Appendix 7

Oil and Gas Resource Assessment

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Appendix 7. Oil and Gas Resource Assessment

A. Introduction

The environmental impacts associated with future oil and gas activities are assumed to be correlated to the economic petroleum potential. That is, higher levels of development are likely to be associated with higher levels of impacts. However, there is no way to accurately predict when or how much of the theoretical (undiscovered) petroleum potential will actually be converted to future production. For the basic oil and gas resource analysis, it is assumed that the entire Planning Area will be open to unrestricted leasing, exploration, and development. It is also assumed that the entire economic fraction of the resource endowment (that part occurring in large pools that can be developed profitably at certain commodity prices) will be both discovered and developed by industry. However, it is acknowledged that it is unlikely that all prospects will be tested or that all economic resources will be discovered by drilling. It is also acknowledged that some restrictions on exploration and development activities will likely apply. Typically, the largest fields are discovered and developed first, and subsequent discoveries are smaller and more costly to develop on a per-barrel basis. At some point, exploration capital is directed to other basins and some of the potentially economic resources are left in the ground. Industry groups could easily lose interest in exploration at any time after a number of costly dry wells. Without an aggressive exploration effort the full potential of the area may never be realized. Even with aggressive exploration, the economically recoverable oil and gas typically represents only a small fraction of the total endowments of recoverable oil and gas.

It is conceivable that future technological advancements will lead to a decrease in oil/gas finding and recovery costs and thereby increase the fraction of resources that can be economically recovered. However, the effects of unknown future technological advances cannot be addressed at this time.

For this assessment, both hypothetical, undiscovered pools and discovered pools were considered for their economic potential. However, discovered pools were treated separately from the population of hypothetical, undiscovered pools.

Pools discovered prior to 1999 have published, mean reserves that are patently too small to support economic development. Some of these discoveries have remained undeveloped for many decades. For example, the Umiat oil field was discovered in 1946, and mean oil reserves are estimated to be 70 MMbbl. However, the Umiat field is viewed as uneconomic because expected low well production rates would not generate revenues sufficient to overcome the high costs associated with development of the field and construction of a lengthy pipeline connecting Umiat to existing North Slope infrastructure. We acknowledge that discovered pools with published reserve estimates have the potential for larger recoverable volumes at low probabilities (i.e., it is possible, but very unlikely, that volumes in excess of published reserves could be recovered). Some of the discovered pools are now available for leasing and might even attract bids from companies willing to gamble against the low probability for high-side reserve volumes. However, in our economic model, these high risks burden hypothetical projects and render them uneconomic even when larger reserves are entertained.

Discoveries announced since 1999 (Table III-01) do not yet have published reserve estimates. These discoveries are not fully appraised in terms of pool size and only represent "discoveries" in the sense that significant oil or gas flow rates were measured from certain geological strata. It is not known whether any of these discoveries will prove to be sufficiently large to justify development. The post-1999 discoveries were removed (for statistical reasons) from the population of hypothetical, undiscovered pools that were explicitly evaluated by the economic model. However, a full spectrum of sizes of undiscovered pools--probably fully representative of the possible sizes of the new (and pre-1999) discoveries--were subjected to economic simulation analysis and in the end could have contributed to the economic endowment.

Two computer models--developed by MMS for offshore resource assessment--were used in evaluating the combined Northwest and Northeast NPR-A Planning Areas. Descriptions of how these computer models were developed and used in the recently completed 1995 National Resource Assessment are provided in USDOI, MMS (1996e) and Sherwood (ed.), (1998). These two computer programs are summarized here.

The Geologic Resource Assessment Program (GRASP) calculates the conventionally recoverable resource potential or "geologic potential." Geologic characteristics of reservoirs and plays are input as ranged variables (in the form of probability distributions) which are sampled randomly ("Monte Carlo" sampling) to determine pool numbers and size. The primary output includes cumulative frequency (or probability distributions) for total oil, gas, and barrels of oil equivalent (BOE) volumes, and a pool rank (or size) distribution for each assessed geologic play. The pool rank distribution displays the number of accumulations expected, with sizes ranked from largest to smallest. These data represent the hydrocarbon pools expected in the assessment area. The output of GRASP is sampled as part of the data used by the Probabilistic Resource Estimates-Offshore (PRESTO) model.

The PRESTO model performs a discovery/development/production simulation and a discounted cash flow analysis for each hypothetical pool forecast by the GRASP model. In a given trial, pools with positive net present value are considered to be commercially viable and therefore, contribute to the play's economic resources. Economic play resources are then summed to create the total economic potential of the assessment area. The economic analysis proceeds as a series of simulation runs at different commodity prices, and the results are displayed in price-supply curves. Higher commodity prices support an increase in the resource volumes that are profitable to produce. At very high (perhaps unrealistic) prices, the economically recoverable resource volume approaches the conventionally recoverable resource volume calculated by the GRASP model.

B. Geologic Assessment

It is important to acknowledge that resource assessments are built on a constantly changing database and most should be viewed as updates of previous work. This is the case for the present assessment. Numerous oil and gas resource assessments have been conducted in the NPR-A (Bird and Powers, 1988). The most recent assessment was completed in 1997 by MMS and BLM as part of the Northeast NPR-A IAP/EIS process (Craig and Sherwood, 1999). In 1995, the U.S. Geological Survey (USGS) completed a regional assessment of all of northern Alaska (Bird, 1995; Attanasi and Bird, 1995) but offered no separate estimates for the NPR-A. The USGS recently completed a new oil and gas assessment of the entire NPR-A, and a summary of results was released in May 2002 (Bird and Houseknecht, 2002a; 2002b). However, the USGS assessment does not provide resource estimates specifically for the Northwest and Northeast NPR-A Planning Areas. Accordingly, MMS and BLM independently assessed the oil and gas potential of the combined Northwest and Northeast NPR-A Planning Areas in support of environmental studies of the impacts of proposed leasing programs. The MMS/BLM assessment was completed in April 2002. A comparison of the results of the 2002 MMS/BLM and USGS assessments is provided in this appendix.

The overall assessment is organized around fundamental units called geologic plays. A play is a group of prospects that share attributes of origination such as trapping mechanism, reservoir stratigraphy, hydrocarbon source, and migration/charging history. Prospects are untested traps that could contain hydrocarbons (oil or gas or a combination of both). Typically, most prospects within a play are "dry" (devoid of recoverable hydrocarbons). The fraction of all of the prospects within a play that may contain hydrocarbons (rather than water) can be viewed as a success rate for the play. If exploration statistics or subjective estimates indicate an overall chance of success of 0.15, then 15 oil or gas pools would be expected to exist among a population of 100 prospects. Using this play approach, the general information about the geology of an area can be converted into estimates of resource potential.

1. Summary of Plays

Identifying geologic plays in the NPR-A began with the grouping of plays based on stratigraphic association. For example, the "Beaufortian" and "Brookian" play groups--as well as play groups within the Ellesmerian sequence (Endicott, Lisburne, and Sadlerochit Groups)--were identified. The stratigraphic column for the NPR-A (Figure III-01) illustrates the major sequences and play groups. Although stratigraphy is the basis for the most fundamental play groupings, further separations and groupings are based on the temperature environment for hydrocarbons and the structural setting.

Some plays are very deeply buried, offering potential for gas resources exclusively, so they must be set apart from oil-bearing plays. The oil potential for a play depends upon reservoir temperature or source type. The rocks underlying NPR-A pass from shallow depths (a few thousand ft) in the north to depths exceeding 36,000 ft in the south. This depth range corresponds to a range in reservoir temperatures from 32 to 585° F (Deming et. al., 1992)[1]. Rocks subjected to temperatures over 400° F will contain only natural gas because at that temperature, heat-driven chemical reactions break petroleum liquids molecules into smaller petroleum gas molecules. In addition, carbon-rich source rocks heated to these temperatures can only generate gas.

Rocks subjected to temperatures exceeding 400° F record this heating event with vitrinite reflectances exceeding 2.0%. Vitrinite reflectances are measured routinely in samples from wells, allowing the mapping of the thermal histories of rocks. Vitrinite reflectances exceeding 2.0% are achieved at depths more than 17,000 ft in the northern parts of the NPR-A. In the southern parts of the NPR-A and along Meade Arch, the 2.0% vitrinite reflectance isograd[2] lies at depths of 7,500 ft (subsea) or less.

Most of the geologic column in the southern NPR-A lies deeper than the 2.0% vitrinite reflectance isograd and offers the potential for gas only. By contrast, most of the geologic column in northern parts of the NPR-A lies above the 2.0% vitrinite reflectance isograd and any oil deposits in this area have probably survived thermal destruction. The lines formed by the intersection of the 2.0% vitrinite reflectance isograd and the stratigraphic tops of play sequences form the northern boundaries of the "gas belts" as shown in the play maps (see Map 99, Map 100, Map 101, Map 102, Map 103, and Map 104). In areas south of the 2.0% isograd lines, the respective play sequences offer potential for natural gas only. The cross section in Figure III-02 illustrates the relationship between thermal maturity isograds and regional structure of rock sequences in the NPR-A.

Play groups were further subdivided on the basis of proximity to the Barrow Arch, a buried ridge along the Beaufort Sea coast (Map 27).Generally, Ellesmerian and Beaufortian rocks near Barrow Arch were deposited in a more proximal setting (closer to source terrane sediment transport direction) and offer clean, porous sandstones (desirable as petroleum reservoirs) that grade into muddy, non-porous rocks to the south.

Most importantly, the Barrow Arch served as a regional destination for hydrocarbons migrating updip within permeable formations from oil-generating areas beneath the Colville basin (Figure III-02). With the exception of Play 8 (Beaufortian-Barrow Arch-East) and Play 17 (Beaufortian-Barrow Arch-West), the southern boundary of the Barrow Arch plays used in this assessment is the same as that adopted by the USGS in their 1995 assessment. The southern boundary of the USGS Barrow Arch plays is described as "arbitrarily selected as the down-dip limit (on the south flank of the Barrow Arch) of the characteristic structural-stratigraphic traps" (Bird, 1995: pp. 16 and 25).

The "Arctic platform" plays occupy the areas between the oil-rich Barrow Arch on the north and the deeply buried gas plays on the south. They offer an intermediate burial environment and a mix of oil and gas resources. The Arctic platform and Barrow Arch play groups are further separated into those areas lying east or west of Meade Arch, which passes south from Point Barrow (Map 27). Meade Arch was chosen as the geologic line of separation between gas-prone plays on the west and oil-prone plays on the east.

Along the Beaufort Sea coast, the westernmost occurrence of pooled oil is in the Simpson field and overlying surface oil seeps (Map 26). In the south, the westernmost occurrence of pooled oil is at the Umiat Oil field. West of the Simpson and Umiat pools we find an area dominated by natural gas; all five known pools (Meade, South Barrow, East Barrow, Sikulik, and Walakpa) are comprised of natural gas. However, this is not to say that liquid hydrocarbons are entirely absent from western NPR-A. Wells in western NPR-A have encountered minor oil shows and some wells in the South Barrow gas field have produced very small quantities of liquid hydrocarbons (Bird, 1988: table 15.5; Magoon and Claypool, 1988: table 21.1). However, most geologic indicators and the results of exploration drilling indicate that western NPR-A is gas-prone. Wells are sparse and widely scattered in central and western NPR-A, making it difficult to determine exactly where oil-prone plays in the east grade into the gas-prone plays in the west. Lacking more detailed well control, we assume that Meade Arch has influenced oil and gas migration in ways that guided oil to the east and gas to the west. For this reason, the crest of Meade Arch is chosen (for purposes of this assessment) as the boundary between oil-prone plays on the east and correlative, but gas-prone plays on the west.

The principal oil source rocks in Northwest NPR-A passed from the temperature interval for oil generation to gas generation approximately 95 million years ago. The same oil source rocks remain within the temperature interval for oil generation in Northeast NPR-A. Accordingly, the thermal maturity of the oil source rocks is much higher (or gas prone) in Northwest NPR-A (Johnsson and Howell, 1996:pl. 1). Even today, heat flow and geothermal gradients are typically higher in Northwest NPR-A than Northeast NPR-A (Deming et al., 1992: figs. 6b and 8b). For Northwest NPR-A, the geologic context predicts a gas-prone province. The widespread gas shows in exploratory wells and discovered gas pools confirm this inference. For this reason, most plays were divided into east and west parts. This division allowed the models to treat the parts with oil-prone and gas-prone characterizations separately. The crest of Meade Arch, as mapped by Kirschner and Rycerski (1988: pl. 9.1) and shown in Map 27 was chosen as the line of east-west separation for gas-prone plays on the west and oil-prone plays on the east.

Potential reservoirs in the Brookian sequence occur in two highly dissimilar depositional settings. In the lower part of the sequence, turbidite sandstones (formed by subsea avalanches of slurries of sediment and water that move down-slope) were deposited at slope bases in the submerged, deep-marine parts of deltas. In the upper part of the sequence, fluvial to shallow marine sandstones were deposited near delta shorelines (Molenaar, 1988). These different depositional environments typically produce different reservoir characteristics (thickness, lateral continuity, and potential storage volumes) that require treatment as separate plays.

In the belt of deformed rocks lying north of the Brooks Range, there are representatives from each play group. These plays were cut by faults and deformed into complex folds by the compressive forces that created the Brooks Range in multiple events between 170 and 65 million years ago. This deformed belt displays multi-storied thrust plates containing structures unlike those in overlying or underlying thrust plates. Five of these plays contained deformed rocks within and north of the Brooks Range. Four of these plays were assessed for this plan. The fifth play (Play 21) lies south of the combined Northwest and Northeast NPR-A Planning Areas, so it is not considered in this assessment.

2. Descriptions of Plays

The play analysis recognizes 23 plays within the NPR-A. Each one is briefly described below, with play areas shown in Maps 99-104.

