income households spend a greater proportion of their income on essential items than higher-income households.

Opponents of reducing the dividend argue it would be regressive, in that all would suffer the same economic loss - regardless of their income. Low-income Alaskans have come to depend on the dividend for a significant portion of their annual household income. Supporters, however, argue everyone should help pay for public services, and that reducing the dividend is one way to ensure all Alaskans contribute to the solution.

Which is Least Painful to the Economy?

There are no recent studies on precisely what would be least harmful to the state's economy, where harm is defined as loss of jobs, household income and economic activity. Is the answer state budget cuts, new taxes, or reducing the dividend? Thoughtful consideration produces some generally accepted assumptions:

- More of the Permanent Fund dividend leaves the state faster than state operating expenses for public services or wages earned by Alaskans, and therefore reduced dividends would be less harmful to the overall economy. Because Alaskans save or invest a greater proportion of their dividends than their wages, and because Alaskans spend a greater proportion of their dividends than their wages on travel and big-ticket purchases manufactured out of state, we believe that reducing dividends would have a smaller overall economic effect on the Alaska economy than a personal income tax or sales tax.

- If, for example, the state wanted to raise $350 million a year, either from a personal income tax or a sales tax, we believe a sales tax would raise more money from out-of-state residents but the income tax, overall, would be less costly to the Alaska economy. A $350 million sales tax might collect about $35 million from out-of-state residents (visitors and workers). A $350 million income tax would collect perhaps $22 million from out-of-state workers, while also reducing Alaskans' federal income tax payments by an estimated $53 million. The net cost to Alaskans of a sales tax would be $315 million vs. $275 million for the income tax.

- Although a sales tax would raise more money overall from visitors, an income tax would collect more revenue from non-residents working in Alaska. A non-resident with $60,000 a year in taxable Alaska wages would pay $1,800 if the state imposed a flat 3% income tax. That same non-resident worker would have to spend $60,000 a year — more than his or her entire paycheck — for the state to collect that same $1,800 a year in sales taxes at a 3% rate. The same math would apply if the non-resident were a seasonal worker earning $10,000 for the summer. The state generally would collect a greater share of that worker's income through an income tax than a sales tax.

A recent report in State Tax Notes addresses the issue of taxes vs. budget cuts. It was prepared by Peter Orszag, senior fellow in tax and fiscal policy at the Brookings Institution, and Joseph Stiglitz, Columbia University economics professor and winner of the 2001 Nobel Prize in economics.

The report suggests tax increases may be less harmful to the economy than spending reductions because some of the tax increase would result in reduced saving rather than reduced consumption. And since much of an individual's savings do not move around the state's economy (the multiplier effect) the same as wages or purchases, a reduction in savings would be less harmful than government budget cuts.

For example, if individual taxes increase by $1, consumption may fall by 90 cents and savings may fall by 10 cents. Some types of government spending reductions, however, would reduce demand in the economy on a dollar-for-dollar basis, and therefore would be more harmful to the economy than a tax increase.

The report continued:

"For states interested in the impact only on their own economy rather than the national economy, the arguments made above are even stronger. In particular, the government spending that would be reduced if direct spending programs are cut is often concentrated among local businesses. ... By contrast, the spending by individuals and businesses that would be affected by tax increases often is less concentrated among local producers — since part of the decline in purchases that would occur if taxes were raised would be a decline in the purchase of goods produced out of state.

"In addition, higher-income families appear to consume relatively more goods and services produced in other regions of the country than lower-income families do. ... A tax increase concentrated on higher-income families thus is likely to have a smaller adverse impact on the state economy than other budget-balancing alternatives."

What Other Effects Might Occur from a Broad-Based Tax?

Economists classify a tax as "efficient" when it has little or no effect on economic behavior. For example, taxes are inefficient when they influence consumer buying, investment or labor market decisions or companies' production decisions. Likewise, taxes are more efficient than government spending cuts if they do less damage to the state's economy.

The size of the tax rate may also influence economic behavior. A personal income tax certainly could influence a person's economic decisions by lowering take-home pay, thereby affecting spending and working decisions. The amount of a sales tax also can make a difference in spending decisions. For example, a person who normally buys goods locally may continue to do so at a low sales tax rate. However, a high tax rate may cause the person to purchase the same product on the Internet or by mail order. The Alaska economy would suffer because the expenditure is made out-of-state and the money would not circulate in the local economy.

New Money vs. Old Money?

Finally, any discussion of closing the state's fiscal gap should include a look at "new money" vs. "old (or recycled) money." The more new money can be brought into the state's economy to close the gap, the less damage to Alaska's economic health. Another way of characterizing this is saying if we can export our tax burden, it does less harm to our economy.

Examples of new money are:

- Surplus earnings of the Permanent Fund. This is money not currently circulating through the Alaska economy because it is mostly invested in stocks and bonds outside of the state.
- State tax and royalty revenues from new oil and gas discoveries.
- Taxes generated by new or expanded economic activity.
- Taxes paid by non-residents.
- Federal tax savings from deducting a state personal income tax
- Cruise ship passenger taxes.

Examples of old, or recycled money include:

- Increased excise taxes, such as alcohol and motor fuel taxes. However, some of the higher taxes would be paid by non-resident workers and tourists.
- Sales taxes.
- Personal income tax.
- Reduced Permanent Fund dividends (the loss to Alaska's economy would be reduced by the amount of dividend money that would have flowed out of state in savings or purchases).

It's also worth considering in these discussions the reality of what has been called the "Alaska Disconnect." That is the disconnect between non-petroleum economic development and the state revenues needed to pay for the increased public services demanded by a growing population. Without a broad-based tax, non-petroleum economic development costs more in public services than it produces in revenues to the state. More jobs means more workers and more families and more children in school, and more public expenses with no additional revenues to pay for those services.

For the past 25 years, Alaska has chosen to take its return on the development of non-petroleum industries in the form of private-sector jobs and private profits rather than state revenues to pay for needed public services. This is not sustainable for much longer.

Specific Taxes

Alcohol Taxes

Alaska's alcohol taxes are assessed and collected at the manufacturing and wholesale level, as are alcohol excise taxes in other states. All of Alaska's alcohol tax revenue is deposited into the general fund. Tax collections in Fiscal Year 2001 totaled $12 million.

How Do Alaska's Tax Rates Compare to Other States?

Alaska's alcohol excise taxes date back to 1933, and the rates have not changed since 1983. The tax, which is assessed per gallon at the wholesale level, averages about 4 cents per drink when translated to commonly sized servings.

- Alaska's tax rates are:
  Beer, $0.35 a gallon Wine, $0.85 a gallon Liquor, $5.60 a gallon

- The national median rate is:
  Beer, $0.19 a gallon Wine, $0.60 a gallon Liquor, $3.30 a gallon

- The highest tax rates in the nation are:

Beer	Wine	Liquor
Hawaii, $0.92 a gallon	Florida, $2.25 a gallon	Florida, $6.50 a gallon

The rates shown above, however, reflect only the general excise tax charged in other states. Most states also collect a general sales tax, a specific alcohol sales tax, or an additional excise tax on alcoholic beverages.

Combining all of the state taxes on alcohol, the national median total state tax per $4.00 drink in a bar is:

- Beer, 30 cents Wine, 32 cents Liquor, 37 cents
  This is 7 to 10 times the four cents per drink excise tax rate in Alaska.

How Much Would the State Raise from Higher Alcohol Taxes?

Proponents of higher alcohol tax rates for Alaska talk in terms of a nickel-a-drink or a dime-a-drink increase, which are easier to understand than the wholesale rates on a per-gallon basis. These tax amounts are based on 12 ounces of beer, four ounces of wine and a one-ounce shot of liquor.

For each nickel-a-drink increase in the tax, the state would gain about $15 million a year in new revenue. It's impossible to know how a tax increase would show up at the retail level. Would any of the tax be absorbed by wholesalers, suppliers or retailers, or would the entire cost fall on the consumer? And would businesses use the tax increase as an occasion to raise prices in excess of the higher tax bill?

What Other Issues Should be Considered?

Several issues would need to be addressed in considering a tax increase:

- Should the state impose a "floor tax" on inventory as of the effective date of the tax increase? Such a tax would deter stockpiling of alcoholic beverages at the old, lower tax rate, and could prevent businesses from overcharging customers the higher tax rate on old inventory purchased under the lower tax rates.
- Would the state impose its alcohol tax on out-of-state purchases brought into Alaska? This would mostly involve mail order and Internet orders by individuals.
- Would the state increase its tax enforcement efforts? Alcohol tax collection and audit work consumes the equivalent of just nine-tenths of a position at the Tax Division. A higher tax might justify a stronger enforcement/audit program.

What are the Costs of Alcohol Abuse, and Would a Tax Increase Help?

Alcohol abuse cost the Alaska economy an estimated $453 million in 1999 in criminal justice and protective services, health care and public assistance, traffic accidents and lost productivity, according to a November 2001 report by McDowell Group for the Governor's Advisory Board on Alcoholism and Drug Abuse. Health care costs alone totaled $48 million. Adult and child protective services attributed to alcohol and other drug abuse in Alaska cost an estimated $44 million in 1999.

Research indicates that higher taxes would decrease consumption and, hopefully, abuse, but there is no agreement on the exact relation between price and consumption.

"Research shows that as with other consumer goods, purchases of alcoholic beverages decline when their prices rise," according to a January 2001 report by the National Institute on Alcohol Abuse and Alcoholism. Other studies and reports suggest the same trends, including a 1998 survey of high school seniors that indicated "increasing alcohol prices will decrease consumption in this group, especially among females."

The Center for Science in the Public Interest put numbers to the theories when it reported: "Studies indicate that a 10% rise in beer prices would cause a 3% to 4% drop in sales, with a slightly bigger drop for a similar price increase for wine and liquor." The Center adds: "Younger people are generally more price sensitive, so higher prices should help delay and reduce drinking within this group. A study by the National Bureau of Economic Research concluded "that even a modest tax increase of 30 cents for a bottle of liquor and 10 cents for a six-pack of beer would decrease drinking among young people as much as raising the drinking age by one year."

Motor Fuel Taxes

How Much is the Tax in Alaska?

The state excise tax on motor fuel in Alaska is 8 cents per gallon, one-third of the national median rate for combined excise and state sales taxes. The 8-cent rate dates back to 1961. The state receives approximately $26 million a year from the tax.

How Much is the Tax in Other States?

The median tax on motor fuel in the other 49 states is 24 cents per gallon. That includes motor fuel excise taxes and fees, and sales taxes. The most expensive excise tax states are Rhode Island, 29 cents; Wisconsin, 27.3 cents; Montana, 27 cents; Pennsylvania, 26.6 cents; and Idaho, 26 cents. Georgia's excise tax, at 7.5 cents, is below Alaska, but Georgia adds on a 3% state sales tax at the pump.

The federal tax rate on a gallon of motor fuel is 18.4 cents.

How Much Would the State Raise from Higher Motor Fuel Taxes?

Each 1 cent increase in the state tax would generate an additional $3 million per year for Alaska.

Cruise Ship Passenger Fee

How Much Do Other Cities and Countries Charge?

The Department of Revenue is not aware of any state tax on cruise ship passengers, but municipal fees exist at most U.S. ports including Seattle, San Francisco, Miami and Port Everglades. The fees generally are in the range of $6 to $7 per passenger, although San Francisco charges $9.50 per passenger. Many charge the fee twice per visit — once per passenger getting on the ship and again as passengers get off the vessel. Taxes, or fees, also are collected at most ports worldwide, including Vancouver, B.C., and Caribbean ports.

The tax usually is levied by the port authority or other government agency in charge of port operations, and often is explained as partially covering the cost of general public services provided to the cruise industry and specifically to embarking and disembarking passengers. This is in addition to providing dock and utility services to the vessel, which are covered under specific port charges.

Do Any Alaska Cities Charge a Passenger Fee?

The only significant port of call in Alaska with a municipal passenger fee is Juneau, which enacted its $5 per passenger fee in 2000 after voters approved the new tax in an initiative on the 1999 general election ballot. Juneau received more than $3 million in tax revenues in calendar 2001.

Sitka and Ketchikan have discussed similar fees but have not adopted any such fee.

Who Would Pay the Fee?

The cruise lines pass on passenger taxes, port fees and other such charges to their passengers through a charge listed separately from the advertised price for the cruise, much like airlines show taxes as a separate line at the bottom of each ticket. Consequently, the tax burden of an Alaska passenger fee would be paid by cruise passengers, unless the competitive nature of the business requires some cruise lines to absorb a portion of the fee.

It is possible that the added cost of the new fee might dissuade some travelers from spending as much money as they might otherwise spend on shore excursions, although, for example, a $30 Alaska fee would add just 2% or 3% to the total cost of an average cruise ticket.

How Much Would the State Raise with a Passenger Fee?

Almost 670,000 cruise ship passengers traveled to Alaska in 2001. A state passenger tax could raise an estimated:

- $25 per passenger, $16.75 million a year
- $30 per passenger, $20 million a year
- $50 per passenger, $33.5 million a year

What About the Municipalities?

One issue that would need to be resolved for a per-capita tax would be tax revenue sharing with municipalities. Although Juneau is the only large port of call with a passenger tax, Ketchikan and Sitka have discussed such a tax in recent years. The issue would be the same as for a statewide sales tax: Would the state take over imposition and collection of cruise ship passenger fees and then return a portion to communities, or would the state collect its own tax and allow municipalities to impose their own fees, too? It is possible the cruise lines would prefer to deal with just one taxing authority, rather than watching as the state and multiple communities adopt different tax rates and rules.

Why Don't Most Cruise Companies Pay Corporate Taxes on Cruise Operations?

The Alaska Supreme Court in 1998 gave the state a victory in its ruling that Alaska could collect corporate income taxes on the apportioned profits of foreign-flagged vessels operating in state waters. This case had nothing to do with passenger taxes; it was limited strictly to the issues of corporate income taxes.

After the state won the case, and the right to tax foreign-flagged cruise ships and other foreign-flagged vessels, the legislature adopted a measure exempting such business activity from state corporate taxes.

The Department of Revenue was unable to provide a strong estimate of possible new revenues to the state from the tax victory in court, mostly because we have never seen a corporate tax return from a cruise line. However, we estimated in 1998 that the state could receive up to $10 million a year in corporate tax revenues if allowed to assess the tax. Because of the legislation exempting foreign-flagged vessels from corporate income taxes in Alaska, the smaller, domestic operators have to pay the tax while their large colleagues in the trade are excused.

Permanent Fund Earnings

How Much Money is Available from the Permanent Fund?

The Department of Revenue and the Alaska Permanent Fund Corporation believe the amount of "surplus" realized earnings available from the Permanent Fund over the next decade will average about $250 million per year under the existing statutory framework for calculating earnings and Permanent Fund dividends. However, the actual amount available in any one year will vary enormously — ranging from $0 to more than $500 million, depending on the performance of the financial markets and the mechanics of how the surplus is determined.

Relying on the surplus under existing statute to help pay for public services could be risky. For example, if the surplus for Fiscal 2001 were determined on the basis of current-year realized earnings only, there would have been no surplus available. The Department of Revenue projects the same will be true for Fiscal Year 2002.

What is Percent of Market Value, and is it a Better System?

The Department of Revenue strongly recommends calculating the amount available for distribution each year from the Permanent Fund using a moving average over a five-year period. More specifically, the department recommends the legislature adopt the Percent of Market Value (POMV) approach, rather than realized earnings, to determine the amount of funds available for distribution. Using such a moving average would reduce the wild swings in the amount that would be available each year vs. using only a single-year's earnings to determine the amount available for distribution.

Such a moving average would not be new to the Alaskans. We currently determine the dividend using a moving average based on the fund's realized earnings over five years.

Under the Percent of Market Value calculation as endorsed by the Permanent Fund Board of Trustees, 5% of the Permanent Fund's total market value, as averaged over the past five years, would be available for distribution each year. Assuming the fund's long-term earnings target is about 8%, the payout limit at 5% would ensure that sufficient earnings remain in the Permanent Fund to protect it from inflation.

At a 5% payout, the Permanent Fund, in the median case, would generate more than $1.3 billion a year, on average, between Fiscal 2003 and Fiscal 2008, according to the Permanent Fund Corporation. The earnings — and the dividends — would continue building over time. A $1.3 billion payout split 50-50 between dividends and public services could, for example, fund a $1,050 dividend (assuming 600,000 eligible Alaskans) and still leave $650 million for the General Fund to help pay for public services. Other possibilities include:

- 60% to Dividends / 40% to Public Services, equals a $1,300 dividend and $520 million for public services.
- 55% to Dividends / 45% to Public Services, equals an $1,190 dividend and $585 million for public services.

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FALL 2002

REVENUE SOURCES BOOK

Forecast & Historical Data

STATE OF ALASKA
DEPARTMENT OF
REVENUE

Tax Division

Tony Knowles, Governor
Wilson L. Condon, Commissioner
Dan E. Dickinson, Director
Charles Logsdon, Chief Petroleum Economist

II. OIL AND GAS PRODUCTION OPPORTUNITIES

Oil Production as an Economic Opportunity

Introduction

Promoting resource development was one of the major themes of Alaska's just-concluded election, which prompts several questions. What are the major opportunities for additional oil development over the next decade? What is needed to exploit these opportunities? And if these opportunities are successful, how will they affect Alaska's public finances? Finally, what can state government do to help or, if it makes a mistake, hinder that development?

Oil development in Alaska may someday occur outside the Cook Inlet and North Slope areas, but that is unlikely over the next 15 years. Though small when compared to the North Slope, the health of the Cook Inlet oil patch will continue to be important, especially for the livelihood of Kenai Peninsula residents. However, new oil development opportunities in Cook Inlet are unlikely to significantly contribute to Alaska's treasury. To find that kind of money, we must look north.

North Slope oil production commenced in 1977 and reached a peak rate of just over 2 million barrels per day in 1988. North Slope production then declined for 13 consecutive years to just over 990,000 barrels per day in Fiscal Year 2001. (See Figure 10, Page 37, and Appendix D.) In Fiscal 2002, it increased a small 1.4% to 1,003,343 barrels per day. We now believe that was a one-year exception, and we forecast a steady, modest decline in North Slope production to 955,000 barrels per day between Fiscal 2003 and 2007. On average, over this five-year period, this new forecast reflects a reduction of about 80,000 barrels per day from our spring estimate.

Much of this reduction comes in our lower forecast of heavy-oil production from the West Sak formation in the Kuparuk Unit and the Schrader Bluff formation in the Milne Point Unit. We had anticipated the producers would invest substantially more money to boost production in both fields.

Beginning in Fiscal 2008, new fields coming online should elevate total production back over the million-barrels-a-day level, and we project North Slope production to exceed 1 million barrels a day from Fiscal 2008 through 2012. Production could start down again after Fiscal 2013 unless producers have significant exploration success, which will require the commitment of substantial money to the exploration and development of new fields.

Is there a significant possibility for increases in North Slope oil production over what we have forecast? That's the positive question, but what about the negative? And what are the chances that production levels may fall short of our forecast? The answer to these questions depends in large part on the amount of money exploration and production companies spend to develop oil resources that have already been discovered on the North Slope and to discover additional oil. Those spending decisions depend — in great part — on world oil prices and government regulatory and fiscal policies. The key in all this is that producers need to spend money so that the state can make money from its oil resources.

There is no question that state government policy decisions will affect the level of investment in North Slope oil exploration and development. And state government decision-makers will have to decide what policies are most likely to maximize the public benefit from North Slope production. However, those decision-makers will not all agree upon what constitutes maximum public benefit. Some would no doubt seek to maximize public revenue, while others would favor an increase in the level of private economic activity — including jobs — in place of some potential public revenue.

Finally, state government's take could be set so high that exploration and production companies invest elsewhere than in Alaska. If this happened, an increased government take in the short run could actually reduce Alaska's total take from oil over the long term. On the other hand, a policy of encouraging development by diminishing the government share could also reduce total take. The balance, sought by the host government in every oil province of the world, is to take a healthy share of the profits derived from oil while remaining competitive in the world marketplace for oil and gas investment dollars.

Assumptions and Rules-of-Thumb

Some of the exploration and producing companies with interests on the North Slope announce their capital expenditure plans each year. What do those plans indicate about the likely amount of future production? To answer this question precisely we would need to be privy to internal company information and analysis not available to us. However, equipped with a few rules-of-thumb, an armchair analyst can make a rough translation of the producers' announced capital plans into likely future production.

Here are the assumptions and rules-of-thumb that we use: [1]

- **Prospectivity of the North Slope**. The producers we have talked with tell us the North Slope is still a "world class" geological basin to explore for oil.

- **Finding Costs**. We assume that on average it costs $1 to find a barrel of oil on the slope. [2] This is a weighted average of our estimate of the cost for finding new fields (just over $1 per barrel) and for finding new satellite accumulations near already discovered fields ($0.60 per barrel). Some North Slope producers have a policy to pursue only satellites. Some pursue both new fields and satellites.

