National Assessment of Oil and Gas Project: Geologic Assessment of Undiscovered Gas Hydrate Resources on the North Slope, Alaska

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National Assessment of Oil and Gas Project: Geologic Assessment of Undiscovered Gas Hydrate Resources on the North Slope, Alaska

By U.S. Geological Survey Alaska Gas Hydrate Assessment Team

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**U.S. Department of the Interior
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Conversion Factors

Inch/Pound to SI

Multiply	By	To obtain
Length		
inch (in.)	2.54	centimeter (cm)
inch (in.)	25.4	millimeter (mm)
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
Area		
square inch (in ²)	6.452	square centimeter (cm ²)
square mile (mi ²)	259.0	hectare (ha)
square mile (mi ²)	2.590	square kilometer (km ²)
Volume		
cubic foot (ft ³)	28.32	cubic decimeter (dm ³)
cubic foot (ft ³)	0.02832	cubic meter (m ³)
Pressure		
pound per square foot (lb/ft ²)	0.04788	kilopascal (kPa)
pound per square inch (lb/in ²)	6.895	kilopascal (kPa)
Density		
pound per cubic foot (lb/ft ³)	16.02	kilogram per cubic meter (kg/m ³)
pound per cubic foot (lb/ft ³)	0.01602	gram per cubic centimeter (g/cm ³)

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

$$^{\circ}\text{C}=(^{\circ}\text{F}-32)/1.8$$

Acronyms Used in Report

USGS	U.S. Geological Survey
TCF	trillion cubic feet
BLM	U.S. Bureau of Land Management
NPRA	National Petroleum Reserve in Alaska
ANWR	Arctic National Wildlife Reserve
TPS	Total Petroleum System
AU	assessment unit
sl	Structure I Hydrate
sII	Structure II Hydrate
sH	Structure H Hydrate
MDT	Schlumberger Modular Dynamic Testing
DOE	U.S. Department of Energy
JOGMEC	Japan Oil, Gas and Metals National Corporation
MPU	Milne Point Unit,
NRCan	Natural Resources Canada
KRU	Kuparak River Unit
PBU	Prudhoe Bay Unit

National Assessment of Oil and Gas Project: Geologic Assessment of Undiscovered Gas Hydrate Resources on the North Slope, Alaska

By U.S. Geological Survey Alaska Gas Hydrate Assessment Team

Abstract

Scientists with the U.S. Geological Survey have completed the first assessment of the undiscovered, technically recoverable gas hydrate resources beneath the North Slope of Alaska. This assessment indicates the existence of technically recoverable gas hydrate resources—that is, resources that can be discovered, developed, and produced using current technology.

The approach used in this assessment followed standard geology-based USGS methodologies developed to assess conventional oil and gas resources. In order to use the USGS conventional assessment approach on gas hydrate resources, three-dimensional industry-acquired seismic data were analyzed. The analyses indicated that the gas hydrates on the North Slope occupy limited, discrete volumes of rock bounded by faults and downdip water contacts. This assessment approach also assumes that the resource can be produced by existing conventional technology, on the basis of limited field testing and numerical production models of gas hydrate-bearing reservoirs.

The area assessed in northern Alaska extends from the National Petroleum Reserve in Alaska on the west through the Arctic National Wildlife Refuge on the east and from the Brooks Range northward to the State-Federal offshore boundary (located 3 miles north of the coastline). This area consists mostly of Federal, State, and Native lands covering 55,894 square miles. Using the standard geology-based assessment methodology, the USGS estimated that the total undiscovered technically recoverable natural-gas resources in gas hydrates in northern Alaska range between 25.2 and 157.8 trillion cubic feet, representing 95 percent and 5 percent probabilities of greater than these amounts, respectively, with a mean estimate of 85.4 trillion cubic feet.

1. Introduction

Approximately 35 years (yr) ago, Russian scientists made what was then a bold assertion that gas hydrates, long a curiosity of physical chemists, should occur in nature. Since then, the U.S. Geological Survey (USGS) and others have built a strong scientific foundation supporting the conclusion

that gas hydrates are a global phenomenon containing potentially huge volumes of gas in terrestrial polar regions and the deep-water portions of most continental margins. Gas hydrates are naturally occurring, ice-like solids in which water molecules trap gas molecules in a cage-like structure known as a clathrate. Although many gases form hydrates in nature, methane hydrate is by far the most common. In 1995, the USGS conducted the first systematic assessment of the in-place natural gas hydrate resources of the United States (Collett, 1995). That study suggests that the amount of gas in the Nation's hydrate accumulations greatly exceeds the volume of known conventional domestic gas resources. The 1995 USGS assessment also estimated that the permafrost-associated gas hydrates on the Alaska North Slope may contain as much as 590 trillion cubic feet (TCF) of in-place gas. Two large gas hydrate accumulations have been identified in the Prudhoe Bay area. The in-place volume of gas estimated within the known gas hydrates in the greater Prudhoe Bay area infrastructure area alone may exceed 100 TCF (Collett, 2002). However, it is important to note that none of the previously published gas hydrate assessments have predicted how much gas could actually be produced from the gas hydrate accumulations in northern Alaska.

In recognition of the importance of gas hydrates as a potential energy resource, the USGS and the U.S. Bureau of Land Management (BLM) entered into an Assistance Agreement in 2002 to assess the volume of gas that could be produced from gas hydrates in northern Alaska. The primary objective of this assessment was to conduct a geology-based analysis of the occurrence of gas hydrates within northern Alaska to determine the role gas hydrate may play as a future domestic-energy resource. This project included three concurrent phases. Phase I focused on the Eileen gas hydrate occurrences in the greater Prudhoe Bay area (fig. 1A–B). Phase II dealt with identifying and characterizing potential gas hydrate accumulations on federally-managed lands in National Petroleum Reserve in Alaska (NPRA) and Arctic National Wildlife Refuge (ANWR), and on lands managed by the State of Alaska between the Colville and Canning Rivers (fig. 1A–B). Phase III entailed a systematic, geology-based appraisal of the volume of gas that can be technically produced from gas hydrates on the North Slope.

Figure 1. A, generalized geographic map of the Alaska North Slope showing the location of coastline, rivers, lakes, major political boundaries, villages, pipelines, and other features. B, map of the physiographic provinces and major tectonic features of the Alaska North Slope (modified from Collett, 1993, 2002). (NPRA, National Petroleum Reserve in Alaska; ANWR, Arctic National Wildlife refuge; TAPS, Trans Alaska Pipeline System)

Figure 1. A, generalized geographic map of the Alaska North Slope showing the location of coastline, rivers, lakes, major political boundaries, villages, pipelines, and other features. B, map of the physiographic provinces and major tectonic features of the Alaska North Slope (modified from Collett, 1993, 2002). (NPRA, National Petroleum Reserve in Alaska; ANWR, Arctic National Wildlife refuge; TAPS, Trans Alaska Pipeline System)—Continued

This report provides a comprehensive review of the USGS assessment of the undiscovered, technically recoverable gas hydrate resources on the Alaska North Slope. This report begins with a review of the USGS assessment methodology used in this study, which is followed by a discussion of what gas hydrates are and a description of some of their more important physical properties. The concept of the gas hydrate petroleum system is introduced, followed by a review of the geologic controls that affect the formation and presence of gas hydrates in northern Alaska. This report also includes a detailed review of the results of gas hydrate-production testing and modeling in Alaska and other comparable settings. The main body of this report deals with the actual Alaska North Slope assessment input requirements and results.

2. USGS Oil and Gas Assessment Methodology

For the first time, the USGS has assessed gas hydrates, a traditionally unconventional resource with no confirmed production history, as a producible resource occurring in discrete hydrocarbon traps and structures. The approach used in this assessment of gas hydrate resources in northern Alaska followed standard geology-based USGS methodologies developed to assess conventional oil and gas resources (fig. 2) (Schmoker and Charpentier, 2005; Schmoker and Klett, 2005). Conventional accumulations, as recognized by the USGS for the purpose of resource assessment, are defined by two geologic characteristics: (1) they occupy limited, discrete volumes of rock bounded by traps, seals, and downdip water contacts, and (2) they depend upon the buoyancy of oil or gas in water for their existence. In applying the USGS

conventional assessment approach on gas hydrate resources, downhole log data from wells and three-dimensional, industry-acquired seismic data were analyzed, with the results showing that gas hydrates on the North Slope occupy discrete hydrocarbon reservoirs, most of which are bounded by faults and downdip water contacts (as discussed in the “Alaska North Slope Gas Hydrate Petroleum System” section).

The USGS conventional assessment methodology is built on the geologic elements used to define a Total Petroleum System (TPS), including hydrocarbon source rocks (source-rock type and maturation and hydrocarbon generation and migration), reservoir rocks (sequence stratigraphy, petrophysical properties, and seismic attribute development), and hydrocarbon traps (trap formation and timing). In this approach, the subdivisions of a TPS, termed “assessment units” (AU), are the basic level of the assessment. In most cases, a TPS consists of all genetically related hydrocarbons generated from the same source rock. In the case of this assessment, each AU was defined mostly on the similarities of the gas hydrate-bearing rocks. Detailed framework studies in stratigraphy and structural geology and the analysis of petroleum geochemistry, combined with historical exploration results, were used to define three gas hydrate AUs in northern Alaska, as described later in the section “Northern Alaska Gas Hydrate Total Petroleum System and Assessment Units.”

The USGS assessment methodology (fig. 2) also requires estimates of the number and sizes of undiscovered accumulations, for which the technically recoverable resources are then calculated by statistically combining the probability distributions of the estimated number and sizes of the undiscovered accumulations, along with associated risks. The techniques used to estimate the number and sizes of undiscovered gas hydrate accumulations in northern Alaska are discussed in the following sections of

Figure 2. Flow diagram showing key steps in the USGS assessment model for undiscovered conventional oil and gas accumulations. Modified from Schmoker and Klett (2005).

this report: “Undiscovered Gas Hydrate Accumulations—Sizes of Accumulations” and “Undiscovered Gas Hydrate Accumulations—Number of Accumulations.” Within the USGS assessment methodology, probabilistic estimates are given for the amount of technically recoverable resources in the hydrocarbon accumulations. In most cases the production histories from existing wells in the assessment unit or from analog settings are used to estimate the relative percent of hydrocarbon that will be recovered from an accumulation. For gas hydrates, however, there are no established production histories to draw upon. In this assessment, data from limited field testing and numerical production modeling were used to establish the expected production characteristics of gas hydrate-bearing reservoirs, as discussed in the section “Gas Hydrate Production Analysis.”

For the purpose of the USGS assessment model, undiscovered petroleum is that which is postulated from geologic knowledge and theory to exist outside of known accumulations. For this gas assessment, it was decided to consider all of the gas hydrate accumulations on the Alaska North Slope as undiscovered because none of the well-log- and seismic-inferred gas hydrate accumulations have established production histories.

3. Gas Hydrate Technical Review

Gas hydrates are naturally occurring “ice-like” combinations of natural gas and water that have the potential to provide an immense resource of natural gas from the world’s oceans and polar regions. Gas hydrates are known to be widespread in permafrost regions and beneath the sea in sediments of outer continental margins. It is generally accepted that the volume of natural gas contained in the world’s gas hydrate accumulations greatly exceeds that of known gas reserves (Collett, 2002). There is also growing evidence that natural gas can be produced from gas hydrates with existing conventional oil and gas production technology (Anderson and others, 2008, Dallimore and others, 2008a, 2008b; Yamamoto and Dallimore, 2008; Moridis and others, 2009).

Gas hydrates are crystalline compounds that result from the three-dimensional stacking of “cages” of hydrogen-bonded water molecules. Generally, each cage can hold a single gas molecule. The empty cagework is unstable, and requires the presence of encapsulated gas molecules to stabilize the clathrate crystal. The compact nature of the hydrate structure makes for highly effective packing of gas. A volume of gas hydrate expands between 150- and 180-fold when released in gaseous form at standard pressure and temperature (14.696 pounds per square inch (psi), 68°F).

Clathrate hydrates can form in the presence of gas molecules over the size range of 4.8–9.0 angstroms. Three distinct structural types can form depending on the size of the largest guest molecules that can be included in the clathrate

cage of water molecules. There are considerable complexities in the structure-size relation; however, methane and ethane individually form Structure I (sI) hydrate, but in certain combinations also form Structure II (sII) hydrate. Propane and isobutane form sII hydrate, either individually or in combination with ethane and methane. Normal-butane and neopentane form sII hydrate only when methane is present as well, and larger hydrocarbon molecules (C5–C9) form Structure H (sH) hydrate, again where methane is present.

On a macroscopic level, many of the mechanical properties of gas hydrates resemble those of ice because hydrates contain about 85 percent water on a molar basis. For a complete description of the structure and physical properties of gas hydrates, see the summary by Sloan and Koh (2008).

4. Alaska North Slope Gas Hydrate Petroleum System

In recent years, the concept of a gas hydrate petroleum system, similar to the concept that guides conventional oil and gas exploration, has gained acceptance (Collett and others, 2009). In a gas hydrate petroleum system, the individual factors that contribute to the formation of gas hydrate can be identified and assessed; the most important include (1) gas hydrate pressure-temperature stability conditions, (2) suitable host sediment or “reservoir,” (3) gas source, and (4) gas migration. In the following discussion, these geologic controls on the stability and formation of gas hydrate deposits in northern Alaska are reviewed and evaluated.

4.a. Gas Hydrate Stability Conditions

Gas hydrates exist under a limited range of temperature and pressure conditions, such that the depth and thickness of the zone of potential gas hydrate stability can be calculated given information on formation temperatures, pore-pressure gradients, and gas and formation water chemistry. Depicted in the temperature/depth plot in figure 3 are a series of subsurface temperature profiles from an onshore permafrost area and two laboratory-derived gas hydrate stability curves for different natural gases (modified from Holder and others, 1987). This gas hydrate phase diagram (fig. 3) illustrates how variations in formation temperature, pore-pressure, and gas composition can affect the thickness of the gas hydrate stability zone. In this example, the mean annual surface temperature is assumed to be 14°F (–10°C); and the depth to the base of permafrost (32°F; 0°C isotherm) is varied for three example temperature profiles, at permafrost depths of 1,000 feet (ft) (305 meters (m)), 2,000 ft (610 m), and 3,000 ft (914 m). Below permafrost, three different example geothermal gradients of 2.19°F/100 ft (4.0°C/100 m), 1.76°F/100 ft (3.2°C/100 m), and 1.10°F/100 ft (2.0°C/100 m) are used to project the sub-permafrost temperature profiles.

Figure 3. Gas hydrate phase diagram showing the depth and temperature conditions suitable for the formation of gas hydrate under various conditions of permafrost depth, geothermal gradient, gas chemistry, and a pore-pressure gradient of 0.433 psi/ft (9.795 kPa/m). Modified from Holder and others (1987). (psi/ft, pounds per square inch per foot; kPa/m, kilopascals per meter)

The two gas hydrate stability curves represent gas hydrates with different gas chemistries: one with 100 percent methane hydrate, and the other with 98 percent methane, 1.5 percent ethane, and 0.5 percent propane. The phase diagram (fig. 3) is constructed assuming a hydrostatic pore-pressure gradient of 0.433 pounds per square inch per foot (psi/ft) (9.795 kilopascals per meter (kPa/m)).

The zone of potential gas hydrate stability in the phase diagram (fig. 3) lies within the depths between the two intersections of the geothermal gradient and the gas hydrate stability curve. For example, in figure 3, the temperature profile projected to an assumed permafrost base of 2,000 ft (610 m) intersects the 100-percent methane-hydrate stability curve at about 656 ft (200 m), thus marking the upper boundary of the methane-hydrate stability zone. A geothermal gradient

of 2.19°F/100 ft (4.0°C/100 m) projected from the base of permafrost at 2,000 ft (610 m) intersects the 100-percent methane-hydrate stability curve at about 3,609 ft (1,100 m); thus, the zone of potential methane-hydrate stability is approximately 2,953 ft (900 m) thick. However, if permafrost is extended to a depth of 3,000 ft (914 m) and if the geothermal gradient below permafrost is 1.10°F/100 ft (2.0°C/100 m), the zone of potential methane-hydrate stability would be approximately 6,890 ft (2,100 m) thick.

Most gas hydrate stability studies assume a hydrostatic pore-pressure gradient (see Collett, 2002). Pore-pressure gradients greater than hydrostatic conditions correspond to higher pore-pressures with depth and a thicker gas hydrate stability zone, whereas a pore-pressure gradient less than hydrostatic corresponds to a thinner gas hydrate stability zone.

The gas hydrate stability curves in figure 3 were obtained from laboratory data published by Holder and others (1987). The addition of 1.5 percent ethane and 0.5 percent propane to the pure methane gas system shifts the stability curve to the right, thus deepening the zone of potential gas hydrate stability. It is well known that dissolved salt can depress the freezing-point of water. Where present in a gas hydrate system, salt (such as NaCl) also lowers the temperature at which gas hydrates form.

Collett and others (1988) and Collett (1993) included extensive analyses of gas hydrate stability conditions in northern Alaska. In support of the present assessment, Lee and others (2008) also used log data from wells drilled since these earlier studies for updating the permafrost (fig. 4) and methane hydrate stability maps (fig. 5A–C; table 1) in northern Alaska as reviewed below.

On the North Slope, the subsurface temperature data needed to assess the distribution of the gas hydrate stability zone are provided by high-resolution, equilibrated well-bore surveys in 46 wells and from well-log estimates of the base of ice-bearing permafrost in 102 other wells (Collett, 1993). Beginning in 1958, a series of 46 North Slope wells, considered to be in or near thermal equilibrium, have been surveyed with high-resolution temperature devices (Lachenbruch and others, 1987; Lee and others, 2008). Geothermal gradients, which are needed to predict the depth and thickness of the gas hydrate stability zone, can be interpreted directly from these equilibrated temperature profiles. However, specific evaluation of subsurface temperatures at any one particular site on the North Slope is subject to error because of the vastness of the region and the limited number of equilibrated well-bore temperature surveys. To augment the limited North Slope temperature database, Collett and others (1988) developed a new method to evaluate local geothermal gradients.

In this method, well-log picks for the base of the ice-bearing permafrost from 102 wells (fig. 4) were combined with regional temperature constants derived from the high-resolution surveys to extrapolate temperature data. The comparison of geothermal gradients calculated from the high-resolution temperature surveys and projected from known ice-bearing permafrost depths are similar over most of the North Slope, with gradient values in the ice-bearing sequence ranging from about 0.82°F/100 ft (1.5°C/100 m) in the Prudhoe Bay area to about 2.47°F/100 ft (4.5°C/100 m) in the National Petroleum Reserve in Alaska (NPRA). The calculated and projected geothermal gradients from below the ice-bearing sequence range from about 0.88°F/100 ft (1.6°C/100 m) to about 2.85°F/100 ft (5.2°C/100 m).

Subsurface pore-pressure gradients calculated from shut-in pressures recorded during drill-stem testing in wells from the North Slope range from 0.41 to 0.50 psi/ft (9.3 to 11.2 kPa/m), with an average gradient of 0.43 psi/ft (9.7 kPa/m), near hydrostatic (Collett and others, 1988). To further evaluate pore-pressure conditions, Collett (1993)

used gamma ray and density well logs to study overburden compaction profiles. Within the near-surface (0–5,000 ft; 0–1,524 m) sediments of the North Slope, no significant pore-pressure discontinuities were observed. Thus, a hydrostatic pore-pressure gradient (0.433 psi/ft; 9.795 kPa/m) is generally assumed when considering gas hydrate stability conditions in northern Alaska.