Play 1. Endicott-Barrow Arch (UBWA0100)

Play 1 covers 600 mi² and lies between drilling depths of 8,000 and 12,000 ft within the combined Northwest and Northeast NPR-A Planning Areas. The area of Play 1 is shown in Map 99. The reservoir objectives are Lower Mississippian Endicott Group quartz-rich sandstones of fluvial to shallow-marine origins, deposited in structural depressions in the eroded surface atop basement. Endicott Group rocks thin toward regional arches and are generally absent from arch crests. The Endicott Group is less than 1,000 ft thick within the play area (Bird, 1988c: fig. 16.10). These rocks are absent from Fish Creek platform (hachured area labeled "Endicott Absent" south of J.W. Dalton well in Map 99). Wedges of Endicott sandstones flanking Fish Creek platform may host stratigraphic traps. Otherwise, potential traps are associated with subtle anticlinal structures and fault structures revealed by seismic mapping of the top of acoustic basement. Petroleum charging for Play 1 was probably from thermally mature Shublik, Kingak, and Pebble Shale Formations deeply buried on the south, or possibly from petroleum migrating northwest along Barrow Arch from the Prudhoe Bay area. Play 1 has been penetrated by seven wells, two of which (East Simpson 2, J.W. Dalton) tested minor amounts of asphaltic crude oil from the Endicott Group.

Play 2. Endicott-Arctic Platform (UBWA0200)

Play 2 covers 1,600 mi ² and lies between drilling depths of 8,000 and 16,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 2 is shown in Map 99. The reservoir objectives are Lower Mississippian Endicott Group quartz-rich sandstones of fluvial to shallow-marine origins, deposited in structural depressions in the erosional surface atop basement. The play sequence (Endicott Group) is present throughout the play area, but is generally less than 1,000 ft thick (Bird, 1988c:fig. 16.10). Play 2 extends westward to Meade Arch where the Endicott Group is absent. Subtle stratigraphic traps may occur in the southern part of the play area along the flexure forming the north edge of the Ikpikpuk-Umiat basin. Truncated wedges of Endicott sandstones flanking Meade Arch may host stratigraphic traps. The history of deeper burial at Play 2 has probably diminished reservoir pore systems more than in Play 1. Play 2 is considered more gas-prone than correlative Play 1 along Barrow Arch. Petroleum charging for Play 2 was probably from gas-prone shales within the lower part of the Ellesmerian sequence to the south in the Ikpikpuk-Umiat basin. The Topogoruk, South Simpson, and West Fish Creek wells, (none of which tested hydrocarbons from the Endicott Group) penetrated Play 2.

Play 3. Ellesmerian (All)-Gas Belt (UBWA0300)

Play 3 covers a maximum of 14,500 mi² and lies between depths of 12,000 and 32,000 ft within the Northwest and Northeast NPR-A Planning Areas (maximum area of Play 3 within NPR-A is 22,036 mi²). Play 3 includes all of the Ellesmerian sequence reservoir objectives (Endicott, Lisburne, and Sadlerochit) south of intersections with their respective 2.0% vitrinite reflectance isograds, where they are so deeply buried that only natural gas has survived thermal destruction. The play areas change for different formations within the Ellesmerian sequence because the 2.0% vitrinite reflectance isograd intersects the deepest formations the farthest north (see Fig. III-02). The area of Endicott rocks (16,700 mi² all NPR-A, 11,200 mi² within Northwest and Northeast NPR-A Planning Area) within Play 3 is shown in Map 99. The area of Lisburne rocks (22,000 mi² all NPR-A, 14,500 mi² within Northwest and Northeast NPR-A Planning Areas) within Play 3 is shown in Map 100. The area of Sadlerochit rocks within Play 3 (20,400 mi² all NPR-A, 12,800 mi² within Northwest and Northeast NPR-A Planning Areas) is shown in Map 101. Endicott strata are absent from most parts of Meade and Wainwright Arches, both passing south from Barrow (Map 99). In the Ikpikpuk and Meade basins, the Endicott Group reaches 10,000 ft in thickness (Bird, 1988c:fig. 16.10). Within the play area, the Lisburne Group ranges from 1,000 to 6,000 ft thick (Bird, 1988c:fig. 16.11) and the Sadlerochit Group ranges from 500 to 3,500 ft thick (Bird, 1988c:fig. 16.12).

Potential traps consist of fault structures in the south, stratigraphic traps along the north flank of the Ikpikpuk-Umiat basin or the flanks of Meade Arch, and some wrench fault structures affecting Endicott strata within the Ikpikpuk-Umiat basin (one tested by the Inigok well). The rocks in Play 3 pass southward beneath a belt of thrust faults and folds in correlative rocks that are related to Brooks Range deformation, the latter analyzed separately as Play 21.

Because of the history of deep burial, reservoir pore systems in Play 3 are predicted to be greatly diminished. Play charging was originally from gas-prone and possibly oil-prone[3] strata within the Ellesmerian sequence, but any trapped liquid hydrocarbons have been cracked to natural gas. The Tunalik, South Meade, Inigok, North Inigok, and Ikpikpuk wells penetrated Play 3. Minor gas, hydrogen sulfide, and elemental sulfur was encountered within the Lisburne Group at the Inigok well (Magoon and others, 1988:pl. 19.21).

Play 4. Lisburne-Barrow Arch (UBWA0400)

Play 4 covers 750 mi² and lies between drilling depths of 8,000 and 10,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 4 is shown in (Map 100). Reservoir objectives include porous dolomites and (possibly) limestones of Mississippian to Pennsylvanian age within the Lisburne Group. The Lisburne Group thins over structural highs like Fish Creek platform and is completely absent by onlap from a large part of the northern NPR-A (Map 100). Generally, the Lisburne Group is no more than 2,000 ft thick within the area of Play 4 but thickens southward (Bird, 1988c:fig. 16.11). Potential traps are mostly associated with subtle anticlinal structures along Fish Creek platform and regional truncations at an unconformity at the base of the Sadlerochit Group. Petroleum charging for this play was probably from thermally mature Shublik, Kingak, and Pebble Shale Formations deeply buried on the south, or from petroleum migrating northwest along Barrow Arch from the Prudhoe Bay area. Seven wells have penetrated Play 4. Minor amounts of oil or asphaltic material were recovered from Lisburne Group rocks at the J.W. Dalton and W.T. Foran wells.

Play 5. Lisburne-Arctic Platform (UBWA0500)

Play 5 covers 3,800 mi² and lies between drilling depths of 9,000 and 16,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 5 is shown in Map 100. Reservoir objectives include porous dolomites and (possibly) limestones of Mississippian - Permian[4] age within the Lisburne Group. The Lisburne Group thickens southward in Play 5, ranging in thickness from zero on the west at the Meade Arch to over 4,000 ft in the Ikpikpuk-Umiat basin (Bird, 1988c:fig. 16.11). Potential traps are small anticlinal structures and subtle stratigraphic-wedge traps, mostly along the flexure forming the northern boundary of the Ikpikpuk-Umiat basin. Play 5 is considered more gas-prone than the correlative Play 4 along Barrow Arch, and greater burial has probably furthered the destruction of porosity in the carbonate reservoir rocks of Play 5. Petroleum charging for this play was probably from gas-prone shales within the Lisburne Group and shales and coals within the Endicott Group that are deeply buried to the south of the play area. The Ikpikpuk, East Teshekpuk, and West Fish Creek wells penetrated Play 5. None of these wells tested hydrocarbons from the Lisburne Group.

Play 6. Sadlerochit/Sag River-Barrow Arch-East (UBWA0600)

Play 6 covers 1,600 mi² and lies between depths of 7,000 and 9,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 6 is shown in Map 101. The primary reservoir objective is the Triassic Ivishak sandstone of the Sadlerochit Group. Sandstones of the Sag River Formation may also reservoir petroleum, but these more typically lack porosity and would form a secondary or supplemental reservoir objective. The Sadlerochit Group ranges in thickness from zero to 1,200 ft within the play area (Bird, 1988c:fig. 16.12). The Sadlerochit Group is absent from the parts of the NPR-A north of the Simpson field (Map 26 and Map 101). However, rocks of the Sag River and Shublik Formations, which are included within this play, extend throughout most of the play area north of the Simpson field where the Sadlerochit Group is absent. The Ivishak sandstone thins to less than 100 ft over structural highs like the Fish Creek platform, but ranges over 400 ft thick within the play area. Average porosities range from 7% to 15% in the play area, reflecting a more marine and sand-poor, or shaly, facies than prevailed to the east in the fan-delta braided-stream systems at Prudhoe Bay[5]. Potential traps are stratigraphic wedges produced by truncation of reservoir sandstones in the northernmost part of the play area, and subtle anticlinal structures along the Fish Creek platform. Petroleum charging for this play was probably from thermally mature Shublik, Kingak, and Pebble Shale Formations deeply buried on the south, or from petroleum migrating northwest along Barrow Arch from the Prudhoe Bay area. At Meade Arch, Play 6 passes west into the correlative (but gas-prone) Play 15. Play 6 was penetrated by 15 wells within the NPR-A and targeted by seven wells offshore. Within the NPR-A, minor amounts of oil or gas were tested at the East Simpson 1, Simpson 1, W.T. Foran, and J.W. Dalton wells. A small amount of oil was tested from the Shublik and Sag River Formations at the Iko Bay well. The Mukluk, Mars, Orion, Antares (#1 and #2), Phoenix, and Fireweed wells (located in Map 101) tested the offshore extension of Play 6 (Map 101). All offshore wells and several NPR-A wells were drilled to test Sadlerochit Group rocks in stratigraphic wedges beneath the Lower Cretaceous unconformity, which are analogous to the trap mechanism at Prudhoe Bay field. The Sadlerochit Group was absent at Orion well. Minor amounts of oil were tested from the play sequence at the Antares #1 well. Significant oil shows, but no pooled oil, were encountered in Sadlerochit Group rocks at Mukluk, Phoenix, Fireweed, and Mars wells. The Mukluk well, drilled at a cost of $120 million on a block of leases acquired for over $1.5 billion in high-bonus bids, is one of the most legendary exploration failures in the history of petroleum development in Alaska.

Play 7. Sadlerochit-Arctic Platform-East (UBWA0700)

Play 7 covers 6,100 mi² and lies between drilling depths of 7,000 and 16,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 7 is shown in Map 101. The primary reservoir objective is the Triassic Ivishak sandstone of the Sadlerochit Group. Sandstones of the Sag River Formation may also reservoir petroleum, but these typically lack porosity. The Sadlerochit Group ranges from zero to 1,500 ft thick within the play area (Bird, 1988c:fig. 16.12). The Ivishak sandstone ranges in thickness from 100 to 300 ft within the play area and average porosities range from 0 to 15%, reflecting a more distal (offshore and deeper water) and shaly facies than prevailed in Play 6 to the north along the Barrow Arch (where mapped average porosities range from 7 to 15 percent). A history of deeper burial for Play 7 also contributes to diminished reservoir properties relative to Play 6. Potential traps are mostly small anticlinal structures along the southeastern extremity of Fish Creek platform and possibly stratigraphic truncations in the Simpson area. Petroleum charging for this play was probably from the thermally mature Shublik Formation deeply buried on the south. At Meade Arch, Play 7 passes westward into the correlative (but gas-dominated) Play 16. At its southern limit along the 2.0% vitrinite reflectance isograd, Play 7 passes into the Ellesmerian (All)-Gas Belt Play 3. The Topogoruk, South Simpson, Ikpikpuk, North Inigok, and West Fish Creek wells penetrated Play 7. No hydrocarbons were tested from the Sadlerochit Group in any of these wells.

Play 8. Beaufortian-Barrow Arch-East (UBWA0800)

Play 8 covers 5,200 mi² and lies between drilling depths of 2,000 and 11,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 8 is shown in Map 102. Play 8 was expanded southward for this assessment, and now includes the northern parts of Play 9 (Beaufortian-Arctic Platform-East) as mapped in the 1997 assessment of the Northeast NPR-A Planning Area (Craig and Sherwood, 1998). The southward expansion of Play 8 reflects the results of seismic mapping and exploration drilling since the 1997 assessment. The Beaufortian sequence ranges from 200 to 1,400 ft thick within the area of Play 8 (Bird, 1988c:figs. 16.15, 16.16). Reservoir objectives include the Cretaceous Kuparuk "C" sandstone[6], three Jurassic sandstones (the

"Alpine," "Nuiqsut," and "Nechelik" sandstones of Kornbrath et al., 1997), and the Upper Jurassic Simpson sandstone (Bird, 1988a:fig. 4.13). These sandstones offer multiple reservoir opportunities within the play, but probably do not overlap in the area of any single prospect. The "Alpine" sandstone, forming the reservoir at the 500-MMbbl Alpine oil field, is probably absent from the northern third of Play 8 because it is truncated by the Lower Cretaceous unconformity. At the Alpine field discovery well, the Alpine sandstone is about 52 ft thick with 47 ft of oil pay. In publicly available wells outside of Alpine field, the Alpine sandstone is extremely thin or represented by shale (Kornbrath et al., 1997: table 5). The Nuiqsut sandstone ranges in thickness from 152 to 224 ft in the Colville delta area east of the NPR-A (Kornbrath et al., 1997). The Nechelik sandstone ranges from 25 to 65 ft thick (Kornbrath et al., 1997:table 5) in the Colville delta wells.

The Kingak and Kuparuk Formations are truncated at the Lower Cretaceous unconformity in an area along the northern coast of the NPR-A (mapped in Map 102). Only the Pebble Shale and related unconformity sandstones (Kuparuk "C") represent the Beaufortian sequence in the truncation area. Potential traps that are easily recognized in seismic data are subtle anticlines along Fish Creek platform and stratigraphic wedges created by erosional truncations at the Lower Cretaceous unconformity. Additional traps are probably associated with sandstone bodies isolated within shales. The Alpine field represents this type of stratigraphic trap. These stratigraphic traps are revealed only in 3-D seismic data as areas of anomalous seismic amplitudes (described by Gingrich, Knock, and Masters, 2001). The MMS and BLM have used 3-D seismic data covering approximately 924 mi^2 in the Northeast NPR-A Planning Area (18% of total play area) to identify seismic amplitude anomalies that might reveal bodies of porous or hydrocarbon-saturated sandstones. The results of this mapping were extrapolated to the remainder of the play area to estimate the number and size range of prospects. The net effect of this extrapolation is a near doubling of prospect density (number of prospects per unit area) above the 1997 assessment of Play 8 in the Northeast NPR-A Planning Area IAP/EIS. The 3-D seismic mapping used in this assessment contributed to a substantial increase in the estimates for undiscovered oil and gas resources in Play 8.