- **Reserve Replacement**. Companies trying to maintain a constant level of worldwide production also try to maintain a constant reserve base. Consequently, if a company or group of companies want to maintain the production rate from a particular area (e.g. the North Slope), we would expect them to invest enough in exploration to maintain a relatively constant reserve base in that same area. Therefore, over time, a constant North Slope production level would require exploration expenditures of $1 for each barrel of newly found oil reserves to replace each barrel of production. Companies can also add to their reserves by spending on new technology to turn uneconomic oil into economically recoverable reserves, such as heavy oil.

(1) These rules-of-thumb come from our discussions with the North Slope producers and our review of available literature.
(2) According to Cambridge Energy Research Associates' (CERA's) "White Paper Outlook for Alaska" (November 1999) ("White Paper") at page 12, "The best performers' North Slope exploration costs are currently about $1.00 per barrel…" BP has recently stated it costs them $2.50 per barrel to find oil in Alaska, but they stated that as one reason why they are discontinuing their frontier exploration activity on the slope. Steve Marshall, President, BP Exploration Alaska, Inc. Speech to Fairbanks Chamber of Commerce, March 22, 2002.
(3) Exxon puts the cost of developing Point Thomson's 400 million barrels of reserves at $1.2 billion. BP puts the cost of developing 55 million barrels of Schrader Bluff heavy oil at $150 million. MIX, the enhanced oil recovery project at Prudhoe Bay, cost $160 million for 50 million barrels. There are other rules-of-thumb that some use to derive future production rates from current capital spending: (1) for greenfield development, $15 million to $20 million for every 1,000 barrels per day of peak-rate production; and (2) for infill drilling, $5 million to $7 million for 1,000 barrels per day. These rules-of-thumb are consistent with the $3 per barrel estimate we use in this analysis.

- Development Costs. Once found, we assume it costs an average of $3 per barrel to drill and build the facilities to produce North Slope oil. Cambridge Energy Research Associates (CERA), in its 1999 White Paper on Alaska's development prospects, stated that it costs $2.50 per barrel to develop North Slope oil. However, a survey of recent announcements regarding field developments indicate that the companies' target is close to $3 per barrel. [3]

- Affordable Development. A significant amount of the oil that has been found on the slope cannot be developed for $3 per barrel, but as technological advances are made more of this found oil can be developed economically at $3 per barrel. In the short term, a producer could maintain its current production level by spending just enough to develop found oil. Eventually, however, technological advances will run up against geologic constraints, and the company's $3 per barrel oil will decline unless new fields are discovered. This newly discovered oil will cost the companies' $4 per barrel - $1 to find the barrel and $3 to develop it.

- Minimum Capital Expense. There is a great deal of discovered oil on the slope that has been developed but not yet produced. Even after building the facilities needed to produce that oil, the companies still must spend additional capital over the years to keep those facilities operable and safe. This spending is often called LTO, or "License to Operate" capital, and is in addition to routine operating and maintenance expenses on the slope. An example of LTO capital would be installation of pollution control equipment to meet new government standards. Based on discussions with the North Slope operators, we estimate the annual LTO expense at about 2% of existing and planned total capital expense for the facility. Consequently, we used a North Slope LTO expense of $300 million per year for this analysis. This is a fixed cost, and it is the minimum amount of capital spending needed to recover the reserves already developed and slated for recovery. Companies view LTO as "non-rate" expenditures, or expenditures that are not made to increase proven reserves. Our LTO estimate may include more than some companies would characterize as LTO for accounting purposes.

In thinking about the cost of finding and developing new oil fields, it is important to remember that future oil prices are uncertain. What that means is even when oil prices are high, producers still make their capital expenditure decisions based on average or low prices — they do not go out and spend more money on high-cost projects just because today's prices may be high. The fact is they are reluctant to gamble investment dollars on high oil prices in the future. As a result, these rules-of-thumb, adopted in a low-oil price environment, seem to apply even in times of higher oil prices.

Department of Revenue Production Projections for Discovered Fields

The table on the next page reflects the following: (1) the Department of Revenue estimates of the amounts of original oil in place for all of the fields discovered on the North Slope; (2) the amounts of production from each of these fields through the end of June 2002; (3) our estimates of the amounts of additional oil recovery from each of these fields over the balance of their productive lives; and (4) our estimates of the total amounts of production from each of these fields.

Table 1 . Projected ANS Production from Discovered Producing Fields
Million Barrels

	Original Oil In Place	Production Through FY 2002	Currently Projected Additional Production	Total Estimated Production
Prudhoe Bay (Oil and NGLs)	23,700	10,670	3,400	14,070
Prudhoe Bay satellites (Midnight Sun, Aurora, etc.)	1,400	17	500	517
Lisburne	1,800	140	40	180
Point McIntyre	900	350	170	520
Greater Point McIntyre Area (Niakuk, etc.)	300	110	50	160
Kuparuk	6,000	1,820	1,140	2,960
Kuparuk satellites excl. heavy oil (Tabasco, Tarn, etc.)	400	40	140	180
West Sak (1)	12,000	6	370	376
Milne Point- Kuparuk and Sag River (2)	1,000	150	220	370
Milne Point- Schrader Bluff (1)	1,600	20	310	330
Duck Island Unit (Endicott, Eider, Sag Delta)	1,200	430	170	600
Badami	160	4	2	6
Alpine	1,100	30	460	490
Northstar	300	10	200	210
Subtotal	**51,860**	**13,797**	**7,172**	**20,969**
Discovered non-producing fields				
Alpine Satellites (Nanuq, Fiord, etc.)	395	0	180	180
Liberty	300	0	150	150
Point Thomson and Others (Sourdough, Yukon Gold)	1,400	0	560	560
Sandpiper	150	0	60	60
NPR-A (Rendezvous/Spark)	800	0	400	400
Ugnu (1)	7,000	0	0	0
OCS Offshore (Kuvlum, Hammerhead) (3)	1,000	0	0	0
Subtotal	**11,045**	**0**	**1,350**	**1,350**
Total	**62,905**	**13,797**	**8,522**	**22,319**

(1) These are heavy oil deposits.
(2) Kuparuk refers to the formation in the Milne Point Unit, not the Kuparuk River Unit.
(3) These fields' barrels were not economic to produce in the mid-1990s. For offshore stand-alone developments the minimum economic field size is 1 billion barrels, and each of these fields is smaller than this. However, these fields may become economic to produce if either technological advances allow for lower development costs or the fields can produce as satellites to larger fields.

Historically, North American oil production operations have recovered about 35 percent of the original oil in place from developed fields. Where modern technology, including water flooding and other means of pressure maintenance are employed, the typical recovery rate in the Lower 48 is 40 percent. But we're doing better than that in many fields in Alaska.

If the projections set forth in Table 1 are realized, about 35 percent of the original oil in place in the discovered North Slope fields will be produced. But if we eliminate the amounts attributable to the three heavy-oil accumulations presented in the table (West Sak, Ugnu and Milne Point–Schrader Bluff), the projections in the table reflect an ultimate recovery of 51% of the original oil in place. Our projected recovery from the main Prudhoe Bay reservoir is almost 60%, and technological innovation may improve this recovery rate, depending in great part on how much the producers invest to develop those reserves. A 1% increase in recovery from the Prudhoe Bay field is the equivalent of finding a new field with 237 million barrels of economically recoverable oil.

Getting back to the heavy-oil accumulation at West Sak, Ugnu and Milne-Schrader, these reserves are enormous, amounting to 20.6 billion barrels of oil in place, or almost a third of the original oil in place in all the discovered fields on the North Slope. Unlike the highly productive sandstone formation at Prudhoe Bay, we project that a little over 3%, or 712 million barrels, of this oil will be recovered. This relatively cold, heavy or viscous oil flows poorly and is difficult to extract from the reservoir. The reservoir rock containing these accumulations crumbles easily, causing sand to impede the flow of oil. Viscous oil is also less valuable because it contains a smaller proportion of the lighter, more valuable hydrocarbons found in conventional oil. Technological developments (horizontal wells and jet pumps, for example) have improved the economic feasibility of recovering some of this oil, but most of it will probably remain uneconomic and in the ground.

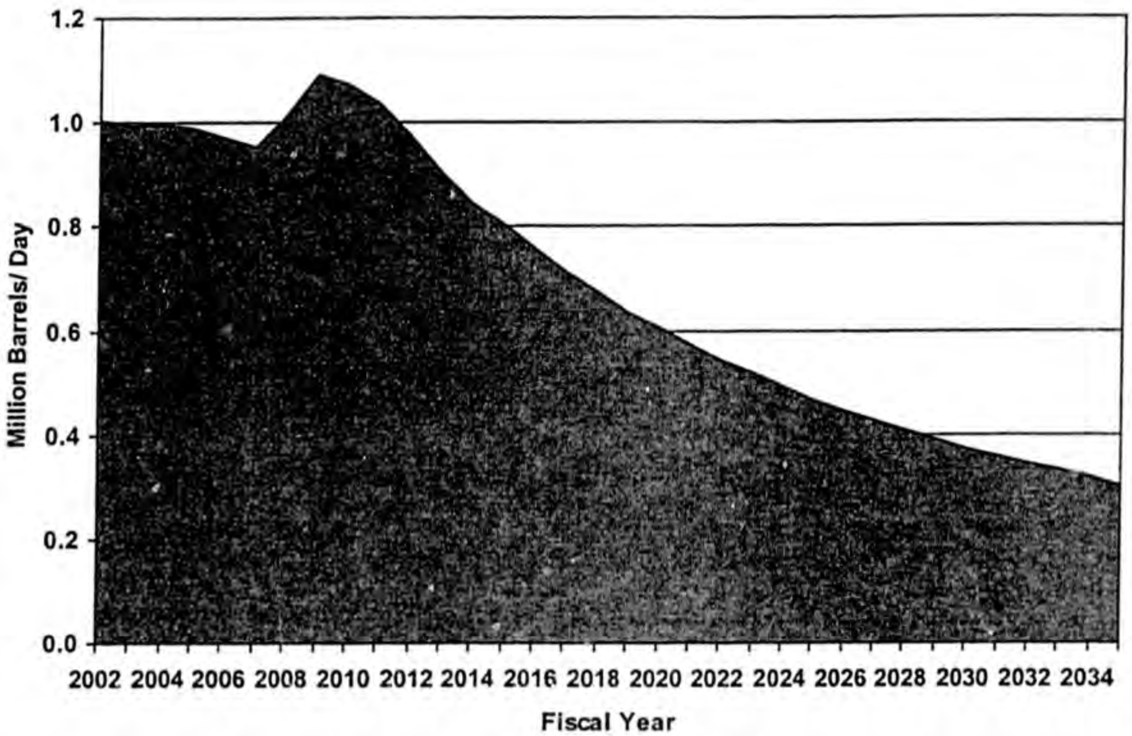
State tax policy could have some effect on whether this oil is produced, but the geology of the reservoir and the cost of extraction have as much to do with production rates as state tax policies.

The estimated production volumes set forth in the column "Currently Projected Additional Production" in Table 1 match (with one small exception) the production volumes the Department of Revenue would normally include in its periodic revenue forecasts. This column includes the department's production estimates from already-discovered fields. Our periodic revenue forecasts, for the most part, also reflect only production from discovered fields. However, where particular circumstances lead us to believe current exploration activity is very likely to result in new production within the next five years, we include estimated production from those undiscovered fields in our forecast.

In this forecast we have included production from as-yet-unverified Kuparuk satellite prospects. The producers have explored and continue to explore in the Kuparuk area. They have enjoyed a high rate of success in finding Kuparuk satellites, and they can bring these satellites on line in three years or less, given the available facilities at Kuparuk. Therefore, we reasoned that to leave these barrels out of the short-term forecast would understate likely production. This forecast includes 99 million barrels from these Kuparuk satellites, with production beginning in Fiscal 2005 at 5,000 barrels per day and peaking in 2007 at 20,000 barrels per day.

That's really what most people look for in our spring and fall production forecasts — how much oil will be produced each year. To arrive at those projections, we take the total production volumes in the "Currently Projected Additional Production" column from Table 1 and allocate those volumes year-by-year to reflect our estimate of the time when the oil will actually be produced. Figure 1 on the next page reflects this production profile. See also Table 8, Page 37; Table 20, Page 60; and Appendix D.

Figure 1. Department of Revenue ANS Production Forecast



The Department of Revenue estimates there could be 8.5 billion barrels of additional production from currently discovered North Slope fields (Table 1). Approximately 3.8 billion of those 8.5 billion barrels could be recovered with only those investments needed to preserve the integrity and safety of the facilities (the LTO investments referred to previously).(4) Production of the other 4.7 billion barrels would require significant additional investment. Table 2 on the next page reflects these amounts field by field.

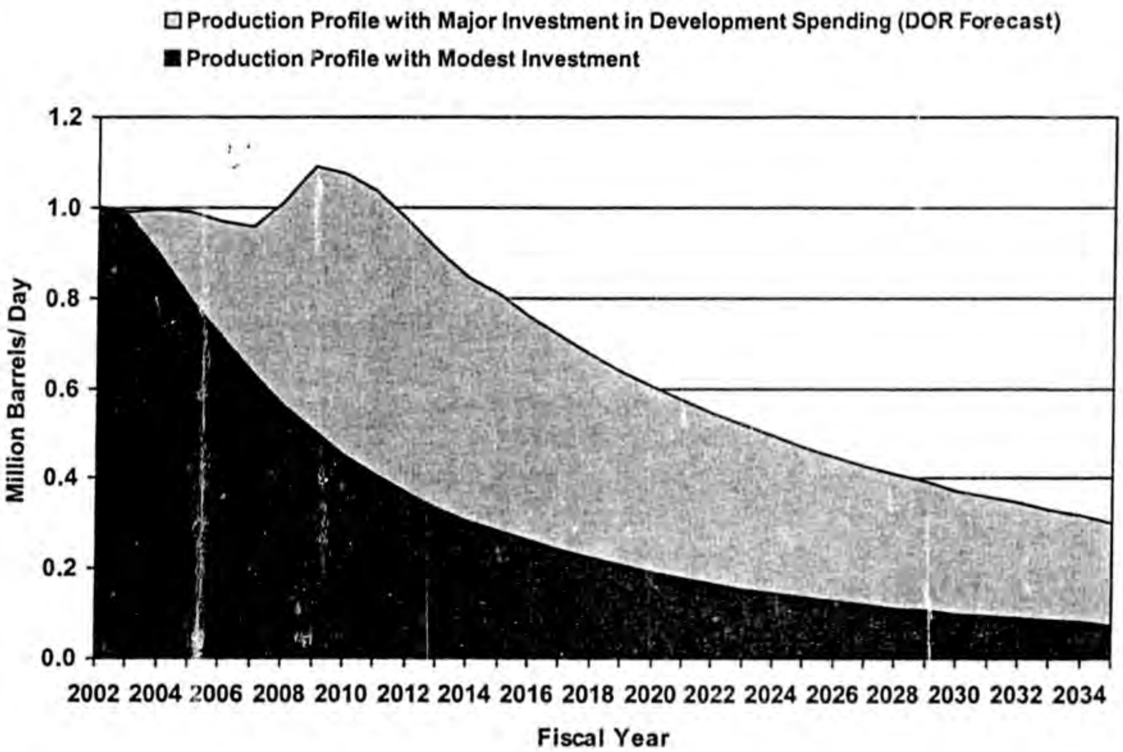
Figure 2 on Page 16 reflects these amounts by year. Clearly then, about one-half of the oil in this forecast will require major additional investment. If that investment is not made, is delayed, or is less than anticipated, then production will fall short of what we forecast.

(4) We derived this 3.8 billion barrels as follows: 1) For fields on decline, we derived a reserve amount and a corresponding production profile for this moderate investment case by first eliminating the reserves and production from anticipated development drilling and EOR/facility expansion projects. Then, we calculated an initial field decline rate by looking at production from each field as a whole (or in some cases at an isolated group of wells in that field) during a period of relatively low investment in that field or field area. We assumed the decline would be exponential (a constant year by year percentage decline) rather than hyperbolic (percentage decline slowing over time); 2) for newer fields not yet on decline, we used a lower-end reserve number in estimating a production profile; and, 3) finally, we assumed no new fields would be discovered and brought online in a moderate investment world.

Table 2. North Slope Remaining Oil Reserves Categorized by Investment Required
Modest Additional Investment orMajor Additional Investment
Million Barrels

	Remaining Reserves Recoverable with Modest Additional Investment	Additional Reserves Recoverable with Major Additional Investment	Total Possible Remaining Reserves from Both Modest and Major Investment
Producing Fields			
Prudhoe Bay (Oil and NGLs)	1,400	2,000	3,400
Prudhoe Bay satellites (Midnight Sun, Aurora, etc.)	160	340	500
Lisburne	40	0	40
Point McIntyre	130	40	170
Greater Point McIntyre Area (Niakuk, etc.)	50	0	50
Kuparuk	850	290	1,140
Kuparuk Satellites excl. heavy oil (Tabasco, Tarn, etc.)	140	0	140
West Sak	50	320	370
Milne Point- Kuparuk and Sag River	170	50	220
Milne Point- Schrader Bluff	120	190	310
Duck Island Unit (Endicott, Eider, Sag Delta)	130	40	170
Badami	2	0	2
Alpine	380	80	460
Northstar	130	70	200
Subtotal	**3,752**	**3,420**	**7,172**
Discovered Non-Producing Fields			
Alpine Satellites (Nanuq, Fiord, etc.)	0	180	180
Liberty	0	150	150
Point Thomson and Related Fields (Sourdough, Yukon Gold)	0	560	560
Sandpiper	0	60	60
NPR-A (Rendezvous/Spark)	0	400	400
Ugnu	0	0	0
OCS Offshore (Kuvlum, Hammerhead)	0	0	0
Subtotal	**0**	**1,350**	**1,350**
Total	**3,752**	**4,770**	**8,522**

Figure 2. ANS Production Forecast
Modest Investment vs. Significant Investment



New Discoveries

According to the most recent assessments by the U.S. Geological Survey, new discoveries in five areas could significantly add to North Slope reserves within the next few decades: (1) the National Petroleum Reserve-Alaska (NPR-A), (2) Arctic National Wildlife Refuge (ANWR), (3) Central North Slope, (4) Eastern Thrust Belt, and (5) Beaufort Shelf. [(5)] Discovery and development of these potential reserves will depend on oil prices, Alaska's competition for oil exploration investment dollars worldwide and, in the case of ANWR, congressional action.

NPR-A.

NPR-A probably contains 9.3 billion barrels of technically recoverable oil, according to the Geological Survey's 2002 assessment of the area. However, the federal agency believes this oil is mostly in relatively small accumulations of 32 million to 256 million barrels. They do not believe NPR-A contains a field as large as Kuparuk (6 billion barrels of original oil in place), let alone one the size of Prudhoe Bay (over 23 billion barrels of original oil in place). Another disadvantage is that USGS believes NPR-A's oil is spread out in multiple accumulations the size of Alpine (429 million barrels), Tarn (70 million barrels) and Nanuq (40 million barrels). These fields, they say, are scattered over an area of 36,000 square miles.

(5) The Minerals Management Service (MMS) made this assessment in 2000.

Due to the small size of the oil reservoirs and the high cost of transporting oil from those reservoirs to market, USGS estimates that NPR-A's reserves are uneconomic at West Coast ANS prices of $20 a barrel or less. However, at a West Coast price of $22 per barrel, 1.3 billion barrels would be economically recoverable. If West Coast ANS prices were $25 per barrel, 3.7 billion of the 9.3 billion barrels would be economic.

In addition to anticipated but undiscovered oil, NPR-A contains some already discovered oil. ConocoPhillips last year announced a discovery on the east side of NPR-A. The Department of Revenue believes that discovery will yield 400 million barrels of recoverable reserves from multiple accumulations, and we have included these barrels in our forecast. These 400 million barrels are included in the estimate of 1.3 billion barrels of economically recoverable oil from NPR-A at $22 a barrel. We forecast production from this discovery to begin in Fiscal 2008 at a rate of 30,000 barrels per day and peaking at 95,000 barrels per day in 2011. Meanwhile, ConocoPhillips plans to continue drilling exploratory wells in NPR-A.

ANWR.

Though the USGS estimates that ANWR contains only slightly more technically recoverable oil than NPR-A (10.3 billion barrels vs. 9.3 billion barrels), ANWR's oil is probably contained in larger reservoirs, according to the USGS. For that reason, USGS believes the ANS West Coast price would have to fall below $16 for all of the projected ANWR reserves to become uneconomic. At $22 per barrel, USGS believes 4 billion barrels of ANWR reserves would be economic (vs. 1.3 billion for NPR-A at the same price). However, ANWR has major hurdles to overcome, including congressional approval, environmental impact studies and lease sales before any exploratory wells could be drilled. Thus the U.S. Energy Information Agency estimates that nine years will pass between congressional approval for oil drilling in ANWR and first production.

Adding New Discoveries to Our Production Forecast.

Using the Geological Survey's assessment of North Slope oil potential and assuming a long-term West Coast price of $22 per barrel, the following table reflects the USGS projection of economically recoverable reserves from future North Slope discoveries.

