GAS HYDRATE RESOURCES OF THE UNITED STATES

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INTRODUCTION

The 1995 National Oil and Gas Resource Assessment, conducted by the U.S. Geological Survey and the Minerals Management Service, has focused on assessing the undiscovered conventional and unconventional resources of crude oil and natural gas in the United States. This assessment includes for the first time a systematic resource appraisal of the *in-place* natural gas hydrate resources of the United States onshore and offshore regions. The Minerals Management Service is historically responsible for the Federal offshore portion of the National Oil and Gas Assessment; however, following a request from the Mineral Management Service, the U.S. Geological Survey has taken the lead on assessing the gas hydrate resources in the offshore Federal waters of the United States. This gas hydrate assessment is also unique to this study in the sense that it is the only energy resource assessed that is reported as an *in-place* resource estimate without regards to its recoverability.

Gas hydrates are crystalline substances composed of water and gas, in which a solid water-lattice accommodates gas molecules in a cage-like structure, or clathrate. Gas hydrates are widespread in permafrost regions and beneath the sea in sediment of outer continental margins. While methane, propane, and other gases can be included in the clathrate structure, methane hydrates appear to be the most common in nature (Kvenvolden, 1988). The amount of methane sequestered in gas hydrates is probably enormous, but estimates of the amounts are speculative and range over three orders-of-magnitude, from about 100,000 to 270,000,000 trillion cubic feet (modified from Kvenvolden, 1993). The estimated amount of gas in the hydrate reservoirs of the world greatly exceeds the volume of known conventional gas reserves. The production history of the Russian Messoyakha gas hydrate field demonstrates that gas hydrates are an immediate source of natural gas that can be produced by conventional methods (Makogon, 1981; Collett, 1993b).

Even though gas hydrates are known to occur in numerous arctic and marine sedimentary basins, little is known about the geologic parameters controlling their distribution. Most of the published gas hydrate resource estimates have, of necessity, been made by broad extrapolation of general knowledge of local geologic conditions

(Kvenvolden, 1993). The primary objectives of this study are to document the geologic parameters that control the occurrence of gas hydrates and to assess the volume of natural gas stored within the gas hydrate accumulations of the United States. The paper begins with a discussion of the geologic parameters that affect the stability and formation of gas hydrates, which is followed by a description of the methodology used to assess the gas hydrate resources. This paper ends with a description of the individual plays that were identified and assessed and a cumulative estimate of the *in-place* gas hydrate resources of the United States onshore and offshore regions.

GAS HYDRATE TECHNICAL REVIEW

Under appropriate conditions of temperature and pressure (fig. 1), gas hydrates usually form one of two basic crystal structures known as Structure I and Structure II (fig. 2). Each unit cell of Structure I gas hydrate consists of 46 water molecules that form two small dodecahedral voids and six large tetradecahedral voids. Structure I gas hydrates can only hold small gas molecules such as methane and ethane, with molecular diameters not exceeding 5.2 angstroms. The unit cell of Structure II gas hydrate consists of 16 small dodecahedral and 8 large hexakaidecahedral voids formed by 136 water molecules. Structure II gas hydrates may contain gases with molecular dimensions in the range of 5.9 to 6.9 angstroms, such as propane and isobutane. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate (Structure I) will contain as much as 164 volumes of methane gas -- because of this large gas-storage capacity, gas hydrates are thought to represent an important source of natural gas.

On a macroscopic level, many of the gas hydrate mechanical properties resemble those of ice, because hydrates contain a minimum of 85 percent water on a molecular basis. Among the exceptions is thermal conductivity, which is relatively low in hydrates; this can be attributed to the molecular structural differences between ice and hydrates. Of interest are the phase-equilibrium properties of gas hydrates, which are mostly controlled by the fit of the guest gas molecules within the hydrate water cages. For example, the addition of propane to a pure methane hydrate changes the hydrate structure (Structure I >> Structure II) and broadens the conditions in which the hydrates can occur. For a complete description of the structure and properties of hydrates see the summary by Sloan (1990).

Onshore gas hydrates are known to be present in the West Siberian Basin (Makogon and others, 1972) and are believed to occur in other permafrost areas of northern Russia, including the Timan-Pechora province, the eastern Siberian Craton, and the northeastern Siberia and Kamchatka areas (Cherskiy and others, 1985). Permafrost-associated gas hydrates are also present in the North American Arctic. Direct evidence for gas hydrates on the North Slope of Alaska comes from a core-test, and indirect evidence comes from drilling and open-hole industry well logs which suggest the presence of numerous gas hydrate layers in the area of the Prudhoe Bay and Kuparuk River oil fields (Collett, 1983; Collett, 1993a). Well-log responses attributed to the presence of gas hydrates have been obtained in about one-fifth of the wells drilled in the Mackenzie Delta, and more than half of the wells in the Arctic Islands are inferred to contain gas hydrates (Judge, 1988; Judge and Majorowicz, 1992). The combined information from Arctic gas-hydrate studies shows that, in permafrost regions, gas hydrates may exist at subsurface depths ranging from about 130 to 2,000 m (Kvenvolden, 1988).

The presence of gas hydrates in offshore continental margins has been inferred mainly from anomalous seismic reflectors that coincide with the predicted phase boundary at the base of the gas-hydrate stability zone. This reflector is commonly called a bottom-simulating reflector or BSR. BSRs have been mapped at depths below the sea floor ranging from about 100 to 1,100 m. (Kvenvolden, 1988). Gas hydrates have been recovered in gravity cores within 10 m of the sea floor in sediment of the Gulf of Mexico (Brooks and others, 1986), the offshore portion of the Eel River Basin of California (Brooks and others, 1991), the Black Sea (Yefremova and Zhizhchenko, 1974), the Caspian Sea (Ginsburg and others, 1992), and the Sea of Okhotsk (Ginsburg and others, 1993). Also, gas hydrates have been recovered at greater sub-bottom depths during research coring along the southeastern coast of the United States on the Blake Outer Ridge (Kvenvolden and Barnard, 1983), in the Gulf of Mexico (Shipboard Scientific Party, 1986a), in the Cascadia Basin near Oregon (Shipboard Scientific Party, 1994), the Middle America Trench (Kvenvolden and McDonald, 1985; Shipley and Didyk, 1982), offshore Peru (Kvenvolden and Kastner, 1990), and on both the eastern and western margins of Japan (Shipboard Scientific Party, 1990, 1991).

Because gas hydrates are widespread in permafrost regions and in offshore marine sediments, they may be a potential energy resource. World estimates for the amount of natural gas in gas hydrate deposits range from 5.0×10^2 to 1.2×10^6 trillion cubic feet (TCFG) for permafrost areas and from 1.1×10^5 to 2.7×10^8 trillion cubic feet (TCFG) for oceanic sediments (adapted from Kvenvolden, 1993). The estimates in table 1 show considerable variation, but oceanic sediments seem to be a much greater resource of natural gas than continental sediments. Current estimates of the amount of methane in the world gas hydrate accumulations are in rough accord at about 7x10^5 trillion cubic feet (TCFG) (reviewed by Kvenvolden, 1993). If these estimates are valid, then the amount of methane in gas hydrates is almost two orders of magnitude larger than the estimated total remaining recoverable conventional methane resources, estimated to be about 9x10^3 trillion cubic feet (TCFG) (Masters and others, 1991).

GEOLOGIC CONTROLS ON GAS HYDRATE DISTRIBUTION

Review of previous gas hydrate studies indicates that the formation and occurrence of gas hydrates is controlled by formation temperature, formation pore-pressure, gas chemistry, pore-water salinity, availability of gas and water, gas and water migration pathways, and the presence of reservoir rocks and seals. In the following section, these geologic controls on the stability and formation of gas hydrates will be reviewed and assessed.

FORMATION-TEMPERATURE, FORMATION PORE-PRESSURE, GAS CHEMISTRY

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. Depicted in the temperature/depth plots of figures 3*A*, 3*B*, and 3*C* are a series 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). These gas-hydrate phase-diagrams (figs. 3*A*, 3*B*, and 3*C*) illustrate how variations in formation-temperature, pore-pressure, and gas composition can affect the thickness of the gas-hydrate stability zone. In each phase-diagram, the mean-annual surface temperature is assumed to be -10¡C; however, the depth to the base of permafrost (0¡C isotherm) is varied for each temperature profile (assumed permafrost depths of 305 m, 610 m, and 914 m). Below permafrost, three different geothermal gradients (4.0¡C/100 m, 3.2¡C/100 m, and 2.0¡C/100 m) are used to project the sub-permafrost temperature profiles. The two gas-hydrate stability curves represent gas hydrates with different gas chemistries. One of the stability curves is for a 100 percent methane hydrate, and the other is for a hydrate that contains 98 percent methane, 1.5 percent ethane, and 0.5 percent propane. The only difference among the three phase-diagrams (figs. 3*A*, 3*B*, and 3*C*) is the assumed pore-pressure gradient. Each phase diagram is constructed assuming different pore-pressure gradient; 9.048

kPa/m [0.400 psi/ft] (fig. 3*A*), 9.795 kPa/m [0.433 psi/ft] (fig. 3*B*), and 11.311 kPa/m [0.500 psi/ft] (fig. 3*C*).

The zone of potential gas-hydrate stability in each phase-diagram (figs. 3*A*, 3*B*, and 3*C*) lies in the area between the intersections of the geothermal gradient and the gas-hydrate stability curve. For example, in figure 3*B*, which assumes a hydrostatic pore-pressure gradient, the temperature profile projected to an assumed permafrost base of 610 m intersects the 100 percent methane-hydrate stability curve at about 200 m, thus marking the upper boundary of the methane-hydrate stability zone. A geothermal gradient of 4.0¡C/100 m projected from the base of permafrost at 610 m intersects the 100 percent methane-hydrate stability curve at about 1,100 m; thus, the zone of potential methane-hydrate stability is approximately 900 m thick. However, if permafrost extended to a depth of 914 m and if the geothermal gradient below permafrost is 2.0¡C/100 m, the zone of potential methane-hydrate stability would be approximately 2,100 m thick.

Most gas-hydrate stability studies assume that the pore-pressure gradient is hydrostatic (9.795 kPa/m; 0.433 psi/ft). Pore-pressure gradients grater than hydrostatic will correspond to higher pore-pressures with depth and a thicker gas-hydrate stability zone. A pore-pressure gradient less than hydrostatic will correspond to a thinner gas-hydrate stability zone. The effect of pore-pressure variations on the thickness of the gas-hydrate stability zone can be quantified by comparing each of the phase diagrams in figures 3*A*, 3*B*, and 3*C.* For example, in figure 3*A*, which assumes a 9.048 kPa/m (0.400 psi/ft) pore-pressure gradient, the thickness of the 100 percent methane-hydrate stability zone with a 610 m permafrost depth and a sub-permafrost geothermal gradient of 2.0¡C/100 m would be about 1,600 m. However, if a pore-pressure gradient of 11.311 kPa/m (0.500 psi/ft) is assumed (fig. 3*C*) the thickness of the methane-hydrate stability zone would be increased to about 1,850 m.

The gas-hydrate stability curves in figures 3*A*, 3*B*, and 3*C* were obtained from laboratory data published in 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. For example, assuming a hydrostatic pore-pressure gradient (fig. 3*B*), a permafrost depth of 610 m, and a sub-permafrost geothermal gradient of 4.0¡C/100 m, the zone of potential methane (100 percent methane) hydrate stability would be about 900 m thick; however, the addition of ethane (1.5 percent) and propane (0.5 percent) would thicken the potential gas-hydrate stability zone to 1,100 m.

PORE-WATER SALINITY

It is well known that dissolved salt can depress the freezing-point of water. For example, the base of the ice-bearing permafrost on the North Slope of Alaska does not coincide with the 0¡C isotherm but with a lower temperature (Collett and others, 1988). This freezing-point depression has been attributed in part to the presence of salt in the unfrozen pore-waters. Salt, such as NaCl, when added to a gas-hydrate system, also lowers the temperature at which gas hydrates form. Pore-water salts in contact with the gas during gas hydrate formation can reduce the crystallization temperature by about 0.06¡C for each part per thousand of salt (Holder and others, 1987). Therefore, a pore-water salinity similar to that of seawater (32 ppt) would shift the gas-hydrate stability curves in figures 3*A*, 3*B*, and 3*C* to the left about 2¡C and reduce the thickness of the gas-hydrate stability zone.

AVAILABILITY OF GAS AND WATER

Most naturally occurring gas hydrates are characterized by two crystal structures known as Structure I and Structure II (reviewed by Sloan, 1990). The ideal gas/water ratio of Structure I gas hydrate is 8/46, whereas the ideal gas/water ratio of Structure II gas hydrate is 24/136. These ideal ratios confirm the observation that gas hydrates contain a substantial volume of gas. For example, if all the cages of Structure I gas hydrate are occupied, each volume of gas hydrate will contain 189 volumes of gas at standard temperature and pressure. The ideal hydrate gas/water ratios also indicate that there is a substantial amount of water stored in the gas-hydrate structure. These high gas and water concentrations demonstrate that the formation of gas hydrate requires a large source of both gas and water. Thus, it becomes necessary to quantify the potential sources of gas and water when assessing a potential gas-hydrate accumulation.

GAS AND WATER MIGRATION PATHWAYS

Other factors controlling the availability of gas and water are the geologic controls on fluid migration. As previously shown, gas hydrates contain a substantial volume of gas and water that must be supplied to a developing gas-hydrate accumulation. If effective migration pathways are not available, it is unlikely that a significant volume of gas hydrates would accumulate. Therefore, geologic parameters such as rock permeability and the nature of faulting must be evaluated to determine if the required gas and water can be delivered to the potential hydrate reservoir.

PRESENCE OF RESERVOIR ROCKS AND SEALS

The study of gas-hydrate samples recovered during research coring operations in oceanic sediments suggests that the physical nature of in-situ gas hydrates may be highly variable (reviewed by Sloan, 1990). Gas hydrates were observed to be (1) occupying pores of coarse-grained rocks; (2) nodules disseminated within fine-grained rocks; (3) a solid, filling fractures; or (4) a massive unit composed mainly of solid gas hydrate with minor amounts of sediment. Because of the limited number of gas-hydrate samples, it is not known if gas hydrates are usually pore-filling material or occur as massive units. A study of well logs from northern Alaska (Collett and others, 1988) indicate that gas hydrates occur there as pore-filling constituents within coarse-grained reservoir rocks. This study suggests that porous rock intervals serve as reservoir rocks in which gas and water can be concentrated in the amounts necessary for gas-hydrate formation. Therefore, the presence of reservoir rocks may play a role in gas-hydrate formation, particularly in well-consolidated rock intervals.

It is also speculated that the presence of effective reservoir seals or traps may play a role in gas-hydrate formation. Gas generated at depth moves upward, generally along tilted permeable carrier beds, until it either seeps at the surface or meets an impermeable barrier (trap) that stops or impedes its flow. As migrating gas accumulates below an effective seal, the total gas concentrations may reach the critical amounts necessary for the formation of gas hydrates. Thus, impermeable seals can provide a mechanism by which the required gas can be concentrated within reservoir rocks.

