GRI-90/0122

ASSESSMENT OF GAS RESOURCES
FOR SECONDARY GAS RECOVERY TECHNOLOGY

FINAL REPORT

Prepared by

M. L. W. Jackson, W. A. Ambrose, and R. J. Finley

Bureau of Economic Geology
W. L. Fisher, Director
The University of Texas at Austin
Austin, Texas 78713

and

M. R. Haas, K. S. McFall, J. A. Rushing, and V. A. Kuuskraa

ICF-Lewin Energy Division
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16. Abstract (Limit: 200 words)

Unrecovered gas resources available through existing technology can be a significant source of reserve additions in maturely explored petroleum provinces. In this study, nonassociated and associated Texas reservoirs were analyzed for gas reserve growth potential. In the nonassociated fluvial Frio Brooks reservoir, infill drilling from 640 to 320 acres per well can potentially increase reserves by 15.7 percent of estimated ultimate recovery. Gas reserve additions may result from improved contact with isolated or partially isolated sandstones that are not effectively drained by conventional development practices.

An additional 14.4 Bcf of gas resources can be potentially recovered by strategic infill drilling down to 10-acre spacing in the Grayburg reservoirs of Dune field, one of many mature West Texas fields located on the Central Basin Platform. Infill wells strategically drilled in the Dune field grainstone facies are projected to be most cost-efficient and productive.

Recoverable associated gas in selected plays is estimated to be from 3.4 Tcf to 5.8 Tcf. The greatest recovery potential for associated gas reserve growth in Texas is in carbonate reservoirs with complex facies architecture in the Permian Basin. Geologically based infill wells in areas of greatest reservoir heterogeneity can recover much of this unproduced gas resource.

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b. Identifiers/Open-Ended Terms

c. COSATI Field/Group

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RESEARCH SUMMARY

Title	Assessment of Gas Resources for Secondary Gas Recovery Technology, Tasks 3a, 4a, 5, and 6.
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5087-212-1526A and B.
Principal Investigators	R. J. Finley and N. Tyler
Report Period	March 1, 1987 – February 28, 1989
Objectives	To select representative gas reservoirs from volumetrically important nonassociated gas plays of Texas for detailed geologic and engineering analysis.

To determine the depositional systems of the selected gas reservoirs and delineate the areal and vertical extent of the gas-producing zones, reservoir engineering characteristics, and reservoir heterogeneity determined from distribution of facies.

To acquire extensive well pressure and production histories, determine gas in place, and characterize each facies in terms of reservoir engineering properties.

To develop a method for estimating gas contacted by infill wells at decreasing well spacing and to predict gas recovered from infill drilling from 640- to 160-acre spacing in each reservoir.

To evaluate the amount of associated gas reserves that can be recovered from carbonate and clastic oil reservoirs that are representative of major oil plays in Texas.

To develop a method for quantifying pay continuity in oil reservoirs and to estimate the amount of associated gas reserves available through strategic infill drilling in the study reservoirs.

To estimate the economic benefits of strategic infill drilling by comparing it with blanket infill drilling.

To extrapolate the results of the associated reservoir analysis to the play level and, if possible, to larger areas.

Technical Perspectives

Railroad Commission District 4 is the leading nonassociated gas-producing district in Texas, and it accounted for 26 percent of 1987 production. Multiple vertically stacked sandstones, numerous faults, and high geothermal gradients in the fluvio-deltaic Frio formation in this district provide abundant good-quality gas-prone reservoirs. The highly complex depositional architecture of Frio reservoirs provides a good opportunity to evaluate compartmentalized gas zones through advanced geological and engineering characterization methods.

Three large-volume reservoirs were selected as representative of Frio fluvial and Frio deltaic depositional settings in South Texas. Structural, stratigraphic, and facies characteristics were mapped in detail for each reservoir to determine geological heterogeneity and to identify potentially untapped gas compartments. Engineering analysis, using a specially modified reservoir simulator, quantified contacted gas as a function of well spacing and provided estimates of gas potentially contacted by infill drilling.

Three representative reservoirs were also examined from associated gas plays in West Texas and in District 2, where a significant amount of gas is produced. A method to quantify pay continuity was adapted from the well-known method of Stiles (1976). Using reservoirs in which zones of permeability were identified on geophysical logs, permeability and thickness were multiplied and evaluated for many sets of well pairs. The resulting plots provide a measure of pay continuity relative to distance between wells.

The economic benefits of geologically determined and blanket infill drilling strategies were examined for each representative reservoir using computer-based modeling programs. Higher permeability areas were selectively chosen for modeling strategic infill drilling. In all cases, strategic infill drilling was the most economically beneficial of the two methods.

Results

About 16 Bcf of incremental technically recoverable gas is estimated to result from infill drilling from 640 to 320 acres per well in the Brooks reservoir, La Gloria field. Infill drilling from 320 to 160 acres per well would contact an additional 9.3 Bcf.

Following the same method used in the analysis of the Brooks reservoir, infill drilling in the Jim Wells reservoir from 640 to 320 acres per well is estimated to recover an additional 13.8 Bcf of natural gas. Further infill drilling to 160 from 320 acres per well recovers an additional 7.7 Bcf. As in the Brooks reservoir, areas of the reservoir with relatively thick net sandstone have the greatest technical potential for infill drilling.

Field data did not show infill wells always to be at appreciably higher pressures than existing producing wells, although two recompletions at 1,000 psi above average reservoir pressure were noted. Infill wells in the Brooks and Jim Wells reservoirs did add gas reserves, however, and the engineering analysis shows that these wells contacted reservoir volume that was not previously in pressure communication with existing producing wells. A probable production mechanism to explain these data is that infill wells drain reservoir volumes that are adjacent to, but discontinuous with, sandstones common to both infill wells and existing producers. Thus, wells placed so that they can be completed in an optimum number of facies having mudstone-rich boundaries can potentially contact the greatest percentage of gas in place at any well spacing.

Using an original gas in place value of 25.5 Bcf and a reservoir pressure at the time of infill drilling of 50 percent of the initial reservoir pressure, infill drilling in the I-92 reservoir in Julian North field from an initial development pattern of 640 acres per well to a spacing of 320 acres per well is estimated to recover an additional 4.7 Bcf of natural gas. Further infill drilling to 160 acres per well recovers 1.0 Bcf. This reservoir contains diagenetic alterations that add to reservoir heterogeneity.

Estimates of the amount of recoverable associated gas in Texas from the major associated gas plays range from 3.4 Tcf (conservative method) to 5.8 Tcf (optimistic method). These estimates are for the major associated gas plays only.

Under blanket infill drilling in Dune field, South Central Basin Platform play, the average cost per Mcf of a recoverable associated gas volume of 250 Bcf is $1.96/Mcf. For strategic infill drilling the average cost is $1.35/Mcf, or 31 percent less on a cost-per-unit basis. Approximately 137 Bcf of associated gas is recoverable from the Frio barrier/strandplain play by infill drilling from current spacing to 10 acres per producer. About 68 Bcf will come from the tidal-inlet facies, which has the greatest infill potential for the play. An estimated 22 Bcf is recoverable from the barrier-core facies, and another 47 Bcf is recoverable from the backbarrier facies. For strategic infill drilling the average cost is $1.80/Mcf, or 17 percent less than blanket infill drilling on a cost-per-unit basis, clearly indicating that strategic infill drilling should be more economical than blanket infill drilling on a regular grid pattern. Approximately 187 Bcf of associated gas is recoverable from the Clearfork Platform play by infill drilling from current spacing to 10 acres per producer.

The greatest recovery potential for associated gas in Texas is in carbonate reservoirs in the Permian Basin. These reservoirs, which commonly have solution-gas drives and poorly developed gas caps, have low recovery efficiencies as a result of complex facies architecture. Geologically based infill wells in areas of greatest reservoir heterogeneity can recover much of this unproduced resource.

Technical Approach

Geologic characterization of the reservoirs studied included electrical and porosity log interpretation. Both public and private log libraries were used. Stratigraphic mudstone markers (indicated by low values on deep resistivity logs) and interpretations based on facies models were used to divide the vertical sandstone sequences into depositional units and subunits; eight stratigraphic markers were correlated on over 200 electric logs throughout La Gloria field. For Julian and Julian North fields, well control was sparse, making correlation difficult. Seventeen stratigraphic markers, at 5,700 to 9,700 ft in depth, were correlated on 43 logs in the Julian area. Twenty-four detailed and fieldwide stratigraphic cross sections were made in

La Gloria field, and four stratigraphic and six structural sections were made in Julian and Julian North fields. These sections were supplemented by over 20 cross sections obtained from hearing files at the Railroad Commission of Texas. In addition, seven fence, or panel, diagrams were made on six La Gloria field reservoirs, and one was made for the Julian North I-92 reservoir. Facies interpretations of fluvial and deltaic environments in these reservoirs were based on net-sandstone-thickness and spontaneous-potential- (SP-) log facies maps and were compared with modern and ancient examples from the literature.

Reservoir data, gas and condensate production, and operating practices were obtained from operators, public records, and private data sources. Geological and engineering data were used to calculate total volumetric gas in place for each reservoir. Production decline curve analysis was then selected as the most appropriate technique to estimate the volume of gas in place contacted by each producing well. Aggregate estimates of contacted gas at various well spacings were used to construct an empirical gas contact function for each reservoir. The function, which relates well spacing to reservoir contact, was used to determine the volume of gas available for reserve growth. Technically recoverable gas estimates were calculated using field development and gas economics models developed or adapted specifically for this analysis.

Estimates of oil and associated gas reserve growth potential of the Dune (Grayburg) and West Ranch (41-A) reservoirs through strategic, or geologically based, infill drilling were based on pay-continuity functions for each of the major facies in these reservoirs. The pay-continuity functions based on logs, cores, other geologic data, historical production data, and engineering analyses related reservoir continuity to horizontal distance between existing well pairs. These pay-continuity functions were used with volumetric and reservoir properties to estimate the amount of recoverable oil and associated gas in each reservoir.

Estimates of the recoverable oil and associated gas in the two plays, San Andres/Grayburg (South Central Basin Platform) and the Frio barrier/strandplain, were projected from amounts determined from the Dune and West Ranch reservoirs, respectively. To determine the oil and associated gas recoverable through strategic infill drilling, these reservoirs were divided into their primary facies, and the volume of reservoir corresponding to each major facies was determined. Pay-continuity functions specific to each of these facies were developed. The determination of recoverable mobile oil remaining in each reservoir was made by weighting the fraction of each major facies in the reservoir and the pay continuity established for each facies.

Project Implications

This project has shown that methods for calculating reservoir contact functions developed in oil reservoir analyses are not directly applicable to gas reservoirs because of the larger spacing between gas wells. Also, irregular spacing of gas wells must be accounted for in estimating reservoir contact functions.

This project has shown the need for additional research to better assess the incremental infield reserve growth of heterogeneous gas reservoirs; GRI has several ongoing projects that address this need. The GRI/DOE/Texas joint venture for infield reserve growth is currently performing detailed analyses of several sandstone reservoirs to determine the potential for reserve growth. Results of the joint venture will be more conclusive than the attached study report.

GRI is also performing statistical analysis on large amounts of production statistics for Texas Railroad Commission Districts 4 and 8 to determine if the fields analyzed in this study and by the joint venture are "typical" of their respective geologic plays. Results of the statistical analysis will also help to quantify the magnitude of incremental infill reserves.

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EXECUTIVE SUMMARY

The well-documented predominance of crude oil reserve growth as the overwhelming contributor to new oil reserves during the last 10 years suggests that the same potential may exist for natural gas. This report estimates the potential of natural gas reserve growth from infill drilling in several major nonassociated and associated gas plays in Texas. Detailed geological and engineering analyses were conducted for selected reservoirs in these plays, representing various geologic environments of deposition.

Nonassociated gas reserve growth from infill drilling was estimated for three reservoirs in the Frio Formation of the Texas Gulf Coast. Detailed geologic mapping of sandstone thickness and distribution of facies types in the study reservoirs formed the basis for the combination of facies-specific reservoir properties and net sandstone thickness values with a well-by-well reservoir engineering analysis. The engineering analysis was used to estimate the volume of gas contacted by existing and infill wells. From this calculation, an empirical function was developed to relate well spacing and interwell distance to reservoir contact. Finally, reservoir modeling analysis was used to estimate the volume of recoverable gas at alternative well spacings.

The results of the analysis show that infill drilling from 640 to 320 acres per well in the nonassociated Frio Brooks gas reservoir can potentially increase reserves by 11.4 percent of estimated ultimate recovery (EUR). The amount of potential reserve increase (ranging from 7.8 to 29.0 percent of EUR in two other reservoirs studied) depends on the specific geology and development history of a reservoir. In addition, the results of the study indicate that mechanisms driving reserve growth from infill development are a combination of the effects of reservoir heterogeneity and reservoir development practices. Gas reserve additions result from improved contact with isolated or partially isolated sandstone pockets that are not effectively drained during the economic lifetime of a producing well. These findings confirm the importance of flow restrictions and reservoir compartmentalization in gas reservoirs as factors in reserve growth. Although these geologic factors are equally important in oil reservoirs, the depletion drive production mechanism in gas reservoirs requires development strategies different from those used for oil reservoirs, where delineation of reservoir compartmentalization and sweep efficiency are the objectives for oil recovery through infill drilling.

Considerable amounts of associated gas are available through geologically based infill drilling that will produce from uncontacted or poorly drained compartments in complex oil reservoirs. Detailed geological study of selected reservoirs allowed the documentation of the control of facies heterogeneity on oil and gas recovery in important plays in Texas. Pay-continuity functions that relate reservoir continuity to horizontal distance between existing wells were developed for each major facies in the study reservoirs. These functions form the basis for projecting the strategic infill oil and associated gas production potential of a reservoir to the play level.

Projection of the amount of recoverable gas in the major associated gas plays in Texas was based on updated amounts of uncontacted and bypassed mobile oil originally calculated by Tyler and others (1984) for each oil play in Texas. Estimates of the amount of recoverable associated gas in selected major associated gas plays range from 3.4 Tcf to 5.8 Tcf. The greatest recovery potential for this resource in Texas is in carbonate reservoirs in the Permian Basin. These reservoirs, which commonly have solution-gas drives and poorly developed gas caps, have low recovery efficiencies as a result of complex facies architecture. Geologically based infill wells in areas of greatest reservoir heterogeneity can recover much of this unproduced natural gas resource.

INTRODUCTION

Purpose and Scope

Unrecovered gas resources available through existing technology can be a significant source of reserve additions in maturely explored petroleum provinces. In 1985, Texas added

916 million barrels of oil reserves while producing 837 million barrels of oil; almost all of these reserves were additions from conventional recovery methods in existing fields rather than new-field discoveries (Finley and others, 1988). The resource base of unrecovered in-place resource (mobile and residual oil) is estimated at 74.5 billion barrels in the volumetrically significant West Texas oil region (Tyler and Banta, 1989); unrecovered gas resources associated with West and North Texas oil are estimated at 23.7 Tcf. Likewise, nonassociated gas resources can be recovered by more strategic application of current technologies in existing fields. Finley and others (1988) estimate that 46 Tcf of gas resources amenable to gas reserve growth exists in Texas reservoirs. About half of this gas was estimated to be economically recoverable at a wellhead price of less than $3.00 per Mcf, using geologically based infill drilling and recompletion strategies (Finley and others, 1988).

This report provides an initial examination of the potential for gas reserve growth in some of the largest gas- and oil-producing regions of Texas. Two potential sources of gas reserve growth are examined: 1) nonassociated gas available from infill drilling programs, to the extent such drilling has occurred to date, and 2) associated gas produced during strategic infill drilling programs in major oil fields of the Permian Basin of West Texas.

Approach to Reservoir Heterogeneity

The geologically complex and highly prolific fluvial and deltaic gas reservoirs in the Tertiary formations of the Texas Gulf Coast commonly contain multiple compartments bounded by vertical and horizontal permeability barriers. An example of this reservoir complexity, or heterogeneity, is illustrated by the Brooks reservoir, which is located in La Gloria field in South Texas (fig. 1) and has a cumulative net production of 200 Bcf (excluding reinjected dry gas). The Brooks reservoir contains multiple, stacked reservoir-quality channel-fill and splay sandstones interbedded vertically and horizontally with shale intervals from 1 to 10 ft thick (fig. 2). The traditional view is that well perforations at 320-acre spacing will efficiently drain the reservoir because it is composed of laterally continuous

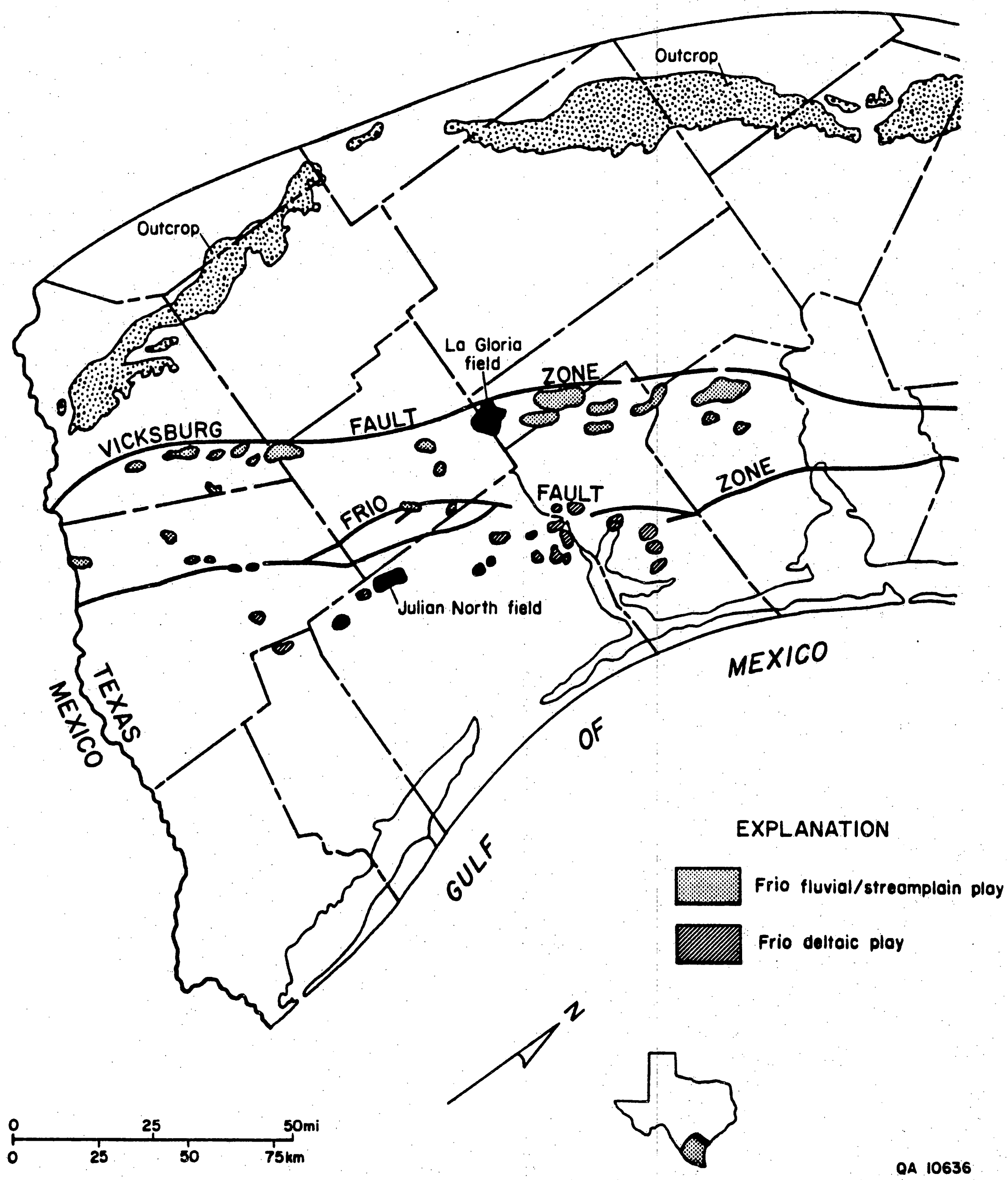


Figure 1. Regional distribution of fields in the Frio fluvial/streamplain and Norias delta system plays downdip of the Vicksburg and Frio fault zones. La Gloria field is located in the updip fluvial segment of the play in Brooks and Jim Wells counties. Julian North field, which produces from wave-modified deltaic reservoirs, is located downdip of the Frio fault zone in Kenedy County. Modified from Galloway and others (1982) and Kosters and others (1989).

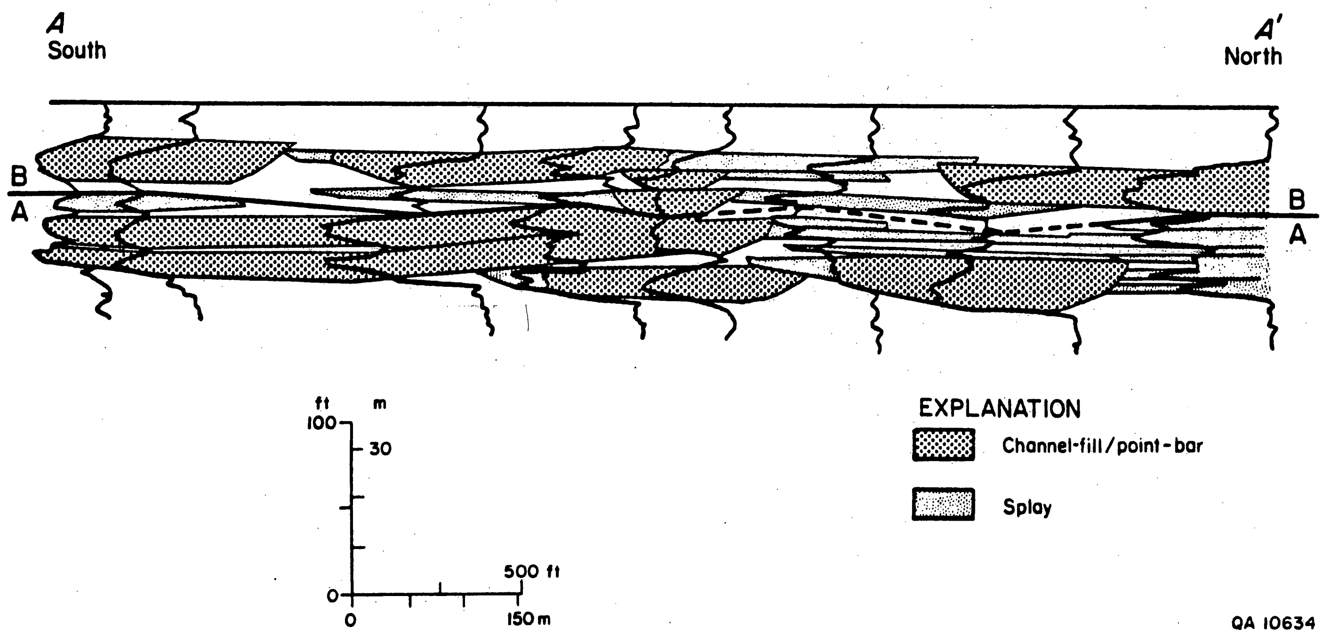


Figure 2. Stratigraphic strike section A-A′, in the Brooks reservoir in La Gloria field, located on Figure 13. Geologic complexity, or heterogeneity, of reservoir sandstone bodies is shown by spontaneous potential- (SP-) log traces. The Brooks is divided into subunits A and B, separated by a thin shale marker that is continuous over most of the field area. Numerous compartments are formed by channel-fill and attached splay sandstones that are lenticular in strike section. Many of these sandstone bodies are partially separated from each other laterally and vertically by shales 1 to 10 ft thick. Some sandstone bodies are almost completely isolated from each other and may contain gas that has not been fully drained by existing wells.

sandstone layers (fig. 3a). Another view of the same reservoir suggests that, because of geologic heterogeneity, some zones may remain incompletely drained at 320-acre spacing (fig. 3b). If such incompletely drained zones exist in the Brooks reservoir, a sand-rich fluvial Frio reservoir in South Texas, then, by analogy, one would expect many more partially or even totally isolated compartments to exist in less sand-rich reservoirs in other areas of the Gulf Coast.

Examples of the influence of reservoir heterogeneity on production are documented in studies of some Louisiana and Midcontinent gas reservoirs. Geologic heterogeneities in Miocene deltaic sandstones in Vermilion Block 16 reservoir, offshore Louisiana, were recognized by Seal and Gilreath (1975). Compartmentalization of reservoirs in Block 16 was implied by major deviations in expected production on a per-well basis and by significant variations in reservoir pressure across the field. Sandstone units thought to represent a single reservoir actually comprised up to six discrete reservoirs. Additional recovery was significant after new infill wells were drilled targeting incompletely contacted reservoir compartments.

Gas reserve growth potential in the giant shallow-marine carbonate and clastic Hugoton field in Oklahoma, Kansas, and Texas is now being tested by infill drilling. Hearings on the heterogeneity of Kansas Hugoton field have resulted in new regulations allowing the drilling of a second well in each section. Pressure analyses comparing volumetric with material balance calculations indicate that substantial amounts (20 to 25 percent) of original gas in place (OGIP) are not in communication with wells at 640-acre spacing in the field (Besly, 1985; Liveris, 1985). It remains to be determined whether infill wells drilled to date support the analyses.

Nonassociated Gas Reserves from Geologically Based Infill Drilling

Poorly drained or entirely uncontacted reservoir compartments are targets for infill drilling or recompletion of wells in all maturely explored Texas gas reservoirs except those with the highest lateral continuity and most efficient drive mechanisms (Finley and others,

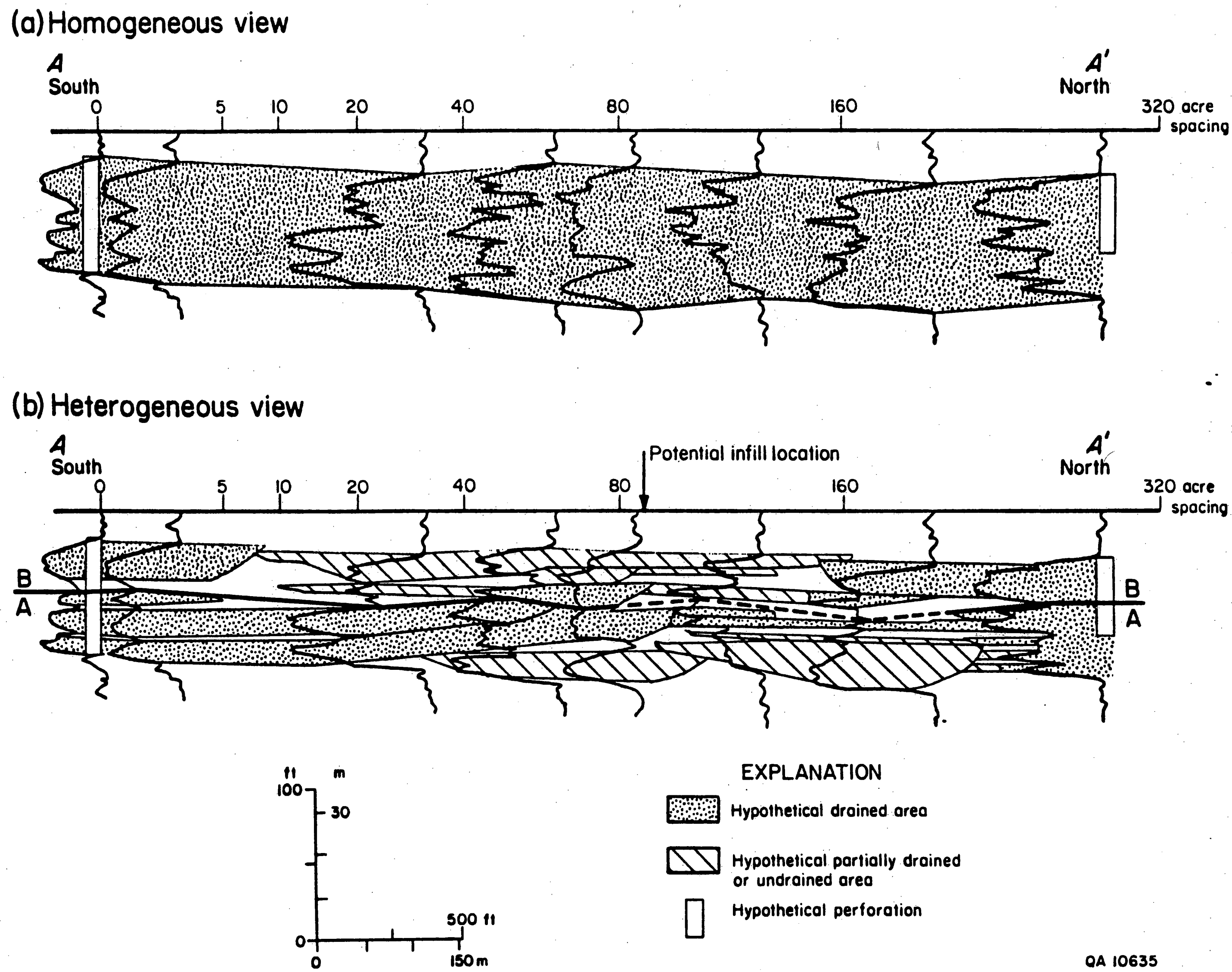


Figure 3. Laterally continuous (homogeneous) and heterogeneous views of the Brooks reservoir, La Gloria field. Portrayed in (a) is the traditional concept of laterally continuous reservoir architecture applied to the Brooks reservoir in La Gloria field. In this view, good sandstone-body continuity results in complete drainage of reservoir compartments, down to the economic pressure limit. Part (b) is a heterogeneous view of the Brooks reservoir showing facies boundaries, as in figure 2. Hypothetical perforations in wells at the ends of the section have only partially drained the reservoir, leaving some compartments at higher-than-average reservoir pressure. A potential infill well location is shown at 80-acre spacing; this well would tap several partially drained compartments. Stratigraphic strike section A-A′ is located on Figure 13.

1988). Traditional gas field drilling and development in clastic reservoirs have often assumed that the sandstones are relatively homogeneous and laterally continuous; however, uniform gas-well spacing is believed to have resulted in the bypassing of isolated sandstone bodies. These isolated sandstones can be delineated by detailed analysis of depositional facies within areas of existing dense well control, and geologically based (strategic) infill drilling can be undertaken in field areas where the potential for adding gas reserves is significant. Even though the most prolific Texas Gulf Coast fields have been extensively drilled, averaging 1.53 wells per mi^2 (Galloway and others, 1982), potential exists for tapping isolated gas reservoirs. Fluvial facies pinch-outs are commonly encountered over distances as close as 300 ft between wells in many of these fields.

In this report, heterogeneity and potential for gas reserve growth in the prolific South Texas region were characterized for two La Gloria field reservoirs, located in the large Frio fluvial/streamplain play, and for one reservoir in Julian North field, representing a setting of lower permeability in the geologically different Frio deltaic play (fig. 1). In the fluvial reservoirs, a large amount of the total technically recoverable gas available is found in relatively small areas of the reservoirs, an amount equal to 16.3 Bcf or about 2 Bcf per well at 320-acre spacing. In the deltaic reservoir, technically recoverable incremental gas is approximately 0.75 Bcf per well.

The availability of gas resources through infill drilling and recompletion is possible because of the predominance of gas reservoirs at 640- to 320-acre spacing. In Texas in 1977, 92 percent of all reservoirs with greater than 30 Bcf cumulative production were at 640- to 320-acre spacing; in those reservoirs, 66 percent of production is from 640-acre spacing and 28 percent of production is from 320-acre spacing (Finley and others, 1988).

Bypassed Gas

A second source of gas reserves growth is available from bypassed gas in discontinuous sandstone lenses located predominantly above the major producing zones in a given reservoir.

This resource has significant potential for development in the Gulf Coast region, especially in the maturely explored region of South Texas, which contains hundreds of vertically stacked, interlayered sandstones. Specific analysis of bypassed gas resources was not undertaken as part of the work reported here. Under the Secondary Gas Recovery project, however, bypassed gas is a major area of emphasis, and assessment of bypassed gas will aid substantially in defining strategic infill drilling potential.

Associated Gas Reserve Growth

Associated gas reserve growth is an important element of future production in oil-rich West Texas. Case studies and specific examples of oil reservoir heterogeneity document the complexity and compartmentalization of these reservoirs (Finley and others, 1988). The directional pay-continuity concept, applied to injector and infill drilling programs, significantly increased waterflood recovery in the Clearfork reservoir, Fullerton field, in the Central Basin Platform of West Texas (Stiles, 1976). Recognition of discontinuous pay distributed in 20 separate layers within the Clearfork platform carbonate reservoir in Fullerton field was a key factor in the waterflood model analysis.

This study indicates that an additional 30.5 million barrels of oil resources can be potentially recovered by strategic infill drilling down to 10-acre spacing in the most permeable areas of Grayburg reservoirs in Dune field, located on the Central Basin Platform. A theoretical model using strategic infill drilling methods showed that Dune field reservoir compartments may be poorly drained at existing 20-acre well spacing on a regular grid pattern. The compartments are found in lenticular, high-permeability grainstone bars encased in low-permeability wackestones. Infill wells strategically drilled in the grainstone facies are projected to be most cost-efficient and productive.

Within Texas, large amounts of oil (estimated at 508.7 million barrels for the South Central Basin Platform play alone [Godec and others, in preparation a) are potentially recoverable from strategic infill drilling down to 10-acre spacing in mature West Texas reservoirs. Associated gas produced with this oil would make, therefore, a significant contribution to statewide gas reserve growth.

NONASSOCIATED GAS RESERVES EVALUATION

Potential Reserve Additions through Strategic Infill Drilling

Introduction

Evaluation of nonassociated gas reserve growth through strategic infill drilling was based on case studies of representative reservoirs chosen from volumetrically significant nonassociated gas plays in Texas. Grouping of Texas gas fields into geologically defined plays and the volumetric ranking of those plays are provided by the Atlas of Major Texas Gas Reservoirs (Kosters and others, 1989). The natural gas play consisting of Frio fluvial-deltaic sandstones along the Vicksburg fault zone is the most prolific of the Texas Gulf Coast gas plays, with cumulative production to 1986 of 11.6 Tcf (figs. 4 and 5). Two reservoirs from this play were studied: the Brooks and Jim Wells, both located in La Gloria field. In addition, a different depositional setting was examined in the I-92 reservoir in Julian North field, located in the Frio Norias delta system play, which lies downdip from the fluvial-deltaic play. Deltaic sediments in the Norias delta system were reworked by marine currents, resulting in reservoirs with higher interconnectedness, or continuity, than those in the updip fluvial system. However, these reservoirs are of lower permeability than those in La Gloria field.

Plays in South Texas are volumetrically large because of the great thickness of reservoir-quality sandstone in Frio depocenters, accumulated during growth faulting along the Vicksburg and Frio fault zones. Structurally simple upper Frio reservoirs were selected to enable detailed stratigraphic control on sandstone continuity.

