Chapter FP

FORMATION PROPERTIES

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CONTENTS

FIGURES

TABLES

ABSTRACT

Eighteen formations, ranging from the basement complex to the Sagavanirtktok Formation, are penetrated by wells west and north of the 1002 Area of the Arctic National Wildlife Refuge. Geological and physical properties can be characterized from data provided by these well penetrations, so that these properties may be inferred within the 1002 Area. In this report we describe the individual formations, point out some rock characteristics as revealed by the well logs, and cite core and log data bearing upon reservoir quality for those formations with reservoir potential.

INTRODUCTION

Each formation expected in one or more of the ANWR plays is described herein in terms of its geological aspects, its well log responses, and, if a potential reservoir, its reservoir quality. Geologic descriptions are in part paraphrased from Bird and Molenaar (1987) and from Bird and others (1987). The well log responses are based upon inspection of the well log plots presented by Nelson and others (Chap. WL). The comments on reservoir quality rely upon drill stem test reports, laboratory data from conventional cores, and capillary pressure data which are presented by Nelson (Chap. PP). Core data and drill stem test results are also shown on the well log plots.

BASEMENT ROCKS

Geologic description. The basement complex, or pre-Mississippian rocks, ranges in age from Precambrian to Devonian and contains a wide variety of lithologies. Of these, carbonate rocks have the best reservoir potential. The Katakturuk Dolomite, of probable Proterozoic age, consists predominantly of light-gray vuggy dolomite. The Nanook Limestone consists of nearly equal amounts of fine-grained limestone and medium-to-coarse-grained, partly vuggy, stromatolitic dolomite. In addition, carbonate rocks of unknown age occur in a basement complex composed largely of argillite in wells in the Point Thomson-Flaxman Island area northwest of the 1002 area (Dumoulin, Chap. CC). The frequencies of occurrence of carbonate rocks, taken from well data, are given in Table FP1.

Well log response. High gamma ray values and density values in excess of 2.7 g/cm^3 indicate calcareous shale from 13,500 feet to TD in well Alaska

State A-1 (Fig. FP1). A thick, massive carbonate interval from 13,260 to 13,410 feet is defined by most logs; gamma-ray values drop to less than 20 API and sonic times decrease to around 50 μs/ft. Limestone and dolomite are also reported in the mud log and in core within the interval 13,000-13,090 feet. Quartzite and schist are reported between 12,925 and 13,000 feet.

An interval of probable Nanook Limestone, previously called Katakturuk Dolomite by Bird and others (1987), comprises the basement rocks penetrated by well Canning River Unit A-1, as shown in Fig. FP2, where the response of the Nanook can be compared with that of the Lisburne Group. The well logs indicate a massive, low (nearly zero) porosity formation devoid of any interbeds. The gamma-ray log is extremely low (6.4 API units from 8,220 to 8,830 feet). Resistivity exceeds 1000 ohm-m except in a few intervals likely to be fractured. The laterolog-8 resistivity curve declines in nine zones, totaling 120 feet out of 654 feet of total penetration. Hence it is possible that up to 18% of total thickness is fractured to some degree. In general, density and neutron logs indicate porosity to be in the 1% range, consistent with 9 core measurements from the bottom of the well which average 0.7% (Table 7.4 of Bird and others, 1987). Sonic travel time averages 48.1 s/ft. At least in this 654-foot sampling of the Nanook, reservoir quality must be judged to be poor.

Reservoir quality. Most of the pre-Mississippian rocks have been subjected to deep burial, heating, and deformation to such an extent that they are not considered prospective for oil or gas. However, some carbonates in the basement complex drilled from the barrier islands north of Point Thomson do contain gas and condensate (see Summaries of drill stem tests for basement rocks).

Analyses of 43 Katakturuk Dolomite cores from outcrops in Katakturuk Canyon of the Sadlerochit Mountains give porosity values for 35 samples of 2.5% and less, with values from the other 8 samples ranging from 3 to 10% (Bird and others, 1987). Permeabilities for these samples were 1 md or less, with many samples less than 0.1 md. From a second study (Clough, 1995), analyses of 20 Katakturuk Dolomite cores from outcrops in the Sadlerochit and Shublik Mountains yielded an average porosity of 3.3% with a range from 0.5 to 8.6%; characteristics of these samples are discussed by Dumoulin in Chap. CC. Again, permeability values were 1 md or less, with 7 samples less than 0.01 md.

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ELLESMERIAN SEQUENCE

Kekiktuk Conglomerate (Endicott Group)

Geologic description. The Kekiktuk Conglomerate is the lowermost of three formations assigned to the Endicott Group, the basal unit of the Ellesmerian sequence. It is composed of as much as 450 feet of nonmarine conglomerate, sandstone, shale, and minor amounts of coal in outcrops. This formation and the overlying Kayak Shale are much thicker in local downwarpings such as the elongate, half-graben that extends from just east of Prudhoe Bay southeasterly toward the ANWR. LePain and others (1994) in their study of Kekiktuk exposures in the northeastern Brooks Range note a fundamental difference between subsurface Kekiktuk in syndepositional extensional fault-bounded basins and outcrop Kekiktuk in an incised upland setting. They recognize six depositional units that record the progressive infilling of a complex network of paleovalleys as much as 420 feet deep developed along the sub-Mississippian unconformity. As the paleovalleys were gradually filled, fluvial environments were superseded by marginal-marine and shallow marine environments. They note further that Kekiktuk distributed in a network of paleovalleys presents a much different subsurface exploration target than Kekiktuk in graben-filling settings. They did not observe fault-bounded Kekiktuk basins in outcrop but wideley scattered exposures and structural complications related to contractional Brookian deformation may obscure their presence.

Well log response. High variance on well logs (Fig. FP3) is caused by (1), large changes in physical properties among sandstone, shale, and coal and (2), bed thicknesses at or below the resolution of logging tools. Thin bed effects cause resistivity tools to give a wide range of readings over short distances. Even zones which appear on the gamma ray to be clean sandstone or conglomerate (for example, 14,520-14,590 feet) contain thin beds of coal or shale.

Reservoir quality. The Kekiktuk Conglomerate forms the reservoir rock in the Endicott Field. Average reservoir parameters are given in Table FP2.

Using a regression equation from Johnsson and others (1993), a value of R_o=0.620 is obtained at a depth of 10,300 feet in well Sag Delta #8. This well is located one mile from the northwest extremity of the Endicott Field.

Three samples from well West Mikkelsen State 1 display entry pressures around 10 psi and well-connected pore distributions (Figs. PP5c and PP6b). The well log character for two of the samples can be viewed in Fig. FP3.

In their analysis of Kekiktuk porosity in the E De K Leffingwell 1 well prior to drilling, Bloch and others (1990) evaluated the effects of framework grain composition, depositional facies, and postdepositional processes, basing their evaluation on about a dozen previous Kekiktuk well penetrations. They concluded that Kekiktuk grain composition (uniformly chert and quartz) is not responsible for observed porosity variations. They interpret the depositional environment of the Kekiktuk to consist of wet-climate fan-deltas. The Leffingwell location is interpreted as the distal, fine-grained facies of a fan-delta, whereas the Endicott field area with its better porosity is located in the proximal, coarser-grained facies. Silica cementation related to burial is the primary postdepositional porosity reducing process. Using burial-history plots, they report successfully predicting an average sandstone porosity of about 6-percent for the Kekiktuk in Leffingwell-1, in agreement with reported log-calculated porosity. Petrographic examination of cuttings shows early quartz overgrowths followed by carbonate cement. Minor dissolution of chert is evident and the resultant secondary pores are partly filled with kaolinite and quartz. Tar-stained kaolinite books filled some pores.

Kayak Shale (Endicott Group)

Geologic description. The Kayak Shale either gradationally overlies the Kekiktuk or, where the Kekiktuk is absent, unconformably overlies the basement complex. The overlying Itkilyariak Formation is not recognized in the wells described herein. The Kayak consists of dark gray marine shale, generally with minor amounts of interedded sandstone near the base and increasing amounts of interbedded limestone and dolomite near the top. Microfossils and megafossils from limestone interbeds indicate the Kayak Shale is Late Mississippian. The overlying Itkilyariak Formation of Mull and Mangus (1972) is recognized only in the West Mikkelsen-1 well where it is reported in Table WL4 as Kayak Shale. The Itkilyariak has a lithologic assemblage similar to that of the Kayak and is distinguished mainly by its red color. It is an areally extensive rock unit in the subsurface of the greater Prudhoe Bay area (e.g., Bird and Jordan, 1976). The West Mikkelsen-1 location is apparently close to the easternmost subsurface extent of the Itkilyariak.

Well log response. The top of the Kayak Shale can be identified on most logs (Figs. FP4 and FP2). Bedding thicknesses of 1 to 5 feet are reflected by high variance in most of the logs. Sonic values in the shalier intervals are approximately 80 μs/ft. Resistivity values are in the 2 to 20 ohm-m range in Mikkelsen Bay State 1 (Fig. FP4) but are in the 80-200 ohm-m range in Canning River Unit A-1 (Fig. FP2). Higher resistivity values, coupled with lower gamma ray and lower neutron response, indicate that the Kayak Shale in Canning River Unit A-1 is considerably siltier (less clay) than in Mikkelsen Bay State 1.

Lisburne Group

Geologic description. The Lisburne Group, of Mississippian and Pennsylvanian age, is composed of limestone with lesser amounts of dolomite and minor amounts of shale and sandstone. Generally, the Lisburne Group gradationally overlies the Kayak Shale and is unconformably overlain by the Sadlerochit Group. Its thickness in outcrop is 1,400 to 2,800 feet. The lower part of the Lisburne, known as the Alapah Limestone, consists of medium-gray, recessive-weathering limestone and dolomite. The upper part, known as the Wahoo Limestone, consists of light-gray, massive and resistant-weathering limestone with minor amounts of dolomite. Dolomite and dolomitic limestone in the Lisburne may have good porosity.

Stratigraphic relations, rock types, and fossils indicate the Lisburne was deposited in a clear, relatively warm, shallow sea. The gradation from predominantly clastic sedimentary rocks (Endicott Group) to predominantly carbonate rocks (Lisburne Group) indicates continued subsidence and a significant reduction in the amount of terrigenous sediment reaching the sea. From the latest Mississippian to the Middle Pennsylvanian, sedimentation kept pace with subsidence and produced thick, shallow-water, bioclastic limestones. Regional upwarping resulted in a retreat of the sea and the development of an erosional unconformity at the top of the Lisburne.

The occurrence of dolostone in the Lisburne in outcrop south of the 1002 Area and in wells west of the 1002 Area is discussed in Chap. CC. Studies of the Lisburne Group outcrops, generally south of the 1002 Area, are summarized in Watts and others, 1995.

Well log response. Logs in Fig. FP5 alternately reflect carbonates (low gamma, high resistivity, low sonic) and shaly clastics (high gamma, low resistivity, high sonic). Throughout the interval from 6,120-6,400 feet, density is higher and sonic travel time is lower than in the rest of the display, and the neutron porosity increases slightly (from nearly zero): these shifts in properties are indicative of dolomite rather than limestone within this interval. Porosity in the carbonates is extremely low, about 1%; all logs are consistent with regard to low porosity in well Canning River Unit A-1.

Reservoir quality. The following descriptors of controls on oil storage and flow in the Lisburne reservoir are taken from Jameson (1994):

1. Four major elements form the Wahoo reservoir in the Lisburne field: (a) depositional layering and stratification, (b) multiple stages of porosity formation, (c) the subunconformity alteration zone (SAZ), and (d) major faults and megafractures. A tortuous flow path exists through these four elements: The first step is cross flow within pay layers to high-permeability streaks, usually found in dolomites. Pay layers then drain into faults and megafractures, and subsequently flow upward to the SAZ and laterally into the well bore. Flow paths vary across the field depending upon the manner of porosity formation, fracturing, and the presence or absence of the SAZ.

2. Roughly 60% of total porosity is Cretaceous-Tertiary in age, and the remainder is in Permian-Triassic dolomite. The Lisburne field is one of the largest carbonate reservoirs in which most porosity is relatively late, i.e., much younger than the host rock. Significant limestone porosity occurs only within and above the transition zone between oil and water. Enormous porosity enhancement occurs below and adjacent to the lower Cretaceous unconformity (LCU) which cuts the Lisburne along the eastern edge of the field. Porosity values as high as 40 to 50% were found in cores; these values are the highest in limestone in the field.

3. When compared with other Paleozoic carbonate oil fields, the Lisburne field has relatively high porosity and low permeability. Porosities in the 10-15% range are common, but these values correspond to an air permeability of 0.1 md and a value closer to 0.01 to 0.001 md at reservoir conditions. The small size of most pores (10-20 μm) is the greatest limitation to

permeability.

4. The subunconformity alteration zone (SAZ) is a unique layer at the top of the formation. It is a thin layer of fractured ferroan dolomite to ankerite which provides very rapid lateral communication over limited distances. In several early wells, nearly all production came from the top few feet in the SAZ. The SAZ is fed via crossflow from fractures in vertical communciation with underlying pay away from the borehole.

5. The effectiveness of faults is best revealed in field performance data. Two cored wells with production logs have each produced over 1.5 million bbl of oil in two years. Neither of these wells has significant matrix porosity or permeability in core or logs.

Permeability and porosity data presented by Belfield (1988) are shown here as Fig. FP6. The 515 data points on unfractured samples indicate a value of 0.1 md at 12% porosity and exhibit a fairly consistent trend on a logk-φ plot. (Jameson (1994) uses a pay cutoff of > 0.1 md.) The samples were measured with confining pressure of 1870 psi and therefore seem to indicate higher matrix permeabilities than those reported by Jameson (1994). The porosity data from Fig. FP6 and statements by Jameson were combined to form a cumulative distribution for porosity in the Lisburne Field (Table FP3). The value of φ_{50}=10% coincides with the field-wide average cited by the Alaska Oil and Gas Commission (1995).

