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Braidplain and Deltaic Reservoir, Prudhoe Bay Field, Alaska

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Introduction

This chapter illustrates, by means of a case study of a super giant field, the excellent reservoir characteristics of braidplain and associated deltaic facies. It also discusses some of the difficulties encountered in most efficiently producing hydrocarbons from this type of sequence.

Braided stream systems produce deposits which can become excellent hydrocarbon reservoirs. Some of the world's largest sandstone reservoirs are composed of braided stream deposits. Typically, the sandstone and conglomerate sheets produced by bar migration and by braidbelt switching are laterally continuous and, relative to most other sand-body types, the deposits can be considered largely homogeneous. In addition, the coarse-grained and relatively clay-free character of most braided stream deposits favors high reservoir quality. This is basically the case for the reservoir discussed in this chapter. However, it must be noted that even reservoirs composed of braided stream deposits exhibit varying degrees of heterogeneity although often, as discussed in this chapter, this does not become apparent until the advent of secondary and tertiary recovery operations.

The Ivishak Sandstone, a largely braidplain facies, is the main producing reservoir of the Prudhoe Bay Field, a super giant that delivers 1.45 million barrels of oil per day (2.3×10^5 m^3/D). This reservoir is currently supplying 17% of the total United States domestic production. Economic justification for the development of the field, which lies 250 miles (400 km) north of the Arctic Circle, was directly linked to the reservoir properties of the sandstones and conglomerates which comprise the reservoir. In particular, their overall high permeability (average 400 md) and laterally extensive nature combine to produce a reservoir capable of sustained high production rates. Such production characteristics more than compensated for the initial and continued financial investment required to develop the field in this remote location. Today, some 20 years after its discovery, the Prudhoe Bay Field represents the largest developed oil and gas accumulation in North America, with in-place reserves of 22 billion barrels of oil (3.5×10^9 m^3) and 47 trillion cubic feet of gas (1.3×10^{12} m^3).

Interest in the petroleum potential of the North Slope of Alaska (Fig. 1-1) began in the early 1900s with the discovery of surface oil seeps near Cape Simpson, east of Point Barrow (Leffingwell, 1919). In 1923, Naval Petroleum Reserve No. 4 (NPRA) was established to exploit potential resources in the area. Through 1963, most exploration was conducted by the U.S. Navy and the U.S. Geological Survey. Industry exploration accelerated in the early 1960s and, after a series of initial disappointments, shifted from the Brooks Range foothills to the coastal plain region east of NPRA and west of the Arctic National Wildlife Range (ANWR). By 1965, the presence of a large structure below Prudhoe Bay had been delineated using seismic data. Nearby exploration wells confirmed that the Permo-Triassic terrigenous clastic succession and the Lisburne Group carbonates contained prospective reservoir sections. The North Alaskan oil boom began on April 15, 1968, with the ARCO-Humble Prudhoe Bay State No. 1 well.

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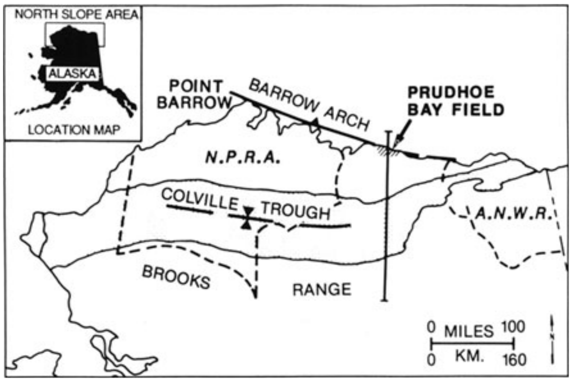


Fig. 1-1. Location of the Prudhoe Bay Field, North Slope, Alaska. Position of N-S cross section shown in Figure 1-2 is indicated.

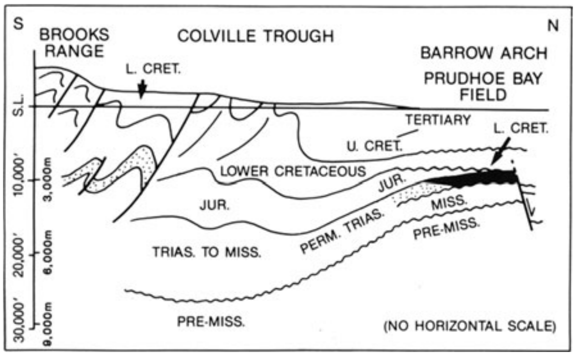


Fig. 1-2. North-south generalized cross section through the Alaskan North Slope from the Brooks Range to the Barrow arch (from Jamison et al., 1980, and reprinted by permission of American Association of Petroleum Geologists).

Initially targeted for the Lisburne Group limestones, the well encountered oil and gas at approximately 8,200 feet (2,500 m) subsea in the Triassic Ivishak Sandstone of the Sadlerochit Group. The confirmation well, Sag River State No. 1, proved conclusively that economic reserves existed in the North Slope and set the stage for the development of the largest oil and gas field in North America.

Regional Setting

The Prudhoe Bay Field lies approximately midway between NPRA to the west and the ANWR to the east (Fig. 1-1). Structurally the field occurs on an anticlinal uplift which forms part of the east-west trending subsurface Barrow arch (Figs. 1-1, 1-2). This basement uplift, which generally parallels the trend of the coastline, represents a major subsurface tectonic feature across the North Slope. The arch had a history of recurrent movement from the Pennsylvanian through the Late Cretaceous (Jones and Speers, 1976), and several unconformities are associated with its sedimentary cover (Fig. 1-2). Of these, the Lower Cretaceous Unconformity (LCU) is the most significant and truncates the reservoir on the eastern flank of the field. The overlying Cretaceous shales form the main seal for the Ivishak Sandstone reservoir.

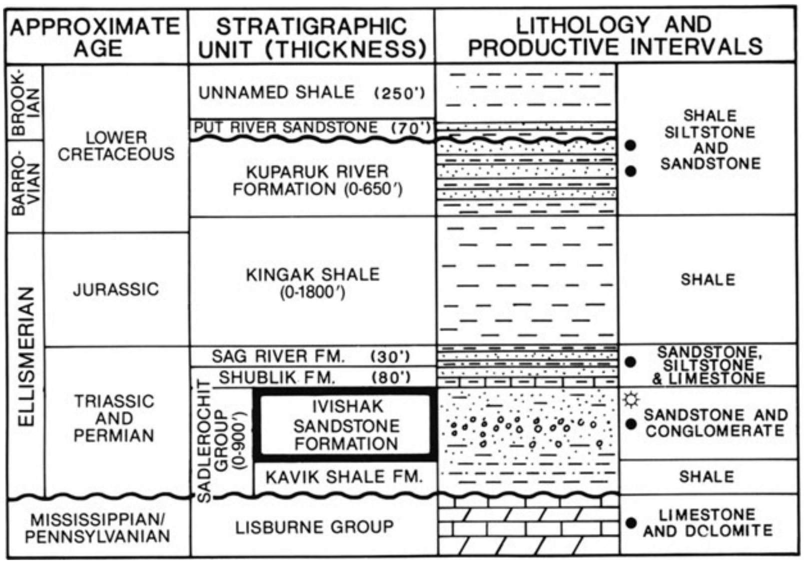


Fig. 1-3. Stratigraphy of the Ellesmerian-Brookian succession (Mississippian-Lower Cretaceous) in the Prudhoe Bay area (modified from Jamison et al., 1980, and Carman and Hardwick, 1983; reprinted by permission of American Association of Petroleum Geologists).

The Ivishak Sandstone is part of the Sadlerochit Group (Fig. 1-3), which includes the underlying Kavik Shale (Jones and Speers, 1976). The Sadlerochit Group rests unconformably upon carbonates of the Mississippian/Pennsylvanian Lisburne Group and is overlain by the upper Triassic Shublik Formation (Fig. 1-3). The Ivishak Sandstone represents the only fluviodeltaic deposits within a marine-dominated Permian through Early Jurassic succession.

Field Characteristics and Production History

The Prudhoe Bay Field underlies an area of more than 225 square miles (585 km^2) at an average depth of 8,500 feet (2,590 m) subsea. The Ivishak reservoir has a maximum light oil column thickness of 425 feet (130 m) and has an average net-to-gross ratio of 0.87. Average porosity, permeability, and water saturation are 22%, 400 md, and 35%, respectively. Field production began in 1977, and presently the field contains more than 900 wells (846 active wells as of February, 1989) ranging in spacing from 1,867 to 2,640 feet (569–805 m). The field is managed by BP Exploration (Alaska) Incorporated, who operate the western part, and ARCO Alaska Incorporated, who operate the eastern part (Fig. 1-4).

Initial production was facilitated by gravity drainage combined with gas-cap expansion. To enhance production and maintain reservoir pressure, a produced-water and seawater injection program was initiated in 1984 in areas with limited aquifer support. Pilot EOR studies involving the use of combined water and miscible gas (WAG) have been in operation since 1983. At present, all three modes of recovery, primary, secondary, and tertiary, are being used concurrently in different parts of the field. This efficient development plan has resulted in the net production of more than 6 billion barrels (9.5×10^8 m^3) of oil.

Comprehensive accounts of the discovery and subsequent development planning of the field can be found in Jamison and others (1980) and Alwin and others (in press).

Reservoir Characteristics

Structure, Trapping, and Oil Type

The Prudhoe Bay Field is a combination structural and unconformity truncation trap. The structure is an anticline with a gently dipping southern flank and a highly faulted northern flank (Figs. 1-2, 1-4). To the north, the accumulation is bounded by northward-dipping normal faults, to the east by truncation along the LCU and overlying unconformable Cretaceous shales, to the south by the oil/water contact, and to the west by another series of normal faults (Fig. 1-4). The truncating unconformity is Early Cretaceous in age, and the overlying Cretaceous shale forms the main seal over the eastern flank of the field. Seismic (Fig. 1-5) and well data clearly show the Cretaceous unconformity truncating progressively older strata in a northeasterly direction. The top of the Ivishak reservoir within the field ranges in depth from 8,000 feet (2,440 m) to 9,200 feet (2,800 m) subsea and dips to the south and west at approximately 1° to 2° (Fig. 1-4). The field has a total hydrocarbon column of approximately 1,200 feet (365 m) from the top of the gas accumulation to the oil/water contact. This contact is tilted and ranges from 8,925 feet (2,720 m) to 9,061 feet (2,762 m) subsea.