Table 3. USGS- Estimated Economically Recoverable Reserves From New North Slope Discoveries at $22 per barrel ANS Price Millions of Barrels

Undiscovered Fields	Reserves
NPR-A Net of Rendezvous	900
Central North Slope Satellites	1,500
Eastern Thrust Belt and Foothills	900
ANWR	4,400
Beaufort Shelf Federal Offshore	2,600
Total Undiscovered	**10,300**

BP recently announced it was using a Brent price of $16 per barrel to evaluate the economic feasibility of its oil production investments worldwide. This price closely approximates a U.S. West Coast ANS price of $16 per barrel, and is slightly below the long-term average price for North Slope crude over the 15-year period 1986 through 2000. Other North Slope producers have not officially announced the oil prices they are using to evaluate the feasibility of new projects. However, we believe some are using a price that is closer to the price the Department of Revenue is projecting in this forecast.

For several years the Department of Revenue has consistently forecast that ANS prices would continue to maintain the long-run average of $16 to $17 per barrel that persisted from 1986 to 2000. As we explain later in this forecast, we are changing our long-run outlook and we are forecasting a substantial increase in the long-run delivered West Coast price of ANS to $22 per barrel. If we are correct in making this change, and if exploration and production companies interested in the North Slope were to base their investment decisions on this higher price, then we believe the production profile reflected in Figure 3 on the next page would be an optimistic — but perhaps achievable — target. We have not included any production from ANWR in this profile because congressional action is required before new exploration could commence there.

Attracting and Monitoring Investment Dollars.

Additions to North Slope production can come in two ways: 1) recovering a greater proportion of the oil in already discovered fields, or 2) discovering new fields or satellites to discovered fields. Over the next decade we project that adequate spending on discovered fields would maintain North Slope production near the million-barrels-a-day level. To keep production at or above a million barrels a day in the following decade, however, companies will have to discover new fields and new satellites to existing fields this decade. Then as discovered field production spending declines, companies will have to spend more money to bring production online from new satellites and new fields.

The figure on the next page illustrates the relationship between investment dollars spent to find and develop oil on the North Slope and the vitality of the oil industry in Alaska over the next two decades and beyond.

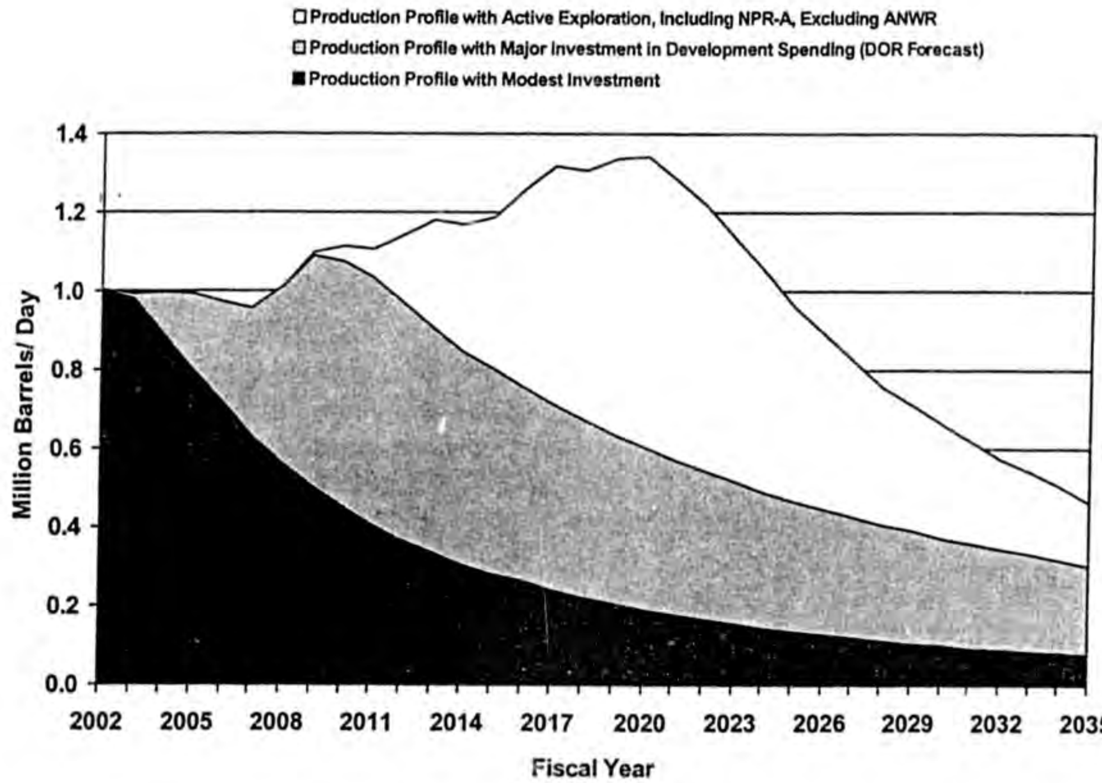
- If North Slope producers invest only at the level required to maintain the safety and integrity of the current production infrastructure, the dark-colored dotted area reflects the likely production profile.

- If the companies involved invest significantly to produce oil that has already been discovered, then the production forecast reflected by the light and dark dotted areas is, we believe, the likely profile. Our current revenue forecast is based upon this production profile.

- If immediate, substantial, successful and continuing exploration occurs, the top line volume profile — or more — may be attainable.

- Finally, even if exploration investments and successes are less than these optimistic hopes, unexpected additional discoveries would add to our forecast projections.

Figure 3. ANS Production Forecast
Modest Investment vs. Significant Investment vs. New Discoveries



For discovered fields, we believe it will cost $3 per barrel to drill the necessary wells and provide the infrastructure to produce the additional 4.7 billion barrels of discovered North Slope oil requiring substantial investment. (These are the 4.7 billion barrels of the 8.5 billion barrels already discovered on the slope that require significant investment, as opposed to the 3.8 billion barrels that could be produced with more moderate investments in the operations, safety and integrity of the facilities.) Therefore, to fully replace the 365 million barrels of reserves (1 million barrels per day) produced each year, the companies must spend around $1.1 billion per year ($3 per barrel x 365 million barrels).[6] In addition, the companies must spend $300 million per year in LTO capital just to preserve the safety and integrity of their facilities and to maintain a base flow of oil.

For undiscovered fields, and to maintain at least a million barrels a day of production in the following decade, new fields will need to be discovered this decade at a projected finding cost of $1 per barrel.

(6) As development spending on discovered fields declines, development spending on newly discovered fields must increase to maintain production levels.

Therefore, to find most of the 6 billion of possible new-field barrels estimated by the Minerals Management Service and USGS, the companies must spend $300 million to $365 million per year (7) in exploration spending at NPR-A, the Central North Slope satellites, Eastern Thrust Belt and foothills, and Beaufort Shelf. That's in addition to the $1.4 billion per year in ongoing development spending on past, present and future discovered fields.

In sum, to reach our most optimistic forecast, the companies will need to spend $1.7 billion to $1.8 billion a year in capital spending. (These investment amounts are only for exploration and development on the North Slope; they do not include downstream investments in the Trans-Alaska Oil Pipeline or marine vessels).

What Do We Know About Current Investment Levels on the North Slope?

ConocoPhillips reports its investments in Alaska in its annual 10K statements filed with the Securities and Exchange Commission and in its annual reports to shareholders. While BP does not separately reports its Alaska investments in its annual reports to securities regulators or its shareholders, it has publicly announced its investment plans for its North Slope operations. ExxonMobil neither separately reports nor publicly announces the amounts it plans to invest in its share of North Slope operations. Since all of ExxonMobil's current North Slope operations are conducted in partnership with other companies and since those partners make public the amount of their Alaska North Slope exploration and development investments, we believe it is possible to derive a reasonably close approximation of ExxonMobil's North Slope investments. Other companies currently active on the North Slope - ChevronTexaco, Anadarko and EnCana — publicly disclose the amounts of their North Slope capital spending programs.

From the information we have been able to compile, the Department of Revenue estimates that over the three-year period 2000-2002 the pertinent companies averaged $1.4 billion in annual exploration and production investment on Alaska's North Slope. This is $300 million to $400 million below the annual investment level we believe is required to achieve the top production profile reflected in Figure 3 on Page 19. Although $300 million to $400 million may represent only a 20% shortfall in our back-of-the-envelope estimations, much of the deficiency is in exploration spending. Lack of exploration spending makes our production forecast for as-of-yet-undiscovered barrels highly speculative.

It looks as though North Slope exploration and production investment for the current year will be about $1.2 billion. This is a 20% drop from spending in the years immediately proceeding 2002. Certainly, the completion of new facilities at Northstar and Alpine account for most of that reduction in 2002. Still, we believe companies are spending less in both development and exploration than they need to replace current production on the schedule we have forecast.

The three major North Slope producers currently take different approaches to adding to their reserve and production base on the North Slope. ConocoPhillips has an active wildcat exploration program and is actively exploring NPR-A. It also has an active satellite exploration program. BP has almost completely abandoned North Slope wildcat exploration, but it has made a significant commitment to the application of new technology to its heavy-oil interests in the Milne Point-Schrader Bluff reservoir and to search for satellite accumulations near the major producing reservoirs. ExxonMobil, it would appear, is seriously moving ahead with the potential development of the Point Thomson field. If that field is developed, BP, ConocoPhillips and ChevronTexaco — as partners in that field — will have to share in that investment. Other than Point

(7) Our most optimistic forecast has production declining below a million barrels a day in 2023. The $300 million of exploration spending postpones the decline another decade. To discover enough barrels to totally replace the 365 million barrels of reserves produced each year will take at least $365 million a year.

Thomson, ExxonMobil, like BP, is missing from frontier exploration and development on the North Slope, although it continues to pay its partner share in Prudhoe Bay production investments and satellite exploration there.

Great Expectations.

To maintain — and with luck increase — Alaska's North Slope oil production at a million barrels per day, this analysis leads to the conclusion that for each barrel leaving the North Slope, $5 must come back to pay for new exploration and development. Is this a realistic expectation? Figures 4 and 5 on Page 23 provide one perspective for thinking about this question.

These two figures depict the per-barrel free cash flow available from North Slope production under two different price scenarios using our current forecast of North Slope costs in Fiscal 2008, the first year we expect production from NPR-A. The costs reflected for the Explorer-Producer would all be actual out-of-pocket costs assuming the company has no ownership interest in feeder pipelines, TAPS or marine tankers. The Integrated-Producer could receive as additional free cash flow roughly $2 per barrel as a consequence of its ownership interests in pipelines and tankers.

At a $22-per-barrel West Coast ANS price, the free cash flows attributable to North Slope production for both the Integrated-Producer at Prudhoe Bay and the Explorer-Producer in NPR-A would be about $7.30 per barrel. We need to hope they will invest more than two-thirds of that amount in new exploration and production if we are to enjoy the benefits of million-barrels-per-day production after 2010. At a $17.70-per-barrel West Coast ANS price (the average price from 1986 to the present), the per barrel free cash flow attributable to North Slope production operations for both hypothetical producers would be about $5.25 per barrel. A $5-per-barrel exploration and production reinvestment would consume almost all of this projected free cash flow, leaving very little to pay interest or dividends for the capital invested in North Slope production operations.

Looking at it coldly from the perspective of the investor, after setting aside money for reserve replacement through exploration and development, there is roughly $2.25 left over from $22 oil to pay interest and dividends. But at a price of $17 per barrel, after subtracting for reserve replacement, the investor essentially gets nothing. It is clear that Alaska needs world oil markets to forget the $17 average price of the past 15 years.

What about new entrants and investors in Alaska? They must bring hundreds of millions of dollars raised from production or investment elsewhere to Alaska. Presumably, they believe Alaska will be a better investment than their alternatives, including the original source of the cash. We must also recognize that the current major investors in Alaska are worldwide, integrated producers evaluating broad portfolios of opportunities. Although we can encourage them to reinvest in Alaska, movement of capital between projects and regions is one of the economic advantages of a large integrated company.

As Alaska matures, companies already producing here will probably require that Alaska operations are positive or at least cash neutral. That is, Alaska oil producers should not expect infusions of money from parent companies but must pay for future opportunities from their own Alaska operations. On the other hand, new entrants must be willing to accept periods of negative cash flow while they explore and develop before any oil — and money — starts to flow.

What Can the State Do to Make This Investment More Likely?

- **Require the Investment.**
  The state could write investment or work commitments into future oil and gas leases, obligating leaseholders to those commitments. If the company doesn't do the work, the state could either take back the lease or require the leaseholder to allow another company to step in and do the work. But such lease terms would probably reduce both the price and marketability of future leases. The state cannot unilaterally change the terms of existing leases.

- **Provide Incentives Through Tax Deductions or Tax Credits.**
  Although there are some nuances, fundamentally the more the government takes, the less there is to reward industry for making investments. Consequently, the lower the government take, the more likely the producer or explorer will invest. The incentive, if it is optimally structured, may lower the government's short-term take with the hope of increasing the long-term public benefit, or it may maintain the current level of total tax revenues while shifting the burden among producers.

  The proceeds from producing oil in Alaska are taxed the same whether they are reinvested in Alaska or elsewhere in the world. The state could modify its production tax or income tax laws to provide a credit or a deduction for reinvestment in Alaska exploration or production. Alaska is particularly alone among major oil producers in not treating oil dollars that are reinvested here more favorably than oil dollars invested elsewhere.

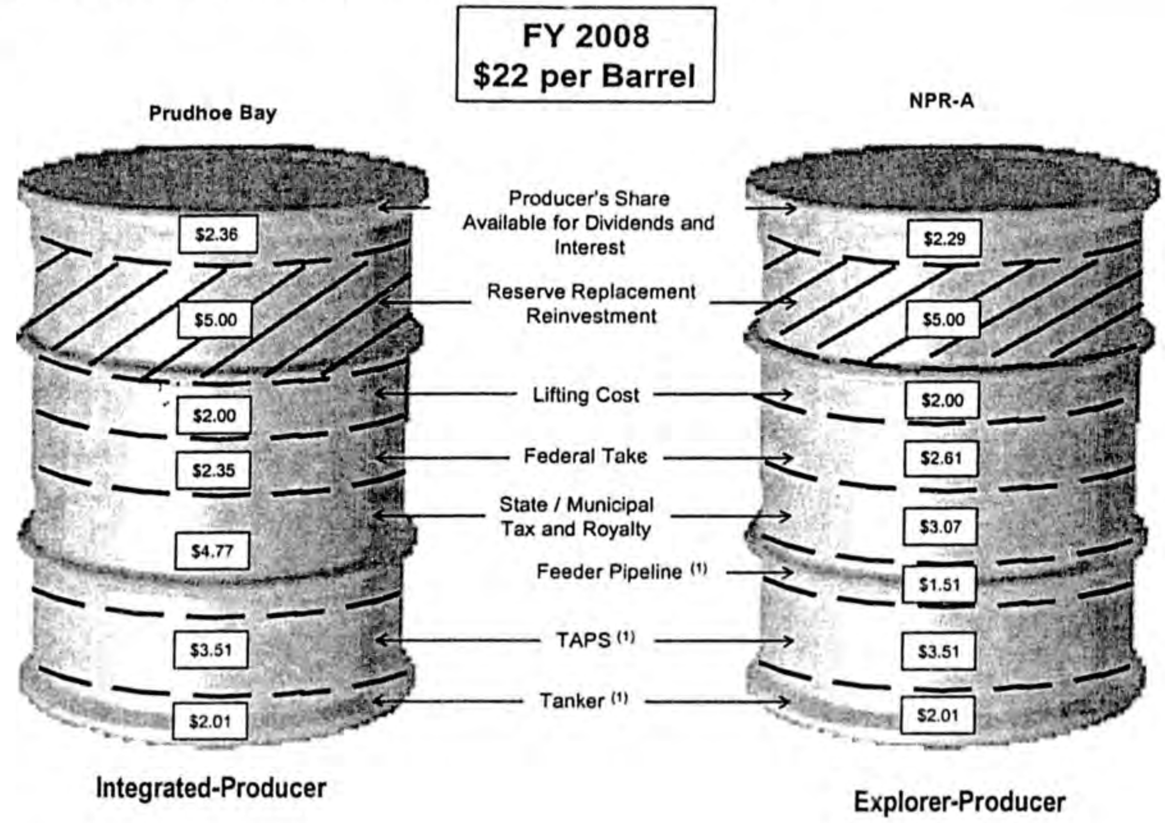
- **Make Alaska's Fiscal System Less Regressive.**
  When oil prices are very low, the state and federal government together take more than 100 percent of the profit from Alaska oil operations. When oil prices are high, the total government take from Alaska oil operations is low compared to comparable oil-producing provinces. This occurs because three major features of Alaska's fiscal system — the 20-mill property tax, the production tax and the royalty provisions in state leases — are not based on profits. Even when prices are so low that oil production operations are unprofitable, the state continues to receive a share from some or all of these sources.

  The state could modify its fiscal system to make it less regressive and thus share the risk of low oil prices and earn more when oil prices were high. Properly structured, such a modification could yield more total revenue for the state while at the same time making Alaska a less risky place to explore and produce oil.

  A less regressive, more progressive fiscal system would require fiscal discipline by the state government, however. When oil prices were high, the state would have to save for the time when oil prices were low. One need only look to the Province of Alberta to appreciate the difficulties governments can encounter in managing huge swings in oil and gas revenue caused by a very progressive fiscal system.

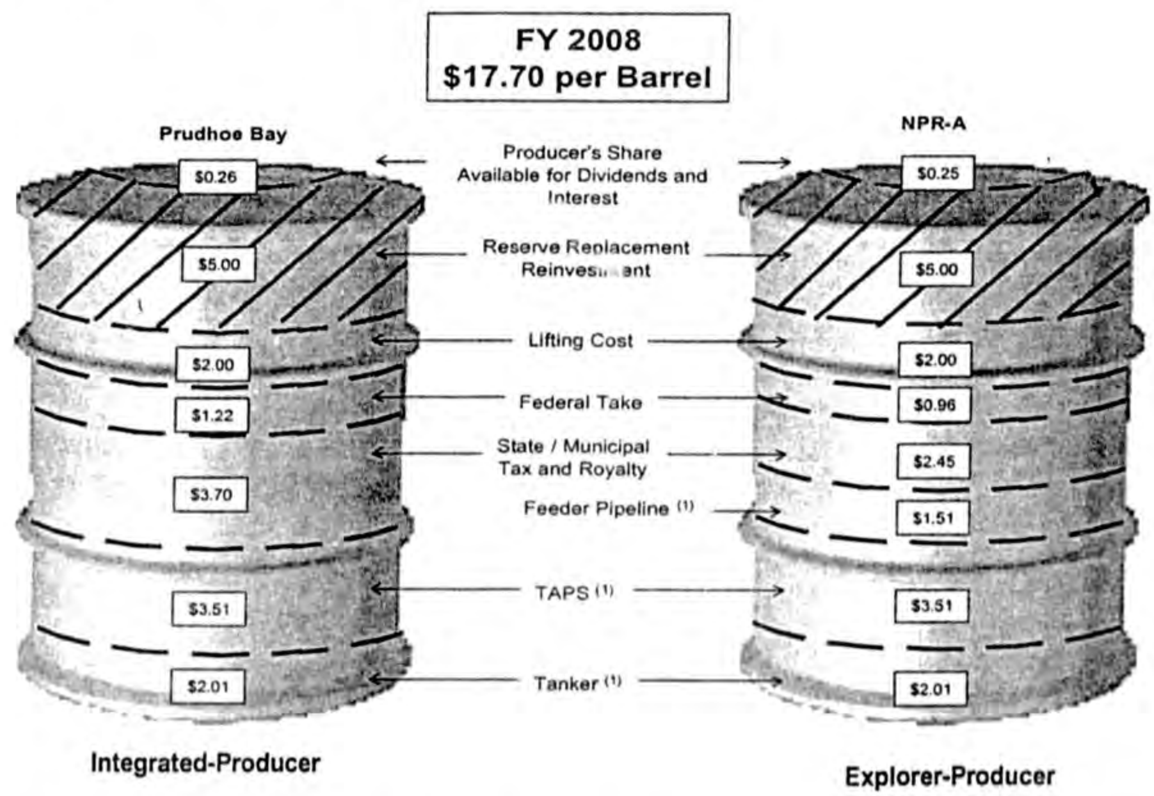
- **Eliminate the Structural Deficit in Alaska's Public Finances.**
  Current or would-be investors in the oil exploration and production opportunities in Alaska are necessarily going to be less willing to invest here if they believe they will be the ones called upon to plug our structural deficit with a "gap tax."

Figure 4. ANS Cash Flow With $5 Reserve Replacement Reinvestment



(1) These are notional tariff values and include capital recovery so an owner of the asset may recapture some of these costs.

Figure 5. ANS Cash Flow With $5 Reserve Replacement Reinvestment



(1) These are notional tariff values and include capital recovery so an owner of the asset may recapture some of these costs.

Gas Production as an Economic Opportunity

North Slope

Alaska's North Slope contains large amounts of natural gas. Prudhoe Bay holds approximately 24 trillion cubic feet (tcf), with 8 tcf at Point Thomson. Other discovered sources make for 35 tcf total discovered gas, and geologists estimate there may be as much as 100 tcf. Commercializing North Slope gas is one of the state's largest potential economic development prizes. A 100-tcf gasline project at 4.5 billion cubic feet (bcf) per day would support a vibrant gas exploration and production industry in Alaska, providing $400 million to more than $1 billion a year in public revenue for almost 60 years, depending on the cost of the project and gas prices.

