2002 Report

Tables & Graphs Edition

December

Alaska Department of
NATURAL
RESOURCES
DIVISION OF OIL AND GAS

Front cover:

Views of Atigun Gorge at central Brooks Range mountain front near Dalton Highway and Trans-Alaska Pipeline route. Thrust sheets of limestone of the Lisburne Group (Mississippian) form the mountain front in the distance; outcrops to the right consist of conglomerate basin fill of the Fortress Mountain Formation (Lower Cretaceous) at the southern margin of the Colville Basin.

Gil Mull

STATE OF ALASKA
Governor Frank H. Murkowski

ALASKA DEPARTMENT OF NATURAL RESOURCES
Tom Irwin, Commissioner

DIVISION OF OIL AND GAS
Mark D. Myers, Director

This publication was released by the Division of Oil and Gas, Anchorage, Alaska. For more information about this report, contact the Division of Oil and Gas, 550 W 7th Ave. Suite 800, Anchorage, Alaska, 99501. This report is also available for download at http://www.dnr.state.ak.us/oil/products.

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Forward

This report replaces the annual "Historical and Projected Oil and Gas Consumption" report that the Division of Oil and Gas has published between 1979 and 1999. The Division issued a 2000 annual report for year-end 1999 data, but did not issue a report for year-end 2000 data. Included in this report are data covering historical production for annual years 2000 and 2001. It includes the division's most recent oil production forecasts by field, and reserve estimates. This is the Tables and Graphs Edition. A complete 2002 Report will be available March 2003 at:

http://www.dog.dnr.state.ak.us.

2002 Report
Tables and Graphs Edition

Alaska Department of Natural Resources

Division of Oil and Gas

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Section One

Leasing Licensing & Incentives

Oil & Gas Units

Leasing

Areawide Leasing

Oil and gas lease sales are the initial step in a process that generates nearly 80 percent of the state's General Fund Revenue. Although the primary purpose of leasing state lands is to provide for oil and gas development and the subsequent economic benefits, the program in itself has been a significant revenue source. Through lease sale bonus bids alone, the state has received over $2 billion in revenue.

The State of Alaska has held 94 competitive lease sales since 1959. To date, 16 million acres have been leased with total cash bonus proceeds exceeding $2 billion. Several leasing methods, authorized under the AS 38.05, the *Alaska Lands Act*, are used to encourage oil and gas exploration and development and maximize state revenue. These methods include combinations of fixed and variable bonus bids, royalty shares and net profit shares. The fixed terms generally involve an obligation to remit royalty payments in the form of a 12.5 or 16-2/3 percent share of gross production paid in-kind or in-value. Occasionally, the state has imposed a fixed royalty rate of 20 percent. The minimum royalty obligation is 12.5 percent. The state has also used sliding-scale royalty terms in its leases based on production or oil price or gross revenue. In several sales, the state has offered acreage and leased with a fixed net profit share in addition to a fixed royalty rate. Net profits are defined as the share of revenues from production from the lease net of investments and ongoing operating costs. Table II.1 (below) summarizes the key features and results of competitive lease sales since 1959.

ALASKA OIL AND GAS LEASING PROGRAM

The most common bid variable used by the state is the cash bonus. The state may require minimum bids of $5 to $10 per acre (and sometimes higher). The state may also use the royalty rate or the net profit share as the bidding variable, though this has happened only rarely (Sale 30 was one of these occasions). As shown in Table II.1, the average high bid for all competitive lease sales held since 1959 is $128.24 per acre.

The division annually issues a new *Five-Year Oil and Gas Leasing Program* that sets out the sale schedule for the succeeding five years. All proposed lease sales are areawide sales held each year. An areawide sale is one in which all available state acreage within a geographic region is included. The four geographic regions are the North Slope, North Slope Foothills, Beaufort Sea, and Cook Inlet. The first such sale was the North Slope Areawide held in June 1998. Since then areawide sales have been held in the other three regions. Areas outside of these regions are available for exploration through other oil and gas programs.

Sale Areas
A total of 20 lease sales are currently scheduled over the next five years; five in each of the regions.

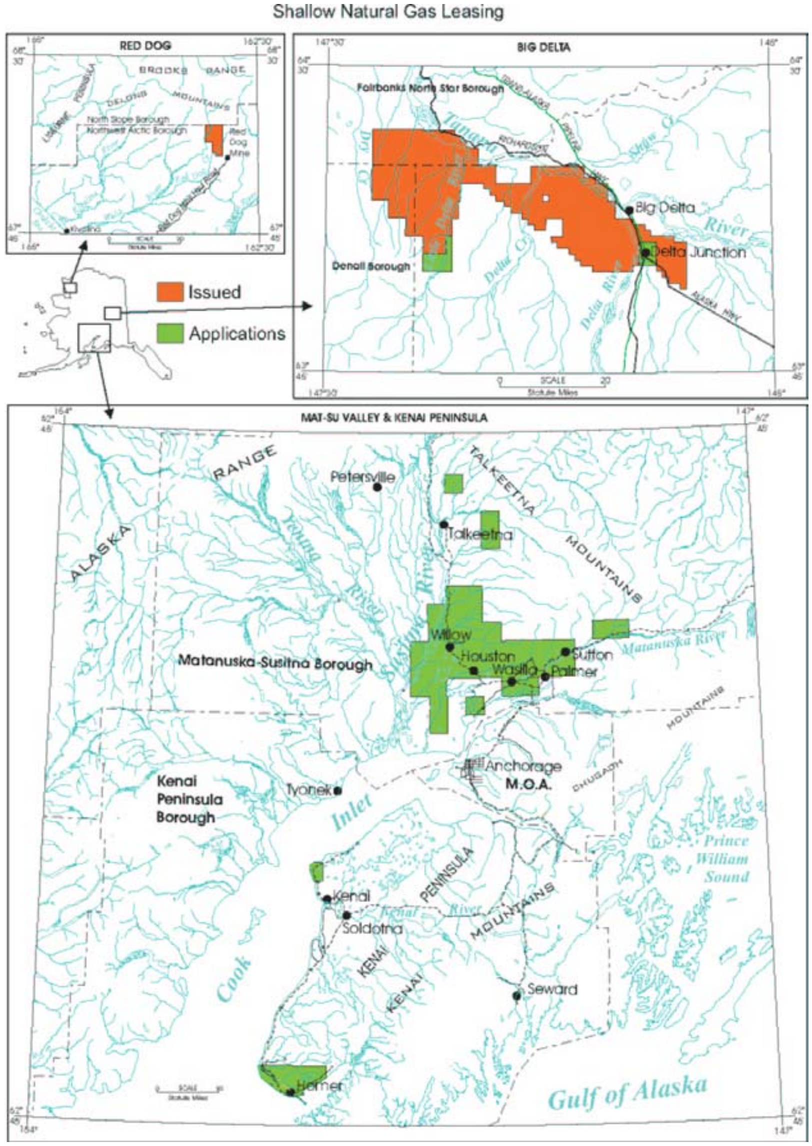
STATE OF ALASKA
FIVE-YEAR OIL AND GAS LEASING PROGRAM

2003 through 2007

Sale	Annually Held In
North Slope Foothills Areawide	May
Cook Inlet Areawide	May
North Slope Areawide	October
Beaufort Sea Areawide	October

If the decision is to proceed with an areawide sale, a sale announcement, including the sale terms, bidding method, tract map, and mitigation measures will be issued 90 days prior to that sale. If a best interest finding or a supplement to a previous finding is required, it will be released at the same time as the sale announcement.

Shallow Gas Leasing



Alaska's newest leasing program allows the Division of Oil and Gas to issue non-competitive leases to explore for and develop natural gas from fields if part of the field is within 3,000 feet of the surface.

To encourage participation, there is no bonus payment to the state for the right to explore on a lease. The application fee is $5000, and the annual rental payments remain at $1 per acre (rather than increasing to $3 per acre, as with a conventional oil and gas lease). The royalty rate is 6.25 percent unless the gas is produced "in direct competition" with conventional gas. Then the royalty is 12.5 percent. The term of a lease is limited to three years, unless the director approves one three-year extension. The lessee has the ability to extend the life of the lease so long as there is production. A lease may consist of up to 5,760 acres, and a lessee may not hold more than 138,240 acres (six townships) of leased land under this program.

If a well penetrates a formation capable of producing that does not extend to within 3,000 feet of the surface or penetrates a formation capable of producing oil, no further operations may be conducted until the lessee complies with all applicable laws and regulations relating to oil and gas exploration and production.

Lands subject to an Exploration License or the state's Five-Year Oil and Gas Leasing Program are not eligible for a shallow gas lease. Also, if the land is held under a coal lease, only that lessee may apply for a shallow gas lease. The Commissioner of Natural Resources may waive any of these limitations.

As of year-end 2002, 69 shallow gas leases have been issued, consisting of 475,225 acres; 198 lease applications are pending.

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable
12/10/1959	1	Cook Inlet	88,055	77,191	87.66%	$52.08	37	31	$4,020,342	Bonus; No Min
7/13/1960	2	Cook Inlet	17,568	16,506	93.96%	$24.70	27	26	$407,655	Bonus; No Min
12/7/1960	3	Mixed	73,048	22,867	31.30%	$1.54	26	9	$35,325	Bonus; No Min
1/25/1961	4	Cook Inlet	400	400	100.00%	$679.04	3	3	$271,614	Bonus; No Min
5/23/1961	5	Mixed	97,876	95,980	98.06%	$74.71	102	99	$7,170,465	Bonus; No Min
8/4/1961	6	Gulf Ak	13,257	13,257	100.00%	$8.35	6	6	$110,672	Bonus; No Min
12/19/1961	7	Mixed	255,708	187,118	73.18%	$79.43	68	53	$14,863,049	Bonus; No Min
4/24/1962	8	Cook Inlet	1,062	1,062	100.00%	$4.80	8	8	$5,097	Bonus; No Min
7/11/1962	9	Mixed	315,669	264,437	83.77%	$59.42	89	76	$15,714,113	Bonus; No Min
5/8/1963	10	Cook Inlet	167,583	141,491	84.43%	$29.23	200	158	$4,136,225	Bonus; No Min
12/11/1963	12	Cook Inlet	346,782	247,089	71.25%	$12.31	308	207	$3,042,681	Bonus; No Min
12/9/1964	13	Mixed	1,194,373	721,224	60.39%	$7.68	610	341	$5,537,100	Bonus; No Min
7/14/1965	14	North Slope	754,033	403,000	53.45%	$15.25	297	159	$6,145,473	Bonus; $1/acre Min
9/28/1965	15	Cook Inlet	403,042	301,751	74.87%	$15.49	293	216	$4,674,344	Bonus; $1/acre Min
7/19/1966	16	Mixed	184,410	133,987	72.66%	$52.55	205	153	$7,040,880	Bonus; $1/acre Min
11/22/1966	17	Cook Inlet	19,230	18,590	96.67%	$7.33	36	35	$136,280	Bonus; $1/acre Min
1/24/1967	18	Mixed	47,729	43,657	91.47%	$33.90	23	20	$1,479,906	Bonus; $1/acre Min
3/28/1967	19	Kachemak Bay	2,560				'RULED INVALID 12/9/74			
7/25/1967	20	Cook Inlet	311,250	256,447	82.39%	$73.14	295	220	$18,757,341	Bonus; $1/acre Min
3/26/1968	21	Ak Pen	346,623	164,961	47.59%	$18.24	308	147	$3,009,224	Bonus; $1/acre Min
10/29/1968	22	Cook Inlet	111,199	60,272	54.20%	$17.29	230	125	$1,042,220	Bonus; No Min
9/10/1969	23	North Slope	450,858	412,548	91.50%	$2,181.66	179	164	$900,041,605	Bonus; No Min
5/12/1971	24	Cook Inlet	196,635	92,618	47.10%	$4.92	244	106	$455,641	Bonus; No Min
9/26/1972	25	Cook Inlet	325,401	178,245	54.78%	$7.43	259	152	$1,324,673	Bonus; No Min
12/11/1972	26	Cook Inlet	399,921	177,973	44.50%	$8.75	218	105	$1,557,849	Bonus; No Min
5/9/1973	27	Cook Inlet	308,401	113,892	36.93%	$9.92	210	96	$1,130,325	Bonus; No Min
12/13/1973	28	Cook Inlet	166,648	97,804	58.69%	$253.77	98	62	$24,819,190	Bonus; No Min
10/23/1974	29	Cook Inlet	278,269	127,120	45.68%	$8.19	164	82	$1,040,910	Bonus; No Min
7/24/1979	29B	Copper Riv	34,678	34,678	100.00%	$4.56	20	20	$158,042	Bonus; No Min
12/12/1979	30	Beaufort Sea	341,140	296,308	86.86%	$1,914.87	71	62	$567,391,497	Net Profit Share (NPS)
9/16/1980	31	North Slope	196,268	196,268	100.00%	$63.12	78	78	$12,387,470	Bonus; No Min
5/13/1981	33	Cook Inlet	815,000	429,978	52.76%	$10.00	202	103	$4,299,782	Royalty; 20% Min
8/25/1981	32	Cook Inlet	202,837	152,428	75.15%	$10.00	78	59	$1,524,282	Royalty; 20% Min
2/2/1982	35	Cook Inlet	601,172	131,191	21.82%	$10.00	149	31	$1,311,907	Royalty; 12.5% Min
5/26/1982	*36	Beaufort Sea	56,862	56,862	100.00%	$573.02	13	13	$32,583,452	Bonus; No Min
8/24/1982	*37	Copper River	852,603	168,849	19.80%	$3.33	217	33	$562,944	Bonus; No Min
8/24/1982	37A	Cook Inlet	1,875	1,875	100.00%	$52.00	1	1	$97,479	Bonus; No Min
9/28/1982	*34	North Slope	1,231,517	571,954	46.44%	$46.70	261	119	$26,713,018	Bonus; No Min
5/17/1983	*39	Beaufort Sea	211,988	211,988	100.00%	$99.05	42	42	$20,998,101	Bonus; $10/acre Min
9/28/1983	40	Cook Inlet	1,044,745	443,355	42.44%	$7.17	284	140	$3,177,178	Bonus; $1/acre Min
5/22/1984	43	Beaufort Sea	298,074	281,784	94.53%	$114.32	69	66	$32,214,794	Bonus; $10/acre Min
5/22/1984	*43A	North Slope	76,079	76,079	100.00%	$125.44	15	15	$1,612,583	Bonus; $10/acre Min
9/18/1984	41	Bristol Bay	1,437,930	278,939	19.40%	$3.03	308	63	$843,965	Bonus; No Min
2/26/1985	46A	Cook Inlet	248,585	190,042	76.45%	$13.28	65	50	$2,523,334	Bonus; $1/acre Min
9/24/1985	45A	North Slope	606,385	164,885	27.19%	$28.25	113	32	$4,657,478	Bonus; $5/acre Min
9/24/1985	47	North Slope	192,569	182,560	94.80%	$63.79	50	48	$11,645,003	Bonus; $5/acre Min
2/25/1986	48	North Slope	526,101	266,736	50.70%	$9.16	104	54	$2,444,342	Bonus; $5/acre Min
2/25/1986	48A	Beaufort Sea	42,053	42,053	100.00%	$12.13	11	11	$510,255	Bonus; $5/acre Min
6/24/1986	49	Cook Inlet	1,189,100	394,881	33.21%	$2.40	260	98	$947,171	Bonus; $1/acre Min

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable
1/27/1987	51	North Slope	592,142	100,632	16.99%	$2.88	119	26	$289,625	Bonus; $2/acre Min
6/30/1987	50	Beaufort Sea	118,147	118,147	100.00%	$56.05	35	35	$6,621,723	Bonus; $5/acre Min
1/26/1988	*54	North Slope	421,809	338,687	80.29%	$13.83	89	72	$4,683,388	Bonus; $5/acre Min
9/28/1988	55	Beaufort Sea	201,707	96,632	47.91%	$152.13	56	25	$14,700,602	Bonus; $10&$25/ac Min
9/28/1988	69A	North Slope	775,555	368,490	47.51%	$16.61	155	75	$6,119,135	Bonus; $5/acre Min
1/24/1989	52	Beaufort Sea	175,981	52,463	29.81%	$33.12	43	15	$1,737,513	Bonus; $10/acre Min
1/24/1989	72A	North Slope	677	677	100.00%	$671.90	1	1	$454,977	Bonus; $10/acre Min
1/29/1991	*67A	Cook Inlet	549,364	191,588	34.87%	$28.77	140	55	$5,511,338	Bonus; $5/acre Min
1/29/1991	*70A	North Slope	532,153	420,568	79.03%	$65.88	135	109	$27,707,541	Bonus; $5/acre Min
6/4/1991	64	North Slope	754,542	34,143	4.52%	$7.10	141	6	$242,389	Bonus; $5/acre Min
6/4/1991	*65	Beaufort Sea	491,091	172,865	35.20%	$40.46	108	36	$6,993,949	Bonus; $5/acre Min
9/24/1991	*74A	Cook Inlet	605,851	26,605	4.39%	$12.06	134	5	$320,853	Bonus; $5/acre Min
1/22/1992	61	North Slope	991,087	260,550	26.29%	$9.32	181	46	$2,429,551	Bonus; $5/acre Min
6/2/1992	68	Beaufort Sea	153,445	0	0.00%	$0.00	36	0	$0	Bonus; $10/acre Min
12/8/1992	75	North Slope	217,205	124,832	57.47%	$78.11	90	55	$9,750,111	Bonus; $10/acre Min
1/26/1993	76	Cook Inlet	393,025	141,504	36.00%	$461.25	86	36	$65,269,167	Bonus; $5/acre Min
1/26/1993	67 A-W	Cook Inlet	282,577	129,810	45.94%	$18.75	69	33	$2,433,864	Bonus; $5/acre Min
5/25/1993	77	North Slope	1,260,146	45,727	3.63%	$25.47	228	8	$1,164,555	Bonus; $5/acre Min
5/25/1993	70 A-W	North Slope	37,655	28,055	74.51%	$48.41	11	8	$1,358,027	Bonus; $10/acre Min
9/21/1993	57	North Slope	1,033,248	0	0.00%	$0.00	196	0	$0	Bonus; $5/acre Min
9/21/1993	75A	North Slope	14,343	14,343	100.00%	$31.36	11	11	$449,847	Bonus; $10/acre Min
10/30/1994	78	Cook Inlet	396,760	136,307	34.36%	$12.14	90	34	$1,654,137	Bonus; $5/acre Min
11/14/1995	67A-W 2	Cook Inlet	152,768	13,804	9.04%	$7.29	36	3	$100,638	Bonus; $5/acre Min
11/14/1995	74W	Cook Inlet	66,703	17,015	25.51%	$31.76	16	4	$540,406	Bonus; $5/acre Min
11/14/1995	76W	Cook Inlet	251,614	14,220	5.65%	$5.61	50	4	$79,722	Bonus; $5/acre Min
11/14/1995	78W	Cook Inlet	260,453	36,478	14.01%	$7.06	56	11	$257,583	Bonus; $5/acre Min
12/5/1995	80	North Slope	951,302	151,567	15.93%	$22.02	202	42	$3,337,485	Bonus; $10/acre Min
10/1/1996	86A	North Slope	15,484	5,901	38.11%	$343.40	13	5	$2,026,247	Bonus; $100/acre Min
12/18/1996	85A	Cook Inlet	1,061,555	173,503	16.33%	$17.92	234	44	$3,109,603	Bonus; $5/acre Min
11/18/1997	86 **	Beaufort Sea	365,054	323,835	88.70%	$86.42	181	162	$27,985,125	Bonus, $10/acre Min
2/24/1998	85A-W	Cook Inlet	757,878	98,011	12.90%	$8.46	157	24	$828,807	Bonus, $5/acre Min
6/24/1998	87	North Slope	Areawide	518,689	N/A	$99.86	N/A	137	$51,794,173	Bonus, $5/acre Min
2/24/1999	NS 1999	North Slope	Areawide	174,923	N/A	$14.85	N/A	40	$2,596,838	Bonus; $5/acre Min
4/21/1999	CI 1999	Cook Inlet	Areawide	114,514	N/A	$10.75	N/A	41	$1,436,685	Bonus; $5/acre Min
8/16/2000	CI 2000	Cook Inlet	Areawide	100,480	N/A	$9.15	N/A	27	$919,750	Bonus; $5/acre Min
11/15/2000	BS 2000	Beaufort Sea	Areawide	25,840	N/A	$13.13	N/A	11	$338,922	Bonus; $10/acre Min
11/15/2000	NS 2000	North Slope	Areawide	652,355	N/A	$15.41	N/A	145	$10,052,665	Bonus; $5/acre Min
5/9/2001	CI 2001	Cook Inlet	Areawide	102,523	N/A	$9.05	N/A	29	$928,085	Bonus; $5/acre Min
5/9/2001	NSF 2001	NS Foothills	Areawide	858,811	N/A	$11.41	N/A	170	$9,799,277	Bonus; $5/acre Min
10/24/2001	BS 2001	Beaufort Sea	Areawide	36,331	N/A	$94.90	N/A	24	$3,447,734	Bonus; $10/acre Min
10/24/2001	NS2001	North Slope	Areawide	434,938	N/A	$15.89	N/A	146	$6,911,572	Bonus; $5/acre Min
5/1/2002	CI 2002	Cook Inlet	Areawide	64,923	N/A	$7.05	N/A	21	$421,841	Bonus; $5/acre Min
5/1/2002	NSF 2002‡	NS Foothills	Areawide	239,386	N/A	$14.32	N/A	51	$3,427,142	Bonus; $5/acre Min
10/24/2002	BS 2002***	Beaufort Sea	Areawide	35,240	N/A	$27.65	N/A	12	$974,487	Bonus; $10&$100/ac Min
10/24/2002	NS 2002***	North Slope	Areawide	39,680	N/A	$41.33	N/A	15	$1,639,898	Bonus: $10/acre Min
TOTAL: 94 Sales				**15,980,769**		**$128.24**		**5,856**	**$2,049,421,251**	

'*Economic Incentive Credits were offered for these sales.
** Sale 86A: State received $259,435; ASRC received $1,766,812.
*** Preliminary Results
‡ Sale NSF 2002 Bonus does not include 20% of Bonus bid retained ($1.25 Million) by the state for relinquished tracts

Licensing

Exploration Licensing

Exploration Licenses are designed to stimulate exploration in Alaska's frontier basins, and complement the state's oil and gas leasing program. The North Slope and Cook Inlet, which are the main thrust of the state's leasing program, remain off limits to Exploration Licensing.

Gil Mull

There are, however, several large sedimentary basins within interior Alaska, some of which are virtually unexplored. The highly variable structural geology of these basins offers the potential for structural traps in overthrust belts and strike slip systems. Various types of clastic and carbonate stratigraphic traps may also be present. Exploration Licensing will allow companies to explore these frontier basins with minimal initial costs.

An area selected for Exploration Licensing must be between 10,000 to 500,000 acres. A license will be awarded to the applicant who has committed the most dollars to an exploration program. The recipient of a license will be required to post a bond in the amount of the work commitment and pay a $1 per acre license fee. There are no additional charges during the term of the license, which can be up to 10 years.

During its term any portion of the licensed area may be converted to oil and gas leases. The term of the leases can then extend beyond the original term of the license. If converted, annual lease rentals are set at $3 per acre.

Licensing Process

The licensing process will be initiated in one of two ways: Each year during the month of April applicants may submit to the Commissioner of the Department of Natural Resources a proposal to conduct exploratory activity within an area they have specified. Or the commissioner, at anytime, can issue a notice requesting the submittal of proposals to explore an area designated by the commissioner. Once a request for proposals has been issued applicants will have 20 days to notify the commissioner of their intent to submit a proposal, and 60 days in which to submit.

Gil Mull

Within 30 days of receiving any proposal the commissioner will either reject it in a written decision or give public notice of the intent to evaluate the proposal's acceptability. This notice will solicit public comments on the proposal(s) and request competing proposals. The commissioner may also modify any proposal and request a new one based on those modifications.

Submitted proposals must (1) describe the area proposed to be subject to licensing, (2) state the specific minimum work commitment expressed in dollars, (3) describe the amount and form of security to be posted based on the projected cost of the planned exploration work, (4) propose the term of the license (unless already established by the commissioner) and (5) verify that a prospective licensee meets minimum qualifications.

Best Interest Finding
After considering all submitted proposals and public comment on those proposals the commissioner shall issue a written finding determining whether or not granting the Exploration License is in the state's best interests. The finding must describe the limitations, conditions, stipulations or changes from the initiating proposal or competing proposals that are required to make the issuance of the license conform to the best interests of the state. If only one proposal was submitted, the finding must also identify the prospective licensee. If the finding concludes that an Exploration License should be awarded and there has only been a single applicant, that applicant will have 30 days after issuance of the finding to accept or reject the license award.

T. Davidson

Bidding Process
If competing proposals are submitted and the commissioner determines that an Exploration License should be awarded, the commissioner will issue an invitation to submit a sealed bid. A bid deposit equal to 20 percent of the license fee must be submitted with the bid. The successful bidder will be the applicant who submits the highest bid in terms of exploration expenditures.

Once notified a successful bidder will have 10 days in which to accept or reject the license award. If the successful bidder fails to accept the award within the allotted time the bid deposit and the right to accept the award are forfeited. The next successive highest bidders will then have an opportunity to accept the award.

Relinquishment of Lands
If by the fourth anniversary of the Exploration License the licensee has completed less than 25 percent of the total work commitment the license will be terminated, with the remainder of the security forfeited to the state. If the licensee has completed less than 50 percent of the total work, then 25 percent of the licensed area will be relinquished, with an additional 10 percent relinquished each successive year until half of the original acreage has been relinquished.

License Applications
The state has issued two Exploration Licenses and currently has two pending.

Licenses Issued:

<u>Copper River Exploration License</u>

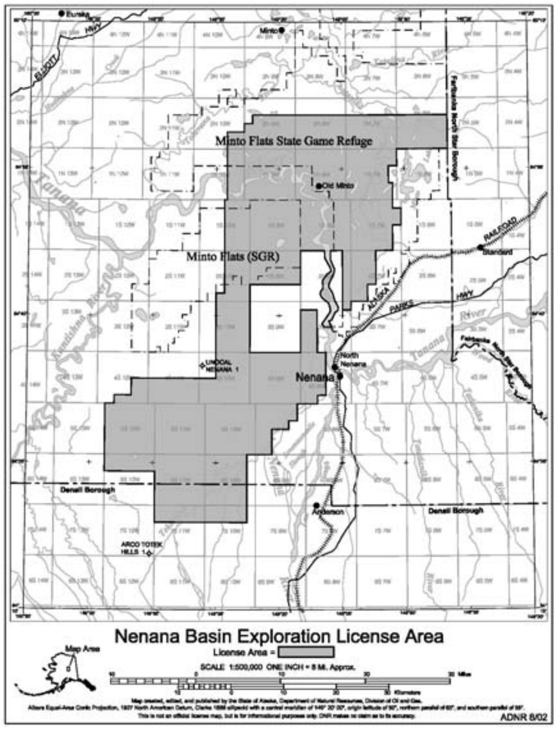
Licensee:	Forest Oil Corporation
Size:	398,445.44 Acres
Exploration Commitment:	$1,420, 000
Term:	5 years
Date Issued:	October 1, 2000

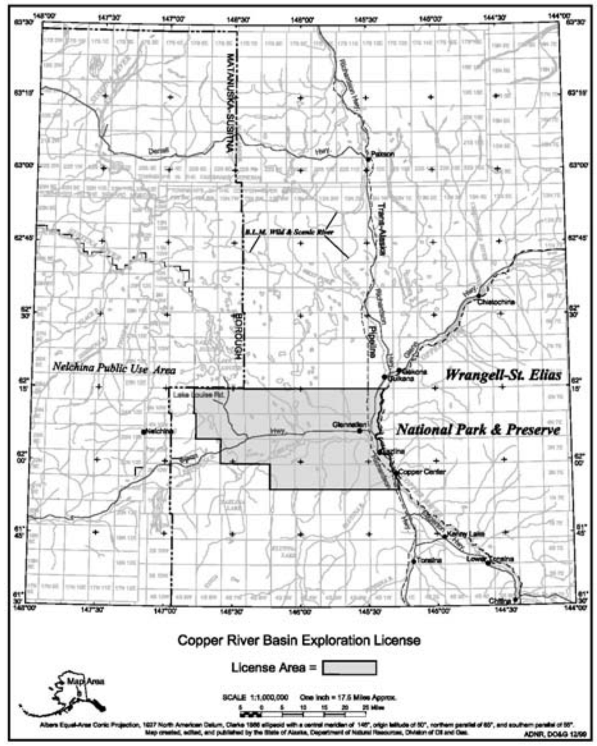
C. Ruff

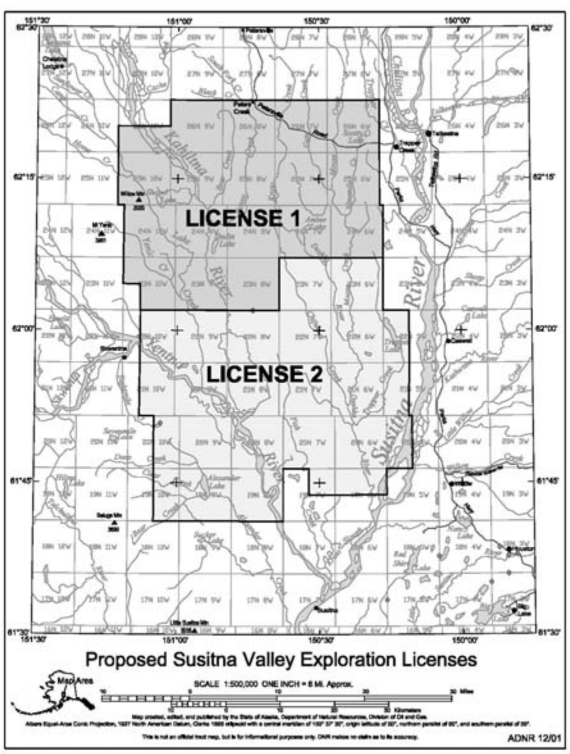
<u>Nenana Basin</u>

Licensee:	Andex Resources
Size:	482,941.83 Acres
Exploration Commitment:	$2,525,000
Term:	7 years
Date Issued:	October 1, 2002

Current Exploration License Areas







Licenses Pending:

Susitna Basin Exploration License I

Licensee:	Forest Oil Corporation
Size:	399,360 Acres

Exploration Commitment:
$2,520,000 proposed by applicant

Term: Not Yet Determined

Susitna Basin Exploration License II

Licensee:	Forest Oil Corporation
Size:	474,420 Acres

Exploration Commitment:
$3,000,000 proposed by applicant

Term: Not Yet Determined

Incentives

Exploration Incentive Credits

The state offers two programs authorizing an Exploration Incentive Credit (EIC).