Hanks and others (1997) analysed the lithologic and structural controls on natural fracture distribution and behavior within the Lisburne Group in the northeast Brooks Range and the subsurface Prudhoe Bay area. They found two main fracture orientations: a north-northwest regional trend that is throughgoing and relatively evenly distributed and an east-northeast trend related to local structure that is variable in character and distribution. A correlation was found between lithology and fracture distribution in more gently deformed areas, with finer grained, more dolomitic lithologies more densely fractured than coarse-grained carbonates. The relationship does not seem to hold in more highly deformed areas. Tight, upright folds may have less fracturing (but more dissolution fabrics) than more gentle folds. Interbedded lithologies with high competency contrasts involved in flexural slip folding may result in high fracture densities on the limbs of anticlines. Thin (<30 cm) shale layers can act as significant impediments to vertical fracture permeability. Fractures related to local, high-angle transverse faults are limited in areal extent, are generally found immediately adjacent to the faults and do not necessarily develop parallel to the faults. Subsurface studies suggest that fracture behavior may be dynamic in that fractures kept open by low differential regional stresses may close (irreversibly) with a drop in formation pressure related to hydrocarbon production. This observation suggests that it may be important to establish the relation between fractures and the regional stress field early in the exploration and production process.

According to Crowder (1990) shallow karst zones are developed in the uppermost Lisburne beneath the Permian (sub-Echooka Formation) unconformity in the Sadlerochit Mountains. Erosional relief on this unconformity of as much as 66 feet may be present locally with perhaps ten times as much regionally.

Echooka Formation

Geologic description. The Echooka Formation consists of 150 to 450 feet of sandstone and siltstone which comprise the basal marine transgressive deposits formed during the northward advance of the sea across the eroded platform composed of Lisburne Group carbonate rocks. According to Crowder (1990), in the Sadlerochit and Shublik mountains, a laterally restricted, crudely channelized chert-pebble and cobble conglomerate forms the base of the Echooka Formation at many localities. The conglomerate, as much as 79 feet thick, is confined to paleovalleys trending northeast-southwest that may have been as wide as 2.5 miles. Above the conglomerate, the Echooka is a well-stratified succession of sandy, fossiliferous calcarenite characterized by upward-fining cycles. Conglomerate layers, which dominate the cycles near the base, become thinner upsection and are replaced by plane-parallel laminated calcarenite. A marked upsection increase in bioturbation is also observed. The upper part of the Echooka is composed of laterally persistent, upward-thinning and upward-fining, glauconitic quartzarenite and siltstone layers medium to thickly bedded separated by intervals of thinly laminated, red, green, and black glauconitic shale. The quartzarenite layers contain abundant hematite-stained burrows and disseminated organic matter and they are intensely bioturbated resulting in the destruction of most primary stratification. Concentrations of glauconite and pyrite characterize various layers.

Well log response. Logs show a single 30-foot thick sandstone unit within a 175-foot thick Echooka Formation at 5,560-5,590 feet in the Canning River Unit A-1 well (Fig. FP7). Otherwise, the logs indicate a generally fining-upwards sequence.

Kavik Member of Ivishak Formation

Geologic description. Consists of 100 to 400 feet of dark-colored, laminated to thin-bedded, silty shale and siltstone, representing prodelta deposits that thicken southward and grade upward into the massive deltaic sandstone. Crowder (1990) notes that sandstone interbeds within the member form a symmetric pattern in vertical sequence, expressed as an upward-thinning and upward-fining cycle, followed by a coarsening and thickening trend that continues into the base of the overlying Ledge Sandstone Member. In the lower 16 to 33 feet of the Kavik shale, quartzarenite interbeds thin rapidly upsection and lose identity entirely within siltstone that composes the middle 30 to 100 feet of the member. The pattern is repeated in reverse in the upper 30 to 100 feet of the Kavik Member, where sandstone interbeds reappear, thicken abruptly upsection, and grade into the overlying Ledge Sandstone Member.

Well log response. Gamma-ray, neutron, resistivity, and sonic logs display a gradational change from shale at bottom of the member to siltstone at top (Fig. FP7). Density log values of 2.68 g/cm^3 indicate negligible porosity throughout the member in well Canning River Unit A-1.

Ledge Sandstone Member of Ivishak Formation

Geologic description. Consists of massive deltaic, northward-thickening and coarsening sandstones ranging in thickness from 100 to more than 575 feet. Sedimentary structures, burrows, and occasional fossils indicate a shallow-marine environment of deposition. The sandstone has low porosity because of silica cementation. In outcrops south of the 1002 area, Crowder (1990) recognizes three parts of the Ledge Member. The lower 80 to 200 feet of the Ledge is composed of medium- to thick-bedded, fine-grained quartzarenite composed of multiple upward-thickening, then thinning, cycles deposited entirely within shallow-marine conditions.The middle 60 to 130 feet of the Ledge is a sequence of upward-thickening and upward-coarsening sandstone and conglomerate overlain by siltstone. These depositional units are interpreted as transitional between marine and nonmarine environments of the lower delta plain and represent the best potential hydrocarbon reservoir facies in the Ivishak Formation. The upper 65 to 130 feet of the Ledge is most variable consisting of interbedded fine- to medium-grained quartzarenite and dark-gray silty shale and sandy siltstone organized into irregular depositional units averaging 25 feet thick. It represents deposition in a lower delta plain environment.

Well log response. Porosity is low throughout the Ledge Member. Porosity in the massive sandstone unit extending from 4800 to 5000 feet in Fig. FP7 is low, as shown by density values of 2.65 g/cm^3, neutron porosity values of 5%, core porosity measurements of 6% and less, and sonic slowness of 55 µs/ft. Because the porosity is low, the neutron log responds mainly to clay minerals in siltstones and mirrors the gamma-ray log. The logs show sandstone-siltstone interbedding throughout the Ledge Member, with the exception of the aforementioned massive sandstone. Resistivity alternates between 30 ohm-m typical of the siltstone and 300 ohm-m typical of the sandstone. Contacts on the logs are gradational with the overlying and underlying units.

Reservoir quality. The excellent reservoir characteristics of the Ledge Sandstone in the Prudhoe Bay field are generally agreed to be the result of a combination of primary and secondary porosity. According to Shanmugam and Higgins (1988), the high porosities are the result of secondary enhancement caused in large part by leaching of detrital chert grains. Weathered chert, authigenic kaolinite, formation waters of meteoric origin, and increase of core porosity and permeability toward the regional Lower Cretaceous unconformity (LCU) are considered evidence for unconformity-related diagenesis. Other investigators (cited in Shanmugam and Higgins) report leaching of early carbonate cement to be an important part of the story. Payne (1987), on the other hand, attributes a long, initial period of shallow burial (~2000 ft) which maintained a loose packing density without early cementation and that later, leaching of chert grains and siderite cement increased porosity. Filling of the reservoir prior to maximum burial was also important. Erickson and Sneider (1997) show that oil filled the reservoir by about 40 m.y. (late Eocene) and that the structurally highest part of the field at that time was at a depth of about 5,000 ft (compared to a present-day depth of 8,000 ft). Once filled with oil, the reservoir should have undergone little if any change in porosity.

Comparison of Ledge Sandstone burial history at Prudhoe Bay (Payne, 1987) with that of the general 1002 area (Marinai, 1987) reveals similar shallow burial (about 2,000 ft) from Triassic to Early Cretaceous time. During Early Cretaceous, both areas were uplifted and partially eroded by the LCU. Subsequently, both areas were buried to maximum depths during Tertiary time. The Ledge in the 1002 area was probably buried much more rapidly than Prudhoe (maximum burial reached at 40 Ma vs 10 Ma or less) and to much greater depths (15,000 ft or greater vs 8,000 ft).

A value of $R_o = 0.405$ was derived from the R_o vs. depth regression equation given by Johnsson and others (1993) for well Prudhoe Bay Unit R-1, assuming a mean reservoir depth of 8,700 feet for Prudhoe Bay Field. In contrast, thermal maturity in the Canning River Unit A-1 well, as measured by vitrinite reflectance, is 1.8 by regression analysis (coefficients a=1.1557972E-4 and b=0.789) at formation mid-depth, and 0.96 and 1.54 from two samples.

Fire Creek Siltstone Member of Ivishak Formation

Geologic description. Consists of as much as 500 feet (in wells Kemik Unit 1 and 2) of siltstone and argillaceous sandstone deposited during a deepening of the sea. Crowder (1990) characterizes the Fire Creek in outcrop as the least variable member of the Ivishak Formation. It is indistinctly bedded and contains highly bioturbated sandy siltstone intervals, which are punctuated by thin quartzarenite beds at no apparent preferred position. Deposition is interpreted to have been entirely within shallow-marine environments at relatively low rates of sedimentation.

Well log response. All logs in Fig. FP7 indicate a layered sequence presumed to be siltstone and shale. Resistivity ranges from 10 to 100 ohm-m; sonic slowness ranges from 55 to 75 µs/ft; gamma ray averages 75 API units.

Shublik Formation

Geologic description. Consists of fossiliferous limestone and calcareous shale, distinctively dark in color. It is 300 to 500 feet thick in the outcrop belt, and depositionally thins to the north in the subsurface west of the ANWR (Table WL6). It has four vertically separated facies: a lower siltstone, a fossiliferous limestone, a mudstone, and a calcareous siltstone. Phosphatic nodules and cements are common just above and below the limestone facies. Rich in organic carbon, it is considered to be an important source rock for Prudhoe Bay oil. It represents continued subsidence of the basin following Sadlerochit deposition. Fine-grained clastic and chemical sedimentation predominated in a sea rich with organisms.

In basin margin positions such as at Prudhoe Bay, the northern part of the Yukon Territory (Dixon and others, 1996), and perhaps even the 1002-area, the Shublik may have reservoir as well as source-rock potential. Kupecz (1995) describes the Shublik Formation within the Prudhoe Bay field as a potentially economic hydrocarbon reservoir comprised of mixed lithology and mineralogy. Its composition includes limestone, phosphate, shale, siltstone, and sandstone, as well as accessory amounts of siderite, glauconite, pyrite, kaolinite, and dolomite. Dissolution of carbonate allochems in the carbonate packstone/grainstone facies resulted in the creation of moldic porosity that improved both porosity and permeability. Areas of highest porosity are in the northern and northeastern parts of the field, which correspond to a combination of facies-controlled reservoir quality improvement toward the northeast and carbonate dissolution along the Lower Cretaceous unconformity and the North Prudhoe Bay fault zone. Oil in place for the Shublik within the Prudhoe Bay unit is estimated to be between 250 and 500 million bbl.

Well log response. The Shublik is characterized by a mean density of 2.67 g/cm^3, and mean sonic slowness of 61 μs/ft (Fig. FP8). High (>150 API units), erratic gamma-ray values throughout most of the Shublik reflect probable uranium in organic material. Resistivity values exceed 100 ohm-m in the limestone and calcareous siltstone units. Resistivity values less than 100 ohm-m are attributed to the lower siltstone facies and the mudstone facies.

Sag River Sandstone

Geologic description. The Sag River Sandstone consists of a gray, resistant, quartzitic sandstone that conformably overlies the Shublik Formation. It ranges in thickness in outcrop, where it is called the Karen Creek Sandstone, from 10 to 125 feet. Marine fossils, bioturbation, bedding features, and widespread distribution indicate depostion over a broad, shallow shelf during a minor regression of the sea. The Sag River Sandstone is oil productive in some wells in the Prudhoe Bay area and contains gas in the Kavik field.

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In the Prudhoe Bay oilfield area, Barnes (1987) describes the Sag River Sandstone as a bioturbated, glauconitic, phosphatic, argillaceous, quartzose fine- to very fine-grained sandstone and siltstone that thins southward from 55 ft to 20 ft in less than 10 miles. The sandstone is composed of quartz, chert, glauconite pellets, and detrital clay stringers and laminae. Average core-plug porosity ranges from 27- to 14-percent and permeability, from 100- to <5-md. Porosity loss is the result of compaction and cementation by clay coatings of grains, minor intergranular phosphate, siderite, quartz overgrowths, carbonate cement. The main reservoir deficiency is the association of low permeability with moderate to high porosity—a function of small pore size. The areal distribution of porosity and permeability show a remarkable correlation to the zone of truncation by the LCU. Contoured values of both porosity and permeability generally parallel the truncation and show increasing values with proximity to the unconformity.

Well log response. Gradational changes in logs reveal a shale-siltstone (coarsening upwards) sequence in lower two-thirds of the Sag River Sandstone (Fig. FP8). Gamma-ray peaks in a ten-foot unit exceed 110 API units, indicating a bed rich in organic material. Barnes (1987) describes a 1-ft thick interval rich in glauconite that coincides with the most prominant gamma-ray marker in the formation in the Prudhoe field area. This bed occurs about 5-10-ft below the top of the formation.

Reservoir quality. The median porosity of the Sag River Sandstone in two wells is 3.5 and 9.0% (Table FP5).

Kingak Shale

Geologic description. The Kingak Shale is a thick marine shale of Jurassic and Early Cretaceous age. It was deposited during the time of extensional faulting along the north Alaska coast. In recognition of this tectonic regime, distinct from the Ellesmerian sequence below and the Brookian sequence above, it was designated a separate sequence—Beaufortian according to Hubbard and others (1987) and Barrovian according to Carman and Hardwick (1983). As defined, the Beaufortian sequence includes the Kingak Shale and related sandstones such as the Kuparuk Fomation, the Kemik Sandstone, and the Thomson sand. In wells east of Prudhoe Bay and north of the Beli well, the Kingak is missing by erosion beneath the LCU. South of the truncation edge it thickens to a maximum of 4,000 ft or more in the Kemik wells, southwest of the 1002 area. The Kingak Shale consists primarily of dark-gray to black, fissile, noncalcareous, clayey to silty shale and less amounts of siltstone. The siltstone and silty shale constitute the middle part of the formation. Ironstone concretions are common to rare throughout the formation. The Kingak is considered a petroleum source rock for Prudhoe Bay field.

Well log response. Resistivity, neutron, and sonic logs reflect the siltstone/silty shale unit from 3,680-4,040 feet (Fig. FP8). Note that the borehole is enlarged throughout most of the Kingak Shale. The contact with the overlying Kemik Sandstone can be discerned on all logs.

