SPE
Society of Petroleum Engineers

SPE 20757

Reservoir Facies, Pore Characteristics, and Flow Units: Lower Permian Chase Group, Guymon-Hugoton Field, Oklahoma

W.T. Siemers, Phillips Petroleum Co., and W.M. Ahr, Texas A&M U.

This paper was prepared for presentation at the 65th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in New Orleans, LA, September 23–26, 1990.

ABSTRACT

The Panhandle-Hugoton field in southwestern Kansas and the panhandles of Oklahoma and Texas is the largest gas field in North America. The field was discovered decades ago; consequently, most published geological studies of the reservoir are limited to generalized descriptions of regional stratigraphy and structure and do not incorporate more recent reservoir techniques. This paper presents a synthesis of detailed petrologic studies of cores and well log data and provides: (1) a discussion of the sedimentologic and diagenetic histories of the Chase Group and their control on the character of the Guymon-Hugoton reservoir, (2) evidence that the Guymon-Hugoton reservoir is comprised of laterally continuous flow units separated by equally continuous barrier layers, and (3) conclusive evidence that the layered, non cross-flow Guymon-Hugoton reservoir can be drained effectively by the present 640-acre well spacing pattern.

The Chase Group in the Guymon-Hugoton field, consists of interlayered carbonates, siliciclastics, and evaporites deposited in repeated, regionally continuous, shallowing upward sequences on a gently dipping, low-relief, shallow-marine ramp. The repeated sequences consist of successively shallower water, marine carbonates (chiefly dolostones) and siliciclastic reservoir rocks capped by shaly redbeds and paleosols. Reservoir pore types, which include intergranular, moldic, intercrystalline, and solution enhanced forms of these types, were formed diagenetically by alteration that occurred soon after deposition and was controlled indirectly by the cyclical, shallowing-upward pattern of sedimentation. Percent porosity and pore character vary between, and to some extent within, carbonate layers, depending on their depositional and diagenetic histories. The pore types within all carbonate layers, however, are interconnected by a well-developed intercrystalline pore network that formed as a result of pervasive, area-wide dolomitization. Interlayered redbeds and paleosols that mark the end of each depositional cycle are composed of siliciclastic mudstones, shales, and argillaceous carbonates which, because of their areal continuity, high threshold entry pressures, and low permeabilities, act as impermeable barriers to vertical fluid flow.

Because of (1) the continuity of the interlayered dolostone and shale intervals, (2) the areally continuous intercrystalline pore network within each dolostone layer, and (3) the isolation of the dolostone layers by the impermeable barrier units, each dolostone layer is a laterally continuous, well-drained flow unit. Independent engineering studies and production data demonstrate that individual flow units (1) have different permeabilities and gas volumes, (2) are not in pressure communication, and (3) exhibit different depletion characteristics. Moreover, replacement well studies show that no virgin pressures have been found in the Guymon-Hugoton field by recent drilling, indicating that the current 640-acre well spacing pattern effectively drains the reservoir. Production and engineering data, therefore, are good indicators of the multilayer, non cross-flow character of the reservoir and are shown here to be direct results of the depositional and diagenetic processes which characterized the Guymon-Hugoton region during Early Permian time.

References and illustrations at end of paper

INTRODUCTION

The Panhandle-Hugoton field extends across portions of southwestern Kansas (Kansas Hugoton), the Oklahoma Panhandle (Guymon-Hugoton), and the Texas Panhandle (Panhandle field) (Figure 1). The Amarillo Oil Company No. 1 Masterson C, drilled in 1918 in northern Potter County, Texas, was the discovery well; four years later, Defender's No. 1

Boles in Seward County, Kansas, opened the Hugoton portion of the field. Subsequent drilling and additional knowledge from pressure data led to the realization that the two fields are a single large unit roughly 275 mi. (295 km) long and 57 mi. (90 km) wide. The combined field, with cumulative production of more than 59.6 tscf, is the largest gas field in North America. Measurements from early Texas and Kansas wells indicated that initial Panhandle-Hugoton pressures were roughly 435 psi (Garlough and Taylor[1] 1941). Initial surface shut-in pressures from Guymon-Hugoton wells, drilled in the late 1940's, however, yielded calculated initial bottom-hole pressures of around 490 psi (J.J. Voelker, pers. commun.).

Many lower and upper Pennsylvanian units may be productive in the region, but the Lower Permian (Wolfcampian) Chase Group is the major gas reservoir in the Hugoton field. Available geologic literature on the Panhandle-Hugoton field addresses primarily the regional stratigraphic, tectonic, and structural characteristics of the field; very little has been published on reservoir characterization utilizing modern sedimentologic and petrographic methods. This paper focuses on the reservoir and barrier units which occur within the Chase Group, emphasizing their stratigraphic correlation and lateral continuity, and their relationship to the sedimentologic and diagenetic processes that affected the Guymon-Hugoton region during the Early Permian. The paper presents information from a major, fieldwide geological study and integrates petrologic data, foot-by-foot whole-core analyses from the Phillips Sheil 2R and the Phillips Buf No. 3 cores from a detailed study area in southern Texas County (Figure 1), and borehole log data from more than 300 wells distributed around the county.

The regional stratigraphy and the major structural elements of the region are presented in Rogatz[2] and Pippin[3]. The Texas Panhandle field is located in the southern-most Anadarko Basin, along the axis and northern flank of the Amarillo Uplift (Figure 1). The Hugoton field is located along the axis of the Hugoton Embayment, a northern extension of the northwestern Anadarko Basin, bounded on the west by the Sierra Grande and Las Animas Uplifts and on the north by the Central Kansas Uplift. The Hugoton field is on a monoclinal structure which dips gently toward the east-southeast and steepens somewhat along the western margin of the basin (Figure 2). Thick anhydrites and dolostones of Leonardian age cap the Wolfcampian section and provide a seal above the Chase Group reservoir. The Hugoton trap is stratigraphic[3], due to the interfingering of marine, primarily carbonate rocks with terrigenous siliciclastic redbeds along the western edge of the field.

REGIONAL STRATIGRAPHY

The Chase Group consists of approximately 345 feet (107 m) of interlayered carbonates, siliciclastics, and evaporites subdivided into mappable formations and members, depending on dominant rock type (Figure 3). The major gas pays in the field are the Florence, Towanda-Ft Riley, Winfield, Krider, and Herington Limestones. These reservoir units are separated by the silty, shaly nonreservoir beds of the Oketo, Gage, Odell and Paddock Shales. The carbonate rocks below the Gage Shale are composed of mostly limestone; those above the Gage are dolostones. The Herington Limestone is overlain by the Hollenburg Member of the Wellington Formation which consists chiefly of siltstones and finely crystalline dolostones. Hollenburg rocks are not reservoir quality rock because of the fine crystal size of the dolostones, the abundance of pore-plugging anhydrite, and the occurrence of clay minerals.

Both reservoir and shaly nonreservoir intervals in the Chase Group have characteristic log profiles that facilitate fieldwide mapping. Regional cross-sections (Figure 4) and isopach maps, constructed from 301 borehole well logs from Texas County, show that both reservoir and nonreservoir units are continuous across the field. In the study area, the Winfield ranges from 40 to 50 feet (12 to 15 m) thick, the Krider ranges from 50 to 55 feet (15 to 17 m) thick, and the Herington ranges from 60 to 65 feet (18 to 20 m) thick. The thicknesses of interlayered nonreservoir units are: the Gage, 10 to 20 feet (3 to 6 m); the Odell, 5 to 10 feet (1.5 to 3 m); and the Paddock, 15 to 25 feet (4.5 to 8 m). Regional mapping shows that these thicknesses are representative of the total field area.