Basin analysis suggests that the structural development of the Prudhoe Bay region focused migrating fluids toward the field during the Late Cretaceous and Early Tertiary. Oil generation and migration began during the deposition of the Colville Group and continued during the deposition of the Sagavanirktok Formation. As the Colville Trough subsided, oil and gas were generated and migrated updip, generally in a northward direction. Hydrocarbon generation and migration were probably complete by the end of the Eocene. A tilting event during the late Eocene (ca. 40 Ma) is interpreted as having caused spillage of some of the original oil column into the western part of the field (Fig. 1-4). High oil saturations within the micropores of rocks of the current gas cap and the occurrence of residual oil far below the present-day oil/water contact suggest that the original oil column was about 2,000 feet (610 m) thick. A heavy oil/tar mat at the base of the present-day oil column is probably the result of a deasphalting process caused by the later introduction of gas into the Ivishak reservoir.

Prudhoe Bay Field oils have an API gravity range of 24.9° to 32.4° (average of 27.9°) and an average sulfur content of 1.01% (Sedivy et al., 1987). The oil is a mixture generated from several source formations. Identified co-sources include the Triassic age Shublik Formation, Jurassic age Kingak Shale, and the organic-rich part of the Lower Cretaceous Pebble Shale (part of the "Unnamed Shale" of Fig. 1-3) (Seifert et al., 1979). Other North Slope reservoirs in the vicinity of the Prudhoe Bay Field (e.g., Kuparuk, West Sak) contain the same oil type as the Ivishak

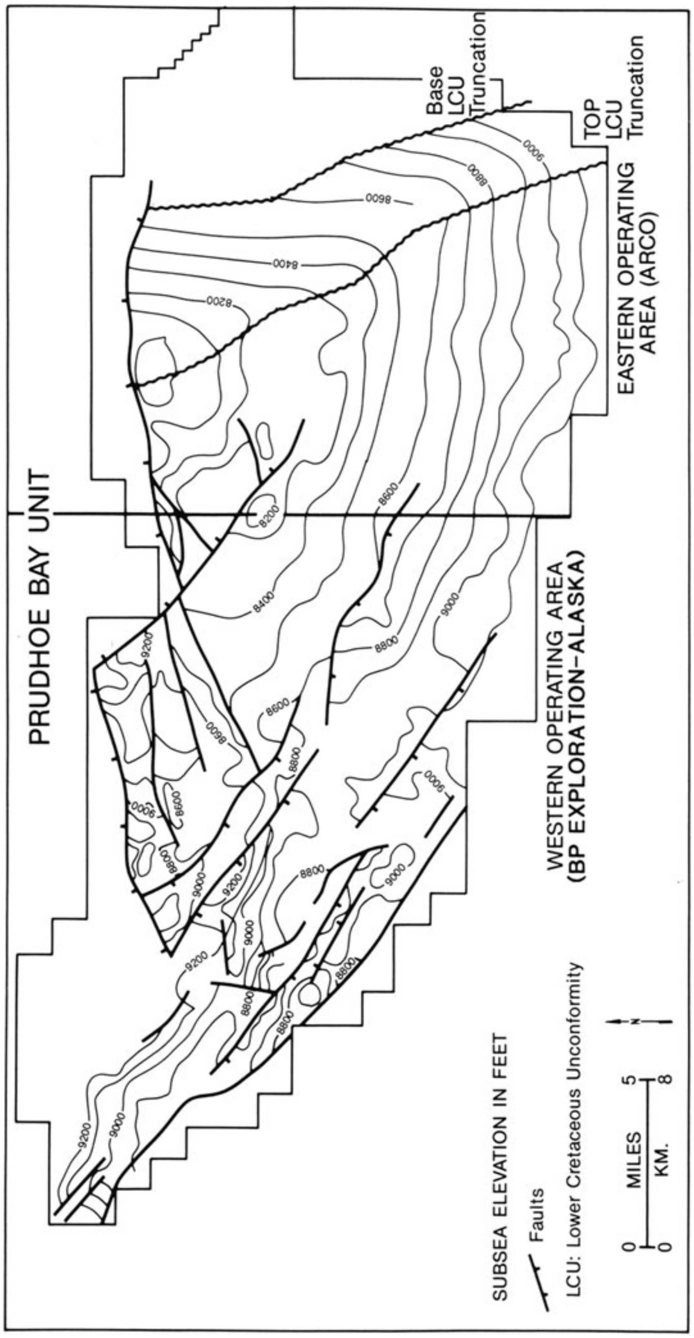


Fig. 1-4. Structure map of the Top Ivishak Sandstone Formation in the Prudhoe Bay Field. Contour interval is 100 feet (30.5 m).

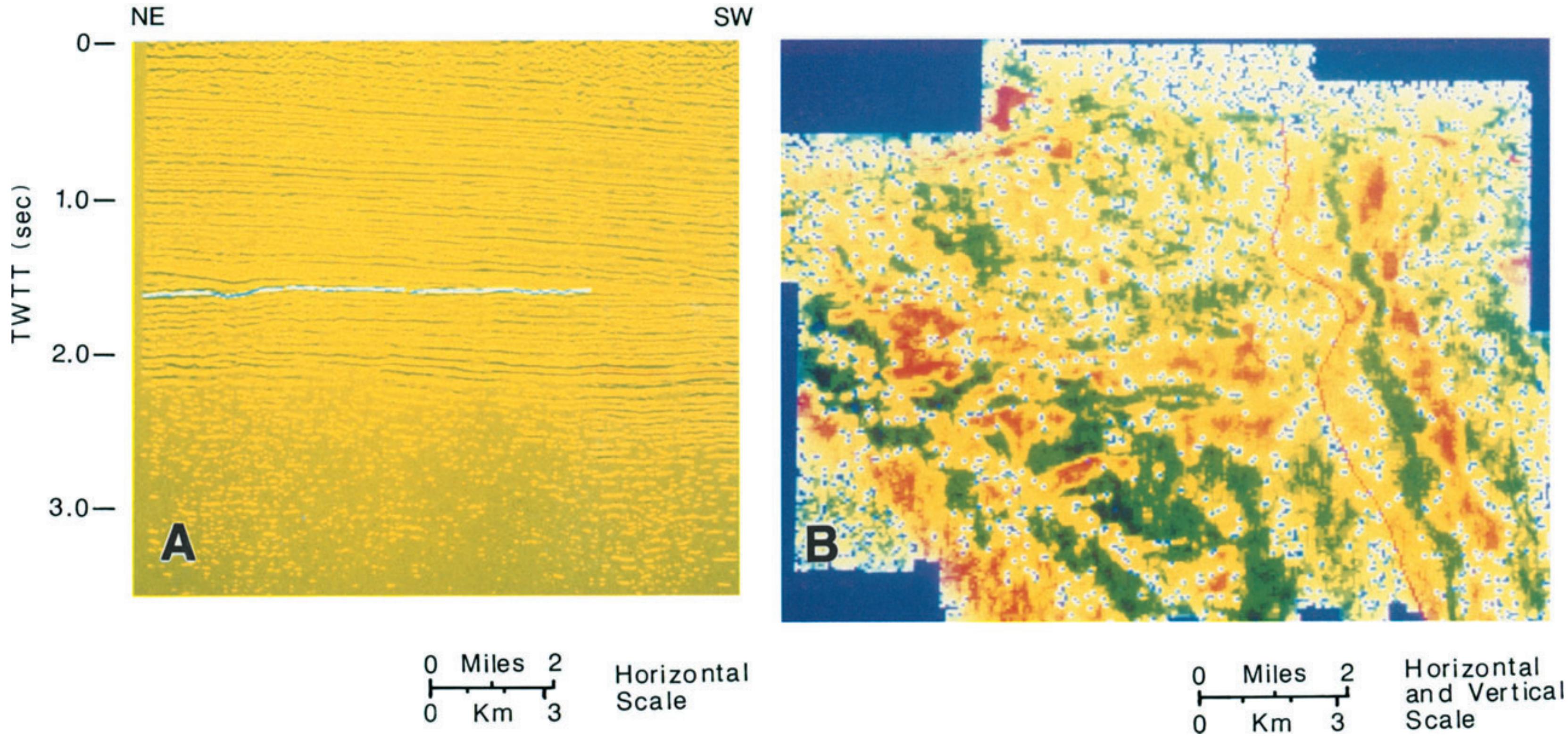


Figure 1-5. (A) Seismic traverse from SW to NE through the northeastern portion of the field. The lower Cretaceous unconformity (LCU) is conspicuously discordant with the underlying formations and truncates the Ivishak (top highlighted) in the NE part of the line. Section displayed in variable intensity. TWTT = Two-way travel time in seconds. (B) Amplitude time slice at approximately 1.8 seconds showing the areal extent of the 3-D seismic survey in the northeastern part of the field. The structural texture of the Ivishak reservoir is evidenced by the coloration of the time slice and shows the trend and dimension of various structural features. The prominent red line denotes the beginning of the truncation of the Ivishak by the LCU to the east.

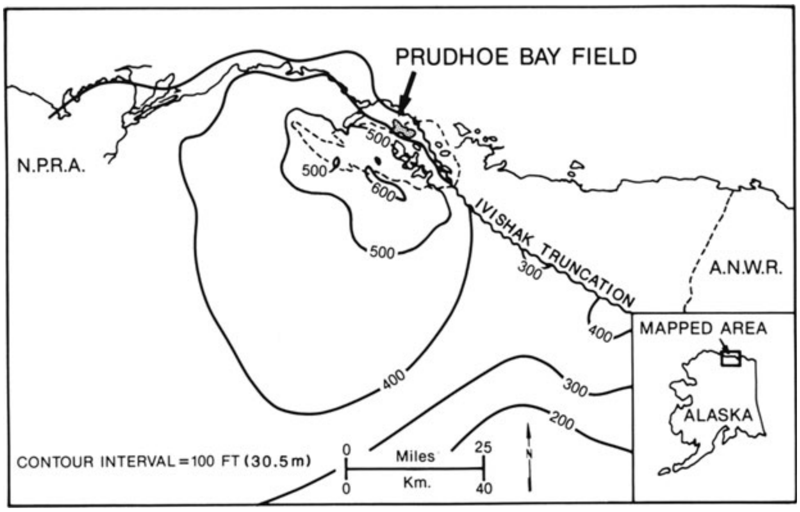


Fig. 1-6. Sandstone thickness map (in feet) of the Ivishak Sandstone in the North Slope region (from Alwin et al., in press, and reprinted by permission of American Association of Petroleum Geologists).

Sandstone, indicating a common co-source for all the oils (Jones and Speers, 1976; Sedivy et al., 1987).