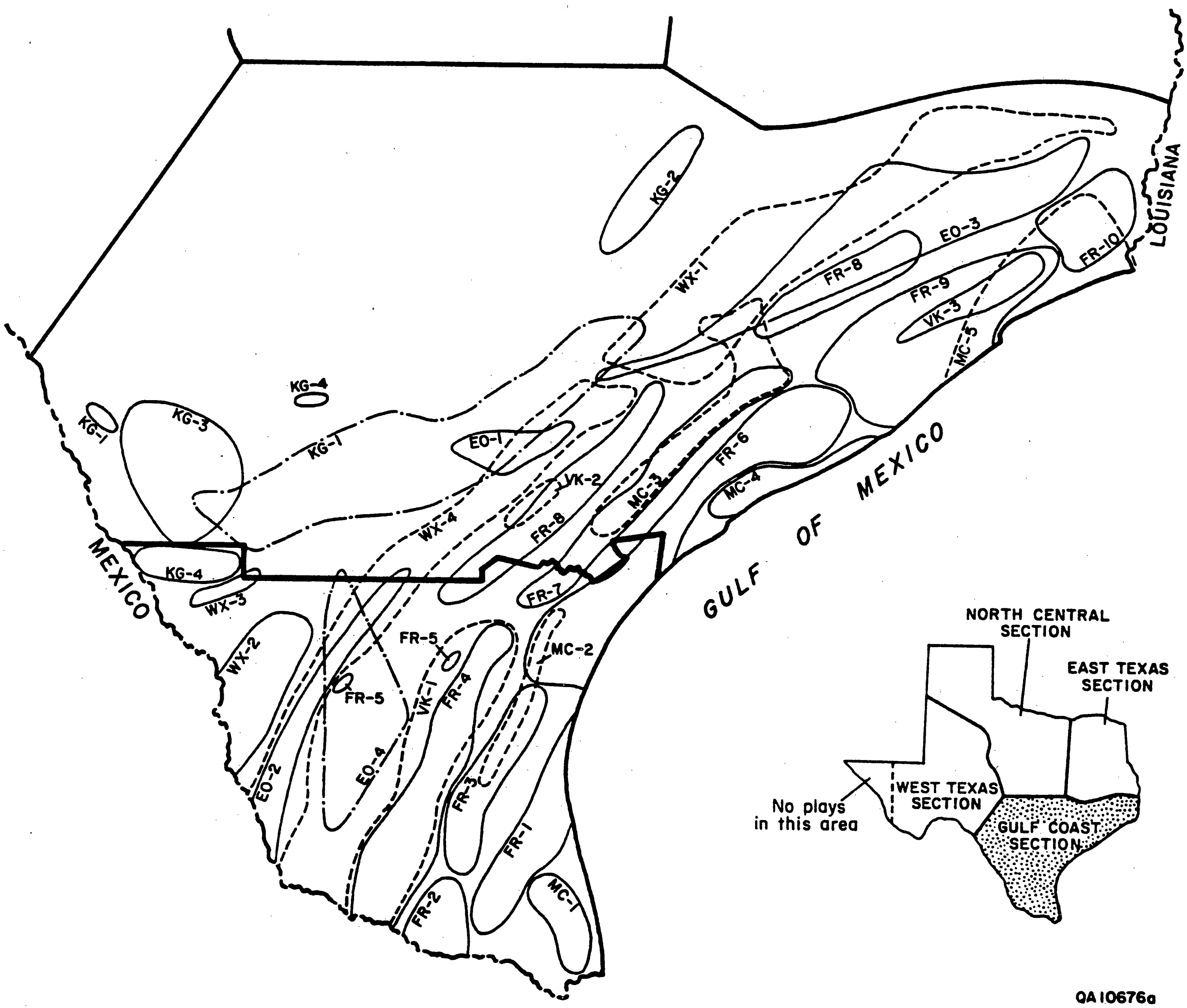
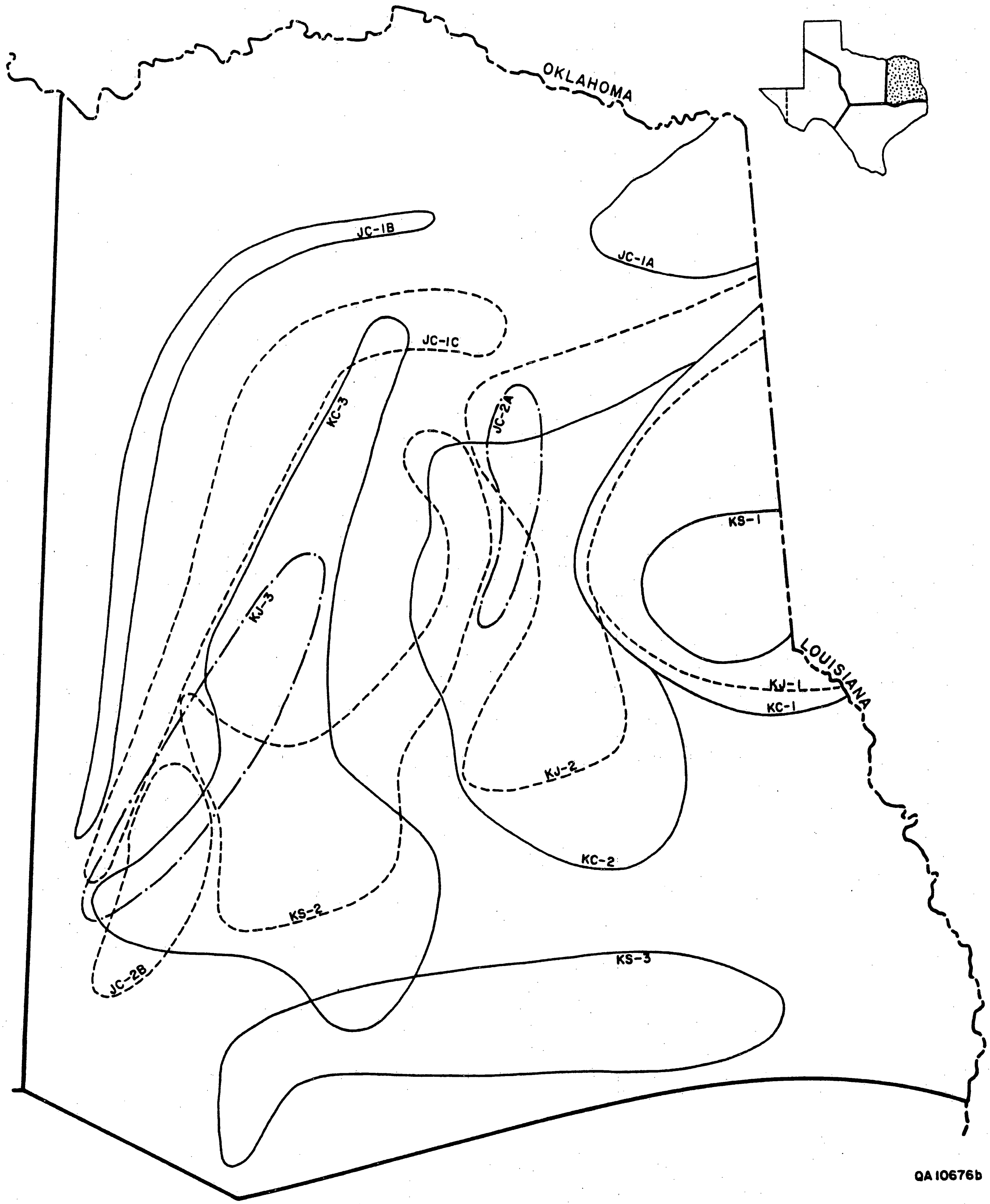


Figure 4. Gas plays from the Atlas of Major Texas Gas Reservoirs (Kosters and others, 1989). Heavy horizontal line on Gulf Coast section denotes northern limit of Texas Railroad Commission District 4. Both the Frio Gueydan fluvial/streamplain play (FR-4) and the Frio Norias deltaic play (FR-3) are in the east-central part of District 4.



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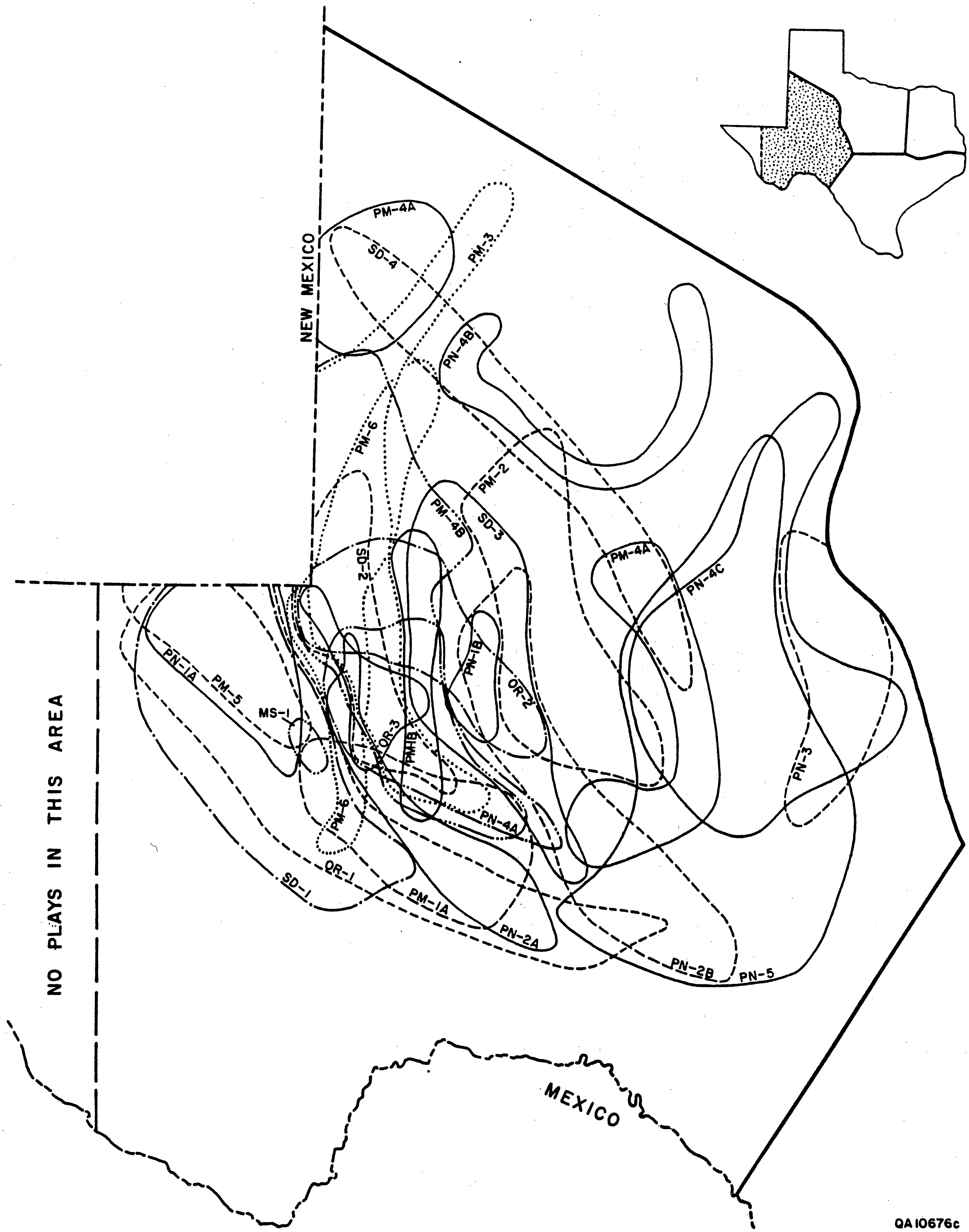

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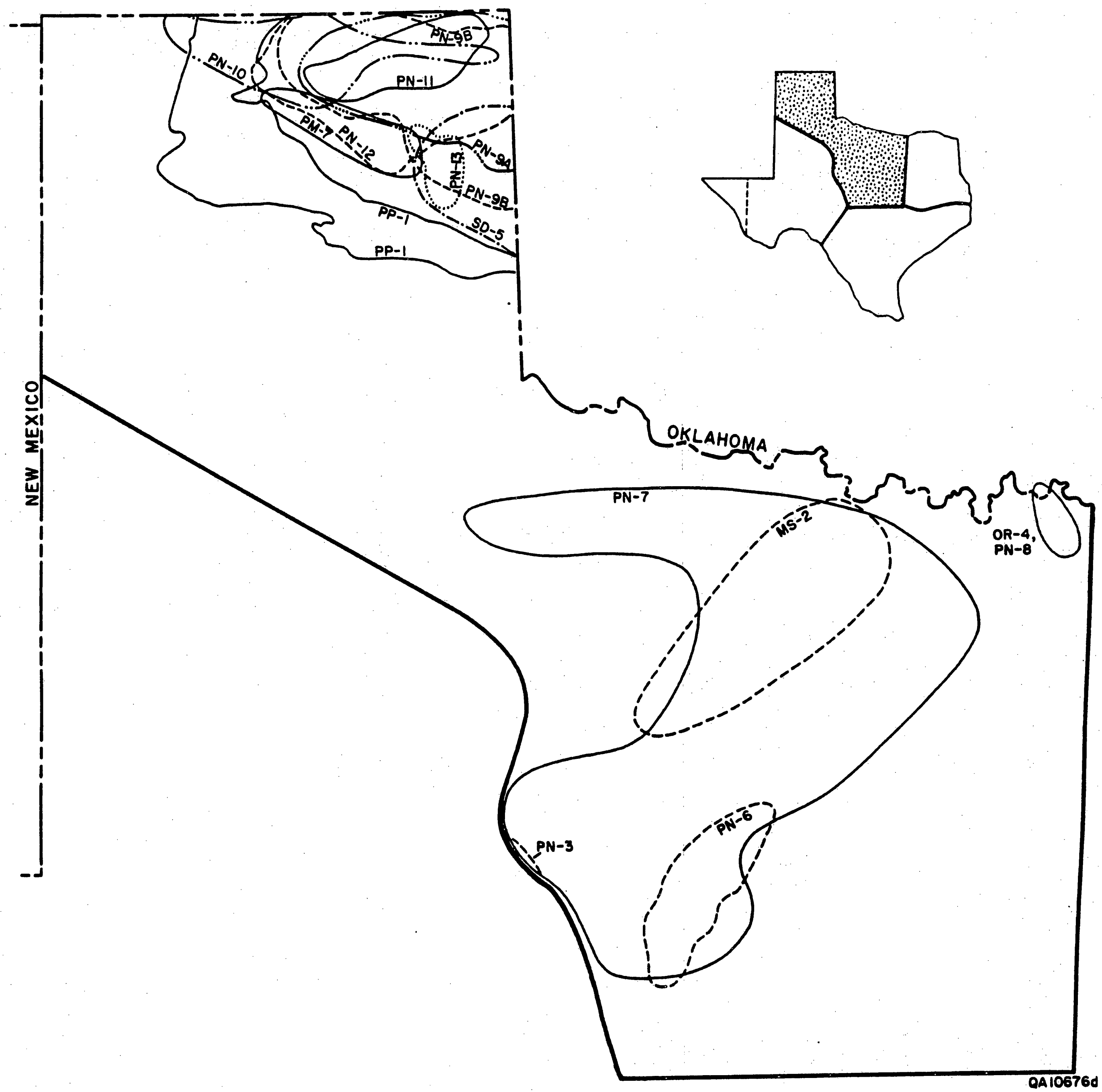

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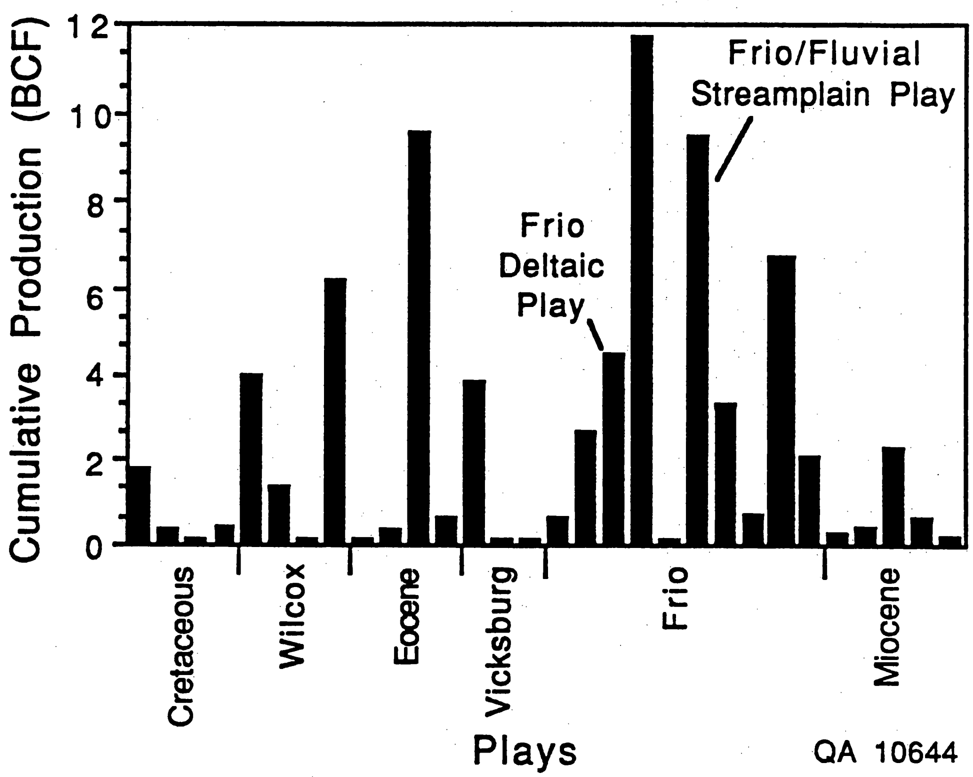


Figure 5. Cumulative production of gas plays on the Texas Gulf Coast. Data from Kosters and others (1989).

Methods

Geology

Geologic characterization of the reservoirs studied included electrical and porosity log interpretation. Both public and private log libraries were used. Stratigraphic mudstone markers (indicated by low values on deep resistivity logs) and interpretations based on facies models were used to divide the vertical sandstone sequences into depositional units and subunits; eight stratigraphic markers were correlated on over 200 electric logs throughout La Gloria field. For Julian and Julian North fields, well control was sparse, making correlation difficult. Seventeen stratigraphic markers, from 5,700 to 9,700 ft in depth, were correlated on 43 logs in the Julian area. Twenty-four detailed and fieldwide stratigraphic cross sections were made in La Gloria field, and four stratigraphic and six structural sections were made in Julian and Julian North fields. These sections were supplemented by over 20 cross sections obtained from hearing files at the Railroad Commission of Texas. In addition, seven fence, or panel, diagrams were made on six La Gloria field reservoirs, and one was made for the Julian North I-92 reservoir. Facies interpretations of fluvial and deltaic environments in these reservoirs were based on net-sandstone-thickness and spontaneous-potential- (SP-) log facies maps and were compared with modern and ancient examples from the literature.

Engineering

Reservoir data, gas and condensate production, and operating practices were obtained from operators, public records, and private data sources. Total volumetric gas in place was calculated for each reservoir. Production decline curve analysis was selected as the most appropriate technique to estimate the volume of gas in place contacted by each producing well. Aggregate estimates of contacted gas at various levels of development drilling were used to construct an empirical gas contact function for each reservoir. The function, which relates well spacing to reservoir contact, was used to determine the volume of gas available for reserve growth. Technically recoverable gas estimates were calculated using a field development model.

Case Study 1—La Gloria Field

Introduction

La Gloria field is located in the prolific gas-prone Frio fluvial play on the downdip margin of the regionally extensive Vicksburg fault zone (fig. 1). Although gas and oil production in the play is dominantly controlled by structural features, as many as one-third of the reservoirs are related to facies pinch-outs (Galloway and others, 1982). The play has reached a supermature stage; Galloway and others (1982) have estimated that major fields in this play have produced over 90 percent of original gas contacted. However, this estimate is based on long-term depletion of only the known, major reservoir compartments. Because of the highly complex architecture of sandstones in the play, numerous isolated and compartmentalized reservoirs remain to be tapped.

Depositional Setting

Frio sediments in South Texas were deposited by the Gueydan fluvial system, a major river system that occupied the Rio Grande Embayment (Galloway, 1977). The Frio fluvial/streamplain play includes the downdip margin of the Gueydan fluvial system and the updip edge of the wave-modified Norias delta system (Galloway and others, 1982) (fig. 6). Frio fluvial sediments in the region of the Vicksburg fault zone merge into deltaic deposits downdip of the Frio fault zone (fig. 7).

The Gueydan fluvial system is characterized by coarse-grained channel-fill and point-bar sandstone laterally associated with crevasse splay sandstone and floodplain mudstone and siltstone (fig. 8). Galloway (1977) interpreted the Gueydan as a coarse-grained meanderbelt system, having a mixed sediment load (fig. 9). Individual channel-fill and point-bar deposits

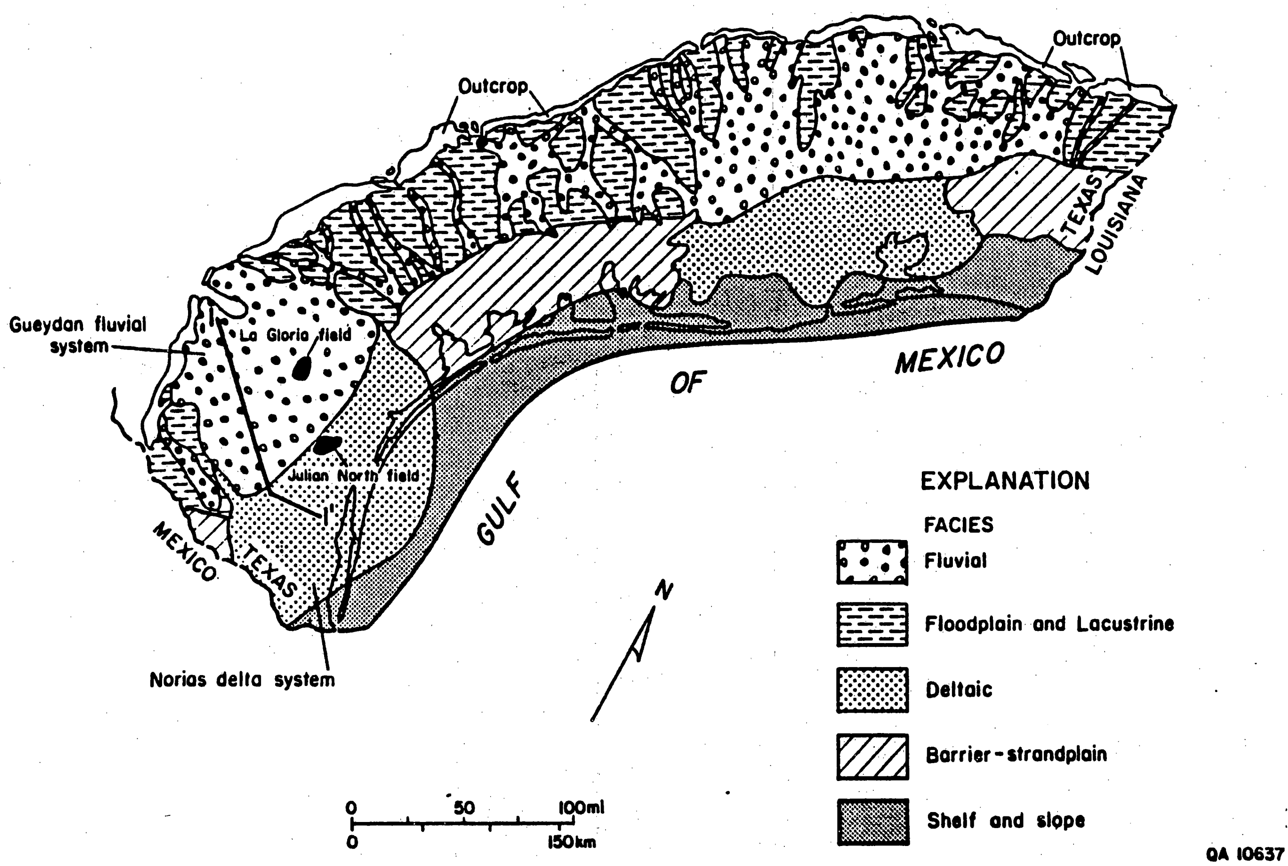


Figure 6. Frio depositional systems in the Texas Gulf Coast. Middle and upper Frio sediments in La Gloria field were deposited in the Gueydan fluvial system, a network of low-sinuosity, bedload streams in the Rio Grande Embayment. Lower and middle Frio sediments in Julian North field were deposited in the Norias delta system downdip of the Gueydan fluvial system. Modified from Galloway and others (1982).

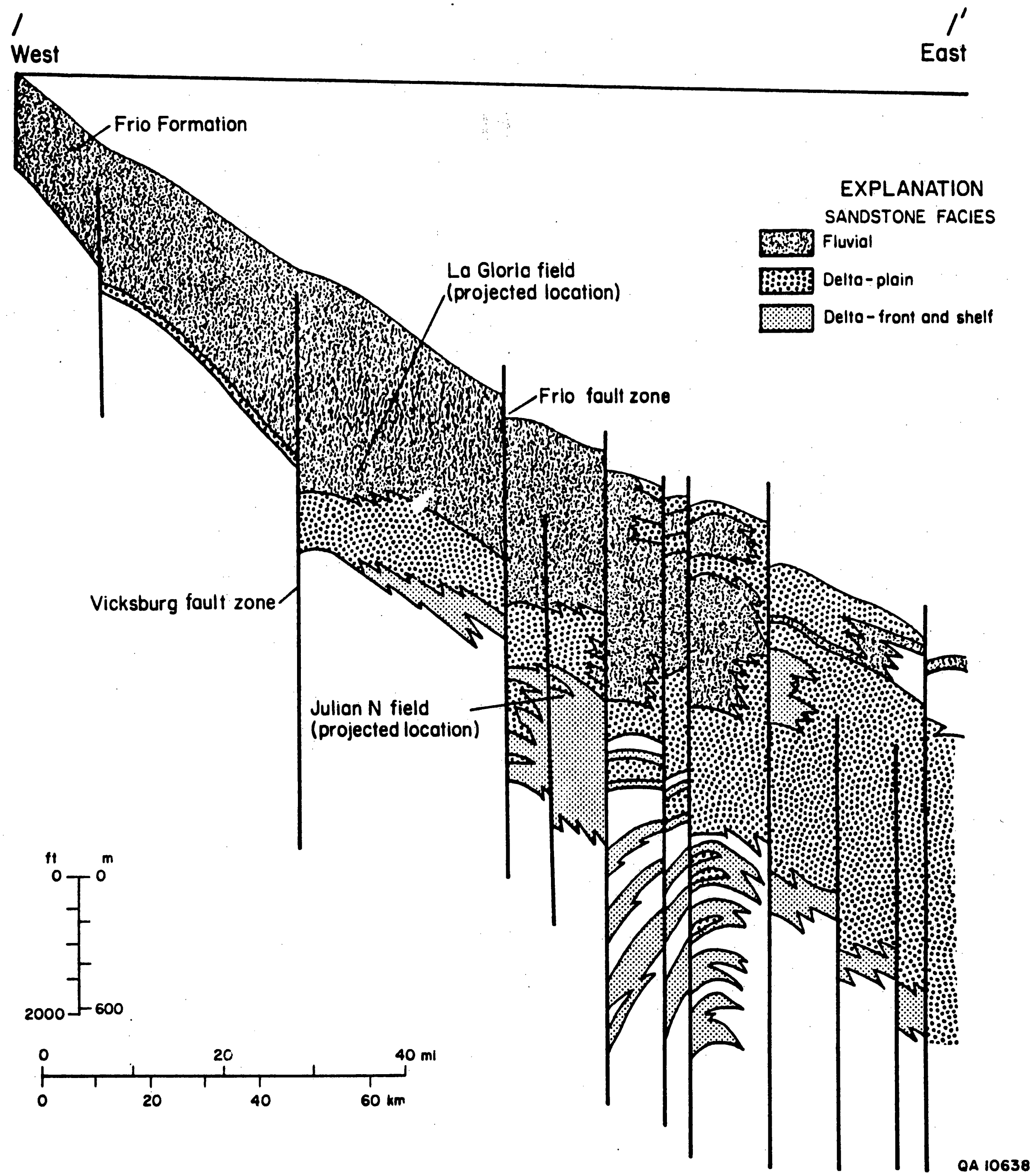


Figure 7. Regional structural cross section 1-1′, located on Figure 6. Middle and upper Frio fluvial facies in the region of the Vicksburg fault zone grade into deltaic and barrier-island facies downdip of the Frio fault zone. Modified from Galloway and others (1982).

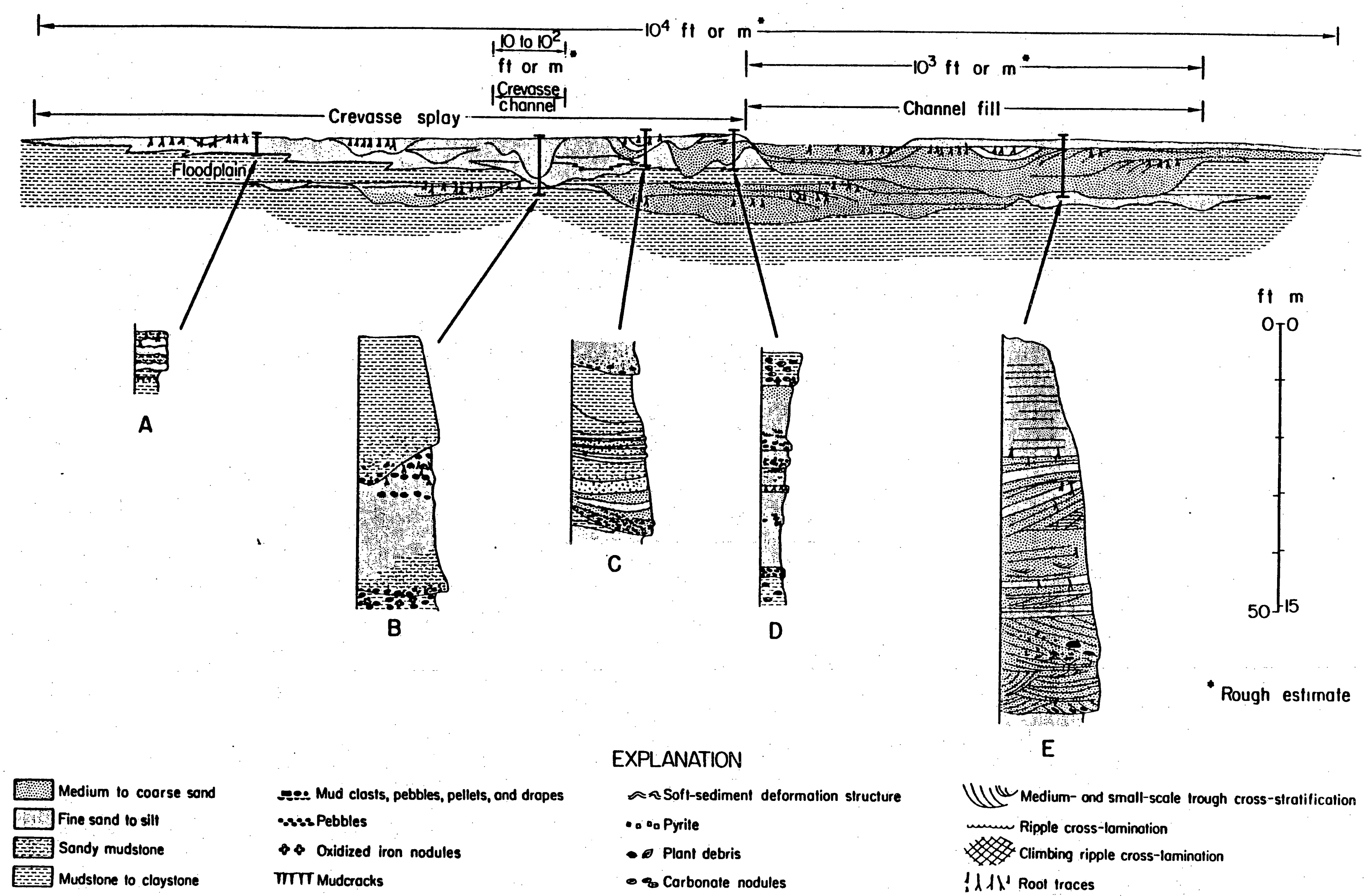


Figure 8. Facies compositions and architecture in a composite cross section made from outcrop descriptions in the Gueydan fluvial system. Complex facies boundaries and heterogeneity are evident. Measured sections A through E are distal splay (A), proximal splay (B), sandy mudstone channel (C), silt-filled channel (D), and sandstone channel (E). From Galloway (1977).

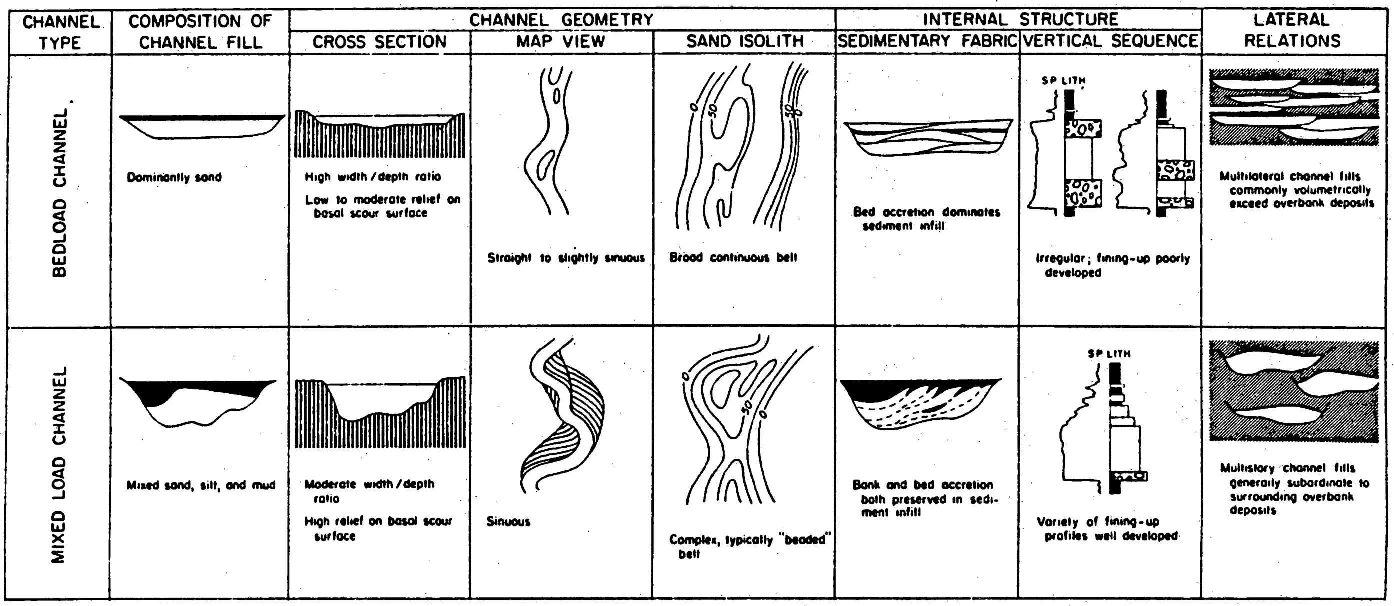


Figure 9. Principal characteristics of bedload and mixed load fluvial systems recognized in middle Frio reservoirs in La Gloria field. Net-sandstone patterns of both types of fluvial systems are recognized in the Brooks and Jim Wells reservoirs, although good lateral continuity of channel-fill deposits in these reservoirs suggests that coarse-grained bedload channels were predominant. Modified from Galloway (1977).

are 10 to 30 ft thick, but they are commonly stacked into aggregate sandstone bodies 50 to 100 ft thick in sand-rich belts over 3,000 ft wide (fig. 10).

La Gloria Field

Geology

The upper Frio reservoirs in La Gloria field are located in the central part of the Gueydan fluvial system. Reservoir facies are developed in aggregate belts of interlayered sandstone bodies; these belts thin and thicken over distances of a few miles or less. A type log from La Gloria field shows evenly spaced sandstone beds separated by mudstone layers, typical of the upper Frio stratigraphic section in this region (fig. 11).

Spontaneous-potential-log (SP-log) responses that are blocky and exhibit sharp bases are interpreted as channel-fill sandstones in La Gloria field because these deposits contain the coarser grained sediments in the fluvial system (fig. 12). Upward-fining SP responses are interpreted as point-bar deposits, reflecting lateral accretion of successive channel sandstones overlain by fine-grained sediments deposited as flood waters receded. Overbank splay and levee deposits are characterized by thin, silty sandstones; these appear on the electric log as spiky to upward-coarsening SP responses, reflecting small unit thickness and low flow-regime of deposition. Floodplain deposits consist of mudstone and siltstone and are identified as a baseline SP response.

The geometry of sandstones in La Gloria field is highly complex, as a consequence of multilateral deposition of river sandstones. Erosion and downcutting of older fluvial sediments by younger rivers resulted in the isolation of numerous relict point-bar, splay, and levee sands, adding to the internal heterogeneity of the reservoir facies.

Trap and drive mechanism

The major trapping mechanism in La Gloria field is structural. Hydrocarbons are produced from fluvial sandstone bodies located over the crest of a broad, northeast-southwest-oriented rollover anticline (fig. 13). The major bounding fault lies along the northeastern part

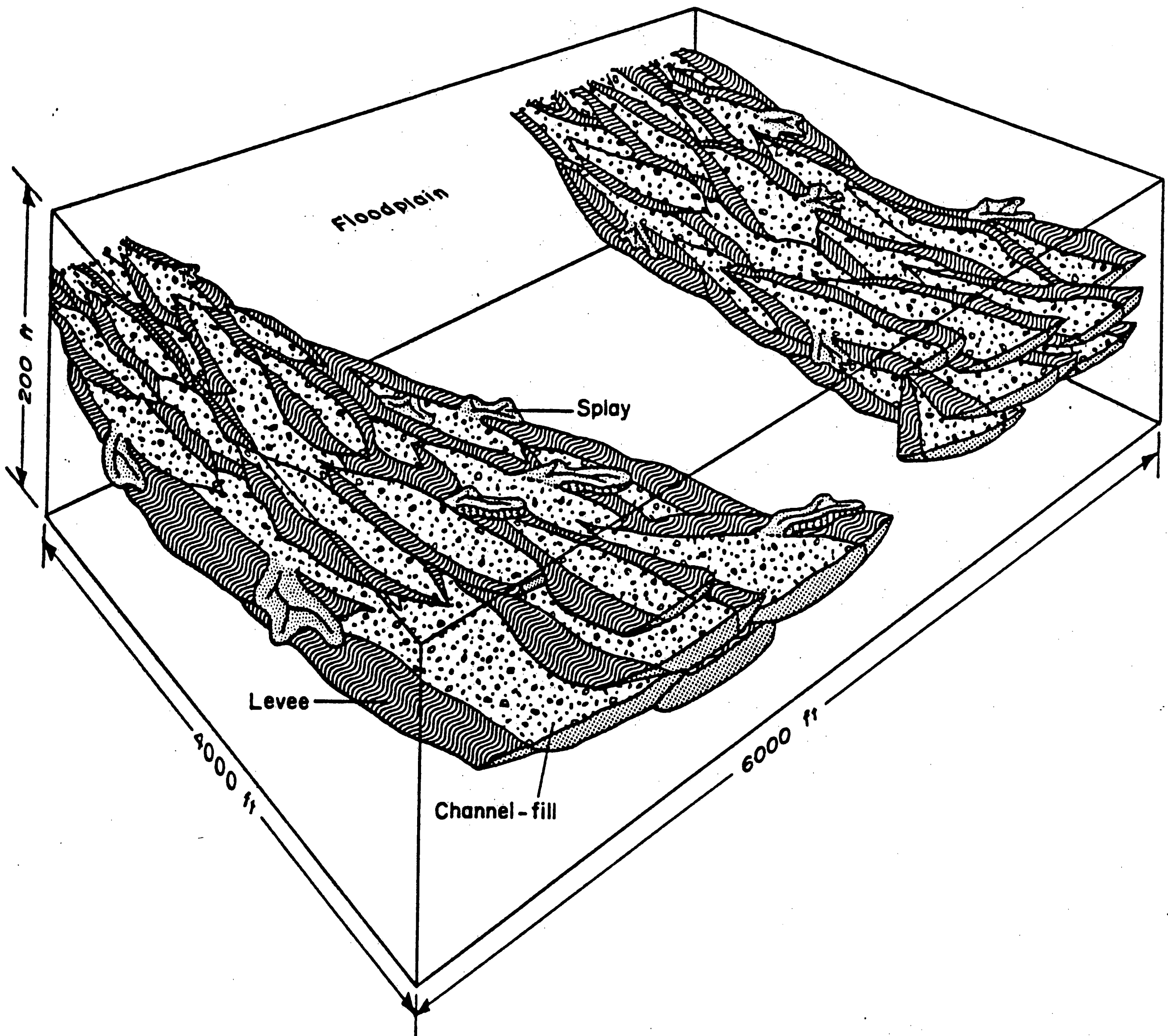


Figure 10. Facies model of bedload fluvial reservoirs in La Gloria field, deposited in dip-parallel belts approximately 3,000 ft wide. Channel-fill sandstone bodies in these belts are commonly stacked into aggregate thicknesses of 50 to 100 ft.