Most of the previous studies of gas hydrate stability conditions in northern Alaska have assumed a pure methane chemistry for the gas being included in the gas hydrate structure (Collett, 1995). The analysis of mud-log gas-chromatographic data from industry exploratory wells generally indicates that methane is the dominant hydrocarbon gas in the near-surface (0–5,000 ft) sedimentary rocks of the North Slope (Collett and others, 1988). Analysis of gas evolved from recovered cored gas hydrate-bearing sedimentary sections in the Prudhoe Bay and Milne Point fields confirm that the *in-situ* gas hydrates are composed mostly of methane in this portion of the North Slope (Collett, 1993; Lorenson and others, 2011).

Pore-water salinity data within the near-surface sediments of the North Slope are available from petroleum production tests, water samples from cores within and below permafrost, and spontaneous potential well-log calculations. These data indicate that the pore-water salinities within the sands both above and below the ice-bearing permafrost section are low, ranging from <1.0 parts per thousand (ppt) to as high as 19 ppt (Collett and others, 1988). Analysis of core-derived pore waters from the Mount Elbert well (discussed later in this report) also confirm the presence of low-salinity pore water, with an average background concentration around 5.0 ppt. The updated gas hydrate stability calculations in Lee and others (2008) for northern Alaska were made assuming a pore-water salinity of 5.0 ppt.

The methane-hydrate stability zone in northern Alaska, as mapped in figures 5A–C (modified from Collett, 1993), covers most of the North Slope. The offshore extent of the gas hydrate stability zone is not well established. Geologic studies (for example Molochushkin, 1978) and thermal modeling of subsea conditions (Osterkamp and Fei, 1993) indicate that permafrost and gas hydrate may exist within the continental shelf of the Arctic Ocean. Subaerial emergence of portions of the Arctic continental shelf to current water depths of roughly 400 ft (roughly 122 m) (Bard and Fairbanks, 1990) during repeated Pleistocene glaciations subjected the exposed shelf to temperature conditions favorable to the formation of permafrost and gas hydrate. Thus, it is speculated that “relict” permafrost and gas hydrate may exist on the continental shelf of the Arctic Ocean to present water depths of 400 ft (roughly 122 m). For this assessment, we assumed the model-derived predictions of permafrost and gas hydrate stability conditions to be accurate and that the offshore limit of the nearshore permafrost-associated gas hydrate stability conditions as depicted in figures 5A–C for the most part corresponds to the 400-ft (roughly 122 m) bathymetric contour.

Figure 4. Map showing the depth to base of permafrost on the Alaska North Slope as determined from equilibrated well-bore temperature surveys in 46 wells (table 1; Lee and others, 2008). Well-log estimates for the base of ice-bearing permafrost in 102 other wells (Collett, 1993) were also used to draw the map contours. Contours in feet (ft). (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 5. Maps of the Alaska North Slope gas hydrate stability zone (modified from Collett and others, 1988): *A*, depth to the top of the hydrate stability zone; *B*, depth to base of the hydrate stability zone; *C*, thickness of the hydrate stability zone. Contours in feet (ft). (NPRA, Natural Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 5. Maps of the Alaska North Slope gas hydrate stability zone (modified from Collett and others, 1988): A, depth to the top of the hydrate stability zone; B, depth to base of the hydrate stability zone; C, thickness of the hydrate stability zone. Contours in feet (ft). (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)—Continued

Figure 5. Maps of the Alaska North Slope gas hydrate stability zone (modified from Collett and others, 1988): *A*, depth to the top of the hydrate stability zone; *B*, depth to base of the hydrate stability zone; *C*, thickness of the hydrate stability zone. Contours in feet (ft). (NPRA, Natural Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)—Continued

Table 1. List of Alaska North Slope wells with equilibrated borehole temperature surveys along with the estimated depth of the base of permafrost (0°C) and the depth to the top (THSZ) and base (BHSZ) of the gas hydrate stability zone. Also listed is the estimated thickness (isopach) of the gas hydrate stability zone (HSZ) (modified from Lee and others, 2008).

[API, American Petroleum Institute; m, meters; ft, feet]

API	Common well name	Latitude	Longitude	Depth (m) to 0°C	Depth (ft) to 0°C	Depth (m) to THSZ	Depth (ft) to THSZ	Depth (m) to BHSZ	Depth (ft) to BHSZ	Thickness (m) HSZ	Thickness (ft) HSZ
50301200010000	US TUNALIK #1	70.2062	161.0687	270	886	258	845	320	1,050	62	204
50301200020000	US PEARD #1	70.7156	158.9999	300	984	248	814	557	1,827	309	1,014
50163200020000	HU KUGRUA #1	70.5866	158.6617	270	886	259	849	390	1,278	131	429
50163200010000	US SO MEADE #1	70.6147	156.8834	200	656	-	-	-	-	-	-
50023100110000	US SO BARROW #3	71.1652	156.5811	380	1,247	232	761	578	1,896	346	1,135
50163200030000	US KUYANAK #1	70.9314	156.0368	320	1,050	233	763	500	1,640	267	877
50023200180000	US TULAGEAK 1	71.1885	155.7329	290	951	250	819	388	1,272	138	453
50023200140000	US WEST DEASE #1	71.1594	155.6296	270	886	257	842	352	1,155	96	313
50279200050000	US E SIMPSON 1	70.9178	154.6180	360	1,181	228	748	556	1,824	328	1,076
50279200040000	HU IKPIKPUK 1	70.4555	154.3322	330	1,083	243	796	652	2,139	409	1,343
50279200020000	HU DREW POINT 1	70.8794	153.8997	320	1,050	232	761	460	1,509	228	748
50279200060000	US J W DALTON 1	70.9209	153.1380	400	1,312	213	700	604	1,982	391	1,282
50103200060000	HU E TESHEKPUK 1	70.5700	152.9447	250	820	-	-	-	-	-	-
50103200170000	US NORTH INIGOK 1	70.2576	152.7660	275	902	258	845	380	1,247	122	402
50103200110000	US NORTH KALIKPIK 1	70.5092	152.3668	210	689	-	-	-	-	-	-
50103200090000	HU WEST FISH CREEK 1	70.3267	152.0597	260	853	-	-	-	-	-	-
50103200070000	HU S HARRISON BAY 1	70.4245	151.7310	380	1,247	225	737	530	1,739	305	1,002
50103200080000	HU ATIGARU PT 1	70.5561	151.7160	400	1,312	217	711	541	1,775	324	1,064
50029202750000	WEST SAK 11	70.3569	149.9908	465	1,526	216	709	747	2,449	530	1,740
50029204190000	SO WEST SAK 14	70.2935	149.9515	465	1,526	215	705	741	2,431	526	1,726
50029205410000	WEST SAK 16	70.4433	149.9483	535	1,755	212	694	845	2,772	633	2,078
50029205420000	SO WEST SAK 17	70.4463	149.7237	550	1,804	210	689	850	2,789	640	2,100
50029200900000	AR WEST SAK RIVER ST 1	70.3397	149.5372	550	1,804	212	694	800	2,625	588	1,930
50029215040000	MPU C-19	70.4915	149.5245	525	1,722	215	705	850	2,789	635	2,083
50029209000000	MPU D-2	70.4905	149.4526	560	1,837	216	709	874	2,867	658	2,159
50029205730000	MO KUPARUK 1	70.3020	149.4169	570	1,870	215	705	857	2,812	642	2,106
50029200130000	AT NW EILEEN ST 1	70.3659	149.3559	530	1,739	207	679	860	2,822	653	2,142
50029201990000	AT HIGHLAND ST 1	70.2869	149.2181	575	1,886	210	689	908	2,979	698	2,290
50029200790000	PUT RIVER N-1: 08-11-13	70.3186	148.9097	615	2,018	209	687	1,019	3,343	810	2,656
50029200250000	PUT RIVER J-3:04-11-13	70.3300	148.8467	635	2,083	209	684	1,063	3,488	855	2,803
50029200470000	PUT RIVER 33-12-13	70.3561	148.8350	650	2,133	206	674	1,180	3,871	975	3,197
50029200840000	PUT RIVER F-2-11-11-13	70.3347	148.7669	630	2,067	216	709	1,048	3,438	832	2,729
50029200850000	PUT RIVER F-3-12-11-13	70.3353	148.7644	630	2,067	229	752	1,105	3,625	876	2,873
50029200540000	PUT RIVER 23-11-13	70.2944	148.7525	540	1,772	210	688	1,065	3,494	855	2,806
50029200590000	PUT RIVER 31-11-14	70.2683	148.6733	640	2,100	210	687	1,085	3,560	876	2,872
50029200060000	PUT RIVER 27-11-14	70.2783	148.5656	615	2,018	211	693	1,050	3,445	839	2,752
50029200490000	NORTH PRUDHOE BAY STATE 1	70.3764	148.5250	596	1,955	206	676	1,057	3,468	851	2,792
50029200350000	PUT RIVER 19-10-15	70.2117	148.4125	585	1,919	218	715	1,048	3,438	830	2,723
50029201330000	EAST BAY STATE #1	70.3106	148.3161	620	2,034	211	691	1,130	3,707	919	3,016
50029200300000	SAG DELTA 31-10-16	70.1822	148.1581	590	1,936	224	734	1,010	3,314	786	2,580
50155200010000	US AWUNA #1	69.1532	158.0214	236	774	264	865	468	1,535	204	670
50137200030000	US LISBURNE #1	68.4863	155.6935	264	866	264	866	783	2,569	519	1,703
50119200010000	US KOLUKTAK 1	69.7524	154.6111	280	919	257	843	540	1,772	283	928
50287200070000	US SEABEE 1	69.3801	152.1753	300	984	258	845	1,070	3,510	812	2,665
50287100180000	BP KUPARUK 1	69.3044	150.8093	265	869	262	860	595	1,952	333	1,093
50223200110000	FO LUPINE 1	69.1009	148.6193	220	722	337	1,106	660	2,165	323	1,060
50223200080000	MO ECHOOKA 1	69.4002	148.2680	265	869	263	864	787	2,582	524	1,719

4.b. Reservoir Rocks

The study of gas hydrate samples indicates that the physical nature of *in-situ* gas hydrates is highly variable (reviewed by Sloan and Koh, 2008). Gas hydrates are observed as (1) occupying pores of coarse-grained sediment; (2) nodules disseminated within fine-grained sediment; (3) a solid substance, filling fractures; or (4) a massive unit composed mainly of solid gas hydrate with minor amounts of sediment. However, most gas hydrate field expeditions have shown that the occurrence of concentrated gas hydrate is mostly controlled by the presence of fractures and (or) coarse-grained sediments in which gas hydrate fills fractures or is disseminated in the pores of sand-rich reservoirs (Collett, 1993; Dallimore and Collett, 2005; Riedel and others, 2006; Collett and others, 2008a, 2008b; Park and others, 2008; Yang and others, 2008). Torres and others, (2008) concluded that hydrate accumulates preferentially in coarse-grained sediments because lower capillary pressures in these sediments permit the migration of gas and nucleation of hydrate. The growth of gas hydrate in clay-rich sediments, however, is less understood. Because high concentrations of gas hydrates in arctic permafrost regions are in sand-dominated reservoirs, such lithologic units have been the focus of gas hydrate exploration and production studies in northern Alaska. Production testing and modeling have also shown that concentrated gas hydrate in sand reservoirs is conducive to existing well-based production technologies (Anderson and others, 2008; Dallimore and others, 2008a, 2008b; Moridis and others, 2009; Yamamoto and Dallimore, 2008).

The northern Alaska oil and gas province extends 600 miles (mi) from the Chukchi Sea on the west to the Canadian border on the east (figs. 1A–B); maximum width is about 200 mi and total area is about 54,000 square miles (mi²). The geology and petroleum geochemistry of rocks on the North Slope of Alaska are described in considerable detail in a number of publications (Lerand, 1973; Grantz and others, 1975; Carman and Hardwick, 1983; Bird and Magoon, 1987; Gryc, 1988; Bird, 1998; Mull and others, 2003). The sedimentary rocks of the North Slope can be conveniently grouped into four sequences representing major episodes in the tectonic development of the region and, to a degree, reflecting its lithologic character. Defined on the basis of source area, these sequences (proposed by Lerand (1973) and applied to northern Alaska by Grantz and others (1975) and modified by Hubbard and others (1987)) are, in ascending order, the Franklinian (Cambrian through Devonian), the Ellesmerian (Mississippian to Jurassic), Beaufortian (Jurassic through Lower Cretaceous), and the Brookian (Cretaceous to Holocene). All of the known and inferred gas hydrate occurrences on the North Slope are in Cretaceous and Tertiary reservoirs of the Brookian sequence (fig. 6), which are the focus of the following discussions on the geologic history of northern Alaska.

Before the recent completion of coring and downhole-logging operations in the BPXA-DOE-USGS Mount Elbert Gas Hydrate Stratigraphic Test Well in the Milne Point field (Hunter and others, 2011), the only direct confirmation of gas hydrate on the North Slope was obtained in 1972 with data from the ARCO-Exxon Northwest Eileen State-2 well, located in the northwest part of the Prudhoe Bay field. Studies of pressurized core samples, downhole logs, and the results of formation-production testing confirmed the presence of three gas hydrate-bearing stratigraphic units in the Northwest Eileen State-2 well (fig. 7) (Collett, 1993). The gas hydrate-bearing core in the Northwest Eileen State-2 well was recovered from a depth of 2,156 ft (657 m). The well was drilled with chilled drilling muds in an attempt to reduce thawing of permafrost and decomposition of the *in-situ* gas hydrate that might exist. A pressure-core system was also used to recover core samples at near *in-situ* conditions in order to reduce core disturbance attributed to gas hydrate dissociation. The presence of gas hydrate in the recovered core was confirmed by a pressure test as described by Hunt (1979, p. 167).

The confirmed gas hydrate occurrence in the Northwest Eileen State-2 well provided an ideal starting point for the development of gas hydrate well-log evaluation techniques (fig. 7). Numerous studies since this early work, including Collett (1993), have shown that in most cases only two well-logging devices are used to identify potential gas hydrates: they are the electrical resistivity and acoustic transit-time logs. For the most part, a gas hydrate-bearing sand reservoir is characterized by relatively high electrical resistivities and rapid acoustic transit times in comparison to water-saturated sands. However, resistivity and acoustic logs behave similarly within a sedimentary section that is saturated with either gas hydrate or ice. Hence, gas shows on the mud log produced from decomposing hydrate generally provide the only means of conclusively differentiating a gas hydrate from ice in Arctic permafrost regions.

Collett (1993) examined well-log data from 445 wells for evidence of gas hydrate based on the well-log responses observed in the Northwest Eileen State-2 well. Most of the wells were located in the greater Prudhoe Bay area; however, all wells in NPRA and most of the exploratory wells to the south and east of Prudhoe Bay were reviewed. Since this earlier work, Lee and others (2008) and Inks and others (2009) examined the well-log data from about 200 additional exploratory and development wells for the presence of gas hydrate. These well-log-based studies revealed the occurrence of two large gas hydrate accumulations, which have been named the Eileen and Tarn gas hydrate accumulations.

The Eileen gas hydrate accumulation was first described by Collett (1993) as six laterally continuous gas hydrate-bearing sandstone units, each of which has been assigned a reference letter (A–F, in ascending order; fig. 8). Many of the wells that penetrated the Eileen accumulation have multiple gas hydrate-bearing units, with individual units ranging from 10 to 100 ft (3 to 30 m) thick. All of the wells are geographically restricted to the area overlying the eastern

Figure 7. A, downhole logs from the Northwest Eileen State-2 well depicting the depth of units B, C, D, and E; data shown include the natural gamma ray log, bulk-density, neutron porosity, acoustic velocity, and electrical resistivity data. B, insert of well logs from the cored gas hydrate interval (unit C) in the Northwest Eileen State-2 well. Data shown include well logs and methane (CH₄) mud-log curve. See figure 9 for well location.

Figure 8. Well log cross section showing the lateral and vertical extent of the Eileen and Tarn gas hydrate accumulations and the associated underlying free-gas zones in the Prudhoe Bay and Kuparuk River oil fields. See figure 9 for the location of the cross section. The gas hydrate-bearing units in the Eileen accumulation are identified with the reference letters A through F. The numbered solid lines are log correlation markers used to construct a regional stratigraphic framework (modified from Collett, 1993). The gas hydrate-bearing portions of units A and B in the Eileen accumulation are shown as ending above the base of the gas hydrate stability zone, which is correct along the path of this southwest- to northeast-trending cross section. However, to the east and south from the Kuparuk River field into the Prudhoe Bay field, units A and B gas hydrates extend to the base of the gas hydrate stability zone and trap free-gas in a downdip position.

part of the Kuparuk River field, the southern part of the Milne Point field, and the western part of the Prudhoe Bay field (figs. 8, 9). The lateral boundaries of the gas hydrate-bearing units as mapped by Collett (1993) are based in many places on widely-spaced well control and therefore are open to interpretation and further refinement. Also, the lateral continuity of gas hydrate occurrences between well sites is still poorly defined, but recent 3D seismic prospecting in the Milne Point area by Inks and others (2009) has provided additional insight to the lateral nature and extent of the well-log-inferred gas hydrate-bearing units in the Eileen accumulation (discussed in a later section). It is also important to emphasize that seismic surveys (reviewed by Lee and others, 2009; Inks and others, 2009) and downhole logs (Collett, 1993) from wells in the western part of the Prudhoe Bay field indicate the presence of several large free-gas accumulations trapped stratigraphically downdip below five (units A–E) of the log-inferred gas hydrates. The total mapped area of all six gas hydrate-units in the Eileen accumulation is about 635 mi²; the areal extent of individual units ranges from 1 to 155 mi² (fig. 9). Collett (1993) estimated the total volume of gas within these accumulations at about 35.3 to 42.4 TCF.

Collett (1993) concluded that the Eileen gas hydrate accumulation is in rocks of the Mikkelsen Tongue of the Canning Formation, which were deposited during a basinwide marine transgression in the Eocene. This sequence (which is mostly marine) thins southwesterly and coarsens laterally into a sand-rich sequence in the western part of the Prudhoe Bay field. Analysis of drilling cuttings (Collett, 1993) and core from the Mount Elbert well (Rose and others, 2011) indicates that the gas hydrate-bearing reservoirs in the Eileen accumulation consist mostly of fine-grained to very fine-grained sands and coarse silts with minor amounts of interbedded coarse sands, conglomerates, and shales deposited in a range of nearshore marine and nonmarine environments. Considering the sand-rich nature of the section at the site of the Mount Elbert well, the interval containing the Eileen gas hydrate-bearing sands are now assigned to the Sagavanirktok Formation (fig. 6; Molenaar and others, 1987b; Bird, 1998; Rose and others, 2011) and are considered the age equivalent of the more distal early Eocene marine shales and minor sands of the Mikkelsen Tongue of the Canning Formation further to the east.

In February of 1992, while drilling the Cirque-1 well near the western edge of the Kuparuk River field, a shallow gas zone (depth of about 2,330 ft; 710 m) was encountered that subsequently blew out the well (Alaska Oil and Gas Conservation Commission, 1992). It was later determined that the well also encountered a thick gas hydrate-bearing interval that contributed to the gas flow problem (Collett and Dallimore, 2002). Subsequent drilling of the Cirque-2 well confirmed the occurrence of gas hydrates near the base of permafrost within the depth interval of about 820 ft to 1,150 ft (250–350 m) (Collett and Dallimore, 2002).

