COORDINATION OF GEOLOGICAL AND ENGINEERING RESEARCH IN SUPPORT OF THE GULF COAST CO-PRODUCTION PROGRAM

FINAL REPORT
(June 1987 - November 1988)

Prepared by

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For

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DISCLAIMER

RESEARCH SUMMARY

Title	Coordination of Geological and Engineering Research in Support of the Gulf Coast Co-Production Program
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5084-212-0924
Principal Investigators	R. J. Finley and D. W. Koppenaal
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Objectives

To investigate the control of depositional environment and diagenetic history on porosity and permeability preservation in the Frio A sandstones, Northeast Hitchcock field.

To select several of the thickest and most laterally continuous Miocene sands in Northeast Hitchcock field for disposal of brines from the Frio 1-A sand. These sands were required to collectively accept approximately 22,000 barrels of brine per day in three disposal wells in Northeast Hitchcock field.

To determine the extent of the main fault block containing Northeast Hitchcock field, thereby defining the maximum area for disposal of brines into these Miocene sands where they have not been offset by major faults.

To determine the lateral extent and thickness of Miocene sands in the fault block containing Northeast Hitchcock and Alta Loma fields.

To document the brine-disposal potential of Miocene sands in Northeast Hitchcock field and other Miocene sands in nearby fields where large volumes of brines have been disposed.

To select potential sites for brine disposal in Northeast Hitchcock field.

To provide detailed geologic descriptions of cores from three Miocene sands in Northeast Hitchcock field that have a good brine-disposal potential. These descriptions were to be reviewed in conjunction with net-sand and log-facies maps in order to make final recommendations for brine disposal sands in Northeast Hitchcock field.

To establish a cooperative research and development program with industry in order to develop, test, and verify methodologies and technologies with near-to mid-term potential for maximizing recovery of gas from conventional reservoirs.

To identify a field for study, develop a cooperative relationship with the operator of the field, and establish a data base from which intensive geological analyses may be built.

To identify compartmentalized and bypassed gas zones in known reservoirs within Seeligson field through detailed log correlations, and analysis and interpretation of net-sandstone maps and log facies maps.

To select wells for recompletion in bypassed or compartmentalized gas zones by integrating cased-hole log evaluation results with advanced geological characterization methods.

To propose recompletion recommendations and present them to the operator, developing recompletion strategies in order to test selected zones.

To investigate the geometry and interpret the depositional setting of lower Miocene sandstones in the Tom O'Connor field area.

Technical Perspectives

Gas and condensate are produced from the Frio A or 9,100 ft sandstone in Northeast Hitchcock field. Investigations were conducted into the structural, stratigraphic, facies, and diagenetic controls of porosity and permeability in the Frio A sandstone. This information defines the size and continuity of Northeast Hitchcock field and problems that may result from high production rates in highly transmissive sandstones.

The best Miocene sands for brine disposal in Northeast Hitchcock field were selected by considering their sand-body complexity, lateral extent, thickness, depth, and documented brine-disposal history, where available. Depositional models, based on core descriptions and interpretation of net-sand and log-facies maps, were constructed for various sands throughout the entire Miocene stratigraphic interval in Northeast Hitchcock field. These models took into account the three important factors of sand-body complexity, lateral extent, and thickness of the sands. Sands having minimal internal complexity and maximum lateral extent and thickness were regarded as the best for brine disposal. Brine-injection data from 43 brine-disposal wells in Hastings West field, located 20 mi from Northeast Hitchcock field in Brazoria County, were compiled in order to determine the brine-disposal capacity of Miocene sands analogous to those in Northeast Hitchcock field, which contained only a few wells that had received brine prior to this study.

Multiple, vertically-stacked fluvial to fluvial-deltaic reservoirs are well documented in Seeligson field. The highly complex depositional architecture of these reservoirs provides an excellent setting for evaluation of reservoirs for compartmentalized and bypassed gas zones through advanced geological characterization methods. Delineating genetic sandstone units from aggregate reservoirs through detailed log correlations and interpretation of net-sandstone isopach and log facies maps is an integral step in identifying potentially undrained compartments. Two zones were targeted for detailed geologic analysis in Seeligson field, Zone 15 and Zone 18-C. Both zones display characteristics found in fluvial depositional environments of the South Texas Frio. Facies heterogeneities are widespread within each zone and may isolate untapped reservoirs. Cased-hole log evaluation has indicated the presence of gas in each zone in specific wells, and detailed mapping has outlined the extent of the potentially undrained compartments.

Major gas resources have been produced from Miocene sandstones of the onshore Gulf Coast region since discovery and development in the 1930's. Many of these reservoirs are in advanced stages of depletion. New pool discoveries, however, suggest that bypassed or untapped compartments are present in these older fields. Examples are the 4,150 and 4,200 ft sandstones of Tom O'Connor field. Because these sandstones occur near the base of a Gulf-wide progradational event and near a growth-fault zone, the analysis of sand-body geometry and depositional environments is considered in terms of sequence stratigraphy and growth-faulting processes.

Results

At Northeast Hitchcock field the presence of the Skolithos assemblage and other structures has substantiated the interpretation of shallow-marine, tidal, distributary-mouth-bar, and channel depositional environments for most of the major reservoir sandstones. Several shaly horizons have the characteristics of interdistributary bays, and the Frio A is capped by a thin sequence of crevasse splays and washover sands that represent the initiation of the transgression that overlapped the Frio in Anahuac times.

The high-energy depositional environment of reworked distributary-mouth-bar sandstones is the major control of the high porosity (~30 percent) and permeability (~1,000 md) in Frio A sandstones at Northeast Hitchcock field. Well-winnowed sandstones having high porosities and permeabilities contain the most abundant authigenic kaolinite and have acted as preferential conduits for migrating acid waters and for major fluid flow during co-production. Authigenic clay can create fluid production problems because of its delicate structure. Dislodged clay will obstruct pore throats at high production rates. A maximum safe rate of fluid production will need to be determined for co-produced wells.

Middle and lower Miocene barrier island sands, buried at depths from 3,500 to 6,800 ft in Northeast Hitchcock field, have the potential for receiving large volumes of co-produced brines from the Frio 1-A reservoir. These sands have high permeabilities in excess of 2,000 md, are internally homogeneous, and are laterally extensive in the field area. The 6,150 ft sand (lower Miocene) was selected for initial brine disposal in the H. D. S. Thompson No. 3 brine-disposal well, based on these criteria. The 3,780 ft sand (middle Miocene) is recommended for future up-hole brine disposal in the H. D. S. Thompson No. 3 well, because it also is more shallow and therefore requires less injection pressure and less cost for brine disposal.

Detailed geologic analyses of two reservoirs in Seeligson field delineate complex, heterogeneous, fluvial sandstones that probably contain isolated, undrained reservoir compartments. Zone 15, which has been developed under the assumption that it is a homogenous and continuous reservoir can be subdivided into at least four individual genetic sandstones within the study area. In many areas, a thin shale bed separates the sandstones, providing a vertical permeability barrier, and facies changes typical of fluvial environments may provide adequate horizontal flow barriers, thereby compartmentalizing reservoirs. Zone 18-C, also developed as a homogeneous and continuous reservoir, is composed of two separate sandstones, one of which had never been tested. Five recompletion recommendations were made for wells in both zones.

Anomalous bottom-hole pressures (BHP) noted in recent Zone 15 completions can be explained through advanced geological characterization methods. Pressures of 1,110-1,200 psi recorded in four wells were considerably higher than the expected BHP's of 300-500 psi in this "depleted" zone. Detailed depositional facies maps reveal two major channel complexes separated by floodplain mudstones. Wells with relatively high pressures are located in an untapped channel complex southwest of the floodplain facies, whereas wells with depleted pressures are found in a channel complex to the northeast of the floodplain mudstones.

The 4,150 and 4,200 ft sandstones, new Miocene gas pools of Tom O'Connor field, developed during growth fault activity along the Vicksburg Fault Zone. Near the fault zone, parasequence gross interval thickness markedly increases, and near the present anticlinal crest, gross interval thickness decreases more than the general, gradual, gulfward decrease in thickness. Log-facies and net-sandstone isopach maps also reflect growth fault activity. Deposition of the 4,150 and 4,200 ft sandstones, as part of an offshore system during initial parasequence deposition, was confined between the Vicksburg Fault Zone and the Tom O'Connor anticlinal crest. Thus, a complementary anticlinal structure appears to have developed gulfward of the Vicksburg Fault Zone and in turn, to have influenced the deposition of offshore sands during the initial progradational phase of parasequence deposition.

Technical Approach

A detailed lithologic description was made of the core cut in the Frio A sandstone at the Delee No. 1 well, Northeast Hitchcock field. Relationships were sought between depositional and diagenetic structures and high porosity and permeability. Sandstone petrography was carried out by point counting thin sections made from the Frio A sandstone core.

More than 15 sand beds, 20 to 150 ft thick, were correlated in the entire Miocene stratigraphic interval in 94 well logs, distributed throughout Northeast Hitchcock and Alta Loma fields. Six structural dip sections and one structural strike section were constructed in Northeast Hitchcock and Alta Loma fields. Net-sand and depositional-facies maps based on SP (spontaneous potential) log patterns were constructed for several sand units in Northeast Hitchcock and Alta Loma fields. These maps formed the basis for constructing depositional models of each sand. The best sites for drilling a brine-disposal well in Northeast Hitchcock field were determined by noting the common occurrence of the thickest and most laterally continuous Miocene sands that could be contacted in one well bore. A brine-disposal well, the H. D. S. Thompson No. 3, was drilled in August, 1987 in one of these sites. Whole cores were taken of three middle and lower Miocene sands which had been previously interpreted as barrier-island in origin. Detailed geological descriptions were made of these cores in order to refine previous depositional systems interpretations and to select a sand for initial brine disposal in the H. D. S. Thompson No. 3 well.

Approximately 250 electric logs were correlated in a 9 mi^2 area of Seeligson field in order to define the stratigraphic framework of more than 20 unit reservoirs. A grid of six structural cross sections was constructed to illustrate the lateral extent, thickness, and variability of sandstone reservoirs within the unit. Net-sandstone isopach and depositional-facies maps were constructed for thirty aggregate zones within the study area. Two zones were selected for detailed geologic evaluation on the basis of sandstone heterogeneity, cased-hole log evaluation results, production histories, bottom-hole pressure characteristics, and the availability of whole core. Highly detailed correlation of SP (spontaneous potential) and resistivity curves identified individual genetic sandstones within each zone, and depositional models for each sandstone were formed by constructing additional net-sandstone isopach and log facies maps. Results from the cased-hole log evaluation project were integrated with advanced geological characterization methods to select wells for recompletion, and recommendations were presented to the unit operator.

In the study of lower Miocene sandstones in the Tom O'Connor field area, a sequence stratigraphic framework was established, and depositional environments were interpreted. The correlation of resistivity markers on wire-line logs served to define parasequence boundaries. Correlation was carried out through a network of cross sections that encompassed about 1,200 mi^2. Log facies and isopach maps were used to interpret the distribution of depositional environments within the sequence stratigraphic framework.

Depositional Environment and Diagenetic History of Upper Frio Sandstones: Controls on Porosity and Permeability Preservation in Northeast Hitchcock Field, Galveston County, Texas

By M. P. R. Light

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DEPOSITIONAL ENVIRONMENT AND DIAGENETIC HISTORY OF UPPER FRIO SANDSTONES: CONTROLS ON POROSITY AND PERMEABILITY PRESERVATION IN NORTHEAST HITCHCOCK FIELD, GALVESTON COUNTY, TEXAS

by
M. P. R. Light

INTRODUCTION

Watered-out reservoirs contain substantial quantities of gas that can be produced by the co-production method. This technology attempts to reduce reservoir pressure through the production of large volumes of water. Free gas, bypassed in the reservoir as it was invaded by the rising gas-water interface, becomes mobilized and recoverable (Tyler and others, 1987). Additional but minor gas dissolved in formation water is produced at the surface as pressure is reduced. Watered-out hydro-pressured gas reservoirs and geopressured prospects can be economically co-produced (Gregory and others, 1983), and watered-out gas reservoirs will become economic sources of natural gas (Dorfman, 1982) in the future.

The co-production potential of Northeast Hitchcock field was analyzed during this project funded by the Gas Research Institute. The results of investigations into the structural, stratigraphic, facies, and diagenetic controls of porosity and permeability in the Frio A sandstone are presented in this report. This information defines (1) the size and continuity of the Northeast Hitchcock field; (2) the source of the high porosity and permeability; and (3) problems that may result from high production rates in highly transmissive sandstones.

REGIONAL BACKGROUND

Northeast Hitchcock field is located 15 mi (24 km) northwest of the city of Galveston (fig. 1) beneath part of the townsites of Hitchcock and La Marque in Galveston County. At Northeast Hitchcock field the Frio A, or 9,100 ft sandstone, is the producing reservoir and is widely

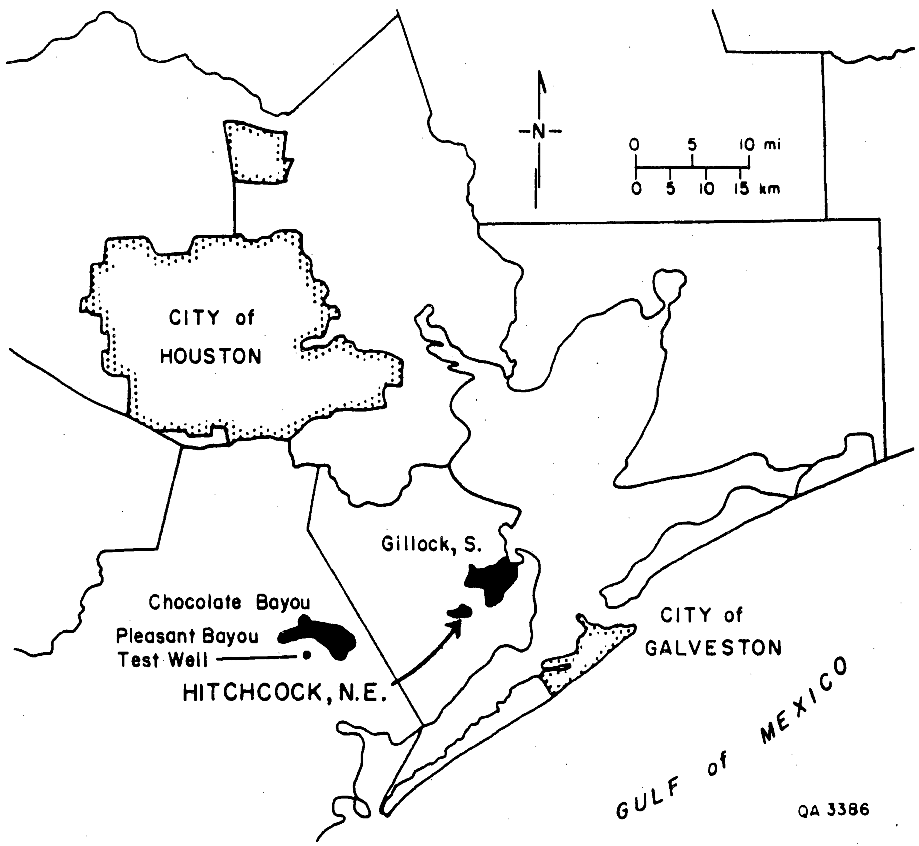

Figure 1. Northeast Hitchcock field location map (modified from Anderson and other, 1984).

distributed in a belt parallel to the Texas coastline. The Frio A is productive in many fields in southern Louisiana and along the Texas Gulf Coast (Anderson and others, 1984).

The T2 marker horizon locally represents the top of the Oligocene Frio Formation and directly overlies the Frio A sandstone reservoir. The Frio A reservoir in Northeast Hitchcock field has an average temperature of 215° F with a geostatic gradient of 0.6 psi/ft (Light, 1985). The top of the geopressured zone occurs approximately 400 ft below the top of the Anahuac formation, or 7,200 ft below sea level, in Northeast Hitchcock field (Light, 1985).

The Frio A sandstone in the Northeast Hitchcock area was deposited on the seaward fringe of the Houston Delta system (fig. 2) (Light, 1985). The regional geology has been outlined by Galloway and others (1982). Several minor, laterally repetitive deltaic cycles compose the Houston Delta system, which is the main locus of terrigenous accumulation in the Frio. Elongate to lobate deltas formed during the most regressive phases in the lower Frio, and more arcuate deltas formed during periods of general transgression and shoreline retreat in the upper Frio (Galloway and others, 1982).

During middle Frio deposition, deltas were supplied by a large fluvial channel system (Chita-Corrigan Fluvial System) 16 to 20 mi north and west of Northeast Hitchcock field. Net-sandstone isopachs show that the position of the fluvial axes changed substantially with time (Galloway and others, 1982). Platform-delta sequences from 50 to 300 ft thick characterize the middle and upper Frio in the Houston Delta system. Blocky sandstones record the development of multistoried wave-reworked sandstones of recurrent delta-destructional phases. The deltas became smaller as successive lobes shifted landward. Transgression and wave-reworking produced thick time-transgressive blanket sandstones. There was a constant switching of delta lobes, destructional marine reworking, and inundation of the abandoned sites (Galloway and others, 1982).

The depositional style of the upper Frio was strongly influenced by the Anahuac marine transgression. This shale wedge, which pinches out updip, marks the invasion of a comparatively sediment-starved shelf and contains a neritic fauna. In part it was deposited contemporaneously with, and is indistinguishable from, the upper Frio prodelta muds (Galloway and others, 1982).

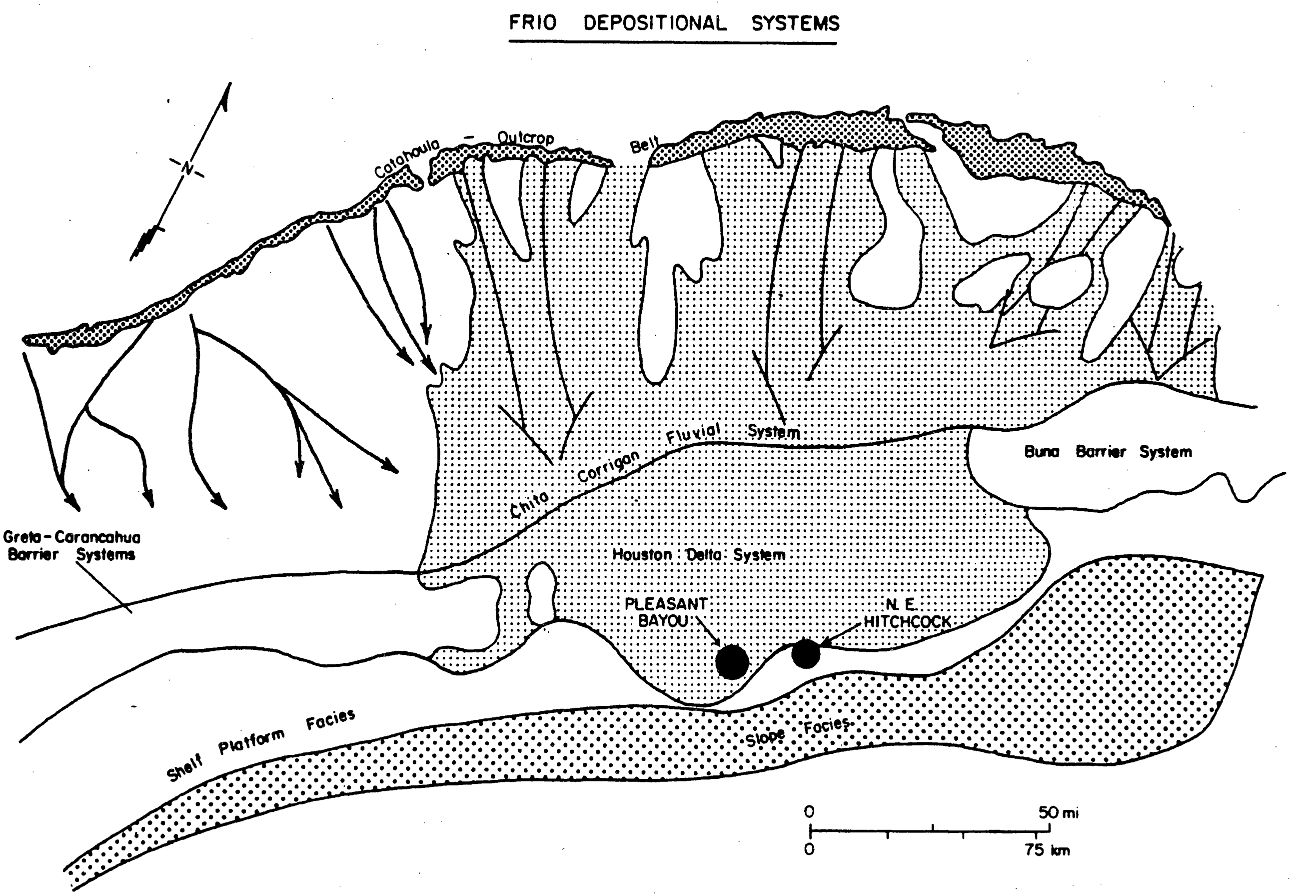

Figure 2. Regional depositional setting of Northeast Hitchcock field, Galveston County, and Pleasant Bayou geopressured-geothermal test wells, Brazoria County, Texas (modified from Galloway and others, 1982).

STRUCTURE

A close pattern of strike-parallel, broadly arcuate fractures was produced by growth faulting during deposition of the Frio (Galloway and others, 1982). In the region around Northeast Hitchcock field, the Frio A sandstone occurs within an ovoid fault block 10.5 mi long and 4.6 mi wide (Light, 1985) in an area characterized by deeply buried salt diapirs (T. E. Ewing, personal communication, 1985). Isolated areas of thick sandstone accumulation may represent sites of major growth faulting or salt-withdrawal basins (Galloway and others, 1982).

Light (1985) has described the detailed structure of Northeast Hitchcock field, which is defined by a northwest plunging anticline of moderate relief truncated on its southeast flank by a major northeast-trending growth fault with several hundred feet of throw (fig. 3). This fault forms the southern boundary of the Frio A reservoir (fig. 3).

A fault wedge upthrown 50 ft forms the northwest flank of the field and probably formed contemporaneously with Frio A sandstone deposition because there is a marked change in sandstone thickness and facies across the fault. Three other arcuate, northeast-trending normal faults dissect the east flank of the reservoir and have throws that vary from 30 to 60 ft (fig. 3). The two western faults appear to have isolated the Cockrell No. 1 Lowell Lemm well from both the Phillips No. 1 Prets well to the west and other wells to the east (Anderson and others, 1984; W. A. Parisi, personal communication, 1984, fig. 3).

A major east-west scissor fault (concave to the north) lies directly south of the Secondary Gas Recovery Delee No. 1 well (fig. 3). Throw on the east-west scissor fault exceeds 100 ft in the west, but its displacement decreases to 30 ft over the crest of the structure. Two other en-echelon scissor faults dissect the original Frio A pay zone in the southern part of the Northeast Hitchcock anticline, but the throw on these faults is less than the 50 ft on the western flank of the reservoir (fig. 3). The fact that these scissor faults do not disrupt the continuity of the reservoir is evident from the subsurface pressure history. The whole region experienced an almost even pressure drop, from the

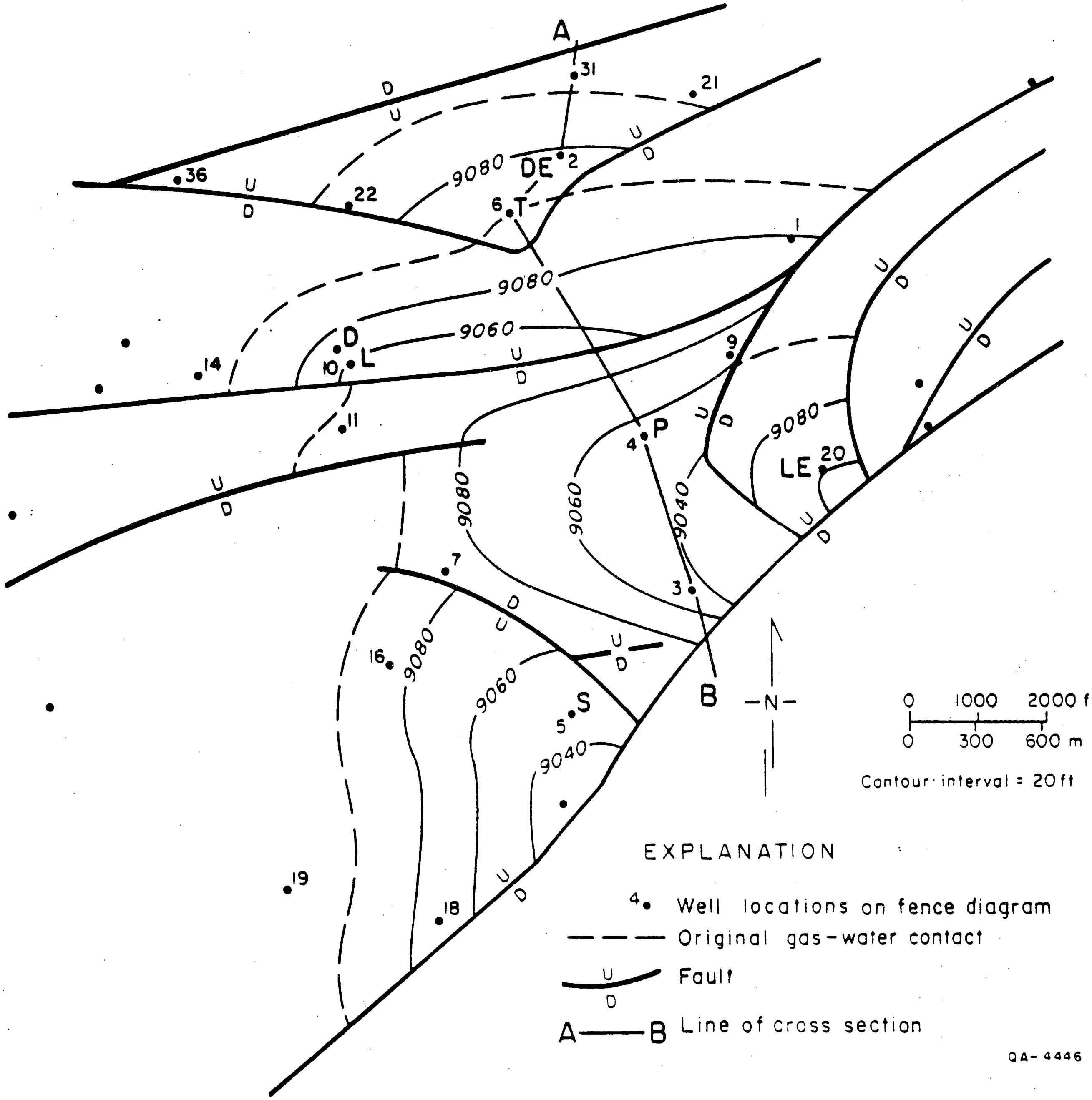

Figure 3. Structure map on top of the Frio A pay zone, Northeast Hitchcock field, Galveston County. Lettered oil well locations are Phillips No. 1 Delaney (DE), Thompson (T), Louise (L), Prets (P), and Sundstrom (S), Secondary Gas Recovery No. 1 Delee (D), and Cockrell No. 1 Lowell Lemm (LE). Cross section A-B is shown on figure 4.

Phillips No. 1 Delaney in the north to the Phillips No. 1 Sundstrom in the south, over a 24-year period from 1957 to 1981 (Anderson and others, 1984).

Thin shale breaks appear to stratify the Frio A reservoir and have clearly acted as permeability barriers that trapped liquid hydrocarbons formed by retrograde condensation during initial production. Much thicker shale layers are evident on electric logs from the Phillips No. 1 Thompson and Prets wells, and their extent over Northeast Hitchcock field has been defined by Ayers (personal communication, 1986). That minor faults have displaced this local vertical partitioning and isolated parts of the Frio A reservoir is shown by the different oil-gas dew points and oil percentages found in PVT analyses of fluid from the Prets and Thompson wells (Anderson and others, 1984). These shale breaks form vertical barriers separating lobate sandstones and were deposited during periods of quiescence between sand deposition. Mapping of fault planes and sandstone lenses has assisted in identifying isolated sections of the reservoir and can be used to determine the best locations for guard wells to reduce water influx (Light, 1985). Furthermore, the location of small sources of trapped free gas in the Northeast Hitchcock field is of great value to field operators completing future co-production wells.

Peterson (personal communication, 1986) mapped four major shale lenses in Northeast Hitchcock field (fig. 4) and demonstrated that the breaks have acted as vertical permeability barriers. Shales have retained small free-gas traps throughout portions of the reservoir, which as a whole has remained fairly homogeneous to pressure and fluid migration (Peterson, personal communication, 1986).

STRATIGRAPHY

Regional Depositional Environment

The Frio A sandstone in Northeast Hitchcock field consists of a stacked sequence of distributary-mouth-bar sandstones and thin delta destructional units that were transgressed by the Anahuac

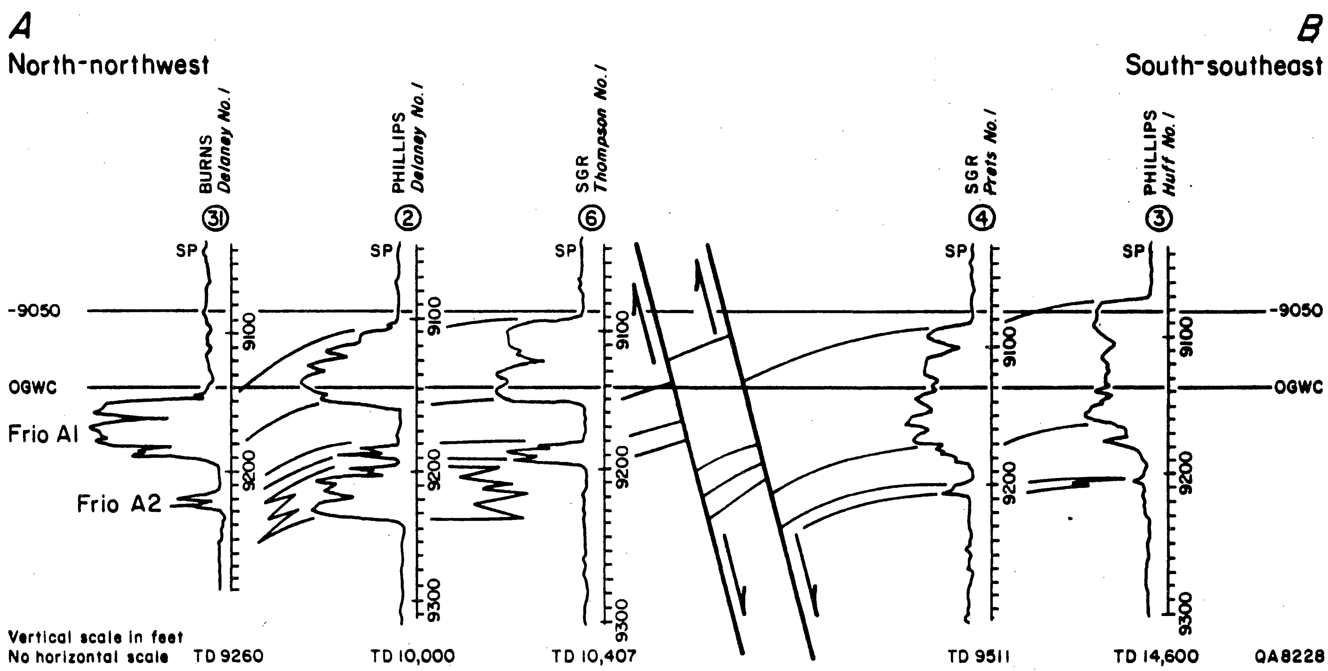

Figure 4. North-south cross section A-B through Northeast Hitchcock field, Galveston County, showing the relationship of the major shale breaks and faults to the original gas-water contact.

shale (fig. 5). Regional analysis of the facies distribution of the Frio A sandstone has been conducted using self potential (SP) profiles from the Pleasant Bayou test wells in the west (Brazoria County) to the Northeast Hitchcock field to the east. In all major sandstone systems in the region there is a transition from thick upward-coarsening sandstones updip to serrate sandstones downdip (fig. 6). Wave-modified sand-rich constructive deltas have produced the characteristic curvilinear strike-parallel distribution of facies (Morton and others, 1983). In Northeast Hitchcock field, the Frio A sandstone shows a well developed lobate-elongate net-sandstone thickness pattern consistent with deposition in a high-constructive delta (fig. 7) (Light, 1985).

The facies and thickness maps imply that a distributary channel prograded 3 mi southeastward from a fault wedge that forms the northwest flank of Northeast Hitchcock field during deposition of the Frio A sandstone (Light, 1985). This distributary formed a major distributary-mouth-bar deposit on the southern, downthrown, block of the fault wedge, and further progradation resulted in deposition of thick sandstones on the downthrown side of the major fault forming the southern boundary of the reservoir (figs. 6 and 7) (Light, 1985). Continuous delta-front sandstones occur in more distal positions, whereas thicker, composite, upward-coarsening SP profiles occur in the southern and eastern part of Northeast Hitchcock field (fig. 6) (Light, 1985). The proximity of the distributary system within the northwest fault wedge is indicated by the SP profiles of the distributary-mouth-bars, which are thin and show upward fining profiles (Light, 1985).

Detailed Facies Interpretations

The Oligocene age Frio Formation has been investigated to a depth of 9,402 ft (2,866 m) in the Secondary Gas Recovery Delee No. 1 well, Northeast Hitchcock field. Three gas-bearing sandstones were intersected below 9,392 ft, 9,366 ft, and 9,322 ft and were respectively 10 ft, 4 ft, and 28 ft thick. The thin, light gray sandstone layers between 9,402 and 9,322 ft consist of subangular grains that are well-sorted, moderately cemented, and of fine to very fine grain size. Abundant calcareous material is present, and the presence of glauconite suggests a shallow marine deposi-

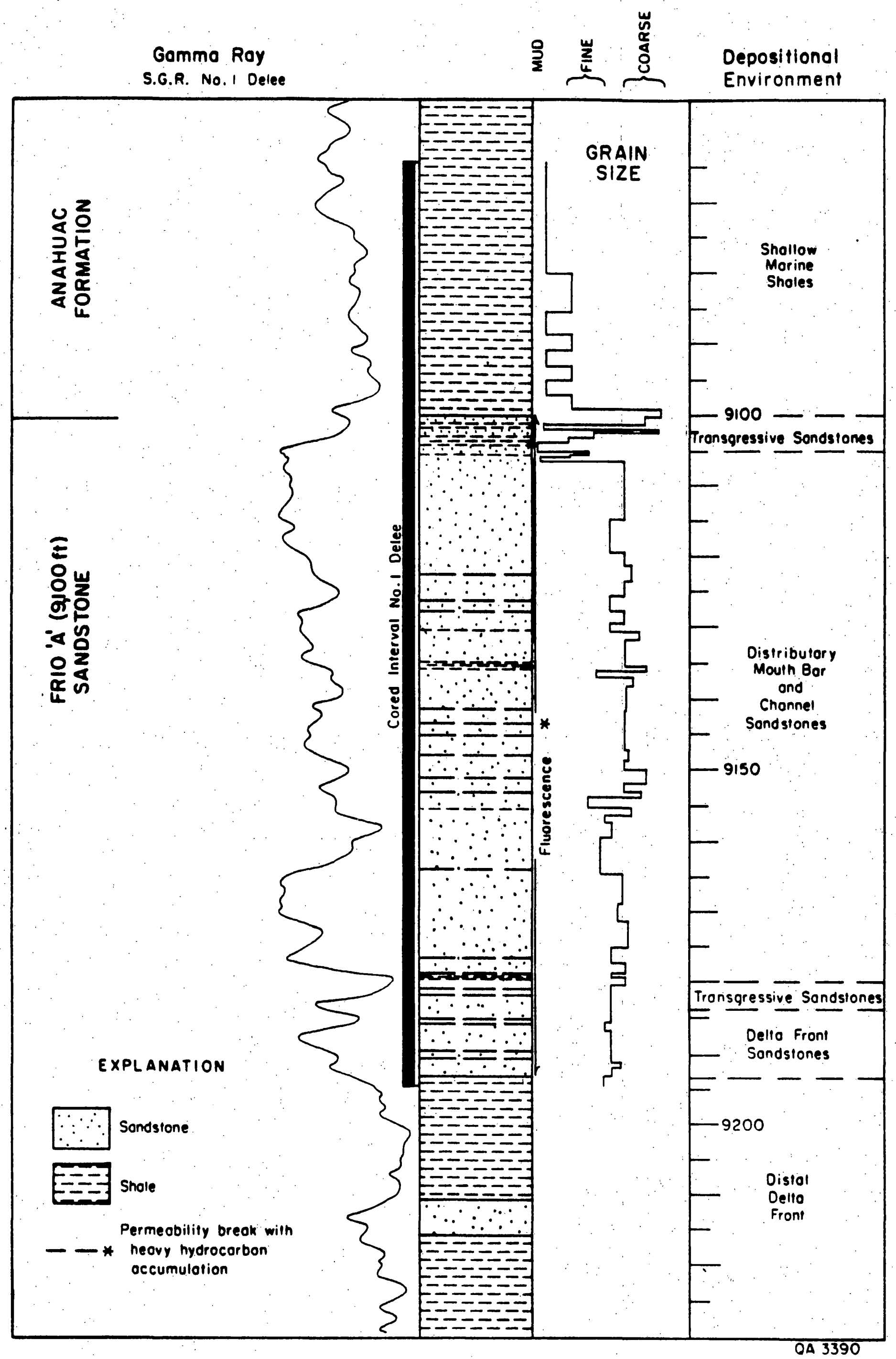

Figure 5. Simplified log of the Frio A sandstone interval in the Secondary Gas Recovery Delee No. 1 well, Northeast Hitchcock field. The gamma-ray response, grain size, and depositional environment are indicated.