Depositional Environment and Facies

The gross thickness of the Ivishak Sandstone in the field ranges from zero at the unconformity contact to 650 feet (200 m) and averages 550 feet (170 m). Net sandstone thickness averages 484 feet (148 m), with a maximum of 572 feet (174 m). Outside the field, sandstone thickness and the percentage of sandstone and conglomerate within the formation decrease toward the south and southwest (Figs. 1-6, 1-7). Both these factors indicate that the source for the Ivishak sediment was to the north of the present-day coastline. Most authors agree that the Ivishak Sandstone was deposited in fluviodeltaic complexes (Fig. 1-8) which prograded southward into a marine basin (Jamison et al., 1980; Melvin and Knight, 1984; McGowen and Bloch, 1985; Lawton et al., 1987; Atkinson et al., 1988). Stratigraphically, the Ivishak comprises two main depositional megacycles (Fig. 1-9): (1) a lower, upward-coarsening "fluvial progradation" (overall regressive) sequence involving a vertical transition from predominantly interbedded sandstone and marine shale to amalgamated sandstone and conglomerate, and (2) an upper, finer-grained interval of fluvial sandstone and shale which is interpreted to represent a period of "fluvial retreat" (overall transgressive). The distinctive

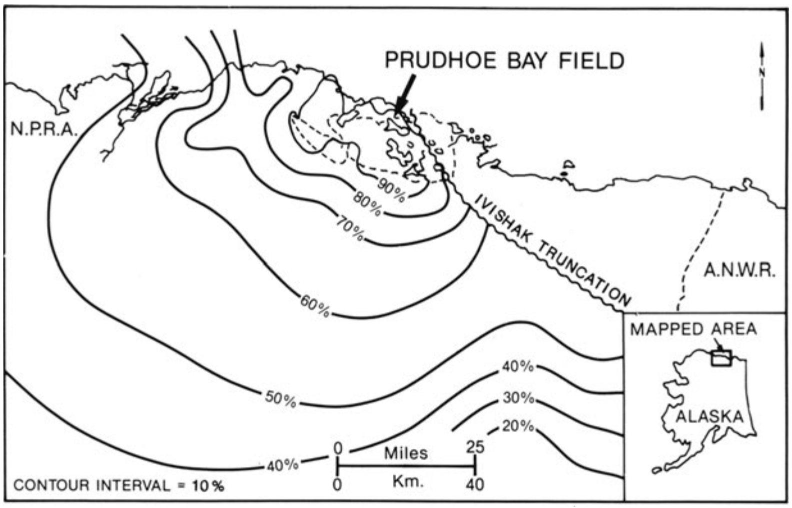


Fig. 1-7. Map of percentage conglomerate/sandstone within the Ivishak Sandstone in the North Slope region (from Alwin et al., in press, and reprinted by permission of American Association of Petroleum Geologists).

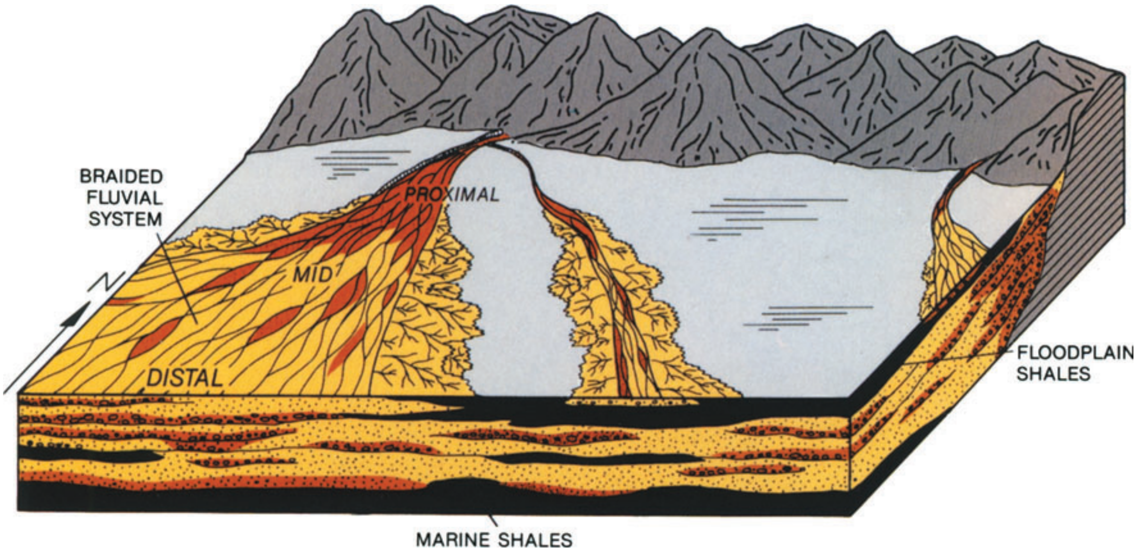


Fig. 1-8. Block diagram illustrating conceptual, braided-river dominated, fluviodeltaic depositional model for the Ivishak Sandstone (modified from Atkinson et al., 1988, and reprinted by permission of the Society of Economic Paleontologists and Mineralogists).

lithologies of the Ivishak Sandstone facilitate a simple, yet effective, petrophysical zonation of the reservoir (zones 1-4, Fig. 1-9). In general, these zones and their subdivisions are stratigraphically continuous throughout the field and can be easily correlated from well logs. Although there is general agreement between these zones/subzones and depositional environment, the relationship is by no means ubiquitous fieldwide (see later discussion).

The Ivishak Sandstone accumulated in depositional environments ranging from delta front to braided stream. Braided-stream processes distributed chert-rich gravel and quartz- and chert-rich sand radially across a coastal plain to construct the subaerial part of the system. Subaerial facies can be broadly categorized as mid-braided stream (alternating conglomerate and sandstone), distal braided/ meandering stream (chiefly sandstone), and abandoned channel-fill, overbank, and pond facies (mudstone, siltstone, and fine-grained sandstone). The fluvial deposits generally comprise multistoried arrangements of erosive-based, upward-fining, channel- and bar-fill sequences. Clast- to matrix-supported conglomerates (Fig. 1-10A), massive (unstratified) to cross-stratified conglomeratic sandstones (Figs. 1-10B, 1-10C), and cross-stratified to parallel-laminated fine- to coarse-grained sandstones (Fig. 1-10D) are the main lithofacies. Marine time-equivalents of the fluvial system are delta-front sandstones (including river-mouth bars and delta fringe/distal bar) and prodelta sandstones, siltstones, and mudstones. Delta-front sandstones were influenced by both fluvial and marine processes and are finer-grained and better sorted than are the contemporaneous fluvial deposits. Dominant lithofacies include parallel- to ripple-laminated sandstone (Fig. 1-11A) and siltstone and bioturbated siltstone and mudstone (Fig. 1-11B). The prodelta sediments comprise interbedded very fine-grained sandstones, siltstones, and mudstones and belong, for the most part, to the underlying Kavik Shale. Grain size decreases and sorting improves from the braided stream through delta front and into the marine-dominated deposits of the Ivishak Sandstone. The scale of sedimentation units decreases from the proximal to the distal facies.

Facies and interpreted environmental relationships are illustrated on north-south (parallel to depositional dip) and west-east (normal to depositional dip) cross sections (Figs. 1-12, 1-13). From north to south, a decrease in the thickness of the conglomeratic mid-braided stream deposits is accompanied by a corresponding increase in thickness in the more sandy, distal-fluvial deposits (Fig. 1-12). The cross section demonstrates a pulsed southward outbuilding of the Ivishak fluviodeltaic system, followed by a northward retreat of the system tract. The east-west cross section (Fig. 1-13) is approximately transverse to the overall sediment transport direction

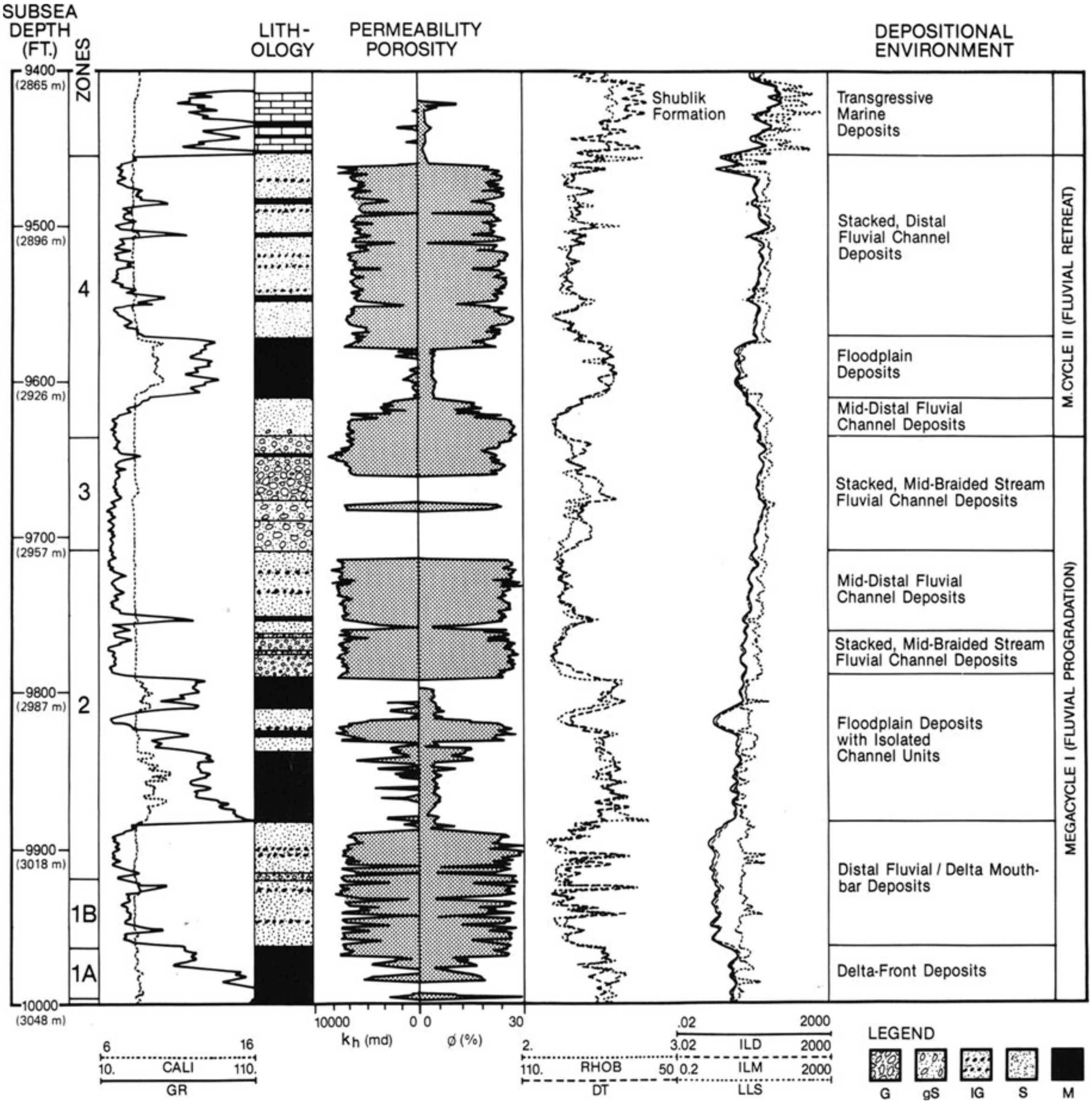


Fig. 1-9. Type log through the Ivishak Sandstone indicating lithology, reservoir quality, depositional environments, and petrophysical zonation (1-4). Lithologic legend: G = conglomerates, gS = conglomeratic sandstones, IG = intraformational conglomerates, S = sandstone, M = shale.