Besides conventional reservoirs and trapping mechanisms, it is possible for gas hydrate to form its own reservoir and trap. As gas migrates into the zone of gas-hydrate stability, it may interact with the available pore water to generate gas hydrate. With the appropriate volumes of gas and water, the pore space within the reservoir rock could be completely filled, thus making the rock impermeable to further hydrocarbon migration. The plugging of gas pipelines and production tubing by gas hydrates is testimony to the sealing potential of gas hydrates (Sloan, 1990). It has also been shown that, in marine environments, gas hydrates can mechanically displace sediments to form their own reservoir. Thus, the availability of reservoir quality rocks may not always be a limiting factor.

ASSESSMENT METHOD

The major goal of this resource appraisal is to estimate the gas hydrate resources in the United States, both onshore and offshore. Similar to the assessment of the conventional resources in the 1995 U.S. Geological Survey (USGS) Oil and Gas Assessment, this appraisal of gas hydrates is based on a play-analysis scheme, which was conducted on a province-by-province basis. We have defined, described, and assessed all the gas hydrate-plays in the United States regardless of their current economic or technological status. Therefore, this assessment is concerned with the *in-place* gas hydrate resources--that is, the amount of gas that may exist within the gas hydrates without reference to its recoverability. In a play analysis method, prospects (potential hydrocarbon accumulations) are grouped according to their geologic characteristics into plays. The geologic settings of the hydrocarbon occurrences in the play are then modeled. Probabilities are assigned to the geologic attributes of the model necessary for generation and accumulation of hydrocarbons. In this appraisal method, geologists make judgments about the geologic factors necessary for the formation of a hydrocarbon accumulation and quantitatively assess the geologic factors that determine its size. For this gas hydrate assessment, a play consists of a single prospect (prospect = play). This assumption has been made due to the relative lack of knowledge pertaining to individual gas-hydrate accumulation sizes and distribution.

ASSESSMENT DATA FORM

The assessment data form used for this gas-hydrate appraisal was modified from a form used for "conventional" oil and gas assessments (Dolton and others, 1987, 1993). An example of the gas-hydrate assessment form is shown in figure 4. This modified assessment data form is divided into two sections: the upper section deals with risking the play and prospect attributes and the lower part deals with assessing the gas-hydrate volumetric parameters. Play attributes are the geologic characteristics that apply to the entire play. In this assessment, the play attributes include the presence of a *natural gas source* (GS) (assessment of both microbial and thermogenic sources); *timing* (T), which relates the time of trap formation and the time of hydrocarbon movement; *migration* (M), which estimates the probability of effective gas movement; and *potential reservoir facies* (R), which estimates the probability of occurrence of a rock that may have porosity capable of containing gas hydrates. The product of these individually assessed probabilities determines the *marginal play probability* (MP), which reflects the favorability for the occurrence of gas hydrates within the play. Prospect attributes are those geologic parameters that control the occurrence of gas hydrates at the prospect level. They include the presence of *trapping mechanisms* (TM), *effective porosity* (P), and *hydrate accumulation* (C); the latter refers to the probability of hydrocarbons being available to the individual prospect with appropriate timing relative to the formation of the trap. Each prospect attribute is assessed as to its probability of occurrence, and the product of these attributes is referred to as the *conditional deposit probability* (CP). The probability that a gas hydrate accumulation exists at a prospect is the product of the *marginal play probability* (MP) and the *conditional deposit probability* (CP).

In the lower part of the assessment data form (fig. 4), the volume of gas hydrates is estimated as a function of the probability distributions of five gas-hydrate volumetric parameters. These parameters are: (1) volume of the hydrate stability field, (2) reservoir-rock thickness, (3) effective porosity, (4) hydrate saturation, and (5) hydrate gas yield. These parameters describe the geologic characteristics of the assessed gas-hydrate play and are treated as statistically independent. These parameters are uncertain quantities, described as distributions, and are assessed by seven fractiles (probabilities of 100, 95, 75, 50, 25, 5, and 0). The volume of gas hydrates was determined by using a modified version of the computer program FASPU (Crovelli and Balay, 1990), which utilizes probability theory to process the geologic data on the assessment data form. The probabilistic method used for calculating gas hydrate resources can be considered in three steps: (1) determine if the play contains gas hydrates; (2) assess the gas volume within the play; and (3) combine (1) and (2) to determine statistically the play resource potential. The estimated resources of each play are aggregated, using probability theory, to determine the total gas hydrate resources.

PLAY AND PROSPECT ATTRIBUTES

In assessing each play, the assessment team reviewed and synthesized extensive data summaries and geologic interpretations. A typical data summary for a play consisted of numerous maps, cross sections, charts, and graphs. Such comprehensive data summaries are critical for a reliable assessment and were based upon data derived from seismic, geological, geochemical, and other studies, as well as subsurface data from analog areas. These syntheses were used to assign risk to the geologic attributes on the assessment data form; judgment values were elicited by consensus. The identified plays have been defined such that each play and prospect attribute could be assigned a single risk probability. For example, a probability of 1 assumes that the attribute is favorable somewhere in the play or prospect, and, even though the attribute may not be favorable throughout the entire play or prospect, it does not affect the gas-hydrate resource potential of the assessed area. As previously discussed, there are nine play and prospect attributes, each of which are discussed in more detail below.

The play attributes *microbial hydrocarbon source* (S1), *microbial source sediment thickness* (S2), and *thermogenic hydrocarbon source* (S4) collectively deal with assessing the potential *hydrocarbon source* of the gas (GS) within a hydrate play. The *hydrocarbon source* play attribute (GS) estimates the probability of occurrence of a rock unit that has generated and expelled gas. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that enough gas is present to form a gas-hydrate accumulation within the play. This evaluation is based on a set of minimum source-rock criteria that includes organic richness (total organic carbon, TOC), sediment thickness, and thermal maturity. 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 formation and distribution of natural gas hydrates (Collett, 1993a; Kvenvolden, 1993). Carbon isotope analyses indicate that the methane in many oceanic hydrates is derived from microbial sources. However, molecular and isotopic analyses indicate a thermal origin for the methane in several offshore Gulf of Mexico and onshore Alaskan gas-hydrate occurrences.

Microbial gas is produced by the decomposition of organic matter by microorganisms. Two primary pathways have been identified for the generation of microbial gas: carbon dioxide (CO_2) reduction and fermentation. Although fermentation is the pathway for gas generation in some modern environments, CO_2 reduction is the most important process leading to the development of ancient microbial gas accumulations. CO_2 needed for reduction to generate methane is mostly from the oxidation and thermal decarboxylation of in-situ organic matter. Thus, abundant organic matter is needed for the formation of microbial methane. Organic matter is generally concentrated in finer grained sediments, and minimum total organic carbon (TOC) values of about 0.5 percent are required for microbial gas generation (Rice, 1993). Finley and Krason (1989) have shown that, for geologic conditions observed on the Blake Bahama Plateau, a marine sediment with a 1 percent organic carbon content (TOC) could yield enough gas to form hydrates within 28 percent of the available pore space of a 50 percent porosity sediment, if all the organic matter were converted to methane. However, organic carbon to methane conversion efficiency of 100 percent is unreasonable (Kvenvolden and Claypool, 1988), and a lower efficiency of 50 percent has been assumed for this assessment (Finley and Krason, 1989). Using the organic carbon to gas hydrate conversion factors developed by Finley and Krason (1989), we have assumed that the minimum organic carbon content (TOC) needed for hydrate formation within most deep marine environments is 0.5 percent, and an organic carbon content (TOC) of 2.0 percent would assure the formation of a methane-hydrate accumulation. For each play identified, therefore, we have assigned a probability of a sufficient *microbial hydrocarbon source* (S1) as 0 if the organic carbon content (TOC) of the sediments is below 0.5 percent. A *microbial hydrocarbon source* (S1) probability of 1.0 was assigned to plays with a sediment organic carbon content (TOC) of 2.0 percent or greater [*microbial hydrocarbon source* probability (S1): TOC ^{3} 2 percent, probability equal to 1; 2 percent > TOC ^{3} 1 percent, probability equal to 0.5; 1 percent > TOC ^{3} 0.5 percent, probability equal to 0.4; TOC < 0.5 percent, probability equal to 0].

Due to the limited thickness of the gas-hydrate stability zone and the relatively low organic carbon content of most sediments, production of microbial methane internally within the gas-hydrate stability zone is a limiting factor for the development of significant gas-hydrate accumulations. Paull and others (1994) have shown that gas recycling and upward migration of methane in a marine sedimentary sequence is essential in forming significant gas-hydrate accumulations. Once a gas-hydrate stability zone is established, microbial gas may accumulate as a result of recycling natural gas from below the base of the stability zone and from continued microbial gas production at depth. Therefore, it is important to assess the volume of in-situ organic carbon (TOC) available for microbial methane generation relative to the thickness of the sedimentary section. Finley and Krason's (1989) organic carbon to gas hydrate conversion factors, used to determine the *microbial hydrocarbon source* probability (S1) in this assessment, assume the source of methane is limited to the conversion of the organic matter within the hydrate stability zone (*i.e.*, no external or recycled gas). Most of the recovered microbial-sourced marine gas-hydrate samples are from areas where the methane-hydrate stability zone was at least 500 m thick (Kvenvolden, 1993), therefore, we have assigned a *microbial source sediment thickness* (S2) probability of 0 for a gas-hydrate play with a sediment thickness of less than 0.5 km. A probability of 1 was used if the play was characterized by sediment thickness greater than 3 km [*microbial source sediment thickness* probability (S2): sediment thickness ^{3} 3 km, probability equal to 1; 3 km > sediment thickness ^{3} 2 km, probability equal to 0.75; 2 km > sediment thickness ^{3} 1 km, probability equal to 0.5; 1 km > sediment thickness ^{3} 0.5 km, probability equal to 0.25; sediment thickness < 0.5 km, probability equal to 0]. The *cumulative microbial hydrocarbon source* probability (S3) is the product of the *microbial hydrocarbon source* (S1) and *microbial source sediment thickness* (S2) probabilities.

Thermogenic methane is generated during the thermochemical alteration of organic matter. During early thermal maturation, thermal methane is produced along with other hydrocarbon and non-hydrocarbon gases and is often associated with crude oil. At the highest thermal maturities, methane alone is formed by the cracking of carbon-carbon bonds in kerogen, bitumen, and oils. As temperature increases during thermal maturation, each of the hydrocarbon species is formed during optimal thermal windows. For methane, optimum generation occurs at 150¡C (Tissot and Welte, 1978; Wiese and Kvenvolden, 1993). For each play assessed, we have assumed a minimum thermal maturation temperature of 150¡C (about 1.3 percent vitrinite reflectance, R_o) for methane. Therefore, a play in which the sedimentary section is thick enough to correspond to a formation temperature of 150¡C or more, the *thermogenic hydrocarbon source* probability (S4) is assigned a 1 [thermogenic hydrocarbon source probability (S4): formation temperature ^{3} 150¡C, probability equal to 1; formation temperature < 150¡C, probability equal to 0].

The *hydrocarbon source* play attribute (GS) is assumed to be either the *cumulative microbial hydrocarbon source* probability (S3) or the *thermogenic hydrocarbon source* probability (S4); the highest of these two probabilities is assigned as the *hydrocarbon source* play attribute (GS). The hydrocarbon source play attribute (GS) is 1 if gas hydrates are known to occur in the play.

The evaluation of the play attribute *timing* (T) is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that a suitable relationship exists between the time of trap formation and the time of gas movement into the play. The evaluation of this attribute is dependent on knowledge of the time of trap formation and estimates of the time of natural gas generation from either microbial or thermogenic sources. Because gas hydrates can form their own trap, this play attribute probability is often equal to 1. When gas hydrates are known to occur in the play, this attribute probability is 1.

The play attribute *migration* (M) estimates the probability of effective movement of natural gas and water through conduits that may be permeable clastic or carbonate rocks, joints, or faults. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that gas and water have migrated in sufficient quantities to form a gas-hydrate accumulation. The evaluation of this attribute is mostly based on structural and stratigraphic information from which inferences can be drawn concerning the presence of suitable migration conduits. When gas hydrates are known to occur in the play, the *migration* (M) play attribute probability is 1.

The *potential reservoir facies* (R) attribute, estimates the probability of occurrence of a rock that may contain porosity and permeability capable of containing a natural gas-hydrate accumulation. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that favorable reservoir rocks occur in the play. In most marine environments the potential reservoir facies attribute probability is 1 because marine gas hydrates can form their own reservoir by mechanically displacing sediments. When gas hydrates are known to occur in the play, this attribute probability is 1.

As previously discussed, the *marginal play probability* (MP) [the product of the *hydrocarbon source* (GS), *timing* (T), *migration* (M), and *potential reservoir facies* (R) play probabilities] expresses the probability that all the first four play attributes are favorable somewhere but not necessarily everywhere in the play. A known gas-hydrate accumulation in the play is an indication that all the play attributes are favorable, and therefore the *marginal play probability* is 1.

The prospect attribute *trapping mechanism* (TM) estimates the probability of occurrence of a structural or stratigraphic configuration that provides a trap for migrating natural gas. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that a trap will exist in the prospect. Data used to assess this attribute includes regional geologic information, seismic records, and appropriate analog comparisons. Gas hydrates are known to form their own trap; therefore, this prospect attribute is often equal to 1.

The *effective porosity* prospect attribute (P) estimates the probability of occurrence of significant interconnected void space within the *potential reservoir facies* (R). Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that porosity equal to or greater than 3 percent will be found within the prospect. Data used to evaluate this attribute is based on available core measurements, well log calculations, and projected analog comparisons. Because gas hydrates form their own void space within unconsolidated sediments and because gas hydrates occur near the surface in relatively high porosity reservoirs, the *effective porosity* prospect attribute probability (P) is often 1.

The *hydrocarbon accumulation* prospect attribute (C) estimates the probability of the combination of *hydrocarbon source* (GS), *timing* (T), and *migration* (M) necessary for the formation of gas hydrate accumulations. Evaluation of this attribute is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that enough gas will be available to fill at least 1 percent of the prospect. This attribute deals primarily with the availability of natural gas to the prospect.

As previously discussed, the *conditional deposit* probability (CP) expresses the probability that the first three prospect attributes are favorable in the prospect and the *conditional deposit* probability (CP) is the product of the three prospect attribute probabilities.

GAS HYDRATE VOLUMETRIC PARAMETERS

As previously discussed and shown on the assessment data form, the volume of gas within the gas hydrates of a given play is dependent on five parameters: (1) volume or geographic area of the hydrate stability zone, (2) reservoir-rock thickness, (3) effective porosity, (4) hydrate saturation, and (5) hydrate gas yield. These volumetric parameters are discussed below and are assessed for each play in the Province and Play Descriptions section of this paper.