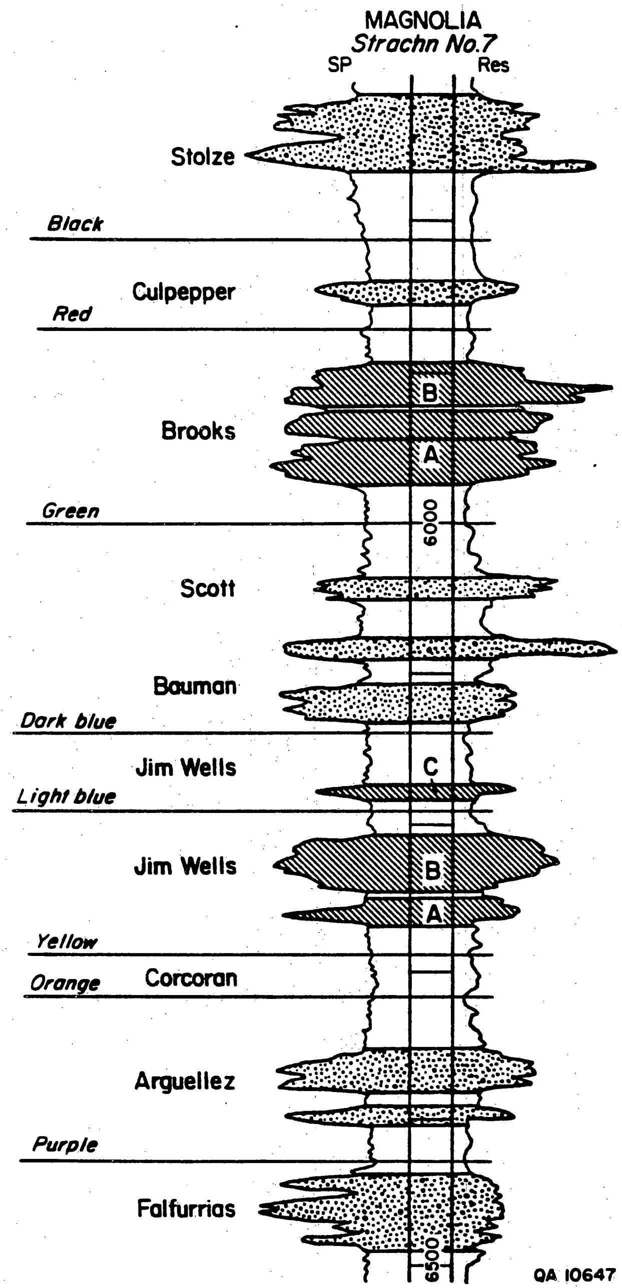


Figure 11. Type log (Magnolia #7 Strachn) of middle Frio fluvial reservoirs in La Gloria field. These heterogeneous reservoirs consist of several stringers, 10 to 30 ft thick. Each stringer is composed of a mosaic of fluvial depositional facies that subdivide the reservoir laterally into poorly drained compartments. The Brooks and Jim Wells nonassociated gas reservoirs have the greatest cumulative gas production in the field, and these reservoirs were selected for detailed geologic and engineering analysis. Marker beds black to purple were used for detailed correlation in La Gloria field.

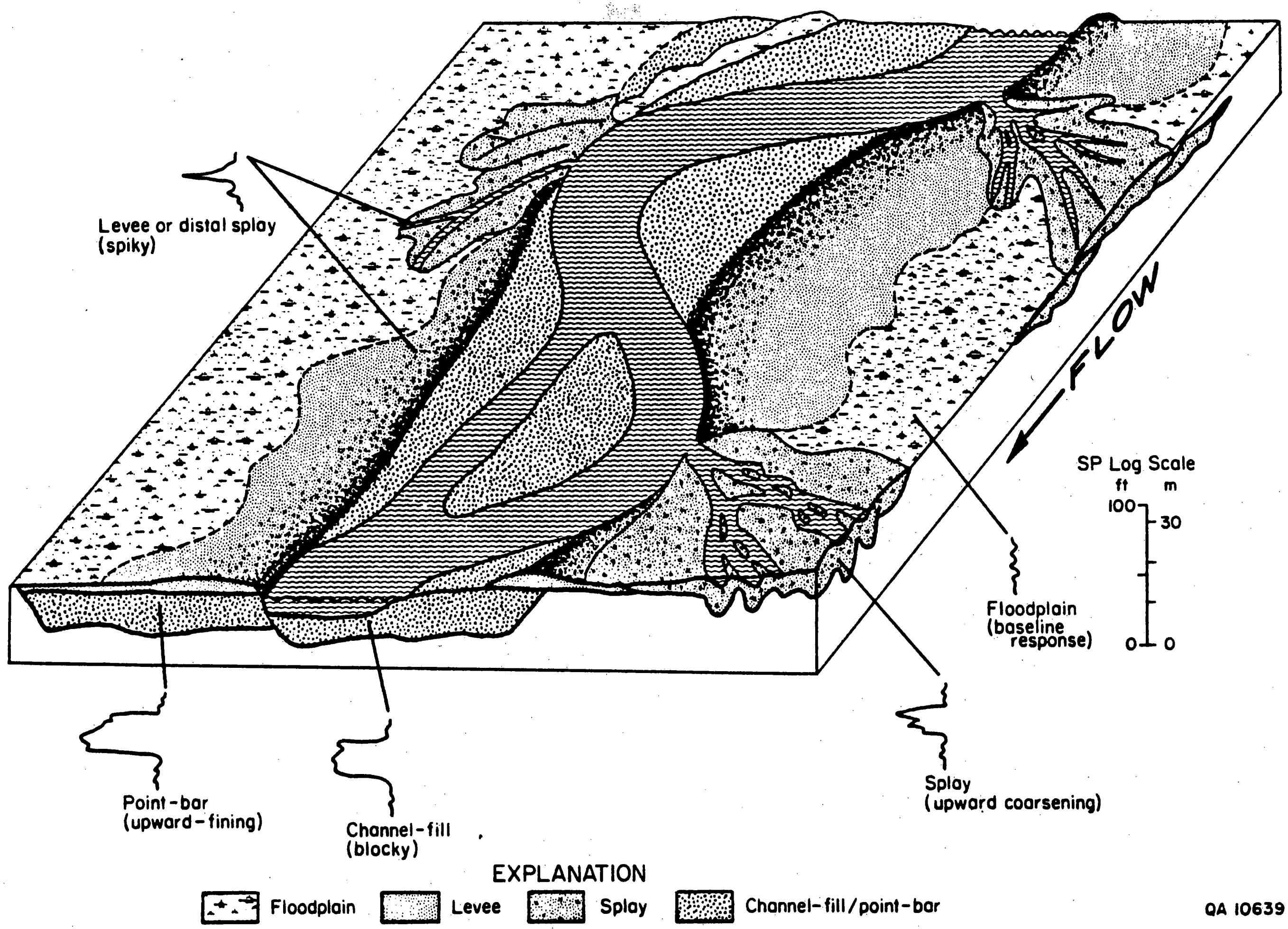


Figure 12. Three-dimensional facies relationships in middle and upper Frio fluvial reservoirs in La Gloria field. High-permeability reservoir facies occur in channel-fill and splay sandstones in the field. The channel-fill sandstones exhibit good continuity along depositional dip (parallel to flow) but poor continuity along strike, where they are bounded by low-permeability levee and floodplain mudstones. Numerous potential reservoir compartments are represented by the splay facies, which are partially connected to the channel-fill facies and partially encased in low-permeability sediments. Characteristic SP-log responses of each facies are shown. Modified from Galloway (1977).

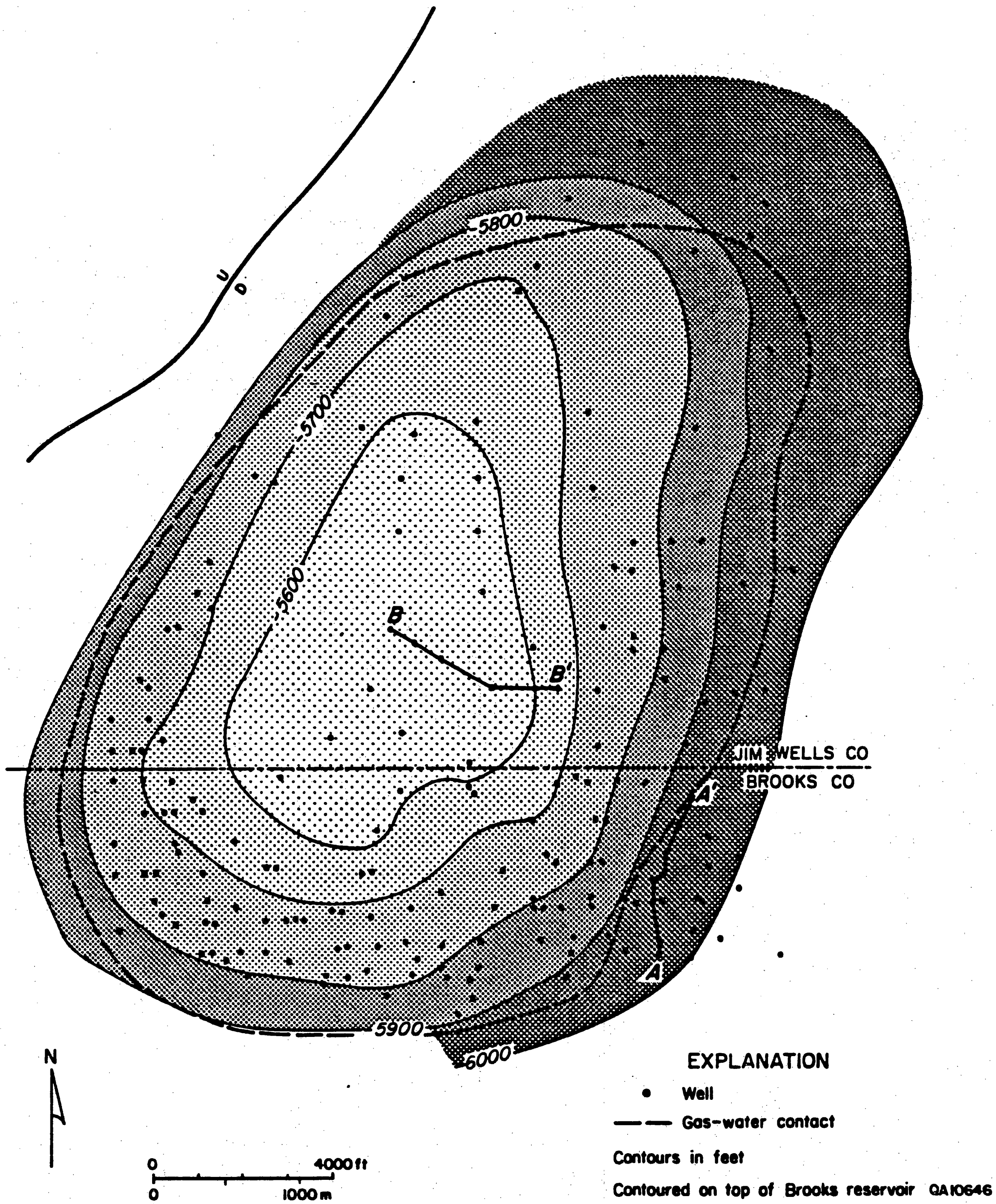


Figure 13. Structure map of La Gloria field, defined by an elongate rollover anticline on the downthrown side of the Vicksburg fault zone. Dense well spacing on the flanks of the field reflects the presence of oil rims in some of the gas reservoirs. Variations in well density are also related to the uneven distribution of lenticular, dip-elongate sandstone bodies that cut across the field structure.

of the field. Structural relief is 200 ft in the unfaulted upper Frio section. Several antithetic faults cut La Gloria field at depths greater than 7,000 ft, 1,000 ft below the Brooks and Jim Wells reservoirs.

Stratigraphic control on gas production in La Gloria field occurs where fluid-flow barriers are associated with boundaries between more permeable facies, such as channel-fill, point-bar and splay sandstones, and less sand-rich and permeable facies, such as levee and floodplain deposits. Localized occurrences of muddy abandoned-channel-fill deposits within belts of sandy point-bar facies tend to further isolate hydrocarbon-bearing units into separate compartments. These muddy channel-fill deposits are non-gas productive. Vertical reservoir seals in La Gloria field are formed by floodplain mudstones that overlie channel-sandstone units (figs. 11 and 12).

The production drive in La Gloria field, typical of many South Texas Frio fluvial/streamplain reservoirs, is gas-cap expansion modified by limited solution gas and water drive in some associated gas reservoirs. Several reservoirs in the field possess very large gas caps. Because of the complexity of Frio reservoir sands, unitization programs, gas cycling, and cooperative operations have been necessary to completely develop and maintain pressure in South Texas fields such as La Gloria (Galloway and others, 1983). La Gloria field was unitized in 1955, and 17 reservoirs in the field have undergone gas cycling for the purpose of recovering condensate. La Gloria cycling plant was the first of its kind in Texas.

Development history

The discovery well of La Gloria field was Magnolia #1 Sam Maun, a gas condensate producer drilled in 1939 to a depth of 7,560 ft and completed in the La Gloria zone in the lower, faulted section of the field. Discovery of 21 gas zones followed in the next few years; gas cycling was initiated in 1941. A gas purchaser was contracted in 1951, and gas cycling ended in 1970 (Wilson, 1967). In the 1960's additional productive zones at depths greater than 7,000 ft were discovered, and in recent years production from thin sandstones, bypassed earlier, has added to field production.

Production from La Gloria field totals over 3.1 Tcf (Dwight's Energydata, Co., 1988); this figure includes approximately 1.3 Tcf of cycled gas (personal communication, Mobil Exploration and Producing U.S., Inc.). Eight reservoirs in La Gloria field, the Arguellez, Brooks, Culpepper, Hornsby "A", Jim Wells, La Gloria, Riley, and Scott, are among the top 100 producing gas reservoirs in the Texas Gulf Coast (Kosters and others, 1989), one of the largest U.S. gas provinces . The Hornsby "A" and La Gloria reservoirs produce from the lower, faulted section of the field, and the remaining six produce from the unfaulted, upper section. An unfaulted section containing two of the most prolific upper Frio reservoirs in the field, the Brooks and the Jim Wells, was selected for detailed study.

Brooks Reservoir

Depositional environments

Fluvial channel-sand complexes in the Brooks reservoir occur in dip-elongate southeast-trending belts, 40 to 70 ft thick (fig. 14). The thickest sandstones lie in the southeastern part of the field, where multiple sandstone units are stacked and mudstone intervals are thin or eroded. In the northern and eastern parts of the field, individual channels are easy to identify because the sandstone units are separated by up to 15 ft of mudstone.

For detailed geologic analysis, the Brooks reservoir was vertically divided into two depositional units, or stringers, according to the thickness and extent of mudstone interlayers (fig. 11). Each stringer consists of a separate system of fluvial channel and floodplain sediments, identified by letter designation (A and B). The A stringer is separated from the B stringer over the central and northern part of the field by a shale interval averaging 10 ft thick. The two stringers are in contact in the southern part of the field. The Brooks A unit is the thickest of the two (fig. 11) and was informally divided into two thinner stringers, the upper A and lower A, because of a shale interval up to 10 ft thick separating the upper and lower A

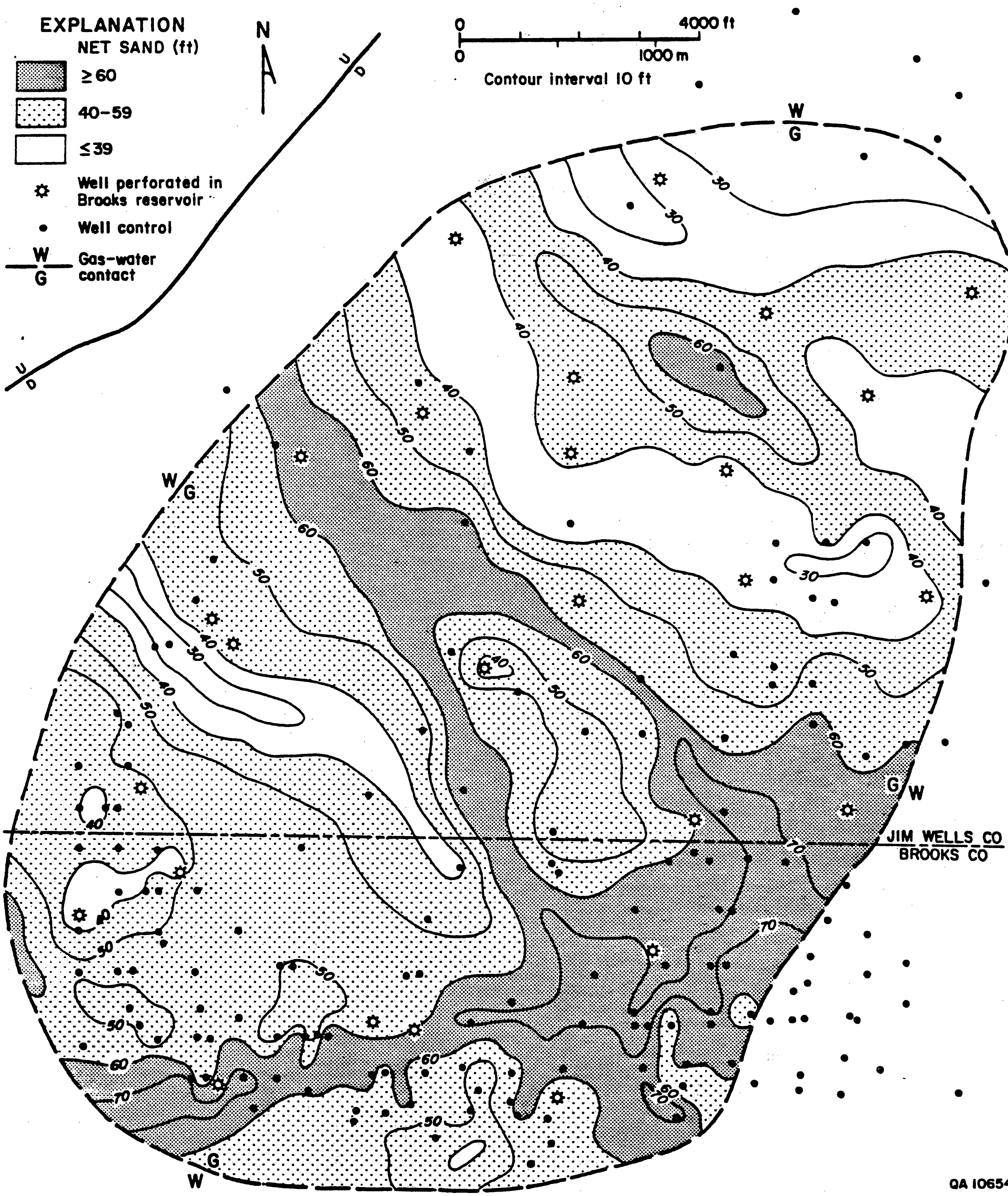


Figure 14. Net-sandstone-thickness map of the undivided Brooks reservoir in La Gloria field. The field area is transected by four interwoven, dip-elongate belts of sandstone more than 50 ft thick. These belts consist of stacked channel-fill and splay sandstone bodies that are individually 10 to 25 ft thick. Many of the wells that produced from the Brooks reservoir were drilled into these main depositional axes.

stringers over about 50 percent of the field. Sandstones in the upper A unit are not present in the northern half of the field, where this unit consists of mudstone. The Brooks B unit also consists of two stringers in the southeastern part of the field, where Brooks sandstones are thickest.

The entire Brooks sandstone interval is encased in 10 to 50 ft of floodplain shales over almost all of the field area. The Brooks may be in poor contact with overlying Culpepper sandstone (fig. 11) in two wells in the east-central and extreme southwest parts of the field. These wells were never perforated in the Brooks or Culpepper zones, however. The Brooks is separated from the underlying Scott reservoir by 30 to 70 ft of mudstone in all areas in the field.

Channel-sandstone belts that comprise the A and B subunits are 20 to 40 ft thick (fig. 14). Thin Brooks upper A channel-sandstone belts are narrow (500 to 800 ft wide), but those in Brooks B complexes are up to 10,000 ft wide in the southern part of the reservoir, where both Brooks B stringers are greater than 10 ft thick. In the southeastern part of the field, the Brooks lower A subunit is eroded by the upper A. Brooks lower A sandstones are thickest in the central portion of the field.

The five depositional facies in the Brooks reservoir consist of dip-parallel, lenticular point-bar and channel-fill sandstones lateral to upward-coarsening splay sandstones (fig. 15) and, lateral and vertical to these framework facies, silty distal splay (or levee) and clayey floodplain facies. The Brooks reservoir is a relatively sandstone-rich fluvial system, as reflected by the significant gas production from this reservoir. Channel, point-bar, and splay facies in the Brooks A subunit are widespread; no sandstone-poor levee or floodplain facies are present in this interval (fig. 15). Channel systems in the thinner Brooks B subunit are flanked by 2,000-ft-wide levee and distal splay deposits in the northern half of the field. Isolated floodplain facies are present in a few areas adjacent to levee deposits. However, the southeastern portion of the field is almost completely channel sandstone where the B stringer increases about two times in thickness. The occurrence of preferentially dip-oriented facies

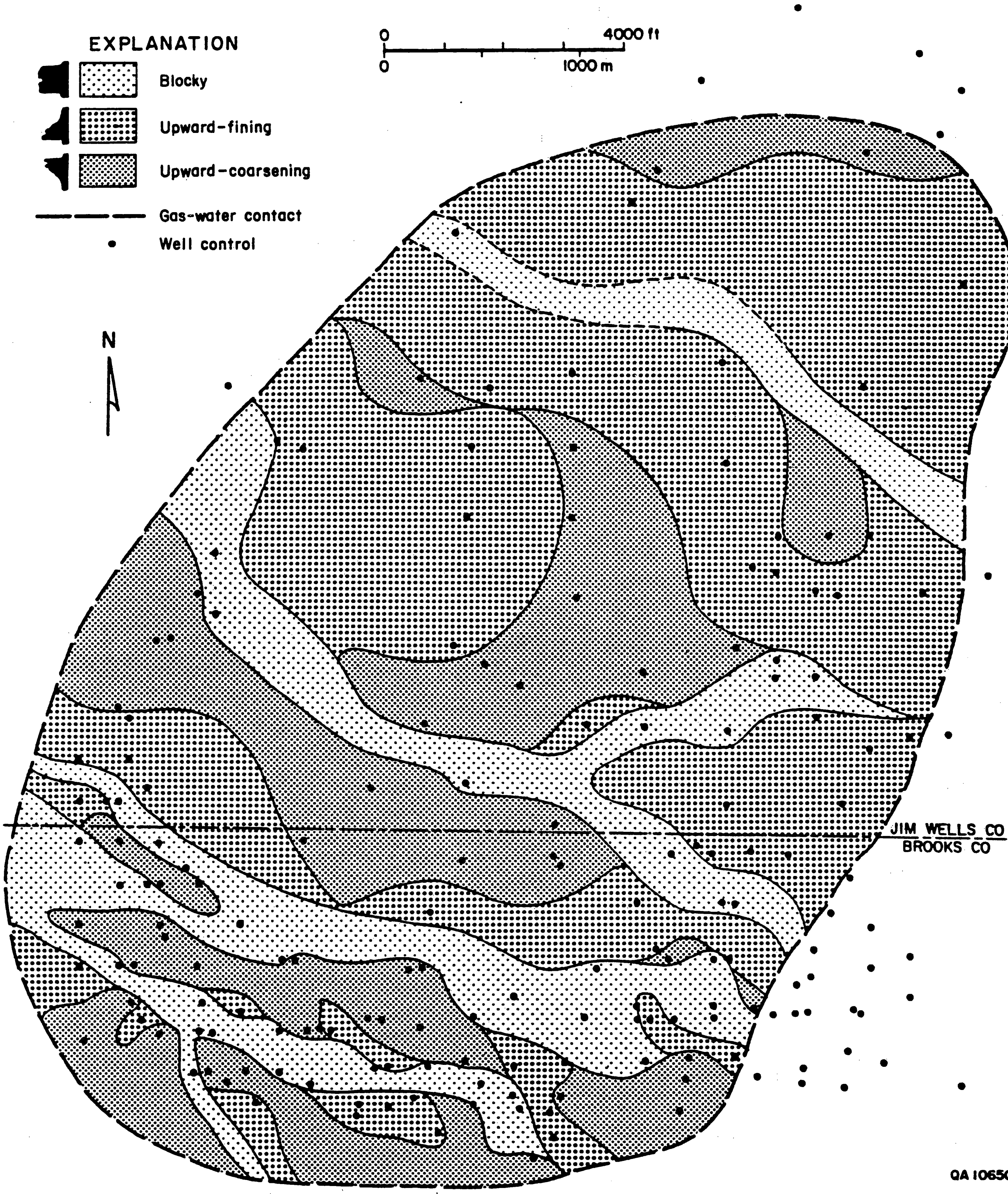


Figure 15. SP-log facies map of the Brooks A subunit in La Gloria field. Channel-fill sandstones, characterized by a blocky SP response, are distributed in narrow (less than 1,500 ft wide), dip-elongate belts, flanked by point-bar and splay facies defined by upward-fining and upward-coarsening SP responses, respectively. Note the lack of levee and floodplain facies in this sandstone-rich unit.

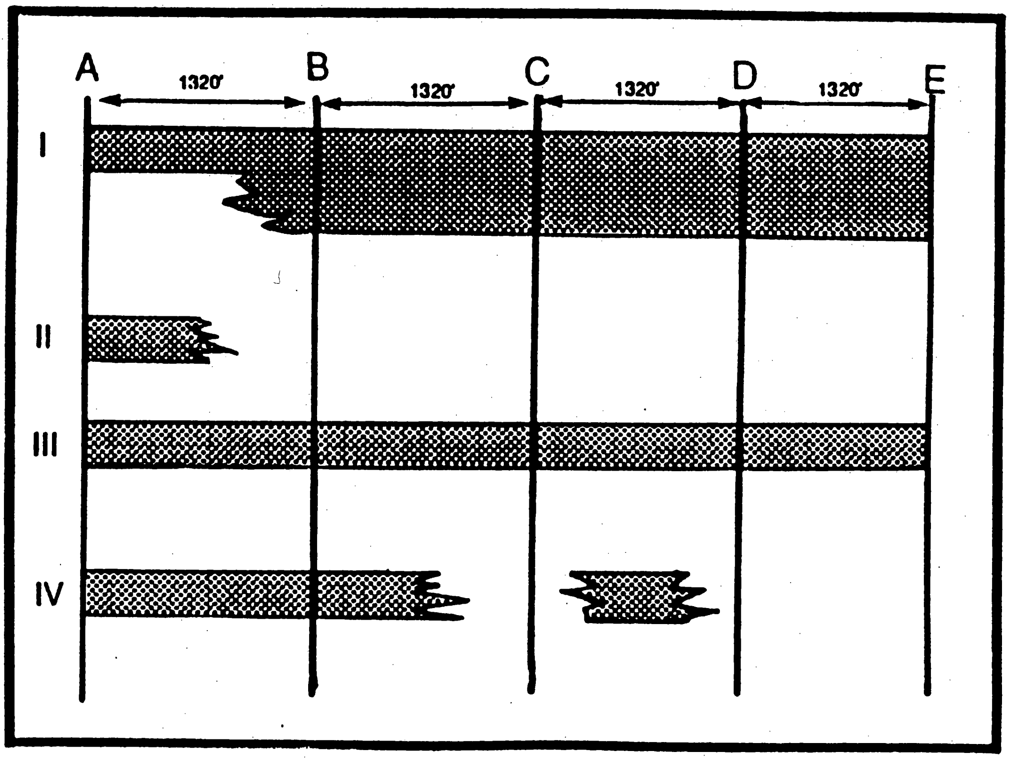
belts for the fluvial framework sandstones leads to variations in facies continuity that can be depicted using the approach of Stiles (1976).

Facies continuity

A semiquantitative method of estimating continuity of reservoir facies in La Gloria field was based on a statistical method described by Stiles (1976). This method of approximating pay continuity was developed because individual-well permeability data were not available for La Gloria field. The Stiles (1976) method of estimating reservoir heterogeneity was originally developed for carbonate reservoirs, in which pay zones occur as numerous thin stringers of variable permeability; the method was modified for clastic fluvial reservoirs in La Gloria field, because the facies architecture is characterized by multiple, discontinuous stringer sandstones.

The Stiles method involves calculating the percentage of continuous reservoir facies between different well pairs in cross section (fig. 16). In the Brooks reservoir, only the relatively permeable channel-fill and splay facies were included in tabulating sandstone-bed continuity among well pairs because channel-fill (with blocky and upward-fining log facies motifs) and splay facies constitute most of the reservoir on a volumetric basis. Analysis of two cross sections of reservoir facies in the Brooks B stringer shows that degree of continuity of reservoir facies is 72 percent along depositional dip but only 27 percent along depositional strike at 160-acre well spacing (fig. 17). The dip orientation and continuity of reservoir facies in the Brooks reservoir is clearly indicated.

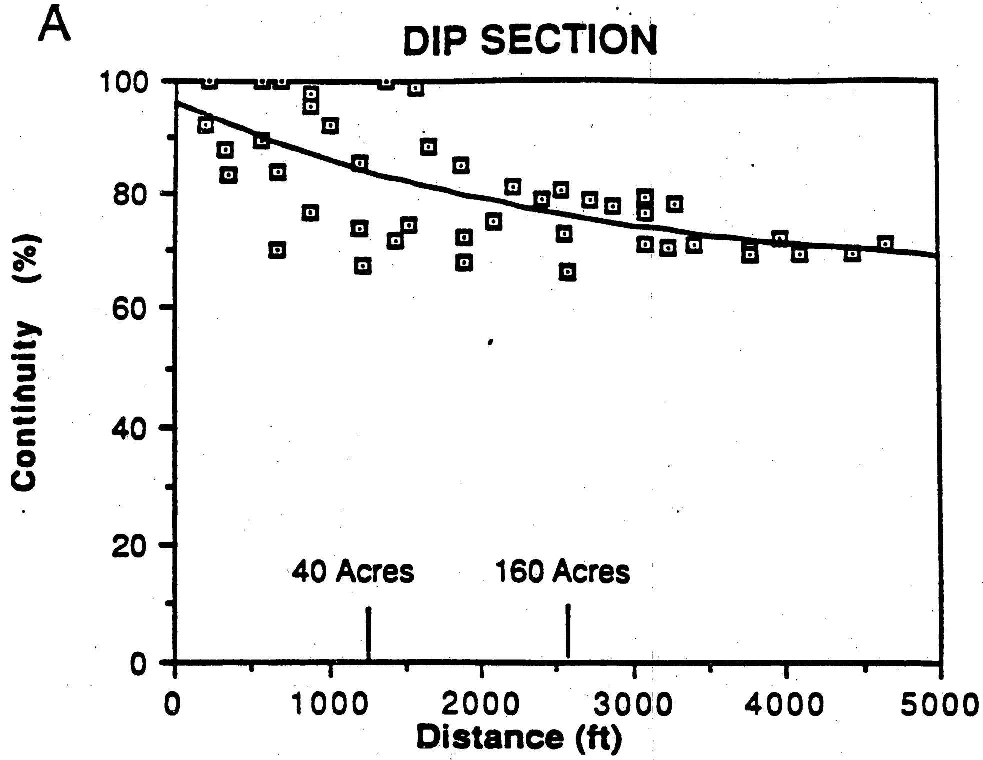
Reservoir-facies continuity indicates that the width of an average channel system in La Gloria field is considerably less than the 320-acre well spacing used in many gas fields. Well spacings of less than 320 acres will more completely contact all of the sandstone intervals in a reservoir. For the Brooks reservoir, as for many Frio fluvial reservoirs, infill completions or recompletions offset preferentially along depositional strike from older wells, particularly into splay facies, have the best probability of contacting partially undrained pay in the field.



$$\% \text{ Continuity} = \frac{\text{Effective Porous Volume}}{\text{Total Porous Volume}} \qquad \% \text{ Continuity Well Pair A-B} = \frac{\text{BED I + III+ IV}}{\text{BED I + II + III + IV}}$$

Figure 16. Schematic illustration of the Stiles (1976) method of calculating the pay-continuity function of a reservoir.

A



B

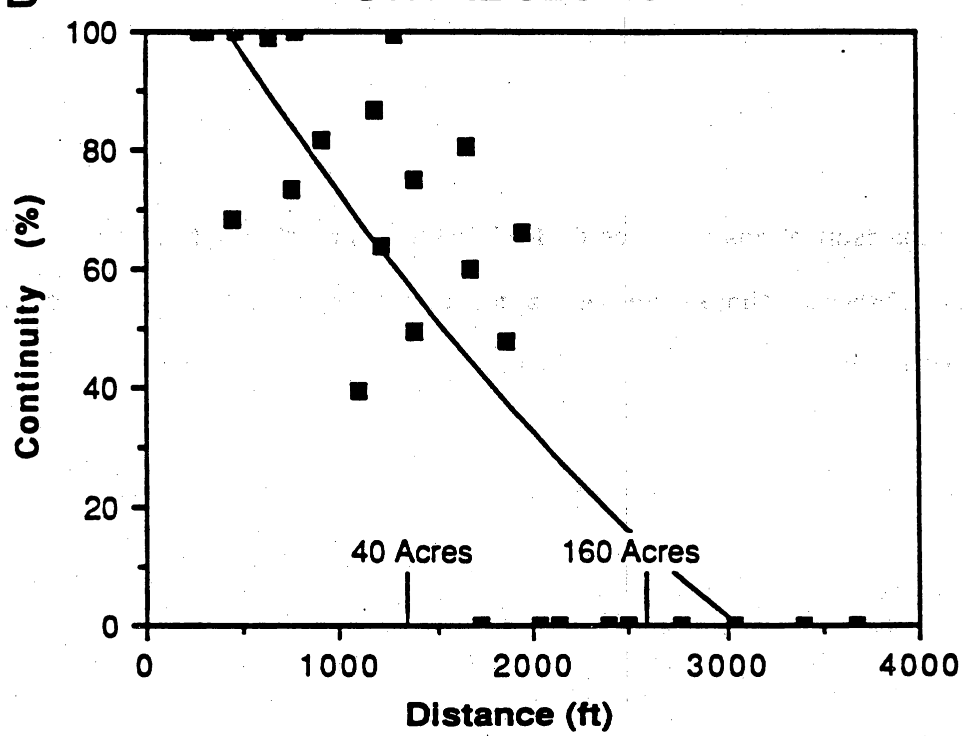


Figure 17. Continuity of channel and splay sandstone facies measured parallel to depositional dip (A) and strike (B) in the Brooks B stringer, La Gloria field. There is little change in facies continuity along dip; however, continuity along strike decreases rapidly. These data indicate that wells drilled along strike are relatively unlikely to encounter interconnected reservoir compartments, even when drilled at 160-acre spacing. Continuity percentage is determined from sandstone bed continuity measured between well pairs, adapted from the methodology of Stiles (1976). The strike section used for this analysis is shown in Figures 2 and 3.

In contrast, less additional gas would be expected to be contacted by infill drilling along known depositional axes delineated by older wells because of the greater reservoir facies continuity in that direction. Contact between major fluvial axes across splay facies is undefined and remains to be examined in field studies involving new well completions.

Location of potential areas to recomplete or drill

A majority of the wells in the Brooks reservoir are perforated in the Brooks B unit, in channel-fill and point-bar sandstones greater than 25 ft thick. No wells are perforated only in the Brooks upper A subunit; the upper A is perforated together with the B in most wells. Four wells are perforated in the A unit alone, and an equal number in the B unit only. Most of the wells are completed through all the Brooks sandstones, however, and have effectively drained the reservoir. Because there are so few floodplain deposits in this reservoir, and they are not of sufficient thickness or extent to partially isolate Brooks sandstone bodies, strictly geological and facies-based delineation of infill drilling prospects is not possible in the Brooks reservoir.

Calculation of reserve growth factor

Comparison of gas volumes derived from volumetric methods with those derived from material balance methods gives an estimate of remaining gas in a reservoir that is not in communication with existing wells and is therefore a target for strategic infill drilling or recompletion. The material balance estimate is used in standard industry practice and, despite its limitations, it is a useful first check on comparison between volumetric and pressure-based gas in place calculations that may offer an indication of gas reserves available because of reservoir heterogeneity.

Post-cycling gas-in-place in the Brooks reservoir was calculated using the traditional material balance method of projecting the trend defined by reservoir-wide bottom-hole pressure, adjusted for the effect of depth and pressure of the reservoir on gas volume, and plotted against cumulative production. For the Brooks reservoir, post-cycling gas-in-place calculated using this method is 196 Bcf (fig. 18).

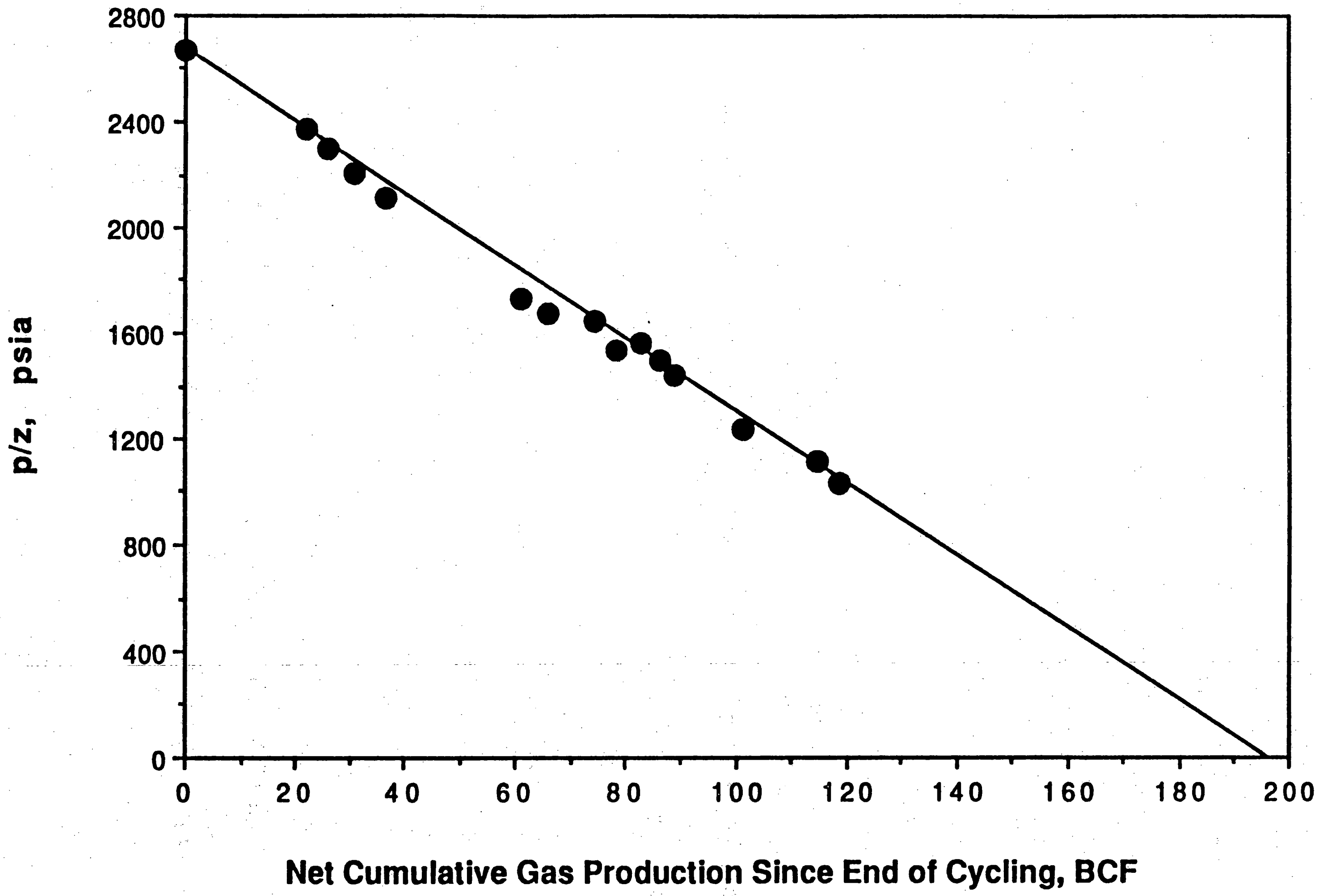


Figure 18. Pressure decline plot for the Brooks reservoir. Material balance estimate of post-cycling gas in place is 196 Bcf. P = average reservoir pressure; z = compressibility factor for natural gas.