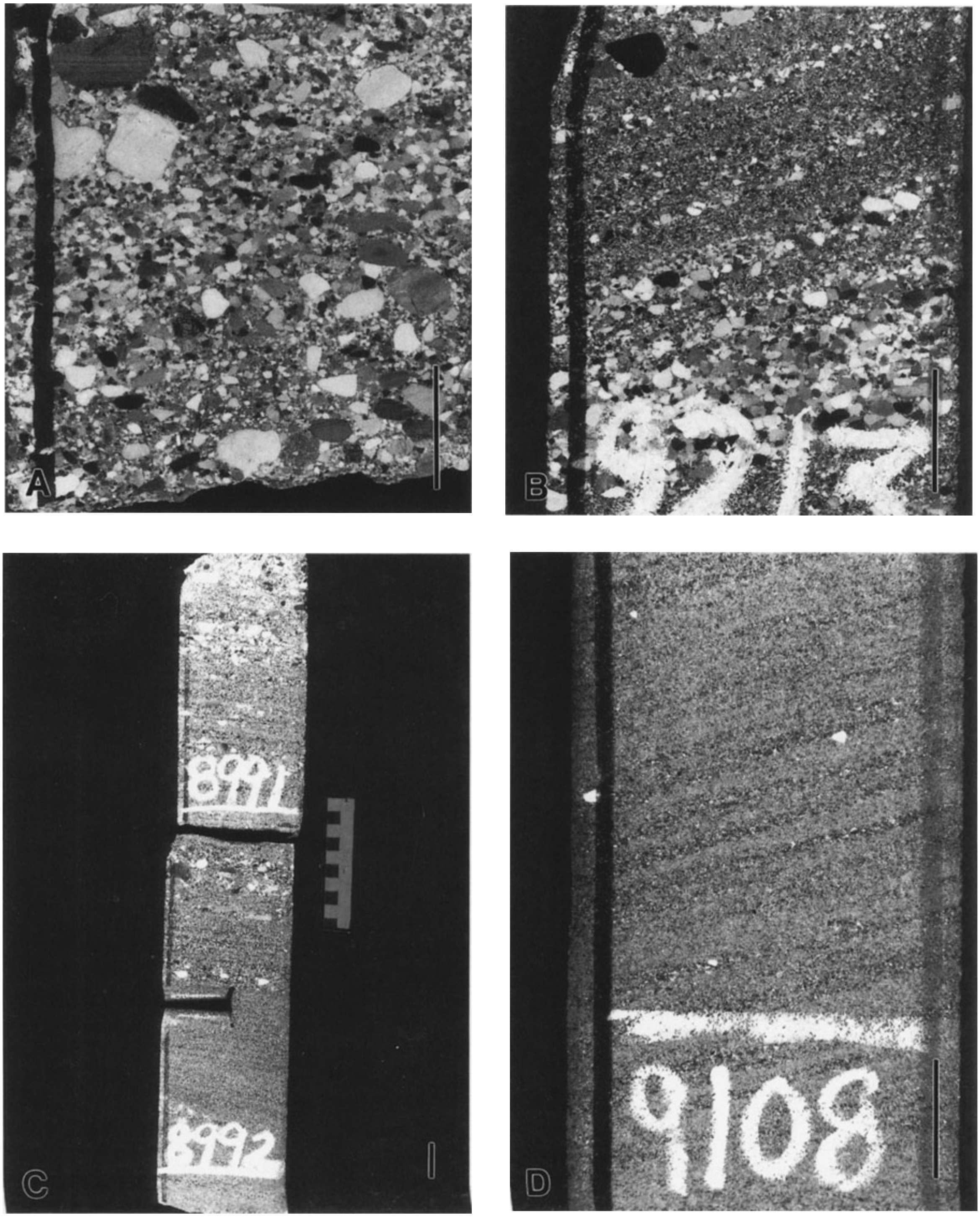


Fig. 1-10. Core photographs representative of the Ivishak fluvial lithofacies: (A) massive, clast- to matrix-supported conglomerate (white and black clasts are microporous and dense chert, respectively), (B) cross-stratified conglomeratic sandstone, (C) cross-stratified pebbly sandstones, and, (D) cross-stratified medium- to coarse-grained sandstone. Scale bar is 1 inch (2.5 cm).

Fig. 1-11. Delta-front lithofacies: (A) low-angle to parallel-laminated, very fine-grained sandstone containing mud drapes and intraformational conglomerate, (B) *Planolites* burrowed delta-front mudstone. Scale bar is 1 inch (2.5 cm).

and illustrates the tendency for more proximal facies to grade laterally at approximately the same stratigraphic level into more distal deposits. This suggests that the Ivishak coastal braidplain consisted of major, braided-river channel belts separated by interfluvial areas comprising overbank deposits and smaller, finer-grained fluvial channels (see Fig. 1-8). The overall vertical succession (prodelta, delta front, distal- to mid-fluvial) in some wells indicates a southward progradation by the Ivishak fluviodeltaic system. Outbuilding was produced by river systems that not only transported coarse-grained sediment to the sea but also spread sediment laterally as the braided channels continually shifted their courses in order to adjust to sediment load, discharge, and slope.

Petrography and Diagenesis

Monocrystalline quartz and chert are the most abundant detrital components in the Ivishak clastic rocks. The Ivishak sandstones are litharenites and sublitharenites (terminology of Folk et al., 1970). The quartz-chert ratio is a function of grain size and increases with increasing distance from the sediment source area. Two types of chert are present: (1) nonporous ("dense") chert, and (2) microporous chert (Fig. 1-14). Other detrital components, typically present in minor amounts, consist of polycrystalline quartz, sedimentary (other than chert) and metasedimentary rock fragments, and trace amounts of feldspar. Detrital clay matrix is a minor constituent except in very fine- grained sandstones, siltstones, and mudstones. The advanced stage of mineralogical maturity suggests that Ivishak rocks originated as a recycled sediment accumulation.

Diagenetic effects were gradually superimposed on the component facies of the fluviodeltaic system. Porosity-reducing diagenesis most commonly consists of partial cementation by quartz, siderite, kaolinite, pyrite, and ferroan carbonate, and compac-

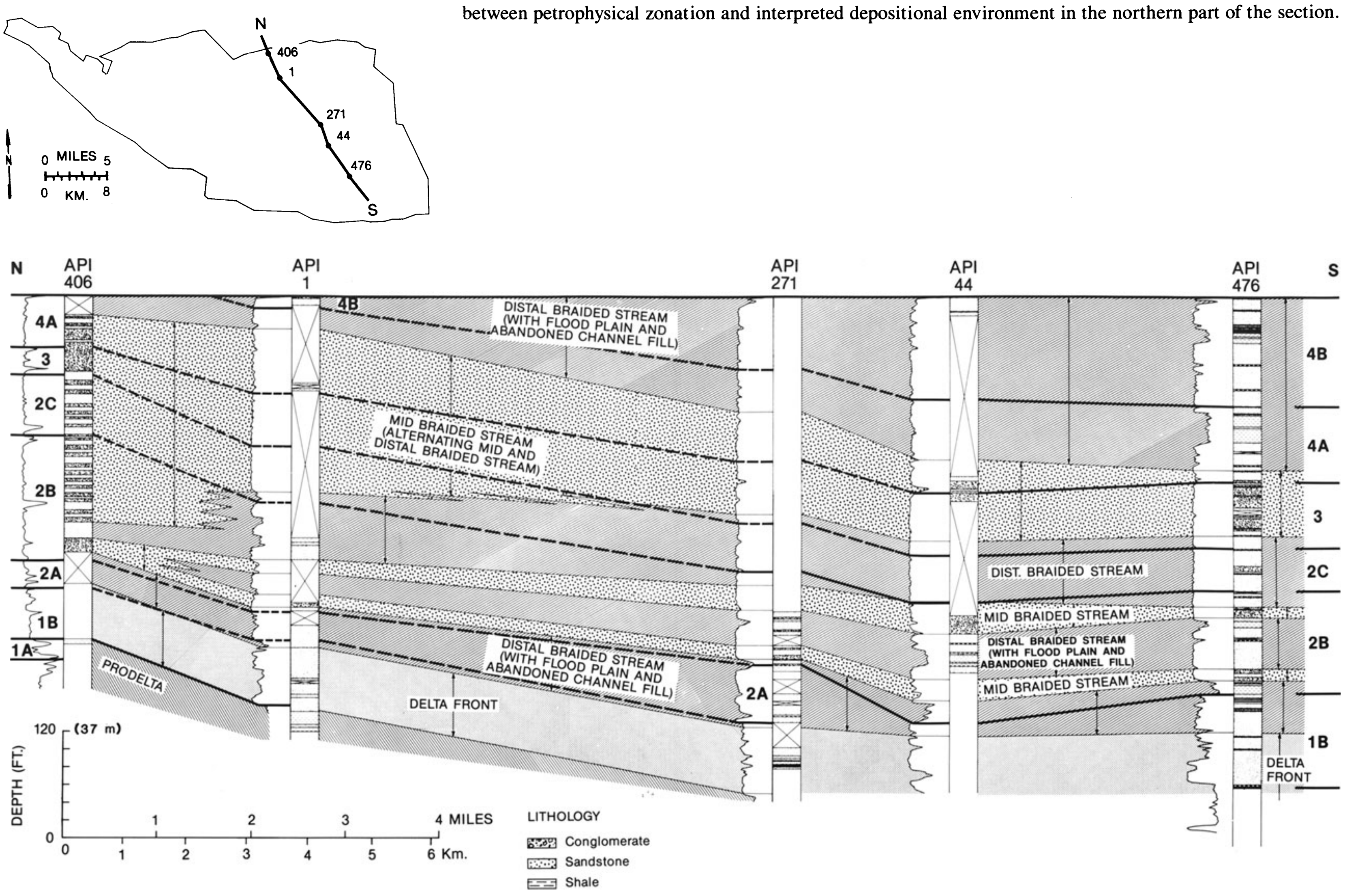


Figure 1-12. North-south stratigraphic cross section through the Ivishak Sandstone illustrating intrareservoir facies distribution and detailed petrophysical zonation (shown as 1A-4A). Note cross-cutting relationship between petrophysical zonation and interpreted depositional environment in the northern part of the section.