Kuparuk River Formation

Geologic description. The Early Cretaceous Kuparuk River Formation is a marine sandstone and shale formation found in the subsurface Prudhoe-Kuparuk area (Fig. FP9). The formation is stratigraphically complex consisting of multiple marine sandstone bodies and unconformities that developed during a time of extensional faulting. The Kuparuk is divided into two members separated by the regional Lower Cretaceous unconformity. The lower member is Berriasian(?) and Valanginian in age and is characterized by as many as six southeasterly prograding sandstone units which characteristically show upward-coarsening log patterns (Masterson and Paris, 1987; Carman and Hardwick, 1983). The upper member of the Kuparuk, the C-unit, overlies the regional Lower Cretaceous unconformity (LCU) and is Hauterivian to Barremian in age. The C-unit is both a stratigraphic- and age-equivalent of the Kemik and Thomson sandstones.

In the Aurora well, the interval from 16,440 to about 17,090 ft displays Kuparuk-like characteristics (Fig. FP10). The uppermost 500 ft of the Kingak Shale (about 17,090 up to 16,620 ft) is of probable Valanginian age (M. Mickey, Micropaleo Consultants, 1997, personal communication) and displays an upward coarsening log pattern. Samples indicate a gradation from shale upward into siltstone and sandstone. Above, from 16,620 to 16,440 ft, is an interval of sandstone that displays a rather blocky log shape suggesting that it may rest unconformably on the upward-coarsening interval just below. According to M. Mickey, the lower part (16,530 to 16,620 ft) is probable Valanginian and the upper part (16,440 to 16,530 ft) is probable Hauterivian. This sandstone is one of the potential reservoir rocks considered in the assessment of the Niguanak/Aurora play. Approximately 100 miles southeast of the Aurora well on the coastal plain of the northern

Yukon Territorry of Canada, the Spring River and Roland Bay wells have penetrated similar-appearing sandstones at the top of a thick interval of Kingak Shale. Known as the Mount Goodenough Sandstone, the interval of sandstone in the Roland Bay well occurs from 4,660 to 4886 ft and that in the Spring River well, from 2,804 to 2,974 ft (J. Dixon, Geological Survey of Canada, 1986, personal communication).

Reservoir Quality. Data on vitrinite reflectance and porosity were obtained from two operating fields.

Kuparuk River Unit. The A unit of the lower member of the Kuparuk Formation is a heterolithic sequence of sandstones, siltstones, and mudstones in a series of regressive cycles (Carman and Hardwick, 1983). Intergranular clays are sparse (less than 5% volume) and are predominantly kaolinite and illite. From 184 core plugs from 11 wells, the arithmetic mean porosity is 23% and the mean horizontal permeability is 81 md. Gross thickness of the A unit is approximately 100 feet and cumulative pay-quality sandstone thickness can range up to 30 feet.

The C unit of the Kuparuk upper member consists of sandstones and siltstones with intergranular clay (Carman and Hardwick, 1983). Glauconite can comprise up to 25% of granular content. Reservoir volume is reduced by bands of siderite-bearing sandstone up to 8 feet thick. Based upon 260 core plugs, the arithmetic mean porosity is 21%. The mean permeability is 90 md, ranging from less than 1 to over 1,350 md. Cumulative pay-quality sandstones may be as thick as 60 feet. Gross thickness of the C unit ranges up to 150 feet. The C unit is a stratigraphic equivalent of the Kemik Sandstone.

An average porosity value for the Kuparuk River Unit of 21% was cited by the Alaska Oil and Gas Commission (1995). Using 6,100 feet as mean reservoir depth, we obtained a vitrinite reflectance value R_o of 0.422 from a regression equation by Johnsson and others (1993) for well Kuparuk River Unit #3A.

Milne Point Unit. Using 6,500 feet as mean reservoir depth, we obtained R_o=0.446 from a regression equation by Johnsson and others (1993) in well Kavearak Point #1. An average porosity value of 22.8% was cited by the Alaska Oil and Gas Commission (1995). Porosity, saturation, and thickness values determined from well logs in thirty wells are given in Table FP6.

Porosity averages from zones within individual wells range from 17 to 31%. Sharma (1994) states that the water saturation values cited in Table FP6 were calculated without the benefit of checking against core data, and appear to be high.

Kemik Sandstone

The Kemik Sandstone (and its equivalents, the Kuparuk C, the Put River sandstone, and the Thomson sand) and the pebble shale unit are separated by a regional unconformity from the rest of the underlying Ellesmerian sequence. However, they are included in the Ellesmerian sequence because they are derived from a northern source.

Geologic description. The Kemik Sandstone consists of fine to very fine grained , well-cemented, noncalcareous sandstone, in medium to thick beds. The medium to dark gray color is probably due to intermixed clay. The sand grains are composed mostly of quartz and chert. Bedding features, scattered fossils, and trace fossils indicate a shallow-marine origin for the Kemik Sandstone. Gross thicknesses of well penetrations in the Kemik are shown in Fig. FP11.

Well log response. The intercept of the Kemik Sandstone within Canning River Unit A-1 (Fig. FP8) has the best reservoir potential of the wells examined here. Here, the Kemik Sandstone is 45 feet thick and appears to be a silicified sandstone of uniform composition. Log character is identical within the section at 3,300 feet and the overthrust section at 3,100 feet. The caliper is less than bit size, indicating the formation of mud cake. However, porosity appears to be quite low, as indicated by the density values of 2.65 g/cm^3. Evidence for intermixed clay comes from gamma-ray values of 60 API, sonic values of 67 μs/ft, and neutron porosity values greater than density porosity values.

Reservoir quality. Overall, reservoir quality appears to be poor in the Kemik. Logs and cuttings description indicate that lithologies range from shale in the W. Kavik well, to interbedded siltstone, shale, and sandstone in the Beli well, to low-porosity siltstone in the Kavik 1, 2, and 3 wells. The Kemik was not cored in wells south of the Point Thomson area, but core was taken in the sandstone/siltstone facies west of Point Thomson, in the Badami 1, Mikkelsen Bay State, and West Mikkelsen 1 wells. The bulk of this core data has porosity values less than 7%, with only a scattering of values from 7 to 15%. The density log confirms that porosity values are generally less than 10%, with the exception of a few isolated thin beds. Variation in grain density due to the presence of siderite and glauconite, and the thin-bedded character, common in several wells, make it difficult to estimate porosity accurately from well logs. A drill stem test in the Fin Creek Unit 1 well recovered 43 bbl of fluid and gas-cut mud, with some gas to the surface. Drill stem tests in the Mikkelsen Bay State well recovered mud and a small quantity of gas, and measured very low shut-in pressures. (See "Summaries of drill stem tests" in Chap. WL).

Thomson Sand

Geologic description. The Thomson sand, penetrated by wells in the Point Thomson area, is a thick conglomeratic sandstone unit that is stratigraphically equivalent to the Kemik Sandstone. It is a lenticular sandstone body that attains a thickness of at least 300 feet and is of good reservoir quality. The conglomerate consists of pebble-to-boulder-size clasts of dolomite, which suggests that it is of local derivation--probably from pre-Mississippian rocks of the basement complex. Dominant lithology is a very fine to fine-grained dololithic sandstone. A typical framework modal composition is 53% detrital dolomite grains, 36% quartz grains, and 11% sedimentary and metasedimentary rock fragments (Gautier, 1987). Gross thicknesses of well penetrations in the Thomson are shown in Fig. FP11.

Well log response. Gamma-ray values range from 70 to 100 API in the Point Thomson wells. Sonic transit times are uniform through the Thomson and usually range from 70 to 75 μs/ft. In fact, all well logs are quite uniform within the Thomson Sand (Plate WL40), demonstrating the vertical uniformity of reservoir properties within the formation.

Grain density values (Table PP5) of 2.81 and 2.84 g/cm^3 in wells Point Thomson Unit 1 and 3 are consistent with a high dolomite fraction; the value of 2.96 g/cm^3 obtained from Alaska State C-1 would be consistent with a high concentration of iron, either as pyrite or as iron-bearing carbonates. Grain density values of 2.70 to 2.75 g/cm^3 in wells west of Point Thomson are consistent with a mix of dolomite (2.81) and quartz (2.65). Given these variations in grain density in the Thomson Sand, it is risky to assess porosity from density logs alone in wells where grain density values are not available.

Porosity was estimated from well logs in six wells (Fig. PP1g), using combinations of logs and core data. Five of the six wells show narrow distributions of porosity, with median values of the distributions ranging from 9 to 17%. These narrow distributions reflect the vertical uniformity of the Thomson sand. The sixth well, Point Thomson Unit 3, has a broader distribution ranging from 10 to 30% with a median value of 20%.

Reservoir quality. Drill stem tests produced condensate and gas from the Thomson in wells Alaska State C-1 (Fig. FP12), Alaska State F-1, Point Thomson 1, and Point Thomson 3. Five measurements on core samples (Fig. FP12) yield an average porosity of 17.6%; core samples from Point Thomson Unit 1 and Point Thomson Unit 3 yielded average porosities of 15.0% and 22.5% (Table PP3). Reservoir quality declines to the west of Point Thomson where Kemik Sandstone is encountered: (1) 28 core samples from well Badami 1 averaged 3.4% porosity and had permeability values of less than 0.1 md, and (2) entry pressures on samples from well W. Mikkelsen 1 exceed 300 psi (Figs. PP5e and PP6d).

Well log analysis of data from Point Thomson Unit 3 yielded a water content ranging from 4.9 to 8.6% with an average of 6%; water saturation ranging from 19 to 63% with an average of 35%; and porosity ranging from 10 to 29% with an average of 20%. A conventional Archie equation was used to obtain water saturations. No capillary pressure data were available from the Thomson sand.

Pebble Shale Unit.

Geologic description. The pebble shale unit either overlies the Kemik or Thomson sandstone or, where the Kemik Sandstone is absent, unconformably overlies the Kingak Shale or older rocks. In the Sadlerochit Mountain area, the pebble shale unit is 200 to 300 feet thick and consists of dark-gray to black, noncalcareous, clayey to silty shale containing minor scattered, rounded and frosted, quartz grains. Its upper contact is placed at the base of a highly radioactive bentonitic shale. This contact is readily apparent on gamma-ray logs. In the ANWR area, the pebble shale is a gas-prone source rock.

Well log response. The top of the pebble shale unit is picked on the well logs at the bottom of the high gamma-ray zone. It appears on the logs as a transition zone, especially on the neutron and density logs which show an upwards increase in porosity response within the pebble shale unit. (Fig.

FP12). It is 0 to 50 feet thick in the Point Thomson area and several hundred feet thick in the Kavik and Kemik areas (Table WL6).

BROOKIAN SEQUENCE

Hue Shale and Gamma-ray Zone

Geologic description. The Hue Shale consists of less than 1,000 feet of black, fissile, noncalcareous, clay shale, bentonite, and tuff. The gamma-ray zone, frequently referred to as the highly radioactive zone, is as much as 200 feet thick and comprises the lower portion of the Hue Shale. The Hue Shale is organic-carbon rich in its lower part (>4% organic carbon) and is considered to be a very good to excellent oil-prone source rock.

Well log response. Sonic values within the Hue Shale exceed 80 μs/ft; resistivity values are less than 10 ohm-m (Fig. FP12). The sonic exceeds 100 μs/ft from 13,240-13,340; this may be indicative of higher organic carbon content. The high gamma-ray response within the gamma-ray zone is attributed to uranium and thorium in organic matter and finely disseminated throughout the matrix (Carman and Hardwick, 1983). The general criterion for top of the Hue Shale is the depth where the gamma-ray response consistently exceeds 150 API, as illustrated in Fig. FP12.

Canning Formation

Geologic description. The type section is the section penetrated between 5,830 and 11,980 feet in the West Staines State 2 well. The upper contact is transitional and is placed at the change from shale to the dominantly sandstone lithologies of the Sagavanirktok Formation. In this study, the top of the Canning Formation was picked at the top of uniform gamma-ray and other logs, indicating a transition from massive shale to mixed lithologies. Use of this criterion placed the Canning-Sagavanirktok contact deeper than shown by Scherr and others, 1991. The basal contact of the Canning Formation is placed either at the lowest sandstone or siltstone interbed located above the Hue Shale, or on subsurface logs, at the boundary of decreased gamma-ray, increased resistivity, or decreased transit-time deflection at the top of the Hue Shale. The Canning Formation consists of slope and shelf deposits that are subdivided, in ascending order, into (1) a turbidite sandstone facies consisting of lower slope and basinal shale with sandstone interbeds, and (2) a thick slope and shelf shale facies.

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The turbidite sandstone facies consist mostly of bentonitic shale and siltstone, with generally thin beds of fine-grained sandstone. Thin beds of bentonite also occur in the Cretaceous section of the Canning Formation. The sandstone beds are generally less than a few feet thick. Graded bedding, bottom marks, and Bouma sequences, although not ubiquitous, indicate a turbidity-current origin for these sandstone beds. The position of the turbidites at or near the base of clinoform beds observed in wells and seismic sections west of the ANWR indicates deposition in water depths ranging from 2,000 to 4,000 feet or more.

The slope and shelf facies ranges in age from Paleocene to Eocence and possibly Oligocene. It consists of of silty, bentonitic shale with minor thin beds of very fine or fine-grained sandstone. The sandstone beds are turbidites in the lower part of the unit and shelf sandstones in the upper part, where they grade into the overlying Sagavanirktok formation.

Well log response and reservoir quality in turbidite sands. Logs from a portion of the Mikkelsen Tongue of the Canning, 2,600 feet thick in the Leffingwell well, are shown in Fig. FP13. Sandy intervals are centered at 5,700, 5,950, and 6,800 feet, as indicated by modest gamma ray, resistivity, and density log decreases. The decrease of sonic travel time with depth reflects compaction. The uniform well log values from 6,000 to 6,800 feet exhibit little evidence of interbedding, and indicate consistent depositional characteristics.