Volumetric gas-in-place was calculated by planimetering two net-sandstone-thickness maps for each Brooks stratigraphic subunit and adding the volumes together for a total reservoir volume. Reservoir characteristics used in calculating the post-cycling volumetric gas-in-place are listed in the integrated analysis below. The resulting estimate is 240 Bcf for the Brooks reservoir. The arithmetic difference between the two estimates of post-cycling gas in place is 44 Bcf, representing a potential target for strategic infill drilling. This target gas volume is 23 percent of the post-cycling gas-in-place calculated by the traditional material balance method, and represents an estimate of the reserve growth potential of the reservoir.

Estimate of potential for gas reserve growth

Integrated geological and engineering analyses of the Brooks reservoir were used to estimate the ability of more intensive field development to add natural gas reserves. This analysis quantified the amount of gas that may be technically produced from infill drilling or recompletion as a function of alternative well spacing, discovery pressure, and production methods. The technically recoverable gas volumes reported in this study represent incremental gas reserves that would remain in the reservoir at abandonment if no additional wells were completed in the target zones.

The 4,878-acre Brooks reservoir was divided areally into eight approximately 640-acre grids for disaggregated analysis. Average reservoir characteristics for each grid were developed from reservoir characteristics of geologic facies calculated on a volumetric, approximately quarter-grid basis. Gas production data were analyzed to estimate the effective drainage area and theoretical ultimate recovery for wells in the reservoir. Analysis of pressure data added to the understanding of how gas is contacted in the reservoir. Incomplete gas production data, changing well-drainage areas, and inconsistent pressure data required that the data be carefully cross-checked. The gas contact function derived from these data quantifies the additional volumes of gas contacted at closer well spacings and is the key determinant of estimates of gas reserve growth in this study. Production modeling was then used to determine how much of this incrementally contacted gas could be produced.

The geologic and engineering analytic methods developed for the Brooks reservoir were also used for the Jim Wells and I-92 reservoirs. Data collection and analysis methodologies will be discussed fully for the Brooks and only briefly referenced for the Jim Wells and I-92 reservoirs.

Production and development history

The Brooks reservoir, the largest gas reservoir in La Gloria field, was discovered in 1939. In 1941 the first production wells were completed, and a gas cycling program was immediately initiated in which dry residue gas from the La Gloria field gas processing plant was reinjected into the Brooks reservoir to maintain reservoir pressure and to maximize condensate production.

The gross gas production from the Brooks reservoir during the cycling program (1941 to 1955) was 132 Bcf. Injected dry gas equalled 103 Bcf, resulting in a net gas production of 29 Bcf. Also during gas cycling, 3 million barrels of condensate liquid were produced from the Brooks reservoir.

During the first ten years of reservoir life, several wells were completed in both the Brooks reservoir and overlying Culpepper reservoir and were produced through the same tubing string. Because of this commingled production, the reported gas and condensate production from the Brooks reservoir for the cycling period were based on reported data as modified by engineering calculations.

Since the end of gas cycling in 1955, the reservoir has been produced under pressure-depletion drive. During this post-cycling period (1955 to present), the field was operated under proration, in which the producing wells were assigned an allowable that limited the maximum production rate to 25 percent of the annual adjusted absolute open-flow potential. During the early years after cycling, most wells were produced at rates less than the allowable and equal to some fraction of the open-hole potential. At present, since the contacted reservoir is almost depleted, compression is required to elevate gas pressures to pipeline levels.

From the end of gas cycling in 1955 through 1987, 171 Bcf of natural gas and over 2 million barrels of condensate have been produced from the Brooks reservoir. Thus, total cumulative production of the Brooks reservoir is about 200 Bcf of gas and 5 million barrels of condensate. The production and development statistics for the Brooks reservoir are summarized in table 1.

Data sources

The first step in estimating gas reserve growth potential in the Brooks reservoir was to estimate the gas in place and the productive capacity of the reservoir. For this, porosity, permeability, net sandstone thickness, water saturation, and pressure data were collected and mapped. These reservoir data, combined with the geologic facies distribution maps, were used to estimate incremental gas recovery from strategic infill drilling.

Data sources for the engineering analysis of the Brooks reservoir included computerized data bases, government-owned files and operator-supplied reports and laboratory analyses. Where possible, data collected from one source were verified by a second, independent source. Sources of data collected for the Brooks reservoir were:

- **Railroad Commission of Texas Files.** The files of the Commission provided detailed information on La Gloria field development history. In addition, certain well tests, required by the state, provided detailed information on each well, such as its open-flow potential. Summary information was also collected on injected volumes of gas and cumulative gas production.
- **Dwight's Database.** Well-by-well natural gas production data, open-flow potential, and selected average reservoir properties were obtained from Dwight's Energydata, Co.
- **Internal Reports from Mobil Corporation.** The files of the Mobil Corporation, the primary operator of the La Gloria field, contained the following data:

Table 1. Production and Development Statistics for the Brooks Reservoir, La Gloria Field.

Development History

- Reservoir discovered in 1939
- First production well completed in February 1941
- Gas cycling program maintained from June 1941 to April 1955
  - Dry gas injected (102.6 Bcf)
  - Reservoir pressure maintained (2,800 psi in 1941; 2,400 psia in 1955)
  - Condensate production maximized (3 million barrels)
  - 19 wells drilled (producers and injectors)
- Reservoir produced under depletion drive conditions from April 1955 to present
  - Wells produced at rates equal to fraction of annually adjusted open-hole potential
  - 8 additional wells drilled (all producers)

Production History

- Initial Producing Gas-Liquid Ratio (Scf/BBL): 30,000–50,000
- Current Producing Gas-Liquid Ratio (Scf/BBL): >100,000
- Net Cumulative Gas Production (Bcf)
  - 1941 to 1955: 29.2*
  - 1955 to 1987: 170.7
- Cumulative Condensate Production (MB)
  - 1941 to 1955: 2,998
  - 1955 to 1987: >2,000

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*During the first 10 years of Brooks reservoir production, several wells were completed in both the Brooks reservoir and overlying Culpepper reservoir and were produced through the same tubing string. Because of this production, the reported gas and condensate production statistics for this period of production in the Brooks reservoir are based on corrections supplied by the operator.

- field development statistics
- mode of field operations
- well completion practices
- well-by-well gas and condensate production
- cumulative gas injection.

• **Geophysical Logs.** The well logs used in the Brooks reservoir analysis included induction-electric, gamma-ray, acoustic, density, and neutron porosity. In addition to providing the basis of the geologic evaluation of the Brooks reservoir, these logs were used to estimate well-specific water saturation and net-sandstone-thickness data.

• **Core Data.** Only limited amounts of core analyses were available for the Brooks reservoir. This information was the sole source of facies-specific porosity and permeability data. The data obtained from the cored intervals were similar to permeability and porosity values in the nearby and depositionally similar Seeligson field, however, where recently collected whole core data were available.

Estimates of key reservoir properties

The data were reviewed and analyzed to develop estimates of key reservoir properties for the Brooks reservoir. Inconsistencies among data were resolved where necessary. Estimates of key data are discussed below and summarized in table 2.

Average and facies-specific properties

Combining operator-supplied core data and geophysical logs, permeability, porosity, and water saturation were derived for each of the five facies in the Brooks reservoir (table 2). The bulk volume of the reservoir was calculated as 241,944 acre-ft by using a planimeter and the net-sandstone-thickness map (fig. 13).

On average, the reservoir has high permeability and good gas-filled porosity. In addition, the reservoir has good productive sand thickness, averaging 49.6 ft. Except for the floodplain

Table 2. Key Reservoir Data Summary for the Brooks Reservoir, La Gloria Field.

Average Reservoir Properties

Area:	4,878 acres
Average Net Sandstone Thickness:	49.6 feet
Bulk Volume:	241,944 acre-feet
Average Porosity:	22.9 percent
Connate Water Saturation:	32.2 percent
Depth:	5,800 feet
Reservoir Temperature:	184°F
Reservoir Pressure After Cycling (1951):	2,395 psia
Current (1987) Reservoir Pressure:	<300 psia
Dry Gas Specific Gravity:	0.65 (Air = 1.0)
API Gravity of Condensate:	55 degrees
Post-Cycling Gas Formation Volume Factor:	0.00683 Rcf/Scf
Estimated Gas In Place After Cycling:	240.4 Bcf
Average Absolute Permeability:	400 md

Facies-Specific Reservoir Properties

Facies Type	Effective Permeability to Gas (md)	Porosity (%)	Water Saturation (%)
Channel Sand	488	24	32
Point Bar Sand	300	24	32
Proximal Splay	188	22	33
Distal Splay	75	21	31
Floodplain	0.1 to 1.0	16	>30

(which contains limited producible volumes of gas), the facies comprising the Brooks reservoir are similar in terms of the basic engineering properties controlling gas recovery. Permeability ranges from 75 to 488 md, porosity ranges from 21 to 24 percent, water saturation ranges from 31 to 33 percent, and net sandstone thickness ranges from 36 to 63 ft.

The initial pressure of the Brooks reservoir at discovery in 1939 was 2,804 psia. After gas cycling and a net production of 29 Bcf of gas and 3 million barrels of condensate, this pressure had declined to 2,395 psia.

Volumetric gas in place

Because of the initial period of gas injection, the analysis includes only the period after cycling, from the beginning of depletion drive to the present. Thus, in this report, volumetric gas in place and post-cycling pressure refer to the point in time immediately after gas cycling rather than to the time of reservoir discovery. The implications of restricting the analysis to the post-cycling time period will be discussed in more detail below.

The post-cycling volumetric gas in place (GIP) for the Brooks reservoir was calculated by aggregating estimates of gas pore volume for over 100 smaller analytical units, consisting of facies-specific reservoir characteristics weighted by volume on a quarter-grid basis. This total reservoir gas pore volume was estimated at 241,994 acre-ft. A gas formation volume factor of 0.00683 Rcf/Scf was calculated on the basis of average post-cycling reservoir pressure and temperature and was used to provide a gas-in-place value of 240 Bcf for the Brooks reservoir.

The analytic units used to estimate the total Brooks reservoir gas pore volume were based on the geologic facies determination. The Brooks A and B units were used as major vertical subdivisions, and average reservoir properties for each of the four fluvial sandstone facies were calculated. Each of the eight 640-acre grids was composed of three to five subgrids, and average reservoir properties were calculated for each subgrid according to the percent by volume of each facies present. Each subgrid consisted of one to four facies types in the Brooks A stringer and one to four types in the Brooks B stringer. These properties were volumetrically averaged by subgrid and aggregated using the method shown in table 3.

Gas contact function for the Brooks reservoir

The fundamental basis for natural gas reserve growth is the increased contact of reservoir volume by new wells or recompletions. The efficiency of reservoir contact by a well is a function of areal placement and vertical completion with regard to complex reservoir heterogeneities and facies distributions. The underlying concept of infill drilling is that closer well spacing recovers a higher percentage of gas in place.

The specific reservoir mechanism controlling this phenomenon needs to be better understood, however, before effective strategies can be developed to optimize infill drilling. The phenomenon was quantified in this study by development of an empirical gas contact function that relates well spacing to reservoir contact, measured in terms of theoretically recoverable gas. This assumes that all of the gas that is contacted can be produced down to an economic limit. Technically (actually producible) gas available from more intensive field development was then estimated from the gas contact function. This volume of incremental reserves represents gas that, without closer well spacing, would remain unproduced at reservoir abandonment. The following sections describe how the gas contact function was developed and applied to the Brooks reservoir.

Concepts and definitions of gas contact

The concept of additional reservoir contact through infill well completions evolved from the ideas and methods first developed for oil reservoirs (Stiles, 1976; George and Stiles, 1978). However, differences in flow characteristics and production mechanisms between oil and gas required the development of a considerably modified methodology for assessing reservoir contact in gas reservoirs.

Table 3. Example of Derivation of Grid-Specific Reservoir Properties (Grid 1, Brooks Reservoir).

Average Reservoir Properties: Subgrid A, Grid 1

Subgrid A	Type of Facies	Fraction of Subgrid Occupied by Facies (F)	Sandstone Thickness (h, feet)	Porosity (ø)	Permeability (k, md)	Water Saturation (Sw)	F*h (feet)	F*h*ø (feet)	F*h*k (md-feet)	F*h*ø*S_W (feet)
Brooks A	Channel Sand Point Bar Sand	0.20 0.80	30.0 29.0	0.24 0.24	488 300	0.32 0.32	6.0 23.2	1.44 5.57	2,928 6,960	0.46 1.78
Subtotals							29.2	7.01	9,888	2.24
Brooks B	Distal Splay Sand Proximal Splay Sand	0.80 0.20	9.5 10.0	0.21 0.22	75 188	0.31 0.33	7.6 2.0	1.60 0.44	570 376	0.49 0.15
Subtotals							9.6	2.04	946	0.64
Subgrid A Totals							38.8[a]	9.05[b]	10,834[c]	2.88[d]

Average Reservoir Properties: All Subgrids, Grid 1

Subgrid	$\overline{h}$ (feet)	$\overline{k}$ (md)	$\overline{ø}$	$\overline{S}_W$	Area, A (Acres)
Subgrid A average	38.8	279.2	0.23	0.32	115.29
Subgrid B average	25.1	282.9	0.23	0.32	141.42
Subgrid C average	49.0	220.7	0.23	0.32	143.46
Subgrid D average	42.4	216.2	0.23	0.32	151.49
Subgrid E average	44.2	254.5	0.23	0.32	141.42
Grid 1: Average Reservoir Properties	40[e]	249[f]	.23[g]	.32[h]	693

Average Reservoir Properties: Subgrid A, Grid 1

a $h = \Sigma F * h = 29.2 + 9.6 = 38.8$ feet
b $k = \Sigma F * h * k/\Sigma F * h = 10{,}384/38.8 = 279.2$ md
c $ø = \Sigma F * h * ø/\Sigma F * h = 9.05/38.8 = 0.2331$
d $S_W = \Sigma F * h * ø * S_W/\Sigma F * h * ø = 2.88/9.05 = 0.3187$

Average Reservoir Properties: Grid 1

e $h_1 = \Sigma A*h/\Sigma A = 40$ feet
f $k_1 = \Sigma A*h*k/\Sigma A*h = 249$ md
g $ø_1 = \Sigma A*h*ø/\Sigma A*h = 0.23$
h $S_{W1} = \Sigma A*h*ø*S_W/\Sigma A*h*ø = 0.32$

George and Stiles (1978) combined geological description, reservoir engineering, and modified operating practices to improve waterflood performance in West Texas carbonates. They recognized the presence of numerous discontinuous pay stringers between wells and based predictions of well performance on reservoir continuity. The raw data they used were from log correlations of discontinuous sandstone bodies between adjacent wells.

The George and Stiles concept is insufficient, however, to establish reservoir contact in a gas reservoir. The high relative permeability, high compressibility, and low viscosity (with pressure decrease) of gas makes gas mobility several orders of magnitude greater than that of oil. Given the location and distribution of discontinuities within and between facies types in a particular reservoir, the mobility of oil may be restricted, while that of gas may not. Facies changes, other reservoir heterogeneities, and reduced permeabilities that tend to compartmentalize and restrict the flow of oil do not restrict the flow of gas in the same manner, and this must be taken into account in a model of gas contacted in a reservoir.

Because facies changes act as a restriction to gas flow rather than as impermeable barriers, estimating reservoir contact requires the modeling of flow within and across different facies as well as an understanding of flow impairments due to decreased permeability, areal well placement, vertical completion strategies, and interference effects. Therefore, the derivation of a gas contact function requires the integration of all of these flow-impedance factors.

Three techniques were considered for use in developing a gas contact function for the Brooks reservoir: multiwell reservoir simulation, pressure analysis, and production-decline type curve analysis. Each of the three methods evaluated is based on theoretical concepts accepted as valid means to estimate potential recovery from an oil or gas well. The usefulness and accuracy of the results from each technique are related to data availability in relation to the data requirements and analytic rigor of each estimation method.

Of the three methods examined, multiwell reservoir simulation can provide the most accuracy and insight into performance of potential infill wells. A multiwell, three-dimensional, finite-difference reservoir simulator models not only areal and vertical variations in reservoir properties but also multiwell interference effects. The goal of multiwell modeling is to match the production and pressure histories from each well in the reservoir with their actual values. Discrepancies between actual and predicted values require changes in assumptions of reservoir properties or flow mechanisms.

This technique requires a detailed, three-dimensional description of reservoir properties and historical production and pressure data for all existing wells. Data available for the Brooks reservoir are neither accurate nor detailed enough for multiwell modeling. However, other reservoirs for which accurate data are available could be modeled using multiwell three-dimensional reservoir simulators.

The pressure analysis technique can be applied to a single well or to a reservoir as a whole, but does not require detailed description of reservoir properties to estimate total reservoir gas contact. This is a graphical material balance technique that plots the ratio of shut-in pressure to gas compressibility factor against cumulative recovery. The plot for a reservoir or well operated under depletion drive will be a straight line, the extension of which to zero pressure estimates ultimately contacted gas. This amount of gas is compared with volumetric estimates in order to obtain an estimate of uncontacted or partially contacted gas reserves.

Pressure measurements in the Brooks reservoir were inadequate to use the well-by-well material balance approach to determine gas contact. The reservoir-wide approach was used in this study only to give a preliminary estimate of reserve growth potential. The validity of the well-by-well technique requires that the volume of a well drainage area or reservoir be constant, with no external energy supplied (e.g., injection or water drive energy), and that the pressure measurements accurately reflect average reservoir pressure in the drainage area. Pressure data must be based on production wells that are shut in for a sufficient time to allow the bottom-hole pressure to build up to the static average reservoir pressure in its drainage area.

Pressure measurements for most producing wells in the Brooks reservoir, however, were based on shut-in periods of less than 24 hours. Because the drainage area of a well consists of the theoretically completely contacted channel sandstone, into which the well is perforated, and partially contacted point bar, proximal splay, and distal splay sandstones (separated from the channel sandstone by silt and clay layers), measured pressures are unlikely to represent the true average reservoir pressure. In addition, erratic histories on well P/Z plots in the Brooks reservoir indicate that individual well pressure measurements appear to have been affected by condensate and water in the wellbore and by interference from adjacent producing wells.

Production-decline type curve analysis, the third technique examined for derivation of a gas contact function, was determined as the most appropriate given the nature of the data available. This technique is based on the ability of production data to reflect the aggregate effects of flow restrictions within and among the various facies contacted by infill wells, without requiring detailed reservoir descriptions or pressure histories.

The gas contact function developed in this study quantifies the amount of incremental gas contacted at increasingly closer well spacings. The function is derived using individual well production streams and a standard production-decline type curve analysis to calculate the percent of gas that is contacted for each constant-well-spacing time period selected for analysis. Once the function is established, amounts of incremental gas contacted at selected infill-well spacings are determined from it and used for assessment of technically recoverable gas.

Methodology for estimating gas contacted by a producing well

The gas contact function for the Brooks reservoir was derived by analyzing well-by-well gas production data. Six steps were followed to estimate the volumes of gas contacted by individual wells at alternate well spacings and to develop the gas contact function for the Brooks reservoir.

STEP 1. Develop Production Data Base for Individual Wells. Monthly production data were obtained from the operator (Mobil) and the Railroad Commission of Texas to establish the gas and condensate production history (1941–1987) of the Brooks reservoir. The completion and facies selection strategies were also examined for each well (table 4). Because the gas/condensate production histories for the wells in the Brooks reservoir were often incomplete, an attempt was made to correct inconsistencies in the data. Since well-by-well gas injection data were not available for the cycling period (1941–1955), the post-cycling period was chosen for detailed analysis.

STEP 2. Establish Average Reservoir-Wide Well Spacing for Discrete Development Periods. The production-decline type curve analysis requires that the reservoir be under depletion drive and in pseudosteady-state flow. The absence of a strong water drive for the Brooks reservoir enables the first condition to be satisfied. The high permeabilities of the channel sandstones assure that the pressure transients will reach the boundary of their respective drainage area relatively rapidly; thus, the second condition is also satisfied.

Gas contact is best estimated for time periods when the number of wells and the drainage pattern are fairly constant in a reservoir, as when few wells are being drilled, shut in, or abandoned. Two time periods after the end of cycling, when the Brooks reservoir was produced at a relatively constant well spacing, were selected for analysis. From 1956 to 1965, six wells were producing (fig. 19) from the Brooks reservoir. Given a total reservoir area of 4,878 acres, average reservoir-wide well spacing was 813 acres in the first development period. From 1965 to 1975, the Brooks reservoir was produced by eleven wells at an average reservoir-wide well spacing of 443 acres per well (fig. 19). Four of these eleven wells had been produced during 1956 to 1965. Of the remaining seven, four were recompleted in the Brooks, one was reopened, and two could not be completely documented but were drilled prior to the end of cycling and we believe were also recompletions into the Brooks reservoir.

The field limit was well established during cycling when wells as close as possible to the periphery of the producing area were developed. All of the post-cycling producing wells are

Table 4. Summary of Facies-Specific Well Completions for the Brooks Reservoir, La Gloria Field, for Wells Used in this Study that Produced after Cycling Was Stopped.

Well No.	Date Production Started From Brooks	Type of Facies Perforated	Initial*** BHSIP (psia)	Reservoir**** BHSIP (psia)
SLGU 1*	Nov. 1941	Channel	?	2,780
SLGU 4	Dec. 1941	Channel	?	2,760
LGU 8**	July 1949	Channel	?	2,690
LGU 27	March 1950	Point Bar	?	?
LGU 16	May 1950	Distal Splay	?	?
LGU 3	Nov. 1957	Proximal Splay	?	1,950
LGU 17	Nov. 1959	Channel and Distal Splay	1,866	1,900
LGU 36	May 1966	Channel	1,208	1,150
LGU 50	June 1966	Channel	1,159	1,120
LGU 26	March 1967	Proximal Splay	1,172	1,150
LGU 64	Aug. 1968	Channel	1,052	1,050
LGU 1	March 1969	Channel	943	950
LGU 15	Nov. 1973	Proximal and Distal Splay	470	510
LGU 100	July 1982	Channel	164	?
LGU 96	June 1983	Channel	170	?

* South La Gloria Gas Unit (SLGU).

** La Gloria Gas Unit (LGU).

*** Initial Bottom-hole Shut-In Pressure (BHSIP) taken from Texas Railroad Commission files.

**** Average Reservoir Bottom-hole Shut-in Pressure (BHSIP) taken from internal Mobil reports or calculated using available data from Texas Railroad Commission files.

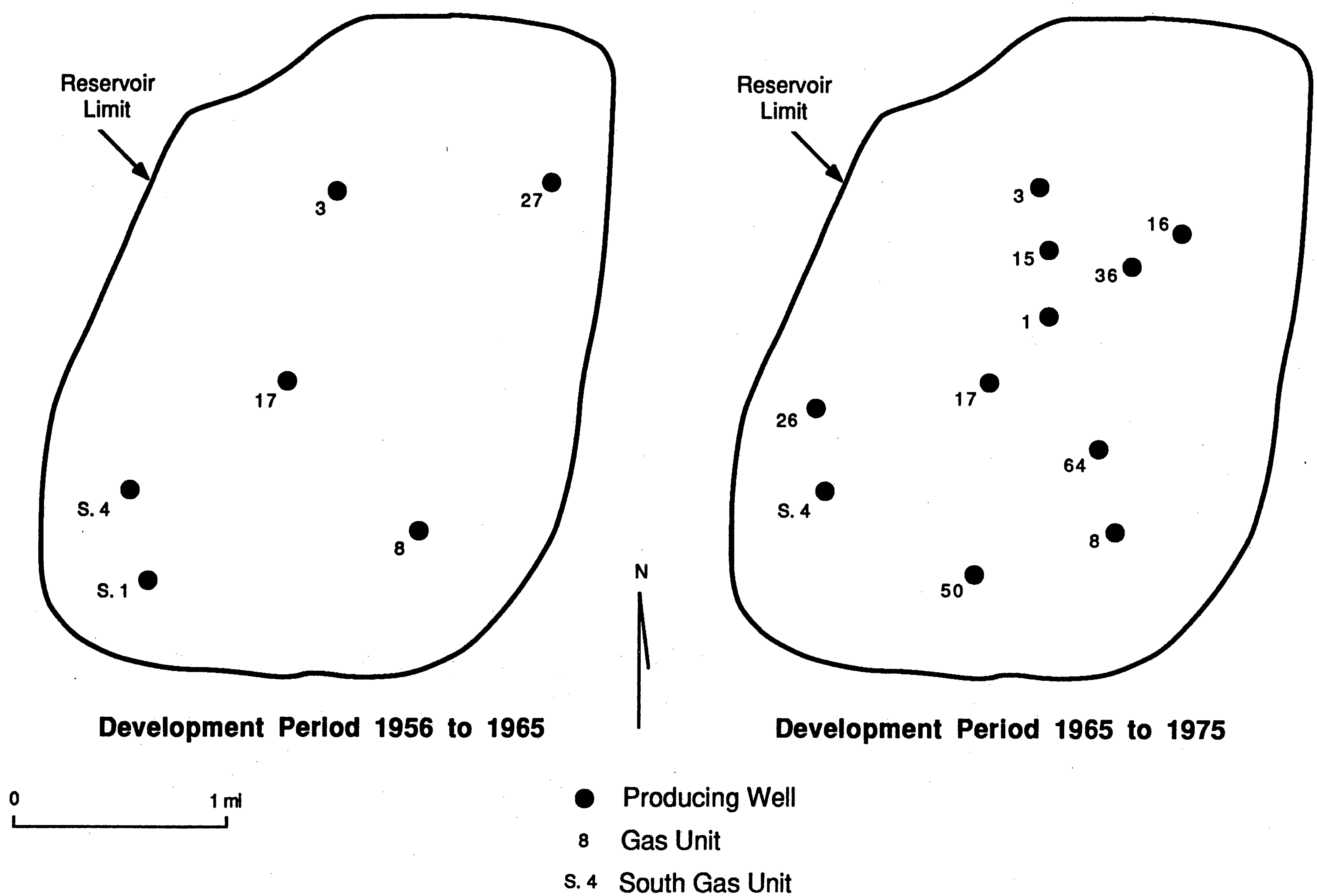

Figure 19. Reservoir development history of the Brooks reservoir, 1956 to 1975.

within the field limit thus established. As time progressed, production was carried on closer to the crest of the reservoir structure in order to drain areas of lower water saturation.

STEP 3. Plot Production-Decline Curves for Individual Wells. The monthly gas production for individual wells was plotted as a function of time for each development period. These plots graphically describe the production history of each well and are used in Step 5 to estimate well-specific gas contact for a specific well spacing. Due to the erratic monthly production volumes from field proration and temporary shut-ins, six-month averaging was used to smooth the data.

STEP 4. Estimate the Ultimately Contacted Gas for Each Well Using Type Curve Analysis. Production-decline type curve analysis was used to evaluate gas in place that is in pressure contact with wells for the well spacing for the Brooks reservoir. Type curves are a preplotted family of curves representing mathematical solutions to gas flow equations with specified well and reservoir boundary conditions. By extrapolation from the proper type curves, the theoretically producible gas remaining in the current drainage pattern of a well may be estimated. Adding this value to cumulative production to date gives the total amount of gas contacted by the well.

The type curves developed by Fetkovich (1980) were used to analyze individual well production histories in the Brooks reservoir. A wide variety of type curves are available in the literature, each one appropriate to a specific type of gas well production method. The Fetkovich curves are most appropriate for the Brooks reservoir because the curves were developed by mathematically incorporating the prorated allowable production method that was used in the post-cycling operation of La Gloria field. Additional details concerning the derivation and use of these type curves are given by Smith (1983).

These curves were generated by combining the empirical gas backpressure equation, $Q = C(P_e^2 - P_{w^2f})^n$ (Rawlins and Schellhardt, 1935), with a linear material balance equation for a volumetric gas reservoir. The derivation of the type curves assumes the outer boundary of the reservoir is closed (i.e., no flow) and the inner boundary (i.e., the wellbore) is at a constant pressure. The family of type curves is presented as a function of x_i, which is the ratio of the initial reservoir pressure (P_i) to the constant backpressure imposed on the well (P_{wf}). As this ratio increases to infinity, the curves model well production at a constant fraction of the annual adjusted open-flow potential, as was the case in the Brooks reservoir.

For each well, the type curves were used to estimate the ultimate recovery and gas in place in the established drainage area of a well. A more complete description of the method and an example from each of the two time periods are presented in the Appendix.

Examples of the type curves used in the analysis are shown in figure 20, for values of x_i from 1.25 to infinity. These particular curves were developed for a gas backpressure equation exponent equal to 1.0. Typical values of n vary from 0.5 for turbulent flow to 1.0 for nonturbulent flow. For the type curve analyses of individual wells in the Brooks reservoir, well-specific gas backpressure exponents (n), as reported by the Railroad Commission of Texas (Form G-1, Gas Well Back Pressure Test, Completion or Recompletion Report and Log), were used. In addition, since these wells were produced at only a fraction of their open-flow potential, only the type curves for x_i=infinity were used.

For each producing well during each development period, the ultimate gas contacted by the well was calculated by adding the cumulative gas production since the end of gas cycling to the estimated gas in place remaining in the drainage area (from the type curve analysis). The effects of well interference and shifting drainage areas, which resulted from changing well spacings over the history of the Brooks reservoir, were isolated by the analysis of individual well production histories during the two development periods of relatively constant well spacing. The analysis assumes that the drainage patterns for each well during individual development periods would remain constant until abandonment. This represents reservoir development and production at a fixed well spacing with no subsequent infill wells or recompletions in the Brooks reservoir. This assumption is critical to the derivation of individual points in the gas contact function because if the well spacing changes (with wells

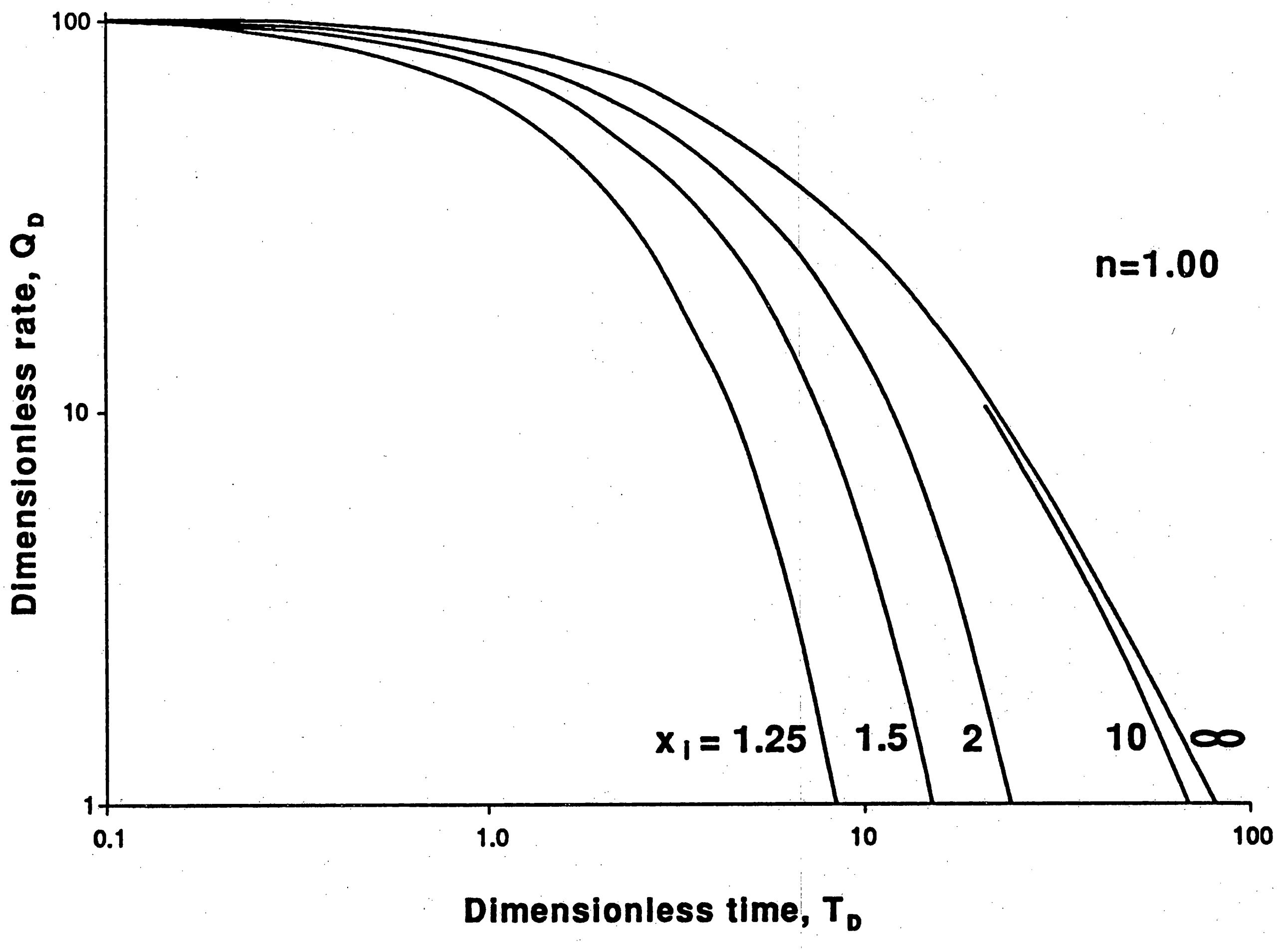

Figure 20. Type curves used in gas production modeling of the Brooks reservoir. Four example curves are shown for values of x_i equal to 1.25, 1.5, 2, 10, and infinity (the ratio of initial reservoir pressure to the constant backpressure imposed on the well). The curves are shown for a gas backpressure exponent (n) of 1.0.

coming on- or off-line), the drainage areas—and thus the gas contacted by existing wells—would also change due to interference effects.

Comparison of the estimated gas contact for wells producing during both development periods illustrates the method of analysis. Four wells (SLGU 4, LGU 8, LGU 3, and LGU 17) established drainage patterns during the first development period that contacted the volumes of gas shown in table 5. A decrease in well spacing would be expected to decrease the volume of gas contacted by these wells. This may be due to interference in the drainage patterns between new and existing wells. Comparison with gas contact values derived for the second period (table 6) shows this to be true for three of the four wells. The fourth well, LGU 3, had numerous shut-in periods and severe cutbacks in production in the last four years of development period one (1962–1965). As a result of this erratic production, LGU 3 did not achieve the complete drainage radius in development period one that it did during development period two. The erratic behavior of LGU 3 was corrected for by using the volume of gas contacted during development period two for that well during development period one. This correction is conservative and is consistent with the behavior of other wells producing during both development periods. Definitive prediction of incremental gas cannot be made for this reservoir because of the production practice.

It should also be noted that the infill development of the Brooks reservoir was not necessarily done with the intent of strategically infill drilling the reservoir. Whether or not the second development period was conducted based on an overall plan for maximizing gas recovery was not determined as part of this study. Rather, the change in average well spacing resulting from the addition of new wells presents the opportunity to investigate, on an initial basis, the potential for incremental recovery as gas reservoir well spacing is reduced.

STEP 5. Aggregate Per-Well Ultimate Gas Contact. The ultimate gas contacted for the six individual wells was summed to establish the total ultimate gas contacted by the six producing wells in the Brooks reservoir at the 813-acre well spacing during the first development period.

Table 5. Summary of Results of Assessment of Reservoir Heterogeneity for the Brooks Reservoir, La Gloria Field.

Development Period One: 1956–1965

• Total Number of Production Wells:	6
• Reservoir Area:	4,878 acres
• Average Well Spacing:	813 acres/well
• Average Interwell Distance:	5,951 feet

Well Number	Ultimate Gas Contacted Since End of Cycling, Bcf
SLGU 1 (See Appendix A for Derivation)	23.9
SLGU 4	40.7
LGU 8	34.9
LGU 27	8.7
LGU 3	39.1
LGU 17	22.2
LGU 5*	1.9
LGU 16*	1.6
ML 1*	3.8

Total Ultimate Gas Contacted Since End of Cycling:	176.8
Gas In Place (GIP) at End of Cycling:	240.4 Bcf
Ratio of Gas Contact to GIP:	73.5 percent

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*These wells produced either for a short time period after the cycling program ended or began producing at the end of development period one. Because LGU 5 and ML 1 were shut in prior to 1960 and LGU 16 produced for a short time beginning in 1965, these wells had no effect on the established drainage patterns of other wells producing in 1965. Therefore, these wells were not included in the calculation of average reservoir-wide well spacings, but the production was considered in the gas contact calculations.

Table 6. Summary of Results of Assessment of Reservoir Heterogeneity for the Brooks Reservoir, La Gloria Field.

Development Period Two: 1965–1975

- Total Number of Production Wells: 11
- Reservoir Area: 4,878 acres
- Average Well Spacing: 443 acres/well
- Average Interwell Distance: 4,393 feet

Well Number	Ultimate Gas Contacted Since End of Cycling, Bcf
SLGU 4	35.2
LGU 8	32.3
LGU 3	39.1
LGU 17	17.1
LGU 16	12.0
LGU 36 (See Appendix A for Derivation)	7.4
LGU 50	6.6
LGU 26	17.1
LGU 64	1.0
LGU 1	3.5
LGU 15	0.4
SLGU 1*	16.5
LGU 27*	8.7
LGU 5*	1.9
ML 1*	3.8

Total Ultimate Gas Contacted Since End of Cycling: 202.2 Bcf
Gas In Place (GIP) at End of Cycling: 240.4 Bcf
Percentage of Gas Contact to GIP: 84.4 percent

*These wells represent all wells that produced between the end of cycling (1956) and the beginning of the second development period (1965). Since they do not affect the established drainage patterns of wells producing in 1975, these wells were not included in the calculation of reservoir-wide well spacing.