This study focuses on the upper Chase Group, the most productive part of the section throughout Guymon-Hugoton field. The gas-water contact is high in the stratigraphic section in the southern Guymon-Hugoton; consequently, the Florence, Towanda-Ft Riley, and much of the Winfield are water-wet and nonproductive in the southern area of the field. The principal gas pay is the Krider Limestone, with subsidiary production from the Winfield and Herington. Towards the north, the gas-water contact occurs at progressively lower stratigraphic levels; consequently, there is potential for production from the lower Chase Group in the northern Guymon-Hugoton.

SEDIMENTOLOGIC AND DIAGENETIC FRAMEWORK

From a study of nine Kansas Hugoton cores, Webb[4] established that the Lower Permian section in southern Kansas was deposited on a low-relief, shallow marine carbonate ramp (Ahr[5], Read[6]). The Chase Group in the Guymon-Hugoton region exhibits a nearly identical succession of rock types with similar lithologic characteristics and sedimentary structures. These strata have been interpreted by Siemers and Ahr[7] to represent cyclical, shallowing-upward, peritidal sequences deposited over the southern part of the Hugoton ramp. Each cycle consists of successively shallower water, anhydritic carbonates and interbedded, fine-grained siliciclastics capped by shaly redbeds and paleosols. Multiple, shallowing upward, shallow marine carbonate sequences result from the progradation of nearshore environments (regressions), followed by marine transgressions. Cyclical patterns of sedimentation are considered to be a response to interactions between carbonate sedimentation, shelf subsidence, and eustatic changes in sea level (Wilson[8], James[9], Schlager[10], Read and others[11]).

The carbonate portion of each cycle consists of limestone (below the Gage) or dolomitized limestone (above the Gage), interpreted to have been deposited in shallow subtidal to intertidal marine environments as mixtures of lime mud and granular skeletal and nonskeletal material. As shoaling progressed circulation became increasingly restricted. The salt concentration increased in shallow evaporative ponds associated with the prograding tidal flats, initiating the precipitation of evaporites on the pond floors. As a consequence of the gravity-driven hydrologic head stemming from their increased density, the heavy, Mg-rich brines percolated downward and dolomitized the underlying intertidal and subtidal limestones.

Continued regression caused fine-grained, siliclastic coastal plain sediments to be spread over the marine carbonates. The diagenetic "redbed" character of these deposits developed as a result of emergence and the oxidization of the iron in the clay minerals. Prezbindowski and others[12] and Siemers and Ahr[7] described the pedogenic character of the Gage, Odell, and portions of the Paddock Shales over much of the Guymon-Hugoton region. Emergence and pedogenesis was accompanied by enhancement of porosity in the underlying carbonate section through leaching. Subsequently, the region was again inundated, initiating deposition of the next cycle, marked by a thin, basal, transgressive lithoclastic carbonate unit which incorporated reworked material from the underlying shaly section capping the previous cycle.

DESCRIPTIVE PETROLOGY AND PETROGRAPHY

This study focuses on the Chase Group above the Gage Shale as represented in the Phillips Sheil 2R and Phillips Buf No. 3 cores. The stratigraphic, sedimentologic, and lithologic character of the Chase Group rocks within the study area (Figure 5) are similar to those of the Chase Group throughout the Hugoton Basin. Repetition of cyclical patterns of sedimentation and diagenesis during the Early Permian produced a succession of interlayered carbonate/ siltstone reservoir and shaly nonreservoir intervals.

Reservoir Units

The nomenclature for the upper Chase Group carbonate formations (Winfield, Krider, and Herington Limestones) is somewhat misleading in that, although limestones are the main lithology in the lower Chase, the section above the Gage is predominantly dolostone. The Krider and Winfield are composed entirely of dolostone, with the exception of some silty dolostone in the Winfield. The Herington is mainly dolostone, although the average clastic ratio of 0.37 is a good indication of the significant amount of dolomitic siltstone also contained in the formation. Depositional textures among the carbonate reservoir rocks (Figure 5) range from dolomudstone and dolowackestone (mud-rich dolostones) through dolopackstone and dolograinstone (grain-rich dolostones).

Lithologic Character

The base of each cycle is a thin dolomudstone which contains reworked, sand-sized, shaly/silty lithoclasts derived from the underlying redbeds/paleosols which cap the previous cycle. The basal lithoclastic dolostone is overlain by a thick section of interbedded, yellowish to brownish gray dolomudstones, dolowackestones, dolopackstones, and dolograinstones, which along with a major siltstone interval in the Herington, constitute the main pay zones in the study area. The Krider is dominated by grainstones and packstones, as indicated by an average grain/mud ratio of 0.72. The Winfield and Herington, each with an average grain/mud ratio of 0.54, are composed of subequal amounts of mud-rich and grain-rich dolostone. Fine to coarse-grained grainstones commonly display current-formed structures that include bedding-parallel or low-angle, inclined planar lamination; large-scale, low-angle cross-lamination; and ripple cross-lamination. Mud-rich dolostones are typically bioturbated and massive with occasional distinct burrow structures.

Skeletal material and pelletoidal grains are the primary framework elements of the dolostones. The diverse biota includes echinoid and crinoid, brachiopod, algal, bryozoan, gastropod, and pelecypod debris. Monaxon sponge spicules are a major constituent of some dolomudstones. Thin, oolitic dolograinstone beds and intraclastic dolowackestone beds are present in the Herington carbonate reservoir section. The primary interstitial material in the grain-rich dolostones and the chief component of the mud-rich dolostones is very fine to medium crystalline (>30μ) dolomitic mud matrix. Anhydrite and small amounts of chalcedony occur as patchy, pore filling and replacement material. Dolostone porosity ranges from poor to excellent and includes primary and diagenetic pore types.

Within the upper one-third of the carbonate interval, the grain-to-mud ratio of the dolostones decreases upwards, with an attendant increase in silt and clay. The uppermost beds are commonly silty dolomudstones to dolomitic siltstones, or argillaceous dolomudstones. The silty upper interval is more pronounced in the Herington where, for example in the Phillips Sheil 2R core, the dolomitic siltstones and silty dolostones constitute the entire upper half of the formation. The dolomitic siltstone beds may be strongly bioturbated or massive, but commonly they exhibit ripple cross-lamination, or bedding-parallel to low-angle inclined planar lamination. Siliciclastic grains consist of angular to subangular, moderate- to well-sorted, medium silt- to lower very fine sand-sized quartz with minor amounts of feldspar and muscovite. Slightly argillaceous, fine to medium crystalline dolomitic mud matrix and pore-filling anhydrite are the major interstitial materials. The porosity of the dolomitic siltstones ranges from poor to excellent and is chiefly intergranular and intercrystalline. Mercury capillary pressure test results (Figure 6) indicate that threshold entry pressures of the dolostone reservoir rocks are less than 100 psia, and are commonly less than 10 psia.