Downhole log data from industry exploratory and development wells located along the western margin of the Kuparuk River field, tied to the well-log responses in the Cirque-2 well, reveal a large gas hydrate accumulation that has been named the Tarn gas hydrate accumulation (Collett, 1993; figs. 8, 9). As shown in figure 9, the Tarn gas hydrate accumulation lies in a fairway extending from the Till-1 well in the north, through the Cirque-Tarn area, to near the North Meltwater field to the south. The gas hydrate-bearing stratigraphic interval in the Tarn area appears to be the updip equivalent of the informally named West Sak sands, which are estimated to contain more than 20 billion barrels of in-place viscous oil and are the focus of development activity in a downdip position to the east of the Tarn gas hydrate accumulation (Werner, 1987). Preliminary analyses of other recently completed wells along the western margin of the Kuparuk River field indicate that the Tarn gas hydrate accumulation may be larger than the Eileen accumulation; however, the Tarn accumulation lies mostly within permafrost unlike the Eileen accumulation, which straddles the base of permafrost.

In 2003, the USGS initiated a study to develop seismic interpretive methods to identify and characterize gas hydrate accumulations and to further characterize the nature of hydrate-bearing reservoirs on the Alaska North Slope. This study dealt primarily with the analysis of a 3D seismic data set from the area of the Milne Point field as provided to the USGS by BP Exploration Alaska, Inc. (figs. 9, 10). Detailed analysis and interpretation of available 3D and 2D seismic data sets, along with seismic modeling and correlation with specially processed downhole well-log data, have led to the development of a viable method for identifying sub-permafrost gas hydrate prospects within the gas hydrate stability zone in the Milne Point area (Lee and others, 2009, 2011; Inks and others, 2009).

Initial seismic interpretation indicated a range of potential gas hydrate prospects, including accumulations at the base of the gas hydrate stability zone (in contact with underlying free gas) and additional hydrate prospects higher in the stratigraphic section. However, well-log data showed that the gas hydrate and free gas saturations in these deeper reservoirs were low due to leaky seals or inadequate charge (Inks and others, 2009). In 2005, the USGS project team completed their delineation, description, and ranking (including probabilistic volumetrics) of 14 gas hydrate prospects (fig. 10) within the Milne Point area. The seismic characterization of the gas hydrate prospects was based on rock physics relations calibrated with downhole log data from nearby offset wells; this enabled the prediction of gas hydrate “pay” thickness and gas hydrate saturation from analyses of seismic amplitudes and peak-trough travel-times (Lee and others, 2009).

The highest ranked Milne Point gas hydrate prospect, named Mount Elbert, is depicted in figures 10 and 11. The pre-drill site evaluation predicted that Mount Elbert would contain roughly 145 BCF (billion cubic feet) of in-place gas

Figure 9. Map of the Eileen and Tarn gas hydrate accumulations overlying portions of the Prudhoe Bay, Kuparuk River, and Milne Point oil fields (modified from Collett, 1993). Also shown are the locations of the Northwest Eileen State-2 (NWEIL), Mount Elbert and Hot Ice gas hydrate research wells and the well log cross-section A-B in figure 8, along with the outline of the Milne Point 3D seismic volume used to identify and map gas hydrate prospects.

in two reservoir sands (units C and D after Collett, 1993) (Inks and others, 2009). The Mount Elbert prospect, like all of the most promising Milne Point prospects, had not been penetrated by existing wells. Therefore, it was decided to drill a stratigraphic test well to confirm the existence of reservoirs, test the prospecting and assessment methodologies, and enable the collection of additional reservoir data to support reservoir-simulation modeling and production test design (Hunter and others, 2011). The Mount Elbert Gas Hydrate Stratigraphic Test Well was completed in February 2007 and yielded one of the most comprehensive datasets yet compiled on naturally occurring gas hydrates. The test well was designed as a 22-day program with the planned acquisition of cores, well-logs, and downhole production test data. It was first drilled and

cased to a depth of 1,952 ft (595 m), then was continuously cored to a depth of 2,494 ft (760 m). After coring, the well was surveyed with a research-level wireline-logging program including nuclear magnetic resonance and dipole acoustic logging, resistivity scanning, borehole electrical imaging, and advanced geochemistry logging (figs. 12, 13). Following logging, Schlumberger Modular Dynamic Testing (MDT) was conducted at four open-hole stations in two hydrate-bearing sandstone reservoirs (fig. 13). Each test consisted of flow and shut-in periods of varying lengths, with one lasting more than 13 hours (hr). Gas was produced from the gas hydrates in each of the tests. Gas hydrates were expected and encountered in two stratigraphic zones (figs. 12, 13): (1) an upper zone (unit D) that contained roughly 46 ft (roughly

Figure 10. Milne Point area gas hydrate prospects identified with 3-D seismic interpretation. Modified from Inks and others (2009). As a condition of the seismic data use agreement, the latitude and longitude of the seismic data and the interpreted features cannot be shown on this map.

14 m) of gas hydrate-bearing reservoir-quality sandstone, and (2) a lower zone (unit C), that contained roughly 52 ft (roughly 16 m) of gas hydrate-bearing reservoir. Both zones displayed gas hydrate saturations that varied with reservoir quality as expected, with typical values between 60 percent and 75 percent. This result conclusively demonstrated the soundness of the gas hydrate prospecting methods developed primarily by the USGS (Lee and others, 2011).

The Milne Point 3D seismic gas hydrate prospecting effort also provided a greater appreciation of the lateral nature of the well-log-inferred gas hydrate-bearing sedimentary units

in the Eileen accumulation. As reported by Collett (1993), the thickness of the well-log-inferred gas hydrate intervals in the Milne Point area range from roughly 10 to roughly 100 ft (roughly 3 to roughly 30 m). However, the nature of the gas hydrate occurrences between wells is poorly constrained. Collett (1993) assumed that the deposits were laterally continuous and were representative of hydrate occurrences throughout the Eileen accumulation. The Milne Point 3-D seismic analysis, however, revealed a much more “patchy” nature, as depicted in the gas hydrate prospect map in figure 10, with individual gas hydrate prospects ranging in

Figure 11. Milne Point Mount Elbert gas hydrate prospect. Shown are a three-dimensional image of a fault-bounded, high-amplitude feature (in a pallet of colors ranging from yellow to magenta, the yellow-imaged portion contains the thickest and most concentrated gas hydrate); bounding faults (in green); and gas hydrate zones (in yellow) in nearby well penetrations as identified from geophysical log data. Modified from Inks and others (2009).

size from about 0.1 to 2.7 mi². The thickness of the seismically imaged gas hydrate occurrences in the Milne Point effort were also determined to range from roughly 30 ft (roughly 9 m) to a maximum thickness of roughly 65 ft (roughly 20m). However, Lee and others (2009, 2011) demonstrated that within the Milne Point 3D seismic data volume there is no significant seismic response to gas hydrate reservoirs less than a cut-off thickness of about 25–30 ft (about 8–9 m). This indicates the probability that the relatively thinner log-inferred gas hydrate occurrences in the Milne Point area are not being seismically imaged. It is therefore likely that gas hydrates between well sites within a given stratigraphic unit are more regionally extensive than those imaged by Inks and others (2009), but thicknesses can only be inferred from available data. The local variability in the nature of the Eileen gas hydrate accumulation is likely controlled by the components of the petroleum system (that is, reservoir, gas source, and gas migration).

The Eileen and Tarn gas hydrate accumulations clearly demonstrate the role of the reservoir in a gas hydrate petroleum system. In both cases, gas hydrate is in pores of coarse-grained sedimentary rocks. It is also clear that the accumulation of gas hydrates is limited to the zone of methane hydrate stability in northern Alaska. Of most importance for this assessment, however, is that the seismic-inferred hydrate accumulations on the Alaska North Slope occupy limited, discrete volumes of rock bounded by faults and downdip water contacts much like conventional hydrocarbon accumulations.

4.c. Gas Source and Migration

It has been shown that the availability of large quantities of hydrocarbon gas from both microbial and thermogenic sources is an important factor controlling the

Figure 12. Open-hole well logs from the cored section of the Mount Elbert gas hydrate stratigraphic test well. Modified from Hunter and others (2011).

formation and distribution of natural gas hydrates (Collett, 1993; Kvenvolden, 1993; Collett, 2002; Lorensen and others, 2011). Carbon isotope analyses indicate that the methane in many oceanic hydrates is derived from microbial sources; however, thermal sources have been observed within several hydrate deposits in the Gulf of Mexico, the Caspian Sea, the Black Sea, and onshore in the Mackenzie Delta of Canada and in northern Alaska (reviewed by Collett, 2002). Recent studies in northern Alaska (Lorensen and others, 2011) and Canada (Dallimore and Collett, 2005) have also documented the importance of thermogenic gas sources to the formation of highly concentrated gas hydrate accumulations.

Typically, not enough microbial methane is generated internally within the gas hydrate stability zone alone to account for the gas content of most gas hydrate accumulations (Kvenvolden, 1993). In addition, most gas hydrate accumulations are in sediments that have not been deeply buried or subjected to temperatures high enough to

form thermogenic gas. Thus, in most cases, the gas is likely concentrated in the hydrate stability zone by a potential combination of processes, one of which, gas migration, would appear to be the critical component within most gas hydrate petroleum systems.

In the greater Prudhoe Bay area, the Sagavanirktok Formation (fig. 6) is cut by a series of northwest-trending high-angle normal faults, generally downthrown to the east (Werner, 1987). Similar faults cut the underlying rocks in this area, suggesting a genetic linkage between the two fault systems that could provide conduits for oil and gas migration from the underlying Prudhoe Bay and Kuparuk River fields. Geochemical similarities suggest that oil and presumably the associated gas within the Sagavanirktok Formation were “spilled” from the underlying Prudhoe Bay Sadlerochit Group reservoir as a consequence of regional tilting during the middle to late Tertiary (Carman and Hardwick, 1983; Masterson and others, 2001).

Figure 13. Well-log-derived gas hydrate saturations, density porosities, and sediment permeabilities for the two gas hydrate-bearing intervals (units C and D) cored in the Mount Elbert gas hydrate stratigraphic test well (modified from Hunter and others, 2011). The intervals tested (Schlumberger Modular Dynamic Testing (MDT) Tests C1, C2, D1, and D2) are also shown. (NMR, nuclear magnetic resonance)

Geochemical analyses of drill cuttings and core samples from wells in both the Eileen and Tarn gas hydrate accumulations indicate that methane is the principal gas in these accumulations (Collett, 1993; Lorenson and others, 2011). Stable methane-carbon isotopic analyses show that the methane within the gas hydrate is likely from mixed microbial and thermogenic sources, with the apparent thermogenic methane migrating from deeper sources, including the Prudhoe Bay field. Masterson and others (2001) and Lorenson and others (2011) have shown that evaporative fractionation and biodegradation of the Sadlerochit-sourced oil in the Sagavanirktok Formation is also an important source of gas within the gas hydrates of both the Eileen and Tarn gas hydrate accumulations.

Collett (1993) adapted a generalized cross section (fig. 14) from Carman and Hardwick (1983) to describe the history of the Eileen and Tarn gas hydrate accumulations. Collett postulated that as thermogenic gas and associated oil moved up the Eileen and other fault zones and encountered the relatively porous and permeable northeast-dipping Sagavanirktok sandstone reservoir units, some of the gas may have been rechanneled updip along these beds. The updip-migrating gas

Figure 14. Schematic west to east cross section through the Prudhoe Bay and Kuparuk River fields illustrating possible gas-migration paths and spatial relations between the Eileen and Tarn gas hydrate accumulations, free-gas and oil accumulations, Eileen and other fault zones, and base of gas hydrate stability (modified from Carman and Hardwick, 1983).

may have mixed with *in-situ* microbial methane and collected in structural and stratigraphic traps where falling temperatures at the end of the Pliocene deepened the permafrost section and converted the trapped gas into gas hydrate.

As discussed above, gas hydrate in onshore Arctic environments is typically closely associated with permafrost. It is generally believed that thermal conditions conducive to the formation of permafrost and gas hydrate persisted in the Arctic since the end of the Pliocene (about 2.59 million years ago) (Collett, 1993, 2002; Lee and others, 2008). From Milne Point seismic and other studies, it also appears that most permafrost-associated gas hydrate accumulations probably developed from preexisting free-gas fields that originally formed in conventional hydrocarbon traps and were later converted to gas hydrate upon the onset of glaciation and cold Arctic conditions (Collett, 1993, 2002; Lee and others, 2009, 2011; Inks and others, 2009; Boswell and others, 2011).

5. Gas Hydrate Production Analysis

Although gas hydrates are known to occur in numerous marine and Arctic settings, until recently little was known about the technology necessary to produce gas from them. Proposed methods of gas recovery from hydrates (reviewed by Collett, 2002) generally deal with dissociating or “melting” *in-situ* gas hydrates by: (1) heating the reservoir beyond hydrate-forming temperatures, (2) injecting an inhibitor such as methanol or glycol into the reservoir to decrease hydrate stability, and (or) (3) decreasing the reservoir pressure below hydrate equilibrium. Recently, several studies have shown that it may be possible to produce methane from hydrates by displacing the methane molecule in the hydrate structure with carbon dioxide; thus releasing methane and sequestering the carbon dioxide (Graue and others, 2006). Among the possible techniques for production of natural gas from *in-situ* gas hydrates, depressurization is considered to be the most economically promising (reviewed by Collett, 2002) and is the only method of gas hydrate production considered in this assessment.

The USGS conventional assessment approach also assumes that the hydrocarbon resource being assessed can be produced by existing conventional technology. The production potential of the known and seismically-inferred gas hydrate accumulations in northern Alaska has not been adequately field tested, but has been the focus of a U.S. Department of Energy (DOE) gas hydrate production research modeling effort as reviewed by Anderson and others (2008). Although verified by only limited field testing (Dallimore and others, 2008a, 2008b; Yamamoto and Dallimore, 2008), numerical production models (for example Anderson and others, 2008) of gas hydrate-bearing reservoirs suggest that gas can be produced from gas hydrate with existing conventional technology. This conclusion is supported by a growing

body of evidence indicating that concentrated gas hydrate accumulations in conventional hydrocarbon reservoirs, such as those in northern Alaska, can be produced with existing technology.

Field studies and associated production modeling studies, such as the Mallik 2002 (Dallimore and Collett, 2005), the Mallik 2006–2008 (Dallimore and others, 2008a, 2008b; Yamamoto and Dallimore, 2008), and the Mount Elbert projects (Hunter and others, 2011) have contributed greatly to our understanding of the technologies required to produce gas hydrates. The results of the gas hydrate-testing programs in northern Canada and Alaska are discussed below, together with a review of the rapidly evolving field of gas hydrate-production simulation.

5.a. Gas Hydrate Production Testing Results

The Messoyakha field, a gas field located in the northern part of the West Siberian Basin, is commonly used as an example of a hydrocarbon accumulation from which gas has been produced from hydrates by reservoir depressurization (Makogon, 1981). Production data and other geologic information have been used to document the presence of gas hydrates within the upper part of the Messoyakha field (reviewed by Collett and Ginsburg, 1998). Long-term production from the gas hydrate part of the Messoyakha field is presumed to have been achieved by simple depressurization. As production began from the lower free-gas portion of the Messoyakha field in 1969, the measured reservoir pressures followed predicted decline relations; however, by 1971, the reservoir pressures began to deviate from expected values. This deviation has been attributed to the liberation of gas from dissociating gas hydrates. Throughout the production history of the Messoyakha field, it is estimated that about 36 percent (about 177 BCF) of the gas withdrawn from the field was from gas hydrate (Makogon and others, 1972). Glenn and Allen (1991) presented evidence that a similar phenomenon may be occurring within gas fields in the vicinity of the city of Barrow in northern Alaska. It should be noted that several later studies do not support the interpretation that gas hydrate contributes significantly to gas production in the Messoyakha field (reviewed by Collett and Ginsburg, 1998).

One of the major goals of the Mallik 2002 Gas Hydrate Production Research Well Program (Dallimore and Collett, 2005) was to advance research pertaining to gas hydrate production by undertaking a suite of well-constrained, short-term production experiments. The scientific goals of this production testing effort were to confirm the feasibility of natural gas production by depressurization and by thermal-stimulation techniques. With these goals in mind, the tests produced gas from gas hydrate with a series of well-constrained and controlled production experiments, each designed to investigate the response of *in-situ* gas hydrate deposits to changes in pressure or temperature.

The Mallik 2002 production test results, combined with other project data, were also used to calibrate gas hydrate-production simulators, which were then used to predict the expected long-term response of the gas hydrate beyond the duration and conditions of the actual tests.

During the Mallik 2002 testing program, the response of gas hydrates to heating and depressurization was evaluated with careful attention to accurately measuring both input conditions and reservoir responses. Pressure draw-down experiments, designed to study the response of gas hydrate to a reduction in formation-pressure conditions, used Schlumberger's Modular Formation Dynamics Tester (MDT) wireline tool to conduct small-scale pressure-drawdown tests within five perforated intervals in the Mallik 5L-38 well. The rationale for most of the MDT tests was to reduce reservoir pressure below gas hydrate stability conditions and then "shut-in" the tool to observe the pressure build-up attributed to flowing formation fluids and gas hydrate dissociation.

The results of three short duration tests demonstrate that gas can be produced from gas hydrates with different concentrations and characteristics, exclusively through pressure stimulation. It was shown (Hancock and others, 2005) that the response of the hydrate-bearing sand reservoirs was similar to a conventional porous-media response. Thus, conventional pressure-transient analytical techniques were used to evaluate the Mallik 2002 MDT test data. Horizontal permeabilities were observed to range from less than 0.001 millidarcy (mD) to as much as 0.1 mD within hydrate-bearing porous media. In contrast, the expected intrinsic permeability (that is, without gas hydrate) of the same sands with only water filling the pores would be on the order of 100 to 1,000 mD. The existence of measurable permeability in a reservoir with high gas hydrate saturations (up to 85 percent) was unexpected. Downhole-measured NMR-log data from the Mallik 5L-38 well also indicated the presence of a movable free-water phase within the hydrate-bearing sandstone reservoirs, which likely represents the compressive porous-media fluid phase along which flow was established and measured during the MDT gas hydrate tests. Downhole acoustic log data from Mallik also shows that gas hydrate is a matrix-supporting, pore-filling material rather than a grain-coating substance. The presence of an interconnected fluid phase at measurable permeabilities indicates that gas hydrate reservoir-depressurization production techniques may be more effective than previously thought.

Thermal stimulation experiments were designed to destabilize gas hydrates by using circulated hot water to increase the *in-situ* temperature. A five-day experiment was undertaken within a 13-m-thick section of highly concentrated gas hydrate-bearing strata. The test was conducted by circulating hot fluids (122°F; 50°C) down the hole at a constant pressure slightly above hydrostatic conditions. Gas from dissociated hydrate flowed to the surface, and was separated from the circulating fluid, measured, sampled, and flared. Gas was continuously

produced throughout the test at varying rates with maximum flow rate reaching 12,700 standard cubic feet of gas per day (scf/day) (Dallimore and Collett, 2005). The total volume of gas was small, reflecting that the test was a controlled production experiment rather than a long-duration conventional well test. It also demonstrated the difficulty of heating a relatively large rock mass by conductive heat flow alone.

The Mallik 2002 production research well program proved for the first time that gas production from gas hydrates is technically feasible. The resulting data allowed (1) the calibration of several reservoir models used to simulate the thermal and depressurization tests, and (2) the rational assessment of the production response of a gas hydrate accumulation if the various tests were extended far into the future. These studies also show that among the possible techniques for production of natural gas from *in-situ* gas hydrates, depressurization would produce more gas than just heating the formation. However, the combination of heating and depressurizing the gas hydrate at the same time would produce the greatest amount of gas.