The procedure was repeated for the eleven producing wells at 443-acre well spacing for the second development period.

STEP 6. Divide Aggregate Ultimate Gas Contact for each Development Period by Volumetric GIP. The post-cycling gas in place for the Brooks reservoir of 240 Bcf calculated earlier is the gas theoretically producible at sufficiently close well spacing. The ratio of ultimate gas contact to the gas in place provides the percentage of the gas in place that is contacted at a specific well spacing. These values derived for the two development periods, therefore, represent the corrected, "contactable" gas as a function of well spacing (at 813 and 443 acres per well) for the Brooks reservoir, and make up the shape of the gas contact function.

Construction of the gas contact function

For the first development period (1956 to 1965) with a well spacing of 813 acres per well, 73.5 percent of the gas in place in the Brooks reservoir was contacted. The drilling of five infill wells in the second development period decreased spacing to 443 acres per well and contacted an additional 10.9 percent of gas in place, for a total of 84.4 percent of gas in place. The results of this analysis are presented in tables 5 and 6.

The data points derived from the assessment of ultimate gas contacted were plotted against average interwell distance and straight line segments used to develop a function relating gas contact to interwell distance (table 7, fig. 21). The third point for the function was derived assuming that a critical interwell distance exists at which the bulk of the reservoir has been contacted. This minimum critical interwell distance was judged to be related to the geometry and extent of different facies in the reservoir. For example, a reservoir characterized by facies occurring in discrete, small isolated pockets would need to be drilled more densely than one characterized primarily by blanket sandstones. Statistical analysis using the physical geologic model and the facies maps of the Brooks reservoir showed that this critical distance occurs at an interwell distance of about 1,320 feet (40 acres per well). The gas contact function was thus assumed to reach essentially 100 percent at this interwell distance. However,

Table 7. Reservoir Contact as a Percentage of Post-Cycling Gas in Place for the Brooks Reservoir, La Gloria Field.

Well Spacing (acres/well)	Reservoir Contact (% GIP)	Reservoir Contact (Bcf)	Incremental Contact (% GIP)	Incremental Contact (Bcf)
640	78.2	188.0	—	—
320	87.5	210.4	9.3	22.4
160	93.0	223.6	5.5	13.2
80	97.2	223.7	4.2	10.1
<40	100.0	240.4	2.8	6.7

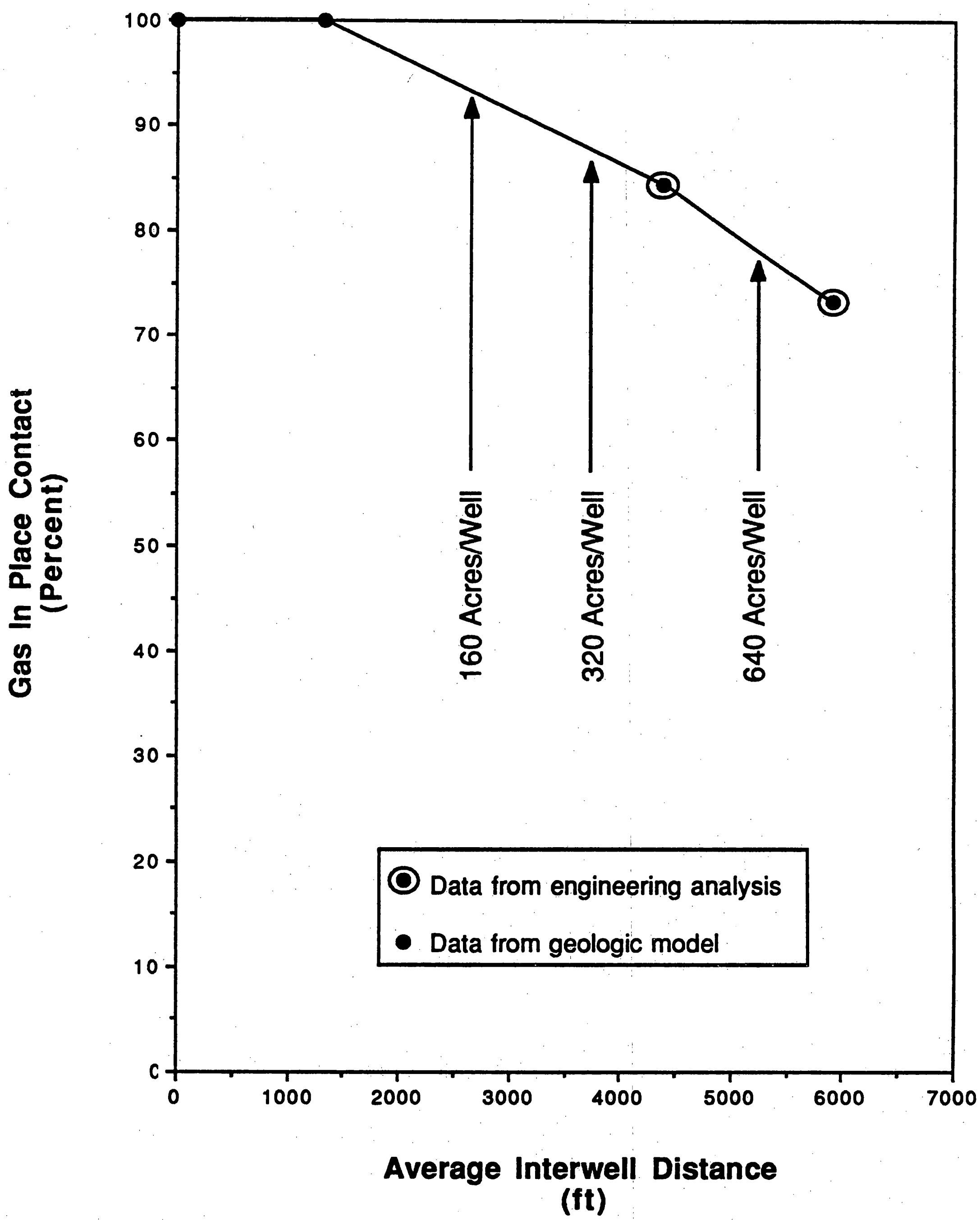


Figure 21. Incremental gas contact function for the Brooks reservoir. Data from the engineering analysis include well spacings of 813 acres per well and 443 acres per well. Data from the geologic model include 100 percent contact at zero interwell distance, and an assumed 100 percent contact at the average minimum facies lens size (1,320 ft) determined from depositional analysis of La Gloria field.

flow between facies units of small size may create aggregate flow units that may be effectively drained at larger well spacings (80 to 160 acres). The degree of contact between facies and the effectiveness of gas flow at different permeabilities are aspects of gas reservoir development that are not understood at this time.

The gas contact function shows that if the Brooks reservoir had originally been developed at a well spacing of 640 acres per well (requiring eight producing wells), approximately 78.2 percent of the post-cycling gas in place would be contacted. A decrease in well spacing to 320 and 160 acres per well incrementally contacts 9.3 percent and 5.5 percent of the gas in place, respectively, bringing the total reservoir contact to 87.5 percent at 320 acres per well and 93 percent at 160 acres per well. Therefore, the analysis indicates that additional volumes of gas could be contacted and recovered from the Brooks and similar gas reservoirs by decreasing well spacing from the traditional 640 or 320 acres per well.

Pressure analyses

Initial pressures of infill wells may range from initial reservoir pressure of a totally isolated pocket to current average reservoir pressure. The initial pressure of an infill well that contacts increased reservoir volume is expected to be higher than the average measured pressure for existing producing wells. However, pressure analyses, within the limits of the quality of the pressure data described previously, showed that all wells completed in the Brooks reservoir during the second development period had initial pressures that were equal to or only slightly higher than the average pressure of existing producing wells. Nevertheless, the modest differences observed do not preclude incremental gas contact.

Eight of the thirteen wells used to make the gas contact function were perforated in higher permeability channel sandstones (table 4). Because of the high permeability and relative abundance of the channel sandstones, as indicated in figure 15, most of the wells were probably in good communication with each other, and the reservoir pressure was relatively depleted. Few wells were perforated in the more heterogeneous point bar, proximal splay, and distal splay (or levee) facies. This suggests that incremental gas recovery from infill drilling in the Brooks reservoir is a result of more efficiently draining facies adjacent to those in which wells have been completed. It is not known to what extent wells in the second development period were expressly targeted for parts of the reservoir thought to be incompletely drained.

To illustrate this effect, three general types of infill well performance possible for reservoirs like the Brooks are presented schematically in figure 22: total communication, isolated compartments, and partial communication. Each of the three cases and all possibilities in between are possible. Geologic mapping of facies types from log and core analyses, even when based on closely spaced wells, can only partially predict which case will govern production in a given infill well with the current state of knowledge. Completion techniques and many other factors, such as diagenetic cementation and natural fracturing, may also influence gas contact.

Case A (fig. 22A) represents the completion of an infill well in the same sandstone body already produced by an existing well. Given sufficient permeability (such as 488 md for the Brooks reservoir channel sandstones) and no discontinuities or flow restrictions, the majority of the gas can be drained from the entire sandstone body by the existing well, down to an economic pressure limit of about 500 psi. Discovery pressures found in the infill well will be equal to the existing producing well and, excluding the effects of acceleration of production, no additional reserves will be added through infill drilling in this case.

Case B represents an isolated compartment not in pressure communication with existing producing wells but penetrated by the infill well. The incremental gas contacted would equal the volume of gas in the compartment that is within the drainage area of the infill well. In this case, the pressure encountered by the infill well would be equal to initial reservoir pressure.

Case C represents the completion of an infill well in the same or in an adjacent sandstone body contacted by an existing producing well. In this case, however, a flow restriction exists between the two wells. The restriction could be of two types: first, the sandstone body common

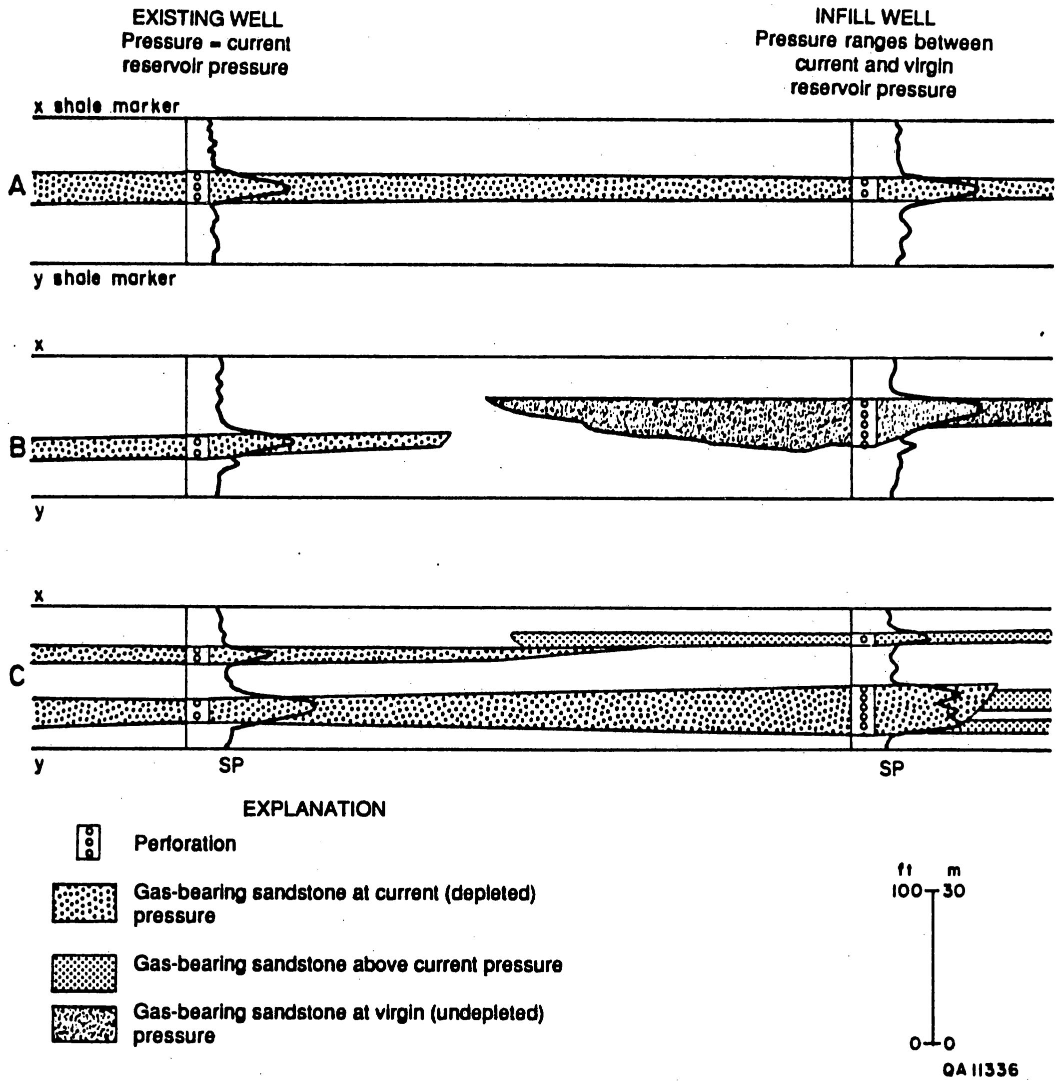


Figure 22. Possible sandbody geometries and pressures encountered by an infill well. Case A shows that the sandbody encountered was in communication with an existing well and that the pressure of the infill well equals that of the existing well. The sandstone body is substantially depleted, and there is little flow restriction between the two wells. This situation is encountered at low interwell distances in heterogeneous reservoirs and at higher interwell distances in relatively homogeneous reservoirs. In case B, a previously undrained or partially drained sandstone body is perforated. Pressure in this sandbody may range from virgin reservoir pressure (high value, isolated compartment), to pressure approaching that of the existing well (low value, partially connected compartment), depending on the characteristics of the intervening mudstone. Case C shows the infill well perforated in the same sandstone body as that of the existing well but much closer to adjacent splay sandstones that contain higher pressures. The flow restriction trapping gas at higher pressures could take the form of a facies boundary, as shown, diagenetic alteration, a change in grain size, or other partially permeable barrier. Pressure encountered in the infill well in case C is likely to be higher than pressure in the existing well because the infill well is closer to a partially permeable barrier. However, this pressure difference may not be detected easily because duration of pressure measurements is sometimes too short.

to both existing and infill wells could be tight (less than 0.1 md), preventing gas from freely flowing to the existing well from the reservoir in the vicinity of the infill well; second, the infill well could drain a volume of reservoir that is adjacent to, but discontinuous with, the sandstone common to both wells. Lower permeability intervening shales, located at the facies contacts, restrict flow to the existing producing well from the vicinity of the infill well.

Case C is thought to be the dominant reservoir mechanism controlling incremental reserves through infill drilling or recompletion in the Brooks reservoir. Most initial producing wells were completed in the higher permeability channel sandstones, effectively draining them and some portion of other immediately adjacent, but discontinuous, productive facies. The Brooks production histories show that later wells, most of which also were completed in the channel sandstones, do not detect significantly higher pressures than the reservoir average. Incremental gas recovery potential in the Brooks reservoir would be related to gas production from non-channel facies or from channel axes not in communication with existing wellbores. An example of the latter case is given below for the Jim Wells reservoir. Because the Brooks reservoir contains relatively less floodplain (non-reservoir) facies compared to the Jim Wells reservoir, its potential for incremental recovery would be expected to be less.

Reservoir pressure used in incremental gas estimates

In making an estimate of incremental gas recovery, it is necessary to use a value for the reservoir pressure encountered by younger wells. A value of 50 percent of initial reservoir pressure (or initial post-cycling reservoir pressure) is used in this study based on recent (late 1987–June 1989) gas well completions made by Union Pacific Resources in the middle and lower Frio of Stratton/Agua Dulce fields.

Stratton field was discovered in 1937 and the immediately adjacent Agua Dulce field was discovered in 1928. Both fields lie directly northwest of La Gloria field, and together they have produced nearly 3 Tcf of natural gas. Reservoirs are depositionally similar to those in La

Gloria field and include fluvial channel fill, point bar, and crevasse splay sandstones that have been tapped by more than 300 gas wells in Stratton field alone.

In assessing the reserve growth potential of Stratton field, it was found that the E series of sandstones, in the depth range of 6,000 to about 6,600 ft, showed potential compartmentalization. Engineering analysis suggested that there was no increase in production decline rates when comparing wells completed in the last three to five years to much older wells in the field. In addition, production volumes for first-year average rates show only small variation with completion date. Pressure depletion in new wells does not appear to be widely affected by past production. These findings are currently being evaluated further to assess whether the same sandstone is actually being completed.

Bottom hole shut-in pressures for 41 wells were compared to expected virgin pressures based on a 0.465 psi/ft pressure gradient. These wells all were completed above 7,000 ft, within the depth range of existing well completions. They would not be considered deeper pool tests. Of these wells, only 10 tested at less than 50 percent of virgin reservoir pressure, and the average for all wells was 71 percent of virgin pressure with a range from 14 to 115 percent. The values above 100 percent could be explained by either inaccurate data or by slight geopressuring in individual reservoirs. The production and pressure histories of these wells are now being examined in detail and individual sandstones carefully correlated. Based on these data, the value of 50 percent virgin pressure used for the incremental gas volume estimate in this report is considered to be conservative.

<u>Estimate of technically recoverable incremental gas</u>

Since not all of the incremental gas in place contacted by closer well spacing can be considered as reserve growth, additional analysis is needed to estimate the proportion of that incremental contact that could be technically produced. This section describes the production modeling of the incremental gas volumes contacted to estimate production timing and total recovery.

Methodology

The calculation of technically recoverable gas from infill drilling relies on the combination of the gas contact function results, the reservoir quality parameters, and data from facies and net-sandstone-thickness maps. A five-step methodology was developed to estimate technically recoverable gas from infill wells. This methodology and the results of its application to the Brooks reservoir are discussed below.

STEP 1. Divide the Reservoir into Grids Representing Fixed Well Spacings. The Brooks reservoir has an areal extent of approximately 4,878 acres. This area was divided into uniform grids representing approximately 640-, 320-, and 160-acre well spacings. The grids were drawn to capture relatively uniform surface areas rather than to divide the reservoir by geologic facies or reservoir properties, since the latter information would generally not be known before development. Thus the model can only approximate the effects of strategic infill drilling. Figure 23 shows the areal grids for the Brooks reservoir at 640-acre well spacing.

STEP 2. Estimate Reservoir Properties and the Volume of Facies Type Within Each Grid. The detailed facies maps of the Brooks reservoir were combined with the net-sandstone-thickness maps to calculate the volume of each facies type occurring within a grid area. Using the volume of each facies type underlying a grid area as a weighting criterion, reservoir properties were assigned to each grid (fig. 24). Table 3 provides an example of how these facies-specific properties were derived. Figure 24 shows that the reservoir is not significantly variable in terms of porosity, permeability (reservoir quality), and initial gas saturation within a proportionally weighted presentation at the 640-acre level. The net sandstone thickness, however, ranges from 37 ft in the northern to 63 ft in the southern portion of the reservoir.

STEP 3. Assess Volumetric Gas In Place in Each Grid. Using the data developed above, the gas in place was calculated for each grid. For this calculation, an average gas formation volume factor was calculated on the basis of post-cycling reservoir pressure and temperature. Figure 25

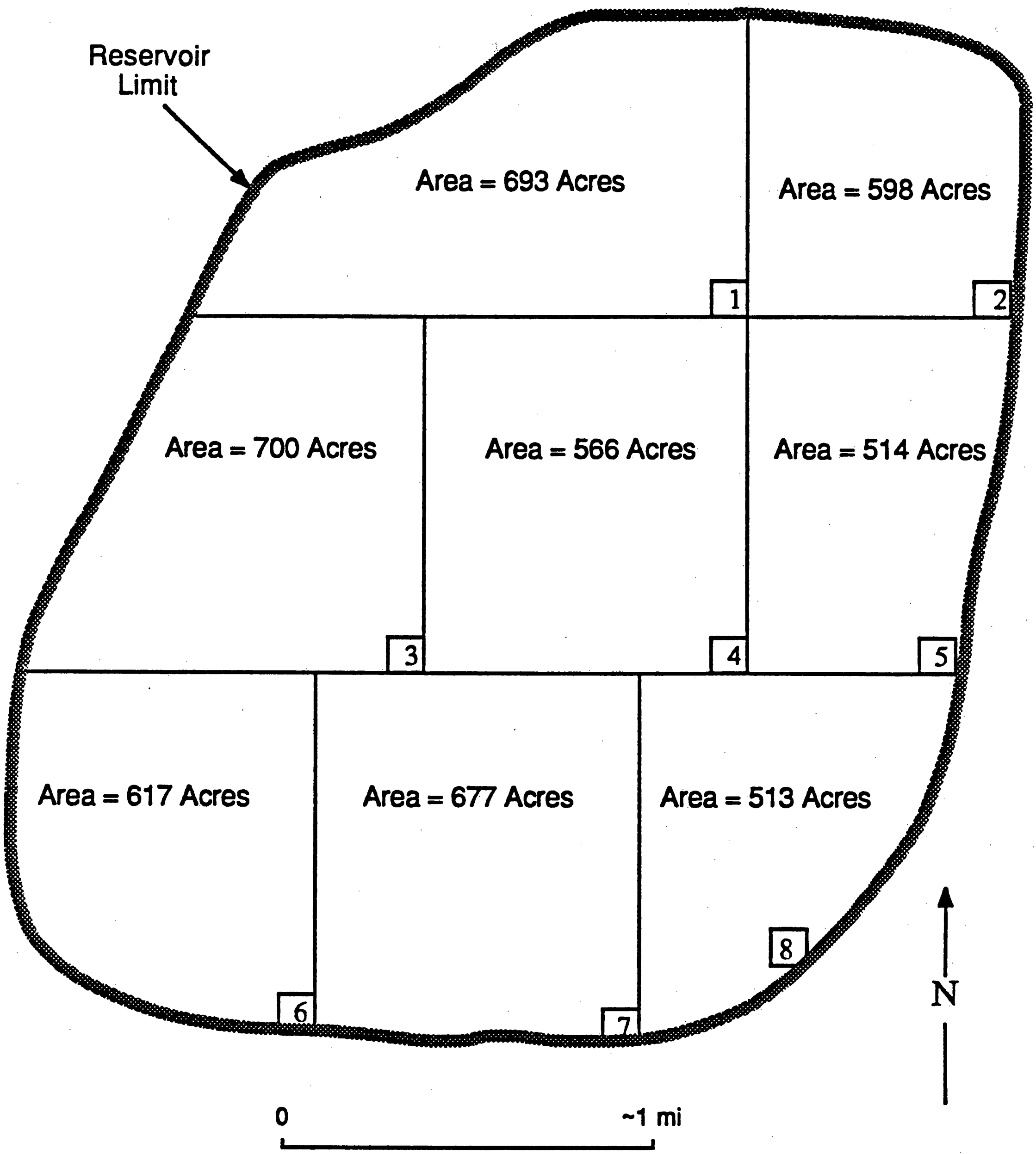


Figure 23. Grid divisions used in the well production model of the Brooks reservoir. Eight grids were used, approximating 640-acre spacing. Grid numbers in this and all subsequent figures are shown in the lower right corner of each grid.

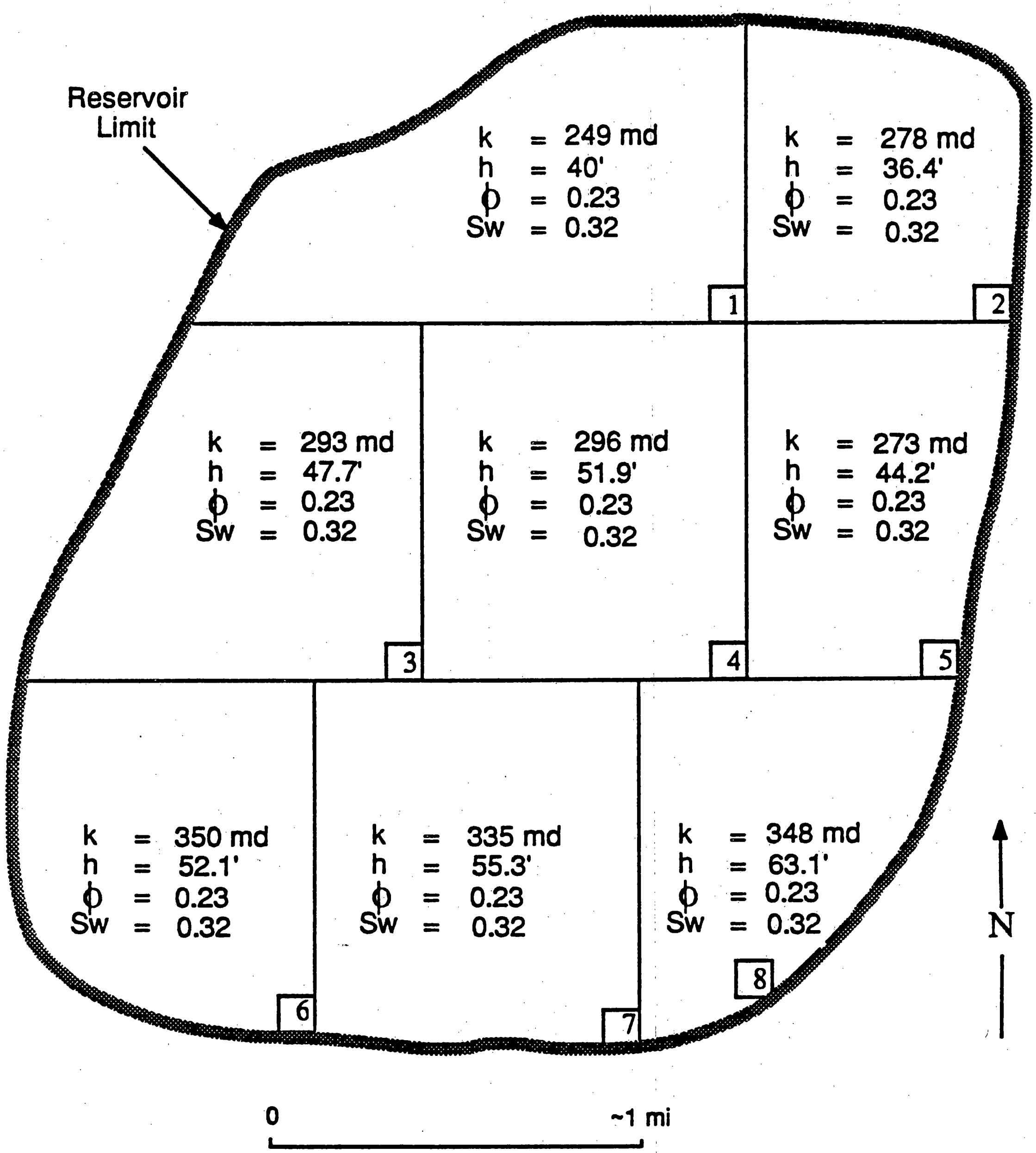


Figure 24. Average grid-specific reservoir properties of the Brooks reservoir at 640-acre grid spacing. Symbols include k, permeability in millidarcys; h, net sandstone thickness in ft; ø, fractional porosity; and S_w, fractional connate water saturation.

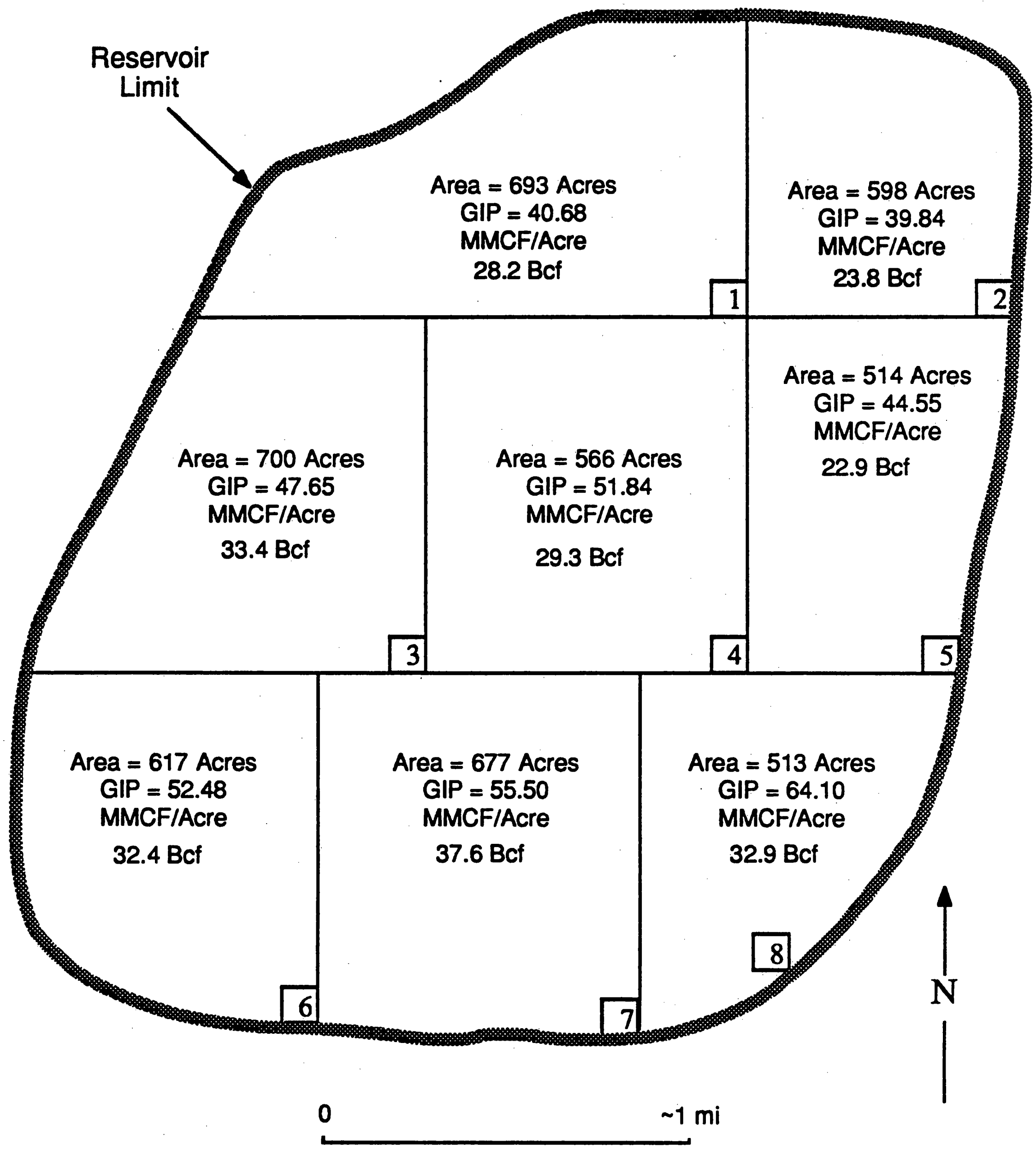


Figure 25. Volumetric gas in place of the Brooks reservoir at the end of the gas cycling program in 1956. Average reservoir pressure at this time was 2,395 psia.

shows the results of this grid-by-grid calculation of gas in place for the 640-acre well spacing. As expected, the areas of highest gas accumulation coincide with the areas of the greatest net sandstone thickness, which are in the southern portion of the Brooks reservoir. The gas in place ranges from a low of 40 MMcf/acre in the north to a high of about 64 MMcf/acre in the south.

STEP 4. Apply Incremental Gas Contact Function to Grid Gas In Place. For each grid area, the incremental gas contact function was applied to the volumetric gas in place to assess the gas available for an infill well at a specific well spacing. For example, a decrease in well spacing from 640 to 320 acres results in an incremental reservoir and gas contact of 9.3 percent, as defined by the gas contact function for the Brooks reservoir. This percentage was applied to the grid-specific volumetric gas in place to calculate the gas available to be contacted and recovered by the first infill wells in a 640-acre grid area.

Figure 26 shows that the largest volumes of gas available for infill drilling are in grid areas 6, 7, and 8 in the southern portion of the reservoir, corresponding to the area of the greatest net sandstone thickness. The sandstone-rich nature of the Brooks reservoir, reflected by the relatively high and uniform distribution of permeability, porosity, and water saturation in the averaged grid areas, precludes strategic infill drilling on the basis of non- or partially communicating boundaries at the 640-acre grid scale used in this study. Only net sandstone thickness varies significantly between grids in the reservoir area. In the Brooks reservoir, therefore, areas of thick net sandstone indicate to an operator where the most productive infill wells could be located.

STEP 5. Model Technically Recoverable Incremental Gas from Infill Drilling. The ICF-Lewin Energy Secondary Gas Production Model was used to model the recovery of incremental gas from infill drilling. The model is based on theoretical work by Fetkovich. Based on the Union Pacific data presented earlier, pressures encountered by infill wells in this model were assumed to be at 50 percent of initial post-cycling pressure of the Brooks reservoir. Not all the additional gas contacted by an infill well is technically recoverable. The pressure drop between

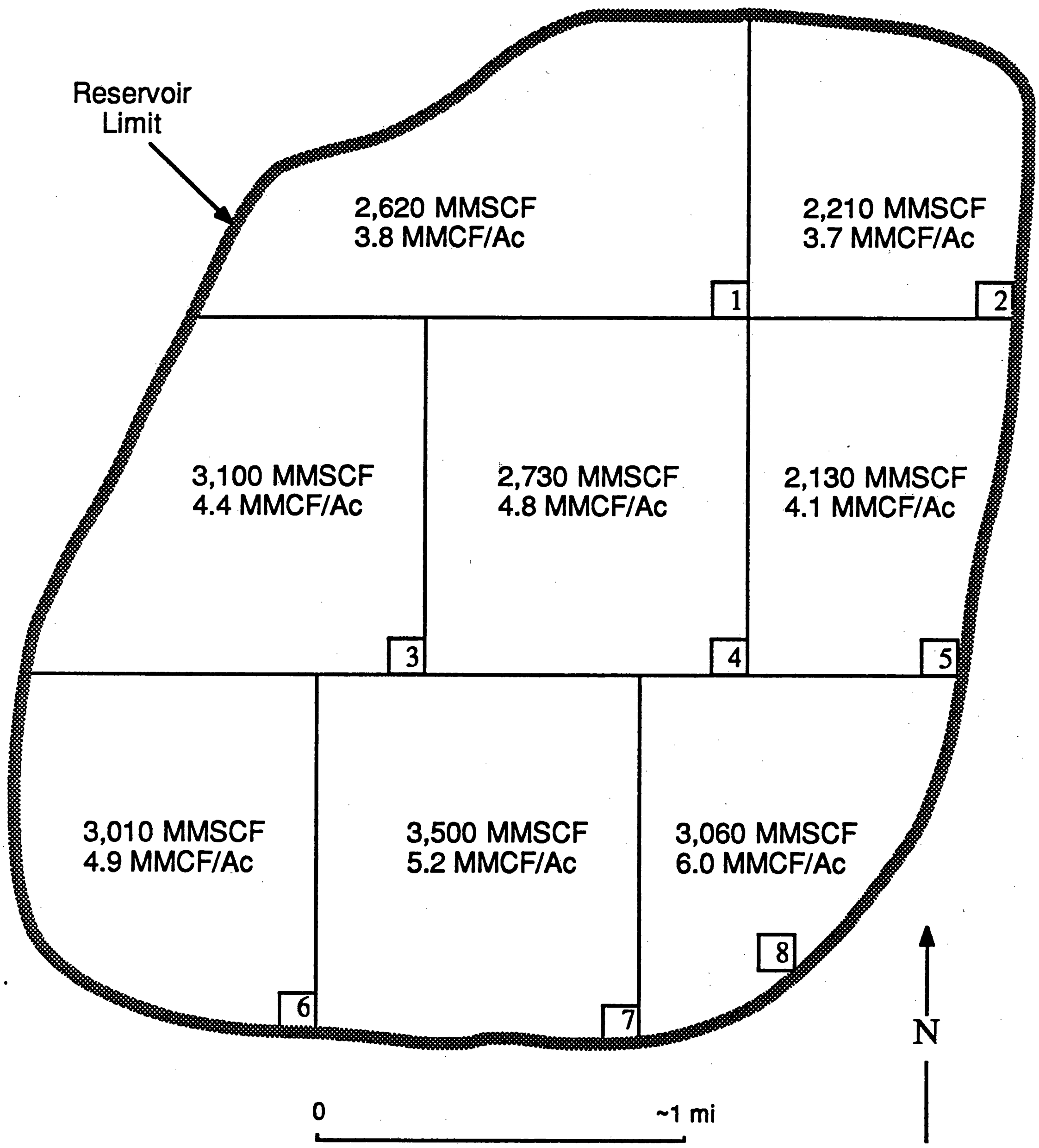


Figure 26. Calculated incremental available gas in the Brooks reservoir for infill drilling from 640- to 320-acre spacing at the end of cycling. End-of-cycling pressure is 2,395 psia.

the surface and the reservoir due to friction losses and the hydrostatic head of the gas is several hundred psi, depending on gas properties, depth, and producing equipment characteristics. Thus, the volume of gas equivalent to 300 psi for these reservoirs was estimated to be technically unproducible.

The engineering analysis assumes an initial development strategy of 640 acres per well in uniform patterns. The infill drilling strategies modeled in the analysis of technically recoverable gas are:

- Infill drilling from 640 to 320 acres per well—one infill well per section
- Infill drilling from 320 to 160 acres per well—two additional infill wells per section

Because this analysis is conducted on an individual well basis, the results also show areas of the reservoir where infill wells could be strategically located.

Results of technical analysis

Technically recoverable gas is referred to in this report as that percentage of volumetric gas in place that can be recovered using current production practice. Table 8 shows the technically recoverable incremental gas (assumed in this report to be 30 years of production down to wellhead pressures of 500 psi under compression) available to all infill wells in each grid of the Brooks reservoir for the two infill strategies. For individual well recoveries, the volume reported for each grid is divided by the appropriate number of infill wells.

Almost 16 Bcf of incremental technically recoverable gas results from infill drilling from 640 to 320 acres per well. This is about 71 percent of the 22 Bcf incrementally contacted gas in place. Infill drilling from 320 to 160 acres per well would contact an additional 13 Bcf of gas in place, with 70 percent of that amount (9.3 Bcf) being technically recoverable.

The results indicate that, because of larger net sandstone thickness, the southern and west-central parts of the field have the largest incremental volumes of technically recoverable gas. These areas might be selected for the first infill wells. For example, for infill drilling from

Table 8. Technically Recoverable Incremental Gas (MMCF) from Infill Drilling, Brooks Reservoir, La Gloria Field.