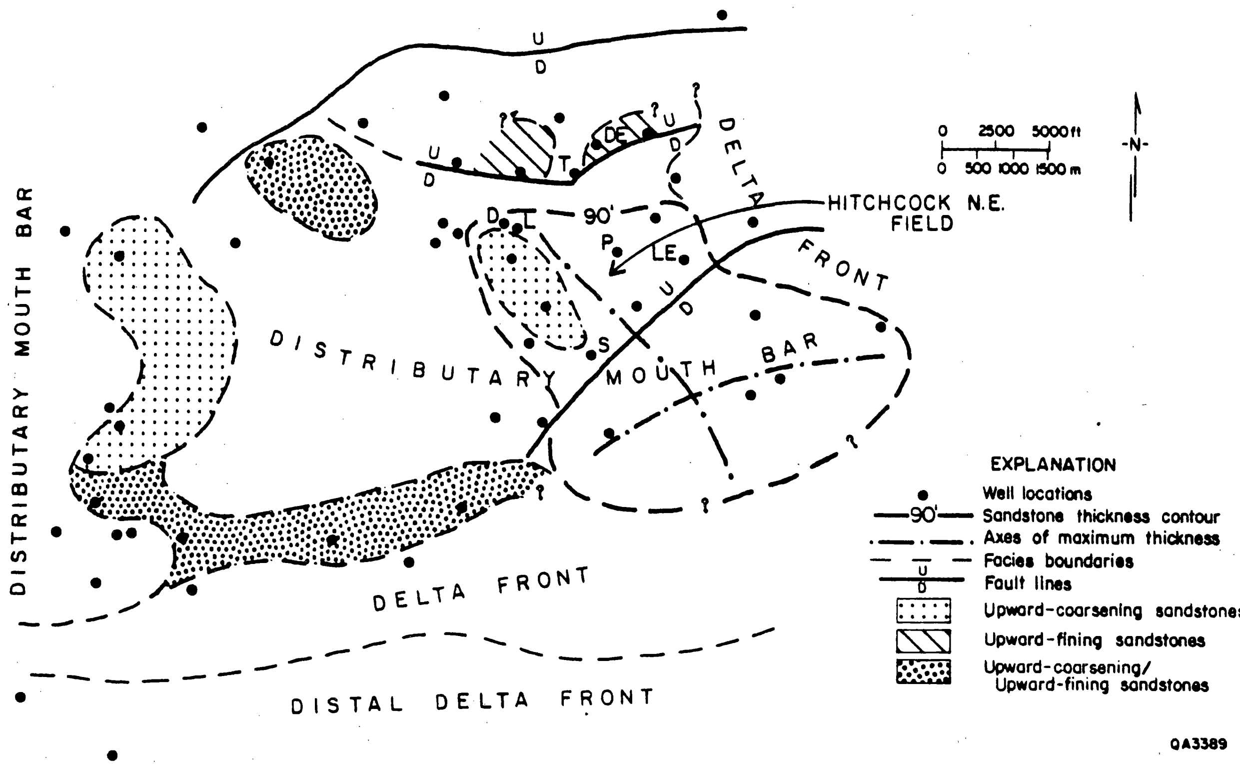

Figure 6. Log-facies map of Northeast Hitchcock field, Galveston County (modified from Tyler, 1984).

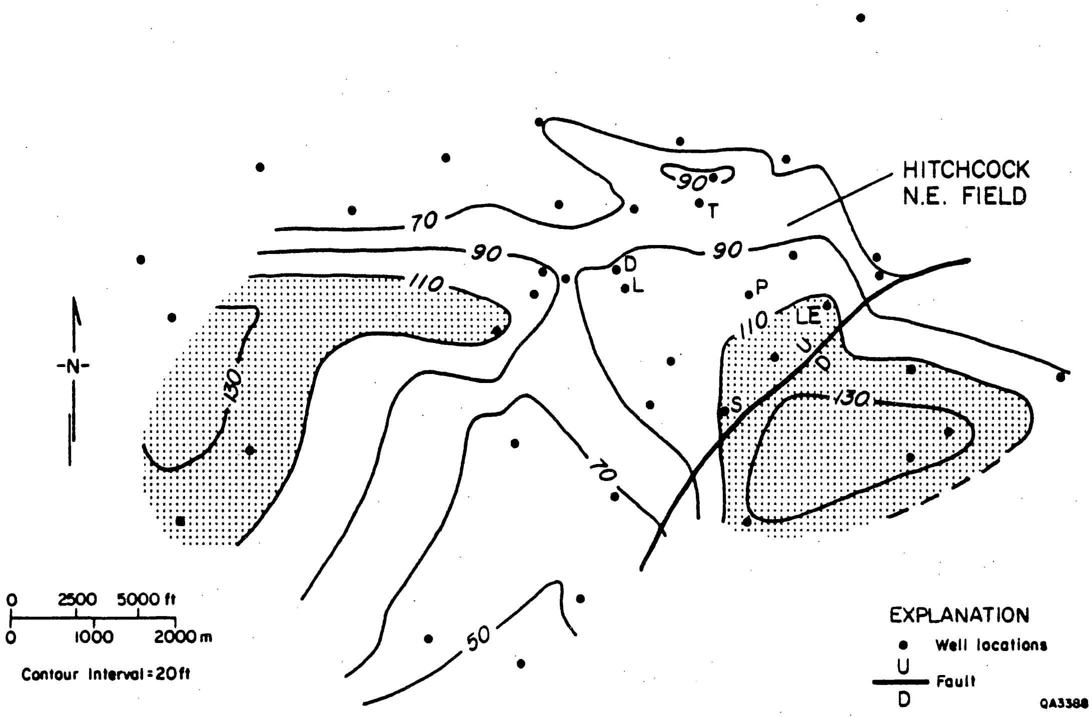

Figure 7. Frio A sandstone-thickness map showing location of Northeast Hitchcock field, Galveston County.

tional environment (Selley, 1970). A crude upward-coarsening and increasing porosity motif shown by rate-of-penetration and SP logs implies that these sandstones were deposited as prograding shoreface marine bars.

Indurated Frio shales in the interval 9,195 to 9,420 ft are dark gray, silty and calcareous. Shales at 9,195 ft, at the base of a 100-ft core cut in the Delee No. 1 well, contain abundant Planolites burrows, common in rocks ranging from the Recent to the Precambrian (Chamberlain, 1978). Planolites are characterized by branched or sparsely branched burrows that are circular, elliptical, or lenticular in section and have unlined distinct walls and poorly defined internal structure (Chamberlain, 1978). The Planolites burrows at 9,195 ft are horizontal, occur in clusters, and overlap parallel to one another consistent with an offshore shelf depositional environment.

Frio A Reservoir Sandstones

The Frio A reservoir in the Delee No. 1 well consists of two sandstone units, a lower sand A2 (9,182 to 9,194.1 ft) and an upper sand A1 (9,101 to 9,179 ft), separated by a 3-ft-thick shale break. The lower sand (A1) is 12.1 ft thick whereas the upper sand (A2) is 78 ft thick. The upper section of the Frio A reservoir was deposited in a transgressive setting and contains three sandy depositional pulses before grading up into the Anahuac shelf shales at 9,101 ft.

The lower Frio A2 sandstones consist of an upward-coarsening stack of cross-bedded, light gray, fine- to medium-grained, sandstone beds 1 to 3 ft thick separated by thin shale breaks. They are moderately sorted and contain subrounded grains; spotty kaolinite cement occurs near the base above a thin rippled shale break at 9,191 ft. In general the sandstones in this interval are indurated by diagenetic cementation. Other shale breaks are calcareous, and an erosional surface occurs at 9,183.5 ft to represent a distributary channel cut into delta front sands.

The Frio A1, a very uniform, fine- to medium-grained, cross-bedded sandstone that is glauconitic and moderately calcareous, forms a 24-ft-thick porous unit from 9,179 to 9,157 ft. It has a sharp basal contact on underlying marine shales. These sandstones are light green or gray-green to tan, moderately- to well-sorted, and contain rounded to subrounded quartz grains. The 24 ft thick package of sandstones consists of superimposed smaller cross-bedded units from 2 to 6.5 ft thick that are highly indurated at the base but less indurated higher up. In the upper part of the package (9,157 to 9,167 ft) the sandstones are more variable in nature, more closely laminated, and are burrowed at various levels.

General Depositional Environment of the Frio A Reservoirs

Coleman and Prior (1980) have described the general sequence characteristic of distributary-mouth-bar deposits. The prodelta section consists of fine-grained clay and silt deposits with parallel, organic-rich silt layers and distorted laminations alternating with burrowed zones. These grade up into rippled and lenticular-laminated silts and clays representing the distal-bar deposits. Above the distal-bar deposits are distributary-mouth-bar deposits composed entirely of clean, well-sorted sands. Small-scale ripple laminations, current-ripple laminations, and a variety of small-scale cross laminae, low-angle cross-bedding, and disturbed laminations are found in these deposits. Mass-movement processes such as small, localized slumps result in distorted laminae. Because of rapid deposition, pore pressures are high within these sands, and a large number of pore fluid-escape structures and localized compactional structures are found in these deposits.

The Frio A sandstones between 9,141 and 9,106 ft have the characteristics of distributary-mouth bars. They are generally medium grained, moderately to well sorted, and they contain angular to subrounded grains of quartz, feldspar, and volcanic rock fragments. The higher permeability sandstones are friable and contain thin calcareous streaks and inclined laminations.

The lower permeability parts of the sandstones are similar but show more variability in grain size from fine-grained calcareous sandstones having convoluted bedding to coarse-grained, erosively-based pebbly sandstones. The latter are poorly sorted, have distorted or convoluted bedding, and contain carbonaceous and calcareous shell fragments and shell molds. Thin, dark gray fissile shale layers occur between sand lobes. The tops of the sandstones are faintly laminated and contain carbonaceous fragments.

Distal-bar deposits are characterized by laminated siltstones, silty sandstones, and clays. Distal bars are a highly favorable environment for burrowing organisms, and distal bar deposits tend to be highly bioturbated (Coleman and Prior, 1980). The decreasing grain size of the glauconitic sandstones between 9,132 and 9,106 ft (2,783.7 and 2,775.5 m) suggests that these sandstones represent a distributary-mouth bar that was overlapped by distal-bar deposits. Although distal-bar deposits in most progradational sandstones grade from finer to coarser sediments vertically (Coleman and Prior, 1980), the reversed grading seen in these sandstones may result from the distributary-mouth bar retreating (R. A. Morton, personal communication, 1984).

Complete crevasse splay sequences that prograded into an interdistributary bay are represented by two sets of laminated shale, siltstone and sandstone between 9,104.8 and 9,101 ft in the upper part of the Frio A reservoir. The poorly sorted and conglomeratic nature indicates a fluvial dominance, and the upward-coarsening fabric suggests that they are crevasse splay deposits that have breached the fluvial channel and are being deposited directly on a washover fan developed on the bayward side of the reworked distributary mouth bar or levee. This represents the terminal depositional event of the distributary before it was transgressed and buried by the Anahuac Formation shales.

Petrography of Frio A Reservoir Sandstones

The diagenetic sequence and its effect on porosity and permeability preservation in the Frio A sandstone core from the Delee No. 1 well has been studied using 17 thin sections from four depths (9,156 ft, 9,166 ft, 9,177.5 ft to 9,178.5 ft, and 9,189.5 ft). At each level 800 to 1,000 grains were counted, and the average mineral composition and porosity estimated. The sandstones are feldspathic litharenites (Folk, 1974). Numerous diagenetic modifications have occurred in these sandstones, as follows. (1) Kaolinite, which postdates quartz overgrowths, has replaced feldspars.

(2) Plagioclase and K-feldspar are altered to sericite along cleavages and are rimmed by later kaolinite; late-stage chlorite cement crosscuts kaolinite intergrowths. (3) Sparry calcite rims corroded feldspars, and iron-rich calcite has replaced micaceous minerals.

Hydration of K-feldspar to kaolinite by acid waters prior to the introduction of hydrocarbons has resulted in a porosity increase of up to 3.5 percent in the well-winnowed distributary-mouth-bar sandstones. Because the conversion of K-feldspar to kaolinite results in a decrease in volume of about 50 percent, the volume of kaolinite is an estimate of the volume of secondary porosity produced by this process.

Porosity in Northeast Hitchcock Field

There is a direct relationship between the degree of winnowing (quartz content) and porosity. This is consistent with the wave-reworked nature of the sandstones in the Frio, which formed during recurrent delta-destructional phases (Galloway and others, 1982; Tyler and Hahn, 1982). The high-energy depositional environment of reworked distributary-mouth-bar sandstones is the major control of the high porosity (~30 percent) and permeability (~1,000 md) in the Frio A sandstones at Northeast Hitchcock field. Although porosity and permeability were subsequently modified by diagenetic reactions, primary porosity was preserved in Frio A reservoirs.

Permeabilities of reservoir sandstones from the S.G.R. Delee No. 1 and Phillips Thompson No. 1 wells, Northeast Hitchcock field, are skewed toward large values, with 48 percent of values between 1,000 and 3,160 md (fig. 8). The distribution has a mode of 1,778 md, an arithmetic mean of 1,149 md, and a geometric mean of 693 md. The geometric mean of the permeabilities of producing sandstones at the Delee No. 1 well is even lower (313 md), which suggests that permeabilities in excess of 1,000 md should not be used in reservoir engineering calculations.

Horizontal permeability normally exceeds vertical permeability in the Northeast Hitchcock sandstones, although there is clear linear relationship between them. This is a consequence of the

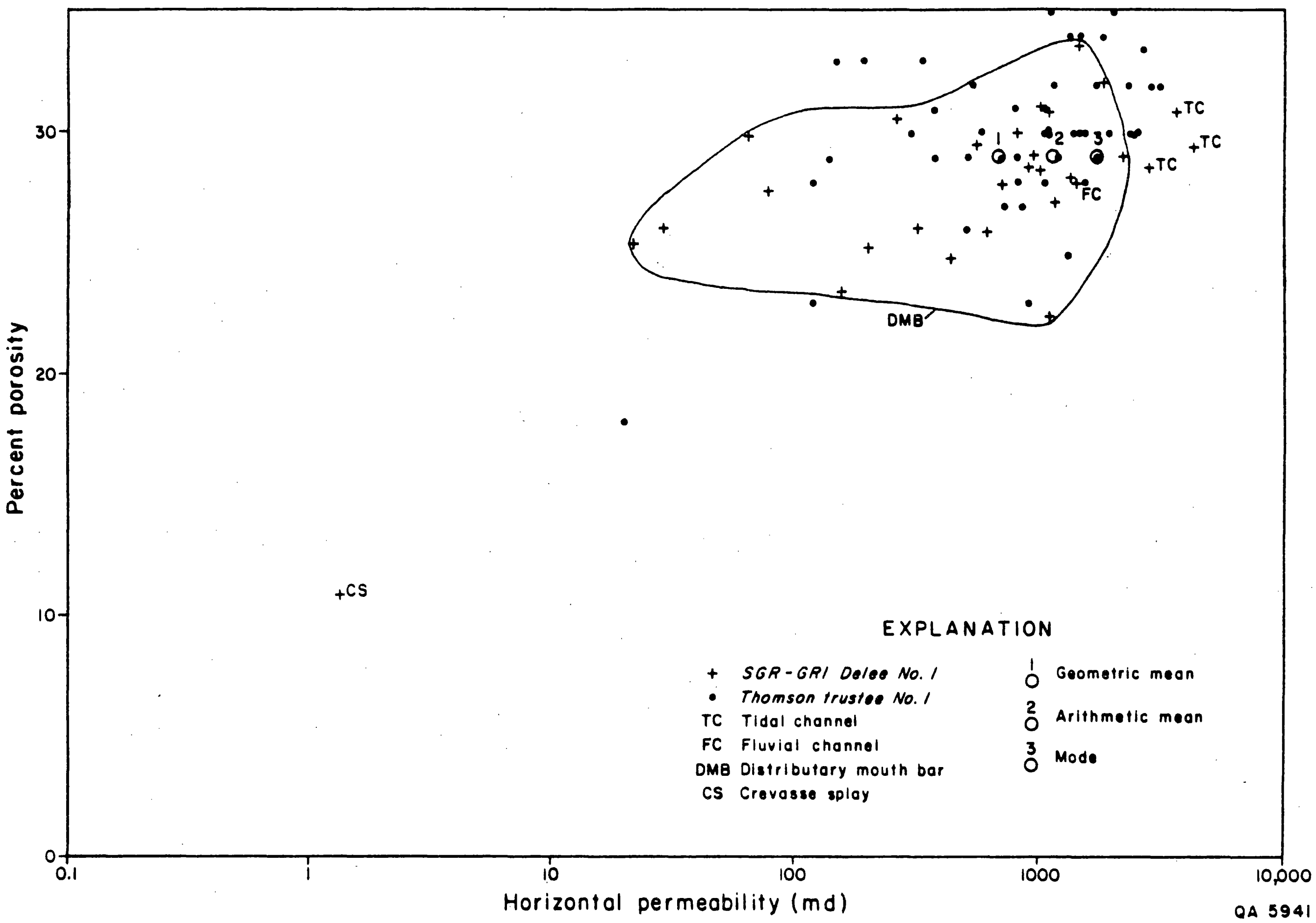

Figure 8. Porosity versus permeability for the Frio A sandstones in Northeast Hitchcock field, Galveston County.

horizontally-bedded nature of the deposits, which have minor horizontal permeability barriers to vertical flow.

Very consistent high-permeability and high-porosity values, which vary from 1,134 to 1,493 md and 28.2 to 33.7 percent, are present in the lower Frio A delta-front sandstones between 9,186.2 and 9,192.1 ft (fig. 8). Low-permeability sandstones appear near the top of the stacked distributary-mouth-bar sandstones between 9,155.2 and 9,179 ft. The decreased permeability in these sandstones is probably a result of the increased content of fines in pore throats.

Tidal channel sandstones show the highest permeabilities of all the sandstones, although their porosities (up to 30.9 percent at 9,149.4 ft) are less than those of the very porous distributary-mouth-bar sandstones. Horizontal permeabilities in the tidal channels range from 2,911 md (9,146.3 ft) to 4,446 md (9,152.2 ft). These high permeabilities are evidently the result of the winnowing and reworking these sandstones have undergone, and the subsequent removal of fine, pore-throat-occluding carbonaceous and shaly material.

Sandstones showing low porosities and permeabilities (158 md and 442 md) occur at 9,125.6 ft and 9,128.6 ft, at the base of a distributary-mouth-bar sequence. The low permeability is directly related to zones of horizontal bioturbation and convoluted laminations. Delta front slump deposits exhibit a very large amount of matrix, which yields a very low permeability because of the intermixing of mud and silt by slumping and burrowing (Morton and others, 1983).

Distributary-mouth-bar sandstones between 9,123.4 and 9,114.8 ft are indurated, kaolinite cemented, non-calcareous and porous at the base but very calcareous and friable at the top. Very high permeabilities are found in the distributary-mouth-bar sandstones at 9,122.3 ft. Evidently excessive winnowing has removed nearly all the fine pore-throat occluding materials. The permeability decreases upwards, which may result from an increase in the clay content, a result of the distributary-mouth-bars retreating (R. A. Morton, personal communication, 1984). Distributary-mouth-bar sandstones between 9,114.8 and 9,105.8 ft also show a decrease in permeability from bottom to top, again a result of the bar sand retreating.

In the transgressive units that form the uppermost part of the Frio A1 reservoir (9,100.6 to 9,101 ft), clusters of Planolites burrows occur in contorted silty and shaly layers. These zones are marked by reduced permeability, which is probably a result of the disruption of the rock fabric caused by the bioturbation.

Blatt and others (1980) have outlined the effect of high clay content on fluid production from reservoir sandstones. In areas of high fluid flow, clays may become dislodged and float through pore channels, where they will become lodged in narrow pore-throats, greatly reducing the permeability of the sandstone. The pore-throats become areas of clay accumulation through which the pore fluid cannot pass, and this problem is severe where sandstones contain a high ratio of expandable smectite to other clays. Expandable smectite clays are easily dislodged and occupy a greater volume per clay particle. Frio A sandstones with high permeabilities (9,118 ft and 9,122.3 ft) preferentially contain kaolinite, which suggests that kaolinite does not occlude porosity and permeability in the distributary-mouth-bar sandstones. However, because of its very delicate structure, authigenic kaolinite can create fluid production problems at the high production rates (Blatt and others, 1980) that are required when gas and water are co-produced. Safe rates of fluid production will need to be determined that will preserve the high transmissibility of the Frio A sandstones, by not causing the migration of clay fines.

Shale Dewatering during Production

The potential for the production of shale waters as a result of major pressure drawdown during co-production of the Northeast Hitchcock field has been examined because this is a possible mechanism for reducing the rate of pressure loss. There is little available evidence that can be used to demonstrate shale fluid flow (dewatering) during production. Formation water at the Phillips Prets No. 1 well has been analyzed on three occasions over an eight-year period (Kharaka and others, 1977), with the more recent analyses being done by the Institute of Gas Technology (IGT) and University of Houston staff (Randolph, 1985). Although uncertainty exists about quality of the early analyses and differences in the sampling points and procedures, there is a slight decrease in chloride-ion concentration of about 5.5 to 8.7 percent that may indicate shale dewatering.

CONCLUSIONS

Depositional environment is the major control of the high porosity in the Frio A sandstones at Northeast Hitchcock field, Galveston County. The high porosity (30 percent) and permeability (1,000 md) of the Frio A reservoir is largely the result of its deposition in a distributary-mouth-bar complex that was subsequently reworked by shallow-marine processes. The wide lateral extent of the Frio A sandstone, which is a consequence of extensive marine reworking, will allow free access to water influx from the southwest extension of this reservoir (Light, 1985).

The best location for guard wells placed below the gas-water contact to control water influx during co-production will be determined by southwest-trending fault systems. This is because Northeast Hitchcock field is situated on the northeast flank of the large Frio A reservoir isolated to the north and south by major growth faults (Light, 1985). Minor faults that dissect Northeast Hitchcock field locally isolate parts of the pay zone (Light, 1985) and modify production rates from parts of the field where permeability breaks are present. The best locations for guard wells will also be defined by the position, and extent, of these zones (Light, 1985).

Carbonate cementation prior to initial leaching has not been the mechanism through which primary porosity is preserved in the Frio A sandstones. Hydration of potassium feldspar to kaolinite by migrating acidic waters prior to the introduction of hydrocarbons resulted in a porosity increase of as much as 3.5 percent in the well-winnowed distributary-mouth-bar Frio A sandstones. Because the conversion of potassium feldspar to kaolinite results in a decrease in volume of about 50 percent, the percentage concentration of kaolinite is a rough estimate of the volume of secondary porosity produced by this process.

Well-winnowed sandstones with high porosities and permeabilities contain the most abundant authigenic kaolinite; these sandstones have acted as preferential conduits for migrating acid waters and for major fluid flow during co-production. Authigenic kaolinite can create fluid production problems because its delicate structure is fragile. In addition, chlorite cements and chlorite rims on quartz overgrowths are present in some sandstones, and these may also be dislodged during high production rates. The dislodged clay and chlorite flakes will obstruct pore throats at high production rates.

A maximum safe rate of fluid production will need to be determined for co-produced wells that will not result in dislodgment and migration of kaolinite, chlorite and fibrous smectite-illite into pore throats (fig. 170). Experimental flow tests conducted at different flow rates on kaolinite-rich sandstones and measurement of resulting changes in permeability could assist in determining the safe upper flow rate.

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GEOLOGIC CHARACTERIZATION OF MIOCENE BRINE-DISPOSAL SANDS, NORTHEAST HITCHCOCK FIELD, GALVESTON COUNTY, TEXAS

William A. Ambrose

INTRODUCTION

Gulf Coast Co-Production Program

Co-production is a technique designed to improve production from geo- and hydropressured gas reservoirs that have been abandoned or have begun to water out. Wells in watered-out gas reservoirs are usually shut in because of unfavorable economics associated with low gas-production rates and brine-disposal problems.

The Gas Research Institute initiated a series of studies to test the potential for co-production in the Gulf Coast, and to safely and efficiently dispose of large volumes of associated brines. This report provides recommendations, using geologic criteria, for subsurface brine disposal in Northeast Hitchcock field (Galveston County, Texas), where co-production has begun from the watered-out, geopressured Frio 1-A (Oligocene) gas reservoir.

Previous studies funded by the Gas Research Institute (Anderson and others, 1985; Randolph, 1985; Light, 1985) indicate that large volumes of gas in the Frio 1-A reservoir in Northeast Hitchcock field (Galveston County, Texas) can be economically produced through co-production, requiring disposal of approximately 22,500 barrels of brine per day collectively in three disposal wells. The optimum sands for receiving these brines should be: (1) laterally continuous and internally homogeneous, (2) consistently thick throughout the field area, (3) not too deeply buried, and (4) capable of receiving large volumes of brine, based on comparison with analogous sands in other fields. Review of these criteria indicates that the best sands in Northeast Hitchcock field for brine disposal are in lower and middle Miocene barrier-island sands, buried at depths from 3,500 to 6,200 ft. These sands have high permeabilities in excess of 2,000 md, excellent lateral continuity, and internal homogeneity favoring disposal of large volumes of brine. Each of these sands should be capable of receiving 6,000 barrels of brine per day per well, based on analogy to active brine disposal into other Miocene barrier-island sands in nearby fields (Ambrose and Jackson, 1987).

Objectives

Five critical tasks were defined to select the best Miocene brine-disposal sands in Northeast Hitchcock field. These tasks were:

1) Determining the extent of the main fault block containing Northeast Hitchcock field, thereby defining the maximum area where Miocene sands have not been offset by major faults.

2) Identifying the best Miocene sands for brine disposal by evaluating their internal heterogeneity, based on interpretation of net-sand and log-facies maps and core description of the most laterally extensive and thickest sands in Northeast Hitchcock field.

3) Documenting the brine-disposal potential of Miocene sands in Northeast Hitchcock field and other Miocene sands in nearby fields where large volumes of brines have been disposed.

4) Selecting potential sites for brine disposal in Northeast Hitchcock field, based on the common occurrence of the thickest and most laterally continuous portions of potential brine-disposal Miocene sands.

5) Describing factors limiting brine-disposal potential of Miocene sands in Northeast Hitchcock field, such as sand body heterogeneity and calcite cement.

Study Area, Data Base, and Methods

Northeast Hitchcock and Alta Loma fields are located in Galveston County, Texas (fig. 1). Alta Loma field was included in the study because it is located within the same major fault block

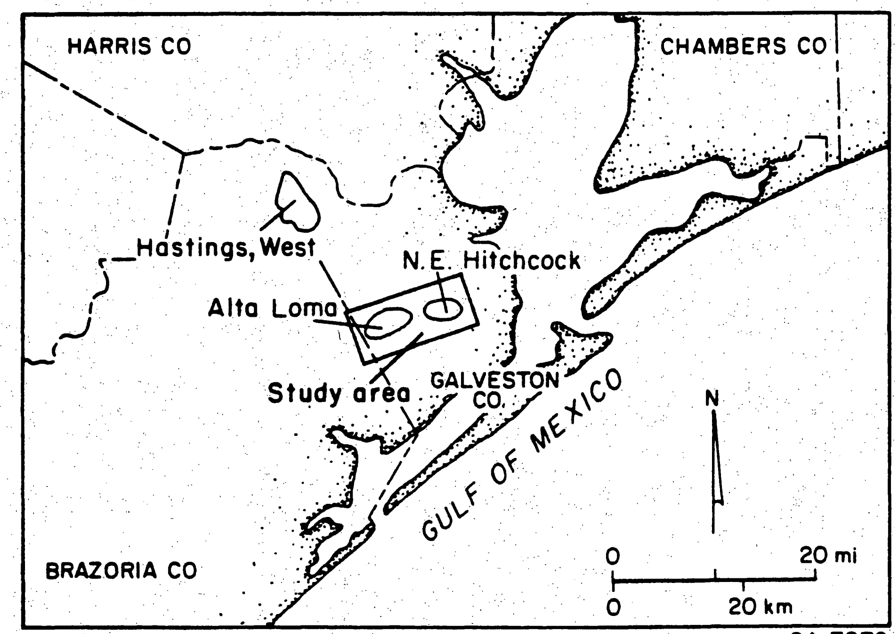

Figure 1. Location of Northeast Hitchcock field, in which several middle and lower Miocene barrier-island sands have been targeted for disposal of brines co-produced with gas from the Frio 1-A reservoir in the field. Hastings West field contained 43 wells in 1985 that were used for brine disposal into Miocene sands analogous to those in Northeast Hitchcock field.

containing Northeast Hitchcock field. Details of this fault block are illustrated on a structure map contoured on the top of the 4,240 ft sand (fig. 2). Two major growth faults that offset Miocene sands from 50 to 200 ft isolate the two fields into a block covering approximately 35 mi^2. Miocene sands in this fault block are offset by 40 ft or less by minor faults.

The database includes 94 well logs distributed throughout Northeast Hitchcock and Alta Loma fields, as well as portions of nearby Franks, Gillock South, Hitchcock, and Sarah White fields, located on fig. 2. The names of the well logs are listed in Table 1.

Brine-disposal histories of Miocene sands in eight of the wells in the data base were incorporated into the study. These sands and wells are indicated on fig. 2. Similar but more extensive brine-disposal data from analogous and correlative Miocene sands in Hastings West field (located on fig. 1) were analyzed in order to determine the brine-disposal potential of other Miocene sands in the region (fig. 3).

Six structural dip sections and one structural strike section were constructed in Northeast Hitchcock and Alta Loma fields (fig. 2) in order to document the location and offset of the major bounding faults and to determine the lateral extent and thickness of Miocene depositional units to be considered for brine disposal. Net-sand and depositional-facies maps based on SP log patterns were constructed for several lower, middle and upper Miocene sands in Northeast Hitchcock field (fig. 4). Net sand thickness was determined from SP logs by using a cutoff line drawn 35 percent of the distance from the SP baseline to a normalized maximum SP deflection for the Miocene in the study area. This value has been successfully used for accurate determination of net sand by the Bureau of Economic Geology in studies of other Tertiary formations in the Texas Gulf Coast (Tyler and Ambrose, 1985).

Depositional facies maps of each Miocene sand selected for study were based on characteristic SP patterns that were interpreted in conjunction with the net sand maps. Application of SP patterns to depositional systems interpretation has been effectively demonstrated in previous studies of the Miocene in the Texas Gulf Coast (Morton and others, 1985), and of other Tertiary units (Galloway and Cheng, 1985; Tyler and Ambrose, 1985).

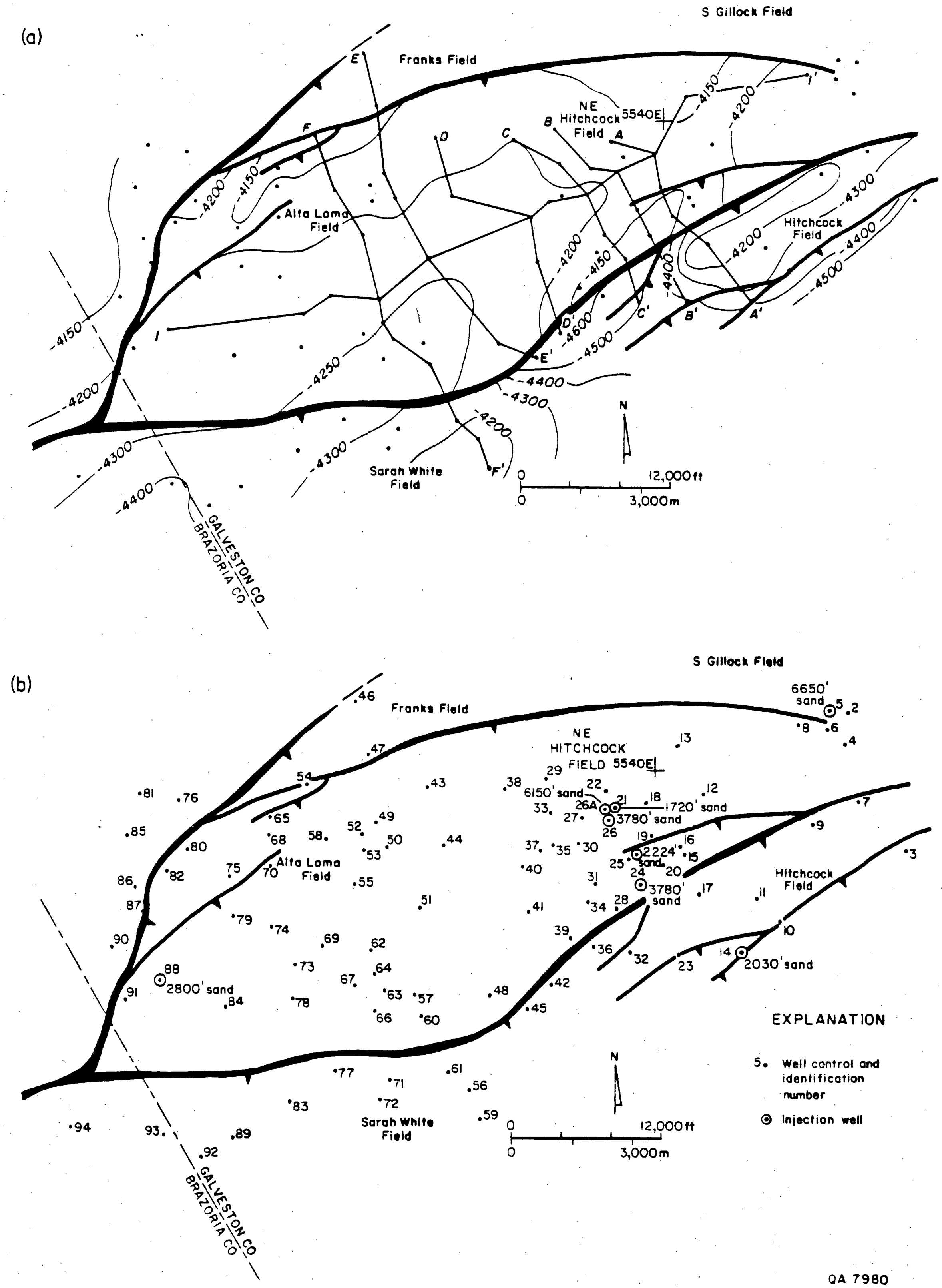

Figure 2. Structure map of Northeast Hitchcock and Alta Loma fields, contoured on top of the 4,240 ft sand (middle Miocene). Two major growth faults, with throws from 50 to 200 ft, isolate these two fields into a 35 mi² fault block. B. Well control used in this study. Miocene sands in six of these wells have received brines; these wells and sands are indicated on the map above. Amounts of disposed brine are indicated on net-sand maps of these sands.

