Chapters P1 – P10 Play Descriptions for Ten Plays

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Chapter P1 Topset Play

by David W. Houseknecht and Christopher J. Schenk

This play includes topset seismic facies identified within Paleocene through Miocene strata in the undeformed part of the ANWR 1002 area (Fig. P1-1). Topset facies include marine shelf, deltaic, and non-marine sedimentary rocks based on analysis of seismic data, outcrops, wire-line well logs, and cores (Houseknecht and Schenk, Chap. BS). Figure AO6 shows the play location and lists its outstanding characteristics.

Source. The most likely hydrocarbon sources for the Topset play are the Hue Shale (Hue-Thomson(!) petroleum system) and Tertiary mudstones within Brookian strata (Canning-Sagavanirktok(?) petroleum system) (Magoon and others, Chap. PS; Houseknecht and Hayba, Chap. HG). In addition, there is a small possibility that hydrocarbons generated in the Shublik Formation (Ellesmerian(!) petroleum system) charged the Topset play (Magoon and others, Chap. PS). Charging of the Topset play from any of these sources could have occurred by migration up dip along growth faults and clinoforms (preserved bedding surfaces within marine slope facies), or by vertical migration through bottomset and clinoform facies. The viability of charge associated with at least two of these petroleum systems (Hue-Thomson(!) and Canning–Sagavanirktok(?)) is demonstrated by geochemical analysis of oils extracted from outcrop samples of topset facies and recovered from topset facies in exploration wells drilled in State and Federal waters offshore from the ANWR 1002 area (Magoon and others, Chap. PS).

Reservoir. Sandstones within the Topset play are some of the best reservoir-quality rocks in the ANWR 1002 area. They were deposited in a spectrum of marine shelf through non-marine depositional systems, and include hummocky bedded marine shelf facies and cross-bedded deltaic and fluvial channel facies (Houseknecht and Schenk, Chap. BS). Based on inferred depositional environments, potential reservoir rocks are likely to be lenticular in nature. Lateral continuity may range from equidimensional sandstone bodies several miles wide in marine shelf facies to linear sandstone bodies less than one mile and a few miles long in fluvial channel facies. Sandstones of the Topset play rarely display less than 10 percent porosity and commonly contain units whose porosity and permeability range from 20 to 30 percent and 500 to 1,000 millidarcies, respectively (Nelson, Chap. PP).

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Trap. Several types of traps have been observed within the Topset play, including anticlines, “growth anticlines”, growth faults, up-dip shelf-edge pinchouts, and stratigraphic lenses (Fig. P1-1). (1) Anticlines displaying apparent four-way closure were mapped within the play area and, although relatively few in number, they represent some of the largest trap geometries observed in the Topset play. Some anticlines occur just north of the trend of the Marsh Creek anticline and appear to be genetically related to that structural trend, whereas others occur farther north and appear to be related either to deeper folding, to incipient thrust faulting that is occurring offshore, or to compaction over “accommodation sills.” (2) The term “growth anticline” is used for structures that appear to have formed as the result of stratal rollover associated with rotational growth faulting, and do not appear to be related to deeper seated structures. “Growth anticlines” are especially common along the trends of Eocene and Oligocene shelf edges (Houseknecht and Schenk, Chap. BS, Fig. BSG11). Many display four-way closure and represent some of the largest potential traps observed in the Topset play. (3) Growth faults represent the most common trap geometry in the Topset play. They display high dips and evidence of syndepositional movement within topset facies, and typically become listric within underlying clinoform (marine slope) seismic facies. Although present throughout the play area, growth faults tend to increase in number and displacement northeastward (approximately perpendicular to the shelf edges shown in Figure BSG11), apparently in relation to the increased thickness of marine slope facies. Potential traps formed by growth faulting span the complete range of sizes considered in this assessment. (4) Up-dip shelf-edge pinchouts occur where topset facies terminate against either regional dip or local structural dip. In some cases, the inferred pinchout is simply defined by the shelf-edge “rollover” that occurs where individual topset reflectors merge into clinoforms. In other cases, the inferred pinchout appears to be caused by slumping or erosion of the shelf edge, resulting in truncation of a thicker interval of topset facies. Both types of shelf edge features are illustrated by Houseknecht and Schenk (Chap. BS). These up-dip shelf-edge pinchouts are potentially large traps, although three-dimensional trap geometries are difficult to document with a widely spaced seismic grid. (5) Stratigraphic lenses of sandstone are present in both marine shelf and deltaic-fluvial channel facies within the Topset play, as demonstrated by outcrop studies. These stratigraphic lenses generally are too small to resolve with existing seismic data, although indications of bars and channels are visible on some seismic lines. This trap type probably represents trap sizes that are near, or below, the minimum in-place accumulation size of this assessment (50 MMBOE).

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Timing. The timing of trap development relative to oil generation is generally favorable. Oil generation in the Hue Shale (Hue-Thomson(!) petroleum system; Magoon and others, Chap. PS) probably occurred about 40 Ma along the southern boundary of the Topset play, migrated northward through time, and occurred about 10 Ma in the northwest corner of the play area (Houseknecht and Hayba, Chap. HG, Fig. HG19). Oil generation in the Canning Formation (Canning–Sagavanirktok(?) petroleum system; Magoon and others, Chap. PS) may have started in the eastern and northern part of the play area about 10 Ma and is likely ongoing today. These inferences suggest that even the youngest traps (in Miocene topset facies) in the northern and eastern parts of the Topset play formed prior to oil generation from two potential source rocks located in those areas. In contrast, traps in the southwestern part of the play area may have formed after oil generation from the Hue Shale in that area. However, in outcrops along the Canning River, just south of the southwestern corner of the ANWR 1002 area topset facies involved in structures associated with uplift of the Sadlerochit Mountains are stained with oil geochemically correlated to the Hue Shale (Magoon and others, Chap. PS; Lillis and others, Chap. OA). This observation suggests that timing between oil migration and trap development is favorable, even in the southwestern part of the play area (see Hayba and others, Chap. FF, for additional discusion).

Play Attributes. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations pertain to Tables RS1a and RS1b.

Play Probability. Based on Kuvlum and Hammerhead discoveries, play probability is 1.0.

Prospect Probabilities. A prospect probability of 0.9 for charge is based on the evidence for two petroleum systems that may have charged the play (Hue-Thomson(!) and Canning-Sagavanirktok(?); Magoon and others, Chap. PS) and abundant evidence for oil migration into topset facies throughout the undeformed area. A probability of 0.6 for reservoirs is based on the common occurrence in wells and outcrops of at least 50 feet of sandstone displaying at least 15% porosity, and the inferred presence of similar reservoir rocks in the play area based on seismic analysis. A probability of 0.5 for trap is based on the common occurrence of stratigraphic trap geometries that require sealing growth faults in a sand-rich section, and the fact that most potential traps are observed on one seismic line and the inability to observe closure in the third dimension represents risk. Although timing of trap development relative to oil generation is generally favorable, the possible development of traps after oil generation in parts of the play area represents additional risk.

Reservoir Thickness. The probability distribution for reservoir thickness is based on interpretation of well logs from State land and offshore, outcrop measured sections, and gross interval thickness of topset facies involved in potential traps on seismic data. Thickness of porous sandstone was measured directly from well logs and outcrops. Gross thickness of topset facies involved in potential traps was measured from seismic data, and then a conservative percentage sandstone was assumed to estimate potential thickness of reservoir facies. Based on these observations, minimum, median, and maximum reservoir thicknesses were estimated to be 50, 150, and 500 feet, respectively.

Area of Closure. Thickness and width of potential trap geometries were measured directly from seismic data. Where crossing seismic lines intersect potential traps, three dimensional geometries were mapped and measured. Where no crossing seismic lines intersect potential traps, aspect ratios were assumed for various trap types based on geologic analogues. Minimum, median, and maximum areas of closure for this probability distribution were estimated to be 500, 2,000, and 20,000 acres respectively.

Porosity. This probability distribution is based on cumulative porosity distributions from well logs in 15 penetrations of topset facies within the Sagavanirktok Formation (Fig. PP1j) show median values ranging from 10 to 34%. Porosity measurements from core and outcrop samples display a similar range of values. The minimum was set at 15% to reflect the porosity considered necessary to produce a 50 MMBO in-place accumulation. The median was set at 25% based on measured porosity of oil stained sandstones from wells and outcrops. The maximum was set at 40%, which is representative of the highest values measured in four wells.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in “Water Saturation” by Nelson (Chap. PP). The value of water content (5%) chosen for this play is representative of fine to very fine-

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grained sandstone. For example, at the median porosity of 25%, the water saturation is 0.05/0.25, or 20%.

Trap Fill. Trap fill estimates are based on the observations that topset traps are relatively small in size and that abundant evidence exists for oil migration into topset facies. Minimum, median, and maximum values for this probability distribution were set at 30%, 70%, and 100% to reflect these observations. The minimum value represents a trap fill percentage required for a 50 MMBO in-place accumulation.

Trap Depth. A probability distribution for depth of potential traps was estimated from depth-converted seismic sections. Minimum, median, and maximum values are 1,000, 5,000, and 10,000 feet, respectively.

Number of Prospects. Potential traps were identified on seismic sections, mapped, and counted. Potential traps confirmed to display four-way closure based on crossing seismic lines were all counted; those observed in two-dimensions only (i.e., one seismic line) were counted and that number was reduced by 50% based on the assumption that approximately half would display four-way closure. The total of these observations represents the minimum number of 40. The median number for this probability distribution was set at 80 based on estimating how many traps of a size sufficient to hold 50 mmbo in-place may be present between seismic lines. The maximum number was set at 125 based on projecting the possible abundance of small stratigraphic traps concentrated along shelf edge features mapped throughout the undeformed area.

Chapter P2 Turbidite Play

by David W. Houseknecht and Christopher J. Schenk

This play includes portions of clinoform (marine slope) and bottomset seismic facies identified within Paleocene through Oligocene strata in the undeformed part of the ANWR 1002 area (Fig. P2-1). Prospective turbidite facies include portions of submarine fan mounds and aprons, and inferred submarine channels incised into older deposits. These inferences are based on analysis of seismic data, outcrops, wire-line well logs, and cores (Houseknecht and Schenk, Chap. BS). Location of the play and a summary of play characteristics is shown in Fig. AO7.

Source. The most likely hydrocarbon sources for the Turbidite play include the Hue Shale (Hue-Thomson(!) petroleum system) and Tertiary-age mudstones within Brookian strata (Canning-Sagavanirktok(?) petroleum system). In addition, there is a small possibility that hydrocarbons generated in the Shublik Formation (Ellesmerian(!) petroleum system) charged the Turbidite play. Inasmuch as turbidite facies occur primarily near the base of marine slope facies and within bottomset facies, they are in ideal positions to be charged by the Hue-Thomson(!) and/or Canning-Sagavanirktok(?) petroleum systems. The inferred reservoir facies are either in direct contact with, or lie a short distance above, inferred source rocks. The viability of charge is demonstrated by oil-stained sandstones from outcrops and cores, and by oils tested from exploration wells drilled near the ANWR 1002 area (Magoon and others, Chap. PS).

Reservoir. Sandstones within the Turbidite play are of moderate to good reservoir-quality. Within the spectrum of sandstone facies that occur within the turbidite depositional system, it appears that channelized sandstone facies have the best reservoir potential (Houseknecht and Schenk, Chap. BS). Amalgamated channel facies commonly display “blocky” wire-line log character and represent a concentration of relatively clean (clay-free) sandstone. In exploration wells near ANWR and in outcrop, inferred turbidite channel sandstones attain maximum thickness of more than 100 feet. However, such channel sandstones may be relatively narrow and, therefore, reservoir facies may require high data density (e.g., 3-D seismic) to define. Although relatively fine grained and clay-rich compared to sandstones of the Topset play, sandstones of the Turbidite play commonly contain units with porosity and permeability in the range of 10 to 20 percent and 100 to 500 millidarcies, respectively (Nelson, Chap. PP).

Trap. Because of their stratigraphic nature, potential traps within the Turbidite play are difficult to characterize accurately due to the density and resolution of available seismic data. Two major trap “indicators” were identified, mounds and channels (Fig. P2-1). Mounded seismic expressions are common within the clinoform and bottomset seismic facies, and many of these features are inferred to be submarine fan deposits (Houseknecht and Schenk, Chap. BS). However, it is likely that the mounds identified on seismic sections represent the overall deposits of submarine fans. Reservoir-quality sandstones probably are limited to the channelized “skeleton” of those fan deposits. Features interpreted as incised channels also are recognized on seismic sections (Houseknecht and Schenk, Chap. BS). These features are characterized by channel-shaped truncation of reflectors within older deposits, and by either channel-shaped or inclined internal reflectors (inferred accretionary bedding). In both mounded and channelized features, we infer that sandstone reservoir facies are encased in mudstone facies thereby forming stratigraphic traps.

Timing. Timing of trap development relative to oil generation is favorable throughout the play area. Most of the potential in this play is associated with Paleocene and Eocene aged turbidite facies. Oil generation from the Hue Shale commenced about 40 Ma (Late Eocene) within the play area, and oil generation from younger source rocks in the Canning Formation would have occurred more recently (Houseknecht and Hayba, Chap. HG; Magoon and others, Chap. PS). Thus, most stratigraphic traps in the Turbidite play pre-date most oil generation from the Hue Shale and any younger source rocks.

Play Attributes. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations pertain to Tables RS2a and RS2b.

Play Probability. Based on the Badami field and the Alaska State A-1 discovery well, play probability is 1.0. The Sourdough well may also represent a discovery in this play, although well information remains proprietary and this cannot be confirmed.

Prospect Probabilities. A prospect probability of 0.9 for charge is based on the close proximity of source rocks, the likelihood of two petroleum systems

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that may charge the play (Hue-Thomson(!) and Canning-Sagavanirktok(?); Magoon and others, Chap. PS), and abundant evidence for oil migration into turbidite facies throughout the undeformed area. A probability of 0.4 for reservoir is based on the uncertainty of the presence of channelized turbidite facies in seismically mapped prospects, and the uncertainty that sandstones will be sufficiently porous for a 50 MMBO in-place accumulation. A probability of 0.6 for trap is based on the predominance of stratigraphic trapping geometries, in which porous reservoir facies are completely encased in mudstone.

Reservoir Thickness. The probability distribution for potential reservoir thickness is based on observations of well logs from State land and offshore, outcrop measured sections, and gross interval thickness of turbidite facies on seismic data within the play area. Thickness of porous sandstone was measured directly from well logs and outcrops. Gross thickness of turbidite facies involved in potential traps was measured from seismic data, and then a sandstone percentage was used to estimate potential thickness of reservoir facies. Based on these observations, minimum, median, and maximum reservoir thicknesses were estimated to be 50, 120, and 400 feet, respectively.

Area of Closure. Thickness and width of potential trap geometries were measured directly from seismic data. Where crossing seismic lines intersect potential traps, three dimensional geometries were mapped and measured. Where only one seismic line intersects potential traps, aspect ratios were assumed for various trap types based on geologic analogues. Minimum, median, and maximum areas of closure for this probability distribution were estimated to be 1,000, 4,000, and 30,000 acres respectively.

Porosity. The probability distribution for porosity is based on cumulative porosity distributions from well logs in 13 penetrations of turbidite facies in the Canning Formation (Fig. PP1i), which show median values ranging from 7 to 21%. Porosity measurements from core and outcrop samples display a similar range of values. The minimum was set at 10% to reflect the porosity considered necessary to produce a 50 MMBO in-place accumulation. The median was set at 18% based on measured porosity of oil-stained sandstones from wells and outcrops. The maximum was set at 30%, which is representative of the highest values measured in four wells.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in “Water Saturation” by Nelson (Chap. PP). The value of water content (6%) chosen for this play is representative of very fine-grained sandstone. For example, at the median porosity of 18%, the water saturation is 0.06/0.18, or 33%.

Trap Fill. Trap fill estimates are based on the close proximity of potential traps to source rocks, the relatively small size of potential traps, the predominance of stratigraphic traps (most commonly, lenticular sandstone completely encased in mudstone), and the abundant evidence of oil migration into turbidite facies. Minimum, median, and maximum values for this probability distribution were set at 40%, 85%, and 100% to reflect these observations.