Logs in the Canning Formation from 11,100 to 12,450 feet in well West Staines (18-9-23) (Fig. FP14), are similar to the Mikkelsen Tongue of the Canning, but with shifts in average values reflecting porosity decreases which can be attributed to compaction. One oil-bearing sand occurs at 11,700 feet.

The turbidite sandstones of the Canning Formation are reported to be rich in argillaceous rock fragments (Gautier, 1987), which explains the limited gamma-ray excursions toward lower values in the sands in Figs. FP13 and FP14.

Three of seven samples with mercury injection data from turbidite sands in well W. Mikkelsen 2 have entry pressures below 100 psi; two of these display a well-connected pore size distribution (Figs. PP5f and PP6e).

Well log response and reservoir quality in laminated sands. In well Badami 2, a 275-foot interval of laminated sandtones, siltstones, and shales was encountered (10,580 to 10,855 feet in Fig. FP15). Oil and gas occurs throughout the interval as recognized in core description, by the open-hole DST result "flowed oil and gas to the surface", and by high resistivity on the deep and medium induction logs. Sidewall cores were obtained from this interval with a mechanical rotary extractor; rotary core was obtained from 10,730 to 10,790 feet.

Log and core data illuminate the nature of the interbedding. Photoelectric peaks and density lows occur where caliper indicates small (order of one-inch diameter) washouts. These peaks are attributed to barite in mud by the Schlumberger engineer. The sidewall-core porosity data, varying from 2.4 to 21.8%, are consistent with a laminated sequence. Thickness of laminations must be less than one foot, because the neutron and acoustic logs do not respond to them. Resistive, low delta-t (DT) intervals several feet thick occur in the sequence and are attributed to calcite-cemented zones, which are recognized in the geological description. Grain density values range from 2.62 to 2.77 (with one value at 2.91) g/cm^3, indicating the presence of calcite and quite possibly other high-density (siderite?) minerals.

Analysis of a drill-stem test over a 588-foot open-hole interval from 10,494 to 11,082 feet in well Badami 2 yielded a permeability of 6.36 md in Canning turbidites. Average porosity of 33 sidewall cores was 11.2 %; average permeability was 5.5 md, and average oil saturation was 14.9%.

Sagavanirktok Formation

Geologic description. The Sagavanirktok Formation is a thick shallow-marine and nonmarine unit overlying and intertonguing with the Canning Formation. It consists mainly of fine- to medium-grained sandstone and generally bentonitic shale with lesser amounts of conglomerate and minor coal. Correlation of well-log markers indicates uniform deposition on a shelf and delta or coastal plain. Deposition was alternately shallow marine and nonmarine in character as the seaway transgressed and regressed across the area. There probably are several disconformities or hiatuses within the section due to sea-level changes, but the dominant depositional pattern was progradation to the northeast.

Well log response. The alternating character of logs within well Point Thomson Unit 1 reflects transitions from conglomerate and sandstones to siltstones and shales (Fig. FP16). High porosity values in these poorly consolidated rocks are reflected in low (2-3 ohm-m) resistivity, density less than 2.4 g/cm^3, and sonic values in excess of 95 μs/ft.

Reservoir quality. All seven samples from the Gyr well show entry pressures less than 100 psi; three of these seven samples are of excellent reservoir quality with very well connected pore distributions and entry pressures around 10 psi (Figs. PP5g and PP6f). Two drill stem tests of the Sagavanirktok in the Hammerhead 1 well yielded oil at rates of 744 and 912 barrels per day.

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Table FP1. Carbonate occurrences in wells penetrating pre-Mississippian basement rocks.

Well Name	TVDSS	Penetration (feet)	Carbonate Thickness (feet)	Drill-stem Test	Lithology
Alaska Island	12834	222	70	gas & condensate	mixed lithology
Alaska State A-1	12879	1286	220	Water	mixed lithology
Alaska State C-1	13134	55	0		Phyllite
Alaska State D-1	12682	330	156		mixed lithology
Alaska State F-1	12708	422	170	gas & condensate	mixed lithology
Canning River A-1	7295	654	654	water	Nanook Limestone
Challenge Island 1	12956	97	25		mixed lithology
E De K Leffingwell 1	14515	107	0		argillite
Mikkelsen Bay	16527	22	10	failed	--
W. Mikkelsen St. 1	15563	6	10		mixed lithology
W. Mikkelsen 2	11586	300	0		shale and argillite
E. Mikkelsen 1	13491	1676	450		shale and limestone
Pt. Thomson 1	13127	138	0		argillite to phyllite
Pt. Thomson 2	13066	1002	145		phyllite and carbonate
Pt. Thomson 3	12888	185	0		phyllite and argillite
Pt. Thomson 4	13060	101	0	water*	phyllite
W. Staines 2	13060	16	0		argillite
W. Staines State	13062	204	0	gas-cut mud*	argillite and quartzite

* DST straddled basement rocks and overlying formation(s).

Table FP2. Average field-wide petrophysical quantities for the oil and gas columns, Kekiktuk Conglomerate, Endicott Field. After Woidneck and others, 1987. [N/G, net-to-gross thickness ratio; Por., porosity; Sw, water saturation; k, permeability]

Zone	Geologic Description	N/G(%)	Por.(%)	Sw(%)	k(md)
Zone 3C	Composed of varying amounts of sandstone and lesser coal and conglomerate. Floodplain environment. Sand-prone sections near top and bottom (3A, 3C); separated by major shaly interval (3B).	51	18	21	
Zone 3B		16	15	38	
Zone 3A		42	20	18	
Total		37	18	22	548
Zone 2B	Consists primarily of medium- to coarse-grained multistory sandstone bedsets deposited within a braided river system. Mud was deposited into lakes. Minor coal and conglomerate also occur. A shale divides Zone 2A from 2B.	94	22	13	
Zone 2A		83	22	13	
Total		88	22	13	1146
Zone 1	Shale and coal prone with minor interbedded sandstones which are generally fine grained and lacking primary depositional structures. Low energy, swampy environment .	8	16	31	218
Total		49	20	17	

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Table FP3. Porosity distribution for Lisburne Field, drawn from Jameson (1994) and Belfield (1988).							
Cum. Distrib. (%)	0	5	25	50	75	95	100
Porosity (%)	1	3	5	10	14	30	50

Table FP4. Porosity of Ledge Member of Ivishak Formation, given as cumulative distributions. Data from the northwest fault block of Prudhoe Bay Field, estimated from Fig. 7 of Wendt and others (1986), are based on core data. Data from three wells are computed from well logs, using a gamma-ray cutoff to distinguish low-clay sandstone. Lowermost zones were deposited in a shallow marine environment, middle and upper zones are fluvial-deltaic.

Location	Zone	Cumulative Distribution (%)						
		0	5	25	50	75	95	100
Prudhoe Bay Field, Northwest Fault Block	4B		14		21		28	
	4A		14		23		26	
	3		7		16		23	
	2C		15		22		27	
	2B		7		22		28	
	2A		8		21		28	
	1A, 1B		7		17		27	
	Average		10		20		27	
Beli Unit 1		2	4	7	9	10	13	21
Canning River A-1		0	0.5	1	2	4	8	10
Canning River B-1		0	2	3	5	6	8	17

Table FP5. Porosity of Sag River Sandstone, given as cumulative distributions. Data from two wells were computed from well logs, using a gamma-ray cutoff to distinguish low-clay sandstone.

Well	0%	5%	25%	50%	75%	95%	100%
Beli Unit 1	3	3.5	6	9	10	12	14
Canning River Unit A-1	0	1	2	3.5	7	8	8.2

Table FP6. Average properties of Kuparuk Formation, Milne Point Unit, determined from well logs in thirty wells. From Table VI-1 of Sharma (1994). Porosity values less than 6% were excluded from the averages.

Zone	Lobe	Gross Thickness (ft)	Net Thickness (ft)	Average Porosity (%)	Water Saturation (%)
Middle	Upper	17	9	22	66
Middle	Lower	21	12	25	67
Lower	Upper	14	6	25	78
Lower	Lower	23	9	25	79

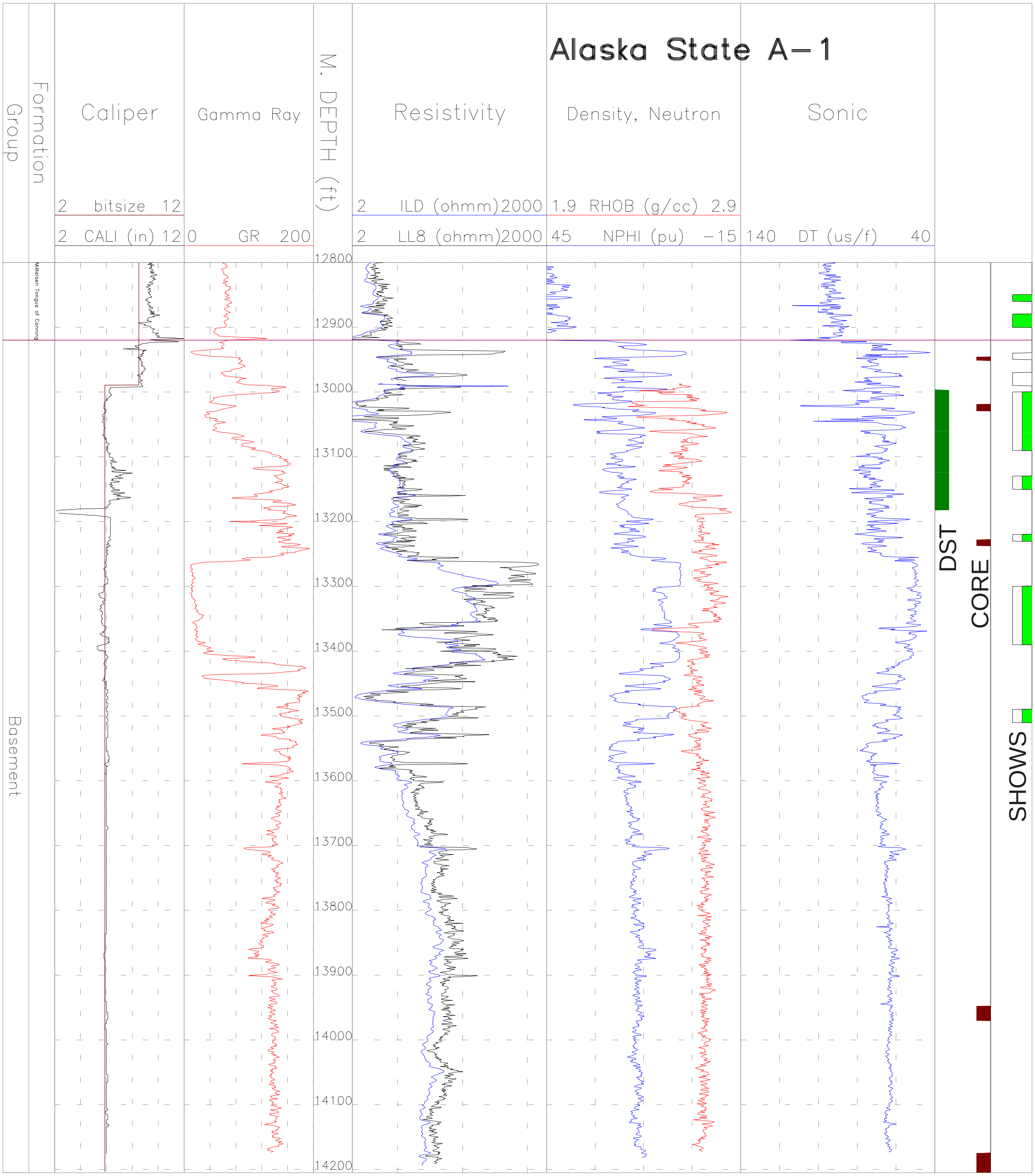

Figure FP1. Well logs within basement complex, in well Alaska State A-1. See "Summaries of drill stem tests" in Chap. WL for details on test results.

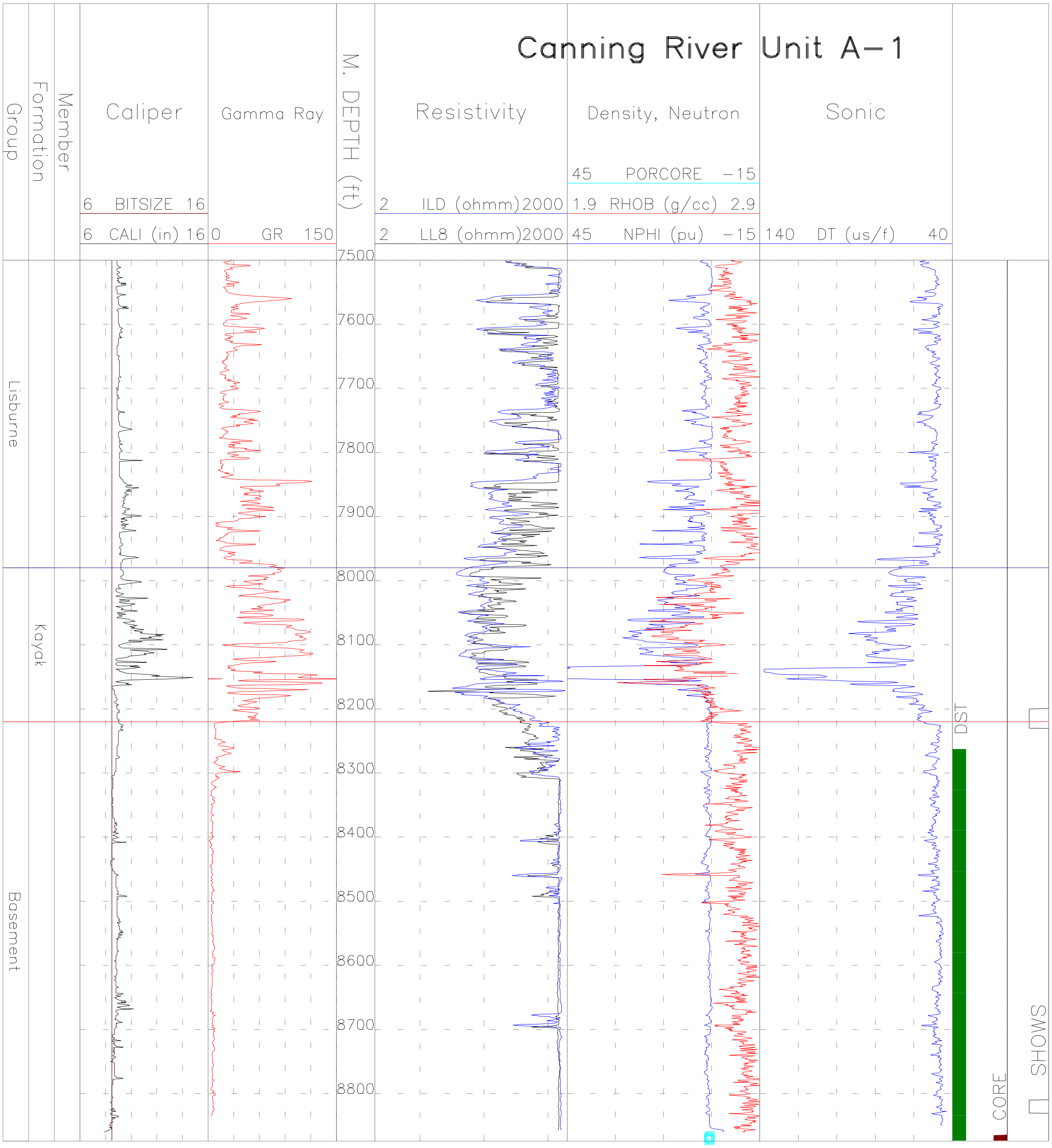

Figure FP2. Well logs within Basement, Kayak Shale, and Lisburne Formation, in well Canning River Unit A-1. See "Summaries of drill stem tests" in Chap.WL for details on test results.