Unfortunately, the gas has not been commercialized due to its distance from markets and the cost risks of arctic construction. Sponsors estimate a gas pipeline to the Midwest would cost $20 billion. This distance creates high transportation expenses, adding to the cost of the gas in a competitive marketplace. If gas prices in the markets cannot cover the expenses and a reasonable profit, the project will not be feasible. Potential project sponsors have looked at lowering the unit costs by increasing the size of the project to ship more gas, but a large project creates its own set of risks, mainly the potential for a large loss if unfavorable events unfold.

The project faces two main risks: (1) the construction cost overrun risk, and (2) the commodity price risk, the latter probably being more problematic. The pipeline will only be financed under conditions where the sponsors agree to pay the tariff regardless whether the gas is shipped. That is the only way investors would agree to loan money for the pipeline. Those "ship-or-pay" contracts mean that even if gas prices are less than the full tariff, the producers would still have to pay the tariff — and lose money on each gas molecule they sell.

Part of the problem for a gasline is that the transportation costs (the pipeline tariff) eat up about 75% c the value of the gas when it's sold coming out of the line. That doesn't leave much margin to cover production costs, taxes, exploration and development costs and profit if gas prices take a tumble. The story is much different for North Slope oil, where the transportation costs consume only 25% of the value when oil prices are in the $20 range.

Because of the slimmer margin for natural gas, the commodity price risk is a problem for the Alaska project. Project sponsors and investors need to focus on what gas prices will be for the next 30 years, the expected term of bonds sold to finance the project.

In any market for any commodity, consumers will purchase the lowest-cost item. Ordinarily, markets evolve by having lower-cost supplies enter the market first, followed by higher-cost supplies as needed to meet demand. There can be only one price in a commodity market, thus the market price for the entire supply will be set by the marginal supply of the last quantity to enter the market. The price of the marginal supply, and thus the market price itself, will be the cost of producing that last unit to enter the market.

In the situation where a specific quantity (such as natural gas) is already in the market, and a lower-priced one subsequently presents itself, consumers will naturally gravitate toward the latter — and the former must match the lower price to stay competitive. This is the challenge for North Slope gas.

Accordingly, a North Slope gas project will not be economically feasible if the gas cannot be transported to market for less than what new competing gas supplies will cost. The market will not pay above the lowest-cost new supply available. Therefore, the feasibility of the project depends largely on how potential sponsors view competing supplies from competing sources. The commodity price risk revolves around whether there are material quantities of lower-price gas to meet the market demand.

Most financial resources recently have focused on a pipeline through Canada, splitting off to the Midwest and West Coast markets, as the most promising option. The potential numerous sources of competing supplies make this a risky project. These could come, for example, from the deepwater Gulf of Mexico, liquefied natural gas (LNG) imports from the Atlantic or Pacific Basin, coal-bed methane, or from new technologies brought on by higher prices, just to name a few. Accordingly, an Alaska project needs to shed — or share — some risks before ever becoming a reality. Certainly, anything that creates more risks is going in the wrong direction.

Although lots of people are working hard to reduce the project risks, one (or both) of two things appear critical if the project is to be economically attractive to sponsors and investors:

- The sponsors and investors must hold the view that Lower 48 gas prices will be high enough in the years ahead so that North Slope gas will be profitable.

- Efforts by the state and/or federal governments to reduce the project risk must be successful. These efforts could include a price support or other means of sharing the commodity price risk, similar to the tax credit provision of the federal energy bill that passed the U.S. Senate this past session but died with adjournment.

Some people believe the best option is to pipe the gas to tidewater, liquefy it, and ship it to Pacific Rim markets as liquefied natural gas (LNG). This may be more risky than a pipeline to the Lower 48. The Pacific Rim is extremely bountiful in gas supplies at tidewater that do not have to bear the cost of an expensive 800-mile arctic Alaska pipeline to reach tidewater. This puts Alaska at a significant competitive disadvantage to other producers with gas at tidewater.

Even if the LNG were to go to Mexico's Baja Peninsula and then by pipe into California, as some have suggested, Alaska still would be at a price disadvantage. LNG tanker costs are relatively insignificant compared to the 800-mile pipeline, and the pipeline disadvantage would more than offset any shipping advantage Alaska might otherwise have over LNG supplies from Indonesia, Australia or East Timor. Moreover, at this time there are no LNG receiving terminals or even plans to start construction on the Baja, where environmental concerns are apparent. If an LNG project were smaller than 4.5 bcf/day, state revenues would be reduced accordingly.

Despite the odds, many Alaskans have not given up on an LNG project. More than 60% of Alaska voters on November 5 approved a ballot measure to create the Alaska Natural Gas Development Authority to acquire and sell gas and build, own and operate a natural gas pipeline for LNG export. It is not clear that the authority reduces any of the risks that are a barrier to development and may, in fact, transfer many of those financial risks to the state. Supporters of the ballot measure say the project would cost $12 billion for 2 bcf/day.

Finally, another option for North Slope gas commercialization is a process where gas can be converted to high-value liquids and marketed with the oil. The technology for this "gas-to-liquids" process (GTLs) is still in the pre-feasibility stage, and at this time it would be prohibitively expensive to use on the North Slope.

Cook Inlet

Annual gas consumption and production in Cook Inlet over the past 20 years has been fairly steady at about 200 billion cubic feet (bcf). Cook Inlet currently has about 2.5 tcf of reserves, or a little over 10 years of consumption. Consumption is allocated approximately 15% to power generation, 15% to gas utilities, 40% to liquefied natural gas (LNG) exports to Japan from the Phillips' terminal at Kenai, and 30% to ammonia/urea production at Agrium's Nikiski plant.

Most Cook Inlet gas was discovered in a few very large fields in the late 1950s and 1960s. Since consumption has not changed materially over this period, the years of remaining reserves have decreased notably over the past several years. Also, there have not been large discoveries in recent years. This has caused many people to be concerned that Cook Inlet is running out of gas.

This, however, may be a premature conclusion. The large discoveries of gas years ago created a supply situation such that new supplies were not needed and any new discoveries would go unsold for years. Thus there was little incentive to look for gas. In the Lower 48, for example, annual discoveries have nearly offset annual consumption, and proven reserves have stood relatively constant at eight years. Companies do not need to invest in developing more new supplies than are needed to keep pace with consumption.

Accordingly, increased exploration is beginning to occur in Cook Inlet to find reserves to meet future demand. There is a large inventory of prospects, and it remains to be seen which ones produce how much gas.

When Would the Constitutional Budget Reserve Fund (CBRF) Fund Balance Fall to $1.0 billion for Different Combinations of State Spending and Oil prices

Annual State Budget	$18/bbl	$22/bbl	$25/bbl	$28/bbl	$30/bbl
$2.2 billion	Aug-05	May-06	Oct-07	Apr-08	May-10
$2.3 billion	Jul-05	Feb-06	Jun-06	Apr-07	Aug-08
$2.4 billion	Jun-05	Dec-05	Feb-06	Oct-06	Jul-07
$2.5 billion	May-05	Oct-05	Nov-05	May-06	Dec-06

Notes: 1. Based on Fall 2003 Revenue Forecast assumptions (except price)
2. Estimates use the Alaska Fiscal Policy Driver Model

P050

FALL 2000 REVENUE SOURCES BOOK

Alaska Department of Revenue
Tax Division

Tony Knowles, Governor
Wilson L. Condon, Commissioner
Dan E. Dickinson, Director
Charles Logsdon, Chief Petroleum Economist

II. ALASKA'S FISCAL OPTIONS

Sources of Government Revenue and the Alaska Economy

The Constitutional Budget Reserve Fund — like the Permanent Fund dividend program — has become a major component of the state's economy. The budget reserve fund contributed almost $4 billion to Alaska's economic base during the 1990s, and was especially important during the low oil prices of FY 1999 when it added more to the state's total personal income than even the dividend program.

And just as you would weaken the economy if you removed or reduced the annual dividend program, you will cause the same problems if no suitable replacement is found before the CBRF runs out of money.

Alaska's economic base depends on "new" money circulating throughout the economy — money from outside that comes in, increases purchasing power, and moves around. New money that comes into the state generates additional income when it is spent, either by businesses or by workers. It can start out as wages or it can begin as payments for goods that then works its way into personal income as it's paid out as wages.

The important thing about the economic base is that the money comes from outside the state, brought into Alaska to pay for goods and services. It could be money from oil, tourism, seafood or timber sales; military or federal civilian payroll; or oil taxes and royalties paid to the state. A dollar paid to the state in oil taxes or a dollar earned by the state from oil royalties could move around the same as a dollar paid in wages by an oil company. The state treasury is simply a stopover before the tax dollar goes out as public employee wages, as a construction contract, an office supply order or other purchase.

Eventually, most every dollar brought into Alaska will find its way back out of state to purchase goods, raw materials or services. The number of times the money circulates through the state's economy before it leaves is called the multiplier effect.

In looking at the state's economic base and the new money that builds that base, we see that here, too, the CBRF is similar to the Permanent Fund dividend program. The dividend program is new money because the cash for the annual checks comes mostly from earnings on investments outside Alaska. It's not simply recirculating money already here. The same is true for the CBRF.

The money in that account came from taxes and royalties paid by oil companies — new money to Alaska, not money already in the pockets of Alaskans or the cash registers of local businesses. As the state uses the CBRF to pay for wages, goods and services, the money is added to Alaska's personal income total.

The point is that when oil prices were at their lowest in Fiscal 1999, the CBRF supplied about one-eighth of the state's total economic base. The $1.1 billion drawn out of the CBRF that year went to wages, goods and services purchased in Alaska. That money then moved through the economy, measured by the multiplier effect. Based on 1995 research by the University of Alaska's Institute for Social and Economic Research, the multiplier effect magnified the CBRF's Fiscal 1999 contribution to Alaska's economic base to $2 billion — about 12 percent of the state's overall personal income that year.

Although oil prices have recovered, the outlook is for the heavy drain on the CBRF to resume in another year. This report forecasts that the CBRF payment to support the activities of state government — and to help fund Alaska's economic base — will average more than $910 million a year from FY 2003-2006. That figure represents the CBRF's contribution before the multiplier effect.

The need for the money will not end in Fiscal 2006, but the money will. Even assuming oil prices remain above historic levels for several more years, the Department of Revenue forecasts the CBRF will hit empty in December 2005. The loss of the budget reserve fund will mean a major reduction in the cash flowing through Alaska's economy, which means the economic base, and the economy itself, will shrink.

If Alaska wants to protect its economic base it will need to find another source or sources of new money. That will not be easy. The three options most often mentioned all have the same drawback: They would simply alter the flow of money already in Alaska, doing nothing to fill the hole.

Broad-based taxes, such as a sales tax or a personal income tax, would mostly take money already moving through the economy and redirect it toward government services. Yes, we could add a little new money to Alaska's economic base by collecting sales taxes from visitors or income taxes from out-of-state workers, but both taxes from outside sources combined would likely fall short of even 10 percent of the $910 million a year average draw from the CBRF.

Reducing the Permanent Fund dividend presents the same problem. Much of that money already is being added to Alaska's economic base. Shifting it from the dividend program to the state treasury to pay for teachers wages or road maintenance contracts or child care assistance would not add to the economic base and would not replace the gaping hole left by the empty CBRF.

It's the same problem with cutting the budget. If you reduce government support for public services to make up for the loss of $910 million a year in CBRF money, the lower spending on goods and services would weaken the state's economic base.

None of these proposals would replace the contribution of the CBRF to Alaska's economic base. Selecting among these proposals — or a combination — would only determine which Alaskans bear the major burden of the economic retrenchment.

One less-painful option for bringing new money into Alaska's economic base is the annual earnings reserve of the Permanent Fund. That's the money left over from each year's investment earnings after dividends are paid and after money is added back to the fund to protect it from inflation. That amount is likely to average around $250 million a year and could be directed toward filling part of the gap left behind by the CBRF. Because that money is not currently part of the state's economic base — it isn't being used for goods or services — it would be new money to Alaska.

Another hope is that a North Slope natural gas project could get under way in the next couple of years, generating public revenue of $200 million to $400 million a year or more in new money for the economic base by 2007. A gas project also would bring additional new money into the state to pay for wages, goods and services in the gas fields and transportation system. New oil discoveries also could produce additional pockets of new money to help cushion the loss of the CBRF.

One more option for bringing new money into the state is to increase taxes on the oil and gas industry. But that carries the risk of driving new investment to other areas worldwide if the industry believes Alaska is extracting too high a price. To fill the entire budget gap of $910 million a year from increased oil and gas taxes alone would require almost tripling the state's three primary oil and gas taxes.

There just isn't any easy or painless answer to replacing the CBRF. Still, we need to talk about an eventual answer. And while we look at the options, Alaskans need to think of the budget reserve fund not just as a funding source for government but as a key part of the state's economic base. We need to think about how to replace that source of money without just moving funds between Alaska's limited pockets. If that's all we're thinking about, the economic reality that hits us when the CBRF is gone will be painful.

For more information on Alaska's economic base and the multiplier effect:

"What Makes the Alaska Economy Tick," by the Institute of Social and Economic Research at the University of Alaska, Anchorage; December 1991.

"Structural Analysis of the Alaska Economy," by the Institute of Social and Economic Research at the University of Alaska, Anchorage; January 1994.

"Structural Analysis of the Alaska Economy: A Perspective from 1997," by the Institute of Social and Economic Research at the University of Alaska, Anchorage; August 1997.

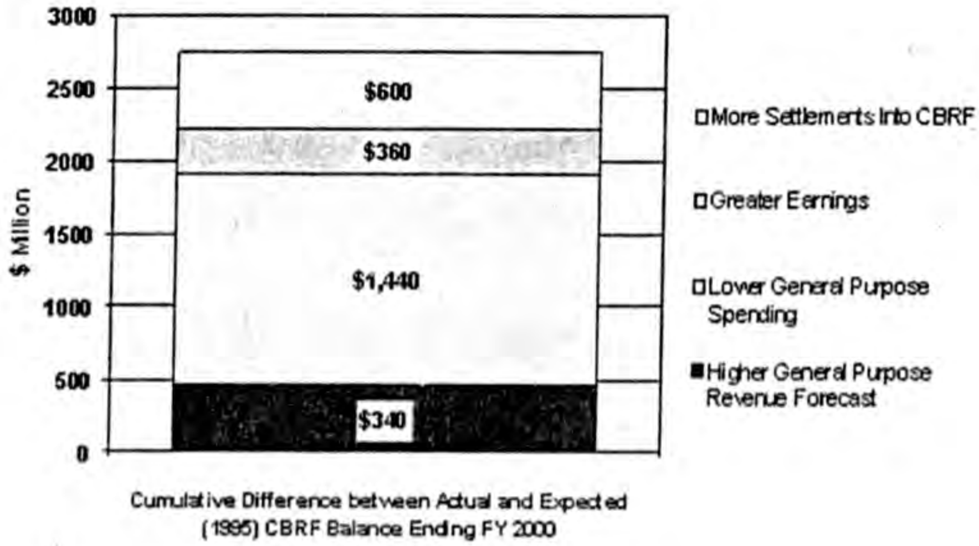
"A Long-Term Economic Development Strategy for Alaska," by the Alaska Science & Technology Foundation; April 2000.

Crying Wolf? A Brief History of Revenue Projections

In 1995, with oil prices hovering in the mid-teens and the state's income falling short of expenditures, the Department of Re nue predicted that we would exhaust the Constitutional Budget Reserve Fund by Halloween 2000. Instead, on October 31, 2000, the CBRF stood at $2.75 billion. How did we get it wrong?

To understand why our reserves grow or shrink, it helps to understand how the state finances its needs. When oil revenues fall short of our projected spending, the state dips into the Constitutional Budget Reserve Fund. That reserve gets its money from the settlement of oil tax and royalty disputes. In FY 1999, we used $1.1 billion from the CBRF to balance the books. Most recently, however, we have seen oil prices climb upwards of $30 per barrel, and for FY 2001, we are projecting a surplus of $117 million.

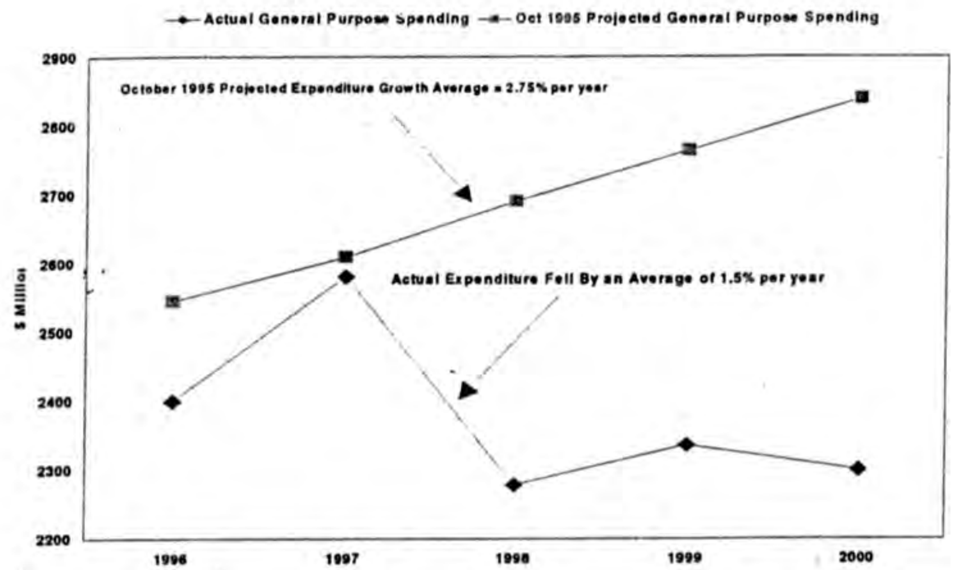
Why We Have More in the CBRF in FY 2000 Than We Expected



This $2.75 billion discrepancy between our 1995 forecast and the CBRF balance in October 2000 can be broken into four pieces.

- First, as can be seen in the chart above, the lion's share is due to lower-than-expected General Fund spending. We had made the assumption in 1995 that spending would increase by 2¾ percent each year through the rest of the 1990s. In fact, spending actually declined by an average of 1½ percent per year in nominal dollars and we used much less of the reserve than we thought we would, leaving an additional $1.4 billion in the fund.

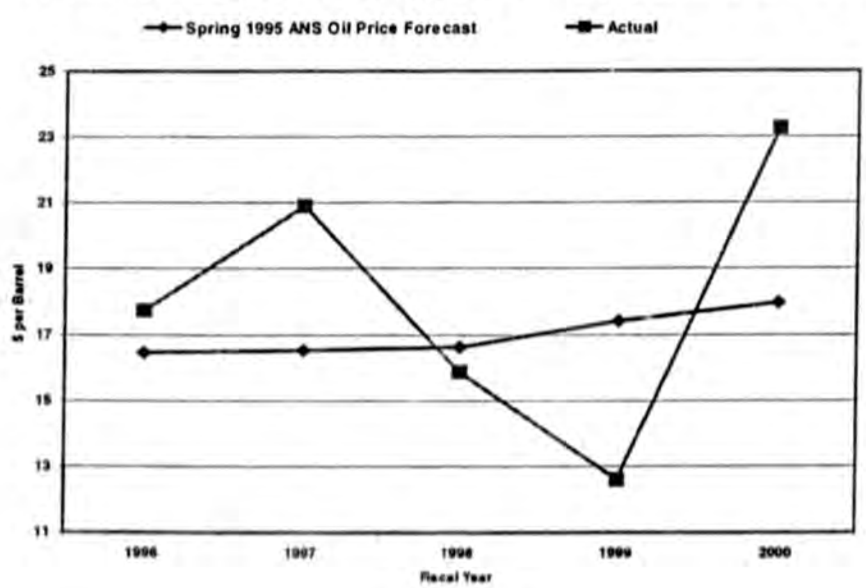
General Purpose Spending, FY 1985-2000



Each of the remaining three parts plays a much smaller role

- Our underestimate of oil revenue available to the General Fund accounted for $340 million of the discrepancy. In 1995 we forecast the price of ANS would drift steadily upward, averaging about $17.15 per barrel from 1995 through 2000. In fact, as the graph below shows, the price increased from 1995 through 1997, generating additional revenue. In 1998 and 1999 it crashed to $5 per barrel below our prediction. Then in FY 2000, the price shot up by $10 per barrel. The average actual price of $18 per barrel over the period 1995 through 2000 exceeded our forecast average by about $0.85 per barrel, but that was still enough to produce substantial income over the five years — money that we didn't have to take from the CBRF.

ANS Price Forecast Spring 1995 and Actual ANS Prices



• In 1995, we underestimated by $600 million how much the CBRF would receive from oil and gas tax and royalty settlements over the next five years.

• Finally, because of the higher than anticipated balances in the CBRF, we earned $360 million more on the money between 1995 and 2000.