The hydrate stability zone volume parameter describes the possible extent of the zone in which gas hydrates may exist. This parameter is evaluated by entering stability zone volumes at seven fractiles ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Intermediate fractile values indicate the relative confidence that the gas-hydrate stability zone volume is at least as great as the recorded fractile values. The primary factors controlling the distribution of the gas-hydrate stability zone are formation temperature or geothermal gradient, formation pore-pressure, gas chemistry, and pore-fluid salinity. In the areas assessed, geothermal-gradient data are available from high-resolution well-bore surveys, near-surface thermal conductivity probe measurements, estimates based on log identification of the base of ice-bearing permafrost, and from temperature profiles projected from marine gas-hydrate bottom simulating reflectors

(BSRs). Most gas-hydrate stability studies assume that the subsurface pore-pressure gradient is hydrostatic (9.795 kPa/m or 0.433 psi/ft). As previously discussed, pore-pressure gradients greater than hydrostatic will result in a thicker gas-hydrate stability zone. Pore-pressure gradients have been calculated from shut-in pressures recorded during drill-stem testing in petroleum wells, from well-log studies of sediment compaction gradients, and from published regional analog studies. The next most important variable when considering gas-hydrate stability is the chemistry of the included gas. In plays with known gas-hydrate accumulations, we have used the chemical analyses of recovered samples to select appropriate gas-hydrate stability curves. In plays where gas hydrates have not been sampled, we have used available mud-log gas-chromatographic data, analyses of formation free-gas samples, and appropriate analogs to predict the gas chemistry of the potential gas-hydrate accumulations. In the plays assessed, pore-fluid salinity data have been obtained from water samples collected during petroleum-formation testing, marine research coring activity, and from spontaneous-potential well-log calculations.

A computer program was written to facilitate calculations of the limits of the gas-hydrate stability zone. In onshore (permafrost) environments, the program requires as input the mean annual surface temperature, the depth to the base of ice-bearing permafrost, the temperature at the base of ice-bearing permafrost, and the ratio between the geothermal gradient from above to below the base of the ice-bearing permafrost. The program will project the geothermal gradient above and below the base of the ice-bearing permafrost. The program also will allow the user to input temperature data from other sources, such as high-resolution equilibrated well-bore temperature surveys. In offshore marine environments, the computer program requires as input information on seabed temperature, geothermal gradient, and water depth. The program calculates the depths of the upper and lower boundaries of the zone of gas-hydrate stability.

The gas-hydrate stability curves used for this study were based on a stability model and experimental results published in Holder and others (1987). For each play assessed, an appropriate gas-hydrate stability curve was selected to represent the suspected gas chemistry and pore-fluid salinities. In this example, the methane stability curve (100 percent methane gas) for a pure water system (no salt) is given as a function of temperature in two equations:

$P(\mathrm{kPa})=\exp[14.7170-1886.79/T\ (\mathrm{K})]$ (from 248 to 273 K or -25 to 0¡C)

$P(\mathrm{kPa})=\exp[38.9803-8533.80/T\ (\mathrm{K})]$ (from 273 to 298 K or 0 to 25¡C)

The P(kPa) represents the dissociation or formation pressure of a methane hydrate at a given temperature, T (K). For the purpose of calculating subsurface gas-hydrate stability conditions, the variable T (K) represents the equilibrium temperature in Kelvins at any given depth. The depth values of the stability curve can be calculated by converting the derived pressure, P (kPa), with the pore-pressure gradient. To calculate the thickness of the gas hydrate stability zone in each of the plays identified, we have selected a series of transects within each play along which we used the prepared bathymetric (plates 1, 8, and 15), seabed temperature (plates 4, 11, and 18), and geothermal gradient (plates 5, 12, and 19) maps to obtain the data necessary to calculate the thickness of the gas hydrate stability zone (plates 6, 13, 20, and 22).

The gas volume parameter reservoir thickness estimates the possible range for the thickness of the potential gas-hydrate reservoir. This parameter is evaluated by entering reservoir thicknesses at seven fractiles ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Intermediate fractile values indicate the relative confidence that the reservoir thickness is at least as great as the recorded fractile values. The recorded thickness values are the maximum reservoir thickness for a single reservoir or stacked multiple reservoir with effective porosity of 3 percent or more. Data used to evaluate this parameter includes seismic records, surface and subsurface geologic maps, and analog comparisons. In most marine basins, the entire gas-hydrate stability zone occurs within sediments with porosities exceeding the 3 percent reservoir limit. Thus, the reservoir thickness parameter is often equal to the thickness of the gas-hydrate stability zone in most offshore gas-hydrate plays. However, within onshore areas the availability of adequate reservoirs is a limiting factor. The gas-hydrate stability zone volume parameter is converted to a gas-hydrate stability zone area parameter (total area of geographic coverage) when assessing an onshore play due to the dependence of reservoir availability.

The effective porosity gas volume parameter is the average value for the amount of interconnected void space in the available reservoir rock. This parameter is evaluated by entering porosity estimates at seven fractiles ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Intermediate fractile values indicate the relative confidence that the effective porosity is at least as great as the recorded fractile values. A minimum threshold value of 3 percent was used and the probability that this minimum value is achieved is incorporated into the *effective porosity* (P) prospect attribute. Data used to evaluate this parameter is based on analyses of recorded petroleum industry and research well cores, well log calculations, and analog comparisons. The mechanical development of porosity by hydrate formation probably does not add a significant amount of porosity to the total available volume. Therefore, we have used available "undisturbed" sediment porosity data to assess the gas-hydrate reservoir volume.

The gas volume parameter hydrate saturation estimates the possible volume of gas hydrates as a percentage of the porous volume within the available reservoirs. This parameter is evaluated by estimating percentage values at seven fractiles ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). Intermediate fractile values indicate the relative confidence that the reservoir is at least as full as the recorded fractile value. A minimum threshold value of 2 percent is used at the 100th fractile. The probability that this minimum value is achieved is incorporated into the *hydrocarbon accumulation* (C) prospect attribute. Evaluation of this parameter is based on analog comparisons from the North Slope of Alaska (Collett, 1993a) and the Blake Outer Ridge (Lee and others, 1993).

The hydrate gas yield volumetric parameter describes how much free gas is stored with a gas hydrate. This parameter is evaluated by estimating percentage values at seven fractiles ranging from 100 percent (total certainty that at least this value will be attained) to 0 percent (total certainty that this value will not be exceeded). If the clathrate structure of a hydrate is completely filled with methane, 1 m^3 of the hydrate would contain 172 m^3 of methane at standard temperature and pressure conditions (STP). Most researchers believe that a completely filled clathrate is not likely to be found in nature. However, gas hydrates are not stable if the clathrate cages are less then 70 percent occupied by gas. For the purpose of this study, we have assumed a minimum threshold hydrate gas yield of 139 m^3 (70 percent cage occupation) for the 100th fractile and a maximum (0 fractile) hydrate gas yield of 164 m^3 (90 percent cage occupation). The intermediate fractile values indicate the relative confidence that the hydrate gas yield parameter is at least as large as the recorded fractile value. This range in the hydrate gas yields fully represents the likely minimum and maximum values that occur in nature (Collett, 1993a).

PROVINCE AND PLAY DESCRIPTIONS

In this assessment, 11 gas-hydrate plays were identified within four offshore and one onshore petroleum provinces (fig. 5); for each play, in-place gas hydrate resources were estimated. Estimates for each of the 11 plays were aggregated to produce the estimate of total gas hydrate resources in the United States. The offshore petroleum provinces assessed consist of the U.S. Exclusive Economic Zone (EEZ) adjacent to the lower 48 States and Alaska. The only onshore province assessed was the North Slope of Alaska, which included State water areas and some offshore Federal waters. The provinces shown in figure 5 are geographic in character; however, their formation represents an attempt to group the individual petroleum provinces along broad geologic lines. Maps depicting the geologic data required for this hydrate assessment have been included in this publication as a series of individual plates. Maps of bathymetry, sedimentary thickness, total organic carbon (TOC) content of the sediments, seabed temperature, geothermal gradient, and hydrate stability zone thickness have been included for all four offshore provinces assessed. Maps depicting the thickness of the onshore gas-hydrate stability zone in northern Alaska are also included.

The primary organization of this part of the report is by the five provinces shown in figure 5. In the following section, each of the provinces is described; the format for each province description includes an introduction covering the geologic setting and a review of the geologic parameters controlling the potential distribution and volume of gas hydrate resources in the province. Following each province description is a systematic discussion of the individual gas hydrate plays within the province. Each play description includes a play map (plates 7, 14, 21, and 23) that shows the play limits and the thickness of the gas-hydrate stability field. Also included are the assessment data forms and the estimate of in-place natural gas hydrate resources.

ATLANTIC OCEAN PROVINCE

GEOLOGIC SETTING

The Atlantic Ocean province covers an area of approximately 1,000,000 km^2; its northern, eastern, and southern borders are the limits of the U.S. Exclusive Economic Zone (EEZ), and its western border is the 3-mile State water boundary. The Atlantic continental margin of the United States is a classic "passive" margin and is generally used as an example of a geologic feature developed during continental rifting (Bally, 1981). During rifting of North America from North Africa and subsequent subsidence, a thick wedge of Mesozoic and Cenozoic sediments built out onto the subsiding continental margin. Major deltaic systems prograded across the continental shelf, which occasionally were interrupted by more open marine conditions. Carbonate reefs and micritic limestone buildups marked the shelf-slope break. The major sedimentary basins along the Atlantic margin are generally elongated parallel to the present-day coast and most contain more than 10,000 m of sediment. The major basins include the Scotian, Georges Bank, Baltimore Canyon Trough, Carolina Trough, and Blake Plateau. North of the Carolinas, the continental margin above 2,000-m bathymetric depth is less than 150 km wide, whereas to the south, into the Florida-Bahama region, the continental margin broadens to about 500 km. Beneath this broad continental shelf region are located the Carolina Trough and Blake Plateau Basin, which is bounded to the northeast by the Blake Outer Ridge.

Seismic profiles along the Atlantic margin are often marked by large-amplitude reflection events that parallel the sea-floor, known as bottom simulating reflectors (BSRs) (Dillon and others, 1993; Lee and others, 1993). BSRs are believed to be caused by large acoustic impedance contrast at the base of the gas-hydrate stability zone that juxtaposes sediments containing gas hydrates with sediments containing free gas. BSRs have been extensively mapped at two locations off the east coast of the United States -- along the crest of the Blake Outer Ridge and beneath the upper continental rise of New Jersey and Delaware (Tucholke and others, 1977; Dillon and others, 1993). The first direct evidence that gas hydrates might be present along the Atlantic margin was found during deep-sea drilling on the Blake Outer Ridge in 1970 (Shipboard Scientific Party, 1972). Cores recovered from the Deep-Sea Drilling Project (DSDP) Sites 102, 103, and 104 contained large quantities of methane, which suggested the presence of gas hydrates. In addition, measured acoustic velocities (>2 km/sec.) within the suspected gas-hydrate-bearing section exceeded normal marine sediment velocities -- this also indicated the presence of gas hydrates. The occurrence of gas hydrates on the Blake Outer Ridge was confirmed during Leg 76 of the DSDP when a sample of gas hydrate was recovered from a sub-bottom depth of 238 m at Site 533 (Shipboard Scientific Party, 1980).

GEOLOGIC CONTROLS ON GAS HYDRATE

Formation Temperature

Within the Atlantic Ocean province, geothermal gradient data are available from 35 sea-floor temperature-probe measurements (Gerard and others, 1962; Langseth and von Herzen, 1970), from well-bore surveys in two research core holes (Shipboard Scientific Party, 1980; Kvenvolden and Barnard, 1983), and from estimates based on identification of BSRs on available seismic records (35 locations) (Tucholke and others, 1977; MacLeod, 1982; Yamano and others, 1982; Krason and Ridley, 1985a, 1985b; Dillon and others, 1993). Additional temperature data (23 geothermal gradients) have been obtained from a geothermal gradient map of North America published by the American Association of Petroleum Geologists and the U.S. Geological Survey (Geothermal Survey of North America Subcommittee, 1976). To further augment our Atlantic temperature data base, we have utilized a method of evaluating heat flow from identified BSRs. In this method, developed by Yamano and others (1982), in-situ temperatures at the BSR can be estimated when the pressure and gas composition are known, thus providing additional geothermal-gradient data.

A comparison of geothermal gradients calculated from the different temperature data sources are similar over most of the Atlantic Ocean province; however, the near-surface temperature probe data of Langseth and von Herzen (1970) generally yield slightly higher geothermal gradients. The geothermal gradient in the Atlantic Ocean province ranges from approximately 3.0¡C/100 m along the coast and increases seaward to values over 4.0¡C/100 m (plate 5).

For the Atlantic Ocean, seabed temperatures needed to calculate the distribution and thickness of the gas-hydrate stability zone are available from numerous publications (Fuglister, 1960; Schroeder, 1963; Barrett, 1965; Gerard and others, 1962; Naval Oceanographic Office, 1967; Tucholke and others, 1977; Kvenvolden and Barnard, 1983; Krason and Ridley, 1985a, 1985b). In general, seabed temperatures at bathymetric depths of less than 500 m range from about 10 to 20¡C, whereas below 1,000 m water depth, the seabed is at a relatively uniform temperature of about 2 to 3¡C (plate 4).

Formation Pore-Pressure

A review of available data sources uncovered no evidence of significant pore-pressure anomalies in the near-surface (0-1,500 m) sedimentary sequence of the Atlantic Ocean province. Therefore, the gas-hydrate stability calculations in this paper for the Atlantic Ocean have been made assuming a hydrostatic pore-pressure gradient (9.795 kPa/m; 0.433 psi/ft).

Gas Chemistry

Analysis of gas samples recovered during research coring [Deep Sea Drilling Project (DSDP) and Ocean Drilling Program (ODP) operations] along the Atlantic margin indicate the presence of mostly methane, some carbon dioxide, occasional hydrogen sulfide, and traces of ethane (Legs 11, 43, 44, 76, 101, 102; Shipboard Scientific Party, 1972, 1978, 1979, 1980, 1986b). Because methane appears to be the dominant hydrocarbon gas within the sediments of the Atlantic margin and because only trace amounts of higher molecular weight hydrocarbon gases have been found, we have assumed a pure methane chemistry for the gas-hydrate stability calculations in the Atlantic Ocean province.

Pore-Water Salinity

Salinity data from the near-surface sediments of the Atlantic Ocean province are available from water samples collected from numerous DSDP and ODP research coreholes (Legs 11, 43, 44, 76, 101, 102; Shipboard Scientific Party, 1972, 1978, 1979, 1980, 1986b). In general, the reported (bulk) pore-water salinities are similar that of sea water (32 ppt), ranging from about 31 to 36 ppt. Therefore, the gas-hydrate stability calculations in this paper for the Atlantic Ocean province have been made assuming a pore-water salinity of 32 ppt (average sea-water salinity).