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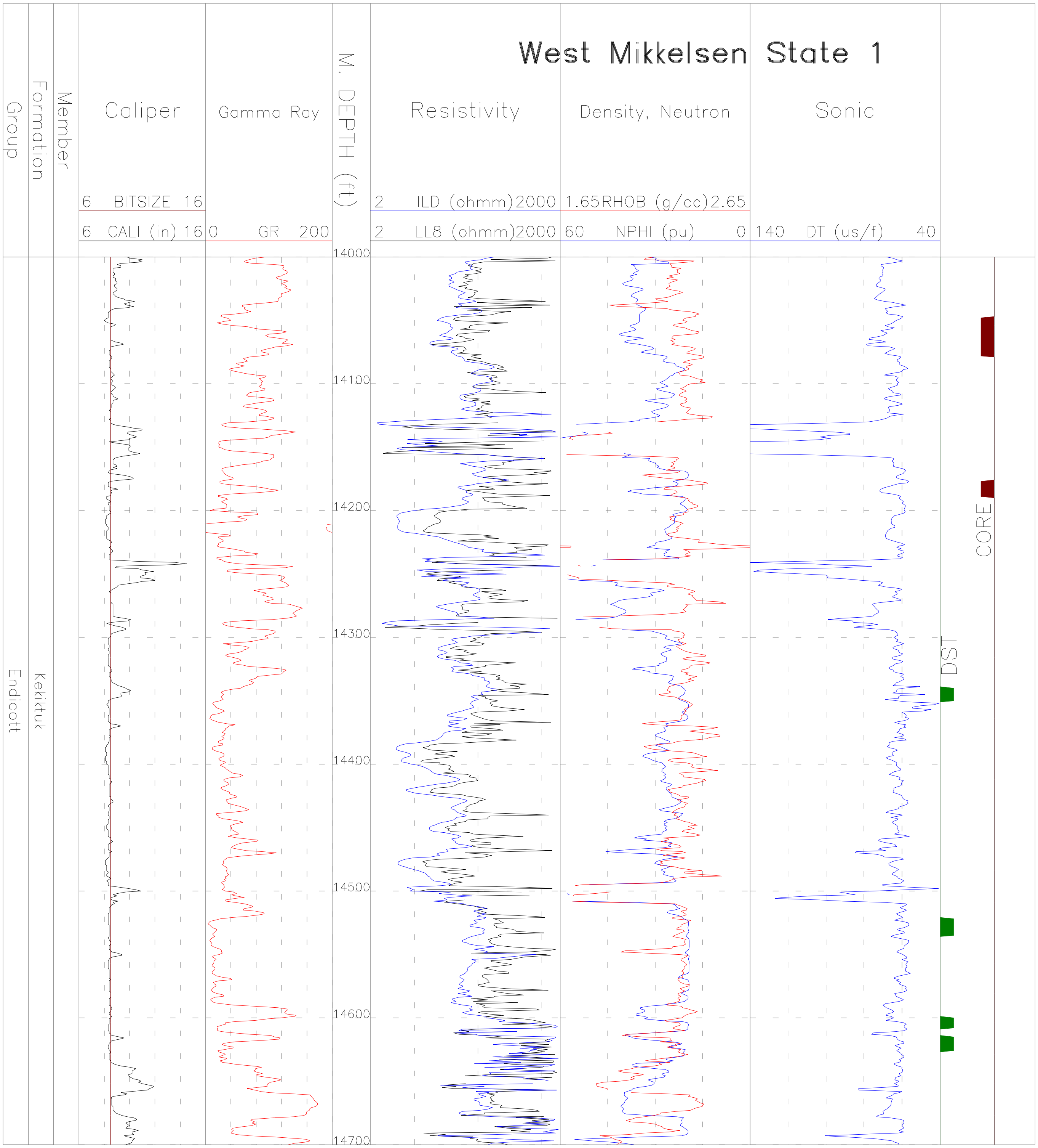

Figure FP3. Well logs within Kekiktuk Conglomerate, in well West Mikkelsen State 1. See "Summaries of drill stem tests" in Chap.WL for details on test results.

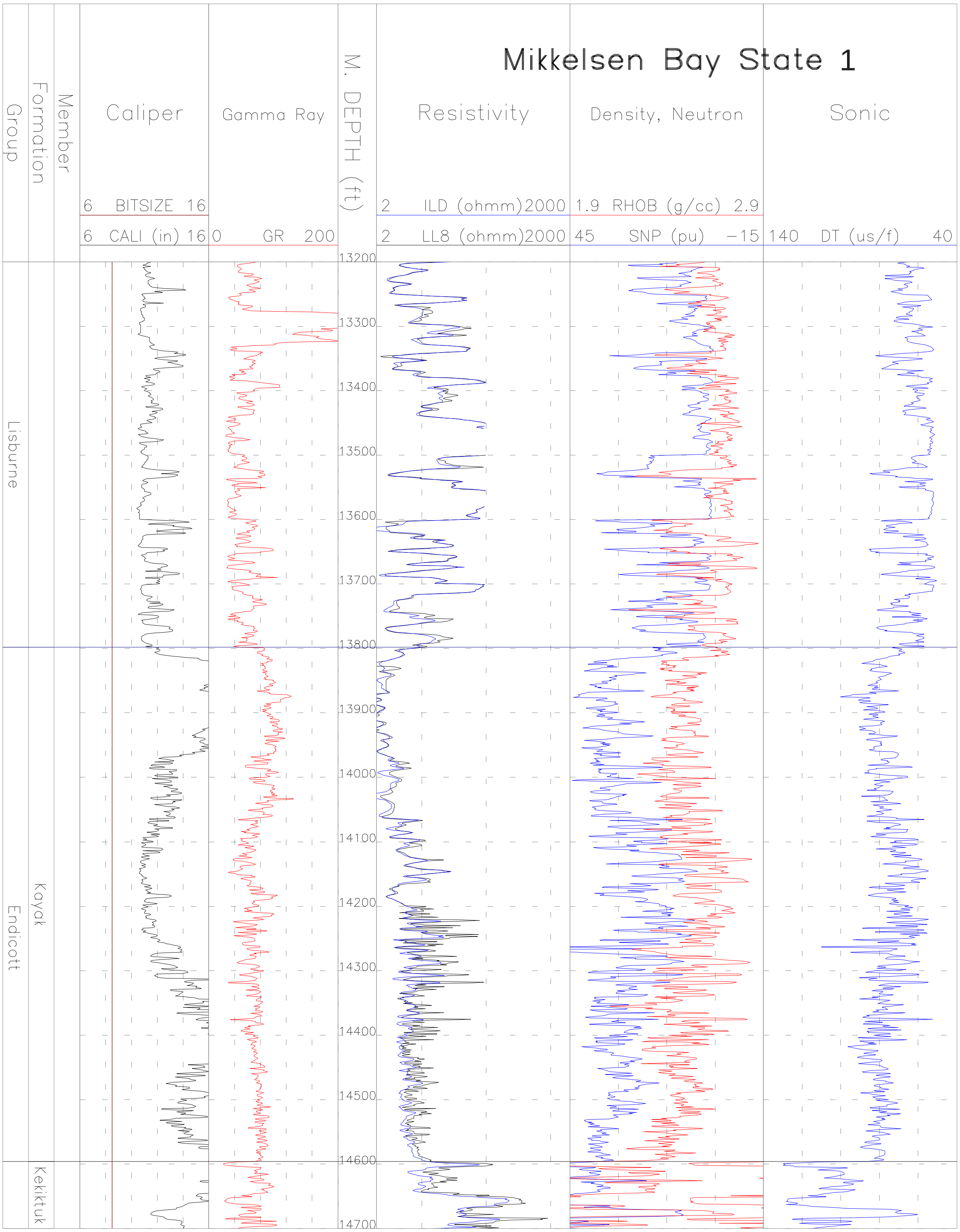

Figure FP4. Well logs within Kayak Shale and Lisburne Formation, in Mikkelsen Bay State 1.

The Oil and Gas Resource Potential of the
Arctic National Wildlife Refuge 1002 Area, Alaska
Open File Report 98-34

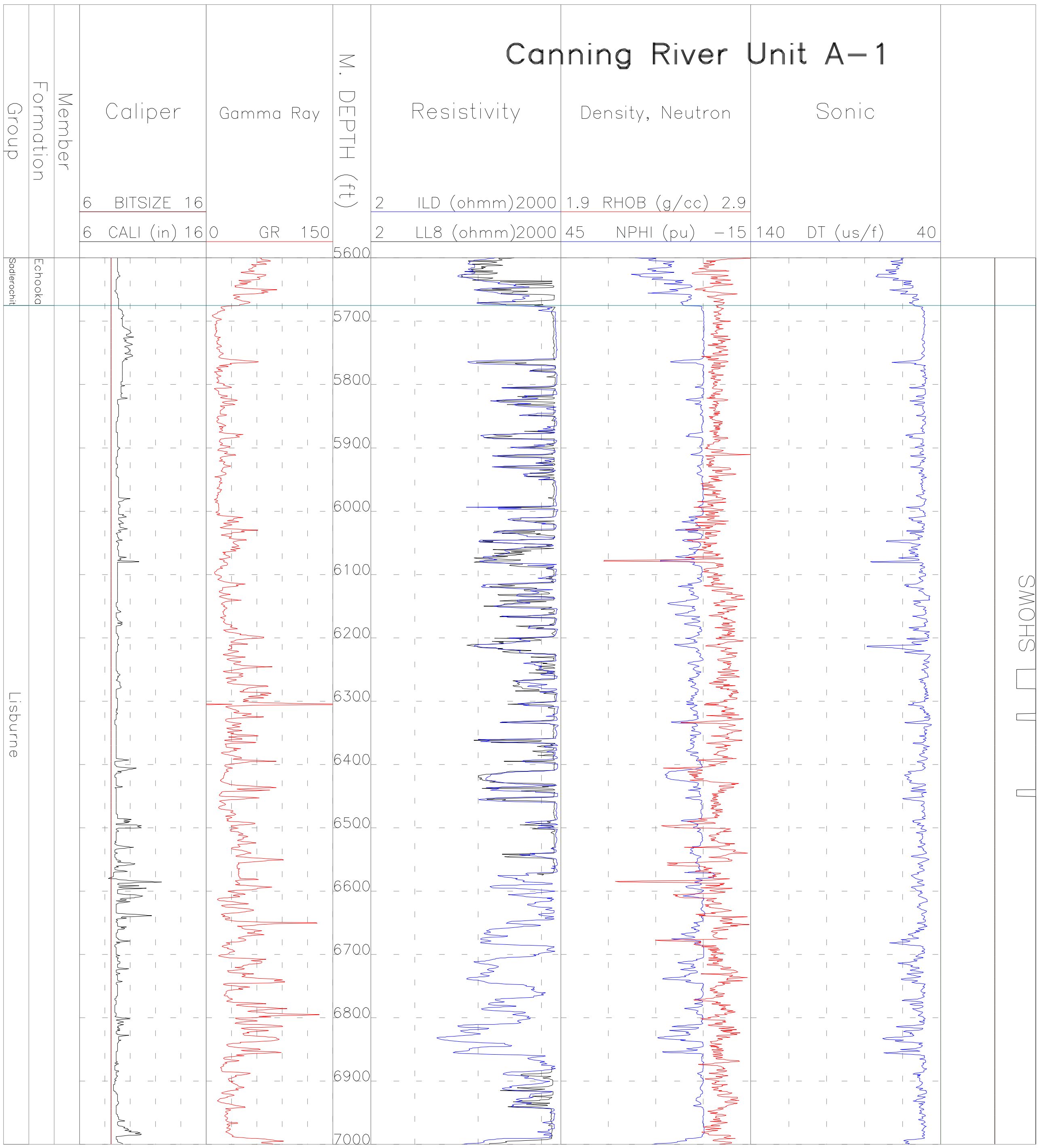

Figure FP5. Well logs within Lisburne Group, in well Canning River Unit A-1.