It is recognized that the Mallik 2002 project contributed a great deal to an understanding of gas hydrates; however, it fell short of delivering all of the data needed to fully calibrate existing reservoir simulators. It was also determined that longer-duration production tests would be required to assess the technical viability of long-term production from gas hydrates; the 2006–2008 Japan Oil, Gas and Metals National Corporation/Natural Resources Canada (JOGMEC/NRCAN) Mallik Gas Hydrate Production Research Program was conducted to address these needs.

As described by Dallimore and others, (2008a, 2008b) and Yamamoto and Dallimore (2008), the 2006–2008 JOGMEC/NRCAN Mallik Gas Hydrate Production Research Program was conducted by JOGMEC, NRCAN, and the Aurora College/Aurora Research Institute to build on the results of the Mallik 2002 project, with the main goal of monitoring long-term production behavior of gas hydrates. The primary objective of the winter 2006–2007 field activities was to install equipment and instruments to allow for long-term gas hydrate production testing during the winter of 2007–2008. The Mallik 2L-38 and Mallik 3L-38 wells were reentered and each well was logged to establish formation properties prior to testing. After completing drilling operations during the 2006–2007 phase of the project, a short pressure drawdown test was conducted to evaluate equipment performance and assess the short term "producibility" of the gas hydrate-bearing reservoir. A 40-ft-thick gas hydrate interval (3,586–3,626 ft; 1,093–1,105 m) near the base of the gas hydrate stability zone was tested for 60 hr by reducing the bottom-hole pressure down to roughly 1,060 psi (equal to a drawdown pressure of roughly 535 psi). Irregular pumping operations, related to excessive sand production, resulted in unstable fluid flow, which greatly complicated the analysis of the test. However, during the most successful 12.5 hr of the

test, at least roughly 29,300 scf of gas were produced. The test results verified the effectiveness of the depressurization method even for such a short duration.

The following winter (2007/2008), the team returned to the site to undertake a longer term production test with the implementation of countermeasures to overcome the problems encountered in the previous year's program. The 2007/2008 field operations consisted of a six-day pressure drawdown test, during which "stable" gas flow was measured at the surface. The 2007/2008 testing program at Mallik established a continuous gas flow ranging from roughly 70,000 to roughly 140,000 scf/day, which was maintained throughout the course of the six-day (139-hr) test (Yamamoto and Dallimore, 2008; Dallimore and others, 2008b). Cumulative gas production volume was approximately roughly 460,000 scf. Total water production during the test was less than roughly 850 barrels (Dallimore and others, 2008b). The 2006–2008 Mallik production tests have shown that "sustained" gas production from hydrates can be achieved by depressurization alone.

As concluded by Yamamoto and Dallimore (2008), all of the Mallik gas hydrate research programs have contributed greatly to an understanding of the energy resource potential of gas hydrates. However, more work is needed to understand the longer-term production response of gas hydrates, and additional production data sets are required to develop a practical understanding of the energy-resource potential of gas hydrates.

As previously discussed in this report, the Alaska Mount Elbert gas hydrate stratigraphic test well project included the acquisition of pressure transient data from four short-duration open-hole dual-packer pressure-drawdown tests using Schlumberger's wireline MDT (Anderson and others, 2008). These tests were conducted in open-hole and were designed to build upon the knowledge gained from cased-hole MDT tests conducted during the Mallik 2002 testing program.

Four 1-m thick zones were tested in the Mount Elbert well (fig. 13): two in unit C (tests C1 and C2) and two in unit D (tests D1 and D2). Each test consisted of multiple stages of varying duration, with each stage consisting of a period of fluid withdrawal (thereby reducing formation pressure) followed by a period where the pump was shutoff and the subsequent pressure build-up was monitored. Gas and water samples were collected during selected flow periods, and a fluid analyzer on the MDT tool enabled the identification (but not volumetric measurement) of gas and water as it entered the tool.

The Mount Elbert MDT program included two types of tests. To investigate the petrophysical properties of the hydrate-bearing reservoirs, each MDT tests began with a "pre-flow test," in which pressure was reduced enough to mobilize unbound formation water but not enough to induce gas hydrate dissociation. To provide insight into gas hydrate response to small scale pressure transients, the pre-flow tests were followed by numerous test stages in which the pressure

reduction was great enough to induce gas hydrate dissociation. Much like the MDT results and the downhole-measured NMR logs from the Mallik 5L-38 well (as discussed above), the MDT and NMR log data from the Mount Elbert well also confirmed the presence of a mobile pore-water phase even in the most highly gas hydrate-saturated intervals. In the Mount Elbert unit D sand, the mobile water phase was determined to be about 8 to 10 percent of total pore volume. In the unit C sand, it appears to range upward to roughly 15 percent (Anderson and others, 2008).

The presence of a mobile water phase appears to be a required prerequisite for the initiation of depressurization for a gas hydrate reservoir that is not in contact with underlying free-gas or water reservoirs. The MDT test data from the early pre-flow stage that targeted fluid withdrawal without gas hydrate dissociation produced pressure responses that are typical of low-permeability porous media, much like the Mallik 2002 MDT tests. Analysis of these pre-flow tests in a variety of advanced reservoir simulators (Anderson and others, 2008) has yielded reservoir permeabilities, in the presence of a gas hydrate phase, of 0.12 to 0.17 mD. Gas hydrate dissociation and production was confirmed in the later stages of each test in which the pressure was drawn down below gas hydrate equilibrium conditions.

In the next section of the report, we review how the Mallik and Mount Elbert production test results are being used to calibrate existing gas hydrate-production simulators and how these models were used in this assessment to predict expected gas production rates from various gas hydrate accumulations in northern Alaska.

5.b. Gas Hydrate Production Modeling

Over the past 10 years, there have been significant advancements in gas hydrate production computer simulators, with studies by Moridis and others (2009, 2011a, 2011b) showing promise for simulating gas production from hydrates in northern Alaska. To better understand the potential reservoir response for the locations considered in this assessment, the USGS collaborated with the participants of the International Code Comparison Group (Anderson and others, 2011a, 2011b) to conduct numerical gas hydrate-production simulations for the idealized Milne Point Unit (MPU), Kuparuk River Unit (KRU), Prudhoe Bay Unit (PBU), and Down-Dip-PBU settings (fig. 15). For ease in making comparisons, the geologic representations input to the models were simplified and homogenized. These analyses relied heavily on the reservoir data acquired from Mount Elbert test well in order to compare production between different geologic settings and between the various participating modeling approaches. Given the similarity of the KRU and MPU settings, only three sets of modeling runs were undertaken (figs. 16A–C).

Figure 15. Montage of log data from wells drilled in Prudhoe Bay Unit (PBU), Kuparuk River Unit (KRU), and Milne Point Unit (MPU) areas. The data are shown relative to interpreted base of ice-bearing permafrost. The indicated zones of reservoir temperature are approximate. Note that the PBU logs (5, 6, 7) show inferred gas hydrate in multiple zones and are the deepest (warmest) identified locations of gas hydrate in areas with established surface facilities. The next data point downdip from these wells (Well #8) has relatively poor log data and the anomalous responses that may reflect drilling effects.

Figure 16. Comparison of typical production simulation results for Alaska North Slope gas hydrate reservoirs. *A*, setting typical for known Kuparuk River Unit (KRU) and Milne Point Unit (MPU) reservoirs (3–4°C); *B*, Westend Prudhoe Bay Unit (PBU) setting (5–6°C); *C*, downdip PBU setting (10–12°C). From Anderson and others (2011b).

Although these cases differed somewhat in reservoir thickness and pressure, sensitivity runs clearly demonstrated that initial reservoir temperature is the primary control on the modeled production rates, with reservoir petrophysics, including intrinsic reservoir permeability, *in-situ* “relative” permeability, and mobile water saturation also being important (Anderson and others, 2011b). The initial MPU modeling results (fig. 16A) showed consistent predictions between the various participating codes, with modest production rates (maximum predicted production rate of 350,000 scf/day) and long “lead” times (time before first gas production occurs and all production is water). Analysis of the PBU case (production from the composite unit C sands) resulted in production rates (maximum predicted production rate of 825,000 scf/day) roughly three times those of MPU and with no lead time (fig. 16B). The Down-Dip-PBU case revealed the clear benefits of higher temperatures, with rates (maximum predicted production rate of 4,300,000 scf/day) increasing another five-fold (fig. 16C; Anderson and others, 2011b). Subsequent incorporation of more detailed geologic input data sets for these locations (that is, detailed vertical reservoir heterogeneity) resulted in increased production rates and the elimination of the production lead time as seen in the MPU model (Anderson and others, 2011b).

As discussed above, the earlier reservoir models (KRU, PBU, and the Down-Dip-PBU models, figs. 16A–C) were based on homogeneous reservoir descriptions, neglecting actual complex reservoir conditions. As shown by Anderson and others (2011b), significant differences between homogeneous and heterogeneous reservoir descriptions can yield much different model results. Therefore, to better constrain the possible extent of disturbance caused by long-term depressurization of a gas hydrate reservoir and to more accurately model the possible gas- and water- production rates, a heterogeneous reservoir model was constructed. Figure 17 shows the hydrate saturations for the upper and lower C sand units as determined by the Archie (1942) relation in the PBU L-106 well. Similar to the homogeneous PBU L-Pad area simulations (as discussed above), the radial extent of the reservoir modeled is roughly 1,475 ft (450 m) and the two hydrate layers are each roughly 59 ft (18 m) thick, with roughly 30 ft (9 m) of shale between. The top and bottom confining layers are each 328 ft (100 m) thick and the porosity of the hydrate-bearing zones is taken from the porosity log in the PBU L-106 well. The upper and lower boundary temperatures were kept constant at 34.9°F (1.6°C) and 39.4°F (4.1°C), respectively.

Depressurization simulations were performed assuming a constant bottom-hole pressure of 392 psi (2.7 MPa), just above the quadruple point for the methane hydrate system in order to prevent the formation of ice in the reservoir. Figure 18 shows the predicted gas and water rates from the heterogeneous simulations on the PBU L-Pad area hydrate deposit. As shown in figure 18, the water rate is predicted to start at its maximum and decrease throughout production, whereas the modeled gas rate increases rapidly throughout the early stages of production. As shown in Anderson and others (2011b), homogeneous L-Pad area hydrate reservoir models predict

maximum gas-production rates as high as 1,000,000 scf/day after a couple of decades of production. However, as shown in figure 18, a heterogeneous reservoir simulation results in predicted gas rates on the order of 3,500,000 scf/day with produced water rates ranging from 1,000–3,000 barrels/day throughout the first six months of depressurization.

With predicted gas production rates from known gas hydrate accumulations in northern Alaska as high as 3,500,000 scf/day, based on existing production technology, there do not appear to be any technical barriers to resource extraction from hydrates; the remaining resource issues deal mostly with the economics of hydrate extraction.

6. Gas Hydrate Assessment Methodology

As introduced in the “USGS Oil and Gas Assessment Methodology” section of this report, an assessment begins (fig. 2) with the volume of rock to be assessed in the total petroleum system (TPS) being apportioned into homogeneous subunits termed assessment units (AUs). The assessment procedure generally estimates the number and size of undiscovered hydrocarbon accumulations and assesses the geologic risk associated with each AU. The next section of the report focuses on defining the limits and nature of the Northern Alaska Gas Hydrate TPS and three associated AUs, the geologic risk associated with each AU, and the methods used to estimate the size and number of undiscovered gas hydrate accumulations in each AU.

6.a. Northern Alaska Gas Hydrate Total Petroleum System and Assessment Units

The Northern Alaska Gas Hydrate TPS (figs. 19A–B) includes Cretaceous and Tertiary reservoir rocks divided into three AUs: from oldest to youngest, the Nanushuk Formation Gas Hydrate AU (fig. 20), the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU (fig. 21), and the Sagavanirktok Formation Gas Hydrate AU (fig. 22).

The geologic model used to define the AUs and to set the limits of the TPS involved defining and characterizing the components of the gas hydrate petroleum system (this is, gas hydrate stability conditions, gas hydrate reservoirs, and gas source and migration) that controlled the presence of gas hydrate accumulations in each AU. As a first step, the factors controlling gas hydrate phase equilibria (which are mostly a function of formation temperature and pressure as described in the “Gas Hydrate Stability Conditions” section of this report) were assessed to map the spatial distribution of the gas hydrate stability zone in northern Alaska (fig. 5A–C). The gas hydrate stability maps in figures 5A and 5B depict the top and base of the gas hydrate stability zone; gas hydrates cannot be present either above or below the zone of gas hydrate stability. Figure 5C shows the thickness and spatial limits of the

Figure 17. Hydrate saturation in the Prudhoe Bay Unit (PBU) L-106 well as calculated by the Archie (1942) relation for $n = 1.5$, 2.0 (model S_h), and 2.5. The gas hydrate saturation in the reservoir model for the layers between 697.7 m (2,289 ft) and 706.2 m (2,317 ft) was assumed to be zero.

Figure 18. Predicted gas and water production from the Prudhoe Bay Unit (PBU) L-106 C-unit methane hydrate deposit for a constant bottom-hole pressure of 2.7 megapascals (MPa). The solid black and dotted grey curves represent the rate of gas produced at the wellhead and gas released in the reservoir respectively, and correspond to the left y-axis. The rate of water production is on the right (y-axis) and is indicated by the dashed black line.

inferred gas hydrate stability zone. As depicted in figure 5C gas hydrates cannot exist outside of the zero contour line on the gas hydrate stability zone thickness map.

The next component of the gas hydrate petroleum system to be considered is the presence of suitable reservoir rocks within the limits of the gas hydrate stability zone, the characterization of which yielded the three AUs defined in this study. It is important to highlight that only gas hydrates lying below the permafrost section were assessed, thereby limiting the AUs to the stratigraphic interval below the base of the permafrost (fig. 4) and above the base of the gas hydrate stability zone (fig. 5B). This decision was based on the results of production modeling, as reviewed in the “Gas Hydrate Production Modeling” section of this report. The results show that gas hydrate depressurization production rates are severely retarded by low reservoir temperatures and the presence of ice within the permafrost section that restricts the propagation of a pressure front into the formation and the flow of gas to the borehole. It is also emphasized that free-gas potentially trapped below the gas hydrate stability zone was not assessed in this study.

As described in the “Reservoir Rocks” section of this report, the known gas hydrate accumulations within the Eileen trend along the western border of the PBU (figs. 7, 8) are limited to sandstone reservoirs in the Sagavanirktok Formation (fig. 6). In this study, however, a total of five Cretaceous and Tertiary sand-rich formations were assessed for gas hydrates. Stratigraphic nomenclature used here is the revised nomenclature of Mull and others (2003) for Cretaceous and Tertiary rocks on the North Slope, as follows: (1) reservoir quality rocks previously included within the Nanushuk Group (Corwin and Chandler Formations) are now assigned to the Nanushuk Formation; (2) Upper Cretaceous reservoir strata previously assigned to the Tuluvak Tongue of the Prince Creek Formation in the Colville Group are now included in the Tuluvak Formation; and (3) reservoir strata previously included in the Kogosukruk Tongue of the Prince Creek Formation (Colville Group), as well as strata previously assigned to the lower part of the Sagwon Member of the Sagavanirktok Formation, are now included in the Prince Creek Formation (fig. 6). The newly revised Tuluvak Formation and the Prince Creek Formation are separated by

Figure 19. A, map of the Northern Alaska Gas Hydrate Total Petroleum System (TPS) (500102) (shaded in tan). B, map of the Northern Alaska Gas Hydrate TPS (shaded in tan) and the gas hydrate stability zone thickness contours (in red) from figure 5C. Contours in feet (ft). (NPRA, Natural Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 19. A, map of the Northern Alaska Gas Hydrate Total Petroleum System (TPS) (500102) (shaded in tan). B, map of the Northern Alaska Gas Hydrate TPS (shaded in tan) and the gas hydrate stability zone thickness contours (in red) from figure 5C. Contours in feet (ft). (NPRA, Natural Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)—Continued

Figure 20. Map of the Nanushuk Formation Gas Hydrate Assessment Unit (AU) (50010203) (shaded in green). (NPRA, Natural Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 21. Map of the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit (AU) (50010202) (shaded in blue). (NPRA, Natural Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 22. Map of the Sagavanirktok Formation Gas Hydrate Assessment Unit (AU) (50010201) (shaded in pale green). (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

the Schrader Bluff Formation, a mostly marine unit composed of reservoir quality sandstone units and shale that can be as thick as 2,500 ft (762 m). Regional relations suggest a general northeasterly progradation of the Tuluva Formation and overlying Schrader Bluff and Prince Creek Formations, which collectively appear to be genetically related, constitute a large-scale sediment package of shallow-marine to marginal-marine facies and coastal-plain facies.

Stratigraphic nomenclature of Mull and others (2003) for Tertiary strata in the Sagavanirktok Formation also includes revisions to previous definitions and terminology of Gryc and others (1951) and Detterman and others (1975) for this formation. In Mull and others (2003), the Sagavanirktok Formation includes three members (ascending order): the Sagwon Member (revised definition), White Hills Member (newly defined), and the Franklin Bluffs Member (revised definition).

Gas source and gas migration are two of the more critical components of both the TPS and AUs. As part of the gas hydrate petroleum system assessment, geochemical analysis of samples recovered from wells that have penetrated known gas hydrate occurrences revealed a link between gas hydrate accumulations on the North Slope and more deeply buried conventional oil and gas accumulations, in which methane migration from depth has charged the reservoir rocks in the gas hydrate stability zone (Collett, 1993; Lorenson and others, 2011). Considering the apparent prolific nature of the hydrocarbon source rocks on the Alaska North Slope (Bird, 1998; Bird and Magoon, 1987; Houseknecht, 2003), it was assumed in this assessment that the gas within the undiscovered gas hydrate accumulations in each of the AUs is solely from more deeply buried thermogenic sources. The geochemical analysis of gas samples from wells and the distribution of known more deeply buried conventional oil and gas accumulations have also been used in this study to further characterize and constrain the occurrence and distribution of the potential gas hydrate accumulations on the North Slope as described in the “Undiscovered Gas Hydrate Accumulations—Number of Accumulations” section of this report.

Because there is no production of gas from gas hydrates on the North Slope and only limited testing of hydrates in the Mount Elbert well (Hunter and others, 2011), the three AUs in the Northern Alaska Gas Hydrate TPS (fig. 19) (the Nanushuk Formation Gas Hydrate AU (fig. 20), the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU (fig. 21), and the Sagavanirktok Formation Gas Hydrate AU (fig. 22)) are all considered to be hypothetical. The potential reservoir facies in the Tuluva, Schrader Bluff, and Prince Creek Formations share a similar geographic distribution, so these formations are grouped together into a single AU.

The remainder of this section provides a summary of the geologic criteria and data used to define the physical distribution of the three AUs. The key geologic consideration that is discussed for each AU relates to the occurrence of potential gas

hydrate reservoir sedimentary facies within the interval below the base of the overlying permafrost section and above the base of the gas hydrate stability zone.

Because of the long history of industry-led exploration activities and USGS resource assessments in northern Alaska, this study had access to a large number of pertinent published reports and databases. One of the more important sources of information was the various data sets published with the previously completed USGS assessments of unconventional and conventional resources in northern Alaska, including the following: (1) 1995 USGS Gas Hydrate Assessment (Collett, 1995); (2) 1999 Oil and Gas Resource Potential of the Arctic National Wildlife Refuge 1002 Area, Alaska (ANWR Assessment Team, U.S. Geological Survey, 1999); (3) 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (Bird and Houseknecht, 2002); (4) 2005 Oil and Gas Assessment of Central North Slope, Alaska (Garritty and others, 2005); and (5) 2007 Geologic Assessment of Undiscovered Coalbed Gas Resources in Cretaceous and Tertiary Rocks, North Slope and Adjacent State Waters, Alaska (Roberts, 2008).