	Grid Identification Number*								Reservoir
	1	2	3	4	5	6	7	8	Total
Volumetric Gas In Place	28,190	23,810	33,360	29,320	22,890	32,360	37,590	32,910	240,430
Total Gas Contact at 640 Acres/Well**	22,040	18,620	26,090	22,930	17,900	25,310	29,400	25,740	188,030
Development Strategy 640 to 320 Acres/Well (One Infill Well)									
Incremental Gas Contact***	2,620	2,210	3,100	2,730	2,130	3,010	3,500	3,060	22,360
Technically Recoverable Incremental Gas	1,900	1,570	2,200	1,980	1,500	2,160	2,480	2,160	15,950
Development Strategy 320 to 160 Acres/Well (Two Infill Wells)									
Incremental Gas Contact****	1,551	1,310	1,835	1,613	1,259	1,780	2,068	1,810	13,226
Technically Recoverable Incremental Gas	1,060	901	1,324	1,166	913	1,187	1,462	1,289	9,302

* See Figure 22 for Grid Identification.

** Total Gas Contact @ 640 Acres/Well = Volumetric GIP × Reservoir Contact @ 640 Acres/Well.

*** Incremental Gas Contact (640 to 320 Acres/Well) = Volumetric GIP × Incremental Reservoir Contact (640 to 320 Acres/Well).

**** Incremental Gas Contact (320 to 160 Acres/Well) = Volumetric GIP × Incremental Reservoir Contact (320 to 160 Acres/Well).

640 to 320 acres per well, nearly half of the total technically recoverable gas is available in grids 3, 6, and 7.

Conclusions

The analysis of the Brooks reservoir delineated net sandstone thickness and facies geometry in this fluvial depositional system. Because there are so few floodplain deposits, and they are not of sufficient thickness or extent to partially isolate Brooks sandstone bodies, strictly geological and facies-based delineation of infill drilling prospects is not possible in the Brooks reservoir.

The net sandstone thickness and facies geometry data were used in combination with engineering analysis to estimate incrementally contacted gas in place and reserve additions as a result of infill drilling. Three-dimensional multiwell reservoir simulation and material balance approaches to derive the gas contact function were rejected due to incomplete and insufficiently detailed data. A production-decline type curve approach was used to estimate the volume of gas contacted by existing producing wells. Total gas in place contacted by existing producing wells at two unique well spacings was estimated and a gas contact function was constructed.

Technical analysis of incrementally contacted gas was used to estimate recoverable volumes. At 640-acre spacing, 78.2 percent of the post-cycling gas in place is estimated to be contacted, and incremental contact at 320 and 160 acres per well is 9.3 and 5.5 percent of the gas in place, respectively. Wells drilled at 320-acre well spacing can add approximately 2 Bcf of reserves per well.

Field data did not show that the later wells had appreciably higher pressures than the average reservoir pressure estimated from the existing producing wells. The newer wells in the Brooks reservoir did add gas reserves, however, and the analysis shows that these wells contacted reservoir volume that was not previously in complete pressure communication with existing producing wells. A probable production mechanism is that newer wells in the Brooks reservoir drain reservoir volumes that are adjacent to, but in part discontinuous (in terms of flow units) with, sandstones common to both newer wells and older producers. Lower permeability intervening shales, located at the facies contacts, restrict flow to existing producing wells from the vicinity of newer wells. In addition, well interference, which alters gas flow characteristics, restricts the volume of gas that is contacted in a reservoir. Increased understanding of the mechanisms of gas reserve growth will require multiwell modeling based on a detailed geologic description of reservoir facies distribution and pressure and production histories.

Jim Wells Reservoir

Stratigraphy

The Jim Wells sandstone reservoir is separated vertically from other La Gloria field reservoirs by 20 to 40 ft of shale. Three distinct depositional sequences, or stringers, make up this reservoir. Two informally defined sandstone subunits, A and B, form the Lower Jim Wells, and a less widely distributed stringer (C) forms the Upper Jim Wells (fig. 11). Stringers A and B are in close vertical proximity; however, stringer C is vertically separated from stringer B by up to 30 ft of shale over the central and southern parts of the reservoir. In the northern part of the reservoir, stringer C may be in erosional contact with stringer B. This stratigraphic complexity, as well as similar variability in fluvial-deltaic systems, forms the basis for potential well recompletions.

Depositional environment

The Jim Wells sandstones, like the Brooks, are distributed in dip-elongate belts oriented northwest-southeast (figs. 27 and 28). The belts are thicker in the northeast part of the field. The main axis of deposition is defined by a 4,000- to 10,000-ft-wide belt of sandstone in the north-central part of the field, 60 to 117 ft in thickness (including both A and B stringers). Another, narrower (1,000 to 3,500 ft) and thinner belt of sandstone cuts across the central part

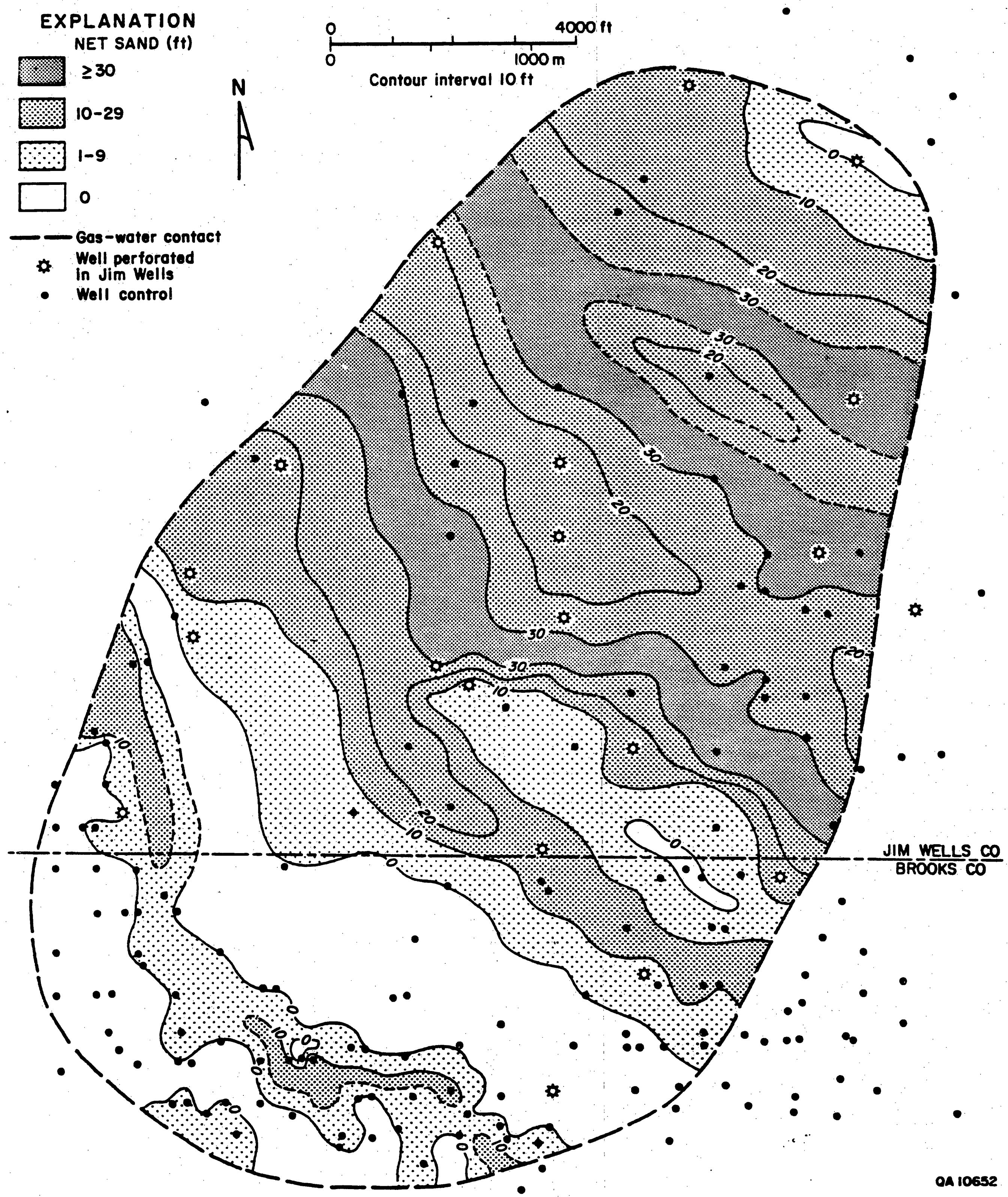


Figure 27. Net-sandstone-thickness map of the Jim Wells A stringer in La Gloria field. Dip-elongate belts of channel-fill and splay sandstones (500 to 1,500 ft wide) are flanked by sandstone-poor levee and floodplain facies. A narrow, irregular channel-sandstone belt in the southwest part of La Gloria field has not been perforated and may contain uncontacted gas in poorly drained reservoir compartments.

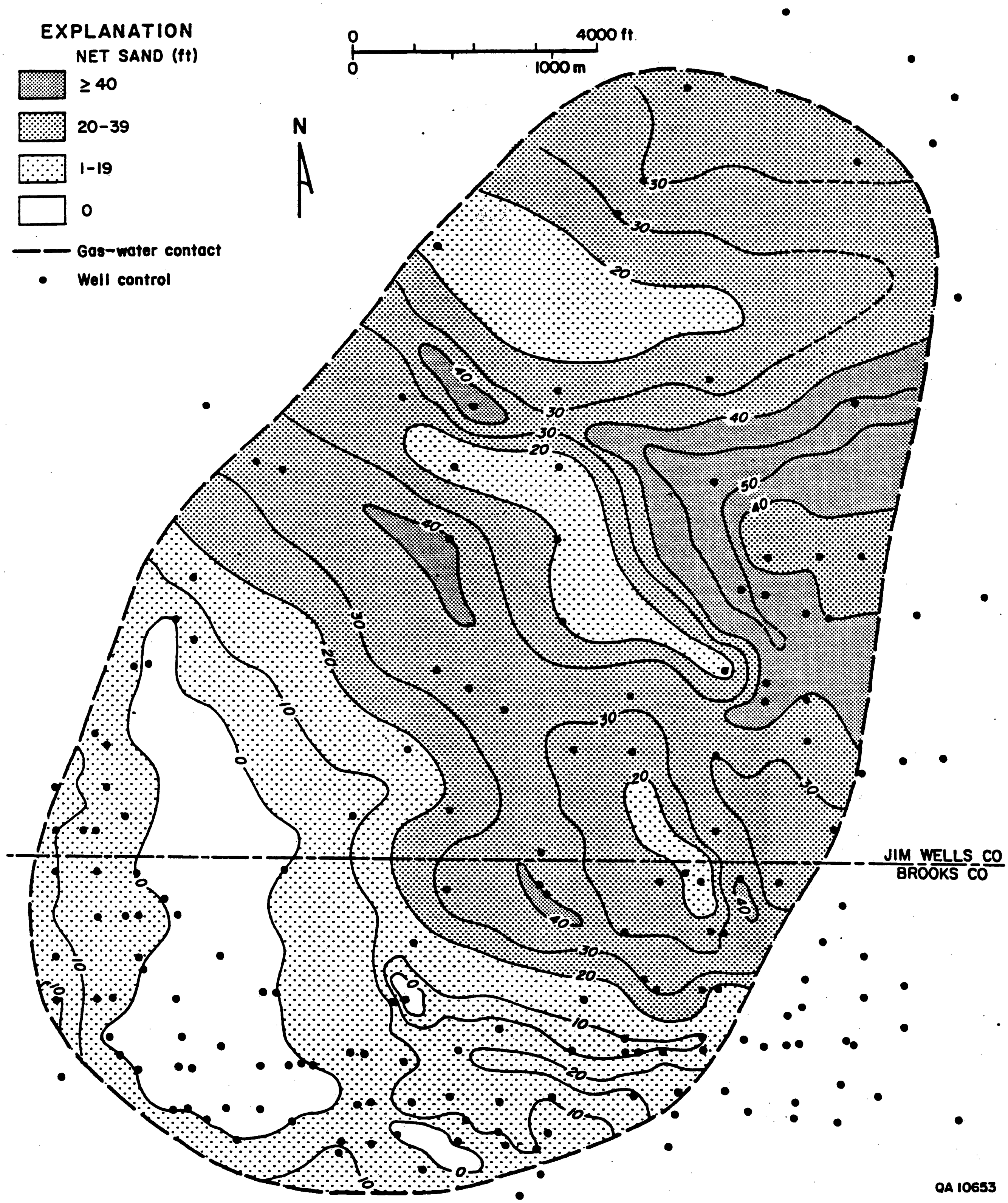


Figure 28. Net-sandstone-thickness map of the Jim Wells B stringer in La Gloria field, which consists of a complex system of dip-parallel channel-fill sandstone bodies (30 ft or more in thickness) that bifurcate and merge in the field area. Interchannel and floodplain environments are represented by large areas of less than 10 ft of net sandstone thickness.

of the reservoir. The Jim Wells sandstone is thinnest in the southern part of the field and pinches out completely in irregularly distributed areas.

Dip-parallel channel-fill and point-bar sands are the skeletal facies in this fluvial system (fig. 29). These facies are compartments that pinch out laterally along strike into muddy levee and floodplain facies. In the northeast part of the field, the channel-sandstone system is dominated by multiple stacked point-bar and channel-fill deposits, which individually are 15 to 30 feet thick. To the southwest, however, a muddy floodplain system is developed adjacent to the main depoaxis. Deposits in this sandstone-poor area consist of individual, isolated point-bar, channel, and splay sandstones 10 to 20 ft thick.

Facies continuity

A different approach to determining facies continuity was used for the Jim Wells reservoir than was used for the Brooks reservoir, in order to further define facies distribution and areal extent. The five facies types present in the Jim Wells reservoir were assigned to dominantly reservoir and dominantly seal facies groups. Channel-fill (blocky), point-bar (upward-fining), and splay (upward-coarsening) facies were placed in the reservoir group, and levee/distal splay (spiky) and floodplain (baseline SP response) facies were placed in the group of reservoir seals. Widths of isolated facies (seal bounded only by reservoir or reservoir bounded only by seal) were measured along strike lines 10 acres apart across the reservoir; figure 30 depicts the continuity of reservoir and seal facies resulting from this analysis. For both facies groups, continuity data suggest that wells drilled more than 40 acres apart are likely to penetrate discrete facies units. This does not, however, imply that the reservoir can be developed to such a close spacing. Flow continuity between facies remains unknown pending further geological and engineering studies. Spacing of wells perforated in the Jim Wells reservoir was as low as 200 to 300 acres although not all wells were producing at the same time.

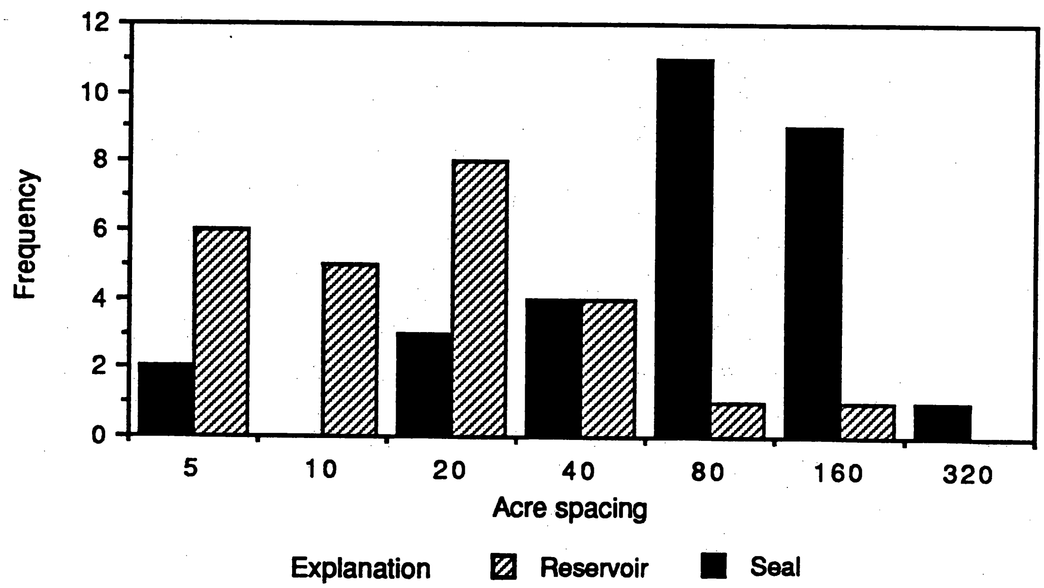


Figure 29. Width, or continuity, of isolated reservoir and seal facies for the Jim Wells reservoir in La Gloria field, measured in the strike direction. These data show that wells drilled on greater than 40-acre spacing are likely to penetrate individual reservoir facies units, because these units are predominantly less than 40 acres in width.

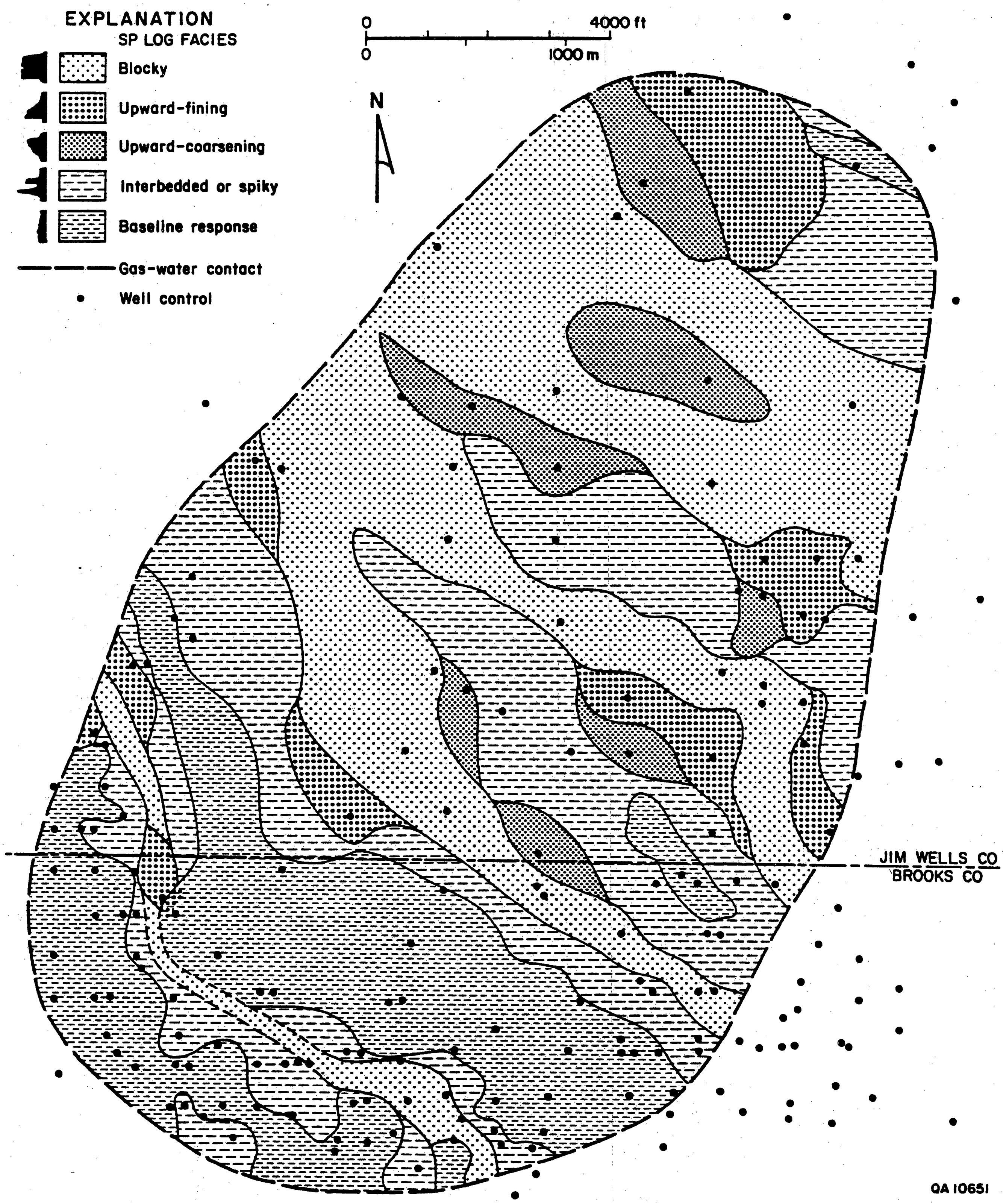


Figure 30. SP-log facies map of the Jim Wells A stringer in La Gloria field. The principal reservoir facies are channel-fill (blocky and upward-fining SP response) and splay (upward-coarsening SP response). These reservoir facies are partially isolated into compartments bounded laterally along depositional strike by lower permeability distal splay and levee facies (interbedded or spiky SP response) and by floodplain facies (baseline SP response).

Infill potential

Most of the Jim Wells gas wells are perforated in channel-fill sandstones in the major depositional axes in the central and northern part of the reservoir. Additional production is from levee and distal splay deposits in the southwest part of the field. Older wells are located structurally low to allow for condensate recovery, while more recent wells are located structurally high to contact higher gas saturations.

Prospects can be generated for potential infill wells in the Jim Wells reservoir by taking into account the vertical and horizontal sandstone-body heterogeneity of individual fluvial reservoirs. Because of the relatively high horizontal compartmentalization in the Jim Wells reservoir compared with that in the Brooks, greater potential exists for productive infill completion. Totally isolated pockets of gas at near-virgin reservoir pressures were not observed in this study and remain to be defined in terms of the permeability contrasts necessary to inhibit gas flow.

A geologically based infill drilling strategy for a heterogeneous reservoir such as the Jim Wells involves integration of four critical factors: (1) lateral reservoir heterogeneity, illustrated on facies maps; (2) vertical reservoir heterogeneity, displayed on maps showing net-shale vertically isolating individual reservoir stringers; (3) distribution of older perforated wells; and (4) field structure and elevation of the gas-water contact. Several maps for each stringer can be combined and simultaneously evaluated for the location of economic infill wells. In this example, a facies map of the Jim Wells A stringer (fig. 29) indicates that fluvial sandstone bodies isolated by relatively large areas of levee and floodplain facies exist in the southwest part of the reservoir. Vertical shale barriers shown on a net-shale map between the Jim Wells A and B stringers are up to 20 ft thick, as determined on SP logs, and therefore these stringers are probably in relative vertical isolation in this area (fig. 31). An isolated channel belt in the southeastern part of the field that has no perforations becomes evident as a potential area for infill completion.

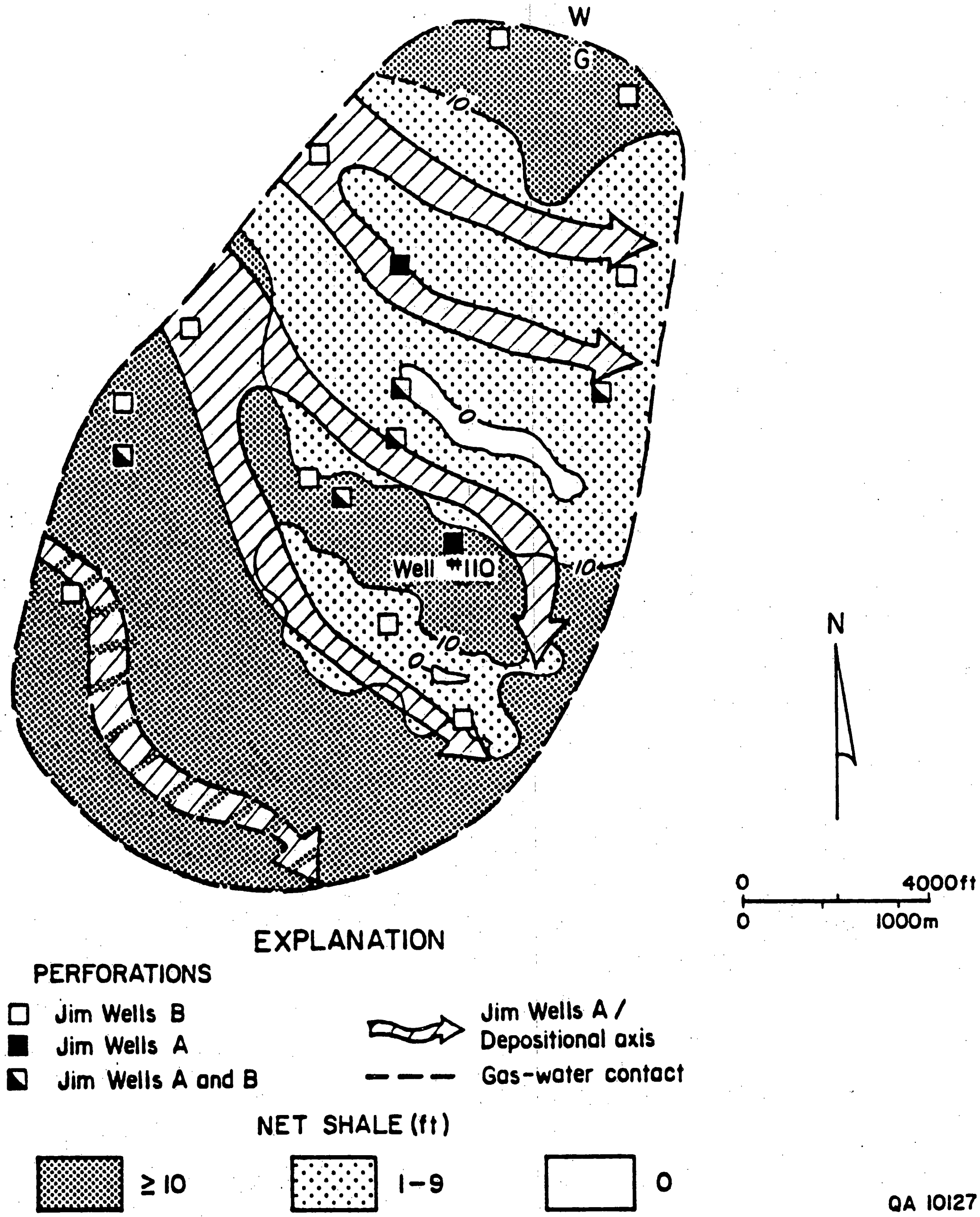


Figure 31. Prospect map for the Jim Wells A reservoir in La Gloria field. Four major elements should be considered in selecting best sites for infill wells in fluvial reservoirs in La Gloria field: 1) The most productive infill wells should be drilled into thick channel-sandstone facies along depositional axes, or into splay facies adjacent to depositional axes; 2) The producing stringer sandstone should be vertically separated from the overlying or underlying stringer sandstone by several feet of low-permeability shale seal. Areas of greatest separation have highest priority for infill wells; 3) New wells must be drilled beyond the drainage radius of older wells (shown as perforations); and 4) Structurally higher field areas along the anticlinal crest should be targeted. Mobil #110 La Gloria Gas Unit, a recent successful infill well, was drilled in an area that satisfies all these criteria. Specific sites for other infill wells in the Jim Wells A include a poorly contacted depositional axis in the southwest part of the field, the southern flank of the next depositional axis northward, and the northern flank of the northernmost depositional axis in the field.

Anomalously high pressures encountered in a recent infill well (Mobil #110 La Gloria Gas Unit) in the Jim Wells reservoir indicate that reservoir heterogeneity can create partially effective flow barriers. Initial pressures recorded in well #110, recompleted in the Jim Wells reservoir in the southeast part of the field (fig. 31), were nearly five times higher than average reservoir pressure and 45 percent of original reservoir pressure (fig. 32). The well contacted a gas-bearing compartment in a splay sandstone that was in poor pressure communication with the remainder of the reservoir (fig. 33). Rapid pressure decline exhibited by this well suggests that it is draining a small isolated compartment in the field. This well was recompleted as a bypassed reservoir and was not originally targeted as an infill well.

Calculation of reserve growth factor

Comparison of gas volumes derived from volumetric methods with those derived from material balance methods was attempted in the Jim Wells reservoir; however, a material balance estimate was not possible because of an estimated 10 to 25 Bcf of gas leakage from the Arguellez reservoir into the Jim Wells reservoir sometime between 1955 and 1958. This leakage may be the cause of an upward step of the pressure decline curve at 90 to 110 Bcf of post-cycling cumulative production (fig. 34).

Estimate of potential for gas reserve growth

Analysis of the Jim Wells reservoir estimated the ability of infill drilling to add natural gas reserves in a fluvial-style Frio reservoir containing a higher percentage of floodplain and mudstone-rich facies than the Brooks reservoir. The same methodology used for data collection, development of the gas contact function, and estimates of technically recoverable gas from infill drilling in the Brooks reservoir is used for the Jim Wells reservoir. Since the methodology was fully discussed previously, it is only briefly discussed here.

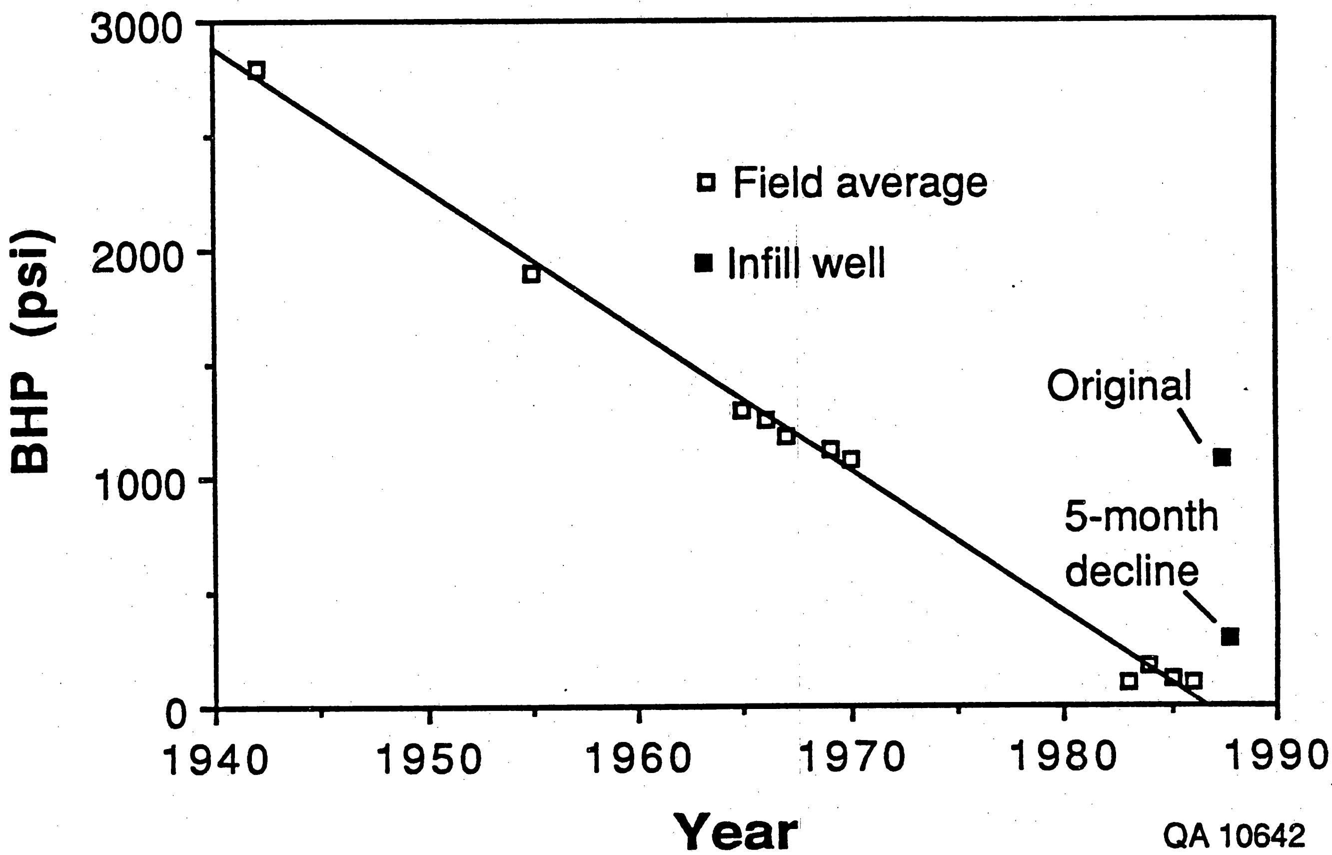


Figure 32. Pressure decline curve for the Jim Wells reservoir in La Gloria field. Anomalous high pressure, 1,310 psi, was recorded in a 1986 infill well (Mobil #110 La Gloria Gas Unit). The rapid drop in pressure over 5 months suggests that the infill well is draining a small reservoir compartment that is in poor communication with the rest of the reservoir. BHP represents average bottom-hole shut-in pressure for the reservoir.

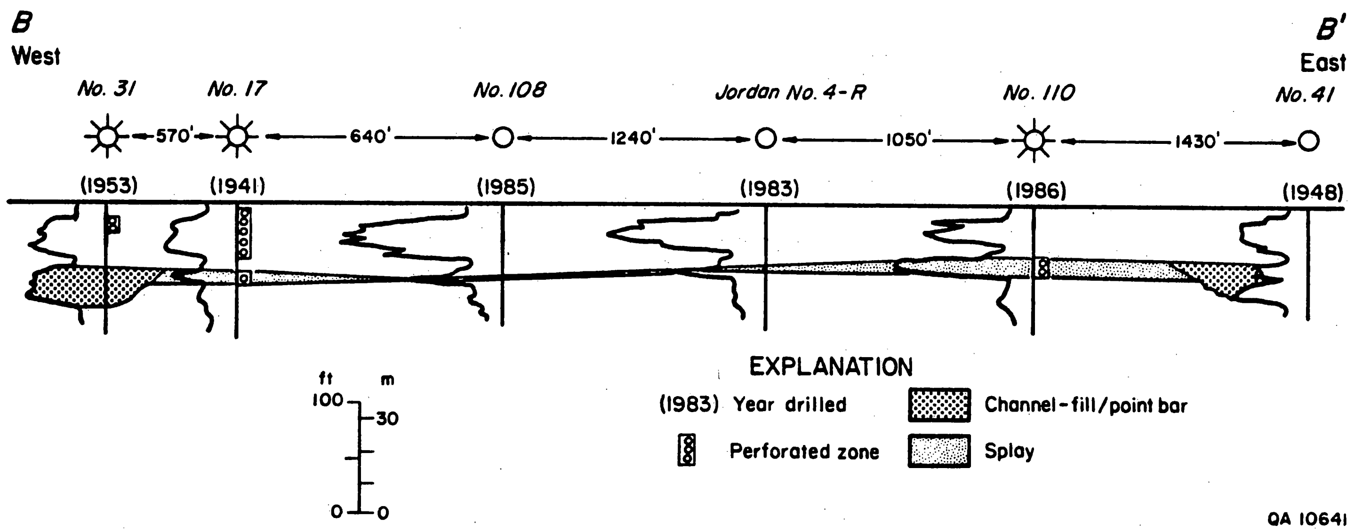


Figure 33. Infill-well development in splay facies in the Jim Wells reservoir, La Gloria field. Mobil #110 La Gloria Gas Unit, drilled in 1986, produces gas from a splay sandstone that is partially isolated by distal splay facies from another productive splay sandstone in Mobil #17 La Gloria Gas Unit. Stratigraphic dip section B-B′ is located on Figure 13.

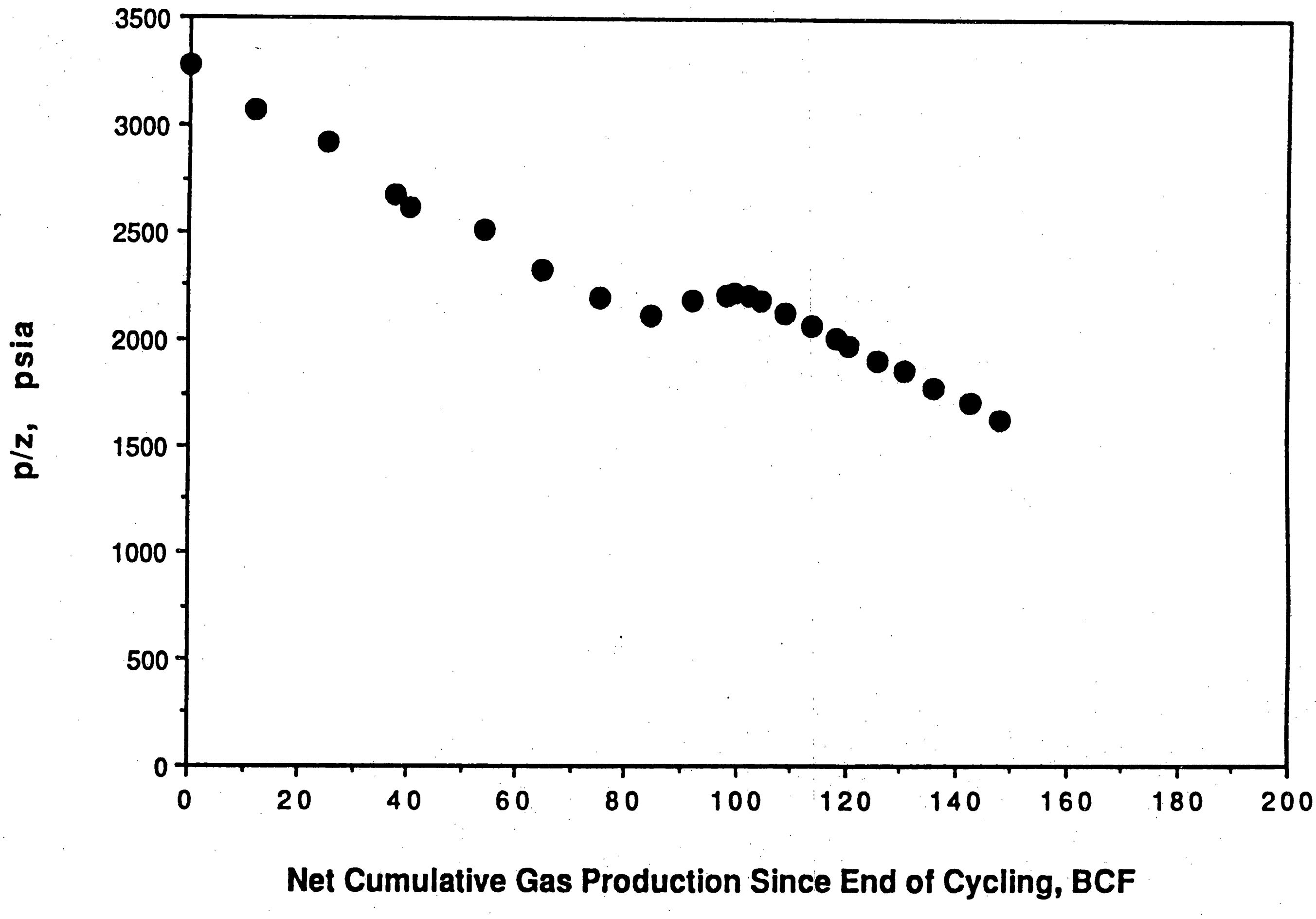


Figure 34. Pressure decline plot for the Jim Wells reservoir. A material balance estimate was not possible because of the large amount of gas leakage from the Arguellez reservoir into the Jim Wells reservoir, shown by an upward step of the pressure decline curve at 90 to 110 Bcf of post-cycling cumulative production. P = average reservoir pressure; z = compressibility factor for natural gas.