Table 1. Well logs used in brine-disposal study of Northeast Hitchcock and Alta Loma Fields

Well Number	Operator and Lease
1	Pan Am. #1 State Moses Lake
2	Pan American #2 Scofield Comm.
3	Mecom #A-1 Univ. of Texas
4	Pan American #D-4 Kohfeldt
5	Pan Am. #D-3 S. Gillock Un.
6	Pan American #DD-1 S. Gillock
7	Pan American #B-1 S. Gillock
8	Pan American #1-N S. Gillock
9	Mid Sts. #1 Westbridge Un.
10	Cockburn #1 Dobbs, et al.
11	Hanson #2 Title and Guar.
12	Total Pet. #1 Stuart
13	Pan American #1 Bogatto Comm.
14	Cockburn #1 Aarco
15	Sue-Ann #1 Dynamic Land Devel.
16	L.B. Wright #1 Schaub
17	Adobe & Cameron #1 Stubbs
18	Phillips #1-A Fox
19	Phillips #1-D Davis
20	Cockrell #1 Lemm
21	Phillips #1 Delaney
22	R.L. Burns #1 Delaney
23	Humble #1 Coon Fee
24	Phillips #1-A Huff
25	Phillips #1 Prets
26	Phillips #1 Thompson
26A	H.D.S. #3 Thompson
27	Kennedy and Mitchell #1 Delaney
28	Phillips #1 Sundstrom
29	Placid #1 Weidman
30	Phillips #1-A Louise
31	Mecom #1 Kipfer
32	Tx. E. Trans. #1 Hitchcock G.U.
33	Mecom #1 Wittgen
34	Phillips #1 Lasalo
35	J.S. Michael #1 Newman
36	Slater et al. #1 Flake G.U.
37	Kimball #1 Knox est.
38	Placid #1 Camp Wallace G.U.
39	Slater et al. #1 Delasandre
40	H&M Gas and Oil #1 Reichmeyer
41	Aikman Pet. #1 Drew Unit
42	Tx. E. Trans. #1 White G.U. 4

Well Number	Operator and Lease
43	Placid #1 Lobit
44	Hassie Hunt #1-A Ghino
45	Tx. E. Trans. #1 White G.U. 3
46	Placid #1 Thompson G.U. 1
47	Placid #1 Crane G.U.
48	Tx. E. Trans. #1 Henck
49	Hassie Hunt #1 S.H. Green
50	Hassie Hunt #3 S.H. Green
51	Hassie Hunt #1-A Brister
52	Hassie Hunt #1 H. Sealy
53	Hassie Hunt #1 M. David
54	Hassie Hunt #1 Nelson
55	Hassie Hunt #1 R.B. Wilkins
56	Gulf #2 Emil Firth est.
57	Phillips #1-A Tacquard
58	Hassie Hunt #1 M. Rogers
59	Alamo Pet. #1 Firth est.
60	Damson #1 G. Latimer
61	Gulf #1 Lowenstein
62	Phillips #1 O'Daniel Un.
63	Phillips #2 O'Daniel Un.
64	Phillips #3-A O'Daniel Un.
65	Hassie Hunt #1 Sayko
66	Phillips #1-A Evans
67	Phillips #1 McVea
68	Hassie Hunt #2 Sayko
69	Hassie Hunt #1 M. Jensen
70	Phillips #2-B Pabst
71	Tx. E. Trans. #4 Craig
72	Tx. E. Trans. #3 Craig
73	Phillips #1 Lauzon
74	Jolensky-Gideon #1 Tacquard
75	Phillips #1-B Pabst
76	Reb. Pet. #1 Chapman
77	Mecom #1 Roos Trustee
78	Phillips #A-1 Christensen
79	Crystal Oil #1 McIlvane
80	Del Mar #1 W.N. Zinn
81	M.P.S. Prod. #1 Chapman
82	Del Mar #1 Harris
83	Tx. E. Trans. #1 Halls Bayou R.
84	Buttes #1 Sun Amoco Fee
85	The Texas Co. #1 Joe Tucker
86	The Texas Co. #B-1 J.W. Harris
87	Tx. E. Trans. #1 Newton
88	Gen. Crude #1 Reitmeyer-Briscoe

Well Number	Operator and Lease
89	Edwin Cox #1 Halls Bayou Ranch
90	Tx. E. Trans. #1 Nana
91	Pan American #1 R.E. Brading
92	Buttes #2 A.B. Marshall
93	Fina, et al. #1 Marshall
94	Phillips #1 McIlvane

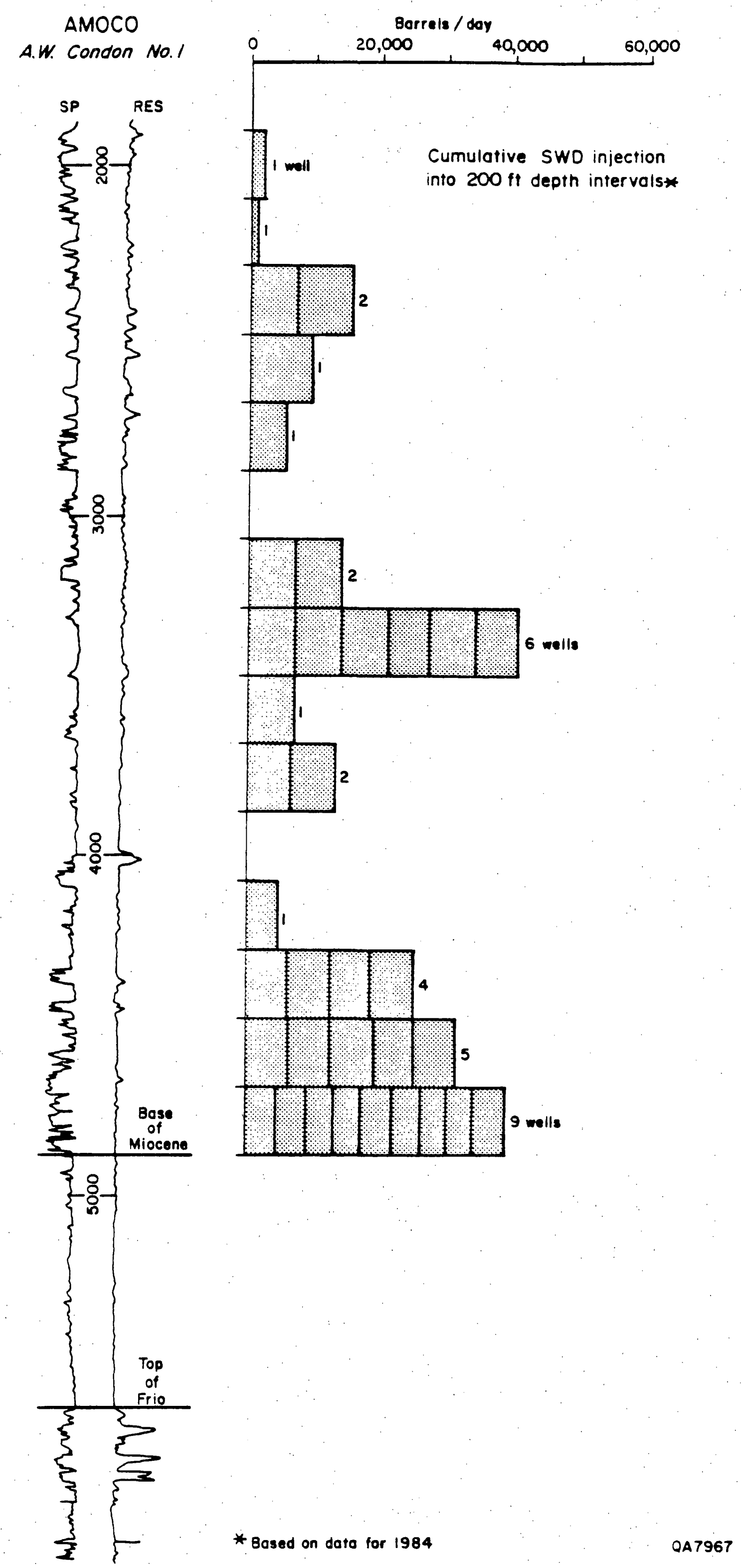

Figure 3. Type log in Hastings West field, located 15 mi northwest of Northeast Hitchcock field. Barrier island and wave-dominated deltaic sands received 242,000 barrels of brine per day in 1985 from 43 wells in Hastings West field. Lower Miocene sheet sands in Hastings West field are capable of receiving 10,000 barrels of brine per day per well. Figures obtained from the Railroad Commission of Texas.

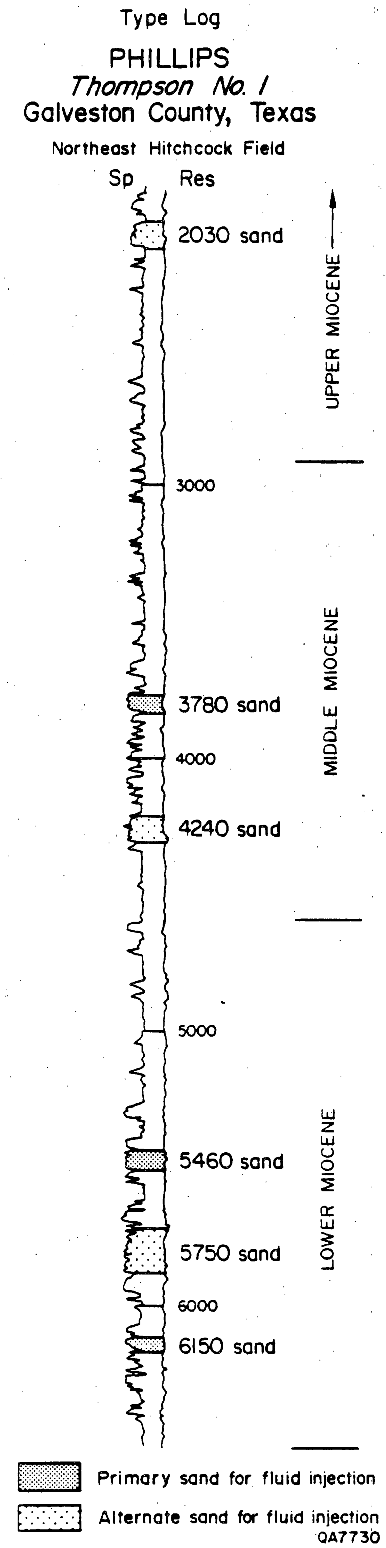

Figure 4. Type log (Phillips Thompson #1; number 26 in this study) in Northeast Hitchcock field. The three best zones for brine disposal (3,780 ft, 5,460 ft, and 6,150 ft) are in barrier island depositional units that contain large volumes of homogeneous barrier-core facies. Three alternate sands (2,030 ft, 4,240 ft, and 5,750 ft) are also shown.

PREVIOUS WORK

In 1987 the Bureau of Economic Geology provided recommendations for the best Miocene brine-disposal sands in Northeast Hitchcock field, based on a study of depositional architecture and brine-disposal history of Miocene sands in the region. These recommendations were summarized in a report by Tyler and others (1987) that also furnished a review of Miocene depositional systems in the region, as well as a discussion of important geologic criteria (sand-body geometry, sand thickness and depth of burial, and brine-disposal history) for selection of good brine-disposal sands. Tyler and others (1987) used these criteria to recommend potential sites in Northeast Hitchcock field for brine-disposal into three Miocene sands, the 3,780 ft (fig. 5), 4,240 ft (fig. 6), and 5,460 ft (fig. 7). These sands were chosen because they are thick, relatively simple barrier-island sand bodies that contain only minor interbedded mud. The best brine-disposal site in Northeast Hitchcock field was selected by noting the common occurrence of the thickest and most laterally continuous portions of these three sands that could be contacted in one well bore. Potential pore volumes available for brine disposal in these sands in the fault block that contains Northeast Hitchcock and Alta Loma fields were calculated from net-sand maps and porosity values of each of these three sands and three alternate sands (Table 2). Porosity values for the sands were derived from previous studies of the shallow Miocene in the Texas Gulf Coast (Doyle, 1979; Galloway and others, 1986).

Three alternate Miocene sands were also designated by Tyler and others (1987) for brine disposal in Northeast Hitchcock field, the 2,030 ft, 5,750 ft, and 6,150 ft. sands. Although these sands were considered as good alternates, they also contain various attributes that may limit their potential for brine-disposal. For example, the 2,030 ft sand (fig. 8) is attractive as a brine-disposal sand because it has a maximum thickness of 75 ft and is not deeply buried in Northeast Hitchcock field, but it has a complex internal geometry, consisting of several lenticular, laterally discontinuous distributary sands separated by delta-plain mud. The 5,750 ft sand (fig. 9) is a thick barrier-

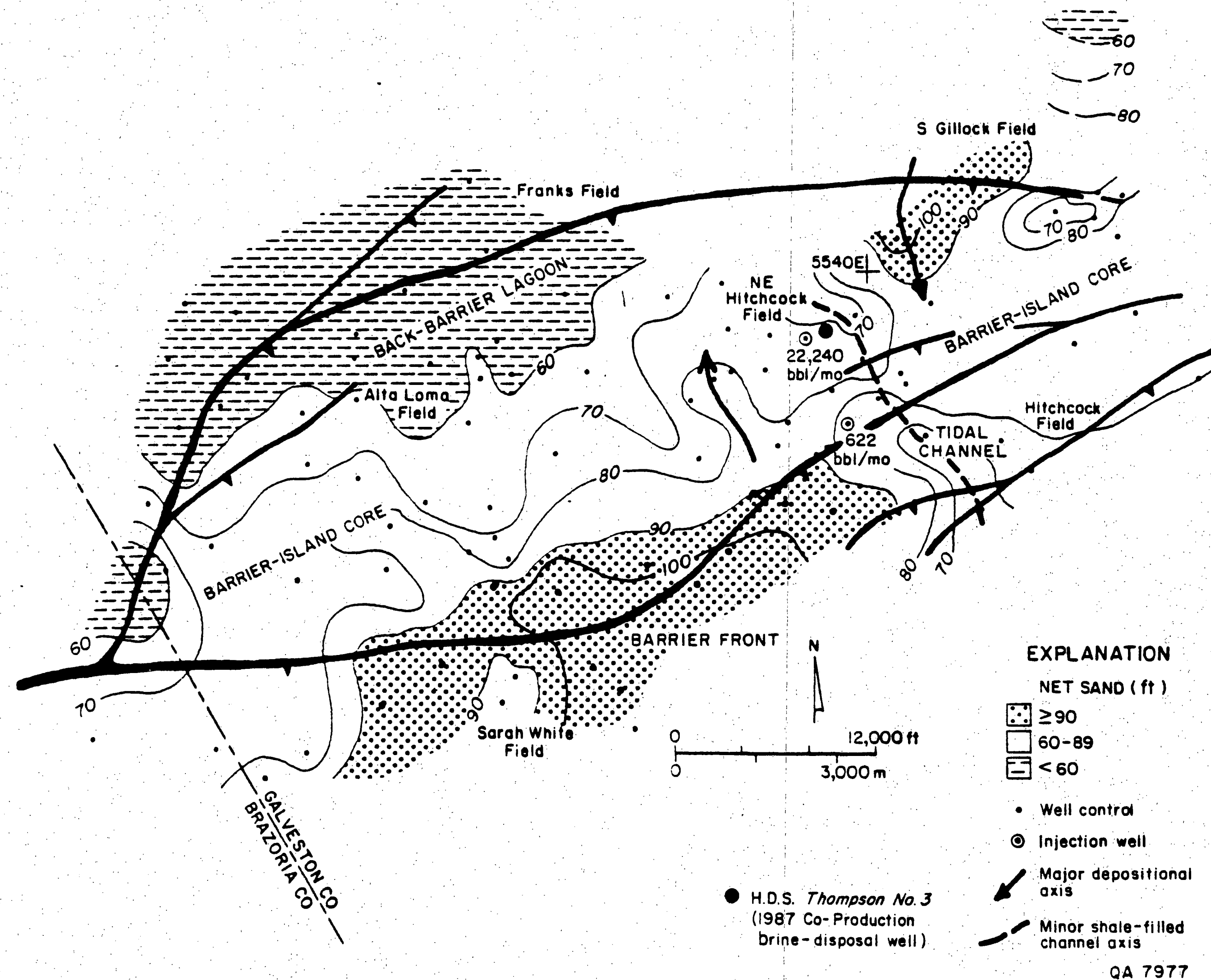

Figure 5. Net-sand and depositional facies map of the 3,780 ft sand (middle Miocene). This barrier island sheet sand contains large volumes of homogeneous barrier-core deposits, and is therefore an excellent choice for future up-hole brine disposal in Northeast Hitchcock field.

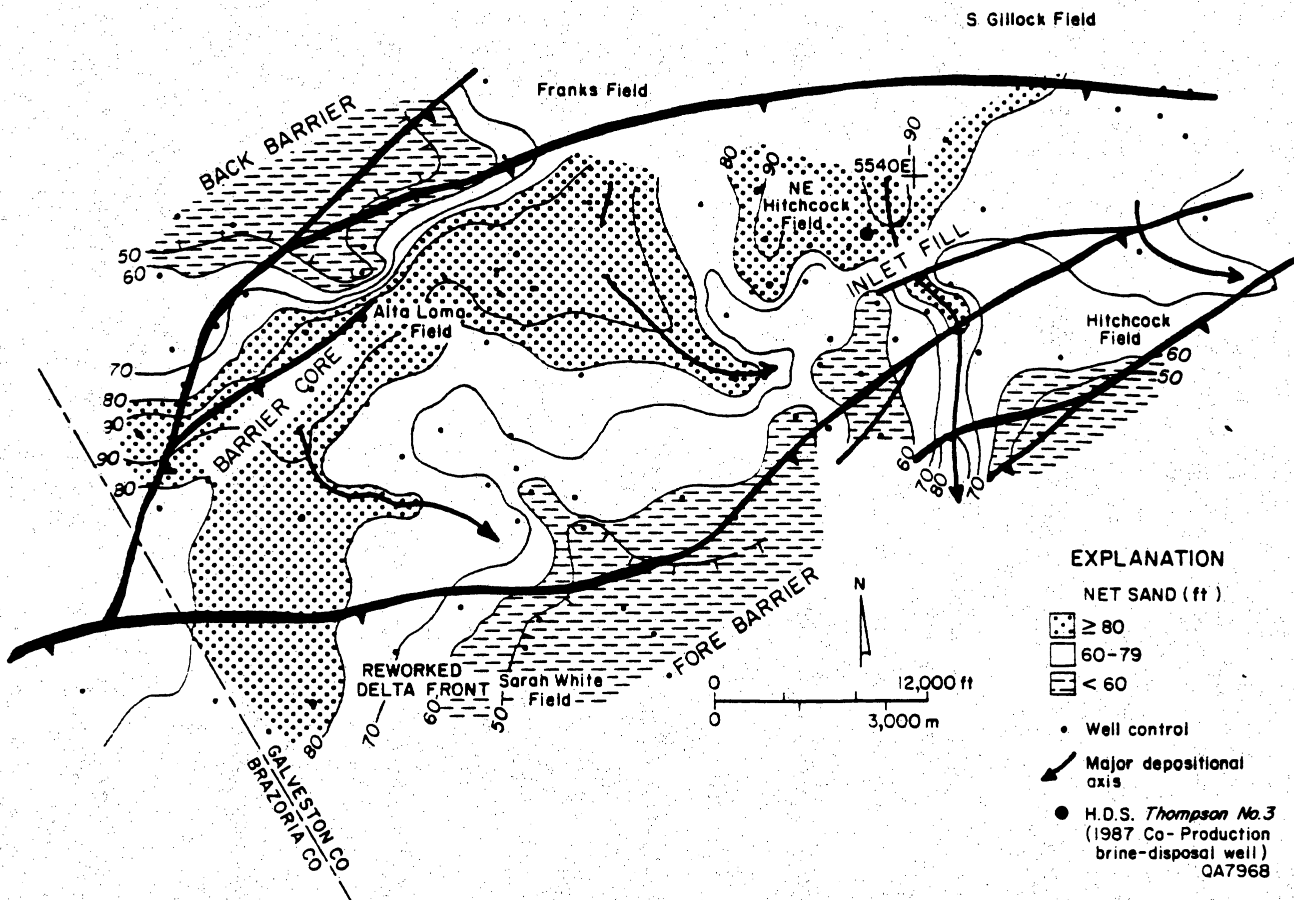

Figure 6. Net-sand and depositional facies map of the 4,240 ft sand (middle Miocene). This barrier island sand contains large volumes of tidal-inlet deposits that interrupt sand-body continuity along the axis of the barrier system. The presence of these tidal-inlet deposits reduce the net brine-disposal potential of the 4,240 ft sand.

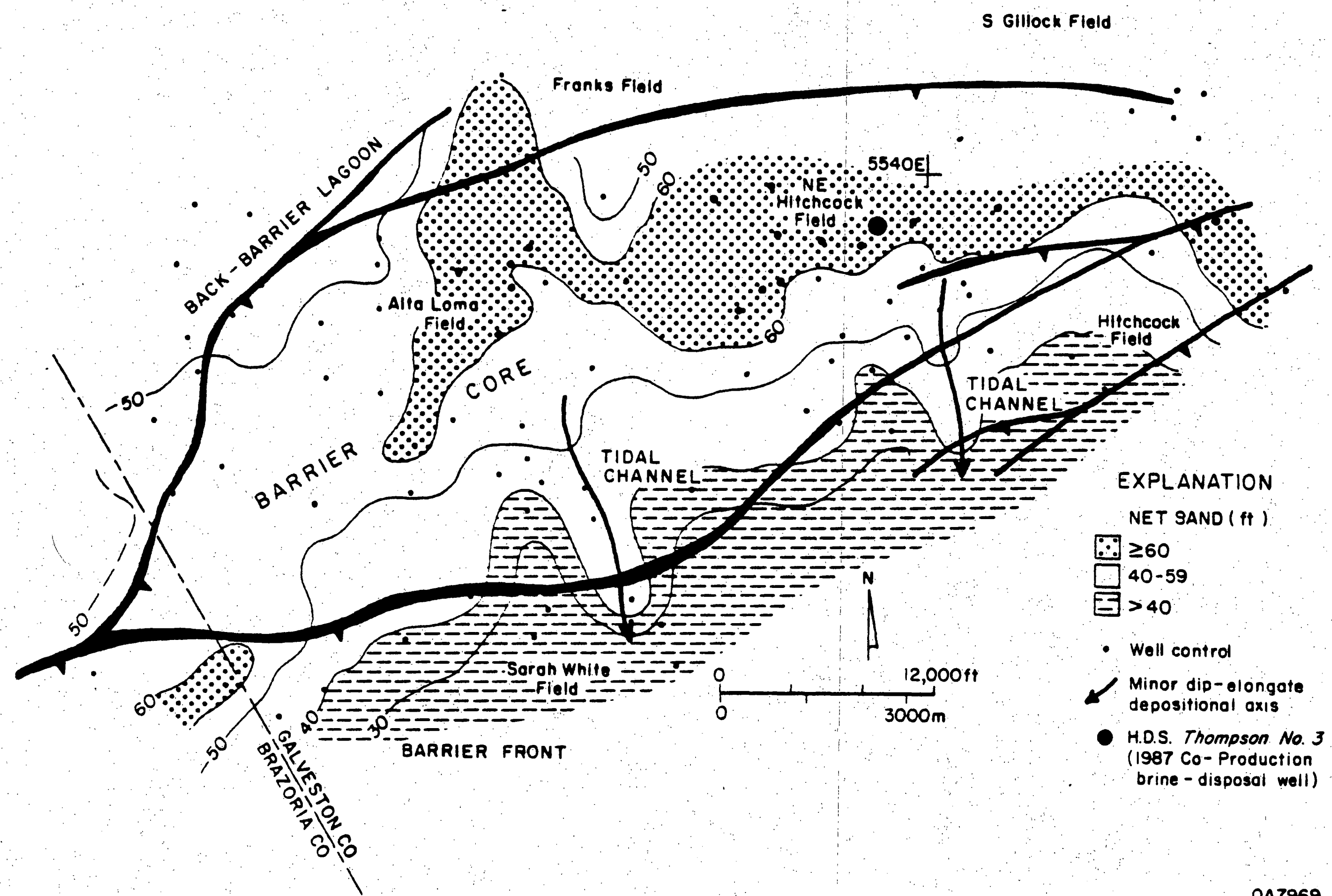

Figure 7. Net-sand and depositional facies map of the 5,460 ft sand (lower Miocene). This sand is very similar to the 3,780 ft sand (fig. 5), and is ideal for disposal of large volumes of brine. The 5,460 ft sand consists of a well-developed barrier core that is continuous throughout the field.

Table 2. Estimated pore volumes in Miocene sands
Northeast Hitchcock and Alta Loma fields

A. Primary brine-disposal sands

Sand	Pore volume (BBLS)	Limiting factors
3780 ft.	2,903,700,000	Virtually none; sheet sand, with minor heterogeneities due to tidal channels and washovers.
4240 ft.	3,071,000,000	Minor number of sand-poor areas separated by lobate distributary channel sand bodies.
5460 ft.	2,131,000,000	Virtually none; barrier island sheet sand.

Total pore volume, primary sands:

8,105,700,000 BBLS

B. Alternate brine-disposal sands

Sand	Pore volume (BBLS)	Limiting factors
2030 ft.	1,764,900,000	High number of reservoir heterogeneities, due to fluvial channel sands encased in floodplain muds.
5750 ft.	8,030,700,000	Contains numerous shale breaks and permeability barriers. Several genetic subunits in the 5750 ft sand result in a complex internal structure.
6150 ft.	1,979,500,000	Virtually none; barrier island sheet sand.

Total pore volume, alternate sands:

11,775,100,000 BBLS

Total pore volume, all sands:

19,880,800,000 BBLS

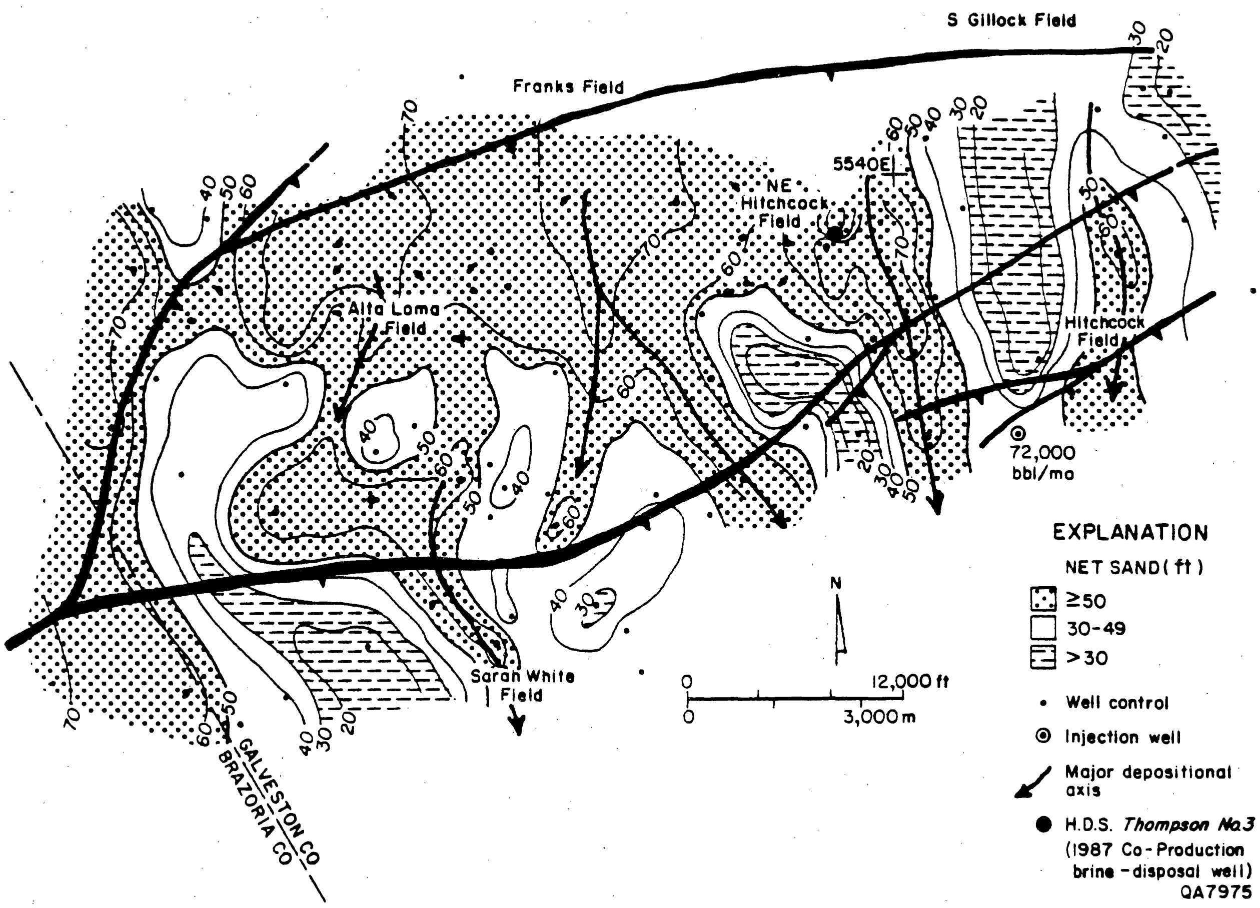

Figure 8. Net-sand map of the 2,030 ft sand (upper Miocene), which is included as an alternate choice for brine disposal because of its shallow depth of burial and the extensive development of 50 to 75 ft of sand in the area. However, several sand-poor areas exist in this depositional unit, because of the lenticular nature of distributary sand bodies in the southern part of the fault block.

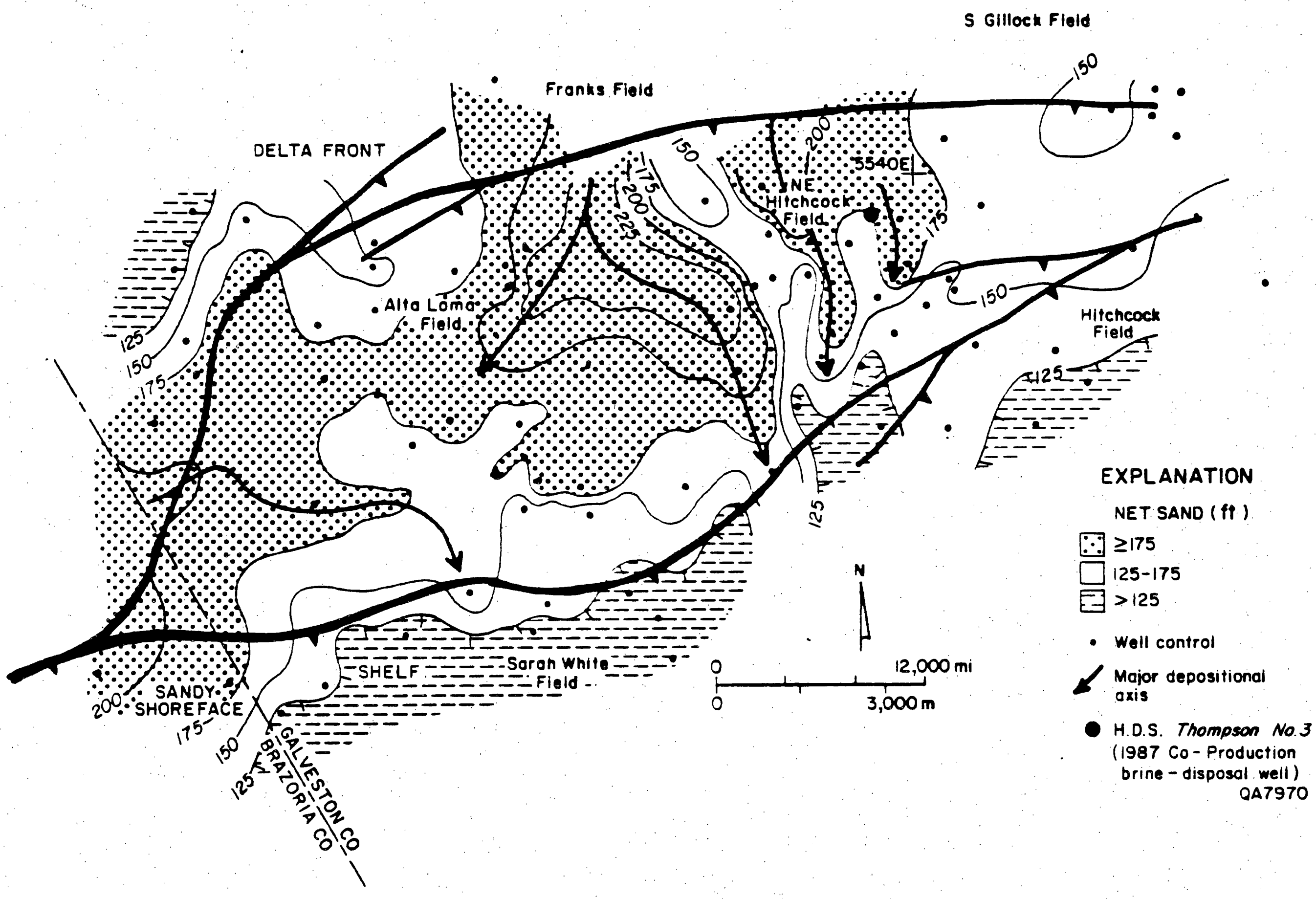

Figure 9. Net-sand and depositional facies map of the 5,750 ft sand (lower Miocene). This interval contains thick, permeable barrier island sands suitable for brine disposal. However, the 5,750 ft sand is a composite of several barrier-island depositional units, and contains numerous shale interbeds that may limit the net brine-disposal potential.

island sand that has a strike-parallel geometry similar to the 3,780 ft and 5,460 ft sands, but it also contains many interbedded mud layers because it is contains several individual barrier-island units. Some of these mud layers are 25 ft thick and may restrict the flow of injected fluids to small compartments within the net sand interval. The 6,150 ft sand (fig. 10) is a laterally continuous barrier-island sand as well, but is more deeply buried, and therefore requires a higher injection pressure for brine disposal than most other Miocene sands in the field.

RECENT WORK

Coring Program

The Bureau of Economic Geology proposed coring the three primary Miocene barrier-island sands (3,780 ft, 4,240 ft, and 5,460 ft) in a new brine-disposal well to be drilled in one of the sites in Northeast Hitchcock field recommended by Tyler and others (1987). Whole cores, 20 ft long, were to taken from each of these sands. The main objectives of obtaining cores were to provide representative samples of the middle and lower Miocene section, to refine previous interpretations of environments of deposition presented in Tyler and others (1987), and to provide additional data on the brine-disposal potential of these sands. Other important reasons for taking the cores included petrologic and diagenetic studies related to fluid sensitivity, determination of basic rock properties such as porosity and permeability, investigation of formation water and rock compatibility and potential problems in migration of fines. Approximately 60 sidewall cores were taken throughout the entire Miocene interval (6,350 ft to 2,000 ft) in Northeast Hitchcock field to provide porosity and permeability data from other sands that were not cored.

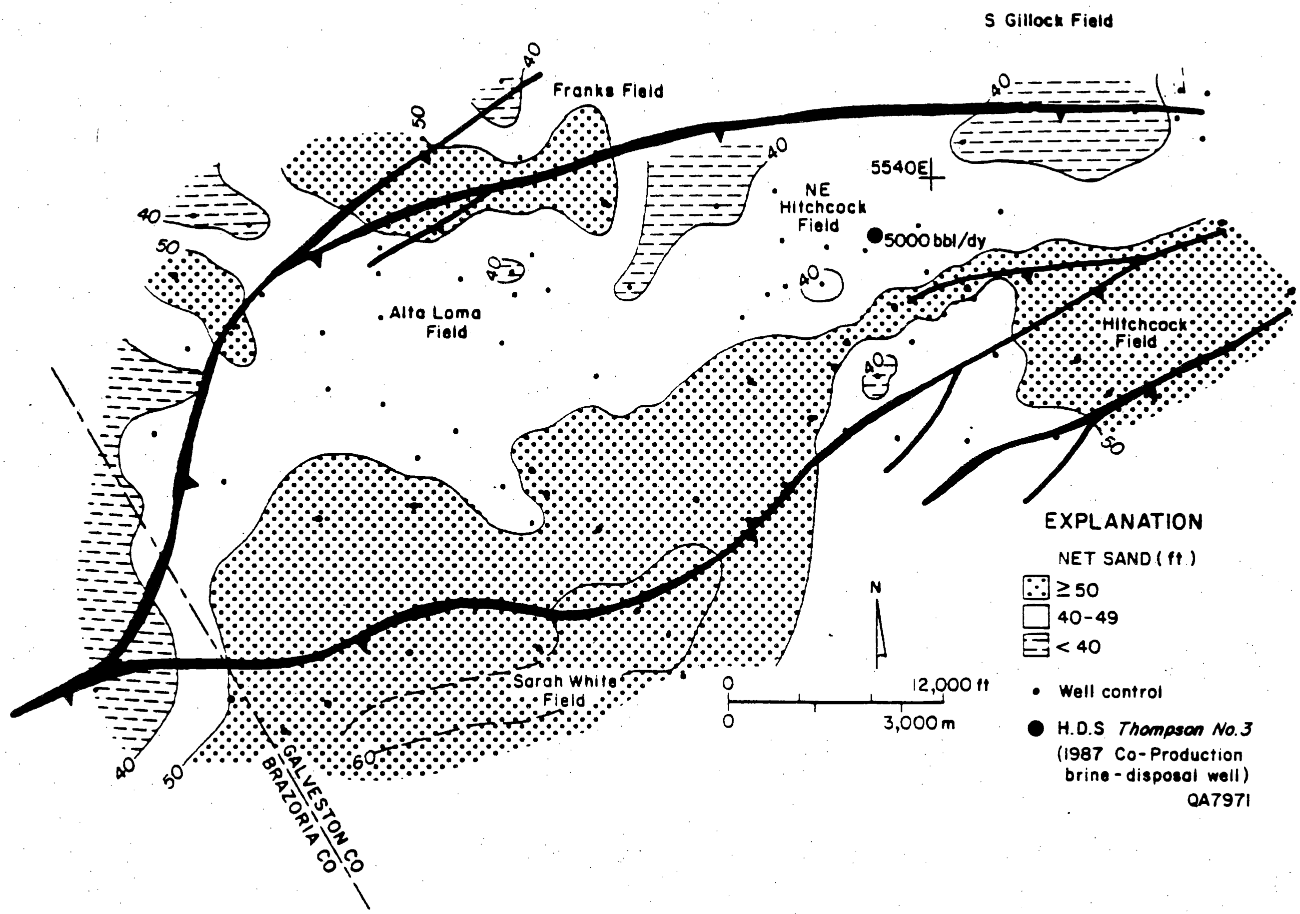

Figure 10. Net-sand map of the 6,150 ft sand (lower Miocene), which has received more than 5,000 barrels of brine per day from October, 1987 to August, 1988. Good sand continuity in barrier-core deposits in the 6,150 ft sand is developed throughout the Northeast Hitchcock-Alta Loma fault block.

Brine-Disposal Well

In August, 1987 a co-production brine-disposal well (H. D. S. Thompson #3; well 26A on fig. 2) was drilled to a total depth of 6,350 ft in the lower Miocene in Northeast Hitchcock field. The objectives in drilling this well were to contact the three primary brine-disposal sands (3,780 ft, 4,240 ft, and 5,460 ft) in one of the recommended sites, to obtain whole and sidewall core samples from these sands, to provide a geological and engineering description of the cores, to run a variety of electrical logs for evaluation of the formation, and finally to select the best sand for initial brine-disposal in the well, based on a review of all available data obtained from cores and electrical logs from the well. Although the coring apparatus failed to retrieve any part of the 3,780 ft sand, approximately 17 ft of the 4,240 ft sand and 20 ft of the 5,460 ft sand were recovered. The 6,150 ft sand was cored as an alternate to the 3,780 ft sand.

Results of Core Analysis

Three major barrier-island facies (barrier core, tidal inlet, and lower shoreface) are recognized in the cores of lower and middle Miocene sands in the H. D. S. Thompson #3 well. Detailed geologic description and analyses of basic rock properties such as mineralogy, texture, permeability and porosity of sediments in these cores, combined with interpretation of net-sand and log-facies maps, facilitated the characterization of the brine-disposal potential of each of these barrier-island facies, leading to the early selection of the 6,150 ft sand for brine disposal. Initial results have fulfilled expectations for disposal of large volumes of Frio brines; the 6,150 ft sand, which contains homogeneous, high-permeability lower shoreface and barrier-core sands, has already received approximately 5,000 Bbl of brine per day since October, 1987.

Lower Miocene barrier islands in the Texas Gulf Coast were deposited on a coastline with relatively high wave energy and low tidal range (Galloway and others, 1986). Barrier islands deposited on wave-dominated coastlines have elongate, linear barrier axes that are separated by tidal inlets at widely spaced intervals; facies typically consist of a wedge- or tabular-shaped barrier core and upper shoreface, wedge-shaped lower shoreface, lenticular, crosscutting tidal inlets, lobate flood-tidal deltas and washover fans in the back-barrier environment, and small, lobate ebb-tidal deltas in the fore-barrier environment (fig. 11). Barrier-island sand bodies are typically tabular, consisting of sheetlike wedges developed in bands parallel to the shoreline. They are internally homogeneous and can contain large reservoir or aquifer volumes, compared to other clastic depositional systems.