The Department of Revenue is not alone in stumbling into the pitfalls of revenue and budget forecasting. Starting in 1989, the Institute of Social and Economic Research (ISER) at the University of Alaska Anchorage issued a series of papers on Alaska's fiscal policy, based on Department of Revenue oil production forecasts and ISER's own oil price and budget projections. At that time, ISER said a continuing decline in revenue would leave Alaska short of its spending needs and the CBRF would run out in 1992. The "Fiscal Gap" has been the center of budget discussions ever since.

For the present, the CBRF is healthy. However, if we assume that over the long run ANS will not maintain its price above the historical average of $17 to $18 per barrel, and if spending remains constant and we do not find additional revenue sources, we still face a fiscal gap. Today that gap is masked by high oil prices, and the day of fiscal-gap reckoning postponed. Our message is: It's better to plan ahead for the wolf's arrival than to cry when it's too late.

What Are the Options for Replacing the CBRF?

Although the state could balance its budget if oil prices remain around $30 a barrel forever, and if new oil fields and other developments make up for declining production at the older fields, few expect that to happen. If oil prices were to average around $20 per barrel through FY 2010 — higher than the average over the past 14 years of $17.70 per barrel — we would need roughly $1 billion per year to balance the budget at current expenditure levels.

Alaska therefore faces the prospect of a continued need to draw on its reserves. For this reason, we are including in this report a discussion of some of the most often mentioned changes to our fiscal system that could be used to help pay for the public services needed by a growing economy. Specifically, we examine broad-based taxes on sales and income, possible changes to oil and gas taxes, and use of some of the earnings from the Permanent Fund.

Broad-based Taxes

Alaska has an extraordinarily narrow tax base centered on the oil and gas industry. In FY 2000 three tax and royalty payers were responsible for more than 75 percent of the money spent from the General Fund.

Given the effect on state revenue from the eventual decline in North Slope oil production and the volatility of oil prices, instituting a personal income tax or a statewide sales tax often surfaces as a potential solution for stabilizing state revenues. Some key concepts to consider in choosing a broad-based tax are summarized below.

- **Revenue** – How much revenue does the tax generate?
- **Exportability** – How much tax do nonresidents pay?
- **Fairness** – How fair is the tax?
- **Economic Effects** – How would the tax change economic behavior?
- **Administrative Cost** – How much does tax administration cost?
- **Changes in Technology** – How would this tax change in the future?

Revenue

Income Tax

How much revenue would a tax generate? The answer to this question really depends on the tax base and the rate structure. Most individuals who work in Alaska already file an U.S. income tax return, thus the most cost-effective income tax base would probably come from that return, using one of three options: (1) adjusted gross income, (2) federal taxable income, or (3) federal tax liability before federal credits.

The table below represents the income tax rates (expressed as a percentage) necessary to generate the indicated revenue amount.

Income Tax Rates Needed to Reach Revenue Projections

$ Million Revenue	Percent Adjusted Gross Income	Percent Federal Taxable Income	Percent Federal Tax Liability
250	2.1	2.9	13.7
300	2.5	3.4	16.3
350	2.9	4.0	18.9
400	3.3	4.5	21.4
450	3.7	5.0	24.0
500	4.1	5.6	26.6

Sales Tax

Although most everyone is familiar with the sales part of a "sales and use" tax, most Alaskans are probably not familiar with the "use" part. What it means is that if a state has a sales and use tax and, for example, a resident buys a car in another state, the resident is liable for the use tax (generally the same rate as the sales tax) when the car comes across the state line. The idea is to protect the state (and its businesses) from losing revenue to sales in other states.

The amount of public revenue that a sales and use tax would generate is the product of the size of the sales tax base and rate. The size of the sales tax base depends on (1) the size and structure of the economy; (2) the specific goods and services included in the base; and (3) the type and size of credits or deductions.

The best four sources of information for estimating the revenue that could be derived from an Alaska sales tax are:

(1) Data from the 98 Alaska cities and boroughs that currently impose sales taxes. This comprises about one-third of Alaska's population.
(2) Data on sales tax revenues from other states similar in size to Alaska.
(3) Data from the U.S. Economic Census for Alaska.
(4) Data from the Consumer Expenditure Survey for Anchorage.

From the four data sources, we conclude that at a rate of 1 percent Alaska statewide sales tax with almost no exemptions would generate roughly $100 million in public revenue a year. However, as is commonly done in other states and in Alaska communities with sales taxes, exempting food and medicine from the Alaska sales tax base would reduce the annual income to the state to roughly $70 million per 1 percent tax rate.

Exportability

Exportability is the extent to which a state can shift its tax burden to out-of-state residents, either through directly charging nonresidents or through deductibility against the federal income tax. The amount of tax nonresidents pay depends on the amount of income nonresidents earn in the state, or in the case of sales taxes the goods and services that nonresidents purchase here.

Income Tax

The easiest way to export a tax is through deduction against federal tax liability. There is no deduction for state or municipal sales taxes; only income taxes are deductible. A deduction, or offset, means part of the tax revenue remains in state instead of going to Washington D.C. We estimate that Alaskans, on average, would recover about 15 percent of the cost of a state income tax by deducting it from their federal tax bills. For example, if a state income tax generated $300 million, $45 million would come from the deductibility of the state income tax against federal income taxes and $255 million would come from the pockets of Alaskans.

Taxing nonresidents also would help relieve the tax burden on Alaskans. The Bureau of Economic Analysis at the U.S. Department of Commerce estimates the nonresident income produced in each state. It's an estimate of the annual income that nonresidents earn in Alaska, minus income that Alaska residents earn in other states. The 1998 figure was $813 million, or, approximately 6 percent of total 1998 earnings in Alaska.

The Alaska Department of Labor provides another source of data on nonresident income in its annual report on nonresident wages. According to the department, the total nonresident earnings for 1998 were $930 million — about 10 percent of total wages paid in the state. There are two reasons why this number is larger than the U.S. Department of Commerce number. First, the state classifies more workers as nonresidents. The Alaska Department of Labor strictly defines a nonresident worker as someone who did not receive a Permanent Fund Dividend that year or apply for it the following year. Second, the Department of Labor number does not address income earned by Alaska residents in other states.

Regardless whether you use the state or federal estimate of nonresident income in Alaska, it's likely that a personal income tax of $300 million a year would generate less than $30 million a year from nonresidents working in Alaska.

Sales Tax

In a recent study, the McDowell Group, an Alaska economic consulting company, estimated that nonresident visitors spent $949 million in Alaska in 1998. Rounding that off to $1 billion a year in visitor spending, a 1 percent statewide sales tax would generate about $10 million from sales to nonresidents. That assumes no exemptions for food or medical care, and makes no allowance for sales exempt under federal law such as airline tickets.

Fairness

Income Tax and Sales Tax

The concept of fairness in taxes is subjective, as the term evokes a host of philosophical and political considerations in addition to the economic ones. Essentially, a majority of the state's residents must perceive any tax system as fair if it is to work well. An unfair tax structure generally reduces support for public expenditure and reduces compliance with the tax system.

Tax equity can be looked at in two ways: ability-to-pay and benefits received. The benefit principle rests on the premise that taxpayers should pay tax in proportion to the value of the public-service benefits they receive. On the other hand, the ability-to-pay principle follows from the belief that taxes should be assessed in terms of some measure of an individual's capacity to pay. Taxes are usually described as progressive, regressive or proportional. If the tax, as a percentage of income, rises as a person's income rises, it is labeled as progressive. If the tax, as a percentage of income, rises as income falls, the tax is considered regressive. A tax that stays the same is deemed as proportional.

Supporters of an income tax say it is progressive, in that it generally assigns a higher tax rate to higher-income households.

Opponents of a sales tax say it is regressive because low-income households spend a greater proportion of their income on essential purchases than do higher-income households. Supporters of a sales tax say it is fair in that it taxes everyone at the same rate.

Economic Effects

Income Tax and Sales Tax
Economists classify a tax as "efficient" when it has little or no effect on economic behavior. For example, sales taxes are inefficient when they influence consumer buying decisions or manufacturers' production decisions.

The size of the tax rate may also influence economic behavior. A personal income tax certainly could influence a person's economic decisions by lowering take-home pay, thereby affecting spending and working decisions. The amount of a sales tax also can make a difference in spending decisions. For example, a person who normally buys goods locally may continue to do so at a low sales tax rate. However, a high tax rate may cause the person to purchase the same product on the Internet or by mail order. In addition to changing the behavior of the individual, the Alaska economy suffers because the expenditure is made out-of-state and the money does not circulate in the local economy.

One measure of the stability of a tax is how state revenue changes as personal income changes. Studies show that as income changes, sales tax revenues change less than income tax revenues.[1] That is, in general, sales tax revenues decrease less in a recession than income tax revenues. Conversely, sales tax revenues increase less in a period of growth than income tax revenue.

Low Administrative, Enforcement and Compliance Cost

Desirable features of any tax system are low administrative, enforcement and compliance costs. These features imply that the tax system should attempt to minimize both individual and business compliance costs (including record keeping costs and fees paid to professional tax preparers), as well as the government's cost of administering, monitoring and enforcing the tax system.

Based on other states' experiences, we believe Alaska's cost of collecting either a sales or an income tax could be as low as 1 percent of total state revenue from the tax, depending on how the tax is structured.

Income Tax
Typically, the compliance cost to an individual for a state personal income tax is relatively minimal when the state tax is based on federal definitions of taxable income.The state tax return generally is simple to complete after federal taxable income and taxes are calculated.

Businesses will incur some additional compliance costs. For the personal income tax, the added costs are mostly associated with bookkeeping for employee tax withholding.

Sales Tax
Individuals have no sales tax compliance cost; the burden falls on businesses to collect the tax, keep the books and send the money to the tax office. Businesses will incur costs for labor, point-of-sale equipment and software and record keeping.

(1) "State Fiscal Issues and Risks at the Start of a New Century," by Donald J. Boyd, Nelson A. Rockefeller Insitute of Government, Albany, New York; June 2000.

Private costs for collecting and remitting sales tax are generally higher for small- and medium-sized businesses. In Washington, the cost to businesses to collect and remit sales tax was 6.47 percent of total sales tax collections for small, 3.35 percent for medium and 0.97 percent for large retailers.[2] Many states allow businesses to retain a small percentage of the sales tax collections to at least partially cover the costs of the tax collection service.

Changes in Technology

Sales Tax

Use of the Internet directly affects a state's ability to collect sales tax revenues. Taxing sales over the Internet would lead to higher cost to businesses of complying with almost 7,500 state and local sales tax jurisdictions. In response, state governments have joined together to propose streamlining existing sales taxes. The key features of these proposals include uniform definitions, simplified exemptions, simplified rates, state administration of local sales taxes, uniform auditing and states assuming a greater responsibility for implementing the system.

Petroleum Fiscal System

The Current System

There are four major components of the fiscal system for oil and gas:

- **Ad Valorem Property Tax** — A 20 mill levy on all petroleum production and transportation equipment.
- **Severance (Production) Tax** — A tax on production of up to 15 percent of value.
- **Royalty** — An ownership interest of an average 12.5 percent of production value.
- **Corporate Income Tax** — An income tax on oil and gas corporation net income of 9.4 percent.

A discussion of each of these taxes can be found in Section IV, Oil Revenue, beginning on Page 39.

Adequacy of the Current System

There are at least two criteria for evaluating the adequacy of a fiscal system:

- The share of the (pre-tax) profits from oil and gas activity in the state that the state receives.
- Whether the system encourages or discourages investment in the state.

[2] "Retailers' Cost of Collecting and Remitting Sales Tax," by Mary Welsh and Frederick C. Kiga, Washington State Department of Revenue, Olympia, Washington; December 1998.

A key parameter for examining the presence of these properties is the degree of *progressivity* of the fiscal system.

Proportional, Progressive and Regressive Fiscal Systems

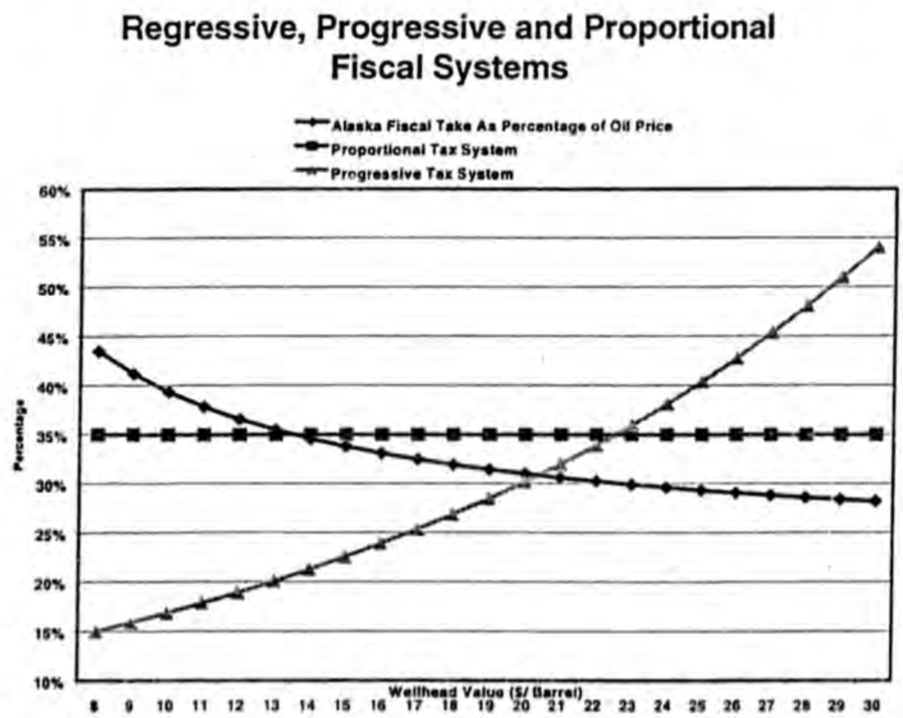
A proportional fiscal system is one in which the state's take is proportional to the profitability of the project. A system where the state's share of profits increases as profits increase is progressive. A system where the state's share of the profits increases as profits decrease (and decrease as profits increase) is called regressive.

Regressive systems create investment risk. Because the state's take is high at low prices, the risk to the investor of either high costs or low prices is exacerbated. Regressive systems also result in low government takes at high prices.

Alaska's petroleum fiscal system is regressive. The state's share as a percentage of the profits drops at higher prices. For instance, in FY 1999 when the wellhead price for North Slope oil averaged just $8.50 per barrel, we estimate the state's share to be about 45 percent of the pre-tax profit (assuming $3 per barrel in upstream operating and depreciation costs). In 2000, the wellhead price averaged $19 a barrel and we estimate the state's share of the pre-tax profit at a little more than 30 percent.

Alaska's share of the profits at low prices is higher than many other oil-producing nations earn at comparable prices, but when prices are high is lower than most other governments earn.

The chart below illustrates Alaska's regressive fiscal system compared to what progressive and proportional systems might look like.



There are three basic elements that in varying degrees make Alaska's system regressive.

- The property tax is clearly regressive because it is largely based on construction costs of facilities, and has nothing to do with income. If costs go up, or if prices go down so that profits go down, the property tax stays relatively constant and takes a bigger share of the smaller profit.

- Since both the severance tax and royalty are based on wellhead values, i.e., and the value at the point of production where the oil or gas leaves the well, all upstream development costs are ignored. Thus the higher the upstream costs, the more regressive the system. In addition, the state's minimum severance tax amounts are regressive at very low prices.

- Since the apportionment method used in Alaska's oil and gas corporate income tax is not based solely on profits in Alaska but instead a portion of worldwide profits, it could be argued that the tax has little to do with local profitability. Although this tax is proportional in relation to the total profitability of integrated oil companies, some say it is regressive because it is not directly and exlusively linked to profits in Alaska.

Several international comparison studies of fiscal systems have found that Alaska is a relatively attractive investment target at high prices and unattractive at low prices.[3] Any attempt to deal with the current system should also address how the state would manage its budget during periods of low oil prices.

However, an advantage to the state from this system is that it provides a public revenue cushion at low prices. The downside, of course, is that it also puts a ceiling on upside potential when prices are high.

There are at least two straightforward ways to make the system less regressive:

- There could be relatively more emphasis on the oil and gas corporate income tax and less on the severance tax by raising the rate on one and reducing it on the other. Moreover, changing the graduated rate schedule of the income tax could significantly increase progressivity. In theory, changing the state's oil and gas corporate income tax away from its worldwide apportionment basis to one based directly on economic performance within the state would probably yield a more consistently progressive effect.

- Alaska could impose an additional tax on oil for every dollar that the price exceeds a specified base price. Such a price-sensitive tax would move the state toward a progressive tax structure. For example, the state could collect 10 cents per barrel for every dollar that the oil price exceeds $14 a barrel. At $20, or $6 over the minimum price, the additional tax would be 60 cents per barrel. At $30 it would be $1.60 per barrel. A similar negative tax for prices below $14 a barrel would share some of the risk of low prices between producers and the state.

[3] Kemp/Rose, "Fiscal Aspects of Investment Opportunity in the UKCS and Norway, Denmark, Netherlands, Australia, China, Alaska (North and South) and the US Outer Continental Shelf; 1993.
A.D. Little/Gault, "Review of International Competitiveness of Alaska's Fiscal System"; August 1995.
Petroconsultants, "Annual Review of Petroleum Fiscal Regimes"; 1996.
Van Meur/ Barrows, "World Fiscal Systems for Oil"; 1997.

Permanent Fund Earnings

A fiscal possibility, though not necessarily a politically popular option, would be to use the annual excess earnings of the Alaska Permanent Fund to help balance the state budget.

The state's three-decade-old savings account generates more investment earnings than are needed each year to pay dividends and inflation-proof the principal of the fund. The excess — between $200 million and $300 million a year — goes into the fund's earnings reserve account. It goes there by default; it doesn't take legislative action to make a deposit into the earnings reserve.

State statute defines how the Permanent Fund Corporation is to calculate its "statutory net income." Another formula in state law uses the five-year average of that income to arrive at the annual dividend transfer. Inflation-proofing also is set in state law and is tied to the consumer price index. What is left behind after dividends and inflation-proofing falls into the earnings reserve.

The annual earnings reserve would be similar under a new payout system endorsed by the Permanent Fund Corporation Board of Trustees. The trustees are proposing a constitutional amendment that would limit the fund's annual payout to 5 percent of market value. A percent-of-market value, or POMV, standard would provide long-term stability in the amount available for distribution each year and would inflation-proof the entire fund — not just the principal. At a POMV of 5 percent a year, all of the investment earnings over 5 percent would automatically remain in the Permanent Fund to protect against inflation. Assuming a long-term investment return of 8 percent and a POMV of 5 percent, the fund would retain 3 percent a year for inflation-proofing.

If, for example, the fund's average market value for the past five years were $26.5 billion, a 5 percent POMV formula would make $1.325 billion available for dividends and whatever else the legislature decides. That could be the earnings reserve or, if at some point the political and public will demands it, the money left after dividends could be put back into the Alaska economy as part of the state budget. If such a system were in place for the 2000 dividend, it would have produced an earnings reserve deposit of about $200 million after paying out $1.12 billion for dividends under the formula in state law.

REVENUE SOURCES
Forecast and Historical Data

FALL 2001

Alaska Department of Revenue
Tax Division

Tony Knowles, Governor
Wilson L. Condon, Commissioner
Dan E. Dickinson, Director
Charles Logsdon, Chief Petroleum Economist

IV. ALASKA'S FISCAL OPTIONS

What Are the Options For Alaska's Fiscal Future?

Any of several events could produce new revenues to reduce the budget gap and help postpone or perhaps even prevent the demise of the Constitutional Budget Reserve Fund. Among the possibilities are unexpectedly high oil prices, large volumes of undiscovered oil, a natural gas project, broad-based taxes such as a statewide sales tax or personal income tax, or use of Permanent Fund earnings. This revenue forecast assumes none of the above. We based our forecast on oil prices within historic averages and on known quantities of oil and existing taxes. And although some Alaskans, and the legislature's Fiscal Policy Caucus, have discussed the options of instituting broad-based taxes and using some of the earnings from the Permanent Fund to help pay for public services, we did not include any money from either of those sources in this forecast.

However, the future is uncertain, and any of the above possibilities could become reality in time.

To help judge the possibilities and their economic value, we offer the following information:

Could Higher Oil Prices Fill the Fiscal Gap?

The short answer is no, not unless you believe in the improbable. Still, that doesn't stop Alaskans from hoping.

A quick study of the numbers, however, shows it certainly is extremely unlikely. Alaska North Slope crude oil would have to fetch higher prices for a longer period than at any time in the pipeline's 24-year history. And not just a little higher for a short time, but a lot higher for a long time.

- **How much is the fiscal gap at high, or low, oil prices?**

At $30 oil, Alaska would still face a half-billion-dollar-a-year fiscal gap over the next 10 years.

At $10 oil, the gap would range between $1.7 billion and $2 billion a year.