Gas-Hydrate Stability Calculations

In most marine environments, the thickness of the gas-hydrate stability zone is equal to the depth below the sea-floor of the base of the gas-hydrate stability zone. Thus, the isopach map in plate 6 depicts both the thickness of the methane-hydrate stability zone and the depth below the sea-floor of the base of the methane-hydrate stability zone in the Atlantic Ocean province. It shows that the methane-hydrate stability zone reaches a maximum thickness of about 700 m in the east-central portion of the Atlantic Ocean province and that gas hydrate should not be present at water depths less than approximately 750 m.

Availability of Gas and Water

Analysis of the gas evolved from the gas-hydrate sample obtained in the DSDP Site 533 corehole on the Blake Outer Ridge revealed that methane was present in high concentrations and methane/ethane ratios of 4,000 to 35,000 indicated that the methane is of microbial origin (Brooks and others, 1983). Carbon isotopic composition of the methane from the recovered gas hydrate sample ranged from -67 to -91 per mill, which supports the contention of a microbial origin for the methane. Geochemical analyses of the carbon isotopic composition of carbon dioxide sampled in the Site 533 corehole further indicated that the formation of the methane resulted from the microbial reduction of carbon dioxide. The organic carbon required for the microbial generation of methane is not widely abundant along the Atlantic margin. The total organic carbon (TOC) content of the near-surface (0-1,500 m) sediments in the Atlantic Ocean province ranges from below 0.5 percent to about 2.0 percent (plate 3; modified from Premuzic, 1980; Premuzic and others, 1982). As previously discussed, TOC contents of less than 0.5 percent are thought to preclude the occurrence of microbially sourced methane hydrate accumulations. Therefore, the map of total organic carbon (TOC) content of the surficial sediments in the Atlantic Ocean province in plate 3 also depicts the limits (areas >0.5 percent TOC) of potential microbial sourced methane hydrate accumulations.

With sediment thicknesses exceeding 15 to 17 km it is also possible that thermochemical alteration of organic matter at depths exceeding 4 km has contributed to the generation of methane in the Atlantic Ocean province (sediment thickness map in plate 2 is modified from Tucholke and others, 1982; Drummond, 1986). However, no significant thermogenic gas accumulations have been discovered along the Atlantic margin.

In most near-surface (0-1,500 m) marine sedimentary sections, water is generally considered to be a ubiquitous substance. In addition, DSDP and ODP drilling have not revealed any evidence of dewatered sediments; thus, the availability of water is not judged to be a limiting gas hydrate formation factor in the Atlantic Ocean province.

Gas and Water Migration Pathways

The "passive" margin nature of the Atlantic Ocean province has not lent itself to the development of significant fault systems, thus limiting the number of potential gas- and water-migration pathways. This limitation reduces the potential for significant gas hydrate accumulations due to the inability of gas and water to migrate and source developing gas hydrate accumulations.

Reservoir Rocks and Seals

Porosities in the near-surface (0-1,500 m) sediments of the Atlantic Ocean province range from about 30 to 80 percent and average about 57 percent (Lee and others, 1993); thus, the entire marine sedimentary section is considered to be an excellent hydrocarbon reservoir based on porosity alone. Due to the high-porosity nature of most marine sediments and because gas hydrates can form their own void space within unconsolidated rocks, we do not consider porosity to be a gas hydrate limiting factor in the Atlantic Ocean province. The relative lack of reservoir seals, on the other hand, may limit the occurrence of gas hydrates along the Atlantic Ocean margin. As previously discussed, the "passive" nature of the Atlantic margin has not lent itself to significant fault development, which, in turn, has limited the number of structural traps that could effect the accumulation of gas hydrates in the Atlantic Ocean Province. However, the BSR-inferred gas hydrate accumulation of the Blake Outer Ridge is associated with a large regional anticinal structure. Stratigraphic traps, common to "passive" margin sequences, may contribute to the accumulation of gas hydrates; however, there is no evidence of stratigraphically controlled gas hydrate accumulations along the Atlantic margin.

Northeastern Atlantic Ocean Play

The Northeastern Atlantic Ocean Play (plate 7; fig. 6) is limited to the sedimentary section in the northern part of the Atlantic Ocean province with organic carbon (TOC) contents exceeding 0.5 percent. This play consists of limited structural and stratigraphic traps in clastic rocks of Cenozoic age. The Cenozoic sedimentary section along the northeastern margin of the United States consists of Paleocene to Eocene shale, Oligocene to Miocene mudstone and shale, Miocene to Pliocene unconsolidated sand, and Pleistocene silty clays, sands, and gravels.

The methane-hydrate stability zone reaches a maximum thickness of nearly 700 m in the southeast corner of the play. Thermal conditions should preclude the occurrence of gas hydrates above the 700-m bathymetric contour along the continental margin.

Potential reservoirs consist of hemipelagic muds and clays, coarse turbidite sands, and well-compacted deltaic to shallow-marine clastics.

The potential for microbially sourced methane within this play is limited due to the low amount of organic carbon within the near-surface (0-1,500 m) sedimentary section. Methane from thermogenic sources may contribute to gas hydrate formation in this play, but there is no evidence of significant thermogenic gas accumulations in the Northeastern Atlantic Ocean play.

Postulated traps are mostly stratigraphic and are related to facies changes along the continental margin. Structural traps are believed to be relatively rare. Shales are expected to provide fair to good seals, although their effectiveness may be reduced due to the poorly consolidated nature of the sedimentary section.

Southeastern Atlantic Ocean Play

The Southeastern Atlantic Ocean play (plate 7; fig. 7) consists of the area in the southern part of the Atlantic Ocean province where the sedimentary section organic carbon (TOC) content exceeds 0.5 percent. The major geologic feature of this play is the Blake Outer Ridge, which is a positive topographic sedimentary feature on the continental slope and rise. The Blake Outer Ridge was built upon transitional continental to oceanic crust by the complex accretion of marine sediments deposited by longitudinal drift currents. West of the Jurassic paleoshelf edge, a thick wedge of Mesozoic sediments exists that progressively thins to the east beneath the Blake Outer Ridge, which consist of Tertiary to Quaternary sediments of hemipelagic muds and silty clays.

The thickness of the methane-hydrate stability zone in this play ranges from zero along the northwestern edge of the play to a maximum thickness of about 700 m along the eastern edge of the play.

The reservoirs in the Blake Outer Ridge area are relatively poor, consisting of hemipelagic muds and clays; however, measured porosities are high, ranging from 40 to 80 percent.

Potential source rocks within this play include deeply buried, thermally mature, marine shales and carbonates. Low organic carbon content (TOC) of the sediments in this play reduces the amount of microbial methane available for gas hydrate formation.

Hydrocarbon traps within this play include both stratigraphic and regional anticlinal structural traps. Minor faults and surrounding thick marine clays are expected to provide poor to fair seals.

GULF OF MEXICO PROVINCE

GEOLOGIC SETTING

The Gulf of Mexico province covers an area of approximately 500,000 km^2; its western, northern, and eastern borders are the State water boundaries of Texas, Louisiana, Alabama, Mississippi, and Florida, and the southern border of the province is the limit of the U.S. Exclusive Economic Zone (EEZ). The geology of the Gulf of Mexico has been studied in detail by many industry, government, and academic research organizations, and it is one of the most hydrocarbon-rich regions in the world (Wilhelm and Ewing, 1972; Bouma, 1982). The oldest sedimentary rocks in the Gulf of Mexico are isolated Triassic red-bed sequences, which are overlain by extensive Jurassic evaporite deposits. Subsidence during the Cretaceous and the development of deep marine conditions lead to the deposition of thick marine clastics throughout the basin. Increased sediment influx during the Tertiary and Quaternary, and glacially induced sea-level fluctuations resulted in the deposition of a thick marine to nonmarine sedimentary section.

The geology of the northwestern and northern margins of the Gulf of Mexico is dominated by salt diapirism and heavy Cenozoic deposition. The geologic features of the region include massive slumps, intraslope basins, graben structures over shallow salt diapers, and growth faults (Bouma, 1982). The Gulf of Mexico is bounded to the east by the broad, partly submerged, Florida platform, which is overlain by a thick, flat-lying Cretaceous and Tertiary sedimentary section composed of mostly limestone. The Florida platform is not considered to be a significant petroleum region.

Bottom-simulating reflectors (BSRs), believed to be related to the occurrence of gas hydrates, have been identified throughout most of the Gulf of Mexico (Shipley and others, 1979; Hedberg, 1980; Krason and others, 1985). Most of the BSRs described by Shipley and others (1979) and Hedberg (1980) in the Gulf of Mexico are restricted to the cores of tightly folded anticlines at water depths ranging from 1,200 to 2,000 m. Krason and others' (1985) detailed study of gas hydrates in the western Gulf of Mexico has revealed numerous BSRs covering an area of approximately 5,000 km^2. This regionally extensive inferred gas hydrate accumulation is found in water depths of 1,200 to 2,700 m, and the BSR sub-bottom depths range from 400 to 600 m.

The first direct evidence of gas hydrates in the Gulf of Mexico was obtained in 1970 on Leg 10 of the DSDP when gas-rich sediment cores were recovered from the deep-water Sigsbee Plain and the Gulf of Campeche (Shipboard Scientific Party, 1973a). The occurrence of gas hydrates in the Gulf of Mexico was confirmed during Leg 96 of the DSDP when numerous gas hydrate samples were recovered from sub-bottom depths ranging from 20 to 40 m in the Orca Basin (Sites 618 and 618A), which is located about 300 km south of Louisiana beneath about 2,000 m of water (Shipboard Scientific Party, 1986a). Near-surface (0-5 m) marine sediment coring has also recovered numerous gas hydrate samples on the Louisiana continental slope (Brooks and others 1986, 1994). These seabed gas hydrate discoveries occur as small to medium nodules, interspersed layers, and as solid masses at water depths ranging from 530 to 2,400 m.

GEOLOGIC CONTROLS ON GAS HYDRATE

Formation Temperature

Within the Gulf of Mexico province, geothermal-gradient data are available from 16 sea-floor temperature probe measurements (Langseth and von Herzen, 1970), from well-bore surveys in three research core holes (Shipboard Scientific Party, 1973a, 1986a), and from estimates based on identification of BSRs on available seismic records (11 locations) (Shipley and others, 1979; Krason and others, 1985; Brooks and others 1986). Additional temperature data (20 geothermal gradients) have been obtained from a geothermal gradient map of North America published by the American Association of Petroleum Geologists and the U.S. Geological Survey (Geothermal Survey of North America Subcommittee, 1976). The geothermal gradient in the Gulf of Mexico ranges from about 2.0 - 3.0¡C/100 m along the coast and increases seaward to values greater than 4.0¡C/100 m in the central portion of the basin (plate 5).

Published water-column temperature data from the Gulf of Mexico (Schroeder, 1963; Naval Oceanographic Office, 1967; Krason and others, 1985; Brooks and others 1986) reveals that, at bathymetric depths of less than 500 m, the seabed temperature ranges from about 12 to 19¡C, whereas below 1,000 m water depth, the seabed is at relatively uniform temperatures of about 4 to 5¡C (plate 4).

Formation Pore-Pressure

Formation over-pressuring is well documented within the Gulf of Mexico (Hunt and others, 1994); however, the major over-pressured zones occur several thousand meters below the zone of predicted gas-hydrate stability (to be discussed later in this paper). Within the near-surface (0-1,500 m) sedimentary section of the Gulf of Mexico, there is no evidence of anomalous pore-pressures. Therefore, the gas-hydrate stability calculations in this paper for the Gulf of Mexico have been made assuming a hydrostatic pore-pressure gradient (9.795 kPa/m; 0.433 psi/ft).

Gas Chemistry

Analysis of gas samples recovered during research coring (DSDP operations) in the deep Gulf of Mexico indicate the presence of mostly methane, some ethane, and traces of carbon dioxide (Shipboard Scientific Party, 1973a). The gas hydrate samples recovered from the DSDP Site 618 corehole also contained predominantly methane, with only small to trace amounts of other gases (Shipboard Scientific Party, 1986a). Four of the eight near-surface (0-5 m) gas-hydrate-bearing sediment cores recovered from the Louisiana slope contained significant amounts of ethane (1.2 - 9.2 percent), propane (0 - 22.8 percent), and iso-butane (0 - 4.5 percent) in addition to methane (61.9 - 93.4 percent) (Brooks and others, 1986). These apparent thermogenic (to be discussed later) gas hydrates are probably near-surface phenomenon and are closely associated with major fault systems that have acted as fluid migration pathways from more deeply buried hydrocarbon sources (Brooks and others, 1986). It appears that most of the gas within the gas-hydrate accumulations in the Gulf of Mexico are from microbial sources;

therefore, we have assumed a pure methane gas chemistry for the gas-hydrate stability calculations in the Gulf of Mexico province.

Pore-Water Salinity

Analysis of water samples collected during ODP research coring operations in the Gulf of Mexico yielded pore-water salinities averaging about 32 ppt (Shipboard Scientific Party, 1973a, 1986a); therefore, the gas-hydrate stability calculations in this paper for the Gulf of Mexico province have been made assuming a pore-water salinity of 32 ppt (average sea water salinity).

Gas-Hydrate Stability Calculations

The isopach map of the methane-hydrate stability zone in plate 6 for the Gulf of Mexico province reveals that the zone in which methane hydrates potentially may exist reaches a maximum thickness of about 600 m in the south-eastern corner of the province, but stability conditions preclude the occurrence of methane hydrates above the 600-m bathymetric contour.

Availability of Gas and Water

Geochemical analysis of the gas evolved from the gas-hydrate samples obtained in the DSDP Site 618 corehole in the Orca Basin yielded methane/ethane ratios of 18,400 and stable methane carbon isotopic compositions of -71.3 per mill, both of which are indicative of hydrocarbon gases generated by microbial processes (Shipboard Scientific Party, 1986a). Geochemical data from other DSDP coreholes within the Gulf of Mexico confirm the predominance of microbially derived methane in the near-surface sedimentary section of the basin (Shipboard Scientific Party, 1973a). However, gas-hydrate-bearing seabed sediment cores from areas of active hydrocarbon seepage on the Louisiana slope contain a significant amount of thermogenic gas (Brooks and others, 1986). As previously indicated, these thermogenic gas hydrates are believed to be a near-surface phenomenon and not widely distributed. Most of the gas hydrates in the Gulf of Mexico are likely derived from microbial natural gas sources; however, the total organic carbon (TOC) content of the near-surface (0-1,500 m) sediments in the Gulf of Mexico is low, averaging about 0.5 percent (plate 3; modified from Premuzic, 1980; Premuzic and others, 1982). It is known that thermogenic gas sources have contributed to gas hydrate formation in the Gulf of Mexico; however, the importance of this source is not known (sediment thickness map in plate 2 is modified from Tucholke and others, 1982; Drummond, 1986).

The water required for gas hydrate formation in the Gulf of Mexico province should be available in ample supply.