Program I: This EIC is included as a term of the lease. AS 38.05.18(i) provides for a system in which a lessee of state land drilling an exploratory well may earn credits based upon the footage drilled and the region in which the well is situated. The statute also provides for an EIC for geophysical work on state land if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area. The geophysical information must be made public following the sale. Drilling information is held confidential for two years. If demonstrated by the lessee as necessary, confidentiality may be extended. The Commissioner of Natural Resources grants credits, which can be as high as 50 percent of the costs. Credits may be applied against royalty and rental payments to the state or taxes, or they may be assigned. Since the state began offering this program, lessees have earned \$54.7 million in credits for exploratory drilling.

B. Havelock

Gil Mull

Program II: This program, adopted in 1994 under AS 41.09.010 allows the Commissioner of Natural Resources to grant an EIC for exploratory drilling, the drilling of a stratigraphic test well and for geophysical work on land in the state, regardless of whether the land is state-owned. This program is designed to encourage oil and gas exploration within remote parts of the state and to provide a means for the state to obtain exploration data from federal lands and certain private lands. As with the first program, the credits may be applied against oil and gas royalties, rentals, lease sale bonus bids and taxes, or they may be assigned. Data derived from drilling will be kept confidential for two years, with no extension of this period. Copies of geophysical data may be shown to interested parties by the state, but may not be transferred to third parties. Credits may be as high as 50 percent of eligible costs if performed on state land, and as high as 25 percent when performed on federal or private land. A credit may not exceed \$5 million per eligible project, and the total of all credits may not exceed \$30 million. Drilling credits are based upon the footage drilled. All activity qualifying for this EIC must be completed by July 1, 2007.

Royalty Reduction

In 1995 the governor signed into law legislation that allowed the Commissioner of Natural Resources to adjust the royalty reserved to the state in order to encourage otherwise uneconomic production of oil and gas. If a delineated field or pool has not previously produced, the royalty can be lowered to 5 percent. If an existing producing field or pool, the royalty may be reduced to as low as 3 percent in order to prolong its economic life as costs per barrel or barrel equivalent increase. In order to establish production of shut-in oil or gas, the royalty may also be reduced to as low as 3 percent. These royalty reduction provisions expire on July 1, 2015.

Gil Mull

Incentives

Discovery Royalty

In 1996 the governor signed into law a measure that permits the granting of discovery royalty for wells in the Cook Inlet sedimentary basin that have discovered oil or gas in a previously undiscovered oil or gas pool, providing that the wells are capable of producing in paying quantities. The discovery royalty is established at 5 percent for 10 years following the discovery of a pool. The discovery royalty applies to all oil or gas from that pool that is attributable to the lease.

Gil Mull

CIRCAC

Cook Inlet Royalty Reduction

In 1998 the governor signed HB 380 that grants a 5 percent temporary royalty on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first ten years of production from six specified fields in the Cook Inlet sedimentary basin. The six fields eligible for royalty reduction were discovered before January 1, 1988 and have been undeveloped or shut. The fields identified in the law are Falls Creek; Nicolai Creek; North Fork; Point Starichkof; Redoubt Shoal; and West Foreland. Production from these fields must begin before January 1, 2004.

Oil and Gas Units

North Slope
Cook Inlet
Non-Unitized Production
Fields and Pools

TABLE 2.1 OIL & GAS UNITS

NORTH SLOPE WEST
Colville River
Southeast Delta
Kuparuk River

NORTH SLOPE CENTRAL
Milne Point
Sakonowyak River
Prudhoe Bay
Northstar
McCovey
Duck Island

NORTH SLOPE EAST
Badami
Slugger
Point Thomson

COOK INLET NORTH
Pioneer
Stump Lake
Lewis River
Pretty Creek
Beluga
North Cook Inlet

COOK INLET CENTRAL
South Granite Point
Nicolai Creek
North Trading Bay
Trading Bay
West McArthur River
South Middle Ground Shoal
Redoubt
Birch Hill
Swanson River
Beaver Creek
Sterling
Cannery Loop
Kenai River

COOK INLET SOUTH
Ninilchik
Falls Creek
South Ninilchik
Deep Creek
Cosmopolitan
North Fork

Oil and Gas Units

Unitization

Unitization is the grouping or pooling of working interest and royalty ownership in oil and gas leases that overlay a common petroleum reservoir. It is the accepted method for developing an oil or gas pool in a manner that maximizes ultimate recovery, prevents economic and physical waste, and protects the rights of all parties with an ownership interest in the accumulation. When leases are unitized, operators can eliminate redundancy and waste by sharing infrastructure and facilities, and by adopting unified reservoir management plans. Without unitization, unregulated development can result in overly dense drilling, rapid loss of reservoir pressure, and undesired production of formation fluids. Unitization minimizes impacts to the environment, protects the value of leases, and ensures efficient energy extraction.

Unit Formation

Gil Mull

The unitization process begins when lessees identify a prospect. The lessees in the proposed unit area select a Unit Operator. A unit operator must be qualified to hold a lease as provided in 11 AAC 82.200 - 11 AAC 82.205 , and must be qualified to fulfill the duties and obligations prescribed in the Unit Agreement. A Unit Agreement defines a contractual relationship between the state, the royalty owners, and the working interest owners of the oil and gas leases included in the unit. The Unit Operator and the state negotiate the terms of the Unit Plan of Exploration or Development for the entire unit area, and the boundaries of the unit area (11 AAC 83.341). All lessees who hold an interest in the reservoir must be invited to join the unit. The Director then writes a Decision and Finding approving or disapproving the unit application. Unitization extends a lease beyond its initial primary term.

C. Ruff

Participating Areas

After delineation drilling and testing, the Unit Operator proposes a participating area within the boundaries of the unit. The Unit Operator must submit a participating area application 90-days before sustained production from a reservoir. Only those lands known to be capable of producing in paying quantities or capable of contributing to production are included in the participating area (11 AAC 83.351). The Unit Operator and state agree on a tract allocation schedule for leases in the participating area. Production volumes and costs are allocated to each tract. An oil and gas unit can have one or more participating areas within its boundaries depending on the geology of the area. Participating areas are described laterally and sometimes limited or defined by depth. After a stated period of time, usually 5 or 10 years to explore and delineate the pools in the unit, the unit boundary contracts down to the area that is contributing to production. The boundaries of the participating area must conform as close as possible to the boundaries of the oil or gas pool.

Unitization Criteria

The Director considers the following criteria when evaluating a unit or participating area application. Does the application,

- promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;
- promote the prevention of economic and physical waste; and
- provide for the protection of all parties of interest, including the state.

In evaluating the above criteria, the Director considers

- the environmental costs and benefits of unitized exploration or development;
- the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;
- prior exploration activities in the proposed unit area;
- the applicant's plans for exploration or development of the unit area;
- the economic costs and benefits to the state; and
- any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

The Unitization process takes about 100 days from the time of filing a complete unit application.

A complete application includes:

1)the unit agreement, including exhibits required under 11 AAC 83.341 or 11 AAC 83.343 , executed by the proper parties;
2) the unit operating agreement executed by the working-interest owners, which is submitted for information only and does not require the commissioner's approval for adoption or amendment;
3) evidence of reasonable effort made to obtain Joinder of any proper party who has refused to join the unit agreement;
4) all pertinent geological, geophysical, engineering, and well data, and interpretations of those data, directly supporting the application;
5) an explanation of proposed modifications, if any, of the standard state unit agreement form; and
6) the application fee prescribed by 11 AAC 05.010

Within 10-days of receipt of a complete application, a public notice is published initiating a 30-day comment period.

Plans of Exploration and Development

The Unit Operator and state must also agree on an initial Unit Plan of Exploration or Development 11 AAC 83.343. In concert with the Unit Agreement and Plans of Exploration, Development and Operation, a Unit Operating Agreement is drafted describing how expenses and revenues are distributed or paid among the Working Interest Owners in the unit. Unit Operators must submit an annual Plan of Development for approval (11 AAC 83.343). Often unit areas are explored and developed at the same time. Failure to meet the goals, objectives, and commitments in the Plan of Exploration or Development can result in default and unit termination.

C. Ruff

Units in Alaska

This section describes current unitized and non-unitized oil and gas fields in Cook Inlet and on the North Slope. Some units are managed by the state, some by the federal government, and some are managed jointly. There are 12 oil and gas units on the North Slope. Seven units produce oil and gas and contain 25 separate producing accumulations or Participating Areas, 12 of the 25 pools are producing within the giant Prudhoe Bay field.

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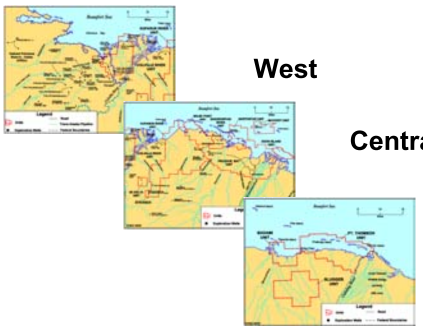
Unit Maps:

The following pages describe each unit. Units can be located on one of six unit maps:

North Slope

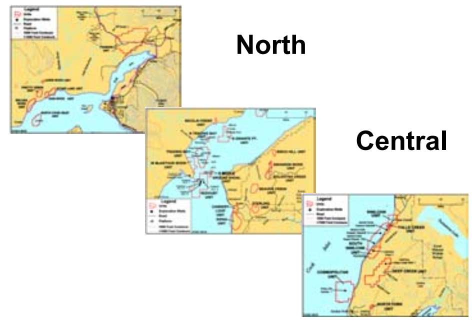


West

Central

East

Cook Inlet

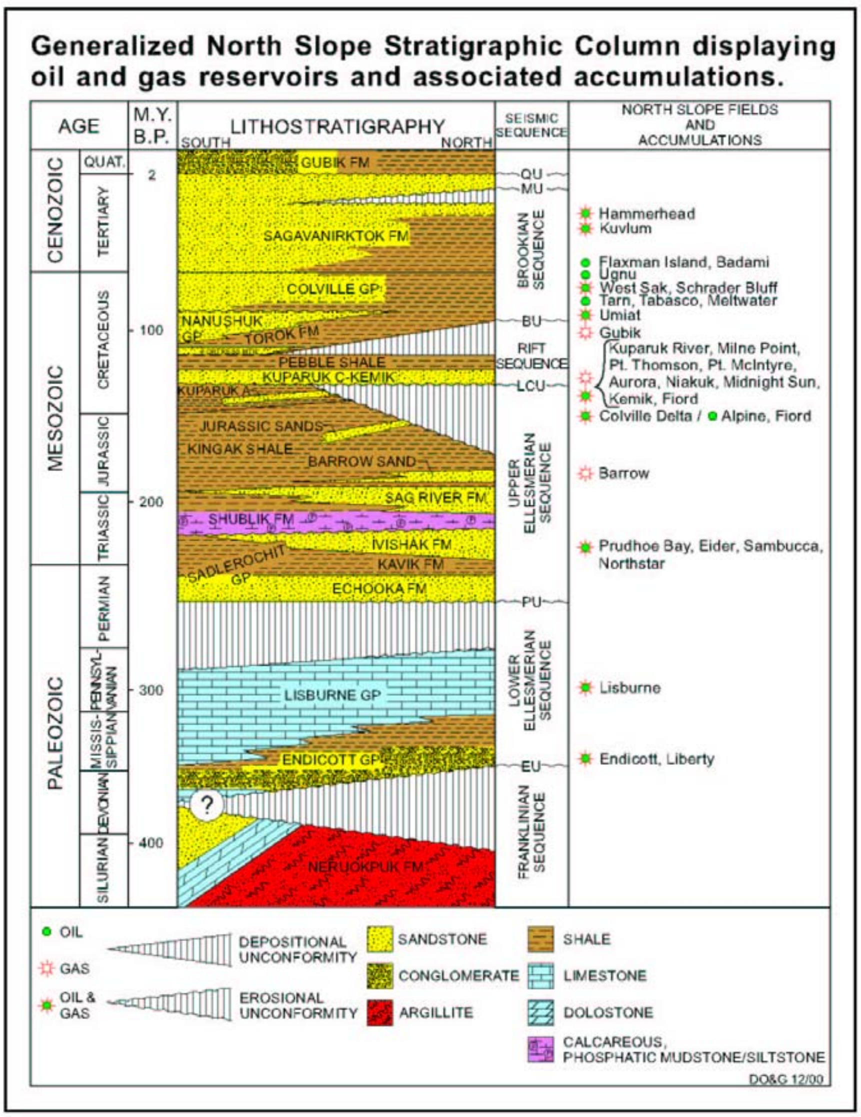


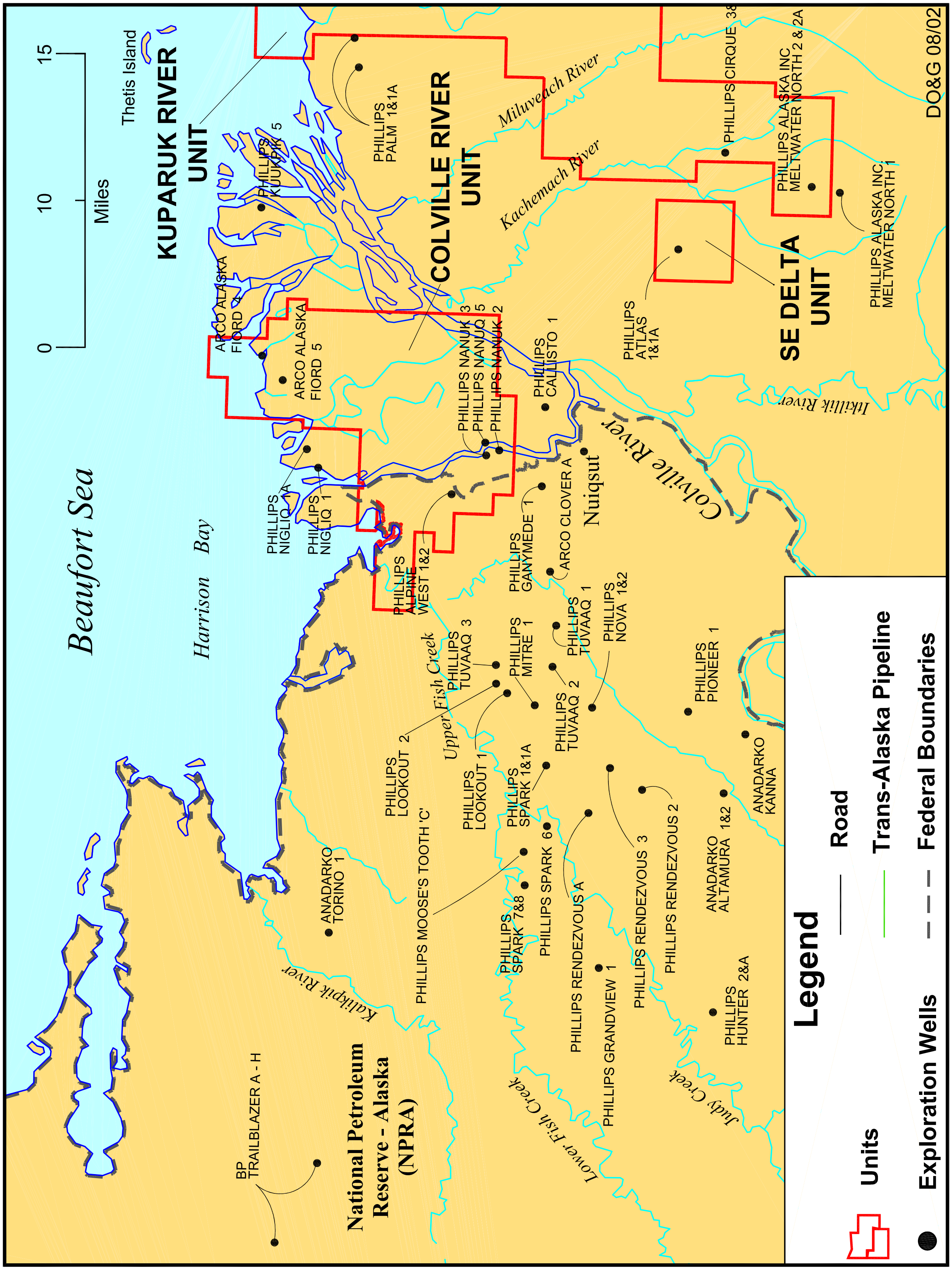
North

Central

South

Figure 2.1 Generalized North Slope Stratigraphic Column




Beaufort Sea
Harrison Bay
Thetis Island
0 10 15
Miles
KUPARUK RIVER UNIT
COLVILLE RIVER UNIT
SE DELTA UNIT
National Petroleum Reserve - Alaska (NPRA)
Nuiqsut
Colville River
Miluveach River
Kachemach River
Itkillik River
Kalikpik River
Upper Fish Creek
Lower Fish Creek
Judy Creek
PHILLIPS PALM 1&1A
PHILLIPS KUUKPIK 5
ARCO ALASKA FIORD 4
ARCO ALASKA FIORD 5
PHILLIPS NANUK 3
PHILLIPS NANUQ 5
PHILLIPS NANUK 2
PHILLIPS CALLISTO 1
PHILLIPS ATLAS 1&1A
PHILLIPS CIRQUE 3&
PHILLIPS ALASKA INC MELTWATER NORTH 2 & 2A
PHILLIPS ALASKA INC MELTWATER NORTH 1
PHILLIPS NIGLIQ 1A
PHILLIPS NIGLIQ 1
ARCO CLOVER A
PHILLIPS GANYMEDE 1
PHILLIPS ALPINE WEST 1&2
PHILLIPS TUVAAQ 3
PHILLIPS MITRE 1
PHILLIPS TUVAAQ 1
PHILLIPS NOVA 1&2
PHILLIPS TUVAAQ 2
PHILLIPS PIONEER 1
PHILLIPS LOOKOUT 2
PHILLIPS LOOKOUT 1
PHILLIPS SPARK 1&1A
ANADARKO KANNA
ANADARKO TORINO 1
PHILLIPS MOOSE'S TOOTH 'C'
PHILLIPS SPARK 6
PHILLIPS SPARK 7&8
PHILLIPS RENDEZVOUS A
PHILLIPS RENDEZVOUS 3
PHILLIPS RENDEZVOUS 2
ANADARKO ALTAMURA 1&2
PHILLIPS GRANDVIEW 1
PHILLIPS HUNTER 2&A
BP TRAILBLAZER A - H
DO&G 08/02
Legend
Road
Trans-Alaska Pipeline
Federal Boundaries
Units
Exploration Wells

North Slope

C. Ruff

Colville River Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska and Arctic Slope Regional Corporation
Operator:	Phillips (Alaska), Inc.
Acres:	75,631
First Production:	2000

Alpine PA

Status:	Producing
Discovery:	1994, ARCO Bergschrund #1
Reservoir:	Jurassic Kingak Formation, Alpine sandstone (-6,850 ft.)
Working Interest:	Phillips (Alaska), Inc. 65%
	Anadarko Petroleum Corp. 22%
	Phillips Alpine AK, LLC 22%

Nanuk Tract Operation

Status:	Producing
Discovery:	2000, ARCO Nanuk #2
Reservoir:	Cretaceous Torok Fm., Nanuq sandstone (-6,140 ft.)
Working Interest:	Phillips (Alaska), Inc. 65%
	Anadarko Petroleum Corp. 22%
	Phillips Alpine AK, LLC 22%

Fiord Discovery

Status:	Undeveloped
Discovery:	1992, ARCO Fiord #1
Reservoir:	Kuparuk/Nechelik sandstones (-6,890 ft. and -7,400 ft.)
Working Interest:	Phillips (Alaska), Inc. 65%
	Anadarko Petroleum Corp. 22%
	Phillips Alpine AK, LLC 22%

B. Havelock

S. Schmitz

Kuparuk River Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Phillips Alaska, Inc.
Acres:	275,965
First Production:	1981

Kuparuk PA

Status:	Producing	
Discovery:	1969, Sinclair Ugnu #1	
Reservoir:	Cretaceous Kuparuk Formation (-5,600 ft subsea)	
Working Interest:	BP Exploration (Alaska), Inc.	39%
	Phillips	55%
	Unocal/Chevron U.S.A., Inc./Exxon	6%

B. Havelock

Meltwater PA

Status:	Producing	
Discovery:	2000, ARCO Meltwater North #1	
Reservoir:	Late Cretaceous Seabee Fm. Bermuda/Cairn sand)	
Working: Interest	BP Exploration (Alaska), Inc.	39%
	Phillips	55%
	Unocal/Chevron U.S.A., Inc./Exxon	6%

Tabasco PA

Status:	Producing	
Discovery:	1986, ARCO Kuparuk River Unit #2T-02	
Reservoir:	Cretaceous Colville Group Tabasco sand	
Working Interest:	BP Exploration (Alaska), Inc.	39%
	Phillips	55%
	Unocal/Chevron U.S.A., Inc./Exxon	6%

Tarn PA

Status:	Producing	
Discovery:	1991, ARCO KRU Bermuda #3	
Reservoir:	Late Cretaceous Seabee Fm., Bermuda sand (-4,376 to -5,990 ft)	
Working Interest:	BP Exploration (Alaska), Inc.	39%
	Phillips	55%
	Unocal/Chevron U.S.A., Inc./Exxon	6%

Kuparuk River Unit, Cont.

West Sak PA

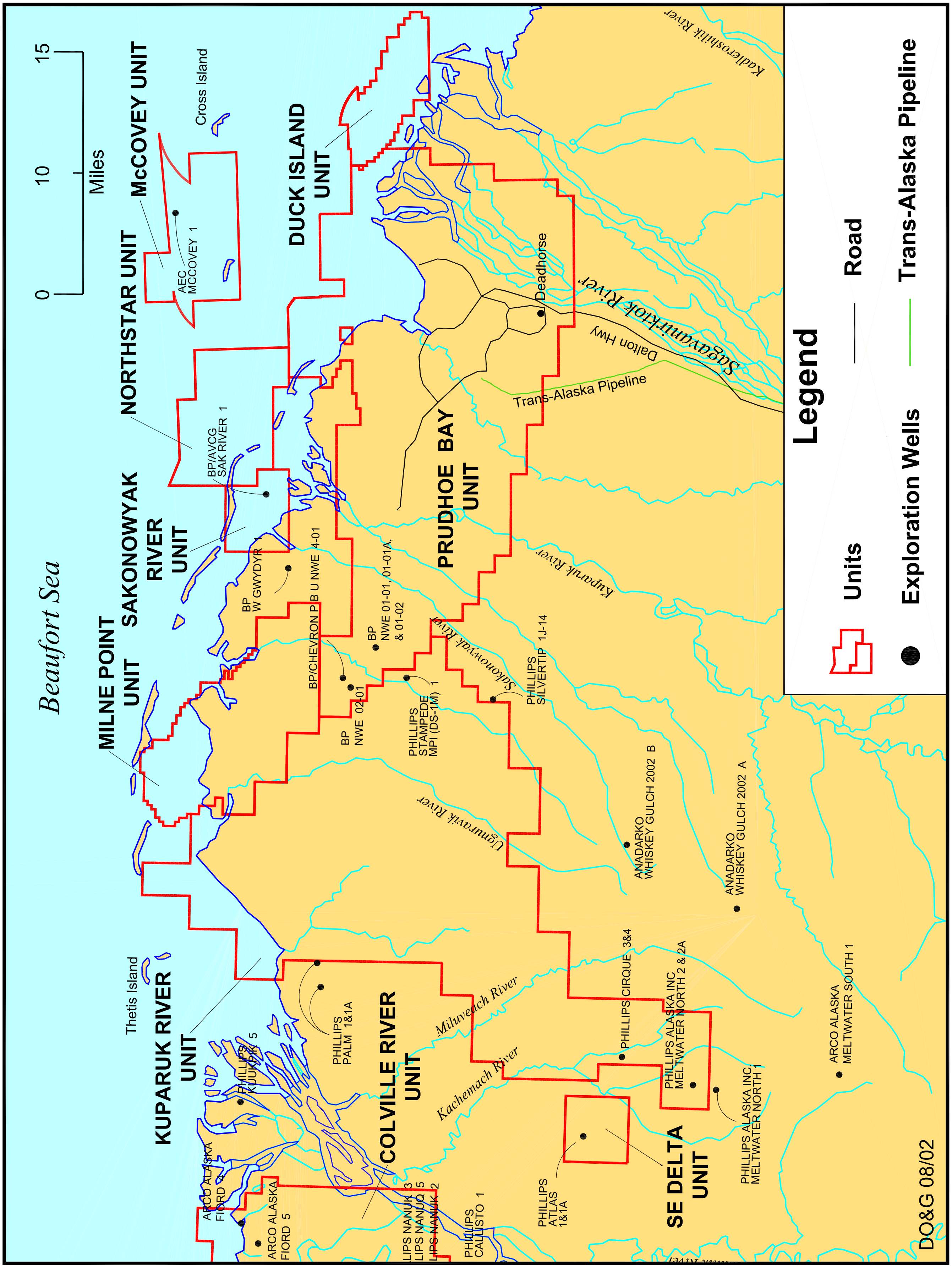
Status:	Producing
Discovery:	West Sak River State #1
Reservoir:	Cretaceous Colville Group
	Tabasco sand
Working Interest:	BP Exploration (Alaska), Inc. 39%
	Phillips Alaska, Inc. 55%
	Unocal/Chevron U.S.A., Inc./Exxon 6%

S. Schmitz

S. Schmitz

Southeast Delta Unit

Status:	Exploration
Royalty Ownership:	State of Alaska
Operator:	Phillips Alaska, Inc.
Acres:	10,240
Working Interest:	Phillips Alaska, Inc. 100%



Beaufort Sea
0
10
15
Miles
Legend
Units
Road
Exploration Wells
Trans-Alaska Pipeline
MILNE POINT UNIT
SAKONOWYAK RIVER UNIT
NORTHSTAR UNIT
McCOVEY UNIT
DUCK ISLAND UNIT
PRUDHOE BAY UNIT
KUPARUK RIVER UNIT
COLVILLE RIVER UNIT
SE DELTA UNIT
Cross Island
Thetis Island
AEC MCCOVEY 1
BP/AVCG SAK RIVER 1
BP W GWYDYR 1
BP/CHEVRON P B U NWE 4-01
BP NWE 01-01, 01-01A, & 01-02
BP NWE 02-01
PHILLIPS STAMPEDE MPI (DS-1M) 1
PHILLIPS SILVERTIP 1J-14
ANADARKO WHISKEY GULCH 2002 B
ANADARKO WHISKEY GULCH 2002 A
PHILLIPS CIRQUE 3&4
PHILLIPS ALASKA INC MELTWATER NORTH 2 & 2A
PHILLIPS ALASKA INC MELTWATER NORTH 1
ARCO ALASKA MELTWATER SOUTH 1
PHILLIPS ATLAS 1&1A
PHILLIPS PALM 1&1A
PHILLIPS KUUKPIK 5
ARCO ALASKA FIORD 4
ARCO ALASKA FIORD 5
PHILLIPS CALLISTO 1
Deadhorse
Dalton Hwy
Trans-Alaska Pipeline
Sagavanirktok River
Kadleroshilik River
Kuparuk River
Sakonowyak River
Ugnuravik River
Miluveach River
Kachemach River
DO&G 08/02

North Slope

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Milne Point Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Phillips Alaska, Inc.
Acres:	68,830
First Production:	1985

Kuparuk PA

Status:	Producing	
Discovery:	1969, Chevron Kavearak Pt. #32-25	
	1993, BP Cascade #1	
Reservoir:	Cretaceous Kuparuk Formation	
	(-7,200 ft subsea)	
Working Interest:	BP Exploration (Alaska), Inc.	91%
	BP America Production Company	9%

Schrader Bluff PA

Status:	Producing	
Discovery:	1969, Chevron Kavearak Pt. #32-25	
Reservoir:	Cretaceous Colville Group	
	Schrader Bluff Fm.	
Working Interest:	BP Exploration (Alaska), Inc.	91%
	BP America Production Company	9%

Sag River Tract Operations (Undefined Pool)

Status:	Producing	
Discovery:	1969, Chevron Kavearak Pt. #32-25	
Reservoir:	Sag River and Ivishak formations	
Working Interest:	BP Exploration (Alaska), Inc.	91%
	BP America Production Company	9%

Sakonowyak River Unit

Status:	Exploration	
Royalty Ownership:	State of Alaska	
Operator:	BP Exploration (Alaska), Inc.	
Acres:	11,515	
Working Interest:	BP Exploration (Alaska), Inc.	62%
	Phillips Alaska, Inc.	19%
	Alaska Venture Capital Group (AVCG)	19%

North Slope

S. Schmitz

Prudhoe Bay Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	273,397
First Production:	1977
Working Interest:	ExxonMobil Alaska Production, Inc. 37%
(Aligned for all PA's	Phillips Alaska, Inc. 37%
~December 2001)	BP Exploration (Alaska), Inc. 27%
	Forest Oil Corporation 2%

Aurora PA

Status:	Producing
Discovery:	1969, Mobil North Kuparuk State #1
Reservoir:	Cretaceous Kuparuk Formation

Borealis PA

Status:	Producing
Discovery:	1969, Mobil West Kuparuk State #1
Reservoir:	Cretaceous Kuparuk Formation

Gas Cap PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Triassic Ivishak Sandstone (-8,800 ft subsea)

Lisburne PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Mississippian Lisburne Group

Midnight Sun PA

Status:	Producing
Discovery:	1997, BP Prudhoe Bay Un MDS #E-100
Reservoir:	Cretaceous Kuparuk Formation

Niakuk PA

Status:	Producing
Discovery:	1985, BP Niakuk #5
Reservoir:	Cretaceous Kuparuk Formation (-9,350 ft.)

Prudhoe Bay Unit, Cont.