Diagenetic Character and Porosity

Some reservoir rocks retain pores with depositional characteristics, but reservoir porosity in the Winfield, Krider, and Herington is mainly diagenetic in origin. The degree to which depositional rock properties are related to total porosity in the study area depends on: (1) the depositional texture (carbonate grain to mud ratio), (2) the detrital siliciclastic grain content, and (3) the types of diagenetic changes that have occurred (e.g., replacement, dissolution, cementation, stylolitization, etc.).

Winfield Porosity. The character of porosity in Winfield dolostones is determined mainly by crystal size in mud-rich rocks and grain content plus crystal size in grain-rich rocks. Some Winfield dolomudstones have been extensively recrystallized, resulting in the development of very large crystal sizes (>100μ) and increased reservoir quality. Intercrystalline, interparticle, moldic, and vuggy pores, which are commonly enhanced by enlargement through leaching, are the characteristic pore types in the Winfield. Solution enhancement correlates with porosity values ranging from 2 to 15 percent and permeabilities of less than 1 to 20 md. Grain-moldic pores connected by solution-enlarged intercrystalline (dolomite) pores (Figure 7) correlate with the highest porosity and permeability values in the formation. Compaction and the occurrence of pore-filling anhydrite reduce the porosity in some Winfield rocks.

Krider Porosity. Solution enlarged intercrystalline and interparticle pores are the most common types in the Krider dolostones. Grain/mud ratios and grain sizes exert the most influence on the origin and nature of the Krider pore system. The character of the intercrystalline pore system (Figure 7) of the mud-rich dolostones is determined by the sizes and shapes of the crystals that constitute the dolomite groundmass (crystal-related textures). The crystal size of this groundmass material in the dolomudstones and dolowackestones is typically larger than 30μ. In the grain-rich packstones and grainstones, porosity is determined by grain content and textures and the crystal-related pore system associated with the muddy matrix. Post-dolomitization leaching enlarged all existing pores and created new grain-moldic, crystal-moldic, and vuggy pores. Large (mm-scale) grains in the middle and lower Krider were leached to form extensive grain-moldic pore networks. The dolomite in the mud-rich dolostones and the matrix dolomite of the grain-rich dolostones are composed of dolomite crystals in the 60 to 80μ size range. Porosity has been reduced somewhat in the Krider by compaction and cementation, but ranges from 5 to 12 percent, with permeability ranging from 318 md in some oolitic grainstones to 0.11 md in some silty, anhydritic dolomudstones.

Herington Porosity. There are three main pore families in the Herington that correspond with three lithologic groups including: (1) siltstones to very fine-grained sandstones, (2) dolostones with low grain/mud ratios, and (3) dolostones with high grain/mud ratios. All of the families have been affected by diagenesis and all show some loss in volume due to compaction and cementation. Siltstone and sandstone porosity is intergranular and may be reduced by carbonate and anhydrite cementation or pressure solution. Most Herington siltstones and sandstones are relatively free from clay-sized matrix. Siltstone and sandstone porosities average 10 to 15 percent, with as much as 16 md permeability. Dolomudstones and dolowackestones exhibit intercrystalline, crystal-moldic, and vuggy pores; grain-rich dolostones exhibit moldic, vuggy, intergranular, and intercrystalline pores. All pore types have been enlarged by leaching. Porosity in dolostones averages 5 to 6 percent, with less than 1 md permeability, except in some spiculiferous dolomudstones which contain spicule-moldic porosity and permeabilities approaching 4 md. Linkage of the moderate amount of porosity in the dolostones with the high siltstone and sandstone porosities has produced a continuous reservoir with a multi-scaled, mixed pore system within the Herington.

<u>Nonreservoir "Barrier" Units</u>

Interlayered nonreservoir units consist mainly of fine-grained siliciclastic rock types including shaly claystones and silty mudstones. The Gage and Odell Shale sections are composed of interbedded, dark reddish brown terrigenous mudstone to claystone and shale. The Paddock Shale consists of a lower 3 to 5 foot (1 to 2 m) thick and an upper 1 to 4 foot (0.3 to 1.2 m) thick interval of shaly, terrigenous mudstone to claystone, with a 10 to 15 foot (3 to 5 m) thick, silty, argillaceous dolostone interval interbedded between the two. The Gage, Odell, and Paddock shales are mappable, continuous formations throughout the Guymon-Hugoton field. The thickness of the lower shaly interval in the Paddock Shale is variable and it may be absent locally. The upper Paddock shale is somewhat thinner in the study area than over much of the field, where the average thickness of the upper shale is about 10 feet (3 m).

The principal rock types in the Gage, Odell, and parts of the Paddock Shales are poorly indurated, mottled, dark reddish brown, limonite-stained, shaly terrigenous mudstones and dolocalcretes which commonly contain irregular to subrounded patches of nodular carbonate (caliche), a form of carbonate cementation typical of soil horizons (paleosols). Less commonly, the redbeds contain desiccation cracks and probable root casts. The shaly claystones and mudstones are composed primarily of non-calcareous to moderately calcareous, siliceous, clay-sized phyllosilicates and small to moderate amounts of angular, medium- to coarse-grained, detrital quartz silt. Illite constitutes more than half of the clay mineral suite, with lesser amounts of smectite, chlorite, and kaolinite. The results of mercury capillary pressure tests (Figure 6) indicate that the threshold entry pressures of the shaly mudrocks are more than 1000 psia.

The effects of subaerial exposure tend to be more localized and less well developed in the Paddock Shale than in the Gage and Odell Shales. Evidence of paleosol development occurs in parts of the upper Paddock shale, but is not observed in the lower shale. The silty, argillaceous carbonates that constitute much of the middle Paddock are mainly dolomudstones, with lesser amounts of pelletoidal wackestone and packstone. Pressure solution effects, expressed as stylolites, solution seams, and solution-seam swarms, are common in the argillaceous dolostones. The dolomudstones consist of rare to abundant, medium to coarse silt-sized, detrital quartz grains floating in a very argillaceous, finely crystalline dolomitic mud matrix. The clay minerals are mainly illite and smectite, with small percentages of chlorite and traces of kaolinite. Porosity in the argillaceous dolostones, including intercrystalline porosity developed through dolomitization, is plugged with clay material as a result of compaction (Figure 8). Threshold entry pressures of the argillaceous dolomudstones range from about 350 to 600 psia (Figure 6).

INTERPRETATION AND DISCUSSION

The Chase section in the Phillips Sheil 2R and Phillips Buf No. 3 wells in the southern Texas County study area consists of repeated shoaling-upward sequences of shallow marine, peritidal, and nonmarine rock types that reflect the cyclical, regional depositional pattern typical of the Lower Permian section in the Hugoton Basin. Shaly, sand-sized lithoclasts contained in the basal dolomudstones, but derived from underlying redbeds and paleosols of the previous cycle, indicate the transgressive nature of the thin dolostone interval which marks the beginning of each repeated sequence. Above this lithoclastic interval are well-segregated, fine-grained siliciclastic and carbonate beds; the carbonates range from burrowed mudstones and wackestones to packstones and grainstones. The rocks contain an open-marine fauna and current-formed sedimentary structures indicative of a well-circulated, shallow subtidal, open-marine sedimentary environment. A gradual, upward decrease in the skeletal grain content (with attendant increases in the carbonate mud and clay mineral content) in the upper dolostones of each sequence documents a trend towards lower energy levels and more restricted, shallower water, peritidal sedimentation. The red coloration of the uppermost terrigenous beds and the presence of light-colored carbonate nodules (caliche) and root casts, indicate emergence and the subaerial development of paleosols. The repeated sequences are areally continuous, indicating that cyclical, shallowing upward, subtidal to restricted peritidal sedimentation was representative of the entire gently dipping, low-relief, shallow marine ramp that characterized the Guymom-Hugoton region during Late Permian time.

