Table 1

Potentially Exportable, Known Gas Reserves for Alaska as of 2000

	Gas Reserves Available for Future Export
Onshore Areas and State of Alaska Lands	
Northern Alaska and Arctic Offshore	26.0 tcf[1] (presently stranded)
Central Alaska	0 tcf
Southern Alaska (Cook Inlet)	0.923 tcf[2] (now consuming 0.078 tcf/yr)
Federal Offshore Areas	
Arctic Offshore (Chukchi and Beaufort Seas)	0 tcf[3]
Bering Shelf and Hope Basin	0 tcf
Pacific Margin continental shelves	0 tcf
Total Gas Reserves Available as of 2000	***26.923 tcf***

[1] Thomas and others, 1996, tbl. 2.3; total known onshore gas reserves remaining in 2000 = 31.617 tcf (see tbls. 2, 3)

[2] 36% of Cook Inlet production in 1998 was directed to LNG exports (AKDO&G, 2000, p. 63). Assuming that the same fraction of 2000 remaining Cook Inlet gas reserves (2.564 tcf including undeveloped fields; see tbl. 4) will be consumed by future LNG exports, we estimate that 0.923 tcf will be exported in the future with depletion of Cook Inlet exportable gas reserves by year 2012. The non-exported 1.641 tcf of year 2000 Cook Inlet gas reserves will be used by local power or gas utilities (1.002 tcf) or ammonia-urea manufacture (0.0.639 tcf). Contract deliveries of 0.0644 tcf per year of LNG from Cook Inlet to Yokohama, Japan consumes about 0.078 tcf per year, or an 83% thermal efficiency (AKDO&G, 1998, p. 41).

[3] 0.7 tcf in known undeveloped oil fields in Beaufort shelf; if developed, would probably be consumed by oil production operations on the leases. 5.0 tcf in Burger structure in Chukchi shelf, considered uneconomic for near term future

tcf: trillion cubic feet

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Table 2

Gas Reserves of Developed Fields, Arctic Alaska, as of Year 2000

FIELD[1]	FIELD TYPE	DISCOVERY DATE	REMAINING GAS RESERVES , tcf (2000)	GAS CONSUMED, tcf (1999)[5]	ORIGINAL GAS RESERVES, tcf
Developed Fields or Fields Under Development-Prudhoe Bay Area					
Badami Unit	Oil	1990	0.039[2]	0.001[4]	0.040
CRU-Alpine	Oil	1994	0.060[2]	0	0.060
CRU-Satellite	Oil	Various	na	na	na
DIU-Endicott	Oil	1978	0.843[2]	0.143[4]	0.986
DIU-Eider	Oil	1998	na	0.003[4]	na
KRU-Kuparuk	Oil	1969	0.590[2]	0.397[2]	0.987
KRU-West Sak	Oil	1969	na	0.001[4]	na
KRU-Tabasco	Oil	1992	na	0.0004[4]	na
KRU-Tarn	Oil	1997	0.021[2]	0.018	0.039
KRU-Kup. Sat.	Oil	Various	na	na	na
MPU-Kuparuk	Oil	1969	0.014[2]	0.020[4]	0.034
MPU-Sch.Bluf.	Oil	1969	na	0.006[4]	na
MPU-Sag Riv.	Oil	1969	na	0.001[4]	na
North Star	Oil	1984	0.450[2]	0	0.450
PBU-Prud. Bay	Oil	1969	23.000[2]	3.048[4]	26.048
PBU-Midnight Sun	Oil	1997	na	0.004[4]	na
PBU-Satellites	Oil	Various	na	na	na
PBU-Lisburne	Oil	1968	0.276[2]	-0.093[4]	0.183
PBU-Niakuk	Oil	1981	0.026[2]	0.046[4]	0.072
PBU-N. Prudhoe	Oil	1970	na	0.006[4]	na
PBU-Pt. McIntyre	Oil	1988	0.577[2]	0.133[4]	0.710
PBU-West Beach	Oil	1976	na	0.013[4]	na
Subtotals			*25.896*	*3.7474*	*29.609*
Developed Fields-Outside Prudhoe Bay Area (Barrow Area)					
East Barrow	Gas	1974	0.005[2]	0.008[4]	0.013
South Barrow	Gas	1949	0.004[2]	0.022[4]	0.026
Walakpa	Gas	1980	0.025[2]	0.007[4]	0.032
Subtotals			*0.034*	*0.037*	*0.071*
Total Developed for Arctic Alaska			***25.930***	***3.7844***	***29.680***

[1] CRU=Colville River Unit; DIU=Duck Island Unit; KRU=Kuparuk River Unit; MPU=Milne Point Unit; PBU=Prudhoe Bay Unit
[2] AKDO&G, 2000, p. 12; here generally rounded to nearest 0.001 tcf
[3] Thomas and others, 1991, tbl. 2-5
[4] AKDO&G, 2000, p. 34-37; here generally rounded to nearest 0.001 tcf
[5] gas consumed by oil production operations on lease or by local community; no gas is exported at present
na = quantity not available; tcf: trillion cubic feet

Table 3

Gas Reserves of Undeveloped Fields, Arctic Alaska, as of Year 2000

FIELD	FIELD TYPE	DISCOVERY DATE	REMAINING GAS RESERVES , tcf (2000)	GAS CONSUMED, tcf (1999)	ORIGINAL GAS RESERVES, tcf
Undeveloped Known Fields-Outside Prudhoe Bay Area					
East Umiat	Gas	1963	0.004[1]	0	0.004
Gubik	Gas	1951	0.600[1]	0	0.600
Kavik	Gas	1969	na[1]	0	na
Kemik	Gas	1972	na[1]	0	na
Meade	Gas	1950	0.020[1]	0	0.020
Point Thomson	Gas/Oil	1977	5.000[2]	0	5.000
Square Lake	Gas	1952	0.058[1]	0	0.058
Umiat	Oil	1946	0.005[1]	0	0.005
Wolf Creek	Gas	1951	na	0	na
Subtotals			*5.687*	*0*	*5.687*
Offshore Undeveloped Known Fields					
Beaufort Sea					
Hammerhead	Oil	1985	Σ = 0.700 tcf (Federal Portion Only for North Star) Individual Field Gas Reserves Not Available		
Kuvlum	Oil	1993			
Liberty	Oil	1982			
Northstar	Oil	1984			
Sandpiper	Gas/Oil	1986			
Chukchi Sea					
Burger	Gas	1990	5.0[3]	0	5.0
Subtotals			*5.700*	*0*	*5.700*
Total Undeveloped for Arctic Alaska			***11.387***	***0***	***11.387***
Total Developed for Arctic Alaska (tbl. 2)			***25.930***	***3.7844***	***29.680***
Totals for Arctic Alaska			***37.317***	***3.7844***	***41.067***