Trap Depth. A probability distribution for depth of potential traps was estimated from depth-converted seismic sections. Minimum, median, and maximum values are 7,000, 12,500, 18,000 feet, respectively.

Number of Prospects. Potential traps were identified on seismic sections, mapped, and counted. All seismically identified trap geometries were counted based on the assumption that most are stratigraphic traps and structural closure is not necessary. However, the seismic expressions used to identify potential traps (e.g., inferred submarine fan mounds) are typically mud-rich and may not contain a large proportion of reservoir quality sandstone. For this reason, the number of mapped features was reduced by more than half to establish the minimum value of 25 prospects. The median was set at 60 for this probability distribution, which represents a conservative count of potential traps observed on the seismic data. The maximum was set at 100 based on the inferred depositional system (Houseknecht and Schenk, Chap. BS) and on the observation that many incised turbidite channels are too small to be resolved using available seismic data.

Chapter P3 Wedge Play

by David W. Houseknecht and Christopher J. Schenk

The Wedge play (Fig. AO8 shows location and characteristics) is based on the presence of a wedge of sediment that pinches out against the lower portion of a northeast-dipping, regional erosional surface at the base of an Eocene depositional sequence (Fig. P3-1). Internal characteristics of the Wedge play are based on seismic facies analysis and analogues because no well penetrations or outcrop exposures of this section are known to exist (Houseknecht and Schenk, Chap. BS).

Source. The most likely hydrocarbon sources for the Wedge play include the Hue Shale (Hue-Thomson(!) petroleum system) and Tertiary mudstones within Brookian strata (the Canning-Sagavanirktok(?) petroleum system). In addition, there is a small possibility that hydrocarbons sourced from the Shublik Formation (Ellesmerian(!) petroleum system) could have charged the Wedge play. The Wedge play occupies a stratigraphic position that is favorable to be charged by the Hue-Thomson(!) and/or Canning-Sagavanirktok(?) petroleum systems, particularly because the erosional surface at the base of the Wedge play may represent a migration pathway for any hydrocarbons generated from sources lower in the stratigraphic section. The inferred reservoir facies were deposited on the erosional surface, and therefore appear to lie in a direct migration pathway. Although there is no direct evidence for petroleum charge to the Wedge play, the presence of charge in the Topset and Turbidite plays, which frame the Wedge play in three dimensions, suggests that charge occurred in the Wedge play, also.

Reservoir. The nature of sedimentary facies within the Wedge play is unknown, except for inferences from seismic facies analysis and analogue considerations. Seismic analysis reveals that many reflectors onlap and pinch out up-dip against the erosional surface that defines the base of the wedge. Some of those reflectors display shingled relationships to one another and a few are bar-shaped. Moreover, the sandstone-rich depositional sequence D, a seismic equivalent to the Staines tongue of the Sagavanirktok Formation (Houseknecht and Schenk, Chap. BS), is truncated by the erosional surface in the up-dip (western) part of the play area. These observations suggest that sand-rich sediments eroded from the Staines tongue were recycled into the wedge. The depositional facies of that sandstone is less certain, but may include shoreface bars, incised channels (submarine or fluvial), and shingled turbidites. Although no direct evidence of reservoir quality is available, the close relationships between the depositional environments of the Wedge play and those of the Topset and Turbidite plays suggest that reservoir properties of the Wedge play may be intermediate between turbidite and topset sandstones.

Trap. Traps within the Wedge play are assumed to be stratigraphic in nature (Fig. P3-1). One trap type consists of up-dip pinchouts of sandstone facies that onlap the erosional surface at the base of the sequence. Another trap type consists of lenses of sandstone encased in mudstone within the wedge. A third trap type consists of shingled turbidite sandstones. In all three cases, seals would consist of mudstones interbedded with, and/or overlying, the potential reservoir rocks.

Timing. Timing of trap development relative to oil generation is favorable throughout the play area. Oil generation from the Hue Shale commenced about 40 Ma (Late Eocene) within the play area, and oil generation from younger source rocks in the Canning Formation would have occurred more recently (Houseknecht and Hayba, Chap. HG; Magoon and others, Chap. PS). Thus, the Eocene aged stratigraphic traps in the Wedge play pre-date most oil generation from the Hue Shale and any younger source rocks.

Play Attributes. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations pertain to Tables RS3a and RS3b.

Play Probabilities. There are no known accumulations in the Wedge play, so probabilities are assigned to the play attributes of charge, reservoir, and trap. Charge probability was set at 1 because of the close proximity of source rocks associated with two petroleum systems (Hue-Thomson(!) and Canning-Sagavanirktok(?); Magoon and others, Chap. PS) and the abundant evidence of oil charge in the closely associated Turbidite and Topset plays. Reservoir probability was set at 0.9 based on the inference that reservoir quality sandstones are present in seismic facies used to define this play. Trap probability was set at 0.8 based on the inferred presence of stratigraphic traps in this play. These attribute probabilities yield a play probability of 0.72.

Prospect Probabilities. A prospect probability of 0.9 for charge is based on the close proximity of source rocks, the likelihood of two petroleum systems charging the play (Hue-Thomson(!) and Canning-Sagavanirktok(?); Magoon and others, Chap. PS), and abundant evidence for oil migration into closely related turbidite facies throughout the undeformed area. A probability of 0.5 for reservoir is based on the seismic evidence suggesting the presence of sand-prone depositional systems and the seismic observation of erosionally truncated topset facies in stratigraphic positions favorable to provide sand to strata of the Wedge play. A probability of 0.5 for trap is based on the predominance of stratigraphic trapping geometries, in which porous reservoir facies are thought to be capped by mudstone (positive), combined with the observation that the viability of some prospects depends on unidirectionally dipping seals (negative). These attribute probabilities yield a prospect probability of 0.22.

Reservoir Thickness. Reservoir facies in the Wedge play may include incised channelized sandstone, shoreface sandstone, and shingled turbidite sandstone facies (Houseknecht and Schenk, Chap. BS). Minimum, median, and maximum values for this probability distribution of 50, 100, 400 feet (Table RS3a) are based on seismic observations and geologic analogues from other basins.

Area of Closure. Thickness and width of potential trap geometries were measured directly from seismic data. Where crossing seismic lines intersect potential traps, three-dimensional geometries were mapped and measured. Where one seismic line intersects potential traps, geologic analogues were used to estimate aspect ratios of various trap types. Minimum, median, and maximum areas of closure for this probability distribution were estimated to be 1,500, 5,000, and 30,000 acres respectively.

Porosity. No samples are available from potential reservoirs of the Wedge play. For this probability distribution, minimum, median, and maximum values were set at 10, 18, and 30%, respectively, based on inferred similarities to potential reservoirs in the Turbidite play.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The value of water content (4%) chosen for this play is representative of fine-grained sandstone. For example, at the median porosity of 18%, the water saturation is 0.04/0.18, or 22%.

Trap Fill. Trap fill estimates are based on the close proximity of potential traps to source rocks, the relatively small size of potential traps, and the predominance of stratigraphic traps (which essentially represent lenticular sandstone completely encased in mudstone). Minimum, median, and maximum values for this probability distribution were set at 40%, 85%, and 100% to reflect these observations. The minimum value represents a trap fill percentage required for a 50 MMBO in-place accumulation.

Trap Depth. A probability distribution for depth of potential traps was estimated from depth-converted seismic sections. Minimum, median, and maximum values are 5,000, 9,000, and 14,000 feet, respectively.

Number of Prospects. Potential traps were identified on seismic sections, mapped, and counted. All seismically identified trap geometries were counted based on the assumption that most are stratigraphic traps and therefore structural closure is not necessary. The minimum was set at 10 (Table RS3b) based on well defined trap geometries identified seismically. The median was set at 15 for this probability distribution based on the assumption that a handful of traps exist between seismic lines. The maximum was set at 35 based on the inferred depositional systems that may be present within the Wedge play and geologic analogues from other basins.

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Chapter P4 Thomson Play

by Christopher J. Schenk and D.W. Houseknecht

The Thomson play was developed to include a set of potential reservoirs in the Thomson sandstone (informal) in the northwestern part of the ANWR 1002 area (Fig. AO9 shows location and outstanding characteristics; Fig. P4-1 illustrates the play concept). The Thomson sandstone is known to contain significant quantities of hydrocarbons in the Point Thomson area immediately west of the play area defined in this study.

The Thomson play concept hinges on the presence of porous sandstones composed largely of detrital carbonate clasts derived from carbonate-bearing Franklinian-age basement rocks along the Mikkelsen High (Fig. P4-1). Like the Kemik Sandstone, the Thomson sandstone had a northerly provenance and was deposited on the Lower Cretaceous unconformity (LCU). The play boundary was postulated from the possible distribution of Franklinian-age carbonate basement rocks (Chap. AO). The Thomson sandstone is differentiated from the Kemik by the significant percentage of detrital carbonate grains as compared to the Kemik Sandstone with its predominance of chert as lithic grains. The Thomson and Kemik play areas overlap, as it is possible that erosion of several basement lithologies on the Mikkelsen High led to the deposition and preservation of sandstones with both Thomson and Kemik compositions in close proximity.

Charge. The source of hydrocarbons for the Thomson play is generally considered to be the Hue Shale (Hue-Thomson petroleum system) and possibly the Shublik Formation (Ellesmerian petroleum system) (Chap. PS). Charging of Thomson reservoirs by these sources would not require much migration as the source rocks and reservoirs are in close proximity. The occurrence of significant hydrocarbons in the Point Thomson area provides a justification for the charge probability of 1.0.

Reservoir. The reservoir for this play is the lithic-rich early Cretaceous age Thomson sandstone, which directly overlies the Lower Cretaceous unconformity. The lithic grains are predominantly carbonate, as distinct from the Kemik Sandstone. Examination of SP and density logs from wells in the Point Thomson area shows that the Thomson sandstone is remarkably uniform in character. The sedimentology of Thomson sandstones may range from coarse-grained graben deposit to a shoreline deposit. A probability of 1.0 for reservoir occurrence in this play is based on the proximity of carbonate-bearing Franklinian-age basement rocks similar to those that were a source of sediment to the Thomson sandstone in the adjacent Point Thomson area.

Trap. Trapping in the Thomson play is postulated to be of several styles, all of which are related to the Thomson sandstone being deposited on the flanks and crest of the low-relief Mikkelsen High. The Thomson may have been deposited in down-dropped blocks associated with a tensional regime created during rifting of the northern margin of Alaska, similar to structures in the Kuparuk River Field in the Prudhoe Bay area. Alternatively, the Thomson sandstone may have been deposited in incised valleys or topographic lows, and stratigraphic trapping would be related to sinuous incised channels that drained the Mikkelsen High during the Lower Cretaceous. The Thomson sandstone may also have been deposited as a transgressive sheet sand or as a shoreline sandstone, with stratigraphic trapping related to the updip pinch-out of sands that might possibly occur as isolated, backstepping transgressive sandstone parasequences. The probability of the presence of a potential trap necessary to produce a field of minimum size was estimated to be 1.0, given the proximity to the Point Thomson area.

Play Attributes. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations pertain to Tables RS4a and RS4b.

Play Probabilities. The probability assigned to each of the three play attributes (charge, reservoir, trap) was 1.0, given the fact that the Point Thomson area immediately west and adjacent to the Thomson play is a proven hydrocarbon area, and that the Thomson play in the 1002 area may simply be an eastward extension of the Point Thomson area. These probabilities yielded a play probability of 1.0.

Prospect Probabilities. The probabilities assigned to the prospect attributes (charge, reservoir, trap) were 0.9, 0.5, and 0.3, respectively. The charge probability was high, given the proximity to Point Thomson, and the reservoir probability was moderate, given the potential for Thomson-like lithologies to be present to the east of Point Thomson. The trap probability was low, reflecting the strong possibility that adequate trapping is not

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developed in the Thomson across much of the play area. These probabilities yield a total prospect probability of 0.14.

Reservoir Thickness. Estimates for the distribution of net reservoir thickness of the Thomson sandstone are constrained by several wells in close proximity to the northwest corner of ANWR 1002 (Chap. FP). In these wells the maximum thickness of the Thomson sandstone is essentially the reservoir thickness because of the high degree of hydrocarbon saturation. The minimum value of 40 feet reflects the thickness required to produce a field of a minimum size of 50 MMBOE in place. The median of 120 feet reflects the approximate average thickness of measured Thomson sandstone from wells adjacent to ANWR, and the maximum of 340 feet reflects the measured maximum thickness of Thomson sandstone in wells adjacent to ANWR.

Area of Closure. Estimates for the distribution of area of closure were developed using the concept that the number of prospects in the Thomson play could range from a single field extension of the existing Point Thomson area to the Thomson having several discrete structural and/or stratigraphic accumulations in the play area. The field extension concept led to the maximum area of closure of 22,000 acres. A minimum size of 1000 acres was based on the requirement of a minimum field size of 50 MMBOE in place.

Porosity. The distribution of porosity hypothesized for undiscovered Thomson reservoirs emulates the porosity distribution measured in six wells penetrating the Thomson sandstone in the Point Thomson area (Fig. PP1g). The minimum value of 10% reflects the porosity required to produce a minimum field size of 50 MMBOE in place, whereas the maximum value of 30% reflects the maximum measured porosity in the Thomson sandstone (Fig. PP1g). Porosity in the Thomson may be a combination of preserved intergranular porosity and secondary porosity after the dissolution of carbonate lithic grains and cements.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The value of water content (6%) chosen for this play is based upon analysis of well logs within the Thomson sandstone in the Point Thomson Unit 3 well (see “Reservoir Quality, Thomson sandstone”, Chap. FP). For example, at the median porosity of 18%, the water saturation is 0.06/0.18, or 33%.

Trap Fill. Estimates of the distribution for trap fill reflect the idea that the Thomson sandstone is in close proximity to the Hue source and that sandstones penetrated in the Point Thomson area to date are nearly saturated with hydrocarbons. These combine to provide an estimate of the high degree of trap fill in these stratigraphic traps (60% at F100, 85% at F50, and 100% at F0). The decrease in trap fill from 100% at F0 was postulated because of potential flushing of hydrocarbons updip towards the crest of the Mikkelsen High, away from reservoirs on the flanks of the Mikkelsen High.

Trap Depth. Estimates for the distribution of trap depths were established from the closest available depth-converted seismic data in the play area, and were also influenced by the results of the thermal maturity modeling (Chap. HG). Trap depth ranged from a minimum of 12,000 feet (F100) to a maximum of 18,000 feet, with a median (F50) of 15,000 feet. These lines of evidence provided an estimate of the possible hydrocarbon split in this play (90% oil, 10% gas).

Number of Prospects. The minimum number of prospects was based on the hypothesis that the Thomson play may simply be an extension of the Point Thomson area, whereas the maximum number of prospects is related to the possible presence of down-dropped block traps and incised channel-fill reservoirs on the flanks of the Mikkelsen High. The maximum number of 15 prospects was constrained by the relatively small Thomson play area.

Chapter P5 Kemik Play

by Christopher J. Schenk and David W. Houseknecht

The Kemik play was developed to encompass a potential set of undiscovered reservoirs in the Hauterivian Kemik Sandstone in the northwestern (undeformed) part of the ANWR 1002 area. The play is bounded to the south by the northwestern margin of the Marsh Creek Anticline and to the west and north by the ANWR boundary (see Fig. AO10 for location and play highlights). The Kemik Sandstone is one of several sandstones deposited on the Lower Cretaceous unconformity (LCU), an erosional surface of regional extent on the North Slope of Alaska (see Fig. P5-1 for cross-section of play concept). All of these sandstones, including the Kemik, Thomson, Kuparuk "C", and the Put River, had a northerly provenance and are included in the Ellesmerian stratigraphic sequence.

The Kemik Sandstone has been described from outcrops around the Sadlerochit Mountains and in the Ignek Valley south of the 1002 area and from scattered outcrops to the southwest of ANWR 1002, where the Kemik has been interpreted as a shallow-marine sandstone. To the north in the subsurface, the Kemik may contain a more coarse-grained proximal facies compared to the Kemik sandstones exposed in the outcrop belt to the south. The Kemik Sandstone is predominantly a lithic to sublithic arenite, with chert the predominant lithic grain type. In contrast, the coeval Thomson sandstone contains a high percentage of detrital carbonate grains, reflecting a provenance from carbonates in the Franklinian-age basement rocks that were exposed on the Mikkelsen High at the time of Thomson deposition. The source of the Kemik Sandstone was from more quartz- and chert-rich lithologies, such as those present in the Ivishak Formation, Lisburne Group, Kekiktuk Formation, and possibly argillaceous basement rocks, all of which were eroded from the Mikkelsen High during the formation of the LCU.