The USGS also maintains several specialized data sets that were used in this assessment. One of the most important data sets is a copy of the State of Alaska well-log database (Alaska Oil and Gas Conservation Commission, 2008)—this database contains the publicly available downhole log data from more than 3,000 North Slope exploratory and development wells. For the most part, log data from wells in Alaska are released by the State two years after the completion of a well. This well-log database was also used to develop an unpublished USGS Alaska formation “tops file” as maintained by Ken Bird (USGS, Menlo Park, California), Dave Houseknecht (USGS, Reston, Virginia), and Phil Nelson (USGS, Denver, Colorado). The USGS Alaska formation “tops file” contains listings of penetration depths of all the major geologic “markers” and formations tops encountered in about 400 wells as of December 1, 1998. This file was developed mostly as a product of the various USGS Alaska North Slope assessment studies.

A number of well-log correlation sections were developed as part of this study and other USGS assessments in northern Alaska (as listed above). Lewis and Collett (2013), for example, compiled a series of nine correlation sections, containing well-log data from more than 122 wells, extending from just west of the Colville River in NPRA and extending to the east near the Sagavanirktok River (fig. 23). These sections include (1) “well-log picks” for the tops of all the major formations and well-log markers, (2) depths of the well-log-inferred gas hydrate accumulations (including those within the Eileen and Tarn gas hydrate accumulation), (3) depths of the top and base of the gas hydrate stability zone, and (4) depths to the base of permafrost and (or) ice-bearing permafrost. Other important published well-log correlation sections were available from Molenaar and others (1987a) and Decker (2007).

Figure 23. Map showing locations of well-log correlation sections within the greater Prudhoe Bay area as compiled by Lewis and Collett (2013).

This project also made use of several extensive grids of 2D seismic lines and 3D seismic volumes (fig. 24). As part of the U.S. Government-managed NPRA exploration program in the 1970s and 1980s, the USGS supervised the acquisition of more than 15,000 mi of 2D seismic data. Miller and others (2000, 2001) included reprocessed digital seismic data for a series of regional reference seismic lines (roughly 4,200 line-miles), which formed a 20×20-mi grid covering the entire NPRA (fig. 24). The USGS NPRA seismic data grid was used in this assessment to help set the western and southern limits of the three AUs. This assessment also had

access to an additional set of multichannel, seismic-reflection lines from ANWR (fig. 24), which were recorded as part of a resource assessment study conducted by the USGS and others in the 1980s (Bird and Magoon, 1987). This seismic data set helped to define the southeastern limits of the Sagavanirktok Formation Gas Hydrate AU (discussed later in this report).

As described in the “Undiscovered Gas Hydrate Accumulations—Sizes of Accumulations” and “Undiscovered Gas Hydrate Accumulations—Number of Accumulations” sections of this report, this study also relied on numerous 3D seismic volumes to help define the limits of the AUs

Figure 24. Map of 2D and 3D seismic profiles, the interpretation of which were used as the base data for this assessment of undiscovered gas hydrate resources on the Alaska North Slope. Most of the 2D seismic lines depicted in or near NPRA are from Miller and others (2000, 2001) and the 2D seismic lines shown in ANWR are from Bird and Magoon (1987). Also shown is the outline of the Milne Point unit 3D seismic volume used to identify and map gas hydrate prospects. The NPRA 3D seismic volumes used in this assessment have not been shown in this figure for confidentiality reasons. (NPRA, National Petroleum Reserve in Alaska; ANWR, Arctic National Wildlife refuge)

and to determine the size and number of undiscovered gas hydrate accumulations. As discussed earlier, the 3D seismic data volume from the MPU covering an area of 155 mi² (figs. 10, 24) (as released to the USGS by BP Exploration Alaska, Inc.) was used to develop and document seismic methods for identifying a series of nine gas hydrate prospects (accumulations) in the MPU (Lee and others, 2009, 2011; Inks and others, 2009). The USGS was also given access by BLM to four additional 3D seismic volumes from NPRA. These additional seismic data volumes from NPRA covered an area of 729 mi², were used under strict data-confidentiality rules, and cannot be released for public disclosure (subject to 43 CFR 3152.6 (a) (b), 43 CFR 3152.7 (a) (2), and 43 CFR 3100.4). To maintain data confidentiality, no portion of the data sets, location information, or names of the NPRA seismic data volumes were used in this report. For descriptive purposes, the four 3D seismic-data volumes were named NPRA 3D Seismic No. 1 through NPRA 3D Seismic No. 4. These four seismic-data volumes provided critical insight to the size and number of undiscovered gas hydrate accumulations in the Nanushuk Formation Gas Hydrate AU and the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU.

The Northern Alaska Gas Hydrate TPS is defined here (figs. 19A–B) to include the area of the Alaska North Slope and adjacent State waters underlain by Cretaceous and Tertiary strata that (1) are in the interval between the base of the permafrost (fig. 4) and above the base of the gas hydrate stability zone (fig. 5B), and (2) are interpreted to contain reservoir quality sandstone deposits with the potential for containing gas hydrate. The TPS thus includes a significant part of the National Petroleum Reserve in Alaska (NPRA), and limited lands in the Arctic National Wildlife Refuge (ANWR). The southern onshore boundary of the TPS is defined by the mapped intersection of Cretaceous continental deposits and the base of permafrost within the mapped zone of gas hydrate stability. The eastern and western limits of the TPS extend to the limits of the Topset Play in the 1001 Area of ANWR (ANWR Assessment Team, U.S. Geological Survey, 1999) and the Brookian Topset Play in NPRA (Bird and Houseknecht, 2002). The offshore limits of the TPS extended to the boundary of the Alaskan State waters.

Recent work summarized by Walsh and others (2007) led to the conclusion that the East Barrow and Walakpa gas fields, located near the village of Barrow, may extend up into the overlying methane hydrate stability zone, thus opening the possibility that gas hydrate may exist in the crest of these two conventional gas fields, neither of which fall within the AUs as defined in this assessment. However, due to the lack of well penetrations in the updip portion of the Walakpa field, it has not been possible to more thoroughly evaluate the occurrence of gas hydrate in this field. There is also no direct geologic evidence for the presence of gas hydrate in the East Barrow gas field. It was therefore decided not to include the Barrow or Walakpa reservoirs in this assessment.

6.a.1. Nanushuk Formation Gas Hydrate Assessment Unit

The Nanushuk Formation Gas Hydrate AU encompasses just over 19,816,320 acres (roughly 30,963 mi²) in the western and central parts of the North Slope (fig. 20). The western and southern limits of the Nanushuk Formation Gas Hydrate AU are defined by the intersection with the base of the permafrost section, within the limits of gas hydrate stability zone, and the mapped limit of the Nanushuk Formation reservoirs. The eastern limit of the AU is defined by the intersection with the base of the gas hydrate stability zone and mapped limit of Nanushuk Formation reservoirs and other older reservoir sections. The northern boundary of the AU is defined mostly by the limit of the Alaska State Waters (from the mean high water line out to 3 nautical miles).

In general, the Nanushuk Formation Gas Hydrate AU is limited to mostly the topset seismic facies as identified from the USGS regional 2D seismic lines and available 3D seismic volumes in NPRA and to the south along the Brooks Range Foothills. Well-log picks for the Nanushuk Formation from 124 wells in the USGS Alaska formation “tops file,” along with several project generated well-log correlation sections, have been used to further refine the limits of this AU. Most of the AU is coincident with (1) the Nanushuk Formation Coalbed Gas AU (Roberts, 2008); (2) the conventional Brookian Topset, Brookian Topset Structural, Brookian Clinoform Central, Brookian Clinoform South Shallow, and Brookian Clinoform South Deep AUs from the 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (Bird and Houseknecht, 2002); and (3) portions of the conventional Brookian Topset, Brookian Clinoform, Brookian Topset Structural North, Brookian Topset Structural South, Brookian Clinoform Structural North, and Brookian Clinoform Structural South AUs from the 2005 Oil and Gas Assessment of Central North Slope, Alaska (Garrity and others, 2005) (see table 2).

The Nanushuk Formation (fig. 6), which is Albian to Cenomanian in age, is exposed along an outcrop belt about 20 mi wide that extends for nearly 400 mi from west to east in the Foothills Province north of the Brooks Range (figs. 1A–B). The Nanushuk Formation overlies the predominantly marine Torok Formation. In the subsurface, the Nanushuk extends across the coastal plain, covering much of the western and central parts of the North Slope; the thickest observed section is 6,150 ft (1,874 m) in the Tunalik 1 well (as documented in the USGS Alaska formation “tops file”). The structural setting of the Nanushuk Formation within the AU coincides roughly with the Alaska North Slope physiographic provinces that are characterized by east-west-trending detachment folds in the foothills and broad, low-amplitude anticlines in the coastal plain (fig. 1B) to the north (Potter and Moore, 2003). Structure contour maps on the top of the Nanushuk in the coastal plain areas indicate that the rocks dip gently southward in the west-central and western parts of the AU, and shift to east and southeasterly dips in the eastern part of the AU (Potter and Moore, 2003).

Table 2. Cross-reference of the gas hydrate assessment units with USGS conventional assessment units in northern Alaska (ANWR Assessment Team, U.S. Geological Survey, 1999; Bird and Houseknecht, 2002; Garrity and others, 2005).

ANWR Assessment¹	Gas Hydrate Assessment Unit
Topset play	SAG
Thin skinned trust-belt play	SAG
Turbidite play	SAG
Wedge play	SAG
Central North Slope Assessment²	Gas Hydrate Assessment Unit
Brookian Topset	NAN/TSBPC/SAG
Brookian Clinoform	NAN/TSBPC/SAG
Brookian Topset Structural North	NAN/TSBPC/SAG
Brookian Topset Structural South	NAN/TSBPC/SAG
Brookian Clinoform Structural North	NAN/TSBPC/SAG
Brookian Clinoform Structural South	NAN/TSBPC/SAG
NPRA Assessment³	Gas Hydrate Assessment Unit
Brookian Topset	NAN/TSBPC/SAG
Brookian Topset Structural	NAN/TSBPC
Brookian Clinoform North	NAN/TSBPC/SAG
Brookian Clinoform Central	NAN/TSBPC
Brookian Clinoform South Shallow	NAN/TSBPC
Brookian Clinoform South Deep	NAN/TSBPC

Key:

NAN = Nanushuk Formation Gas Hydrate Assessment Unit

TSBPC = Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit

SAG = Sagavanirktok Formation Gas Hydrate Assessment Unit

¹The oil and gas resource potential of the Arctic National Wildlife Refuge 1002 area, Alaska, 1999 (ANWR Assessment Team, U.S. Geological Survey, 1999).

²Oil and gas assessment of central North Slope, Alaska, 2005 (Garrity and others, 2005).

³Petroleum resource assessment of the National Petroleum Reserve in Alaska (NPRA), 2002 (Bird and Houseknecht, 2002).

6.a.2. Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit

The Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU encompasses more than 9,179,520 acres (roughly 14,343 mi²) in the central and east-central parts of the North Slope (fig. 21). Because of their genetic similarities (as previously discussed) the Tuluvak, Schrader Bluff, and Prince Creek Formations (fig. 6) were assessed jointly as one AU. The western and southern limits of the AU are marked by the intersections (subcrop) of the Tuluvak, Schrader Bluff, and Prince Creek reservoir facies with the base of the permafrost section within the limits of the gas hydrate stability zone. The eastern limit of the AU is defined by the intersection with the base of the gas hydrate stability zone and the mapped limit of Prince Creek Formation reservoirs. The western permafrost-subcrop and eastern limit of the Tuluvak, Schrader Bluff, and Prince Creek reservoir facies were also mapped with the available NPRA 2D and 3D seismic data sets as described

above. Although strata also interpreted to be equivalent to the Prince Creek and Tuluvak Formations have been reported in outcrops as far west as the Utukok River near Corwin Bluff (fig. 14) (Mull and others, 2006), the AU boundary was not extended to that area because neither formation has been identified in wells that far west. The northern boundary of the AU is almost entirely defined by the limit of the Alaska State Waters (from the mean high water line out to three nautical miles; fig. 24).

Much like the Nanushuk Formation Gas Hydrate AU, the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU is mostly limited to the topset seismic facies, as identified from the USGS regional 2D seismic lines and available 3D seismic volumes in NPRA and to the area east of the Colville River (fig. 24). Well-log picks for the Tuluvak, Schrader Bluff, and Prince Creek Formations from 94 wells in the USGS Alaska formation “tops file” were used to further define the limits of this AU. Project-developed, well-log correlation sections (Lewis and Collett, 2013) and the Umiat field to Milne Point field Brookian sequence stratigraphic correlation section from Decker (2007) provided valuable insight into the distribution of the reservoir facies within the AU. It is important to emphasize that the well-log-inferred gas hydrates of the “Tarn accumulation” along the western border of the KRU (fig. 23; Collett, 2002) are within reservoir rocks of the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU (see the “Reservoir Rocks” section of this report).

The Prince Creek and Tuluvak Formations Coalbed Gas AU of Roberts (2008) falls almost entirely within the limits of the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU. The Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU also includes portions of the conventional Brookian Topset, Brookian Topset Structural, Brookian Clinoform North, Brookian Clinoform Central, Brookian Clinoform South Shallow, and Brookian Clinoform South Shallow AUs from the 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (Bird and Houseknecht, 2002), along with portions of the conventional Brookian Topset, Brookian Clinoform, Brookian Topset Structural North, Brookian Topset Structural South, Brookian Clinoform Structural North and, Brookian Clinoform Structural South AUs from the 2005 Oil and Gas Assessment of Central North Slope, Alaska (Garrity and others, 2005) as summarized in table 2.

As previously discussed, the Tuluvak, Schrader Bluff, and Prince Creek Formations have been jointly assessed in this report. The Tuluvak Formation (fig. 6) is Turonian-Coniacian in age and outcrops generally consist of conglomerate, sandstone, shale, carbonaceous shale, and coal. The Tuluvak Formation for the most part is poorly exposed in outcrop, but subsurface well-log data indicate thicknesses range from 140 ft (43 m) thick in the Colville Delta 1 well to as much as 1,450 ft (442 m) thick in the Aufeis Unit 1 well (as documented in the USGS Alaska formation “tops file”). The age of the Schrader Bluff Formation is Santonian to

Maastrichtian. The unit consists dominantly of marine sandstones and shale, with the upper part mostly of shallow-marine sandstones that grade upward into sandstones of the overlying Prince Creek Formation (fig. 6). The thickness of the Schrader Bluff Formation is as much as roughly 2,500 ft (roughly 762 m) in the Chandler River region and decreases northward to about 1,800 ft (549 m) in the Umiat area (fig. 1A). The Prince Creek Formation (fig. 6) is Campanian through Paleocene in age, and is characterized in outcrop by interbedded conglomerate, sandstone, mudstone, carbonaceous shale, and coal; no complete section, however, is exposed. Because of its lithologic similarity with the underlying Schrader Bluff Formation, the two formations are difficult to separate in the subsurface. The aggregate thickness of the undifferentiated Prince Creek and Schrader Bluff Formations ranges from about 100 ft (30 m) to almost 5,000 ft (1,524 m). The structural characteristics of this AU are similar to those described above in the Nanushuk Formation Gas Hydrate AU, with east-west-trending detachment folds in the foothills regions and only slightly deformed and gently east-dipping strata in the coastal plain.

6.a.3. Sagavanirktok Formation Gas Hydrate Assessment Unit

The Sagavanirktok Formation Gas Hydrate AU (fig. 22) encompasses just over 6,776,320 acres (roughly 10,588 mi²) in the east-central part of the North Slope (fig. 1A–B). The western and southern boundaries of the AU represent the subcrop of the Sagavanirktok Formation reservoir facies with the base of the permafrost section within the limits of the gas hydrate stability zone based on drill-hole data and a limited number of 2D seismic lines (fig. 24). Well-log picks for the Sagavanirktok Formation from 253 wells in the USGS Alaska formation “tops file” extended the eastern boundary of the AU to the Canning River (fig. 1A). Because of the lack of drilling in ANWR, 2D seismic data were used to estimate the downdip intersection of the Sagavanirktok reservoir facies with the gas hydrate stability zone. The northern boundary of the AU is defined mostly by the limit of the Alaska State Waters (from the mean high water line out to 3 nautical miles).

Much like the case for the other two assessed gas hydrate AUs, the Sagavanirktok Formation Gas Hydrate AU is mostly limited to the topset seismic facies as identified from the USGS regional 2D seismic lines. Project-developed well-log correlation sections (Lewis and Collett, 2013), along with the published well-log correlation sections from Decker (2007), provided basic data for outlining the distribution of the reservoir facies in this AU. It is important to note the well-log inferred and cored gas hydrates in the “Eileen accumulation” along the western border of the PBU (fig. 23) (Collett, 1993, 2002) are within reservoir rocks of the Sagavanirktok Formation Gas Hydrate AU (see “Reservoir Rocks” section of this report).

Most of the Sagavanirktok Formation Gas Hydrate AU is coincident with (1) the Sagavanirktok Formation Coalbed Gas AU (Roberts, 2008); (2) the conventional Brookian Topset and Brookian Clinoform North AUs that were defined for the 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (Bird and Houseknecht, 2002); (3) portions of the conventional Brookian Topset, Brookian Clinoform, Brookian Topset Structural North, Brookian Topset Structural South, Brookian Clinoform Structural North and, Brookian Clinoform Structural South AUs that were defined for 2005 Oil and Gas Assessment of Central North Slope, Alaska (Garritty and others, 2005); and (4) portions of the Topset Play, Thin Skinned Thrust-Belt Play, Turbidite Play, and Wedge Play that were defined for the 1999 Arctic National Wildlife Refuge 1002 area assessment (ANWR Assessment Team, U.S. Geological Survey, 1999) (see table 2).

The Sagavanirktok Formation (fig. 6) is Paleocene–Miocene in age and generally consists of conglomerate, sandstone, mudstone, carbonaceous shale, and coal. It was deposited in a northeast-prograding deltaic system (Molenaar, 1983), and becomes younger from southwest to northeast across the AU. The formation also thickens from the southwest to the northeast, with a maximum thickness of about 9,000 ft (2,743 m) along the northeastern boundary of the AU. Structurally, most of the AU lies north of the detachment folds that characterize the Foothills province (fig. 1B), although the Sagavanirktok Formation is exposed on the limbs of gently folded anticlines along the southeastern boundary of the AU. In the greater PBU area, the Sagavanirktok Formation is also cut by faults that are generally downthrown to the east (displacements from 50 to 200 ft; 15 to 61 m) that are also believed to provide pathways for gas migration from deeply buried hydrocarbon sources into the overlying hydrate-bearing reservoirs as reviewed in “Section 4.c. Gas Source and Migration” of this report.

6.b. Assessment Unit Probabilities

After defining the limits of the three gas hydrate AUs, the assessment unit probabilities for each AU was determined. The assessment-unit probabilities as determined for each of the AUs in this study (as further reviewed in the Assessment-Data Form section of this report) relate a series of geologic risks associated with the existence of gas hydrate in each the AUs. In this assessment, three risking elements (attributes) of charge, rocks, and timing address the question of the probability of occurrence of at least one gas hydrate accumulation of minimum size, somewhere in the AU, that has the potential to be added to reserves (Schmoker and Klett, 2005). Each element in this risking structure applies to the AU as a whole, and each geologic element in an AU is reasonably homogeneous in terms of charge, rocks, and timing. In this assessment, the combination of geologic probabilities and the number and size of undiscovered accumulations (as reviewed

in the next two sections and detailed in the accompanying appendices) yield the probability distribution for the amount of technically producible gas stored within the gas hydrate accumulations in each AU.