[1] Thomas and others, 1991, tbl. 2-5
[2] AKDO&G, 1998, tbls. 1, 4; here generally rounded to nearest 0.001 tcf
[3]mean value, in range of possible values from 2 tcf (F95) to 10 tcf (F05); preliminary estimate by J. Craig, 1993
na = quantity not available; tcf: trillion cubic feet

Table 4
Cook Inlet—State of Alaska Lands
Gas Reserves of Developed and Known Undeveloped Fields as of Year 2000
(No Federal OCS Reserves)

FIELD	FIELD TYPE[1]	DISCOVERY DATE[1]	REMAINING GAS RESERVES , tcf (2000)	GAS CONSUMED, tcf (1999)	ORIGINAL GAS RESERVES, tcf
Developed Fields or Fields Under Development					
Beaver Creek	Oil/Gas	1972/1967	0.097[2]	0.145[2]	0.242
Beluga River	Gas	1962	0.600[2]	0.666[2]	1.266
Cannery Loop	Gas	1959	0.020[2]	0.089[2]	0.109
Granite Point	Oil/Gas	1965/1993	0.019[2]	0.119[2]	0.138
Ivan River Group[4]	Gas	1966-1979	0.020[2]	0.082[2]	0.102
Kenai	Gas	1959	0.225[2]	2.162[2]	2.387
McArthur River	Oil/Gas	1965/1968	0.383[2]	1.001[2]	1.384
Middle Ground Shoal	Oil/Gas	1962/1982	0.008[2]	0.104[2]	0.112
North Cook Inlet	Gas	1962	0.917[2]	1.411[2]	2.328
North Trading Bay	Oil/Gas	1965/1979	0.019[2]	0.012[2]	0.031
Sterling	Gas	1961	0.030[2]	0.003[2]	0.033
Swanson River[6]	Oil/Gas	1957/1960	0.108[2]	0.189[2]	0.297
Trading Bay	Oil	1965	0.027[2]	0.063[2]	0.090
West McArthur River	Oil	1991	na[2]	0.001[2]	~0.001
Subtotals			*2.473*	*6.047*	*8.520*
Known Undeveloped or Shut-In Fields					
Albert Koloa	Gas	1968	0[3]	0.0001 (test)[2]	0.0001
Birch Hill	Gas	1965	0.011[2]	0.0001 (test)[2]	0.0111
Falls Creek	Gas	1961	0.013[2]	0.00002 (test)[2]	0.01302
Mowquawkie	Gas	1965	0[3]	0.001[2]	0.001
Nicolai Creek	Gas	1966	0.002[2]	0.001[2]	0.003
North Fork	Gas	1965	0.012[2]	0.0001 (test)[2]	0.0121
North Middle Ground Shoal[6]	Gas	1964	na[3]	na	na
Redoubt Shoal	Oil	1968	0[3]	0[2]	na
Tyonek Deep[5]	Oil	1991	0.030[2]	0	0.030
West Foreland	Gas	1962	0.020[2]	0	0.020
West Fork	Gas	1960	0.003[3]	0.004[2]	0.007
Subtotals			*0.091*	*0.00632*	*0.09732*
Totals for Cook Inlet			***2.564***	***6.05332***	***8.61732***

[1]AOGCC (1997)
[2]AKDO&G, 2000, p. 13 & 38-40; generally rounded to nearest 0.001 trillion cubic feet (tcf)
[3]AKDO&G, 1998, tbl. 1; generally rounded to nearest 0.001 trillion cubic feet (tcf)
[4]Ivan River Group includes Ivan River (1966), Lewis River (1975), Pretty Creek (1979), and Stump Lake (1978) Units
[5]beneath North Cook Inlet field
[6]see Middle Ground Shoal field
[7]Federal onshore lands and producing properties. As of 1999, 2.811 tcf of gas had been produced from Swanson River oil field, but 2.888 tcf of gas (produced from other fields) had been injected for reservoir pressure maintenance (AKDO&G, 2000, p. 40)
na = not available

Table 5

Uses of Cook Inlet Produced Gas in 1998[1]

Manner of Gas Use	Quantity, tcf, (% of annual production)
Field Operations (Used on Lease, Vented, Flared)	0.017 (8%)
Electrical Power Generation	0.033 (15%)
Gas Utility Sales	0.027 (13%)
Ammonia-Urea Manufacture for Export	0.054 (25%)
LNG Export to Yokohama, Japan	0.078 (36%)
Miscellaneous	0.006 (3%)
Total 1998 Gas Production	*0.215 (100%)*

[1] AKDO&G, 2000, p. 63
tcf: trillion cubic feet

Table 6

1995-1999 Average LNG Shipping Prices[1] and Recent Price Volatility
LNG Leaving Port Nikiski, Cook Inlet, Alaska and Delivered to Yokohama, Japan

Year	Average Shipping Price $U.S. (Nominal) /mcf[2]
1995	$3.41
1996	$3.65
1997	$3.83
1998	$2.91
1999	$3.08
September, 1998 (U.S. oil at $11.28/bbl)	$2.69
December, 1999 (U.S. oil at $22.55/bbl)	$3.81
September, 2000 (U.S. Oil at $30.03/bbl)	$4.33[3]
Average 5-Year 1995-1999 LNG Price	*$3.38*

[1] LNG prices from DOE, 1999a and 2000, web site postings, *ftp://ftp.eia.doe.gov/pub/oil_gas/natural_gas* and *http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/prices.html*; oil prices from *http://www.eia.doe.gov/oil_gas/petroleum/info_glance/prices.html* and *ftp://ftp.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/txt/tables01.txt*

[2] 1 mcf (thousand cubic feet) of Cook Inlet gas ≈ 1.01 mmbtu (million British thermal units); Swain, 1999, tbl. 5