Steve Schmitz

North Prudhoe Bay PA

Status: Producing
Discovery: 1970, ARCO North Prudhoe Bay State #1
Reservoir: Triassic Sadlerochit Group

Oil Rim PA

Status: Producing
Discovery: 1968, Richfield Prudhoe Bay State #1
Reservoir: Triassic Ivishak sandstone (-8,800 ft subsea)

Polaris PA

Status: Producing
Discovery: 1969, Mobil North Kuparuk State #1
Reservoir: Cretaceous Colville Group, Schrader Bluff Fm.

Point McIntyre PA

Status: Producing
Discovery: 1988, ARCO Pt. McIntryre #3A
Reservoir: Cretaceous Kuparuk Formation

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West Beach PA

Status: Producing
Discovery: 1976, ARCO West Beach #3
Reservoir: Cretaceous Kuparuk Formation

Western Niakuk PA

Status: Producing
Discovery: 1985, BP Niakuk #5
Reservoir: Cretaceous Kuparuk Formation (-9,350 ft.)

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Northstar Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska/United States
Operator:	BP Exploration (Alaska), Inc.
Acres:	23,343
First Production:	2001

Northstar PA

Status:	Producing
Discovery:	1984, Shell BF-47 (Seal Island) #1
Reservoir:	Triassic Ivishak Sandstone (-11,000 ft. subsea)
Working Interest:	BP Exploration (Alaska), Inc. 98%
	Murphy E&P Company, Inc. 1%

McCovey Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/United States
Operator:	EnCana Oil and Gas (USA), Inc.
Acres:	20,371
Working Interest:	Phillips Alaska, Inc. 50%
	Chevron USA 50%

US Fish & Wildlife Service

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Duck Island Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	28,189
First Production:	1994

Eider PA

Status:	Producing
Discovery:	1998, BP Duck Island Unit MPI #2-56/EID
Reservoir:	Triassic Ivishak Sandstone
Working Interest:	BP Exploration (Alaska), Inc. 100%

Endicott PA

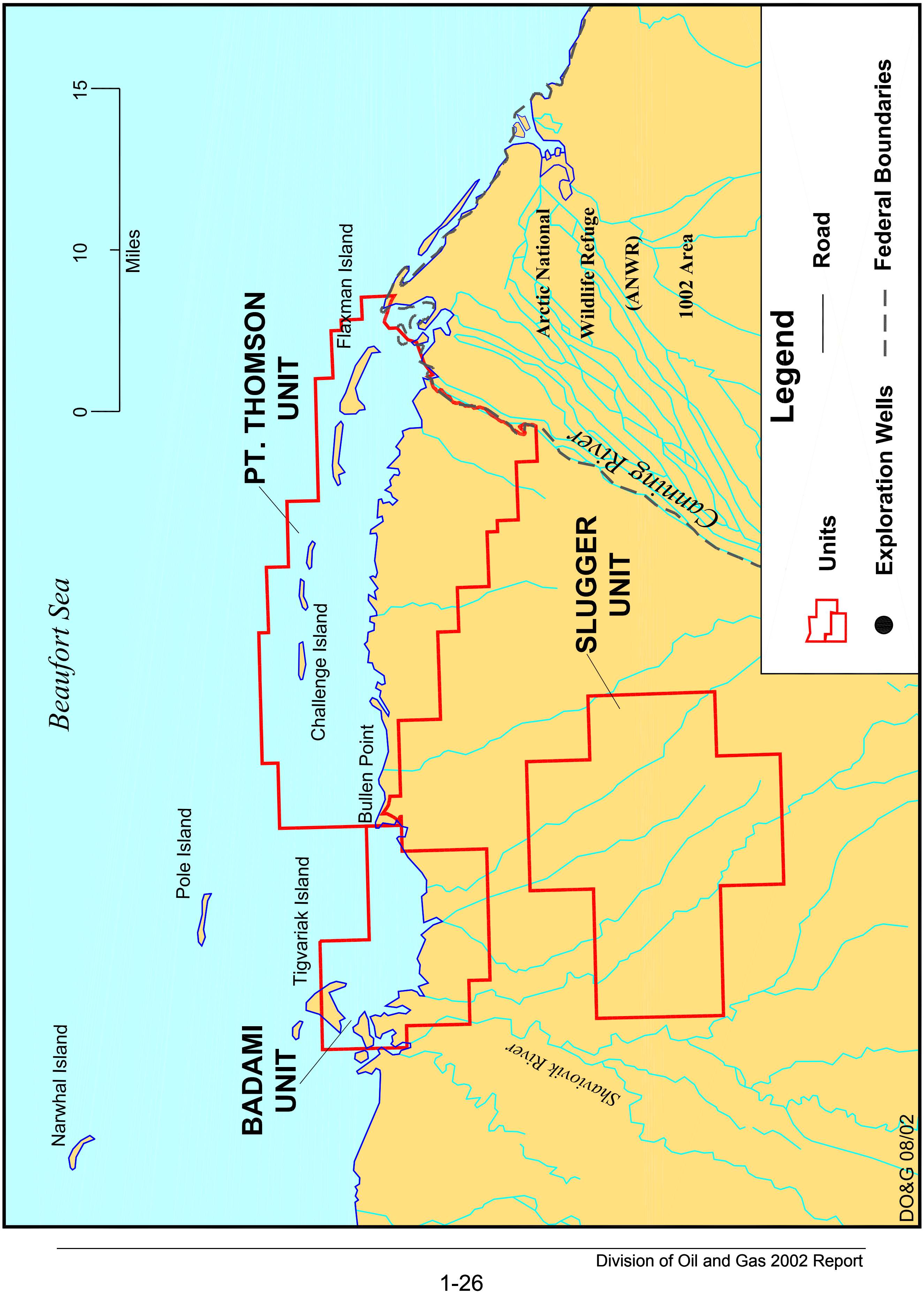
Status:	Producing
Discovery:	1978, Sohio Sag Delta 34633 #4
Reservoir:	Mississippian Kekiktuk Conglomerate (-10,000 ft subsea)
Working Interest:	BP Exploration (Alaska), Inc. 68%
	Exxon 21%
	Unocal 10%
	Doyon Ltd./NANA Regional Corporation/Phillips 1%

Sag Delta North PA

Status:	Producing
Discovery:	1982, Sohio Sag Delta #9
Reservoir:	Mississippian Alaphah Limestone
Working Interest:	BP Exploration (Alaska), Inc. 98%
	NANA Regional Corporation/Doyon Ltd. 2%

S. Schmitz

S. Schmitz


Beaufort Sea
0
10
15
Miles
Narwhal Island
Pole Island
Tigvariak Island
BADAMI UNIT
Bullen Point
Challenge Island
PT. THOMSON UNIT
Flaxman Island
SLUGGER UNIT
Arctic National
Wildlife Refuge
(ANWR)
1002 Area
Canning River
Shaviovik River
Legend
Units
Road
Exploration Wells
Federal Boundaries
DO&G 08/02

B. Havelock

Badami Unit

Status:	Producing oil and gas
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	37,401
Working Interest:	BP Exploration (Alaska), Inc. 100%

Badami Sands PA

Status:	Producing
Discovery:	1990, Conoco Badami #1
Reservoir:	Tertiary Canning Formation
	Badami sandstone (-9,900 ft)
Working Interest:	BP Exploration (Alaska), Inc. 100%

Slugger Unit

Status:	Exploration	
Royalty Ownership:	State of Alaska	
Operator:	Phillips Alaska, Inc.	
Acres:	79,508	
Working Interest:	BP Exploration (Alaska), Inc.	39%
	Phillips Alaska, Inc.	31%
	Chevron USA	30%

Gil Mull

S. Schmitz

Point Thomson Unit

B. Havelock

Status:	Development
Royalty Ownership:	State of Alaska
Operator:	ExxonMobil
Acres:	116,000
First Production:	~2008
Discovery:	1977, Exxon Pt. Thomson #1
Working Interest:	BPAmoco 42%
	ExxonMobil 37%
	Chevron 19%
	Others <3%

Point Thomson Sands Discovery

Status:	Undeveloped
Discovery:	1977, Exxon Pt. Thomson #1
Reservoir:	Lower Cretaceous Thomson sandstone (-12,834 ft.)

Flaxman Discovery

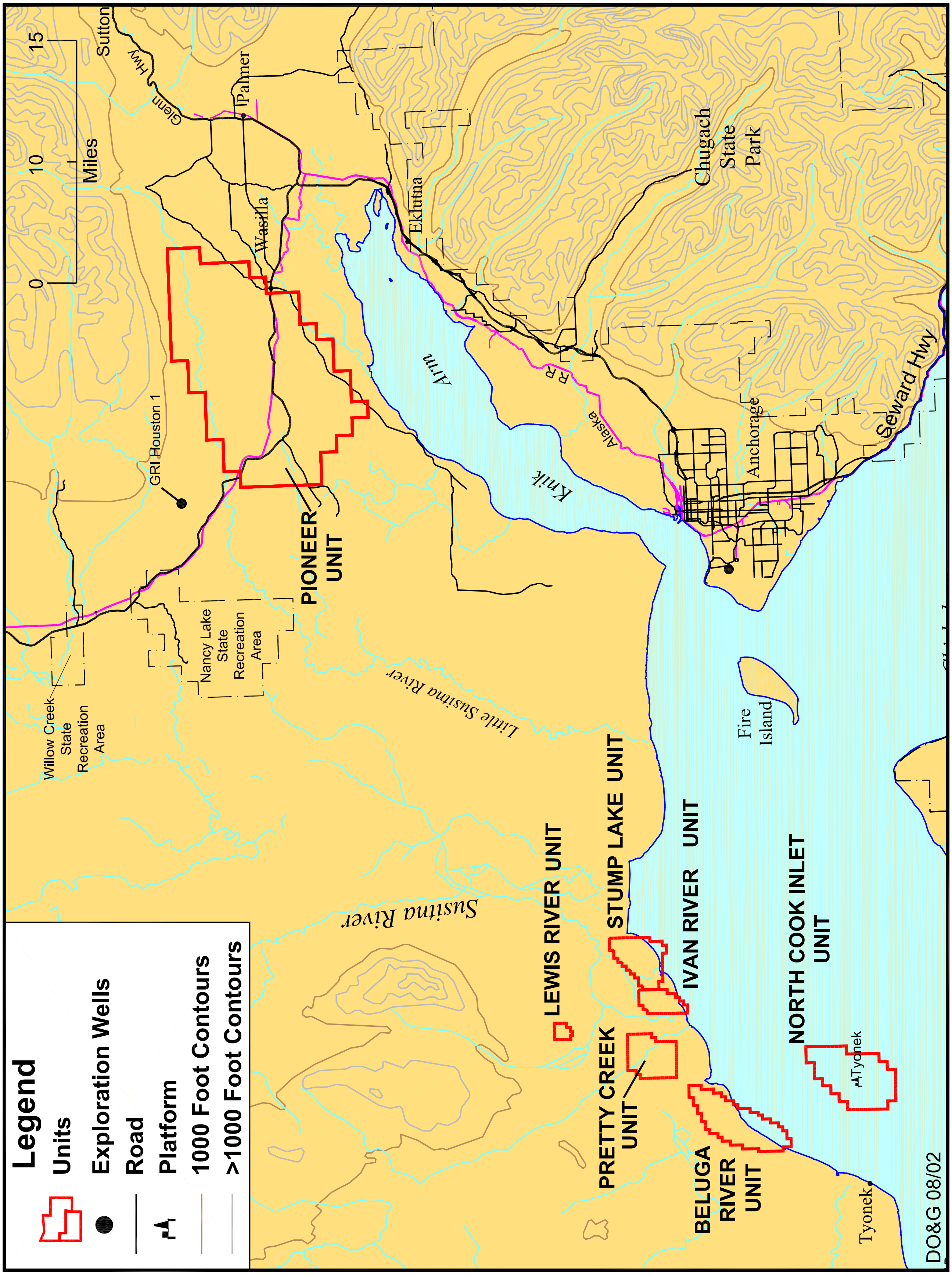
Status:	Undeveloped
Discovery:	1975, Exxon Alaska State A #1
Reservoir:	Tertiary Flaxman sand (-12,565 ft.)

Sourdough Discovery

Status:	Undeveloped
Discovery:	1994, BP Sourdough #2
Reservoir:	Reservoir information not available

S. Schmitz

S. Schmitz


Legend
Units
Exploration Wells
Road
Platform
1000 Foot Contours
>1000 Foot Contours
0
10
15
Miles
Sutton
Glenn Hwy
Palmer
Wasilla
Eklutna
Chugach State Park
Knik Arm
Alaska RR
Anchorage
Seward Hwy
GRI Houston 1
PIONEER UNIT
Willow Creek State Recreation Area
Nancy Lake State Recreation Area
Little Susitna River
Susitna River
Fire Island
LEWIS RIVER UNIT
STUMP LAKE UNIT
IVAN RIVER UNIT
NORTH COOK INLET UNIT
Tyonek
PRETTY CREEK UNIT
BELUGA RIVER UNIT
Tyonek
DO&G 08/02

Cook Inlet

ADCED

Pioneer Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/United States/ Cook Inlet Regional Corporation/ Alaska Mental Health Trust/ University of Alaska/Fee
Operator:	Evergreen Resources, Inc.
Acres:	49,263
Reservoir:	Tertiary Tyonek Formation Coalbed methane target
Working Interest:	Evergreen Resources Alaska, Inc. 100%

B. Havelock

Stump Lake Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	13,691
First Production:	1990

Stump Lake Gas Pool #1 PA

Status:	Shut-in 1978, Restart 1990, Shut-in 2000
Discovery:	1978, Chevron Stump Lake Unit #41-33
Reservoir:	Tertiary Beluga Formation
Working Interest:	Unocal 100%

B. Havelock

Ivan River Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	9,301
First Production:	1990

Ivan River Gas Pool #1 PA

Status:	Producing Gas
Discovery:	1966, Chevron Ivan River Unit #44-1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Unocal 100%

B. Havelock

Lewis River Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	3,200
First Production:	1984

Lewis River PA #1

Status:	Producing
Discovery:	1975, Cities Lewis River #1
Reservoir:	Tertiary Tyonek and Beluga formations
Working Interest:	Unocal 100%

Lewis River PA #2

Status:	Producing
Discovery:	1975, Cities Lewis River #1
Reservoir:	Tertiary Tyonek and Beluga formations
Working Interest:	Unocal 100%

Pretty Creek Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	6,718
First Production:	1986

Beluga PA

Status:	Suspended
Discovery:	1979, Chevron Pretty Creek Unit #2
Reservoir:	Tertiary Beluga Formation
Working Interest:	Unocal 100%

US Fish & Wildlife Service


B. Havelock

Beluga River Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska/United States/Fee
Operator:	Phillips Alaska, Inc.
Acres:	12,743
First Production:	1968

Beluga-Sterling Gas Pool PA

Status:	Producing gas	
Discovery:	1962, Chevron Beluga River Unit 212-35 #1	
Reservoir:	Tertiary Sterling Formation	
Working Interest:	Chevron USA	33%
	Phillips Alaska, Inc.	33%
	Municipality of Anchorage	33%


CIRCAC

North Cook Inlet Unit

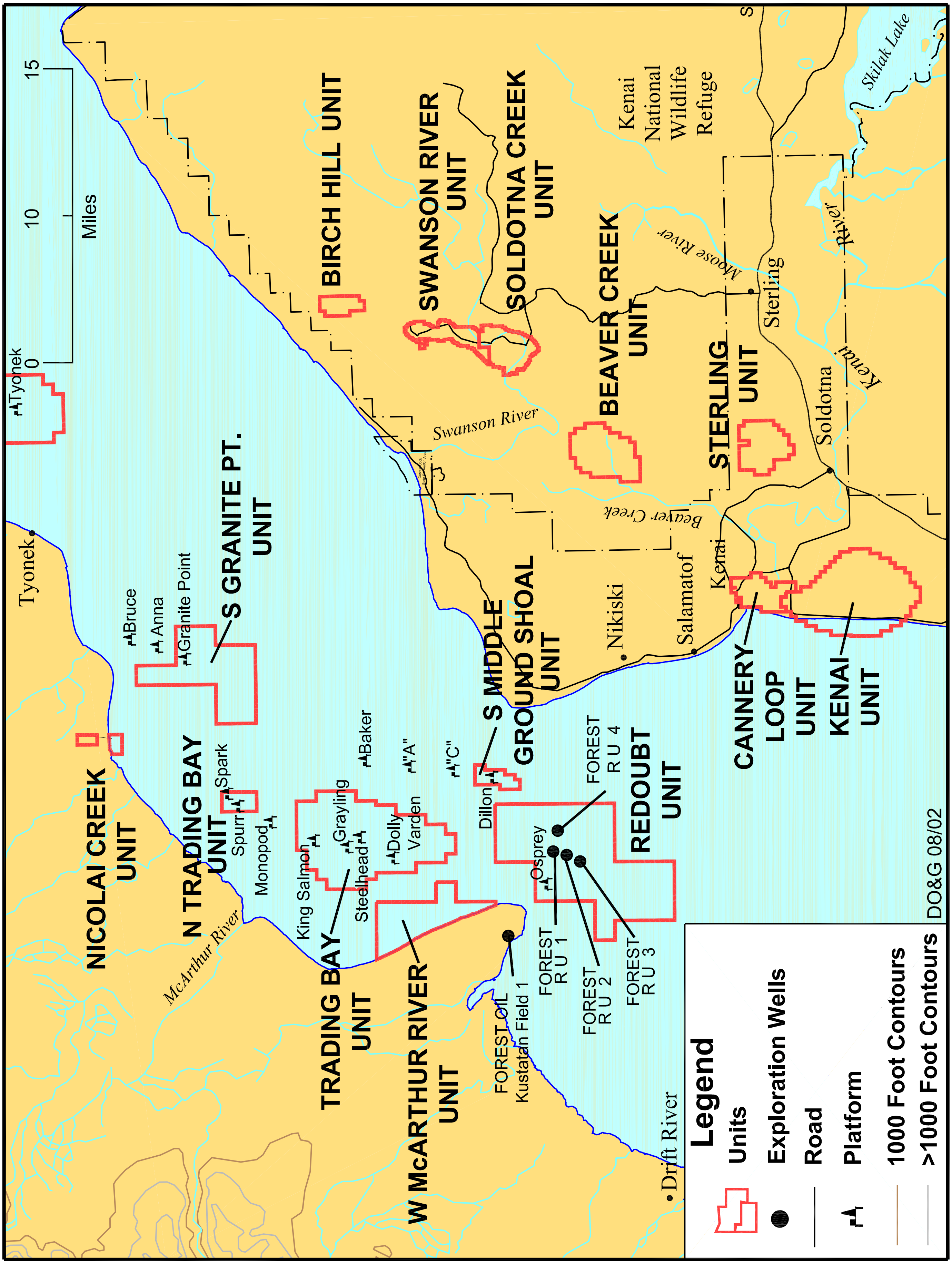
Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	Phillips Petroleum Company
Acres:	23,368
First Production:	1970

North Cook Inlet Initial PA

Status:	Producing gas	
Discovery:	1962, Pan Am Cook Inlet State 17589 #1	
Reservoir:	Tertiary Tyonek, Beluga and Sterling formations	
Working Interest:	Phillips Petroleum Company	100%


D. Colley


D. Colley



Tyonek
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Miles
NICOLAI CREEK UNIT
N TRADING BAY UNIT
S GRANITE PT. UNIT
Bruce
Anna
Granite Point
Spark
Spurr
Monopod
McArthur River
King Salmon
Grayling
Steelhead
Dolly Varden
Baker
"A"
"C"
Dillon
Osprey
TRADING BAY UNIT
W McARTHUR RIVER UNIT
FOREST OIL Kustatan Field 1
FOREST R U 1
FOREST R U 2
FOREST R U 3
FOREST R U 4
REDOUBT UNIT
S MIDDLE GROUND SHOAL UNIT
Drift River
BIRCH HILL UNIT
SWANSON RIVER UNIT
SOLDOTNA CREEK UNIT
BEAVER CREEK UNIT
STERLING UNIT
Swanson River
Kenai National Wildlife Refuge
Moose River
Skilak Lake
Sterling
Soldotna
Kenai River
Beaver Creek
Nikiski
Salamatof
Kenai
CANNERY LOOP UNIT
KENAI UNIT
DO&G 08/02
Legend
Units
Exploration Wells
Road
Platform
1000 Foot Contours
>1000 Foot Contours

Cook Inlet

South Granite Point Unit

CIRCAC

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	10,209
First Production:	1967

Granite Point Sands PA

Status:	Producing	
Discovery:	1965, Mobil Granite Point 11965 #1	
Reservoir:	Tertiary Tyonek Formation	
Working Interest:	ExxonMobil	75%
	Unocal	25%

Hemlock PA

Status:	Producing	
Discovery:	1965, Mobil Granite Point 11965 #1	
Reservoir:	Tertiary Hemlock Conglomerate	
Working Interest:	ExxonMobil	75%
	Unocal	25%

Nicolai Creek Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	Aurora Gas, LLC
Acres:	9,123
First Production:	Shut-in 1977, Restart 2001

Nicolai Creek Gas Pool “A” PA

Status:	Shut-In	
Discovery:	1966, Texaco Nicolai Creek State #1A	
Reservoir:	Tertiary Tyonek and Beluga formations	
Working Interest:	Aurora Gas, LLC	100%

Nicolai Creek Gas Pool “B” PA

Status:	Producing gas	
Discovery:	1967, Texaco Nicolai Creek Unit #3	
Reservoir:	Tertiary Tyonek and Beluga formations	
Working Interest:	Aurora Gas, LLC	100%

Cook Inlet

Redoubt Unit


B. Havelock

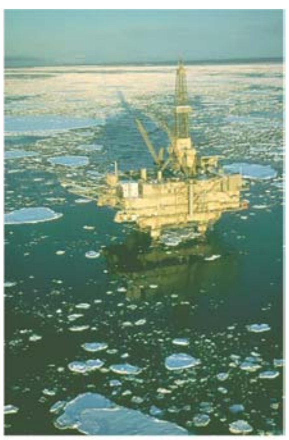
Status:	Development
Royalty Ownership:	State of Alaska
Operator:	Forest Oil Company
Acres:	23,526
First Production:	N/A

Hemlock PA

Status:	Proposed
Discovery:	1968, Pan Am Redoubt Shoal Unit #2
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	Forest Oil Corporation 100%

Trading Bay Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	32,115
First Production:	1967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Grayling Gas Sands PA

Status:	Producing gas
Discovery:	1968, Trading Bay Unit #G-18
Reservoir:	Tertiary Tyonek Formation (-2,500 to -6,500 ft. subsea)
Working Interest:	Unocal 50%
	Marathon Oil Company 50%

McArthur River Hemlock Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	Unocal 53%
	Forest Oil Corporation 47%

McArthur River Middle Kenai G Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Unocal 50%
	Forest Oil Corporation 47%

McArthur River West Foreland Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary West Foreland Formation
Working Interest:	Unocal 50%, Forest Oil Corporation 47%

CIRCAC

North Trading Bay Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Marathon Oil Company
Acres:	6,400
First Production:	Shut-in 1992

Hemlock and "G" Formation PA

Status:	Suspended
Discovery:	1965, Chevron Trading Bay #1A
Reservoir:	Tertiary Hemlock and Tyonek formations
Working Interest:	Marathon Oil Company 81%
	Unocal 19%

West McArthur River Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Forest Oil Corporation
Acres:	6,330
First Production:	1994

Area 1 PA

Status:	Producing oil
Discovery:	1991, Stewart West McArthur River #1
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	Forest Oil Corporation 100%

West Foreland Field

Status:	Producing gas
Discovery:	1962, West Foreland #1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Forest Oil Corporation 100%

South Middle Ground Shoals Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	3,840
First Production:	1967

South Middle Ground Shoal Tertiary System PA

Status:	Producing gas and oil
Discovery:	1962, Pan Am MGS State 17595 #1
Reservoir:	Tertiary Hemlock and Tyonek formations
Working Interest:	Unocal 100%

Birch Hill Unit

Status:	Suspended
Royalty Ownership:	United States
Operator:	Phillips Alaska, Inc.
Acres:	1,240
First Production:	Shut-in 1965

Gas Pool #1 PA

Status:	Shut-in
Discovery:	1965, Chevron Birch Hill Unit #22-25
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Unocal 79%
	CIRI Production Company 20%
	Marathon Oil Company 1%

Swanson River Unit

Status:	Producing Oil and Gas
Royalty Ownership:	United States/CIRI
Operator:	Unocal
Acres:	7,880
First Production:	1960

"B, C, D & E" Zone Gas Pools #1 and #2 Consolidated Hemlock PA

Status:	Producing
Discovery:	1957, Richfield Swanson River Unit #34-10
Reservoir:	Tertiary Hemlock, Lower Tyonek and Beluga formations
Working Interest:	Unocal/Marathon Oil Company

Cook Inlet

Beaver Creek Unit

Status:	Producing Oil and Gas
Royalty Ownership:	United States, Fee
Operator:	Unocal
Acres:	4,960
First Production:	1973

Sterling Gas, Beluga Gas, and Beaver Creek Oil Pools

Status:	Producing oil and gas
Discovery:	1972, Marathon Beaver Creek #4
Reservoir:	Tertiary Hemlock, Lower Tyonek and Beluga formations
Working Interest:	Marathon Oil Company

Sterling Unit

Status:	Producing Gas
Royalty Ownership:	United States/CIRI/State of Alaska/Fee
Operator:	Marathon Oil Company
Acres:	3,600
First Production:	1962

"A" Zone PA (Sterling Formation Gas Zone PA)

Status:	Producing
Discovery:	1961, UNOCAL Sterling Unit #23-15
Reservoir:	Tertiary Sterling Formation
Working Interest:	Marathon Oil Company 100%

Lower Beluga PA

Status:	Producing
Discovery:	1999, UNOCAL Sterling Unit #41-15
Reservoir:	Tertiary Beluga Formation
Working Interest:	Marathon Oil Company 100%

Tyonek PA

Status:	Producing
Discovery:	1999, UNOCAL Sterling Unit #41-15
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Marathon Oil Company 100%

Cook Inlet

Cannery Loop Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska/United States/CIRI/Fee
Operator:	Marathon Oil Company
Acres:	1,900
First Production:	1988
Working Interest:	Marathon Oil Company 100%

Beluga Formation Undifferentiated Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Beluga Formation

Sterling Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Sterling Formation

Tyonek D Zone Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Tyonek Formation

Upper Tyonek Formation Undifferentiated Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Tyonek Formation

Kenai River Unit

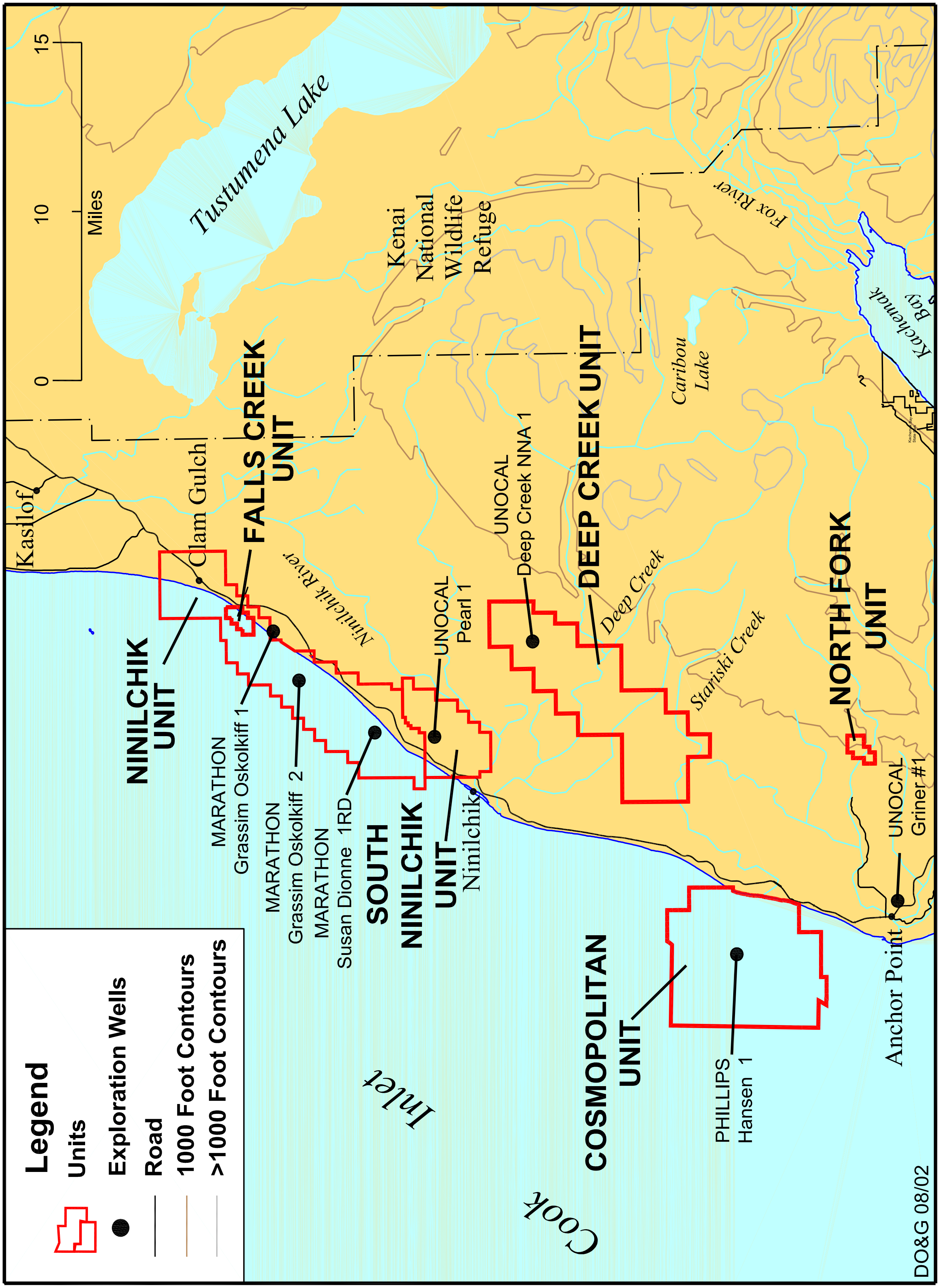
Status:	Producing Gas
Royalty Ownership:	State of Alaska/United States/CIRI/Fee
Operator:	Marathon Oil Company
Acres:	8,264
First Production:	1961
Working Interest:	Marathon Oil Company 100%