Figure 10.
Annual Fiscal Gap at $30/ Barrel Oil

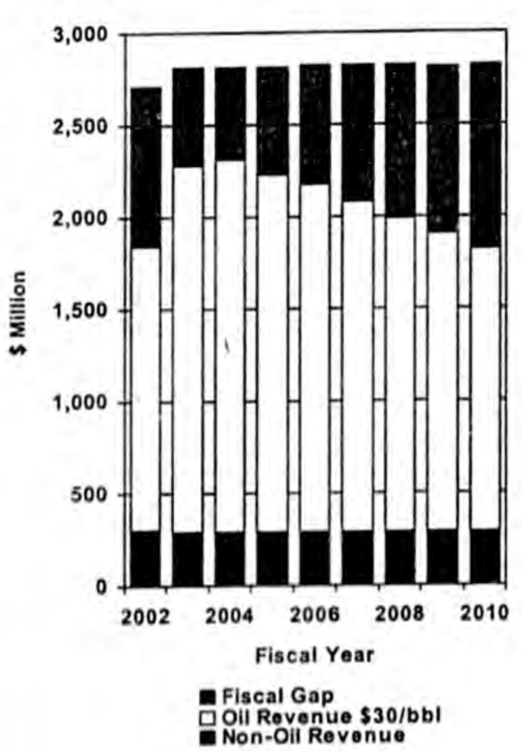
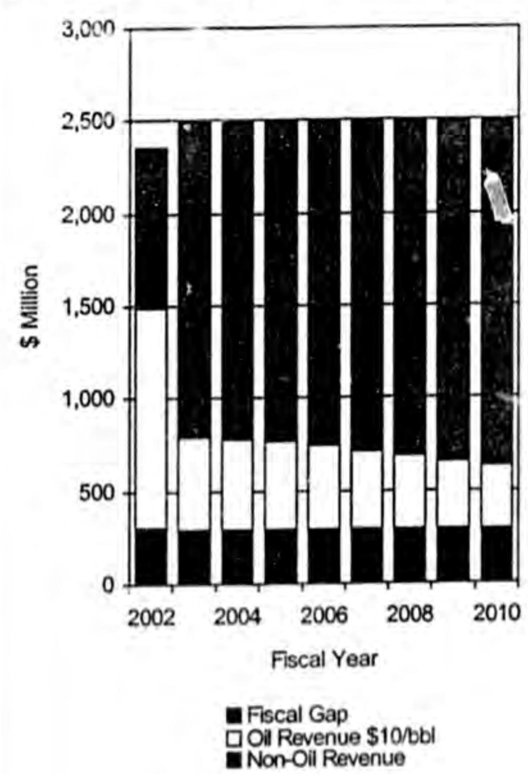


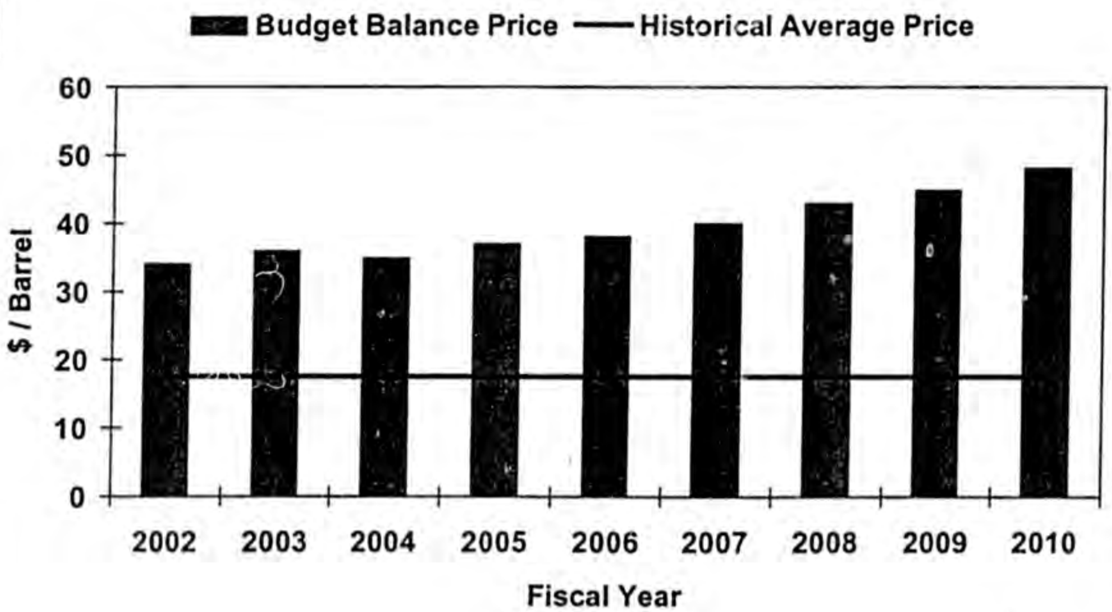
Figure 11.
Annual Fiscal Gap at $10/ Barrel Oil



▪ How high would oil prices have to climb to balance the state budget through the end of the decade?

Although we believe North Slope oil production will average around 1 million barrels per day through 2010, the state's declining production tax rate requires a higher price every year just to maintain the same revenues. North Slope oil would have to average $34 a barrel in Fiscal 2002 to balance the budget. The price would have to average $39.50 a barrel over the next eight years to cover a $2.5 billion state budget, but that's just the average. The number gets further out of reach each year. In Fiscal 2010, the price would need to be roughly $48 a barrel.

Figure 12. Oil Price Necessary to Balance the Budget



▪ If we want to continue using the Budget Reserve Fund to fill the gap, how high would oil prices have to climb to keep the fund alive until the end of the decade?

To reach 2010 with something, anything, in the Budget Reserve Fund would require oil averaging over $30 a barrel for the next eight years — more than 60% higher than the Department of Revenue forecast and 50% higher than U.S. Department of Energy estimates.

Keep in mind that prices would have to hold fairly steady around the $30 average — the state could not afford a couple of bad years along the way if we wanted to maintain the Budget Reserve Fund and pay our bills. For example, if North Slope oil dipped below $15 for a year or more, as has happened three times since 1989, the Budget Reserve Fund would take such a deep hit that it might hit empty even if prices rebounded the next year.

▪ How likely is it that oil prices will climb high enough to balance the budget in some years, or at least extend the life of the Budget Reserve Fund?

Prices could rise above projections in the short term — maybe even enough to balance the budget for a little while. But it would take a major, sustained global shortage of oil to create the consistent, high oil prices for the long term that could save the Budget Reserve Fund, and such a shortage is extremely unlikely.

Oil is a market-traded commodity, with the forces of supply and demand determining the price. When supply exceeds the demand, which is the world situation this year, prices fall. As oil gets cheaper, demand recovers, which, over time, leads to higher prices as demand builds to match supply. But when demand gets too high, squeezing the supply, prices rise and demand falls back down. Prices eventually come down, too. Oil prices don't just move up and down, they always move up and down. High oil prices also push users to rely more on substitute fuels and conservation, serving as a natural relief valve to cut demand when prices climb too far. Because of how the market works, it is highly unlikely that oil prices could ever stay high enough long enough to solve Alaska's budget problem.

Here are some numbers to consider:

▪ Since a transparent market price for ANS West Coast deliveries emerged in the mid-1980s, Alaska North Slope crude oil delivered to California and Washington refineries has never averaged more than $28 a barrel in a year. As if that was not sobering enough, the price has averaged below $20 a barrel for all but three years since 1988.

▪ The West Coast ANS price has averaged above $30 a barrel in only six months of the past 175 months, and has never reached the $33 a barrel that Alaska would need for the entire year to balance the Fiscal 2002 budget.

▪ Any discussion of the potential for high oil prices would not be complete without looking at the low side of oil prices. Alaska North Slope crude averaged $9.39 a barrel in December 1998, its lowest monthly price ever.

▪ And while North Slope oil has exceeded $30 a barrel on the West Coast six out of the past 175 months, it has fallen below $15 a barrel in 39 of those months.

▪ If OPEC nations wage a price war with non-OPEC producers, and if oil drops to $10 a barrel as it did in late 1998, and if the price stays on the bottom for two years, the Budget Reserve Fund would be empty by September 2003.

Higher — or Lower — Oil Production

Oil production could exceed our forecast, which includes only barrels from fields that are producing or have been discovered. For those that have been discovered, we included production only from those fields we expect to start pumping by 2010.

It is possible, however, that some of the discovered fields could start producing sooner than expected, meaning more production and more revenue to the state. We also expect new oil discoveries on the North Slope, but we do not believe these new fields will begin producing before 2010.

However, these undiscovered fields might also begin producing sooner. We have estimated in this section how much additional production we believe could possibly come from the accelerated development of known reserves and new discoveries.

On the other side of the fiscal coin, it is possible that some of the forecast production from as yet undeveloped fields could be postponed past the expected start-up dates in this forecast. For every upside there is a downside.

Possible Higher Oil Production

We forecast that "new oil," oil that has been discovered but is not yet flowing through TAPS, will constitute a substantial 13.8% of North Slope production by Fiscal 2005 and 27.1% by Fiscal 2010. Clearly, Alaska is depending on a fair amount of this new oil just to meet our revenue forecast.

But what about undiscovered oil? Oil companies continue to lease new lands and drill exploratory wells in search of reserves, and it is future production from these areas that is harder to predict.

To come up with a credible estimate of potential undiscovered oil that might be produced before 2010, we relied on geological work done by the U.S. Geological Survey and the federal Bureau of Land Management. We then derived an estimate of the North Slope's undiscovered, economically recoverable barrels that could possibly come into production before 2011. We provide in Table 10 our estimate of the potential additional production from these undiscovered reserves over the next decade. These barrels would come from three areas: the National Petroleum Reserve-Alaska (NPRA), the Foothills and the area east of Prudhoe Bay and the Central North Slope. We do not include any production from the Arctic National Wildlife Refuge in this table because even if Congress this winter gives the go-ahead for drilling in ANWR we would not expect to see any production until after 2010.

Table 10. Additional Potential Barrels from Undiscovered Fields
million barrels per day

Fiscal Year	NPRA	Foothills and East of Prudhoe Bay	Central North Slope Satellites	Total
2006			0.014	0.014
2007	0.040		0.028	0.068
2008	0.037	0.034	0.045	0.117
2009	0.035	0.060	0.065	0.159
2010	0.039	0.083	0.082	0.203

If all of the additional undiscovered production were to come online as estimated in Table 10 — 203,000 barrels per day by Fiscal 2010 — the state would receive an estimated $173 million in additional oil and gas tax and royalty payments in Fiscal 2010. That's a little more than 10% of what would be needed to close the budget gap that year. The revenue to the state is held down by the Economic Limit Factor and the lower production tax rate charged on oil flow for the first five years of production from new fields.

This undiscovered new oil could come from:

National Petroleum Reserve-Alaska.
The Bureau of Land Management's 1998 projection of 600 million barrels of economically recoverable reserves in NPRA might well prove to be too conservative. Phillips and Anadrako have drilled six wells and a side-track in their first two NPRA exploration seasons, and announced in May 2001 that they had discovered three separate hydrocarbon accumulations. The area encompassed by the wells is comparable to the area overlying the Alpine reservoir, with potential reserves in Alpine's 429 million barrel neighborhood. Phillips and Anadarko will conduct additional drilling and well data analysis this winter to establish the commercial value of their find.

For the sake of this exercise, we estimate these NPRA discoveries could go into production in the second quarter of Fiscal 2007 at 40,000 barrels per day.

It is likely that the recent NPRA discoveries are just the beginning. Phillips and its partners have not stopped exploring their NPRA leases, and Phillips recently requested permits for 15 additional well sites for the 2001-2006 drilling seasons. Phillips isn't the only company exploring in the NPRA. In fact, only a quarter of the money spent in the first NPRA sale was for leases overlying Phillips's recent discoveries. Anadarko plans to drill two wells at its Altamura prospect in the NPRA this exploration season. The BLM plans additional lease sales in 2002 and 2004.

If NPRA yielded 600 million barrels rather than our projected 325 million barrels, the larger reserves could add an additional 37,000 barrels of daily production to our estimate by 2010.

Foothills and East of Prudhoe Bay.
Though the Foothills petroleum potential is mostly for gas reserves, the USGS estimates there are 500 million barrels of technically recoverable reserves in the Central Foothills.[1] Based on a 1993 estimate for costs and exploration success, the USGS forecasts that 50% of this technically recoverable oil would be economically recoverable at an $18 per barrel ANS price, and 70% of this oil would be recoverable at a $30 per barrel ANS price.[2] To take into account technological advances that have lowered costs and increased exploration efficiency, we assume that the midpoint (60%, or 300 million barrels) of the technically recoverable oil could be economically recoverable for our estimate of undiscovered oil production.

For this discussion, we estimate Foothills production could be 83,000 barrels per day by Fiscal 2010.

(1) See USGS Open-File Report 95-75I, "Economics and undiscovered conventional oil and gas accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Alaska", by Emil Attanasi and Ken Bird ("USGS[95]") at Table 3, Page 37.
(2) USGS[95] at Table 3, Page 37.

Central North Slope Satellites and the Beaufort Sea.
The USGS in 1995 estimated perhaps 4.3 billion barrels of technically recoverable, undiscovered oil in the central and eastern coastal regions of the North Slope. The USGS believed this oil would mainly be in the turbidite and Barrow Arch Beaufortian geological plays.(3) The USGS also stated that less than half of this technically recoverable oil would be economically recoverable.(4) Of the estimated 3.6 billion barrels of technically recoverable oil remaining net of post-1995 discoveries, 1.5 billion barrels could be economically recoverable.

To find and produce these reserves will require substantial investments in exploration and development, and due to capital constraints these reserves would come on slowly. We derived a conservative production forecast by assuming a minimum of 75 million barrels of additional Central North Slope reserves could be put into production each year starting in 2003. This estimate would give Alaska an additional 82,000 barrels a day of production by Fiscal 2010.

Arctic National Wildlife Refuge (ANWR).
The U.S. Department of Energy estimates it could take a decade after approval of ANWR exploration for the first production.(5) Even if Congress approves ANWR this winter, it is likely the first production would not come online until 2011, removing ANWR from our estimate of undiscovered oil production for this decade.(6)

Possible Lower Oil Production

The North Slope, like other mature provinces, depends upon production from new fields to offset declines in older fields. In our predictions of oil flow from discovered fields, which already are included in our revenue forecast, we include barrels from anticipated developments in the second half of this decade from Point Thomson (Fiscal 2008), Sourdough (2008), Yukon Gold (2009), Sandpiper (2008) and Nanuq (2005).

(3) USGS[95] Table 3, Page 37.

(4) Of the Eastern Coastal region's 1,632 million barrels of technically recoverable reserves, 39% (638 million barrels) should be economically recoverable. Of the Central Coastal region's 2,002 million barrels of remaining technically recoverable reserves, 45.75% (916 million barrels) should be economically recoverable. The economic recovery factors reflect mid-points between the $18 and $30 cases of USGS[95] Table 3.

(5) Energy Information Association (EIA) report entitled "Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment" reads, in part, "Seven to 12 years are estimated to be required from an approval to explore and develop to first production from the ANWR area. This study uses nine years to 2010." The EIA estimated that the full 10.3 billion barrels of technically recoverable oil would be economic to recover.

(6) A lease sale in 2004 could yield the state approximately $160 million. Assuming a 10-cent rule of thumb as a bonus bid, the companies would pay $320 million for access to 3.2 billion barrels. The state would receive half of this amount if revenue is shared in the same percentages as it is for the NPRA.

Table 11 shows our projections for oil production from these fields, totaling 103,000 barrels per day by Fiscal 2010. These fields represent almost 40% of the "new oil" included in our revenue forecast for Fiscal 2010, and also represent a substantial economic loss to the state if they do not start up as expected.

Table 11. Anticipated Production from New Fields This Decade
thousand barrels per day

Fiscal Year	Point Thompson	Sourdough	Yukon Gold	Liberty	Sandpiper	Total
2004						
2005				35		35
2006				55		55
2007				52		52
2008	20	10		42	12	84
2009	30	15	10	34	15	104
2010	30	15	15	29	14	103

Some of these developments could be deferred or cancelled. Specifically, Point Thomson, a field discovered in the mid-1970s and still undeveloped, might remain undeveloped for the next 10 years. A gas condensate reservoir such as Point Thomson is expensive to develop because of the facilities needed to cycle its high-pressure gas. After extensive negotiations, the state Department of Natural Resources and the Point Thomson Unit Owners recently agreed to a development plan that could result in liquid production by 2008. However, the Point Thomson Unit owners could forego development and pay compensation to the state for unfulfilled drilling obligations. The Department of Natural Resources estimates there are about 200 million barrels of liquid reserves at Point Thomson.

Sourdough and Yukon Gold are two small oil reservoirs located near Point Thomson. If Point Thomson is developed, it is more likely these fields would come online a few years later. However, if Point Thomson is not developed, these small reservoirs probably would not be developed either. To account for this uncertain production in our forecast, we have reduced the estimated reserves by 50%, resulting in around 60 million barrels recoverable from each of these two fields.

We forecast that an offshore field, Liberty, will be brought on line in Fiscal 2005. After experiencing significant cost overruns with Northstar, however, BP may be less likely to proceed with this 180-million-barrel field. We also estimate that 59 million barrels of oil will be recoverable from Sandpiper, an offshore field. This field also might not be developed.

Prudhoe Bay has been in decline since 1988. We forecast that Prudhoe Bay will decline at a slower rate than it did during most of the 1990s, with production falling by an average 5.3% per year 2001 and 2011. However, the steeper decline rate of 1992 to 1999 could return in 2002 if development drilling is less than we have projected. If the 1992-to-1999 decline rate continues throughout this decade, Prudhoe Bay production would run about 122,000 barrels per day under our forecast for Fiscal 2010. Such a steep production drop could reduce state revenues by an estimated $191 million in 2010.

Alaska Natural Gas Project

If the gasline is built, how much could it help fill the state's budget gap? First, the project has its own economical hurdles to jump over.

The governor, Alaska's congressional delegation, the state legislature and many community leaders are actively supporting a pipeline project following the Alaska Highway. A 4 billion cubic feet per day Alaska Highway gasline would be expensive, costing an estimated $14.3 billion to deliver the gas to Chicago. A gas treatment plant, estimated at $2.6 billion, also would be needed to remove impurities in much of the North Slope gas. Recently, a joint study team comprised of the major North Slope producers said the project is not economic based on the preliminary cost estimate of $17.9 billion and certain market assumptions. However, the study team has been trying to reduce the project's costs, and the governor, the legislature and others are pushing for federal tax incentives to further help reduce the project's costs. If all of the efforts are successful, and if there are no regulatory delays, the producers estimate the gasline could start making deliveries by 2008.

If the project is built, the state would collect revenue in four ways: royalties, production taxes, property taxes and corporate income taxes. An Alaska Highway gasline project under the state's existing fiscal system could yield as much as $400 million a year to the state's General Fund by Fiscal 2010. That's using the producers' study team cost numbers.

On the high side, what if the producers — or other partners — find a way to reduce construction costs by 20%? And what if the gas brings $4 per thousand cubic feet on the market, instead of $3.50 as projected in most models? With such favorable economics, the state could receive as much as $700 million in tax and royalty revenue in Fiscal 2010.

(1) Some interested parties are considering the possibility of reaching the U.S. market by shipping North Slope gas as LNG to the West Coast or Mexico, or to markets in the Far East. The oil companies also are reviewing a pipeline route to the Lower 48 that would go under the Beaufort Sea and tie in to gas reserves in Canada's Mackenzie Delta where the line would head upriver to connect with the supply grid in central Alberta.

The Economic Limit Factor

As you think about the state's fiscal situation, it's also worthwhile to look at existing revenue sources and ask if they are working as intended. A major part of the state's oil and gas tax structure is the Economic Limit Factor.

Alaska oil production tax revenues have declined rapidly over the past several years due, in part, to the ELF. The ELF is a multiplier between 0 and 1 that reduces the actual tax rate for a field, based on average well productivity and the field's total daily production. One of the principal purposes of the ELF is to ensure that the production tax does not discourage development of smaller oil and gas fields.

The ELF formula is complicated, but the result is the smaller the field or less productive the wells, the lower the tax rate.

$$\text{ELF} = \left[1 - \frac{(300 \text{ X wells})}{\text{volume}}\right]^{\wedge\left[\frac{(150{,}000)}{\text{volume}}^{\wedge 1.53333}\right]}$$

"Wells" is the number of producing wells in the field and "volume" is the total daily production for the field. Under the formula, the smaller the field the smaller the ELF factor, or fractional multiplier, to apply against the full production tax rate. The larger or more productive the field, the larger the fractional multiplier to apply to the tax rate.

The full oil production tax rate is 15%, with a 12.25% rate for the first five years of a field's production. For example, if the ELF were 0.5, the effective tax rate would be 7.5% (15% times 0.5). If the ELF for a smaller field were 0.2, the actual tax rate would be 3% (15% times 0.2).

As field or well productivity declines, the ELF will decline as well. Because the two factors of well and field productivity are related exponentially in the ELF equation, the drop in the ELF will be much steeper than if either of the two factors were applied alone.

The current ELF formula took effect in 1989. One idea behind the ELF was that the actual tax rate should decline over time so that the production tax does not cause fields to prematurely shut down as they become less economic due to falling production. Since 1989, the following trends in North Slope oil development have resulted in a larger ELF discount and a marked decline in the average tax rate and, subsequently, state revenues:

- The rapid decline in production from older, larger fields.
- No discoveries of new, large fields sufficient to offset the decline in the largest fields.
- Exploration and development of new, smaller "standalone" fields with maximum production of 50,000 to 100,000 barrels per day.
- Development of satellite fields with maximum production in the range of 5,000 to 50,000 barrels per day. The ELF reduces the tax rate on these smaller fields such that most fields producing less than 20,000 barrels per day pay little or no production tax. These satellite fields use existing processing facilities at larger fields.