Petroleum charging for Play 8 was probably from thermally mature Shublik, Kingak, and Pebble Shale Formations that are more deeply buried on the south. The Kingak Formation has been identified as the source for the low-sulfur, high-gravity (40 ° API) oil at Alpine field (Masterson, 2001:p. 25) and it is presumed to be the primary generating source for oil resources across Play 8. The low viscosity (high gravity) crude oils anticipated for Play 8 move easily through pore systems and are more efficiently recovered from reservoirs. High-gravity oils also attract a higher market price. For these reasons, the high-gravity oils are an important element of the commercial viability for the Alpine play. However, some pools within the play could contain relatively high-viscosity "Barrow-Prudhoe" type crude oils (high sulfur) averaging 28° API gravity, as found in the Kuparuk, Nuiqsut, and Nechelik sandstones in the Colville delta area (Kornbrath et al., 1997:table 5). These high-viscosity oils do not pass easily through the pore systems of the muddy Alpine sandstones and offer challenges to commercial development. Play 8 is separated along Meade Arch from a correlative gas-prone play (17) to the west that includes Walakpa gas field and the Barrow area gas fields.

Thirty-three wells penetrated Play 8 in the NPR-A, including fourteen wells drilled on leases acquired in 1999. Minor amounts of gas or oil were encountered at the W.T. Foran and West Dease wells. The North Inigok well tested 80 thousand cubic feet per day (Mcfd) of gas from Alpine-equivalent sandstone. The South Simpson well tested 75 Mcfd of gas from the Simpson sandstone (Bird, 1988: table 15.5). Fourteen exploration wells (including one sidetrack well) were drilled on 1999-acquired leases in the Northeast NPR-A (Map 26). No announcements have been made concerning the Trailblazer A-1 and Trailblazer H-1 wells drilled by BP Exploration (Alaska) Inc. or the Puviaq 1 well completed in 2003 by Conoco-Phillips. Conoco-Phillips Alaska announced in 2001 that one of its seven exploration wells was a dry hole, but five wells and a sidetrack well encountered oil or gas and condensate. Long-term flow testing at the Spark 1A well produced 1,550 bbl of liquid hydrocarbons and 26.5 million cubic ft per day (MMcfd) of gas. Long-term flow testing at the Rendezvous "A" well produced 360 barrels per day (bpd) of liquid hydrocarbons and 6.6 million cubic ft per day (MMcfd) of gas. Long-term testing at the Lookout 2 well produced 4,000 bpd and 8 MMcfd. All of these exploration wells are located 15 to 25 mi southwest of the 500-million-barrel Alpine field, now producing over 100,000 bpd (Petroleum News Bulletin, 2002). All of these exploration wells targeted the Alpine field reservoir formation that occurs within the "Beaufortian" play group. The recent exploration wells are shown on Map 26 and the public announcements of test results are listed in Table III-01 .

Play 9. Beaufortian-Arctic Platform-East (UBWA0900)

Play 9 covers 4,000 mi^2 and lies between drilling depths of 8,000 and 17,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 9 is shown in Map 102. The Beaufortian sequence ranges from 1,700 to 3,700 ft thick within the play area (Bird, 1988c: figs. 16.15 and 16.16). Reservoir objectives include the Cretaceous Kuparuk "C" sandstone, three sandstones within the upper part of the Jurassic Kingak Formation ("Alpine," "Nuiqsut," and "Nechelik" sandstones of Kornbrath et al., 1997), and the "Simpson" sandstone occurring in the lower part of the Jurassic Kingak Formation in northwestern parts of Play 9.

The Simpson sandstones are present only in the northwestern-most part of the play area and they range from 110 to 180 ft thick (Bird, 1982). The three Upper Jurassic sandstones may be locally present anywhere within the play area. At the Alpine field discovery well, the Alpine sandstone is about 52 ft thick with 47 ft of oil pay. In publicly available wells outside Alpine field, the Alpine sandstone is extremely thin or represented by shale (Kornbrath et al., 1997:table 5). The Nuiqsut sandstone ranges from 152 to 224 ft thick. The Nechelik sandstone ranges in thickness from 25 to 65 ft (Kornbrath et al., 1997:table 5). Although these sandstones offer multiple reservoir opportunities within the play, they probably do not actually overlap in the area of any single prospect.

No potential traps are recognized in available seismic interpretations (Tetra Tech, 1981: Map KJ) of Play 9. Most potential traps are probably associated with sandstone bodies isolated within shales. Alpine field probably represents this type of trap (Gingrich, Knock, and Masters, 2001). Seismic amplitude mapping within a 924-mi^2 3-D seismic survey in Play 8 in the Northeast NPR-A Planning Area has identified anomalies that may correspond to porous or hydrocarbon-saturated sandstones. The results of this mapping were extrapolated to the entire area of Play 9 to estimate the numbers and areal sizes of prospects.

Petroleum charging of Play 9 was probably from thermally mature Shublik and Kingak Formation shales within and south of the play area. The Pebble Shale may form a source for oil in Kuparuk-equivalent sandstones in southern parts of Play 9. The Shublik Formation is viewed generally as the dominant source for the low (20° to 28° API) gravity Prudhoe Bay geochemical family of oils (Claypool and Magoon, 1985:p. 49). The high (40° API) gravity, low-sulfur oil at Alpine field is probably derived from the Kingak Formation (Masterson, 2001). Play 9 passes into a gas-only Play 10 to the south and a gas-dominated Play 18 on the west. Regionally, the Inigok and Topogoruk wells have penetrated Play 9, encountering no pooled hydrocarbons.

Play 10. Beaufortian-Gas Belt (UBWA1000)

Play 10 covers 4,100 mi^2 in the Northeast and Northwest NPR-A (total area of Play 10 within NPR-A is 5,670 mi^2) and lies between drilling depths of 7,000 and 26,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 10 is shown in Map 102. The Beaufortian sequence ranges from approximately 3,200 ft to 4,300 ft thick within the play area (Bird, 1988c:figs. 16.15 and 16.16). The Beaufortian sequence consists mostly of Cretaceous-age[7] Kingak Formation shales and sandstones deposited on a south-facing shelf, slope, and deep basin plain (Bird and Molenaar, 1992: p. 368, fig. 5). Play 10 straddles a shelf edge mapped by Bird (1988c:fig. 16.15) along a zone of abrupt thinning of the Kingak Formation (observed in seismic data).

All of the Play 10 rocks are deeply buried and are expected to offer only modest reservoir porosities at best. The only anticipated resource is natural gas derived from thermally over-mature and gas-generative Shublik, Kingak, and Pebble Shale Formations. No wells have penetrated play 10. However, Tunalik well, just north of the play area in the west, encountered very strong gas shows in a Kuparuk(?)-equivalent Cretaceous sandstone at 12,500 ft within the Beaufortian sequence. Nine wireline formation tests were attempted in this interval, but all failed to sample pressures or formation fluids.

Play 11. Brookian Turbidites-Arctic Platform-East (UBWA1100)

Play 11 covers 9,100 mi² and lies between drilling depths of 2,000 and 16,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 11 is shown in Map 103. The Torok Formation, which contains the turbidite sandstone reservoir objectives, ranges from 2,000 to 10,000 ft thick within the play area (Bird, 1988c: fig. 16.17), but sandstones are generally confined to channeled submarine fan systems in the lowermost 2,000 ft. The turbiditic sandstones were deposited in slope or basin-floor settings near the toe of the east-prograding Nanushuk-Torok delta system[8] that ultimately filled the Colville basin. To the north, sandstones are generally sparse and thin, but preserve modest porosities. To the south, near the axis of the Colville basin, sandstones are abundant and relatively thick, but generally lack porosity because of deep burial. McMillen (1991) recognizes sand-rich low-stand fans and shaly, high-stand fans within the Torok Formation. Identification of the sand-rich fans may be the key to exploration success in Play 11. The lack of pore-system continuity, and quality are the chief antagonists to the success of this play.

North-trending seismic anomalies in the area of the Fish Creek paleo-slump feature (located in Map 103) were originally interpreted as submarine canyons incised into the Torok Formation and older units, with intervening bands mapped as erosional relicts. This interpretation suggests that these submarine canyons could have locally captured substantial thickness of turbidite sandstones, forming oil traps. However, three wells, the Atigaru Point, South Harrison Bay, and West Fish Creek wells, actually penetrated the supposed submarine canyons and did not encounter any unusual thickness of turbiditic sandstones. In fact, Weimer (1987) and Homza (2001) reject the "submarine canyon" hypothesis altogether, interpreting the seismic anomalies as slope-failure slides of blocks of (Torok) slope sediments and Pebble Shale, draped by younger pelagic slope sediments offering negligible reservoir potential. However, there is potential for upslope ponding of turbiditic sandstones behind slide blocks. Three potential upslope "ponds" were penetrated by the Atigaru Point, South Harrison Bay, and West Fish Creek wells, encountering very sparse sandstone with oil and gas shows in the lower Torok Formation. The concept of slump-ponded sandstones should not be discounted as traps because such features are part of the trap mechanism at the Tarn (50 million barrels [MMbbl] of oil) and Meltwater (52 MMbbl of oil) fields east of the NPR-A (Hastings, 2001). Although Fish Creek slide is a very prominent and large example of slumps within the Torok Formation, such features are widely observed outside Fish Creek slide. In some cases, ponded sediment upslope from slump blocks is associated with seismic amplitude anomalies suggesting the presence of porous or hydrocarbon-saturated sandstones.

In the NPR-A, turbiditic sandstones within the Torok Formation are mostly Early Cretaceous in age (Middle Albian to Cenomanian; Huffman, Ahlbrandt, and Bartsch-Winkler, 1988:fig. 13.11). Comparable turbiditic sandstones to the east that form the reservoirs at Tarn (50 MMbbl of oil) and Meltwater (52 MMbbl of oil) discoveries are mostly part of the Canning Formation (terminology of Molenaar, Bird, and Collett, 1986) of Late Cretaceous age. The younger (Canning Formation) Brookian turbidite sandstones east of the NPR-A are generally better prospects for petroleum because sedimentary recycling has removed many of the ductile (soft) particles that cause the rapid porosity loss with burial observed in the older Brookian turbidites to the west, within the NPR-A.

Seismic data reveal some anticlinal structures draped over the Lower Cretaceous unconformity along the Fish Creek platform that could form potential traps if sandstones are present in the basal Torok Formation immediately above the unconformity. However, most traps are probably stratigraphic, consisting of turbiditic sandstones filling incised slope channels, mounded submarine fans, and turbiditic sandstones ponded upslope of slumps. Such sandstones are isolated (forming sealed volumes) by draped pelagic shales and form potential traps. The MMS and BLM used 3-D seismic data in a 308-mi² survey area in the Northeast NPR-A Planning Area to identify these types of stratigraphic traps. Seismic amplitude mapping on chronostratigraphic (time-correlative) surfaces within the Torok Formation and the overlying Nanushuk Group reveals numerous anomalies that may represent porous or hydrocarbon-saturated sandstones. The survey area represents only 3 percent of the 9,100-mi² play area. However, the entire play area is believed to share the same geologic context and characteristics of the much smaller area in the 3-D seismic survey. The results of the seismic amplitude mapping for the Torok Formation were extrapolated over the entire play area to estimate the numbers and size range of prospects. This extrapolation yielded an increase in the number of prospects (12-fold increase in prospect density or numbers of prospects per unit area) and a decrease in the size of the prospects (a 50% decrease in the mean prospect size) relative to the 1997 assessment of Play 11 for the Northeast NPR-A Planning Area. The net effect of the 3-D seismic data for prospect forecasting was a substantial increase in the estimates for oil and gas potential within Play 11.

Petroleum charging of Play 11 was probably from the thermally mature Shublik, Kingak, and Pebble Shale Formations that directly underlie the Brookian turbidite reservoirs within and south of the play area. Torok shales are also a charging source, chiefly for gas. At least 28 wells have penetrated Play 11 within the NPR-A. Small amounts of gas or oil were recovered from Brookian turbiditic sandstones in the South Harrison Bay, South Simpson, Drew Point, and Ikpikpuk wells.

Play 12. Brookian Turbidites-Gas Belt (UBWA1200)

Play 12 covers 7,900 mi² (total area within NPR-A, 18,984 mi²) and lies between drilling depths of 8,000 and 22,000 ft within the Northeast and Northwest NPR-A Planning Areas. Play 12 extends south beneath Play 23 to the front of the Brooks Range but is obscured beneath the complex structures of overlying rocks in the southern part of the play area. The area of Play 12 is shown in Map 103. The Torok Formation, containing the turbidite sandstone reservoir objective, ranges from 5,000 to 15,000 ft thick within the play area (Bird, 1988c: fig. 16.17). However, sandstones are generally confined to the lowermost 2,000 to 5,000 ft, with the greater thickness encountered in southern parts of the play where the Fortress Mountain Formation is present beneath the Torok Formation. The turbiditic sandstones were deposited in slope or basin-floor settings near the toe of the east-prograding Nanushuk-Torok delta system that ultimately filled the Colville basin. Extensive destruction of pore systems is expected because of compaction in response to deep burial. However, overpressure or secondary leaching may have acted to preserve or restore porosity in some areas.

To estimate the numbers of structural traps in the deformed, southern part of Play 12, it was assumed that structures would mimic those mapped in seismic data in Play 22, which occurs in overlying thrust plates. Structural relations of deformed-belt plays in the southern NPR-A are illustrated in the cross-section of Figure App-01. Additional traps are probably stratigraphic, consisting of bodies of turbiditic sandstones isolated within shales. Such prospects are accounted in the assessment as "unidentified" prospects. The geologic context of Play 12 is quite different from that of the area of 3-D seismic surveys in the Northeast NPR-A Planning Area and the results of that mapping were not extrapolated to Play 12.