Gas and Water Migration Pathways

The occurrence of fault-controlled thermogenic gas-hydrate accumulations within the near-surface sedimentary section of the Gulf of Mexico reveals the presence of effective natural gas migration pathways. In addition, most of the Gulf of Mexico province is dominated by large-scale growth faults, salt diapers, and graben features, which have contributed to the migration and accumulation of significant conventional hydrocarbon resources.

Reservoir Rocks and Seals

Porosities in the near-surface (0-1,500 m) sediments of the Gulf of Mexico province are similar to those in the Atlantic Ocean province, ranging from 30 to 80 percent; thus, the entire marine sedimentary section can be considered to be an excellent reservoir based on porosity alone. The abundance of structural traps in the Gulf of Mexico directly contribute to the formation and accumulation of gas hydrates. For example, most of the Gulf of Mexico BSR-inferred gas-hydrate accumulations occur within anticlinal structures and are in close association with major fault systems.

Gulf of Mexico Play

The Gulf of Mexico play, the only play within the Gulf of Mexico province, is limited to the area in the province where the organic carbon (TOC) content of the sedimentary section exceeds 0.5 percent (plate 2). The Gulf of Mexico play covers an area of approximately 240,000 km^2 and is divided into a northern and southern section (plate 7; fig. 8). This play consists of abundant structural, stratigraphic, and combined structural-stratigraphic traps in clastic rocks of Mesozoic to Quaternary age. The sedimentary section in the Gulf of Mexico play is characterized by interbedded turbidite clastics and hemipelagic muds.

The methane-hydrate stability zone reaches a maximum thickness of more than 600 m within the deepest portion of the Gulf of Mexico, and the 600-m bathymetric contour is the upper limit of the methane-hydrate stability zone.

Potential reservoirs consist of turbidite sands, limited shelf carbonates, and hemipelagic muds and silts.

Potential source rocks beneath the play sequence include numerous thermally mature gas sources, some of which have contributed to the fault-controlled thermogenic gas hydrate occurrences on the Louisiana slope. Low organic carbon content (TOC) of the sediments in this play reduces the amount of microbial methane available for gas hydrate formation.

Hydrocarbon traps in this play are mostly structural and are often related to large-scale growth faults and salt diapers.

PACIFIC OCEAN PROVINCE

GEOLOGIC SETTING

The Pacific Ocean province covers an area of approximately 800,000 km^2; its northern, western, and southern borders are the limits of the U.S. Exclusive Economic Zone (EEZ), and its eastern border is the 3-mile State water boundary of Washington, Oregon, and California. The structural development and depositional history of the Pacific coast margin are mostly controlled by the motion of the Pacific and North American plates as reviewed by Atwater and Molnar (1973). Because of the active tectonic history of the Pacific Ocean province, during which older basins were destroyed and new ones created, rocks prospective for petroleum are limited mainly to basins that formed during Cenozoic time. The major Cenozoic basins along the Pacific margin include the Eel River, Point Arena, Bodega, Outer Santa Cruz, Santa Maria, and Santa Barbara-Ventura. The northern part of the Pacific Ocean province, offshore from Washington and Oregon, contains numerous small forearc basins composed of thick sedimentary and volcanic rocks of Tertiary age. This northern region is stratigraphically complex but only moderately folded and faulted; only several small occurrences of natural gas have been reported. The California coastal basins south of the Mendocino Fracture Zone contain very thick Neogene sedimentary rock fill. Several of these basins have been exceedingly rich in discovered petroleum, including the Santa Maria and Santa Barbara-Ventura Basins.

BSRs, believed to be related to the occurrence of gas hydrates, have been extensively mapped on the inner continental margin of northern California (Field and Kvenvolden, 1985). These constitute a single, inferred, gas-hydrate accumulation that covers an area of at least 3,000 km^2 on the Klamath Plateau and the upper continental slope at water depths ranging from 800 to 1,200 m. Limited seismic data show that this regionally extensive inferred gas-hydrate occurrence extends northward to offshore Oregon and seaward at least to the base of the slope (3,000 m). The occurrence of gas hydrates in the

Pacific Ocean Province was confirmed in 1989 when numerous gas-hydrate samples were obtained during seabed (0-6 m) sediment coring operations (water depths ranging between 510 and 642 m) in the Eel River Basin (Brooks and others, 1991). Recovered gas-hydrate samples consisted of dispersed crystals, small nodules, and layered bands. The location of these gas hydrates coincides nearly, but not exactly, with the area of BSR-inferred gas hydrates described by Field and Kvenvolden (1985) along the northern California coast. These gas hydrate-samples appear to confirm Field and Kvenvolden's (1985) observation that gas hydrates are present north of the Mendocino Fracture Zone but are probably absent to the south, into the Point Arena Basin. Recently, gas hydrates were unexpectedly recovered along the Pacific margin from a relatively restricted zone within 19 m of the sea-floor in three ODP (Leg 146) research coreholes: Sites 892A, 892D, and 892E (Shipboard Scientific Party, 1994). All of these coreholes are located on the Oregon continental slope in about 675 m of water.

GEOLOGIC CONTROLS ON GAS HYDRATE

Formation Temperature

Within the Pacific Ocean province, geothermal gradient data are available from 10 sea-floor temperature-probe measurements (Langseth and von Herzen, 1970), from well-bore surveys in six research core holes (Shipboard Scientific Party, 1992, 1994), and from estimates based on identification of BSRs on available seismic records (10 locations) (Field and Kvenvolden, 1985; Krason and Ciesnik, 1986; Singh and others, 1993; Zwart, 1993). Additional temperature data (13 geothermal gradients) have been obtained from a geothermal-gradient map of North America published by the American Association of Petroleum Geologists and the U.S. Geological Survey (Geothermal Survey of North America Subcommittee, 1976). The geothermal gradient in the Pacific Ocean province ranges from about 3.0 - 5.0¡C/100 m along the coast and increases seaward to values of more than 7.0¡C/100 m in the northwest and southwest corners of the province (plate 12).

Pacific Ocean seabed temperatures necessary to calculate the thickness of the gas-hydrate stability zone are available from a number of publications (Lee and Cox, 1966; Field and Kvenvolden, 1985; Krason and Ciesnik, 1986; Brooks and others 1991; Shipboard Scientific Party, 1992, 1994). In general, seabed temperatures at bathymetric depths of less than 500 m range from about 6 to 8¡C, whereas, below 1,000 m water depth, the seabed is at relatively uniform temperature of about 2¡C (plate 11).

Formation Pore-Pressure

Within the near-surface (0-1,500 m) sedimentary section of the Pacific Ocean province, there is no evidence of significant pore-pressure anomalies. Therefore, the gas-hydrate stability calculations in this paper for the Pacific Ocean province have been made assuming a hydrostatic pore-pressure gradient (9.795 kPa/m; 0.433 psi/ft).

Gas Chemistry

Analysis of gas samples recovered during research coring (DSDP and ODP operations) in the Pacific Ocean province indicate the presence of mostly methane, some carbon dioxide, occasional hydrogen sulfide, and varying amounts of ethane and propane (Shipboard Scientific Party, 1970, 1973b, 1981, 1992, 1994). The occurrence of ethane (0-5,723 ppmv) and propane (0-1,788 ppmv) appears to be limited to several coreholes located on the continental slope near Washington (Shipboard Scientific Party, 1992). The gas-hydrate samples recovered from the sea-floor (0-6 m subsurface) in the Eel River Basin by Brooks and others (1991) contained mostly methane, with only small to trace amounts of ethane and propane. Geochemical analysis of the gas-hydrate samples recovered during Leg 146 of the ODP (Shipboard Scientific Party, 1994) indicate the presence of mainly methane (132,767 ppmv) with only minor amounts of carbon dioxide (578 ppmv) and ethane (77 ppmv). In addition, carbon disulfide (CS_2) was identified in the sediment gases associated with the recovered gas hydrate samples on Leg 146. Because methane appears to be the dominant hydrocarbon gas within the sediments of the Pacific margin and because the occurrence of other hydrate-forming gases appears to be limited, we have assumed a pure methane chemistry for the gas-hydrate stability calculations in the Pacific Ocean province.

Pore-Water Salinity

Salinity data from the near-surface (0-1,500 m) sedimentary section of the Pacific Ocean province are available from water samples collected from numerous DSDP and ODP research coreholes (Legs 5, 18, 63, 139, 146; Shipboard Scientific Party, 1970, 1973b, 1981, 1992, 1994). The reported (bulk) pore-water salinities are similar to that of sea water (32 ppt), ranging from about 30 to 36 ppt. Therefore, the gas-hydrate stability calculations for the Pacific Ocean province have been made assuming a pore-water salinity of 32 ppt (average sea-water salinity).

Gas-Hydrate Stability Calculations

The isopach map in plate 13 shows that the methane-hydrate stability zone is about 400 m thick throughout most of the Pacific Ocean province, and gas hydrates should not be present at water depths less than approximately 600 m.

Availability of Gas and Water

The seabed (0-6 m) gas-hydrate samples recovered from the Eel River basin by Brooks and others (1991) contained mostly methane and only small to trace amounts of ethane with methane/ethane ratios of 456 to 8,030, which indicates a microbial gas source. The stable carbon isotopic composition of the methane evolved from these seabed gas hydrates ranges from -57.6 to -69.1 per mill, which also indicates a microbial source for the methane within the gas hydrates. Analysis of the gas evolved from the gas-hydrate samples in the ODP Site 892 coreholes on the Oregon continental slope revealed that methane was present in high concentrations, and methane/ethane ratios of 102 to 4,397 indicated that both microbial- and thermogenic-sourced natural gas is included within the recovered gas-hydrate samples (Shipboard Scientific Party, 1994). On the basis of molecular composition alone, however, the relative amount of thermogenic gas within these samples is unknown; stable carbon isotopes are required to ascertain the degree of microbial and thermogenic gas mixing at ODP Site 892. Most of the gas hydrates in the Pacific Ocean province are likely derived from microbial natural gas sources. The organic carbon required for the microbial generation of methane is abundant in the Pacific Ocean province, with the total organic carbon (TOC) content of the near-surface (0-1,500 m) sediments ranging from 1.0 to 2.0 percent (plate 10; modified from Premuzic, 1980; Premuzic and others, 1982). It is likely that thermogenic gas sources have contributed to gas-hydrate formation in the Pacific Ocean province; however, the importance of this source is not known (sediment thickness map in plate 9 is modified from Drummond, 1986).

The water required for gas hydrate formation in the Pacific Ocean province should be available in ample supply.

Gas and Water Migration Pathways

The active tectonic nature of the Pacific continental margin has lead to the development of significant fault systems, which, in turn, provide potential gas and water migration pathways. ODP Leg 146 has revealed large-scale fluid flow systems within the accretionary wedge of the Juan de Fuca Plate (Shipboard Scientific Party, 1994), which further indicates the presence of effective migration pathways in the Pacific Ocean province. There is also evidence that the ODP Site 892 gas-hydrate occurrences are closely associated with a large thrust fault that may have acted as a migration conduit for the gas required for gas-hydrate formation (Shipboard Scientific Party, 1994).

Reservoir Rocks and Seals

Porosities in the near-surface (0-1,500 m) sediments of the Pacific Ocean province are similar to those observed in most marine basins (averaging about 60 percent); thus, the entire marine sedimentary section can be considered an excellent reservoir based on porosity alone. The moderately to highly faulted nature of the Pacific continental margin has lead to the development of numerous structural traps; however, none of the known gas-hydrate accumulations in the Pacific Ocean province occur within conventional hydrocarbon traps.

Northern Pacific Ocean Play

The Northern Pacific Ocean play covers an area of approximately 253,000 km^2 and is limited to the region north of the Mendocino Fracture Zone within the Pacific Ocean province (plate 14; fig. 9). Tectonically, the region north of the Mendocino Fracture Zone is characterized by active plate subduction. This play consists of abundant structural traps in clastic rocks of mostly Tertiary age. The lithostratigrahic section in the Northern Pacific Ocean play is dominated by shallow-marine-type sediments, including well-indurated mudstone, siltstone, and minor amounts of sandstone and conglomerate.

The methane-hydrate stability zone is about 400 m thick throughout most of the play, and the 600-m bathymetric contour marks the approximate eastern limit of the methane-hydrate stability zone.

Potential reservoirs consist of shallow marine clastics, with measured porosities of about 60 percent.

Potential source rocks within this play include deeply buried, thermally mature, marine and nonmarine shales. Relatively high organic carbon contents (TOC) within the near-surface sediments of this play represents an important source of microbial methane.

Hydrocarbon traps in this play are mostly structural and are often associated with large-scale tectonic plate movement.

Southern Pacific Ocean Play

The Southern Pacific Ocean play covers an area of approximately 442,000 km^2 and is limited to the region south of the Mendocino Fracture Zone within the Pacific Ocean province (plate 14; fig. 10). Tectonically, this play is characterized by right-lateral strike-slip plate movement. This play includes abundant structural and stratigraphic traps in fractured chert-shale reservoirs and conventional clastic reservoirs of Micocene to Pleistocene age.

The thickness of the methane-hydrate stability zone in this play ranges from zero along the eastern edge of the play to a maximum thickness of about 400 m within the center of the play.

Potential reservoirs consist of high-porosity uncompacted hemipelagic muds and clays, coarse sands, and deltaic to shallow-marine clastics.

Potential source rocks are organic-rich mudrocks of Miocene and early Pliocene age. In addition, high organic carbon contents (TOC) within the seabed sediments may be an important source of microbial methane.

Hydrocarbon traps in this play consist of mainly structural traps associated with faulting; however, several of the conventional oil and gas fields in the Santa Maria Basin are stratigraphically trapped.

ALASKA OFFSHORE PROVINCE

GEOLOGIC SETTING

The Alaska Offshore province includes all the Federal waters within the U.S. Exclusive Economic Zone (EEZ) adjacent to Alaska. We have divided this province into four plays: Beaufort Sea, Bering Sea, Aleutian Trench, Gulf of Alaska. The tectonic setting for each of the assessed plays can be classified as either active or quiescent. The Aleutian Trench and Gulf of Alaska plays are located south and southeast of the volcanogenic arc of the Aleutian Islands, which is the northern boundary of the subducting Pacific Ocean plate. The Bering Sea and Beaufort Sea plays, on the other hand, are in tectonically quiescent settings and are characterized by thick sedimentary sections.

The Beaufort Sea is the southern part of the Arctic Ocean east of the Chukchi Sea, offshore of the northern coast of Alaska. The Beaufort Sea play is underlain mainly by sediments derived from the Brooks Range in Alaska. The Early Cretaceous to Tertiary uplift of the Brooks Range to the south introduced large volumes of terrigenous sediments to the north into the developing Canada Basin (Grantz and May, 1984). Hydrocarbon discoveries in Tertiary sediments of the Alaskan Beaufort continental shelf indicate good hydrocarbon-generation potential in correlative lithologies throughout the play.