The ELF Effect on Revenue

In FY 1990, non-royalty North Slope production was about 570 million barrels and the ELF was 0.94. Applied against the full tax rate of 15%, the average ELF produced an actual, average tax rate of 14.1%. Assuming a $15 per barrel tax base, the production tax revenues to the state would have been $1.206 billion.

570 million barrels X $15 X 14.1% = $1.206 billion

In FY 2000, production was down to 365 million barrels, a 34% decline, and the average North Slope ELF was 0.69, for an actual rate of 10.35%. The revenues at $15 per barrel would have been $567 million.

365 million barrels X $15 X 10.35% = $567 million

Although production fell 34% from 1990 to 2000, total production tax revenues over that same period — because of ELF — at the same hypothetical $15 wellhead price dropped 53%. And while we forecast North Slope production remaining relatively flat between 2002 and 2010, because of ELF the average tax rate will fall 52%. It is reasonable for the ELF factor to push tax rates lower as production declines; fixed operating costs will increase on a per barrel basis, and there may be additional operating expenses to cover factors such as gas and water handling. In addition, it is reasonable for the ELF to decline to zero by the end of a field's life.

However, does the existing ELF formula reduce tax rates too quickly? At Kuparuk, for example, 2000 production was 212,000 barrels per day and the ELF was 0.60. By 2010, production is expected to still hold above 100,000 barrels per day, but the ELF will be zero. The field is forecast to keep producing 10 years beyond that. Is the ELF going to zero sooner than it needs to ensure maximum production?

This can be seen in another way. Under the existing ELF, for example, a field of 50,000 barrels per day with an average per well productivity of 450 barrels per day would have an ELF of 0.003. A 200,000 barrels per day field with the same well productivity would have an ELF of 0.493. The smaller field's actual production tax rate would be 0.045%, and the larger field would pay a production tax of 7.395%. It is doubtful that the per barrel operating costs of the two fields would be so different as to justify the larger field paying a tax rate 164 times higher than the other field. It is worth asking: Is the ELF formula doing its job the way it should, or is does it need changing?

As mentioned above, one of the changes over the past 10 years has been the development of satellite fields, which share existing facilities with larger fields. These fields have lower production, with maximum levels in the 5,000 to 50,000 barrels per day range. The ELFs associated with these satellite fields are very low, and zero in many cases. However, given the degree to which these fields share costs with large, profitable fields, and the degree to which many of these costs have already been recovered, the economics of such fields are not the same as those of similarly sized fields that stand alone.

One possible modification to lessen these problems would be to have separate components in the ELF formula for total field production and well productivity. While both of these are key indicators of profitability, they are largely independent. Thus, rather than treat them exponentially, where their effects overexaggerate economic tendencies when mixed, the ELF formula could be modified so that these distinct features could be summed.

For example, the ELF could consist of a total field productivity component and a separate well productivity component. Each of these components could be weighted 50% in the final ELF factor for each field.

This would result in less drastic swings in tax rates as field or well productivity changes. In general, where rates are now high they would be lower, and where they are now low they would be higher. The ELF would decline less drastically over time.

As a side benefit, this would also make the ELF easier to understand.

There are two other major problems with the production tax. First, because the tax rate is fixed, the government's share of profits is high when profits are low, and low when profits are high. This is called a "regressive" system and creates an unbalanced situation. At low prices or high costs, the burden of the tax creates additional investment risk. At high prices the state's share of the profits is much less than in internationally comparable conditions and the state leaves money on the table.

In addition, oil price could be incorporated into the ELF formula, so that the tax rate would vary with oil price. Bringing price into the ELF formula would create a "progressive" tax system, where the government's share of profits would vary proportionally with the profits. Having the tax rate vary with price is another way to better balance the tax system under a wide range of economic conditions, while maintaining international competitiveness for attracting investment.

The other major problem with the production tax is that it does not encourage re-investment in the state. Alaska's tax system is based on gross revenue at the wellhead: exploration, development and upstream operating costs are not deductible. Unlike other jurisdictions, the regressive system in Alaska does not allow deduction of exploration and development costs. In those other jurisdictions, taxes are reduced by investing there, and companies that invest pay less taxes than those that do not.

There is no such mechanism in Alaska. This may induce companies to take their Alaska profits and invest them elsewhere. A tax credit for exploration and development would enhance interest in investing here. The credit could be capped so as not to drop the actual production tax rate too much, but enough to be attractive to exploration and development.

The current ELF mechanism, established in 1989, was predicated on conditions that were in place then. Those conditions have changed. Would it be appropriate to change the ELF as a consequence? While frequent changes in resource taxes create instability — particularly where the economics are marginal — tax changes made in response to new conditions or structural deficiencies may be in the public interest.

Broad-based Taxes

Personal Income Tax

As Alaska moves closer to the day when the CBRF hits empty, more people are discussing the possibility of bringing back the personal income tax — Alaskans paid income taxes until 1980, when the legislature abolished the tax — and perhaps instituting a statewide sales tax. Most people probably do not remember, but Alaska's personal income tax was fairly heavy, and if the same rates and rules were in effect today that were in effect in the 1970s, Alaskans would pay about $750 million this year in state taxes.

Of course, no one is suggesting such a heavy tax burden on wage earners. However, as Alaska faces a billion-dollar-plus annual shortfall in paying for public services, the possibility of an income tax often comes up at public meetings.

A personal income tax could be assessed on one of three options: The tax could be computed on:

- Adjusted gross income (no deductions for children, charitable donations, home mortgage payments or other typical deductions).
- Taxable income (income after deductions allowed).
- Federal tax liability (a percentage of each taxpayer's federal tax bill).

An income tax would collect money from non-residents working in Alaska. There are no exact numbers for non-resident wages in Alaska, but estimates range from 3% to 10% and we figure the true number is probably in the middle. Even at 6% or so, an income tax that raised $300 million would collect almost $20 million a year from non-residents.

Other points to consider in whether or how to adopt a state income tax are:

- The tax would be deductible from federal income taxes for Alaskans who itemize. IRS statistics indicate that about 25% of Alaska taxpayers itemize their deductions.
- The tax rate could be flat — everyone pays the same percentage of their income — or the rates could be graduated so that wealthier people paid higher rates (just like the federal tax table).

The table below represents some sample income tax rates (expressed as a percentage) and the revenue each would generate.

Table 12. Income Tax Rates Needed to Reach Revenue Projections

$ Million Revenue	Percent Adjusted Gross Income	Percent Federal Taxable Income	Percent Federal Tax Liability
250	2.09	2.87	13.72
300	2.48	3.41	16.29
350	2.87	3.95	18.86
400	3.27	4.49	21.44

Sales Tax

More than one-third of the state's population lives in communities that collect a sales tax. Almost 100 cities and boroughs have a sales tax, with the distinction for the highest tax rate going to Wrangell at 7% on purchases — even on residential rent. Those 100 communities collected more than $119 million in 2000, the latest year for which totals are available.

The state has never imposed a sales tax, leaving that revenue source to the cities and boroughs. However, some have suggested a state sales tax as a tool to help close the budget gap. How much money could be raised would depend on which goods and services are exempted from the tax, such as food and medical care. The department estimates:

- If all retail goods and services in the state were taxed, the state would raise about $100 million a year for each 1% of tax.

- If all food and beverages, medical care and medicines were exempted, the revenue would run about $70 million a year for each 1% of tax.

- Would the state join the national movement among states toward uniformity in rules to avoid sales tax losses to out-of-state businesses?

It's hard to say how much of the sales tax would be paid by visitors from out of state, although we believe it could be substantial, perhaps 10% or more of total tax revenues. Visitors spend heavily on gifts, food, lodging and tours.

Issues in considering a state sales tax are:

- What items, if any, should be exempted from the tax?

- Loss of local control if the state sets the rules for exemptions.

- Would a state tax, added to an existing municipal tax, hurt the economy in those communities that would have a combined rate of 7%, 8% or 9%?

Permanent Fund Earnings

One more possibility under discussion is to start using some of the earnings from the Alaska Permanent Fund.

The savings account was established in 1976 to save some of the state's oil wealth for when state revenue from North Slope production could no longer keep up with the need for public services. The dividends did not come along until 1982, although many Alaskans probably think of the Permanent Fund as a dividend generator first and as an eventual source of revenue for public services second.

In normal years — of which Fiscal 2001 was not — the Permanent Fund generates more investment earnings than are needed to pay dividends and inflation proof the fund. That excess of between $175 million and $300 million a year goes into the Earnings Reserve Account. It goes there by default; it doesn't take legislative action to make a deposit into the Earnings Reserve.

Those surplus earnings could be used to help fill the budget gap.

Legislative Fiscal Policy Caucus

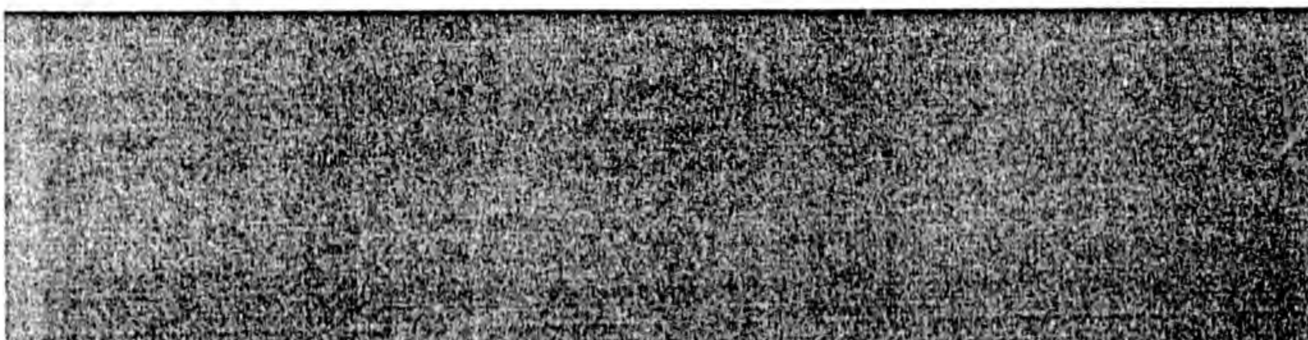
A group of two dozen legislators, mostly House members and almost evenly split between Democrats and Republicans, held a series of town meetings in their communities this past summer and fall to discuss the state's fiscal problem. The caucus then got together in Anchorage on November 30 and December 1 to put together a starting point for legislative discussion during the 2002 session. The caucus members believe they need to take action in 2002 to prevent a fiscal crisis if the CBRF hits empty in the summer of 2004.

That starting point includes an income tax, a sales tax, an increase in alcohol and motor fuel (gasoline) taxes, a $25 tax on cruise ship passengers, $100 million a year in additional tax revenue from the oil and gas industry, a reduction in oil and gas royalty deposits to the Permanent Fund from post-1979 leases, and using the annual surplus earnings of the Permanent Fund plus changing the dividend formula to maintain the annual check to Alaskans at $1,250.

That collection of revenue sources would generate an estimated $1 billion in new revenues in Fiscal 2004, still short of closing the state's budget gap — which will grow each year as oil revenues decline. The additional revenue, however, would extend the life of the CBRF to the summer of 2008, allowing more time for a complete fiscal plan for the state. Caucus members expressed the hope that new oil discoveries, a natural gas project or other economic development project would add to state revenues before the end of the decade.

Alaska Department of Revenue
Tax Division

December 2003



REVENUE SOURCES BOOK

FALL 2003

3.

RESOURCE DEVELOPMENT OPPORTUNITIES

Looking for New Oil Reserves

There are essentially three phases involved in bringing new oil and gas reserves into production: leasing, exploration and development. In this section we will examine current trends in leasing and exploration as well as new development issues on the Alaska North Slope.

Leasing

The state's leasing program continues to be quite successful. There are currently over 4.8 million acres of state land under oil and gas leases. Since 1995, lease sale bonuses and rents have generated over $200 million for the state. Leases are owned by many different oil companies and private citizens. As of today, ConocoPhillips controls the largest amount of acreage at 925,785 acres. The top ten companies control 3.7 million acres while 90 other entities control the remaining 1.2 million acres.

Table 3-1. State-Owned Leases
Thousands

Company	Acreage	Percent
ConocoPhillips	926	19.0%
Anadarko	514	10.6%
Petro-Canada	411	8.4%
BP	406	8.4%
Union	321	6.6%
Chevron USA	296	6.1%
Encana	236	4.9%
ExxonMobil	191	3.9%
Burlington Resources	184	3.8%
Forest	179	3.7%
All Others	1,201	24.7%
Total	**4,863**	

Source: Lessee's Acreage Summary, Division of Oil and Gas, Alaska Department of Natural Resources, November 2003.

Since 1995 the total amount of acreage under lease has more than doubled. This suggests a successful ongoing leasing program that is generating state revenue and making a significant amount of acreage available to exploration. The diversity of ownership suggests that some leases are pursued with an eye to selling them to an entity that has the ability to explore or gain access to existing facilities. The bottom line is that considerable acreage is in the hands of lessees and the ownership of leases is diversified between large companies and smaller firms and individuals.

Exploration

In order to produce oil or gas you need to find it. Exploration is driven by many factors but the primary one is the likelihood of finding oil or gas in sufficient quantity to justify commercial production. The North Slope of Alaska has been explored by geologists since the beginning of the last century and ideas about where to drill the next exploration well continue to be refined as new pools are discovered.

The likelihood of finding oil or gas in sufficient quantity to justify commercial production is enhanced first by the availability of acreage with good potential. The use of improved technology provides a higher probability of discovery. The existence of surface facilities to collect, process and move the production to market lowers the cost of developing a discovery, thereby reducing the field size that is necessary to declare commercialization.

Table 3-2. Total Alaska Exploratory Wells, North Slope and Cook Inlet, 1995-2003

	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Total Wells	8	10	13	14	5	8	19	21	14	113
Prudhoe Unit			1	5	1			1		8
Other North Slope Onshore	3	4	4	5	1		4	1	0	22
Other North Slope Offshore			2					1	4	7
NPR-A						4	5	4	1	14
Alpine (Colville River Unit)	4	5		1	2	1	5		1	19
Southwest Kuparuk			4		1	3	2	3		13
Cook Inlet	1	1	2	2			4	3	3	16
Shallow Gas				1				8	5	14

Source: Well data from Alaska Oil and Gas Conservation Commission through November 2003.

Exploratory drilling in Alaska is risky. On the North Slope, since 1994, we estimate that about 70% of the wells failed to discover economically recoverable reserves. There were good years in which over 60% of the wells drilled led to commercial discoveries, interspersed with bad years where drilling failed to yield a commercial discovery.

Table 3-3. North Slope Exploration Summary, 1994-2002

	Total Wells	Oil Discovery	Suspended	Plugged and Abandoned
1994	6	0	1	5
1995	7	4	2	1
1996	9	2	2	5
1997	10	6	1	3
1998	10	6	0	4
1999	5	2	3	0
2000	7	0	0	7
2001	16	3	5	8
2002	10	1	2	7

In addition to being risky, drilling exploration wells in Alaska is expensive, especially "wildcat" wells or wells drilled in remote locations. The United States Geological Survey (USGS) estimates that drilling a wildcat well in a remote area like the National Petroleum Reserve-Alaska (NPR-A) costs over two-and-a-half times what it would cost to drill a development well at Prudhoe Bay.(1) The USGS believes that the accumulations in the NPR-A will be moderate in size, in the reserves range "commonly developed as "stand alone" or satellite fields on the central Alaska North Slope in recent years" of less than 250 million barrels. Large accumulations like Prudhoe Bay "are not expected to occur."(2)

Between 1995 and 2003 an average of approximately 12 exploratory wells were drilled annually on the North Slope and in Cook Inlet (see Table 3-2 on the prior page.) In 1999, the year of the last major oil price crash, only five North Slope wells were drilled.

A flurry of exploration activity occurred in 2000, 2001 and 2002 as the result of several key events: (1) the discovery of Alpine; (2) the leasing of NPR-A acreage close to the developing Alpine field; (3) discoveries and development of Tarn and Meltwater, southwest of the main Kuparuk field; and (4) high oil prices.

Oil discoveries were announced in the NPR-A but no specific development plans have been made public. The two key factors that underpin exploration activity, attractive acreage and proximity to existing surface facilities were definitely in play during this period. ConocoPhillips drilled 10 of the 14 NPR-A wells drilled over the 2000-2003 time period, with BP drilling two wells and Anadarko drilling one. Drilling in the NPR-A tapered off to one well in 2003 at Puviaq.

Seven offshore wells were drilled over the period 1995-2003: Liberty and Warthog in 1997, McCovey in 2002 and three wells in the Oooguruk Unit and one offshore Kuparuk in 2003. Marginally economic oil reserves lie in Liberty and oil was discovered in the Oooguruk Unit. The other three wells found little or no oil.

BP, as a Prudhoe Bay unit operator, continued a steady program of exploring near existing fields in the late 1990's that resulted in the several new commercial discoveries. BP has announced that they will not be exploring outside of existing units. Other unit partners such as ConocoPhillips and ExxonMobil would have paid a proportional share of the cost of these wells.

In 2002, policymakers decided that something must be done to encourage wildcat exploration on the North Slope. The number of exploratory wells drilled there had declined from 16 in 2001 to six to 2003. The second largest producer in Alaska, BP, swearing off frontier exploration in Alaska, had laid off or sent their exploration people to Houston, and sold off their exploration lands and 3-D seismic. As pointed out previously, wildcat exploration is expensive and risky. To encourage wildcat exploration, the legislature passed and the governor signed into law SB 185, that provides for a credit against exploration expenses for wells drilled far away from other wells or unit infrastructure.

(1) See USGS Open-File Report 03-44, "Economics of Undiscovered Oil in Federal Lands on the National Petroleum Reserve, Alaska," (January 2002) by Emil D. Attanasi [NPR-A Economic Report] at Pages 20-21.
(2) See USGS Fact Sheet 045-02, "U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPR-A)" [NPR-A Fact Sheet].

Activity in the Cook Inlet saw an average of two wells per year with a total of 10 wells drilled between 2001 and 2003. The effect of higher natural gas prices and seasonal shortages of natural gas to supply industrial demand, as well as royalty incentives, all played a role in encouraging the search for new gas reserves in the Cook Inlet region.

The other major boost to exploration activity is in the drilling of shallow gas wells targeting coal bed methane as evidenced by the 13 shallow gas wells drilled by Evergreen over the last two years. Higher gas prices, proximity to the existing natural gas grid and local market as well as favorable royalty treatment no doubt have contributed to interest in exploring for this resource.

Given the high cost of drilling exploratory wells, it should come as no surprise that nearly 80% of the non-shallow gas exploratory wells over the 1995-2002 period were drilled by the two major producers/operators on the North Slope, ARCO/ConocoPhillips and BP. ARCO/ConocoPhillips accounted for roughly 60% of the exploratory wells drilled. The third major producer, ExxonMobil, did not drill any exploratory wells.

However, other companies have been drilling. In 2003, Pioneer Natural Resources drilled the three wells in the Oooguruk Unit between Kuparuk River Unit and Thetis Island that discovered oil. Winstar drilled offshore from Oliktok Point. Forest Oil has been very active exploring the Redoubt Unit in the Cook Inlet. Marathon and Unocal, as well as ConocoPhillips, have been active exploring for gas in the Cook Inlet.

Conclusion

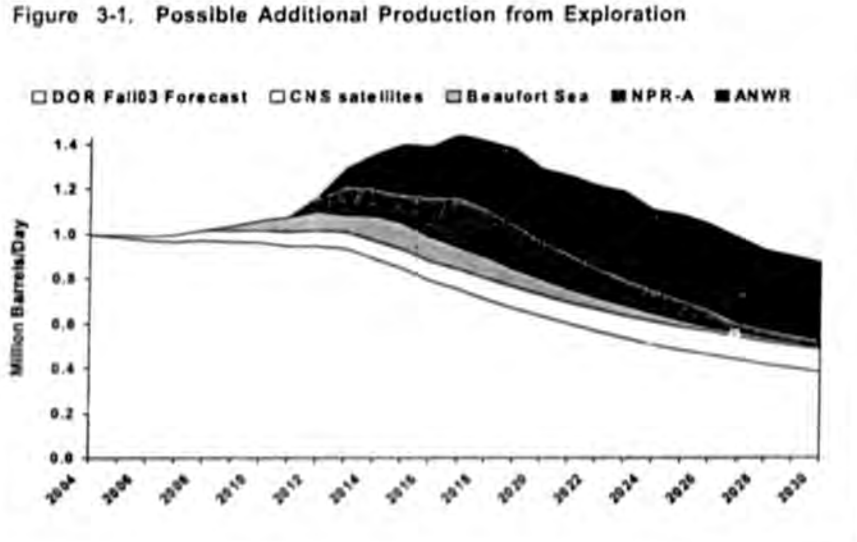
- Recent exploration activity has been relatively concentrated in one firm, ConocoPhillips.
- New entrants, however, are buying leases and in some cases drilling wells (Encana, Winstar, and Pioneer Resources)
- Major increases in exploration drilling are going to overwhelmingly be driven by the opening up of new areas that are located close to existing surface infrastructure. The most recent example is the NPR-A, where the eastern area lies close to the western edge of the North Slope oil gathering infrastructure at Alpine.
- Although oil and gas prices can make a difference in terms of cash available to explore, high oil prices alone may not be enough to cause the biggest current producers on the North Slope to drill North Slope exploration wells in 2004.
- Clearly, investment in surface infrastructure can dramatically improve the commerciality of exploring and development. This is the motivation for the initiative by the state to plan for road and bridge access to the NPR-A. Some exploration wells have been drilled recently by companies with little or no access to surface facilities; however most wells are drilled by companies with existing production and facilities.