Sterling Formation Gas Zone PA (A Zone PA)

Status:	Producing
Discovery:	1959, UNOCAL Kenai Unit #14-6
Reservoir:	Tertiary Sterling Formation

Beluga PA (Beluga Formation Gas Zones PA)

Status:	Producing
Discovery:	1959, UNOCAL Kenai Unit #14-6
Reservoir:	Tertiary Beluga Formation (-4,595 to -5,108 ft. subsea)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Fox River
Kachemak Bay
Caribou Lake
Kasilof
Clam Gulch
FALLS CREEK UNIT
NINILCHIK UNIT
Ninilchik River
UNOCAL Deep Creek NNA 1
DEEP CREEK UNIT
Deep Creek
UNOCAL Pearl 1
Stariski Creek
NORTH FORK UNIT
MARATHON Grassim Oskolkiff 1
MARATHON Grassim Oskolkiff 2
MARATHON Susan Dionne 1RD
SOUTH NINILCHIK UNIT
Ninilchik
UNOCAL Griner #1
COSMOPOLITAN UNIT
PHILLIPS Hansen 1
Anchor Point
Cook Inlet
DO&G 08/02

Cook Inlet

B. Havelock

Ninilchik Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI/Fee
Operator:	Marathon Oil Company
Acres:	27,860
Working Interest:	Marathon Oil Company 40%
	Unocal 38%
	Anadarko Petroleum Corporation 11%
	Phillips Alaska, Inc. 11%

Falls Creek Unit

Status:	Shut-In
Royalty Ownership:	State of Alaska/United States
Operator:	Marathon Oil Company
Acres:	564
First Production:	Shut-in 1961

Falls Creek PA

Status:	Suspended
Discovery:	1961, Chevron Falls Creek Unit #43-1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Marathon Oil Company 45%
	Unocal 30%
	Phillips Alaska, Inc. 25%

South Ninilchik Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI/Fee
Operator:	Unocal
Acres:	6,998
Working Interest:	Unocal 100%

Deep Creek Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI
Operator:	Unocal
Acres:	22,617
Working Interest:	Unocal 100%

Cook Inlet

Cosmopolitan Unit

D. Colley

Status:	Exploration
Royalty Ownership:	State of Alaska/United States
Operator:	Phillips Alaska, Inc.
Acres:	23,369
Working Interest:	Phillips Alaska, Inc. 57%
	Anadarko Petroleum Corporation 20%
	Forest Oil Corporation 14%
	Devon Energy Production Company 4%
	ExxonMobil 4%
	Others 1%

Starichkof Discovery

Status:	Exploration
Discovery:	1967, Penzoil Starichkof St. #1
Reservoir:	Tertiary Hemlock Conglomerate

North Fork Unit

Status:	Shut-In
Royalty Ownership:	State of Alaska
Operator:	Gas-Pro Alaska, LLC
Acres:	2,480
First Production:	Shut-in in 1965

North Fork PA

Status:	Suspended
Discovery:	1965, Chevron North Fork Unit #41-35
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Gas-Pro Alaska, LLC 73%
	Phillips Alaska, Inc. 27%

D. Colley

B. Havelock

Non-Unitized Production

Middle Ground Shoal Field

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Cross Timbers Oil Co./ Forest Oil Company/ Unocal
First Production:	1967
Discovery:	1962, Pan Am MGS State 17595 #1
Reservoir:	Tertiary Hemlock and Tyonek formations

Granite Point Field

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
First Production:	1967
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Hemlock and Tyonek formations

Fields and Pools

FIELD NAME	TYPE OF FIELD	LOCATION	UNIT	DATE DISCOVERED	OPERATOR
ALBERT KALOA	GAS	Cook Inlet, west side, onshore.		1/4/1968	CIRI
ALPINE	OIL	North Slope, Colville Delta, onshore.	Colville River	3/27/1994	Phillips
AURORA	OIL	North Slope, central, onshore.	Prudhoe Bay	8/24/1969	BP
BADAMI	OIL & GAS	North Slope, Canning R., onshore.	Badami	4/27/1990	BP
BEAVER CREEK	OIL & GAS	Cook Inlet, east side, onshore.	Beaver Creek	12/17/1972	UNOCAL
BELUGA RIVER	GAS	Cook Inlet, west side, onshore.	Beluga River	12/1/1962	Phillips
BIRCH HILL	GAS	Cook Inlet, east side, onshore.	Birch Hill	6/9/1965	Phillips
BOREALIS	OIL	North Slope, central, onshore.	Prudhoe Bay	8/8/1969	BP
BURGER	OIL & GAS	OCS, Chukchi Sea, offshore		10/14/1989	
CANNERY LOOP	GAS	Cook Inlet, east side, onshore.	Cannery Loop	6/24/1979	Marathon
CANNERY LOOP BELUGA	GAS	Cook Inlet, east side, onshore.	Cannery Loop	6/24/1979	Marathon
CANNERY LOOP STERLING	GAS	Cook Inlet, east side, onshore.	Cannery Loop	10/23/2000	Marathon
CASCADE	OIL	North Slope, central, onshore.	Milne Point	3/14/1993	BP
COLVILLE DELTA	OIL	North Slope, Colville Delta, onshore.		4/26/1985	Phillips
EAST BARROW	GAS	North Slope, western, onshore.	Barrow	5/4/1974	NS Borough
EAST KURUPA	GAS	North Slope, foothills, onshore		3/1/1976	
EAST UMIAT	GAS	North Slope, foothills, onshore.		3/28/1964	UMC Petroleum
EIDER	OIL	North Slope, central, onshore.	Duck Island	3/20/1998	BP
ENDICOTT	OIL	North Slope, central, onshore.	Duck Island	2/14/1978	BP
FALLS CREEK	GAS	Cook Inlet, east side, onshore.	Falls Creek	4/10/1961	Marathon
FIORD	OIL	North Slope, Colville Delta, onshore.	Colville River	4/18/1992	Phillips
FISH CREEK	OIL	North Slope, NPRA, onshore.		9/4/1949	Phillips
FLAXMAN	OIL	North Slope, Canning R., offshore.	Point Thomson	9/6/1975	Exxon
GRANITE POINT	OIL & GAS	Cook Inlet, west side, offshore.		5/16/1965	UNOCAL
GRANITE POINT TYONEK	GAS	Cook Inlet, west side, offshore.		8/5/1965	UNOCAL
GUBIK	GAS	North Slope, foothills, onshore.		8/11/1951	
GWYDYR BAY	OIL	North Slope, central, onshore.	Prudhoe Bay	11/25/1969	BP
HAMMERHEAD	OIL	OCS, Beaufort Sea, offshore.		10/11/1986	Anadarko
HEMI SPRINGS	OIL	North Slope, central, onshore.		4/3/1984	
IVAN RIVER	GAS	Cook Inlet, west side, onshore.	Ivan River	10/8/1966	UNOCAL
KALUBIK	OIL	North Slope, Colville Delta, onshore.	Alpine	5/1/1992	Phillips
KATALLA	OIL	Gulf of Alaska, onshore.		1/1/1902	
KAVIK	GAS	North Slope, foothills, onshore.		11/5/1969	Phillips
KEMIK	GAS	North Slope, foothills, onshore.		6/17/1972	BP
KENAI	GAS	Cook Inlet, east side, onshore.	Kenai	10/11/1959	Marathon
KENAI STERLING	GAS	Cook Inlet, east side, onshore.	Kenai		Marathon
KUPARUK RIVER	OIL & GAS	North Slope, central, onshore.	Kuparuk River	4/7/1969	Phillips
KUVLUM	OIL	OCS, Beaufort Sea, offshore.		10/1/1992	Union Texas Pet.
LEWIS RIVER	GAS	Cook Inlet, west side, onshore.	Lewis River	10/1/1975	UNOCAL
LIBERTY	OIL	OCS, Beaufort Sea, offshore.		3/3/1983	BP
LISBURNE	OIL & GAS	North Slope, central, onshore.	Prudhoe Bay	12/19/1967	BP
LONE CREEK	GAS	Cook Inlet, west side, onshore.	Moquawkie	10/12/1998	Anadarko
MCARTHUR RIVER	OIL & GAS	Cook Inlet, west side, offshore.	Trading Bay	9/29/1965	UNOCAL
MCARTHUR RIVER TYONEK	GAS	Cook Inlet, west side, offshore.	Trading Bay		UNOCAL
MEADE	GAS	North Slope, NPRA, onshore.		8/21/1950	
MELTWATER	OIL	North Slope, central, onshore.	Kuparuk River	4/26/2000	Phillips
MIDDLE GROUND SHOAL	OIL	Cook Inlet, mid channel, offshore.	N & S MGS	6/10/1962	UNOCAL/Cross Timbers
MIDNIGHT SUN	OIL	North Slope, central, onshore.	Prudhoe Bay	12/20/1997	BP
MIKKELSON	OIL	North Slope, central, onshore.		11/11/1978	Exxon/Phillips
MILNE POINT	OIL	North Slope, central, onshore.	Milne Point	8/9/1969	BP
MOQUAWKIE	GAS	Cook Inlet, west side, onshore.	Moquawkie	11/28/1965	CIRI
N MID GROUND SH (MGS)	GAS	Cook Inlet, mid channel, offshore.	N Mid Ground Sh	6/10/1962	UNOCAL
N MIDDLE GROUND SHOAL	GAS	Cook Inlet, mid channel, offshore.		11/15/1964	UNOCAL/Cross Timbers
NANUQ	OIL	North Slope, Colville Delta, onshore.	Colville River	5/7/2000	Phillips
NIAKUK	OIL	North Slope, central, offshore.	Prudhoe Bay	3/7/1985	BP
NICOLAI CREEK	GAS	Cook Inlet, west side, onshore.	Nicolai Creek	4/28/1966	UNOCAL
NORTH COOK INLET	GAS	Cook Inlet, mid channel, offshore.	N Cook Inlet	8/21/1962	Phillips
NORTH FORK	GAS	Cook Inlet, east side, onshore.	North Fork	12/20/1965	UNOCAL
NORTH PRUDHOE	OIL & GAS	North Slope, central, onshore.	Prudhoe Bay	3/31/1970	BP
NORTHSTAR	OIL & GAS	North Slope, central, offshore.	Northstar	1/30/1984	BP
NPRA LOOKOUT	OIL/COND	North Slope, NPRA, onshore.			Phillips
NPRA RENDEZVOUS	OIL/COND	North Slope, NPRA, onshore.			Phillips
NPRA SPARK	OIL/COND	North Slope, NPRA, onshore.		4/12/2000	Phillips
ORION	OIL	North Slope, central, onshore.	Prudhoe Bay	8/8/1969	BP
PALM	OIL	North Slope, central, onshore.	Kuparuk River	2/21/2001	Phillips
PETE'S WICKED	OIL	North Slope, central, onshore.	Prudhoe Bay	2/24/1997	BP
POINT MCINTYRE	OIL & GAS	North Slope, central, offshore.	Prudhoe Bay	3/22/1988	BP
POINT THOMSON	OIL & GAS	North Slope, Canning R., onshore.	Point Thomson	12/8/1977	Exxon
POLARIS	OIL	North Slope, central, onshore.	Prudhoe Bay	8/24/1969	BP

Fields and Pools

PRETTY CREEK	GAS	Cook Inlet, west side, onshore.	Pretty Creek	2/20/1979	UNOCAL
PRUDHOE BAY	OIL & GAS	North Slope, central, onshore.	Prudhoe Bay	12/19/1967	BP
REDOUBT SHOAL	OIL	Cook Inlet, west side, offshore.	Redoubt Shoal	9/21/1968	Forest
SAG DELTA NORTH	OIL	North Slope, central, onshore.	Duck Island	1/25/1982	BP
SAG RIVER	OIL	North Slope, central, onshore.	Milne Point	8/9/1969	BP
SAMBUCCA	OIL	North Slope, central, onshore.	Prudhoe Bay		BP
SANDPIPER	OIL	OCS, Beaufort Sea, offshore.	Sandpiper	1/25/1986	Murphy
SCHRADER BLUFF	OIL	North Slope, central, onshore.	Milne Point	8/9/1969	BP
SIKULIK	GAS	North Slope, western, onshore.		4/18/1988	NS Borough
SIMPSON	OIL	North Slope, NPRA, onshore.		10/23/1950	
SOURDOUGH	OIL	North Slope, Canning R., onshore.	Point Thomson	4/27/1994	BP
SOUTH BARROW	GAS	North Slope, western, onshore.	Barrow	4/15/1949	NS Borough
SQUARE LAKE	GAS	North Slope, NPRA, onshore.		4/18/1952	
STARICHKOF	OIL	Cook Inlet, east side, offshore.	Cosmopolitan	4/1/1967	Forest
STERLING	GAS	Cook Inlet, east side, onshore.	Sterling	7/11/1961	Marathon
STERLING BELUGA	GAS	Cook Inlet, east side, onshore.	Sterling	1/19/1999	Marathon
STERLING TYONEK	GAS	Cook Inlet, east side, onshore.	Sterling		Marathon
STINSON	confidential	North Slope, Canning R., offshore		8/20/1990	Phillips
STUMP LAKE	GAS	Cook Inlet, west side, onshore.	Stump Lake	5/14/1978	UNOCAL
SWANSON RIVER	OIL & GAS	Cook Inlet, east side, onshore.	Swanson River	7/19/1957	UNOCAL
TABASCO	OIL	North Slope, central, onshore.	Kuparuk River	10/18/1986	Phillips
TARN	OIL	North Slope, central, onshore.	Kuparuk River	2/2/1991	Phillips
THETIS ISLAND	OIL	North Slope, central, offshore.		4/28/1993	Anadarko
TRADING BAY	OIL	Cook Inlet, west side, offshore.	N Trading Bay	6/17/1965	UNOCAL
TRADING BAY TYONEK	GAS	Cook Inlet, west side, offshore.	N Trading Bay		UNOCAL
TYONEK DEEP	OIL	Cook Inlet, mid channel, offshore.	N Cook Inlet	11/5/1991	Phillips
UGNU	OIL	North Slope, central, onshore.	Kuparuk River	8/9/1969	Phillips
UMIAT	OIL	North Slope, foothills, onshore.		12/26/1946	U.S. Dept Interior
WALAKPA	GAS	North Slope, western, onshore.		2/7/1980	NS Borough
WEST BEACH	OIL & GAS	North Slope, central, onshore.	Prudhoe Bay	7/22/1976	BP
WEST FORELAND	GAS	Cook Inlet, west side, onshore.		3/29/1962	Phillips
WEST FORK	GAS	Cook Inlet, east side, onshore.		9/26/1960	CIRI
WEST MCARTHUR RIVER	OIL & GAS	Cook Inlet, west side, onshore.	W Mcarthur River	12/2/1991	Forest
WEST SAK	OIL	North Slope, central, onshore.	Kuparuk River	8/9/1969	Phillips
WOLF CREEK	GAS	North Slope, NPRA, onshore.		6/4/1951	
WOLF LAKE	GAS	Cook Inlet, west side, onshore.		11/12/1983	Maratthon

Section Two

Historic and Forecast Production

Introduction

This section enumerates historic and projected oil and gas production for various North Slope and Cook Inlet producing areas. **Remaining Reserves** of oil and gas are reported in Tables III.1 (North Slope) and III.2 (Cook Inlet). These figures are derived from the sum of forecasted production during 2002 through 2034 (2022 for Cook Inlet).

Historic Production is summarized by producing area or unit as follows:

	Producing Region	Hydrocarbon Type	Table or Figure
Historic			
	North Slope	Oil	Table III.3
	Incremental Production	Oil	Figures III.1A & B
	Cook Inlet	Oil	Table III.4
	North Slope	Gas	Table III.5 and Figure III.2
	Cook Inlet	Gas	Table III.6
Forecast			
	North Slope	Oil	Table III.7 and Figure III.3A & B
	Cook Inlet	Oil	Table III.8 and Figures III.4
	North Slope	Gas	Table III.9 and Figure III.5
	Cook Inlet	Gas	Table III.10 and Figures III.6

Historic information is based on data from the Alaska Oil and Gas Conservation Commission (AOGCC) and the Division of Oil and Gas (DOG) Royalty Accounting. The forecast of North Slope oil production is based primarily on estimates prepared by the Alaska Department of Revenue. Forecast oil and gas production in Cook Inlet is based DOG assumptions about future rates of production decline on a field-by-field basis. Similarly, the forecast of gas production in the North Slope is based on DOG methods and assumptions. These are enumerated in footnotes. Detailed estimation assumptions are available from DOG on request.

North Slope

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Badami Unit	2	39	14.6%	0	6
Barrow					
East Barrow	-	5	0.0%	-	-
South Barrow	-	4	0.0%	-	-
Walakpa	-	25	0.0%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	431	-	10.0%	43	-
CRU Satellite	120	-	12.5%	15	-
TOTAL CRU	551	60		58	60
Duck Island Unit	162	843	12.5-14.4%	20	121
Kuparuk River Unit					
Kuparuk	1,031	590	12.5%	129	74
West Sak[2]	343	-	12.5%	43	-
Tabasco	11	-	12.5%	1	-
Tarn	83	21	12.5%	10	3
Meltwater	33		12.5%	4	
Kuparuk Satellite	94	-	12.5%	12	-
TOTAL KRU	1,595	611		199	76
Milne Point Unit	503	14	14.6%	73	2
North Star	191	450	16.0%	31	72
Prudhoe Bay Unit					
Initial Participating Areas					
Prudhoe IPAs[2]	3,024	-	12.5%	378	-
PBU Satellites[3]	482	-	12.5%	60	-
TOTAL PBU IPA	3,506	23,000	12.5%	438	2,875
Greater Point McIntyre Area					
Lisburne	36	276	12.5%	5	35
Niakuk	44	26	12.5%	6	3
North Prudhoe Bay State	-	-	12.5%	-	-
Pt. McIntyre	154	577	13.8%	21	80
West Beach	-	-	12.5%	-	-
TOTAL GPMA	234	879		31	117
TOTAL PBU	3,741	23,879		470	2,992
Point Thomson	435				
Other Undeveloped[4]	174	8,000	12.5%	22	1,000
TOTAL North Slope (State Lands)	6,920	33,930		873	4,330

Notes:

[1] Remaining recoverable reserves are based on the sum of forecasted production from 2002 through 2034. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[2] Oil Rim and Gas Cap.

[3] Includes Midnight Sun, Aurora, Borealis, and Polaris.

[4] Includes Liberty and other known on- and off-shore accumulations.

Source: Alaska Department of Natural Resources and Department of Revenue.

Cook Inlet

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Beaver Creek	0.3	87.0	-	-	-
Beluga River	-	413.2	7.5%	-	31.0
Cannery Loop	-	20.0	4.0%	-	0.8
Granite Point	13.3	14.2	12.5%	1.7	1.8
Ivan River, Lewis River, Pretty Creek, Stump Lake	-	15.0	12.5%	-	1.9
Kenai	-	160.7	2.1%	-	3.4
MacArthur River	51.9	265.1	12.5%	6.5	33.1
Middle Ground Shoal	16.6	5.0	12.5%	2.1	0.6
North Cook Inlet	-	674.7	12.5%	-	84.3
North Trading Bay	0.1	-	12.5%	0.0	-
Sterling	-	30.0	12.4%	-	3.7
Swanson River	4.9	87.1	-	-	-
Trading Bay	5.6	27.0	12.5%	0.7	3.4
West Fork	-	-	-	-	-
West MacArthur River	8.4	0.8	12.5%	1.1	0.1
					-
Undeveloped					-
Birch Hill	-	-	-	-	-
Falls Creek	-	-	12.5%	-	-
Lone Creek	-	-	-	-	-
Nicolai Creek	-	-	12.5%	-	-
North Fork	-	-	12.5%	-	-
Redoubt Shoal	59.9	-			-
Tyonek Deep	25.0	30.0	12.5%	3.1	3.8
West Foreland	-	20.0	12.5%	-	2.5
Wolf Lake[2]	-	50.0	-na-	-	-
Other Proven/ Undeveloped[3]		341.0	12.5%		42.6
TOTAL COOK INLET	186.0	2,240.7		15.1	213.0

Notes:

[1] Remaining recoverable reserves are based on the sum of forecasted production from 2002 through 2022. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[2] Subsurface lands owned by Cook Inlet Region, Incorporated.

[3] Includes the Ninilchik and Kasilof exploration units and other exploration areas on the Kenai Peninsula.

Source: Alaska Department of Natural Resources.

North Slope (Millions of Barrels per Year)

	Badami	Colville River			Northstar	Duck Island									
		Alpine	Nanuk	TOTAL Colville River		Eider[1]	Endicott	Endicott	Endicott	Endicott	Sag Delta North[1]	Sag Delta North[1]	Sag Delta North[1]	Ivishak[1]	TOTAL Duck Island Unit
	oil	oil	oil		oil	oil	oil	ngl	inj	net	oil	ngl	net	oil	
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1981	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1982	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1983	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1985	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1986	-	-	-	-	-	-	0.011	-	0.007	0.004	-	-	-	-	0.004
1987	-	-	-	-	-	-	8.796	0.003	0.014	8.785	-	-	-	-	8.785
1988	-	-	-	-	-	-	37.441	0.492	-	37.933	-	-	-	-	37.933
1989	-	-	-	-	-	-	35.746	0.839	-	36.585	0.349	0.005	0.354	-	36.939
1990	-	-	-	-	-	-	36.181	0.845	-	37.026	1.542	0.028	1.570	-	38.596
1991	-	-	-	-	-	-	38.996	1.170	-	40.165	2.309	0.048	2.357	-	42.522
1992	-	-	-	-	-	-	40.603	1.468	-	42.071	1.002	0.011	1.013	-	43.084
1993	-	-	-	-	-	-	38.433	1.551	-	39.984	0.761	0.007	0.768	-	40.752
1994	-	-	-	-	-	-	33.916	1.481	-	35.397	0.368	0.003	0.371	-	35.768
1995	-	-	-	-	-	-	32.998	1.203	-	34.201	0.235	0.001	0.236	-	34.437
1996	-	-	-	-	-	-	26.450	1.013	-	27.463	0.199	0.001	0.200	-	27.663
1997	-	-	-	-	-	-	21.121	1.550	-	22.671	0.255	0.002	0.257	-	22.928
1998	0.731	-	-	-	-	0.395	16.775	1.265	-	18.040	0.193	0.001	0.194	-	18.629
1999	1.150	-	-	-	-	0.605	13.529	1.324	-	15.009	-	-	-	0.179	15.793
2000	0.930	2.231	-	2.231	-	0.248	11.622	1.426	-	13.048	-	-	-	0.148	13.444
2001	0.675	28.688	0.019	28.707	1.266	0.660	9.637	1.324	-	10.961	-	-	-	0.142	11.763
TOTAL	3.486	30.919	0.019	30.938	1.266	1.908	402.255	16.955	0.021	419.344	7.213	0.107	7.320	0.469	429.040

Notes:

[1]AOGCC combined 1999 production volumes for Eider and Sag Delta North and reported these data in the "Ivishak Pool."

North Slope (Millions of Barrels per Year)

	Prudhoe Bay Unit Initial Participating Areas (IPAs) and Satellites								
	Prudhoe Bay[2]	Prudhoe Bay	Prudhoe Bay	Prudhoe Bay[2]	Midnight Sun	Polaris (Schrader Bluff)	Aurora	Borealis	TOTAL PBU IPAs + Satellites
	oil	ngl	inj	net	oil	oil	oil	oil	
1969	0.277	-	0.217	0.060	-	-	-	-	0.060
1970	1.193	-	0.879	0.314	-	-	-	-	0.314
1971	1.157	-	0.833	0.324	-	-	-	-	0.324
1972	0.922	-	0.792	0.130	-	-	-	-	0.130
1973	0.944	-	0.817	0.127	-	-	-	-	0.127
1974	2.170	-	1.640	0.530	-	-	-	-	0.530
1975	2.870	-	2.147	0.723	-	-	-	-	0.723
1976	4.604	-	3.611	0.993	-	-	-	-	0.993
1977	115.258	-	2.075	113.183	-	-	-	-	113.183
1978	397.679	-	-	397.679	-	-	-	-	397.679
1979	468.412	-	-	468.412	-	-	-	-	468.412
1980	555.394	0.254	-	555.648	-	-	-	-	555.648
1981	555.170	0.450	-	555.620	-	-	-	-	555.620
1982	558.889	0.500	-	559.389	-	-	-	-	559.389
1983	560.837	0.311	-	561.148	-	-	-	-	561.148
1984	561.952	0.317	-	562.269	-	-	-	-	562.269
1985	568.534	0.056	-	568.590	-	-	-	-	568.590
1986	561.538	0.230	-	561.768	-	-	-	-	561.768
1987	572.045	14.610	-	586.655	-	-	-	-	586.655
1988	559.412	19.274	-	578.686	-	-	-	-	578.686
1989	505.940	16.928	-	522.868	-	-	-	-	522.868
1990	470.140	16.094	-	486.234	-	-	-	-	486.234
1991	465.399	21.307	-	486.706	-	-	-	-	486.706
1992	432.587	23.902	-	456.489	-	-	-	-	456.489
1993	385.811	23.879	-	409.690	-	-	-	-	409.690
1994	351.493	22.825	-	374.318	-	-	-	-	374.318
1995	313.629	26.810	-	340.439	-	-	-	-	340.439
1996	282.060	30.549	-	312.609	-	-	-	-	312.609
1997	252.421	31.580	-	284.001	-	-	-	-	284.001
1998	221.781	30.983	-	252.764	0.061	-	-	-	252.825
1999	194.338	29.423	-	223.761	1.696	0.027	-	-	225.484
2000	187.056	30.145	-	217.200	1.441	0.414	0.261	-	219.317
2001	166.718	27.526	-	194.244	1.305	0.419	1.738	1.346	199.052
TOTAL	10,278.630	367.952	13.011	10,633.571	4.503	0.861	1.999	1.346	10,642.280

Notes:
[2]Production for the Prudhoe Bay IPAs includes oil and condensates.