[3] DOE Fossil Energy web site, *www.fe.doe.gov*, January 2001

Table 7

Conventional Natural Gas Resource Base for Alaska as of 2000

(Risked, Undiscovered, Conventionally Recoverable; Excludes Coalbed Gas and Gas Hydrates)

Area	F95[15] (tcf)	Mean (tcf)	F05[15] (tcf)	Area Chance[16]
Arctic Alaska				
Northern Alaska[1]	23.3	63.5[3]	124.3	1.0[1]
Beaufort shelf[2]	12.86	32.07[4]	63.27	1.0[2]
Chukchi shelf[2]	13.56	60.11[5]	154.31	1.0[2]
Subtotal[15]		155.68[6]		
Bering Shelf, Hope Basin, and Central Alaska				
Hope basin (offshore)[2]	0.0	3.38[7]	11.06	0.61[2]
Bering shelf[2]				
Navarin basin	0.0	6.15	18.18	0.88
North Aleutian basin	0.0	6.79[8]	17.33	0.72
St. George basin	0.0	3.00	9.72	0.94
Norton basin	0.0	2.71	8.74	0.72
St. Matthew-Hall basin	0.0	0.16	0.69	0.44
Central Alaska[1]	0.5	2.8[9]	7.3	1.0[1]
Subtotal[15]		24.99		
Pacific Margin and Southern Alaska				
Southern Alaska (mostly Cook Inlet-State of Alaska Lands)[1]	0.7	2.1[10]	4.3	1.0[1]
Cook Inlet (Federal Offshore)[2]	0.66	1.39[11]	2.49	1.0[2]
Gulf of Alaska (Federal Offshore)[2]	0.94	4.18[12]	10.59	0.99[2]
Shumagin-Kodiak shelf[2]	0.0	2.65[13]	11.35	0.4[2]
Subtotal[15]		10.32		
Subtotal for Alaska Federal Offshore		122.59		
Subtotal for Alaska Onshore		68.4		
Total Undiscovered Gas Potential for Alaska[15]		***190.99***[14]		

[1] USGS, 1995, tbl. 2, and CD DDS-36, *region1\convtab.tab*
[2] Craig (2000)
[3] estimated at 68.2 tcf by PGC (1997, tbl. 55 and 1999, tbl. 52)
[4] estimated at 33.5 tcf by PGC (1999, tbl. 53)
[5] estimated at 19.5 tcf by PGC
[6] estimated at 121.2 tcf by PGC
[7] estimated at 0.6 tcf by PGC
[8] estimated at 6.5 tcf by PGC
[9] PGC (1999, tbl. 52) estimate for "Interior Basins" province = 0.5 tcf
[10] PGC estimate for "Cook Inlet-Susitna" province = 4.5 tcf
[11] estimated at 2.1 tcf by PGC (1999, tbl. 53)
[12] PGC (1999, tbl. 53) estimates for "N. Gulf of Alaska Shelf" and "Southeastern Alaska Shelf" provinces sum to 1.7 tcf
[13] estimated at 1.7 tcf by PGC (1999, tbl. 53)
[14] PGC (1999, tbl. 53) total for Alaska = 143.1 tcf
[15] Fractile values (F95, F05 gas quantities) are not additive. F05 represents a 1 in 20 (or 5%) chance that the indicated gas quantity will be exceeded. Mean values may be added.
[16] chance that the area contains at least one pool of oil or gas capable of flowing to a conventional wellbore

na: not available
tcf: trillion cubic feet

Table 8

Gas Hydrate Gas Resource Base for Alaska

(Unconventional, Continuous-Type Gas Resources)

	Gas In Place (tcf)[1]		
Area	**F95 (tcf)**	**Mean (tcf)**	**F05 (tcf)**
Alaska Offshore Province			
Beaufort Sea	0	32,304	116,555
Bering Sea	0	73,289	264,899
Aleutian Trench	0	21,496	183,663
Gulf of Alaska	0	41,360	257,835
Alaska Onshore Province (Northern Alaska)			
Topset Play (Onshore)	0	105	388
Topset Play (Offshore[2])	0	43	161
Foldbelt Play (Onshore)	0	414	1,914
Foldbelt Play (Offshore[3])	0	28	128
Total Gas Hydrate Resource Base for Alaska[4]		***169,039***	

[1] Collett and Kuuskraa, 1998, tbl. 1; USGS, 1995. "In place" means volume of gas resource stored in hydrates in subsurface, if brought in entirety to surface conditions. Not all of the subsurface resource would be recovered by any method for extraction and recovery efficiencies for gas hydrate production are not known.

[2] Includes some shelf areas of Beaufort and Chukchi Seas north of Brooks Range foldbelt

[3] Includes offshore extension of Brooks Range foldbelt into Chukchi Sea

[4] Fractile values (F95, F05 gas quantities) are not additive. F05 represents a 1 in 20 (or 5%) chance that the indicated gas quantity will be exceeded. Mean values may be added.

tcf: trillion cubic feet

Table 9

Total Gas Resource Base for Alaska as of Year 2000

Trillions of Cubic Feet (tcf)

Area	Exportable Reserves (tcf)[1]	Conventional Undiscovered (tcf)[2]	Deep Tech. Conv. Recoverable (tcf)[3]	Gas Hydrates (tcf)[4]	Coal Bed Methane (tcf)[5]	Total (Sums by Rows, tcf)
Northern Alaska (Onshore)	26.000	63.5	17.7	519	ne	608.5
Beaufort Sea	0	32.07	ne	32,325[7]	ne	32,357.07
Chukchi Sea	0	60.11	ne	50[7]	ne	110.11
Bering Sea[6]	0	22.19	ne	73,289	ne	73,311.19
Central Alaska (Onshore)	0	2.8	ne	ne	ne	2.8
Southern Alaska (Onshore)	0.923	2.1	0.2	ne	ne	3.023
Pacific Margin (Offshore)	0	8.22	ne	62,856	ne	62,864.22
Alaska Total by Category	***26.923***	***190.99***	***17.9***[3]	***169,039***	***1,000***	***170,256.913***

[1] Potentially exportable, known gas reserves as of 2000 (tbl. 1). Northern Alaska reserves are presently stranded because of the absence of a transportation infrastructure.