The only anticipated resource in Play 12 is natural gas derived from the Shublik, Kingak, Pebble Shale, and Torok Formations. Play 12 has not been penetrated by any wells. Tunalik well, just north of the play area, found strong gas shows in sandstones in the lower part of the Torok Formation (Magoon and others, 1988:pl. 19.2).

Play 13. Brookian Topset-Arctic Platform-East (UBWA1300)

Play 13 covers 8,600 mi² and lies between drilling depths of 1,000 ft (everywhere exposed at land surface) and 7,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 13 is shown in Map 104. Across most of NPR-A, the Brookian "topset" sequence consists of the mostly Lower Cretaceous (Middle Albian to Cenomanian) Nanushuk Group (Figure III-01). Upper Cretaceous "topset" sandstones of the Colville Group are present in the eastern NPR-A (distribution shown in Map 104). The reservoir objectives are fluvial, deltaic, and shelf rocks deposited as distributary channel fill, distributary-mouth bars, and offshore bars. These sandstones were deposited near the paleo-shoreline(s) of the east-prograding delta system that simultaneously deposited the turbiditic sandstones of Plays 11, 12, and 19 in deep water on the delta slope(s) or on the basin floor(s) to the east. A belt of sandstone-rich Nanushuk Group, dominated hypothetically by "coastal-barrier" sandstones (reworked by shoreline processes, i.e., wave swash) passes from the Ikpikpuk well southeast to the Umiat area (Huffman, Ahlbrandt, and Bartsch-Winkler, 1988:fig. 13.4). This sandstone-rich belt may offer reservoir qualities superior to the more typical Nanushuk sandstones found elsewhere.

Within the play area, the Nanushuk Group ranges from 0 to 3,500 ft thick. The Nanushuk Group is absent in the Barrow area because of local uplift and erosion (Map 104). From the Ikpikpuk River to the eastern boundary of NPR-A, the Nanushuk Group is overlain by as much as 5,000 ft of Upper Cretaceous prodelta shales and fluvial-deltaic sandstones of the Colville Group (Figure III-01). The distribution of the Colville Group in eastern NPR-A is shown in Map 104. The Colville Group sandstones could form potential petroleum reservoirs in eastern NPR-A, but are generally quite shallow and extend directly to the land surface on the west. Sandstones within the Nanushuk Group in Play 13 have not been buried deeply, so they often preserve modest porosities. Fine grain size and clay contents offer the greatest challenges to reservoir quality (Huffman, Ahlbrandt, and Bartsch-Winkler, 1988).

The Brookian topset sequence is unstructured in the play area (Tetra Tech, 1981:Maps K1-K4) and any traps probably consist of discontinuous sandstone bodies isolated within shales. Play concepts for such traps might include shelf-edge, low-stand wedges or channel complexes isolated beneath shales that onlap a younger flooding surface. For example, an incised channel near the paleo-shelf edge that was ultimately filled with sandstone forms the trap for the Tabasco oil pool (30 MMbbl of oil) in the Kuparuk unit (Map 104) (Konkler et al., 1995). A 308-mi² 3-D seismic survey in the northeastern NPR-A helped identify the sizes and numbers of stratigraphic prospects in the Brookian topset sequence on the Arctic platform. Seismic amplitude mapping on chronostratigraphic surfaces within the Nanushuk Group and underlying Torok Formation revealed numerous anomalies that may represent porous or hydrocarbon-saturated sandstones. The survey area represents only 4 percent of the 8,600 mi² area of Play 13. However, all of Play 13 is believed to share the geological attributes of the 3-D seismic survey area. The results of the seismic amplitude anomaly mapping were extrapolated to the entire play area in order to estimate the numbers and size range of prospects. This extrapolation yielded a 12-fold increase in prospect density but a two-fold decrease in mean prospect area relative to the 1997 assessment of Play 13 in the Northeast NPR-A Planning Area. The net effect of this application of 3-D seismic mapping is a substantial increase in the estimates of oil and gas potential for Play 13.

It is likely that petroleum charging of Play 13 was mostly from the thermally mature, gas-prone Torok shales filling the lower parts of the Colville basin. Shales of the Shublik, Kingak, and Pebble Shale Formations underlie Colville basin and are potential sources for oil. However, several thousand feet of overpressured Torok shales intervene between the "topset" reservoirs and the deeper, thermally mature oil sources. Denial of access to migrating oil by this shale barrier (diverted north beneath the barrier toward Barrow Arch) may be the chief threat to success of prospects within this play. However, Shublik-derived oil was found in Nanushuk sandstones at Fish Creek and Pebble Shale-derived oil was found at Simpson field. The Fish Creek field was discovered through drilling at surface seeps , and the quantity of oil present is unknown. At Simpson field (12 MMbbl of oil, also discovered by drilling on seeps), oil-charged Nanushuk sandstones are truncated and sealed at the wall of the shale-filled Simpson paleocanyon (Map 104). At least 28 wells have penetrated Play 13 in the NPR-A. Two oil fields (Simpson and Fish Creek) were discovered and minor amounts of gas were tested at the East Topogoruk well.

Play 14. Brookian Foldbelt (UBWA1400)

Play 14 covers 8,400 mi² (total area within NPR-A, 17,110 mi²) and lies between drilling depths of 1,000 (everywhere exposed at land surface) and 16,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 14 is shown in Map 104. The play area extends from the southern edge of the Nanushuk topset outcrop belt to unfolded Brookian topset rocks on the north. Reservoir objectives within the Brookian Foldbelt play are sandstones of the principally Lower Cretaceous (Middle Albian to Cenomanian) Nanushuk Group. However, some sandstones that occur sparsely within upper parts of the Torok Formation share the same shallow fold structures involving topset strata and have tested gas at some wells. These Torok Formation sandstones are included in Play 14 because they may represent minor regressions in the Nanushuk-Torok delta system and they share the same shallow structures as the overlying Nanushuk Group.

The Nanushuk Group in Play 14 ranges from 1,000 to 10,000 ft thick (Bird, 1988c:fig. 16.18). The Nanushuk Group along the eastern boundary of NPR-A is overlain by up to 3,500 ft of Upper Cretaceous prodelta shales and fluvial-deltaic sandstones of the Colville Group that are also folded (Bird, 1988c:figs. 16.19, 16.20). The distribution of the Colville Group (identified as "Upper Cretaceous") is shown in Map 104. The Colville Group sandstones form potential petroleum reservoirs in the foldbelt in the eastern NPR-A, but are generally quite shallow and extend along fold axes directly to the land surface on the west. However, some Colville Group sandstones in the Gubik anticline are charged with gas (tested 2,060 Mcf of gas per day at Gubik No. 1; Molenaar, Bird, and Collett, 1986). Stratigraphic barriers providing western permeability seals on the east-plunging folds are required to complete the traps on some anticlines in these folded Upper Cretaceous rocks. Sandstones within the Nanushuk Group in Play 14 have been buried more deeply (and uplifted) than those in the unstructured area to the north in Play 13, but are overall coarser-grained and retain modest porosities. Clay contents and compaction of soft particles in sandstones are the greatest challenges to survival of reservoir pore systems (Huffman, Ahlbrandt, and Bartsch-Winkler, 1988: fig. 13.5).

Traps are mostly large anticlines reaching 100,000 acres in closure area that formed over deeper thrust faults. Prospect areas and numbers were estimated from existing publicly-available seismic structure maps by Tetra Tech (1981:Maps K1-K4). In the southern third of the play area, anticlines are breached and the entire column of Nanushuk Group sandstones extends directly to the land surface. Any hydrocarbons once trapped in these anticlines would have been lost when they were breached by erosion. The structural style of the folds in Play 14 is illustrated in the cross section of Figure App-01.

Petroleum charging of Play 14 was probably from thermally mature Torok Formation shales, primarily a source for gas. The Pebble Shale, Kingak Formation, and Shublik Formation beneath Colville basin might form sources for oil. However, several thousands of feet of overpressured Torok shales typically intervene between Nanushuk and Colville Group reservoirs and the Pebble Shale, Kingak, and Shublik oil sources below the floor of Colville basin. Denial of access to migrating oil by this shale barrier may be a significant problem for many prospects in this play, although nearly a billion barrels of oil somehow made its way--perhaps along thrust faults passing from source to reservoir--to Umiat field (70 MMbbl of oil) in the eastern part of the play area (Map 104). Small gas fields in the foldbelt play have also been discovered at Meade, Square Lake, Wolf Creek, East Umiat (east of NPR-A), and Gubik fields. Small amounts of gas were tested from foldbelt structures at Oumalik, Titaluk, Knifeblade, Koluktak, Eagle Creek, and Tungak Creek (Map 104). Small amounts of gas (rate not measured) were tested from turbiditic sandstones at Akulik well, west of the NPR-A. Gas was also tested from sandstones of the Torok Formation at 2,652 ft (rate too small to measure) and at 5,366 ft (6.7 MMcf of gas per day with minor high-gravity oil) in the Seabee well (Bird, 1988b:p. 330, table 15.5; Magoon and Claypool, 1988:p. 526, table 21.1).

Play 15. Sag River/Shublik-Barrow Arch-West (UBWA1500)

Play 15 covers 600 mi² and lies at drilling depths between 2,000 and 7,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 15 is shown in Map 101. The primary reservoir objectives are the sandstones of the Sag River Formation and/or the carbonates of the Shublik Formation. The Sadlerochit Group is absent owing to onlap at the south edge of the play area (Bird, 1988c:fig. 16.12). Potential traps are stratigraphic wedges produced by truncation of reservoir sandstones, and subtle anticlinal structures in the Barrow area. It is likely that petroleum charging for this play was mostly from Pebble Shale, Kingak, and Shublik Formations that are now deeply buried, thermally over-mature, and gas-generative. The play may have been additionally charged by petroleum migrating northwest along Barrow Arch from the east, or, in the northernmost parts of the play, by petroleum migrating south from areas of deep burial to the north, offshore from the Beaufort shelf. Play 15 was penetrated by most of the development wells for the Barrow gas fields. Minor amounts (to 2.6 barrels) of oil (high-sulfur, low-gravity, "Barrow-Prudhoe" type) and gas (to 800 Mcf of gas per day) were tested from the Sag

River Formation at three of these wells.

Play 16. Sadlerochit-Arctic Platform-West (UBWA1600)

Play 16 covers 1,800 mi² and lies at drilling depths between 7,000 and 13,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 16 is shown in Map 101. The primary reservoir objective is the Triassic Ivishak sandstone of the Sadlerochit Group. Sandstones of the Sag River Formation may also contain petroleum. The Ivishak sandstone ranges from 0 to 150 ft thick within the play area and average porosities range from 0 to 15%. This reflects a more marine and shaly facies than prevailed in Play 6 (mapped porosities of 7 to 15%) in the Northeast NPR-A Planning Area along the Barrow Arch. A history of deeper burial for Play 16 also contributes to its relatively diminished reservoir properties.

Potential traps are mostly small stratigraphic closures related to onlap of the structural high at Barrow. A few subtle anticlinal structures draped over basement are also present (Tetra Tech, 1981:Map TPS). Petroleum charging for this play was probably from the thermally over-mature and gas-generative Shublik, Kingak, and Pebble Shale Formations deeply buried on the south. The exploration experience in this area has shown that Play 16 is gas prone (as are all other plays west of Meade Arch), although sparse oil shows suggest that oil accumulations cannot be ruled out. At Meade Arch, Play 16 passes eastward into the correlative but more oil-prone Play 7. At its southern limit, Play 16 passes into the Ellesmerian (All) Gas Belt play (3). The Peard, Kugrua, and Brontosaurus wells penetrated Play 16. Kugrua well penetrated the Sadlerochit Group in a shale facies. No hydrocarbons were tested from the Sadlerochit Group or other Play 16 units at these wells, although a trace of dead oil (asphaltic material) was noted (mud log) in cherty Ivishak conglomerates at Brontosaurus.

Play 17. Beaufortian-Barrow Arch-West (UBWA1700)

Play 17 covers 1,500 mi² and lies between drilling depths of 1,500 and 8,500 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 17 is shown in Map 102. Play 17 lies west of Meade Arch and includes the gas fields under production near Barrow, Alaska. The Beaufortian sequence ranges from 400 to 1,700 ft thick within the area of Play 17 (Bird, 1988c:figs. 16.15, 16.16). Reservoir objectives include the Cretaceous Walakpa[9] sandstone, the Jurassic Simpson sandstone (distribution mapped by Bird, 1988a:fig. 4.13), and the Jurassic Barrow sandstone, the latter occurring in the lower part of the Kingak Formation (Figure III-01). The Walakpa sandstone ranges from 5 to 40 ft thick and is generally thickest in southern parts of the play area. At Walakpa gas field, the sandstone averages 24 ft (net pay) thick, with an average porosity of 24% and an average permeability of 187 millidarcys (md) (State of Alaska, Oil and Gas Conservation Commission, 1994:p. 219). The Simpson sandstone, ranging from 110 to 180 ft thick, was penetrated by five wells (Topogoruk, South Simpson, South Meade, Peard, and Kugrua). The Barrow sandstone ranges from 0 to 130 ft thick and is typically 110 ft thick in the area of the Barrow gas fields. The average porosity of the Barrow sandstones is about 20%, and permeability averages 25 md (Lantz, 1981:p. 198). Play 17 may contain the Jurassic sandstones ("Alpine," "Nuiqsut," and "Nechelik" sandstones of Kornbrath et al., 1997) that were recently discovered to be productive at the Alpine field and in the Colville delta area adjacent to northeastern NPR-A. Sandstone in the Kuyunak well may be correlative to the Kuparuk "C" sandstone but Houseknecht (2001) correlates it to the Alpine sandstone. The entire Kingak Formation is absent from an area along the northern coast at Barrow because of erosional truncation at the Lower Cretaceous unconformity (shown in Map 102).