Charge. The source of hydrocarbons for the Kemik play is interpreted to be predominantly the Hue Shale of the Hue-Thomson(!) petroleum system (Chap. PS). Migration of hydrocarbons from the Hue Shale would have been either down into Kemik reservoirs immediately underlying the Hue in structural traps or laterally into Kemik reservoirs where the sandstones were updip from the Hue source, such as along the flanks of the Mikkelsen High. Good evidence exists from several localities along the outcrop belt that the Kemik Sandstone contains traces of hydrocarbons (Chap. FI), indicating that hydrocarbons may have migrated through or have been reservoired in the Kemik. Considerations of the thermal maturity and burial history of the Hue Shale and maximum burial depths of this play lead to a determination that 90% of the undiscovered hydrocarbons in this play are oil and 10% are gas (Chap. HG).

Reservoir. Several possibilities exist for potential Kemik Sandstone reservoirs in the 1002 area. The Kemik may be present as a coarser-grained, nearshore marine facies in the 1002 area relative to the very fine grained, shallow-marine sandstone that crops out to the south of the 1002 area, or the Kemik may be present only in structural low areas within the 1002 area, analogous to the "C" zone reservoirs in down-dropped blocks in the Kuparuk River field in the Prudhoe Bay area. The Kemik Sandstone may also be present in the 1002 area as incised valley fills, with the coarse-grained sandstones deposited in fluvial to estuarine environments. Alternatively, as interpreted by Mull (1987), there may be little reservoir-type Kemik sandstone in the 1002 area, as much of the area was interpreted as a back-barrier lagoon during Kemik deposition. The uncertainty of the presence of adequate Kemik reservoirs in 1002 is strongly reflected in the risk structure of this play. Analogue hydrocarbon accumulations for the Kemik occur in sandstones of the Kuparuk River Field "C" zone.

Trap. Three potential styles of trapping are postulated for the undiscovered Kemik reservoirs in the 1002 area. The first is a large stratigraphic trap associated with a possible stratigraphic pinch-out of the Kemik Sandstone to the north of the outcrop belt. The second possibility is a set of incised valley-fill reservoirs that are trapped by the overlying mudstones, and by sinuosity of the incised valleys. Third, the potential exists for the Kemik Sandstone to have been involved in down-dropped blocks associated with normal-fault displacements of the LCU. We interpreted this structural style from several seismic sections in the undeformed area.

Play Attributes. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations pertain to Tables RS5a and RS5b.

Play Probabilities. Charge and trap probabilities at the play level were assigned values of 1.0 because of analogue accumulations of hydrocarbons in sandstones of the Kuparuk River Field "C" zone, and because Kemik equivalent sandstones contain shows of hydrocarbons in several Mikkelsen

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Bay area wells west of the 1002 area. The play probability for the presence of adequate reservoirs was assigned a 0.3 because of the possibility that adequate Kemik reservoirs may not be present in much of the 1002 play area. These probabilities yielded a Kemik play probability of 0.3.

Prospect Probabilities. The probability that a random prospect in this play would be charged with hydrocarbons was estimated to be 0.9, indicating that the Hue Shale was an effective source rock (Chap. PS). The probability that a random prospect had adequate trapping for a field of minimum size was assigned a probability of 0.8, given the interpretation of the seismic data. The prospect risk for the presence of an adequate Kemik reservoir was assigned a probability of 0.2, reflecting the fact that adequate reservoir rock may not exist over a large part of the play area. These probabilities yielded a total prospect probability of 0.14.

Net Reservoir Thickness. Estimates of net thickness of undiscovered Kemik reservoirs ranged from 40 feet at the minimum to 180 feet at the maximum, with a median of 70 feet (Table RS5a). Approximately 40 feet of net reservoir thickness is required at the minimum to produce a field of 50 MMBOE in place. The maximum thickness of 180 feet reflects the estimation that a hypothetical northern coarse-grained facies would be thicker than the maximum sandstone thickness measured in outcrops to the south, which was about 100 feet, but less than the maximum gross measured thickness of the Kemik Sandstone, which was 280 feet in the Kemik 1 well southwest of ANWR. A median value of 70 feet reflects the estimation that not all of the gross sandstone thickness in the postulated coarser grained facies would be of potential reservoir quality.

Area of Closure. The estimates for area of closure are based upon interpretations of the seismic data and postulated stratigraphic traps in the Kemik play. A maximum size of 13,000 acres was based on the hypothesis that a large stratigraphic play may exist in potential reservoir sandstones of the Kemik in the undeformed 1002 area. The remainder of the distribution was estimated from the dimensions of structural off-sets on the LCU measured on the seismic lines, together with an aspect ratio of 3:1 and an estimation for prospects that fall between seismic lines. The minimum size of 1000 acres is required to produce a field size of 50 MMBOE in place.

Porosity. Estimates of porosity for the hypothetical northern coarse-grained facies of the Kemik ranged from a minimum of 10% to a maximum

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of 26%, with a median of 16%. The minimum of 10% reflects the porosity required to produce a minimum field size of 50 MMBOE in place. Cumulative porosity distributions from well logs in four penetrations of the Kemik Sandstone southwest of ANWR (Fig. PP1h) show median values from 3 to 10%. These values are from the very fine-grained quartz-cemented sandstone facies of the Kemik. If a coarser grained facies exists to the north in 1002, significant potential for both preserved intergranular porosity and for secondary porosity development upon dissolution of lithic grains and cements exists in the Kemik.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The value of water content (6%) chosen for this play is representative of very fine-grained sandstone. For example, at the median porosity of 16%, the water saturation is 0.06/0.16, or 37.5%.

Trap Fill. Given the proximity of the Kemik Sandstone to source rocks, the Kemik was considered to have a high percentage of trap fill, especially given the relatively small size of the structural traps and the possibility for stratigraphic traps close to the source. The distribution of trap fill (minimum of 60%, median of 85%, and maximum of 100%) reflects the interpretation that stratigraphic traps in this play would be nearly filled, as would the smaller structural traps.

Trap Depth. Estimates for the distribution of undiscovered trap depths is based upon an examination and interpretation of all available depth-converted seismic data in the undeformed area of 1002. The distribution ranges from a minimum of 12,000 feet to a maximum of 18,000 feet, with a median of 15,000 feet in the play area.

Number of Prospects. The number of prospects estimated for the Kemik play (Table RS5b) ranged from a minimum of 15, which reflects the most reliable interpretations of the seismic data set, to a maximum of 40, which includes the possibility of stratigraphic traps, between-line prospects, and structural traps beyond the available seismic grid. The median number of prospects is 24, which includes estimates for all on-line prospects.

Chapter P6 Undeformed Franklinian Play

by John S. Kelley, John A. Grow, and Philip H. Nelson

This play lies in the northwestern part of the 1002 area (Fig. AO11) where the Franklinian sequence was broadly warped but not significantly faulted or folded during Brookian folding and thrusting. This play is defined by the presence of Brookian sequence lying directly on Franklinian rocks; the Hue Shale and Canning Formation of the Brookian sequence are considered to be the primary source rocks as well as the seals in this play (Fig. P6-1). Other features of the Undeformed Franklinian play are summarized in Fig. AO11.

Pre-Mississippian metasedimentary basement rocks, referred to as the Franklinian sequence, underlie the Ellesmerian and Brookian sequences throughout the 1002 area (Bird, Chap. GG). The Franklinian is separated from the overlying sequences by a profound angular unconformity (called the PMU) which records a regional middle Paleozoic surface with little residual topographic relief. The southern boundary of this play, separating it from the Deformed Franklinian play, is defined by the northern boundary of the Thin-skinned Thrust-belt play, rather than a distinct boundary in the Franklinian itself. The eastern limit of the Undeformed Franklinian play is the saddle in the Hulahula low that marks the transition on to the west flank of the Aurora Dome (Fig. GG3). The shallowest Franklinian in the play area is 13,400 feet below sea-level in the northwestern part of the 1002 area , while the deepest Franklinian is in the northern part of the Hulahula low (~25,000 feet below sea level).

Where the Franklinian rocks crop out in the Sadlerochit and Shublik Mountains immediately south of the 1002 area, the Proterozoic Katakturak Dolomite is the dominant lithology with the bedding within the Franklinian forming a south-dipping homocline (Kelley, Chap. BR). In the west-central part of the play, the seismic fabric within the Franklinian indicates a west-northwest trending antiform that underlies the PMU. In the north-central 1002 area, the seismic fabric rolls over into a north-northeast dipping limb of this anticline (Figs. BR1 and SC2). Kelley (Chap. BR) interpreted these north-dipping fabrics as Katakturak Dolomite overlain by Lower Paleozoic argillites and carbonates unconformably (?) overlain by possibly Lower to Middle Devonian clastic rocks in the northern and northeastern part of the 1002 area. Drilling in State of Alaska lands just northwest of the 1002 area has encountered a complex mix of argillite, clastic, and carbonate lithologies of uncertain age (Dumoulin, Chap. CC).

Based upon thermal maturity considerations, traps above 17,000 feet are presumed to be oil-filled, whereas traps between 17,000 and 21,000 feet are presumed to be gas-filled. This play is considered a mixed oil (80%) and gas (20%) play.

Source and seal. There are no known source rocks within the Franklinian, and the oil and gas charge would have to come from overlying younger formations. Where the Ellesmerian sequence overlies the Franklinian, in the southern part of the 1002 area, the Franklinian is considered unlikely to be sourced by any rocks of the Ellesmerian (Shublik Formation) or Brookian sequences, because the hydrocarbons would have to migrate downward through several thousand feet of middle and lower Ellesmerian rocks. Therefore, this play is defined by the presence of Brookian sequence lying directly on Franklinian rocks, and the Hue Shale and Canning Formation of the Brookian sequence are considered to be the primary source rocks as well as the seals in this play (Fig. P6-1). There is also the possibility of charge from the Shublik Formation west of the 1002 area migrating a relatively short distance into this play area.

Reservoir properties. Although matrix porosity in the Franklinian is usually very low, good reservoirs are possible within fractured carbonates with secondary karst-enhanced porosity, and some secondary porosity in clastic units. Secondary porosity development during Cretaceous subaerial erosion along with fracture porosity induced by Brookian compression (without major faulting) are considered likely. Kelley (Chap. BR) has also suggested that primary porosity could exist in the inferred Devonian clastic section in the northern and northeastern part of the 1002 area.

Because of the generally poor resolution of the seismic reflection data within the Franklinian rocks, the lithologies are very difficult to interpret. Consequently, judging the probability of favorable reservoir characteristics is the most difficult aspect of assessing the Undeformed Franklinian play.

Trap. While the Deformed Franklinian play has folds and faults with thousands of feet of closure and offset, there are just two prospects within the undeformed Franklinian where small faults may have caused folds with a few hundred feet of closure. The other prospects in the Undeformed

Franklinian play appear to be residual topographic highs, in the range of 100 to 400 feet, on the Lower Cretaceous unconformity, that is, buried hills, as illustrated in Fig. P6-1. Stratigraphic and structural traps within the Franklinian are possible, but they are very difficult to map with the present widely-spaced seismic data, which have limited resolution within these metasedimentary rocks.

Volumetric Parameters. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). Rationales for Tables RS6a and RS6b are provided in the following paragraphs.

Net Reservoir Thickness. The vertical closures of the five mapped structures are 100, 200, 300, 600, and 1500 feet. Net reservoir thickness was estimated to range from 50 to 300 feet.

Area of Closure. The five structures revealed on a 1:100,000-scale structure contour map on the top of the pre-Mississippian have areas ranging from 2,000 to 11,000 acres. The range was limited to 2,000 acres at the low end by the 50 million barrel cutoff (Schuenemeyer, Chap. ME) and extended to 20,000 acres at the high end.

Porosity. Porosity values in basement carbonates in the Point Thomson-Flaxman Island area are in the 0 to 3% range with higher values in some thin intervals (see “Reservoir Quality in Basement Complex” by Dumoulin, Chap. CC). Drill stem tests in Alaska State F-1 and Alaska Island 1 (Fig. AO3) produced gas at rates of several thousand MCF per day (see “Summaries of Drill Stem Tests” by Nelson and others, Chap. WL, and Plate WL43). With this evidence of productive fractures, we envision that significant porosity enhancement can occur below the Lower Cretaceous Unconformity (Fig. P6-1), somewhat akin to porosity enhancement in the Lisburne (see “Reservoir Quality, Lisburne Group” in Nelson and Bird, Chap. FP). Consequently, a distribution of porosity values similar to the Lisburne Group in the Lisburne field (Fig. FP6) and greater than encountered in the Point Thomson area are possible.

Porosity values used in the probability distribution for this play ranged from 8 to 20% with a median of 14%. The minimum of 8% accomodates the 50 million barrel in-place cutoff (Schuenemeyer, Chap. ME). A low value of 0.2 for the probability of potential reservoir facies at the prospect level

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compensates for a porosity range which is acknowledged to be high for basement rocks.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The low value of water content (2%) chosen for this play is believed to be representative of carbonates. For example, at the median porosity of 14%, the water saturation is 0.02/0.14, or 14.3%.

Trap Fill. It is difficult to define the lower extent of a reservoir of enhanced porosity or fractured carbonate. The top of the trap is directly exposed to overlying Hue or Paleocene source rock, as in the case of the Thomson and Kemik plays. But, because a smaller fraction of the trap is directly exposed to source rock, the average trap fill is probably less than that of the Thomson or Kemik. For this reason and because of the adjustment of the porosity range cited above, a range of trap fill from 25 to 100 % with a median of 50% was chosen for this play.

Trap Depth. From a seismic map of the top of the Franklinian, the shallowest Franklinian lies at roughly 13,000 feet below sea level, while the deepest lies at roughly 25,000 feet. Depth to crests of five mapped prospects ranges from 15,200 to 18,500 feet, while the depth to base of the prospects ranges from 15,300 to approximately 20,000 feet. Based upon these data, the trap depth minimum was set to 13,000 feet, the median to 17,000 feet, and the maximum to 21,000 feet.

Number of Prospects. Only five features were revealed by the seismic survey, which serves as a minimum number of potential prospects. Other possible prospects could lie between seismic lines (widely spaced in this portion of the 1002 area) or could be controlled by the extent of porosity enhancement or stratigraphic traps rather than by basement relief. Although prospects smaller than 2,000 acres were precluded by the 50 million barrel cut-off, there is a significant possibility of more prospects between the relatively widely-spaced seismic lines in the northwestern part of the 1002 area. Therefore, the number of prospects in the assessment of this play was estimated to range from 6 to 24 with a median of 12.

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Play Probabilities.

Probability of charge (C) is set at 1.0. Because of the presence of hydrocarbons at Point Thomson in the Franklinian, the proximity to source rock, and the timing of generation, the charge at play level has a probability of 1.0.

Probability of reservoir (R) is set at 0.7. Upon testing, several Point Thomson wells have flowed water at significant rates. Limited primary porosity is expected, but secondary porosity due to fracturing and karst enhancement is expected somewhere within this play area.

Probability of timely trap formation (F) is set at 0.9. Because traps in the Franklinian appear to exist in the Point Thomson field, trap probability is high at the play level.

Prospect Probabilities.

Probability of charge (c) is set at 0.8. Proximity of source rock and timing of hydrocarbon generation provide high confidence for charge.

Probability of reservoir (r) is set at 0.2. Because the matrix porosity in the Franklinian is very low and fractures may not be present everywhere, high risk is assigned at the prospect level. This low probability compensates for a porosity distribution which meets the 50 million barrel in-place cut-off criterion.

Probability of timely trap formation (f) is set at 0.7. Low amplitude folding of Franklinian rocks and/or residual topographic relief in the Undeformed Franklinian play area will form relatively good traps. The Hue Shale and basal turbidites are expected to form good seals. Trap timing is considered favorable because the traps developed shortly after the deposition of sealing rocks.