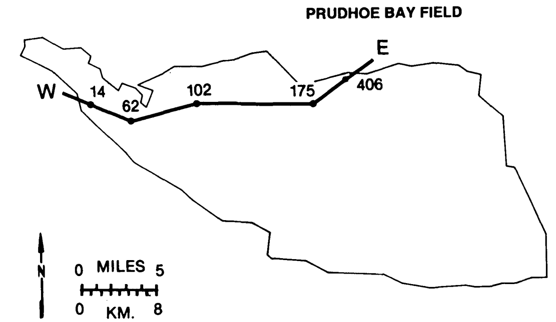
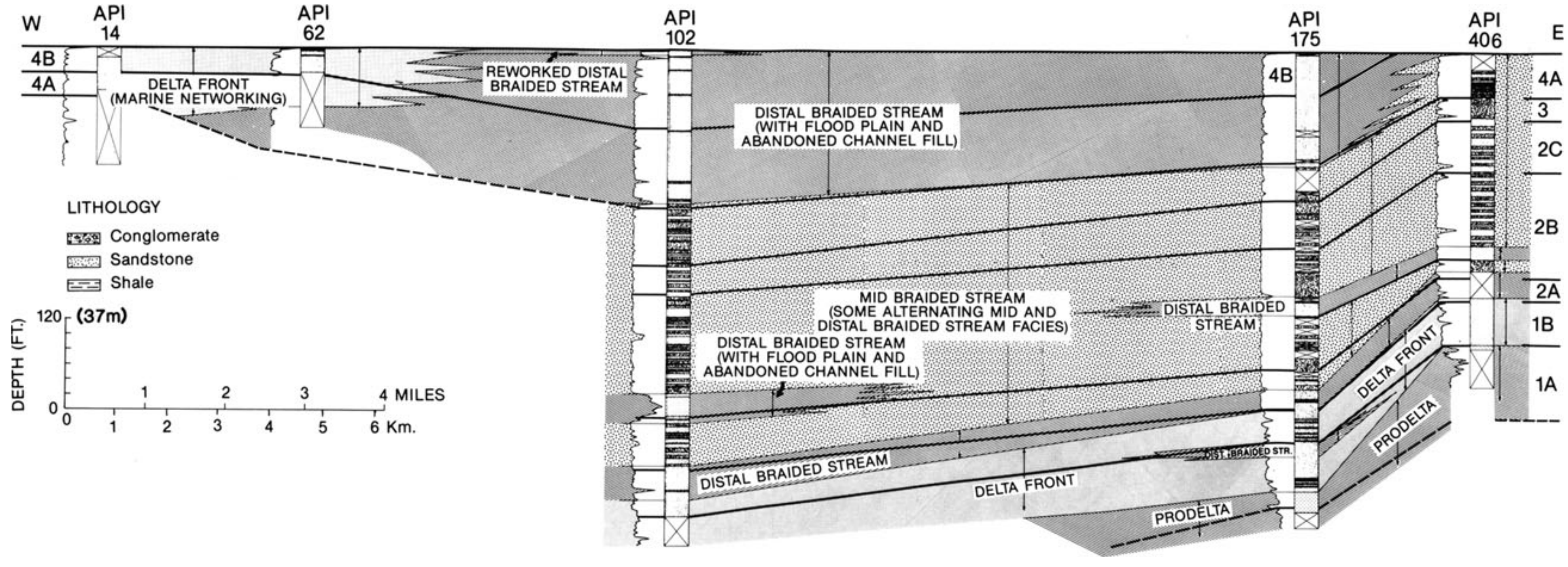


Fig. 1-13. East-west stratigraphic cross section through the Ivishak Sandstone illustrating intrareservoir facies distribution and detailed petrophysical zonation (marked as 1A-4A). Note cross-cutting relationship between petrophysical zonation and interpreted depositional environment in the western and eastern parts of the section.



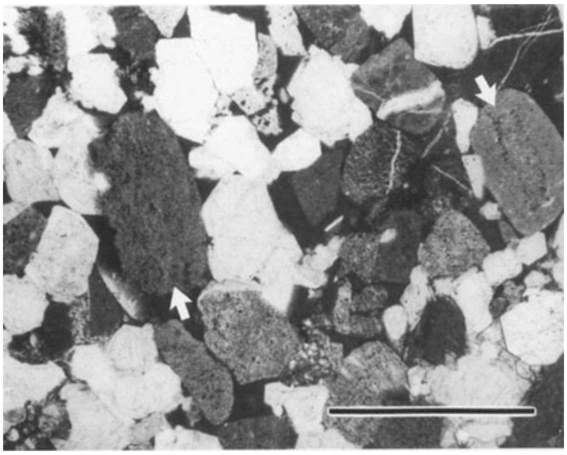


Fig. 1-14. Photomicrograph of typical medium-grained Ivishak Sandstone consisting of detrital quartz with well-developed overgrowths and dense and microporous chert (arrowed). Scale bar is 1 mm. Plane polarized light.

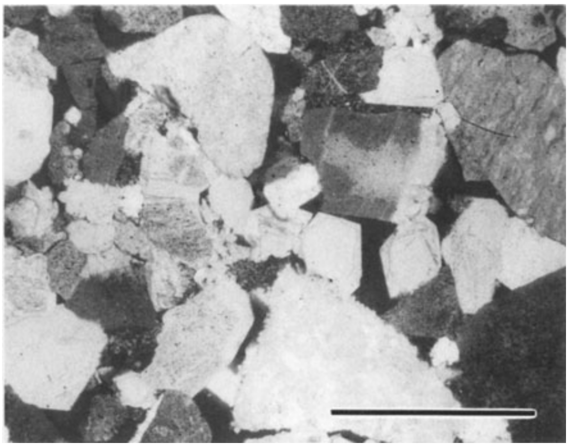


Fig. 1-15. Photomicrograph of typical coarse-grained Ivishak Sandstone displaying limited mechanical compaction. Scale bar is 1 mm. Plane polarized light.

tion (including formation of stylolites and pseudomatrix). The fabric of most samples is characterized by tangential and long grain-to-grain contacts (Fig. 1-15). Pore types include primary intergranular macropores, relatively sparse secondary intragranular macropores, and micropores. Secondary macroporosity is the result of partial to complete dissolution of siderite cement and sedimentary rock fragments. Micropores, an important form of microscopic heterogeneity in the reservoir, occur in partially leached chert fragments and in kaolinite cement.

Reservoir Quality

Reservoir quality is, to a large extent, controlled by sedimentary facies (Table 1-1; Figs. 1-16, 1-17) and, in particular, by their textural characteristics. At the reservoir scale, grain size is the primary control of permeability, and a decrease in grain size from more proximal to more distal facies is generally accompanied by decreasing permeabilities. However, sorting also significantly influences reservoir quality of the sandstones. In sandy conglomerates and conglomeratic sandstones, grain size bimodality is a major control of porosity and permeability (Fig. 1-18). For example, sandy conglomerates of lower mid-braided stream affinity have lower porosities but higher permeabilities than do moderately sorted, medium- to coarse-grained sandstones of distal braided-stream origin (Table 1-1; Figs. 1-16, 1-17). This observation is in agreement with the conclusion of Clarke (1979) that "the effects of bimodality are more important than diagenesis in determining the quality of some oil-field reservoirs."

Comparison of the overall permeability trends among facies of the Ivishak Sandstone with permeability patterns displayed by unconsolidated sands with analogous grain size and sorting (Beard and Weyl, 1973) indicates that the general trends which existed in the unconsolidated original sediments are still recognizable in spite of the diagenetic overprint. Secondary porosity appears only to have enhanced trends in reservoir quality that existed in the Ivishak sediments prior to burial.

Reservoir Heterogeneity and Production Behavior

Although the Ivishak succession is characterized by a high percentage of sandstone and conglomerate, and in comparison to many other reservoirs can be regarded as relatively homogeneous, it does exhibit significent degrees of internal heterogeneity. Heterogeneity exists at scales ranging from the macroscopic (vertical scale in tens of feet, tens of meters; horizontal scale in hundreds of feet, hundreds of meters) to the mesoscopic (vertical and horizontal scales in ones to tens of feet; decimeters to meters)

Table 1-1. Relationship between depositional facies and average core-plug-measured porosities and permeabilities in a well in the eastern part of the field. This well had the most complete core coverage and the largest number of samples analyzed for porosity and permeability of all the wells available in the field. Reservoir quality trends observed in this well are representative of the field.

Facies	Total thickness ft (m)	$\bar{k}$ (md)	ϕ (%)	Comments
Mid-braided stream	13 (4.0)	639.0	22.5	* No conglomerate
Lower mid-braided stream	35 (10.7)	512.0	18.9	* 16 conglomerate samples, $\bar{k}$ = 359 md; 19 sandstone samples, $\bar{k}$ = 640 md
Mid-braided stream to distal-braided stream	27 (8.2)	495.0 495.0	23.9 23.9	* 1 conglomerate sample, $\bar{k}$ = 71 md; 26 sandstone samples
Upper distal-braided stream	64 (19.5)	685.0	25.2	* No conglomerate
Distal-braided stream	248 (75.6)	349.0	22.6	
Distal-braided stream to delta front	18 (5.5)	73.0	20.3	
Delta front	44 (13.4)	13.0	14.9	13 samples coarser than fine-grained, $\bar{k}$ = 33 md; 30 samples fine-grained and finer, $\bar{k}$ = 7 md
Floodplain	63 (19.2)	0.8	5.0	

* Measured permeability in conglomerates is low owing to the inability to obtain accurate measurements in this facies using core plug samples. Whole core and selective pressure test data suggests significantly higher permeability values.