The Barrow-area gas fields are unique structural traps on the flank of Avak structure, a semi-circular feature interpreted to represent a Cretaceous-age meteorite impact crater (Kirschner and others, 1991). Elsewhere in Play 17, potential traps that are easily recognized in seismic data are stratigraphic wedges created by erosional truncations at the Lower Cretaceous unconformity. Additional traps are probably associated with sandstone bodies isolated depositionally within shales. For example, the Walakpa field occurs within Walakpa sandstones apparently laterally sealed within shales. Seismic amplitude mapping within a 924-mi² 3-D seismic survey from correlative Play 8 has identified anomalies that may correspond to porous or hydrocarbon-saturated sandstones. The results of this mapping were extrapolated to the entire area of Play 17 (1,500 mi²) in order to estimate the numbers and size range of prospects for Play 17.

Current interpretations suggest that petroleum charging for Play 17 was probably from thermally over-mature and gas-generative Shublik, Kingak, and Pebble Shale Formations that are deeply buried on the south. The exploration experience shows that the area is primarily a gas province. However, 2.6 bbl of oil were recovered from the Sag River Formation (Play 15) beneath the Barrow-area gas fields, and oil has been recovered from the Pebble Shale or Kingak Formation in other wells in the Barrow area (Magoon and Claypool, 1988). The oils from the Barrow area appear to fall into one of two groups: 1) "Prudhoe-type" high-sulfur, low-gravity (16^{o} to 24° API) oils pooled in the Sag River sandstone (Play 16), or 2) "Pebble Shale-type" low-sulfur, high-gravity (30° to 41° API) oils pooled in the Pebble Shale or Kingak Formation (Magoon and Claypool, 1988: p. 528, table 21.2). Because the entire geologic column above basement is thermally immature at Barrow (Bird and Molenaar, 1992), both oil groups probably migrated to the Barrow structures from thermally mature sources to the north and/or south, perhaps before gas later invaded the structures.

Original recoverable reserves for the two gas fields near Barrow are 26 billion cubic feet (Bcf) at South Barrow field, and 13 Bcf at East Barrow field (Lantz, 1981; State of Alaska, Dept. of Natural Resources, 2000). Production at the Barrow fields is primarily from the Barrow sandstones, but a Walakpa-equivalent sandstone has also produced at some field wells. Basement rocks (argillite) tested gas at the South Barrow No. 4 well (Bird, 1988b:p. 326, table 15.5). The Walakpa gas field (12 mi south of the Barrow fields) is estimated to contain 32 to 180 Bcf in ultimate gas reserves in the Walakpa sandstone (State of Alaska, Dept. of Natural Resources, 2000; Kornbrath et al., 1997). The Peard, Brontosaurus, and Kuyunak wells penetrated Play 17. Gas shows were noted in the Beaufortian sequence at Peard. Pooled gas appears (cased-hole logs) to be present in the Walakpa sandstone penetrated at the Brontosaurus well.

Play 18. Beaufortian-Arctic Platform-West (UBWA1800)

Play 18 covers 3,000 mi² and lies between drilling depths of 2,000 and 17,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 18 is shown in Map 102. The Beaufortian sequence ranges from 1,400 to 3,800 ft thick within the play area (Bird, 1988c: figs. 16.15, 16.16). Reservoir objectives include the Lower Cretaceous sandstones at Tunalik well (equivalent to Kuparuk(?) sandstones) and possibly some Jurassic sandstones (equivalent to the "Alpine," "Nuiqsut," and "Nechelik" sandstones of Kornbrath et al., 1997). The Jurassic Simpson and Barrow sandstones that are found to the north in Play 17 do not extend south into the Play 18 area (Bird, 1988a:fig. 4.14).

The Upper Jurassic sandstones encountered near Alpine field have not been observed in wells in western NPR-A, but they could be present in some of the sparsely drilled eastern parts of Play 18. At Tunalik well, a sandstone possibly equivalent to the Kuparuk sandstone is over 500 ft thick, with porosities averaging 11% (Sherwood and others, 1998:pl. 13.4).

One potential trap recognized in available seismic interpretations is a low-amplitude anticline (Tetra Tech, 1981:Map KJ). Additional traps are probably associated with sandstone bodies isolated within shales. Seismic amplitude mapping within a 924-mi² 3-D seismic survey in Play 8 in the northeastern NPR-A has identified anomalies that may correspond to porous or hydrocarbon-saturated sandstones. To estimate the numbers and areal sizes of prospects, the results of this mapping were extrapolated to the entire area of Play 18 (3,000 mi²).

Petroleum charging of Play 18 was probably from thermally over-mature (gas-generative) Shublik, Kingak, and Pebble Shale formations within and south of the play area. The exploration experience to date suggests that Play 18 is gas-prone. The Kugrua, Tunalik, and South Meade wells penetrated Play 18. The Tunalik well apparently encountered pooled gas in Kuparuk-equivalent sandstones between 12,508 and 12,603 ft, but nine wireline tests failed to sample formation fluids. Play 18 passes into a correlative gas-only play (Play 10) to the south and a correlative oil-prone play (Play 9) on the east.

Play 19. Brookian Turbidites-Arctic Platform-West (UBWA1900)

Play 19 covers 5,500 mi² and lies between drilling depths of 1,000 (i.e., land surface) and 16,000 ft within the Northwest and Northeast NPR-A Planning Areas. The area of Play 19 is shown in Map 103. Play 19 lies west of Meade Arch and south of the Chukchi Sea coast. The Torok Formation, which contains the turbidite sandstone reservoir objectives, ranges from 3,000 to 9,000 ft thick within the play area (Bird, 1988c:fig. 16.17), but sandstones are generally confined to the lowermost 2,000 ft. In the western NPR-A, turbiditic sandstones within the Torok Formation are mostly Early Cretaceous (Middle Albian to Cenomanian; Huffman, Ahlbrandt, and Bartsch-Winkler, 1988:fig. 13.11). The turbiditic sandstones were deposited in slope or basin-floor settings near the toe of the east-prograding Nanushuk-Torok delta system[10] that filled the Colville basin. To the north, sandstones are generally sparse and thin, but preserve modest porosities. To the south, sandstones are abundant and relatively thick, however they generally lack porosity because of deep burial. Reservoir presence, continuity, and pore-system quality are the chief antagonists to the success of this play. McMillen (1991) recognizes sand-rich, low-stand fans and sand-poor (shaly), high-stand fans within the Torok Formation. Identification of the sand-rich fans via 3-D seismic data may be the key to exploration success in Play 19.

Older, conventional seismic data reveal two large anticlinal features at the base of the sequence (Lower Cretaceous unconformity) south of Barrow (Tetra-Tech, 1981:Map KJ), and turbiditic sandstones at the base of the sequence may drape this feature. Most traps are probably stratigraphic, consisting of bodies of turbiditic sandstones isolated within shales that are difficult to identify in conventional seismic data. Seismic amplitude mapping within a 308-mi² 3-D seismic survey in northeastern NPR-A (in correlative Play 11) has identified anomalies on chronostratigraphic surfaces within the Torok Formation. These anomalies may correspond to porous or hydrocarbon-saturated sandstones. The results of this mapping were extrapolated to the entire area of Play 19 (5,500 mi²) in order to estimate the numbers and size range of prospects.

Petroleum charging of Play 19 was probably from the thermally over-mature (gas-generative) Shublik, Kingak, and Pebble Shale Formations that directly underlie the Brookian turbidite reservoirs within and south of the play area. Torok shales also might constitute a source, chiefly for gas. The exploration experience has shown that Play 19 is gas-prone. Twenty-eight wells, mostly in the Barrow gas fields (23 wells), have penetrated Play 19. No turbiditic sandstones were tested, although gas shows were associated with these sandstones in the Peard, Tunalik, and Brontosaurus wells.

Play 20. Brookian Topset-Arctic Platform-West (UBWA2000)

Play 20 covers 6,400 mi² (total area within NPR-A, 6,726 mi²) and lies between drilling depths of 1,000 (i.e., land surface) and 7,000 ft within NPR-A. The area of Play 20 is shown in Map 104. Across Play 20, the Brookian "topset" sequence consists of the mostly Lower Cretaceous (Middle Albian to Cenomanian) Nanushuk Group. Upper Cretaceous "topset" sandstones of the Colville Group are not present. The reservoir objectives are deltaic and fluvial rocks deposited as distributary-mouth bars and shorelines of the east-prograding delta system that simultaneously deposited the turbiditic sandstones of Plays 11, 12, and 19 in deeper waters to the east. Within the play area, the Nanushuk Group ranges from 0 to 8,000 ft thick. Sandstones within the Nanushuk Group in Play 20 have not been buried deeply, so they often preserve modest porosities, with fine grain size and clay contents offering the greatest challenges to reservoir quality (Huffman, Ahlbrandt, and Bartsch-Winkler, 1988). Petroleum charging of Play 20 was probably from the Torok shales that fill the lower parts of Colville basin. Potential sources include thermally over-mature and gas-generative shales of the Shublik, Kingak, and Pebble Shale Formations underlying the western Colville basin. However, the shallow sandstones forming the reservoir objectives in Play 20 are separated from these deep petroleum sources by as much as 5,000 ft of overpressured Torok shales. Denial of access to migrating petroleum by this shale barrier (migrating oil or gas probably was diverted north beneath the shale barrier toward Barrow Arch) may be the chief threat to success of prospects within this play. Minor oil shows were found in Nanushuk sandstones at Tunalik and Peard wells, suggesting some transmissibility of oil through the underlying Torok shales.

The Brookian topset sequence is virtually unstructured in the play area and mapping with conventional seismic data (Tetra Tech, 1981:Map K1-K4) failed to identify any traps. Traps probably consist of discontinuous sandstone bodies isolated within shales. Play concepts for such traps might include low-stand wedges or prograding complexes high on slopes, or traps that are isolated beneath shales that onlap a younger flooding surface. Seismic amplitude mapping from a 308-mi² 3-D seismic survey in the northeastern NPR-A (in correlative Play 13) has identified anomalies on chronostratigraphic surfaces within the Nanushuk Group. These amplitude anomalies may correspond to porous or hydrocarbon-saturated sandstones. To estimate the numbers and sizes of prospects, the results of this mapping were extrapolated to the entire area of Play 20 (6,400 mi²).

Seven wells penetrated Play 20. Exploration drilling to deeper horizons encountered mostly gas. This suggests that the play is generally gas-prone. Minor oil shows were noted in Nanushuk Group sandstones at Tunalik and Peard wells. None of the seven wells encountered pooled hydrocarbons.

Play 21. Endicott/Lisburne-Thrust Belt (UBWA2100)

Play 21 covers 6,300 mi² and ranges in potential drilling depths between 1,000 ft (i.e., land surface) and 38,000 ft within the NPR-A, but lies entirely south of the Northwest and Northeast NPR-A Planning Areas. The area of Play 21 is shown in Map 99. Play 21 involves complex structures created by thrust faults rising from beneath the Brooks Range. The structural architecture of Play 21 is illustrated in the cross section of Figure App-01. Play 21 was not quantitatively assessed and is not described further.

Play 22. Beaufortian-Deep Detached Foldbelt (UBWA2200)

Play 22 covers an area of 4,100 mi² as shown in Map 102 (total within NPR-A, 13,709 mi²). The play is generally deeply buried, ranging from 12,000 ft to 26,000 ft in drilling depths. However, Beaufortian-equivalent rocks also occur in the thrust stack at shallow depths beneath Cretaceous cover strata in the thrust stack north of the Brooks Range front. These rocks are locally exposed in places like the Surprise Creek locality described by Mull (1997) west of the NPR-A. While Beaufortian-equivalent rocks in the thrust stack cannot be mapped in seismic data, farther north, and at much greater depths, Beaufortian rocks can be recognized in seismic records. These rocks are involved in a belt of detached folds and thrust faults extending to 60 mi north of the range-front of the Brooks Range. In regional seismic records, the complex appears to be enclosed within a low-angle duplex or triangle zone tapering northward beneath roof thrust(s) in the lower part of the Brookian sequence or the upper part of the Beaufortian sequence. A schematic interpretation of the structure of Play 22 is shown in Figure App-01.

Available seismic structure maps (Tetra Tech, 1981:Map KJ) illustrate that Play 22 lies mostly down dip from the Beaufortian gas belt (Play 10), and therefore, would offer potential for gas only. Because of the complex burial history and widespread extreme thermal maturity, the majority of potential reservoir rocks in Play 22 probably offer only small amounts of relict intergranular porosity, or porosity related to fractures. The Beaufortian sequence across most of Play 22 is primarily in a basinal (shale) facies, but some shelf sandstones may be present within northern parts of the play area (shelf-edge mapped by Bird, 1988c:fig. 16.15). Most traps in Play 22 are fault-bend folds with anticlinal closure or fault-truncation closure. Stratigraphic traps, consisting of bodies of sandstone isolated within shales, are probably also present.

Beaufortian(?) sandstones in Play 22 were penetrated at the 13,200- to 13,500-ft (measured depth) interval in the Seabee well in the southeast NPR-A and below 15,670 ft in the Tulugak well east of the NPR-A (Map 102). A Beaufortian sandstone at the Seabee well with vitrinite reflectance of 1.99% was associated with strong gas shows and flow into the well during drilling. The Tulugak well tested gas at 936 Mcfd from a 30-foot-thick (15,840 to 15,870-ft) Beaufortian(?) sandstone at a thermal maturity of 2.45% vitrinite reflectance (calculated from Johnsson, Howell, and Bird, 1993: table 2). Play 22 is viewed primarily as a gas play.