The Bering Sea play spreads to the north of the Aleutian Islands and is bounded by western Alaska, eastern Siberia, and the Bering Strait. The Bering Sea Basin, typical of many other marginal basins surrounding the Pacific Ocean, contains a thick (2-9 km) section of mostly Cenozoic sediment impounded behind the outer island arc of the Aleutian Islands (Cooper and others, 1979). Regional geologic studies suggest that the major requirements for hydrocarbon formation and accumulation are present throughout the play (Carlson and others, 1985).

The Aleutian Trench is located south of the Aleutian Island Chain, which links the Alaska Peninsula on the east to the Kamchatka Peninsula to the west. The Aleutian Island Chain is a large, mostly submerged mountain range of volcanic and sedimentary rocks. Sandwiched between the Aleutian Trench and the Aleutian Islands is the 20- to 300-km-wide Aleutian accretionary wedge (McCarthy and others, 1984). Within this accretionary wedge of mostly Miocene through Pleistocene marine sediments, seismic reflection profiles reveal an abundance of potential hydrocarbon traps. Petroleum geology studies of the Aleutian Island arc system reveal that all the conditions necessary for the formation of hydrocarbon accumulations exist in the Aleutian Trench play (McCarthy and others, 1984; Kvenvolden and von Huene, 1986).

The geology of the Gulf of Alaska play is not well known. Theories pertaining to the tectonic development of this region are frequently embroiled in controversial scientific debates. Within the continental slope of the Gulf of Alaska play, the prevailing lithologies consist of clayey silt and turbidite sands interbedded with volcanic ash (Krason and Ciesnik, 1987). The petroleum potential for this area is generally considered to be poor (Kvenvolden and von Huene, 1986; Krason and Ciesnik, 1987).

The most extensive BSR-inferred gas-hydrate accumulation mapped in Alaska is in the Beaufort Sea play (Grantz and others, 1982; Kvenvolden, 1987; Finley and Krason, 1988). The BSRs described by Grantz and others (1982) occur within 300 to 700 m of the sea floor, where water depths range from about 500 to more than 2,500 m. This inferred gas-hydrate accumulation, not yet directly tested by the drill, covers an area of at least 7,500 km^2.

BSRs, believed to be related to the occurrence of gas hydrates, have been identified on the Bering Sea continental slope and rise near the Navarin Basin in water depths ranging from 1,000 to 2,400 m (Marlow and others, 1981; Carlson and others, 1985;

Krason and Ciesnik, 1987). The sub-bottom depths of these BSRs range from about 200 to 500 m. Other regional geophysical surveys imply that large areas of the deep-water (3,700 - 4,000 m) portion of the Bering Sea Basin are underlain by pore-filling deposits of methane hydrates (Scholl and Hart, 1993). Seismic surveys have revealed numerous distinctive acoustic velocity and amplitude anomalies (VAMPs), indicative of local gas-hydrate occurrences, throughout the Bering Sea play. Scholl and Hart (1993) determined that the VAMPs in the Bering Sea occur over an area of approximately 400,000 km^2. No gas hydrates have been recovered from the Bering Sea play, possibly due to limited drilling.

Seismic reflection profiles from the area of the Aleutian Trench and Arc system commonly reveal BSRs at sub-bottom depths near 1,000 m (Kvenvolden, 1987). DSDP research coring in the Aleutian accretionary wedge (Site 186; Shipboard Scientific Party, 1973c), near the margin of the Atka Basin, encountered a high amount of methane gas in close association with a BSR, suggesting that BSRs in this area are a reflection of free-gas underlying a gas-hydrate-bearing section.

Seismic reflection profiles from the Gulf of Alaska have revealed BSRs on the upper continental slope southeast of Kodiak Island at water depths from 1,600 to 2,300 m and at sub-bottom depths of 570 to 670 m (Kvenvolden and von Huene, 1986; Krason and Ciesnik, 1987). MacLeod (1982) also shows depths of BSRs in sediments of the Gulf of Alaska, but the locations are not given. Other than seismic data, there is no evidence of gas hydrates in the Gulf of Alaska.

GEOLOGIC CONTROLS ON GAS HYDRATE

Formation Temperature

Within the Alaska offshore province, geothermal-gradient data are available from 85 sea-floor temperature-probe measurements (Foster, 1962; Langseth and von Herzen, 1970; Scholl and Hart, 1993), from well-bore surveys in seven research coreholes (Shipboard Scientific Party, 1973b, 1973c, 1993), and from estimates based on the identification of BSRs on available seismic records (41 locations) (Cooper and others, 1979; Shipley and others, 1979; Marlow and others, 1981; Grantz and others, 1982; MacLeod, 1982; McCarthy and others, 1984; Carlson and others, 1985; Kvenvolden and von Huene, 1986; Krason and Ciesnik, 1987; Kvenvolden, 1987; Finley and Krason, 1988; Scholl and Hart, 1993). Additional temperature data (35 geothermal gradients) have been obtained from the geothermal-gradient map of North America published by the American Association of Petroleum Geologists and the U.S. Geological Survey

(Geothermal Survey of North America Subcommittee, 1976). The geothermal gradient in the Beaufort Sea play ranges from about 3.0- 5.0¡C/100 m (plate 19). In the Bering Sea play, the geothermal gradient is about 4.0¡C/100 m along the northeastern edge of the play and increases to the southwest to values exceeding 8.0¡C/100 m near the Aleutian Islands (plate 19). The geothermal gradient in both the Aleutian Trench and Gulf of Alaska plays ranges from very low values of less than 2.0¡C/100 m in the deep-marine portion of the plays to values exceeding 6.0 - 7.0¡C/100 m beneath the Aleutian Islands. The geothermal-gradient pattern observed in the Aleutian Trench play (plate 19) can be directly attributed to the regional heat flow pattern across the Aleutian Trench--Arc system (Shipboard Scientific Party, 1973c).

Seabed temperatures needed to calculate the thickness of the gas-hydrate stability zone in the Alaska Offshore province are available from a number of publications (Navy Hydrographic Office, 1958; Schroeder, 1963; Shipboard Scientific Party, 1973b, 1973c, 1993; Shipley and others, 1979; Kvenvolden and von Huene, 1986; Krason and Ciesnik, 1987; Finley and Krason, 1988; Scholl and Hart, 1993; Schweitzer, 1993). In the Beaufort Sea play, the seabed temperature is relatively uniform, averaging about 0¡C (plate 18). In the Bering Sea, Aleutian Trench, and Gulf of Alaska plays, the seabed temperature at bathymetric depths of less than 500 m is about 5¡C, whereas below 1,000 m water depth, the seabed is at a temperature of about 2¡C (plate 18).

Formation Pore-Pressure

The review of all available data has revealed no evidence of significant pore-pressure anomalies within the near-surface (0-1,500 m) sedimentary section of the Alaska Offshore province. Therefore, the gas-hydrate stability calculations for the Alaska offshore province have been made assuming a hydrostatic pore-pressure gradient (9.795 kPa/m; 0.433 psi/ft).

Gas Chemistry

Relatively few gas samples have been collected from the Alaska Offshore province due mainly to the lack of drilling. Analysis of the gas samples recovered during DSDP (Legs 18 and 19; Shipboard Scientific Party 1973b, 1973c), ODP (Leg 145; Shipboard Scientific Party 1993), and seabed (Cooper and others, 1979; Marlow and others, 1981; Carlson and others, 1985; Kvenvolden and von Huene, 1986; Krason and Ciesnik, 1987; Finley and Krason, 1988; Scholl and Hart, 1993) sediment coring in the Alaska Offshore province indicates the presence of mostly methane and only small to trace amounts of other hydrate-forming hydrocarbon gases. Because methane appears to be the dominant hydrocarbon gas within all the plays of the Alaska offshore province, we have assumed a pure methane chemistry for the gas-hydrate stability calculations in the Alaska Offshore province.

Pore-Water Salinity

Salinity data from the near-surface (0-1,500 m) sedimentary section of the Alaska Offshore province are available from water samples collected during DSDP (Legs 18 and 19; Shipboard Scientific Party 1973b, 1973c), ODP (Leg 145; Shipboard Scientific Party 1993), and seabed (Krason and Ciesnik, 1987; Finley and Krason, 1988) sediment coring activity. The reported (bulk) pore-water salinities are similar to that of sea water (32 ppt), ranging from about 30 to 36 ppt. Therefore, the gas-hydrate stability calculations for the Alaska Offshore province have been made assuming a pore-water salinity of 32 ppt (average sea-water salinity).

Gas-Hydrate Stability Calculations

The isopach map in plate 20 shows that the methane-hydrate stability zone in the Beaufort Sea play is more than 700 m thick in the north-central portion of the play, and methane hydrates should not occur above the 500-m bathymetric contour. Throughout most of the Bering Sea play, the methane-hydrate stability zone is about 400 m thick. The gas-hydrate stability zone in the Aleutian Trench and Gulf of Alaska plays reaches a maximum thickness of about 1,200 m within and to the south of the Aleutian Trench. Thermal conditions should preclude the occurrence of methane hydrates above the 600-m bathymetric contour in both the Aleutian Trench and Gulf of Alaska plays.

Availability of Gas and Water

There are insufficient data to fully interpret the availability of natural gas in most of the Alaska Offshore province. All of the plays here appear to contain hydrocarbon gas of mostly microbial origin; however, thermogenic gas has also been found in most of the plays (Shipboard Scientific Party 1973b, 1973c, 1993; Marlow and others, 1981; McCarthy and others, 1984; Carlson and others, 1985; Kvenvolden and von Huene, 1986; Krason and Ciesnik, 1987; Finley and Krason, 1988; Scholl and Hart, 1993). The organic carbon required for the microbial generation of methane is generally available in amounts sufficient for the formation of methane hydrates in most of the Alaska offshore plays (plate 17; modified from Premuzic, 1980; Premuzic and others, 1982). The near-surface (0-1,500 m) sedimentary section in the Aleutian Trench play exhibits the greatest range in available organic carbon (TOC), with values ranging from below 0.5 percent to very high values of over 2.0 percent. It is likely that thermogenic gas sources have contributed to gas-hydrate formation in the Alaska Offshore province; however, the importance of these sources is not known (sediment thickness map in plate 16 is modified from Drummond, 1986; Tucholke and others, 1982).

The water required for formation of gas hydrates in the Alaska Offshore province should be available in ample supply.

Gas and Water Migration Pathways

The quiescent tectonic setting of the Beaufort Sea and Bering Sea plays has not lent itself to the development of significant fault systems, thus limiting the number of potential gas- and water-migration pathways. However, the active tectonic nature of the Aleutian Trench and Gulf of Alaska plays has lead to the development of major normal-fault systems, large-scale grabens, and numerous sub-basins along the southern continental margin of Alaska, which may allow for numerous migration pathways.

Reservoir Rocks and Seals

Porosities in the near-surface sediments (0-1,500 m) of the in the Alaska Offshore province are similar to those observed in most marine basins (ranging from about 30 to 80 percent); thus, the entire marine sedimentary section can be considered to be an excellent reservoir based on porosity alone. The active tectonic nature of the Aleutian Trench and Gulf of Alaska plays has lead to the development of numerous structural traps. On the other hand, the quiescent tectonic setting of the Beaufort Sea and Bering Sea plays has not lent itself to the development of significant structural traps that could effect the accumulation of gas hydrates. Stratigraphic traps may contribute to the accumulation of gas hydrates in these plays; however, there is no evidence of stratigraphically controlled gas-hydrate accumulations in the Offshore Alaska province.

Beaufort Sea Play

The Beaufort Sea play (plate 21; fig. 11) is limited to a sedimentary section of clastic detritus derived from the uplift of the Brooks Range to the south. This play consists of limited structural and stratigraphic traps related to facies changes or traps formed against small-displacement faults. The Cretaceous and Tertiary sedimentary section in the Beaufort Sea play varies in thickness from less than 1 km over the Barrow Arch to 11 km beneath the outer Beaufort Sea continental shelf.

The thickness of the methane-hydrate stability zone in this play ranges from zero along the southern edge of the play to a maximum thickness of about 700 m in the north-central portion of the play.

Potential reservoirs consist of high-porosity hemipelagic muds and clays, coarse turbidite sands, and deltaic to shallow-marine clastics.

The proximity of huge conventional hydrocarbon accumulations along the southern margin of the Beaufort Sea play indicates that rich, mature source rocks exist in the region. However, the composition and thermal history of the strata beneath the outer continental shelf and slope of the Beaufort Sea are not known due to limited drilling. Adequate organic carbon (TOC) content of the sediments on the Beaufort Sea continental margin indicates a good potential for microbial methanogensis (plate 17).

Hydrocarbon traps within this play likely include stratigraphic traps associated with regional facies changes.

Bering Sea Play

The Bering Sea play (plate 21; fig. 12) is limited to the deep-water (more than 700 m) portion of the Bering Sea Basin to the southwest of the Alaskan continental shelf. The Bering Sea play consists of mostly stratigraphic traps in a thick (1 to 9 km) flat-lying Cenozoic sedimentary section. Major lithologies in the play are represented by diatomaceous mudstones and siltstones interbedded with sandstones, shales, and volcanic ashes.

The methane-hydrate stability zone is about 400 m thick throughout most of the play, and thermal conditions should preclude the occurrence of methane hydrates above the 600-m bathymetric contour in the Bering Sea.

Porous marine lithologies within the Bering Sea play consist of diatomaceous sediments with varying amounts of silt and clay that is more compressed with depth (reported porosities range from 58 to 85 percent).

Organic carbon content values for the near-surface (0-1,500 m) sedimentary section in the Bering Sea play average about 1 percent, which indicates there should be an adequate supply of microbial methane for gas-hydrate formation (plate 17). Regional petroleum studies suggest that only limited parts of the play have conditions favorable for thermogenic hydrocarbon generation.

Postulated traps are mostly stratigraphic and are related to facies changes along the continental margin. Structural traps are believed to be relatively rare.

Aleutian Trench Play

The Aleutian Trench play (plate 21; fig. 13) covers an area of about 530,000 km^2 and is limited to the region south of the Aleutian Islands and west of the Shumagin Islands where the organic carbon content of the sedimentary section exceeds 0.5 percent (plate 17). The play consists of abundant structural and stratigraphic traps in Tertiary turbidite sandstones and porous diatomaceous pelagic deposits.

The thickness of the methane-hydrate stability zone ranges from zero near the 600-m bathymetric contour along the northern margin of the play to about 1,200 m along the southern boundary of the play.

Potential reservoirs consist of hemipelagic muds and clays, turbidite sandstones, diatomaceous sediments, and volcanic ashes.

The organic carbon (TOC) content of the sediments in the Aleutian Trench play varies from 0.5 to over 2.0 percent (plate 17), which may represent an important source of microbial methane. Due to the limited thickness (0 to 3 km) of the sedimentary section in the Aleutian Trench play, it is unlikely that a significant amount of thermogenic gas would be found in the play.

Hydrocarbon traps in this play are mostly structural and are often associated with large-scale tectonic plate movement.