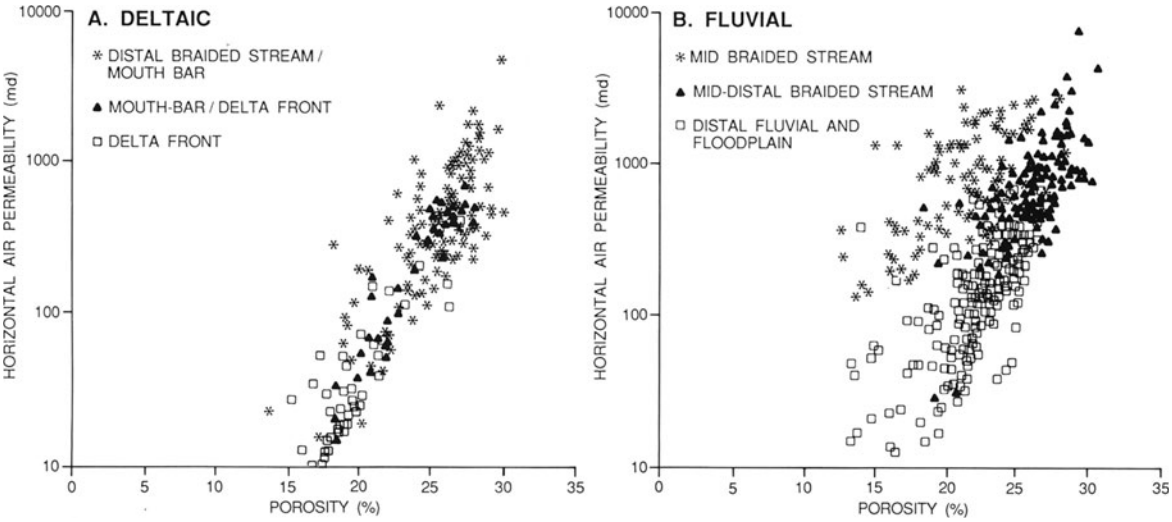


Fig. 1-16. Relationship between depositional facies and core plug measured porosity/permeability for the deltaic and fluvial components of the Ivishak reservoir. Note relatively low permeabilities associated with mid-braided stream facies owing to inability to obtain representative plug samples in this predominantly conglomeratic lithology. Whole core and production test measurements from this facies indicate much higher permeabilities than those suggested here.

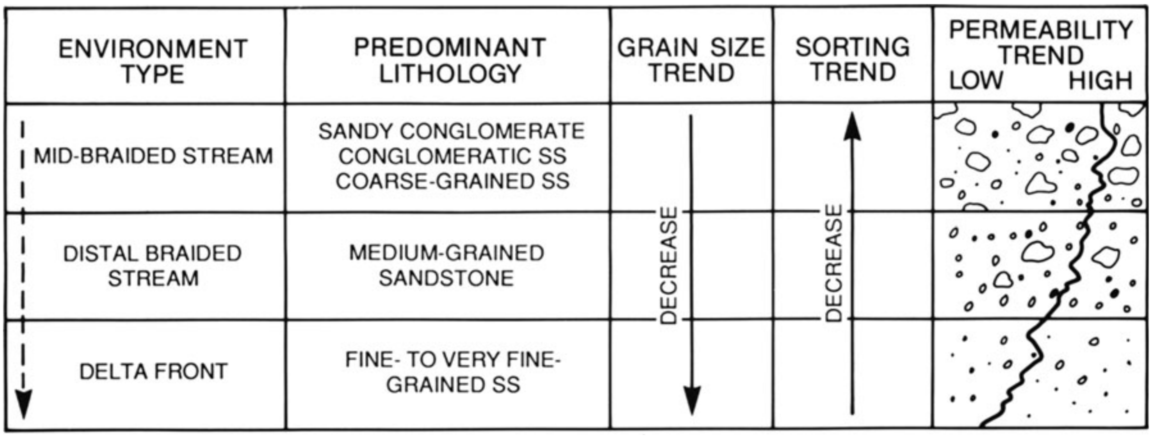


Fig. 1-17. Qualitative relationship among depositional facies, lithology, sediment texture, and permeability.

and ultimately to the microscopic (vertical and horizontal scales in tenths to hundreds of inches; millimeters).

One of the most important forms of macro- to mesoscopic heterogeneities are the shale intervals, which occur throughout the reservoir (Fig. 1-19). Previous studies have shown that the relative extent of a shale interval in the reservoir is linked to its depositional environment (Geehan et al., 1986). Continuous shales, those which extend over two or more well spacings, were deposited in floodplain, prodelta, and marsh/bay environments (Fig. 1-19). They occur throughout the Ivishak succession but are most common in the lower parts of the reservoir in the eastern part of the field. Of these shales, the thick floodplain deposits act as the most effective vertical permeability barriers and commonly divide the oil column into isolated production intervals. Depending upon their location within the field, "continuous" shales may be either advantageous or disadvantageous to production (Fig. 1-20). Locally, shale barriers can assist in increasing production rates by preventing both gas coning and water influx. Elsewhere, their presence can be detrimental. First, they may reduce pressure support from the gas cap if production takes place below these shales. Second, shales can promote gas underrunning where production-induced pressure sinks develop below them when they are continuous updip into the gas cap (Geehan et al., 1986; Haldorsen and Chang, 1986). Discontinuous shales, those smaller than the interwell distance, comprise abandoned channel fills and thin intrachannel drape deposits (Fig. 1-19). They are widespread in their distribution and occur throughout the fluvially dominated parts of the reservoir. Where present, the shales form partial baffles to vertical fluid flow and act to reduce effective vertical permeability in the reservoir. In areas where gravity drainage occurs, oil may accumulate on top of the shales and be bypassed as the gas cap expands downward (Geehan et al., 1986; Haldorsen and Chang, 1986).

Recent studies have shown that mesoscale heterogeneities resulting from permeability variation within the sandstones and conglomerates also exert a significant control on reservoir performance. Dur-

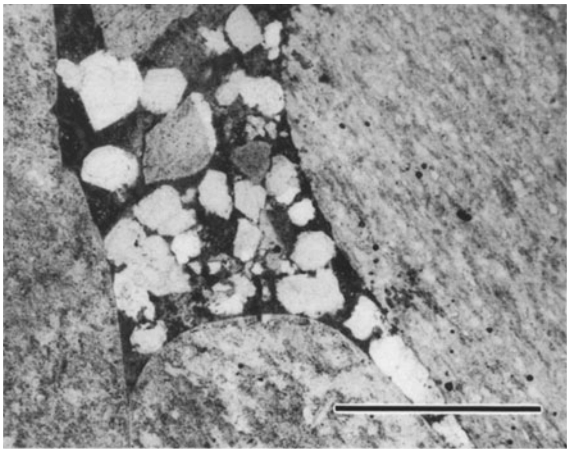


Fig. 1-18. Photomicrograph of quartz and chert grains filling interstices between a framework of chert granules and pebbles. Scale bar is 1 mm. Plane polarized light.

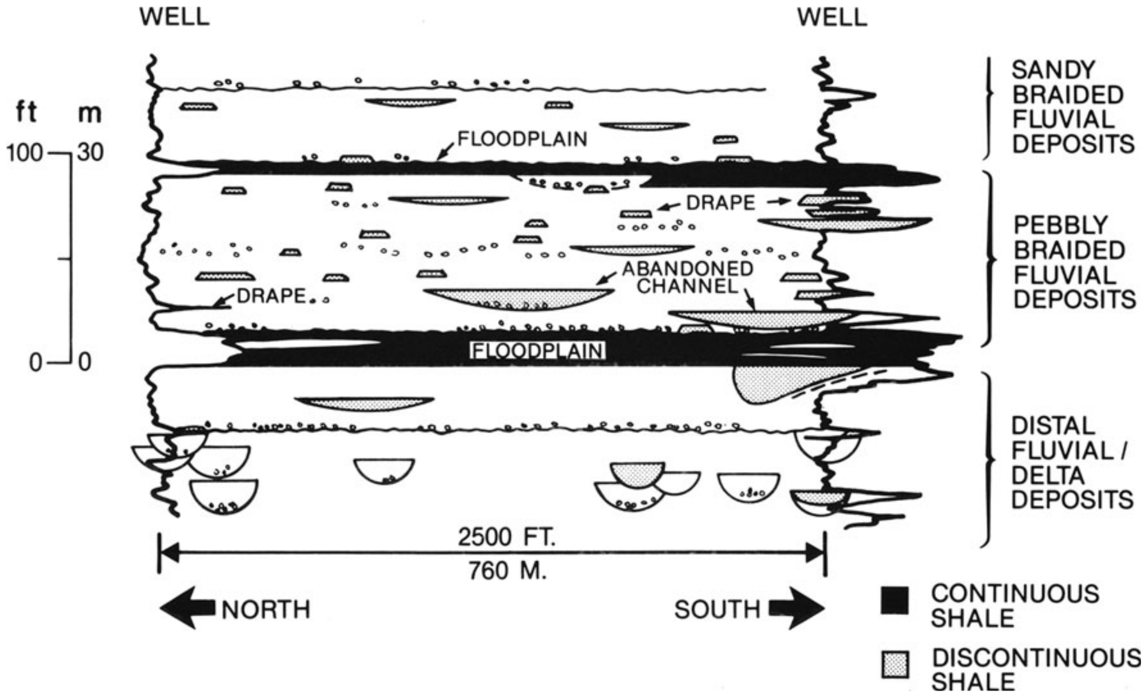


Fig. 1-19. Interpreted depositional environments and associated genetic shale facies of the zone 2 interval of the Ivishak Sandstone in the eastern part of the field. Interpretations based upon log response and core data (modified from Geehan et al., 1986, and reprinted by permission of Academic Press).

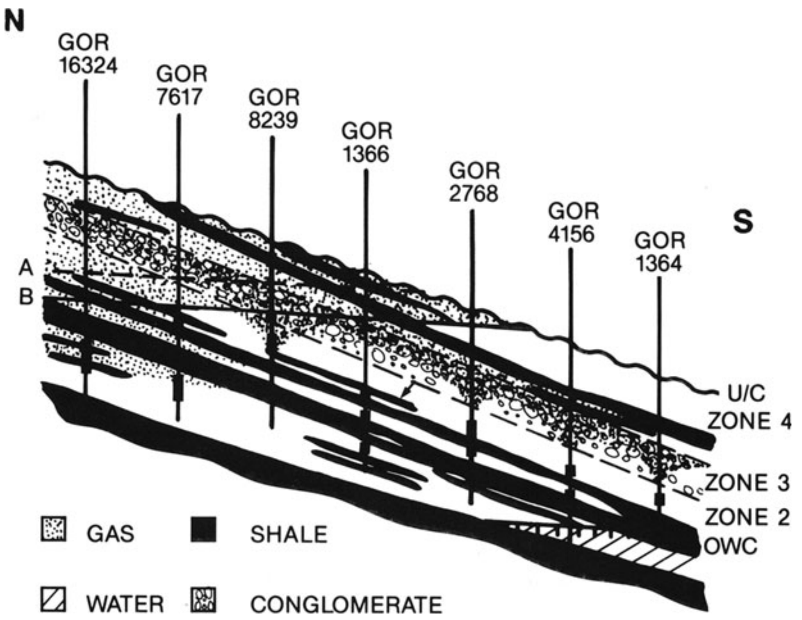


Fig. 1-20. Schematic north-south cross section through the eastern part of the field illustrating gas underrunning shales. Arrow indicates a "continuous" shale which inhibits gas coning but which does not intersect the gas cap and promote underrunning. GOR = gas:oil ratio for each well, A = position of original gas/oil contact (1977), B = position of gas/oil contact as of March, 1983 (modified from Geehan et al., 1986, and reprinted by permission of Academic Press).