Production and development history

The Jim Wells reservoir, located several hundred feet below the Brooks reservoir (fig. 11), was discovered in 1939. The first production well was completed in January 1940, and production commenced in May 1941. Within two years, 12 wells were drilled into the Jim Wells reservoir: eight as gas producers and, initially, four for gas injection. From May 1941 to September 1951, the Jim Wells reservoir was operated under a gas cycling program. Gross gas production during this 10-year period (1941 to 1951) was reported to be 218.2 Bcf, of which 194.1 Bcf was reinjected. Net production during this time period was 24.1 Bcf of natural gas and 4.7 million barrels of condensate.

Since the end of gas cycling in 1951, the reservoir has been produced under pressure depletion drive. During the post-cycling period, the field was operated under the same proration conditions as the Brooks reservoir, which limited the maximum production rate per well to 25 percent of the annual adjusted absolute open-flow potential. Most wells have been produced at rates less than this allowable. Since the Jim Wells reservoir is currently almost depleted, compression is required to elevate gas pressures to pipeline levels.

Including the net gas and condensate produced during the gas cycling period, cumulative production through 1987 from the Jim Wells reservoir is 198.8 Bcf of gas and approximately 6.7 million barrels of condensate. Production and development statistics for the Jim Wells reservoir are summarized in Table 9.

Data sources

The same data sources used for the Brooks reservoir were analyzed to estimate gas in place and the productive capacity of the Jim Wells reservoir. These data sources are:

- Texas Railroad Commission files
- Dwight's Database
- Internal reports from Mobil Corporation

Table 9. Production and Development Statistics for the Jim Wells Reservoir, La Gloria Field.

Development History

- Reservoir discovered in 1939
- First production well completed in January 1940
  - — 12 wells drilled (8 producers and 4 injectors)
- Reservoir produced under gas cycling program from May 1941 to September 1951
  - — Dry gas injected (194.1 Bcf)
  - — Reservoir pressure maintained (3,010 psia in 1941; 2,895 psia in 1951)
  - — Condensate production maximized (4.7 million barrels)
- Reservoir produced under depletion drive conditions from September 1951 to present
  - — 7 additional wells drilled (all producers)
  - — Wells produced at less than proration limit of 25 percent of open-hole potential

Production History

- Initial Producing Gas-Liquid Ratio (Scf/BBL): 30,000–50,000
- Current Producing Gas-Liquid Ratio (Scf/BBL): >100,000
- Net Gas Production (Bcf)
  - — 1941 to 1951: 24.1
  - — 1951 to 1987: 174.7
- Condensate Production (MB)
  - — 1941 to 1951: 4,700
  - — 1951 to 1987: >2,000

• Geophysical logs

• Core data

The specific types of data obtained from each source were summarized in the discussion of the Brooks reservoir.

Estimates of key reservoir properties

A variety of data sources were reviewed and analyzed to develop estimates of key reservoir properties for the Jim Wells reservoir. Inconsistencies between data sources were resolved where necessary. Estimates of key data are discussed below and summarized in table 10.

Average and facies-specific reservoir properties

Because limited core analyses were available for the Jim Wells reservoir, the average facies-specific permeability and porosity values derived for the Brooks reservoir were assumed to be representative of the Jim Wells reservoir. This assumption is based on the geologic similarities of facies types in the two reservoirs. The Jim Wells reservoir has relatively high permeability and good gas-filled porosity. Excluding the floodplain, porosity ranges from 21 percent in the distal splay facies to 24 percent in the channel sandstones, and permeability ranges from 75 to 488 md.

Average water saturation was estimated from geophysical logs in the Jim Wells reservoir and ranges from 27 percent in the channel sandstones to 34 percent in the distal splay facies. The facies-specific reservoir data are summarized in table 10.

The Jim Wells reservoir is characterized by high average porosity (22.9 percent) and good permeability (310 md). The average net productive sandstone thickness is 43.3 ft, with a reservoir bulk volume of 174,309 acre-ft and an area of 4,025 acres. The initial pressure of the Jim Wells reservoir (1939) was 3,010 psia. After gas cycling and a net production of 24.1 Bcf of gas and 4.7 million barrels of condensate, the average reservoir pressure declined to 2,895 psia.

Table 10. Key Reservoir Data Summary for the Jim Wells Reservoir, La Gloria Field.

Average Reservoir Properties

Area:	4,025 acres
Average Net Sandstone Thickness:	43.3 feet
Bulk Volume:	174,309 acre-feet
Average Porosity:	22.9 percent
Connate Water Saturation:	29.9 percent
Depth:	6,100 feet
Reservoir Temperature:	188°F
Initial Reservoir Pressure (1941):	3,010 psia
Reservoir Pressure After Cycling (1951):	2,895 psia
Current (1987) Reservoir Pressure:	<300 psia
Dry Gas Specific Gravity:	0.65 (Air = 1.0)
API Gravity of Condensate:	55 degrees
Post-Cycling Gas Formation Volume Factor:	0.00560 Rcf/Scf
Estimated Gas In Place After Cycling:	217.7 Bcf
Average Absolute Permeability:	310 md

Facies-Specific Reservoir Properties

Facies Type	Effective Permeability to Gas (md)	Porosity (%)	Water Saturation (%)
Channel Sand	488	24	27
Point Bar Sand	300	24	32
Proximal Splay	188	22	30
Distal Splay	75	21	34
Floodplain	0.1 to 1.0	16	>30

Volumetric gas in place

Using the calculated reservoir properties and the estimated post-cycling reservoir pressures and temperatures, the gas in place for the Jim Wells reservoir at the end of cycling was estimated to be 217.7 Bcf. The methodology used to establish volumetric gas in place for the Jim Wells reservoir was the same as used for the Brooks reservoir.

Gas contact function for the Jim Wells reservoir

The development of the gas contact function for the Jim Wells reservoir followed the same methodology previously discussed for the Brooks reservoir. The application of this methodology to the Jim Wells reservoir and the results of the analysis are presented below.

After completion of the gas cycling program in 1951, the Jim Wells reservoir was produced at a relatively constant well spacing from 1951 to 1965. During this period, there were seven producing wells, resulting in an average reservoir-wide well spacing of 575 acres per well (5,005 ft of interwell distance). After 1965, the reservoir-wide well spacing did not remain constant for a sufficient period of time to estimate accurately gas contacted by individual wells. Thus, estimated gas contact as a function of well spacing could be derived empirically for the Jim Wells gas contact function for only a single development period. Because the volume of gas leakage from the Arguellez reservoir into the Jim Wells during the mid-1950's is unknown and the timing is uncertain, the leaked volume was not included in the analysis, resulting in a conservative estimate for gas reserves growth.

As in the Brooks reservoir analysis, the production decline type curves developed by Fetkovich (1980) were used to analyze individual Jim Wells reservoir well production histories. For each producing well, the ultimate gas contacted was calculated by adding the cumulative production since the end of cycling and the estimated gas in place remaining in the drainage area (from the type curve analysis). The individual well estimates for ultimate gas contact were then summed to derive total gas contacted at the then-current well spacing. This value, 184.2 Bcf, represents the total ultimate gas contacted at the well spacing of 575 acres per well calculated for the 1951 to 1965 development period. Therefore, in the Jim Wells reservoir, 84.6 percent (184.2 Bcf) of the 217.7 Bcf gas in place was contacted at a well spacing of 575 acres per well (table 11).

The percentage of gas in place that was contacted during the 1951 to 1965 development period was plotted against interwell distance. In the absence of additional empirically derived estimates of gas contact at spacings greater than 575 acres, the Jim Wells reservoir gas contact function was assumed to have the same basic shape as the gas contact function developed for the Brooks reservoir. At 40 acres per well (1,320 ft of interwell distance), essentially 100 percent of the reservoir is expected to have been contacted.

Discussion of the gas contact function

The gas contact function for the Jim Wells reservoir is tabulated in table 12 and is shown graphically in figure 35. At a well spacing of 640 acres (5,280 ft of interwell distance), 81.7 percent of the post-cycling gas in place in the Jim Wells reservoir is contacted by producing wells. Decreasing the average reservoir-wide well spacing to 320 acres per well (3,374 ft of interwell distance) and 160 acres per well (2,640 ft of interwell distance) contacts additional gas in place of 8.2 and 4.6 percent, respectively. This increases the total reservoir contact at 160 acres per well to 94.5 percent of post-cycling gas in place.

The Jim Wells reservoir contains a higher percentage of mudstone-rich facies than the Brooks reservoir, indicating that infill wells in the Jim Wells reservoir would have to be drilled to closer well spacings than in the Brooks reservoir to contact the same proportion of original gas in place. The analysis of the two reservoirs, however, found that as a percentage of post-cycling gas-in-place, 3.5-percent higher reservoir contact was achieved initially at large well spacings in the Jim Wells reservoir. This may be partially due to the fact that wells used in the gas contact function from the Jim Wells reservoir were completed in both channel and distal splay facies (table 13), possibly contacting relatively more gas at initial development

Table 11. Summary of Results of Assessment of Reservoir Heterogeneity for the Jim Wells Reservoir, La Gloria Field.

Development Period One: 1951–1965

• Total Number of Production Wells:	7
• Reservoir Area:	4,025 acres
• Average Well Spacing:	575 acres/well
• Average Interwell Distance:	5,005 feet
• Volumetric Gas In Place in 1951:	217.7 Bcf
• Total Estimated Ultimate Gas Contacted:	184.2 Bcf
• Ratio of Gas Contact to GIP:	84.6 percent

Table 12. Reservoir Contact as a Percentage of Post-Cycling Gas in Place for the Jim Wells Reservoir, La Gloria Field.

Well Spacing (acres/well)	Reservoir Contact (% GIP)	Reservoir Contact (Bcf)	Incremental Contact (% GIP)	Incremental Contact (Bcf)
640	81.7	177.8	—	—
320	89.9	195.7	8.2	17.9
160	94.5	205.7	4.6	10.0
80	97.7	212.7	3.2	7.0
<40	100.0	217.7	2.3	5.0

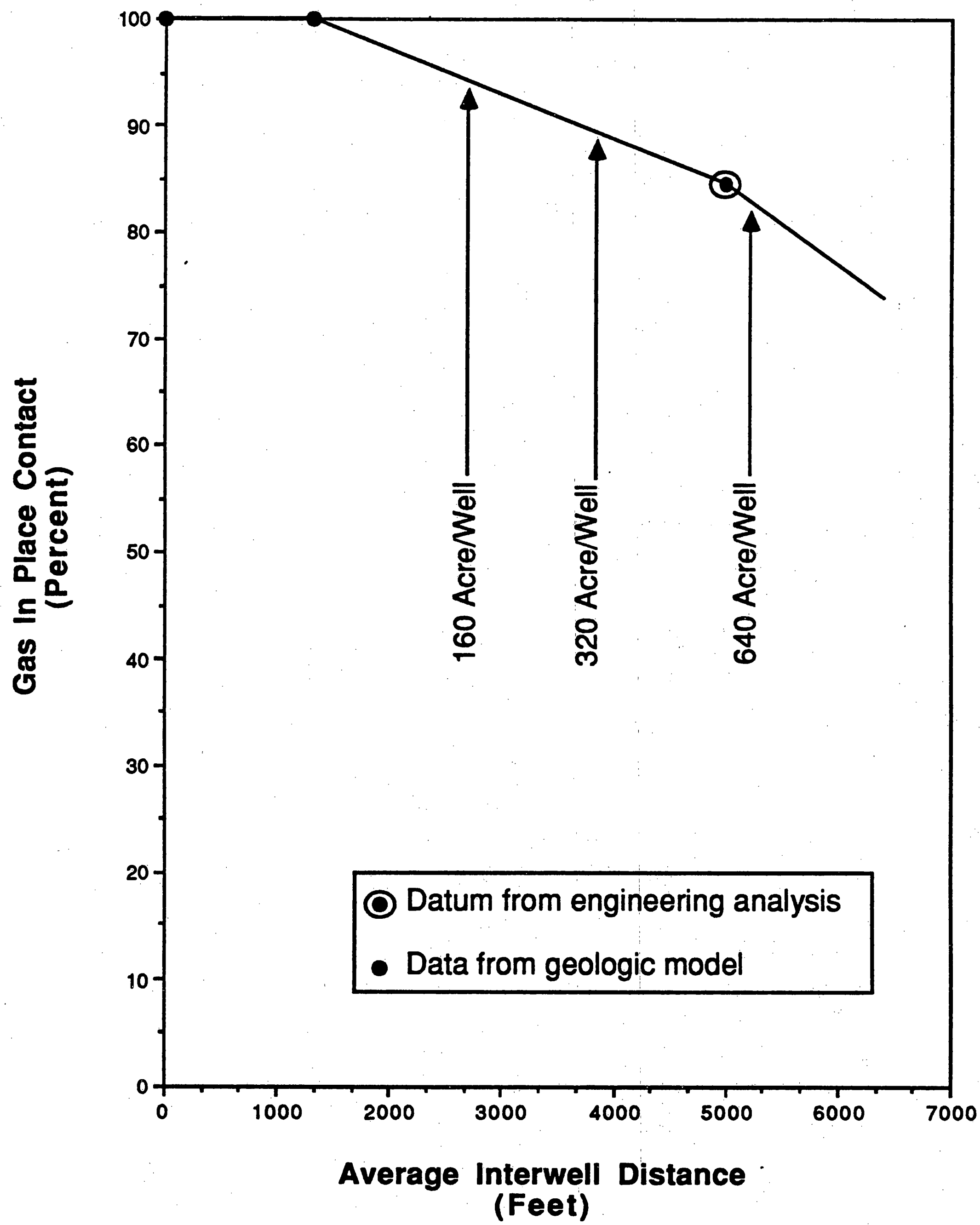


Figure 35. Incremental gas contact function for the Jim Wells reservoir. Datum from the engineering analysis represents an average well spacing of 575 acres per well. Data from the geologic model include 100 percent contact at zero interwell distance, and an assumed 100 percent contact at the average minimum facies lens size (1,320 ft) determined from depositional analysis of La Gloria field.

Table 13. Summary of Facies-Specific Well Completions for the Jim Wells Reservoir, La Gloria Field, for Wells Used in this Study that Produced after Cycling Was Stopped.

Well No.*	Date Production Started From Jim Wells	Type of Facies Perforated	Initial BHSIP (w)
LGU 9	May 1941	Channel and Proximal Splay	?
LGU 26	July 1948	Distal Splay	2,821
LGU 20	Dec. 1949	Channel	2,934
LGU 1	Dec. 1951	Channel and Distal Splay	2,875
LGU 4	Oct. 1952	Channel and Distal Splay	2,562
LGU 22	April 1956	Channel	1,918
LGU 15	June 1963	Distal Splay	1,320
LGU 67	Oct. 1969	Channel and Distal Splay	1,074
LGU 31	Feb. 1970	Channel	1,083
SLGU 19	March 1971	Point Bar	?
LGU 49	May 1976	Proximal Splay and Channel	1,384
LGU 42	March 1985	Channel and Point Bar	?
LGU 110	June 1987	Proximal Splay	1,380

* This table lists only wells producing after gas cycling.

spacing than in the Brooks reservoir, where many wells were completed only in the channel sandstones. This suggests that completion in facies separated by mudstone-rich or other flow-restricting boundaries may be a factor in high gas contact at initial (wide) well spacings. If so, then infill drilling in reservoirs with initial development in different, partially communicating facies will contact less incremental gas than in reservoirs that contain wells drilled in one or two facies types that have good communication between them. One may also note that the Jim Wells reservoir had a higher initial pressure than the Brooks reservoir. This pressure difference may be in small part responsible for the higher amount of gas contacted at initial well spacing in the Jim Wells reservoir than in the Brooks reservoir.

Pressure analysis

Two wells in the Jim Wells reservoir appear to have been completed in partially isolated compartments. LGU 49 and LGU 110 were recompleted and drilled in 1976 and 1987, respectively, when the Jim Wells reservoir was substantially depleted. Although calculation of an accurate average reservoir pressure was difficult because of incomplete pressure data for many wells, both wells had initial pressures in excess of the current pressures measured in adjacent wells, indicating penetration of a partially isolated sandstone body.

In 1976, when average reservoir pressure was less than 1,000 psi, LGU 49 had an initial Jim Wells shut-in pressure of 1,384 psi. The well produced less than 120 MMcf over seven months before being abandoned. In 1987, when LGU 110 was drilled and had an initial Jim Wells shut-in pressure of 1,380 psi, average reservoir pressure was probably less than 500 psi. Well 110 produced 50 MMcf through mid-1987 and was almost depleted at that time. The cumulative volume of incremental reserves added from these two wells is less than 0.2 Bcf. Both of these wells were completed in these zones as secondary, not primary targets.

The small size of the isolated sandstone bodies contacted by these two infill wells in the Jim Wells reservoir suggest that the principal mechanism controlling gas reserve growth may be well placement and completion practices that recognize facies geometry as determined by the location and extent of lower permeability shales and other permeability barriers within and between facies. Stimulation strategies designed to optimize overall gas flow, although not analyzed in this report, may also be important in gas reserve growth. A complete understanding of reserve growth potential requires an integration of geologic models with reservoir engineering practice.

Estimate of technically recoverable gas

The data used to estimate technically recoverable gas for the Jim Wells reservoir and the results of the technical analysis are discussed below. The methodology used is the same as that used for the Brooks reservoir.

The Jim Wells reservoir has an areal extent of 4,025 acres. This surface area was divided into six, approximately equal, 640-acre grids (fig. 36). For each grid, the reservoir properties were calculated using the net sandstone maps and the detailed facies maps of the Jim Wells reservoir (fig. 37). Some reservoir properties are fairly uniform—porosity averages 23 percent in each grid, water saturation ranges somewhat from 29 to 31 percent, and permeability ranges from 275 to 347 md. Net sandstone thickness, however, ranges widely among the six grids, from 72 ft in the northeast to 15 ft in the south. Based on post-cycling reservoir pressure and temperature, an average gas formation volume factor of 0.00560 Rcf/Scf was used for the entire reservoir.

Using the data developed above, volumetric gas in place was calculated for each grid (fig. 38). The gas in place ranges from a high of 59 Bcf (91 MMcf/acre) in the northeast to a low of 12 Bcf (18 MMcf/acre) in the south. The areas of highest gas in place correlate with the highest values of net sandstone thickness in the northeast.

The reservoir contact function developed for the Jim Wells reservoir was used to estimate the volume of gas that would be available to infill wells. For each grid, the gas contact as a percentage of post-cycling gas in place was multiplied by the total grid volumetric gas in place to arrive at an estimate of additional gas available for an infill well. Figure 39 shows the

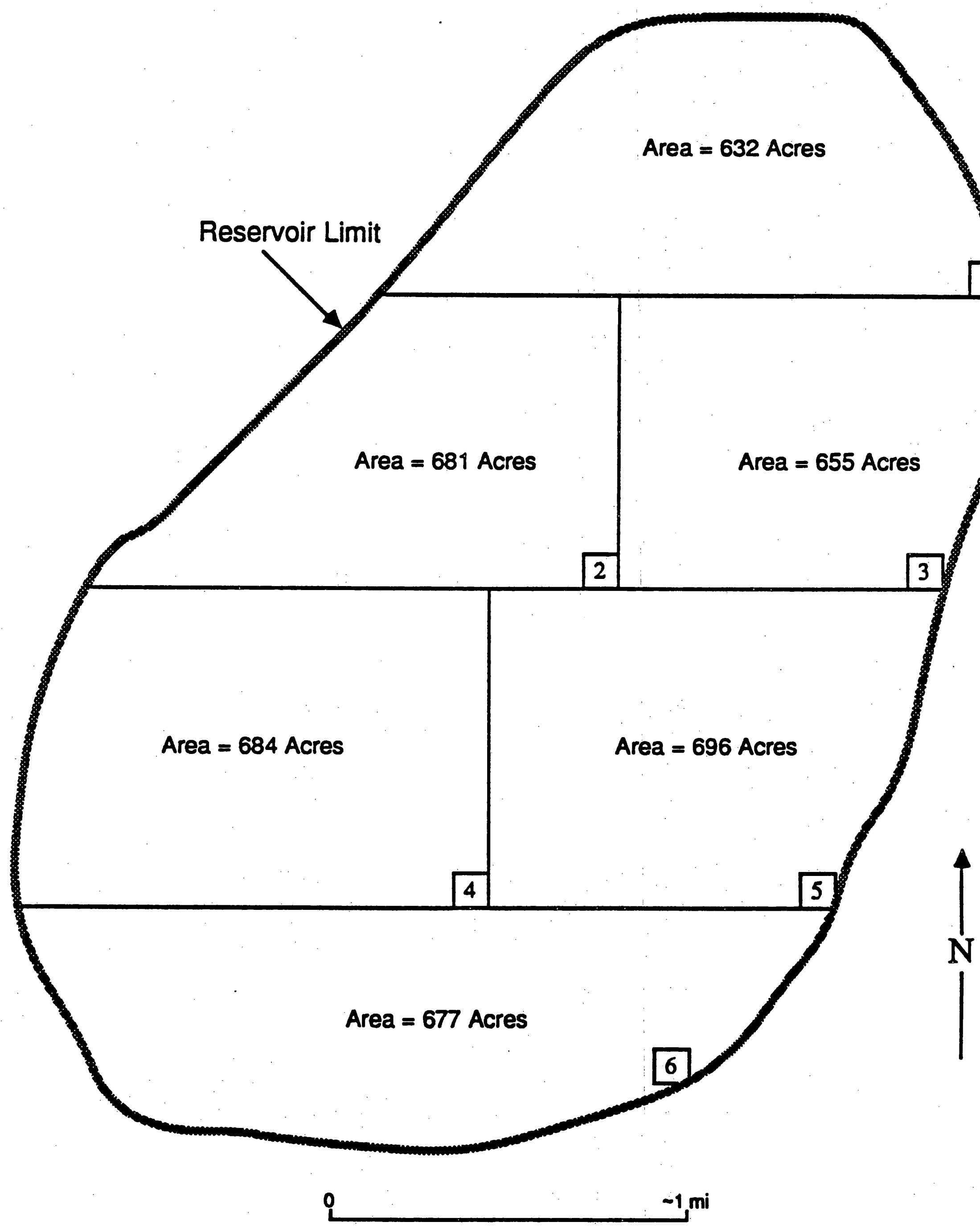


Figure 36. Grid divisions used in the well production model of the Jim Wells reservoir. Six grids were used, approximating 640-acre spacing. Grid numbers in this and all subsequent figures are shown in the lower right corner of each grid.

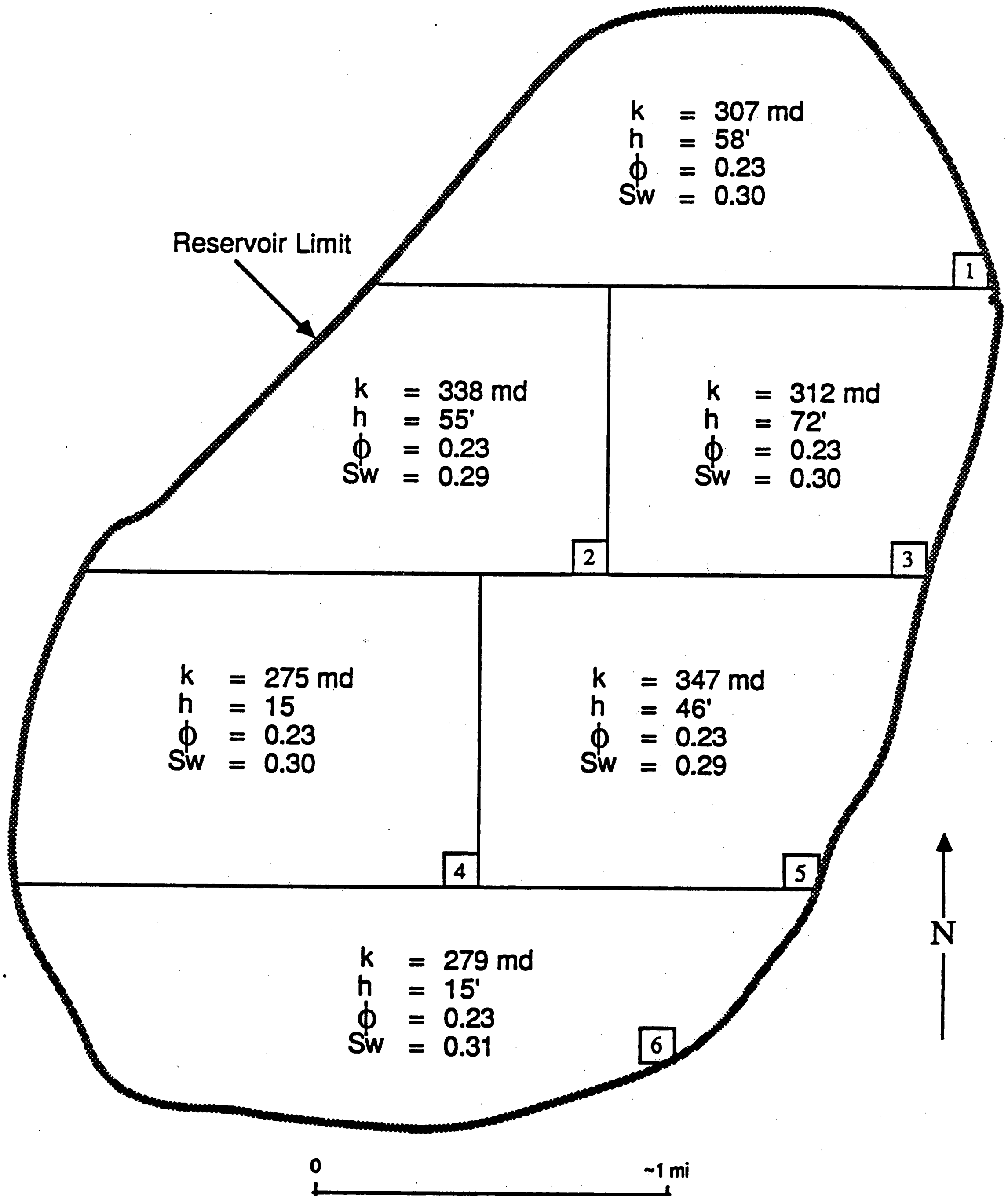


Figure 37. Average grid-specific reservoir properties of the Jim Wells reservoir at 640-acre grid spacing. Symbols include k, permeability in millidarcys; h, net sandstone thickness in ft; ø, fractional porosity; and S_W, fractional connate water saturation.

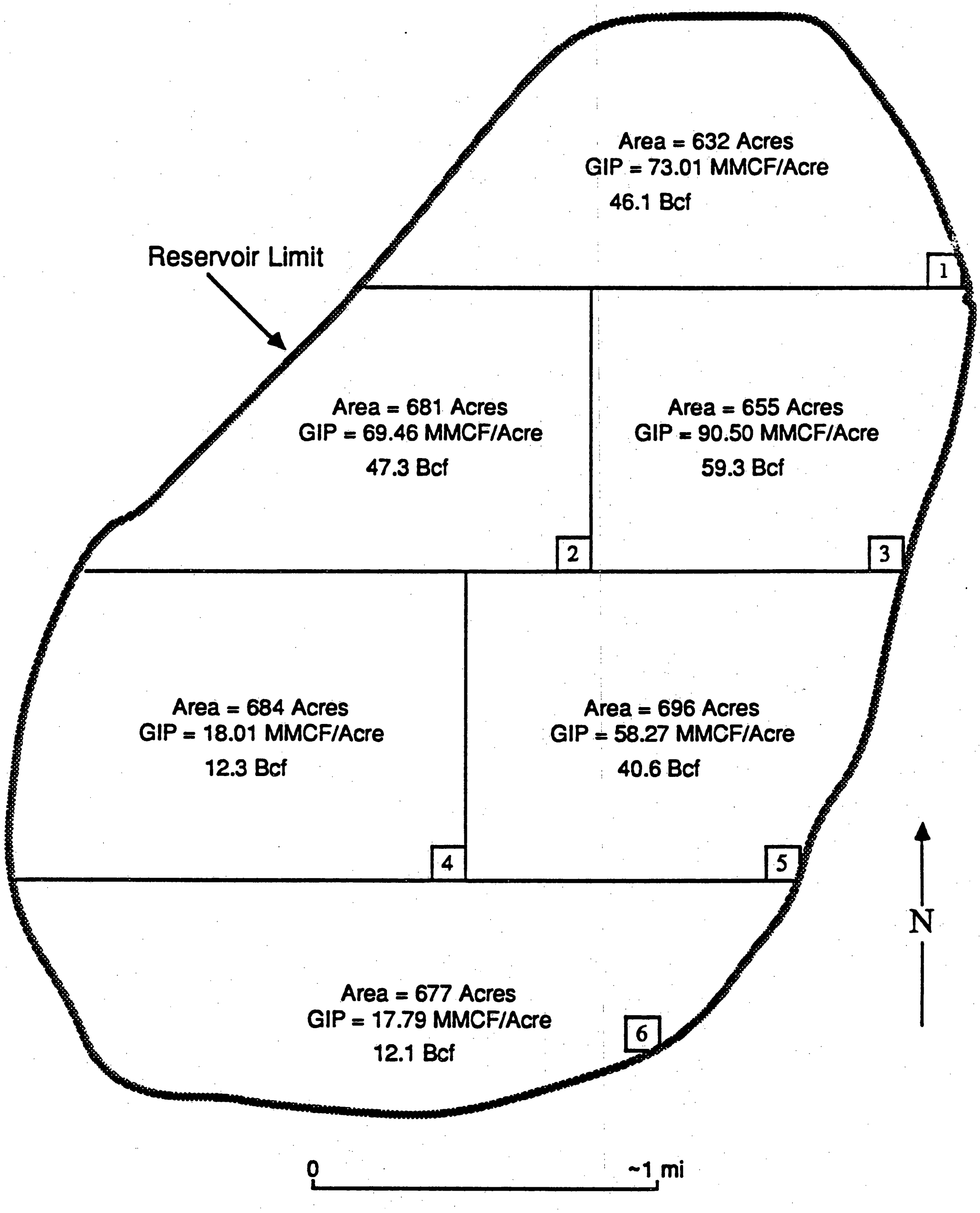


Figure 38. Volumetric gas in place of the Jim Wells reservoir at the end of the gas cycling program in 1951. Average reservoir pressure at this time was 2,895 psia.

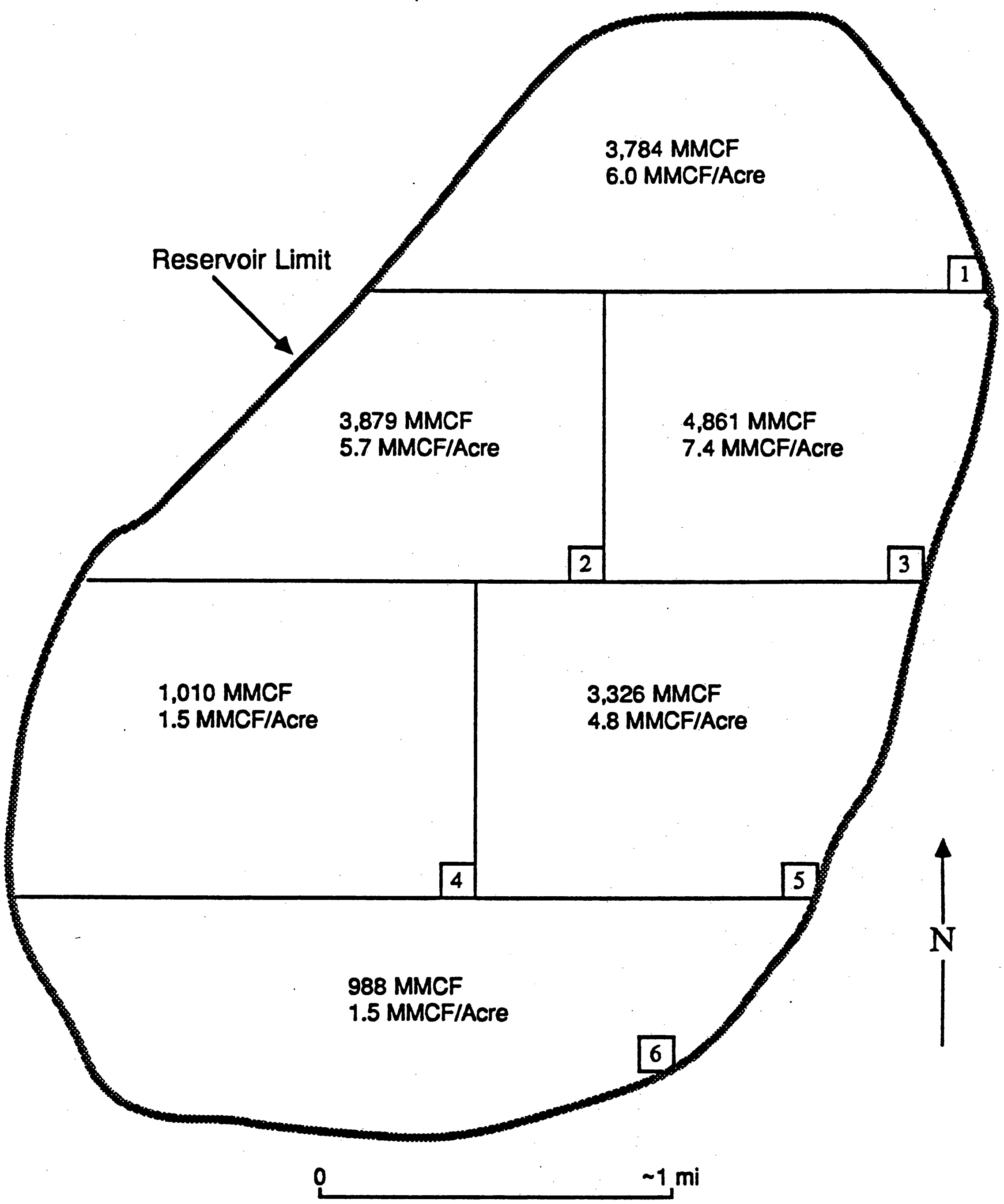


Figure 39. Calculated incremental available gas in the Jim Wells reservoir for infill drilling from 640- to 320-acre spacing at the end of cycling, at an end-of-cycling pressure of 2,895 psia.

results of the multiplication of the 8.2 percent gas in place derived from the gas contact function by the gas in place for all six grids. This calculation establishes the volume of incremental gas contacted by infill wells drilled to decrease well spacing from 640 to 320 acres per well in each grid. Initial infill wells would be optimally located in those portions of the reservoir containing thicker net sandstone because larger volumes of incremental gas contact are predicted in those areas.

The volume of technically recoverable incremental gas available in each grid is shown for two infill development strategies, 640 to 320 acres per well and 320 to 160 acres per well (table 14). Based on the same assumption used in the analysis of the Brooks reservoir that the incremental gas is found at an average pressure of 50 percent of initial reservoir pressure, infill drilling for the Jim Wells reservoir from 640 to 320 acres per well could recover an additional 13.8 Bcf of natural gas. This volume represents 77 percent of the 17.8 Bcf of incrementally contacted gas. Further infill drilling to 160 acres per well from 320 acres per well recovers an additional 7.7 Bcf of the 10.0 Bcf of incrementally contacted gas. Areas of the reservoir with relatively thick net sandstone have greatest technical potential for infill drilling. For example, nearly 70 percent of the total technically recoverable gas can be produced from Grids 1, 2, and 3 for infill wells drilled to 320 acres per well from an initial development pattern of 640 acres per well.

Conclusions

This study characterized the sandstone geometry and fluvial facies types and evaluated the potential for strategic infill drilling in the Brooks and Jim Wells reservoirs, La Gloria field. Because the Brooks reservoir is so sandstone rich, floodplain deposits do not isolate pockets of gas, and facies-based delineation of strategic infill drilling prospects is not possible in this reservoir. The Jim Wells reservoir, however, is sufficiently variable to allow for strategic well placement based on geologic interpretation of depositional systems. Geologic tools such as the net-sandstone-thickness and SP-log facies maps are important in the

Table 14. Technically Recoverable Incremental Gas (MMCF) from Infill Drilling, Jim Wells Reservoir, La Gloria Field.

	Grid Identification Number*						Reservoir
	1	2	3	4	5	6	Total
Volumetric Gas In Place	46,144	47,301	59,275	12,316	40,559	12,045	217,640
Total Gas Contact at 640 Acres/Well	37,699	38,645	48,428	10,062	33,137	9,841	177,812
Development Strategy 640 to 320 Acres/Well (One Infill Well)							
Incremental Gas Contact	3,784	3,879	4,861	1,010	3,326	988	17,848
Technically Recoverable Incremental Gas	2,921	3,003	3,731	773	2,575	761	13,764
Development Strategy 320 to 160 Acres/Well (Two Infill Wells)							
Incremental Gas Contact	2,123	2,176	2,727	567	1,866	554	10,013
Technically Recoverable Incremental Gas	1,611	1,656	2,122	435	1,420	428	7,672

* See Figure 39 for grid identification.

identification of non- or partially communicating boundaries that may trap gas bypassed in early field development.

Based on the geological characterization of the two study reservoirs, potential for gas reserve growth from infill drilling was estimated using engineering analysis of reservoir development and production history. A 9.3- and 8.2-percent increase in gas contacted through infill drilling from 640- to 320-acre spacing was estimated in the Brooks and Jim Wells reservoirs, respectively. Areas of these reservoirs containing thicker net sandstone would provide the best opportunity for infill wells drilled or recompleted to recover these additional gas reserves. In both reservoirs, a large amount of the total technically recoverable gas available is found in three grid areas, an amount equal to 16.3 Bcf of gas reserves, or about 2 Bcf per well at 320-acre spacing.