Gulf of Alaska Play

The Gulf of Alaska play (plate 21; fig. 14) is limited to the region south of the Kodiak Island and Prince William Sound area and east of the Shumagin Islands where the sedimentary section organic carbon (TOC) content exceeds 0.5 percent (plate 17). This play consists of relatively limited structural and stratigraphic traps in clayey silt and sandstone deposits of Cenozoic age.

The thickness of the methane-hydrate stability zone ranges from zero along the northern edge of the play to a maximum thickness of about 1,200 m within the center of the play.

Potential reservoirs consist of unconsolidated hemipelagic muds and clays, turbidite sandstones, diatomaceous sediments, and volcanic ashes.

Low organic carbon (TOC) content of the sediments in this play indicates a low amount of microbial methane available for gas hydrate formation. The potential for thermogenically derived hydrocarbons in this play is believed to be moderate to low (Kvenvolden and von Huene, 1986).

Hydrocarbon traps in this play should consist of mainly structural traps associated with large-scale tectonic plate movement.

ALASKA ONSHORE PROVINCE

GEOLOGIC SETTING

The Alaska Onshore province extends 950 km from the Chukchi Sea on the west to the Canadian border on the east. Its maximum width is about 320 km. The total area of the province is about 140,000 km^2. 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; and Gryc, 1988). The sedimentary rocks of the North Slope can be conveniently grouped into three sequences that indicate major episodes in the tectonic development of the region and, to a degree, 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) are, in ascending order, the Franklinian (Cambrian through Devonian), the Ellesmerian (Mississippian to lower most Cretaceous), and the Brookian (Lower Cretaceous to Holocene).

The only confirmation of natural-gas hydrate on the North Slope was obtained in 1972 when ARCO and EXXON successfully recovered a core containing gas hydrates (reviewed by Collett and others, 1988). Well-log data from an additional 445 North Slope wells were examined for possible gas-hydrate occurrences (Collett, 1993a). This review of all available data revealed that gas hydrates are inferred to occur in 50 of the surveyed wells. Many of these wells have multiple gas-hydrate-bearing units, and individual occurrences range from 3 to 31 m thick. The well-log inferred gas hydrates occur in six laterally continuous sandstone and conglomerate units and are geographically restricted to the east end of the Kuparuk River production unit and the west end of the Prudhoe Bay production unit. Open-hole logs from wells in the west end of the Prudhoe Bay field also indicate the presence of a large free-gas accumulation trapped stratigraphically downdip below four of the log-inferred gas hydrates. The potential volume of gas within the log-inferred gas hydrates (exclusive of the associated free-gas) of the Prudhoe Bay-Kuparuk River area is approximately 37 to 44 trillion cubic feet (at STP) [approximately 1.0×10^{12} to 1.2×10^{12} cubic meters of gas] (Collett, 1993a).

GEOLOGIC CONTROLS ON GAS HYDRATE

Formation Temperature

On the North Slope, subsurface temperature data come from high-resolution, equilibrated well-bore surveys in 46 wells and from estimates based on identification of the base of ice-bearing permafrost in 102 other wells (Collett and others, 1988). 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). Geothermal gradients needed to predict the depth and thickness of the gas-hydrate stability zone can be interpreted directly from these equilibrated temperature profiles. The high-resolution temperature surveys have provided 39 geothermal gradients within the ice-bearing sequence and 35 below the base of the ice. 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 data base, a new method of evaluating local geothermal gradients has been developed (for a complete description of this method see Collett and others, 1988). In this method, well-log picks for the base of the ice-bearing permafrost from 102 wells have been combined with regional temperature constants derived from the high-resolution surveys to extrapolate temperature data.

A 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 1.5¡C/100 m in the Prudhoe Bay area to about 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 1.6¡C/100 m to about 5.2¡C/100 m.

Formation Pore-Pressure

On the North Slope, pressure data from petroleum drill-stem testing in 17 wells, and log evaluation of discontinuities in overburden compaction profiles (pore-pressure profiles) in 22 wells have been used to evaluate pore-pressures within the near-surface sediments (0-1,500 m).

Pore-pressure gradients calculated from shut-in pressures recorded during drill-stem testing in wells from the North Slope range from 9.3 to 11.2 kPa/m, with an average gradient of 9.7 kPa/m (0.43 psi/ft), near hydrostatic (data from State of Alaska well files). To further evaluate pore-pressures, well logs have been used to study overburden compaction profiles. Within the near-surface (0-1,500 m) sediments of the North Slope, no significant pore-pressure discontinuities were observed. Pore-pressures in the wells we have examined are a product of a hydrostatic pore-pressure gradient; therefore, the gas-hydrate stability determinations for northern Alaska in this paper assume a hydrostatic pore-pressure gradient (9.795 kPa/m; 0.433 psi/ft).

Gas Chemistry

The analysis of mud-log gas-chromatographic data from 320 wells indicates that methane is the dominant hydrocarbon gas in the near-surface (0-1,500 m) sedimentary rocks of the North Slope (Collett and others, 1988). Analysis of gas evolved from recovered gas-hydrate samples in the Prudhoe Bay area suggest that the in-situ gas hydrates are composed mostly of methane (87 to 99 percent). Therefore, the gas-hydrate stability calculations in this paper for northern Alaska have been made assuming a pure methane chemistry.

Pore-Water Salinity

Salinity data within the near-surface sediments of the North Slope are available from petroleum drill-stem and production tests, water samples from cores within the permafrost sequence, and spontaneous potential well-log calculations. Analyses of 55 water samples collected during petroleum formation testing in rock units from below the permafrost sequence are available. These analyses indicate that (bulk) pore-water salinities range from 0.5 to 19.0 ppt. Spontaneous potential well-log calculations indicate that pore-water salinities within the near-surface sediments of the North Slope are similar, ranging from 2 to 19 ppt. Analysis of cores from within the ice-bearing sequence of the BP 12-10-14A well (located in the Prudhoe Bay oil field) indicates that salinities within the sands of the ice-bearing permafrost sequence are also low, ranging from 0.15 to 0.50 ppt (Howitt, 1971). The gas-hydrate stability calculations in this paper for northern Alaska have been made assuming a pore-water salinity of 19 ppt (maximum recorded value).

Gas-Hydrate Stability Calculations

The calculated total thickness of the methane-hydrate stability zone in northern Alaska is isopached in plate 22; this map reveals that the methane-hydrate stability zone on the North Slope is thickest in the Prudhoe Bay area, with calculated values slightly greater than 1,000 m. The offshore extent of the gas-hydrate stability zone is not well established; however, "relic" permafrost and gas hydrates may exist on the Beaufort Sea continental shelf to a present water depth of 50 m (Collett, 1993a).

Availability of Gas and Water

Geochemical similarities suggest that a large amount of the gas within the hydrate stability zone of the Prudhoe Bay-Kuparuk River area of the North Slope has migrated from deep thermogenic gas sources (Collett and others, 1990). The stable carbon isotopic composition of the methane within the gas-hydrate-bearing rock units averages approximately -49 per mill, suggesting that the hydrates contain gas from a mixture of thermogenic and microbial sources. Geochemical analyses indicate that about 50 to 70 percent of the methane within the hydrate stability field has migrated from thermogenic sources (Collett, 1993a). Locally within the Prudhoe Bay-Kuparuk River area, the occurrence of gas hydrates appears to be controlled by the availability of a significant thermogenic gas source. Outside the immediate Prudhoe Bay-Kuparuk River area there appears to be a limited supply of natural gas that may restrict the occurrence of additional gas hydrate resources.

The Prudhoe Bay-Kuparuk River gas-hydrate accumulation lies within and beneath a thick (500 to 600 m) permafrost sequence, which may restrict regional ground-water flow. Recharge into an arctic sedimentary basin is usually limited to thawed zones beneath large lakes and major rivers. However, Deming and others (1992) suggest that the bulk of ground-water recharge on the North Slope takes place in the Brooks Range.

Their proposed topographically driven ground-water flow system, which would transport water from areas of high elevation in the Brooks Range to areas of low elevation on the coastal plain, would provide the water necessary for gas-hydrate formation in the Prudhoe Bay-Kuparuk River area. The lack of pore-pressure anomalies within the North Slope sedimentary sequence (as discussed in a previous section) also indicates that there is a sufficient source of water to maintain regional ground-water flow and hydrostatic pore-pressures.

Gas and Water Migration Pathways

The occurrence of gas hydrates in the Prudhoe Bay-Kuparuk River area is largely controlled by the availability of a significant quantity of thermogenic hydrocarbon gas that has migrated from depth along major fault systems. The occurrence of large thermogenic-gas accumulations within the near-surface sedimentary section of the North Slope reveals the presence of effective natural-gas migration pathways. The review of regional seismic data also reveals numerous near-surface faults that may act as gas- and water-migration pathways.

Reservoir Rocks and Seals

As previously noted, most of the well-log-inferred gas hydrates in the Prudhoe Bay-Kuparuk River area occur in a series of laterally continuous lower Tertiary sandstone and conglomerate units. These gas-hydrate-bearing rock units likely served as lateral conduits for up-dip-migrating thermogenic gas and provided the reservoirs in which to concentrate the gas required for gas-hydrate formation.

Multiple trapping mechanisms for the gas incorporated in the hydrates may exist in the Prudhoe Bay-Kuparuk River area. For instance, deeply buried fault traps described by Werner (1987) may extend into the overlying gas-hydrate units. In addition, most of the sediments that make up the gas-hydrate reservoir rocks were deposited in a delta-plain to shelf environment in which stratigraphic traps are common. Lateral facies changes may provide hydrocarbon traps within these horizons; however, because these rocks are unconsolidated, the efficiency of potential seals may be reduced. Ice-bearing permafrost is believed to be an impermeable barrier to migrating gas. Although ice-bearing permafrost is not believed to be the trapping mechanism for any conventional hydrocarbon accumulations on the North Slope (Werner, 1987), it may form traps within the near-surface (0-1,500 m) sedimentary sequence.

Two plays (plate 23) were defined and individually assessed within the Alaskan Onshore province: (1) Topset play and (2) Fold Belt play.

Topset Play

The Topset play (plate 23; fig. 15) consists of stratigraphic traps and sandstone reservoirs of Cretaceous and Tertiary age and includes those rocks represented on seismic records in the topset position of a clinaform sequence. This play is limited to the relatively undeformed rocks north of the Brooks Range fold belt. These rocks, the Nanushuk Group and Sagavanirktok Formation, consist of marine and nonmarine deltaic sandstone, siltstone, shale, conglomerate, and coal.

The methane-hydrate stability zone in this play reaches a maximum thickness of about 1,000 m within the area of the Prudhoe Bay field. The northern offshore limit of the hydrate stability zone corresponds with the 50-m bathymetric contour.

Reservoir rocks consist of sandstone and conglomerate and may comprise as much as 75 percent of the total thickness of the gas-hydrate stability zone, even though individual beds seldom exceed 20 m. Fair to good reservoir continuity is expected, but marked changes may occur over short distances.

Potential source rocks within the play interval are interbedded deltaic shales and mudstones, which are immature. Beneath the methane-hydrate stability zone are numerous potential thermally mature gas sources, some of which have contributed to the known gas hydrate accumulations in the Prudhoe Bay-Kuparuk River area.

Postulated traps are mostly stratigraphic and are related to facies changes, or traps formed against small-displacement normal faults. Faults and interbedded shales are expected to provide only fair to poor conventional seals.

This play includes onshore State lands and offshore State and Federal waters. The gas-hydrate resource estimate for this play is divided into two parts, with one estimate representing the hydrate resources within the State lands and waters and the second representing the offshore Federal hydrate resources (exclusive of the deep marine hydrate resources of the Beaufort Sea play).

Fold Belt Play

The Fold Belt play (plate 23; fig. 16) consists of anticlinal traps in Cretaceous and Tertiary sandstone reservoirs in the northern part of the Brooks Range fold belt. The play is situated north of the Brooks Range thrust belt and south of undisturbed deposits of the Topset play; its western border is the Chukchi Sea; its eastern border extends offshore to the 50-m bathymetric contour in the Beaufort Sea. In the eastern part, this play encompasses rocks of the Sagavanirktok and Canning Formations, Hue Shale, pebble shale unit, and Kemik Sandstone; in the western part of the play, it includes parts of the Nanushuk Group and Torok Formation.

The methane-hydrate stability zone in this play reaches a maximum thickness of about 500 m in the north-central portion of the play area, and thermal conditions preclude the occurrence of gas hydrates in about half of the play.

Potential reservoirs are sandstone units, representing deltaic and shallow-marine environments. Sandstone porosities are expected to range from about 5 to 20 percent.

Potential source rocks include gas-prone shale units of the Nanushuk Group and the Sagavanirktok, Torok, and Canning Formations. Gas-prone source rocks within the play range from immature to mature.

Conventional traps within this play consist of fault-cored anticlines related to Brooks Range thrusting. Stratigraphic traps, such as updip pinchouts on the flanks of anticlines, may also be present. Shales are expected to provide fair to good seals, although the effectiveness of these seals may be reduced by faulting.

This play includes onshore State lands and offshore State and Federal waters. The gas-hydrate resource estimate for this play is divided into two parts, with one estimate representing the hydrate resources within the State lands and waters and the second representing the offshore Federal hydrate resources (exclusive of the deep-marine hydrate resources of the Beaufort Sea play).

ESTIMATES OF IN-PLACE RESOURCES

The estimates of *in-place* gas-hydrate resources included in this report are presented in the form of complementary cumulative probability distributions (table 2, fig. 17). These distributions summarize the range of estimates generated by the FASPU computer program (Crovelli and Balay, 1990) as a single probability curve in a "greater than" format (fig. 17). Our estimates are reported at the mean and at the 95th, 75th, 50th, 25th, and 5th fractiles (table 2). We consider the 95th and 5th fractiles to be "reasonable" minimum and maximum values, respectively

In-place gas resources within the gas hydrates of the United States are estimated to range from 112,765 to 676,110 trillion cubic feet of gas (TCFG) [3,193 to 19,142 trillion cubic meters of gas (TCMG)], at the 0.95 and 0.05 probability levels, respectively (table 2, figure 17). Although these ranges of values show a high degree of uncertainty, they do indicate the potential for enormous quantities of gas stored as gas hydrates. The mean in-place value for the entire United States is calculated to be 320,222 TCFG (9,066 TCMG). This assessment of in-place gas hydrates represents those deposits that constitute the resource base *without reference to recoverability*.

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FIGURE AND TABLE CAPTIONS

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Table 2 Estimates of the in-place gas resources within the gas hydrates of the United States.

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Figure 2. Two gas hydrate crystal structures: *A*, Structure I; and *B*, Structure II (modified from Sloan, 1990).

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Table 1.--World estimates of the amount of methane in gas hydrates of continental and oceanic settings (modified from Kvenvolden, 1993).