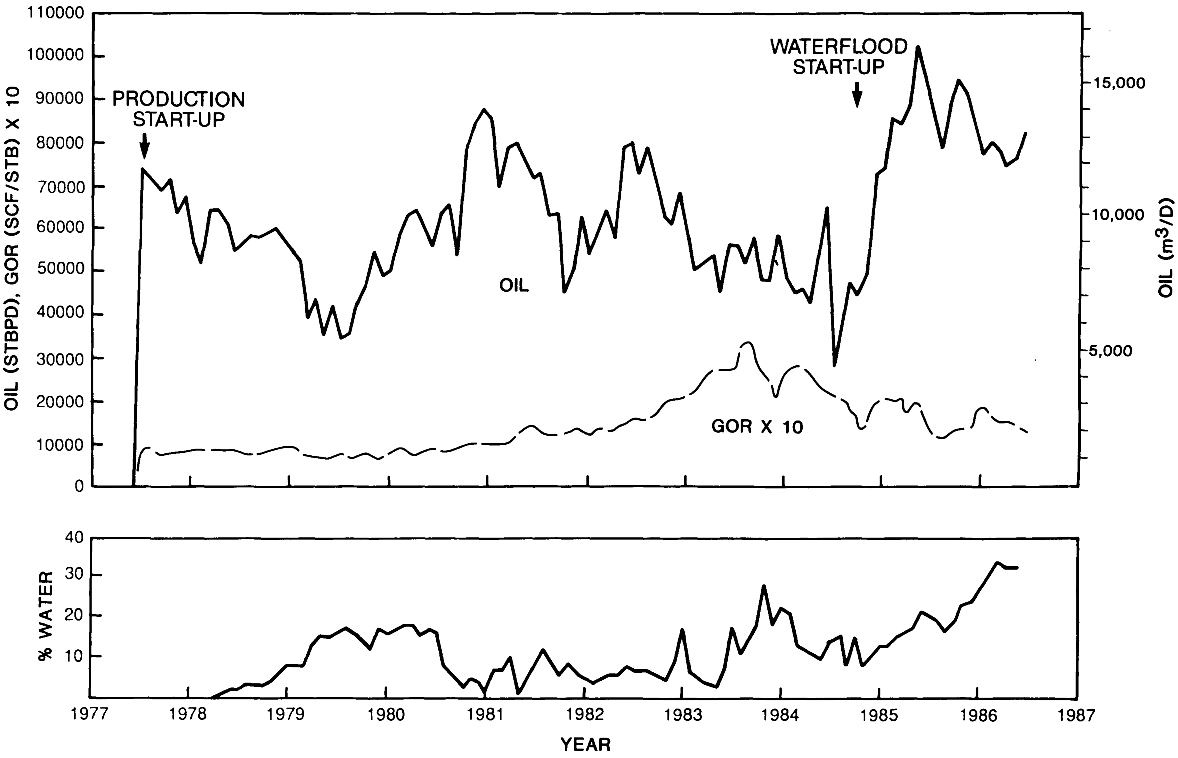


Fig. 1-21. Typical production-history curves for a single drill-site area (34 wells) in the eastern part of the field. Note the increase in oil production and decrease in gas:oil ratio (GOR) associated with late 1984 waterflood start-up.

ing primary production from the field, the presence of high-permeability intervals within the coarse-grained, fluvial deposits facilitated high oil production rates from many wells. As emphasis switches to secondary and tertiary recovery techniques, these same high permeabilities are presenting difficulties in optimizing recovery from the field. Field development problems result primarily because the permeabilities are not uniform within the reservoir. In many wells, permeability profiles are highly irregular, with thick intervals of good overall horizontal permeability (100s of md) being punctuated by thinner horizons of extremely high permeability (1,000s of md). This irregularity is the result of the facies distribution within the Ivishak Sandstone where coarser (high permeability)- and finer (lower permeability)-grained channel fills alternate.

The control exerted on reservoir performance by this facies variation is illustrated by an example from the production/injection characteristics of a single drill site in the eastern part of the field. This drill site comprises a total of 34 wells, 10 of which are currently used for water injection. A production summary for the area is illustrated in Figure 1-21. In this area, detailed geological studies supported by engineering data have been used to subdivide the reservoir into a series of major mappable "flow units" (Fig. 1-22). A flow unit is here defined in the sense of Ebanks (1987) as "a volume of the total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and predictably different from the properties of other rock volumes, i.e., flow units". There is a close relationship between the reservoir flow unit subdivision and gross depositional facies (Fig. 1-22). Furthermore, as discussed in the previous section, the production/injection characteristics of each flow unit are strongly influenced by the relative reservoir properties of the component facies. In wells perforated throughout the entire Ivishak interval, injected water more easily enters flow units V1, V2, and V3. These flow units are composed predominantly of coarser-grained, braided-stream conglomerates and conglomeratic sandstones. In contrast, it is relatively

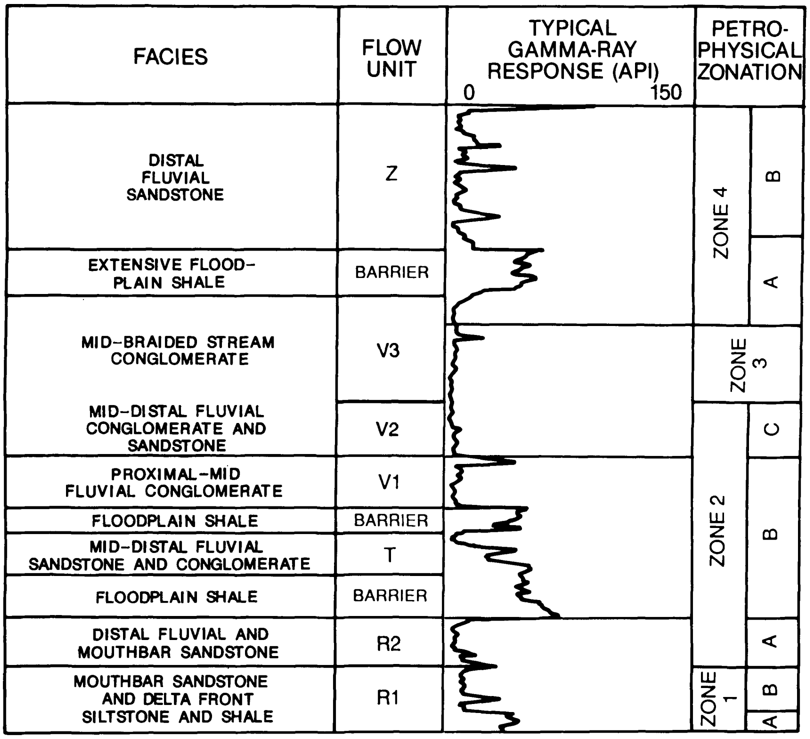


Fig. 1-22. Type log illustrating the relationship between depositional facies, petrophysical zonation, and flow-unit subdivision in the drill site of Figure 1-21. Flow units Z, V, T, and R are named after shale mapping units.

more difficult to inject water into flow units Z, R1, and R2, which are dominated by finer-grained, distal-fluvial and delta-front deposits (Fig. 1-22). The ability to inject water is a reflection of the effective permeabilities of each of the flow units, which are governed by the grain size and sorting characteristics of the component depositional facies.

Flow-unit mapping in the drill site has helped recognize and predict several high-permeability "thief zones" within the reservoir. These thief zones are typically clast-supported conglomerates with exceedingly high permeabilities and lateral extents of several well spacings (thousands of feet; hundreds of meters). A more detailed examination of the injectivity profile of a particular well highlights this thief-zone problem (Fig. 1-23). In this well, which was perforated selectively throughout the V2-Z interval, spinner data indicate that very high flow rates (95% of the total injected water) occurred initially in a relatively thin, 10- foot (3.0-m) thick conglomeratic zone within the V3 interval (8,915-8,925 ft, 2,717-2,720 m, Fig. 1-23). This conglomeratic interval, with an estimated permeability of more than 4,000 md, acts as a major thief zone. Although several other zones were open to flow in this well, no water entered at these levels despite measured air permeabilities from core of more than 200 md. Following well-profile modification and the isolation of this thief zone, water injection into the overlying more distal fluvial sandstones has been fairly uniform. This is a product of the similar grain-size distributions and sorting characteristics that these sandstones possess, in contrast to the underlying conglomerates (Fig. 1-23).

Microscopic-scale heterogeneities also exist within the reservoir. These further complicate the saturation distribution and recovery efficiency across the field. The most important of these are the micropores present within chert grains and clasts in the sandstones and conglomerates. The amount of microporous chert varies throughout the field, but in places it can be as high as 35% of the total rock volume. Measured intragranular porosity in microporous chert averages 40% and may be more than 60% in some instances (Alwin et al., in press). Where present, the chert makes formation evaluation difficult, since the micropores may be filled with either water or oil depending upon location within the field. Where these micropores occur in the oil column, they are often water saturated. In such cases, calculated water saturations from resistivity logs may indicate values as high as 60%, but the zones produce water-free oil.