North Slope (Millions of Barrels per Year)

	Greater Point McIntyre Area (GPMA)																TOTAL Prudhoe Bay Unit (IPA+GPMA)
	Lisburne	Lisburne	Lisburne	Niakuk[3]	Niakuk[3]	Niakuk[3]	North Prudhoe Bay State	North Prudhoe Bay State	North Prudhoe Bay State	Point McIntyre	Point McIntyre	Point McIntyre	West Beach	West Beach	West Beach	TOTAL GPMA	
	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net		
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.060
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.314
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	397.679
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	555.648
1981	0.002	-	0.002	-	-	-	-	-	-	-	-	-	-	-	-	0.002	555.622
1982	0.208	-	0.208	-	-	-	-	-	-	-	-	-	-	-	-	0.208	559.597
1983	0.087	-	0.087	-	-	-	-	-	-	-	-	-	-	-	-	0.087	561.235
1984	0.294	-	0.294	-	-	-	-	-	-	-	-	-	-	-	-	0.294	562.563
1985	1.123	-	1.123	-	-	-	-	-	-	-	-	-	-	-	-	1.123	569.713
1986	3.594	-	3.594	-	-	-	-	-	-	-	-	-	-	-	-	3.594	565.362
1987	16.199	0.458	16.657	-	-	-	-	-	-	-	-	-	-	-	-	16.657	603.312
1988	15.095	1.008	16.103	-	-	-	-	-	-	-	-	-	-	-	-	16.103	594.789
1989	13.737	1.093	14.830	-	-	-	-	-	-	-	-	-	-	-	-	14.830	537.698
1990	14.669	1.204	15.873	-	-	-	-	-	-	-	-	-	-	-	-	15.873	502.107
1991	13.316	1.337	14.653	-	-	-	-	-	-	-	-	-	-	-	-	14.653	501.359
1992	12.517	1.464	13.981	-	-	-	-	-	-	-	-	-	-	-	-	13.981	470.470
1993	8.473	1.277	9.750	-	-	-	0.418	0.015	0.433	7.543	0.090	7.633	0.724	0.009	0.733	18.549	428.239
1994	6.846	0.939	7.785	3.383	0.028	3.411	0.727	0.031	0.758	37.684	0.548	38.232	0.512	0.012	0.524	50.710	425.028
1995	5.454	0.823	6.277	7.004	0.077	7.081	0.702	0.034	0.736	50.225	0.679	50.904	0.163	0.005	0.168	65.166	405.605
1996	4.465	0.674	5.139	10.937	0.108	11.045	0.126	0.003	0.129	57.926	0.825	58.751	0.474	0.025	0.499	75.563	388.172
1997	3.002	0.416	3.418	10.265	0.136	10.401	-	-	-	58.498	1.042	59.540	0.319	0.027	0.346	73.705	357.706
1998	2.468	0.331	2.799	10.356	0.128	10.484	0.001	0.001	0.002	47.553	1.009	48.562	0.096	0.006	0.102	61.949	314.774
1999	2.203	0.326	2.529	9.857	0.131	9.988	0.008	0.001	0.009	33.460	0.831	34.291	0.603	0.067	0.670	47.486	272.970
2000	3.203	0.601	3.804	7.336	0.101	7.437	0.003	0.001	0.003	23.737	0.675	24.413	0.401	0.053	0.454	36.111	255.428
2001	3.054	0.622	3.675	6.978	0.109	7.087	-	-	-	18.094	0.600	18.693	0.110	0.014	0.125	29.580	228.632
TOTAL	130.008	12.573	142.581	66.116	0.818	66.934	1.984	0.085	2.070	334.720	6.299	341.019	3.402	0.218	3.621	556.224	11,198.504

Notes:

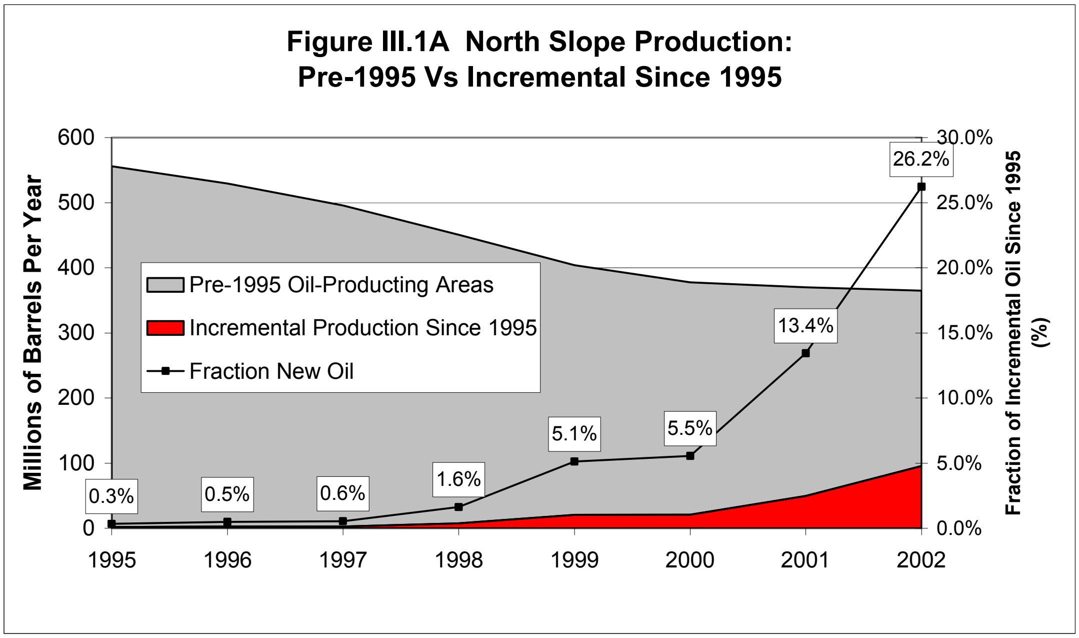
[3]Niakuk production volumes for 1994-1998 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

North Slope (Millions of Barrels per Year)

	Kuparuk River Unit								Milne Point Unit				TOTAL OIL	TOTAL NGL	TOTAL INJECT-ED	TOTAL NET
	Kuparuk	Kuparuk	Kuparuk	Tabasco	Tarn	West Sak	Melt-water	TOTAL Kuparuk River Unit	Milne Point	Sag River	Schrader Bluff	TOTAL Milne Point Unit				
	oil	ngl	net	oil	oil	oil	oil		oil	oil	oil					
1969	-	-	-	-	-	-	-	-	-	-	-	-	0.277	-	0.217	0.060
1970	0.006	-	0.006	-	-	-	-	0.006	-	-	-	-	1.199	-	0.879	0.320
1971	-	-	-	-	-	-	-	-	-	-	-	-	1.157	-	0.833	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	0.922	-	0.792	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	0.944	-	0.817	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	2.170	-	1.640	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	2.870	-	2.147	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	4.604	-	3.611	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	115.258	-	2.075	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	397.679	-	-	397.679
1979	-	-	-	-	-	-	-	-	-	-	-	-	468.412	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	555.394	0.254	-	555.648
1981	1.092	-	1.092	-	-	-	-	1.092	-	-	-	-	556.264	0.450	-	556.714
1982	32.406	-	32.406	-	-	-	-	32.406	-	-	-	-	591.503	0.500	-	592.003
1983	39.876	-	39.876	-	-	0.006	-	39.882	-	-	-	-	600.806	0.311	-	601.117
1984	46.084	-	46.084	-	-	0.124	-	46.208	-	-	-	-	608.454	0.317	-	608.771
1985	78.926	0.761	79.687	-	-	0.326	-	80.013	0.704	-	-	0.704	649.613	0.817	-	650.430
1986	93.900	1.072	94.972	-	-	0.300	-	95.272	4.709	-	-	4.709	664.052	1.302	0.007	665.347
1987	102.448	1.257	103.705	-	-	-	-	103.705	0.040	-	-	0.040	699.528	16.328	0.014	715.842
1988	110.891	0.256	111.147	-	-	-	-	111.147	-	-	-	-	722.839	21.030	-	743.869
1989	109.770	-	109.770	-	-	-	-	109.770	3.715	-	-	3.715	669.257	18.865	-	688.122
1990	107.206	-	107.206	-	-	-	-	107.206	6.624	-	0.004	6.628	636.366	18.171	-	654.537
1991	113.571	-	113.571	-	-	-	-	113.571	6.701	-	0.756	7.457	641.048	23.862	-	664.910
1992	118.506	-	118.506	-	-	-	-	118.506	5.812	-	1.135	6.947	612.162	26.845	-	639.007
1993	115.166	-	115.166	-	-	-	-	115.166	5.704	-	1.060	6.764	564.093	26.828	-	590.921
1994	111.795	-	111.795	-	-	-	-	111.795	5.648	-	1.030	6.678	553.402	25.867	-	579.269
1995	106.999	-	106.999	-	-	-	-	106.999	7.352	0.173	1.167	8.692	526.101	29.632	-	555.733
1996	99.459	-	99.459	-	-	-	-	99.459	12.665	0.346	1.090	14.101	496.197	33.198	-	529.395
1997	95.970	-	95.970	-	-	0.001	-	95.971	17.055	0.363	1.536	18.954	460.806	34.753	-	495.559
1998	91.702	-	91.702	0.483	3.534	0.562	-	96.281	18.314	0.162	1.943	20.419	417.110	33.724	-	450.834
1999	82.394	-	82.394	1.920	9.541	1.190	-	95.045	17.488	-	2.178	19.666	372.365	32.103	-	404.468
2000	74.133	-	74.133	1.911	8.767	1.520	-	86.330	16.572	-	2.498	19.069	344.431	33.002	-	377.433
2001	68.265	-	68.265	1.318	8.052	1.998	0.149	79.782	15.273	0.248	3.818	19.339	339.969	30.194	-	370.163
TOTAL	1,800.565	3.346	1,803.911	5.631	29.894	6.027	0.149	1,845.612	144.375	1.292	18.214	163.882	13,277.252	408.353	13.032	13,672.573

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by FIeld and Pool" (Monthly Reports).

North Slope (Billion Cubic Feet per Year)



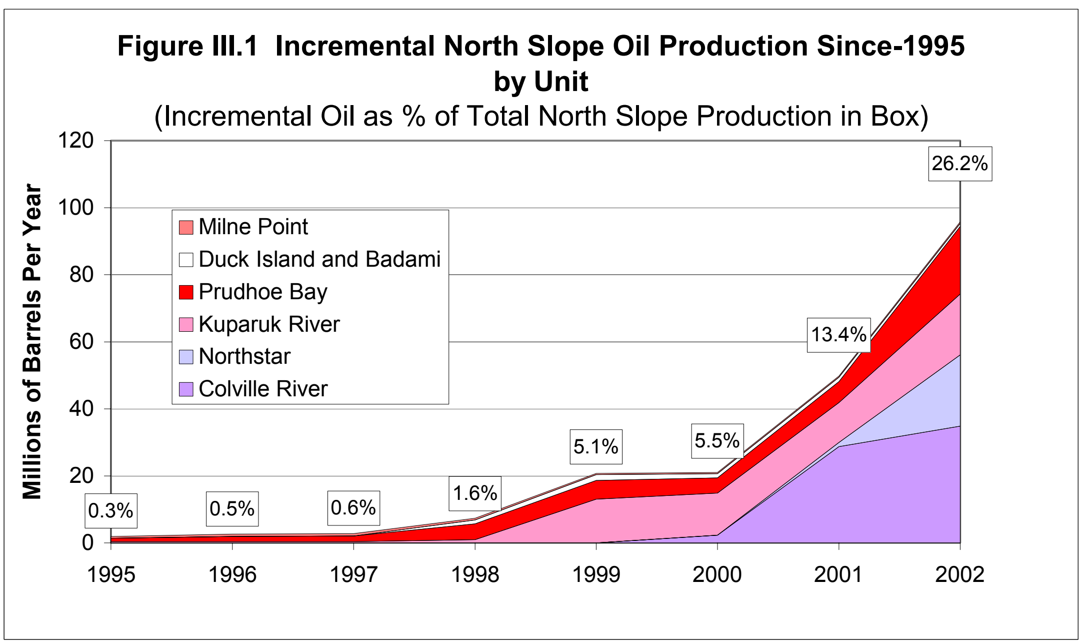


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Table III.4 Oil Production-Historic

Cook Inlet (Millions of Barrels per Year)

	Beaver Creek	Cannery Loop[1]	Granite Point[2]	Kenai[1]	McArthur River[3]	McArthur River[3]	McArthur River[3]	Middle Ground Shoal[4]	North Trading Bay Unit	Redoubt Shoal
	oil	ngl	oil	ngl	oil	ngl	net	oil	oil	oil
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-
1965	-	-	0.002	-	0.001	-	0.001	0.027	-	-
1966	-	-	-	-	0.003	-	0.003	2.649	-	-
1967	-	-	7.052	-	0.749	-	0.749	7.404	0.002	-
1968	-	-	13.131	-	21.782	-	21.782	14.134	0.185	0.002
1969	-	-	9.183	0.002	31.301	-	31.301	10.467	4.310	-
1970	-	-	7.522	0.002	40.165	0.426	40.591	12.719	3.265	-
1971	-	-	5.577	0.001	40.537	0.593	41.130	11.304	2.029	-
1972	0.002	-	4.663	0.002	40.774	0.570	41.344	9.719	2.553	-
1973	0.416	-	4.767	0.001	38.884	0.661	39.545	10.239	2.022	-
1974	0.375	-	4.237	-	39.145	0.654	39.799	9.001	2.127	-
1975	0.322	-	4.361	0.001	40.876	0.644	41.520	8.670	1.530	-
1976	0.302	-	4.471	0.001	35.810	0.653	36.463	8.864	1.096	-
1977	0.276	-	4.711	-	33.235	0.733	33.968	7.617	0.970	-
1978	0.223	-	4.867	0.001	30.223	0.730	30.953	6.382	0.797	-
1979	0.211	-	4.613	-	25.440	0.541	25.981	5.545	0.609	-
1980	0.214	-	4.394	-	20.894	0.412	21.306	4.854	0.372	-
1981	0.180	-	3.975	-	18.022	0.484	18.506	4.291	0.235	-
1982	0.182	-	3.467	-	15.806	0.449	16.255	3.573	0.132	-
1983	0.170	-	3.550	-	13.564	0.332	13.896	3.381	0.117	-
1984	0.159	-	3.287	-	11.707	0.317	12.024	3.238	0.080	-
1985	0.146	-	3.052	-	7.454	0.194	7.648	3.098	0.113	-
1986	0.158	-	3.169	-	7.942	0.228	8.170	3.211	0.220	-
1987	0.185	-	2.803	-	7.375	0.196	7.571	2.834	0.246	-
1988	0.141	-	2.677	-	7.143	0.162	7.305	2.742	0.195	-
1989	0.227	-	2.275	-	6.955	-	6.955	2.769	0.179	-
1990	0.212	-	1.462	-	4.265	-	4.265	2.688	0.121	-
1991	0.179	-	2.064	-	7.247	-	7.247	2.670	0.168	-
1992	0.175	-	2.522	-	7.397	-	7.397	2.423	0.030	-
1993	0.153	-	2.488	-	6.636	-	6.636	2.160	-	-
1994	0.140	<.001	2.209	-	7.091	-	7.091	2.785	-	-
1995	0.132	<.001	2.580	-	6.622	-	6.622	2.823	-	-
1996	0.125	<.001	2.556	-	6.102	-	6.102	2.396	-	-
1997	0.119	-	2.432	-	5.059	-	5.059	2.223	-	-
1998	0.103	-	2.079	-	4.817	-	4.817	2.156	-	-
1999	0.100	-	1.787	-	4.697	-	4.697	1.968	-	-
2000	0.092	-	1.742	-	4.822	-	4.822	1.894	-	0.002
2001	0.085	-	1.620	-	5.353	-	5.353	2.032	-	0.001
TOTAL	5.504		137.347	0.011	605.895	8.979	614.874	186.950	23.703	0.005

Notes:

[1]These gas fields temporarily produced NGLs.

[2]Includes Middle Kenai and Undefined Hemlock pools.

[3]Includes Hemlock, Middle Kenai G, and West Foreland Pools.

[4]Includes A, B, C, D, E, F, and G pools

Cook Inlet (Millions of Barrels per Year)

	Swanson River[5]	Swanson River[5]	Swanson River[5]	Trading Bay[6]	Trading Bay	Trading Bay	West McArthur River	COOK INLET TOTAL OIL	COOK INLET TOTAL NGL	COOK INLET TOTAL
	oil	ngl	net	oil	ngl	net	oil			
1958	0.036	-	0.036	-	-	-	-	0.036	-	0.036
1959	0.187	-	0.187	-	-	-	-	0.187	-	0.187
1960	0.558	-	0.558	-	-	-	-	0.558	-	0.558
1961	6.327	-	6.327	-	-	-	-	6.327	-	6.327
1962	10.259	-	10.259	-	-	-	-	10.259	-	10.259
1963	10.740	-	10.740	-	-	-	-	10.740	-	10.740
1964	11.054	-	11.054	-	-	-	-	11.054	-	11.054
1965	11.099	-	11.099	0.002	-	0.002	-	11.131	-	11.131
1966	11.712	-	11.712	-	-	-	-	14.364	-	14.364
1967	12.980	-	12.980	0.727	-	0.727	-	28.914	-	28.914
1968	13.619	0.004	13.623	3.292	-	3.292	-	66.145	0.004	66.149
1969	13.151	0.070	13.221	5.626	-	5.626	-	74.038	0.072	74.110
1970	12.408	0.063	12.471	6.335	0.039	6.374	-	82.414	0.530	82.944
1971	11.466	0.077	11.543	6.714	0.039	6.753	-	77.627	0.710	78.337
1972	8.896	0.012	8.908	6.033	0.025	6.058	-	72.640	0.609	73.249
1973	10.064	0.098	10.162	5.803	0.051	5.854	-	72.195	0.811	73.006
1974	9.765	0.096	9.861	5.425	0.043	5.468	-	70.075	0.793	70.868
1975	8.754	0.089	8.843	4.598	0.031	4.629	-	69.111	0.765	69.876
1976	7.591	0.090	7.681	4.270	0.026	4.296	-	62.404	0.770	63.174
1977	5.981	0.086	6.067	3.306	0.044	3.350	-	56.096	0.863	56.959
1978	4.870	0.065	4.935	2.770	0.019	2.789	-	50.132	0.815	50.947
1979	4.344	0.080	4.424	2.284	0.014	2.298	-	43.046	0.635	43.681
1980	3.724	0.064	3.788	1.794	0.006	1.800	-	36.246	0.482	36.728
1981	2.938	0.048	2.986	1.435	0.005	1.440	-	31.076	0.537	31.613
1982	2.999	0.048	3.047	1.251	0.002	1.253	-	27.410	0.499	27.909
1983	3.017	0.045	3.062	0.964	0.004	0.968	-	24.763	0.381	25.144
1984	2.517	0.039	2.556	0.995	0.005	1.000	-	21.983	0.361	22.344
1985	2.165	0.026	2.191	0.915	0.004	0.919	-	16.943	0.224	17.167
1986	2.055	0.054	2.109	0.826	0.002	0.828	-	17.581	0.284	17.865
1987	2.059	0.030	2.089	0.689	0.001	0.690	-	16.191	0.227	16.418
1988	2.127	0.033	2.160	0.691	-	0.691	-	15.716	0.195	15.911
1989	1.875	0.024	1.899	1.085	-	1.085	-	15.365	0.024	15.389
1990	1.878	0.019	1.897	0.522	-	0.522	-	11.148	0.019	11.167
1991	1.962	0.023	1.985	1.048	-	1.048	0.002	15.340	0.023	15.363
1992	1.773	0.019	1.792	0.856	-	0.856	0.002	15.178	0.019	15.197
1993	1.576	0.018	1.594	0.742	-	0.742	0.098	13.853	0.018	13.871
1994	1.672	0.023	1.695	0.743	-	0.743	0.921	15.561	0.023	15.584
1995	1.712	0.017	1.729	0.722	-	0.722	0.922	15.513	0.017	15.530
1996	1.521	0.019	1.540	0.589	-	0.589	1.296	14.585	0.019	14.604
1997	1.065	0.012	1.077	0.602	-	0.602	0.645	12.145	0.012	12.157
1998	0.911	0.009	0.920	0.700	-	0.700	1.037	11.803	0.009	11.812
1999	0.794	-	0.794	0.645	-	0.645	0.914	10.905	-	10.905
2000	0.638	-	0.638	0.637	-	0.637	0.893	10.720	-	10.720
2001	0.609	-	0.609	0.574	-	0.574	1.222	11.497	-	11.497
TOTAL	227.448	1.400	228.848	76.211	0.360	76.571	7.952	1,271.015	10.750	1,281.765

Notes:

[5]Includes Hemlock pool.

[6]Includes Hemlock, Undefined, and B, C, D, and E pools.

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports) and Alaska Department of Revenue.

North Slope (Billion Cubic Feet per Year)

	Badami			Barrow		Duck Island								
	Badami	Badami	Badami	East Barrow	South Barrow	Walakpa	Eider	Eider	Eider	Endicott[1]	Endicott[1]	Endicott[1]	Sag Delta	TOTAL Duck Island
	gas	inj	net	gas	gas	gas	gas	inj	net	gas	inj	net	gas	
1958	-	-	-	-	0.119	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	0.132	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	0.172	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	0.172	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	0.197	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	0.211	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	0.249	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	0.389	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	0.438	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	0.475	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	0.504	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	0.582	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	0.619	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	0.627	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	0.675	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	0.707	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	0.765	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	0.799	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	0.832	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	0.879	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	0.893	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	0.913	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	1.027	-	-	-	-	-	-	-	-	-
1981	-	-	-	0.037	1.009	-	-	-	-	-	-	-	-	-
1982	-	-	-	0.717	0.532	-	-	-	-	-	-	-	-	-
1983	-	-	-	0.689	0.541	-	-	-	-	-	-	-	-	-
1984	-	-	-	0.693	0.650	-	-	-	-	-	-	-	-	-
1985	-	-	-	0.632	0.678	-	-	-	-	-	-	-	-	-
1986	-	-	-	0.589	0.589	-	-	-	-	0.195	-	0.195	-	0.195
1987	-	-	-	0.590	0.622	-	-	-	-	8.237	5.615	2.622	-	2.622
1988	-	-	-	0.661	0.598	-	-	-	-	34.834	28.023	6.811	-	6.811
1989	-	-	-	0.475	0.758	-	-	-	-	41.194	33.033	8.161	0.236	8.397
1990	-	-	-	0.488	0.733	-	-	-	-	42.490	35.523	6.967	1.416	8.383
1991	-	-	-	0.583	0.662	-	-	-	-	60.246	51.136	9.110	2.347	11.457
1992	-	-	-	0.439	0.628	0.252	-	-	-	97.047	85.082	11.965	0.703	12.668
1993	-	-	-	0.259	0.441	0.585	-	-	-	120.116	100.682	19.434	0.529	19.963
1994	-	-	-	0.223	0.261	0.858	-	-	-	116.810	102.534	14.276	0.259	14.535
1995	-	-	-	0.099	0.052	1.109	-	-	-	127.191	113.839	13.352	0.152	13.504
1996	-	-	-	0.064	0.051	1.160	-	-	-	123.968	111.638	12.330	0.099	12.429
1997	-	-	-	0.114	0.041	1.126	-	-	-	124.737	111.495	13.242	0.157	13.399
1998	0.459	0.005	0.454	0.146	0.081	1.110	2.122	-	2.122	119.981	109.440	10.541	0.122	12.785
1999	1.693	1.718	-0.025	0.123	0.055	1.281	4.879	-	4.879	126.274	116.944	9.331	0.120	14.329
2000	4.557	4.020	0.537	0.090	0.037	1.352	2.428	-	2.428	140.704	128.599	12.105	0.095	14.628
2001	5.312	4.786	0.526	0.086	0.042	1.348	6.494	-	6.494	134.122	125.915	8.208	0.093	14.794
TOTAL	12.022	10.529	1.492	7.796	22.267	10.181	15.923	-	15.923	1,418.146	1,259.497	158.649	6.328	180.900

Notes:

[1]The small Endicott dry gas volume for 1996 was an injection of processed gas into Endicott when the field resumed operation.

North Slope (Billion Cubic Feet per Year)

	Prudhoe Bay Unit Initial Participating Areas					Greater Point McIntyre Area (GPMA)[3]										TOTAL
	Midnight Sun	Prudhoe Bay	Prudhoe Bay	Prudhoe Bay	TOTAL Prudhoe Bay Unit IPA	Lisburne	Lisburne	Lisburne	Niakuk[4]	N. Prudhoe Bay	Point McIntyre	Point McIntyre	Point McIntyre	West Beach	TOTAL GPMA	Prudhoe Bay Unit (IPA+ GPMA)
	gas	gas	inj	net		gas	inj	net	gas	gas	gas	inj	net	gas		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	0.243	-	0.243	0.243	-	-	-	-	-	-	-	-	-	-	0.243
1970	-	1.037	-	1.037	1.037	-	-	-	-	-	-	-	-	-	-	1.037
1971	-	0.889	-	0.889	0.889	-	-	-	-	-	-	-	-	-	-	0.889
1972	-	0.658	-	0.658	0.658	-	-	-	-	-	-	-	-	-	-	0.658
1973	-	0.699	-	0.699	0.699	-	-	-	-	-	-	-	-	-	-	0.699
1974	-	2.022	-	2.022	2.022	-	-	-	-	-	-	-	-	-	-	2.022
1975	-	3.046	-	3.046	3.046	-	-	-	-	-	-	-	-	-	-	3.046
1976	-	5.077	-	5.077	5.077	-	-	-	-	-	-	-	-	-	-	5.077
1977	-	94.936	68.118	26.818	26.818	-	-	-	-	-	-	-	-	-	-	26.818
1978	-	307.966	271.854	36.112	36.112	-	-	-	-	-	-	-	-	-	-	36.112
1979	-	432.475	390.136	42.339	42.339	-	-	-	-	-	-	-	-	-	-	42.339
1980	-	597.148	546.510	50.638	50.638	-	-	-	-	-	-	-	-	-	-	50.638
1981	-	647.768	595.106	52.662	52.662	0.003	-	0.003	-	-	-	-	-	-	0.003	52.665
1982	-	756.884	697.812	59.072	59.072	0.374	-	0.374	-	-	-	-	-	-	0.374	59.446
1983	-	818.993	754.044	64.949	64.949	0.154	-	0.154	-	-	-	-	-	-	0.154	65.103
1984	-	846.674	768.899	77.775	77.775	0.343	-	0.343	-	-	-	-	-	-	0.343	78.118
1985	-	936.613	846.786	89.827	89.827	1.902	-	1.902	-	-	-	-	-	-	1.902	91.729
1986	-	970.290	882.882	87.408	87.408	8.677	-	8.677	-	-	-	-	-	-	8.677	96.085
1987	-	1,228.527	1,105.023	123.504	123.504	64.906	56.741	8.165	-	-	-	-	-	-	8.165	131.669
1988	-	1,404.992	1,248.094	156.898	156.898	94.670	87.815	6.855	-	-	-	-	-	-	6.855	163.753
1989	-	1,412.853	1,244.284	168.569	168.569	104.746	102.248	2.498	-	-	-	-	-	-	2.498	171.067
1990	-	1,481.462	1,317.106	164.356	164.356	107.592	101.542	6.050	-	-	-	-	-	-	6.050	170.406
1991	-	1,768.837	1,583.472	185.365	185.365	124.360	112.457	11.903	-	-	-	-	-	-	11.903	197.268
1992	-	1,951.156	1,761.397	189.759	189.759	154.468	141.598	12.870	-	-	-	-	-	-	12.870	202.629
1993	-	2,116.808	1,921.633	195.175	195.175	130.882	122.991	7.891	-	1.103	5.392	3.979	1.413	0.592	10.999	206.174
1994	-	2,402.584	2,204.235	198.349	198.349	101.260	99.748	1.512	2.471	2.646	38.795	34.461	4.334	1.119	12.082	210.431
1995	-	2,716.959	2,497.702	219.257	219.257	80.866	104.272	-23.406	7.241	2.482	46.637	21.687	24.950	0.446	11.713	230.970
1996	-	2,750.907	2,535.603	215.304	215.304	67.013	93.000	-25.987	8.757	0.206	56.584	30.444	26.140	2.720	11.836	227.140
1997	-	2,794.735	2,577.617	217.118	217.118	39.999	75.249	-35.250	10.523	-	70.009	35.945	34.064	2.739	12.076	229.194
1998	0.130	2,801.402	2,588.527	212.875	213.005	33.111	50.399	-17.288	8.381	0.018	70.828	49.276	21.552	0.545	13.208	226.213
1999	3.781	2,772.147	2,566.580	205.567	209.348	33.214	52.187	-18.973	8.469	0.114	62.586	41.672	20.915	4.452	14.976	224.324
2000	9.288	2,913.985	2,716.721	197.265	206.553	52.322	62.621	-10.299	5.069	0.049	57.664	43.549	14.115	5.638	14.572	221.125
2001	6.750	2,757.974	2,577.173	180.801	187.552	57.490	55.529	1.961	5.836	-	56.251	43.549	12.702	1.453	21.952	209.504
TOTAL	19.949	39,698.747	36,267.314	3,431.433	3,451.382	1,258.352	1,318.397	-60.045	56.747	6.618	464.746	304.562	160.184	19.705	183.208	3,634.591

Notes:

[2] AOGCC figires for Aurora, Borealis and Polaris not separted from PBU.

[3]Liquids from the Greater Point McIntyre Area flow to the Lisburne Production Center (LPC). At the LPC gas from these liquids is returned and reinjected into the GPMA fields. Consequently, production and injection data may appear to be anomolous.

[4]Niakuk production volumes for 1994-1999 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

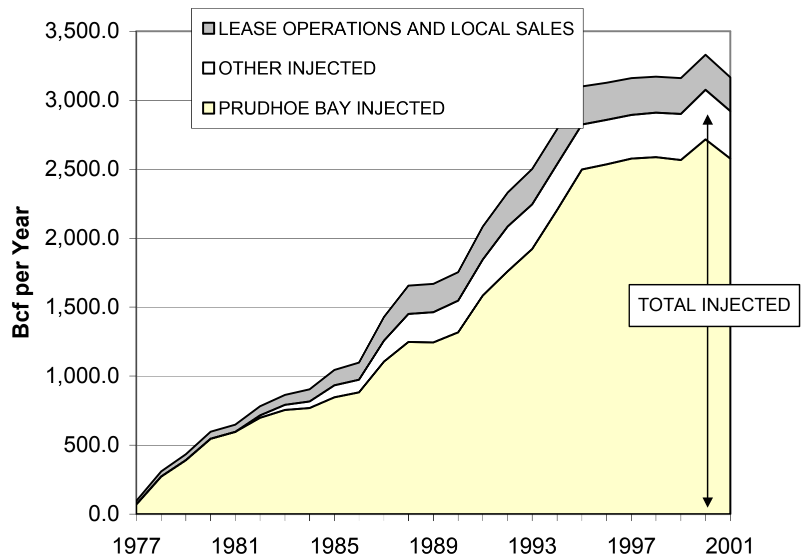
North Slope (Billion Cubic Feet per Year)

	Kuparuk River Unit									Milne Popint Unit					
	Kuparuk	Kuparuk	Kuparuk	Tabasco	Tarn	Tarn	Tarn	West Sak	TOTAL Kuparuk River Unit	Milne Point	Milne Point	Milne Point	Sag River	Schrader Bluff	TOTAL Milne Point Unit
	gas	inj	net	gas	gas	inj	net	gas		gas	inj	net	gas	gas	
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1981	0.615	-	0.615	-	-	-	-	-	0.615	-	-	-	-	-	-
1982	22.989	17.822	5.167	-	-	-	-	-	5.167	-	-	-	-	-	-
1983	44.391	38.277	6.114	-	-	-	-	0.005	6.119	-	-	-	-	-	-
1984	57.389	47.930	9.459	-	-	-	-	0.079	9.538	-	-	-	-	-	-
1985	104.279	85.909	18.370	-	-	-	-	0.134	18.504	0.253	-	0.253	-	-	0.253
1986	114.889	90.449	24.440	-	-	-	-	0.108	24.548	1.644	0.197	1.447	-	-	1.447
1987	125.089	89.191	35.898	-	-	-	-	-	35.898	0.011	-	0.011	-	-	0.011
1988	119.883	87.906	31.977	-	-	-	-	-	31.977	-	-	-	-	-	-
1989	107.519	83.323	24.196	-	-	-	-	-	24.196	0.978	0.320	0.658	-	-	0.658
1990	116.579	91.273	25.306	-	-	-	-	-	25.306	2.718	1.401	1.317	-	-	1.317
1991	123.207	95.982	27.225	-	-	-	-	-	27.225	3.515	1.704	1.811	-	0.244	2.055
1992	122.767	96.625	26.142	-	-	-	-	-	26.142	3.015	1.632	1.383	-	0.536	1.919
1993	120.599	94.339	26.260	-	-	-	-	-	26.260	2.967	1.836	1.131	-	0.518	1.649
1994	120.273	93.288	26.985	-	-	-	-	-	26.985	3.524	2.305	1.219	-	0.515	1.734
1995	112.418	84.317	28.101	-	-	-	-	-	28.101	4.340	3.399	0.941	0.113	0.656	1.710
1996	107.811	83.632	24.179	-	-	-	-	-	24.179	6.120	4.307	1.813	0.299	0.464	2.576
1997	105.644	85.893	19.751	-	-	-	-	-	19.751	9.463	6.998	2.465	0.437	0.644	3.546
1998	117.517	103.604	13.913	0.112	4.476	1.195	3.281	0.213	17.519	8.949	6.351	2.598	0.179	1.008	3.785
1999	117.193	98.330	18.863	0.305	13.395	16.502	-3.107	0.385	16.447	8.371	6.137	2.234	0.019	1.199	3.451
2000	109.638	97.762	11.875	0.203	17.777	16.552	1.225	0.399	13.703	8.207	6.195	2.012	-	1.480	3.492
2001	105.305	91.823	13.482	0.180	15.538	15.039	0.499	0.429	14.590	8.631	7.498	1.133	0.228	2.380	3.741
TOTAL	2,075.994	1,657.676	418.318	0.800	51.186	49.288	1.898	1.752	422.769	72.705	50.280	22.426	1.274	9.644	33.344

North Slope (Billion Cubic Feet per Year)

	TOTAL GAS	TOTAL INJECTED	TOTAL NET
1958	0.119	-	0.119
1959	0.132	-	0.132
1960	0.172	-	0.172
1961	0.172	-	0.172
1962	0.197	-	0.197
1963	0.211	-	0.211
1964	0.249	-	0.249
1965	0.389	-	0.389
1966	0.438	-	0.438
1967	0.475	-	0.475
1968	0.504	-	0.504
1969	0.825	-	0.825
1970	1.656	-	1.656
1971	1.516	-	1.516
1972	1.333	-	1.333
1973	1.406	-	1.406
1974	2.787	-	2.787
1975	3.845	-	3.845
1976	5.909	-	5.909
1977	95.815	68.118	27.697
1978	308.859	271.854	37.005
1979	433.388	390.136	43.252
1980	598.175	546.510	51.665
1981	649.432	595.106	54.326
1982	781.496	715.634	65.862
1983	864.773	792.321	72.452
1984	905.828	816.829	88.999
1985	1,044.491	932.695	111.796
1986	1,096.981	973.528	123.453
1987	1,427.982	1,256.570	171.412
1988	1,655.638	1,451.838	203.800
1989	1,668.759	1,463.208	205.551
1990	1,753.478	1,546.845	206.633
1991	2,084.001	1,844.751	239.250
1992	2,331.011	2,086.334	244.677
1993	2,500.791	2,245.460	255.331
1994	2,791.598	2,536.571	255.027
1995	3,100.761	2,825.216	275.545
1996	3,126.223	2,858.624	267.599
1997	3,160.368	2,893.197	267.171
1998	3,170.890	2,908.797	262.093
1999	3,160.054	2,900.069	259.985
2000	3,330.982	3,076.018	254.964
2001	3,165.943	2,921.313	244.630
TOTAL	45,230.882	40,917.541	4,313.341

Figure III.2 ANS Gas Production 1977 - 2001



Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports).