The depositional and diagenetic processes, and other factors that create reservoir character must be understood to accurately characterize a reservoir, its pore characteristics, the distribution of porosity, and the extent of reservoir and nonreservoir ("flow" and "barrier") units. In this study, porosity is considered in terms of three end-member pore types: (1) primary, depositional pores, (2) diagenetically formed pores, and (3) fractures. The character and lateral extent of primary porosity in carbonates is determined by the depositional texture (grain size, shape, and fabric), rock composition, and the geometry of the depositional facies. Diagenetic porosity in carbonate rocks is controlled by paleohydrology, fluid composition, pressure, and temperature, and may be related to depositional texture and rock composition. Fractures in carbonate reservoirs are mainly independent, although minor interdependencies may exist, of depositional and diagenetic facies patterns, particularly in mixed-lithology carbonate reservoirs (Nelson[13]). Fracturing is mapped, therefore, on the basis of relationships to features other than intrinsic rock properties. The amount of fracturing that occurs in the cores from the study area indicates that fracturing is not an important contributor to reservoir performance on a fieldwide basis in the Guymon-Hugoton field (H. E. Farrell, pers. commun.).

The diagenetic history of the Guymon-Hugoton area reservoir rocks evolved through three major stages of fluid-rock interaction. Although burial overburden pressure increased through time, discrete episodes of diagenesis punctuated the otherwise gradual process. The pore network in the upper Chase Group is mainly the result of dolomitization followed by moderate dissolution of remaining soluble constituents. The dolomitization processes were causally related to the cyclical, shallowing-up sedimentation history of the region, but dolomitization was widespread and was not constrained by depositional facies boundaries.

<u>Stage 1 Diagenesis</u>. Shortly after deposition and before burial compaction had reduced depositional porosity and permeability, each of the repeated sequences in the upper Chase Group was exposed to an influx of brines, which formed as a result of evaporative conditions at the surface during cyclical low-stands in sea-level (regressions). The brines emplaced nodular to thin, lenticular evaporites near the sediment/water interface and percolated downward through the section dolomitizing the underlying limestones. The dolomitization process was rate sensitive in that only the fine-grained carbonate muds (high surface area/volume ratio) were replaced, leaving the coarser grained skeletal and nonskeletal framework materials partially undolomitized and subject to dissolution during Stage II diagenesis. Moreover, complete dolomitization of only the carbonate muds is probably an indication that dolomitization occurred rather quickly. Many impurities were incorporated into the Stage 1 dolomite, giving it a brownish, turbid, inclusion-rich appearance. The dolomite crystals are typically larger than 30μ in rhomb size, and range from subhedral to anhedral, depending on the extent of compaction, partial dissolution, and later dolomite cementation.

Dolomitization of limestones increases their porosity in proportion to the amount of dolomitization after roughly 50 percent of the limestone has been dolomitized because the porosity that forms thereafter is maintained by a developing framework of dolomite crystals (Murray[14]; Weyl[15]). Consequently, the widespread dolomitization of the upper Chase Group, limited only by the extent of the original limestone deposit, produced an extensive intercrystalline pore network within the subtidal and peritidal Chase carbonates. Intercrystalline porosities in association with dolomite crystal sizes larger than 30μ, such as those that characterize the Guymon-Hugoton dolostones, correlate with optimum reservoir quality in dolostone reservoirs (Lucia[16]).

The clay-minerals in the argillaceous dolomudstones of the middle Paddock were not completely removed during dolomitization. With modest cementation and subsequent compaction, the clay material was sandwiched between the dolomite crystals, minimizing the intercrystalline porosity generated as the rocks were dolomitized. Because of the high, measured threshold entry pressures that result from the clay-plugged pore system, much of the dolostone in the middle Paddock is an impermeable barrier to fluid flow.

Stage II Diagenesis. Stage II diagenesis was marked by leaching of soluble materials in the shallow subsurface. Dissolution of undolomitized, coarse-grained, carbonate material (mainly pelletoidal, skeletal and oolitic grains) and siliceous spicular material formed a significant amount of moldic porosity, the actual volume of which varied with the grain content of the precursor limestone. Leaching also produced crystal-moldic porosity and enhanced the intercrystalline pore system by removal of remaining undolomitized lime mud in the matrix.

Stage III Diagenesis. Stage III diagenesis was marked by deeper burial accompanied by compaction and late cementation by dolomite and anhydrite. Dolomite overgrowths (cement) formed on leached Stage I dolomite and clear, euhedral to subhedral dolomite crystals precipitated in and around the perimeter of large, leached, Stage I pores, resulting in a minor loss in porosity. This second generation of dolomite is cross-cut by stylolites. Locally, late dolomite cementation associated with crystal sizes less than 30μ in rhomb size may diminish reservoir quality.

Almost contemporaneously with precipitation of the second generation of dolomite, the rocks were subjected to cementation and replacement by anhydrite which further reduced reservoir porosity. This burial anhydrite was probably introduced by downward-moving, sulfate-rich brines associated with the regressive phases of the sedimentary cycles. Some of the sulfates may also have been dissolved from overlying evaporites by undersaturated fluids which percolated downward and reprecipitated anhydrite in the subsurface. Generally, replacement and pore-filling anhydrite cement increases as the anhydrite content of the overlying, restricted, peritidal "cap" of the shallowing-upwards sequence increases. Irregardless of origin, this generation of anhydrite is the chief cause of porosity and permeability reduction in the Winfield, Krider, and Herington formations; locally, the reduction may be dramatic.

Stylolites and solution seams which cross-cut earlier cements and grain boundaries indicate that pressure solution was associated with the increasing depths of burial. The effects of pressure solution, however can not be correlated from well-to-well and do not interfere with continuity of reservoir porosity.

Some intervals in the Winfield and Krider were affected by an episode of yet later (post-burial andydrite) leaching, which partially removed minor amounts of late dolomite and anhydrite. The cores of more soluble Stage I dolomite crystals were leached, whereas, the more unsoluble Stage III dolomite rim cements were preserved, producing "hoppers" (skeleton crystals) of Stage III dolomite. Anhydrite in the affected intervals exhibits corroded crystal edges.

Synthesis

Reservoir porosity (quality) in the upper Chase Group in the Guymon-Hugoton field is a result of the combined depositional and diagenetic history of the region. Cyclical, shallowing-upward sedimentation on a shallow marine carbonate ramp produced a succession of regionally continuous, subtidal and peritidal carbonates and fine-grained siliciclastics and interbedded, restricted peritidal, argillaceous carbonates and redbeds/paleosols. These depositional sequences became the framework for a regionally continuous, multilayered, non cross-flow gas reservoir consisting of interlayered carbonate/siltstone reservoir flow units separated by impermeable, barrier shales and shaly carbonates. Diagenetic processes, primarily dolomitization and dissolution associated with the shallowing-upward sedimentary cycles, produced a continuous pore system within each carbonate/siltstone interval. The carbonate/siltstone intervals, therefore, are laterally continuous flow units insulated from each other by the shaly barriers.