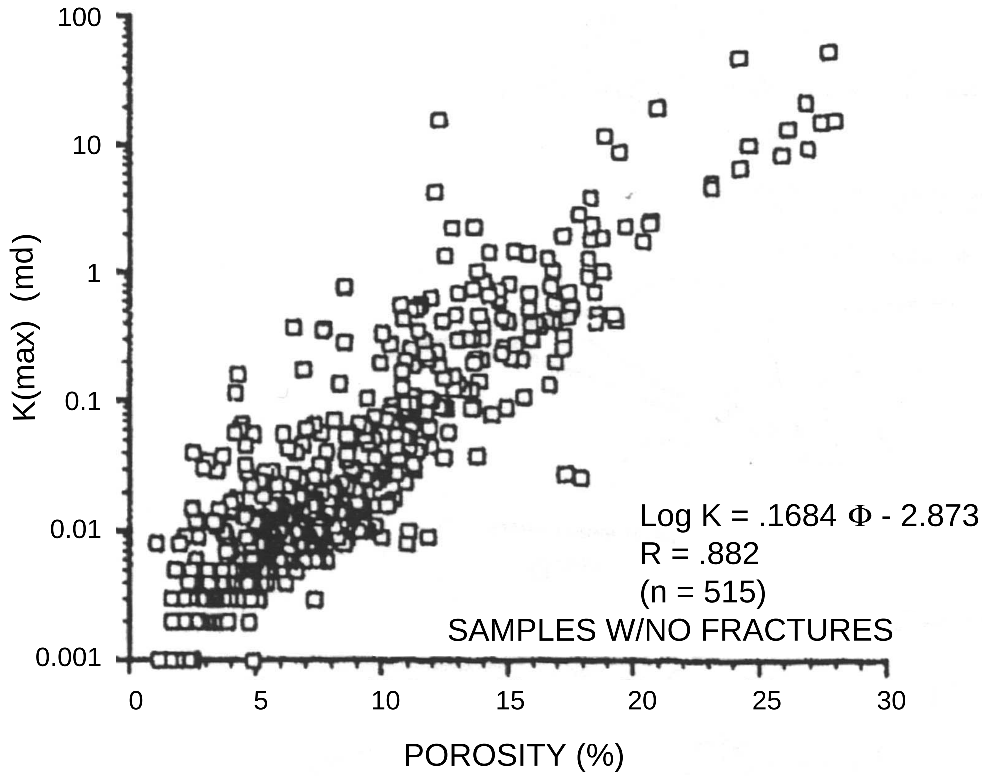

Figure FP6. Maximum horizontal permeability and porosity data from Lisburne Field, measured under confining pressure of 1870 psi on full-diameter cores. Samples selected to be free of fractures. From Belfield (1988).

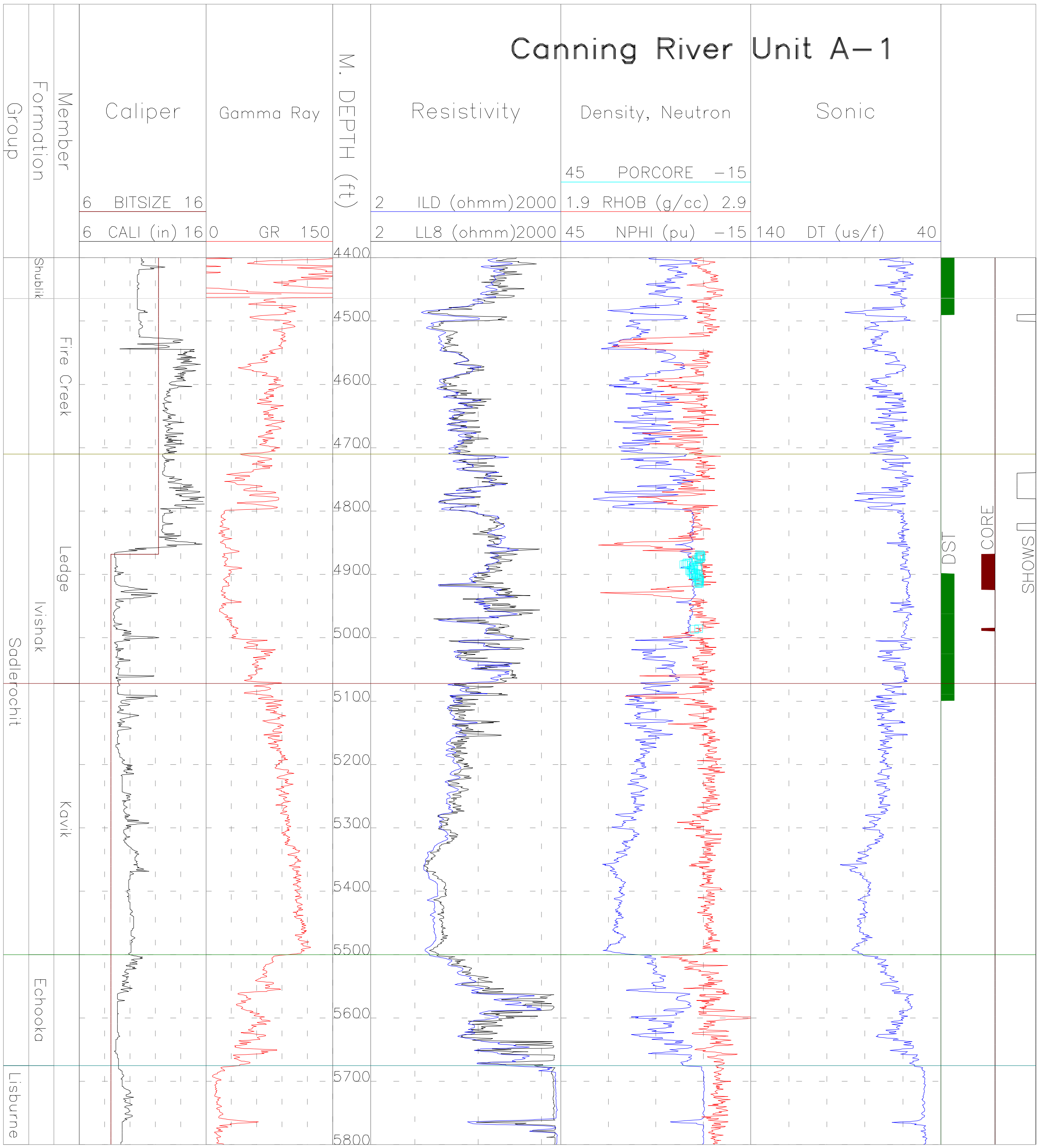

Figure FP7. Well logs within Echooka and Ivishak Formations, in well Canning River Unit A-1. See "Summaries of drill stem tests" in Chap. WL for details on test results.

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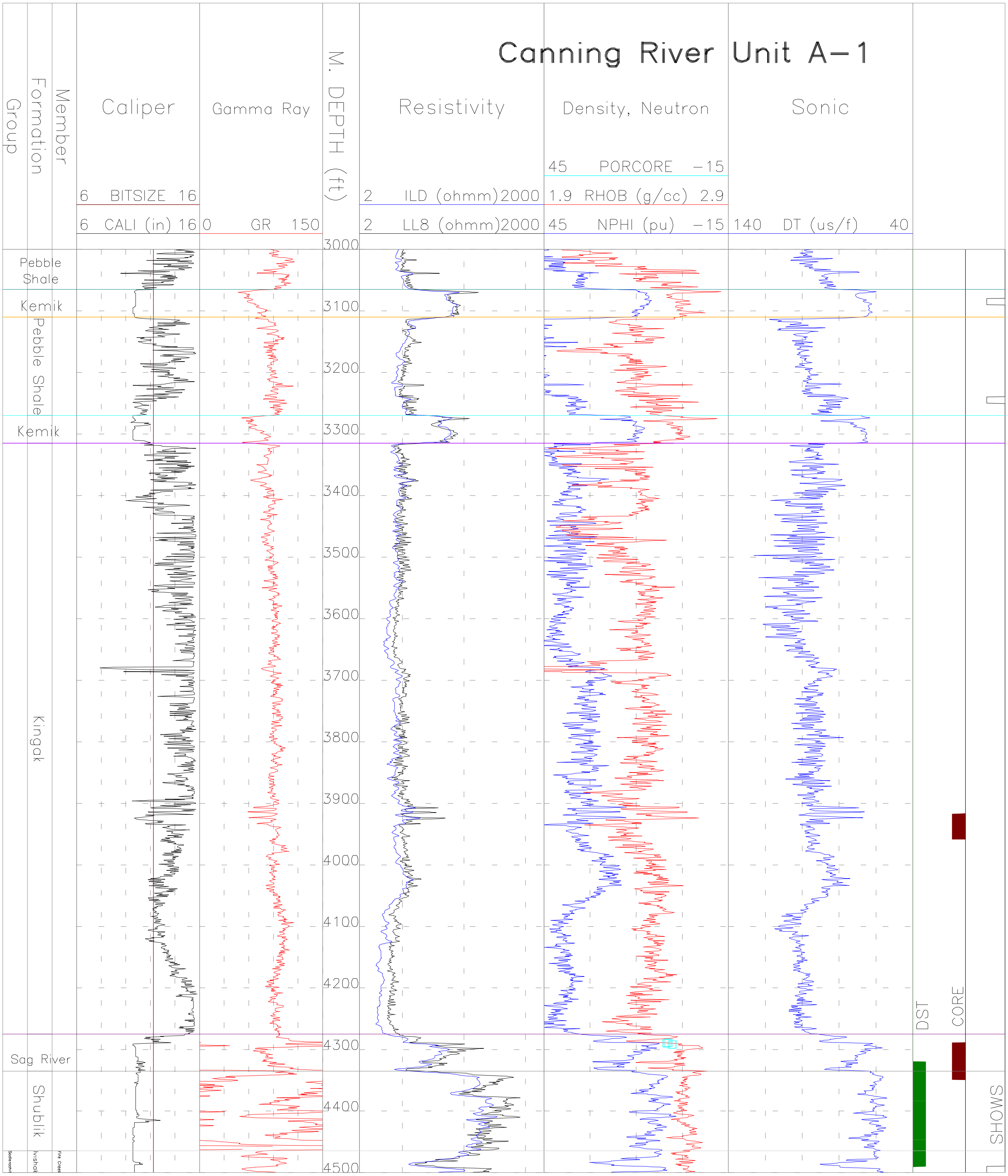

Figure FP8. Well logs within Shublik, Sag River, Kingak, and Pebble Shale unit, in well Canning River Unit A-1. See "Summaries of drill stem tests" in Chap.WL for details on test results.

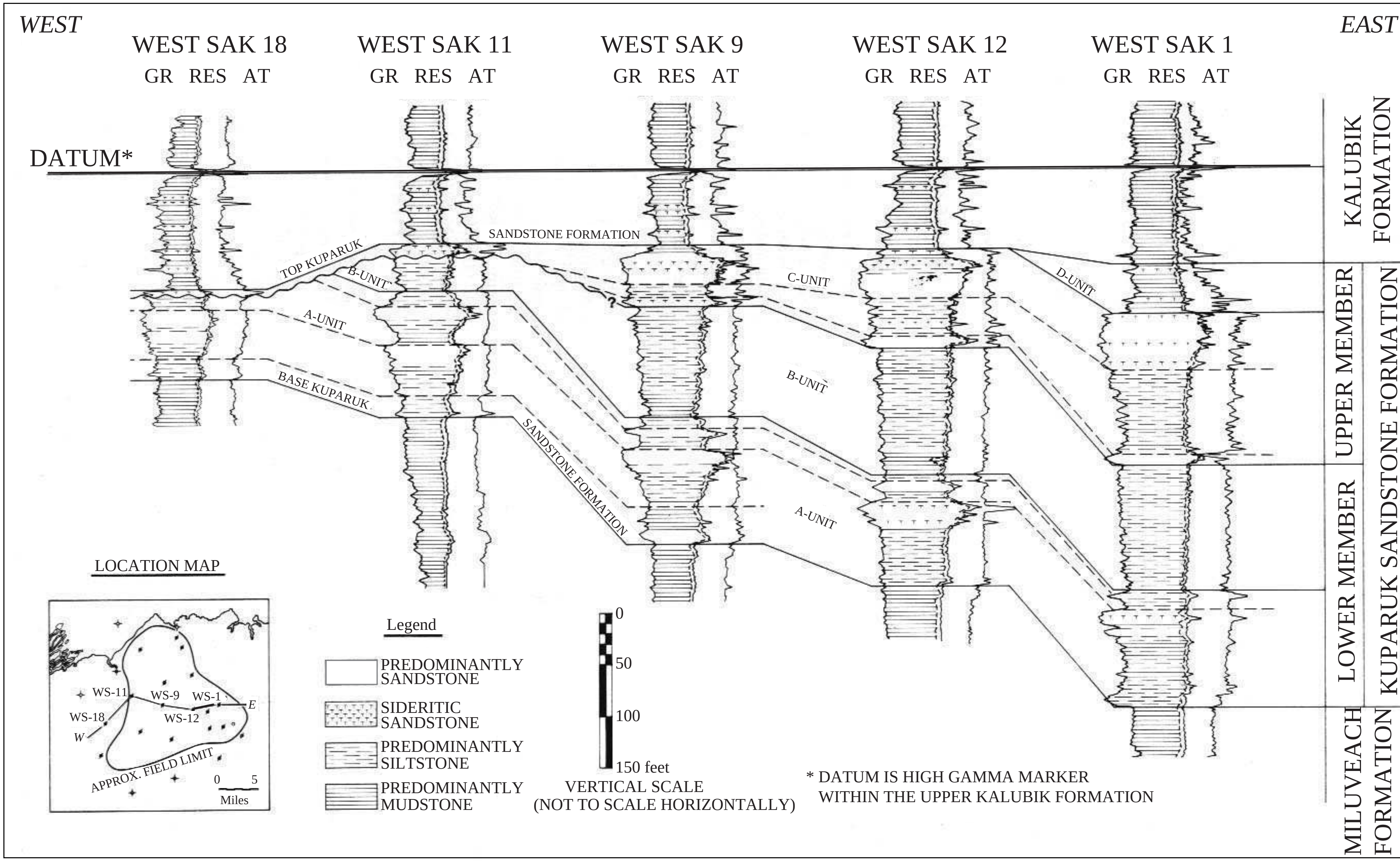

Figure FP9. Cross section of Kuparuk Formation, from Carman and Hardwick, 1983. Well logs are gamma ray (GR), resistivity (RES), and acoustic (AT).