[2] Risked, mean, undiscovered, conventionally recoverable gas resources (tbl. 7); only a small fraction of this gas may be economically recoverable.

[3] subcategory of "Conventional Undiscovered" gas resources[2] and already included in those estimates (col. 3); mean, undiscovered, technically recoverable, deep (>15,000 feet) conventional gas resources (Dyman and others, 1998, tbl. 1); southern Alaska estimate is for Cook Inlet

[4] gas volumes (surface conditions***) in place*** as unconventional, continuous-type gas hydrate deposits (tbl. 8; Collett and Kuuskraa, 1998, tbl. 1). Recoverability of methane from gas hydrates is not known and is not implied by these estimates. It is unlikely that all of the in place gas would be recoverable.

[5] Smith (1995) estimated that in-place coal bed methane resources for all of Alaska might reach 1,000 trillion cubic feet. The most likely volume of coal bed methane for all of Alaska was estimated at 57 tcf by PGC (1997, tbl. 55 and 1999, tbl. 53). The PGC estimate includes but does not separate northern Alaska, Gulf of Alaska (noted in PGC report as Bering River), and the Alaska Peninsula of southern Alaska (noted in PGC report as Chignik and Herendeen Bay)

[6] includes Hope basin

[7] Topset play (offshore) of Collett and Kuuskraa (1998, tbl. 1), with 43 tcf, arbitrarily split between Chukchi (21 tcf) and Beaufort (22 tcf) Seas. The Foldbelt play (offshore) of Collett and Kuuskraa, with 28 tcf, was assigned to the Chukchi Sea.

ne: no estimates available

Table 10

Economic, Undiscovered Natural Gas Resources for Alaska

(Risked, Undiscovered, Conventional, Economically Recoverable; Excludes Coal Bed Gas and Gas Hydrates)

Area	**Domestic U.S. Gas Price (Mean (tcf) at Gas Prices $2.00-$2.11/mcf[1])**	**Asian LNG Market Price (Mean (tcf) at Gas Prices $3.34 to $3.52/mcf[2])**
Arctic Alaska		
Northern Alaska[3]	No economic gas resources	
Beaufort shelf[4]	2.934	4.200
Chukchi shelf[5]	No economic gas resources	No economic gas resources
Subtotals	***2.934***	***4.200***
Bering Shelf, Hope Basin, and Central Alaska		
Hope basin (offshore)[8]	0.614	1.506
Bering shelf[7]		
Navarin basin	0.036 (~negl.)	0.075 (~negl.)
North Aleutian basin	0.880	1.272
St. George basin	0.049 (~negl.)	0.103 (~negl.)
Norton basin	0.024 (~negl)	0.072 (~negl.)
St. Matthew-Hall basin	Gas not evaluated; no economic gas	
Central Alaska[3]	Gas not evaluated; no economic gas	
Subtotals	***1.603***	***3.028***
Pacific Margin and Southern Alaska		
Southern Alaska (Cook Inlet—State Lands)[6]	1.033	3.556
Cook Inlet (Federal Offshore)[9]	0.599	0.997
Gulf of Alaska (Federal Offshore)[10]	No economic gas resources	
Shumagin-Kodiak shelf[7]	0.004 (~negl.)	0.449
Subtotals	***1.636***	***5.002***
Subtotals for Alaska Federal Offshore	5.140[11]	8.674[11]
Subtotals for Alaska Onshore	1.033	3.556
Total Undiscovered Gas Potential for Alaska	***6.173***	***12.230***

[1] These gas prices approximate the 1993-1997 five-year average well head prices for domestic U.S. gas ($1.99/mcf) as reported by DOE (1999a) and form a useful convention

[2] These gas prices bracket the 1995-1999 five-year average shipping price ($3.38/mcf) for LNG leaving Port Nikiski, Cook Inlet and bound for Yokohama, Japan (see tbl. 6) and form a useful benchmark; prices in late 2000 for Nikiski LNG have exceeded $4.00/mcf

[3] Attanasi, 1998, p. 8

[4] Craig (2000); prices for gas delivered to Prudhoe Bay plantgate, rather than outside export markets.

[5] Chukchi shelf gas was not assessed in Year 2000 study. We estimate that $3.63/mcf represents the minimum processing and delivery cost to Yokohama, Japan using a modified version of the Yukon-Pacific TAGS-LNG model (the latter described in tbl. 17).

[6] Attanasi, 1998, tbl. 1; calculated by present authors as sums of separately tabulated entries for associated gas (with oil) fields and conventional non-associated gas fields, at gas prices of $2.00/mcf and $3.34/mcf in Year $1994 (here assumed equivalent to Year $2000 because of little overall inflation in prices or costs in the 1994-2000 period)

[7] Craig (1998b, tbl. 27.12), at gas prices of $2.11/mcf and $3.52/mcf; not amended from 1995

[8] Craig (2000); prices are for gas delivered to hypothetical Kivalina plantgate

[9] Craig (2000); prices are for gas delivered to gas pipeline network in Cook Inlet basin

[10] Craig (2000)

[11] MMS (2001) reports totals of 1.6 tcf and 3.0 tcf for the $2.11/mcf and $3.52/mcf cases, respectively. Because local markets were used in the economic models, the Beaufort shelf and Hope Basin results shown here were not included in that report.

tcf: trillion cubic feet

~negl.: essentially negligible, reported values are artifacts of analytical method

Table 11
Summary of Gas Transportation Scenarios Used in 1995 and 2000 Assessments for Economically Recoverable Gas in Alaska Arctic and Bering Shelf Federal Offshore
(modified after Craig [2000], Sherwood and Craig [2000], and Craig [1998a, tbl. 26.3])