Field-wide, well-head shut-in pressure data (M. J. Fetkovich, pers, commun.) and threshold entry pressure data, and pressures from drill stem tests performed on the Phillips Buf No. 3 well (Figure 6) illustrate the continuous, multilayer, non cross-flow character of the Guymon-Hugoton reservoir. Well-head shut-in pressure data show that an areally uniform drop in fieldwide reservoir pressures within the field has been occurring since the middle 1960's. Original discovery pressures of about 490 psi have been depleted uniformly across the field because of the regionally continuous porosity and permeability of the dolostone flow units. Pressure differences between the Winfield, Krider, and Herington flow units are the result of differences in reservoir quality and drainage characteristics. Such differences are an indirect and direct consequence, respectively, of the depositional character (composition and texture) of the original sediment and of the variability in the rate and scale of Early Permian diagenetic processes (dolomitization, dissolution, cementation compaction) responsible for the individual pore characteristics of each flow unit. Pressure differences between the flow units have been maintained because of the areal continuity and the high threshold entry pressures associated with the constituent mudstones and argillaceous dolomudstones of the barrier units.

CONCLUSIONS

The Lower Permian Chase Group gas reservoir in the Guymon-Hugoton field is composed of repeated sequences of interlayered carbonates, siliciclastics, and evaporites which were deposited on a gently dipping, low-relief, shallow marine carbonate ramp.

1. Each sequence grades upward from subtidal carbonates through restricted peritidal carbonates (chiefly dolostones) and fine-grained siliciclastics to nonmarine, shaly redbeds and paleosols.

2. Interlayered carbonates and shaly layers form a regionally continuous, multilayered

reservoir consisting of carbonate/siltstone flow units separated by shaly barriers.

3. No vertical communication or crossflow occurs between the separate flow units because of the high threshold entry pressures associated with the barrier units.

4. Good drainage occurs within each individual flow unit because of the areal continuity of each unit, and a laterally continuous intercrystalline pore system within each flow unit which resulted from widespread dolomitization that was not constrained by depositional facies boundaries.

ACKNOWLEDGEMENTS

The authors would like to thank Phillips Petroleum Company for permission to publish portions of the Guymon-Hugoton geological study and to acknowledge many colleagues who provided help and insight to the study. Bill Via and Riley Needham provided encouragement and corporate support for the project during a difficult period of time. Special thanks are extended to David Ellen, John Williams, Tom Moore, and Mohammed Nagaty for the work they did in preparing the isopach and structure maps and the regional cross-sections. Thanks to Helen Farrell for her work regarding the fracture characteristics of the Chase Group. Many thanks go to Teri Nichols, Kelly Curtis, and Penny Blass for the technical support that they provided to the project and for their patience.

REFERENCES

1. Garlough, J. L. and Taylor, G. L.: "Hugoton Gas Field, Grant, Haskell, Morton, Stevens, and Seward Counties, Kansas, and Texas County, Oklahoma," in Levorson, A. I. (ed.): Stratigraphic Type Oil Fields, American Association of Petroleum Geologists, Tulsa (1941) 78-104.

2. Rogatz, H.: "Shallow Oil and Gas Fields of the Texas Panhandle and Hugoton," in Oil and Gas Fields of the Texas and Oklahoma Panhandles, Panhandle Geological Society (1961) 8-37.

3. Pippin, L.: "Panhandle-Hugoton Field, Texas-Oklahoma -- The First Fifty Years," in Halbouty, M. T. (ed.), Geology of Giant Petroleum Fields, American Association of Petroleum Geologists, Memoir 14 (1970) 204-222.

4. Webb, J. C.: "Testimony Before the State Corporation Commission, State of Kansas," Kansas Corporation Commission, Kansas Docket No. C-164, Transcript of Proceedings, Volume XXXVI (1985) 8116-8315.

5. Ahr, W. M.: "The Carbonate Ramp: An Alternative to the Shelf Model," Transactions of Gulf Coast Association of Geological Societies, Volume XXXIII (1973) 221-225.

6. Read, J. F.: "Carbonate Platform Facies Models," Bulletin of American Association of Petroleum Geologists 69 (1985) 1-21.

7. Siemers, W. T. and Ahr, W. M.: "Geologic Controls on the Production Characteristics of Cyclical, Mixed Carbonate-Clastic Gas Reservoirs, Lower Permian Chase Group, Guymon-Hugoton Field, Oklahoma" (Abst.), Bulletin of American Association of Petroleum Geologists 74 (1990) 763.

8. Wilson, J. L.: Carbonate Facies in Geologic History, Springer-Verlag, New York (1975) 471.

9. James, N. P.: "Introduction to Carbonate Facies Models," in Walker, R. G (ed.), Facies Models, Geoscience Canada, Reprint Series 1 (1979) 109-119.

10. Schlager, W.: "The Paradox of Drowned Reefs and Carbonate Platforms," Bulletin of Geological Society of America 92 (1981) 197-210.

11. Read, J. F., Grotzinger, J. P., Bova, J. A., and Koerschner, W. F.: "Models for Generation of Carbonate Cycles," Geology 14 (1986) 107-114.

12. Prezbindowski, D. R., Passaretti, M. L., and Tapp, G. S.: "Pedogenesis, A Major Diagenetic Process in Giant Hugoton Gas Field" (Abst.), Bulletin of American Association of Petroleum Geologists 72 (1988) 238.

13. Nelson, R. A.: Geologic Analysis of Naturally Fractured Reservoirs, Gulf Publishing Company, Houston (1985) 320.

14. Murray, R. C.: "Origin of Porosity in Carbonate Rocks," Journal of Sedimentary Petrology 30 (1960) 59-84.

15. Weyl, P. K.: "Porosity Through Dolomitization: Conservation-of-Mass Requirements," Journal of Sedimentary Petrology 30 (1960) 85-90.

16. Lucia, F. J.: "Physical Parameters Estimated From Visual Descriptions of Carbonate Rocks: A Field Classification of Carbonate Pore Space," Journal of Petroleum Technology 35 (1983) 629-637.