Chapter P7 Deformed Franklinian Play

by John A. Grow, Christopher J. Potter, Philip H. Nelson, William J. Perry, Jr., and John S. Kelley

The Deformed Franklinian play includes hydrocarbon potential in basement carbonate rocks involved in thrust-faulted anticlines. Salient features of the Deformed Franklinian play are summarized in Fig. AO12, while the cross-section of Fig. P7-1 illustrates the play concept. The play lies between the Undeformed Franklinian play to the north and west, the Ellesmerian Thrust-Belt play to the south and southeast, and Niguanak High to the east.

As in the undeformed area, the play requires the presence of Brookian sequence lying directly on Franklinian sequence rocks. Otherwise, this play is similar to the Ellesmerian Thrust-Belt play (Chap. P9) in terms of structural style. The Deformed Franklinian play involves major basement folds and reverse faults with thousands of feet of relief (Fig. P7-1). The shallowest Franklinian rocks in the play area are 5,000 feet below sea-level at the southern 1002 boundary, while the deepest are in the Hulahula low at 31,000 feet below sea-level. The Franklinian rocks in this play have been faulted and folded into simple anticlines, plunging anticlines with possible up-dip fault closures, and monoclines bounded by one or more thrust faults.

The surface vitrinite reflection values are relatively high in this play area (Plate VR1). As discussed below, trap depths range from 5,000 to 31,000 feet subsea. The eastern half of the play area is deeper than 17,000 feet subsea, which is the base of the oil window inferred from thermal gradients in the closest wells. These depths indicate that the Deformed Franklinian play is primarily a gas play (20% oil and 80% gas).

Source. The concept of source for this play is quite similar to that of the Undeformed Franklinian play (Chap. P6). Because there are no known source rocks within the Franklinian, the oil and gas charge would have to come from overlying younger formations. The Cretaceous Hue Shale and Canning Formation of the Brookian sequence are considered to be the primary source rocks as well as the seals in this play (Fig. P7-1). There is also the possibility of charge from the Triassic Shublik Formation west of the 1002 area migrating a relatively short distance into this play area. As a third possibility, footwall source rocks (Hue shale and Canning Formation) can charge reservoir rocks in the hanging wall across reverse faults (Fig.

P7-1). Although dominantly gas, the overall probability of charge in this play is good, as in the Undeformed Franklinian play (Chap. P6).

Reservoir. As discussed in the Undeformed Franklinian play description (Kelley and others, Chap. P6), the Katakturak Dolomite is the dominant Franklinian lithology in the Sadlerochit Mountains and is inferred to be the dominant lithology within the Deformed Franklinian play. Because of intensive faulting and folding in this play area, fractured carbonate reservoirs are more likely in this play than in the Undeformed Franklinian play. Field observations and well data show: (1) production of water from the Katakturak (or Nanook Limestone) over a 600-foot interval in Canning River Unit A-1 at a rate of 600 barrels per day (see "Summaries of Drill Stem Tests", Nelson and others, Chap. WL), (2) copious groundwater flow from the Katakturak in the Sadlerochit Mountains, (3) karstification in the Sadlerochit mountains that could produce porosity. Fracturing is highly likely to accompany formation of the structures, providing permeable pathways along which potential reservoirs could form and be accessed.

Traps and seal. The basal Brookian turbidites and Hue Shale are the most likely top seals. Simple four-way closures were a small fraction of the mapped prospect areas in this play. However, if up-dip faults within the Franklinian are assumed to be sealing, then vertical closures of up to 4,000 feet and areas up to 22,000 acres are possible for some of the mapped prospects. The mapped seismic prospects in this play were bounded by faults in most cases and needed sealing faults to achieve significant size. Unfortunately, studies of Lower Paleozoic carbonate reservoirs have shown that faults within carbonate rocks are generally not good seals (Hendrick 1992; Carpenter and Evans, 1991). This consideration led to a significantly lower probability of trap formation in this play than in the Undeformed Franklinian play (Chap. P6).

Volumetric Parameters. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations are pertinent to Tables RS7a and RS7b.

Net Reservoir Thickness. The estimate of net reservoir thickness-to-gross thickness in this play is based upon the frequency of fractured/porous zones in the Canning River Unit A-1 well, which intersects Katakturak dolomite (or a dolomitic interval of Nanook Limestone, see Dumoulin, Chap.

CC) over a 654-foot interval. The laterolog-8 resistivity log is used as an indicator of fracturing. Resistivity values decrease to values less than 1,000 ohm-m in nine zones, totaling 120 feet, for a fractured-to-gross interval ratio of 0.18 (see "Well Log Response of Basement Rocks" in Nelson and Bird, Chap. FP). Consequently the gross thickness was multiplied by 0.2 to estimate net reservoir thickness.

Evaluation of five structures on the seismically mapped basement shows a range of total vertical closure from 800 to 4,000 feet. If we assume that the deformed basement would have the most chance of developing fracture porosity, and apply a net-to-gross ratio of 0.2, then the net reservoir thickness ranges from 160 to 800 feet for the mapped prospects. Because the sample set is limited, this range was extended to higher and lower thickness values, and a median of 300 feet was selected.

Area of Closure. The five mapped prospects range from 15,000 to 22,000 acres. The three by six mile seismic grid precludes any larger closure areas, but prospects smaller than grid resolution are likely. The minimum area of closure (2,000 acres) was determined by the 50 million barrel cutoff (Schuenemeyer, Chap. ME). The median value of 12,000 acres was chosen to be slightly smaller that the smallest mapped prospect.

Porosity. As with the Undeformed Franklinian play, the minimum value of the final porosity distribution was set to accommodate the 50 million-barrel minimum field size (Schuenemeyer, Chap. ME). Data were not sufficient to justify a significant difference between the porosity distributions assigned to the Undeformed Franklinian and the Deformed Franklinian plays. Therefore, the porosity distribution used for the Undeformed Franklinian play was adopted for this one (minimum, median, and maximum of 8, 14, and 20%), with the observations discussed above ("Reservoir properties") providing justification that porous reservoirs exist in this play.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The low value of water content (2%) chosen for this play is believed to be representative of carbonates. For example, at the median porosity of 14%, the water saturation is 0.02/0.14, or 14.3%.

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Trap Fill. The mapped prospects in this play are partially dependent on fault seals. Therefore, the trap fill distribution was estimated to range from 20 to 100%, with a median of 45%, slightly less than that of the Undeformed Franklinian play.

Trap Depth. The crests for the five mapped prospects ranged from 9,000 to 24,500 feet subsea. Although the depth range for the Franklinian within the entire play area is from 5,000 to 31,000 feet subsea, the maximum trap depth was set to 25,000 feet subsea. Because four of the five prospects have crests between 9,000 and 13,000 feet; a median depth of 10,500 feet was chosen to fit within this range.

Number of Prospects. The five mapped prospects determined the minimum of the distribution. A median value of 12 and a maximum value of 20 allow for the likelihood of smaller prospects between the seismic lines.

Play Probabilities.

Because of the presence of hydrocarbons at Point Thomson in Franklinian rocks, proximity to source rock, and timing of generation, the charge at play level (C) has a probability of 1.0.

Probability of reservoir (R) is set at 0.8. Upon testing, several Point Thomson area wells and the Canning River Unit A-1 well flowed water at significant rates. Limited primary porosity with significant fracturing is expected. Because of deformation, the probability of fracturing is higher than in the Undeformed Franklinian play area.

Probability of timely trap formation (F) is set at 0.5. Because basement-involved faults are among the youngest thrust structures within the 1002 area (Miocene faulting), it is possible that the structures postdate migration (Potter and others, Chap BD). However, it is also possible that some of the structures may have received hydrocarbons generated in Brookian sediments in the footwalls of reverse faults.

Prospect Probabilities.

Probability of charge (c) is set at 0.8. Proximity to source rock and timing of hydrocarbon generation indicate risk for charge is low, as in the Undeformed Franklinian play area.

Probability of reservoir (r) is set at 0.5. Because the matrix porosity in Franklinian rocks is low and fractures may not be present everywhere, a risk factor of 0.5 is assigned. This is higher than assigned in the undeformed Franklinian area because deformation will favor fracturing.

Probability of timely trap formation (f) is set at 0.2. Because the traps have formed after the main hydrocarbon generation pulse, trap timing considerations increase the risk. The requirement for seals along faults in carbonate rocks also contributes to the high risk.

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Chapter P8 Thin-Skinned Thrust-Belt Play

by William J. Perry, Jr.[1], Christopher J. Potter[2], and Philip H. Nelson[1]

The Thin-Skinned Thrust-Belt play is based upon seismically defined structural closures in Brookian strata within the thin-skinned thrust belt (see Fig. P8-1 for a cross-section of the play concept and Fig. AO13 for location and play highlights). The play extends eastward and southeastward from the northern edge of Brookian thrusting and contractional folding along the northwestern flank of the Marsh Creek anticline to the southern margin of the Aichilik high (Fig. BD2). The northern boundary of the play bends southeastward at Jago Spit and includes the oil seep and oil-impregnated sands near Angun Point (see Bader and Bird, 1986), extending to the eastern limit of offshore State lands near Angun Point.

Within the play area, the thin-skinned thrust belt consists of generally northeast-trending folds and thrust-bounded structures which have formed above a detachment lying above and close to the pre-Mississippian basement. Where Brookian rocks lie directly on pre-Mississippian basement, the detachment is in the Cretaceous Hue Shale or in mud-rich Paleocene rocks. Where an Ellesmerian or Beaufortian section is present, the detachment appears to lie in the Kingak to pebble shale interval (see stratigraphic column in Fig. AO13). Rocks involved in the thin-skinned structures include a mud-rich (Canning Formation) facies and a sand-rich (Sagavanirktok Formation) facies. Brookian thrusting within the 1002 Area occurred during Paleocene to Miocene (or younger?) time (Potter and others, Chap. BD). The thrust belt generally propagated from south to north as a passive roof duplex (Banks and and Warburton, 1986).

Figure BD2 shows the approximate location of the seismic profiles available for our study. North-northwest-trending dip-parallel seismic profiles reveal anticlinal and imbricate (duplex) structures in two dimensions which could form prospective traps if four-way closure is present. East-west- to northeast-trending profiles illustrate the presence of 4-way closures at several localities where they cross the dip-parallel profiles. Gravity and magnetic surveys also provided critical information concerning the nature, size and position of structures (Saltus and others, Chap. GR, and Phillips, Chap. AM). From the seismic profiles, estimates of depth, height, width, and facies type were extracted for 44 separate features from a sampling of 12 dip-parallel seismic lines. From these basic data, histograms of the trap

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depth, net thickness, and area were formed (Fig. P8-2). Cumulative distribution functions based upon these data were then used in the assessment calculation, as described below. Because of a gravity low over the anticlinal and imbricate structures within the Aichilik high (Fig. BD2) at the southeastern margin of the play, the structures are believed to consist of Hue, pebble, and Kingak shales, with no reservoir potential. Therefore the Aichilik high was not included in our analysis of potential prospects. Using the Cordilleran and Ouachita-Marathon thrust belts as conceptual analogues, the bulk of the hydrocarbons should be present in the frontal structures, i. e., the Marsh Creek anticline and Jago Ridge (Fig. BD2) culminations.

Play Attributes. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). The following explanations pertain to Tables RS8a and RS8b.

Net Reservoir Thickness. Gross reservoir thicknesses was based on amplitude of anticlines or on height of lens-shaped imbricate slices, as seen on seismic sections. Gross thicknesses were converted to net reservoir thicknesses based on assumptions concerning sand/shale ratios. Based on wells adjacent to the 1002 area (Table PP1), a net-to-gross ratio of 0.13 was used for Canning-type facies (turbidites), a ratio of 0.4 for Sagavanirktok-type facies (topsets), and intermediate ratios for combinations of the two. Net reservoir thicknesses are expected to range from 90 to 700 ft with an average of about 130 ft.

Area of Closure. Because four-way closure cannot be seen on individual (two-dimensional) seismic profiles, we calculated areas of closure based upon the assumption that the dip-parallel seismic profiles cross the short axis of thin-skinned structures. An aspect ratio of 8:1 was used, based upon analog data from Cordilleran thrust-belt fields (Table P8-1). The area of closure for fields that exceed the 50 million barrels of oil (mmbo) minimum size is expected to range from 1,000 to 20,000 acres, with a median of 6,000 acres (Table RS8a).

Porosity. Porosity was computed in accordance with the Schmoker-Hester algorithm (see "Porosity as function of vitrinite reflectance" in Nelson, Chap. PP) for a trap depth of 4,000 feet and using coefficients appropriate for the area southeast of the Marsh Creek Anticline (Fig. PP4). This computation yielded a minimum of 5%, a median of 15%, and a maximum of 30%. To meet the 50 mmbo cutoff, the minimum was increased to 9%. A compensating change was made in the reservoir risk at the prospect level. Thus for this play, the projected range in porosity for an individual reservoir, as derived from the Schmoker-Hester algorithm, was applied to represent the expected range of average porosity in a play. The high porosity tail of the porosity distribution (Table RS8a) was retained to complement the very shallow depths of the trap depth distribution (minimum of 1,000 feet).

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The value of water content (6%) chosen for this play is representative of very fine-grained sandstone. For example, at the median porosity of 15%, the water saturation is 0.06/0.15, or 40%.

Trap Fill. From 10 Cordilleran fields, including the Umiat oil field, we determined an average trap fill of about 38% and a range from 13 to 100% (Table P8-1). The Umiat trap is about 26% filled with hydrocarbons (height of hydrocarbon column versus height from top of trap down to spill point). A wide range of trap fill (20 to 100%) is assigned to this play, with a median of 50%.

Trap Depth. From the seismic sections, trap depths were found to range from 700 to 12,000 feet. A range of 1,000 (considered minimal for permafrost) to 12,500 feet, with a median of 4,000 feet, was assigned to this play. Depth to the basal detachment ranges from about 10,000 to 15,000 ft under the Marsh Creek anticline and 9,000 to 16,000 ft over the Niguanak high to more than 30,000 ft in the deeper part of the Hula Hula low.

Number of Prospects. On the 12 dip-parallel seismic profiles surveyed, 44 apparent closures were measured, many of which were expected to be less than the 50 mmbo minimum size. An estimate was made of the number of prospects which would be less than 1,000 acres in area (taken to be the minimum acreage for a 50 mmbo field), and a corresponding fraction was eliminated from the population. Several of the larger prospects appear to have been intersected by more than one seismic line. The total number of prospects of greater than 50 mmbo minimum size is estimated to range from 17 to 60, with a median of 40 (Table RS8b).

Play Probabilities. The presence of Umiat, East Umiat, and Gubik fields in NPRA to the west and analogue fields in the Beaufort Sea and Mackenzie Delta to the east confirm the presence of charge and reservoir at play level. Therefore C=1.0 and R=1.0 at the play level.

Although analogue fields are present, timely trap formation is not absolutely assured at the play level; there may be an overall problem with time of oil generation and migration versus time of trap formation (Potter and others, Chap. BD). A probability of F=0.9 is assigned at the play level.

Prospect Probabilities. Proximity to source rock (Hue, pebble and Canning shales), depth of burial, and surface seeps give high confidence for charge which was set at a probability of c=0.8.

Depth of burial and possible absence of coarse-grained material, particularly in the northeastern part of the play, provide considerable risk for reservoir which was set at a probability of r=0.5. This includes a reduction to compensate for the increase in the porosity values at the 75th, 95th and 100th fractiles on the porosity distribution (Table RS8a).

The structures in this play are younger than the primary phase of hydrocarbon generation. However, the structures in the frontal zone may have captured hydrocarbons generated in the undeformed area as in analogue thrust belts, or Tertiary source rocks might have generated hydrocarbons. As in all thrust-belt settings, the presence of nonsealing faults may be a significant problem. For these reasons, the probability of timely trap formation at the prospect level is set at f=0.4.