Cook Inlet (Billion Cubic Feet per Year)

	Albert Kaloa	Beaver Creek	Beaver Creek	Beaver Creek	Beluga River	Birch Hill	Cannery Loop[1]	Falls Creek	Granite Point	Ivan River	Kenai[2]	Lewis River	McArthur River (TBU)	Middle Ground Shoal	Moquaw-kie	Nicolai Creek
	gas	gas	inj	net	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	0.215	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	1.460	-	-	-	-	-
1963	-	-	-	-	0.014	-	-	-	-	-	3.106	-	-	-	-	-
1964	-	-	-	-	0.137	-	-	-	-	-	4.493	-	-	-	-	-
1965	-	-	-	-	-	0.065	-	-	-	-	5.985	-	-	-	-	-
1966	-	-	-	-	-	-	-	0.019	-	-	33.375	-	-	1.200	-	-
1967	-	-	-	-	0.168	-	-	-	4.890	-	39.624	-	0.220	3.215	0.034	-
1968	-	-	-	-	2.018	-	-	-	10.036	-	46.014	-	6.155	6.654	0.353	0.026
1969	-	-	-	-	3.038	-	-	-	8.043	-	59.340	-	14.194	6.006	0.514	0.387
1970	0.095	-	-	-	3.571	-	-	-	9.211	-	80.612	-	19.688	6.137	0.083	0.202
1971	0.024	-	-	-	4.055	-	-	-	7.753	-	72.184	-	19.304	5.147	-	0.141
1972	-	0.002	-	0.002	4.142	-	-	-	5.773	-	76.007	-	19.722	4.075	-	0.066
1973	-	0.207	-	0.207	4.929	-	-	-	4.518	-	71.345	-	19.063	4.826	-	0.006
1974	-	0.150	0.019	0.131	5.596	-	-	-	3.265	-	68.485	-	19.599	4.260	-	0.011
1975	-	0.322	-	0.322	6.980	-	-	-	3.390	-	77.175	-	21.471	4.199	-	0.083
1976	-	0.261	0.091	0.170	11.211	-	-	-	3.205	-	79.467	-	19.027	4.347	-	0.108
1977	-	0.203	0.100	0.103	13.353	-	-	-	3.634	-	81.886	-	19.706	4.108	-	0.032
1978	-	0.329	0.144	0.185	14.253	-	-	-	3.860	-	97.290	-	18.585	3.290	-	-
1979	-	0.182	0.079	0.103	16.994	-	-	-	3.287	-	97.029	-	16.605	2.744	-	-
1980	-	0.180	0.029	0.151	17.002	-	-	-	3.233	-	98.846	-	15.590	2.628	-	-
1981	-	0.217	0.020	0.197	17.248	-	-	-	3.509	-	105.800	-	15.206	2.502	-	-
1982	-	0.396	0.037	0.359	18.653	-	-	-	2.780	-	115.913	-	16.240	2.374	-	-
1983	-	8.344	0.031	8.313	18.084	-	-	-	2.578	-	112.978	-	14.375	2.663	-	-
1984	-	9.335	-	9.335	19.833	-	-	-	2.340	-	110.109	0.696	15.076	2.726	-	-
1985	-	10.927	-	10.927	22.571	-	-	-	2.147	-	115.842	1.644	10.676	2.622	-	-
1986	-	17.773	-	17.773	25.357	-	-	-	2.415	-	82.470	1.338	13.560	1.593	-	-
1987	-	15.528	-	15.528	23.971	-	-	-	2.431	-	90.014	0.345	13.277	1.586	-	-
1988	-	14.346	-	14.346	25.586	-	9.400	-	2.543	-	76.299	0.045	16.722	1.635	-	-
1989	-	12.321	-	12.321	30.126	-	11.255	-	2.251	-	65.706	0.095	31.000	1.965	-	-
1990	-	12.474	-	12.474	39.512	-	12.502	-	1.431	0.676	38.393	1.485	51.456	2.579	-	-
1991	-	10.403	-	10.403	38.494	-	12.318	-	1.586	2.132	25.581	1.420	61.196	1.587	-	-
1992	-	7.368	-	7.368	36.534	-	10.635	-	2.246	1.774	24.187	0.706	70.070	2.377	-	-
1993	-	6.336	-	6.336	31.739	-	9.516	-	2.444	8.238	23.826	0.383	62.512	2.941	-	-
1994	-	1.304	-	1.304	34.212	-	6.361	-	2.077	15.996	18.853	0.244	50.027	3.025	-	-
1995	-	1.915	-	1.915	35.645	-	5.535	-	1.942	12.027	16.484	0.126	54.914	2.138	-	-
1996	-	3.042	-	3.042	36.930	-	2.072	-	2.251	6.605	13.294	0.114	67.275	0.852	-	-
1997	-	4.626	-	4.626	35.002	-	3.130	-	2.551	5.297	12.672	0.066	66.838	1.051	-	-
1998	-	3.743	-	3.743	33.391	-	3.021	-	2.635	4.532	9.736	0.102	73.822	1.882	-	-
1999	-	3.288	-	3.288	35.987	-	2.871	-	2.464	3.579	9.916	0.246	68.997	2.751	-	-
2000	-	4.793	-	4.793	38.750	-	4.239	-	2.209	2.620	12.833	0.134	65.016	1.485	-	-
2001	-	5.340	-	5.340	41.786	-	4.175	-	1.936	3.799	19.964	0.220	62.264	1.319	-	0.278
TOTAL	0.119	155.656	0.550	155.106	746.871	0.065	97.030	0.019	122.864	67.275	2,194.808	9.408	1,129.448	106.489	0.984	1.340

Notes:

[1] Cannery Loop includes CLU Beluga, CLU Upper Tyonek, CLU Tyonek D, and CLU Sterling Undefined in the Kenai formation.

[2] Kenai includes Sterling #3, 4, 5.1, 5.2, and 6 Pools, Beluga Undefined, and Tyonek.

Cook Inlet (Billion Cubic Feet per Year)

	North Cook Inlet	North Fork	North Trading Bay Unit[3]	Pretty Creek	Sterling	Stump Lake	Swanson River	Swanson River[4]	Swanson River[4]	Trading Bay[5]	West Fork	West McArthur River	Wolf Lake	TOTAL GROSS	TOTAL INJECTED	TOTAL NET
	gas	gas	gas	gas	gas	gas	gas	inj	net	gas	gas	gas	gas			
1958	-	-	-	-	-	-	0.006	-	0.006	-	-	-	-	0.006	-	0.006
1959	-	-	-	-	-	-	0.027	-	0.027	-	-	-	-	0.027	-	0.027
1960	-	-	-	-	-	-	0.119	46.482	-	-	-	-	-	0.119	46.482	-
1961	-	-	-	-	-	-	1.293	-	1.293	-	-	-	-	1.508	-	1.508
1962	-	-	-	-	0.025	-	2.071	0.259	1.812	-	-	-	-	3.556	0.259	3.297
1963	-	-	-	-	0.046	-	7.646	6.478	1.168	-	-	-	-	10.812	6.478	4.334
1964	-	-	-	-	0.058	-	7.176	5.620	1.556	-	-	-	-	11.864	5.620	6.244
1965	-	-	-	-	0.120	-	5.973	4.843	1.130	-	-	-	-	12.143	4.843	7.300
1966	-	0.105	-	-	0.157	-	6.363	28.770	-	-	-	-	-	41.219	28.770	12.449
1967	-	-	-	-	0.180	-	13.541	37.944	-	0.722	-	-	-	62.594	37.944	24.650
1968	-	-	0.045	-	0.198	-	25.434	58.316	-	2.916	-	-	-	99.849	58.316	41.533
1969	7.881	-	1.175	-	0.265	-	40.756	67.215	-	5.944	-	-	-	147.543	67.215	80.328
1970	40.947	-	0.725	-	0.265	-	50.396	73.139	-	6.430	-	-	-	218.362	73.139	145.223
1971	45.024	-	0.419	-	0.267	-	66.569	73.892	-	8.678	-	-	-	229.565	73.892	155.673
1972	41.580	-	0.635	-	0.172	-	67.441	76.133	-	5.033	-	-	-	224.648	76.133	148.515
1973	42.709	-	0.588	-	0.027	-	74.067	87.482	-	2.951	-	-	-	225.236	87.482	137.754
1974	44.238	-	0.600	-	0.032	-	80.869	86.793	-	2.712	-	-	-	229.817	86.812	143.005
1975	45.622	-	0.478	-	0.035	-	90.665	97.976	-	2.134	-	-	-	252.554	97.976	154.578
1976	45.091	-	0.318	-	0.035	-	101.427	113.279	-	2.155	-	-	-	266.652	113.370	153.282
1977	47.201	-	0.272	-	0.029	-	106.911	118.279	-	2.619	-	-	-	279.954	118.379	161.575
1978	46.757	-	0.217	-	0.024	-	106.934	114.557	-	2.211	0.052	-	-	293.802	114.701	179.101
1979	49.448	-	0.153	-	0.025	-	116.266	120.268	-	1.560	0.770	-	-	305.063	120.347	184.716
1980	41.540	-	0.197	-	0.026	-	118.855	120.636	-	1.355	0.476	-	-	299.928	120.665	179.263
1981	49.486	-	0.264	-	0.023	-	103.592	106.137	-	1.160	0.030	-	-	299.037	106.157	192.880
1982	45.368	-	0.445	-	0.024	-	105.654	113.023	-	1.187	0.086	-	-	309.120	113.060	196.060
1983	47.877	-	0.660	-	0.022	-	97.505	95.353	2.152	0.896	0.067	-	-	306.049	95.384	210.665
1984	46.981	-	0.649	-	0.018	-	96.710	93.687	3.023	0.911	0.037	-	-	305.421	93.687	211.734
1985	45.819	-	0.526	-	0.012	-	92.104	89.025	3.079	1.005	0.022	-	-	305.917	89.025	216.892
1986	43.838	-	0.513	0.067	0.002	-	95.083	93.602	1.481	0.866	-	-	-	284.875	93.602	191.273
1987	42.889	-	0.537	0.776	-	-	84.063	87.013	-2.950	0.897	-	-	-	276.314	87.013	189.301
1988	44.989	-	0.270	0.871	-	-	102.600	99.734	2.866	1.041	-	-	-	296.347	99.734	196.613
1989	45.287	-	0.217	0.641	-	-	104.094	107.802	-3.708	1.215	-	-	-	306.173	107.802	198.371
1990	45.014	-	0.060	0.607	-	0.528	104.395	106.031	-1.636	0.407	-	-	-	311.519	106.031	205.488
1991	44.695	-	0.079	0.742	-	1.608	105.057	105.157	-0.100	0.865	0.460	-	-	308.223	105.157	203.066
1992	44.411	-	0.013	0.762	-	1.504	104.533	104.724	-0.191	0.692	1.364	-	-	309.176	104.724	204.452
1993	45.529	-	-	0.333	0.007	0.778	97.701	93.052	4.649	0.619	0.625	0.031	-	293.558	93.052	200.506
1994	52.689	-	-	0.203	0.224	0.454	124.420	97.148	27.272	0.648	0.206	0.216	-	311.159	97.148	214.011
1995	53.541	-	-	0.256	0.184	0.288	101.781	73.086	28.695	0.526	0.016	0.231	-	287.549	73.086	214.463
1996	55.976	-	0.023	0.301	0.037	0.185	76.159	42.820	33.339	0.386	-	0.309	-	265.811	42.820	222.991
1997	52.466	-	0.511	0.383	0.005	0.132	51.898	23.163	28.735	1.122	-	0.152	-	237.902	23.163	214.739
1998	53.964	-	0.695	0.435	-	0.080	36.917	11.089	25.828	0.843	-	0.241	-	226.039	11.089	214.950
1999	51.629	-	0.241	0.028	0.125	0.054	37.483	7.731	29.752	0.445	-	0.212	-	220.318	7.731	212.587
2000	52.841	-	0.152	-	0.329	0.032	32.421	2.729	29.692	0.469	-	0.211	-	218.535	2.729	215.806
2001	55.531	-	-	0.080	0.149	0.000	30.405	8.356	22.049	0.420	-	0.288	0.114	228.068	8.356	219.713
TOTAL	1,518.858	0.105	11.677	6.486	3.146	5.643	2,875.381	2,898.823	241.020	64.040	4.211	1.891	0.114	9,123.931	2,899.373	6,224.558

Notes:

[3] Based on quantities reported for undefined pools in the Trading Bay Unit.

[4] Gas from other fields was injected into the Swanson River field to maintain reservoir pressure. Consequently, production and injection volumes may appear anomalous. The very high gas injection volume for 1960 was an accounting adjustment.

[5] Based on quantities reported for Hemlock, Middle Kenai B through E, G-NE Hemlock-NE, W Foreland, and M. Kenai Unallocated in the Trading Bay Unit.

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports).

North Slope (Millions of Barrels per Year)

					Prudhoe Bay Unit				Kuparuk River Unit							
	Badami	Colville River	Northstar	Duck Island Unit	Prudhoe Bay IPAs[2]	Prudhoe Bay Satellites	Greater Pt Mac Area[3]	PBU IPA+Sat+ GPMA	Kuparuk IPA	Kuparuk Satellites	KRU IPA+Sat	Milne Point Unit	Pt Thomson Unit	Other North Slope[4]	NPRA[5]	**North Slope**
1969	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	-	0.1
1970	-	-	-	-	0.3	-	-	0.3	0.0	-	0.0	-	-	-	-	0.3
1971	-	-	-	-	0.3	-	-	0.3	-	-	-	-	-	-	-	0.3
1972	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	-	0.1
1973	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	-	0.1
1974	-	-	-	-	0.5	-	-	0.5	-	-	-	-	-	-	-	0.5
1975	-	-	-	-	0.7	-	-	0.7	-	-	-	-	-	-	-	0.7
1976	-	-	-	-	1.0	-	-	1.0	-	-	-	-	-	-	-	1.0
1977	-	-	-	-	113.2	-	-	113.2	-	-	-	-	-	-	-	113.2
1978	-	-	-	-	397.7	-	-	397.7	-	-	-	-	-	-	-	397.7
1979	-	-	-	-	468.4	-	-	468.4	-	-	-	-	-	-	-	468.4
1980	-	-	-	-	555.6	-	-	555.6	-	-	-	-	-	-	-	555.6
1981	-	-	-	-	555.6	-	0.0	555.6	1.1	-	1.1	-	-	-	-	556.7
1982	-	-	-	-	559.4	-	0.2	559.6	32.4	-	32.4	-	-	-	-	592.0
1983	-	-	-	-	561.1	-	0.1	561.2	39.9	0.0	39.9	-	-	-	-	601.1
1984	-	-	-	-	562.3	-	0.3	562.6	46.1	0.1	46.2	-	-	-	-	608.8
1985	-	-	-	-	568.6	-	1.1	569.7	79.7	0.3	80.0	0.7	-	-	-	650.4
1986	-	-	-	0.0	561.8	-	3.6	565.4	95.0	0.3	95.3	4.7	-	-	-	665.3
1987	-	-	-	8.8	586.7	-	16.7	603.3	103.7	-	103.7	0.0	-	-	-	715.8
1988	-	-	-	37.9	578.7	-	16.1	594.8	111.1	-	111.1	-	-	-	-	743.9
1989	-	-	-	36.9	522.9	-	14.8	537.7	109.8	-	109.8	3.7	-	-	-	688.1
1990	-	-	-	38.6	486.2	-	15.9	502.1	107.2	-	107.2	6.6	-	-	-	654.5
1991	-	-	-	42.5	486.7	-	14.7	501.4	113.6	-	113.6	7.5	-	-	-	664.9
1992	-	-	-	43.1	456.5	-	14.0	470.5	118.5	-	118.5	6.9	-	-	-	639.0
1993	-	-	-	40.8	409.7	-	18.5	428.2	115.2	-	115.2	6.8	-	-	-	590.9
1994	-	-	-	35.8	374.3	-	50.7	425.0	111.8	-	111.8	6.7	-	-	-	579.3
1995	-	-	-	34.4	340.4	-	65.2	405.6	107.0	-	107.0	8.7	-	-	-	555.7
1996	-	-	-	27.7	312.6	-	75.6	388.2	99.5	-	99.5	14.1	-	-	-	529.4
1997	-	-	-	22.9	284.0	-	73.7	357.7	96.0	0.0	96.0	19.0	-	-	-	495.6
1998	0.7	-	-	18.6	252.8	0.1	61.9	314.8	91.7	4.6	96.3	20.4	-	-	-	450.8
1999	1.2	-	-	15.8	223.8	2.0	47.5	273.0	82.4	12.7	95.0	19.7	-	-	-	404.6
2000	0.9	2.2	-	13.4	217.3	1.0	36.1	255.4	74.1	12.2	86.3	19.1	-	-	-	377.4
2001	0.7	28.7	1.3	11.8	193.7	5.4	29.6	228.6	68.3	11.5	79.8	19.3	-	-	-	370.2
2002	0.6	34.8	17.7	10.3	177.3	24.5	15.2	216.9	58.8	18.3	77.1	18.6	-	-	-	376.1
2003	0.5	35.7	22.1	10.6	157.0	18.1	22.4	197.5	57.9	18.9	76.8	20.5	-	-	-	363.6
2004	0.5	36.2	22.6	10.2	150.5	23.7	19.9	194.1	57.4	19.7	77.1	22.6	-	-	-	363.3
2005	0.4	36.5	22.3	9.4	142.6	28.9	17.7	189.2	55.3	22.0	77.3	23.5	-	-	-	358.5
2006	0.3	39.7	19.7	8.8	137.0	30.3	15.7	183.0	52.7	24.6	77.3	23.1	-	-	-	351.9
2007	0.3	46.1	15.8	8.3	132.0	31.3	13.9	177.2	50.2	25.9	76.1	22.4	5.5	1.8	5.5	348.1
2008	0.2	47.5	12.6	7.7	126.9	30.5	12.4	169.8	47.9	26.3	74.2	22.3	19.2	6.4	15.5	340.7
2009	-	41.8	10.1	7.2	121.7	28.2	11.1	161.0	45.6	26.5	72.1	22.4	26.8	10.0	23.7	324.8
2010	-	35.0	8.1	6.8	117.0	26.0	10.2	153.2	43.5	26.7	70.2	22.2	25.5	12.8	27.6	308.2
2011	-	29.6	6.5	6.4	112.6	24.0	9.4	146.0	41.3	26.7	68.1	21.6	24.4	14.7	26.7	292.9
2012	-	25.2	5.4	6.1	108.3	22.2	8.8	139.3	39.3	25.8	65.1	20.8	23.2	14.0	24.4	275.8
2013	-	21.7	4.6	5.7	104.5	20.5	8.1	133.1	37.2	24.3	61.5	20.0	22.2	12.8	22.0	259.4
2014	-	18.8	4.0	5.3	103.1	19.0	7.5	129.6	35.2	22.9	58.1	19.2	21.1	11.6	19.8	246.7
2015	-	16.5	3.6	5.0	101.7	17.6	6.9	126.2	33.4	21.6	55.0	18.5	20.2	10.4	17.8	235.2
2016	-	14.6	3.2	4.8	97.9	16.3	6.4	120.6	31.8	20.5	52.2	17.7	19.2	9.2	16.0	222.4
2017	-	13.1	2.9	4.6	94.4	15.0	6.0	115.4	30.3	19.4	49.7	16.8	18.4	8.3	14.4	210.8
2018	-	11.7	2.7	4.4	91.1	13.6	5.5	110.2	28.9	18.4	47.3	16.0	17.5	7.4	13.0	199.9
2019	-	10.6	2.5	4.3	88.0	12.5	5.1	105.7	27.7	17.5	45.2	15.2	16.7	6.7	11.7	190.1
2020	-	9.6	2.3	4.1	85.1	11.9	4.8	101.7	26.5	16.7	43.2	14.5	15.9	6.0	10.5	181.5
2021	-	8.7	2.2	3.9	82.3	11.0	4.5	97.7	25.5	15.9	41.4	13.8	15.2	5.4	9.5	173.1
2022	-	8.0	2.0	3.8	79.6	10.0	4.2	93.9	24.6	15.0	39.6	13.1	14.5	4.9	8.5	165.2

Notes:

[1] Figures include NGLs.

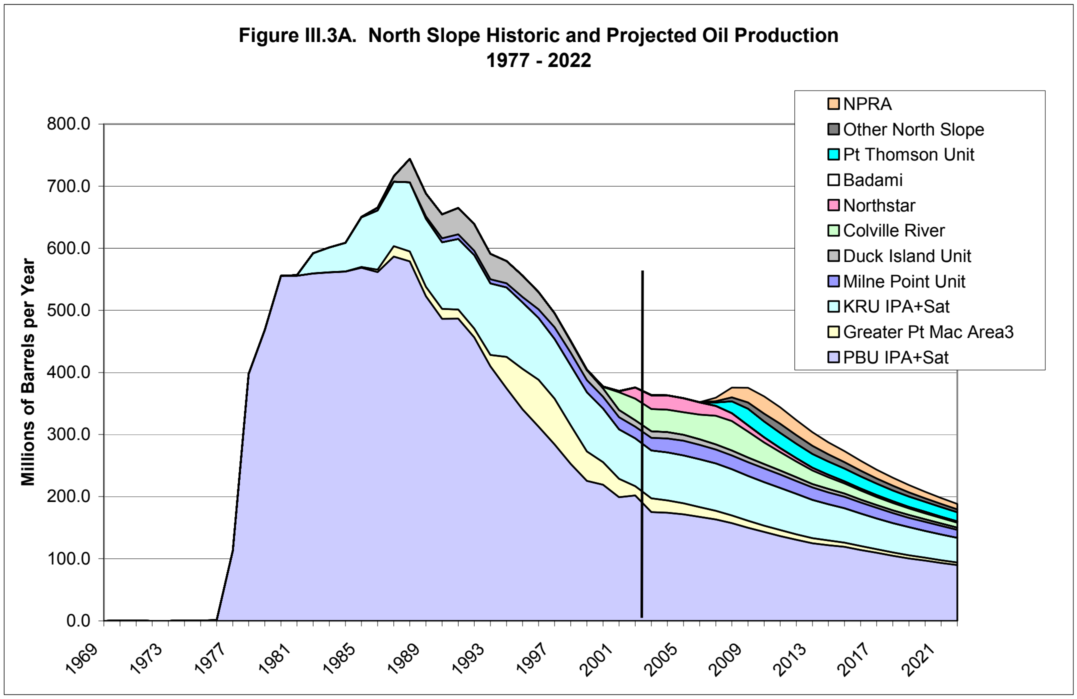
[2] Oil Rim and Gas Cap.

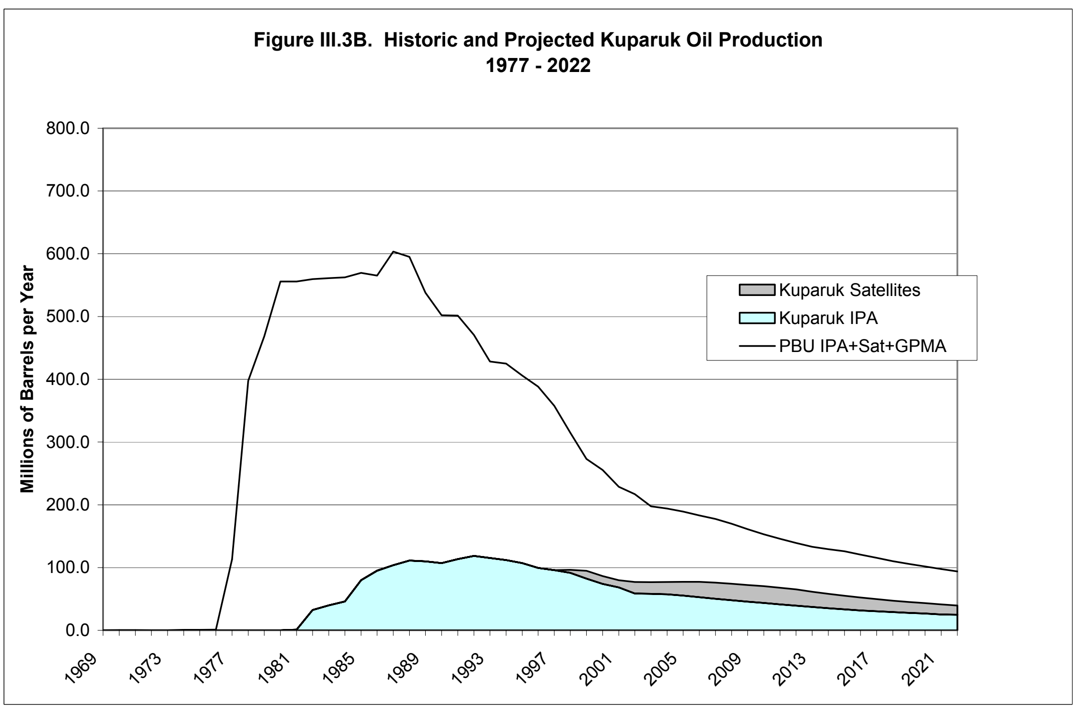
[3] Includes Lisburne, Niakuk, North Prudhoe Bay, Point MacIntyre PA, and West Beach.

[4] Risked Production for Slugger and other Eastern North Slope (excludes 1002 Area).

[5] Based on Alaska Department of Revenue estimates.

North Slope (Millions of Barrels per Year)



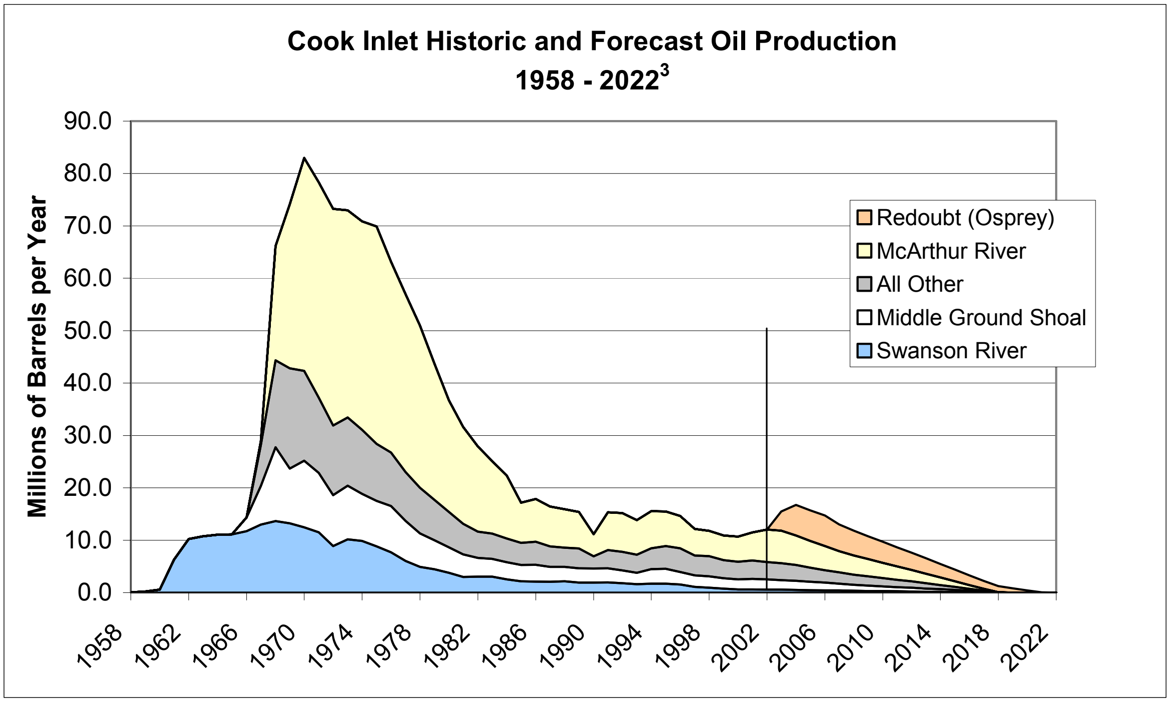


Note:
Figures III.3A and III.3B correspond to Table III.7.