Barrier-core facies represent the massive, strike-elongate framework of the barrier island and are a composite of well-sorted beach, upper shoreface, and dune sands (fig. 11). The barrier core is one of the most homogeneous components of barrier-island systems because internal stratification and variations in grain size are poorly developed. Together with associated shoreface facies, the barrier core contains large volumes of clean, well-sorted sand with few discontinuous mud layers, and therefore has an excellent brine-disposal potential.

The lower shoreface represents the seaward margin of the barrier core, and extends seaward from the outermost bar to the break in slope between the shoreface toe and the flat shelf (McCubbin, 1982). Lower shoreface deposits are muddier and more heterogeneous than barrier-core deposits because they accumulate in a lower-energy setting offshore. They are typically upward-coarsening, grading upward from interbedded inner-shelf silt and mud to crossbedded and planar bedded fore-barrier sands. The geometry of the lower shoreface facies is strike-parallel, similar to that of the barrier-core facies (fig. 11).

Tidal inlets are deep, narrow channels that cut across barrier islands, acting as conduits through which sediments are transported back and forth from inner-shelf to back-barrier environments. Wave-dominated tidal inlets migrate laterally along the shoreline for many miles in the direction of longshore drift, eroding into previously deposited facies (Moslow and Tye, 1985). Inlet-fill facies typically consist of erosionally bounded deposits that accumulate on the updrift margin of the inlet (fig. 11). They tend to be internally heterogeneous, characterized by a basal lag

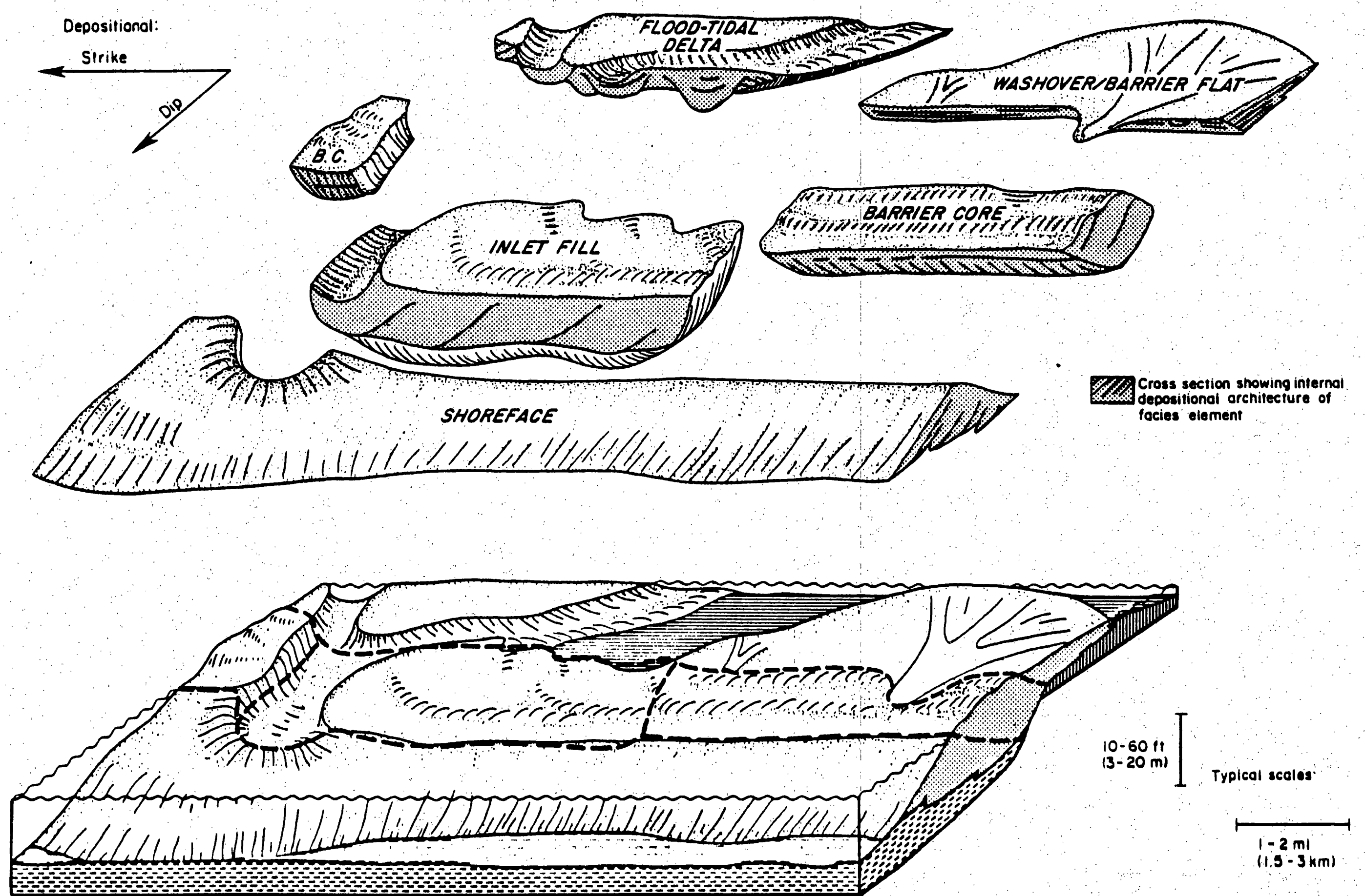

Figure 11. Facies architecture of microtidal barrier islands. Lateral continuity of homogeneous barrier core and barrier shoreface facies is commonly disrupted by dip-parallel, heterogeneous tidal inlet facies. Flood-tidal delta and washover fan facies form other intrareservoir compartments that pinch out landward into muddy lagoonal sediments. From Galloway and Cheng (1985).

consisting of shell debris and an upward-fining texture that represents channel infilling and abandonment. Inlet-fill sequences are commonly capped by upward-coarsening sediments deposited by lateral accretion of spit platforms and barriers that accrete laterally over the abandoned inlet-fill (Heron and others, 1984).

Barrier-core facies in the 5,460 ft sand (fig. 12) and upper 10.5 ft of the 6,150 ft sand (fig. 13) have the greatest potential for brine-disposal of all other facies in cores of the H. D. S. Thompson #3 well. Barrier-core facies in these cores are composed of clean, upward-coarsening sand; grain sorting and roundness increases upward, shell fragments and mud layers are uncommon, and no calcite-cemented zones are observed. Analysis of the H. D. S. Thompson #3 cores indicates that the barrier-core facies contains less clay than either the tidal-inlet or lower shoreface facies, and that sands in this facies have the best sorting and texture index and the highest permeability to Frio Formation water (Table 3).

In contrast to the barrier-core facies in the 5,460 ft sand, the tidal-inlet facies in the 4,240 ft sand and in the lower 6 ft of the 6,150 ft sand (fig. 14) is a less favorable choice for brine disposal because it is moderately to poorly sorted, containing mud interbeds and thin, tightly calcite-cemented zones that serve as permeability barriers. In the 4,240 ft sand, the tidal-inlet facies is about 9 ft thick (fig. 14). The lower 5 ft contains several irregular, erosional surfaces characterized by a medium- and coarse-grained lag of abraded shells. Thin (2 to 4 in) zones of calcite cement, caused by dissolution of shell material are most common in the lower inlet-fill section. These cemented zones result in a reduction of the net brine-disposal potential of the sand by reducing the net Kh (permeability multiplied times thickness) of the sand and by acting as barriers to fluid flow. Grain sorting in the tidal-inlet facies is worse than either the barrier-core or lower shoreface facies, although median grain size is greater than in the lower shoreface (Table 3).

Lower shoreface facies are observed in the lower 6.5 ft of the 4,240 ft sand and from a 4 ft thick interval in the 6,150 ft sand from 6,136 ft to 6,140 ft. This facies consists of sparsely burrowed, very fine-grained sand and thin bands of interbedded silt. Although the lower shoreface

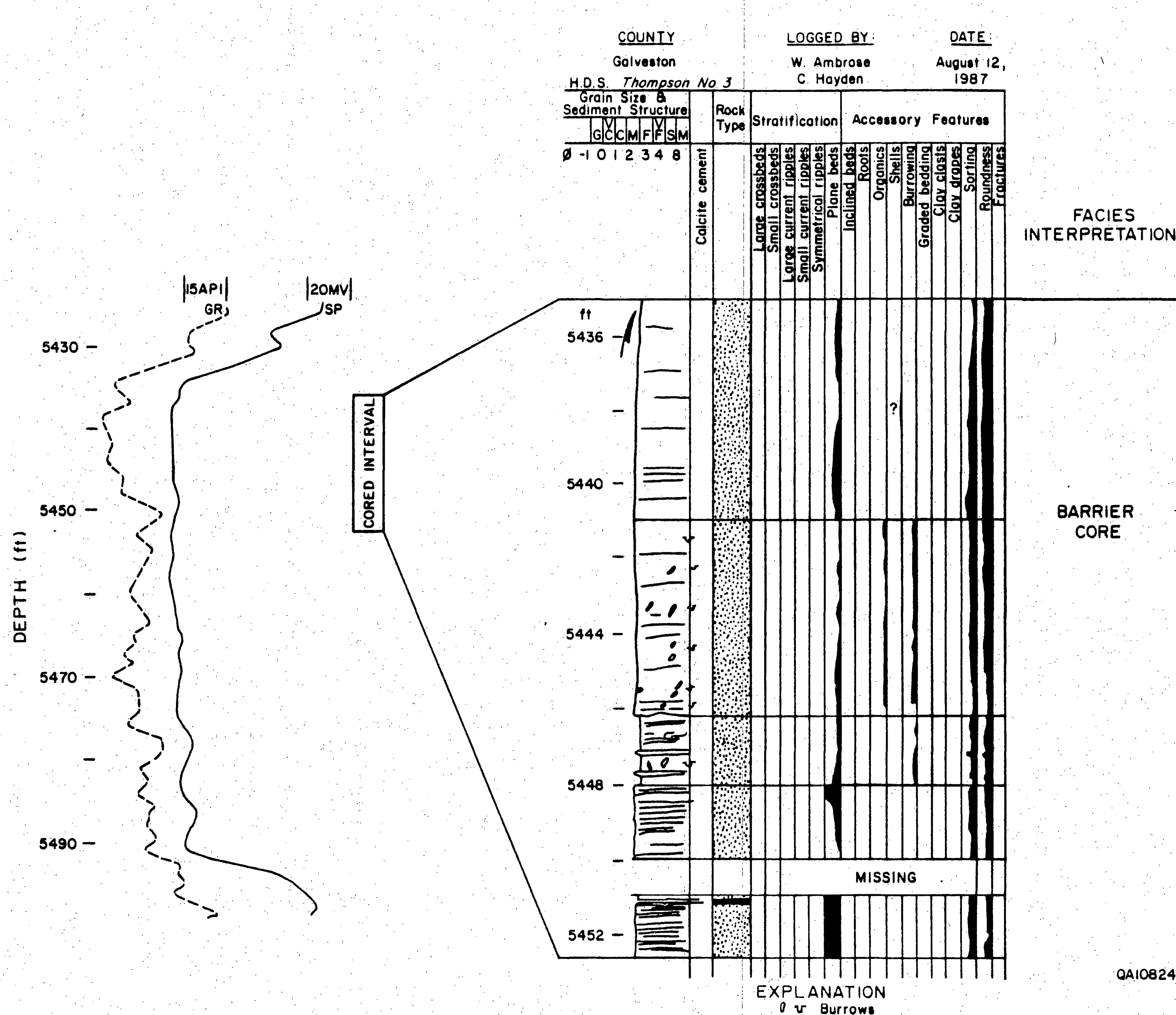

Figure 12. Core description and log response of the 5,460 ft sand (lower Miocene) from the H. D. S. Thompson #3 brine-disposal well in Northeast Hitchcock field.

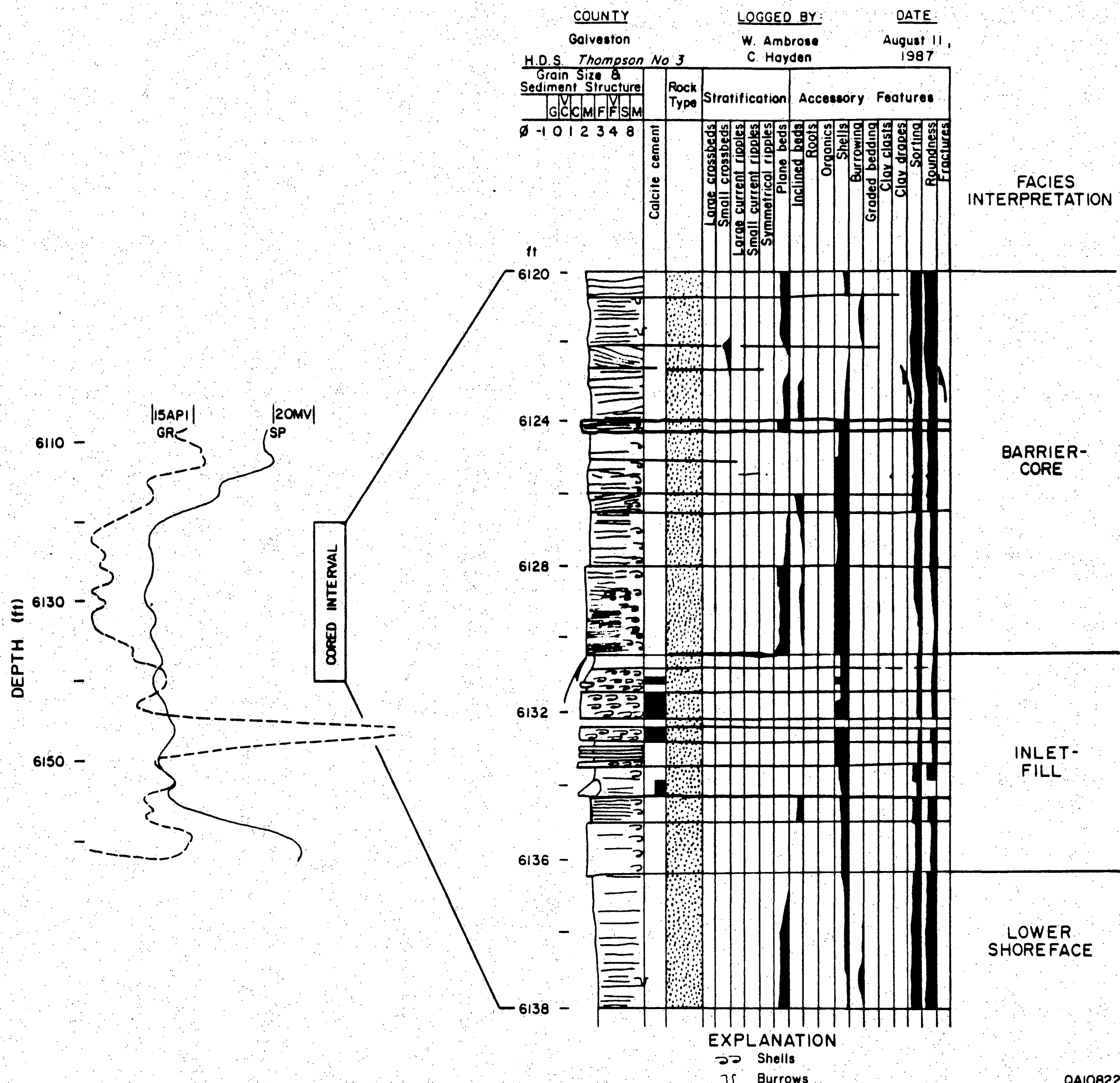

Figure 13. Core description and log response of the 6,150 ft sand (lower Miocene) from the H. D. S. Thompson #3 brine-disposal well in Northeast Hitchcock field.

Table 3. Reservoir properties of Miocene barrier - island sands cored in the H.D.S. Thompson No. 3 brine - disposal well

	Facies		
	BARRIER CORE	TIDAL INLET	LOWER SHOREFACE
SAND BODY AND INTERVAL	5,460 FT (5435-5452.5) 6,150 FT (6120-6130)	4,240 FT (4240-4253) 6,150 FT (6130-6136)	4,240 FT (4253-4259.5) 6,150 FT (6136-6140)
MINERALOGY			
% QUARTZ	75	74	59
% FELDSPAR	19	10	25
% CALCITE	0	3	3
% CLAY	5	12	12
% OTHER	1: Fe-DOLOMITE	1: PYRITE	1: PYRITE OR Fe-DOLOMITE
MEDIAN GRAIN SIZE (PHI)	2.73	2.92	3.19
STANDARD DEVIATION IN GRAIN SIZE (PHI)	0.97	1.05	1.04
PERMEABILITY TO FRIO WATER (MD)	2,570	NONE REPORTED	1,890
POROSITY (PERCENT)	32	NONE REPORTED	35
TEXTURE INDEX	29	48	NONE REPORTED

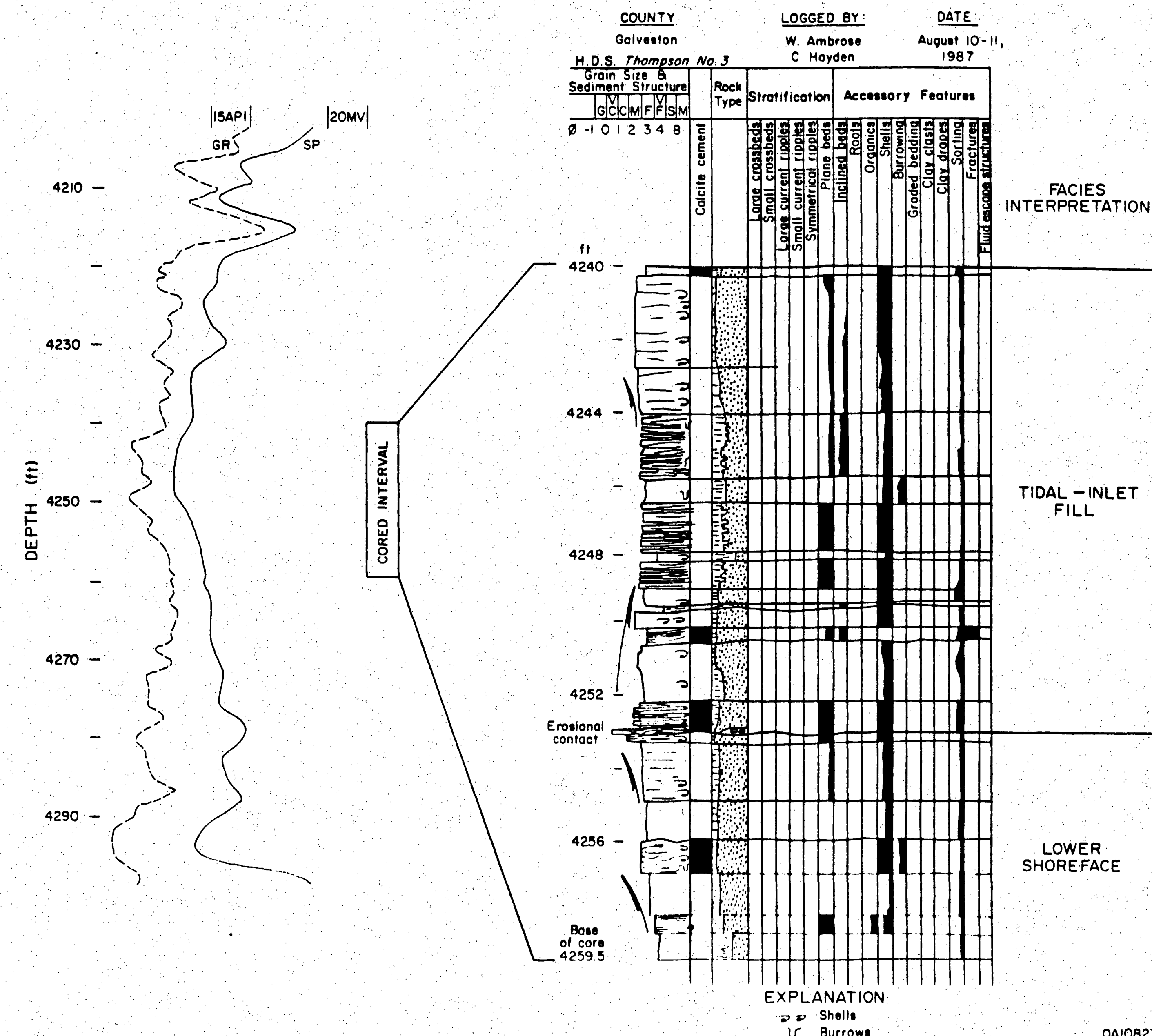

Figure 14. Core description and log response of the 4,240 ft sand (middle Miocene) from the H. D. S. Thompson #3 brine-disposal well in Northeast Hitchcock field.

has lower permeability to Frio Formation water than does the barrier-core facies (1,890 md versus 2,570 md), permeability in this facies is still acceptable for brine disposal.

Brine Disposal in the 6,150 Ft Sand

In mid-October, 1987 Frio brines were injected into the 6,150 ft sand in the H. D. S. Thompson #3 well (#26A, fig. 2). This sand was selected for initial brine disposal on the basis of its blanket geometry and excellent average brine permeability of 2,500 md. Other sands that were selected for later up-hole brine disposal in the H. D. S. Thompson #3 well were the 5,750 ft, 5,460 ft and 3,780 ft sands, all of which are thick, laterally continuous, and extremely permeable barrier-island sands.

The 6,150 ft sand has received 1,251,343 barrels of brine from mid-October, 1987 to August 1, 1988 in a 30 ft thick interval that has a Kh of 40 darcy-ft. Although the 6,150 ft sand has received 7,500 barrels of brine per day over periods of several consecutive weeks, this sand has instead throughout its entire brine-disposal history an average of only 5,000 barrels of brine per day because of the high cost of electricity ($64 per day) associated with the amount of energy involved in pumping the brines into the formation to depths of 6,150 ft, where the required injection pressure is 364 p.s.i.a. In order to offset these expenses, the Gas Research Institute received approval from the Railroad Commission of Texas to also dispose of co-production brines into shallow upper Miocene fluvio-deltaic sands at 2,224 ft in a new disposal well (S.G.R. Prets #2; fig. 2) and to re-enter an older well (Phillips Thompson #2, also known as Phillips Delaney #1; well #21, fig. 2) in Northeast Hitchcock field, where brines were injected into lower Pliocene sands at 1,720 ft. Power costs for these sands are lower because of the shallow depths involved. For example, the electricity costs for disposal in the 2,224 ft sand are only $32 per day. However, these sands have a lower injectivity index (108 for the 2,224 sand and 53 for the 1,720 ft sand) than the 6,150 ft sand, which has an injectivity index of 125. The injectivity index is defined as the number of barrels injected per day, divided by the injection pressure, in p.s.i.a. Additionally, the 6,150 ft sand has a much higher Kh product (40 darcy-ft) than does the 1,720 ft sand (10 darcy-ft) over a comparably thick injection interval.

FURTHER RECOMMENDATIONS

Several important factors such as depth, sand-body geometry, and total pore volume available for injection must be considered in selecting effective but economic brine-disposal sands. The best sand for future up-hole disposal in the H. D. S. Thompson #3 well is the middle Miocene 3,780 ft sand, a laterally continuous barrier-island sand that has an average thickness of 70 ft, in contrast with the shallow but heterogeneous upper Miocene 2,224 ft sand, which has an average thickness of only 25 ft in Northeast Hitchcock field. Power costs for brine-disposal pumps in the 3,780 ft sand should be only about $45 per day instead of $64 per day in the 6,150 ft sand, which is currently receiving brines in the H. D. S. Thompson #3 well. Additionally, the 3,780 ft sand has over 3 billion barrels of pore volume available for brine disposal in the Northeast Hitchcock-Alta Loma fault block, approximately 3 times as much in the 2,224 ft sand, which has a heterogeneous sand-body geometry similar to the 2,030 ft sand (fig. 8). Finally, the 3,780 ft sand is deeper below the base of the fresh water aquifer than either the 2,224 ft or 1,720 ft sands in Northeast Hitchcock field and therefore presents less risk of fresh-water contamination.

CONCLUSIONS

Core analysis and brine-disposal histories of lower and middle Miocene sands confirm previous conclusions by Tyler and others (1987) that barrier-island sands are capable of receiving large volumes of brines co-produced from the Frio 1-A reservoir in Northeast Hitchcock field. These sands are ideal, from a geological perspective, for brine disposal because they have high permeabilities in excess of 2,000 md, are internally homogeneous, and have a great lateral extent in the field, resulting in large amounts of pore volumes available for brine disposal without much pressure buildup.

Certain barrier island sands in Northeast Hitchcock field, such as the 4,240 ft sand, contain large volumes of heterogeneous, poorly sorted tidal-inlet facies. This facies also contains minor amounts of tightly calcite-cemented zones as a consequence of post-depositional dissolution of shells at the base of the tidal inlet. The net brine-disposal potential of the 4,240 ft sand should be lower than other barrier island sands such as the 5,460 ft and 6,150 ft, which are dominantly composed of homogenous, well sorted barrier-core facies. This facies has less clay and calcite cement than the tidal inlet facies, based on study of cores obtained from the H. D. S. Thompson #3 brine-disposal well.

The middle Miocene 3,780 ft sand is recommended over the 4,240 ft sand for future up-hole brine disposal in the H. D. S. Thompson #3 well, because it best satisfies geological and economic criteria for brine disposal in other Miocene sands above the 6,150 ft sand, which is currently receiving brines. Certain of the most laterally continuous upper Miocene fluvial and deltaic sands are reasonable choices for future up-hole brine disposal in the H. D. S. Thompson #3 well, because these sands can accept brines at lower costs, as they are not as deeply buried. However, these sands have a lower net brine-disposal capacity than middle and lower Miocene barrier-island sands because they are discontinuous and have a complex sand-body architecture. Future selection of brine-disposal sands in Northeast Hitchcock field and in other areas must be made by considering several important factors that include brine-disposal history of the area as well as sand-body complexity, thickness, and depth of burial.

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SECONDARY GAS RECOVERY: CASE STUDIES IN SEELIGSON FIELD, JIM WELLS COUNTY, TEXAS

by Lee A. Jirik

INTRODUCTION

Unrecovered gas in a mature hydrocarbon province can be a cost-effective source of reserve additions when compared with new field exploration because exploration costs currently account for about 60 percent of the cost to find and develop a new gas field. Reserve additions from known fields benefit from investments already made in reservoir development and production infrastructure. Extension of new recovery techniques to gas in known fields involves reserve additions from untapped compartments within established reservoirs and recompletion of bypassed reservoirs through evaluation of cased-hole logging techniques. This study presents case histories documenting geological methodologies applied to maximizing the recovery of gas from conventional reservoirs in a mature field.

Seeligson field is located in the highly prolific Frio fluvial/deltaic hydrocarbon play along the margin of the Vicksburg Fault Zone in South Texas (Kosters and others, in preparation). Characteristic of the fields in this play, Seeligson field contains multiple, vertically stacked reservoirs with hydrocarbons trapped primarily in rollover anticlines downdip of the major Vicksburg growth fault. The highly complex depositional architecture of these reservoirs increases the probability that gas is contained in numerous undrained compartments. Additionally, bypassed gas, or gas-bearing zones that have not been identified as gas productive, may be encountered within or uphole from a producing interval. Detailed geological analyses of selected reservoirs within Seeligson field demonstrate how advanced characterization of reservoir geometries and depositional environments can be effectively used to identify unrecovered gas zones and select potential recompletion prospects.

Objectives

The overall objective of the study was to establish a cooperative research and development program with industry in order to develop, test, and verify methodologies and technologies with near-to mid term potential for maximizing recovery of cost competitive gas from conventional reservoirs. Specific objectives for this study include:

(1) Identify a suitable field available for study. Field selection would be the result of a screening process that would involve numerous geologic and engineering factors.

(2) Develop a cooperative relationship with the operator of the selected field. This relationship would be crucial in the areas of data acquisition, information transfer, and development of recompletion strategies.

(3) Establish a data base from which intensive geological analyses may be built; define stratigraphic and structural framework of the field; and select specific reservoirs to be targeted for detailed analysis.

(4) Using results of the cased-hole evaluation program performed by ResTech, Inc., identify potential untapped compartments and bypassed gas zones.

(5) Apply advanced characterization methods to reservoirs with favorable log analysis results in order to delineate geologically-based recompletion strategies.

(6) Present recompletion recommendations to operator.

Study Area and Data Base

Texas Railroad Commission (TRC) District 4, in South Texas, is the leading non-associated gas producing district in Texas, with production from Tertiary Wilcox, Vicksburg, and Frio Formations. South Texas fields often contain multiple, stacked, heterogeneous fluvial to fluvial-deltaic reservoirs that trap hydrocarbons along regional growth fault trends. More than 200 gas fields located in District 4 were evaluated as potential study areas for the Secondary Gas Recovery project.

Data from TRC and other commercial sources were compiled to determine field location and size, reservoir age, and cumulative production. Seeligson field was selected as the study area because of its geologic setting, stratigraphic and structural framework, production history, availability of data, and the willingness of unit operator Sun Exploration and Production Company to participate in the cooperative program.

Seeligson field is located in Jim Wells and Kleberg counties, along the margin of the extensive Vicksburg fault zone (fig. 1). The field is bounded updip by a large northeast-southwest trending growth fault that offsets Frio sands several hundred feet. The eastern, downdip boundary of the field is defined primarily by the limits of production as no significant bounding faults segment the field into a well-defined block. Within the field, subsidiary highs occur on the primary rollover anticline that defines the structural configuration of the field (fig. 2). Seeligson field covers approximately 50 mi^2. This study focuses on unitized Frio reservoirs within a 9 mi^2 area in the central part of the field (fig. 2).

The data base consists of more than 330 well logs distributed throughout the field; approximately 250 are located within the study area. A base map was prepared using current, unitized well numbers (fig. 3); well names and numbering systems used prior to unitization are not included in this report. Additional data used in the study included modern log suites for several wells within the area, for example, sonic, neutron/density, and thermal decay time (TDT) logs and repeat formation testers (RFT), mineralogic analyses, whole core, and core analysis reports. Well history summaries for more than 100 wells in the study area provided crucial completion and production information. Bottom-hole pressure data were acquired for wells producing from Zone 15. Sun Exploration and Production Company provided most of the well log, well history, and pressure data used in this study. BEG and ResTech, Inc. proposed and completed a data collection program in the Sun P. Canales No. 141 well, drilled in November, 1987, which included the acquisition of 36 ft of whole core, an open-hole sonic log (BHC), repeat formation tester (RFT) data in several sandstones, sidewall cores in sandstones and shales throughout the unit, and a full-waveform cased-hole sonic log.

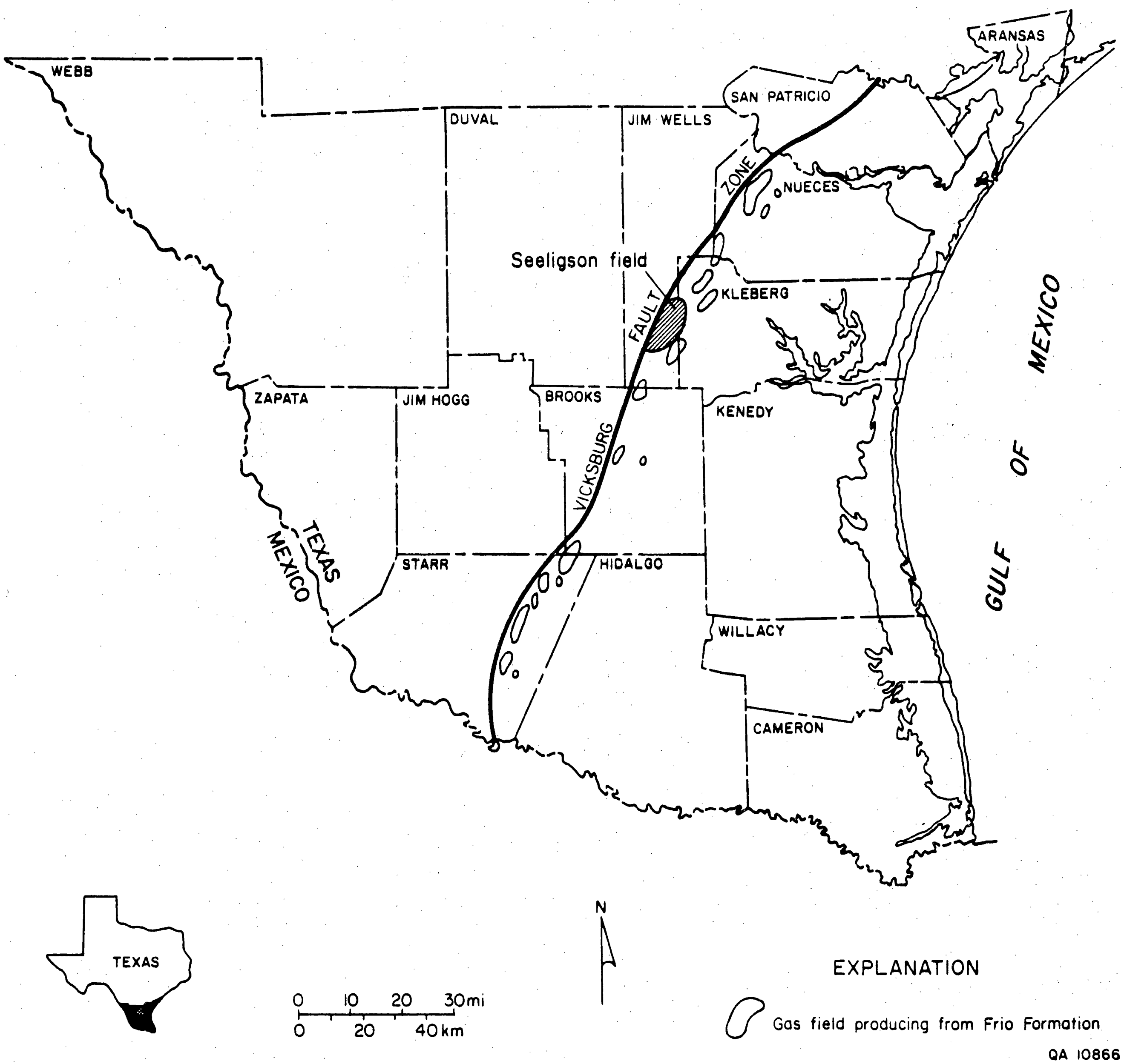

Figure 1. Location of Seeligson field, Jim Wells and Kleberg Counties, Texas. Seeligson field is located along the margin of the Vicksburg fault zone in a highly prolific Frio hydrocarbon play.

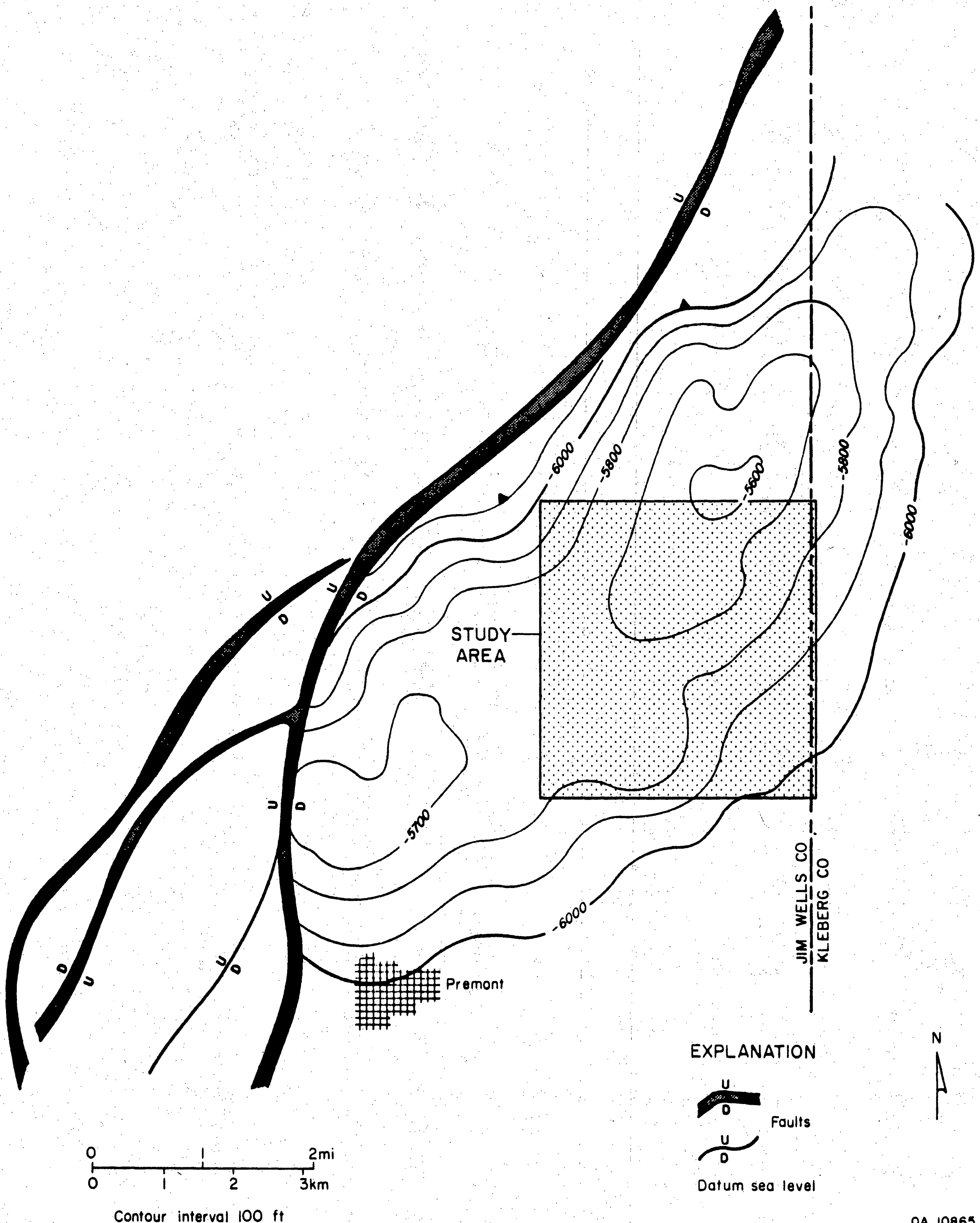

Figure 2. Structure map of Seeligson field, contoured on the Textularia mississippiensis (lower Frio) zone. The principal growth fault, with throws from 300 to 1,700 ft, forms the western boundary of the field. This study focused primarily on a 9 mi² area in the east-central part of the field. Modified from Geomap, Inc. (1988).