Analogue accumulations. North Slope: Gubik area (Robinson, 1958; Collins and Robinson, 1967), Umiat oil field (~70 million barrels recoverable oil, Molenaar, 1983), and Adlartok - west Beaufort fold-thrust belt discovery (estimated > 100 million barrels recoverable oil, Dixon and others, 1994; Dixon, 1996); Cordilleran thrust belt, Canadian Foothills sector: Pincher Creek, Lookout Butte, and Waterton gas fields (Gordy and others, 1977; French, 1984); Cordilleran thrust belt, Wyoming Salient sector: Whitney Canyon-Carter Creek Gas Field (Bishop, 1983), and Painter Reservoir, Ryckman Creek, Carter Creek, and Anschutz Ranch East fields (Frank and others, 1983; Lamerson, 1983; Lelek, 1983)

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Table P8-1. Trap fill in percent and aspect ratio (length/width or L/W) of analogue fields on the North Slope and Cordilleran thrust belt.

Field(s)	References	Thrust-belt Setting	L/W	% trap fill*
Umiat	Molenaar (1983)	NPRA	5	25.95
Sukunka-Bullmoose	Barss and Montandon (1983)	British Columbia	12.2	
-do-	-do-	British Columbia	10	
-do-	-do-	British Columbia	14.7	
-do-	-do-	British Columbia	8.75	
Knowlton	Napier (1983) and Johnson (1984)	Montana	5.05	29.4
Blackleaf Canyon	-do-	Montana	9.05	28.6
Pincher Creek	French (1984)	Alberta	10.2	
Waterton	-do-	Alberta	8.6	
Anschutz Ranch E. - east lobe	Lamerson (1983)	Wyoming	3.94	38.2
Anschutz Ranch E. - west lobe	Lamerson (1983) and Lelek (1983)	Wyoming	4.38	19.3
Carter Creek	Lamerson (1983)	Wyoming		100
Painter Reservoir	Lamerson (1983) and Frank and others (1983)	Wyoming	5.2	18.8
East Painter Reservoir	-do-	Wyoming	4.5	70
Rychman Creek	Lamerson (1983)	Wyoming		12.8
Whitney Canyon-Carter Creek	Bishop (1983)	Wyoming	9.4	38
Average			**7.9**	**38.1%**
Standard Deviation			**3.3**	**26.9%**

* Calculated from published cross sections, from highest to lowest point in trap.

Chapter P9 Ellesmerian Thrust-Belt Play

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The Ellesmerian Thrust-Belt play consists of potential for gas in thrust-faulted structures involving Ellesmerian clastic and carbonate rocks in the southern and southeastern part of the 1002 area (Fig. AO14), where the Ellesmerian section is clearly mappable from the seismic data. The Ellesmerian sequence consists of Mississippian through Early Cretaceous strata. Salient characteristics of the Ellesmerian Thrust-Belt play are summarized in Fig. AO14, while the cross-section of Fig. P9-1 illustrates the play concept.

Structural setting and timing. Erosional truncation of the Ellesmerian in the western part of the 1002 area has removed the most prospective part of the section, and, combined with the absence of mappable prospects in the west, only the Ellesmerian in the southern and southeastern part of the 1002 area was considered prospective for this play. In the play area, the Ellesmerian possesses depositional thicknesses of up to 6,000 feet, thins depositionally to the north (in contrast to thinning due to erosional truncation in the west), and tectonically thickens by repetition to 10,000 feet in the southeast corner (Figure NA5). There appear to be thin-skinned detachments above the Sadlerochit and Shublik, with only minor removal of thrust slices by tectonic transport of the Ellesmerian below that level. The Ellesmerian is folded and faulted at long wavelengths visible on the seismic sections.

The Ellesmerian sequence is structurally attached to the underlying Franklinian metasedimentary rocks over most of the play area (Cole and others, Chap. SM, Plate SM1), even though the Ellesmerian is separated from the Franklinian by a profound angular unconformity similar to that observed in outcrops in the Sadlerochit Mountains. The structures involving this Franklinian-Ellesmerian section appear to have begun forming in the southern part of 1002 area in Miocene time based upon apatite fission track studies (Murphy, Chap. FT). These structures postdate the formation of thin-skinned structures in this area, and also postdate the time of maximum burial and hydrocarbon generation. Thus the timing of trap formation relative to oil generation is not favorable for this play.

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Reservoir lithologies. Based upon a tie to the Beli well west of the 1002 area, the seismic character of the Ellesmerian includes a highly reflective upper unit (Sadlerochit Group and Shublik Formation), a transparent middle unit (Lisburne Group), and a highly reflective basal unit (Endicott Group) (Fig. NA5-NA7). Because the Jurassic and Lower Cretaceous part of the Ellesmerian (Kingak Shale, Kemik Sandstone, and Pebble shale) is either too thin or involved in thin-skin detachments, only the Endicott through the Shublik part of the Ellesmerian can be mapped in the seismic data with confidence. Consequently, potential reservoirs in this play include sandstones of the Ivishak and Sag River Formations, Kekiktuk Conglomerate, and carbonates of the Lisburne Group (reservoir properties are discussed by Nelson and Bird in Chap. FP).

Seals. In this play, six prospects are large enough that they can be clearly mapped from one seismic line to another. Of these six, two east-plunging anticlines are the subsurface continuations of the Sadlerochit Mountains. All potential prospects in this play are plunging and require up-plunge cross faults for closure (that is, there are no simple four-way closures). Thus, these structures require a combination of lateral fault seals and fine-grained top seals. Potential top seals include the Kingak Shale, Hue Shale, or siltstones of the Canning Formation.

Source Rocks. Source rocks may include the Shublik Formation, Hue Shale, and Canning Formation. The most probable migration pathways are from underlying footwall source rocks into overthrust hanging-wall reservoirs (Fig. P9-1).

The vitrinite reflectance map (Plate VR1) shows a 0.6 reflectance isograd (top of oil window) approximating the northern boundary of this play, the 1.3 isograd (base of oil window) approximately bisecting the play, and the 2.0 isograd approximating the southern boundary of the 1002 area and the play. From downward projection of thermal maturity using a suitable vitrinite gradient, we conclude that most of the play interval lies below the zone of oil generation. Moreover, gas accumulations have been found in the Kemik Unit 1, Kavik 1, and Kavik Unit 3 wells (Fig. AO3; Plates WL26, WL22, and WL24) which penetrate the west-plunging continuation of the Sadlerochit Mountains. Hence this is a 100% gas play.

Volumetric Parameters. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer

(Chap. RS). The following explanations are pertinent to Tables RS9a and RS9b.

Net Reservoir Thickness. From the seismic profiles it appears that the Ellesmerian section is dominated by Lisburne and other lower Ellesmerian rocks. Thus it was assumed that the formations likely to be reservoirs are the Ledge, Kekiktuk, and Lisburne. The average ratios of net reservoir thickness to gross thickness of the Ledge (0.65) and Kekiktuk (0.22) formations are given in Table PP1, but the ratio for the Lisburne was not determined. Assuming that the ratio for the Lisburne is 0.13, then the weighted (by thickness) ratio of net reservoir thickness to gross thickness in the lower Ellesmerian is 0.25. The factor of 0.25 was applied to the range of thickness estimates from the seismic sections (median and maximum total thicknesses of 1,200 and 6,000 feet) to produce median and maximum net reservoir thicknesses of 300 and 1,500 feet.

Area of Closure. From the seismic map, areas of structural closure range from 6,000 to 45,000 acres. The minimum area of closure (2,000 acres) was chosen to be smaller than the smallest mapped prospect to allow for features missed by the 3x6 mile seismic survey.

Porosity. Porosity values were assigned as a rough average of clastic and carbonate rocks and have a median value of 11%.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in “Water Saturation” by Nelson (Chap. PP). For the mix of clastic and carbonate reservoir lithologies in this play, a water content of 3.5% was chosen, intermediate between fine sands and carbonates. For example, at the median porosity of 11%, the water saturation is 0.035/0.11, or 31.8%.

Trap Fill. Trap fill is judged to be low because sealing faults are required for virtually all the prospects. None of the six mapped prospects have simple four-way closure, and all require up-plunge and/or up-dip sealing faults (Fig. P9-1). A large part of the play area is composed of north-dipping monoclines, with little indication of possible trap development. Analogs from the Anadarko basin indicate that faults in carbonate sections do not provide good seals (Grow and others, Chap. P7). Thus, the median trap fill was 25%, one of the lowest for all the plays in the assessment.

Trap Depth. The depth range for this play is 2,000 to 17,000 feet subsea.

Number of Prospects. There are six mapped prospects, occupying most of the play area. Consequently, the number of prospects is small, ranging from 4 to 8.

Play Probabilities. A play probability of 1.0 was assigned because of the presence of the Kemik and Kavik gas fields, and fields in the Prudhoe Bay area.

Prospect Probabilities.

Probability of charge (c) is set at 0.9. Because the prospect can be charged by Paleozoic as well as by Mesozoic and early Tertiary source rocks, the probability of gas charge is high.

Probability of reservoir (r) is set at 0.6 Although the Ellesmerian rocks contain world-class reservoirs in analog fields, the rocks outcropping immediately adjacent to the 1002 area are very poor reservoirs.

Probability of timely trap formation (f) is set at 0.2. The traps might have been formed at a much later date than the peak hydrocarbon generation, and fault closure is required, hence the high risk for trap.

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Chapter P10 Niguanak-Aurora Play

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This play consists of two very large structures, the Aurora dome and Niguanak high, in the northeastern 1002 area (Fig. NA1) where, beneath the Brookian sequence, seismically mapped thrust sheets or imbricate thrust stacks may contain trapped hydrocarbons in basement carbonates or sandstones of the Franklinian, or possibly Beaufortian and/or Ellesmerian, rocks. Because of the uncertainties of the thrust structure(s) involved, (Fig. P10-1), the play is assessed in two scenarios, --as two large prospects (one for each high) or as multiple prospects within each primary structure.

The Niguanak and Aurora structures were identified as prospects 18 and 19 by Callahan and others (1987, Figure 23.2 and Table 23.1). Salient characteristics of the Niguanak-Aurora play are summarized in Fig. AO15, while the cross-sections of Fig. P10-1 illustrate the play concepts.

Structural setting. Although these two structural highs are separated by the major north-verging Niguanak thrust fault system, with the Niguanak high on the south and the Aurora dome on the north, there appear to be imbricated internal thrust sheets within each of these two larger structures (Grow and others, Chap. NA). Above 19,000 feet below sea level, the highs are contained within a composite single closed structure with a total area of over 400,000 acres. Above 16,800 feet, two separate highs are evident with crests lying 8,800 and 13,800 feet subsea for the Niguanak high and Aurora dome, respectively. Because the Niguanak high appears to be separated into multiple stacked thrust sheets, it is uncertain whether this feature should be assessed as a single prospect or as a collection of prospects within a play. Although the seismic coverage over the Aurora dome is not as good as over the Niguanak high, we believe that it also is composed of multiple thrust sheets.

Two Scenarios. Because of the uncertainty as to whether the Niguanak high and Aurora dome should be assessed as a play consisting of two large, individual and unique prospects or as a play with many separate prospects, the assessment was computed in two ways and then aggregated in proportion to the probability of the two scenarios: 0.3 in the case of the two large prospects and 0.7 in the case of the many smaller prospects. The two scenarios are mutually exclusive; only one can exist. Thus, this play consists of the "two dome" scenario (probability 0.3) and the "many prospect" scenario (probability 0.7).

Within the two-dome scenario, the prospect charge, reservoir, and timely trap formation probabilities (0.8, 0.2, and 0.5, respectively) yield a combined probability of 0.08 that the Niguanak high contains hydrocarbons in excess of 50 million barrels, and a slightly higher probability of 0.096 that the Aurora dome contains hydrocarbons in excess of 50 million barrels (assuming 0.8, 0.2, and 0.6 prospect probabilities for charge, reservoir, and timely trap formation). The two occurrences are believed to be highly correlated, that is, if the Niguanak high contains hydrocarbon then it is highly likely that the Aurora dome does also. Note that the distinction between play and prospect collapses in the two-dome scenario; play and prospect occupy the same space and are equivalent. Thus in Fig. ME1, the outer computational loop (play level, box 1) is not present, and two parallel inner loops (prospect level, box 5) exist, one for Niguanak and one for Aurora, each using the same distributions of volumetric parameters.

In the many-prospect scenario, the combined Niguanak high and Aurora dome area is treated like the other plays. In this scenario, there is both a play probability (0.648, assuming charge, reservoir, and timely trap formation probabilities of 0.9, 0.8, and 0.9, respectively) and a prospect probability (0.168, again assuming 0.7, 0.4, and 0.6 for charge, reservoir, and timely trap formation). These two probabilities are used in the computational process just as depicted in Fig. ME1.

After the hydrocarbon-in-place is computed for each scenario, the results are combined in the proportions of 0.3 for the two-dome scenario and 0.7 for the many-prospect scenario.

Source and seal. The Niguanak high and Aurora dome may be sourced by a combination of Lower Cretaceous pebble shale and Hue shale, as well as the Tertiary Canning Formation, which may occur over and on the flanks of these domes (within the Brookian sequence in Fig. P10-1). For the two-dome and many prospect scenarios, the seals over the tops of the domes may include a combination of shales from the Jurassic-Lower Cretaceous Kingak Shale up through the Tertiary Canning Formation turbidites. In the case of the many-prospect scenario, fault seals must be assumed within the Niguanak high and Aurora dome. Interbedded sands and shales, possibly of

Devonian age (Kelley, Chap. BR), may provide adequate seals, even when faulted. However, Franklinian dolomites may be a significant component in both domes, and faults within dolomites may not form good seals.

Reservoir lithologies. The complex internal deformation within these two features makes it uncertain as to what rock sequences compose these imbricate thrust stacks. Gravity modeling indicates that pre-Brookian rocks within both the Niguanak high and Aurora dome have bulk densities of 2.7 g/cm^3 or higher (Figs. GR9 and GR10). Velocity estimates based on seismic reprocessing (Figs. NA11 and NA12) indicate that both features are composed of rocks having velocities in the range of 15,000 to 18,000 feet/second. The high density and velocity values measured within these two highs suggest that they are composed primarily of Franklinian rocks (including Devonian clastics), but lesser components of Beaufortian and Ellesmerian rocks are not precluded (see Grow and others, Chap. NA).

The many-prospect scenario incorporates a greater amount of thrusting and faulting than the two-dome scenario (Fig. P10-1). As a consequence, fracture density and reservoir quality should be greater in the many-prospect scenario than in the two-dome scenario.

Volumetric Parameters. Distributions of volumetric parameters and probability estimates assigned to this play are given by Schuenemeyer (Chap. RS). Rationales for Tables RS10a, RS11a, RS10b and RS11b are provided in the following paragraphs.

Net Reservoir Thickness. The net reservoir thickness for the Niguanak-Aurora play is based upon drilling results within pre-Mississippian rocks at Point Thomson. Thus, a range of 50 to 300 feet with a median of 150 feet was assumed for both scenarios.

Area of Closure. For the many-prospect scenario, the maximum area is based upon the largest single coherent prospect within Niguanak high, which covers 120,000 acres. The minimum and median closure areas for the many-prospect scenario were 5,000 and 20,000 acres, respectively. For the two-dome scenario, the minimum, median, and maximum are 120,000, 180,000, and 250,000 acres.

Porosity. Based on the possibility of fractures and secondary porosity, a porosity distribution range from 5 to 20% with a median of 10% was adopted. The same porosity distribution was assumed for both scenarios.

Water Saturation. Water saturation (water volume per pore volume) is computed from porosity by assuming the product of water saturation and porosity to be equal to a fixed water content (water volume per rock volume), as discussed in "Water Saturation" by Nelson (Chap. PP). The low value of water content (2.5%) chosen for this play is representative of carbonates. For example, at the median porosity of 10%, the water saturation is 0.025/0.10, or 25%.

Trap Fill. Trap fill range is 20 to 100% with a median of 45% for the many-prospect scenario, the same for as the Deformed Franklinian play. Trap fill is less for the two-dome scenario (range of 10 to 100%, but median of 20%) because it was considered unlikely that there would be sufficient charge to fill such extremely large structures.

Trap Depth. The range of trap depths is from 9,000 to 15,000 feet subsea for the two-dome scenario and 8,500 to 18,000 feet subsea for the many-prospect scenario, with medians of 12,000 and 13,000 feet respectively.

Number of Prospects. The number of prospects in the many-prospect scenario ranges from 1 to 20 with a median of 10. By definition, there are two prospects in the two-dome scenario.