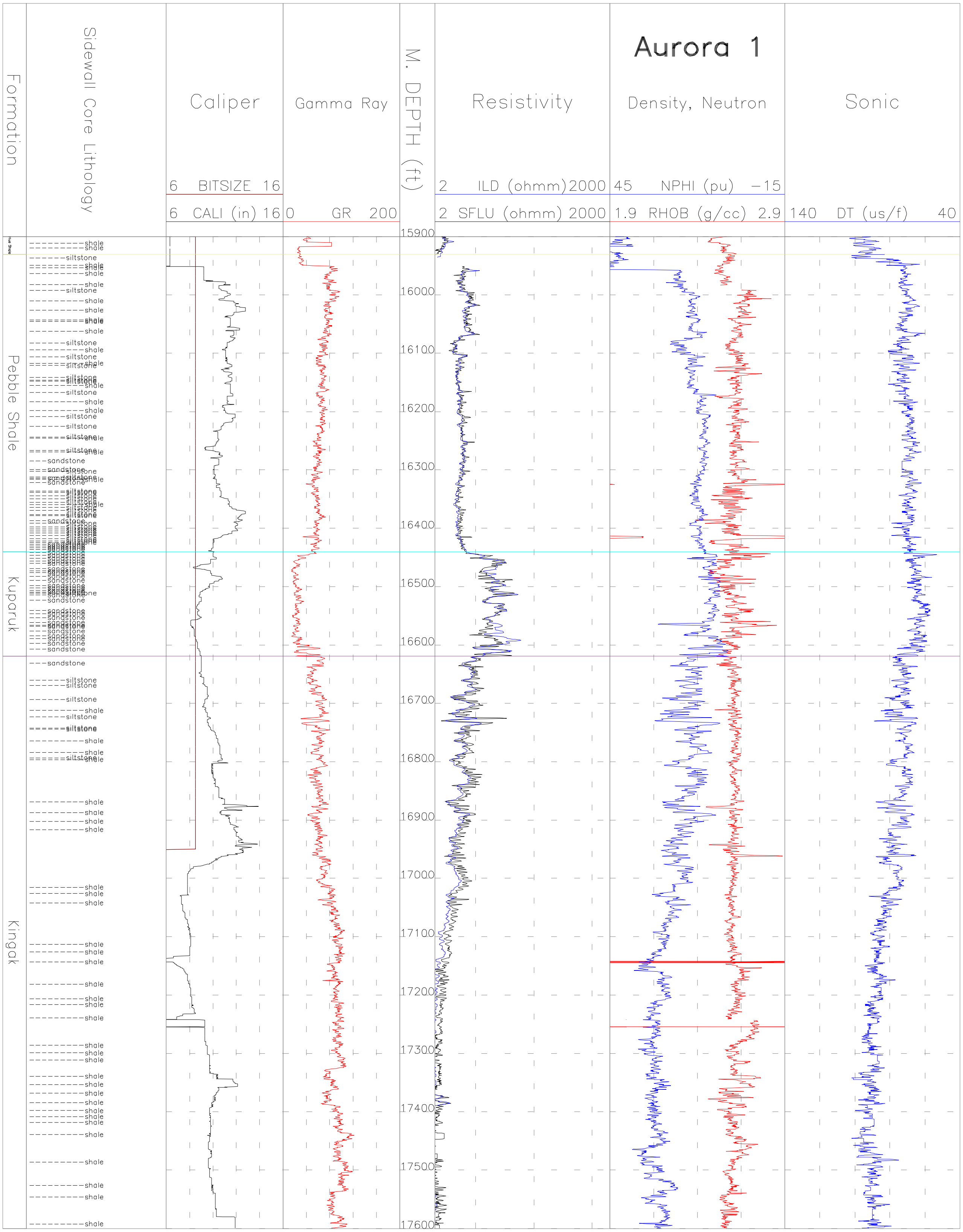

Figure FP10. Well logs within Pebble Shale, Kuparuk Formation, and Kingak Shale, from well Aurora 1. Lithology descriptions from sidewall cores (second column) are displaced according to grain size (sandstone to left, shale to right).

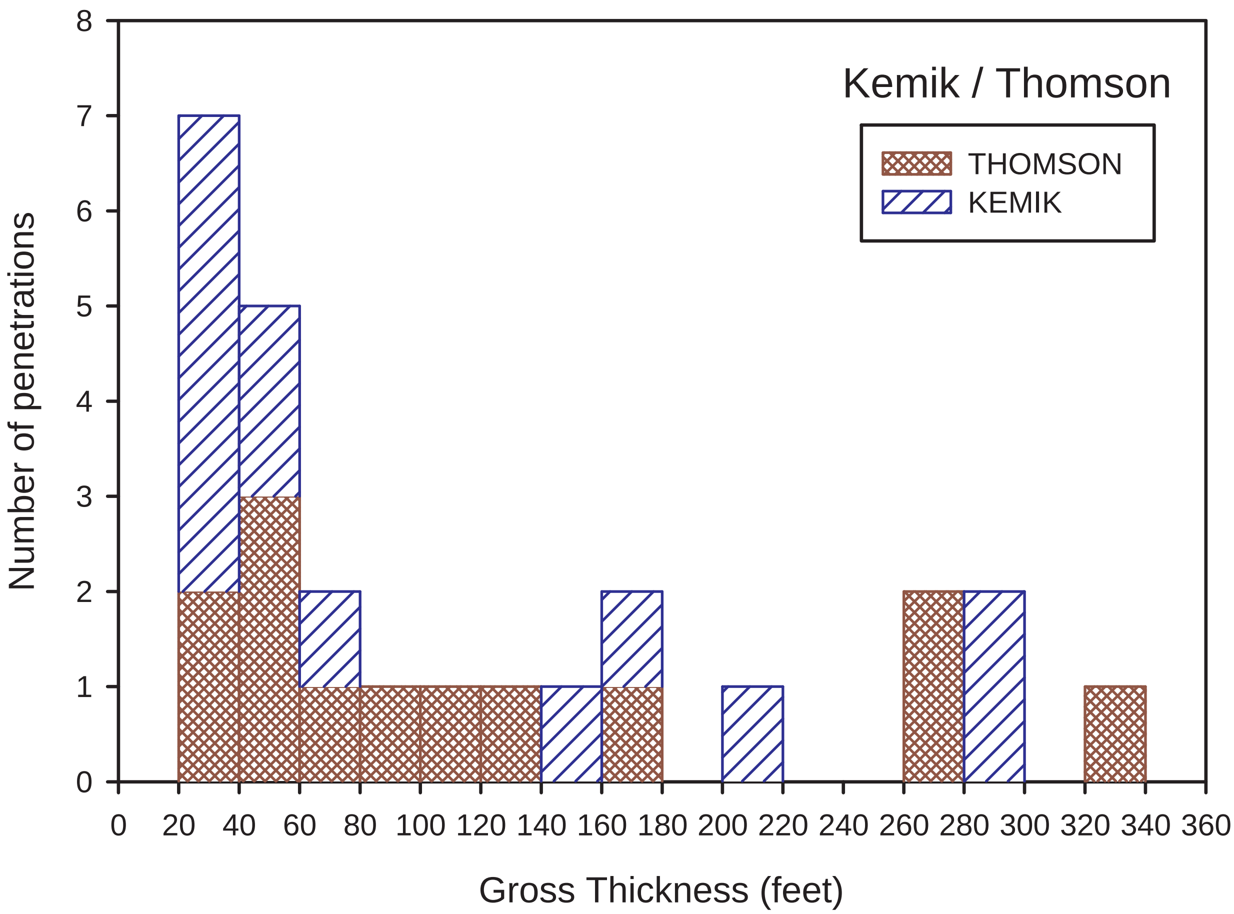

Figure FP11. Gross thickness of Kemik and Thomson formations where penetrated by wells.

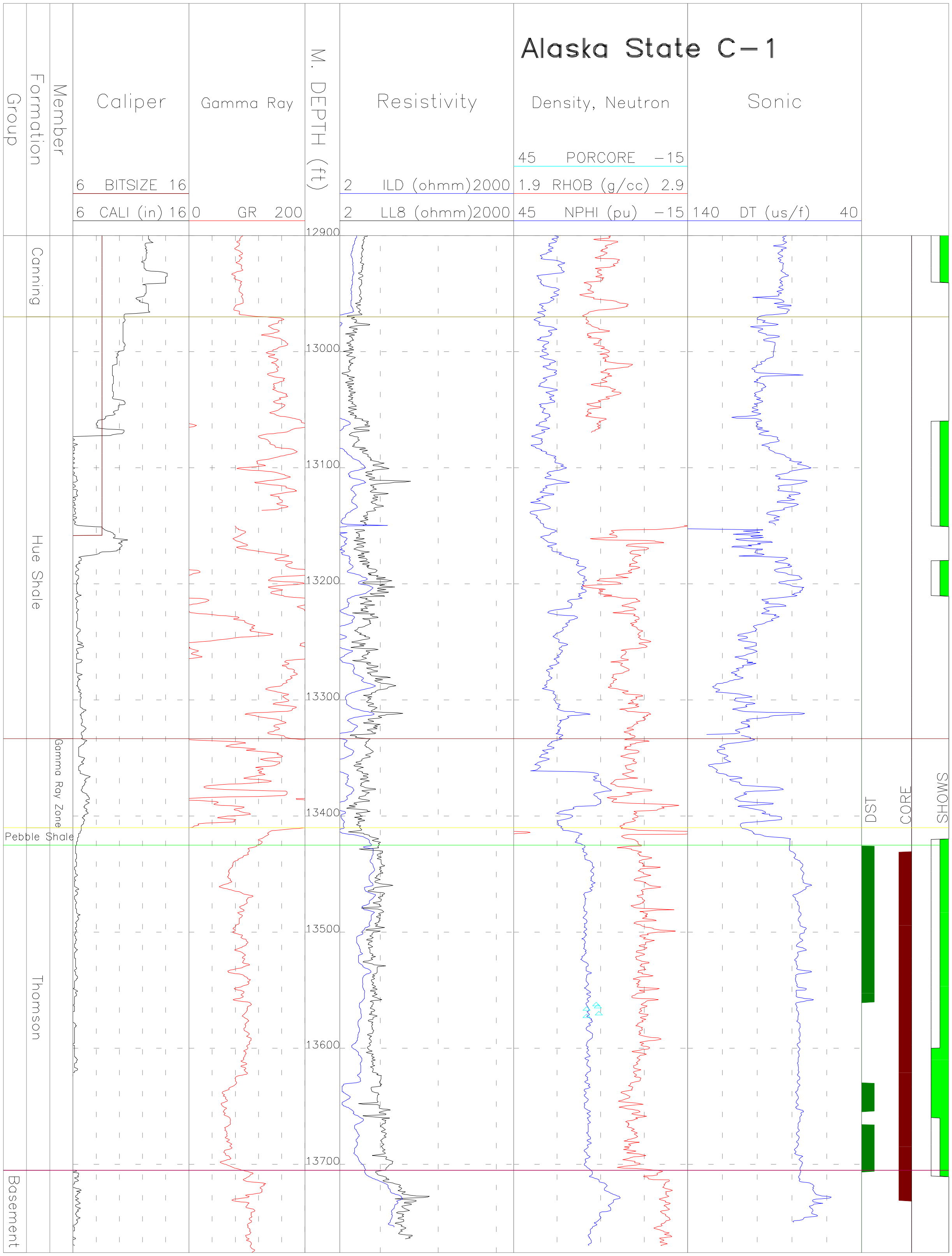

Figure FP12. Well logs within Thomson Sand, Pebble Shale Unit, and Hue Shale, from well Alaska State C-1. Oil and gas were tested in the interval 13,426-13,560 feet. Neutron porosity (NPHI) is on sandstone scale, although the Thomson Sand is dolomitic. See "Summaries of drill stem tests" in Chap.WL for details on test results.