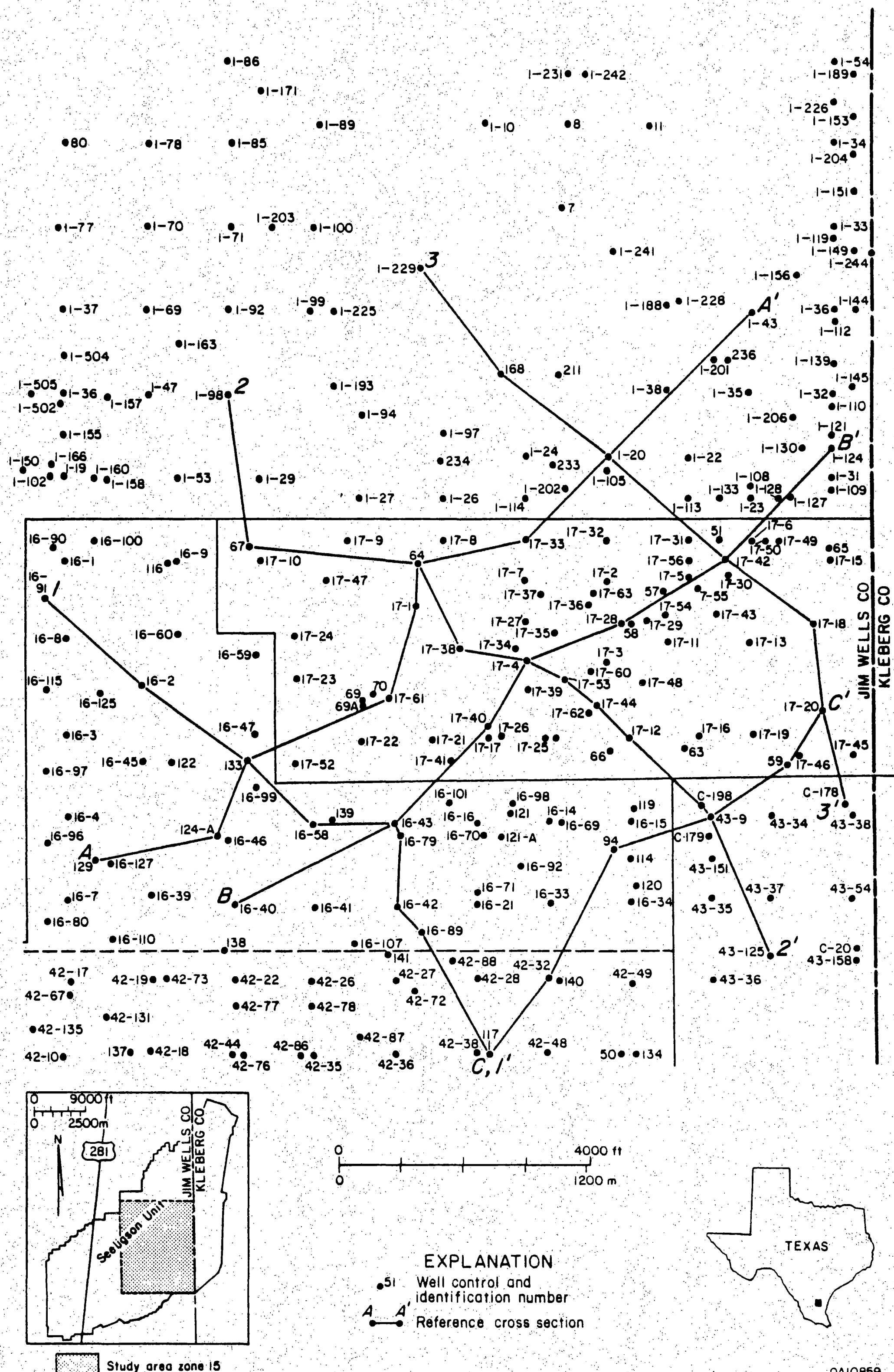

Figure 3. Base map of study area within Seeligson field showing well control, identifying well numbers, and grid of reference cross sections.

Methods

A grid of six structural cross sections (three strike-oriented and three dip-oriented) was constructed across the study area to illustrate the lateral extent, thickness, and variability of sandstone reservoirs within the unit (fig. 3). More than thirty reservoirs are productive from the unit in the study area. Aggregate zones display varying degrees of heterogeneity; over twenty zones are illustrated on schematic strike cross section A-A' (fig. 4). Net-sandstone-isopach and depositional-facies maps based on SP log pattern were constructed for 30 sandstones in the unit. Net-sandstone thickness was determined from electric logs using a cutoff line drawn approximately one-third of the distance from the SP baseline to the maximum SP deflection for sandstones within the unit. Depositional-facies maps were based on characteristic SP patterns that were interpreted in conjunction with net sandstone maps. This method of mapping has been effectively used in previous studies of the Frio along the Texas Gulf Coast (Galloway and Cheng, 1985; Tyler and Ambrose, 1985; Ambrose and Jackson, 1988).

Two sandstone zones were chosen for intensive study. Initial consideration was given to reservoirs showing the greatest lateral variability, although final selection involved consideration of numerous factors, including log analysis results, production histories, and bottom-hole pressure characteristics. Several detailed stratigraphic cross sections and net-sandstone isopach and SP-log-facies maps were prepared in order to illustrate lateral relationships, sandstone distribution, and facies variations of the specific zones of interest.

Well completion and production data were compiled from summaries provided by Sun Exploration and Production Company and from information available at the Texas Railroad Commission and integrated into the study.

Whole core from the Sun P. Canales No. 141 well was described visually. Petrographic analyses were performed on seven thin sections taken from core plug trim tips. Thirty-four thin sections were prepared and analyzed from sidewall core taken in the well. Several samples of whole

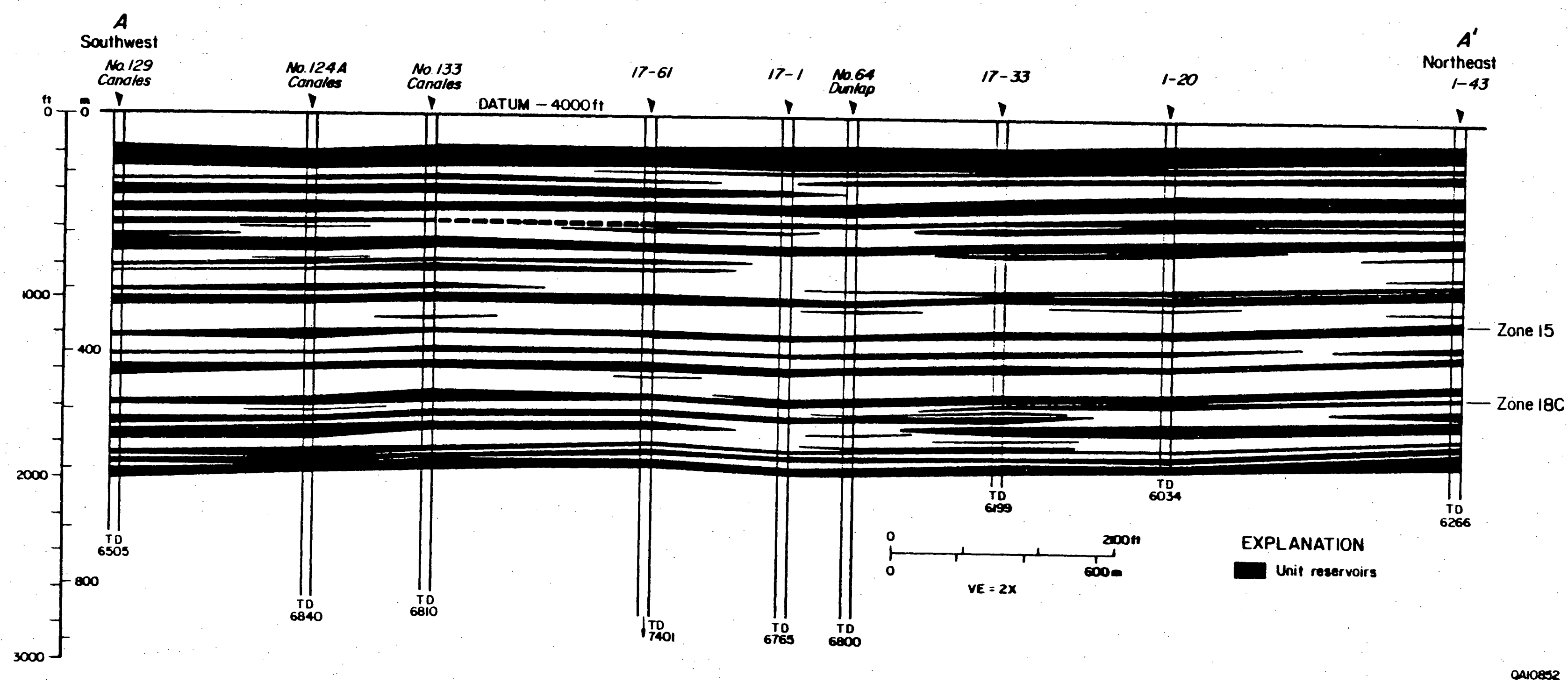

Figure 4. Schematic structural strike-section A-A' through east-central part of Seeligson field (see fig. 3 for location). Multiple, vertically-stacked, multilateral reservoirs are characteristic of the field. Zones 15 and 18-C were studied in detail.

core were analyzed on the scanning electron microscope (SEM). ResTech, Inc. incorporated the mineralogic data into their petrophysical evaluation of Seeligson wells (Howard and Bolin, 1988).

FRIO DEPOSITIONAL SYSTEMS IN THE TEXAS GULF COAST

The Oligocene Frio Formation is one of the principal progradational wedges of the Gulf Coast Basin. Frio sediments were deposited along the northern margin of the basin, an extracratonic basin characterized by rapid subsidence in areas of sediment loading. Thickness of Frio sediments accumulated to greater than 10,000 ft where the continental shelf built basinward beyond the underlying Mesozoic shelf margin. Galloway and others (1982) divided the Frio into separate but related depositional systems primarily on the basis of sandstone-isolith and facies maps. Major progradational depocenters were designated the Houston and Norias delta systems, located in the Houston and Rio Grande embayments, respectively. These delta systems were fed by the Chita-Corrigan Fluvial system (Houston delta) and the Gueydan Fluvial system (Norias delta). Separating the two major fluvial-deltaic complexes is the Choke Canyon/Flatonia coastal lake/streamplain system and the Greta/Carancahua barrier/strandplain system (Galloway and others, 1982).

South Texas Frio Depositional Systems

Frio sediments in South Texas were deposited by a system of major extrabasinal rivers, the Gueydan Fluvial System, along the axis of the Rio Grande Embayment (Galloway, 1977). Seeligson field is located at the downdip edge of this system, near where it grades into the Norias Delta System (fig. 5). The Gueydan Fluvial System is characterized by coarse-grained, bed load channel-fill and point bar sandstones flanked by widespread crevasse-splay deposits and floodplain mudstones and siltstones. The Gueydan Fluvial System channel-fill sandstones are interpreted to have been deposited in bedload, straight to slightly sinuous streams with broad, well developed

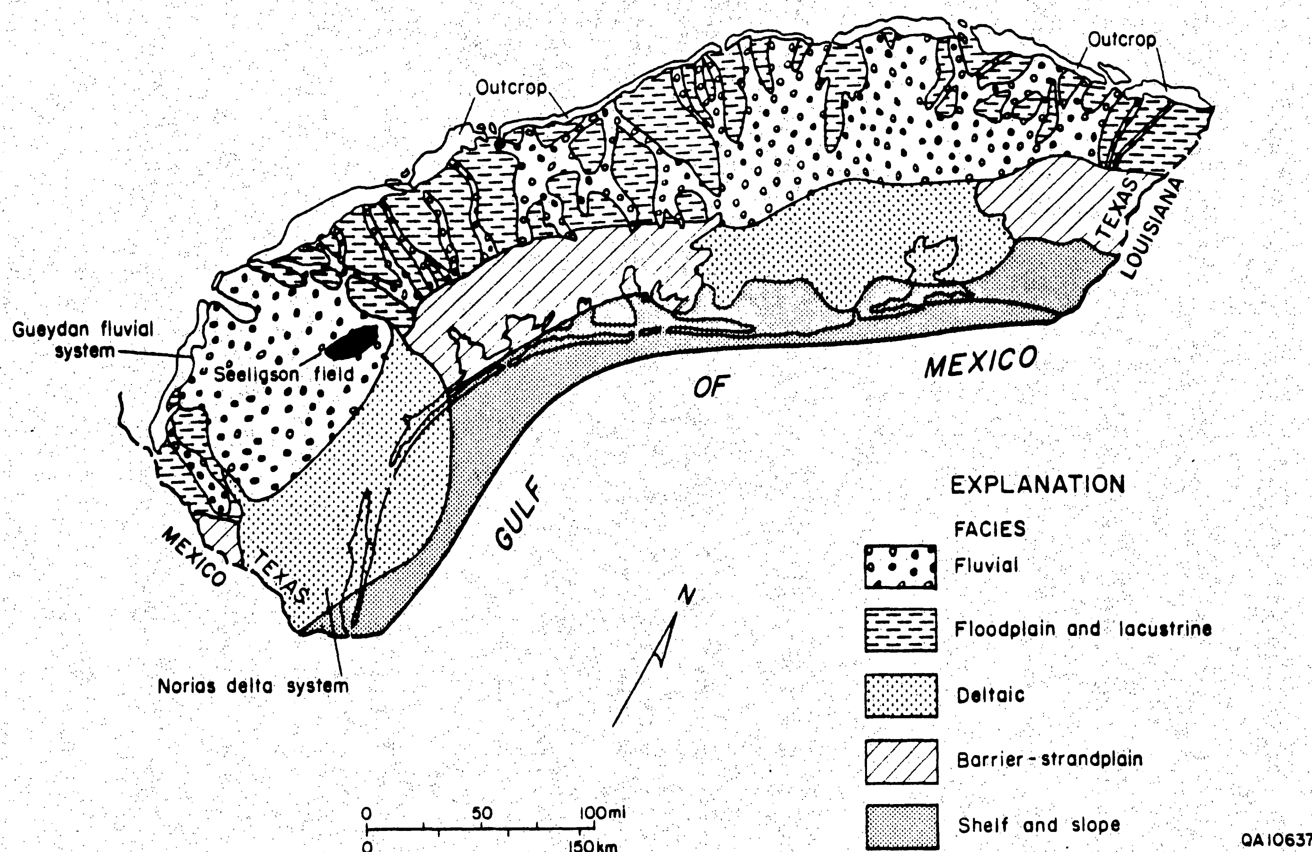

Figure 5. Frio depositional systems along the Texas Gulf Coast. Middle and upper Frio sediments were deposited in the Gueydan Fluvial System which consisted of a network of low-sinuosity, bedload streams in the Rio Grande Embayment. Modified from Galloway and others (1982).

natural levees (Galloway, 1977, fig. 6). Individual bed thickness of channel-fill sequences are 10 to 30 ft but often amalgamate into units of up to 100 ft. These amalgamated sandstone bodies may develop into multilateral belts up to several miles wide (Galloway, 1982).

Frio Depositional Systems, Seeligson Field

Sandstones of the Seeligson unit display characteristics typical of Gueydan Fluvial System deposits. Nanz (1954) described the dip-oriented, lenticular Zone 19-B reservoir as the delta-plain deposit of an Oligocene river, probably an ancestral Rio Grande. Analysis of net sandstone isopach maps for thirty productive sandstones within the Seeligson unit reveal predominantly dip-elongate trends common in fluvial provinces. Log facies maps, used in conjunction with net sandstone maps, illustrate the spectrum of facies associated with fluvial depositional environments. Maps of Zones 11-B, 17, and 20-B are representative of the trends observed in many of the reservoirs throughout the unit section. Net sandstone thicknesses range from 2 to 43 ft forming belts of sandstones up to 1 mile wide oriented normal to regional strike (figs. 7, 8, 9). Channel-fill and point-bar sands, crevasse splay deposits, and levee and overbank siltstones and mudstones, as illustrated on SP log facies maps, are characteristic facies of Seeligson unit reservoirs (figs. 10, 11, 12). These reservoirs are complex and may contain gas within numerous isolated, undrained compartments.

RESERVOIRS SELECTED AS CANDIDATES FOR RECOMPLETION

The stacked fluvial sandstone bodies and stringers in the Seeligson unit provided numerous opportunities for selecting specific reservoirs to study in detail. The criteria that were used to make the final selection of zones for detailed analysis are listed below. Two reservoirs, Zone 15 and Zone 18-C, were ultimately selected as candidates to be evaluated for recompletion.

Factors that were considered in selection of reservoirs for intensive geological analysis include:

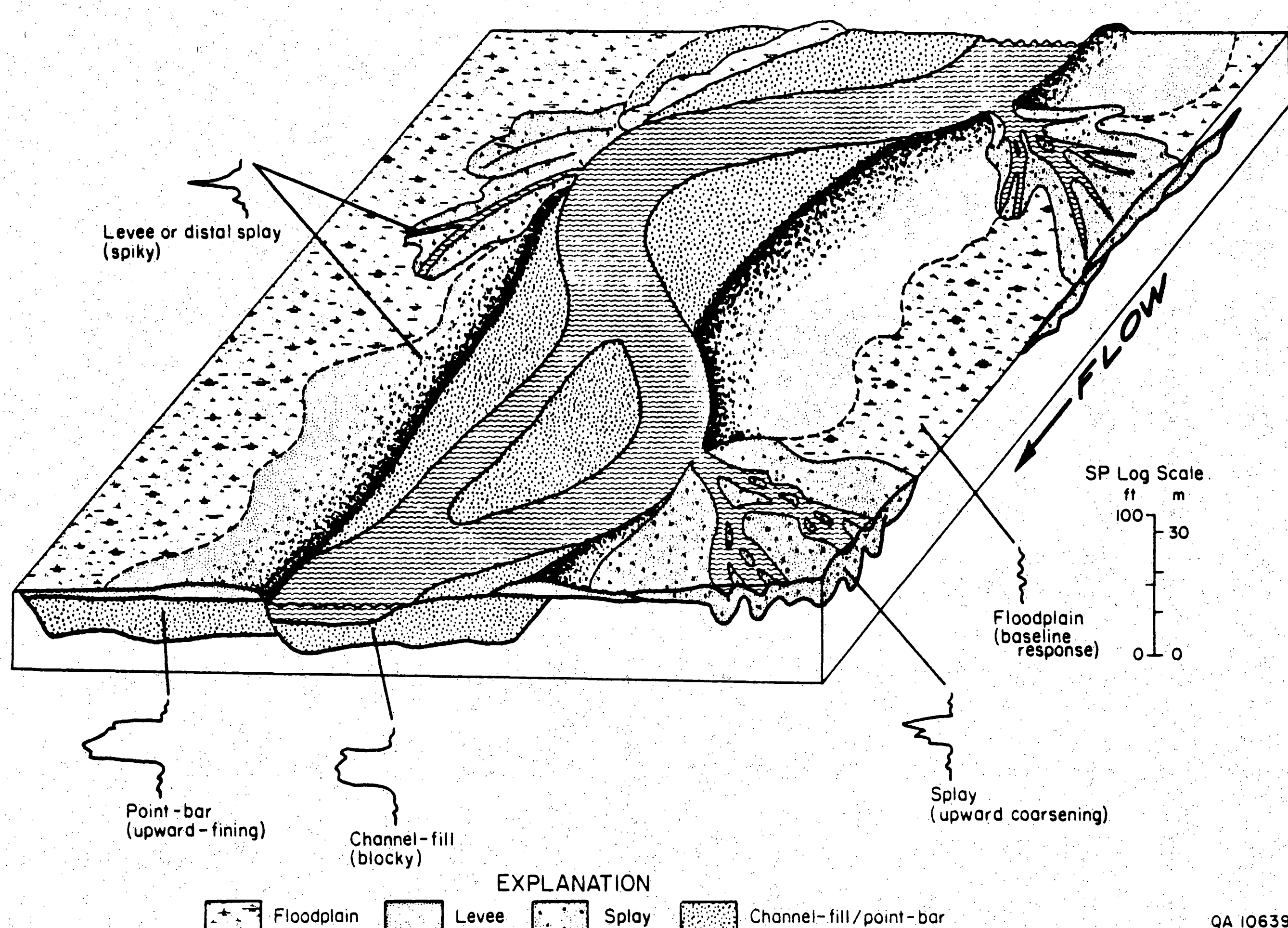

Figure 6. Three dimensional facies relationships in middle and upper Frio fluvial reservoirs in Seeligson field. Characteristic SP-log responses of each facies are shown. Modified from Galloway (1977).

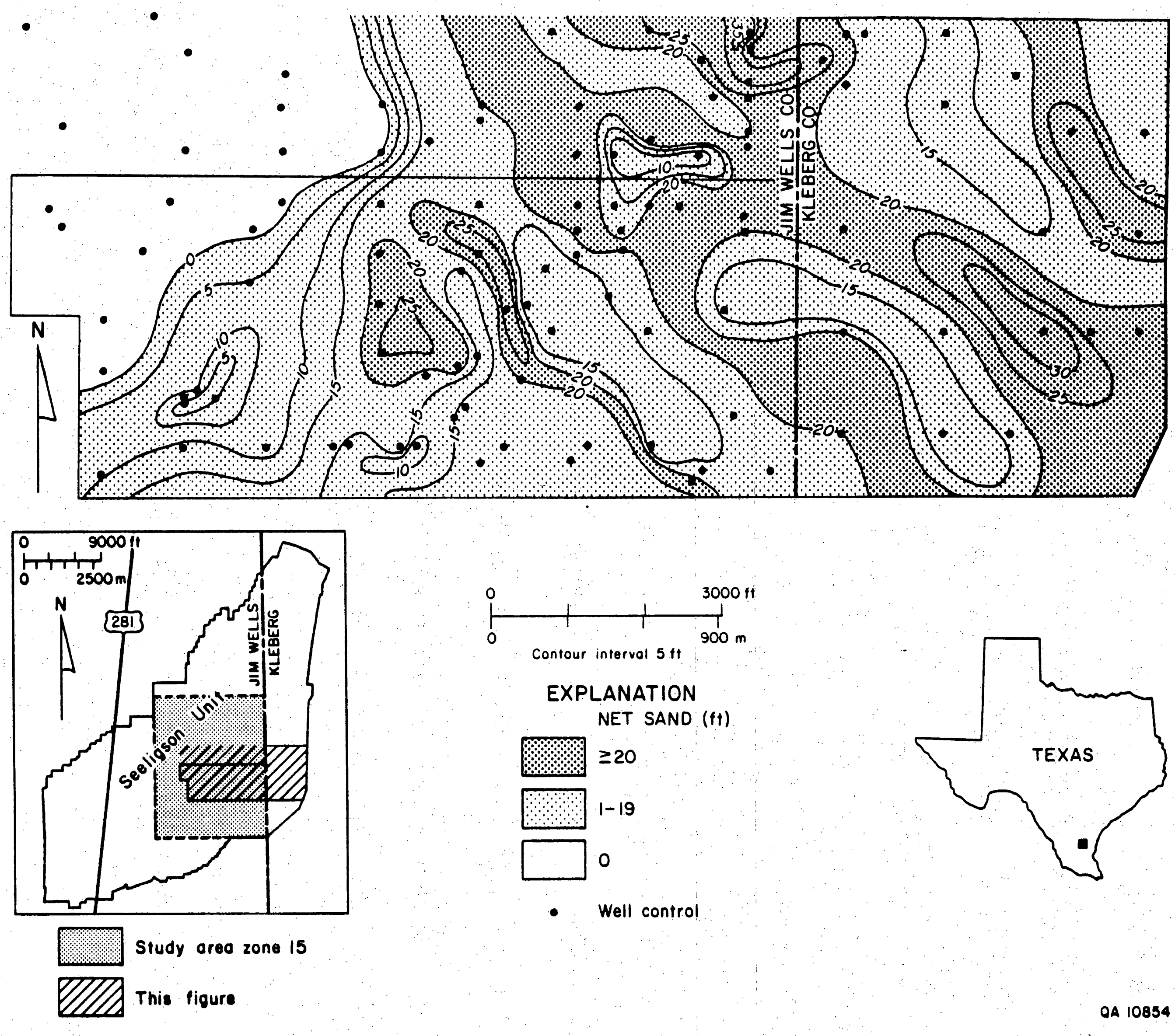

Figure 7. Net sandstone isopach of Zone 11-B. Dip-parallel depositional trends are typical of fluvial environments in Seeligson reservoirs.

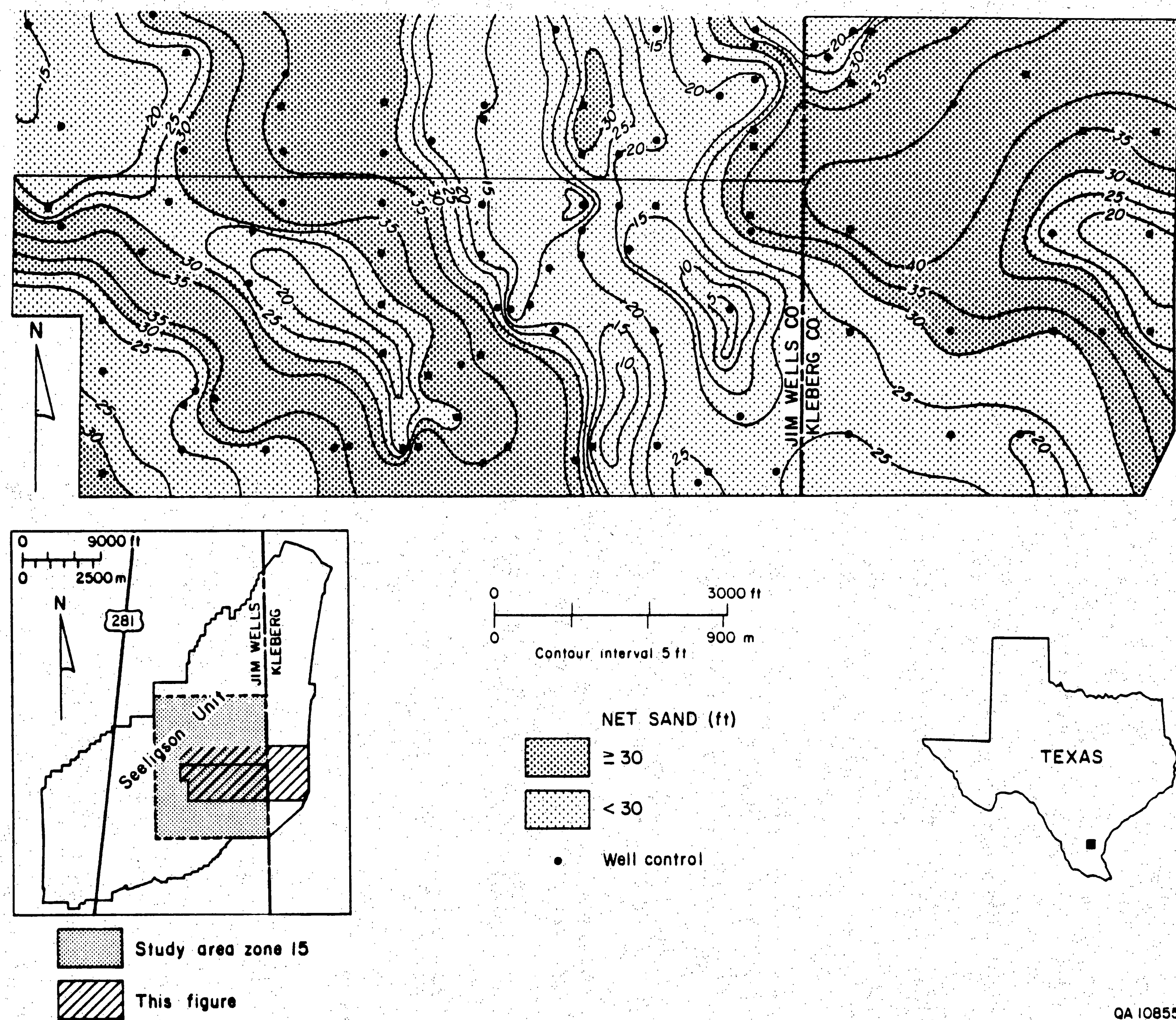

Figure 8. Net sandstone isopach of Zone 17.

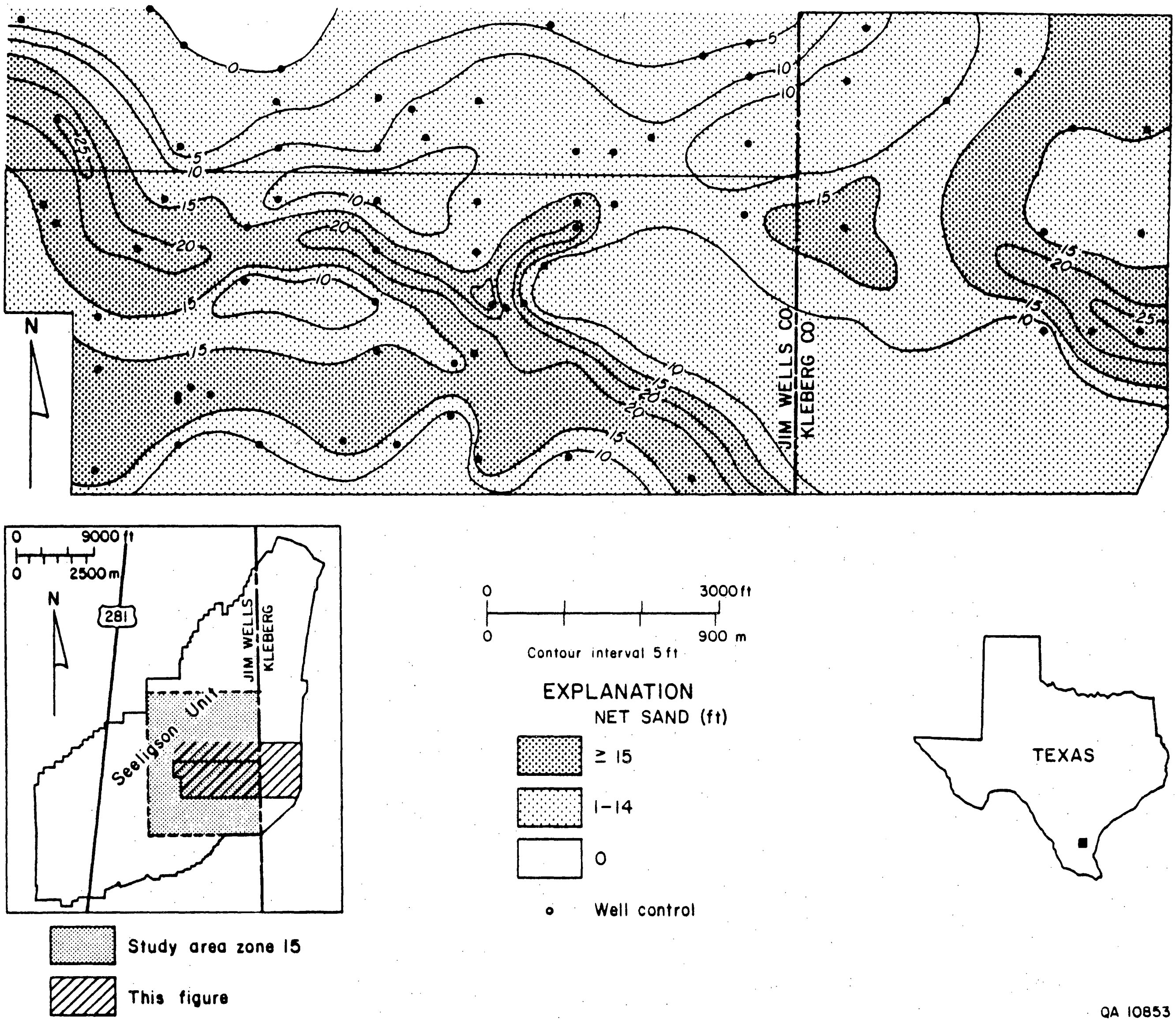

Figure 9. Net sand isopach of Zone 20-B.

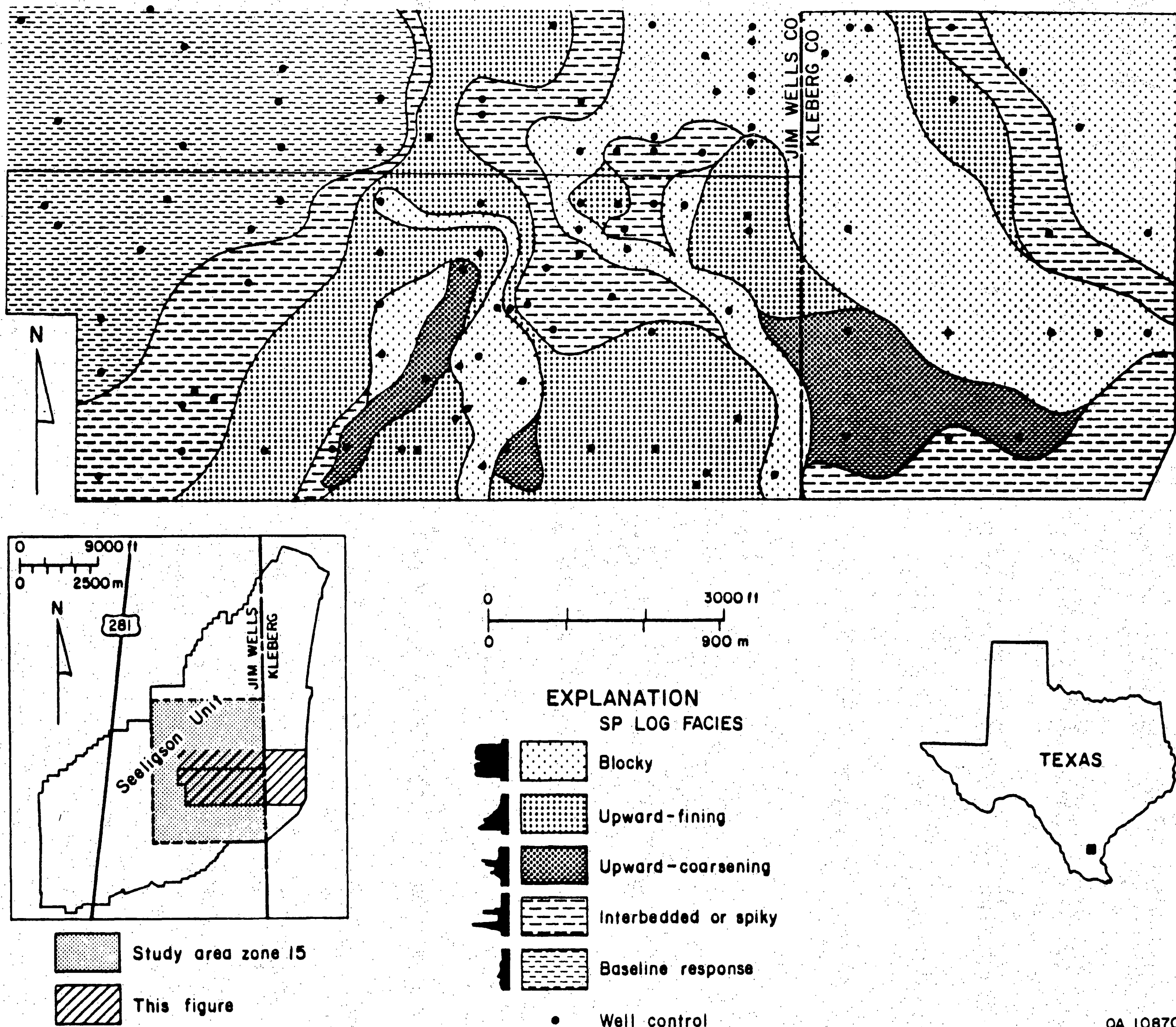

Figure 10. SP log facies of Zone 11-B. Blocky and upward-fining log curve shapes define reservoir-quality channel-fill deposits. Upward-coarsening patterns represent crevasse splay sands; spiky and baseline log responses are indicative of levee/overbank and floodplain facies.