Play Probabilities. See above discussion of "two scenarios". We have used a play probability of 1.0 for the two-dome scenario and the following play probabilities for the many-prospect scenario:

Probability of charge (C) is set at 0.9. Proximity to Brookian source rocks and timing of generation suggest high probability for charge.

Probability of reservoir (R) is set at 0.8. Because of multiple opportunities for reservoir rocks in the Franklinian (including Devonian clastics), and some possibility in Beaufortian, and Ellesmerian rocks, the probability of reservoir being present is high.

Probability of timely trap formation (F) is set at 0.9. The Niguanak-Aurora area has the most well-defined structural closures in the 1002 area.

Prospect Probabilities for the Many-Prospect Scenario

Probability of charge (c) is set at 0.7. Proximity to source rocks and timing of generation are favorable factors for charge.

Probability of reservoir (r) is set at 0.4. Because the Franklinian is considered to be the dominant lithology within multiple thrust stacks composing the Niguanak high and Aurora dome, the average reservoir quality is probably low. Because both the Kemik and Franklinian rocks are generally poor reservoirs, and the presence of Beaufortian and Ellesmerian rocks is not likely, the overall reservoir risk is high.

Probability of timely trap formation (f) is set at 0.6. Structures at Niguanak and Aurora are well defined, however there is moderate risk present at the individual closure level.

Prospect Probabilities for the Two-Dome Scenario

Probability of charge (c) is set at 0.8 for both Niguanak high and Aurora dome. Rocks with high levels of total organic carbon have been drilled in the Aurora well. Depth of burial is favorable.

Probability of reservoir (r) is set at 0.2 for both Niguanak high and Aurora dome. The two-dome scenario is less likely to have abundantly fractured reservoirs than the many-prospect scenario (r=0.4). Only one sandstone interval of reservoir quality, judged to be Kuparuk Formation or equivalent, is present below the Brookian rocks in the Aurora well (Plate WL8).

Probability of timely trap formation (f) is set at 0.5 for Niguanak, 0.6 for Aurora. The trap at Niguanak high is defined on gravity data and on multiple seismic lines. Seal is questionable, but may be better at Aurora because of finer-grained rocks.

Reference Cited

Callahan, James E., Brougham, Gary W., and Bascle, Robert J., 1987, Economically recoverable oil resources: *in* Bird, Kenneth J., and Magoon, Leslie B. (editors), 1987, Petroleum Geology of The Northern Part of the

Arctic National Wildlife Refuge, Northeastern Alaska, U. S. Geological Survey Bulletin 1778, p. 299-307.

Fig. P1-1. Schematic illustration of Brookian seismic sequences in the ANWR 1002 area showing strata involved in the topset play (Houseknecht and Schenk, Chap. BS). Sketches at right illustrate trap types observed on seismic data, mudstone-prone foreset facies (light green), sandstone-prone topset facies (yellow), and potential locations of oil accumulations (dark green). Scale of sketches at right; horizontal = a few miles, vertical = several hundred feet.

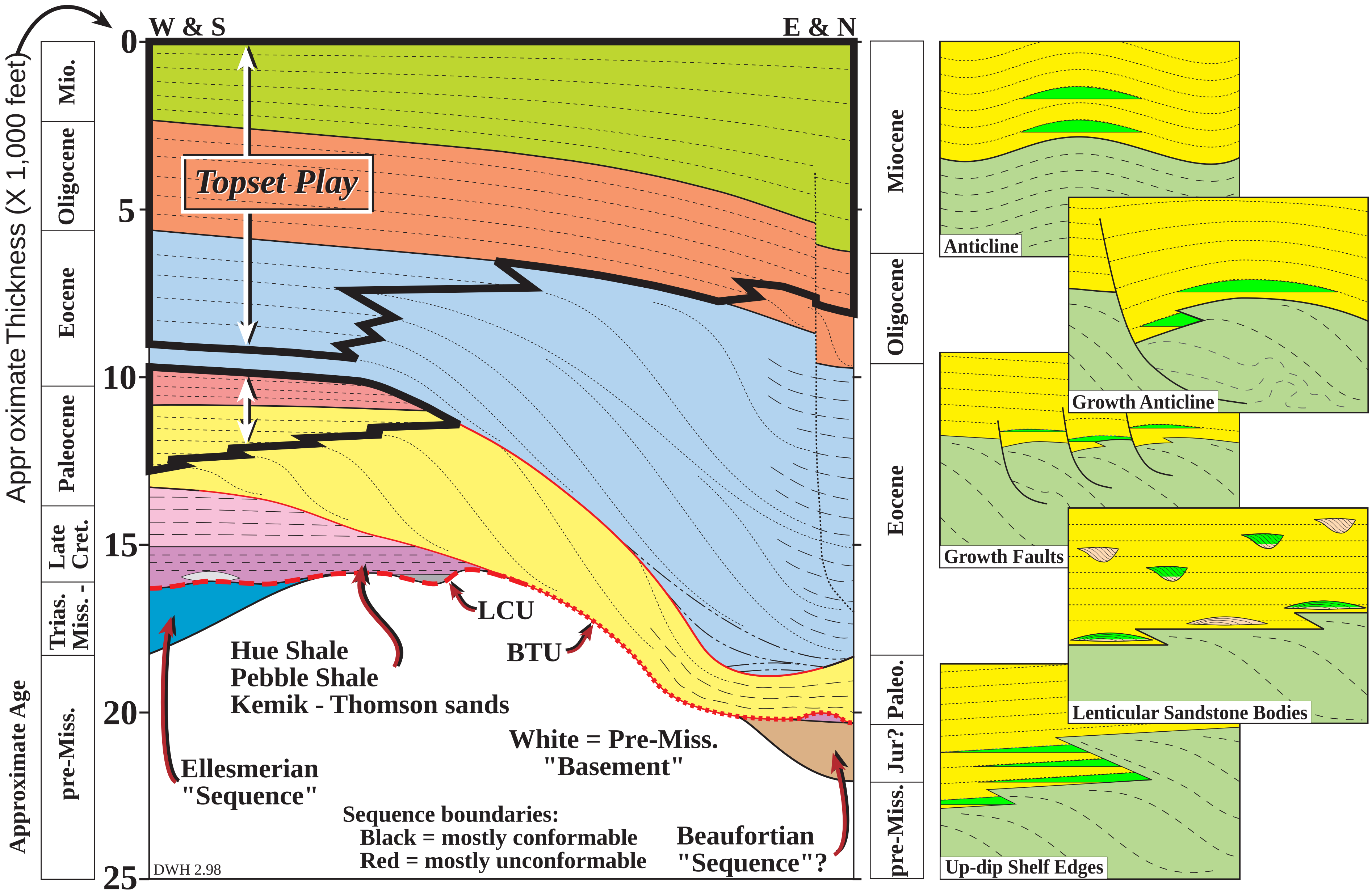

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Fig. P2-1. Schematic illustration of Brookian seismic sequences in the ANWR 1002 area showing strata involved in the turbidite play (Houseknecht and Schenk, Chap. BS). Sketches at right illustrate trap types observed on seismic data; light green = mudstone-prone foreset and bottomset facies, orange = submarine fan lobe facies, narrow lenses = sandstone-prone turbidite channel facies, and dark green = potential locations of oil accumulations. Scale of sketches at right; horizontal = a few miles, vertical = several hundred feet.

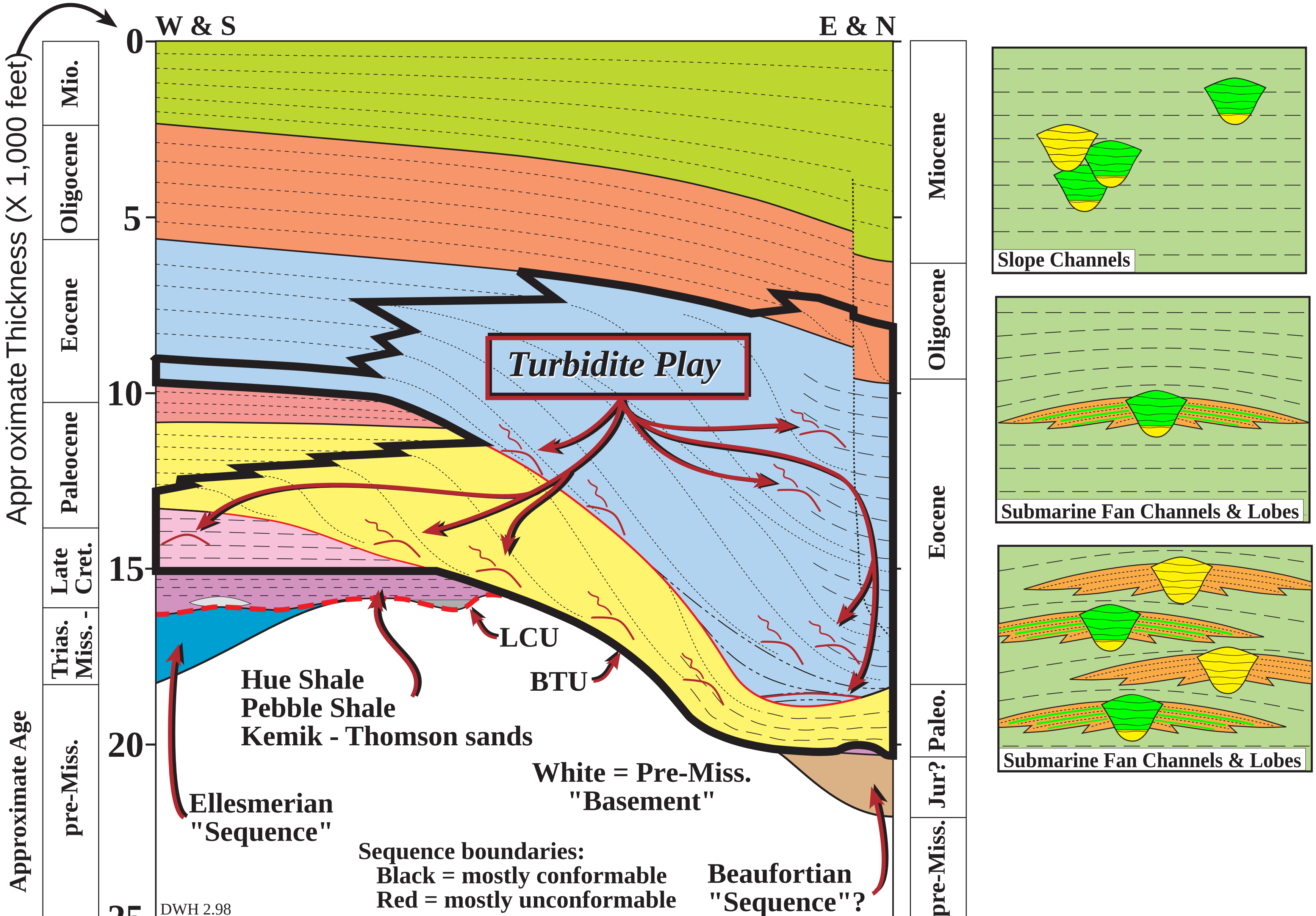

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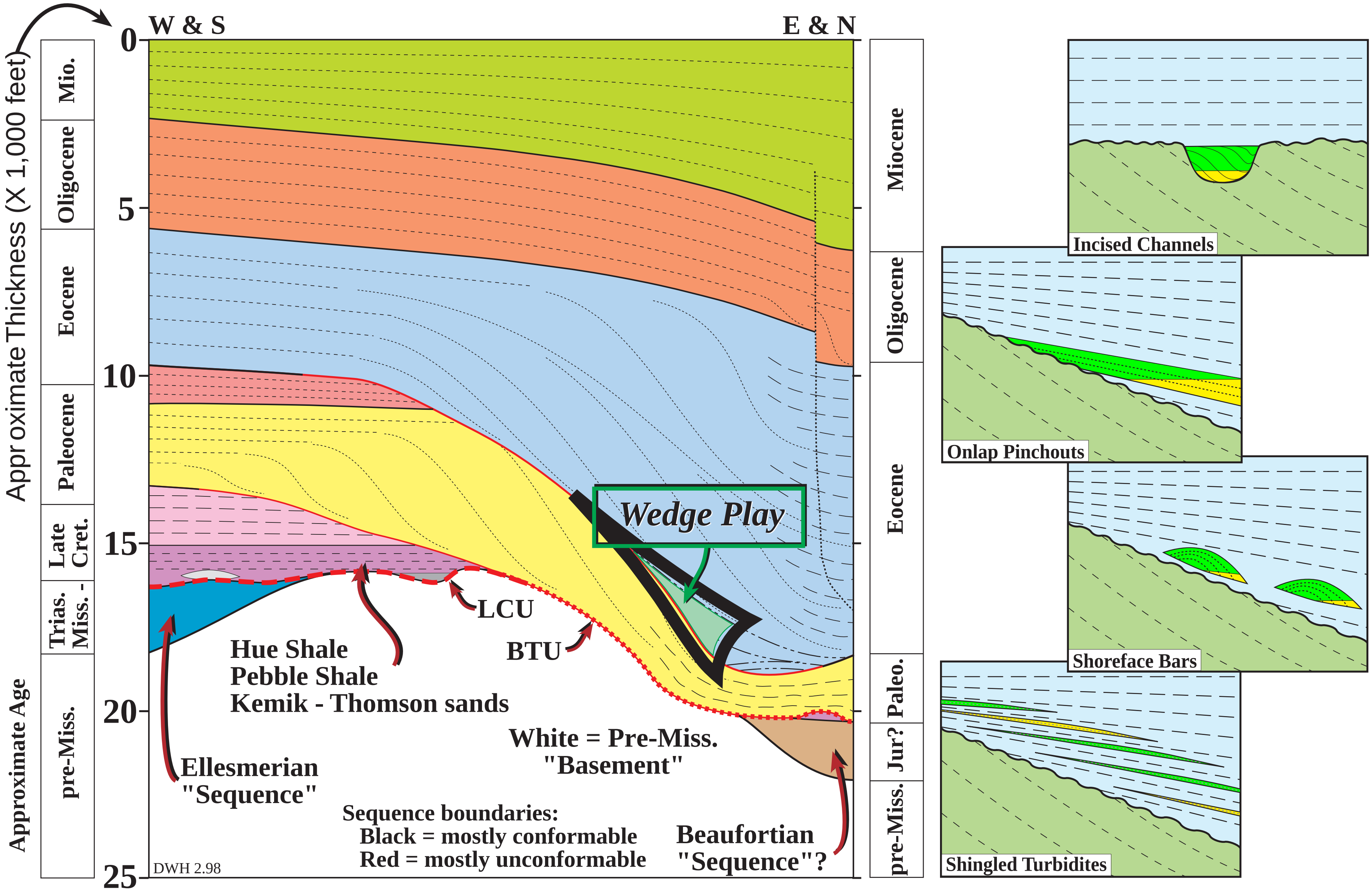
Fig. P3-1. Schematic illustration of Brookian seismic sequences in the ANWR 1002 area showing strata involved in the wedge play (Houseknecht and Schenk, Chap. BS). Sketches at right illustrate trap types observed on seismic data; light green = mudstone-prone foreset facies, light blue = mudstone-prone wedge facies, lenses = sandstone-prone depositional facies within wedge, and dark green = potential locations of oil accumulations. Scale of sketches at right; horizontal = a few miles, vertical = several hundred feet.