Cook Inlet (Millions of Barrels per Year)

	Beaver Creek[1]	Granite Point[1]	McArthur River	Middle Ground Shoal	Redoubt (Osprey)	Swanson River	Trading Bay[1]	West McArthur River[1]	Kenai and NTB	**TOTAL OIL and NGL[2]**
1958	-	-	-	-	-	0.036	-	-	-	0.036
1959	-	-	-	-	-	0.187	-	-	-	0.187
1960	-	-	-	-	-	0.558	-	-	-	0.558
1961	-	-	-	-	-	6.327	-	-	-	6.327
1962	-	-	-	-	-	10.259	-	-	-	10.259
1963	-	-	-	-	-	10.740	-	-	-	10.740
1964	-	-	-	-	-	11.054	-	-	-	11.054
1965	-	0.002	0.001	0.027	-	11.099	0.002	-	-	11.131
1966	-	-	0.003	2.649	-	11.712	-	-	-	14.364
1967	-	7.052	0.749	7.404	-	12.980	0.727	-	0.002	28.914
1968	-	13.131	21.782	14.134	0.002	13.623	3.292	-	0.185	66.149
1969	-	9.183	31.301	10.467	-	13.221	5.626	-	4.312	74.110
1970	-	7.522	40.591	12.719	-	12.471	6.374	-	3.267	82.944
1971	-	5.577	41.130	11.304	-	11.543	6.753	-	2.030	78.337
1972	0.002	4.663	41.344	9.719	-	8.908	6.058	-	2.555	73.249
1973	0.416	4.767	39.545	10.239	-	10.162	5.854	-	2.023	73.006
1974	0.375	4.237	39.799	9.001	-	9.861	5.468	-	2.127	70.868
1975	0.322	4.361	41.520	8.670	-	8.843	4.629	-	1.531	69.876
1976	0.302	4.471	36.463	8.864	-	7.681	4.296	-	1.097	63.174
1977	0.276	4.711	33.968	7.617	-	6.067	3.350	-	0.970	56.959
1978	0.223	4.867	30.953	6.382	-	4.935	2.789	-	0.798	50.947
1979	0.211	4.613	25.981	5.545	-	4.424	2.298	-	0.609	43.681
1980	0.214	4.394	21.306	4.854	-	3.788	1.800	-	0.372	36.728
1981	0.180	3.975	18.506	4.291	-	2.986	1.440	-	0.235	31.613
1982	0.182	3.467	16.255	3.573	-	3.047	1.253	-	0.132	27.909
1983	0.170	3.550	13.896	3.381	-	3.062	0.968	-	0.117	25.144
1984	0.159	3.287	12.024	3.238	-	2.556	1.000	-	0.080	22.344
1985	0.146	3.052	7.648	3.098	-	2.191	0.919	-	0.113	17.167
1986	0.158	3.169	8.170	3.211	-	2.109	0.828	-	0.220	17.865
1987	0.185	2.803	7.571	2.834	-	2.089	0.690	-	0.246	16.418
1988	0.141	2.677	7.305	2.742	-	2.160	0.691	-	0.195	15.911
1989	0.227	2.275	6.955	2.769	-	1.899	1.085	-	0.179	15.389
1990	0.212	1.462	4.265	2.688	-	1.897	0.522	-	0.121	11.167
1991	0.179	2.064	7.247	2.670	-	1.985	1.048	0.002	0.168	15.363
1992	0.175	2.522	7.397	2.423	-	1.792	0.856	0.002	0.030	15.197
1993	0.153	2.488	6.636	2.160	-	1.594	0.742	0.098	-	13.871
1994	0.140	2.209	7.091	2.785	-	1.695	0.743	0.921	-	15.584
1995	0.132	2.580	6.622	2.823	-	1.729	0.722	0.922	-	15.530
1996	0.125	2.556	6.102	2.396	-	1.540	0.589	1.296	-	14.604
1997	0.119	2.432	5.059	2.223	-	1.077	0.602	0.645	-	12.157
1998	0.103	2.079	4.817	2.156	-	0.920	0.700	1.037	-	11.812
1999	0.100	1.787	4.697	1.968	-	0.794	0.645	0.914	-	10.905
2000	0.092	1.742	4.822	1.894	0.002	0.638	0.637	0.893	-	10.720
2001	0.085	1.620	5.353	2.032	0.001	0.609	0.574	1.222	-	11.497
2002	0.073	1.607	6.209	1.972	-	0.548	0.584	1.059	-	12.053
2003	0.073	1.607	6.209	1.826	3.653	0.548	0.584	0.986	-	15.487
2004	0.073	1.461	5.661	1.753	5.844	0.511	0.548	0.913	-	16.765
2005	0.037	1.315	5.114	1.607	5.844	0.475	0.511	0.804	-	15.706
2006	0.037	1.169	4.566	1.461	5.844	0.438	0.475	0.731	-	14.720
2007	0.037	1.059	4.018	1.278	5.114	0.402	0.438	0.657	-	13.003
2008	-	0.950	3.653	1.132	4.748	0.365	0.402	0.584	-	11.834
2009	-	0.840	3.287	1.023	4.383	0.329	0.365	0.548	-	10.775
2010	-	0.767	2.922	0.913	4.018	0.292	0.329	0.475	-	9.716
2011	-	0.694	2.557	0.804	3.653	0.256	0.292	0.402	-	8.656
2012	-	0.584	2.192	0.731	3.287	0.219	0.256	0.365	-	7.634
2013	-	0.475	1.826	0.620	2.930	0.178	0.221	0.304	-	6.555
2014	-	0.365	1.461	0.509	2.573	0.139	0.187	0.243	-	5.477
2015	-	0.256	1.096	0.398	2.216	0.099	0.153	0.182	-	4.399
2016	-	0.146	0.731	0.287	1.859	0.060	0.119	0.120	-	3.322
2017	-	0.037	0.365	0.176	1.502	0.020	0.084	0.059	-	2.244
2018	-	-	-	0.065	1.145	-	0.050	-	-	1.260
2019	-	-	-	-	0.788	-	0.016	-	-	0.804
2020	-	-	-	-	0.431	-	-	-	-	0.431
2021	-				0.074	-	-	-	-	0.074
2022	-				-	-	-	-	-	-

Cook Inlet (Millions of Barrels per Year)



Notes (from previous page):

[1] "All Other" includes: Beaver Creek, Granite Point, Kenai, North Trading Bay, Trading Bay, and West McArthur River.

[2] Figures include NGLs and are net of injections.

[3] Figure III.3 corresponds to Table III.8.

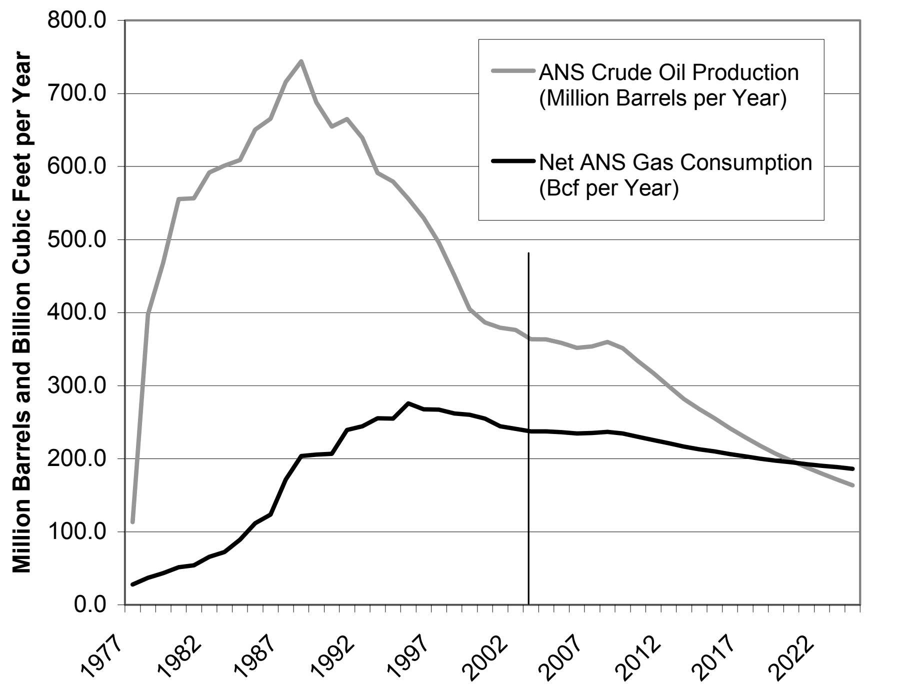
Source: Historic data: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports). Forecast prepared by Alaska DNR.

Table III.9 and Figure III.5 Gas Consumption-Forecast

North Slope (Billion Cubic Feet per Year)

Year	Net Gas Consumption on the North Slope (Bcf per Year)
2002	246.2
2003	248.9
2004	248.0
2005	245.5
2006	245.1
2007	243.1
2008	246.0
2009	241.1
2010	236.0
2011	231.4
2012	227.1
2013	222.5
2014	218.9
2015	215.2
2016	211.7
2017	208.5
2018	205.6
2019	202.9
2020	198.5
2021	196.2
2022	194.0
2023	191.9
2024	190.1

Figure III.5 Forecast of Net ANS Gas Consumption for Lease Operations and Local Gas Sales



Notes: Net ANS Gas consumption refers to gas produced for lease operations and for local sales to North Slope utilities and pipelines. Most gas produced on the lease is re-injected into the field for enhanced oil recovery and recycling. Historic quantities of injected gas are shown in Table III.5. Gas injection is expected to remain fairly constant at about 8 Bcf per day for the foreseeable future. Many factors influence the quantity of gas used for lease operations, including demand for power, oil field compression and pipeline pump stations. New field and satellite development will, to some extent, offset the decline in gas used for lease operations and pipelines in mature fields. Also, many North Slope fields are "gas constrained" meaning that oil production is limited by gas handling capacity.

The forecast of net ANS gas production is based on an ordinary least squares regression of the historic relationship between net ANS gas consumption and ANS crude oil production, taking into account major additions to gas handling capacity in 1990 (GHX1) and 1995 (GHX2). Detailed estimation results are available on request.

Cook Inlet (Billion Cubic Feet per Year)

	Beluga River[1]	McArthur River (TBU)[2]	North Cook Inlet[3]	Swanson River[4]	Kenai[5]	All Other[6]	Proven / Undeveloped[7]	TOTAL NET
	Beluga River	McArthur R	North Cook I	Swanson Rive	Kenai	All Other	Proven Undeveloped	
1958	-	-	-	0.0	-	-	-	0.0
1959	-	-	-	0.0	-	-	-	0.0
1960	-	-	-	-	-	-	-	-
1961	-	-	-	1.3	0.2	-	-	1.5
1962	-	-	-	1.8	1.5	0.0	-	3.3
1963	0.0	-	-	1.2	3.1	0.0	-	4.3
1964	0.1	-	-	1.6	4.5	0.1	-	6.2
1965	-	-	-	1.1	6.0	0.2	-	7.3
1966	-	-	-	-	33.4	1.5	-	12.4
1967	0.2	0.2	-	-	39.6	9.0	-	24.7
1968	2.0	6.2	-	-	46.0	20.2	-	41.5
1969	3.0	14.2	7.9	-	59.3	22.3	-	80.3
1970	3.6	19.7	40.9	-	80.6	23.1	-	145.2
1971	4.1	19.3	45.0	-	72.2	22.4	-	155.7
1972	4.1	19.7	41.6	-	76.0	15.8	-	148.5
1973	4.9	19.1	42.7	-	71.3	13.1	-	137.8
1974	5.6	19.6	44.2	-	68.5	11.0	-	143.0
1975	7.0	21.5	45.6	-	77.2	10.6	-	154.6
1976	11.2	19.0	45.1	-	79.5	10.3	-	153.3
1977	13.4	19.7	47.2	-	81.9	10.8	-	161.6
1978	14.3	18.6	46.8	-	97.3	9.8	-	179.1
1979	17.0	16.6	49.4	-	97.0	8.6	-	184.7
1980	17.0	15.6	41.5	-	98.8	8.1	-	179.3
1981	17.2	15.2	49.5	-	105.8	7.7	-	192.9
1982	18.7	16.2	45.4	-	115.9	7.3	-	196.1
1983	18.1	14.4	47.9	2.2	113.0	15.2	-	210.7
1984	19.8	15.1	47.0	3.0	110.1	16.7	-	211.7
1985	22.6	10.7	45.8	3.1	115.8	18.9	-	216.9
1986	25.4	13.6	43.8	1.5	82.5	24.6	-	191.3
1987	24.0	13.3	42.9	(3.0)	90.0	22.1	-	189.3
1988	25.6	16.7	45.0	2.9	76.3	30.2	-	196.6
1989	30.1	31.0	45.3	(3.7)	65.7	30.0	-	198.4
1990	39.5	51.5	45.0	(1.6)	38.4	32.7	-	205.5
1991	38.5	61.2	44.7	(0.1)	25.6	33.2	-	203.1
1992	36.5	70.1	44.4	(0.2)	24.2	29.4	-	204.5
1993	31.7	62.5	45.5	4.6	23.8	32.3	-	200.5
1994	34.2	50.0	52.7	27.3	18.9	31.0	-	214.0
1995	35.6	54.9	53.5	28.7	16.5	25.2	-	214.5
1996	36.9	67.3	56.0	33.3	13.3	16.2	-	223.0
1997	35.0	66.8	52.5	28.7	12.7	19.0	-	214.7
1998	33.4	73.8	54.0	25.8	9.7	18.2	-	215.0
1999	36.0	69.0	51.6	29.8	9.9	16.3	-	212.6
2000	38.7	65.0	52.8	29.7	12.8	16.7	-	215.8
2001	41.8	62.3	55.5	22.0	20.0	18.1	-	219.7
2002	40.0	52.0	56.0	20.0	19.3	27.6	6.0	220.9
2003	36.8	49.0	56.0	17.6	19.3	26.4	10.0	215.1
2004	33.9	42.0	53.0	14.9	19.3	24.2	16.0	203.3
2005	31.1	36.0	53.0	12.2	19.3	24.0	21.0	196.7
2006	28.7	30.0	53.0	9.6	19.3	19.7	27.0	187.2
2007	26.4	24.0	53.0	6.9	15.4	19.5	30.0	175.3
2008	24.3	17.4	47.1	4.3	12.3	17.4	28.0	150.7
2009	22.3	10.7	41.8	1.6	9.9	15.3	25.0	126.6
2010	20.5	4.0	37.2	-	7.9	13.0	23.0	105.7
2011	18.9	-	33.0	-	6.3	9.8	21.0	89.1
2012	17.4	-	29.3	-	5.1	8.7	19.0	79.4
2013	16.0	-	26.1	-	4.0	8.5	17.0	71.7
2014	14.7	-	23.2	-	3.2	7.5	15.0	63.6
2015	13.5	-	20.6	-	-	7.4	14.0	55.6
2016	12.4	-	18.3	-	-	6.4	13.0	50.1
2017	11.5	-	16.3	-	-	6.4	12.0	46.1
2018	10.5	-	14.4	-	-	4.0	11.0	40.0
2019	9.7	-	12.8	-	-	3.0	10.0	35.5
2020	8.9	-	11.4	-	-	-	9.0	29.3
2021	8.2	-	10.1	-	-	-	8.0	26.3
2022	7.5	-	9.0	-	-	-	6.0	22.5

Notes:

[1] Production assumed to decline at 9.2% per year after 2009.

[2] Exponential decline after 2007, based on actual data 1998-2001 and DNR estimates for 2002-2007.

[3] DNR estimate; decline rate of 11.6% after 2007.

[4] Net gas injections reported for Swanson River 1966-82. Exponential decline after 2003, based on actual data 1998-2001 and estimate for 2002.

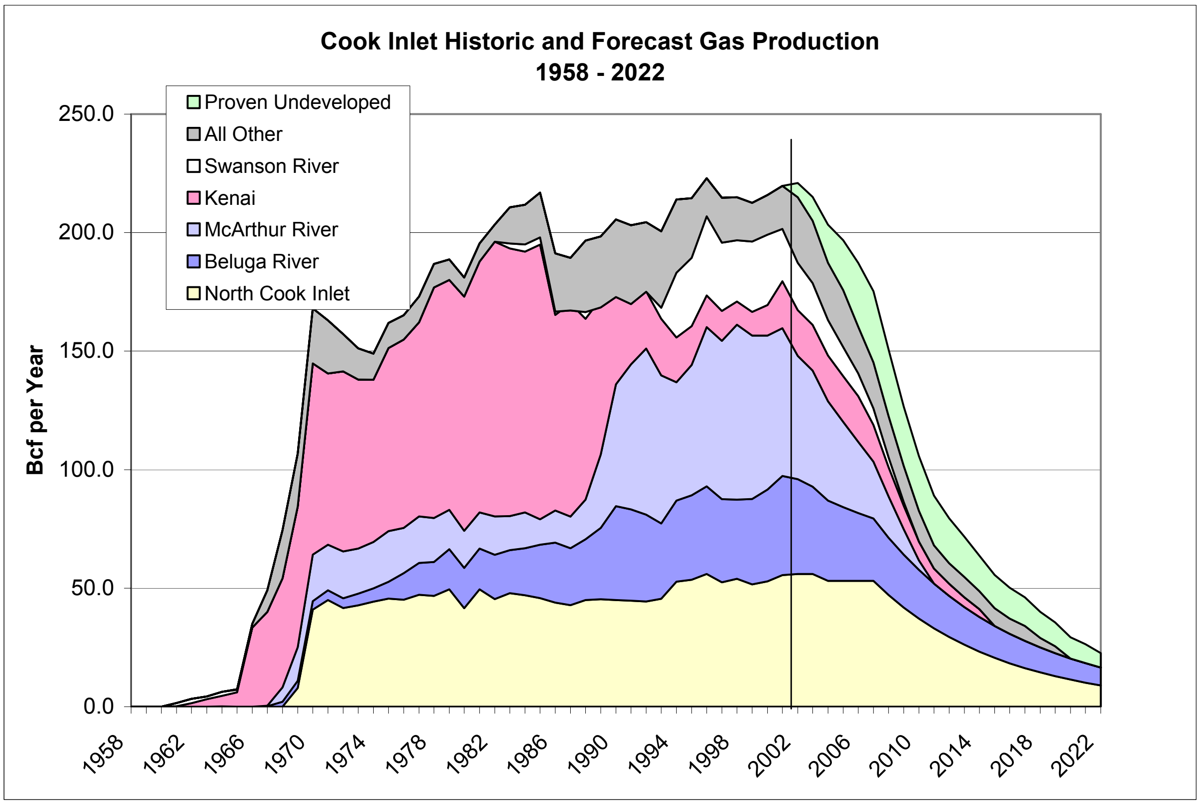
[5] Kenai includes Sterling #3, 4, 5.1, 5.2, and 6 Pools, Beluga Undefined, and Tyonek. Forecast based on assumption that Kenai production is level at 2001 levels with decline after 2006.

[6] All Other includes Beaver Creek, Cannery Loop, Granite Point, Lewis R, Lone Creek, MGS, Nicolai Creek, North Trading Bay, Sterling, Trading Bay, W McArtur R and Wolf Lake.

[7] DNR estimates based primarily on gas prospectivity in the Ninilchik and Kasilof exploration units and other exploration areas on the Kenai Peninsula.

Source of Historic Data: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", Monthly Reports. Forecast prepared by DNR based on reasonable assumptions about field decline rates and zero reserves appreciation beyond existing proven and undeveloped rerserves.

Cook Inlet (Billion Cubic Feet per Year)



Note:
Figure III.6 corresponds to Table III.10.

Section Three

Royalty Production and Revenue

Introduction

The State of Alaska receives a royalty of approximately 12.5 percent of the oil and gas produced from its leases. The State may take its share of oil production "in-kind" or "in-value." When the State takes its royalty share in-kind (RIK), it assumes possession of the oil or gas. The commissioner of Natural Resources may sell the RIK oil or gas in a competitive auction or through a non-competitive sale negotiated with a single buyer. When the State takes its royalty in-value (RIV), the State's lessees who produce the oil or gas market the State's share along with their own share of production. The lessees remit cash payments on a monthly basis for the State's RIV share.

Over the last 30 years the State has taken about one-half of its royalty oil as RIK.[1] The State has sold nearly 800 million barrels of RIK oil during this time, most of it in-state. These in-state sales provided an important stimulus to the Alaska's refining industry by providing long-term supplies of oil to each of the State's four refineries (see Section III for more on Alaska's refining industry). Over the years, State RIK sales fueled many controversies and policy debates over the appropriate use of the State's natural resources.

Cook Inlet

In 1969 the commissioner of Natural Resources negotiated a sale of 100 percent of the State's royalty from Cook Inlet to the Alaska Oil and Refining Company. Within months of signing the contract Alaska Oil and Refining Co. merged with the Tesoro Petroleum Company. Tesoro subsequently built a new refinery in Nikiski on the Kenai Peninsula next to Chevron's refinery, built in 1964. Between 1969 and 1985 the State sold all of its Cook Inlet royalty oil to the Tesoro refinery. By 1980 the production decline in the Cook Inlet prompted Tesoro to negotiate the first of several sales contracts with the State for supplies of RIK oil from the North Slope. By the end of 1985 Tesoro had replaced its Cook Inlet RIK volumes with supplies of RIK from the North Slope.

In 1987 the State began to export Cook Inlet RIK oil to the Chinese Petroleum Company. These volumes were produced from fields on the West Side of the Cook Inlet after the Federal government exempted Cook Inlet production from Export Administration regulations. The State sold 97 percent of the royalty production from the McArthur River, Trading Bay, North Trading Bay, and Granite Point fields in a series of one-year competitive auctions. In 1991 deliveries under the last Chinese Petroleum contract were halted under force majeure following the December 1989 eruption of the Mount Redoubt volcano. There have been no Cook Inlet RIK sales since. (See Table V.8.)

[1] The state also sold 10.4 Bcf of RIK gas in a contract to Alaska Pipeline Co (Enstar) from 1977 through 1984 from Cook Inlet royalty production. In a bid to encourage development of the gas resource in Prudhoe Bay, the state entered 20-year contracts in January 1977 to supply El Paso Natural Gas Co., Tenneco Alaska, Inc and Southern Natural Gas Co. with 25%, 50%, and 25%, respectively, of Prudhoe Bay Unit RIK gas. The contracts terminated in May 1978 when the proposed El Paso Trans-Alaska Gas Pipeline did not receive Federal certification.

North Slope

Over the past 25 years, the State has held nine RIK sales involving portions of its Alaska North Slope (ANS) royalty oil production. These sales are summarized in Table V.7 and Figure V.3. In 1976, the State signed a six-year contract with Golden Valley Electric Association (GVEA), the electric utility in Fairbanks, to sell approximately 3,300 barrels of ANS crude oil per day as turbine fuel. GVEA did not exercise its option to take RIK until 1981 and it traded these volumes with Mapco (now Williams Alaska) in exchange for refined fuel. The State subsequently sold RIK ANS to GVEA in two other contracts until 1992. As in the first contract, GVEA traded these volumes with Mapco.

In 1978 the State contracted with Earth Resources Company of Alaska, predecessor to Mapco Alaska and now Williams Alaska Petroleum Company, to supply 15 percent of Prudhoe Bay RIK oil production less the quantity dedicated to GVEA. This 25-year contract expires in December 2003. Williams receives a maximum of 35,000 barrels per day of RIK oil produced from the Prudhoe Bay Unit under this contract and has since supplemented this supply with new agreements for another 28,000 barrels per day. Williams is now the only purchaser of State RIK ANS crude oil. When the two Williams' contracts expire at the end of 2003, the royalty oil production available for new sales will rise to 120,000 barrels per day. Available royalty will decline thereafter at about 5 percent per year.

As mentioned above, Tesoro has been an important North Slope RIK customer. Tesoro negotiated and bid for several contracts that supplied it with RIK supplies from 1980 to 1998. Chevron was another big purchaser of North Slope RIK for oil supplied to its Nikiski refinery from 1980 through 1991 when it finally shut down its Nikiski refinery. In one of these contracts Chevron took RIK barrels from Tesoro in exchange. Petro Star Inc. purchased North Slope RIK from 1986 through 1991 for its new refinery at North Pole. In 1992 Petro Star negotiated a 10-year contract with the State for a supply of RIK from the Kuparuk River Unit. With this contract in hand, Petro Star was able to build the State's newest refinery in Valdez. As it happened, Petro Star elected to take no oil under this contract and the contract expired automatically nine months after it had been signed.

The State also held competitive auctions of RIK oil during the early 1980s as part of a program to routinely offer RIK short-term contracts. Winners of these sales included in-state refineries but also several outside refineries. Many of these buyers were also ANS producers. About 46 million barrels of Alaska North Slope RIK crude oil were sold in these auctions but the program was interrupted after the general collapse of oil prices in the mid 1980s. In January 2000, the Division of Oil and Gas published a "Notice of Interest in Sale of State Royalty Oil." The response to this notice by prospective RIK purchasers prompted the division to plan for a competitive bid auction for volumes of RIK oil produced from several North Slope fields. The sale was subsequently held in August 2000 but no bids were offered.

In 2002 the State solicited offers and subsequently negotiated a draft contract with Anadarko Petroleum Company and EnCana Corporation for 350 million cubic feet of gas from the Prudhoe Bay and Pt. Thomson Units should a North Slope gas pipeline be built. The Division of Oil and Gas published a "Preliminary Best Interest Finding and Determination for the Sale of Alaska North Slope Royalty Gas" on March 29, 2002. Further work on this sale was postponed by the State in April. A final finding still must be published, and the sale must be submitted to the Alaska Royalty Oil and Gas Development Board and the Legislature for approval.

Royalty-in-Kind Policy

The earliest RIK sales, notably Tesoro's first Cook Inlet contract, the first GVEA contract, and the Alpetco contract, generated controversy and debate in the State. Several issues arose as the RIK program evolved. Is the State better off negotiating sales one-on-one or auctioning RIK through competitive tenders? How much public input should be encouraged? Should the State subsidize the local refining industry through price breaks? What kind of oversight should be required? The debates of these questions led to the present program as set out in statutes and regulations.

When disposing royalty oil or gas, the commissioner is bound by AS 38.05.182 and AS 38.05.183. Furthermore, the legislature established the Alaska Royalty Oil and Gas Development Board (Royalty Board) under AS 38.06 to oversee the department's RIK program. Regulations under Title 11, Chapters 3 and 26 govern the actual disposition of royalty and the sale of RIK. (See http://www.legis.state.ak.us/folhome.htm for more information.)

The rules that govern the sale of RIK may be reduced to a few principles.

- Any disposition of the State's royalty must be in the State's best interest. The State should sell its royalty rather than take it in-value as long as the best interests of the State are served.
- The State must receive a price for its RIK that is at least as much as it receives when the State takes its royalty in-value.
- Under certain circumstances, the State may sell its oil in a negotiated sale, but competitive sales are preferred.
- Although the price of RIK must equal or exceed the price of RIV, a review of each sale must consider economic, social, and environmental effects. In this way, benefits may be attributed to the sale of RIK to local refineries that would not be generated by sales to outside purchases.
- The public is a part of the process. Depending on the terms of the sale, the commissioner will publish best interest findings and solicit comments on the sale from the public.
- The Royalty Board must be notified of any disposition of RIK. For supply contracts for more than one year, the Royalty Board must evaluate the economic, social, and environmental effects of the sale, convene a public hearing, and recommend approval of the sale to the legislature.
- The legislature approves long-term contracts by enacting legislation.

Table V.1 Recent Royalty Oil Production and Revenues

North Slope, 1996-2001

	Badami	Colville River Unit	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Northstar	Prudhoe Bay Unit RIV	Prudhoe Bay Unit RIK	TOTAL Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousands of Barrels)										
1996	-	-	3,679.6	11,366.3	1,800.6	-	19,133.3	25,081.1	44,214.3	61,060.8
1997	-	-	3,324.4	10,978.3	2,657.0	-	18,399.6	26,139.6	44,539.2	61,498.8
1998	106.1	-	2,692.5	10,886.2	2,833.4	-	11,810.5	27,981.6	39,792.1	56,310.2
1999	179.2	1.3	2,263.3	10,822.0	2,699.2	-	15,508.5	19,070.7	34,579.2	50,544.1
2000	144.6	196.6	1,943.1	9,897.9	2,613.9	-	13,053.5	19,290.3	32,343.8	47,140.0
2001	104.0	2,785.5	1,696.9	9,076.4	2,687.9	212.9	13,643.5	15,187.0	28,830.6	45,394.3
Revenues (Thousands of Dollars)										
1996	-	-	$57,988	$188,462	$28,404	-	$296,101	$436,377	$732,478	$1,007,332
1997	-	-	$42,866	$150,137	$33,777	-	$242,341	$383,701	$626,042	$852,822
1998	-	-	$18,147	$82,772	$18,608	-	$69,281	$227,032	$296,313	$415,841
1999	-	$57	$26,461	$136,802	$31,596	-	$170,204	$259,246	$429,450	$624,366
2000	$2,612	$4,539	$42,350	$220,539	$56,730	-	$275,928	$461,464	$737,392	$1,064,162
2001	$1,051	$47,972	$31,796	$160,694	$47,356	$1,584	$236,464	$279,804	$516,268	$806,722

Cook Inlet & Statewide, 1996-2001

	Granite Point Field	South Granite Point Unit	Cannery Loop Field	North Middle Ground Shoal	Middle Ground Shoal	South Middle Ground Shoal	Trading Bay Filed	Trading Bay Unit	West McArthur Unit	**TOTAL Cook Inlet**	**TOTAL STATE**
Production (Thousands of Barrels)											
1996	320.3	-	0.0	50.6	216.5	32.5	73.6	762.7	162.0	1,618.2	62,679.0
1997	303.5	-	-	42.0	150.6	26.8	75.1	632.4	80.6	1,311.0	62,809.8
1998	259.8	-	-	44.7	196.0	28.8	87.1	602.4	116.2	1,335.0	57,645.2
1999	172.4	51.0	-	38.2	181.9	24.6	82.7	587.2	114.3	1,252.2	51,796.3
2000	119.2	98.5	-	43.5	170.5	22.8	79.6	602.8	111.6	1,248.6	48,388.5
2001	109.3	92.9	-	39.7	194.4	19.8	72.3	671.1	152.9	1,352.4	46,746.7
Revenues (Thousands of Dollars)											
1996	$5,825	-	-$6	$1,000	$4,266	$613	$1,188	$13,330	$2,257	$28,474	$1,035,805
1997	$5,175	-	-	$764	$3,655	$490	$1,192	$10,561	$1,795	$23,633	$876,456
1998	$2,813	-	-	$544	$2,244	$346	$853	$5,902	$1,107	$13,809	$429,650
1999	$2,090	$1,388	-	$662	$3,073	$406	$1,261	$8,917	$1,583	$19,380	$643,746
2000	$4,201	$3,840	-	$1,491	$4,647	$821	$2,632	$17,073	$2,790	$37,495	$1,101,657
2001	$2,515	$2,051	-	$959	$4,338	$476	$1,522	$13,908	$2,941	$28,710	$835,432

Revenues include principal and interest from revisions and settlements in the year received.