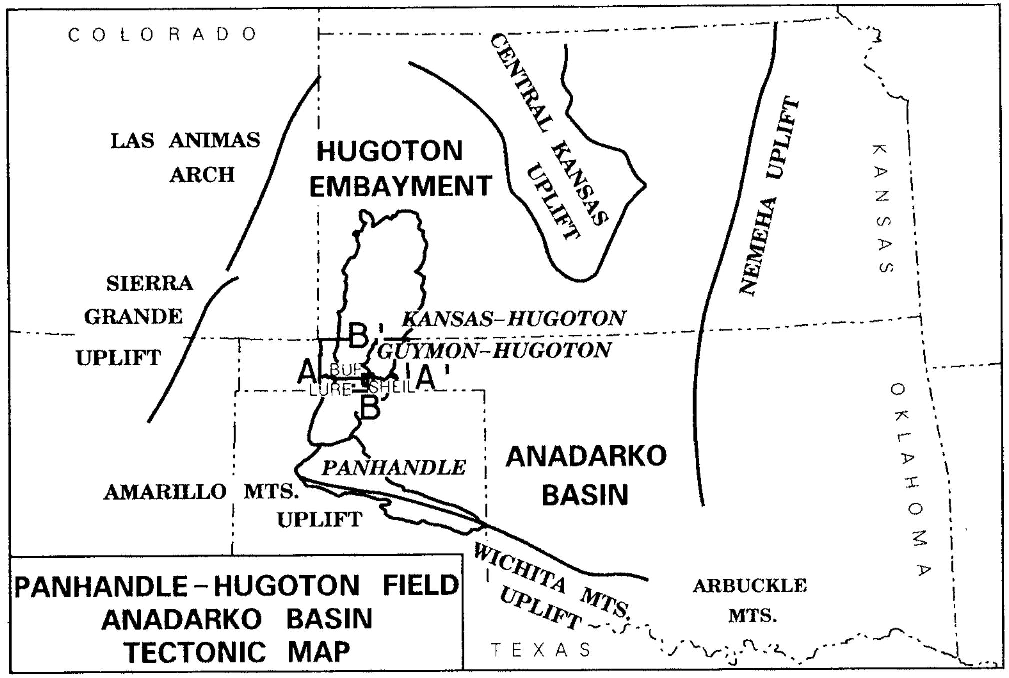

Fig. 1—Location and regional tectonic map.

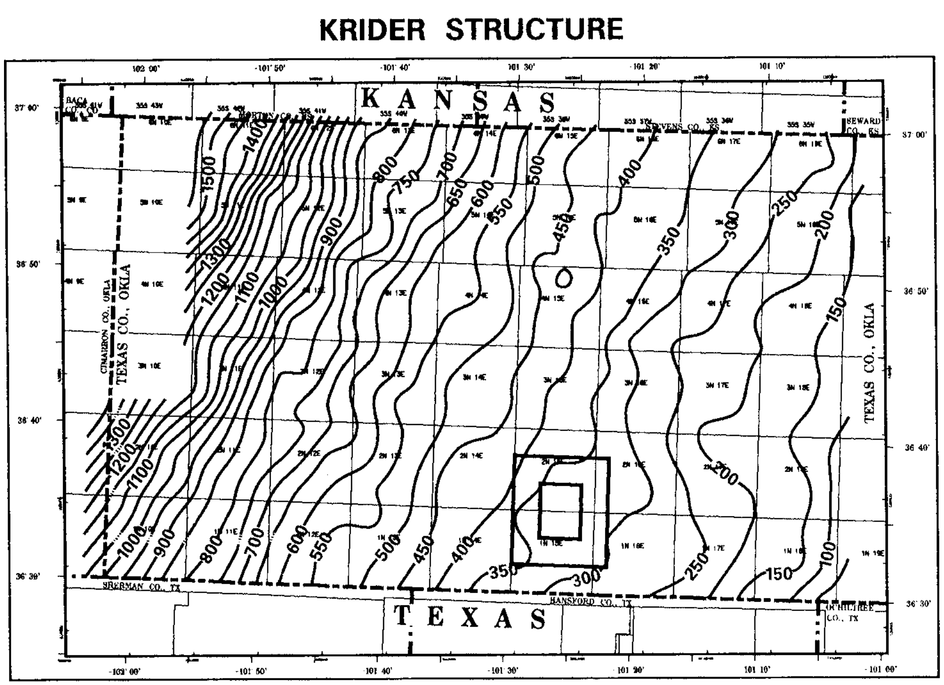

Fig. 2—Regional structure map.

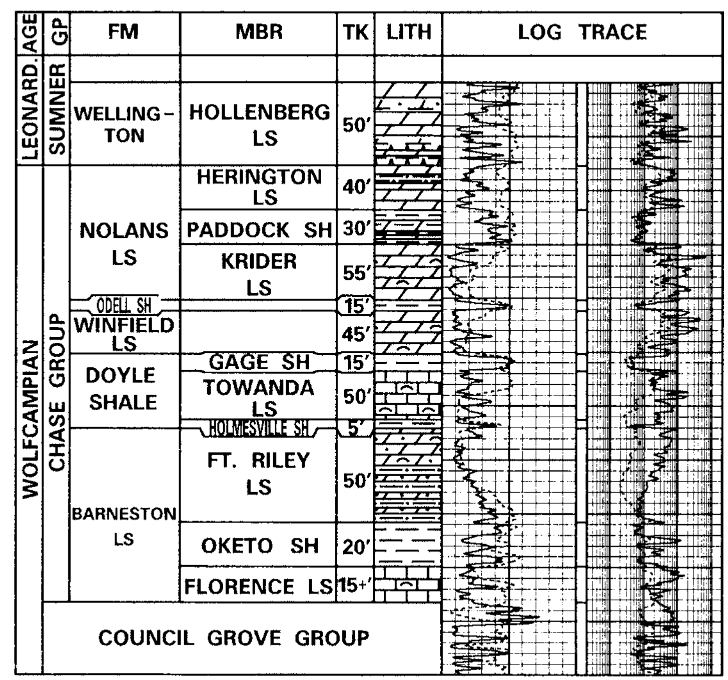

Fig. 3—Regional and local stratigraphic nomenclature.