Play 23. Fortress Mountain Formation-Deep Detached Foldbelt (UBWA2300)

Play 23 covers 5,700 mi² (total area within NPR-A, 11,900 mi²) and ranges from 2,000 ft to 22,000 ft in drilling depth (most mapped prospects are between 7,000 and 12,000 ft) within the Northeast and Northwest NPR-A Planning Areas. The area for Play 23 is shown in Map 103. Play 23 involves strata of the lowermost part of the Colville basin fill in a belt of detached folds and thrust faults extending up to 60 mi north of the Brooks Range front. The complex is enclosed within a triangle zone that tapers northward beneath shallow roof thrust(s) in the Torok Formation and above floor thrusts in the lowermost part of the Fortress Mountain Formation or underlying Beaufortian sequence. A cross-section interpretation of the context and structure of Play 23 is shown in Figure App-01.

Play 23 might also extend an unknown distance southward beneath the overriding thrust stack of the Endicott/Lisburne thrust belt (Play 21). In fact, sandstones, conglomerates, and shales of the Neocomian Okpikruak Formation were encountered in the Lisburne well beneath a thrust fault bearing rocks of the Etivluk Group (Pennsylvanian to Jurassic) (Magoon and others, 1988: pl. 19.23). However, in terms of practical access for petroleum exploration drilling, the play is limited on the south by the Brooks Range front.

Play 23 consists of imbricate thrusts and duplexes in a sequence of turbiditic sandstones underlying the Torok Formation. This group of rocks has also been called the "Fortress Mountain Formation" in recognition of an apparent kinship with the Fortress Mountain Formation exposed in the foothills of the Brooks Range. The term "Fortress Mountain Formation" is applied to the subsurface play involving thrust-faulted turbiditic sandstones beneath the Torok Formation in Colville basin. However, the turbiditic sandstone sequence at the base of the Torok Formation in southern Colville basin is somewhat older (Barremian-Aptian) and it may not be directly correlative to the Fortress Mountain Formation (Albian) exposed in the southern foothills.

At the Seabee well, the Fortress Mountain Formation is 5,460 ft thick. At the Tulugak well east of the NPR-A, the Fortress Mountain Formation is 7,770 ft thick. At the Tulaga well, the Fortress Mountain Formation is 1,505 ft thick. The Fortress Mountain Formation was incompletely penetrated at Awuna (minimum thickness, 8,220 ft), East Kurupa (minimum thickness, 5,658 ft), West Kurupa (minimum thickness, 4,065 ft), and Big Bend (minimum thickness, 2,425 ft) wells. These are structural thicknesses and may include thrust repetitions.

In the Seabee and Awuna wells, individual sandstones in the "Fortress Mountain Formation" range from 10 to more than 100 ft thick, with aggregate (net) sandstone thickness up to 3,377 ft (Tulugak well), or 48%, of the penetrated thickness. Porosities are low, particularly in deeper parts of the sequence, ranging from 0 to 15%. Aggregate sandstones with sonic log porosities exceeding 10% range up to 2,293 ft (61% of net sandstone thickness) in the Tulugak well. Individual sandstones are thin, muddy, and probably low in permeability. However, a tremendous amount of sandstone is clearly present in the Fortress Mountain Formation penetrated by these wells and there is ample opportunity across the play for the occurrence of porous, reservoir-quality sandstones.

In the exposures of "type" Fortress Mountain Formation in the southern foothills, conglomerate and sandstone beds may range to several hundreds of feet thick, the thickest beds being associated with debris flows filling inner-fan channels (Crowder, 1987). Sparse measurements on surface samples from diverse sandstone facies in the Fortress Mountain Formation yielded porosities from 2% to 14% with permeabilities of less than 0.5 md (Molenaar, Egbert, and Krystinik, 1988:table 12.2).

In the parts of the play area east of 155° W. Longitude, seismic data reveal that the Fortress Mountain Formation is deformed by imbricate thrusts and duplexes that are often disharmonic to the structure of the overlying Nanushuk sequence (broad, gentle folds and triangle zones). An example of the relationship between Fortress Mountain (Play 23) and Nanushuk (Play 14) structures as observed in seismic data is shown in the cross section in Figure App-01.

In the parts of Play 23 west of 155° W. Longitude, seismic data do not clearly reveal an independent set of structures in the lower part of the Brookian sequence beneath the shallow fold train involving Nanushuk Group strata. Typically, no coherent seismic reflections are observed below the folded Nanushuk Group.

Play 23 ranges from 2,000 ft to 22,000 ft in drilling depths. The shallower structures offer the greatest potential for survival of sandstone pore systems and oil deposits. Deep structures that lie beneath the 2.0% vitrinite reflectance isograd would probably lack porous sandstones and would offer potential for gas only. Sandstones in deep structures are likely to be thoroughly compacted, offering only small amounts of relict intergranular porosity, or porosity related to fractures.

Most traps in Play 23 are fault-bend folds or duplex "horses" involving the Fortress Mountain Formation sandstones in anticlinal closures or fault-truncation closures. Seismic mapping using conventional seismic data identified 77 potential traps ranging up to 53,000 total acres in area (Tetra Tech, 1981:Maps KF-KF2). In Play 23, it is anticipated that traps will contain oil or natural gas derived from shales of the underlying Ellesmerian and Beaufortian sequences.

The seven wells penetrating the Fortress Mountain Formation in Colville basin (Awuna, West Kurupa, East Kurupa, Tulugak, Tulaga, Big Bend, and Seabee wells) encountered the top of the Fortress Mountain Formation at depths ranging from 3,000 to 6,000 ft shallower than the 2.0% vitrinite reflectance isograd. Therefore, the upper parts of the Fortress Mountain Formation in these wells are found within the depth interval in which oil accumulations might have survived thermal destruction. However, formation tests at these seven wells did not yield oil and suggest that Play 23 is gas-prone. The Seabee and Awuna wells were specifically drilled to test structures involving the Fortress Mountain Formation (Bird, 1988a:p. 95). At the Seabee well, minor oil shows and strong gas shows were widely observed in the Fortress Mountain Formation, but no tests were conducted. At the Awuna well, most sandy intervals in the Fortress Mountain Formation were associated with strong gas shows. A test of one 115-ft thick interval yielded salt water at 2,057 barrels per day (Bird, 1988b:p. 329), indicating substantial formation permeability. Gas was tested from two zones at an aggregated rate of 5,100 Mcf of gas per day in the East Kurupa 1 well (between depths of 7,000 and 9,300 ft in the Fortress Mountain Formation). In the West Kurupa well, minor oil shows were noted in sidewall cores of the Fortress Mountain Formation and gas shows were logged for most sandstones. Three tests of Fortress Mountain Formation sandstones produced small amounts of gas at rates of 5 to 10 Mcf of gas per day, with rates generally declining through the flow test periods (indicating a limited reservoir volume). Two intervals of Fortress Mountain Formation sandstones in the Tulugak well flowed gas at rates from 12 to 148 Mcf of gas per day. The Big Bend well encountered gas shows, but no oil shows. The Tulaga well encountered oil and gas shows in the upper part of the Fortress Mountain Formation but no tests were conducted.

Houseknecht and Schenk (2001) and Bird (2001) have described an area on Desolation Creek where thick turbiditic sandstones of the Torok Formation are oil stained, friable, and may represent an exhumed oil field (Houseknecht, 2000, pers. comm.) lying east of NPR-A, south of the Grandstand well and within an eastern extension of Play 23. The location of these oil-stained sandstones is shown in Map 103. The structural context for the oil-stained sandstones is shown in the cross section in Figure App-01.

South of Colville basin, minor shows of oil, gas, and asphaltic oil were noted in pre-Fortress Mountain (Neocomian Okpikruak Formation) rocks in the Lisburne well (Husky Oil NPR Operations, Inc., 1983:p. 14). Solid hydrocarbon material filling fractures up to 25 cm wide are widely observed in field exposures of the Fortress Mountain Formation in the southern foothills, possibly documenting important oil migration (Molenaar, Egbert, and Krystinik, 1988:p. 271).

C. Conceptual Aspects of the Geologic Modeling Approach

There are several conceptual differences between the present (2002) assessment and the 1997 MMS/BLM assessment of the Northeast NPR-A Planning Area.

- The present assessment analyzes 3-D seismic surveys in the Northeast NPR-A Planning Area for indicators of potential stratigraphic traps. These data were used to forecast the numbers and size range of prospects in correlative plays across the northern half of the NPR-A. Data from nine proprietary wells drilled on leases acquired in 1999 in the Northeast NPR-A Planning Area were also incorporated into the assessment of some plays.
- The present assessment expands the area of the Alpine-correlative plays (Play 8. Beaufortian-Barrow Arch-East; Play 17. Beaufortian-Barrow Arch-West) about 30 mi southward, based on proprietary exploratory wells and seismic data. These southward revisions of play boundaries allowed the Alpine-correlative plays to capture the most promising (northern) parts and bulk of resources formerly assigned to Play 9 and Play 18. This expansion greatly increased the resources for the Alpine-correlative plays and particularly for Play 8.
- The 1997 MMS/BLM assessment does not predict huge (40 Bbbl in-place), low-gravity oil deposits similar to the West Sak and Schader Bluff reservoirs overlying the nearby Kuparuk and Milne Point fields. The MMS/BLM assessment of the correlative play (Brookian topset, Play 13) models relatively few small pools (largest pool, 28 MMbbl of oil). This modeling produces a small overall undiscovered resource potential. No accumulations of the scale of the large West Sak-Ugnu pools are anticipated in these plays in the Northwest or Northeast NPR-A Planning Areas.
- In the present assessment, unidentified prospects for each play were estimated. In most petroleum provinces, it is generally acknowledged that large numbers of prospects remain undetected, even in the most thoroughly mapped areas. "Unidentified" prospects exist for a variety of reasons. Some areas lack sufficient seismic data to map all prospects. Smaller prospects may be missed because they fall between widely spaced seismic lines, or stratigraphic prospects are missed because the seismic data lack sufficient resolution of subsurface detail. Many areas have not been tested sufficiently by drilling to understand the geology and particular relationships that operated to create oil and gas pools in those areas. At the outset of exploration of new areas, new fields and plays are often unexpectedly found while drilling to reach another targeted reservoir.
- Because unidentified prospects could contain significant resource volumes, they should be recognized in assessments of oil and gas potential. For each of the 22 geologic plays quantitatively assessed for the combined Northwest and Northeast NPR-A Planning Areas, the numbers of known or mapped prospects were supplemented with additional unidentified prospects. Estimates of the numbers of unidentified prospects are based on joint consideration of 3-D seismic mapping, completeness of mapping, well control, and the geologic complexity. In areas of complex stratigraphy or structure, sparse seismic data or well control, and uncertain geology (timing, migration paths, reservoir stratigraphy), relatively large fractions of total prospects are likely to remain unidentified. Beaufortian plays, for example, are thought to contain primarily stratigraphic prospects, so for that reason, substantial numbers of unidentified prospects were included in the prospect number distributions.
- Prospect burial depths have well-documented effects on reservoir properties. Most of the plays identified within the Planning Area have been subjected to extremes in burial depth, temperatures, and thermal maturity. Reservoir yield factors (barrels of oil recoverable per acre-foot of reservoir, or millions of cubic feet of gas recoverable per acre-foot of reservoir) are the product of variables (porosity, permeability,

hydrocarbon saturation) that vary systematically with burial depth. Overall, yield factors generally decline with increasing burial depth. For this assessment, yield factors were calculated using @RISK (commercial software) and entering probability distributions for each variable in the yield equations. Yield factors reflect the balance between depositional environment and post-depositional destructive processes related to burial conditions. The deep burial histories of Gas Belt plays have adversely affected reservoir pore systems. In contrast, reservoirs in plays along the Barrow Arch have not been deeply buried, and repeated exposures of strata at erosional unconformities may have removed earlier cements and restored porosity. Generally, the highest yield factors were assigned to the Barrow Arch plays (e.g., Play 8, 316 bbl oil/acre-ft and 0.580 MMcf gas/acre-ft) and the lowest yield factors to Gas Belt plays (e.g., Play 10, 0.164 MMcf gas/acre-ft). Arctic Platform plays suffered intermediate burial histories and therefore offer intermediate reservoir yield factors e.g., Play 9, 65 bbl oil/acre-ft and 0.483 MMcf gas/acre-ft).

- The proportion of oil and gas in reservoirs is another key variable in this assessment. The principal oil source rocks known to occur in northern Alaska (Shublik, Kingak, and Pebble Shale Formations) underlie all of the study area. Oil generated upon thermal maturation should have migrated into overlying (Beaufortian and Brookian) strata or northward (updip) toward the Barrow Arch. Consequently, the plays along the Barrow Arch have the highest probability for pooled oil (in this model, 35% chance for pools that are 100% oil). For the Lisburne and Endicott plays on the Arctic Platform, reservoirs lie below recognized oil source-rocks and hydrocarbons must be generated from unknown Paleozoic sources. Accordingly, the probability for oil pools is smaller (in this model, 10% to 30% probability for pools that are 100% oil). Shallow reservoirs in the Brookian Topset play are isolated from underlying oil sources by several thousand feet of shales (largely gas prone and often overpressured). Gas Belt plays are universally assigned a 100% gas resource mix. A relatively high potential for gas in plays west of Meade Arch is based partly upon the discoveries of gas fields and the observation of widespread gas shows. The high thermal maturity of relatively shallow rocks west of Meade Arch (based on vitrinite reflectance data in the Kugrua and South Meade wells) bolsters this notion, which seems to preclude oil from a large area of western NPR-A.
- Effective reservoir (pay) thickness is an essential factor controlling potential storage volumes and recovery from oil and gas pools. The depositional thicknesses of sandstone formations in the Beaufortian and Ellesmerian plays were probably greatest along the Barrow Arch. However, subsequent erosional events have truncated some of these rocks in northern NPR-A. Although sandstone formations deposited to the south in the Arctic Platform plays have greater preservation potential (because unconformities are incised less deeply), they become shaly and are deeply buried toward the south, adversely affecting porosity. Because of these very different processes, it was concluded that reservoir pay thicknesses are relatively similar for the Barrow Arch and Arctic Platform play groups. Pay thicknesses in Beaufortian and older plays far to the south of Barrow Arch in the Gas Belt areas are much less because of distal depositional environments and destruction of porosity/permeability related to deep burial.
- Exploration chance is an estimate of the statistical frequency of occurrence of oil and gas accumulations in a play. The exploration chance is important to play assessment because it determines the fraction of prospects (or fraction of potential petroleum storage volume) that will be filled with petroleum rather than water. In this way, the exploration chance directly determines play resource endowments. The probability that a play will have at least one hydrocarbon accumulation (i.e., the play is "successful") is termed the <u>play chance</u>. But even if it is known that a play is "successful", it is then necessary to also estimate the proportion of the untested prospects in the play that will be "successful"--that is, the fraction of prospects that can be expected to contain some form of petroleum rather than water. The probability that any given prospect within a play will be filled with petroleum is termed the <u>prospect chance</u>. Play and prospect chances, estimated as decimal fractions, are multiplied to obtain <u>exploration chance</u>. Each play is associated with an independent exploration chance. The exploration chance is predicated on geological factors, rather than economic factors, in the GRASP model. Geologic success is defined as the existence of pooled hydrocarbons that can be recovered from a well bore rather than some minimum pool size. Conventional hydrocarbon accumulations do not include continuous-type deposits (non-pooled) or those not recoverable by standard technology. The Barrow Arch has gathered migrating hydrocarbons into traps all along its crest. All petroleum generated in areas to the north or south of Barrow Arch has tried to migrate to the arch. Some hydrocarbons reach the arch and some were trapped en route on the flanks of the arch. By a coincidence of geologic history, Ellesmerian and Beaufortian rocks are in a more proximal (shallow water) setting (higher quality reservoirs) along the Barrow Arch. For these reasons, plays along the Barrow Arch have the highest exploration chances. By contrast, the low exploration chances for the Gas Belt plays reflect a combination of negative factors including the deep water deposition (thin, muddy reservoirs), the destruction of reservoir quality (deep burial and compaction of pores), and the poor

seismic definition for deeply buried subtle traps.