Table V.2 Recent Royalty Oil Production by Lessee

North Slope

	Production (Thousands of Barrels)					
	1996	1997	1998	1999	2000	2001
Amerada Hess	-	-	-	-	-	-
Amoco	360	297	237	199	119	-
Anadarko	-	-	-	0	43	613
Arco	12,394	11,120	9,522	10,729	-	-
BP	18,375	16,683	13,595	14,233	11,869	11,075
Chevron	116	99	64	91	77	81
CIRI	36	30	1	-	-	-
DOYON	7	6	5	4	4	3
Exxon	6,364	5,571	3,563	4,815	-	-
ExxonMobil	-	-	-	-	4,596	5,287
Forcenergy/Forest Oil	-	5	3	4	2	2
L L & E	5	-	-	-	-	-
Mapco 1978 Contract	13,037	12,652	11,148	12,442	12,718	12,522
Mapco 1997 Contract	-	466	4,451	-	-	-
Marathon	6	-	-	-	-	-
Mobil	280	237	155	195	-	-
NANA	22	18	14	12	11	8
Oxy	155	208	224	212	189	-
Petrofina	-	-	32	54	43	31
Phillips	231	190	113	151	10,201	12,482
Shell	7	-	-	-	-	-
Tesoro	14,346	13,022	11,498	-	-	-
Texaco	63	52	31	41	35	38
Union Texas Petroleum	-	-	-	0	-	-
Unocal	976	842	771	732	659	587
Williams 1998 Contract	-	-	884	6,628	6,572	2,665
North Slope TOTAL	66,779	61,499	56,312	50,544	47,140	45,394

Cook Inlet

	Production (Thousands of Barrels)					
	1996	1997	1998	1999	2000	2001
Cross Timbers/XTO	-	-	-	182	170	194
Forcenergy/Forest Oil	-	377	436	425	428	495
Marathon	386	-	-	-	-	-
Mobil/Exxon Mobil	100	110	91	76	74	70
Shell	216	151	196	-	-	-
Stewart	162	30	-	-	-	-
Unocal	754	643	612	569	576	593
Cook Inlet TOTAL	1,618	1,311	1,335	1,252	1,249	1,352

Revenues include principal and interest from revisions and settlements in the year received.

Table V.3 Recent Royalty Oil Revenue by Lessee

North Slope

	Revenues (Thousands of Dollars)					
	1996	1997	1998	1999	2000	2001
Amerada Hess	-$118,215	$34,097	-	-	-	-
Amoco	$5,403	$3,674	$1,556	$2,404	$2,562	-$0
Anadarko	-	-	-	$12	$982	$10,374
Arco	$190,182	$155,281	$72,786	$135,879	-	-
BP	$256,839	$216,022	$85,232	$158,955	$249,682	$208,250
Chevron	$1,712	$1,274	$368	$1,044	$1,608	$1,422
CIRI	$518	$423	$12	-	-	-
DOYON	$103	$83	$41	$39	$82	$54
Exxon	$90,516	$71,707	$19,733	$52,342	-	-
ExxonMobil	-	-	-	-	$98,415	$83,945
Forcenergy/Forest Oil	-	$63	$17	$43	$50	$38
L L & E	$68	-	-	-	-	-
Mapco 1978 Contract	$207,138	$185,000	$90,752	$166,427	$304,389	$223,123
Mapco 1997 Contract	-	$6,032	$38,590	-$60	$90	$1,075
Marathon	$84	$1	-	-	-	-
Mobil	$4,035	$3,026	$851	$2,166	-	-
NANA	$310	$255	$122	$120	$220	$163
Oxy	$2,248	$2,778	$1,533	$2,626	$4,290	$0
Petrofina	-	-	$168	$616	$807	$284
Phillips	$3,175	$2,377	$752	$1,379	$228,306	$211,865
Shell	$102	-$5	-	-	-	-
Tesoro	$229,239	$192,669	$92,288	$191	-$623	$1,632
Texaco	$880	$664	$149	$398	$842	$653
Union Texas Petroleum	-	-	-	$12	-	-
Unocal	$14,896	$11,463	$6,013	$9,078	$14,851	$9,868
Williams 1998 Contract	-	-	$5,402	$92,688	$157,608	$53,975
North Slope TOTAL	$1,007,332	$852,822	$416,365	$626,358	$1,064,162	$806,722

Cook Inlet

	Revenues (Thousands of Dollars)					
	1996	1997	1998	1999	2000	2001
Cross Timbers/XTO	-	-	-	3,073	4,647	4,338
Forcenergy/Forest Oil	-	6,166	4,209	6,296	10,950	9,831
Marathon	6,620	-7	-	-	-	-
Mobil/Exxon Mobil	1,810	1,882	1,094	1,165	1,824	1,525
Shell	4,266	3,655	2,244	-	-	-
Stewart	2,257	1,104	-	-	-	-
Unocal	13,521	10,834	6,262	8,846	20,074	13,016
Cook Inlet TOTAL	28,474	23,633	13,809	19,380	37,495	28,710

Revenues include principal and interest from revisions and settlements in the year received.

Table V.4 Recent Royalty Gas Production and Revenues

North Slope, 1996-2001

	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit	TOTAL North Slope
Production (Thousand Cubic Feet)					
1996	32,446	107,807	9,466	1,467,794	1,617,513
1997	35,605	90,487	26,034	1,337,301	1,489,427
1998	36,255	79,552	27,156	1,178,761	1,321,724
1999	168,919	78,783	27,611	1,092,217	1,367,530
2000	31,785	135,929	27,436	1,061,761	1,256,911
2001	30,780	98,806	28,978	1,341,442	1,500,006
Revenues					
1996	$30,497	$96,452	$29,676	$1,318,431	$1,475,056
1997	$31,402	$63,482	$28,326	$1,154,595	$1,277,804
1998	$27,554	$32,473	$23,723	$949,674	$1,033,424
1999	$150,373	$50,763	$26,108	$937,602	$1,164,845
2000	$39,659	$160,539	$33,872	$1,156,060	$1,390,130
2001	$33,017	$119,259	$31,606	$1,114,358	$1,298,240

Revenues include principal and interest from revisions and settlements in the year received.

Cook Inlet, 1996-2001

	Beluga River Unit	Cannery Loop Unit	South Granite Point Unit	Granite Point Field	Ivan River Unit	Kenai Unit	Lewis River Unit	Nicolai Creek	North Middle Ground Shoal Unit	Middle Ground Shoal
Production (Thousand Cubic Feet)										
1996	2,777,105	122,528	-	109,798	1,167,827	159,084	11,389	-	403	996
1997	2,628,297	186,477	-	141,763	935,228	140,655	7,057	-	17,965	-
1998	2,508,785	163,775	1,127	162,690	800,046	111,751	11,959	-	131,092	-
1999	2,704,980	167,759	28,102	67,573	631,597	111,459	29,916	-	246,030	-
2000	2,913,658	236,492	55,787	73,754	461,437	149,187	16,232	-	72,167	-
2001	3,143,083	318,033	5,491	59,671	667,307	234,786	26,852	32,297	52,739	-
Revenues										
1996	$3,942,906	$205,833	-	$180,076	$1,995,187	$250,307	$19,865	-	$14,576	$613
1997	$4,598,164	$325,190	-	$191,592	$1,318,780	$249,102	$9,943	-	$23,979	-
1998	$4,264,931	$231,820	$1,353	$221,096	$1,070,859	$156,838	$15,585	-	$160,470	-
1999	$3,782,832	$271,607	$30,115	$82,135	$757,916	$294,223	$35,899	-	$300,841	-
2000	$4,657,037	$482,859	$58,151	$215,085	$5,338,631	$298,388	$508,075	-	$808,397	-
2001	$6,947,145	$1,216,499	$5,995	$82,050	$932,562	$476,303	$37,703	$61,686	$88,702	-

	South Middle Ground Shoal	North Cook Inlet Unit	Pretty Creek Unit	Spark Platform	Sterling Unit	North Trading Bay Unit	Stump Lake Unit	Trading Bay Field	Trading Bay Unit	TOTAL Cook Inlet	TOTAL State
Production											
1996	489	6,910,165	41,347	2,814	558	57	44,183	-	7,248,017	18,596,759	20,214,272
1997	-	6,490,318	53,928	62,872	81	-	30,942	19,031	6,982,452	17,697,067	19,186,494
1998	-	6,665,243	61,640	85,882	4	-	18,332	-	7,841,950	18,564,277	19,886,001
1999	-	6,372,036	3,982	28,044	15	-	11,978	-	7,333,019	17,736,489	19,104,019
2000	-	6,548,758	-	-	4,384	18,632	6,839	-	6,802,700	17,360,027	18,616,938
2001	-	6,732,002	11,471	-	8,820	-	56	-	6,509,275	17,801,883	19,301,889
Revenues											
1996	$72	$11,615,706	$69,483	$3,796	$1,514	$77	$31,502	-	$10,286,938	$28,618,453	$30,093,509
1997	-	$12,054,437	$75,855	$94,178	$140	-	-	$22,797	$10,147,976	$29,112,134	$30,389,938
1998	-	$8,874,018	$82,099	$118,197	$8	-	$71	-	$10,768,856	$25,966,200	$26,999,624
1999	-	$8,914,102	$4,778	$31,511	$19	-	$12,836	-	$8,917,539	$23,436,353	$24,601,199
2000	-	$14,057,602	$678,220	-	$6,825	$25,859	$1,253,836	$1,999	$10,743,014	$39,133,978	$40,524,108
2001	-	$14,301,074	$18,009	-	$16,076	$5,601	$67	-	$12,636,322	$36,825,794	$38,124,034

Revenues include principal and interest from revisions and settlements in the year received.

Table V.5 Recent Royalty Gas Production by Lessee

North Slope

	Production (Thousand Cubic Feet)					
	1996	1997	1998	1999	2000	2001
Arco	387,761	400,895	393,981	412,016	-	-
BP	761,862	657,646	560,854	627,551	488,604	735,945
Chevron	17,786	16,561	5,070	-	-	1
Exxon	297,260	284,187	264,969	241,821	-	-
Exxon Mobil	-	-	-	-	298,217	293,045
Forest Oil	-	-	-	-	-	3
Mobil	101,256	84,433	78,519	74,713	-	-
NANA	32,446	25,930	-	-	-	-
Oxy	1,512	1,988	2,134	2,203	1,997	-
Phillips	17,630	17,786	16,197	9,226	468,093	470,986
Unocal	-	-	-	-	-	27
North Slope TOTAL	1,617,513	1,489,427	1,321,724	1,367,530	1,256,911	1,500,007

Cook Inlet

	Production (Thousand Cubic Feet)					
	1996	1997	1998	1999	2000	2001
Arco	930,529	812,591	760,156	902,501	-	-
Aurora Power	-	-	-	-	-	32,296
Chevron	809,536	830,436	843,072	1,026,724	1,002,570	1,303,514
Danco	85	-	-	-	-	-
Marathon	4,475,074	3,995,784	4,062,765	4,347,695	4,358,280	4,234,315
Mobil/ Exxon Mobil	22,815	50,177	55,372	21,509	52,341	4,118
Municipal Light & Power	-	-	905,557	775,755	677,169	617,794
Phillips	6,910,165	6,490,318	6,665,243	6,372,036	7,782,678	7,953,777
Shell	1,038,035	985,270	-	-	-	-
Unocal	4,410,520	4,532,490	5,272,111	4,290,269	3,486,988	3,656,068
Cook Inlet TOTAL	18,596,759	17,697,067	18,564,277	17,736,489	17,360,026	17,801,882

Revenues include principal and interest from revisions and settlements in the year received.

Table V.6 Recent Royalty Gas Revenues by Lessee

North Slope

	Revenue					
	1996	1997	1998	1999	2000	2001
Arco	$326,746	$325,488	$297,465	$343,610	-	-
BP	$658,038	$543,435	$451,204	$539,789	$539,435	$593,254
Chevron	$47,435	$33,157	$7,165	-	-	$19
Exxon	$229,871	$207,325	$182,809	$185,339	-	-
Exxon Mobil	-	-	-	-	$318,417	$264,849
Forest Oil	-	-	-	-	-	-
Mobil	$168,198	$127,870	$79,937	$86,789	-	-
NANA	$30,782	$23,282	-	-	-	-
Oxy	$964	$1,929	$1,887	$1,937	$1,744	-
Phillips	$13,021	$15,319	$12,957	$7,381	$530,534	$440,117
Unocal	-	-	-	-	-	-
North Slope TOTAL	$1,475,056	$1,277,804	$1,033,424	$1,164,845	$1,390,130	$1,298,239

Cook Inlet

	Revenue					
	1996	1997	1998	1999	2000	2001
Arco	$1,352,425	$1,411,208	$1,262,404	$1,169,971	-	-
Aurora Power	-	-	-	-	-	$61,686
Chevron	$1,073,740	$1,551,102	$1,559,786	$1,605,202	$1,697,968	$3,135,824
Danco	$799	-	-	-	-	-
Marathon	$6,181,274	$6,061,206	$5,736,683	$5,557,091	$6,795,330	$10,428,942
Mobil/ Exxon Mobil	$19,482	$47,489	$55,372	$21,509	-$246	$4,113
Municipal Light & Powe	-	-	$1,442,741	$1,007,659	$1,082,297	$1,415,666
Phillips	$11,615,706	$12,054,437	$8,874,018	$8,914,102	$15,934,374	$16,696,729
Shell	$1,517,354	$1,635,854	-	-	-	-
Unocal	$6,857,672	$6,350,838	$7,035,196	$5,160,819	$13,624,255	$5,082,834
Cook Inlet TOTAL	$28,618,453	$29,112,134	$25,966,200	$23,436,353	$39,133,978	$36,825,794

Revenues include principal and interest from revisions and settlements in the year received.

Table V.7 and Figure V.1 North Slope Royalty in-Kind Sales

1979-2001 (Barrels per Year)

	Alpetco	Chevron	Williams (Mapco)	Golden Valley Elec Assoc	Tesoro	Petro Star	1st Comp Sale	2nd Comp Sale	Quasi-Comp Sale	ANS TOTAL RIK	ANS TOTAL RIV	ANS TOTAL RIK + RIV
1979	-	-	446,996	-	-	-	-	-	-	446,996	10,584,481	11,031,477
1980	12,020,950	882,414	5,976,024	-	3,427,388	-	-	-	-	22,306,777	47,047,583	69,354,360
1981	26,046,878	859,928	8,808,400	398,051	1,661,385	-	14,046,953	-	-	51,821,595	17,666,128	69,487,723
1982	898,714	-	9,632,099	764,762	36,841	-	1,432,108	-	-	12,764,524	61,136,212	73,900,736
1983	-	11,674,998	11,723,755	1,208,406	5,793,973	-	-	-	-	30,401,132	44,599,235	75,000,367
1984	-	14,053,279	13,093,397	1,870,505	7,531,155	-	-	-	-	36,548,337	39,396,031	75,944,369
1985	-	7,804,392	13,260,754	1,928,544	17,218,912	-	-	22,511,409	1,716,754	64,440,764	16,633,246	81,074,010
1986	-	6,934,482	13,168,483	1,881,232	23,538,192	52,667	-	4,686,801	1,862,051	52,123,907	30,262,661	82,386,568
1987	-	9,330,563	14,094,537	2,013,539	18,404,806	539,575	-	-	-	44,383,020	43,899,311	88,282,331
1988	-	9,315,264	13,814,522	1,981,998	18,307,014	590,832	-	-	-	44,009,630	44,068,971	88,078,602
1989	-	8,611,606	12,529,175	1,784,782	16,387,093	607,468	-	-	-	39,920,122	40,833,646	80,753,768
1990	-	8,099,292	12,735,412	1,670,494	15,368,565	621,220	-	-	-	38,494,983	37,242,490	75,737,473
1991	-	6,290,546	11,183,462	1,670,699	15,336,301	618,247	-	-	-	35,099,255	42,537,362	77,636,617
1992	-	-	6,303,005	801,795	14,412,451	-	-	-	-	21,517,251	60,174,977	81,692,228
1993	-	-	9,086,280	-	9,814,311	-	-	-	-	18,900,591	55,796,583	74,697,174
1994	-	-	11,812,241	-	10,312,487	-	-	-	-	22,124,728	50,657,903	72,782,631
1995	-	-	12,680,470	-	13,703,946	-	-	-	-	26,384,415	43,664,553	70,048,968
1996	-	-	13,037,159	-	14,345,554	-	-	-	-	27,382,712	39,396,515	66,779,227
1997	-	-	13,117,616	-	13,021,937	-	-	-	-	26,139,553	35,359,288	61,498,841
1998	-	-	16,483,827	-	11,497,733	-	-	-	-	27,981,560	28,330,383	56,311,943
1999	-	-	19,070,664	-	-	-	-	-	-	19,070,664	31,473,445	50,544,109
2000	-	-	19,290,297	-	-	-	-	-	-	19,290,297	27,848,612	47,138,909
2001	-	-	15,187,012	-	-	-	-	-	-	15,187,012	30,207,251	45,394,263
	38,966,543	83,856,765	276,535,587	17,974,807	230,120,043	3,030,009	15,479,061	27,198,210	3,578,804	696,739,828	878,816,868	1,575,556,696

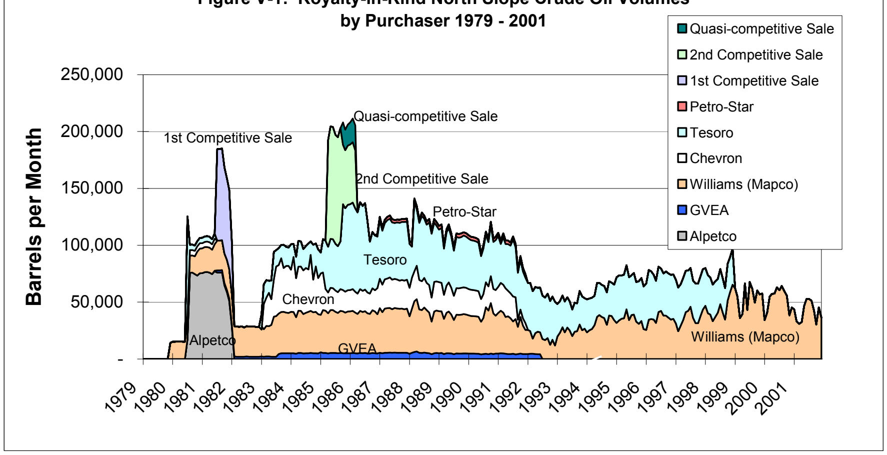


Figure V-1: Royalty-in-Kind North Slope Crude Oil Volumes by Purchaser 1979 - 2001

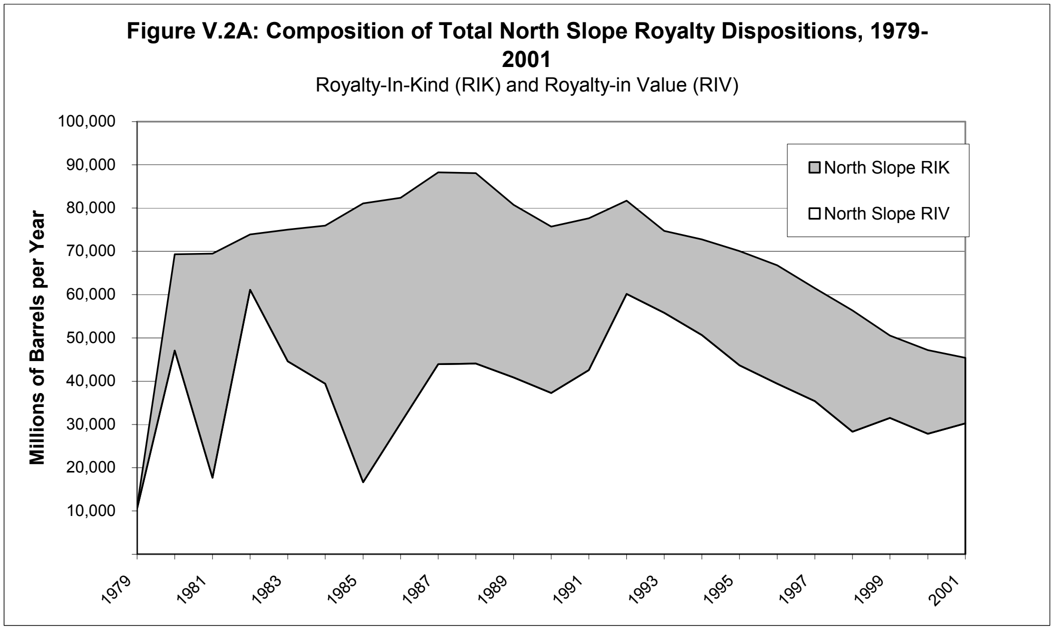
Table V.8 Cook Inlet Royalty in-Kind Sales

1979-2001 (Barrels per Year)

	Tesoro[1]	Chinese Petroleum[2]	CI TOTAL RIK	CI TOTAL RIV	CI TOTAL RIK + RIV	STATE TOTAL RIK	STATE TOTAL RIV	TOTAL RIK + RIV
1979	4,850	-	4,850	-	4,850	5,297	10,584	15,881
1980	4,094	-	4,094	-	4,094	26,401	47,048	73,449
1981	3,561	-	3,561	-	3,561	55,382	17,666	73,048
1982	3,065	-	3,065	-	3,065	15,830	61,136	76,966
1983	2,719	-	2,719	-	2,719	33,120	44,599	77,719
1984	2,432	-	2,432	-	2,432	38,980	39,396	78,376
1985	1,383	-	1,383	462	1,845	65,824	17,095	82,919
1986	-	-	-	1,922	1,922	52,124	32,185	84,309
1987	-	625	625	1,104	1,729	45,008	45,003	90,011
1988	-	799	799	912	1,711	44,809	44,981	89,790
1989	-	1,274	1,274	389	1,663	41,195	41,223	82,417
1990	-	579	579	481	1,060	39,074	37,723	76,797
1991	-	331	331	1,355	1,685	35,430	43,892	79,322
1992	-	-	-	1,662	1,662	21,517	61,837	83,354
1993	-	-	-	1,515	1,515	18,901	57,311	76,212
1994	-	-	-	1,718	1,718	22,125	52,376	74,500
1995	-	-	-	1,719	1,719	26,384	45,383	71,768
1996	-	-	-	1,618	1,618	27,383	41,015	68,397
1997	-	-	-	1,311	1,311	26,140	36,670	62,810
1998	-	-	-	1,335	1,335	27,982	29,665	57,647
1999	-	-	-	1,252	1,252	19,071	32,726	51,796
2000	-	-	-	1,249	1,249	19,290	29,097	48,387
2001	-	-	-	1,274	1,274	15,187	31,481	46,668
	22,104	3,608	25,712	21,276	46,988	722,452	900,093	1,622,544

Notes:
1 East and west side.
2 West side export.

North Slope and Cook Inlet



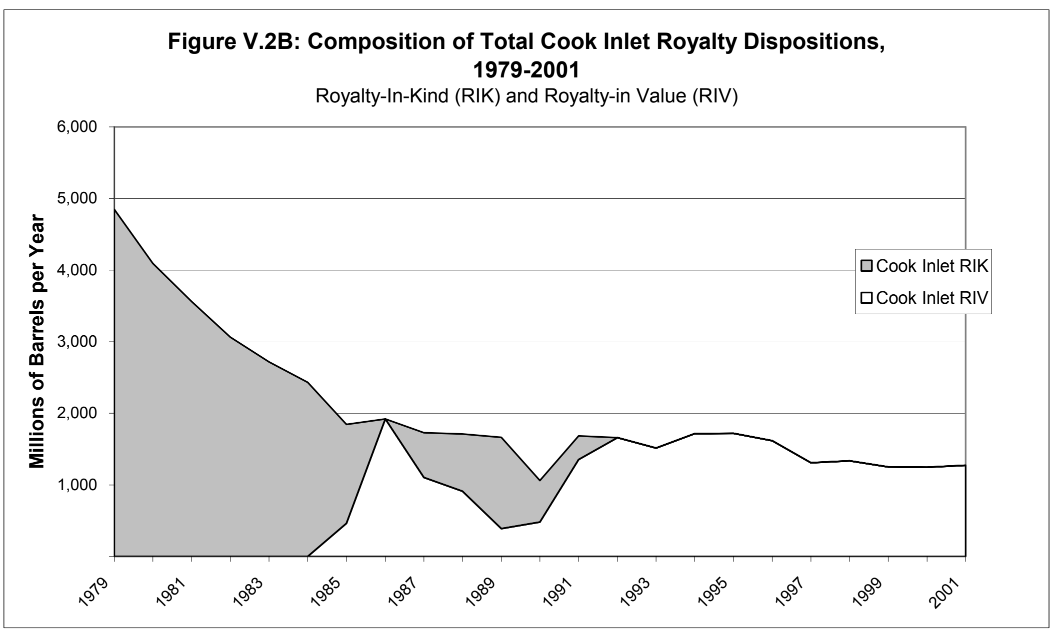
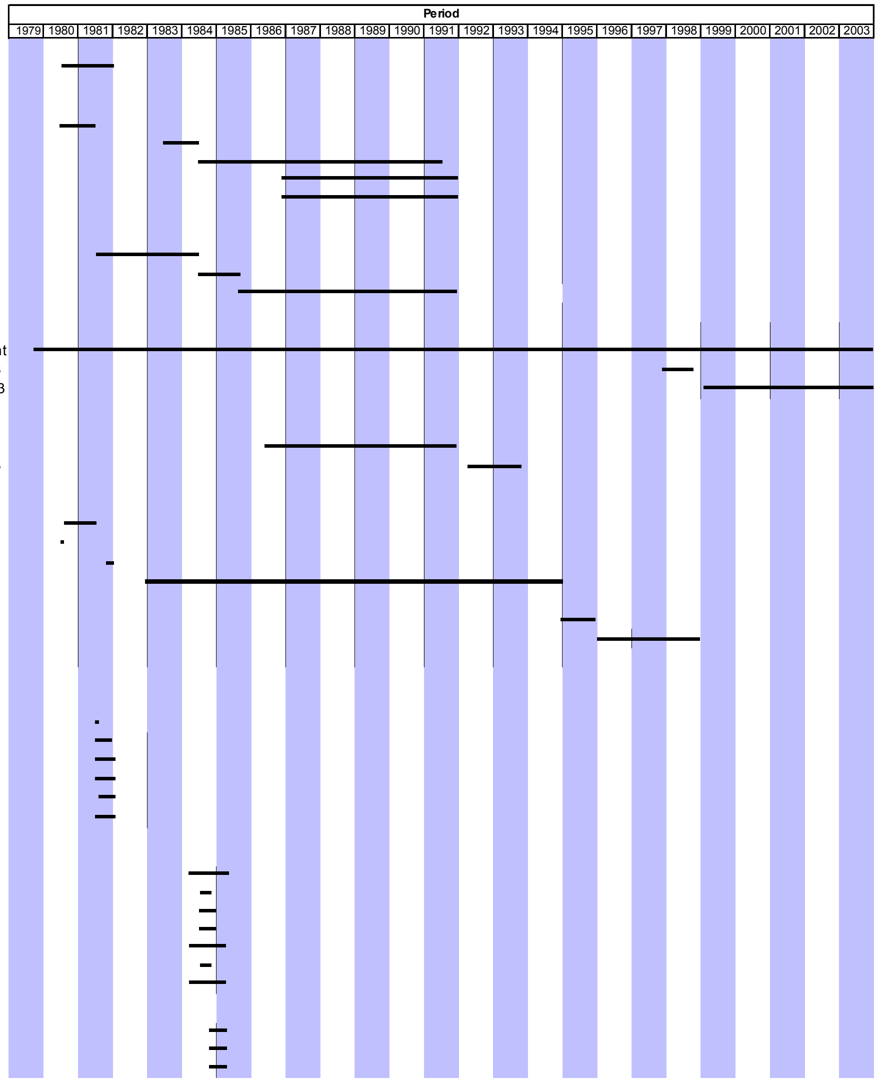


Figure V.3 Major North Slope Royalty in-Kind Sales Contracts

1979-2003

Purchaser / Contract	
Negotiated In-Kind Sales	
Alpetco	
Chevron	
Chevron 1	7/80 - 6/81
Chevron 2	5/83 - 5/84
Chevron 3	5/84 - 7/91
Kuparuk	12/86 - 12/91
Petrostar Purchases	12/86 - 12/91
Golden Valley Electric Association	
GVEA 1	6/81 - 5/84
GVEA 2	6/84 - 9/85
GVEA 3	10/85 - 12/91
MAPCO	
Mapco 1	11/79 - Present
Mapco 2	12/97 - 11/98
Mapco 3	12/98-12/2003
Petrostar	
Petro Star	12/86 - 12/91
Petro Star JV	3/92 - 12/93
Tesoro	
Tesoro 1	7/80 - 6/81
Tesoro 2	7/80
Tesoro 3	12/81 - 1/82
Tesoro 4	1/83 - 12/94
Tesoro 5	10/85 - 8/90
Tesoro 6	1/95 -12/95
Tesoro 7	1/96-12/98
Competitive In-Kind Sales	
First Competitive RIK Sale	
Alaska Petroleum Co.	Jul-81
ARCO Products Co.	7/81 - 12/81
Oasis Petroleum Co.	7/81 - 1/82
Shell	7/81 - 1/82
Sohio	8/81 - 1/82
Union	7/81 - 1/82
Second Competitive RIK Sale	
Chevron 4	4/85 - 3/86
Chevron 5, 6, 7	4/85 - 9/85
Sohio	4/85 - 12/85
Texaco 1	4/85 - 12/85
Texaco 2	4/85 - 3/86
Union 2	4/85 - 9/85
US Oil & Refining - B	4/85 - 3/86
Quasi-Competitive RIK Sale	
Chevron 8	10/85 - 3/86
Union 3	10/85 - 3/86
US Oil & Refining - 1,2,	10/85 - 3/86



Source: Alaska Department of Natural Resources, Division of Oil and Gas