Province	Gas Transportation Scenario
Arctic Alaska Offshore	
Beaufort shelf	The Year 2000 assessment of Beaufort shelf (Craig, 2000) assumes the existence of an unspecified gas transportation system (possible either gas-to-liquids or gas pipeline) originating at the Prudhoe Bay complex. Gas produced with oil on Beaufort shelf would be gathered via subsea pipelines to either of 2 central offshore gas storage and processing facilities (located approximately at “BEAU” in fig. 11), then transported via 120-mile subsea and land gas pipelines to the Prudhoe Bay “plantgate”, where the gas is sold. Gas sales prices at the Prudhoe Bay plantgate determine the economically recoverable gas resources of Beaufort shelf.
Chukchi shelf	We assume the existence of an 800-mile TAGS gas pipeline from the Prudhoe Bay area to Valdez, Alaska. Gas was assumed to be transported via subsea pipelines that gather to either of two central offshore gas storage and processing facilities (located at “CHUK” in fig. 11), then transported via 150-mile subsea trunk gas pipelines to the northwest coast of Alaska, then via a 400-mile overland gas pipeline to the Prudhoe Bay area. Gas was then taken down the TAGS line to Valdez, converted to LNG, then shipped via tanker 4,000 miles to Yokohama, Japan, and delivered to existing regasification plants. Gas sales prices in Japan therefore determine the economically recoverable gas resources of Chukchi shelf. The results of this study are shown in figure 14. Gas was not assessed in the Craig (2000) study because Chukchi gas development is viewed as probably occurring far beyond the 2007-2012 5-year planning cycle for which that study was conducted.
Hope Basin and Bering Shelf	
Hope basin	The Craig (2000) assessment assumed that gas and condensate would be marketed to a hypothetical onshore industrial complex at Kivalina, where the gas, condensate, and possible synthetic fuels (from gas-to-liquids) would be marketed to the zinc mining operations at Red Dog, the Bering Sea fishing fleet, and local communities. Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “HB” in fig. 11), then is transported via a 100-mile subsea trunk pipeline to a “plantgate” at Kivalina port. Prices at the Kivalina plantgate determine the economically recoverable gas resources of Hope basin.
Norton basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “NOR” in fig. 11), then transported via 65-mile subsea trunk pipeline to Nome, converted to LNG at a newly-built gas plant, then shipped as LNG to Japan, where gas sales prices determine the economically recoverable gas resources of Norton basin.
Navarin basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “NAV” in fig. 11), then is transported via a 700-mile subsea trunk pipeline to Balboa Bay on the Alaska Peninsula, converted to LNG at newly-built gas plant, then shipped as LNG to Japan, where prices determine the economically recoverable gas resources of Navarin basin.
St. George basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “SGB” in fig. 11), then is transported via a 340-mile subsea trunk pipeline to Balboa Bay on the Alaska Peninsula, converted to LNG at newly-built gas plant, then shipped as LNG to Japan, where prices determine the economically recoverable gas resources of St. George basin.
North Aleutian basin	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at “NAS” in fig. 11), then is transported via 70-mile subsea trunk pipeline to Balboa Bay on the Alaska Peninsula, converted to LNG at newly-built gas plant, then shipped as LNG to Japan, where prices determine the economically recoverable gas resources of North Aleutian basin.

LNG: Liquefied natural gas

Table 12

Summary of Gas Transportation Scenarios Used in 1995 and 2000 Assessments for Economically Recoverable Gas in Alaska Pacific Margin Federal Offshore
(modified after Craig [2000], Sherwood and Craig [2000], and Craig [1998a, tbl. 26.3])

Province	Gas Transportation Scenario
Pacific Margin Offshore	
Shumagin-Kodiak shelf	Gas is transported via subsea pipelines that gather to a central offshore gas storage and processing facility (located at "KS" in fig. 11), then is transported via a 215-mile subsea trunk pipeline to the port of Nikiski in Cook Inlet, where it is converted to LNG at the existing plant, then shipped as LNG to Japan, where gas sales prices determine the economically recoverable gas resources of Shumagin-Kodiak shelf.
Cook Inlet	In the Craig (2000) study, gas is assumed to be marketed locally to industries and communities along the shores of Cook Inlet. Gas from producing oil fields and non-associated gas fields is gathered to a central offshore storage and processing facility (located approximately at "COOK" in fig. 11) and then conveyed by a 125-mile subsea trunk line to the existing gas transmission pipeline network, with landfall probably near Kenai. Cook Inlet basin gas prices determine the economically recoverable gas resources of the Cook Inlet Federal Offshore.
Gulf of Alaska shelf	In a 1995 internal study, we assumed that Gulf of Alaska gas would be co-produced with oil and then gathered via subsea pipelines to offshore gas storage and processing centers (located approximately between the "GOA" sites in fig. 11) and then conveyed via a 30-250 mile subsea gas pipeline to Yakutat, where newly constructed LNG and port facilities would process and load the gas on tankers bound for existing regasification plants in Japan, 4,000 miles to the west. Gas sales prices in the Asian Pacific rim markets and the high cost of constructing new LNG and port facilities at Yakutat therefore determine the economically recoverable gas resources of the Gulf of Alaska shelf. The results of this study are shown in figure 20. However, a 1995 study published by Craig (199a, tbl. 26.3) noted that gas is predicted to be associated with oil and would probably be used for decades at the lease to enhance oil recovery and to fuel lease operations. Sensitivity studies found that any attempt to market gas during oil production placed a negative economic burden on oil production. The Craig (2000) resource assessment reaches similar conclusions and notes that gas development on the Gulf of Alaska shelf is very unlikely in the 2007-2012 time frame of that assessment.

LNG: Liquefied natural gas

Table 13
Gas Trunk Pipeline Lengths Used in 1995 and 2000 MMS Economic Assessments
(modified after Craig, 1998a, tbl. 26.2 and Craig, 2000)

Federal Offshore Province	Basin Pipeline Lengths[1] (miles)
Beaufort shelf[2]	120
Chukchi shelf[2]	550
Hope basin	100
Norton basin	65
Navarin basin	700
St. George basin	340
North Aleutian basin	70
Shumagin-Kodiak shelf	215
Cook Inlet basin (Federal OCS)	125
Gulf of Alaska shelf[3]	30-250[4]

[1] Basin pipelines are large-diameter trunk lines and may include both overland and offshore segments. New pipelines are modeled as capital costs.
[2] Arctic gas is presently stranded by lack of a gas transportation infrastructure from the Prudhoe Bay area. Basin pipeline lengths are distances required to reach the Prudhoe Bay infrastructure from offshore gathering facilities.
[3] gas mostly coexists with oil and would be retained on-site for decades to enhance oil recovery and lease operations
[4] entered as “play pipelines” in original table 26.2 of Craig (1998a)

Table 14
Gas Shipping Routes and Marine LNG Tariffs
(modified after MMS [2001], Sherwood and Craig [2000], and Craig [1998a, tbl. 26.1])