D. Geologic Assessment Results

The assessment of conventionally recoverable hydrocarbon potential is summarized as a cumulative probability graph (Fig. App-02), representing the aggregation of the 22 geologic plays analyzed in the Northwest NPR-A Planning Area. Separate curves for oil (including crude oil plus natural gas liquids), gas (including non-associated and associated gas), and BOE (barrels-of-oil equivalent) are shown. The BOE sums the oil and gas resources on an energy-equivalent basis, where 5,620 ft^3 gas is presumed to equal the energy content of 1 bbl of oil. These resources represent pooled hydrocarbons that are recoverable with conventional technology and without regard for economic viability.

Fig. App-02 illustrates a very important concept: undiscovered resource volumes should be portrayed in the context of probability distributions to reflect the uncertainties associated with the input model data. There is a much higher probability of occurrence for small resource volumes than for large resource volumes. For example, there is a 95% chance (19-in-20 chance) that the combined Northeast and Northwest NPR-A Planning Areas contain at least 6.817 BBO (billion barrels oil), and there is a 5% chance (1-in-20 chance) the planning areas contain 11.817 BBO. The oil resource differential across this probability range represents about a twofold increase based entirely on the probability level. Other probabilities can be selected for statistical summaries (for example, 90% or 9-in-10 chance). More frequently, the mean of the distribution is used to compare or summarize results for different plays or areas. Important concepts to remember include: 1) the fact that a wide range of possibilities for resource potential is typical for estimates because oil and gas assessments are based on uncertain data input as ranges; and 2) potential resource volumes should be presented in the context of associated probabilities, where large volumes are less likely than small volumes .

To summarize the information contained in the cumulative probability curves, the risked mean oil volume (including crude oil and gas-condensate) is 9.101 BBO, and the risked mean gas volume (including both associated and non-associated gas) is 37.309 Tcf. These risked mean (or expected) volumes fall within wide ranges of resource potential. Recoverable oil volume estimates range from 6.817 to 11.817 BBO (95% and 5% probabilities), and corresponding gas volumes could range from 23.002 to 56.213 Tcf (95% and 5% probabilities). Aggregated oil and gas resources are represented as BOE (barrels of oil equivalent). The mean resource aggregate for the combined Northwest and Northeast NPR-A Planning Areas is 15.740 billion BOE, with extreme ranges (95% and 5% probabilities) of 11.358 to 21.057 billion BOE.

The individual contributions of the 22 plays are displayed in Table App7-01 . Reported play endowments are provided for 95% probability (F95), the mean, and 5% probability (F05) levels. It is apparent that four plays (Play 6. Sadlerochit-Barrow Arch-East; Play 8. Beaufortian-Barrow Arch-East; Play 14. Brookian Foldbelt; and Play 23. Fortress Mountain-Deep Detached Foldbelt) dominate the resource potential of the combined Northwest and Northeast NPR-A Planning Areas, accounting for 80% of the total oil potential and 66% of the total gas potential. Each of these four plays offers "high-side" (5% chance) oil resource potentials over a billion barrels. Two other plays are of secondary importance (Play 1. Endicott-Barrow Arch-East and Play 11. Brookian Turbidites-Arctic Platform-East), and together these plays contribute 10% of the total oil resources.

It is important not to focus exclusively on the mean resource volumes of plays. Large pools - rare perhaps, but possible - in some of the low-resource plays could become commercial fields. The mean sizes of the three largest oil and gas pools in each play are listed in Table App 7-01. Mean resource volumes are reported for these pools, but each pool has a high potential volume associated with a low probability. For example, the largest oil pool (rank 2) in Play 8 is 634 MMbbl of oil in mean volume. For this same pool, there is a 5% chance that 1,611 MMbbl of oil could be present. All of the pools listed in Table App 7-01 have maximum potential sizes that are two to three times larger than the size at the mean. Figure App-03 displays a pool rank plot for the

Alpine-correlative Play 8. Here, the oil and gas contents of the141 possible pools are displayed as ranges (lengths of vertical bars) of possible resources between the 75% and 25% probability levels.

E. Economic Assessment

The purpose of the economic assessment is to determine the portion of the undiscovered, conventionally recoverable hydrocarbon endowment that is commercially viable (produced at a profit) under given engineering and economic conditions. The PRESTO computer program developed by MMS performs the economic analysis. PRESTO simulates activities beginning with the discovery of an oil or gas pool and ending with delivery of the hydrocarbons to market. The computer model schedules the costs associated with exploration, development, and production in relation to the income from sales of oil and gas. A discounted cash-flow analysis calculates the net present value of development of a hypothetical discovery under different sets of randomly sampled geologic, engineering, and economic variables. Each PRESTO run is composed of 1,000 trial simulations. Pools simulated with positive net present value are added to play-level resource totals and then play-level resources are aggregated to recoverable estimates for the entire assessment area.

It is important to acknowledge that the computer simulations are made without knowledge of exact prospect locations, and many of the prospects are unmapped at the present time. The modeling simulations occur in an artificially compressed time frame, generally "discovering" all pools within the primary lease term (10 years). The annual funding and drilling equipment required to reproduce this exploration effort is unprecedented. Also, site-specific engineering requirements for future field developments in the NPR-A could differ markedly from the generalized engineering models assumed for our assessment. The cost and delays associated with regulatory actions are not considered at this stage of the economic evaluation.

The cost of dry holes prior to making a commercial discovery is not added to the economic burden of simulated discoveries. Given the high cost of operations in northern Alaska, successful early exploration efforts are the key to continued industry funding. Future price expectations and possible technological advancements influence corporate strategies and funding, but these factors cannot be accurately evaluated because each company may have different concepts. Generally speaking, higher oil prices could spark more industry interest in exploring a new area. Increased exploration drilling could result in more discoveries. Challenging conditions are likely to drive technology advancements to lower unit costs and recover larger portions of the resource base to increase profitability. A contrary set of circumstances--such as a series of expensive, dry exploration wells coupled with low oil prices--could force industry to abandon an area before making any commercial discoveries. However, temporary changes in industry attitudes do not affect the available resource potential calculated by the PRESTO model.

At the present time there is no transportation system to move natural gas from the North Slope to outside markets, and huge volumes of gas resources discovered in northern Alaska have been stranded for decades. Recently, numerous proposals to commercialize the stranded resources are being discussed by industry and government groups. A new gas transportation system (likely a large diameter pipeline) seems far more likely today than five years ago. New discoveries of associated (with oil pools) and nonassociated gas (separate from oil pools) in the NPR-A could feed into a future gas transportation system when it is constructed. Considering the long lead-time between leasing and production for remote areas of the North Slope, the timing for a future pipeline system could fit with new discoveries in the NPR-A. Consequently, an economic analysis of natural gas production has been included, assuming that a major transportation system is available to carry gas production from NPR-A. A tariff of $2.50 per Mcf was applied to the economic simulation to cover the costs of conditioning and transportation of natural gas from the Prudhoe Bay area to markets in the U.S.

1. Economic Modeling Approach

The operational aspects of the PRESTO computer model are discussed in detail in Sherwood et al (1998) and only some basic concepts of the model are discussed here.

The economic results are controlled to a large degree by the preceding geologic assessment. This is because pool characteristics determined by the GRASP geologic model are transferred as input parameters into the PRESTO economic model. Although variables are randomly sampled in PRESTO, the midpoints of the input distributions are sampled more frequently than the extremes of the distributions. Although extreme cases are theoretically possible, geologic plays with small pools and thin reservoirs are likely to be evaluated as poor economic plays.

Although the geologic assessment analyzed 22 plays, many of these plays are highly unlikely to contain economic resources (pools too small and remote). Screening criteria were used to separate the plays with possible economic potential from those unlikely to have any economic potential. The screening criteria for economic modeling were:

1. plays contain less than 1% of the total oil or gas resources;
2. the mean size of the largest pool in the play is less than current satellite developments; and
3. plays are unproven with no discoveries made to-date.

These screening criteria reduced the original 22 GRASP plays to 11 plays assessed by the PRESTO model.

Although the assessment is described as a play-based analysis, the basic units of the PRESTO model are individual pools. The PRESTO computer program conducts a pool-by-pool development simulation under changing geologic, engineering, and economic variables. If individual pools cannot support the costs of development wells, facilities, and pipelines, these resources do not contribute to the play-level resource volumes. The possibility that small satellite pools could be developed at somewhat lower unit costs by sharing nearby infrastructure is difficult to model properly in PRESTO because of the intrinsic stand-alone field assumptions.

Under normal circumstances, the first pools developed in an area must support the initial costs of new infrastructure, such as staging areas, processing facilities, and main pipelines connected to TAPS. The added costs for new infrastructure are supported by realizing the economies of scale for large projects. This means that the biggest fields are usually developed first. To accommodate this typical situation, a complicated set of capital cost inputs (for new infrastructure) and tariffs (costs to share existing infrastructure) were used for play groups in the same area. All oil and gas production from NPR-A was assumed to utilize North Slope infrastructure, such as common-carrier pipelines, TAPS and tankers, with transportation costs defined by published tariffs.

Prospect mapping using seismic data is important in MMS/BLM assessment efforts. Prospects are identified on regional maps or extrapolated from trend maps in adjacent areas containing the same play conditions. To account for prospects that have not been mapped (either because they lack seismic data or they are not mappable with the available data) extrapolations of prospect size and number are made from geologic analogs. Structural prospects are usually identified and tested first in a frontier area. Later play concepts involving stratigraphic plays (for example, the Alpine-equivalent plays) depend on the availability of advanced 3-D seismic data. Because these data sets are not routinely collected as part of early regional surveys in the exploration phase, stratigraphic plays carry an extra level of uncertainty with regard to the size and location of new prospects. The location and characteristics of a potentially commercial pool can only be confirmed by actual drilling.

The PRESTO program applies variables using ranges for most engineering parameters. To allow for a more realistic simulation, ranges for costs are varied 25% around the most-likely (or mode) value. This accounts for the uncertainties associated with different states of nature. No attempt is made to forecast new engineering technology that might be developed in response to higher-than-normal commodity prices. Conventional technology and standard North Slope engineering practices are assumed by the simulation model.

Economic assumptions are reviewed and modified (if necessary) for each resource assessment, and minor revisions were made for the present work as compared to the 1999 assessment for the Northeast Plan area. Changing geologic assumptions and economic inputs can produce differences between present and past assessments. For the present assessment, economic and engineering cost inputs assume 2002 as the base year, and commodity prices and costs are inflated equally at a constant rate of 3%. The discount rate approximates the after-tax rate of return on investment. Cash flow items are discounted/deflated back to present dollars using a combined rate of 15.4% (1.12 discount x 1.03 inflation).

Price adjustments were made for the quality of crude oil for each play. The play-level price adjustments range from -$1.20/bbl for 20° API crude oil to +$1.00/bbl for 40° API light oil. This approximation replicates the Quality Bank Allowance (QBA), since the State of Alaska does not release the QBA data for individual North Slope fields. All North Slope oil production is added to the Alaska North Slope (ANS) stream carried by TAPS and tankers to assumed West Coast markets. The standard ANS crude oil (now 28° API) is given a -$.60 price adjustment for quality relative to World Oil (32° API), which is a composite of sources that are delivered to domestic refineries.

2. Economic Assessment Results

The results of the economic evaluation are summarized in the price-supply curves (displayed as Figure App-04 and Figure App-05) which show resource volumes (horizontal axis) plotted in relation to commodity prices (vertical axis). Despite the inverted plotting format, price is the independent variable and resource volume is the dependent variable. Typically, an increase in oil or gas prices will result in an increase in the volume of oil or gas that can be profitably recovered. This is because the increased value of the production stream offsets the higher development costs for smaller fields with higher unit (per-barrel) costs. At very high (perhaps unrealistic) prices, the economically recoverable resource curves approach the conventionally recoverable endowment. Oil and gas prices are linked in the model using a volume factor of 5.62 thousand cubic ft per barrel (Mcf/bbl) and BTU-price discount factor (0.80).