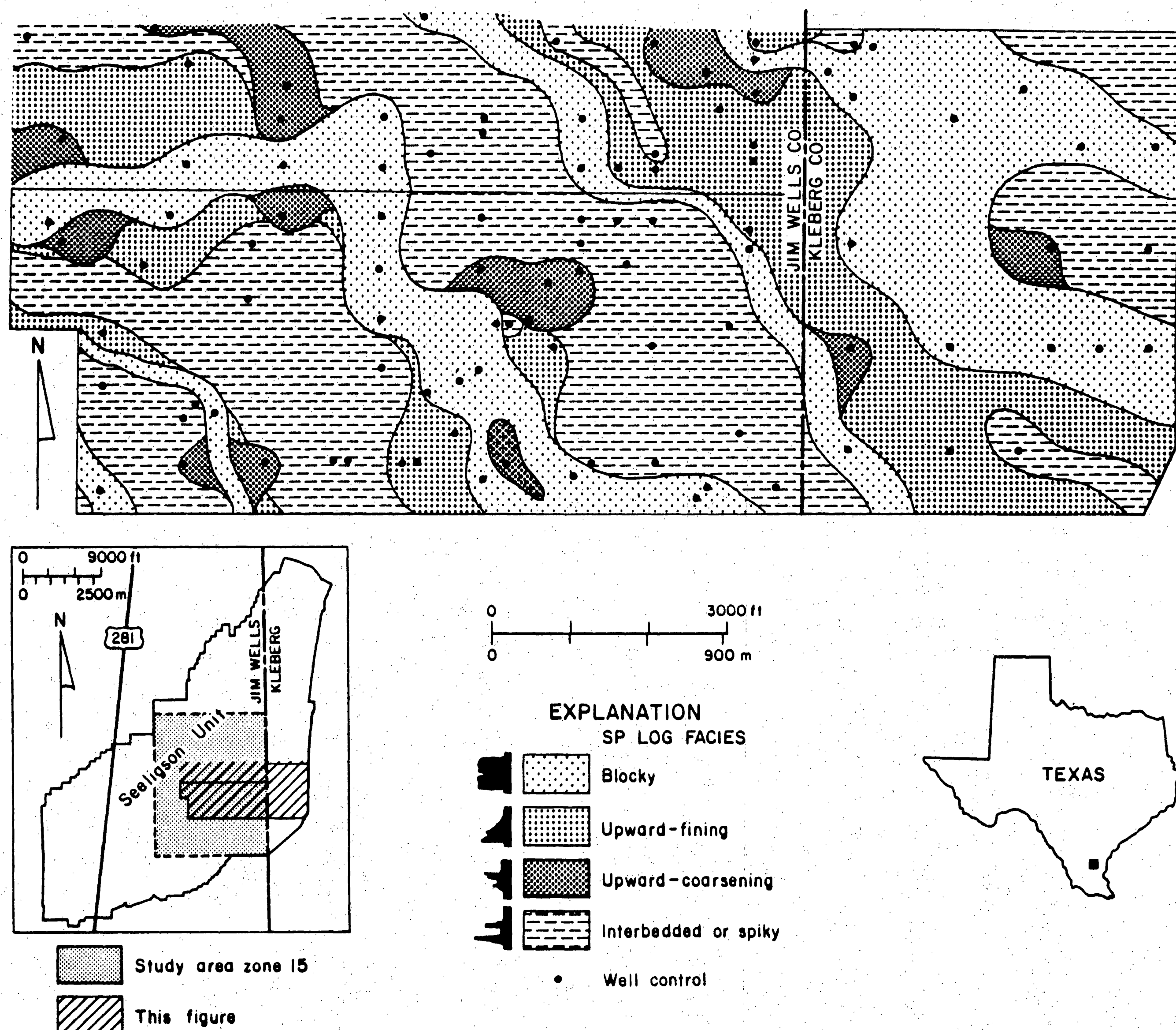

Figure 11. SP log facies of Zone 17.

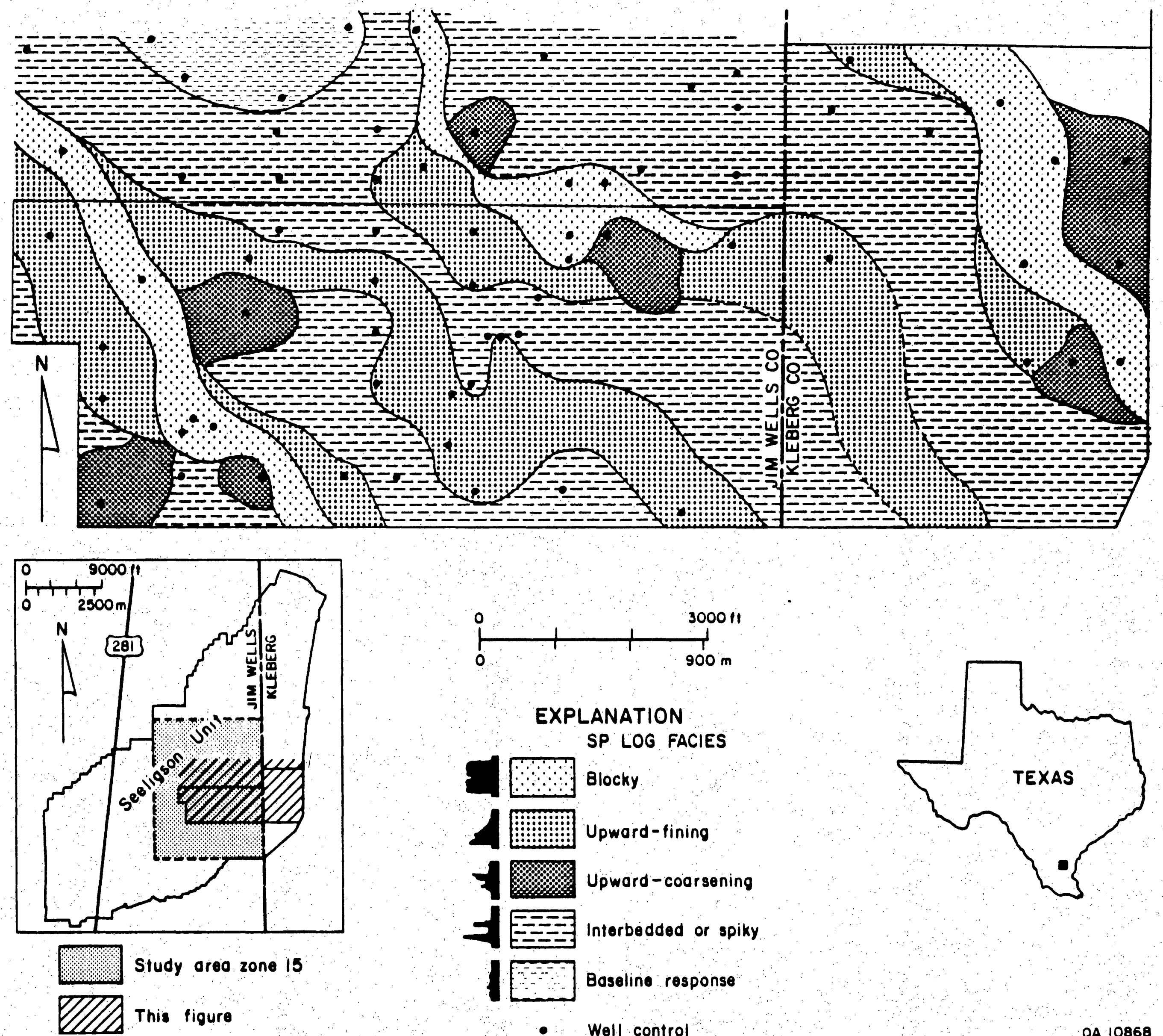

Figure 12. SP log facies of Zone 20-B.

(1) degree of complexity within the aggregate reservoir to allow identification of component genetic sand bodies (sandstone heterogeneity);

(2) results of log analysis performed by ResTech, Inc., including gas shows and inferred bypassed or compartmentalized gas zones;

(3) extent of past or current production from zone of interest within the study area;

(4) evidence of anomalous bottom-hole pressures or production histories; and

(5) availability of whole core.

Sandstone Heterogeneity

More than 140 Frio and Vicksburg reservoirs have been documented across Seeligson field (Nanz, 1954), and of these, more than thirty Frio reservoirs are productive within the 9 mi^2 detailed study area. These multiple, vertically-stacked, dominantly fluvial sandstones exhibit varying degrees of complexity. Although each zone is generally less than 100 ft thick, the majority are composite intervals of several genetic cycles. Aggregate sandstone distribution patterns, as mapped on net-sandstone isopachs within the unit, illustrate dominantly dip-parallel depositional trends generally indicative of fluvial environments (figs. 7, 8, 9). The interbedded sandstones and shales reflect the diversity of the environments of deposition within each zone. Fluvial environments, which include channel-fill, channel margin, overbank, and crevasse-splay facies, are characteristically discontinuous and may contain internal permeability differences that tend to segment reservoirs into compartments. These characteristics are favorable for identification of reservoirs that may contain bypassed or compartmentalized gas resources. Regional cross sections and net sandstone isopach maps of aggregate Zones 15 and 18-C illustrate these characteristics, and, by meeting additional criteria, led to their selection for detailed analysis.

Log Analysis: Indication of Bypassed or Compartmentalized Gas Zones

Analysis of modern logs such as TDT, cased-hole-sonic, pulsed-neutron, and bulk-density logs, was a critical step in evaluating recompletion prospects. Wells with TDT logs were evaluated to determine those with the best potential gas shows. Of those, five were selected for digital cased-hole sonic logging. Acquisition of cased-hole sonic data allowed comparison of porosity calculated from TDT logs to porosity calculated from sonic logs to determine gas effect and to calculate water saturation (Howard and Bolin, 1988). Old electric logs available for each well were compared with newly acquired sonic data to calculate original open-hole water saturation and to compare it with cased-hole water saturation. Howard and Bolin (1988) presented results of cased-hole log evaluation and identified potential gas productive sands in each of the five wells. Two wells were recommended for recompletion in Zone 15 and one well was recommended for recompletion in Zone 18-C (Howard and Bolin, 1988).

Production History

Seeligson field was discovered in 1937 when the Magnolia A. A. Seeligson No. 7 was drilled to a depth of 8,141 ft and encountered hydrocarbons in non-unit Zone 22-5. More than 1,000 wells have since been drilled in the field, and cumulative production exceeds 1.3 Tcf from unit reservoirs (D. Sadler, personal communication 1988). Most of the gas is trapped on the crest of the rollover anticlinal structures associated with the major Vicksburg growth fault, although the contribution of stratigraphic controls (sand body pinch-outs or facies changes) is substantial. Galloway and others (1982) have estimated that stratigraphic features may contribute to trapping in about one-half of the fields within this play. Sun Exploration and Production Company has been evaluating recompletion opportunities in Seeligson field in a systematic manner across the field and have added significant volumes of natural gas to cumulative production totals. Consequently, the need to focus on reservoirs that have had relatively few completions in the study area became apparent. Both

Zone 15 and Zone 18-C satisfied this requirement, as neither zone has been densely developed within the study area.

Pressure and Production Anomalies

Reservoir heterogeneities or compartmentalization of reservoirs may be indicated where there are significant bottom-hole pressure variations across the field. In addition, production characteristics that deviate from expected results may indicate heterogeneities between wells. Sun Exploration and Production Company engineers identified several reservoirs that they have encountered during their recompletion program with unpredictable drainage histories or anomalous pressure readings. Zone 15 was among those reservoirs cited by Sun as having unpredictable pressures and production irregularities.

Whole Core

Thirty six feet of whole core from Zone 15 was taken in the Sun P. Canales No. 141 as part of a cooperative data acquisition program. The availability of core, petrographic, and SEM analyses, as well as the utility of visual description in aiding depositional environment interpretations, made Zone 15 an ideal choice for detailed study.

ZONE 15

General Description

The middle Frio Zone 15 occurs midway through the unitized section at 5,320 ft (log depth) in the 1-24 well (fig. 13). Zone 15 was identified and mapped throughout Seeligson field and has been developed as a homogeneous, continuous reservoir. This study used about 250 electric logs to

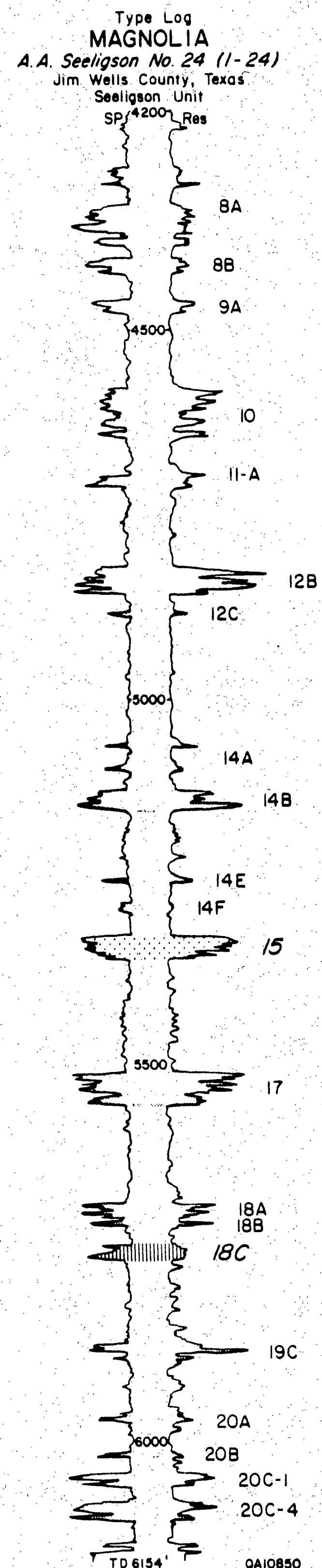

Figure 13. Type log in Seeligson field. Over 20 reservoirs are represented in this well; within the study area over thirty vertically-stacked, dominantly fluvial reservoirs may be encountered. Zones 15 and 18-C were selected for detailed geologic evaluation.

re-correlate and re-define the stratigraphic framework of Zone 15 in the local area of interest. Highly detailed SP and resistivity correlations reveal that Zone 15 can be subdivided into at least four individual genetic sandstones within the study area, here informally named the 15-A through 15-D sandstones. The most common stratigraphic occurrence of Zone 15 within the study area is a two-part sandstone body (15-B and 15-C) that is in places separated by a very thin (1-5 ft) shale bed (fig. 14). Throughout the study area the zone has different configurations; in the southwestern part, the interval consists of 15-A, B, and C sands coalesced into an amalgamated unit; in other areas, the interval is a relatively thick sandstone that may be composed of 15-B and C sands without intervening shales, and in several cases only one individual sandstone body composes the interval (fig. 14). Standard production and development practices generally overlook this level of interval heterogeneity and therefore bypass opportunities to identify and exploit additional gas resources.

Pressure Anomalies

Thirteen wells have produced more than 57 Bcf of gas from the aggregate Zone 15 within the study area. Bottom-hole pressure data from 11 wells were plotted against time (fig. 15). Significant deviations above the curve are found in recently completed wells 16-97, 16-124A, 42-67 and P. Canales No. 141, where BHP's are in the 1,100-1,200 psi range. These anomalous pressures were considerably higher than the expected BHP's of 300-500 psi (more than 35 years of production has depleted the reservoir pressure). Detailed geologic evaluation of reservoir facies indicates that wells falling on the decline curve are concentrated in an area within about one mile of each other in channel-fill and channel-margin deposits in the north central and northwest part of the area (fig. 16). Wells 1-225, 1-114, 1-98, and 1-163 lie within a major channel-fill complex and most likely drain the same reservoir. Well 17-1 lies in a proximal splay deposit that is attached to the major channel complex and is also apparently draining the same reservoir. Farther to the west, wells 1-157, 1-47, 1-160 lie in an adjacent channel-fill complex that may be separated from the central

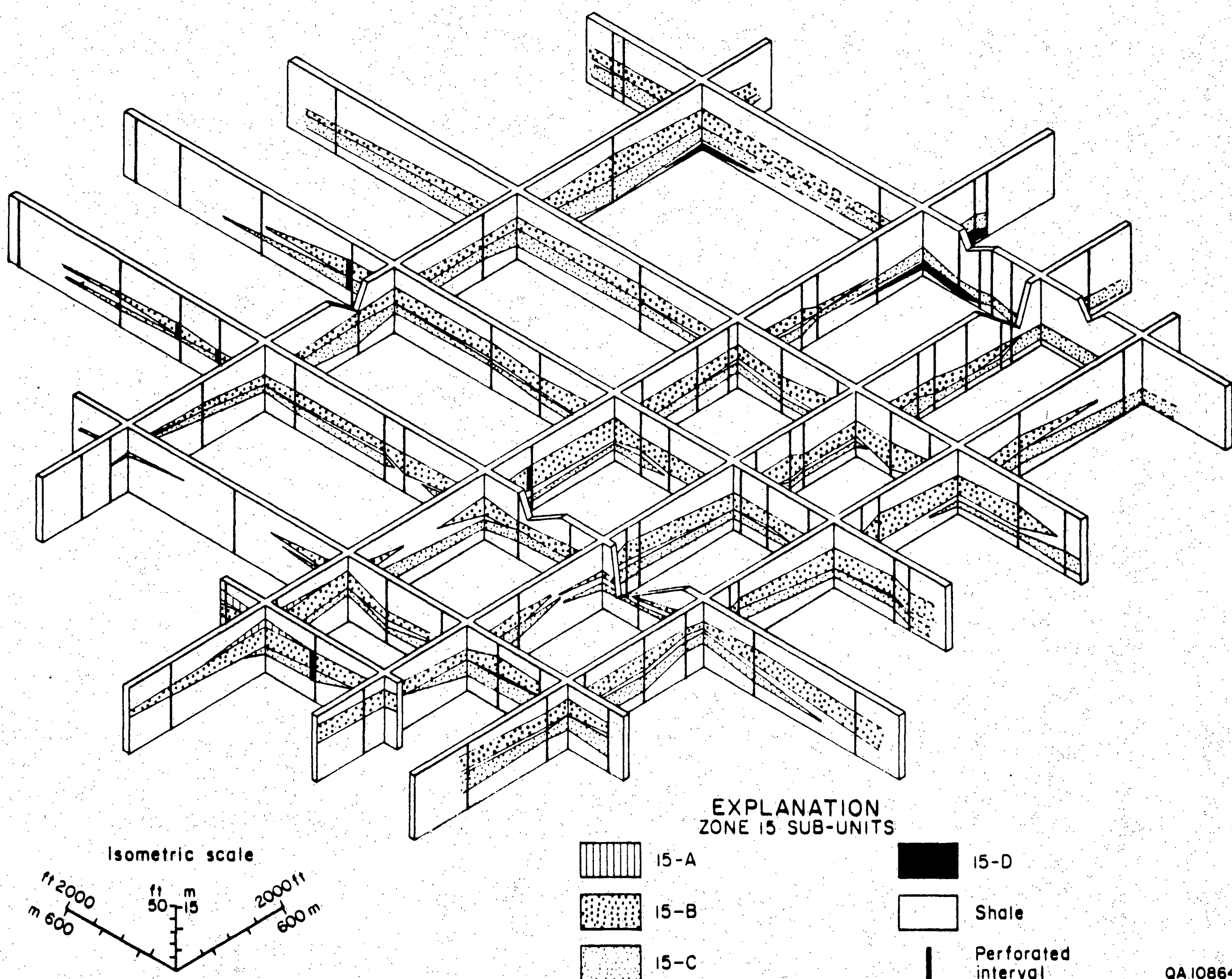

Figure 14. Fence diagram of Zone 15. The reservoir has been subdivided into four component genetic sandstones, 15-A through 15-D. Sands 15-B and 15-C have the greatest distribution within the area of interest and are frequently vertically isolated by a thin shale bed. Refer to figure 14a for location.

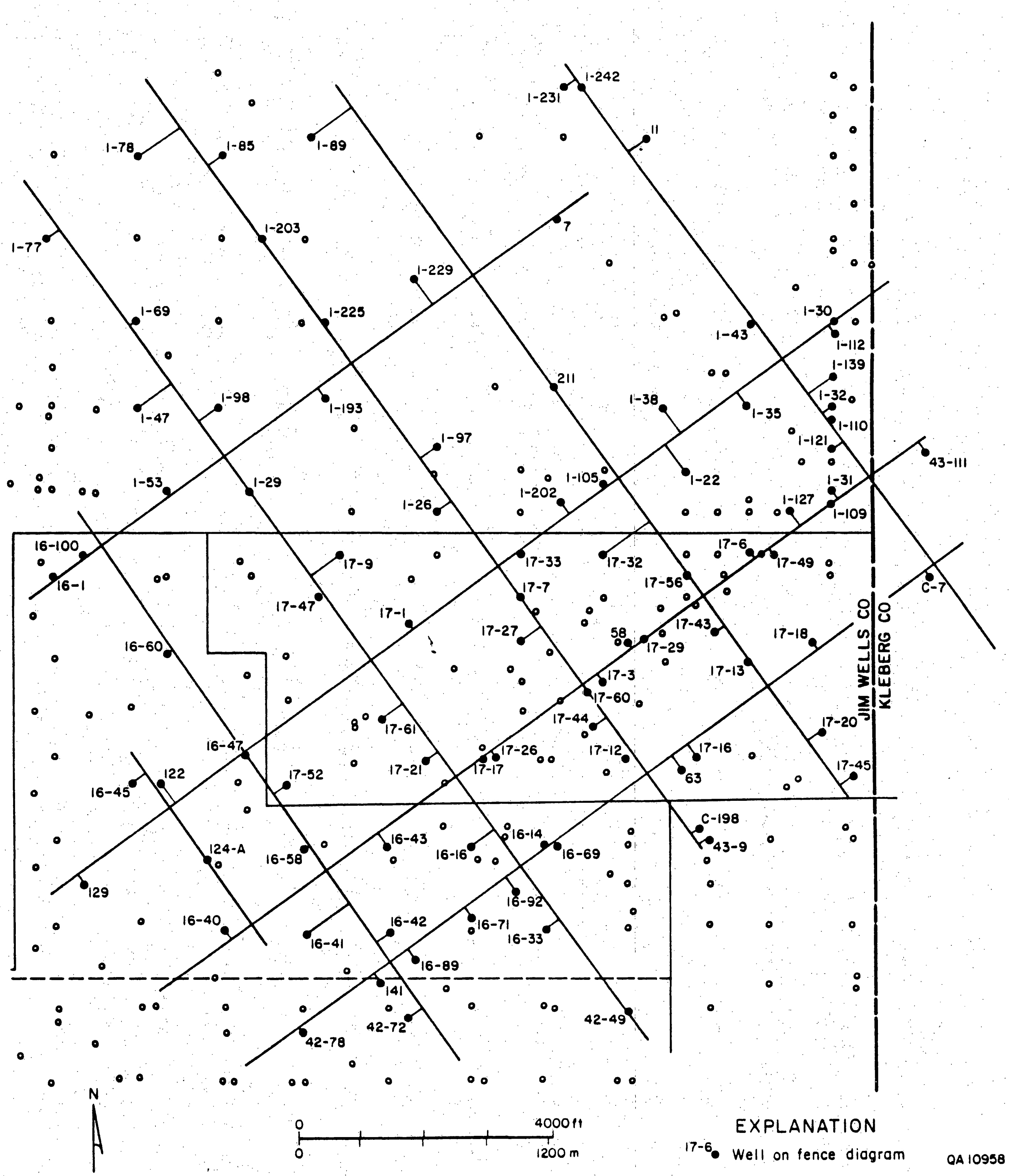

Figure 14a. Location of wells in fence diagram. Fence diagram shown in figure 14.

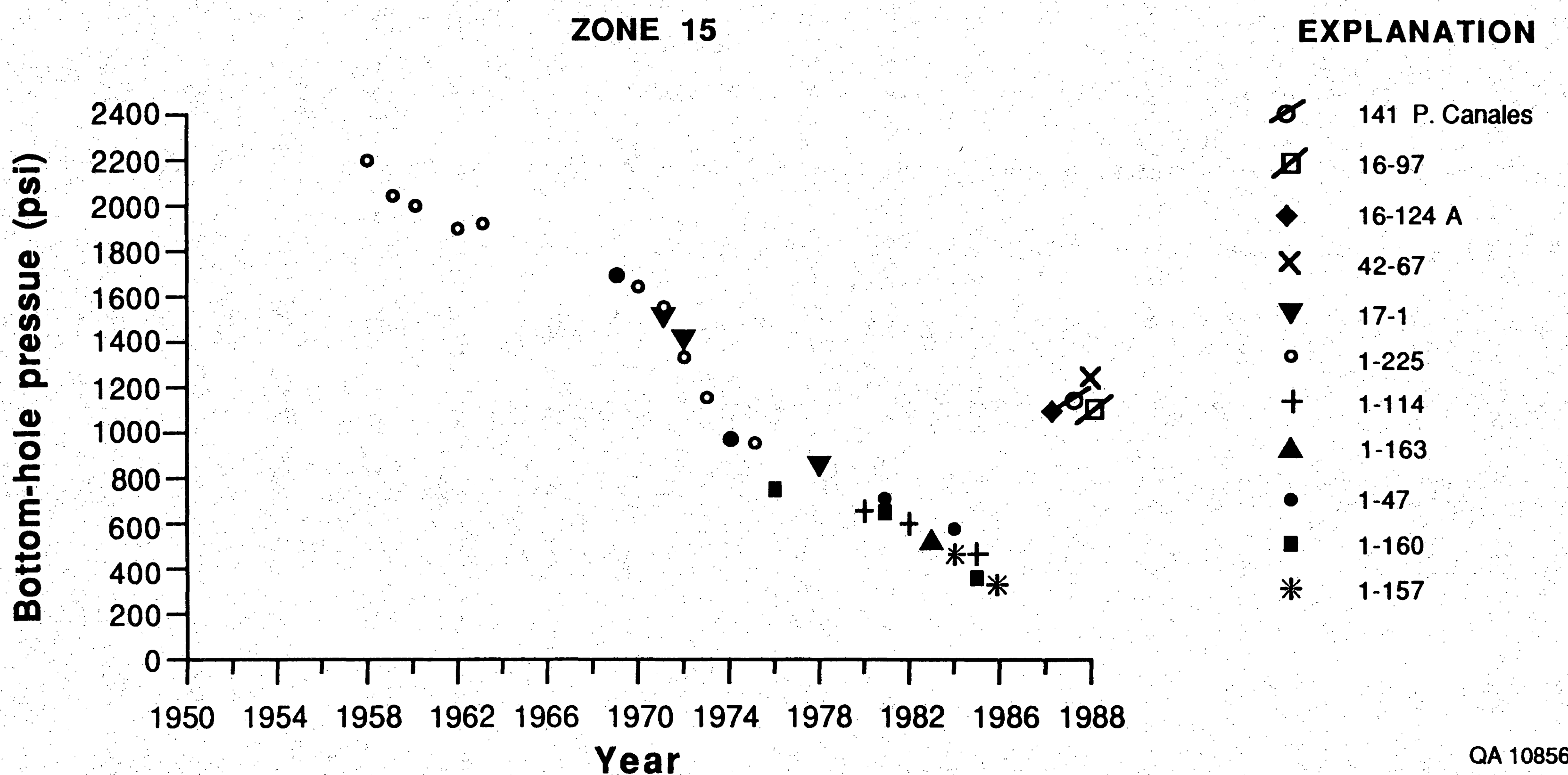

Figure 15. Bottom-hole pressure vs. time for eleven wells productive in Zone 15. Data from Sun Exploration and Production, Inc.

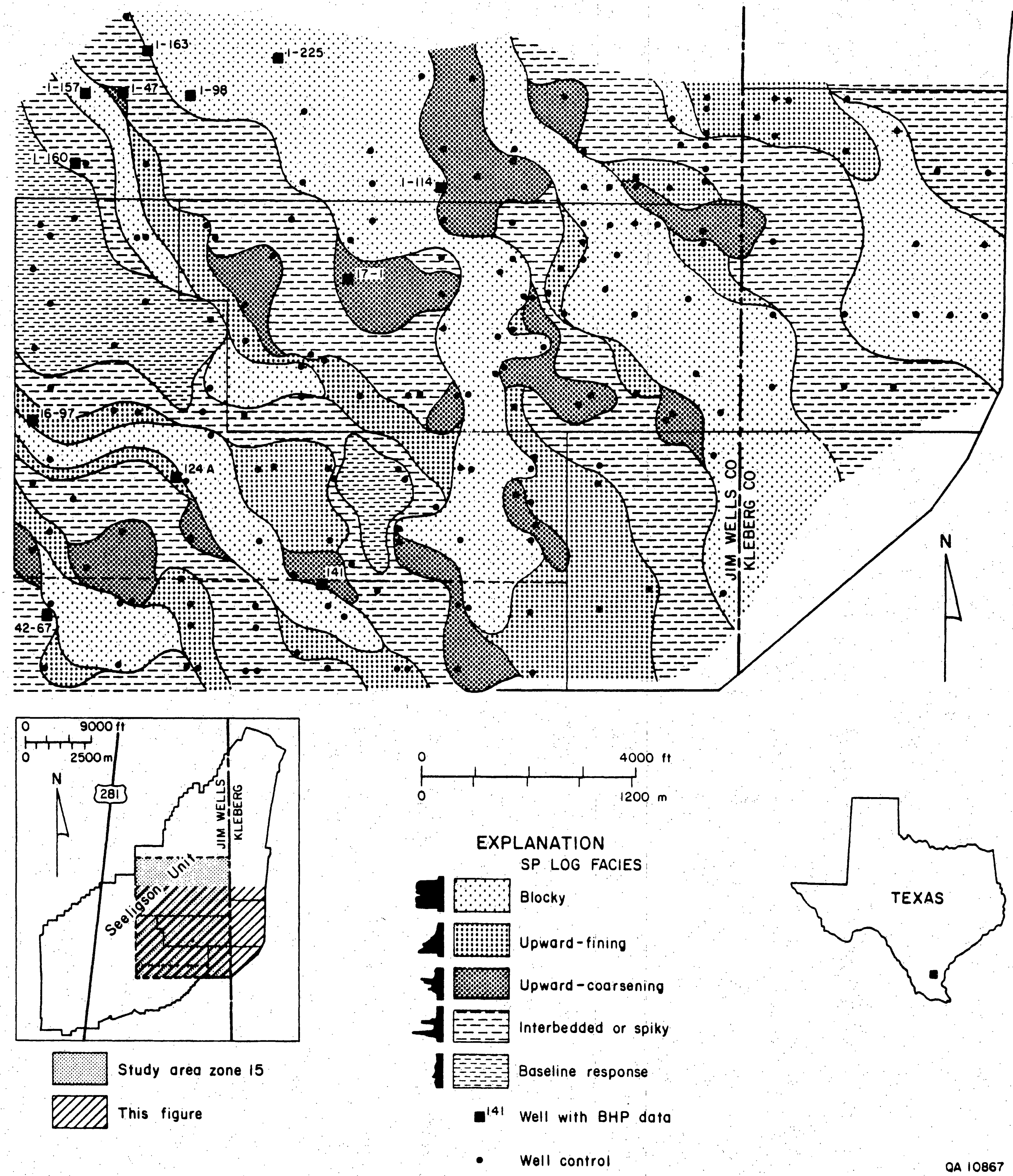

Figure 16. SP log-facies map of aggregate Zone 15. Two major channel complexes are separated by a tongue of floodplain silts and muds. Anomalously high bottom hole pressures were noted in recompleted wells located in the southwestern channel complex.

channel by finer-grained levee/overbank deposits, although reservoir pressures indicate that there is good communication between the two channel complexes. The four wells that show BHP's above the decline curve (fig. 15) are located in the southwestern part of the study area, approximately one mile from the wells described above. The salient geological feature separating the group of higher pressure wells from those with depleted pressures is a tongue of floodplain mud that averages 2,000 ft in width and extends about one mile into the area before grading into overbank deposits. Muddy facies re-form in a small area 2,500 ft farther downdip between the channels. Three of the wells (16-97, 16-124A, and P. Canales No. 141) are found in the same channel-fill deposit; the fourth (42-67) occurs in another channel-margin sandstone (fig. 16). The fact that four wells have bottom-hole pressures significantly higher than expected in a depleted reservoir can be explained geologically by their location in channel-fill complexes horizontally separated by muddy floodplain facies from the depleted reservoirs of a different channel complex. The floodplain mudstones provide an adequate permeability barrier that restricts flow and isolates at least two separate reservoirs that had previously been assumed to be a single, homogeneous reservoir.

DETAILED GEOLOGIC EVALUATION

This study focused on delineating genetic facies distribution of sub-units 15-B, 15-C, and 18-C in an attempt to discover prospective untapped compartments and bypassed gas zones.

Zone 15-B

Sandstone Distribution

Zone 15-B sandstones exhibit predominantly dip-elongate net sandstone patterns typical of fluvial environments. Net sandstone thickness across the study area ranges from 2 ft to 20 ft with high net-sandstone areas forming elongate, dip-parallel belts of channel-fill facies. Two primary depositional axes appear within the study area; the greatest concentration of sandstone occurs in the east-central and southwest areas, which are divided by a narrow tongue of shale. In the southeast corner of the area the axes converge to form a relatively broad, dip aligned belt of sandstone (fig. 17). The contour patterns suggest that areas of high net sandstone values, particularly where they align in sub-parallel belts, represent areas of channel-fill deposits, and lobate or isolated thicks may represent overbank or proximal crevasse-splay facies. Low net sandstone values (1 to 10 ft) are indicative of channel-margin environments and levee or overbank deposits. Zero sandstone areas are occupied by broad, muddy floodplains and interchannel mudstones or muddy abandoned-channel deposits.

Depositional Environment

SP log facies mapping uses representative SP curve shapes to characterize depositional environments. SP log responses of Seeligson field (and South Texas Frio) channel-fill and point-bar sandstones are generally blocky and sharp based. Point bar sands may also display crude upward-fining patterns (Galloway, 1977). Another log response typical of channel-fill sandstones is a blocky-serrate pattern, representative of shale interbedding among stacked channel-fill sandstones. Crevasse-splay deposits may be characterized by upward-coarsening log patterns as well as by the patterns described for channel-fill sandstones, although individual beds may be thinner. Overbank and levee deposits are characterized by thin, spiky log responses, and silty and muddy floodplains are represented in baseline responses.

Log facies maps illustrate environments typical of South Texas Frio fluvial systems. Channel-fill facies, flanked laterally by overbank-splay and levee deposits, course through the study area from northwest to southeast (fig. 18). Channel widths are generally less than one mile; most average about 2,000 ft. Crevasse-splay facies attached to channels are numerous throughout the area. Thin levee and overbank deposits occur between channels and merge with floodplain mudstones to the west and southwest (fig. 18).

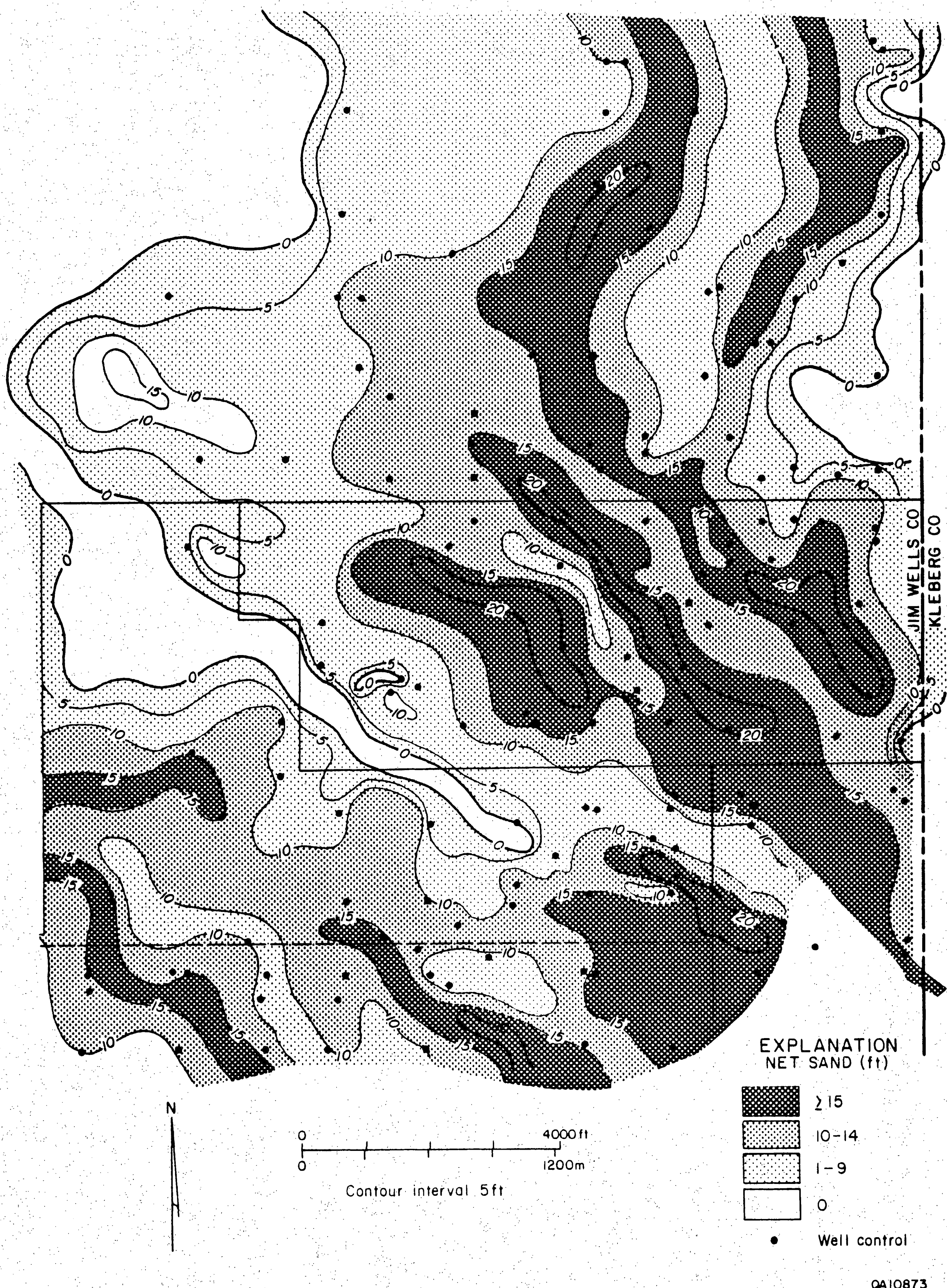

Figure 17. Net-sandstone isopach of Zone 15-B. Primary depositional axes occur in the east-central and southwest part of the area. Note the tongue of shale separating the principal depocenters.