6.c. Undiscovered Gas Hydrate Accumulations—Sizes of Accumulations

Two of the critical components of the USGS assessment methodology are the accurate prediction of (1) the expected size and (2) the number of undiscovered hydrocarbon accumulations. This assessment of the gas hydrate resources on the North Slope relied heavily on the analysis of industry-acquired three-dimensional seismic data, which used to characterize the size, number, and distribution of gas hydrate accumulations in each of the three AUs.

The results of the MPU gas hydrate 3D seismic prospecting study of Inks and others (2009), as reviewed in the “Reservoir Rocks” section of this report, provided the starting point for predicting the size of undiscovered gas hydrate accumulations on the North Slope. Inks and others (2009) presented a seismic-evaluation workflow designed to identify gas hydrate prospects (accumulations) and to estimate the volume of gas within the seismic-inferred gas hydrate accumulations. They identified a total of 14 seismic-inferred gas hydrate accumulations within the MPU (fig. 10) and estimated the in-place volume of gas within each accumulation (table 3). The identification of gas hydrate in the sandstone parts of the Sagavanirktok Formation by Inks and others (2009) was based primarily on seismic character analysis and correlation with well-log responses.

Rock-physics modeling and seismic trace modeling by Lee and others (2009) were used to establish seismic attributes for various types of gas hydrate accumulations. Modeled seismic amplitudes are small at relatively low gas hydrate saturations near 40 percent, and become larger with increasing gas hydrate saturations. In this study, a large positive seismic amplitude response signified highly saturated gas hydrate-bearing sediments. The modeling of Lee and others (2009) documented that the quality (that is, mostly frequency content) of the MPU 3D seismic volume limited the identification of gas hydrate occurrences to a minimum thickness of roughly 25 ft (roughly 8 m) and a minimum saturation of roughly 40 percent gas hydrate; gas hydrate occurrences below these values could not be identified with the 3D volume used in this study.

To calculate gas hydrate saturations and thicknesses of the gas hydrate accumulations in the MPU, the “thin-bed” modeling approach as described by Lee and others (2009) and Inks and others (2009) was used. For each inferred gas hydrate occurrence in this modeling approach, a time isochron of the wavelet from peak to trough was calculated, and the amplitudes of both the peak and trough were extracted. In each case, the seismic amplitude of the peak event and the travel-time between the peak and trough were used to

calculate the thickness of the hydrate-bearing unit and the gas hydrate saturation within each accumulation (fig. 25A–B). This information was then used to compute the in-place volume of gas within each of the seismic inferred gas hydrate accumulations in the MPU (fig. 10, table 3). For this study, statistical distributions for bulk rock volume, sediment porosity, gas hydrate saturation, and net-to-gross reservoir thickness were used and applied based on specific ranges of values for each of the individual gas hydrate intervals examined in this study. Volumetric calculations using a standard Monte Carlo simulation method were performed for each seismic-inferred gas hydrate accumulation. The Monte-Carlo-derived median in-place gas volumes calculated for each of the gas hydrate accumulations in the MPU (table 3) were taken forward in the assessment process as the primary information on the expected size of the gas hydrate accumulations. These calculated volumes thus represent one set of potential analogs for undiscovered gas hydrate accumulations within areas with no 3D seismic data coverage.

To expand the database of analog gas hydrate accumulations, four additional 3D seismic volumes from NPRA were subjected to the same gas hydrate prospecting protocol and volumetric analysis as applied to the MPU 3D seismic volume. As described in the “Northern Alaska Gas Hydrate Total Petroleum System and Assessment Units” section, the 3D seismic volumes from NPRA were used under strict confidentiality rules, and only the number of gas hydrate accumulations, size of each accumulation, and volume of gas within each accumulation are included in this report (table 3).

In most cases, the conventional USGS assessment methodology only considers the size of the oil and (or) gas accumulation being assessed in terms of technical recoverable resources; the size of the accumulation is normally obtained from historical production data in the AU or an appropriate analog. As discussed in the “Gas Hydrate Production Analysis” section of this report, there has been no confirmed, sustained production of gas from gas hydrate anywhere in the world. Thus, the next step in the Alaska gas hydrate assessment was to ascertain how much of the in-place gas within the 3D seismic-inferred gas hydrate accumulations could be technically produced (table 3). The first approach used in this assessment to calculate percent of gas that can be recovered from a gas hydrate accumulation was relatively straightforward and based mostly on simple reservoir engineering concepts. As a starting point, it was assumed that gas hydrate dissociation in the annular space around the producing well is complete and that the dissociation front moves away from the borehole as production continues through time (that is, no gas hydrate remaining as isolated pockets or lenses in the annular space).

The borehole annular volume, which was previously filled with gas hydrate, is now filled with a likely mixture of water and gas that has evolved from the dissociated gas hydrate. But if it is assumed that the annular volume is completely filled with gas from dissociated hydrate (no water) at abandonment, all of the water and other gas released

Table 3. List of 3D seismic imaged gas hydrate accumulations in the Milne Point Unit and the National Petroleum Reserve in Alaska, listed by the name of the accumulation and associated gas hydrate assessment unit. Also listed is the areal size of each accumulation along with the estimated median in-place and technical recoverable volume of gas within each accumulation (see figs. 27, 28).

[mi², square miles; km², square kilometers; bcf, billion cubic feet]

Milne Point Unit— Gas hydrate accumulation	Formation	Area (mi²)	Area (km²)	Area (acres)	Gas hydrate assessment unit	Median in-place volume of gas (bcf)	Median technical recoverable volume of gas (bcf)
Grays Peak	Sagavanirktok	0.1	0.3	85	SAG	6	5
Uncompahgre Peak	Sagavanirktok	0.3	0.8	167	SAG	11	9
Pikes Peak	Sagavanirktok	0.5	1.3	298	SAG	13	11
Redcloud Peak	Sagavanirktok	0.3	0.8	194	SAG	18	15
Blanca Peak	Sagavanirktok	0.5	1.3	328	SAG	22	19
Mt. Bierstadt	Sagavanirktok	0.4	1.0	268	SAG	32	27
Maroon Peak	Sagavanirktok	0.6	1.6	375	SAG	33	28
Mt. Princeton	Sagavanirktok	0.7	1.8	449	SAG	38	32
Mt. Bierstadt	Sagavanirktok	0.5	1.3	332	SAG	42	36
Mt. Sneffels	Sagavanirktok	0.8	2.1	516	SAG	46	39
Mt. Elbert “D”	Sagavanirktok	0.4	1.0	267	SAG	52	44
Mt. Antero	Sagavanirktok	1.5	3.9	955	SAG	75	64
Mt. Elbert “C”	Sagavanirktok	1.7	4.4	1,106	SAG	93	79
Crestone Peak	Sagavanirktok	2.7	7.0	1,728	SAG	186	158

National Petroleum Reserve in Alaska— Gas hydrate accumulation	Formation	Area (mi²)	Area (km²)	Area (acres)	Gas hydrate assessment unit	Median in-place volume of gas (bcf)	Median technical recoverable volume of gas (bcf)
Long’s Peak	Schrader Bluff	1.7	4.42	1,085	TSBPC	33	28
Windom Peak	Prince Creek	1.6	4.1	1,007	TSBPC	39	33
Mt. Columbia	Tuluvak	4.3	11.2	2,757	TSBPC	132	112
Humboldt Peak	Prince Creek	5.9	15.2	3,760	TSBPC	141	120
Mt. Massive	Tuluvak	6.9	17.7	4,384	TSBPC	190	162
Sunlight Peak	Prince Creek	8.9	23.2	5,725	TSBPC	201	171
Mt. Harvard	Tuluvak	7.9	20.6	5,080	TSBPC	210	179
Mt. Bross	Tuluvak	11.6	29.9	7,397	TSBPC	293	249
Kit Carson Peak	Tuluvak	12.8	33.2	8,206	TSBPC	382	325
Mt. Evans	Tuluvak	22.9	59.3	14,651	TSBPC	611	519

NAN = Nanushuk Formation Gas Hydrate Assessment Unit

TSBPC = Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit

SAG = Sagavanirktok Formation Gas Hydrate Assessment Unit

from the hydrate must have been produced up the wellbore. As shown in figure 26, at a well-abandonment pressure of 25 percent of the initial assumed formation pressure, roughly 85 percent of the original in-place gas hydrate must have been produced, and the borehole annular space could hold no more than roughly 15 percent of the gas evolved from the dissociated gas hydrate. It is acknowledged that the borehole annular space would likely contain a significant volume of water, but for calculation purposes, the presence of water in the borehole annular space would result in even higher gas recovery ratios. In this assessment, a gas hydrate recovery ratio of 85 percent (assuming a well-abandonment pressure 25 percent of hydrostatic) was used to convert the in-place gas volume estimates within each of the 3D seismic-inferred hydrate accumulations to a technically recoverable gas volume (table 3). It is important to emphasize that numerical gas hydrate production simulations (as reviewed by Anderson and others, 2011a, 2011b) also indicate relatively high gas-recovery ratios for producing gas hydrate accumulations.

Upon closer examination of the relative size (volume of technically recoverable gas) of the 3D seismic-inferred gas hydrate accumulations (table 3), it was determined that the accumulations as imaged in NPRA were generally larger than those in the MPU. Also, the seismic-imaged gas hydrate accumulations in NPRA were in reservoirs associated with the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU, whereas the MPU gas hydrate accumulations are limited to reservoirs within the Sagavanirktok Formation Gas Hydrate AU. Because of the apparent size difference between the gas hydrate accumulations in the Tuluvak-Schrader Bluff-Prince Creek and Sagavanirktok AUs, it was decided not to merge the accumulation sizes from the NPRA and MPU 3D seismic mapping effort and to use each set of accumulation sizes as independent analogs for inferred gas hydrate accumulations in various geologic settings throughout the Northern Alaska Gas Hydrate TPS. In figures 27A–B, the size (volume of technically recoverable gas) of the 3D-imaged gas hydrate accumulations in the MPU and NPRA have been depicted

Figure 25. Maps showing pre-drill estimates of *A*, gas hydrate saturation, and *B*, reservoir thickness for hydrate unit C in the Mount Elbert prospect. Modified from Inks and others (2009). As a condition of the seismic data use agreement, the latitude and longitude of the seismic data volume or the interpreted features cannot be shown on these maps.

Figure 26. Gas hydrate recovery ratio (percent of in-place gas within gas hydrates that would be recovered) as a product of the producing well abandonment pressure (pressure is shown as a percent of hydrostatic pore pressure).

in two bar graphs. For the most part, the accumulation sizes shown in figures 27A–B are characterized by log-normal distributions with increasing accumulation sizes to the right on the x-axes. However, analyses of well log and 2D seismic-inferred gas hydrate accumulations from outside the 3D seismic-imaged regions suggest that the accumulation sizes depicted in figures 27A–B may not fully represent the complete range of potential gas hydrate accumulation sizes within the Northern Alaska Gas Hydrate TPS.

Detailed 2D seismic mapping and well-log studies south of the MPU in the Eileen trend of the PBU (fig. 23) indicate the occurrence of fault-bounded gas hydrate accumulations considerably larger than those mapped in the MPU, with one accumulation covering an area of roughly 11 mi². It appears the Sagavanirktok section in the MPU, which overlies the Barrow arch, is more highly faulted than the same reservoirs to the south into the PBU, thus leading to the variable accumulation sizes from north-to-south along the Eileen gas hydrate trend. To more accurately represent the full range of the potential gas hydrate-accumulation sizes in the Eileen trend, two hypothetical accumulations were added to the MPU 3D seismic-inferred distribution (fig. 28A), with the size of these two larger accumulations imported from the NPRA 3D seismic-inferred size distribution (table 3, fig. 27B).

It was also determined that the NPRA 3D seismic-inferred accumulation size distribution (as depicted in figure 27B) did not accurately represent the full range of gas hydrate accumulation sizes likely to occur in NPRA. As discussed above, the ability of a given 3D seismic volume to image a potential gas hydrate accumulation is dependent on the frequency content of the available seismic data and the thickness and relative concentration of gas hydrate occurrences in the area being assessed. The frequency content of most of the NPRA 3D seismic volumes was considerably less than that of the MPU 3D volume used in this study; thus, it was assumed that some of the smaller

gas hydrate accumulations in NPRA were not imaged. It was decided to augment the NPRA 3D seismic-inferred gas hydrate accumulation distribution with three relatively small hypothetical accumulations (fig. 28B) as imported from the MPU seismic inferred size distribution (table 3, fig. 27A).

The last critical step in the analysis of the “modified” MPU and NPRA 3D seismic-inferred gas hydrate accumulation size distributions (table 3, figs. 28A–B) was the selection of the minimum accumulation size to be considered in this assessment. Based mostly on the statistical nature of the two gas hydrate-size distributions, the minimum accumulation size was assumed to be 20 billion cubic feet (BCF) (3.33 Million Barrels of Oil Equivalent (MMBOE)) of technically recoverable gas. This minimum accumulation size is smaller than those used in other USGS assessments in northern Alaska, in recognition of the fact that most of the seismically inferred gas hydrate accumulations are in stacked reservoir sections and would likely be produced together from the same wells and production facilities.

The selection of the minimum, median, and maximum undiscovered accumulation sizes for each of the three gas hydrate AUs (as required within the USGS assessment methodology) is further discussed in the “Assessment-Data Form” section of this report.

6.d. Undiscovered Gas Hydrate Accumulations—Number of Accumulations

The next most critical component in the USGS assessment methodology is the accurate prediction of the number of undiscovered gas hydrate accumulations that may exist in the Northern Alaska Gas Hydrate TPS. It was again decided to rely on the MPU and NPRA 3D seismic analysis results to predict the possible number of gas hydrate accumulations in each of the AUs. As discussed earlier, the 3D seismic data volume from the MPU (figs. 9, 10, 24) covers an area of 155 mi², whereas the four 3D seismic volumes in NPRA cover an area of 729 mi². A total of nine gas hydrate accumulations (exceeding the minimum accumulation size for this assessment of 20 BCF) were identified within the coverage area of the MPU 3D seismic volume. Similarly, there were 10 gas hydrate accumulations (exceeding the minimum accumulation size for this assessment of 20 BCF) within the area covered by the four 3D seismic volumes in NPRA. In each case, the number of seismic-inferred gas hydrate accumulations relative to the area each survey covers was used to develop a “gas hydrate discovery ratio,” which for the MPU 3D volume is 0.0581 gas hydrate accumulations for every square mile and for the NPRA 3D volumes is 0.0137 gas hydrate accumulations for every square mile. These “gas hydrate discovery ratios” were then used to estimate the number of gas hydrate accumulations (exceeding the minimum accumulation size) that may be within the areas of the North Slope without available 3D seismic coverage.

Figure 27. Bar-graph showing sizes of 3D-imaged gas hydrate accumulations in *A*, the Milne Point Unit (MPU, see fig. 10 for location) and *B*, the National Petroleum Reserve in Alaska (NPR). Detailed data are given in table 3.

Figure 28. Bar-graph showing sizes of the 3D-imaged gas hydrate accumulations in A, the Milne Point Unit (MPU; see fig. 10 for location), and B, the National Petroleum Reserve in Alaska (NPRA), that have been modified to account for larger and smaller inferred gas hydrate accumulations in the MPU and NPRA, respectively. Also accumulations with sizes below the minimum accumulation size (20 BCF) have been deleted from these plots.

Before attempting to use the MPU or NPRA 3D seismic-derived “gas hydrate discovery ratios,” it was recognized that these ratios are subject to uncertainty and are best represented as a probability distribution. For this assessment, the actual “gas hydrate discovery ratio” calculated from the MPU (0.0581 accumulations per square mile) and NPRA (0.0137 accumulations per square mile) prospecting efforts were set at the statistical mode; for the distribution around the mode, the maximum number of accumulations in each case was set at three times the value of the mode, and the minimum number of accumulations was set at the actual number of seismic identified gas hydrate accumulations in each of the AUs or was set at one in AUs with no 3D seismic inferred gas hydrate accumulations.

The next and final step in the assessment was to assign the appropriate “gas hydrate discovery ratio – distribution” (table 4) to each AU. However, the regional analysis of available 2D seismic and well-log data, along with geochemical analyses of well drill cuttings, core samples, and mud logs, indicates that the geologic controls on the occurrence of gas hydrate are not uniform throughout the defined AUs (Lorenson and others, 2011). As discussed in the “Gas Source and Migration” section of this report, most of the gas within the near-surface Eileen and Tarn gas hydrate accumulations had migrated from deeply buried thermogenic sources and is closely linked to the presence of conventional oil and gas fields. Thus, by considering the role of gas source and migration within the gas hydrate petroleum system, it is reasonable to assume that in areas with known conventional oil and gas accumulations and (or) in areas with evidence of an active petroleum system delivering thermogenic gas to the gas hydrate stability zone, there is an increased likelihood that these anomalous areas will contain significantly more gas hydrate accumulations.

To assess the potential contribution of thermogenic gas migration to the formation of gas hydrate accumulations on the North Slope, gas geochemistry data from 35 “wells-of-opportunity” (table 5, fig. 29; Lorenson and others, 2011; Lorenson and Collett, 2011) were examined. The “wells-of-opportunity,” as described by Lorenson and Collett (2011), are mostly industry exploratory and development wells from which the USGS received drill cuttings and flowed gas samples in order to ascertain the composition and source of the gas within the inferred gas hydrate accumulations. For the wells listed in table 5 and highlighted on the map in figure 29 as wells with either significant or limited evidence of thermogenic gas in the gas hydrate stability zone, the area around these wells is more likely to contain a higher number of gas hydrate accumulations. The same is also true for the area around known conventional oil and gas fields (table 6). As discussed above, gas hydrate accumulations are commonly closely associated with more deeply buried conventional oil and gas fields that have leaked or possibly spilled gas that has migrated into the overlying gas hydrate stability zone, thus leading to a greater likelihood for the occurrence of gas hydrate.

Table 4. Determinations of “gas hydrate discovery ratio—distributions” resulting from the Milne Point Unit and the National Petroleum Reserve in Alaska 3D seismic gas hydrate prospecting effort.