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ANWR Plays: Thomson

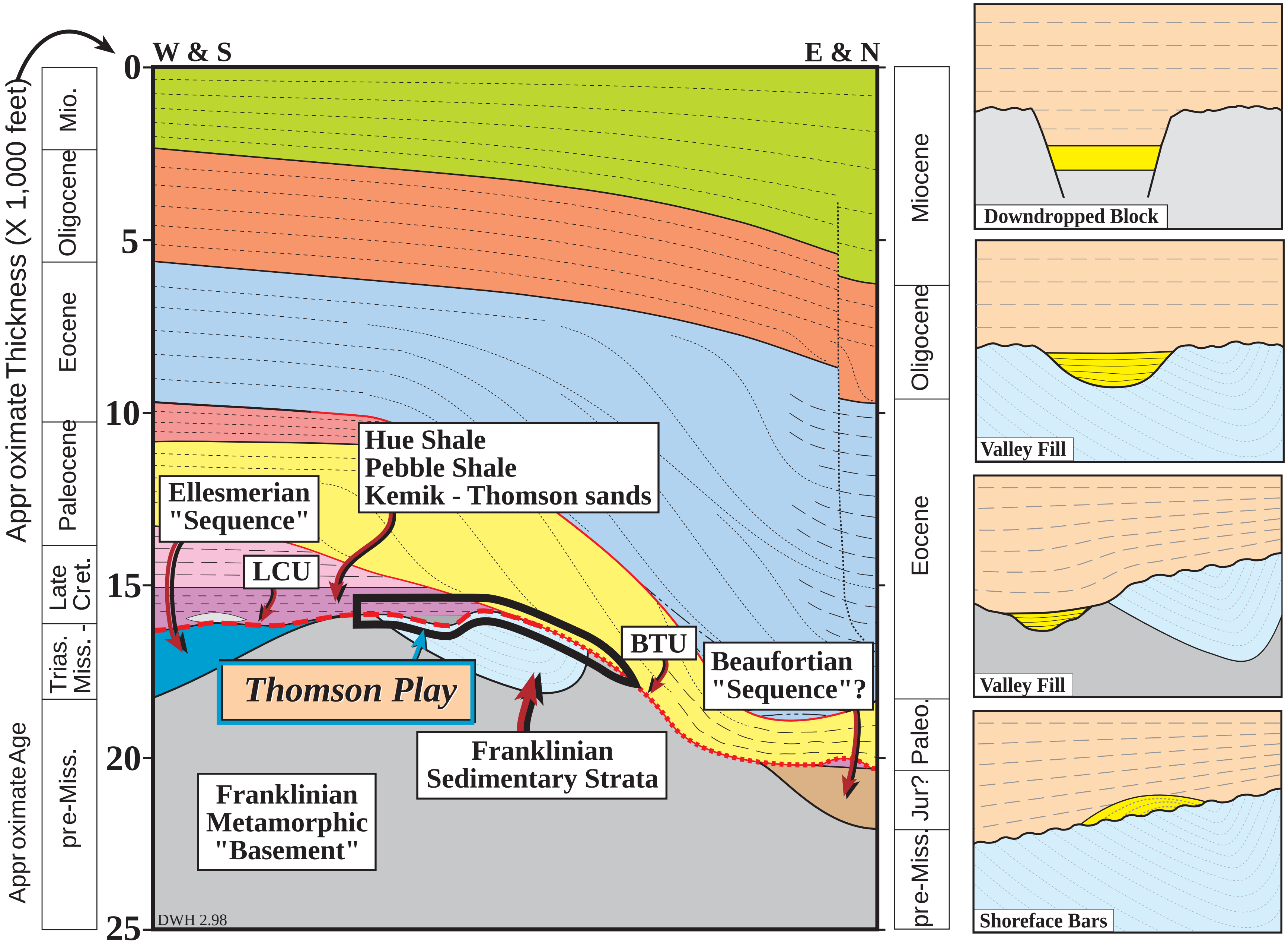

Figure P4-1. Schematic illustration of Brookian seismic sequences showing strata involved in the Thomson play. Sketches at right illustrate trap types: Thomson reservoirs are shown in yellow. Sketches at right have a horizontal scale of a few miles and a vertical scale of several hundred feet.

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ANWR Plays: Kemik

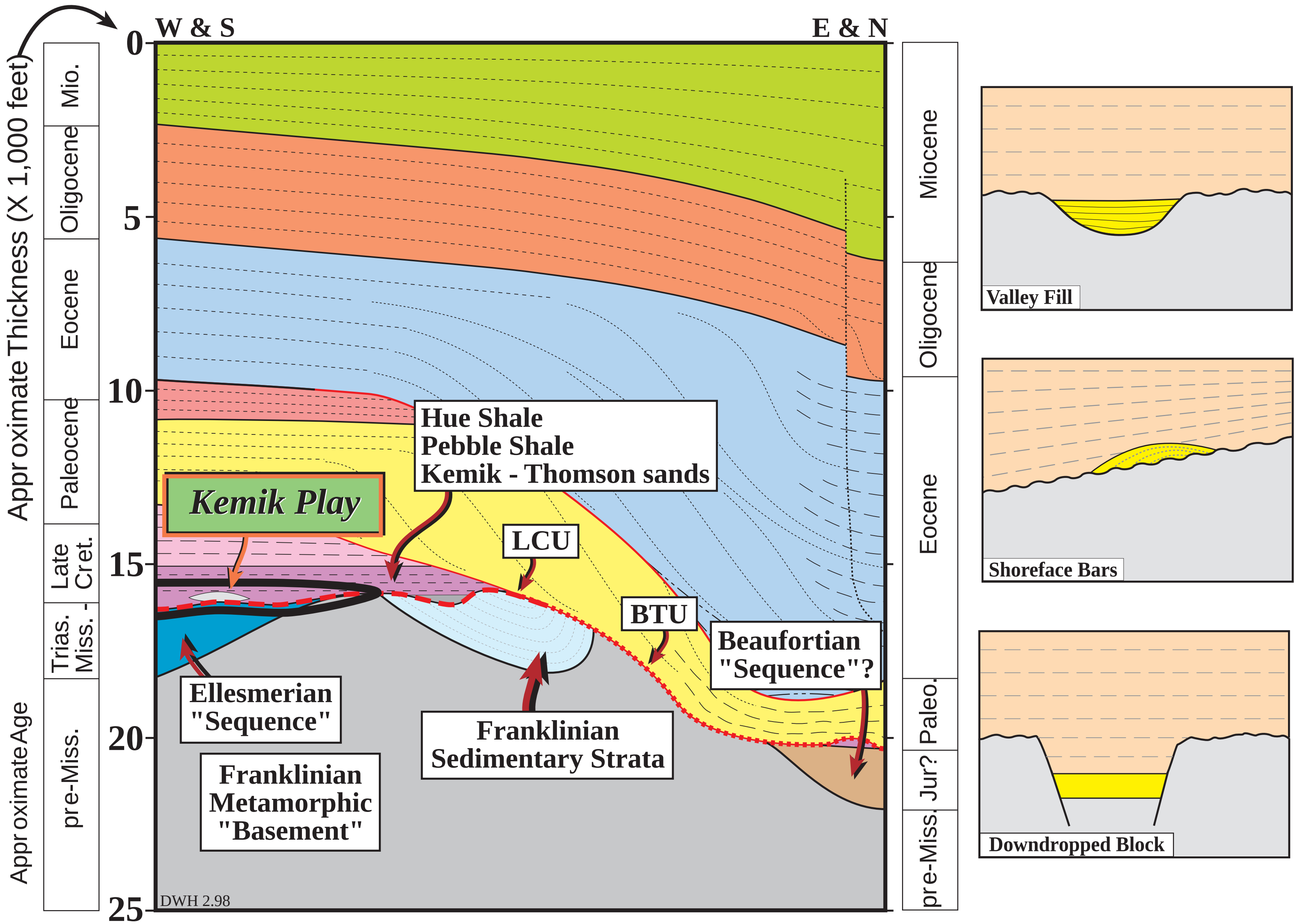

Figure P5-1. Schematic illustration of Brookian seismic sequences showing strata involved in the Kemik play. The Kemik Sandstone is one of several sandstones deposited on the Lower Cretaceous unconformity (LCU). Sketches at right illustrate trap types; Thomson reservoirs are shown in yellow. Sketches at right have a horizontal scale of a few miles and a vertical scale of several hundred feet.

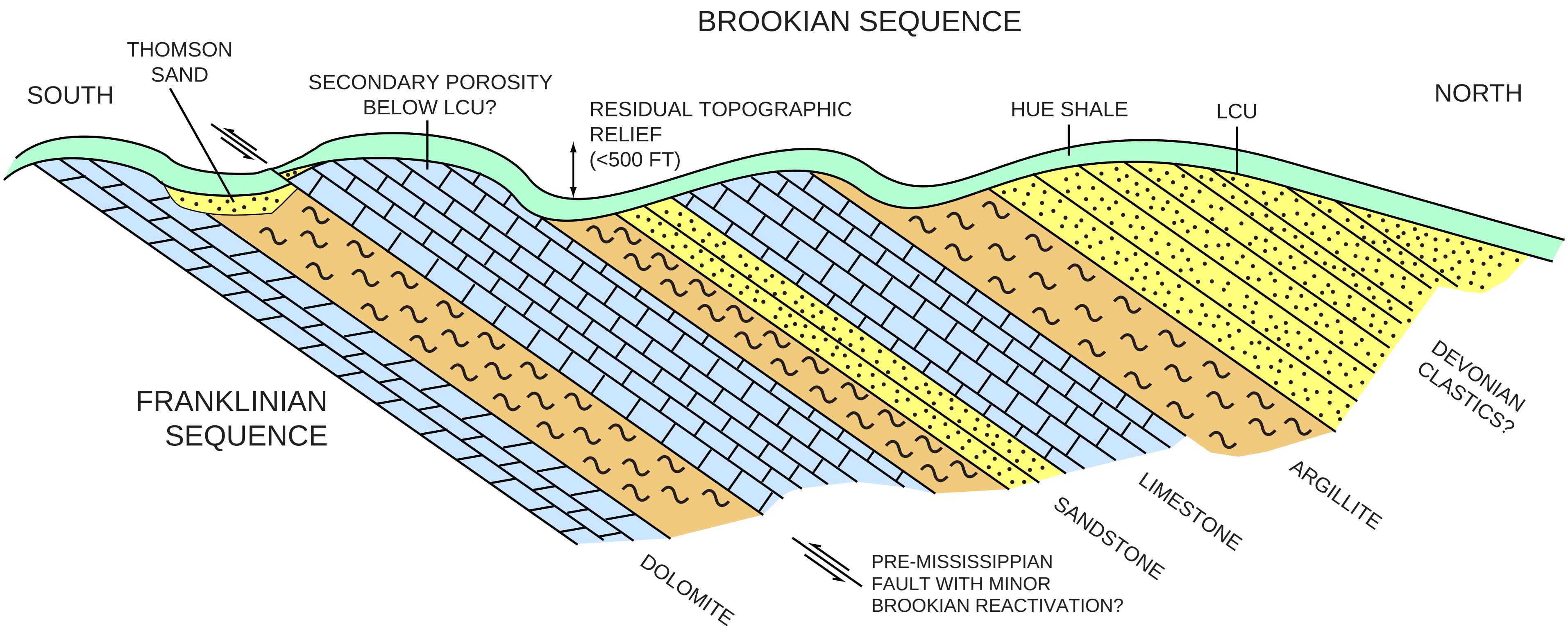

Figure P6-1. Undeformed Franklinian play. The Lower Cretaceous Unconformity (LCU) cuts across the Franklinian sequence and has several hundred feet of residual topographic relief, which provides closures over buried hills. Although the unconformity is broadly warped by foreland basin tectonic loading, it is not affected by major Brookian faulting. Minor Brookian faults, however, may be reactivated pre-Mississippian faults (Kelley, Chapter BR). In the western part of the play area, the most likely source and seal rocks are the Hue Shale. In the eastern part of the play area, the Hue Shale generally is missing due to erosion by Paleocene turbidites (Houseknecht and Schenk, Chapter BS) and the Franklinian reservoirs may be sourced from the Paleocene.

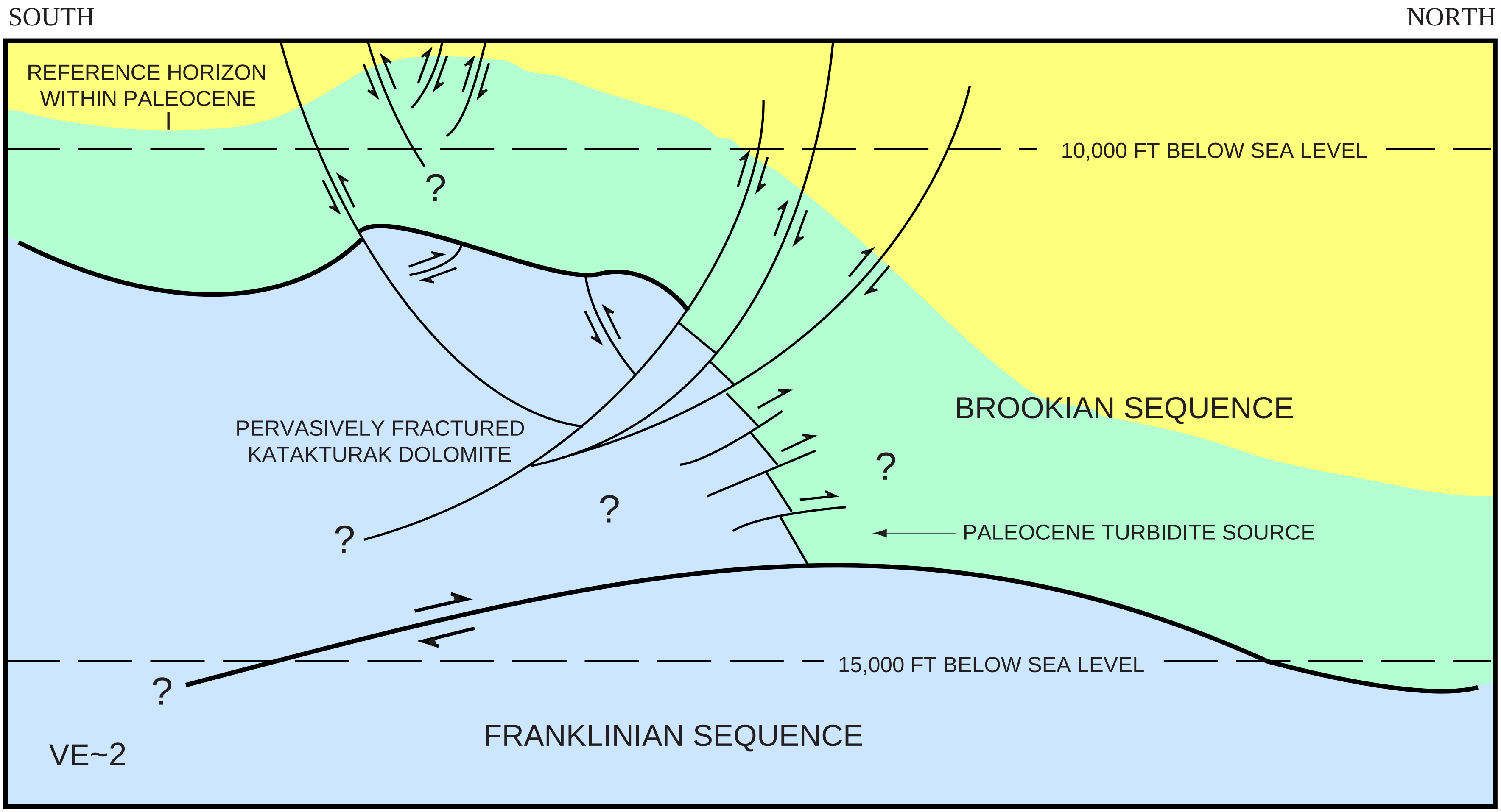

Figure P7-1. Deformed Franklinian play. The deformed Franklinian play includes folded and thrusted Franklinian sequence rocks, which may have thousands of feet of closure and plunge relief. The primary reservoir is inferred to be fractured Katakturak Dolomite, which is involved in complex folds, thrusts, and back-thrusts. While the Brookian sequence provides both source and sealing rocks in this play, most of the mapped prospects for this play require sealing faults within the Franklinian. Vertical exaggeration is roughly x2.