Developing New Oil Fields

Exploration and aggressive development of found oil reserves could place ANS production on an increasing path by the end of this decade. Here, we have highlighted four areas that could be sources for such growth: the Central North Slope satellites, Beaufort Sea, NPR-A and ANWR. ANWR could provide as much — or more — in oil reserves and production as the other three areas combined. Oil exploration incentives, as provided in the recently adopted exploration tax credit, as well as the initiative to build a new year-round access road to the NPRA-A are designed to encourge the exploration necessary to realize this additional oil production.

Also, exploration is not the only way to add reserves. For instance, more aggressive development of heavy oil resources could add reserves and production. Whether we reach this higher production path depends crucially on the level of exploration and development spending, something which must increase from depressed 2002 and 2003 levels.

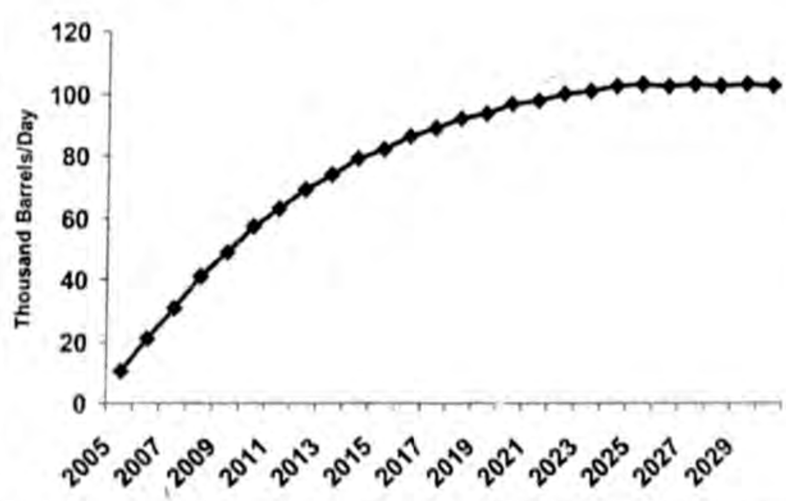
Figure 3-1. Possible Additional Production from Exploration



Central North Slope Satellites

In its last slope-wide evaluation of oil and gas resources, the USGS estimated that there were 2.3 billion barrels of technically recoverable, undiscovered oil reserves in the Central coastal regions of the North Slope. The USGS believed this oil would mainly be in the "Turbidite" and "Barrow Arch Beaufortian" geological plays.[1] Since that evaluation in 1995, producers have discovered and put into production more Turbidite (Meltwater, Tarn, Tabasco, Midnight Sun and Aurora) and Barrow Arch Beaufortian (Alpine and Polaris) reservoirs.[2] Adjusting these technically recoverable barrels to take into account recent discoveries, we estimate that there are about 1.9 billion barrels of technically recoverable oil still remaining to be found in the Central Coastal regions. The USGS also felt that around half of this technically recoverable oil would be economically recoverable.[3] Of the estimated 1.9 billion barrels of technically recoverable oil remaining net of post-1995 discoveries, 880 million barrels should be economically recoverable.

Figure 3-2. Potential Increase in Production from Central North Slope Satellite Fields



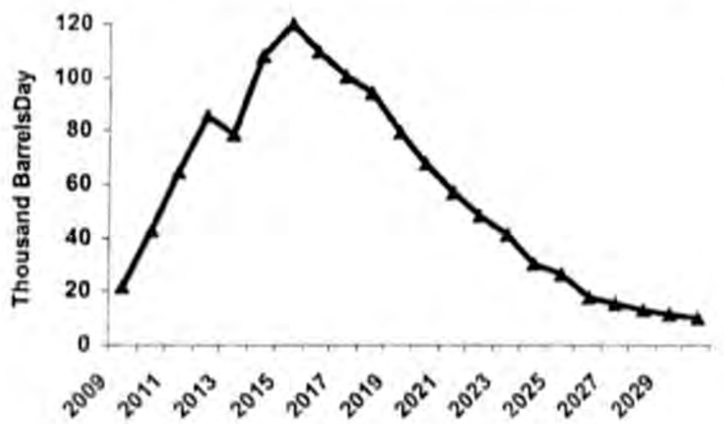
(1) USGS Open-File Report 95-75I, Emil Attanasi and Ken Bird, "Economics and undiscovered conventional oil and gas accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Alaska," [USGS95], Table 3, Page 37.
(2) Since these barrels were put into production and therefore economically recoverable, we could have adjusted the economically recoverable, rather than technically recoverable, reserve numbers down. However, recent discoveries will not only turn undiscovered barrels into discovered barrels. They will add geological information that increases the estimate of undiscovered, technically recoverable, reserves. To roughly offset this effect we have kept constant the percentage of technically recoverable barrels that are economically recoverable.
(3) Of the Central Coastal region's 1.9 billion barrels of remaining technically recoverable reserves, 45.75% (916 million barrels) should be economically recoverable. The economic recovery factors reflect mid-points between the $18 and $30 cases of USGS[95] Table 3.

Finding and producing these reserves will require further investments in exploration and development. Due to capital constraints, these reserves will come on slowly. We derive a conservative production forecast for these satellites and fields by assuming that 75 million barrels of additional Central North Slope reserves will be put into production every other year starting in 2005. The 75 million barrels assumption is conservative because in 2001 and 2002 the producers put three satellites with about 300 million barrels of reserves into production. However, in 2003 there were no new satellite discoveries put into production. Exploration efforts continue though. Pioneer recently announced an oil find just north of Kuparuk in the newly formed Oooguruk unit. By 2010, currently unannounced satellite developments could add around 50,000 barrels a day to our forecast.

Beaufort Sea

In total, U.S. Minerals Management Service (MMS) estimates that there are 8.82 billion barrels of technically recoverable reserves and 2.27 billion barrels of economically recoverable oil at $18 per barrel oil prices and around 2.5 billion barrels at $22 per barrel. The MMS recently held Beaufort Sea Lease Sale 186 that garnered $10 million in bonus bids. For the Beaufort Shelf area, the MMS projects that the three fields developed from areas leased in this sale will yield 460 million barrels of reserves. See James D. Craig, "Economic Results, Beaufort Shelf Province."

Figure 3-3. Possible Production from Beaufort Sea-Lease Sale 186



NPR-A

In 2001, ConocoPhillips announced an oil discovery in the NPR-A. Currently, the Bureau of Land Management (BLM) is completing an environmental impact statement (EIS) for possible development of these discoveries as Alpine satellites. We estimate that the NPR-A will yield 430 million barrels of oil in our production forecast. Production starts in FY 2009 and ramps up to 60,000 barrels a day by 2015.

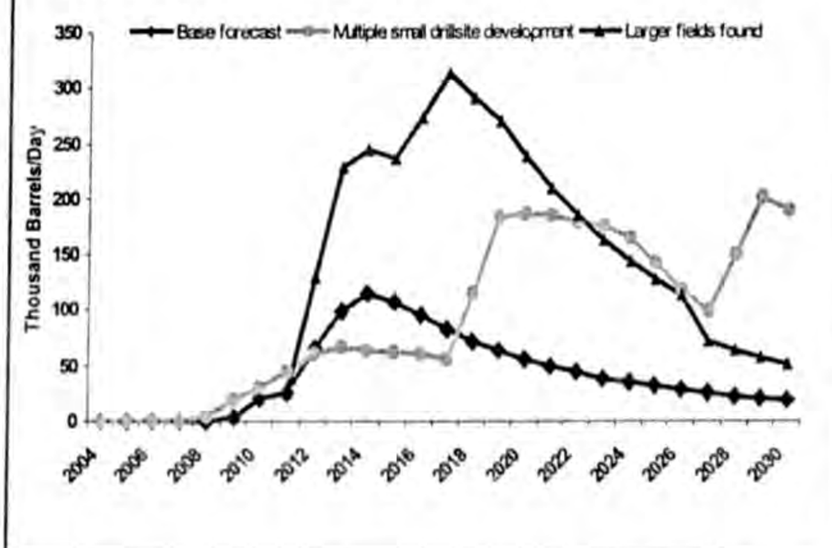
The NPR-A might yield more oil reserves, oil reserves that could be produced at a higher rate. The USGS evaluated the oil and gas resources in the NPR-A in 2002, and concluded that there were 9.3 billion barrels of technically recoverable reserves there. Of that amount, the USGS concluded that 1.3 billion barrels would be economic to explore for and produce at a $22 per barrel ANS West Coast oil price — our long run price forecast.[1] In the EIS, BLM envisions a development of multiple drill sites along with two new central processing facilities in the NPR-A. Provisionally, the BLM estimates the NPR-A reserves from this development would be around 1.4 billion barrels, slightly higher than the USGS's 2002 number.

How quickly these reserves are produced depends on the pace of exploration and the size of the fields discovered. Since 2000, 14 exploration drills have been drilled in the NPR-A and a further three or four are planned for the 2003-2004 drilling season. The USGS assumed that there were about eight accumulations with 256 to 512 million barrels in the NPR-A, three of which were in "Subarea 110" of the NPR-A, the area closest to Alpine and TAPS.[2] For the NPR-A these are large fields, and these larger fields would be produced before smaller accumulations since they are easier to find and more economic to develop.[3] After an initial round of exploration (assuming 20 wildcat wells), the USGS believes that one of these three 256-512 million barrel fields would result in a 430 million barrel field discovery. Under the USGS's cost and development assumptions, to overcome the challenges facing NPR-A development requires that the potential prize of a larger field (400 million barrels or more) is needed for exploration at $22 per barrel oil prices. Once found, a relatively small field (250 million barrel) will be economic. Explorers just will not incur high exploration costs to look for those fields.

(1) See NPR-A fact sheet.
(2) See USGS fact sheet histogram. The USGS divided the NPR-A into eight subareas for the purpose of estimating product transportation costs to TAPS. See Economic report at Page 17.
(3) See USGS fact sheet, "The economic analysis simulates exploration by assuming that larger accumulations will be discovered early..."

The graph illustrates the production from the NPR-A in our forecast, and the additional production from the NPR-A if a larger field is found or, alternatively, if smaller fields are found and can be economically produced. Lowering exploration costs (through the recently enacted SB 185 or through a permanent road) make the higher forecast more likely to occur. The USGS estimates that the initial finding costs per barrel for the NPR-A is $0.39, or $168 million.[1] Explorers pay out these millions of dollars years before first production. Decreasing the cost of this frontier exploration by roughly 30% due to the passage of SB 185 will increase the rate of return on a 430 million barrel field a full percentage point — from 13% to 14% — at $22 per barrel oil prices.

Figure 3-4. NPR-A Production Forecast

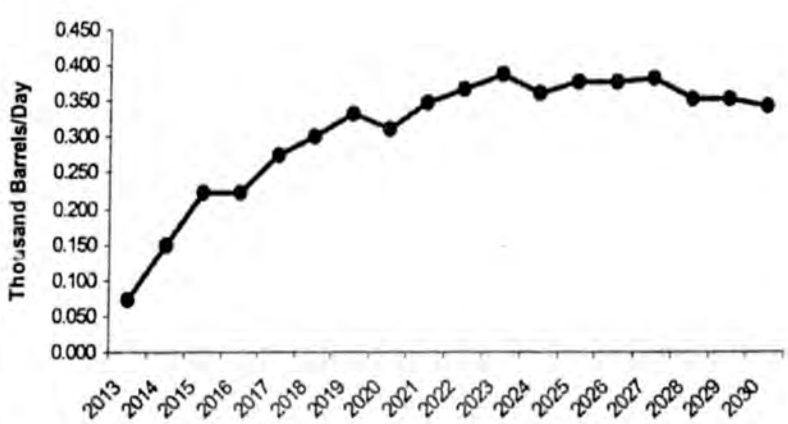


ANWR

The USGS estimates that there are 10.3 billion barrels of technically recoverable reserve in the Arctic National Wildlife Refuge (ANWR), or more barrels than the original estimate for the giant Prudhoe Bay field. At our forecast price of $22 per barrel, the USGS estimates that 4.4 billion barrels are economically recoverable from federal lands, and almost another billion from non-federal lands. Since ANWR production will probably come from larger fields (with an 80% chance of there being a 1.024 to 2.048 billion barrel field), production should ramp up quickly. We estimate that once Congress opens ANWR to oil exploration and development it will take seven years for the first oil to be produced from the area. If opened in 2006, ANWR is assumed to add between 200 and 400 thousand barrels a day of production by the middle of the next decade.

(1) See NPR-A Economic Report, Table 4, Page 37.

Figure 3-5. ANWR Production Forecast



Gas Line

The producers, the state and other interested parties continue to explore ways to monetize the over 30 trillion cubic feet of natural gas on the North Slope.[1] The three largest producers on the North Slope (BP, ConocoPhillips, and ExxonMobil) have looked at a project to pipe about 4.5 billion cubic feet of gas per day to markets in the Lower 48 or Canada. Many hurdles must be overcome for the project to proceed. If these hurdles are overcome, the state stands to receive around $600 million a year in royalty and severance tax payments per year. Including corporate income tax and property tax, revenues to the state and municipalities increase to around $1 billion per year. [2]

(1) Producers on the North Slope currently use the natural gas there to enhance oil production through miscible injection (EOR) projects, cycling and pressure maintenance. Natural gas also is used as field fuel, to fuel some of the pump stations on the Trans-Alaska pipeline and is sold in small quantities to local utilities.
(2) For purposes of this analysis, we have assumed a $4 per mmBtu price at market. We have not factored in possible changes to the state fiscal system. The state and municipal-take is based on the current fiscal structure. We also have not taken into account oil losses due to gas voidage from an oil and gas reservoir.

Conclusion

In our forecast of oil and gas base revenue (production tax and royalty), we project a decline of 30% by FY 2010 and almost 50% by FY 2015. However, by FY 2015 revenue from future oil exploration and a gas line could more than offset this anticipated decline in oil and gas base revenue from currently producing or discovered fields. With a very active oil and gas exploration and development effort, by FY 2015 our oil and gas base revenue could be 30% higher than it is today.

Figure 3-6. Possible Increases to the State's Severance Tax and Royalty Revenue from Future Exploration and Gas Line Project

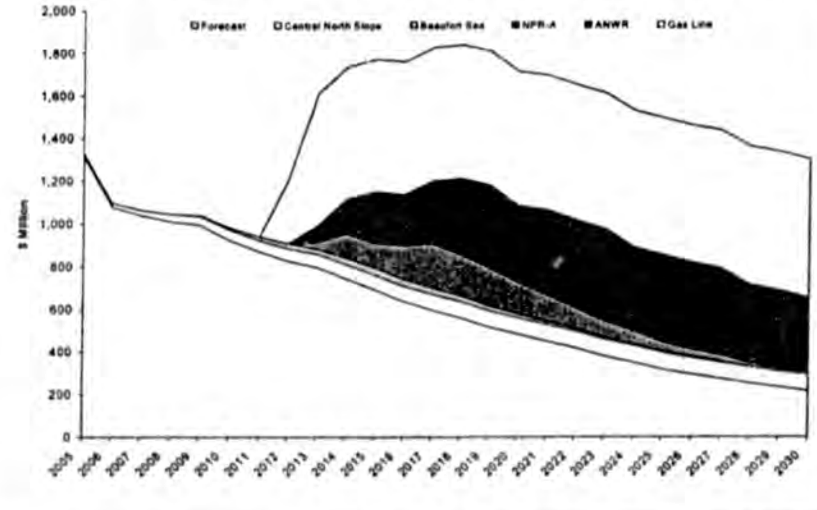


Table 3-4. Cummulative Revenue from New Oil Exploration and Gas Line Project to FY 2030 $ Millions (Undiscounted Dollars)

	Central North Slope and Satellites	Beaufort Sea	Additional NPR-A	ANWR	Gas Line	Total
2006	27	0	0	0	0	27
2010	174	18	0	0	0	192
2015	480	145	261	484	2,156	3,526
2020	854	268	1,145	2,122	5,282	9,672
2030	1,622	338	1,644	6,058	11,671	21,332

Minerals

Alaska's traditional resource-based industries in mining, fish, tourism and timber all have potential for growth. In this Revenue Sources Book, we have chosen to examine the mining industry. Most of this information comes from the "Alaska Minerals Industry 2002" report, Department of Natural Resources, 2003.

Mining

Between 2001 and 2002, the production value of industrial, energy and metal minerals increased 10% to over $1 billion. Industrial minerals (e.g., sand and gravel) increased from $82.4 million to $152.2 million, mostly as a result of increased road repair and construction. Energy minerals (e.g., coal) decreased from $48.3 million to $37.6 million, mostly due to the loss of exports to Korea. Metal minerals increased from $788.6 million to $823.1 million, mostly as a result of an increase in the price of gold.

In 2002, zinc prices decreased by more than 12% from 2001 but, as production increased, the total value of zinc decreased only by 1%. Even with prices dropping since the first half of 2001, zinc still accounted for over 60% of the production value for all metals.

Both gold and silver prices increased by 14% and 5%, respectively in 2002 and have continued to rise in 2003. In fact the price of gold in 2003 (January-October) is currently 16% higher and zinc prices are 3% higher than in 2002. According to Andrew Keen at the London Metal Exchange, lead and zinc prices should improve slowly in 2004. Additionally, Korea has signed a new two-year agreement to once again import coal from Alaska.

Employment in the minerals industry in 2002 was 2,824 full-time equivalent jobs, down by 11 from 2001. Average annual earnings in 2002 of $63,763 were among the highest in the state.

Producing Mines

The four largest producing mines in Alaska are:

Red Dog: Is a joint venture between Nana Regional Corporation and Teck-Cominco and the largest producer of zinc concentrate in the world. Out of a total of 718,106 tons of zinc produced in Alaska in 2002, Red Dog accounted for 637,800 or 89%. Red Dog has almost 550 employees.

Fort Knox: Is owned by Kinross Gold Corporation and produced 410,519 ounces of gold in 2002. This is 73% of the total production of gold in the state. Fort Knox has almost 400 employees.

Greens Creek: Is a joint venture between Kennecott Minerals and Hecla mining and is the third largest silver producer in North America. Out of a total of 17,858,183 ounces of silver produced in Alaska in 2002, Greens Creek produced 10,913,183 or 61%. Greens Creek has over 260 employees.

Usibelli Coal: Is owned by Usibelli Coal Mines Inc. and has among the lowest sulfur coal in the world. Usibelli produced 1,157,879 tons of coal which is essentially all of the commercial coal produced in Alaska. Usibelli had approximately 80 employees in 2002. In 2003, Korea signed a contract valued at $20 million with Usibelli to resume importing coal from Korea.

Advanced Stage Projects

The three largest advanced stage projects are:

Pogo: Is a joint venture between Sumitomo and Teck-Cominco and the closest of the three projects to construction. Start of construction should be by late 2003 or early 2004 and production should begin in late 2005 or early 2006. The mine should produce greater than 375,000 ounces of gold per year and should employ about 360 employees during production.

Kensington: Is owned by Coeur d'Alene min and still has some hurdles to overcome before construction can begin. However, if production does occur, then the mine should produce approximately 85,000 ounces of gold per year and have about 225 employees.

Donlin Creek: Is a joint venture between Placer Dome, NovaGold Resources, Calista Corporation and TKC and has the largest gold resource in Alaska. According to the Alaska Journal of Commerce (Bradner, 2003) the largest "challenge" to overcome for Donlin Creek to become a producing mine is to find enough power to operate the mine.

Revenue

According to the Department of Natural Resources, the mining industry paid $15.2 million to the state and municipalities in 2002. Most of this revenue was from payments to municipalities ($9.7 million.) The mining industry makes revenue payments to the state in the form of rents and royalties, corporation income taxes (if the businesses are subchapter C corporations) and mining license taxes. We do expect some increase in the state revenues as a result of strong gold prices, improving zinc prices, a new coal contract with South Korea and in the long run from new developments.

The only advanced stage project development that we included in the forecast was Pogo because this project is the closest to construction and is the most likely to begin production within the next five years. No tax revenue would be realized in the two-year forecast window because production is not slated to begin until early 2006. Additionally, because of the 3½-year tax holiday after production starts, we would not see any mining license revenue until FY 2010 or 2011 at the earliest. Exploration credits may be applied against 50% of royalties and tax liabilities and further reduce revenue.