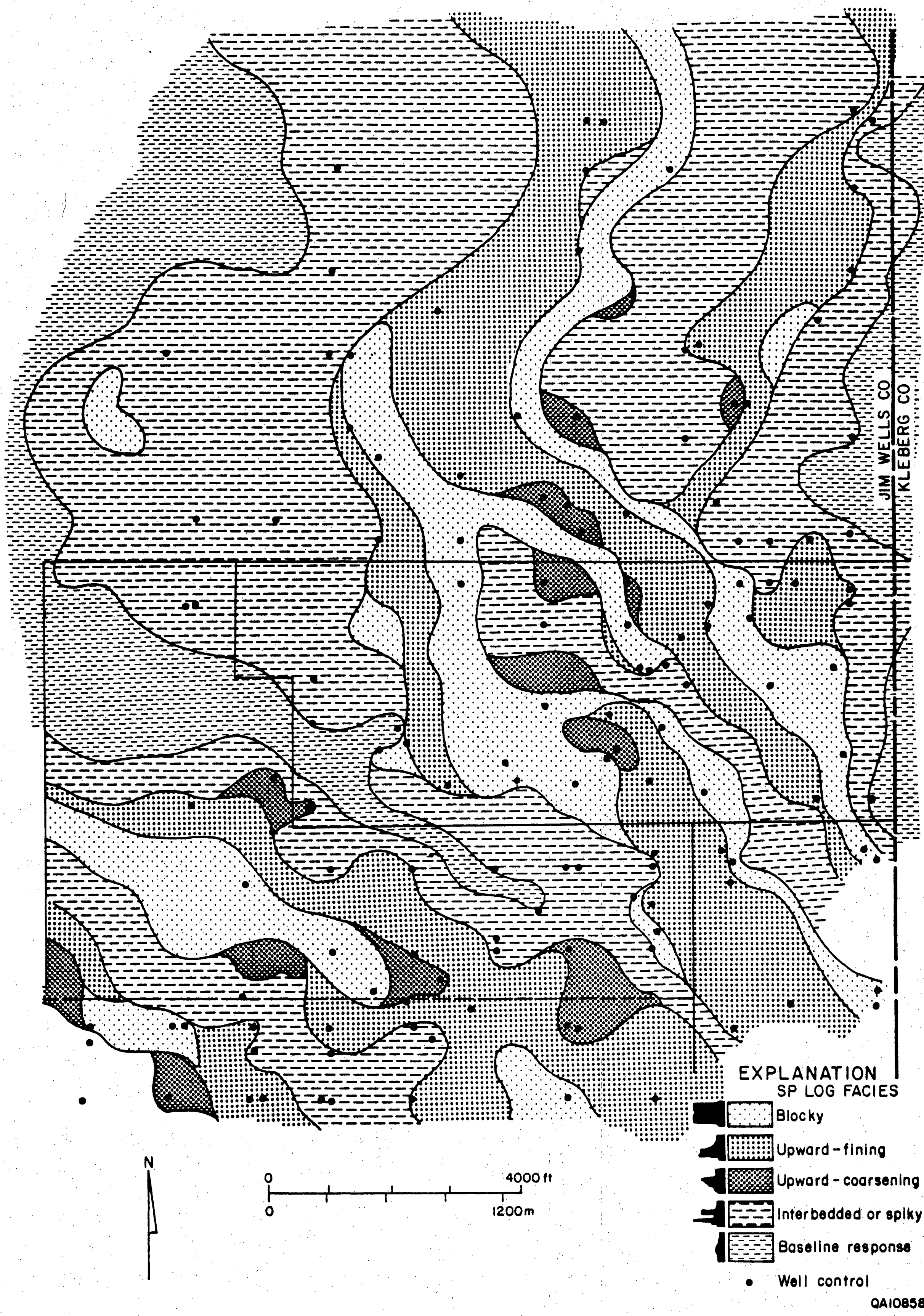

Figure 18. SP log-facies map of Zone 15-B. Fluvial channels, crevasse splays, natural levee and overbank deposits, and interchannel floodplain muds are represented in this interval.

Interpretation of Zone 15 depositional environments was aided by the availability of whole core from the Sun P. Canales No. 141 well. The cored interval (5,406-5,442 ft) included 27 ft of sandstone and 9 ft of shale from Zone 15. Core recovered from Zone 15-B consists of 8.5 ft of very fine to fine grained sandstone (the complete interval is interpreted to be 14 feet thick on the basis on the triple combo log; 10 ft of the interval was cored, with 1.5 ft not recovered). Cored 15-B sandstones coarsen upward very slightly through the first two feet, then maintain a constant to slightly upward fining grain size through the next six feet. The upper four feet (which were not cored), display an upward fining pattern based on log interpretations. Overall, grain size variations are minor, ranging from fine to very fine sand. Horizontal to slightly inclined laminations are observed, and flattened shale clasts occur at an erosional scour surface. Whole core analyses indicate sandstone porosities in the 19-22% range, and permeabilities ranging from 61-270 millidarcys. This interval is interpreted as a lower- point-bar deposit.

Zone 15-C

Sandstone Distribution

Zone 15-C sandstones exhibit predominantly dip-oriented net-sandstone patterns typical of fluvial environments. Net sandstone values range from 2 to 20 ft and high net sandstone areas are concentrated primarily in elongate belts of sediment less than 1,000 ft wide (fig. 19). Four principal 15-C depositional axes transect the study area but do not locally converge. The 15-C sandstone pinches out to the west into a broad floodplain, and several isolated shale outs (abandoned channel mud plugs?) occur around and between depositional axes (fig. 19). In contrast to the distribution of overlying 15-B sandstones, 15-C sandstones are thinner and were deposited in narrower bands. In several areas, both 15-B and 15-C sandstones occupy the same depositional axis, although channel migration or abandonment is suggested in areas where 15-B sandstones overlie muddy or silty facies of the 15-C interval.

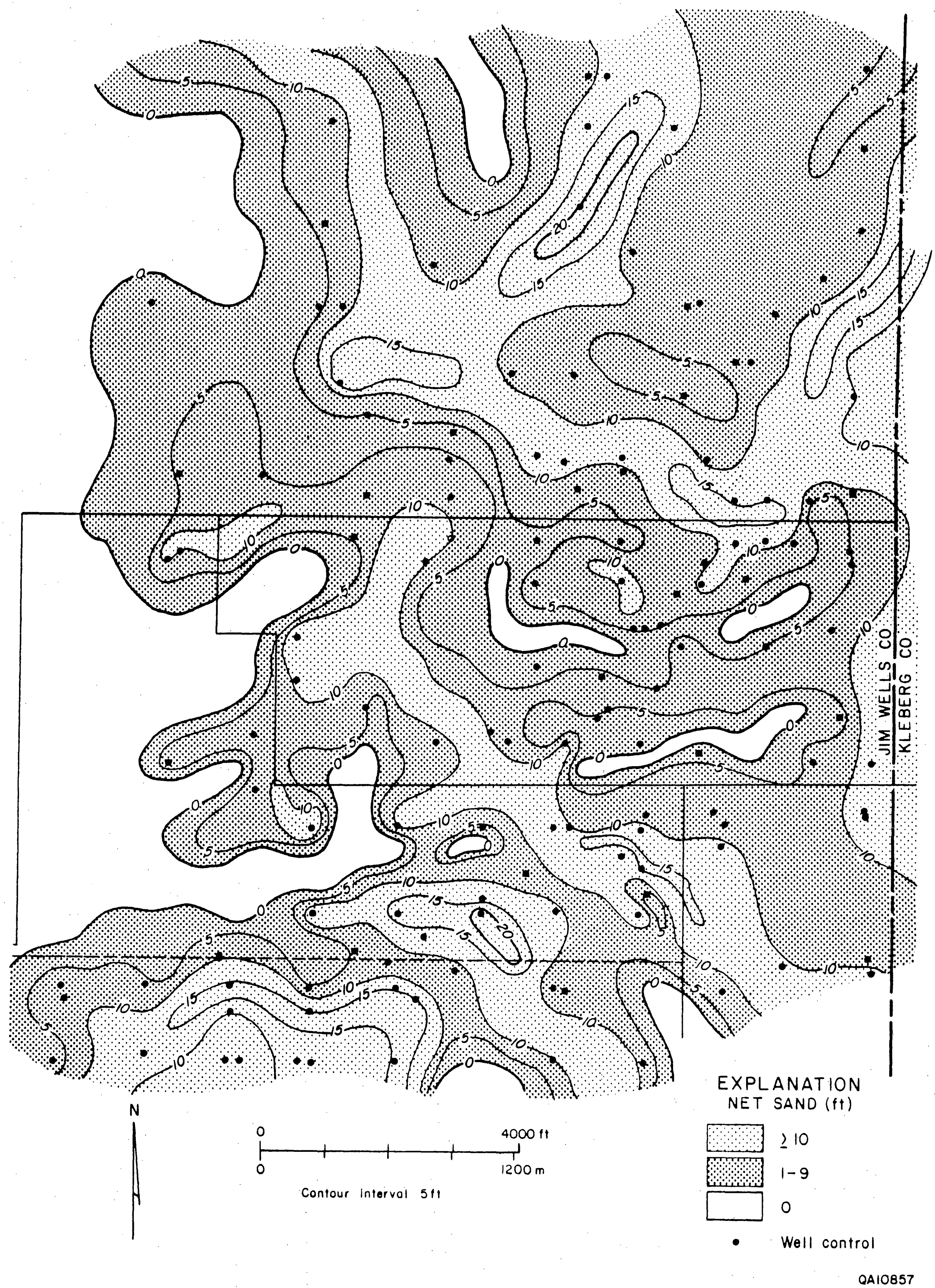

Figure 19. Net-sandstone isopach of Zone 15-C. Primary depositional axes occur in the northeastern, central, and southwestern part of the area. Sandstones pinch out in several localized areas and near the western edge of the study area.

Depositional Environment

SP log facies mapping of the 15-C interval (fig. 20) illustrates blocky, sharp-based SP log patterns that define narrow (less than 1,000 ft) channels winding through the study area in a northwest-southeast direction. These channel-fill and point-bar sandstones, which are also characterized by upward-fining SP responses, are flanked by relatively broad lobes of upward-coarsening crevasse-splay deposits. Widespread, well developed splay sandstones are more common here than in overlying Zone 15-B and are typical of Gueydan Fluvial/Streamplain environments (Galloway, 1977). Spiky SP curves delineate levee and overbank deposits that form broad, fine-grained interchannel aprons. A broad, muddy floodplain (baseline SP response) covers the western one-fourth of the study area, and several locally muddy areas may represent mud plugs occupying abandoned channels (fig. 20).

Whole core taken in Zone 15 from the Sun P. Canales No. 141 includes 10 ft of sandstone and siltstone that comprise the 15-C interval. The base of the sandstone at 5,428 ft (core depth) is defined by an erosional scour surface with gravel-sized rip-up mud clasts. Horizontal to slightly inclined laminations with possible cross-cutting and minor scour surfaces are observed in the first three feet of the medium-grained sandstone, which have porosity values of 11-21% and permeabilities of 3-400 md. These features are interpreted to have been formed in a proximal crevasse-splay environment. Climbing ripples occur at 5,424.5-5,425.2 ft, followed by abundant thin, horizontally bounded beds of very-fine sandstone with silt drapes. The remaining five feet of core are characterized by slightly upward-coarsening medium-grained sandstone with occasional flattened clay clasts and very faint horizontal laminations. Porosity ranges from 21-27% and permeabilities from 400-1,100 md in this interval. Overall, interpretations made from the ten feet of 15-C core indicate proximal-splay and splay-channel environments of deposition.

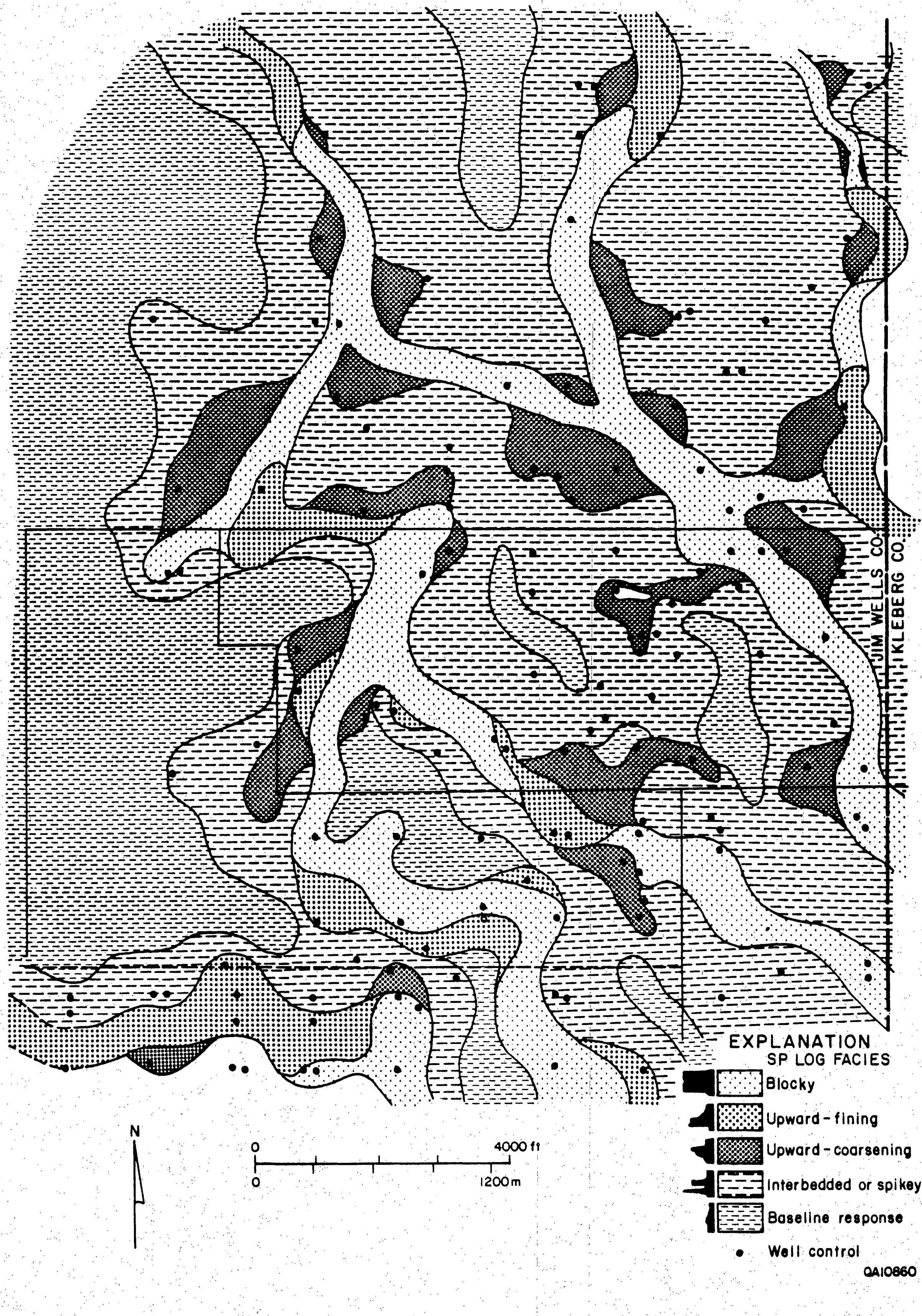

Figure 20. SP log-facies map of Zone 15-C. Crevasse splay deposits are more widespread than in Zone 15-B. Localized muddy areas may represent mud plugs in abandoned channels.

Zone 18-C

General Description

Zone 18-C occurs at 5,733 ft on the type log (fig. 13). This middle Frio sandstone is the lowest reservoir within the three-part Zone 18 interval.

The detailed study area for Zone 18-C differs somewhat from the Zone 15 map area; the northern and southern boundaries are cropped, and the eastern boundary has been extended into Kleberg County. The principal reason for this modification is the restricted development of the 18-C sandstone throughout the area of interest. Zone 18-C sandstone occurs principally in the northern half of the area and trends in a west-to-east direction (fig. 21). More than 50 electric logs were used to update the stratigraphic framework of the 18-C interval, and three cross sections were constructed to illustrate lateral relationships of producing and prospective reservoirs. Detailed SP and resistivity correlations identify an interval composed of two individual genetic sandstones, separated in places by a thin shale bed and coalescing in other areas to form a single sandstone unit (fig. 22). For purposes of this study, the two stratigraphic sub-units of Zone 18-C are informally named the 18-C upper and the 18-C lower.

Production

Gas production from the 18-C reservoir throughout Seeligson field totals 22 Bcf from eight wells. Within the area of interest, only one well has produced from the 18-C, well 1-168, with cumulative production totaling just over 660 MMCFG. The primary trapping mechanism, as in Zone 15 sandstones, is structural; gas is produced from the crest of rollover anticlinal structures formed on the downthrown side of the major Vicksburg fault. However, because of the limited distribution of 18-C sandstones within the study area, the occurrence of localized structural highs and pinch-outs of the sandstone (stratigraphic traps) are of paramount importance when searching for traps.

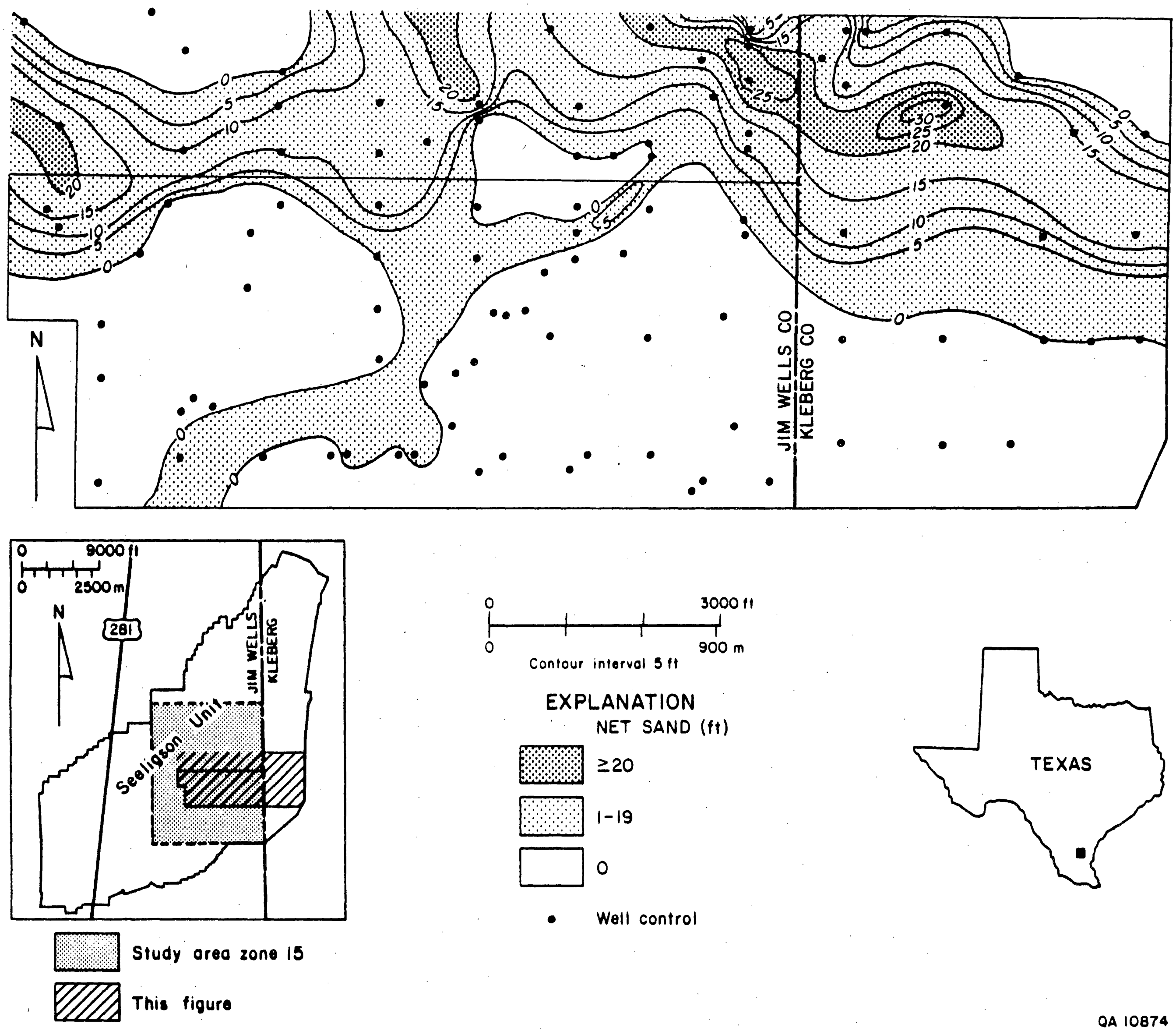

Figure 21. Net-sandstone isopach of aggregate Zone 18-C. Sandstone thicks (>20 ft) are found in dip-aligned pods and indicate primary axes of deposition.

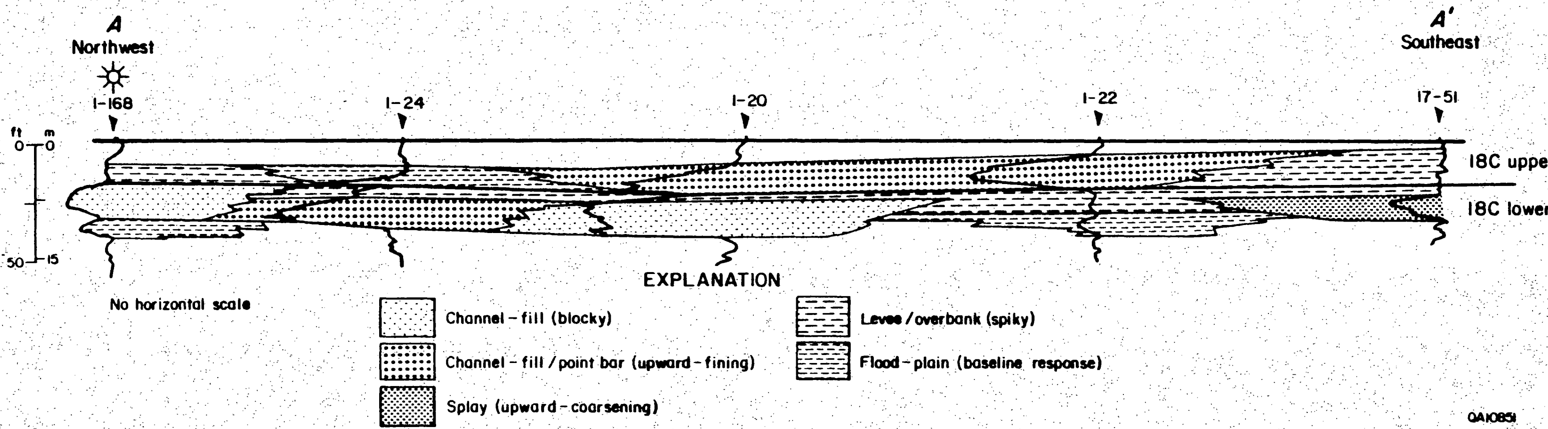

Figure 22. Stratigraphic cross section A-A' illustrating upper and lower sands within Zone 18-C (see fig. 23 for location). Recompletion target is channel-fill/point bar sandstone of 18-C upper in well 1-22. Facies changes in both upper and lower units should compartmentalize 18-C lower reservoir in well 1-168 and isolate potential gas-bearing 18-C upper zone in well 1-22.

Sandstone Distribution

Aggregate Zone 18-C sandstones range from 2 to 32 ft thick across the study area. Overall distribution of sandstone runs primarily from west to east, with the sandstones pinching out to the north and south, forming a ribbon of sand approximately 1 mi wide. A narrow zone of northeast to southwest trending, very thin (less than 3 ft) sandstone intersects with the main depositional axis in the central part of the study area (fig. 21). Net sandstone highs are concentrated in roughly three sub-parallel, dip-oriented elongate beads, suggesting deposition in fluvial channel environments.

Sandstone distribution patterns vary in the 18-C upper and lower component sandstones. The 18-C lower sandstone follows the same trend and occupies nearly the same width as the aggregate unit, although net sandstone values are less, ranging from 2 to 22 ft. The net sandstone contours are aligned in a west to east trending band with four separate, arcuate pods outlining the principal areas of deposition (fig. 23). Net sandstone patterns of this type are characteristic of point-bar and channel-fill sandstones in mixed-load fluvial systems (Galloway, 1977).

The 18-C upper sandstone belt, while following the same west to east trend, occupies a narrower area than the underlying 18-C lower sandstone (fig. 24). Throughout the west and central portions of the study area the belt rarely exceeds 1,500 ft; only in the eastern part of the area does the width of the belt approach 4,000 ft. Net sandstone thicknesses range from 1 to 20 ft, and areas of greatest sandstone thickness are concentrated in arcuate-shaped beads typical of point-bar and channel-fill sandstones (fig. 25).

Depositional Environment

Zones 18-C lower and 18-C upper each consist of single, narrow, fluvial channels trending west to east through the study area. Sharp-based, blocky and upward fining log responses define the axis of the channel-fill deposits; in the 18-C lower sandstone, the width of the axis is approximately

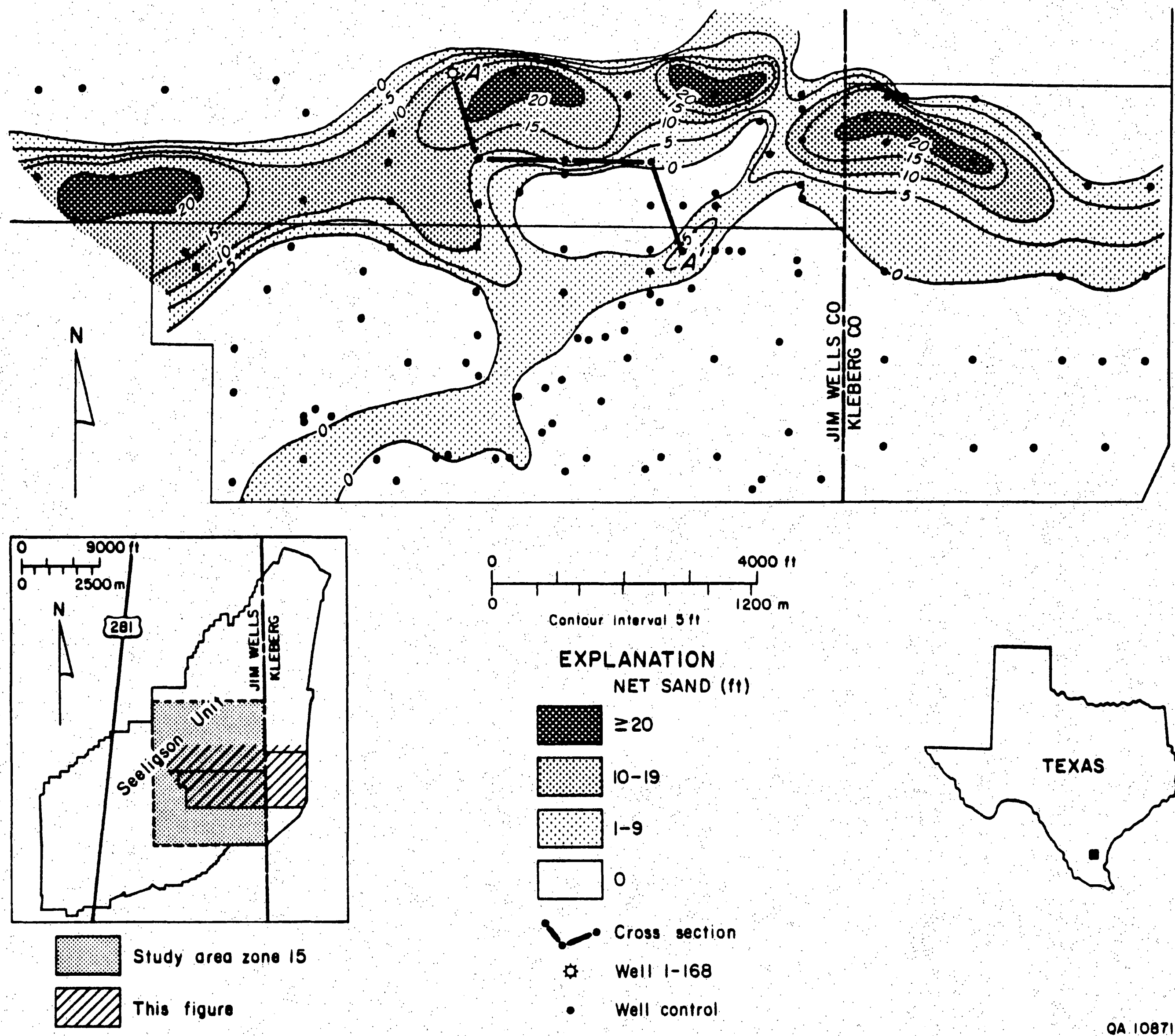

Figure 23. Net-sandstone isopach of Zone 18-C lower.

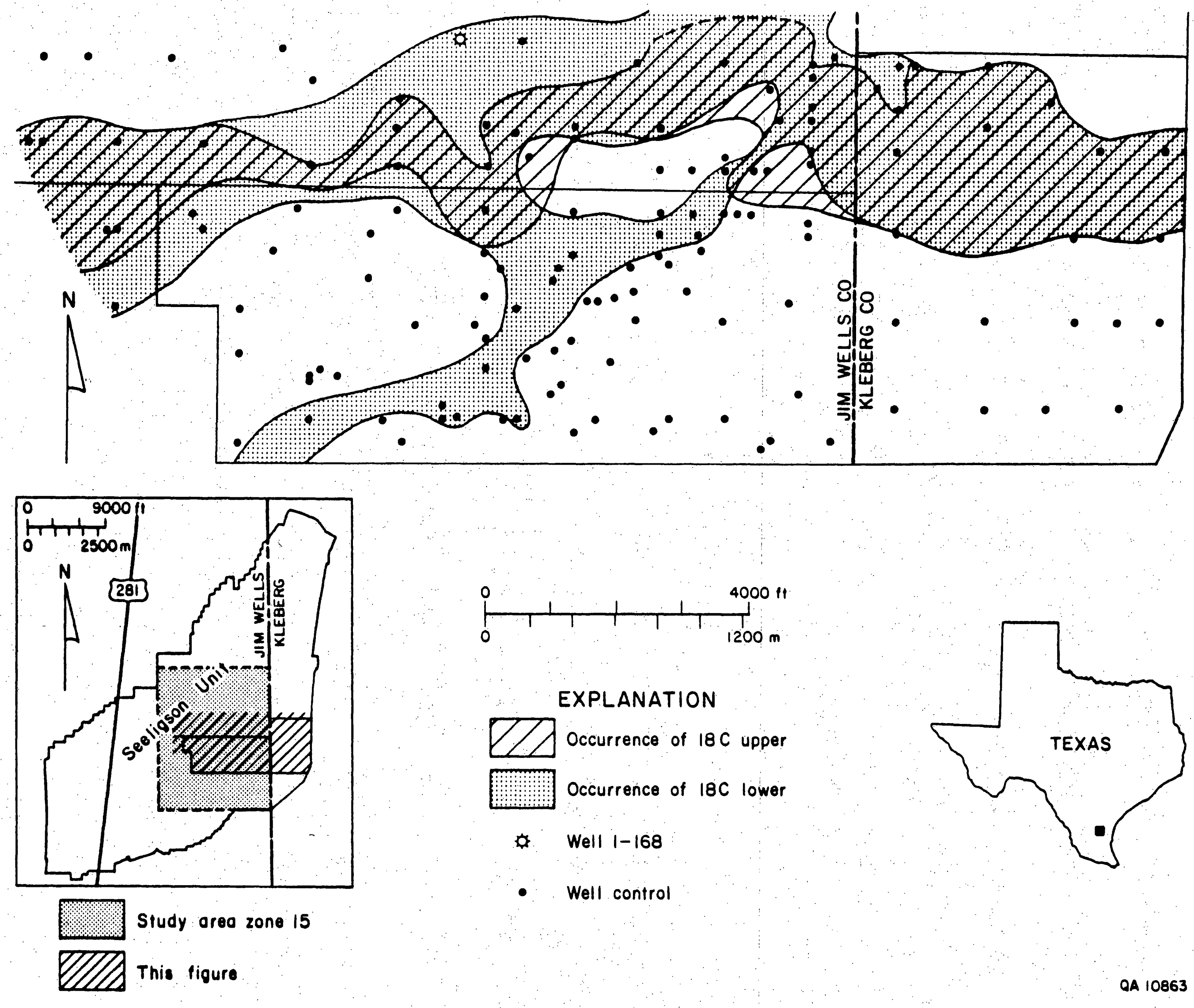

Figure 24. Relationship of Zone 18-C upper and lower channels. Important feature is the absence of production from the 18-C upper channel.

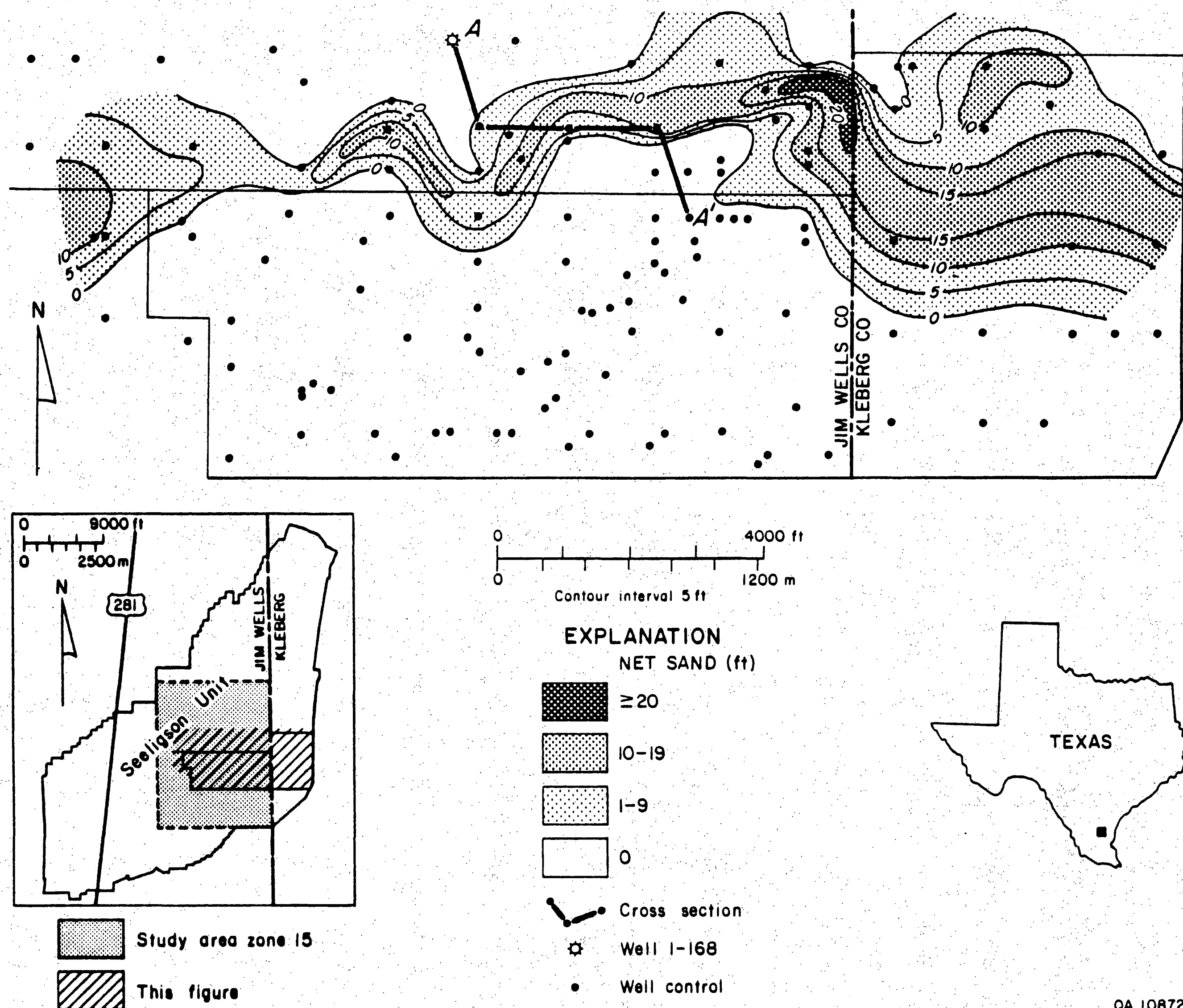

Figure 25. Net-sandstone isopach of Zone 18-C upper.

1,000 ft and is continuous through the area. Channel-margin deposits (spiky log responses) are very narrow and grade into floodplain siltstones and mudstones (baseline log response). Zone 18-C upper facies are similar to those of 18-C lower, although channel-fill and point-bar deposits are narrower and are found in discrete pods rather than in a continuous belt. As in the 18-C lower, the channel axis is bordered by very narrow channel-margin deposits that grade into floodplain mudstones.

RECOMPLETION RECOMMENDATIONS AND RESULTS

Four wells were recommended to Sun Exploration and Production Company for recompletion in Zone 15; three would test the 15-C sandstone and one would test the 15-B sandstone. One well was recommended for recompletion in Zone 18-C, testing the 18-C upper sandstone. A summary of recommendations and results on a well-by-well basis follows.

Well 17-17

Zone 15-C sandstone occurs at an electric log depth of 5,390-5,400 ft. In well 17-17, the C sandstone is separated from 15-B by 4 ft of shale (fig. 26). Facies mapping identifies the 15-C as a reservoir quality channel-fill deposit (fig. 20). There are no current completions in this channel, and the closest production from 15-C, well 16-124A, should be isolated horizontally by muddy floodplain facies (fig. 20). The structural position of well 17-17 is located on the flank of a local high (fig. 27).