Price-supply curves are fully risked resource volumes, including: 1) the geologic risk that hydrocarbons are pooled and recoverable from reservoirs; and 2) the economic risk that the pools, if discovered, would generate a positive cash flow through their field life. Possible investment risk associated with access and regulatory restrictions are not accounted for in the PRESTO model. However, potential costs associated with access limitations and mitigation requirements are treated in a later analysis for leasing and development scenarios. The price-supply analysis does not imply that all of the hydrocarbon resources will be converted to producing reserves in a specific timeframe, only that they are theoretically present and could be commercially viable if discovered. In the PRESTO model, all pools are "discovered" and developed by simulation. However, historical experience has shown that it is unlikely that enough wells will be drilled to completely evaluate the resource potential of any area. With a lesser exploration effort, the estimated resource potential may never be realized as actual production.

As discussed previously, the mean geologic resource endowments (undiscovered, conventionally recoverable) are 9,101 MMbbl of oil and 37.309 Tcf of gas for the combined Northwest and Northeast NPR-A Planning Areas. For purposes of discussion, crude oil and gas-derived liquids are counted as "oil." Non-associated gas and associated/dissolved gas are counted as "gas." The price-supply curves for oil and gas (Figure App-04 and Figure App-05) indicate a clear correlation to market prices. No resources are economically recoverable at prices below approximately $15.00/bbl ($2.14/Mcf). At a benchmark price of $18.00 ($2.56/Mcf) only 134 MMbbl of oil and 0.212 Tcf of gas are economically viable, representing 1.5% (oil) and 0.5% (gas) of the total geologic resource base. The fraction of economically recoverable resources rises quickly at prices above $20.00/bbl ($2.85/Mcf), increasing more than four-fold at a price of $25.00/bbl ($3.56/Mcf). At $27.00/bbl ($3.84/Mcf), at least one economic pool was discovered in each of the 1,000 simulation runs. At a benchmark price of $30.00/bbl

($4.27/Mcf), 5,697 MMbbl of oil and 15.830 Tcf of gas are economically viable, representing 63% (oil) and 42% (gas) of the mean geologic resource base.

Commodity prices have a major influence on economically recoverable volumes. Higher commodity prices invariably lead to higher resource recovery. Because the resource estimates will be used primarily for lease sale planning and environmental impact analysis, some reasonable price brackets were selected. With regard to probability levels, the mean resource case is the most relevant because it represents the average statistical outcome of the economic analysis. In economic terms, the risked mean case is often referred to as the "expected value." Another advantage to using the risked mean is that components (individual plays, sub-areas, and other items) can be added and subtracted without violating statistical principles.

Two price levels were used to bracket economically recoverable oil and gas volumes. The $18.00/bbl price represents normal, historical conditions and the $30.00/bbl price represents improbable, high-side conditions. Long term prices above $30.00/bbl could prompt advancements in technology as well as changes in energy consumption that would affect many of the economic assumptions in the model. It is important to remember that the bracketing prices represent long-term averages of real (inflation-adjusted) values considering that a typical field life could span decades. These bracketing prices should not be compared to short-term price spikes that occur over a few months or years. The Energy Information Agency (U.S. Dept. of Energy, 2001) provided a 2010 forecast of a "low price" ($17.64/bbl, in year 2000 dollars) and "high price" ($30.01bbl, in year 2000 dollars) level. These EIA prices correspond to $19.28 and 32.79 in 2003 dollars.

The resource allocation for each play in the combined Northwest NPR-A and the Northeast NPR-A Planning Areas is given in Table App 7-02 using the bracket prices of $18.00/$2.56 and $30.00/$4.27, respectively. The oil and gas volumes listed in Table App 7-02 were gathered from the PRESTO printout (not picked from price-supply graphs). Using the low-price ($18.00/$2.56), only two of the eleven plays contain 97% of the undiscovered economic oil resources and 98% of the undiscovered economic gas resources. The Beaufortian, Barrow Arch-East play is an extension of the recent discoveries at Alpine and adjacent areas in Northeast NPR-A Planning Area. The Sadlerochit, Barrow Arch-East play has similarities to the rich fields surrounding the super-giant Prudhoe Bay field. Using the high-price bracket ($30.00/$4.27) six plays contribute to the economic resource base, however the Beaufortian play still dominates the economic oil (73%) and gas (55%) potential. Two plays located in the southern part of the assessment area (Brookian Foldbelt and Fortress Mountain) hold estimated gas resources amounting to 32% of the total economic resources at $4.27/Mcf.

F. MMS/BLM and U.S. Geological Survey Assessments

Summaries of the results of a U.S. Geological Survey (USGS) resource assessment of NPR-A were released as web site postings in May 2002 (Bird and Houseknecht, 2002a; 2002b). A comparison of the USGS and MMS-BLM assessments completed in 2002 shows that both assessments reach the same fundamental conclusions. Perceived differences between the USGS and MMS-BLM assessments arise mainly from the different geographic areas considered by the assessments. The USGS assessed the entire NPR-A while the MMS-BLM assessed a subarea of NPR-A (the combined Northwest and Northeast Planning Areas). The combined Northwest and Northeast Planning Areas occupy 62 percent of the land area of NPR-A. Further complicating direct comparisons of these assessment results is the fact that the combined Northwest and Northeast Planning Areas enclose the oil-prone areas of northern and eastern NPR-A and exclude some of the gas-prone areas of southern and western NPR-A. These differences in land areas and geological biases lead to some minor differences in results of the MMS-BLM and USGS assessments. If these differences are set aside, the results of the USGS and MMS-BLM assessments are seen to be broadly consistent in the critical areas of: (1) overall oil and gas resources proportioned to the areas assessed; (2) identification and quantification of dominant plays; (3) forecasts for maximum sizes of hypothetical, undiscovered oil and gas pools; and (4) estimated quantities of economically recoverable oil.

Overall Oil and Gas Resources Proportioned to the Areas Assessed. The 2002 USGS assessment (Bird and Houseknecht, 2002a) estimated that the entire Federal part of NPR-A (excludes State of Alaska waters along the coast and Native lands within NPR-A) may contain mean undiscovered resources of 9.3 billion barrels (Bbbl) of oil and 59.7 trillion cubic feet (Tcf) of non-associated (no oil present) natural gas. To obtain the total resource endowment, add 1.37 Bbbl of natural gas liquids (NGL) and 10.3 Tcf of associated gas (solution and gas cap gas), reported separately as part of the USGS assessment by Schuenemeyer (2003). Total undiscovered resources of 10.67 Bbbl oil (crude oil plus NGL) and 70.0 Tcf gas (non-associated plus associated) were obtained for the 2002 USGS assessment of the entire Federal part of NPR-A.

The 2002 MMS-BLM assessment (this study) estimated that the combined Northwest and Northeast Planning Areas contain mean undiscovered resources of 9.101 Bbbl oil (crude oil plus NGL) and 37.309 Tcf gas (non-associated plus associated). Thus, the outward volumetric differences between the two groups amount to 17% more for oil and 88% more for gas in the USGS results.

The MMS-BLM and USGS assessments are more consistent if the different sizes and petroleum characteristics of the assessed areas are accounted for. The MMS-BLM assessment area captures 62% of the entire Federal area of NPR-A. The MMS-BLM results for the combined Northwest and Northeast Planning Areas indicate 9.101 Bbbl or 85% of the 10.67 Bbbl NPR-A (Federal part) oil/NGL endowment reported by the USGS. The proportion of oil (85%) associated with the MMS-BLM assessment area exceeds the proportion of NPR-A land surface area (62%) captured by the MMS-BLM assessment because the northern and eastern parts of NPR-A are relatively oil prone. Both assessments indicate that the northern and eastern parts of NPR-A are enriched in oil resources relative to gas resources. Considering natural gas, the MMS-BLM results for the combined Northwest and Northeast Planning Areas indicate 37.309 Tcf or 53% of the 70.0 Tcf NPR-A (Federal part) total gas endowment reported by the USGS. This is consistent with the fact that the USGS assessment includes the gas-prone 38% of the NPR-A land area that lies outside the combined Northwest and Northeast Planning Areas, and complements the geological bias of the combined Planning Areas toward oil. The distortions of assessment results caused by geological bias are diminished if the gas resources in both assessments are converted to oil-equivalent resources by setting each barrel of oil equal to 5,620 cubic feet of gas on an energy-equivalent basis. The MMS-BLM assessment thus finds a total endowment of 15.740 Bbbl-equivalent, 58% of which is oil. By the same process, the USGS assessment finds a total endowment of 23.126 Bbbl-equivalent, 46% of which is oil. The MMS-BLM energy-equivalent endowment is 68% of the USGS energy-equivalent endowment, fairly close to the proportion of NPR-A land area (62%) captured by the combined Northwest and Northeast Planning Areas.

Identification and Quantification of Dominant Plays . The MMS-BLM and USGS assessments both view the Alpine plays (those correlative to the rocks containing the 500 MMbbl Alpine oil field) as the dominant plays in NPR-A. The Alpine plays offer the highest resource potential and are driving current exploration programs in NPR-A. Both assessments use the term Beaufortian to identify the groups of plays that are correlative to the Alpine oil field. For the MMS-BLM assessment of the combined Northwest and Northeast Planning Areas, 56% (5.068 Bbbl) of the oil endowment of the assessment area (9.101 Bbbl) is associated with Beaufortian plays. For the USGS assessment of the entire NPR-A (Federal land, State waters, and Native lands), 69% (7.233 Bbbl) of the overall oil endowment (10.558 Bbbl) is associated with Beaufortian plays (these oil quantities are from Bird and Houseknecht, 2002b, and do not include NGL).

Forecasts for Maximum Sizes of Hypothetical, Undiscovered Oil and Gas Pools. The sizes of the undiscovered oil and gas pools forecast by the MMS-BLM and USGS assessments are consistent. This is important because the sizes of the largest hypothetical oil pools are critical to success in the economic modeling. Individual pools must support a costly infrastructure, and profitable development economics require a large asset. A play with a large overall oil endowment but consisting of many small pools will have no economic value.

In the 2002 MMS-BLM assessment of the combined Northwest and Northeast Planning Areas, the largest hypothetical undiscovered oil pool is forecast to contain 634 MMbbl (on average, within a possible range from 128 to 1,610 MMbbl). This pool is associated with play 8 (a Beaufortian play correlative to the Alpine oil field of

500 MMbbl). The next largest oil pool in the same play contains 441 MMbbl. The 2002 USGS assessment of NPR-A does not report specific pool sizes but identifies one oil pool in the size range of 512 to 1,024 MMbbl, associated with a Beaufortian play correlative to the Alpine oil field (Bird and Houseknecht, 2002a:figs. 5, 6). Both assessments forecast one oil pool in the size range of 512 to 1,024 MMbbl as the largest in their respective assessment areas. In both assessments, the largest pools are associated with Beaufortian plays.

In the 2002 MMS-BLM assessment of the combined Northwest and Northeast Planning Areas, the largest hypothetical undiscovered gas pool is forecast to contain 2.861 Tcf gas (mean size, with a possible range from 0.279 to 8.912 Tcf). This pool is associated with MMS-BLM Beaufortian play 8. The 2002 USGS assessment identified approximately 8 hypothetical undiscovered gas pools in the size range from 1.536 to 12.288 Tcf gas (Bird and Houseknecht, 2002a:fig. 5). The USGS assessment forecasts more gas pools of the largest size classes mostly because it includes a large gas-prone part of NPR-A that lies outside the MMS-BLM assessment area.

Estimated Quantities of Economically Recoverable Oil and Gas. The economic results of the MMS-BLM and USGS assessments are also quite consistent. The 2002 MMS-BLM economic assessment of the combined Northwest and Northeast Planning Areas forecasts that 5,697 MMbbl of oil and NGL (mean) will be economically recoverable at a market oil price of $30/bbl. The 2002 USGS economic assessment of NPR-A forecasts that 5,720 MMbbl of oil and NGL (mean) will be economically recoverable at a market oil price of $30/bbl (Attanasi, 2003:tbl. 4; Bird and Houseknecht, 2002:fig. 7). The economic results of both assessments are essentially identical and reflect the fact that both assessment areas capture those areas and plays that are most promising for economic discoveries.

The MMS-BLM reports economically recoverable gas estimates, largely because of the gas resources associated with the Beaufortian plays and the assumption that a transportation system will be available to receive new gas supplies from NPR-A in the foreseeable future. The 2002 USGS assessment did not report economic quantitites of natural gas because the major gas transportation system does not exist at the present time.

Summary. The results of the MMS-BLM and USGS assessments confirm a shared view of the fundamental petroleum attributes of NPR-A, despite the fact that two independent teams assessed different areas using different computer models. Independent studies must inevitably produce some differences in detail, but both assessments strongly agree on the fundamental geological drivers of future oil development in NPR-A.

G. Endnotes

[1] Using a geothermal gradient of 28° C/km, the maximum reported among wells in the southern Colville basin by Deming et al. (1992:table 1).

[2] Surface of equal thermal maturity, in this case represented by equal values of vitrinite reflectance, a property of particles of organic matter that is measured with special microscopic equipment in the laboratory on prepared well samples.

[3] No oil sources have been recognized among the pre-Triassic sequence north of the Brooks Range.

[4] Permian rocks occur at the top of the Lisburne Group in the Inigok well, just south of the play area (Molenaar, Bird, and Collett, 1986).

[5] Average porosity 22% in Prudhoe Bay field (Melvin and Knight, 1984; AOGCC, 1994:p. 95).

[6] Uppermost sandstone in Kuparuk field (Carman and Hardwick, 1983), but here occurring as an unconformity sandstone locally mantling the Lower Cretaceous unconformity.

[7] Generally entirely Jurassic in age to north in correlative Arctic Platform (Plays 9 and 18) and Barrow arch (Plays 8 and 17) plays.

[8] Specifically, the Kurupa-Umiat lobe of Huffman, Ahlbrandt, and Bartsch-Winkler (1988:fig. 13.11).

[9] Lower Cretaceous sandstone resting directly upon the Lower Cretaceous unconformity (LCU).

[10] Specifically, the Corwin lobe of Huffman, Ahlbrandt, and Bartsch-Winkler (1988, fig. 13.11).