Milne Point Unit		Number of accumulations per square mile
High probability		
Minimum		0.0111
Mode		0.0581
Maximum		0.1750
Middle probability		
Minimum		0.0056
Mode		0.0278
Maximum		0.0833
Low probability		
Minimum		0.0028
Mode		0.0139
Maximum		0.0417
National Petroleum Reserve in Alaska		Number of accumulations per square mile
High probability		
Minimum		0.0056
Mode		0.0137
Maximum		0.0417
Middle probability		
Minimum		0.0028
Mode		0.0083
Maximum		0.0250
Low probability		
Minimum		0.0028
Mode		0.0056
Maximum		0.0167

In order to assess the relative impact of thermogenic gas sources on the number of gas hydrate accumulations in each of the AUs, the “gas hydrate discovery ratio—distributions,” as described above and listed in table 4, were expanded to include three options: (1) high probability, (2) middle probability, and (3) low probability. Within an area determined to have a high probability for the presence of thermogenic gas in the gas hydrate stability zone, the actual seismic-derived “gas hydrate discovery ratio—distribution” calculated from the available 3D surveys (table 4: mode of 0.0581 gas hydrate accumulations per square mile for the MPU and 0.0137 gas hydrate accumulations per square mile for NPRA) was assigned to this area. For an area with a middle probability for the presence of thermogenic gas in the gas hydrate stability zone, the actual seismic derived “gas hydrate discovery ratio—distribution” was reduced by 50 percent, which yielded a new middle probability mode of 0.0278 gas hydrate accumulations per square mile for the MPU distribution and 0.0083 gas hydrate accumulations per square mile for the NPRA distribution (table 4). For an area with a low probability for the presence of thermogenic gas in the gas hydrate stability zone, the actual seismic-derived “gas hydrate discovery ratio—distribution” was again reduced by another 50 percent, which yielded a new low probability mode of 0.0139 gas hydrate

Table 5. List of wells of opportunity (see fig. 29) in which analyses of gas samples have been used to ascertain the composition and source of the gas within each of the gas hydrate assessment units in northern Alaska. Wells highlighted in blue are characterized by “significant” evidence for thermogenic gas in the mapped limits of the gas hydrate stability zone, whereas wells highlighted in green are assessed to have “limited” evidence of thermogenic gas in the gas hydrate stability zone. (API, American Petroleum Institute)

Well API number	Operator current name	Well name	Surface latitude	Surface longitude
Wells with significant evidence of thermogenic gas				
50029233020000	BP EXPL ALASKA INC	MT. ELBERT 1	70.4556	149.4132
50029232950000	CONOCOPHILLIPS AK	KUPARUK RIVER UNIT WEST SAK 1R-EAST	70.3954	149.5591
50029232960000	CONOCOPHILLIPS AK	KUPARUK RIVER UNIT WEST SAK 1H-SOUTH	70.3949	149.5579
50029210840000	ARCO ALASKA INC	KUPARUK RIVER UNIT 2B-10	70.2894	149.9375
50029211840000	ARCO ALASKA INC	KUPARUK RIVER UNIT 2D-15	70.2840	149.7617
50029206990000	ARCO OIL & GAS CORP	WEST SAK 23	70.4037	149.9383
50103200860000	ARCO ALASKA INC	KUPARUK RIVER UNIT 3H-9	70.4118	150.0117
50029216560000	ARCO ALASKA INC	KUPARUK RIVER UNIT 3K-9	70.4332	149.7608
50029219970000	CONOCO INCORPORATED	MILNE POINT UNIT E-4	70.4554	149.4367
50029203530000	SOHIO PETROLEUM CO	PRUDHOE BAY UNIT R-1	70.3455	148.9108
50029220470000	BP EXPL ALASKA INC	PRUDHOE BAY UNIT S-26	70.3536	149.0302
50029220460000	BP EXPL ALASKA INC	PRUDHOE BAY UNIT Z-7	70.2977	149.1955
50029217870000	BP EXPL ALASKA INC	PRUDHOE BAY UNIT Z-8	70.2978	149.1996
50103203490000	PHILLIPS ALASKA INC	KUPARUK RIVER UNIT TARN 2N-305	70.1713	150.3143
50103203600000	PHILLIPS ALASKA INC	ATLAS 1	70.1518	150.5505
50029230610000	BP EXPL ALASKA INC	MILNE PT UNIT SCHRADER BLUFF S-15	70.4097	149.4663
50103204770000	CONOCOPHILLIPS AK	CARBON 1	70.2479	151.8888
50103204800000	CONOCOPHILLIPS AK	SPARK 4	70.2884	151.7924
50103204790000	CONOCOPHILLIPS AK	SCOUT 1	70.2867	151.9571
50103205060000	CONOCOPHILLIPS AK	IAPETUS 2	70.4079	151.1831
50279200170000	FEX LP	AMAGUQ 2	70.3932	155.8066
50029232990000	CONOCOPHILLIPS AK	ANTIGUA 1	70.1809	149.5267
50279200110000	CONOCOPHILLIPS AK	KOKODA 1	70.2850	153.1375
50279200120000	CONOCOPHILLIPS AK	KOKODA 5	70.3344	153.2046
50103204810000	CONOCOPHILLIPS AK	PLACER 1	70.3467	150.3983
Wells with limited evidence of thermogenic gas				
50279200180000	FEX LP	AKLAQYAAQ 1	70.5573	155.4204
50279200130000	CONOCOPHILLIPS AK	NOATAK 1	70.3802	153.1335
50301200030000	U S DEPT OF INTER AK	WAINWRIGHT 1	70.6441	160.0237
50103201900000	EXXON CO USA	THETIS ISLAND 1	70.5539	150.1522
50279200090000	TOTAL E&P USA INC	CARIBOU 26-11 1	70.1898	153.0876
Wells with no evidence of thermogenic gas				
50279200190000	FEX LP	AKLAQ 6	70.7123	154.6077

accumulations per square mile for the MPU distribution and 0.0056 gas hydrate accumulations per square mile for the NPRA distribution (table 4).

The AU maps in figures 30, 31, and 32 depict the areas in each AU that exhibit low, middle, or high probability for the presence of thermogenic-derived gas hydrate accumulations. The Nanushuk Formation Gas Hydrate AU (fig. 30, table 7) was divided into four regions with two low probability and two middle probability map units; each area was assigned the appropriate NPRA “gas hydrate discovery ratio—distribution” as listed in table 4. The Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU (fig. 31, table 8) was divided into six regions with one low probability, three middle probability, and two high probability map units; each area was assigned the appropriate NPRA “gas hydrate discovery ratio—distribution” as listed in table 4. The Sagavanirktok Formation Gas Hydrate AU (fig. 32, table 9) was divided into five regions with one low probability, three middle probability,

and one high probability map units; each area was assigned the appropriate MPU “gas hydrate discovery ratio—distribution” as listed in table 4.

The selection of the final minimum, mode, and maximum number of undiscovered gas hydrate accumulations, as required within the USGS assessment methodology, for each of the three gas hydrate AUs are further discussed in the “Assessment-Data Form” section of this report.

7. Assessment-Data Form

Information required for the assessment of the undiscovered gas hydrate resources on the Alaska North Slope, was entered on a form termed the Seventh Approximation Data Form for Conventional Assessment Units (Klett and others, 2005). The completed forms for each AU are reproduced in Appendixes A–1, A–2, and A–3. The assessment-data form contains six sections as described below.

Figure 29. Map showing locations of the wells of opportunity (table 5) from which the analysis of gas samples were used to ascertain the composition and source of the gas within each of the gas hydrate assessment units in northern Alaska. Also shown are the locations of discovered conventional oil and gas fields (table 6). (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

7.a. Identification Information

Identification information includes the assessors' names, the date of the assessment meeting at which input data were discussed and reviewed, and the names and numerical codes for each AU. Following a numbering system established by the USGS to facilitate petroleum resource assessments, the following unique numbers have been assigned to the Alaska North Slope gas hydrate TPS and AUs:

Northern Alaska Gas Hydrate TPS: 500102

Sagavanirktok Formation Gas Hydrate AU: 50010201

Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU: 50010202

Nanushuk Formation Gas Hydrate AU: 50010203

In this system "5" denotes the region (North America), "001" denotes the province (North Slope Alaska), and "02" denotes the TPS. The AUs are numbered as shown above with the last two digits denoting the specific AU.

7.b. Characteristics of Assessment Unit

This section of the form contains basic input data and information about the nature of the AU. In the first entry, the AU is classified as being either oil-prone or gas-prone. Because the assessment was for gas hydrates, it was assumed that all three AUs as defined contain only gas. The minimum accumulation size for all three AUs was set at 20 billion cubic feet (BCF) (3.33 MMBOE) of technically recoverable gas. Because none of the well-log- and (or) seismic-inferred gas hydrate accumulations on the North Slope have been produced, all of the AUs are considered hypothetical with no discovered accumulations exceeding the minimum gas hydrate accumulation size.

The assessment unit probability attributes for all three AUs were rated high, with a probability of 1.0 (or 100 percent) that there was at least one undiscovered gas hydrate accumulation greater than the minimum size existing in each AU. Ample evidence of gas hydrate occurrences in the Eileen and Tarn trends justifies the high ranking of the assessment unit probability for the Sagavanirktok Formation Gas Hydrate AU and the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU. It can also be assumed that the Nanushuk Formation Gas Hydrate AU, being part of a prolific petroleum system, should have a high assessment unit probability ranking.

7.c. Undiscovered Accumulations

The third section of the data form is for recording the number and sizes of undiscovered oil and gas accumulations used to calculate the undiscovered resources that have potential for additions to reserves within the forecast span of 30 years. Minimum, median, and maximum values (F_{100} , F_{50} , and

Table 6. List of conventional oil and gas fields (see fig. 29) used in part to assign "gas hydrate discovery ratio—distributions" to various portions of the gas hydrate assessment units.

Field	Field type	Field	Field type
UMIAT	Oil	NORTHSTAR SADLEROGCHIT	Oil
SOUTH BARROW	Gas	NORTHSTAR SAG RIVER	Oil
FISH CREEK	Oil	HEMI SPRINGS	Oil
MEADE	Gas	NIAKUK	Oil
SIMPSON	Oil	COLVILLE DELTA	Oil
WOLF CREEK	Gas	SANDPIPER	Oil
GUBIK	Gas	HAMMERHEAD	Oil
SQUARE LAKE	Gas	STUMP ISLAND	Oil
EAST UMIAT	Gas	POINT MCINTYRE	Oil
PRUDHOE BAY	Oil	SIKULIK	Gas
LISBURN	Oil	BURGER	Oil
KUPARUK	Oil	BADAMI	Oil
SCHRADER BLUFF	Oil	STINSON	Oil
WEST SAK	Oil	TARN	Oil
UGNU	Oil	TABASCO	Oil
KUPARUK	Oil	FIORD	Oil
SAG RIVER	Oil	KALUBIK	Oil
AURORA	Oil	KUVLUM	Oil
KAVIK	Gas	CASCADE	Oil
GWYDYR BAY	Oil	THETIS ISLAND	

F_0 fractals) are estimated for the sizes of the undiscovered accumulations. The number of undiscovered accumulations, however, is reported as minimum, mode, and maximum values.

As discussed in the "Undiscovered Gas Hydrate Accumulations—Number of Accumulations" section and shown in tables 7, 8, and 9, the number of undiscovered gas hydrate accumulations has been derived from (1) the analysis of the petroleum system controlling the presence of gas hydrate in each AU and (2) the application of "gas hydrate discovery ratio—distributions" resulting from the analysis of the 3D seismic volumes in the MPU and NPRA. The actual values entered into the assessment-data form were slightly altered from the mathematically derived number of undiscovered gas hydrate accumulations as listed in tables 7, 8, and 9. This was done for the purpose of more accurately predicting the minimum number of undiscovered gas hydrate accumulations and of rounding the estimated number of accumulations to the nearest significant value.

As discussed in the "Undiscovered Gas Hydrate Accumulations—Sizes of Accumulations" section and shown in figures 28A–B, the sizes of the undiscovered gas hydrate accumulations in each of the AUs were determined by applying the two accumulation-size distributions developed in this study from the analysis of the 3D seismic volumes in the MPU and NPRA. In all three AUs, the minimum accumulation size was set at 20 BCF (3.33 MMBOE). For the Sagavanirktok Formation Gas Hydrate AU, the MPU 3D seismic-derived accumulation size distribution as shown in figure 28A was used to derive a median accumulation size of 45 BCF (rounded up from the mathematically derived value of 44 BCF). The maximum size of the accumulations in the Sagavanirktok Formation Gas Hydrate AU was projected from

Figure 30. A, map of the Nanushuk Formation Gas Hydrate Assessment Unit showing areas outlined with high, middle or low “gas hydrate discovery ratio—distributions” (see table 7). B, same as A, but also includes locations of wells of opportunity and discovered oil and gas fields from figure 29. (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 30. A, map of the Nanushuk Formation Gas Hydrate Assessment Unit showing areas outlined with high, middle or low “gas hydrate discovery ratio—distributions” (see table 7). B, same as A, but also includes locations of wells of opportunity and discovered oil and gas fields from figure 29. (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)—Continued

Figure 31. A, map of the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit showing areas outlined with high, middle or low “gas hydrate discovery ratio—distributions” (see table 8). B, same as A, but also includes locations of wells of opportunity and discovered oil and gas fields from figure 29. (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 31. A, map of the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit showing areas outlined with high, middle or low “gas hydrate discovery ratio—distributions” (see table 8). B, same as A, but also includes locations of wells of opportunity and discovered oil and gas fields from figure 29. (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)—Continued

Figure 32. A, Map of the Sagavanirktok Formation Gas Hydrate Assessment Unit with the areas outlined with high, middle or low “gas hydrate discovery ratio—distributions” (table 9); B, with location of wells of opportunity and discovered oil and gas fields (fig. 29). (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)

Figure 32. A, Map of the Sagavanirktok Formation Gas Hydrate Assessment Unit with the areas outlined with high, middle or low “gas hydrate discovery ratio—distributions” (table 9); B, with location of wells of opportunity and discovered oil and gas fields (fig. 29). (NPRA, National Petroleum Reserve in Alaska; ANWR, Alaska National Wildlife Refuge)—Continued

Table 7. Estimates of the number of undiscovered gas hydrate accumulations in the Nanushuk Formation Gas Hydrate Assessment Unit (see fig. 30).[mi², square mile]

Map unit	Area (mi ²)	Number of gas hydrate accumulations		
		Minimum	Mode	Maximum
Low 1	3,030	8	17	51
Low 2	19,675	55	109	328
Middle 1	7,617	21	63	190
Middle 2	641	2	5	16
Total -	30,963	86	195	585
Used -		1	195	600

Table 8. Estimates of the number of undiscovered gas hydrate accumulations in the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit (see fig. 31).[mi², square mile]

Map unit	Area (mi ²)	Number of gas hydrate accumulations		
		Minimum	Mode	Maximum
Low 1	2,002	6	11	33
Middle 1	3,011	8	25	75
Middle 2	2,640	7	22	66
Middle 3	1,210	3	10	30
High 1	2,738	15	38	114
High 2	2,742	15	38	114
Total -	14,343	55	143	433
Used -		1	145	450

Table 9. Estimates of the number of undiscovered gas hydrate accumulations in the Sagavanirktok Formation Gas Hydrate Assessment Unit (see fig. 32).[mi², square mile]

Map unit	Area (mi ²)	Number of gas hydrate accumulations		
		Minimum	Mode	Maximum
Low 1	3,510	10	49	146
Middle 1	5,361	30	149	447
Middle 2	910	5	25	76
Middle 3	253	1	7	21
High 1	554	6	32	97
Total -	10,588	52	262	787
Used -		9	260	800

the MPU accumulation size distribution at a value of 450 BCF. For the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU and the Nanushuk Formation Gas Hydrate AU, the NPRA 3D seismic-derived accumulation size distribution as shown in figure 28B was used to derive a median accumulation size of 120 BCF for both AUs. The maximum size of the accumulations in the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU and the Nanushuk Formation Gas Hydrate AU was also projected from the NPRA accumulation size distribution at a value of 675 BCF, but it was decided to increase the maximum accumulation size in the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU to 700 BCF to account for some of the apparent larger structures mapped in this AU.

7.d. Assessment of Coproducts

As described in the “Gas Hydrate Technical Review” section, in almost all cases, gas hydrates in nature contain mostly methane with only one reported case of a Structure H hydrate (recovered in a shallow core from an oil seep in the Gulf of Mexico) that was stabilized with a liquid range hydrocarbon. Thus, it was assumed that the undiscovered gas hydrate accumulations predicted in this assessment would not contain any natural gas liquids (that is, no coproducts).

7.e. Selected Ancillary Data for Undiscovered Accumulations

The data entered into this section of the form are useful for economic and environmental analyses of the assessment results, but do not contribute directly to the assessment calculations. Ancillary data as shown for each of the AUs include estimates of the inert-gas content (mostly nitrogen in this assessment), carbon dioxide content, hydrogen sulfide content, and estimated drilling and water depths.

7.f. Allocations of Assessed Undiscovered Resources

The resource allocation portion of the form includes input percentages necessary to allocate assessed undiscovered gas hydrate resources to various land entities of interest within each AU, as well as to the offshore portion of each entity. For this assessment, entities of interest include the State Lands (State of Alaska), the Federal Lands (Bureau of Land Management; U.S. Fish and Wildlife Service), Private Lands, Tribal Lands, a small category of Other Lands, and Alaska Offshore (State of Alaska). The estimated additions to reserves are also classified by the ecosystem in which they are likely to be found.

8. Resource Assessment Results

The USGS assessment strategy provides estimates of the volumes of undiscovered petroleum resources that are technically recoverable (table 10). For the Northern Alaska Gas Hydrate TPS, the USGS estimates that the total undiscovered natural gas resources in gas hydrate range between 25.2 and 157.8 trillion cubic feet (TCF; 95-percent and 5-percent probabilities of greater than these amounts, respectively), with a mean estimate of 85.4 TCF. Of this mean estimate, (1) about 24 percent (20.6 TCF) is in the Sagavanirktok Formation Gas Hydrate AU, (2) 33 percent (28.0 TCF) is within the Tuluva-Schrader Bluff-Prince Creek Formations Gas Hydrate AU, and (3) 43 percent (36.9 TCF) is in the Nanushuk Formation Gas Hydrate AU (table 10). Given that relatively few wells have penetrated the expected gas hydrate accumulations in these three AUs, there is significant

Table 10. Alaska North Slope—Gas hydrate assessment results. Results shown are fully risked estimates. F95 represents a 95-percent chance of at least the amount tabulated; other fractiles are defined similarly. Fractiles are additive, assuming perfect positive correlations.

[BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids; NGL, natural gas liquids; TPS, total petroleum system; AU, assessment unit]

Total Petroleum System and Assessment Unit	Field type	Total undiscovered resources							
		Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean
Northern Alaska Gas Hydrate TPS									
Sagavanirktok Formation Gas Hydrate AU	Gas	6,285	19,490	37,791	20,567	0	0	0	0
Tuluwak-Schrader Bluff-Prince Creek Formations Gas Hydrate AU	Gas	8,173	26,532	51,814	28,003	0	0	0	0
Nanushuk Formation Gas Hydrate AU	Gas	10,775	35,008	68,226	36,857	0	0	0	0
Total Undiscovered Resources		25,233	81,030	157,831	85,427	0	0	0	0

geologic uncertainty in these estimates that is reflected in the range of estimates in table 10. Of the estimated 85.4 TCF of gas within hydrates on the North Slope, 56 percent is on federally managed lands, 39 percent on lands and offshore waters managed by the State of Alaska, and 4 percent on Native lands.

The mean estimate of 85.4 TCF of gas within the gas hydrates of northern Alaska is considerably less than the 590 TCF reported in the 1995 USGS assessment (Collett, 1995). It is critical to note that the 1995 assessment only dealt with estimating the in-place volume of gas with hydrates, whereas this more recent assessment dealt only with technically recoverable gas. Also, the 1995 assessment included the offshore Federal waters (fig. 1A–B), which were not included in this assessment. In addition, the assessment results reported here are based on geologic data that were not previously available, which afforded a greatly improved appreciation of the North Slope gas hydrate petroleum system.

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10. Appendixes

Appendix 1. Basic input data (Seventh data form) used in estimates of the numbers and sizes of undiscovered gas hydrate accumulations in the Sagavanirktok Formation Gas Hydrate Assessment Unit (50010201) in the Northern Alaska Gas Hydrate Total Petroleum System.