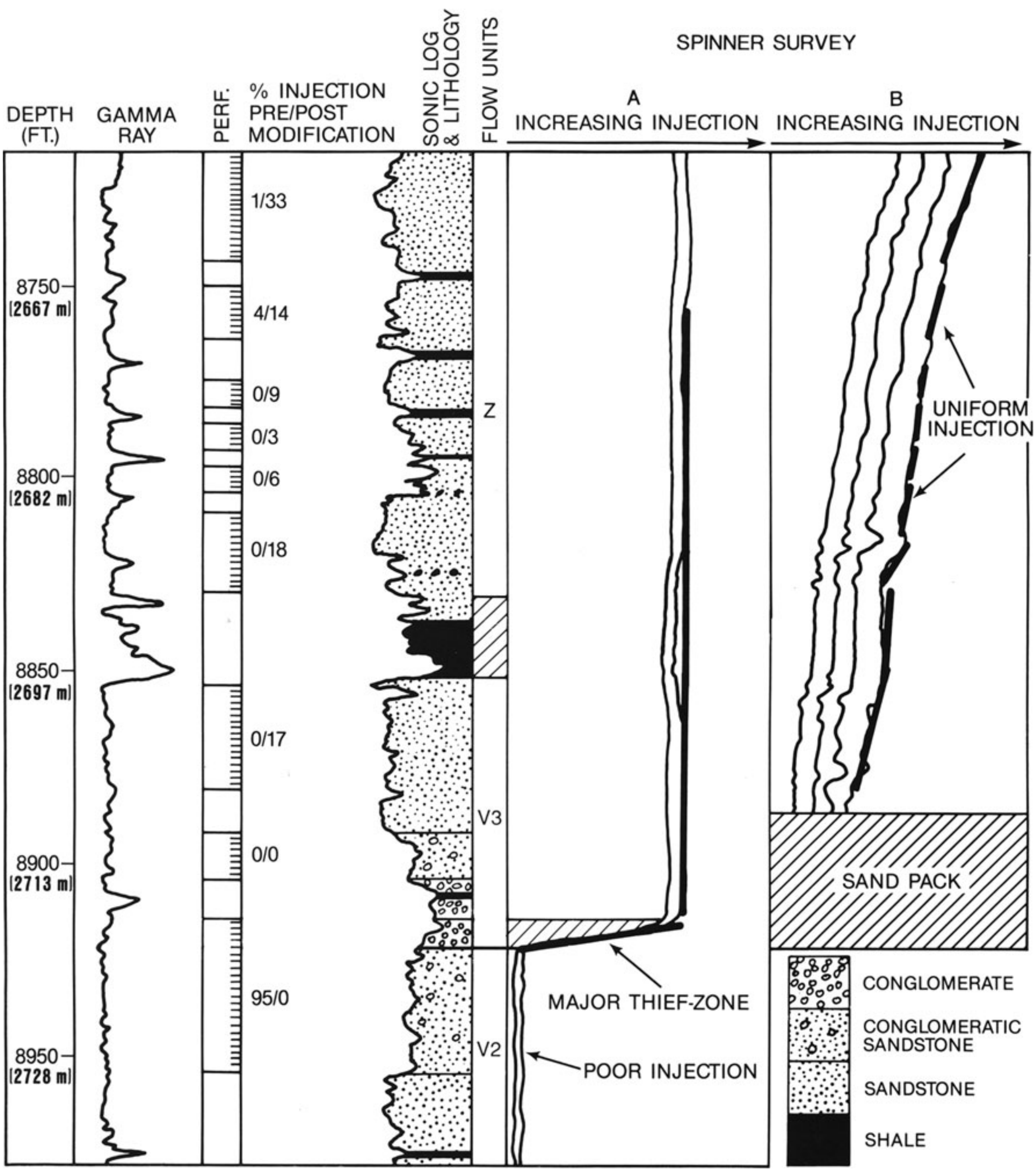


Fig. 1-23. Spinner survey data through an injector well in the drill site of Figure 1-21. (A) Preprofile modification: high-permeability conglomeratic thief zone within the V3 flow unit takes 95% of total injected water. (B) Postprofile modification: fairly uniform injection into sandstones with similar grain-size and sorting comprising the upper V3 and Z flow units. PERF. on the figure refers to perforations.

Exploration and Production Strategy

The location of the giant Ivishak accumulation is the result of a delicate relationship among several key factors. These factors are the presence of a thick and extensive section of excellent reservoir rocks within a structural/stratigraphic trap, favorable burial history, presence of rich source rocks and a geothermal gradient sufficient to generate hydrocarbons, and the proper timing of focused migration of hydrocarbons into the trap.

Exploration outside the field has shown that the Ivishak Sandstone is laterally continuous across the North Slope region on the southern flank of the Barrow arch. To the south, in the Colville Trough, the Ivishak succession becomes increasingly finer grained and eventually passes distally into marine shales. The Ivishak thus forms a clastic wedge-like interval on the flank of a major basement uplift. Exploratory drilling has followed the Ivishak trend north and west of Prudhoe Bay. Several favorable structures with good reservoir quality have been encountered, but only one other significant hydrocarbon accumulation, Seal Island, has been found. Despite the presence of more than 300 million barrels (4.8×10^{10} m^3) of oil in place, this field is currently uneconomic. Although good hydrocarbon shows have been encountered in other wells drilled along the Ivishak trend, leaky seals combined with unfavorable tectonic histories appear to have prevented any economic hydrocarbon accumulation. The laterally extensive nature, high net-to-gross ratio, and overall good reservoir quality of the sandstones and conglomerates comprising the reservoir have resulted in a relatively straightforward development strategy for the field. Development wells have been drilled on a standard 160/80-acre spacing from a series of drill sites throughout the field. The waterflood and water-alternating gas (WAG) programs are utilizing an inverted nine-spot pattern in the central part of the field whereas on the periphery, where the oil leg is thinnest, a five-spot pattern has been adopted. Future modifications to this strategy are dependent upon integrating field economics with the results of continued reservoir monitoring and description efforts.

Summary

The Ivishak Sandstone reservoir at Prudhoe Bay comprises an extensive, sheet-like body of amalgamated sandstones, conglomerates, and interbedded shales of deltaic and braidplain origin. Reservoir quality is primarily controlled by sediment grain size and sorting and, hence, by depositional facies and environment. The highest permeability intervals with the greatest flow and injection rates are associated with coarser-grained, mid-braided stream conglomerates and conglomeratic sandstones. In contrast, lower permeabilities and poorer production/injectivity are characteristic of the finer-grained, distal fluvial and deltaic sandstones.

Despite the predominance within the reservoir of high permeability sandstones and conglomerates, the presence of numerous intrareservoir shales, together with a complicated facies distribution, has combined to produce a reservoir with a variable, heterogeneous, and layered fabric. As development strategy has changed from primary to secondary and tertiary recovery, the significance of this reservoir heterogeneity for ultimate field production has become increasingly evident. The current goal of combined geological and engineering reservoir description in the field is to quantify and map heterogeneity using the flow unit concept. Through this methodology, an efficient reservoir management program is being formulated to maximize the ultimate recovery from this super giant field.

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Reservoir Summary

Field: Prudhoe Bay
Location: North Slope, Alaska
Operators: ARCO Alaska, Inc., BP Exploration (Alaska) Inc.
Discovery: 1968
Basin: Colville Trough
Tectonic/Regional Paleosetting: Combination extensional rift and later compressional foreland basin
Geologic Structure: Faulted, truncated anticline
Trap Type: Combination anticline/subunconformity with three-way dip closure
Reservoir Drive Mechanism: Gravity drainage with gas-cap expansion (with limited aquifer support)

- **Original Reservoir Pressure:** 4,335 psi (3.0×10^4 kPa) at 8,575 feet (2,614 m) subsea
- **Present Pressure:** 3,750 psi (2.6×10^4 kPa) at 8,800 feet (2,682 m) subsea
- **Pressure Gradient:** 0.50 psi/ft (11.3 kPa/m)

Reservoir Rocks

- **Age:** Early Triassic (?), early-middle Scythian
- **Stratigraphic Unit:** Ivishak Sandstone
- **Lithology:** Very fine- to very coarse-grained sandstones (litharenites and sublitharenites) and chert-rich, pebble- to cobble-grade conglomerates
- **Depositional Environment:** Fluviodeltaic
- **Productive Facies:** Fluvial channel-fill sandstones and conglomerates and delta-front/mouth-bar sandstones
- **Petrophysics**
  - **Porosity Type:** Intergranular; secondary microporosity
  - **ϕ:** Average 22%, range 10 to 30%, cutoff 12% (cores)
  - **k:** Average 400 md, range 20 to >4,000 md, cutoff 20 md (cores)
  - **S_w:** Average 35%, range 5 to 60% (cores)
  - **S_0:** Average 18%, range 25 to 30% (relative to water; cores)

Reservoir Geometry

- **Depth:** 8,000 to 9,200 feet (2,440–2,800 m)
- **Areal Dimensions:** 37 by 12 miles (60×19 km)
- **Productive Area:** 150,500 acres (6.1×10^4 ha.)
- **Number of Reservoirs:** 1
- **Hydrocarbon Column Height:** 425 feet (130 m)
- **Fluid Contacts:** Oil/water at 8,925 to 9,061 feet (2,720–2,762 m) subsea, tilted; gas/oil at 8,575 feet (2,614 m) subsea
- **Gross Sandstone Thickness:** 0 to 650 feet (0–200 m)
- **Net Sandstone Thickness:** Average 484 feet (148 m), maximum 572 feet (174 m)
- **Net/Gross:** 0.87

Hydrocarbon Source, Migration

- **Lithologies and Stratigraphic Units:** Marine shales (organic, pyritic & phosphatic), Shublik Formation (Triassic), Kingak Shale (Jurassic), and Pebble Shale (Lower Cretaceous)
- **Average TOC:** Pebble Shale 5.0%, Kingak 1.7%, Shublik 2.1%
- **Kerogen Type:** Pebble Shale Type II/III, Kingak Type II/III with minor I, Shublik Type II with minor Type I & III
- **Time of Hydrocarbon Maturation:** Late Cretaceous-Tertiary
- **Time of Trap Formation:** Late Cretaceous
- **Time of Migration:** Late Cretaceous to late Eocene

Hydrocarbons

- **Type:** Naphthenic to aromatic intermediate crude
- **GOR:** 745 SCF/bbl (131 m^3/m^3)
- **API Gravity:** 27.9°
- **FVF:** 1.36
- **Viscosity:** 0.8 cP (0.8×10^3 Pa·s) at 200°F (93°C)

Volumetrics (Ivishak reservoir, primary and EOR)

- **In-Place:** 21,500 MMBO (3.4×10^9 m^3), 46.5 TCFG (1.3×10^{12} m^3)
- **Cumulative Production:** 5,500 MMBO (8.8×10^8 m^3), 7 TCFG (2.0×10^{11} m^3)

Volumetrics (Ivishak reservoir, primary and EOR) (*cont.*)
- **Ultimate Recovery:** NA
- **Recovery Efficiency:** NA

Wells
- **Spacing:** 1,867 to 2,640 feet (570–805 m), nominal 80 to 160 acres (32.4–64.8 ha.)
- **Total:** 846 active (December 31, 1988)
- **Projected Number of Wells:** 1,346 through December 31, 1992
- **Types:** Vertical, high angle, and horizontal
- **Drilling Mud:** Lightly dispersed freshwater system
- **Well Treatment:** Perforated underbalanced; later treatments may include acid stimulation
- **Testing Practice:** Wells brought on slowly to avoid formation damage

Typical Well Production
- **Average Daily:** 2,400 BO (382 m^3)
- **Cumulative:** 10 MMBO (1.6×10^6 m^3)

Other
- **Water Salinity (TDS):** Variable, mean 20,000 ppm
- **Resistivity of Water:** Variable, mean 0.344 ohm-m at 68°F (20°C)
- **BH Temperature:** 175° to 230°F (79 °–110°C)
- **Geothermal Gradient:** 2.3°F/100 feet (4.1°C/100 m)
- **EOR Techniques:** Waterflood and miscible gas (WAG)

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Key Words

Prudhoe Bay Field, Alaska, Colville trough, Ivishak Formation, Triassic, Scythian, fluviodeltaic, braided-stream deposits, super giant field, North Slope, Sadlerochit Group, EOR, unconformity truncation trap, reservoir heterogeneity, flow units, braidplain reservoir.