Offshore Provinces	Transit[1] and Destination Ports	Distance (miles)[2]	Marine LNG Tariff ($/mcf)[3]
Beaufort shelf	No Shipping; Piped to Prudhoe	na	na
Chukchi shelf	Valdez to Yokohama	4000	$0.80
Hope basin	No Shipping; Piped to Kivalina	na	na
Norton basin	Nome to Yokohama	3100	$0.93
St. George basin	Balboa Bay to Yokohama	3000	$0.60
Navarin basin	Balboa Bay to Yokohama	3000	$0.60
North Aleutian basin	Balboa Bay to Yokohama	3000	$0.60
Cook Inlet	No Shipping; Piped to Nikiski	na	na
Gulf of Alaska shelf	Yakutat to Yokohama	4000	$1.20
Shumagin-Kodiak shelf	Nikiski to Yokohama[4]	3800	$1.14

[1] Transit ports are hypothetical sites (except for pipeline delivery and sales points at Prudhoe Bay, Kivalina, and Nikiski) for new shore-based gas LNG facilities. Transit ports are located in figure 11.
[2] Distances are obtained from Defense Mapping Agency (1985) and are converted from nautical miles to statute miles (1.0 nautical mile = 1.151 statute mile). Tanker routes are great circle tracks.
[3] Gas tariffs for liquified natural gas (LNG) are assumed to average $0.20/mcf per 1,000 miles for large LNG carriers (125,000 cubic meters ship capacity or 2.8 bcf delivered). Tariffs for smaller LNG carriers (20,000 cubic meters ship capacity or 0.4 bcf delivered) that can access shallow water ports are assumed to average $0.30/mcf per 1,000 miles.
[4] Route presently in use for Cook Inlet gas exports (fields beneath State of Alaska lands). See tables 1, 4, 5.

Table 15

Total Gas Processing and Transportation Tariffs[1]

Federal Offshore Province	Gas Processing and Handling Tariffs ($/mcf)	Marine LNG Tariff ($/mcf)	Total Tariffs (Gas Processing and Transportation) ($/mcf)[2]
Beaufort shelf[4]	Not Estimated	Not Estimated	Not Estimated
Chukchi shelf	$2.83	$0.80	$3.63
Hope basin[5]	Not Estimated	Not Estimated	Not Estimated
Norton basin	$1.02	$0.93	$1.95
Navarin basin	$1.32	$0.60	$1.92
St. George basin	$1.40	$0.60	$2.00
North Aleutian basin	$0.75	$0.60	$1.35
Shumagin-Kodiak shelf[6]	$2.33[5]	$1.14	$3.47
Cook Inlet basin (Federal OCS)[7]	Not Estimated	Not Estimated	Not Estimated
Gulf of Alaska shelf	$1.84	$1.20	$3.04

[1] Processing and transportation tariffs do not include costs of field discovery and appraisal drilling, development well drilling, installing production platforms, building new pipelines, or building new gas plants, all which are treated as capital costs

[2] from Craig, 1998a, tbl. 26.2

[3] Five-year 1993-1997 average delivered prices for gas loaded at Port of Nikiski in Cook Inlet and bound for Yokohama, Japan (DOE, 1999a)

[4] Gas development modeled as gas delivered via pipeline to Prudhoe Bay plantgate.

[5] Gas development modeled as gas delivered via pipeline to Kivalina industrial complex plantgate.

[6] The higher tariff for Shumagin-Kodiak shelf relative to other southern Alaska basins reflects the use of an expanded, existing Nikiski facility, with a tariff for capital cost recovery, operating costs, and marine terminal loading fees. Other basins have lower tariffs because major new infrastructure costs (LNG plant and marine terminal) are handled separately as pre-production capital costs.

[7] Gas development modeled as gas delivered via pipeline to existing gas transmission pipeline network near Nikiski.

Table 16

Economic, Undiscovered Natural Gas Resources for Alaska Offshore At $6/mcf ($2000)

(Risked, Undiscovered, Conventional, Economically Recoverable Gas as Read from $6/mcf Price on Price Supply Graphs; Excludes Coal Bed Gas and Gas Hydrates)

Area	**Mean Resource Case** Economic Gas (tcf) at $6/mcf	**High (F05) Resource Case[1]** Economic Gas (tcf) at $6/mcf
Arctic Alaska Offshore		
Beaufort shelf[2]	4.66	14.30
Chukchi shelf[2]	20.00	Not Calculated
Subtotals	*24.66*	- -
Bering Shelf and Hope Basin		
Hope basin	2.27	7.22
Norton basin	negligible	negligible
Navarin basin	negligible	negligible
St. George basin	negligible	negligible
North Aleutian basin	5.90	15.30
Subtotals	*8.17*	*22.50*
Pacific Margin Offshore		
Gulf of Alaska[3]	0.31	Not Calculated
Cook Inlet (Federal Offshore)	1.24	1.92
Shumagin-Kodiak shelf	1.40	6.40
Subtotals	*2.95*	- -
Total Undiscovered Gas Potential for Alaska Federal Offshore at $6/mcf	***35.78***	- -

[1] The high resource case is the low-probability case; F05 corresponds to a 5% probability that the indicated resource quantities will be met or exceeded.

[2] Arctic gas presently stranded by lack of transportation system

[3] Gulf of Alaska gas is modeled as mostly associated with oil and would be largely used to enhance recovery in oil fields and for lease operations