SEVENTH APPROXIMATION DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

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Region:	North America	Number:	5
Province:	Northern Alaska	Number:	5001
Total Petroleum System:	Northern Alaska Gas Hydrate	Number:	500102
Assessment Unit:	Sagavanirktok Formation Gas Hydrate	Number:	50010201
Based on Data as of:			
Notes from Assessor:			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) or Gas (≥20,000 cfg/bo overall): Gas

What is the minimum accumulation size? 3.33 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 0 Gas: 0
Established (>13 accums.) Frontier (1-13 accums.) Hypothetical (no accums) X

Median size (grown) of discovered oil accumulations (mmbo):

1st 3rd 2nd 3rd 3rd 3rd

Median size (grown) of discovered gas accumulations (bcfg):

1st 3rd 2nd 3rd 3rd 3rd

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. CHARGE: Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	<u>1.0</u>
2. ROCKS: Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	<u>1.0</u>
3. TIMING OF GEOLOGIC EVENTS: Favorable timing for an undiscovered accum. ≥ minimum size:	<u>1.0</u>

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0) <u>0</u>	mode <u>0</u>	maximum <u>0</u>
Gas Accumulations:	minimum (>0) <u>9</u>	mode <u>260</u>	maximum <u>800</u>

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum <u> </u>	median <u> </u>	maximum <u> </u>
Gas in Gas Accumulations (bcfg):	minimum <u>20</u>	median <u>45</u>	maximum <u>450</u>

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS

(uncertainty of fixed but unknown values)

<u>Oil Accumulations:</u>	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	<u> </u>	<u> </u>	<u> </u>
NGL/gas ratio (bngl/mmcfg)	<u> </u>	<u> </u>	<u> </u>
<u>Gas Accumulations:</u>	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	<u>0</u>	<u>0</u>	<u>0</u>
Oil/gas ratio (bo/mmcfg)	<u> </u>	<u> </u>	<u> </u>

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS

(variations in the properties of undiscovered accumulations)

<u>Oil Accumulations:</u>	minimum		mode		maximum
API gravity (degrees)	<u> </u>		<u> </u>		<u> </u>
Sulfur content of oil (%)	<u> </u>		<u> </u>		<u> </u>
Depth (m) of water (if applicable)	<u> </u>		<u> </u>		<u> </u>
	minimum	F75	mode	F25	maximum
Drilling Depth (m)	<u> </u>		<u> </u>		<u> </u>
<u>Gas Accumulations:</u>	minimum		mode		maximum
Inert gas content (%)	<u>1</u>		<u>2</u>		<u>4</u>
CO ₂ content (%)	<u>1</u>		<u>2</u>		<u>5</u>
Hydrogen-sulfide content (%)	<u>0</u>		<u>0</u>		<u>0</u>
Depth (m) of water (if applicable)	<u>0</u>		<u>10</u>		<u>20</u>
	minimum	F75	mode	F25	maximum
Drilling Depth (m)	<u>300</u>		<u>1200</u>		<u>1400</u>

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO STATES

1. Alaska represents 100 area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

<u>Gas in Gas Accumulations:</u>	
Volume % in entity	100

2. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

3. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

4. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

5. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

6. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

Assessment Unit (name, no.)
 Sagavanirktok Formation Gas Hydrate, 50010201

7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO LAND ENTITIES
Surface Allocations (uncertainty of a fixed value)

1. <u>Federal Lands</u>	represents	<u>18.03</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>10.00</u>	<u> </u>
2. <u>Private Lands</u>	represents	<u>0.16</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>0.00</u>	<u> </u>
3. <u>Tribal Lands</u>	represents	<u>3.04</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>3.00</u>	<u> </u>
4. <u>Other Lands</u>	represents	<u>1.44</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>2.00</u>	<u> </u>
5. <u>AK State Lands</u>	represents	<u>59.14</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>67.00</u>	<u> </u>
6. <u>AK Offshore</u>	represents	<u>18.19</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>18.00</u>	<u> </u>

Assessment Unit (name, no.)
 Sagavanirktok Formation Gas Hydrate, 50010201

7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO FEDERAL LAND SUBDIVISIONS
Surface Allocations (uncertainty of a fixed value)

1. <u>Bureau of Land Management (BLM)</u>	represents	<u>0.97</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>0.00</u>	<u> </u>
2. <u>BLM Wilderness Areas (BLMW)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
3. <u>BLM Roadless Areas (BLMR)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
4. <u>National Park Service (NPS)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
5. <u>NPS Wilderness Areas (NPSW)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
6. <u>NPS Protected Withdrawals (NPSP)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>

Assessment Unit (name, no.)
 Sagavanirktok Formation Gas Hydrate, 50010201

7. US Forest Service (FS) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. USFS Wilderness Areas (FSW) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. USFS Roadless Areas (FSR) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. USFS Protected Withdrawals (FSP) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. US Fish and Wildlife Service (FWS) represents 17.06 area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10.00

12. USFWS Wilderness Areas (FWSW) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

13. <u>USFWS Protected Withdrawals (FWSP)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
14. <u>Wilderness Study Areas (WS)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
15. <u>Department of Energy (DOE)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
16. <u>Department of Defense (DOD)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
17. <u>Bureau of Reclamation (BOR)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
18. <u>Tennessee Valley Authority (TVA)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

19. Other Federal represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

20. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

Assessment Unit (name, no.)
Sagavanirktok Formation Gas Hydrate, 50010201

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO ECOSYSTEMS
Surface Allocations (uncertainty of a fixed value)

1. <u>Coastal Plain (CSTP)</u>	represents	<u>30.12</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>30</u>	<u> </u>
2. <u>Foothills (FTHL)</u>	represents	<u>51.68</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>52</u>	<u> </u>
3. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
4. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
5. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
6. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>

Assessment Unit (name, no.)
 Sagavanirktok Formation Gas Hydrate, 50010201

7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

Appendix 2. Basic input data (Seventh data form) used in estimates of the numbers and sizes of undiscovered gas hydrate accumulations in the Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate Assessment Unit (50010202) in the Northern Alaska Gas Hydrate Total Petroleum System.

**SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)**

IDENTIFICATION INFORMATION

Assessment Geologist:	T.S. Collett, W.F. Agena, M.W. Lee, M.V. Zyrianova	Date:	4-Jun-08
Region:	North America	Number:	5
Province:	Northern Alaska	Number:	5001
Total Petroleum System:	Northern Alaska Gas Hydrate	Number:	500102
Assessment Unit:	Tuluvak-Schrader Bluff-Prince Creek Form Gas Hydrate	Number:	50010202
Based on Data as of:			
Notes from Assessor:			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) or Gas (≥20,000 cfg/bo overall): Gas

What is the minimum accumulation size? 3.33 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size:	Oil: <u>0</u>	Gas: <u>0</u>
Established (>13 accums.)	Frontier (1-13 accums.)	Hypothetical (no accums.) <u>X</u>

Median size (grown) of discovered oil accumulations (mmbo):

1st 3rd 2nd 3rd 3rd 3rd

Median size (grown) of discovered gas accumulations (bcfg):

1st 3rd 2nd 3rd 3rd 3rd

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. CHARGE: Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	<u>1.0</u>
2. ROCKS: Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	<u>1.0</u>
3. TIMING OF GEOLOGIC EVENTS: Favorable timing for an undiscovered accum. ≥ minimum size:	<u>1.0</u>

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0) <u>0</u>	mode <u>0</u>	maximum <u>0</u>
Gas Accumulations:	minimum (>0) <u>1</u>	mode <u>145</u>	maximum <u>450</u>

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum <u> </u>	median <u> </u>	maximum <u> </u>
Gas in Gas Accumulations (bcfg):	minimum <u>20</u>	median <u>120</u>	maximum <u>700</u>

Assessment Unit (name, no.)

Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202**AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS**

(uncertainty of fixed but unknown values)

<u>Oil Accumulations:</u>	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	<u> </u>	<u> </u>	<u> </u>
NGL/gas ratio (bnlg/mmcfg)	<u> </u>	<u> </u>	<u> </u>
<u>Gas Accumulations:</u>	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	<u>0</u>	<u>0</u>	<u>0</u>
Oil/gas ratio (bo/mmcfg)	<u> </u>	<u> </u>	<u> </u>

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS

(variations in the properties of undiscovered accumulations)

<u>Oil Accumulations:</u>	minimum		mode		maximum
API gravity (degrees)	<u> </u>		<u> </u>		<u> </u>
Sulfur content of oil (%)	<u> </u>		<u> </u>		<u> </u>
Depth (m) of water (if applicable)	<u> </u>		<u> </u>		<u> </u>
	minimum	F75	mode	F25	maximum
Drilling Depth (m)	<u> </u>		<u> </u>		<u> </u>
<u>Gas Accumulations:</u>	minimum		mode		maximum
Inert gas content (%)	<u>1</u>		<u>2</u>		<u>4</u>
CO ₂ content (%)	<u>1</u>		<u>2</u>		<u>5</u>
Hydrogen-sulfide content (%)	<u>0</u>		<u>0</u>		<u>0</u>
Depth (m) of water (if applicable)	<u>0</u>		<u>5</u>		<u>15</u>
	minimum	F75	mode	F25	maximum
Drilling Depth (m)	<u>300</u>		<u>900</u>		<u>1200</u>

Assessment Unit (name, no.)

Tuluwak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO STATES

Surface Allocations (uncertainty of a fixed value)

1. Alaska represents 100 area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

<u>Gas in Gas Accumulations:</u>	
Volume % in entity	100

2. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

3. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

4. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

5. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

6. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

Assessment Unit (name, no.)

Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

7. _____ represents _____ area % of the AU

Oil in Oil Accumulations: minimum mode maximum

Volume % in entity

Gas in Gas Accumulations:

Volume % in entity

8. _____ represents _____ area % of the AU

Oil in Oil Accumulations: minimum mode maximum

Volume % in entity

Gas in Gas Accumulations:

Volume % in entity

9. _____ represents _____ area % of the AU

Oil in Oil Accumulations: minimum mode maximum

Volume % in entity

Gas in Gas Accumulations:

Volume % in entity

10. _____ represents _____ area % of the AU

Oil in Oil Accumulations: minimum mode maximum

Volume % in entity

Gas in Gas Accumulations:

Volume % in entity

11. _____ represents _____ area % of the AU

Oil in Oil Accumulations: minimum mode maximum

Volume % in entity

Gas in Gas Accumulations:

Volume % in entity

12. _____ represents _____ area % of the AU

Oil in Oil Accumulations: minimum mode maximum

Volume % in entity

Gas in Gas Accumulations:

Volume % in entity

Assessment Unit (name, no.)
Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO LAND ENTITIES

Surface Allocations (uncertainty of a fixed value)

1. <u>Federal Lands</u>	represents	<u>43.47</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>50.00</u>	<u> </u>
2. <u>Private Lands</u>	represents	<u>0.03</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>0.00</u>	<u> </u>
3. <u>Tribal Lands</u>	represents	<u>3.48</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>4.00</u>	<u> </u>
4. <u>Other Lands</u>	represents	<u>1.07</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>1.00</u>	<u> </u>
5. <u>AK State Lands</u>	represents	<u>45.35</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>38.00</u>	<u> </u>
6. <u>AK Offshore</u>	represents	<u>6.59</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>7</u>	<u> </u>

Assessment Unit (name, no.)
Tuluwak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO FEDERAL LAND SUBDIVISIONS

Surface Allocations (uncertainty of a fixed value)

1. <u>Bureau of Land Management (BLM)</u>	represents	<u>43.47</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>50</u>	<u> </u>
2. <u>BLM Wilderness Areas (BLMW)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
3. <u>BLM Roadless Areas (BLMR)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
4. <u>National Park Service (NPS)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
5. <u>NPS Wilderness Areas (NPSW)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
6. <u>NPS Protected Withdrawals (NPSP)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>

Assessment Unit (name, no.)

Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

7. <u>US Forest Service (FS)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
8. <u>USFS Wilderness Areas (FSW)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
9. <u>USFS Roadless Areas (FSR)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
10. <u>USFS Protected Withdrawals (FSP)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
11. <u>US Fish and Wildlife Service (FWS)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
12. <u>USFWS Wilderness Areas (FWSW)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____

Assessment Unit (name, no.)
Tuluwak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

13. <u>USFWS Protected Withdrawals (FWSP)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
14. <u>Wilderness Study Areas (WS)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
15. <u>Department of Energy (DOE)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
16. <u>Department of Defense (DOD)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
17. <u>Bureau of Reclamation (BOR)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____
18. <u>Tennessee Valley Authority (TVA)</u>	_____	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum		mode	maximum
Volume % in entity	_____		_____	_____
<u>Gas in Gas Accumulations:</u>				
Volume % in entity	_____		_____	_____

Assessment Unit (name, no.)

Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 5001020219. Other Federal represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

20. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

Assessment Unit (name, no.)

Tuluwak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO ECOSYSTEMS

Surface Allocations (uncertainty of a fixed value)

1. Coastal Plain (CSTP)	represents	31.29	area % of the AU
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<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

<u>Gas in Gas Accumulations:</u>	
Volume % in entity	31

2. Foothills (FTHL) represents 62.12 area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

<u>Gas in Gas Accumulations:</u>	
Volume % in entity	62

3. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

4. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

5. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

6. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity			

Gas in Gas Accumulations:
Volume % in entity

Assessment Unit (name, no.)

Tuluvak-Schrader Bluff-Prince Creek Formations Gas Hydrate, 50010202

7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

Appendix 3. Basic input data (Seventh data form) used in estimates of the numbers and sizes of undiscovered gas hydrate accumulations in the Nanushuk Formation Gas Hydrate Assessment Unit (50010203) in the Northern Alaska Gas Hydrate Total Petroleum System.

**SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)**

IDENTIFICATION INFORMATION

Assessment Geologist:	T.S. Collett, W.F. Agena, M.W. Lee, M.V. Zyrianova	Date:	4-Jun-08
Region:	North America	Number:	5
Province:	Northern Alaska	Number:	5001
Total Petroleum System:	Northern Alaska Gas Hydrate	Number:	500102
Assessment Unit:	Nanushuk Formation Gas Hydrate	Number:	50010203
Based on Data as of:			
Notes from Assessor:			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) or Gas (≥20,000 cfg/bo overall): Gas

What is the minimum accumulation size? 3.33 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size:	Oil: <u>0</u>	Gas: <u>0</u>
Established (>13 accums.)	Frontier (1-13 accums.)	Hypothetical (no accums.) <u>X</u>

Median size (grown) of discovered oil accumulations (mmbo):	1st 3rd <u> </u>	2nd 3rd <u> </u>	3rd 3rd <u> </u>
Median size (grown) of discovered gas accumulations (bcfg):	1st 3rd <u> </u>	2nd 3rd <u> </u>	3rd 3rd <u> </u>

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. CHARGE: Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	<u>1.0</u>
2. ROCKS: Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	<u>1.0</u>
3. TIMING OF GEOLOGIC EVENTS: Favorable timing for an undiscovered accum. ≥ minimum size:	<u>1.0</u>

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0) <u>0</u>	mode <u>0</u>	maximum <u>0</u>
Gas Accumulations:	minimum (>0) <u>1</u>	mode <u>195</u>	maximum <u>600</u>

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum <u> </u>	median <u> </u>	maximum <u> </u>
Gas in Gas Accumulations (bcfg):	minimum <u>20</u>	median <u>120</u>	maximum <u>675</u>

Assessment Unit (name, no.)
 Nanushuk Formation Gas Hydrate, 50010203

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS

(uncertainty of fixed but unknown values)

<u>Oil Accumulations:</u>	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	<hr/>	<hr/>	<hr/>
NGL/gas ratio (bngl/mmcf)	<hr/>	<hr/>	<hr/>
<u>Gas Accumulations:</u>	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcf)	<hr/> 0	<hr/> 0	<hr/> 0
Oil/gas ratio (bo/mmcf)	<hr/>	<hr/>	<hr/>

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS

(variations in the properties of undiscovered accumulations)

<u>Oil Accumulations:</u>	minimum		mode		maximum
API gravity (degrees)	<hr/>		<hr/>		<hr/>
Sulfur content of oil (%)	<hr/>		<hr/>		<hr/>
Depth (m) of water (if applicable)	<hr/>		<hr/>		<hr/>
	minimum	F75	mode	F25	maximum
Drilling Depth (m)	<hr/>		<hr/>		<hr/>
<u>Gas Accumulations:</u>	minimum		mode		maximum
Inert gas content (%)	<hr/> 1		<hr/> 2		<hr/> 4
CO ₂ content (%)	<hr/> 1		<hr/> 2		<hr/> 5
Hydrogen-sulfide content (%)	<hr/> 0		<hr/> 0		<hr/> 0
Depth (m) of water (if applicable)	<hr/> 0		<hr/> 5		<hr/> 15
	minimum	F75	mode	F25	maximum
Drilling Depth (m)	<hr/> 300		<hr/> 600		<hr/> 750

Assessment Unit (name, no.)
 Nanushuk Formation Gas Hydrate, 50010203

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO STATES
Surface Allocations (uncertainty of a fixed value)

1. <u>Alaska</u>	represents	<u>100</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>100</u>	<u> </u>
2. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
3. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
4. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
5. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
6. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>

Assessment Unit (name, no.)
 Nanushuk Formation Gas Hydrate, 50010203

7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

Assessment Unit (name, no.)
 Nanushuk Formation Gas Hydrate, 50010203

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO LAND ENTITIES
Surface Allocations (uncertainty of a fixed value)

1. <u>Federal Lands</u>	represents	<u>81.50</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>81.00</u>	<u> </u>
2. <u>Private Lands</u>	represents	<u>0.01</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>0.00</u>	<u> </u>
3. <u>Tribal Lands</u>	represents	<u>5.00</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>5.00</u>	<u> </u>
4. <u>Other Lands</u>	represents	<u>0.50</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>1.00</u>	<u> </u>
5. <u>AK State Lands</u>	represents	<u>8.56</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>9.00</u>	<u> </u>
6. <u>AK Offshore</u>	represents	<u>4.43</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>4</u>	<u> </u>

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7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

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ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO FEDERAL LAND SUBDIVISIONS
Surface Allocations (uncertainty of a fixed value)

1. <u>Bureau of Land Management (BLM)</u>	represents	<u>81.49</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>81</u>	<u> </u>
2. <u>BLM Wilderness Areas (BLMW)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
3. <u>BLM Roadless Areas (BLMR)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
4. <u>National Park Service (NPS)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
5. <u>NPS Wilderness Areas (NPSW)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
6. <u>NPS Protected Withdrawals (NPSP)</u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>

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7. US Forest Service (FS) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. USFS Wilderness Areas (FSW) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. USFS Roadless Areas (FSR) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. USFS Protected Withdrawals (FSP) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. US Fish and Wildlife Service (FWS) represents 0.01 area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

0

12. USFWS Wilderness Areas (FWSW) represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

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13. <u>USFWS Protected Withdrawals (FWSP)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
14. <u>Wilderness Study Areas (WS)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
15. <u>Department of Energy (DOE)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
16. <u>Department of Defense (DOD)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
17. <u>Bureau of Reclamation (BOR)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____
18. <u>Tennessee Valley Authority (TVA)</u>	represents	_____	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

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19. Other Federal represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

20. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>			
Volume % in entity	_____	_____	_____

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ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO ECOSYSTEMS
Surface Allocations (uncertainty of a fixed value)

1. <u>Coastal Plain (CSTP)</u>	represents	<u>40.47</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>41</u>	<u> </u>
2. <u>Foothills (FTHL)</u>	represents	<u>55.10</u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u>55</u>	<u> </u>
3. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
4. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
5. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
6. <u> </u>	represents	<u> </u>	area % of the AU
<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	<u> </u>	<u> </u>	<u> </u>
<u>Gas in Gas Accumulations:</u>			
Volume % in entity	<u> </u>	<u> </u>	<u> </u>

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7. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

8. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

9. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

10. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

11. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

12. _____ represents _____ area % of the AU

<u>Oil in Oil Accumulations:</u>	minimum	mode	maximum
Volume % in entity	_____	_____	_____

<u>Gas in Gas Accumulations:</u>
Volume % in entity

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