TDT and digital cased-hole sonic logs were run in well 17-21, approximately 1,000 ft west of well 17-17. Preliminary evaluation of the logs indicated gas in the 15-B sandstone, and the equivalent gas effect could be assumed for the underlying 15-C sandstone (W. Howard, personal communication, 1988). Log correlations between wells 17-21 and 17-17 are very good.

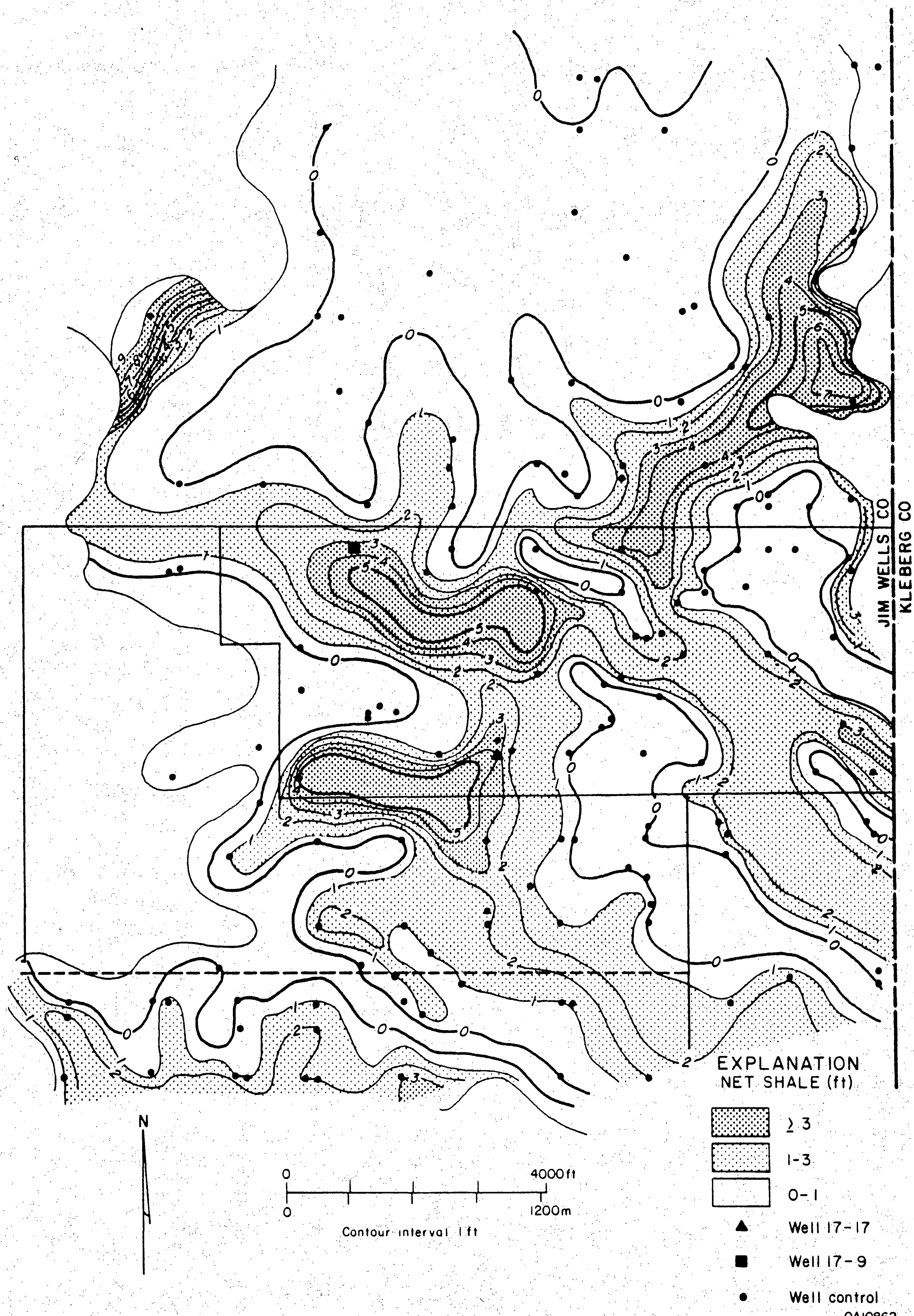

Figure 26. Thickness of shale between Zones 15-B and 15-C. Net shale values greater than 3 ft should provide an adequate permeability barrier between the two sandstones; net shale values of 1-3 ft might provide a moderate flow barrier.

Most production in the study area is from Zone 15-B sandstones. The nearest well that perforated the 15-C sandstone is well 16-124A, approximately 4,500 ft to the southwest, where 15-B and 15-C coalesce into an amalgamated unit and currently are producing 1,400 MCF/day.

This recompletion candidate was selected on the basis of its geological merit and the strength of preliminary log analysis in an adjacent well. The 15-C sandstone was identified as an isolated channel-fill situated near the crest of a local structural high, separated vertically from the productive, overlying 15-B sandstone and horizontally from the nearest 15-C perforations by muddy floodplain facies (fig. 14). Log analysis in the adjacent 17-21 well was favorable, and the log correlation with well 17-17 is excellent. In addition, Sun Exploration and Production Company had slated the 17-17 well for recompletion in shallower Zone 7F, requiring only incremental expense to test Zone 15-C. Sun Exploration and Production Company geologists and engineers accepted the concept but uncovered previously overlooked mechanical problems in the hole and were unable to agree to a test of this zone in this well. There were no nearby wells available for optional selection.

<u>Well 17-9</u>

Zone 15-C occurs at an electric log depth of 5,361-5,370 ft in well 17-9. Stratigraphically, the setting is similar to that of the 17-17 well, in that the 15-C sandstone is separated from 15-B by 5 ft of shale that should provide an adequate vertical permeability barrier (fig. 26). The 15-C sandstone in well 17-9, however, has been interpreted as a channel-margin deposit that is very close to its westward lateral pinchout. The nearest completion in 15-C sandstones is approximately 3,000 ft to the northwest in well 1-98, where production is from amalgamated 15-B and 15-C sandstones. Several facies changes occur between wells 17-9 and 1-98 (fig. 20) that might provide lateral flow barriers. The structural position of well 17-9 is near the crest of a local high (fig. 27).

A TDT log was run in this well, and interpretations were made by Sun Exploration and Production Company. They concluded that the aggregate interval should contain gas.

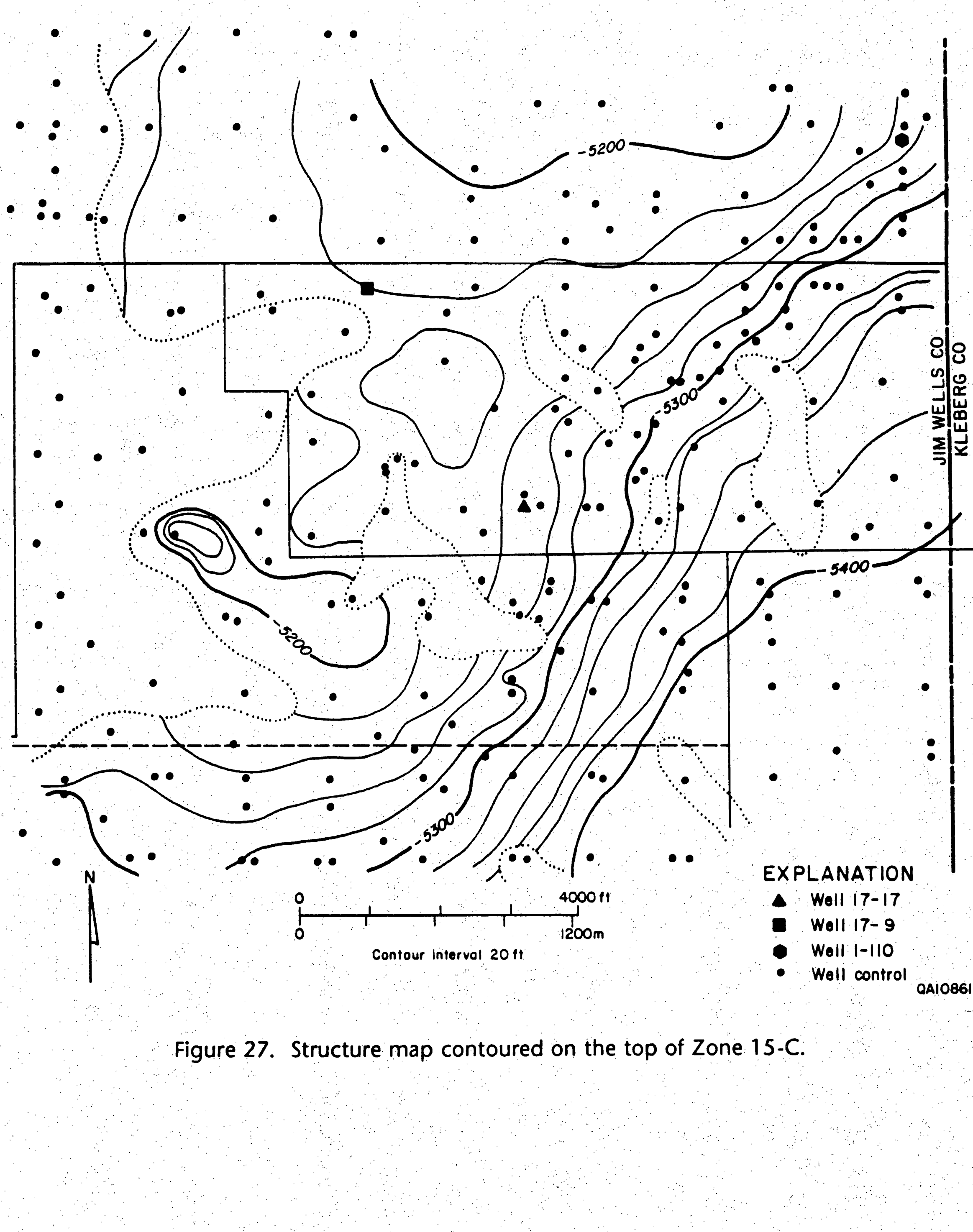

Figure 27. Structure map contoured on the top of Zone 15-C.

As is the case throughout the study area, most Zone 15 production is from 15-B sandstones. Well 1-98 is the closest well to perforate 15-C sands, but the two sub-units are coalesced, producing about 220 MCF/day.

Well 17-9 was selected by Sun for recompletion in Zone 15 based primarily on the results of their log analysis, which favored the upper unit, 15-B. This offered a unique opportunity to recommend testing a concept that might produce two separate results. The geological interpretation of an untapped channel-margin deposit isolated vertically from the overlying productive sandstone and horizontally by facies heterogeneities argued a strong case for probable compartmentalization. Because Sun Exploration and Production Company had already begun work on the recompletion of this well, it was proposed that they test the 15-C sandstone first, by itself. If the reservoir was indeed compartmentalized, relatively high pressure and possible hydrocarbons might be encountered. Unfortunately, the entire zone (both B and C sandstones) was simultaneously perforated before the recommendation was made. The well was tested, acidized and swabbed from 6/18/88 to 7/1/88. No gas was recovered, although indications of slightly higher than expected pressures were encountered during testing (D. Sadler personal communication, 1988).

Well 1-110

Zone 15-C occurs at an electric-log depth of 5,390-5,402 ft in well 1-110. This well is located in an area where the highly productive 15-B sandstone pinches out (fig. 14), and there are no nearby wells completed in the 15-C sandstone. Facies maps identify the 15-C in well 1-110 as a channel fill sandstone trending north to south (fig. 20). The well is located on the flank of the primary structural high in the area (fig. 27). A TDT log was run in the well and evaluated by Sun; their interpretations indicate that gas should be present in this sandstone.

There is no production from the 15-C sandstone in this channel or in the area. The closest well to perforate this interval is more than 1 mile away, in a well where the 15-B and 15-C sandstones coalesce to form a composite sandstone.

This recommendation offered an opportunity to test an untapped channel-fill sandstone. The salient characteristic of this selection was the identification of the 15-C as the sole sandstone in the interval because of the pinchout of the overlying 15-B. The sandstone had previously been assumed to be the 15-B, which is highly developed in and around the area, and would likely preclude recompletion. After presenting the results of the detailed geological evaluation to Sun and emphasizing the stratigraphic interpretations as well as the potential for reservoir compartmentalization in an untapped channel, they agreed with the conceptual framework but ultimately rejected the recommendation in this well because of its structural position. Sun did, however, agree to recomplete a well updip of 1-110 based on the geologic analysis as part of another package presentation.

Well 1-22

Zone 15-B is located at an electric-log depth of 5,335-5,347 ft. Log facies mapping illustrates a series of coalescing channels flanked by numerous crevasse splays; sandstone 15-B in well 1-22 is interpreted as a splay deposit (fig. 18). The well is located on the rim of the primary structural high in the area. TDT and digital cased-hole sonic logs were run in the well; log analyses indicate a gas productive zone (Howard and Bolin, 1988).

Most of the gas produced from Zone 15 within the study area is from the 15-B sandstone, and several wells within less than a mile radius have perforated 15-B sands. Because many wells simultaneously produce from both 15-B and 15-C reservoirs, cumulative production figures can not be disaggregated to the sub-unit level. However, cumulative gas production for Zone 15 reservoirs within the study area is about 57 Bcf.

This recommendation would test the horizontal isolation of an untapped splay sandstone. The crevasse splay is attached to a channel fill sandstone that has also not been drilled; however, significant production from 15-B has come from adjacent and merging channels. Sun Exploration and Production Company agreed with this recommendation, although at this time no activity has begun toward testing this reservoir.

A similar geologic setting resulted in a successful infill well in La Gloria field, located about six miles southwest of Seeligson field (W. Ambrose personal communication, 1988). Mobil Oil drilled the La Gloria Gas Unit (LGU) No. 110, completed in the Jim Wells reservoir. Jackson and others (in preparation) mapped the Jim Wells reservoir and interpreted a crevasse splay environment at the LGU No. 110. The reservoir had been extensively produced from adjacent channels and other facies, depleting reservoir pressures to the 200-300 psi range. Initial pressure in the Jim Wells for the LGU No. 110 was about 1,300 psi, and the well has produced over 50 MMCF of gas, documenting a facies-controlled undrained reservoir compartment.

Well 1-22

Zone 18-C occurs from 5,731-5,752 ft in well 1-22. The target sandstone is the 18-C upper, which has been identified as a separate genetic sandstone body and interpreted as a reservoir quality channel-fill deposit horizontally and (to a lesser degree) vertically isolated from the productive 18-C lower. This lateral relationship is best seen on cross section A-A' (fig. 22). Structural position of the well is on the flank of a local high. TDT and digital cased-hole sonic logs were run in well 1-22. Log analysis indicated that an apparent gas productive zone would be found in Zone 18-C, although it should be considered a low resistivity pay.

Gas production from Zone 18-C within the study area is restricted to well 1-168, which has produced of 663 MMCF (cumulative). Detailed stratigraphic analysis identifies this productive sandstone as the 18-C lower; no perforations have been made through the 18-C upper unit.

It was recommended that Sun Exploration and Production Company recomplete well 1-22 in the 18-C, upper sandstone, based on the documented geologic evaluation and the favorable log analysis. This recompletion would test an untapped channel sandstone that had previously been treated as the equivalent to the producing subjacent sand (18-C lower) and would not have been considered for additional testing because of its proximity to the sole producing well in the area. Sun agreed to recomplete the well, and perforated, acidized and swabbed from 6/25/88 through 7/6/88 before the well died. No recovery of gas was made, although early shut-in tubing pressures indicated relatively strong pressures were encountered (D. Sadler personal communication, 1988). Final bottom-hole pressures will be taken when the well stabilizes. It is possible that this zone might have been productive if it had been tested for a longer period of time. Duggan and Langston (1988) indicate that a considerable amount of gas reserves may be recoverable from depleted reservoirs, as long as completion and stimulation procedures employ a great deal of patience. They cite examples where more than 30 days of stimulation was required before the well became successful.

CONCLUSIONS

Advanced geological characterization methods can be applied when searching for compartmentalized reservoirs or bypassed gas zones in established fields. Integrating these methods with engineering and petrophysical assessments results in the prediction of isolated hydrocarbon-bearing zones which can then be tested through well recompletions or infill well drilling. In Seeligson field, as in many other fields where multiple, vertically-stacked, predominantly fluvial reservoirs comprise the stratigraphic framework, abundant opportunities for evaluating potentially undrained reservoir compartments are present.

This study focused on only two of over thirty reservoirs within a small segment of Seeligson field. Zone 15, which has been developed under the assumption that it is a homogeneous and continuous reservoir, is in fact composed of several separate heterogeneous sandstones. Zone 18-C, also developed under the assumption that it is a homogeneous, continuous reservoir, was found to be composed of two separate sandstones, one of which had never been tested. Five recompletion recommendations were made for wells in both zones. Unfortunately, two were rejected due to mechanical and/or operational problems, two remain untested, and one (Zone 18-C upper) was briefly tested and considered unsuccessful.

Detailed geologic evaluation did, however, explain anomalous bottom-hole pressures documented between wells completed in Zone 15. Relatively high pressures in four recent recompletions are fundamentally controlled by facies heterogeneities. Two channel complexes are separated by a muddy floodplain facies. One is heavily developed with depleted reservoir pressures, but the other was untapped, and anomalously high pressures were encountered upon recompletion.

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LOWER MIOCENE SANDS IN THE TOM O'CONNOR FIELD AREA, REFUGIO COUNTY, TEXAS

by
D. R. Kerr

INTRODUCTION

The Tom O'Connor field, located in Refugio County Texas, is a northeast to southwest trending anticlinal trap with multiple producing intervals. Structural rollover is related to growth fault activity along the Vicksburg Fault zone. Both Oligocene Frio and Miocene sandstones produce gas at Tom O'Connor as well as in adjacent fields (fig. 1). Tom O'Connor field has produced approximately 1 Tcf of gas since its discovery in the 1930's. Miocene sandstone reservoirs are included in the Atlas of Major Texas Gas Reservoirs (Kosters and others, in preparation) as part of the "Moulton/Pointblank streamplain along reactivated Frio Faults" play. Many of the reservoirs in this play are in advanced stages of depletion; however, new pools continue to be discovered. Within Tom O'Connor field, the 4,150 and 4,200 ft sandstones are examples of new pool discoveries, and as of 1985, have produced 400 MMCF of gas.

Lower Miocene sandstones were deposited during the initial offlap of the early Miocene progradational episode (Galloway and others, 1986). Prior to offlap, deposition of Anahuac shelf mudstones of the late Oligocene to early Miocene represent a Gulf-wide transgressional episode. Subsequent to offlap, deposition of <u>Marginulina</u> <u>ascensionensis</u> shelf mudstones represent a second, shorter transgressional episode. Near the present-day shoreline early Miocene progradation deposited more than 2,000 ft of fluvial and nearshore sands and muds and shelf sands and muds at the transition between the North Padre Delta depositional system and the Matagorda Barrier/Strandplain depositional system (Galloway and others, 1986).

This study focused on the nature of initial progradation and geometry of sandstone bodies deposited during progradation. A sequence stratigraphic framework was developed over a regional network of cross sections that extended into adjacent counties and joined with the wider network

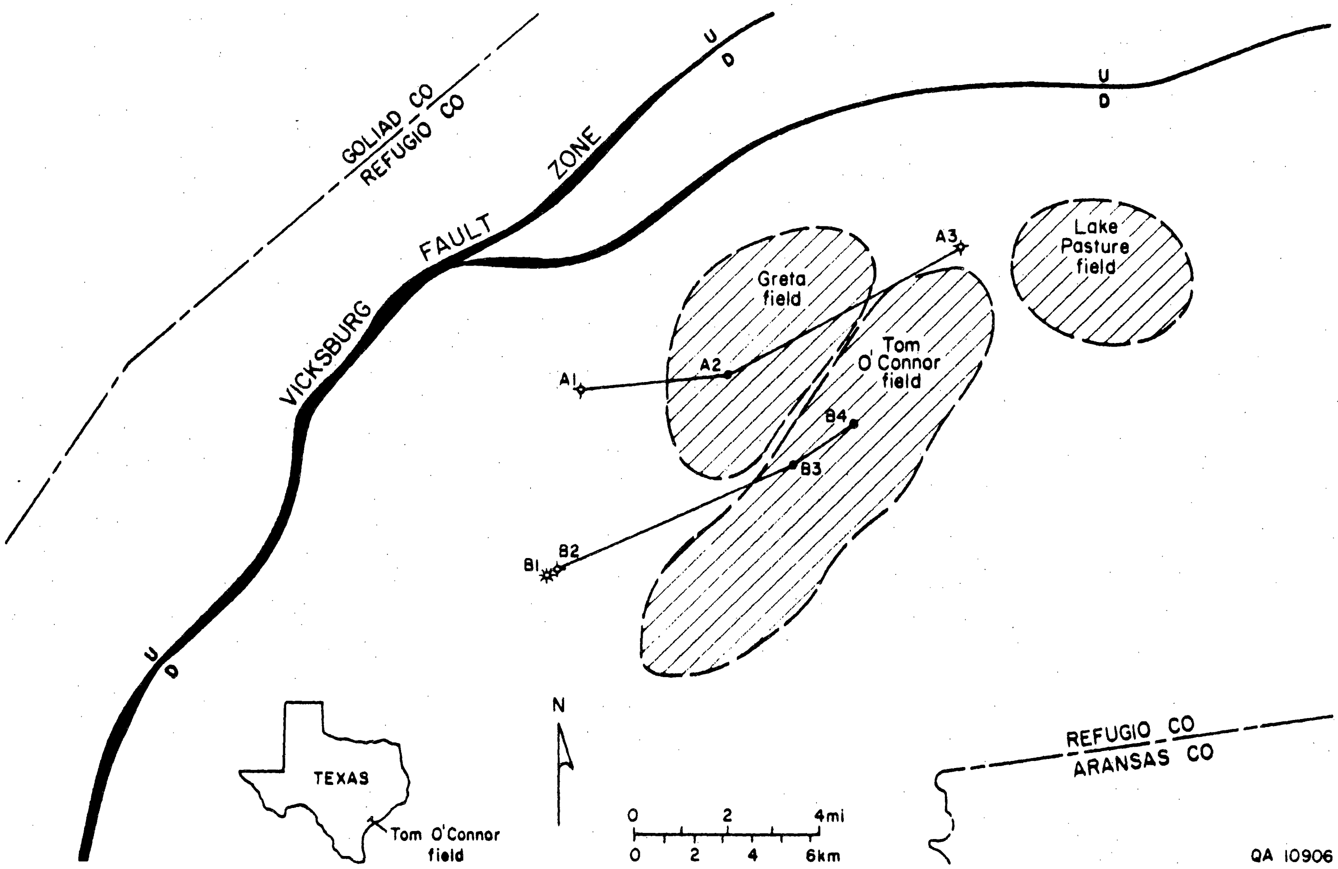

Figure 1. Index map. Location of Tom O'Connor field is shown along with that of adjacent fields with production from Miocene sandstones. The Vicksburg Fault Zone, a growth fault, was apparently active during deposition of lower Miocene sediment. Cross sections A and B are illustrated in figure 2.

of Dodge and Posey (1981) and Morton and others (1985). Within this stratigraphic framework, log-facies and isopach maps were used to refine the distribution of environmental elements within the broader depositional systems outlined by Galloway and others (1986). This report discusses the stratigraphic framework and log facies of the interval that includes the 4,150 and 4,200 ft sandstones.

STRATIGRAPHIC FRAMEWORK AND LOG FACIES

The Anahuac Shale and Oakville sandstones are constructed of parasequences. Parasequences are transgressive/regressive facies successions that are separated by marked marine flooding surfaces (Van Wagoner and others, 1987). These surfaces are disconformities that are lower in rank than the unconformity surfaces separating stratigraphic sequences. Parasequences are the "building blocks" of stratigraphic sequences. This study examined mostly the parasequence development that followed maximum flooding (approximated by the Heterostegina-Marginulina zone) through progradation of early Miocene sands.

Wireline log identification of parasequences is based on two criteria. (1) Each parasequence should coarsen upward; even in muddy intervals this trend is noted on the amplified short-normal resistivity profile (fig. 2, parasequence 7). The parasequence boundary is commonly marked by a thin, low resistivity interval or low resistivity marker (Vail, personal communication, 1988). (2) Parasequences are correlative over a wide region (100's to 1,000's of square miles). Parasequences can contain one or more transgressive/regressive facies patterns representing relatively local coastal retrogradation and progradation, but it is the regionally continuous transgressive intervals that distinguish one from the other.

In the lower Miocene, parasequences in the Anahuac Shale (subsequent to maximum flooding) are about 40 to 50 feet thick. In the overlying basal Oakville the parasequences progressively thicken to 100 to 200 feet. Local variations in thickness occur in the vicinity of growth faults and their attendant structures and where erosion along the parasequence disconformities has removed

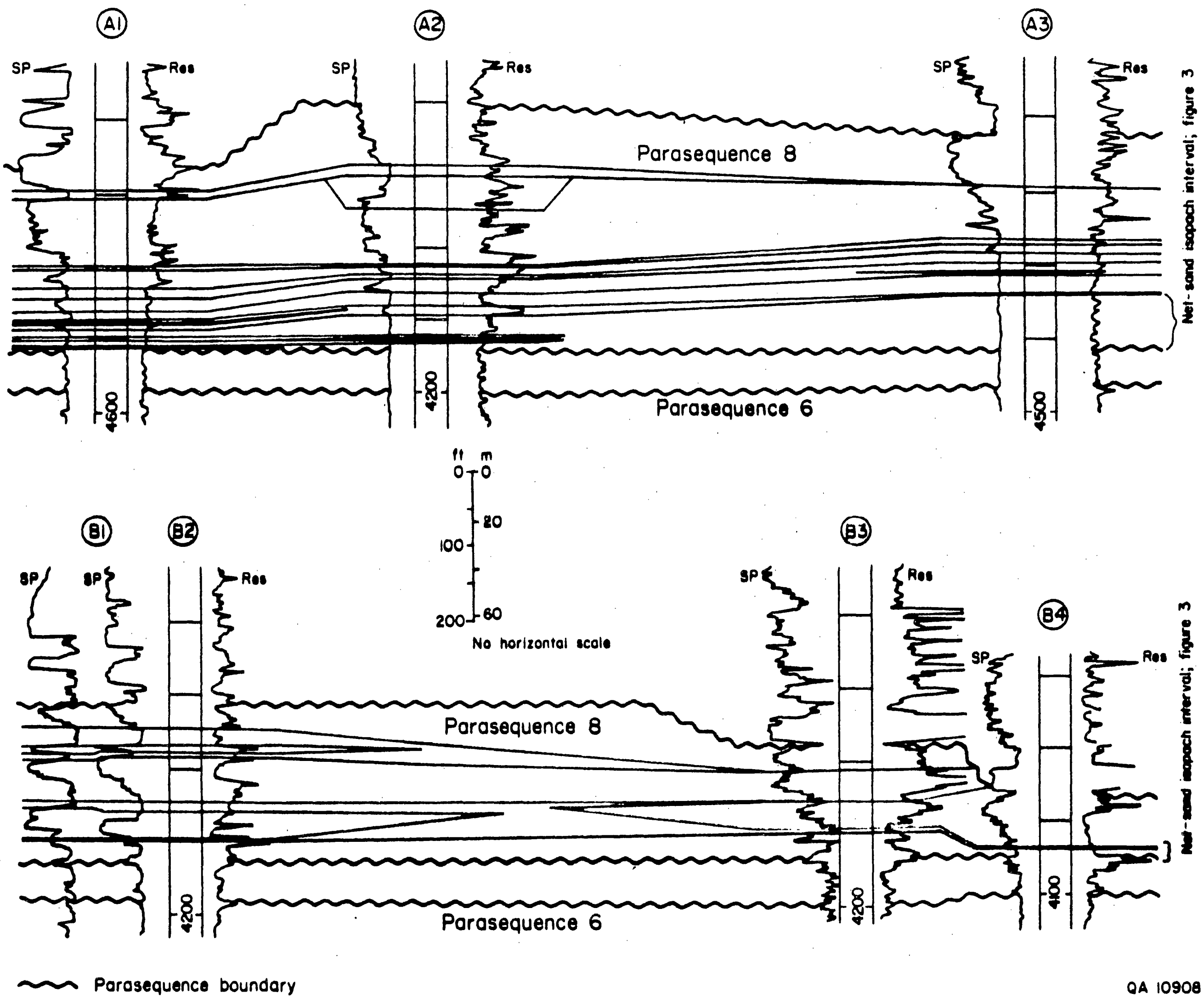

Figure 2. Cross sections A and B. Serrated lines separate parasequences that are based on a regional wireline log cross-section network. See figure 1 for location of wells and table 1 for well identification.

Table 1. List of well names for wireline logs used in figure 2.

Figure Reference	Operator	Well Name	Tobin Grid
A 1	Tennessee Gas Transmission Co.	Hynes F-25	13S-23E-9
A 2	Atlantic Refining Co.	Tom O'Connor 8	13S-23E-8
A 3	Southern Petroleum Exploration, Inc.	Hynes 1	13S-24E-4
B1	Seaboard Oil Co. and R.W. Young	Hynes A4	14S-23E-4
B2	B. Graham	Fox 1	14S-23E-4
B3	Quintana	Tom O'Connor C67	14S-23E-2
B4	Quintana	Tom O'Connor C75	14S-23E-1

part of the previously deposited parasequence (for example, base of parasequence 9 in well A1, fig. 2). Parasequence 8, which includes the 4,150 and 4,200 ft sandstones in its lower part, is 150 to 300 feet thick on the footwall near the Vicksburg Fault Zone and thins to 100 feet about 10 miles away (southeast), then gradually thins to 50 feet over another 20 miles. The abrupt thinning near the Vicksburg Fault Zone is approximately coincident with growth-fault related anticlinal structures such as the Tom O'Connor anticline.

Wire-line log character and sand-body geometry are used to delimit three facies elements. Facies 1 has a funnel-shaped log character (for example, 4,125 to 4,240 ft in well A3, fig. 2) representing progradational, sand-rich coastal settings. Facies 1 is further divided based on geometry into Facies 1a with a broad, lenticular geometry and Facies 1b with a depositional-strike-parallel, lenticular geometry. Facies 1a is regarded as the outbuilding of channel mouth bars, the deposits of which are typically stacked into 20 to 30 ft thick units (fig. 2). Facies 1b is regarded as the deposits of the barrier/strandplain core that typically occur as single sand bodies within a parasequence.

Facies 2 has a bell-shaped log profile and a narrow, lenticular geometry (for example, 3,900 to 3,950 ft in well A2, fig. 2); it is interpreted as channel-fill depositional setting. Channel-fill deposits are generally thicker where they were deposited immediately above a parasequence boundary (as compared to channel-fill deposit thickness within the upper parts of a parasequence (>50 ft). Facies 1 and 2 are the principal sandstone intervals of the lower Miocene in the Tom O'Connor area. They develop into 50 to 100 ft thick complexes in the upper intervals of a parasequence. Facies 1 grades shelfward and downward into Facies 3.

Facies 3 has a serrate to suppressed, straight log character and a gentle, Gulf-ward thickening wedge geometry. Facies 3 is interpreted to represent lower shoreface to offshore environments. The serrate log profile reflects the interstratified mudstone and sandstone composition of Facies 3. The 4,150 and 4,200 ft sandstones of Tom O'Connor field are examples of sandstones included in Facies 3. These 2 to 10ft thick sands reside in two positions within a parasequence. First, they rest at the base where they probably represent reworking of former Facies 1 or 2 sands during transgression (for example, 4,120 ft in well B2 and 4,130 ft in well B3, fig. 2). Second, they reside between the parasequence base and the progradational Facies 1 and 2 complexes (for example, 4,080 ft in well A2, fig. 2). In the latter case, Facies 3 sandstones are either isolated in mudstones or laterally contact the thick progradational Facies 1 and 2 complexes.

Figure 3 illustrates the net-sandstone distribution of the lower parasequence 8, the interval encompassing the 4,150 and 4,200 ft sandstones (fig. 2). Net sand thickness increases to a maximum observed thickness of 25 ft toward the Vicksburg Fault Zone, following parasequence gross thickness described above. The isopach interval is composed of several 2 to 5 ft thick sandstones that tend to increase in number toward the fault zone (compare interval in B vs A of fig. 2). The net-sandstone zero isopach traverses the crest of the Tom O'Connor anticline, and net-sandstone isopachs appear to deflect around the Greta anticline as well. The net-sand isopach map pattern suggests that a positive bathymetric feature may have limited offshore sand sedimentation (Facies 3) during the initial, transgressive phase of parasequence 8.

CONCLUSIONS

Parasequence 8, which contains the Tom O'Connor field new gas pool 4,200 and 4,150 ft sandstones, developed during growth fault activity along the Vicksburg Fault Zone. Near the fault zone, gross interval markedly thickens to 300 ft. About 6 mi gulfward, or along the southeast flank of Tom O'Connor field, the parasequence thins to less than 100 ft, and farther gulfward, the parasequence reaches 100 ft before gradually thinning to about 50 ft out to the southeastern limit of the area mapped (approximately 20 mi from the fault zone). Thus, a complementary anticlinal structure appears to have developed gulfward of the Vicksburg Fault Zone during deposition of this particular parasequence. Moreover, this growth fault activity may have influenced local bathymetry.

Log-facies and net-sandstone isopach maps also reflect growth fault activity. Deposition of the 4,150 and 4,200 ft sandstones, as part of the offshore system during initial parasequence

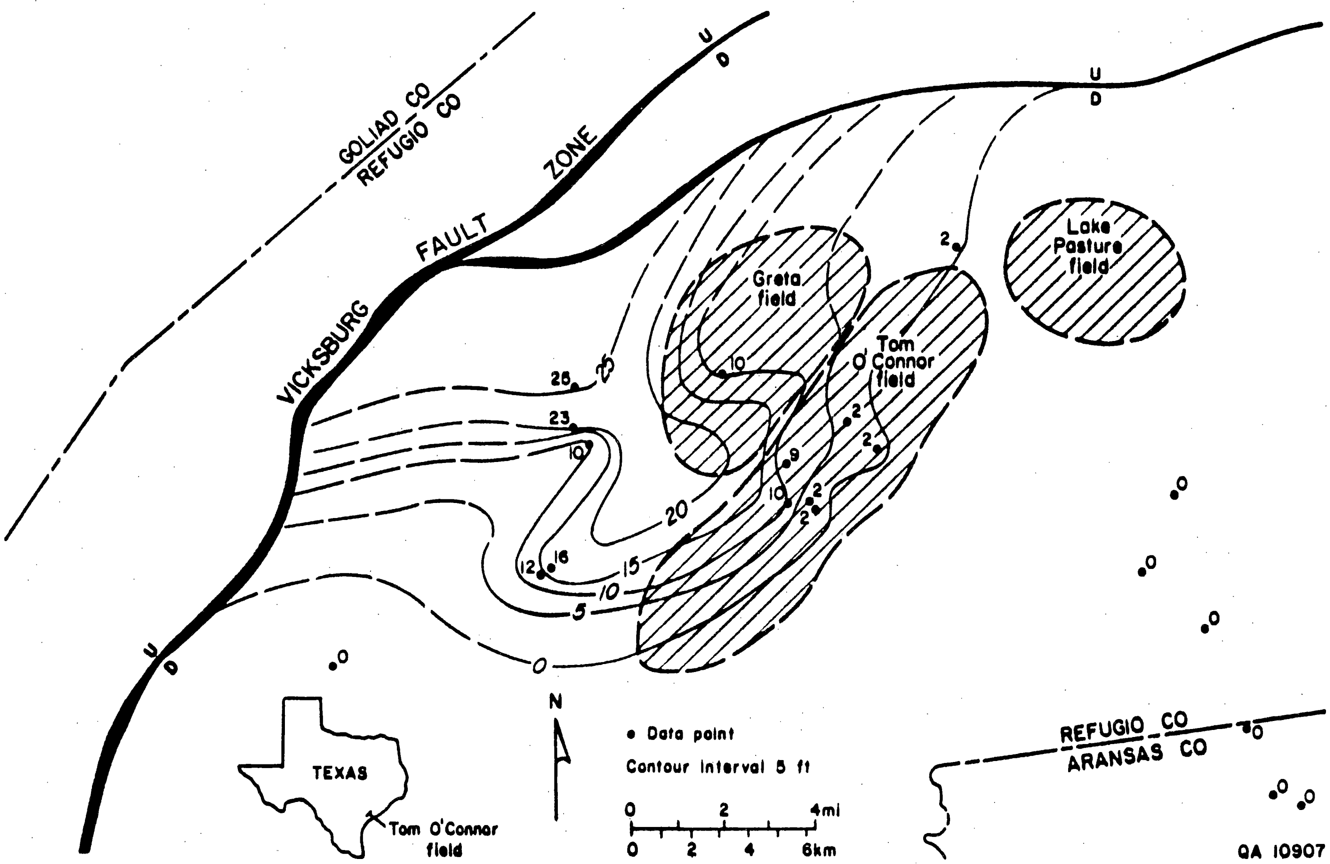

Figure 3. Net-sandstone isopach map. Net sandstone thickness of the lower part of parasequence 8 (fig. 2) is mapped in 5-foot contour intervals. Note net sandstone thickness increases toward Vicksburg Fault Zone and terminates along crest of Tom O'Connor field anticline.

deposition, was confined between the Vicksburg Fault Zone and the contemporaneous anticlinal crest. Maximum net-sandstone thickness is 25 ft, and the sandstone edge (zero net-sandstone isopach) is limited by the anticlinal flank through Tom O'Connor field. Progradation of the fluvial and barrier/strandplain (or delta) systems surmounted the anticlinal crest and proceeded gulfward.

To what extent growth faulting and its complementary structural elements affect the distribution of offshore sands (e.g. 4,150 and 4,200 ft sandstones) remains to be examined elsewhere. The relationship between growth faulting, bathymetry and offshore sand sedimentation may prove to be a means for producing reservoir compartments in relatively thin, gas-prone offshore sandstones.

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