tcf: trillion cubic feet; mcf: 1,000 cubic feet

Table 17

Current Options for Transportation and Marketing of Alaska Natural Gas

GAS MARKETING OPTION	BASIC ELEMENTS AND TECHNOLOGY
PIPELINE TO CANADA	***Gas pipeline to Canadian pipeline network.*** Original proposal was *Alaska Natural Gas Transportation System (ANGTS)*, but other proposals have been announced. Gas pipeline (1,400 or 2,100 miles) along Mackenzie Valley or Alaska Highway to Canadian gas pipeline system. A 1995 study of ANGTS estimated gas delivery costs from $2.82 to $4.17 per mcf.[1] **Main positives**: proven technology. **Main negative**: high cost.
TAGS-LNG	***Trans-Alaska Gas Pipeline System and Conversion to Liquefied Natural Gas***. Large-diameter (36-42 inch) gas pipeline to Valdez with shipment as cryogenically liquefied natural gas or "LNG" to Asian markets. LNG is converted back to gas in a regasification plant at delivery site and is then used in conventional natural gas applications. LNG purchaser will provide receiving port facilities and regasification plant. Current proposal design capacities range from 0.46 to 0.9 tcf per year. Breakeven flat oil price = $19.36 per barrel oil price equivalent[1] or $3.77/mcf LNG for a 0.85 tcf per year project modeled in 1996 DOE study. Other estimates for LNG delivery costs (to Japan) for the TAGS-LNG project are as high as $6.97/mcf.[6] **Main positives**: proven technology; premium price received in Asian markets. **Main negatives**: large initial investment; no presently-identified long-term market; size of project (up to 0.7 tcf per year) very large compared to world LNG market (4.3 tcf per year) and Asian LNG market (3.2 tcf per year); many projects with competitive advantages; no significant future cost reductions.
GTL	***Gas to Liquids Conversion***. Project requires a northern Alaska plant that converts gas permanently to diesel-like liquid fuel or other chemical feed stocks which are then pumped through the Trans-Alaska oil pipeline and then shipped in conventional tankers to Pacific rim ports. No large-scale project is currently proposed but a DOE study modeled a hypothetical project at 2.5 tcfg per year converted to 300,000 barrels of liquid product per day at peak output[4], with a total investment of $13 billion.[5] The converted product is refined and may attract a $5 to $10 premium (over oil price) per barrel. Breakeven flat oil price = $19.94 per barrel[1] oil price equivalent in 1996 DOE study. Estimates for conversion costs are falling rapidly with aggressive new research programs and more recent estimates for conversion costs falling near $15 per barrel[3] with new technologies. **Main positives**: small-scale start-ups possible, with future expansion; known market for refined product attracting premium prices; use existing oil transportation infrastructure and extend operating life of TAPS line; large cost reductions foreseen with new technology. **Main negatives**: unproven technology at needed scale of project; present high costs (but declining with new technologies).

[1] Thomas and others, 1996, pp. xiv, 3-4; "breakeven" includes 10% rate of return for Prudhoe Bay gas only
[2] Jones, 1999, p. 19
[3] Singleton, 1997, tbl. 1
[4] Thomas and others, 1996, p. B-24, tbl. B.12
[5] Thomas and others, 1996, tbl. 2
[6] Attanasi, 1995, tbl. 4

Table 18

Experimental Options for Transportation and Marketing of Stranded Natural Gas

GAS SHIPMENT OPTION	BASIC ELEMENTS AND TECHNOLOGY
COSELLE CNG	***Cran and Stenning "COSELLE" Compressed Natural Gas Containment Vessels.*.** New type of pressurized gas containment vessel (small-diameter pipe coiled into a carousel rather than individual bottles) for transporting compressed natural gas in ships at costs as low as \$0.60/mmbtu or 20% of LNG shipping costs (\$3.25/mmbtu for comparable volume of LNG)[1]
NGH	***Pelletized Hydrates of Natural Gas***. Gas is mixed with water and chilled to produce hydrate pellets which can be bulk loaded (like grain) into refrigerated storage in otherwise conventional freighter ships. System can be scaled to any need. Hydrates are melted at receiving location and gas is used in conventional applications. Costs of NGH transportation system estimated to be only 75% of LNG systems[2]
Submarine LNG Tankers	***LNG Containment Vessels Placed Aboard Submarines***. Proposed for shipment of ice-bound Kara Sea gas from Russia to Asian markets. Twenty-two Russian-built submarine tankers, each with capacity of 170,000 cubic meters (6 mmcf). Subsea gas production piped to LNG plant on Novaya Zemlya Island, then transferred to submarine LNG tankers for an 11-day voyage beneath ice of Arctic Ocean to Alaska's St. Matthew Island, then transferred to conventional surface LNG tankers for shipment to Asian ports. Fleet capacity will be 21 million tons or 1.05 tcf per year. No cost estimates published.[3]

[1] Stenning, 1999, fig. 1
[2] JPT, 1999, fig. 1; LeBlanc, 1995
[3] George,1996; 1997

Table 19

AEO 2001 World Oil Price Forecasts

(Shown in \$1995)

Case	Year				
	1999	2005	2010	2015	2020
Reference[1]	\$15.36	\$18.44	\$18.91	\$19.37	\$19.83
Low Economic Growth[2]	\$15.36	NR	\$18.32	\$18.52	\$18.73
High Economic Growth[2]	\$15.36	NR	\$19.36	\$20.09	\$20.81
Low World Oil Price[3]	\$15.36	NR	\$13.36	\$13.36	\$13.36
High World Oil Price[3]	\$15.36	NR	\$23.59	\$24.98	\$25.15

[1] AEO (2000, tbl. A1); discounted (3.1% per year) from \$1999 to \$1995, price per barrel
[2] AEO (2000, tbl. B1); discounted from \$1999 to \$1995, price per barrel
[3] AEO (2000, tbl. C1); discounted from \$1999 to \$1995, price per barrel
Reference, Low World Oil Price, and High World Oil Price cases graphed in figure 38
NR: not reported

Table 20

Comparative Economics of GTL vs. TAGS-LNG Projects for Northern Alaska Gas
(from 1995 DOE Study[3])

Economic Element	GTL[1]	TAGS-LNG[2]
NPV_{10} with 2.4% Real Oil Price Growth[3]	$10.7 billion	$11.5 billion
Total Capital Investment[4]	$12.9 billion	$16.9 billion
Breakeven (NPV_{10} = 0) Flat Oil Price[5]	$19.94/bbl	$19.36/bbl
LNG Price Equivalent to Breakeven Flat Oil Price[6]	$3.88/mcf	$3.77/mcf
Earliest Economic Viability (Using AEO 2001 *Reference Case*)[7]	2020+	2015

[1] GTL: Gas to Liquids, or F-T synthesis

[2] TAGS-LNG: Trans-Alaska Gas Pipeline System and Conversion to Liquefied Natural Gas for Marine Shipment to Asian Pacific rim (primarily Japan)

[3] Thomas and others, 1996, tbl. 1; NPV_{10}: net present value carrying a 10% return on investment; calculated here with an assumed 2.4% annual real (above inflation) growth in oil prices; in $1995

[4] Thomas and others, 1996; for a 17 million metric ton (0.85 tcf) per year TAGS-LNG project (the Yukon Pacific proposal is for a 14 mmt or 0.7 tcf per year project), and, a 300,000 barrel per day GTL project; in $1995

[5] Thomas and others, 1996, p. xiv; B1-B2; in $1995; world oil price, assumed to be $1 greater than Alaska North Slope crude price.