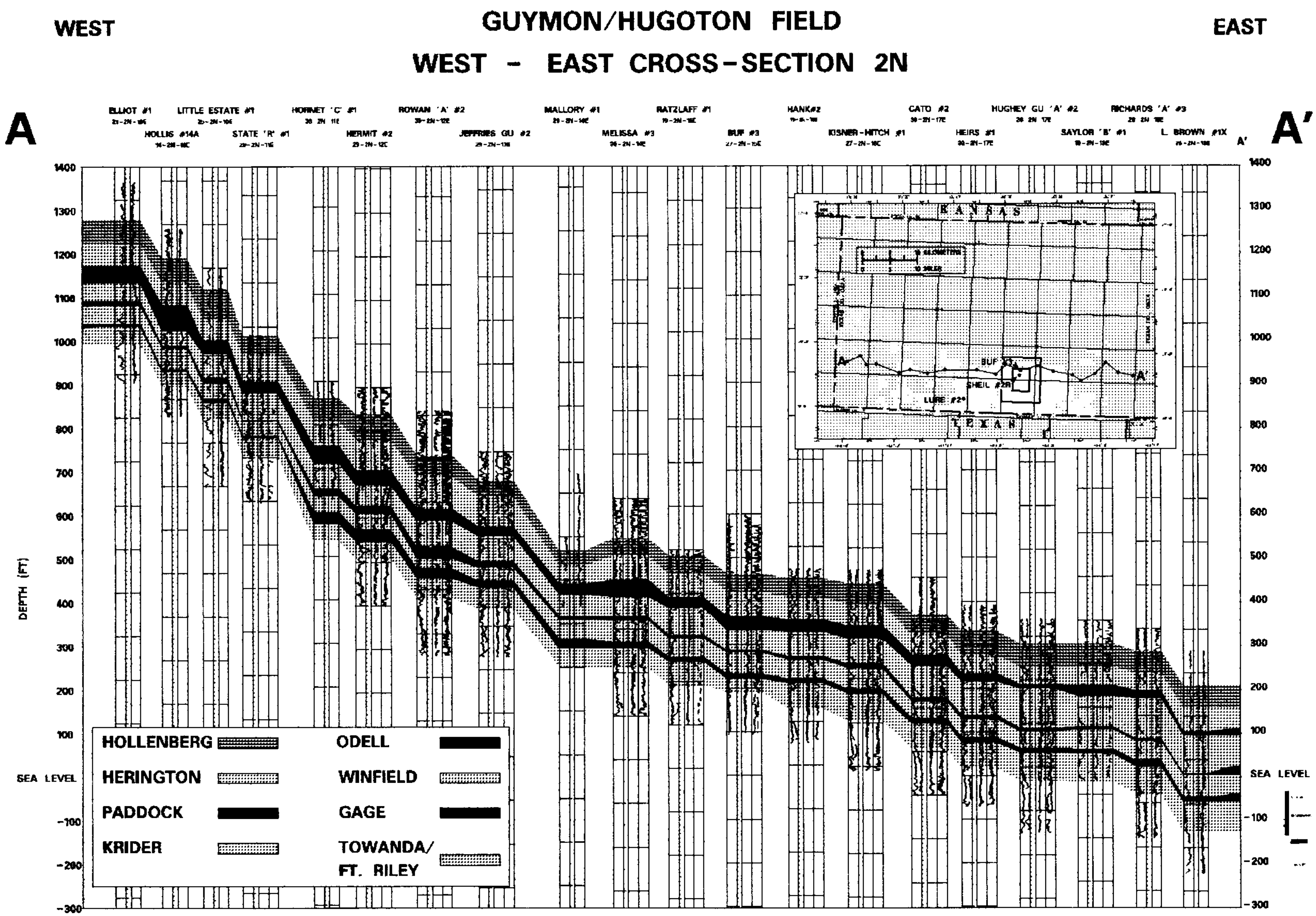

Fig. 4A—Regional cross section east-west.

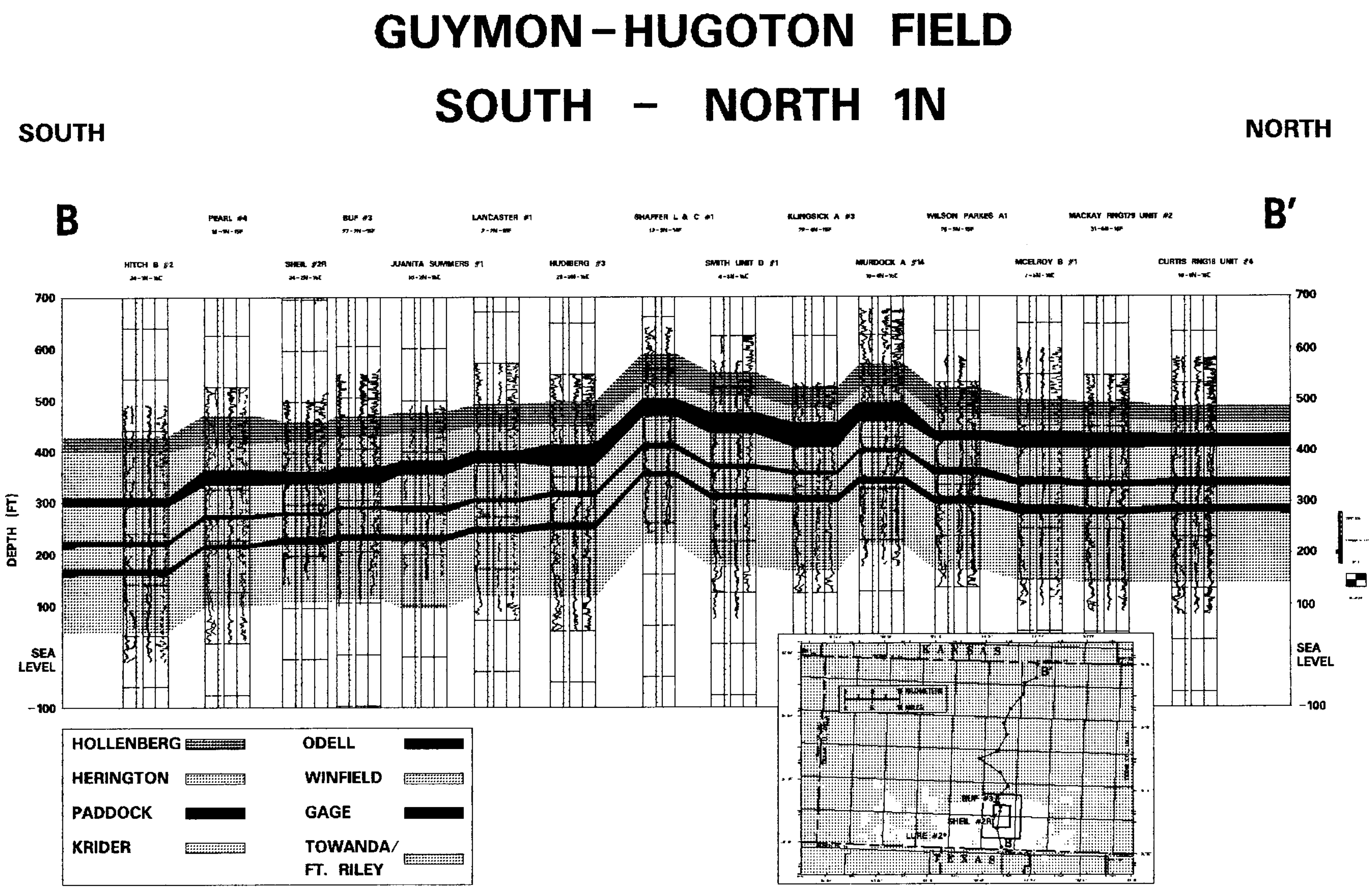

Fig. 4B—Regional cross section north-south.

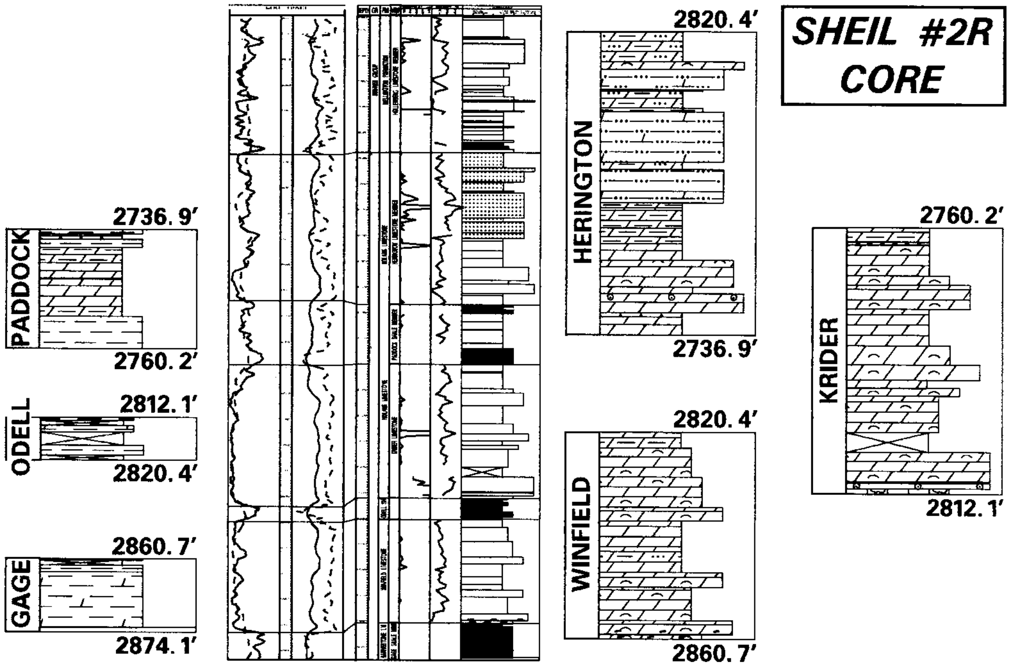

Fig. 5—Detailed stratigraphic section.