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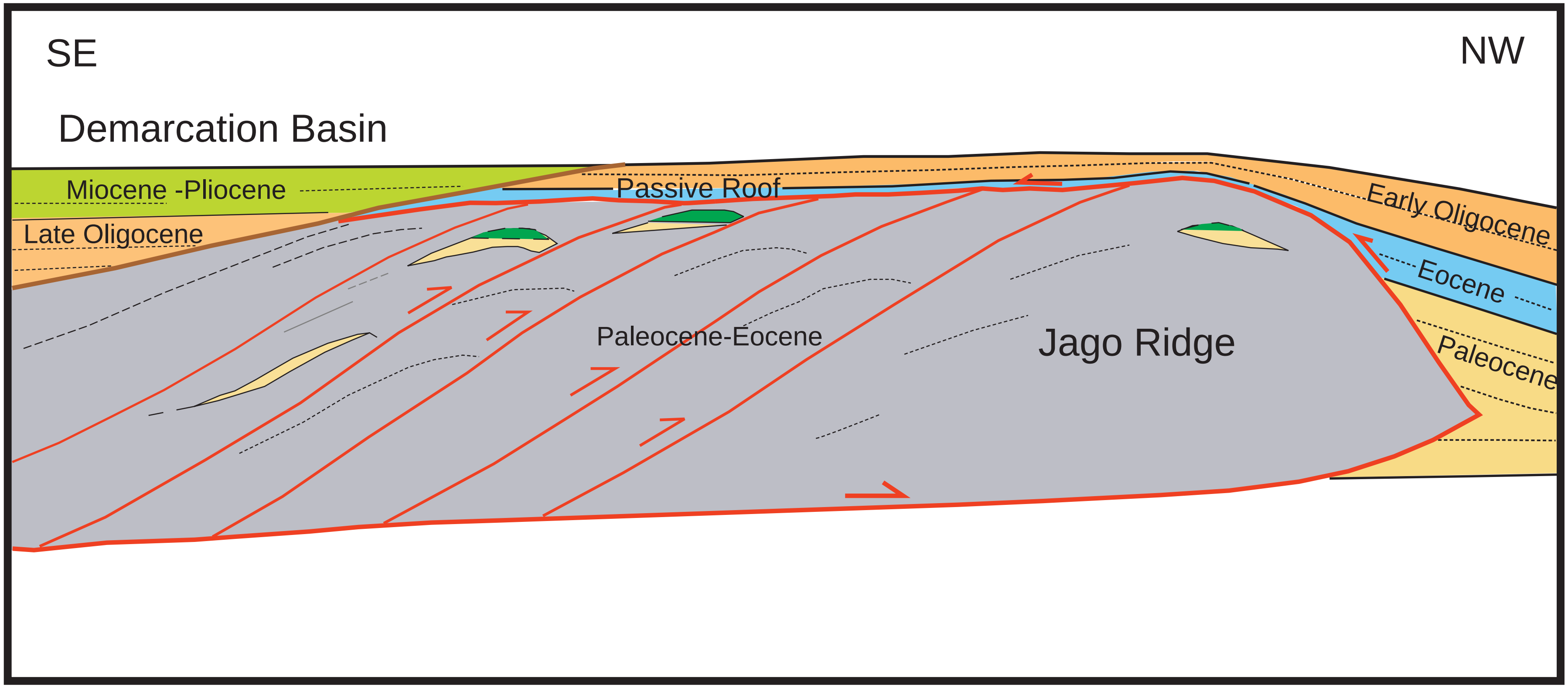

Figure P8-1. Diagrammatic section across eastern part of Thin-skinned Thrust-belt Play showing hypothetical turbidite sandstone reservoirs, with structurally trapped oil in green. Deformed wedge is believed to be composed of both Paleocene and Eocene mud-dominated sediments of the Canning Formation. Southward sloping contact at base of Demarcation basin-fill represents unconformity related to Oligocene sealevel drop.

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Thin-Skinned Thrust-Belt Play

Volumetric Parameter Distributions

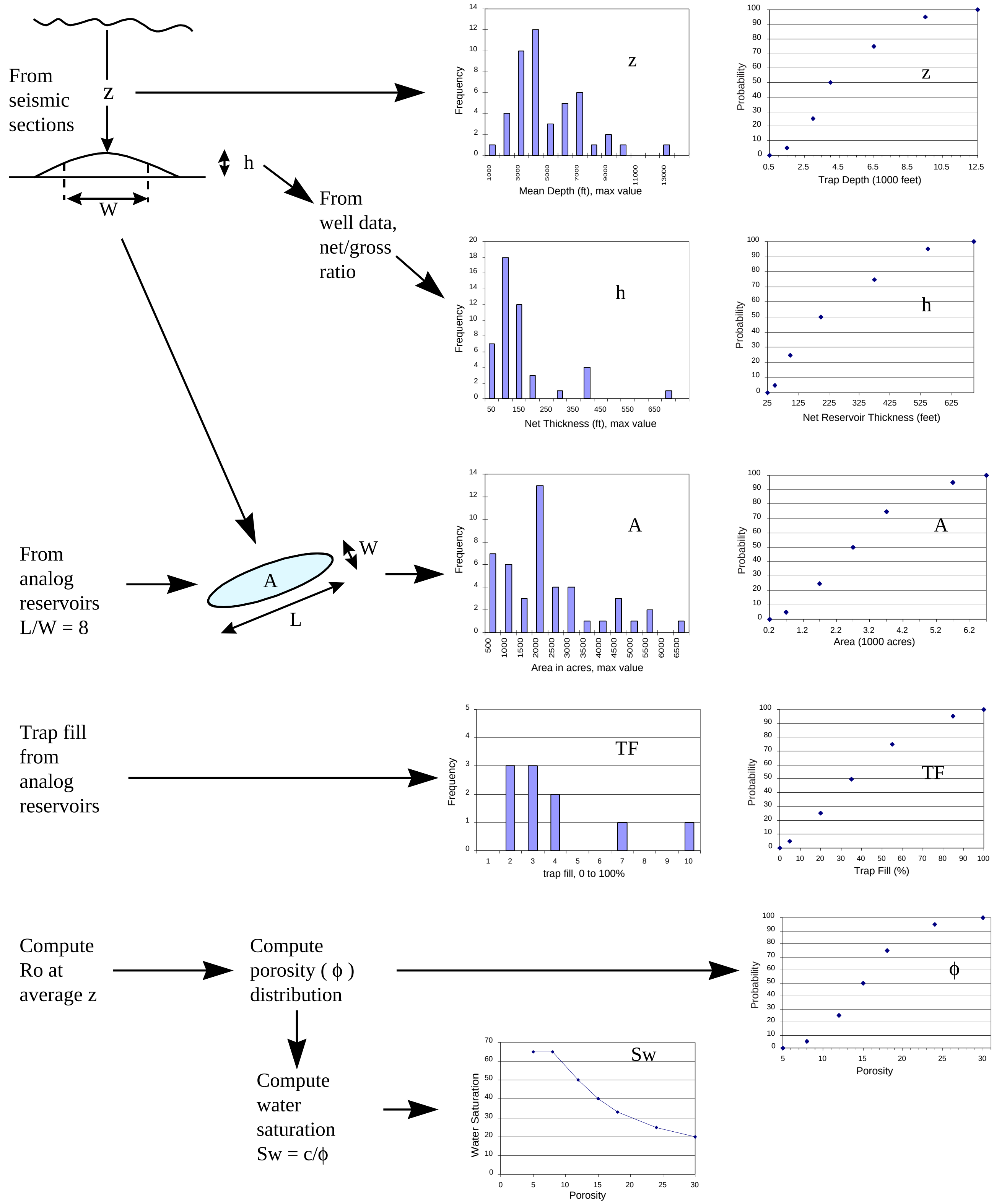

Figure P8-2. Diagram showing the steps used in preparing the volumetric parameters for the Thin-skinned Thrust-belt Play.

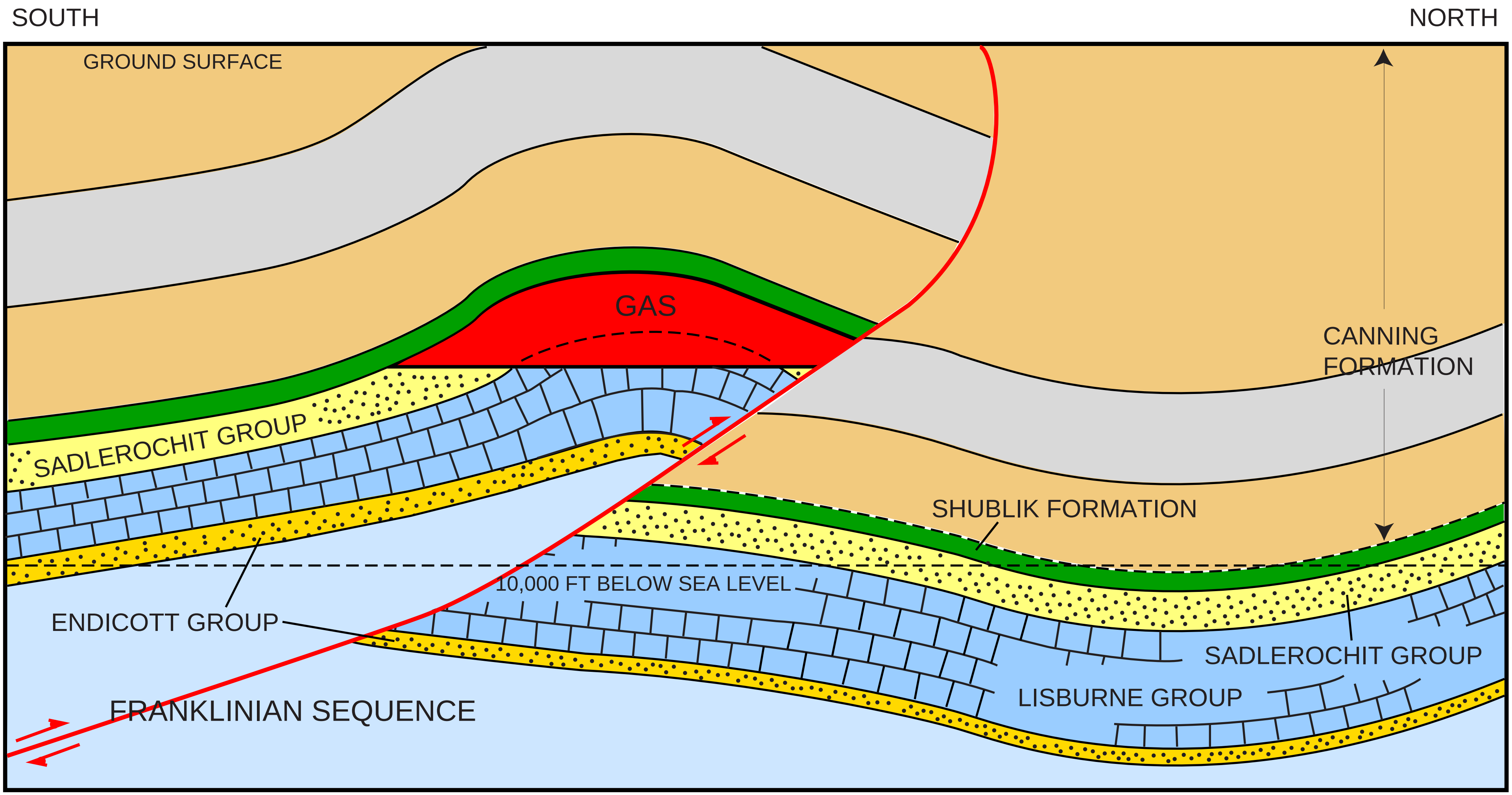

Figure P9-1. Ellesmerian Play. Generalized cross section showing the Ellesmerian sequence (Lisburne Group, Sadlerochit Group, Shublik Formation) and the underlying Franklinian sequence rocks, which are involved in large-scale folds and thrusts. This is a confirmed play because of the gas accumulations at the Kavik field just southwest of the 1002 area.

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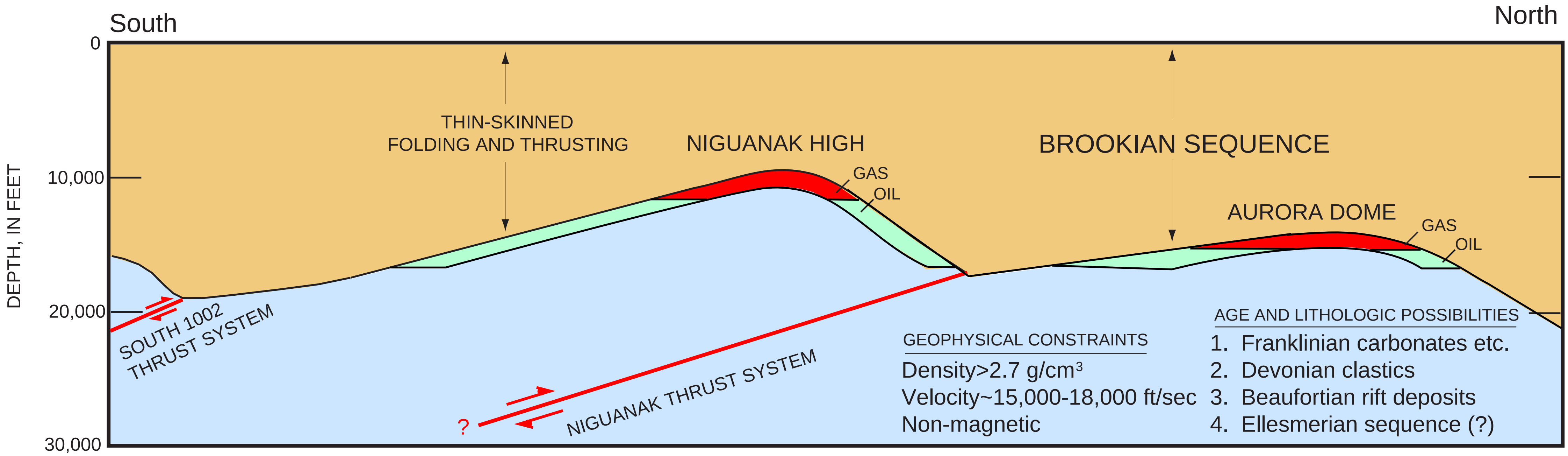
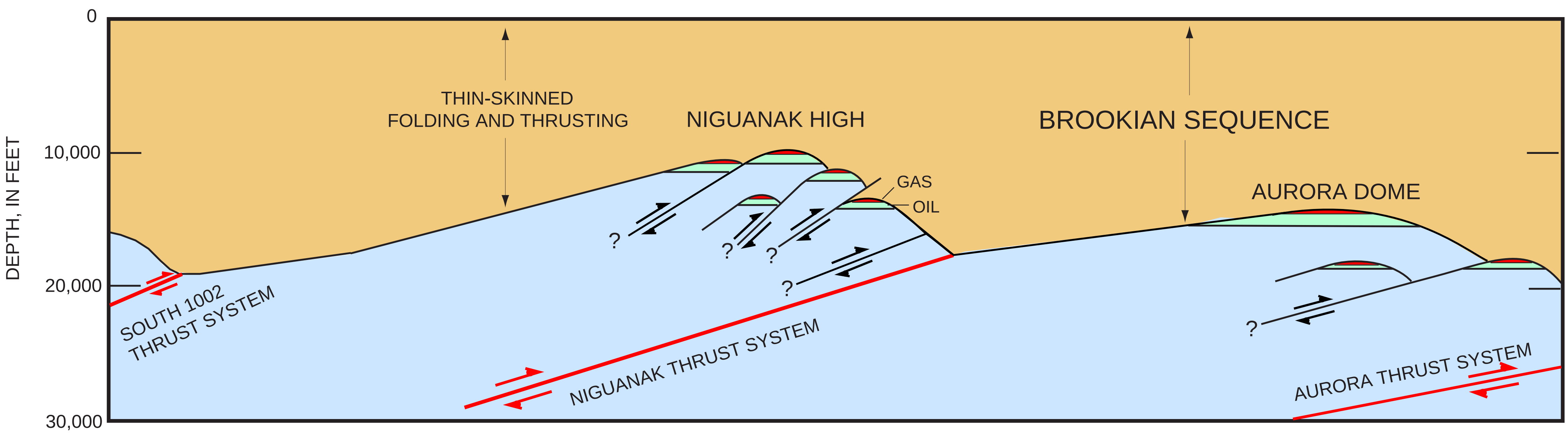


A. Two-prospects scenario



B. Many-prospects scenario

Figure P10-1. Niguanak-Aurora play. This play involves two uniquely large prospects in the northeastern part of the 1002 area (Fig. NA1). Both structures appear to be composed of imbricated stacks of north-verging thrust sheets of enigmatic composition (Grow and others, Chapter NA). Two different scenarios were considered for the Niguanak high and Aurora dome, depending on whether the structures are or are not broken into multiple reservoir compartments.