[6] On energy parity, in $1995, calculated as [$oil price/5.13 (btu conversion)]; modified from conversion formula of Thomas and others (1996, p. B-11) which uses 10% LNG Asian price bonus over energy parity with oil.

[7] based on AEO (2001, tbl. A1) price forecasts for world oil (*reference case*; see tbl. 19) and breakeven flat oil prices calculated by Thomas and others (1996, p. xiv)

Table 21
Historical Data for Oil and Gas Leasing in the Alaska Federal Offshore

YEAR	NO. TRACTS OFFERED	TOTAL ACRES OFFERED	NO. TRACTS LEASED	TOTAL ACRES LEASED	FRACTION LEASED	TOTAL HIGH BIDS ACCEPTED ($)	TOTAL HIGH BIDS ACCEPTED ($1999)	AVERAGE BID ($) VALUE PER ACRE	AVERAGE BID ($1999) VALUE PER ACRE	NUMBER OF EXPLORATION WELLS	LAG (YRS) FR. LEASE TO TEST, BY DRILL DATE	FOOTAGE (FT) DRILLED	LAG (YRS) FR. LEASE TO TEST, BY LEASE DATE	LAG (YRS) FR. LEASE TO PRODUCTION, BY LEASE DATE
1976	189	1,008,499	76	409,058	0.41	559,836,587	1,129,823,436	1,369	2,763	0	0	0	1.4	
1977	135	768,580	87	495,307	0.64	398,471,313	779,987,598	804	1,574	7	1	100,021	2.2	
1978	0	0	0	0		0	0	0	0	6	1.7	62,280	0	
1979	46	173,423	24	85,776	0.49	488,691,138	899,928,010	5,697	10,491	4	2	33,311	4.6	21+
1980	210	1,195,569	35	199,261	0.17	109,751,073	196,030,395	551	984	4	3	42,610	3	
1981	328	1,854,547	14	78,850	0.04	4,576,395	7,928,289	58	100	0	0	0	3.3	
1982	478	2,610,860	121	662,860	0.25	2,055,632,336	3,454,162,384	3,101	5,211	3	3	38,255	4	18+
1983	897	5,068,538	155	876,815	0.17	744,332,202	1,213,124,721	849	1,384	2	3.5	31,209	1.4	
1984	6,455	35,822,442	390	2,135,703	0.06	1,383,177,658	2,186,542,607	648	1,024	13	1.7	114,499	3.1	
1985	0	0	0	0		0	0	0	0	21	1.9	208,478	0	
1986	0	0	0	0		0	0	0	0	6	3.3	61,866	0	
1987	0	0	0	0		0	0	0	0	1	8	14,650	0	
1988	7,910	43,908,928	552	3,087,676	0.07	593,294,267	830,071,437	192	269	1	4	18,325	2.3	
1989	0	0	0	0		0	0	0	0	2	3	25,158	0	
1990	0	0	0	0		0	0	0	0	3	4	25,416	0	
1991	6,893	37,544,952	85	436,217	0.01	23,924,329	30,542,817	55	70	4	4	37,786	2	
1992	0	0	0	0		0	0	0	0	1	8	8,500	0	
1993	0	0	0	0		0	0	0	0	3	6.7	28,439	0	
1994	0	0	0	0		0	0	0	0	0	0	0	0	
1995	0	0	0	0		0	0	0	0	0	0	0	0	
1996	1,413	7,282,795	29	100,025	0.01	14,429,363	15,813,323	144	158	0	0	0	1	
1997	88	427,886	2	9,766	0.02	253,965	269,955	26	28	2	1	25,111	0	
1998	247	920,983	28	86,371	0.09	5,327,093	5,492,233	62	64	0	0	0	0	
1999	0	0	0	0		0	0	0	0	0	0	0	0	
2000	0	0	0	0		0	0	0	0	0	0	0	0	
TOTALS	***25,289***	***138,588,002***	***1,598***	***8,663,685***		***$6,381,697,719***	***$10,749,717,205***			***83***		***875,915***		

($): denotes nominal dollars ($1999) : denotes inflation-adjusted dollars, from nominal dollars (of the time) to 1999 dollars using average annual inflation (i)=3.1% [$1999=$NOMINAL $(1+i)^n$, where n=1999-Nominal Year

Table 22

Offshore Oil and Gas Resources Sequestered by Moratorium of North Aleutian Basin
(Moratorium on Offshore Oil and Gas Leasing and Exploration Until Year 2012)

Oil and Gas Resources	Low Resource Case (F95)	Mean	High Resource Case (F05)
Recoverable Oil Resources[1]	0.00 bbo	0.230 bbo	0.57 bbo
Economic Oil Resources at $18/bbl[2]	0.00 bbo	0.024 bbo	0.20 bbo
Economic Oil Resources at $30/bbl[2]	nr	0.036 bbo	nr
Recoverable Gas Resources[1]	0.00 tcfg	6.790 tcfg	17.33 tcfg
Economic Gas Resources at $2.11/mcf[2]	0.00 tcfg	0.880 tcfg	7.71 tcfg
Economic Gas Resources at $3.52/mcf[2]	nr	1.272 tcfg	12.30 tcfg[3]
Economic Gas Resources at $6/mcf[4]	nr	5.900 tcfg	15.30 tcfg

[1] Sherwood and others, 1996, tbl. 1. "Recoverable oil and gas resources" refer to undiscovered, conventionally recoverable resources. F95 represents a 95% chance that the indicated quantity will be met or exceeded, whereas F05 represents a 1-in-20 (or 5%) chance that the indicated quantity will be exceeded

[2] Craig, 1998b, tbls. 27.11, 27.12; oil and gas prices in $2000.

[3] estimated from price-supply graph of Craig (1998b, fig. 27.5c)

[4] table 16, this report; gas price in $2000.

bbo: billions of barrels of oil

tcfg: trillions of cubic feet of gas