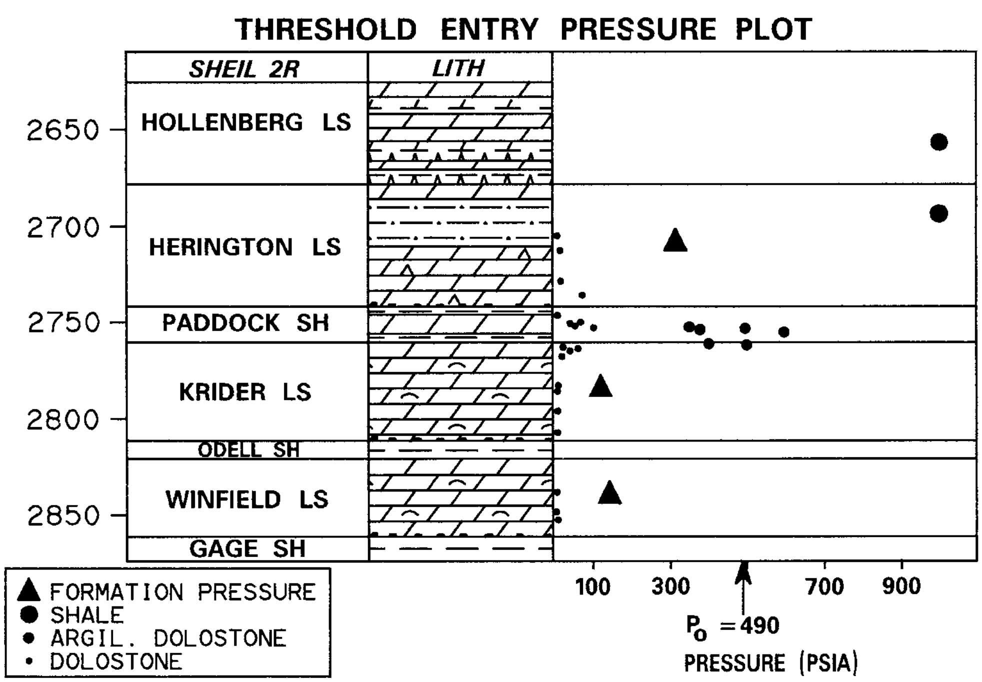

Fig. 6—Pressure and threshold entry pressure plot vs. rock type.

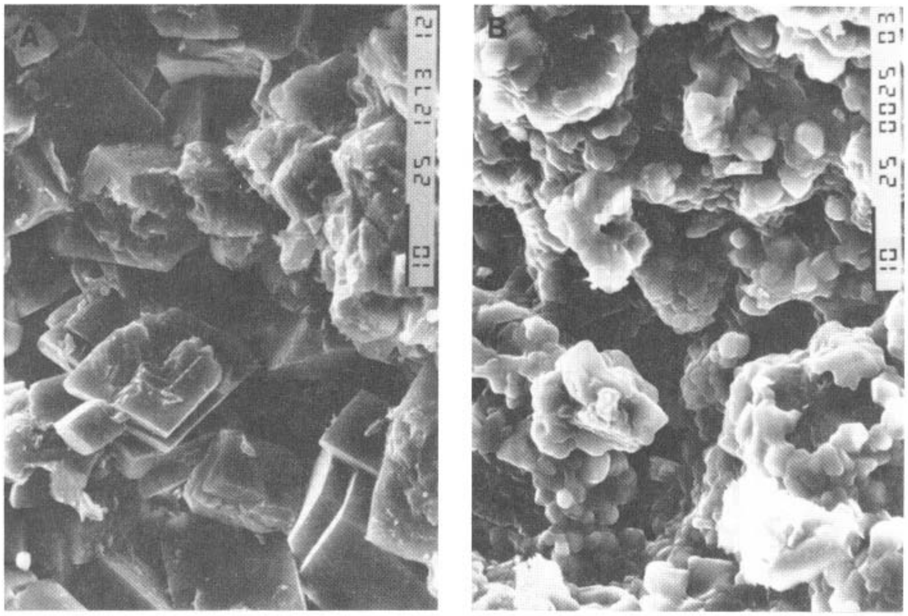

Fig. 7—Scanning electron micrographs illustrating intercrystalline porosity: (a) between dolomite crystals formed during dolomitization and (b) solution-enhanced formed by near-surface leaching of the intercrystalline pores, which provides the areally continuous pore network within the dolostone flow units that is responsible for the good drainage characteristics of the reservoir.

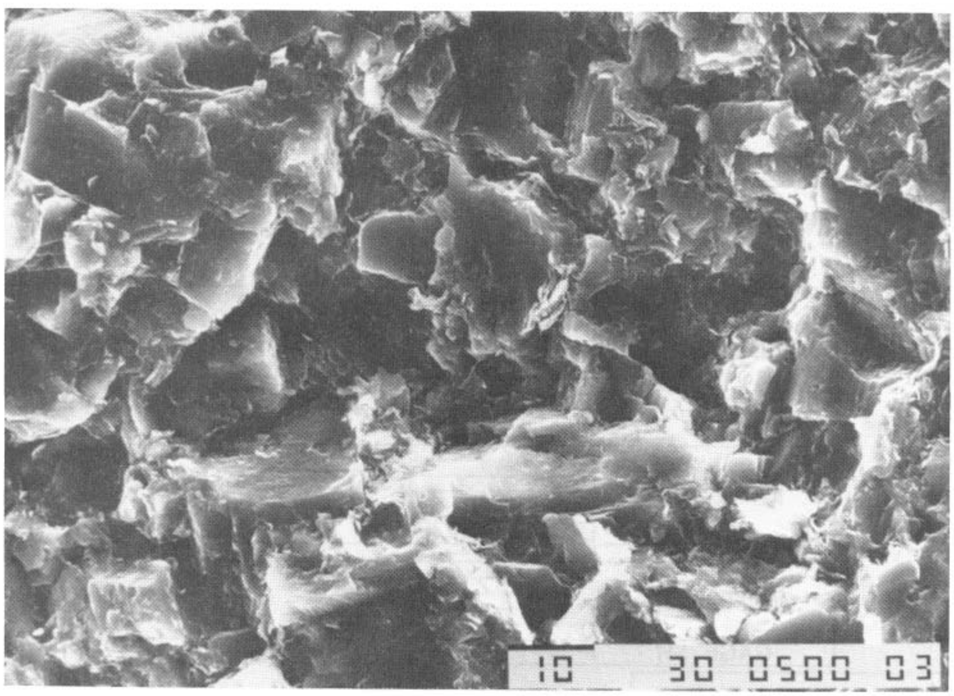

Fig. 8—Scanning electron micrograph illustrating a clay-plugged argillaceous dolomudstone.