The Oil and Gas Resource Potential of the
Arctic National Wildlife Refuge 1002 Area, Alaska
Open File Report 98-34

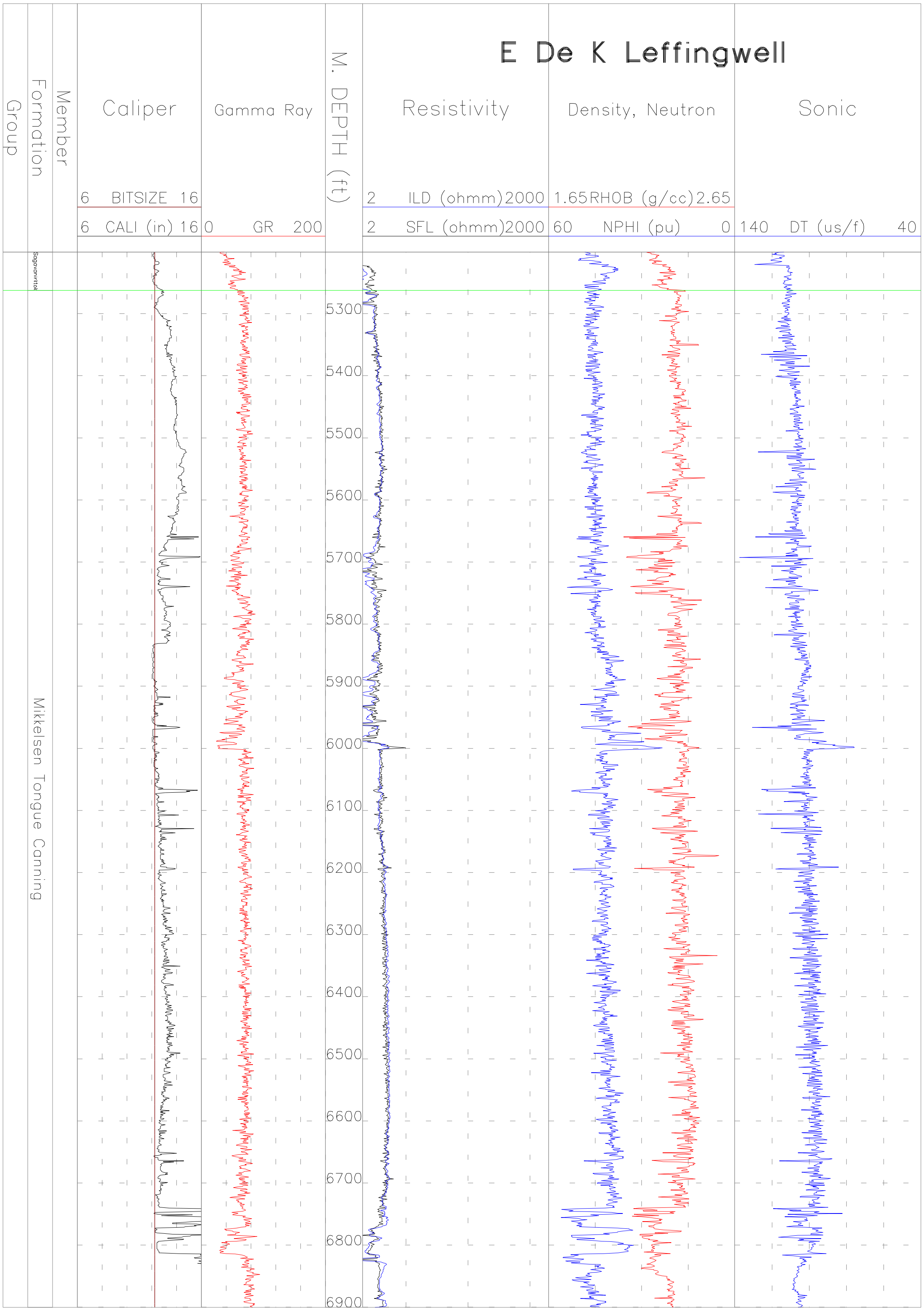

Figure FP13. Well logs within the Mikkelsen Tongue of Canning Formation, from well E De K Leffingwell.

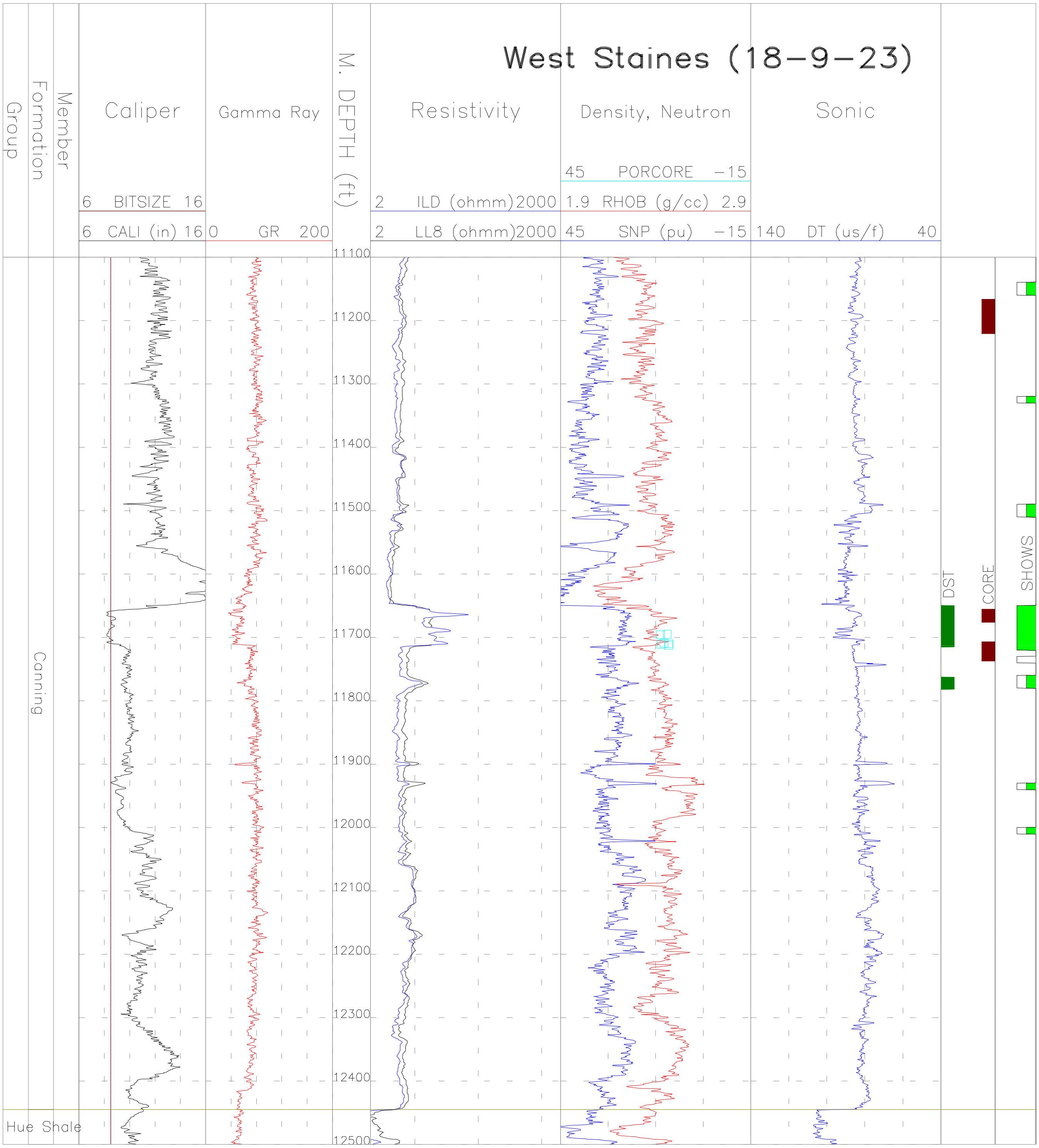

Figure FP14. Well logs within the Canning Formation, from well West Staines (18-9-23). See "Summaries of drill stem tests" in Chap.WL for details on test results.

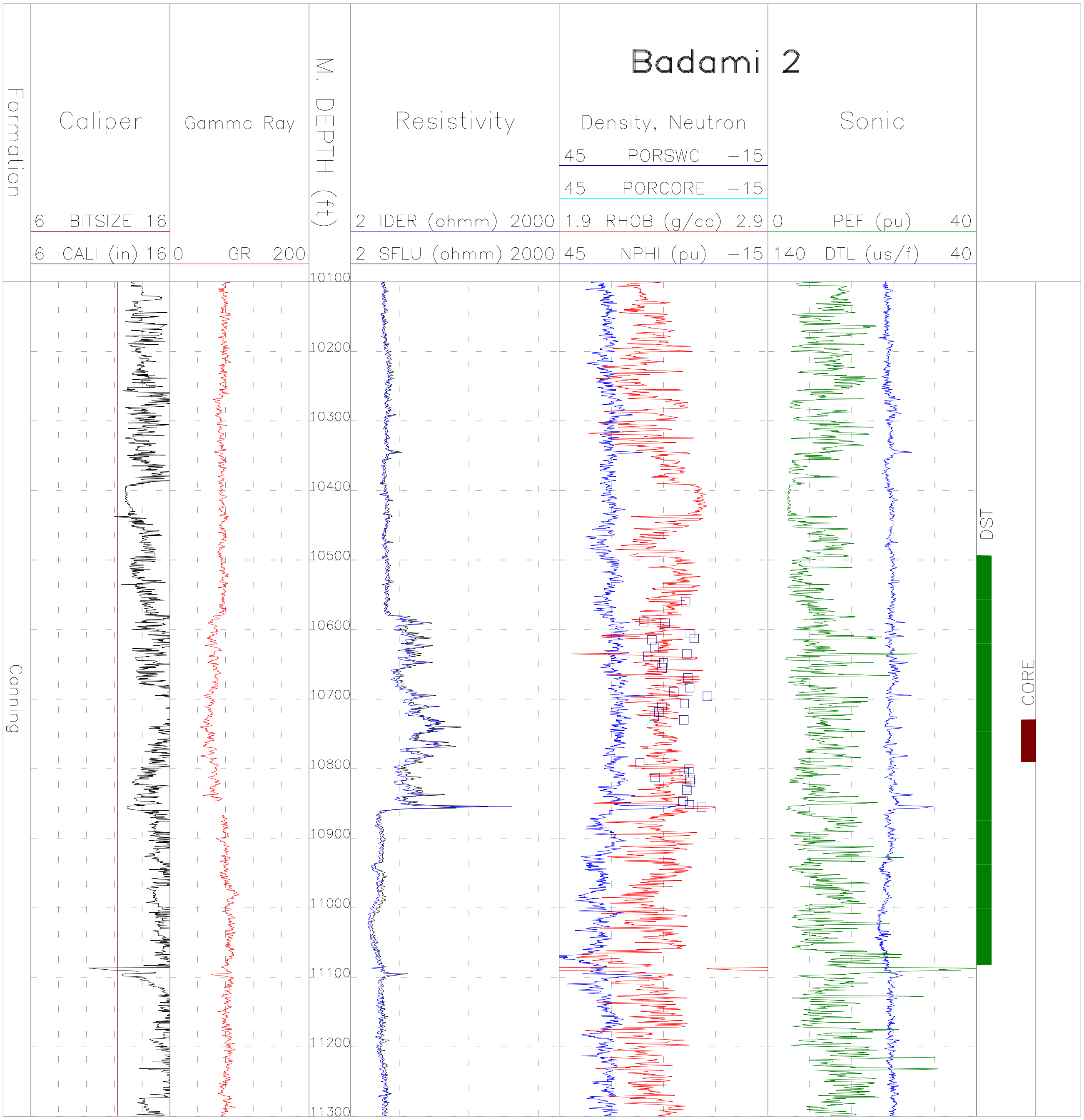

Figure FP15. Well logs within the Canning Formation, from well Badami 2. See "Summaries of drill stem tests" in Chap.WL for details on test results.

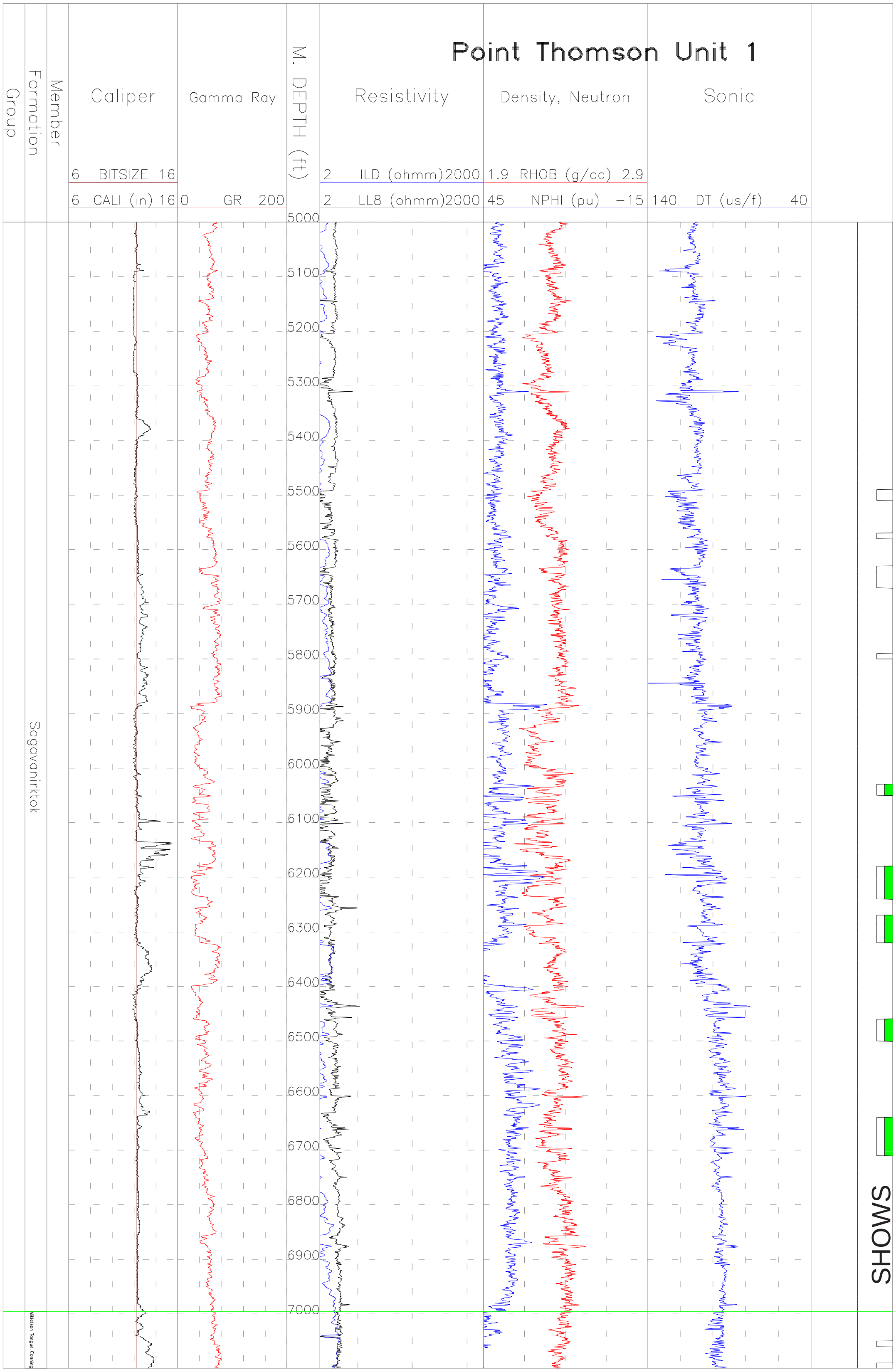

Figure FP16. Well logs within Sagavanirktok Formation, from well Point Thomson Unit 1.