Continental Gas Hydrates

Estimated in-place natural gas resources		Reference
(trillion cubic feet)	(cubic meters)	
5.0×10^{2}	1.4×10^{13}	Meyer (1981)
1.1×10^{3}	3.1×10^{13}	McIver (1981)
2.0×10^{3}	5.7×10^{13}	Trofimuk and others (1977)
2.6×10^{4}	7.4×10^{14}	MacDonald (1990)
1.2×10^{6}	3.4×10^{16}	Dobrynin and others (1981)

Oceanic Gas Hydrates

Estimated in-place natural gas resources		Reference
(trillion cubic feet)	(cubic meters)	
1.1×10^{5}	3.1×10^{15}	McIver (1981)
1.8 to 8.8×10^{5}	5 to 25×10^{15}	Trofimuk and others (1977)
7×10^{5}	2×10^{16}	Kvenvolden (1988)
7.4×10^{5}	2.1×10^{16}	MacDonald (1990)
1.4×10^{6}	4×10^{16}	Kvenvolden and Claypool (1988)
2.7×10^{8}	7.6×10^{18}	Dobrynin and others (1981)

Remaining Recoverable Conventional Natural Gas		
Estimated in-place natural gas resources		**Reference**
(trillion cubic feet)	**(cubic meters)**	
9×10^3	2.5×10^{14}	Masters and others (1991)

Table 2.--Estimates of the in-place gas resources within the gas hydrates of the United States

ESTIMATED IN-PLACE NATURAL GAS RESOURCES (TRILLIONS OF FT^3)						
PROVINCES/PLAYS	MEAN	F_{95}	F_{75}	F_{50}	F_{25}	F_5
Atlantic Ocean Province						
Northeastern Atlantic Ocean play	30,251	0	0	14,128	49,448	109,491
Southeastern Atlantic Ocean play	21,580	6,464	11,656	17,660	27,196	49,448
Gulf of Mexico Province						
Gulf of Mexico play	38,251	11,444	20,839	31,435	49,448	88,300
Pacific Ocean Province						
Northern Pacific play	53,721	16,035	29,315	45,916	67,108	123,619
Southern Pacific play	7,350	0	0	0	0	63,576
Alaska Offshore province						
Beaufort Sea play	32,304	0	0	15,188	52,980	116,555
Bering Sea play	73,289	0	0	34,613	120,087	264,899
Aleutian Trench play	21,496	0	0	0	0	183,663
Gulf of Alaska play	41,360	0	0	0	0	257,835
OFFSHORE PROVINCES TOTAL	**319,632**	**112,346**	**190,709**	**275,482**	**397,936**	**675,503**

Table 2.--Estimates of the in-place gas resources within the gas hydrates of the United States
(Continued)

ESTIMATED IN-PLACE NATURAL GAS RESOURCES (TRILLIONS OF FT^3)						
PROVINCES/PLAYS	MEAN	F_{95}	F_{75}	F_{50}	F_{25}	F_5
Alaska Onshore province						
Topset play--State lands & waters	105	0	0	0	0	388
Topset play--Federal waters	43	0	0	0	0	161
Fold Belt play--State lands & waters	414	0	0	0	490	1,914
Fold Belt play--Federal waters	28	0	0	0	33	128
ONSHORE PROVINCES TOTAL	**590**	**0**	**0**	**236**	**668**	**2,357**

UNITED STATES TOTAL	**320,222**	**112,765**	**191,261**	**276,119**	**398,626**	**676,110**

Figure 4.--Gas hydrate assessment data form used to estimate the volume of natural gas trapped within a gas hydrate play. S3 = Cumulative microbial hydrocarbon source probability, GS = Hydrocarbon source play attribute.

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	S1	S3	GS	S1*S2=S3, if S3=1 , then GS=1 If S4=1, then GS=1 Use the > value of S3 or 34
	Microbial source sediment thickness (S2)	S2			
	Thermogenic hydrocarbon source (S4)	S4			
	Timing (T)			T	
	Migration (M)M				
	Potential reservoir facies (R)			R	
	Marginal play probability (GS*T*M*R=MP)			MP	
Prosp. Attrib.	Trapping mechanism (TM)			TM	
	Effective porosity (>3%) (P)			P	
	Hydrocarbon accumulation (C)			C	
	Conditional deposit probability (TM*P*C=CP)			CP	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume or Area of hydrate stability zone (10^{12}m^3 or 10^{6}m^2)							
	Reservoir thickness in nonmarine systems (m)							
	Effective porosity (%)							

	Hydrate saturation (%)							
	Hydrate gas yield (m^3)							

Figure 6A.--Northeastern Atlantic Ocean Play--Assessment data form.

Play: Northeastern Atlantic Ocean

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	0.85	0.85	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)0.8				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			0.8	
Prosp. Attrib.	Trapping mechanism (TM)			0.8	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.8	
	Conditional deposit probability (TM*P*C=CP)			0.64	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	94.4	100.3	112.1	118.0	123.9	135.7	141.6
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 6B.--Northeastern Atlantic Ocean Play--Estimated natural gas resources

Play: Northeastern Atlantic Ocean

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	14,128
0.25	49,448
0.05	109,491
Mean value	30,251
Standard deviation	41,285

Figure 7A.--Southeastern Atlantic Ocean Play--Assessment data form.

Play: Southeastern Atlantic Ocean

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			1.0	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			1.0	
	Conditional deposit probability (TM*P*C=CP)			1.0	

	Attribute	Probability of equal to or greater than						
Gas Vol. Param.		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12} m^3$)	34.5	36.6	40.9	43.1	45.3	49.6	51.7
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

	Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
	Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 7B.--Southeastern Atlantic Ocean Play--Estimated natural gas resources.

Play: Southeastern Atlantic Ocean

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	6,464
0.75	11,656
0.50	17,660
0.25	27,196
0.05	49,448
Mean value	21,580
Standard deviation	14,728

Figure 8A.--Gulf of Mexico Play--Assessment data form.

Play: Gulf of Mexico

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			1.0	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			1.0	
	Conditional deposit probability (TM*P*C=CP)			1.0	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	61.1	64.9	72.6	76.4	80.2	87.9	91.7
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 8B.--Gulf of Mexico Play--Estimated natural gas resources.

Play: Gulf of Mexico

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	11,444
0.75	20,839
0.50	31,435
0.25	49,448
0.05	88,300
Mean value	38,251
Standard deviation	26,105

Figure 9A.--Northern Pacific Ocean Play--Assessment data form.

Play: Northern Pacific Ocean

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			1.0	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			1.0	
	Conditional deposit probability (TM*P*C=CP)			1.0	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	85.8	91.2	101.9	107.3	112.7	123.4	128.8
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 9B.--Northern Pacific Ocean Play--Estimated natural gas resources.

Play: Northern Pacific Ocean

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	16,035
0.75	29,315
0.50	45,916
0.25	67,108
0.05	123,619
Mean value	53,721
Standard deviation	36,662

Figure 10A.--Southern Pacific Ocean Play--Assessment data form.

Play: Southern Pacific Ocean

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	0.5	0.125	0.125	
	Microbial source sediment thickness (S2)	0.25			
	Thermogenic hydrocarbon source (S4)	0.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			0.125	
Prosp. Attrib.	Trapping mechanism (TM)			0.8	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.8	
	Conditional deposit probability (TM*P*C=CP)			0.64	

	Attribute	Probability of equal to or greater than						
Gas Vol. Param.		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	146.8	156.0	174.3	183.5	192.7	211.0	220.2
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 10B.--Southern Pacific Ocean Play.

Play: Southern Pacific Ocean

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	0
0.05	63,576
Mean value	7,350
Standard deviation	30,592

Figure 11A.--Assessment data form.

Play: Beaufort Sea

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	0.5	0.5	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)0.8				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			0.8	
Prosp. Attrib.	Trapping mechanism (TM)			0.8	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.8	
	Conditional deposit probability (TM*P*C=CP)			0.64	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12} m^3$)	100.8	107.1	119.7	126.0	132.3	144.9	151.2
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

	Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
	Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 11B.--Beaufort Sea Play--Estimated natural gas resources.

Play: Beaufort Sea

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	15,188
0.25	52,980
0.05	116,555
Mean value	32,304
Standard deviation	44,086

Figure 12A.--Bering Sea Play--Assessment data form.

Play: Bering Sea

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	0.5	0.5	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)0.8				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			0.8	
Prosp. Attrib.	Trapping mechanism (TM)			0.8	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.8	
	Conditional deposit probability (TM*P*C=CP)			0.64	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	228.7	243.0	271.6	285.9	300.2	328.8	343.1
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

	Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
	Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 12B.--Estimated natural gas resources.

Play: Bering Sea

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	34,613
0.25	120,087
0.05	264,899
Mean value	73,289
Standard deviation	100,033

Figure 13A.--Aleutian Trench Play--Assessment data form.

Play: Aleutian Trench

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	0.5	0.125	0.125	
	Microbial source sediment thickness (S2)	0.25			
	Thermogenic hydrocarbon source (S4)	0.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			0.125	
Prosp. Attrib.	Trapping mechanism (TM)			0.8	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.8	
	Conditional deposit probability (TM*P*C=CP)			0.64	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	429.3	456.1	509.8	536.6	563.4	617.1	643.9
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

	Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
	Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 13B.--Aleutian Trench Play--Estimated natural gas resources.

Play: Aleutian Trench

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	0
0.05	183,663
Mean value	21,496
Standard deviation	89,458

Figure 14A.--Gulf of Alaska Play--Assessment data form.

Play: Gulf of Alaska

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	0.4	0.4	0.4	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	0.0			
	Timing (T)			1.0	
	Migration (M)0.8				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			0.32	
Prosp. Attrib.	Trapping mechanism (TM)			0.8	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.8	
	Conditional deposit probability (TM*P*C=CP)			0.64	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Volume of hydrate stability zone (x $10^{12}m^3$)	322.7	342.9	383.2	403.4	423.6	463.9	484.1
	Reservoir thickness in nonmarine systems (m)	-	-	-	-	-	-	-

	Effective porosity (%)	30	32.8	43.8	57.5	68.8	77.8	80
	Hydrate saturation (%)	2	3.2	8	14	20.5	25.7	27
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 14B.--Gulf of Alaska Play--Estimated natural gas resources.

Play: Gulf of Alaska

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	0
0.05	257,835
Mean value	41,360
Standard deviation	102,643

Figure 15A1.--Topset Play--Assessment data form for the onshore State lands and waters portion of the play.

Play: Alaska Onshore Province--Topset Play - State lands and waters

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			0.3	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.2	
	Conditional deposit probability (TM*P*C=CP)			0.06	

	Attribute	Probability of equal to or greater than						
Gas Vol. Param.		100	95	75	50	25	5	0
	Area of hydrate stability (x $10^6 m^2$)	50609	53772	60098	63261	66424	72750	75913
	Reservoir thickness in nonmarine systems (m)	15	23	30	61	91	152	229

	Effective porosity (%)	10	15	20	25	27	30	32
	Hydrate saturation (%)	2	3.2	10.5	18.9	32	63.8	90
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 15A2.--Topset Play--Assessment data form for the offshore Federal waters portion of the play.

Play: Alaska Onshore Province--Topset Play - Federal waters

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			0.3	
	Effective porosity (>3%) (P)			1.0	
	Hydrocarbon accumulation (C)			0.2	
	Conditional deposit probability (TM*P*C=CP)			0.06	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0

Area of hydrate stability (x $10^6 m^2$)	20950	22259	24878	26187	27496	30115	31424
Reservoir thickness in nonmarine systems (m)	15	23	30	61	91	152	229
Effective porosity (%)	10	15	20	25	27	30	32
Hydrate saturation (%)	2	3.2	10.5	18.9	32	63.8	90
Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 15B$_1$.--Topset Play--Estimated natural gas resources within the onshore State lands and waters portion of the play.

Play: Alaska Onshore Province--Topset Play - State lands and waters

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	0
0.05	388
Mean value	105
Standard deviation	712

Figure 15B$_2$.--Topset Play--Estimated natural gas resources within the offshore Federal waters portion of the play.

Play: Alaska Onshore Province--Topset Play - Federal waters

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	0
0.05	161
Mean value	43
Standard deviation	295

Figure 16A1.--Fold Belt Play--Assessment data form for the onshore State lands and waters portion of the play.

Play: Alaska Onshore Province--Fold Belt Play - State lands and waters

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			0.6	
	Effective porosity (>3%) (P)			0.8	
	Hydrocarbon accumulation (C)			0.9	
	Conditional deposit probability (TM*P*C=CP)			0.432	

Gas Vol. Param.	Attribute	Probability of equal to or greater than						
		100	95	75	50	25	5	0
	Area of hydrate stability (x $10^6 m^2$)	41376	43962	49134	51720	54306	59478	62064
	Reservoir thickness in nonmarine systems (m)	1.5	8.6	15.8	22.9	55.3	78.7	152.4

	Effective porosity (%)	3	7	11	15	19.3	26.3	32
	Hydrate saturation (%)	2	15.6	37	52.5	56	76.5	90
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 16A2.--Fold Belt Play--Assessment data form for the Offshore Federal waters portion of the play.

Play: Alaska Onshore Province--Fold Belt Play - Federal waters

	Attribute			Probability of favorable	Comments
Play Attrib.	Microbial hydrocarbon source (S1)	1.0	1.0	1.0	
	Microbial source sediment thickness (S2)	1.0			
	Thermogenic hydrocarbon source (S4)	1.0			
	Timing (T)			1.0	
	Migration (M)1.0				
	Potential reservoir facies (R)			1.0	
	Marginal play probability (GS*T*M*R=MP)			1.0	
Prosp. Attrib.	Trapping mechanism (TM)			0.6	
	Effective porosity (>3%) (P)			0.8	
	Hydrocarbon accumulation (C)			0.9	
	Conditional deposit probability (TM*P*C=CP)			0.432	

	Attribute	Probability of equal to or greater than						
Gas Vol. Param.		100	95	75	50	25	5	0
	Area of hydrate stability (x $10^6 m^2$)	2758	2930	3275	3447	3619	3964	4136
	Reservoir thickness in nonmarine systems (m)	1.5	8.6	15.8	22.9	55.3	78.7	152.4

	Effective porosity (%)	3	7	11	15	19.3	26.3	32
	Hydrate saturation (%)	2	15.6	37	52.5	56	76.5	90
	Hydrate gas yield (m^3)	139	140.3	145.3	151.5	157.8	162.8	164

Figure 16B_1.--Fold Belt Play--Estimated natural gas resources within the onshore State lands and waters portion of the play.

Play: Alaska Onshore Province--Fold Belt Play - State lands and waters

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	490
0.05	1,914
Mean value	414
Standard deviation	925

Figure 16B$_2$.--Fold Belt Play--Estimated natural gas resources within the offshore Federal waters portion of the play.

Play: Alaska Onshore Province--Fold Belt Play - Federal waters

Probability (equal to or greater than)	Estimated in-place natural gas resources (trillions of ft^3)
0.95	0
0.75	0
0.50	0
0.25	33
0.05	128
Mean value	28
Standard deviation	62