The geologic and engineering analyses have provided new insights into possible production mechanisms for reserve growth. The reserve growth potential of a given geologic setting may be influenced by the specific development history of a reservoir. Given the geologic complexity of a reservoir, the volume of gas in place contacted by initial development wells is determined by a combination of well placement, completion, and production practices sensitive to the distribution of facies types. Wells completed in a highly continuous facies will completely contact the gas in place in that facies and some portion of gas in place in adjacent facies. Wells completed adjacent to and vertically across many facies boundaries will contact a proportionally greater percentage of total reservoir gas in place. Thus, wells placed so that they can be completed in an optimum number of facies having mudstone-rich boundaries can potentially contact the greatest percentage of gas in place at any well spacing.

More analysis is required to understand the correlation between geologic description and natural gas reserve growth. Because of the high mobility of gas and the interaction of geologic and development factors in controlling gas reserves growth, reserve growth analysis must be approached on the basis of an understanding of geologic reservoir heterogeneity, engineering analysis, and the additional information on reservoir geometry that can be provided by geophysical methods.

Case Study 2—Julian North Field

Geologic Setting

Julian North field is located downdip of the Frio Fault Zone in South Texas, northeast of the boundary of Brooks, Hidalgo, and Kenedy Counties (fig. 1). The field lies in the Norias deltaic system, part of the proximal Frio deltaic sandstones in the Rio Grande Embayment play, as designated by the Atlas of Major Texas Gas Reservoirs (Kosters and others, 1989). Fine grain size and advanced diagenetic destruction of porosity and permeability have resulted in low production from this mature play; mudstone constitutes three-quarters of the play volume (Galloway and others, 1982). Shale-cored rollover anticlines and faulted anticlines that formed during syndepositional growth faulting are the most abundant trap types in this play. Drilling density is low, averaging one well per 10 square miles (Galloway and others, 1982).

Depositional Setting

Julian North field lies in the Norias delta system at the downdip limit of fluvially derived sediments in the middle and lower Frio Formation (Galloway and others, 1982) (figs. 6 and 7). The Norias system consists of well-defined, vertically stacked deltaic lobes (Galloway and others, 1982) represented by thick, upward-coarsening, wave-reworked sandstones. Analogous depositional systems have been described by Weise (1980) in the Cretaceous San Miguel Formation in the Maverick Basin of Texas (fig. 40). Depositional units in the San Miguel Formation consist of a variety of wave-dominated deltaic and coastal environments, with sediment patterns ranging from lobate (moderate wave energy) to strike-elongate (high wave energy) (fig. 41). Net-sandstone patterns of lower Frio reservoirs in Julian and Julian North fields also occur in variations of two basic varieties, strike-parallel sandstone sheets and dip-parallel sandstone belts (fig. 42). Facies maps of these lower Frio units range from lobate forms

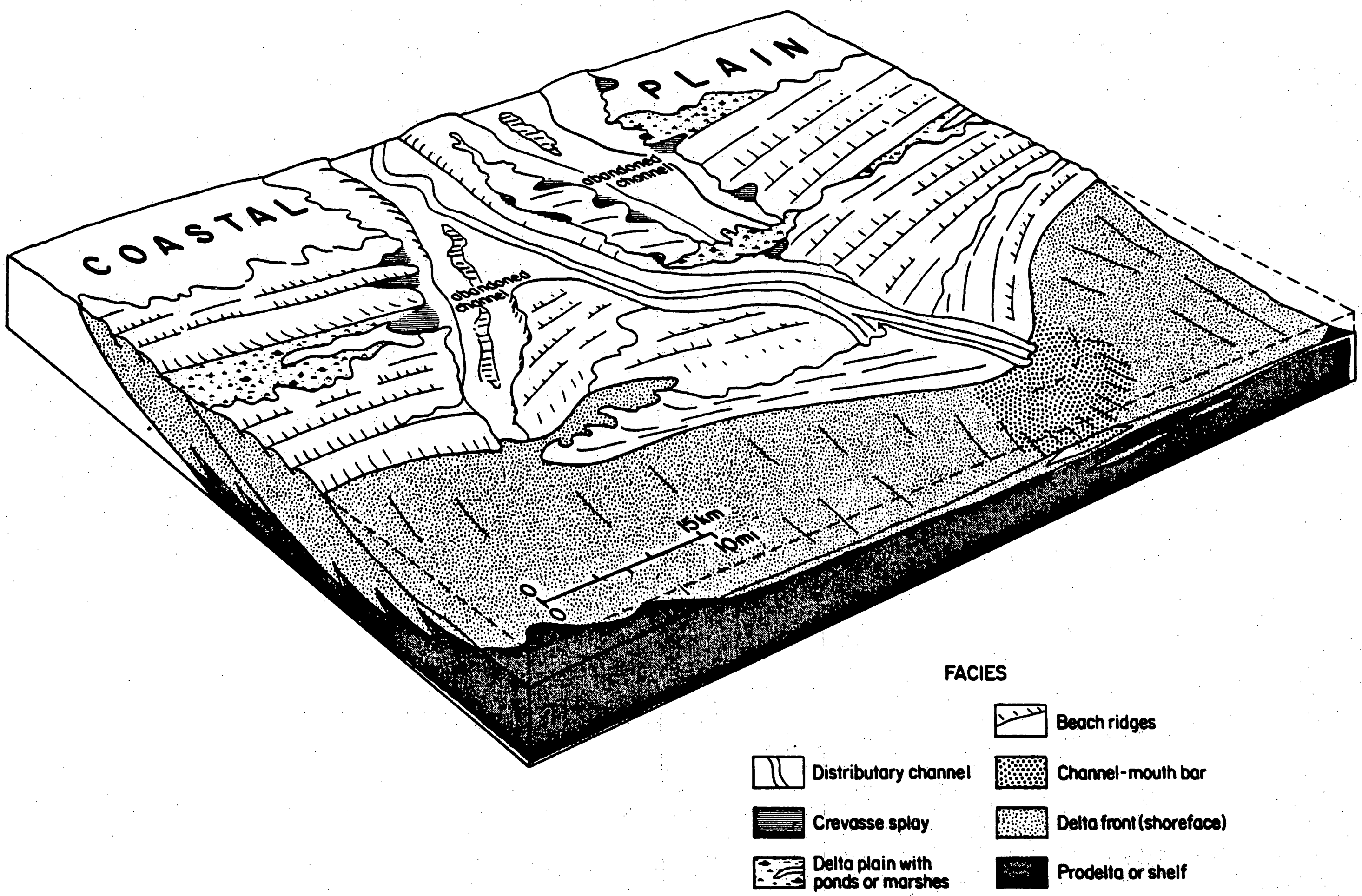


Figure 40. Depositional model of lower Frio wave-dominated deltaic reservoirs in Julian North field. These reservoirs are characterized by good sandstone-body continuity and may contain few undrained reservoir compartments at the minimum-allowed well spacing. From Weise (1980).

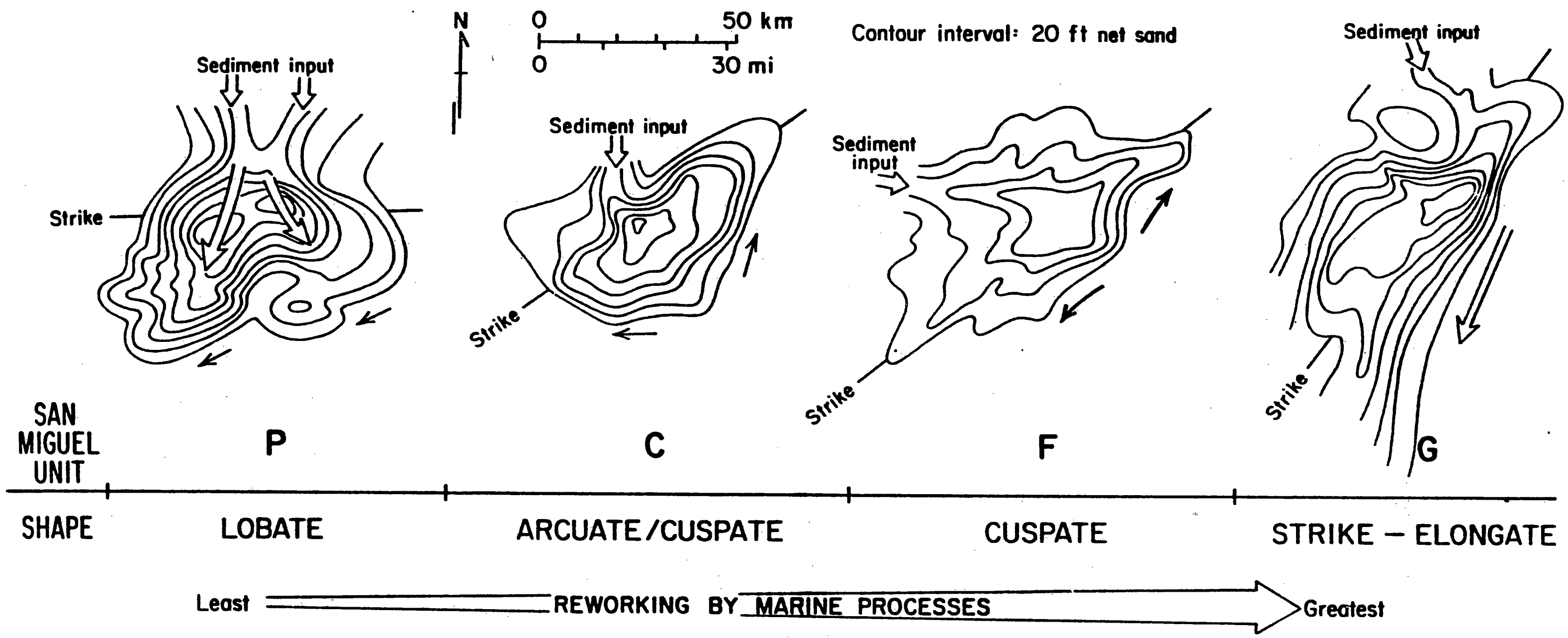


Figure 41. Spectrum of delta types on wave-dominated coastlines. Deltaic reservoirs with lobate net-sandstone patterns such as the I-92 and J-68 in Julian North field were deposited on coastlines with moderate wave energy. Strike-elongate net-sandstone-thickness patterns indicate strong reworking of deltaic sands by marine processes. Examples shown are from Cretaceous San Miguel deltas in the Maverick Basin, Texas. Relative magnitude and direction of sand transport are indicated by the weight and direction of arrows. From Weise (1980).

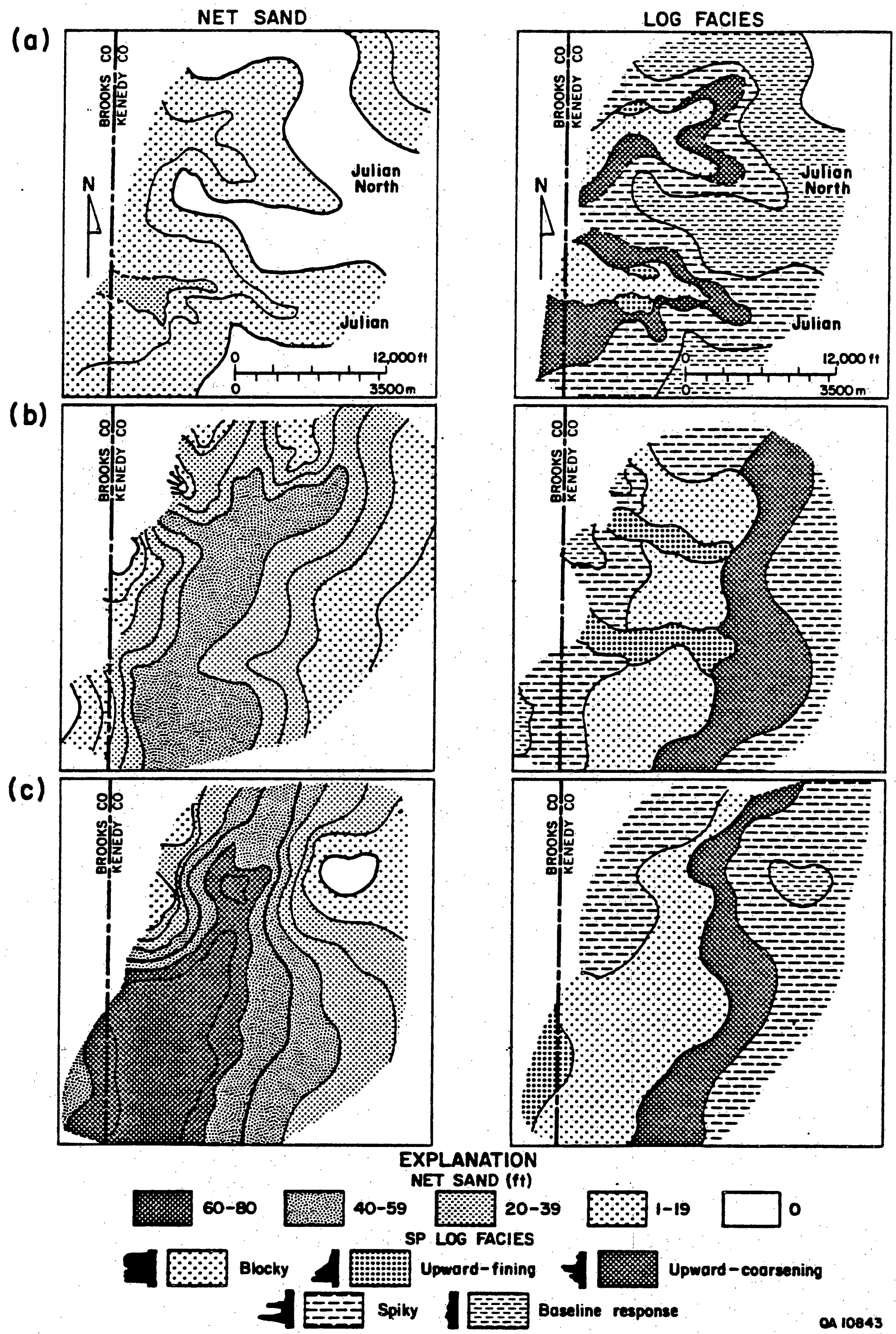


Figure 42. Net-sandstone-thickness (left column) and SP-log facies (right column) maps of the Julian and Julian North field area. The 21-A reservoir (a) exhibits well-defined dip-elongate digitate patterns that may represent delta distributary channels and delta-mouth-bar deposits. The 22-A reservoir (b) has two distinct east-west-trending channels representing tidal inlet deposition flanked by barrier core sandstones. The 22-J (c) reservoir exhibits strike-elongate facies patterns probably representative of wave-reworked delta distributary sandstones and barrier-bar deposits.

representing delta distributaries to completely strike-elongate barrier islands developed on a wave-dominated coastline. Sandstone-body continuity in these systems is good to excellent, except where strike-parallel barrier-core sandstones are transected by dip-oriented tidal inlets, or where distributary-channel sandstones are flanked laterally by sand-poor interdeltaic facies. Net sandstone thickness is 5 to 20 ft in delta-distributary and delta-mouth-bar facies, and 40 to 80 ft in barrier and tidal facies. These strike-parallel belts extend laterally tens of miles, but only a few miles downdip. Dip-elongate tidal-inlet facies are less than one mile wide and one to three miles long. SP-log responses are upward-coarsening for channel-mouth-bar facies, blocky for barrier-core facies, and upward-fining for tidal-inlet facies. Both dip-elongate and strike-elongate depositional systems are observed in the nine reservoirs evaluated in Julian and Julian North fields.

Field Description

Development history

Discovered in 1953, Julian North field has produced 16.8 Bcf through 1986 from two nonassociated gas reservoirs (fig. 43). The two reservoirs, J-68 and I-92, are also known as the Frio 10,000 and the Frio 9300, respectively. These reservoirs are in the lower Frio, approximately 2,000 ft above the underlying Vicksburg, according to paleontologic information from Humble #1 Santa Fe Julian Pasture, located in Julian field.

Trap

Julian North field occupies the northern part of an anticline created by rollover into a large, north-south-trending growth fault that is part of the Frio fault zone (fig. 44). The anticline is dome-shaped on the southern end, tapering northward to a structurally lower, northeast-trending ridge that encompasses the Julian North field. Julian field is located in the southern part of the anticlinal structure. No evidence for faulting was found in Julian or Julian North fields within the reservoir studied in this report.

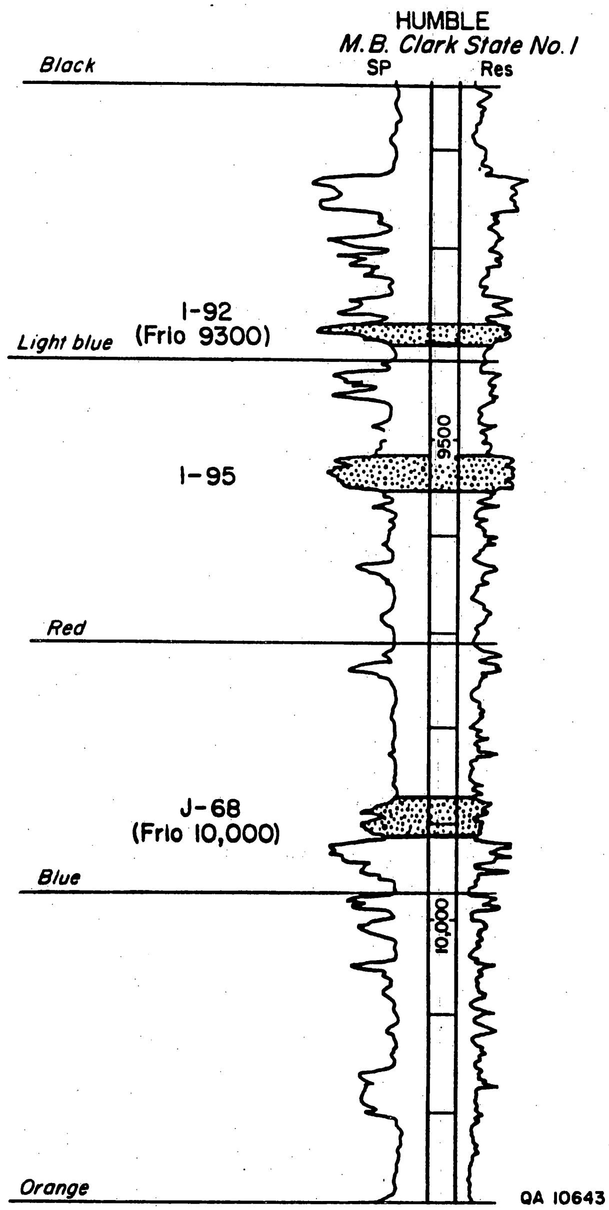


Figure 43. Type log (Humble #1 M.B. Clark State) of the I-92 and J-68 nonassociated gas reservoirs in Julian North field. Both of these lower Frio reservoirs, producing from wave-modified deltaic sediments, are relatively continuous compared with middle Frio fluvial reservoirs in La Gloria field. However, widespread diagenetic alteration severely limits porosity and permeability in Julian North field. Upward-coarsening SP-log patterns covering 200-300 ft of vertical distance represent barrier-bar or delta-front sandstones (such as the I-95) overlain by delta-mouth-bar and delta distributary facies.

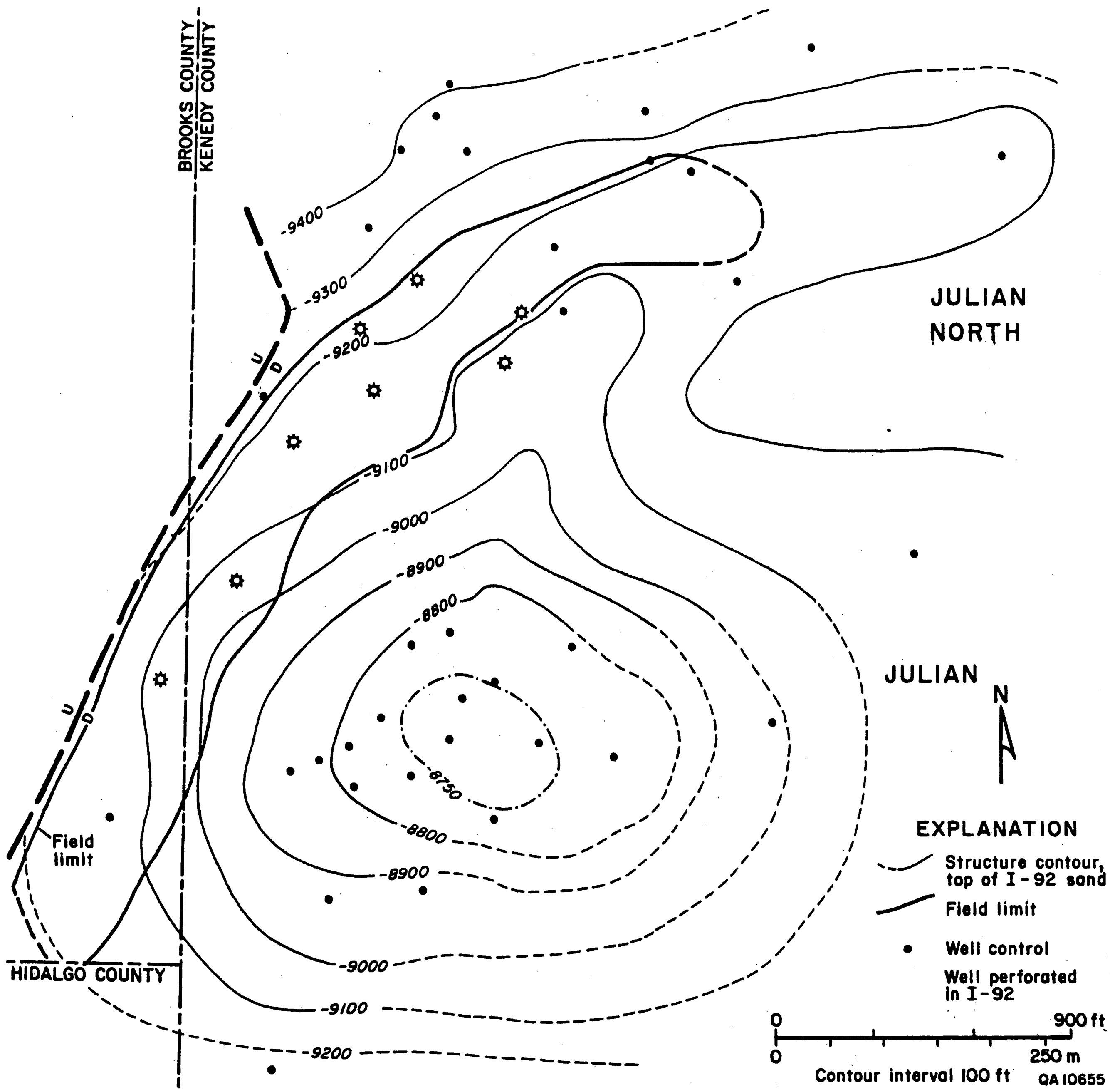


Figure 44. Structure map of Julian and Julian North fields, contoured on top of the I-92 nonassociated gas reservoir. Most of the producing wells in the I-92 reservoir are located in the Julian North field area, which is located on the northern flank of the anticlinal structure.

I-92 Reservoir

Net-sandstone and log-facies maps of nine lower Frio reservoirs in Julian and Julian North fields were used to determine the extent of reservoir sands. Because the J-68 reservoir had few wells and an intermittent production history, the I-92, also known as the Frio 9300, was selected for analysis. All major Julian field reservoirs were cycled and were not modeled because of lack of engineering data.

Depositional environment

The I-92 reservoir exhibits a strong lobate net-sandstone geometry, indicating moderate marine reworking of deltaic sediments (fig. 45). Three dip-parallel distributary-channel sandstone bodies, 10 to 16 ft thick and 1,000 to 3,000 ft wide, merge downdip with a strike-parallel irregular sandstone sheet less than 5 ft thick. Facies distribution is predominantly strike-parallel, with upward-coarsening and spiky forms being the dominant SP-log responses (fig. 46). Distributary-channel sands were encountered in two wells in the northern part of the reservoir. Greatest net sandstone thicknesses are found west of the structural crest of the reservoir against a field-bounding fault. Low permeability modifies further the approach to producing this reservoir.

Infill potential

Sand-poor areas between the three distributary-channel sand bodies (fig. 45) may partially isolate and compartmentalize these distributary-channel sandstones. The downdip terminus of these sandstone bodies, where they merge into the thin, strike-parallel delta-front sheet sandstones on the downdip margin of Julian and Julian North fields, may also contain poorly drained reservoir compartments. However, variations in diagenesis may account for the principal porosity and permeability heterogeneities in this reservoir.

Seven wells that have produced from the I-92 reservoir are evenly spaced over the northern three-quarters of the area. One of these wells was hydraulically fractured, and two

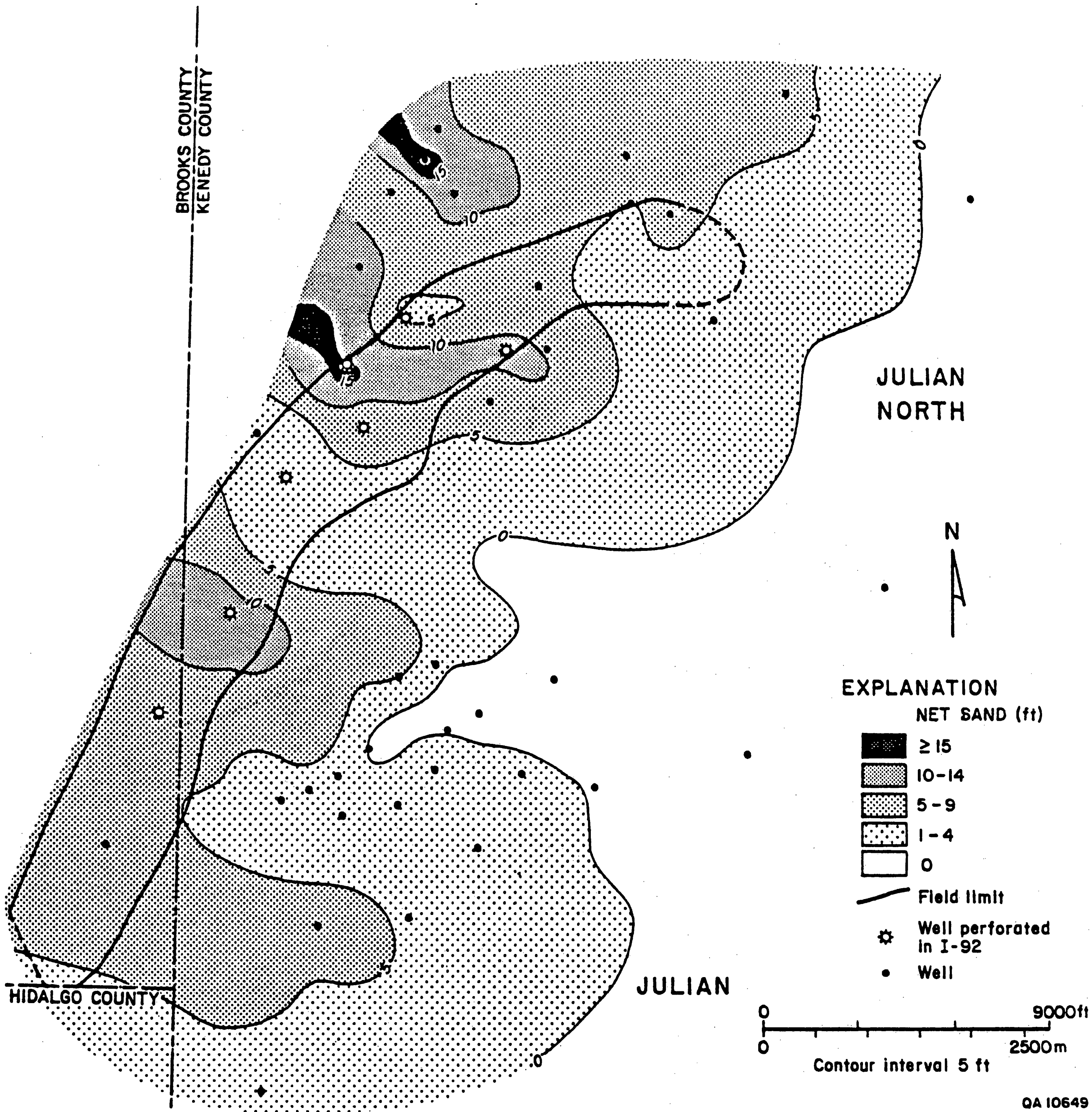


Figure 45. Net-sandstone-thickness map and reservoir limit of the I-92 nonassociated gas reservoir in Julian North and Julian fields. Dip-parallel sandstones, more than 10 ft thick, represent distributary channels merging downdip with a continuous sandstone sheet (0 to 5 ft thick) deposited in a wave-reworked delta-front environment.

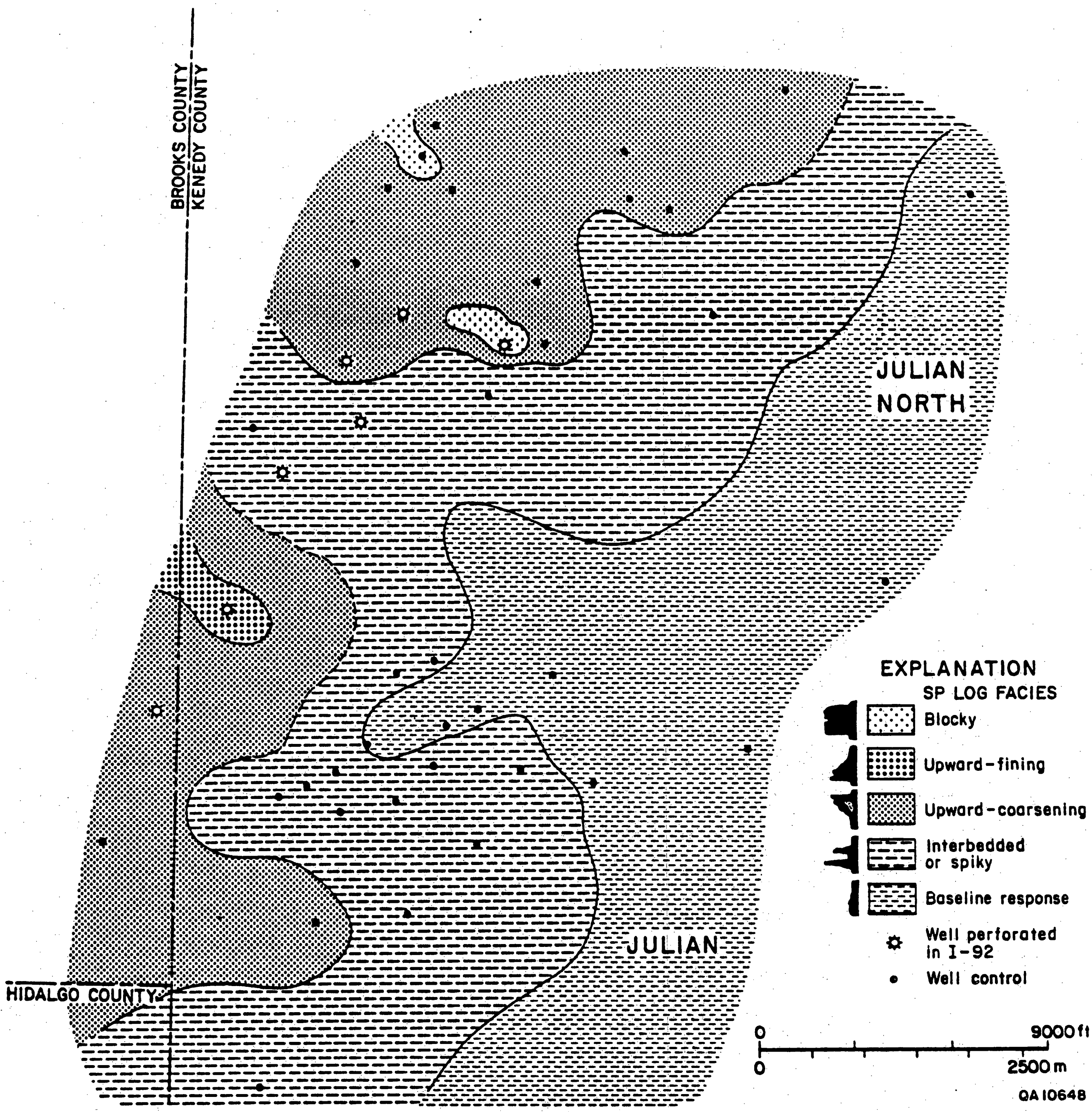


Figure 46. SP-log facies map of the I-92 nonassociated gas reservoir in Julian North and Julian fields. This wave-modified deltaic reservoir consists of a system of narrow, dip-parallel distributary channel sandstones characterized by a blocky SP response, merging downdip with a strike-parallel delta-front sandstone sheet defined by upward-coarsening and spiky SP-log responses.

have been acidized to increase production. A thick sand is present in the southernmost well in the reservoir, and the deep resistivity on the geophysical log indicates a gas show. The region around this well has the best potential for yielding additional gas; it lies along strike of the sandstone sheet that comprises the reservoir. Because of the young age of this field compared with that of La Gloria, the I-92 reservoir may not be developed to its full potential under primary recovery conditions, which may include completion of the southernmost well in the reservoir. Additional gas may be trapped in heterogeneities caused by diagenetic variations, but according to facies maps alone, the reservoir sandstone is relatively continuous and there are few opportunities for infill drilling into partially isolated compartments. High sandstone-body continuity is to be expected in this type of deltaic reservoir.

The question of advanced recovery is judged to be more one of approach in siting the additional and most recent wells. Placing new wells structurally downdip in a low-permeability, stratigraphically controlled trap in the I-92 reservoir represents an approach beyond that of current practice.

Facies continuity

The reservoir/seal type of facies analysis was also made for three Julian reservoirs (fig. 47). Because these reservoirs exhibit both strike and dip net-sandstone-thickness patterns, strike and dip data were combined. Continuity of Julian delta-distributary and barrier-bar facies is much higher than fluvial Jim Wells facies, even in reservoirs that exhibit cross-cutting tidal channel or digitate log patterns (fig. 42). Wells drilled at less than 160-acre spacing in the Julian field area are likely to contact mostly directly interconnected reservoir compartments.

Calculation of reserve growth factor

Comparison of gas volumes derived from volumetric methods with those from material balance methods was performed for the I-92 reservoir in the same way as was done for the Brooks reservoir. Pressure-decline analysis results in a material balance original gas-in-place

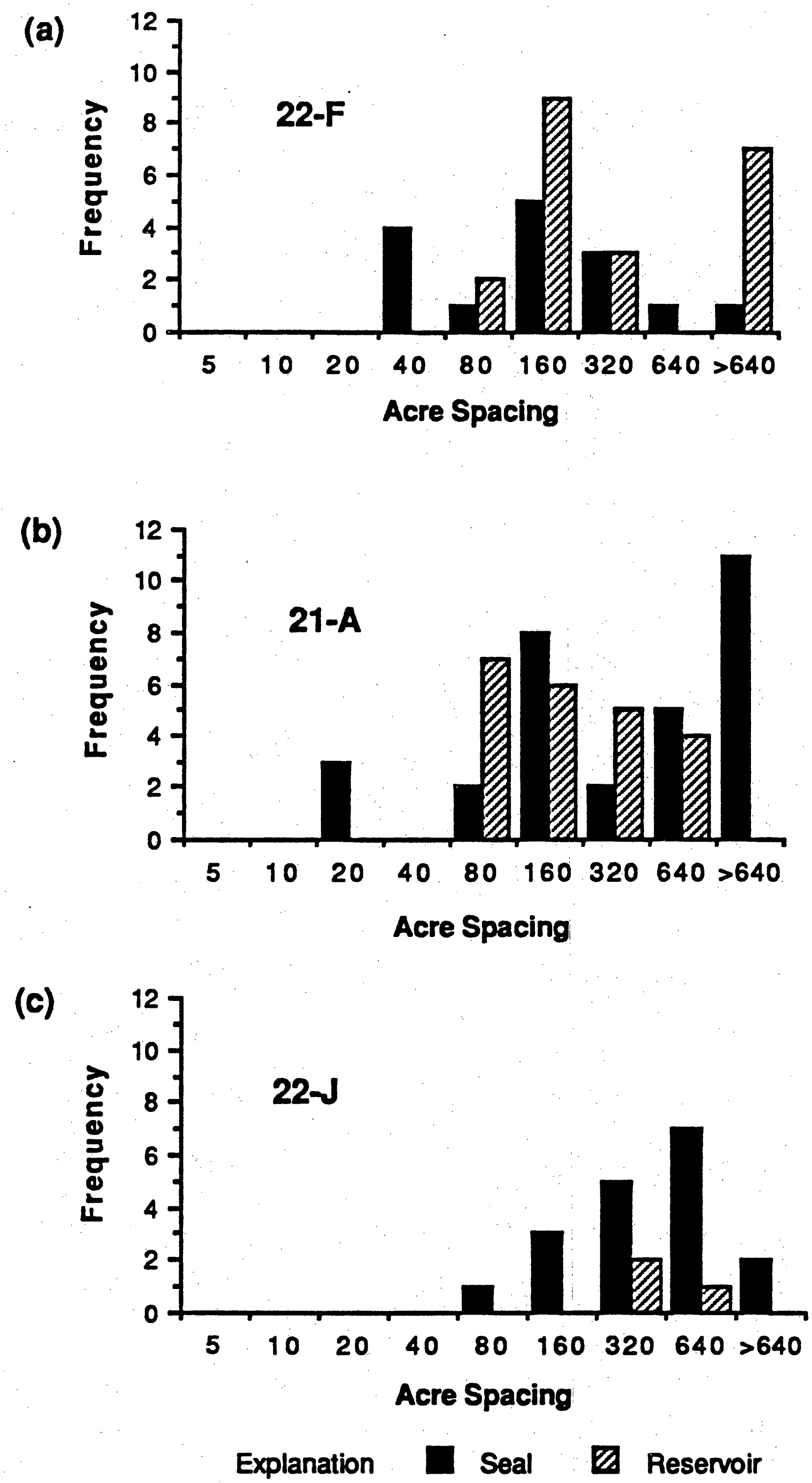


Figure 47. Width, or continuity, of isolated reservoir and seal facies for the 22-F (a), 21-A (b), and 22-J (c) reservoirs in Julian and Julian North fields measured along the strike and dip directions. Data indicate that continuity is high; reservoir compartments can be effectively contacted by wells spaced at 640 to 160 acres.

estimate of 20.7 Bcf (fig. 48). The volumetric estimate for the I-92 reservoir is 25.5 Bcf, discussed below. The target gas volume is 4.8 Bcf, or 23 percent of original gas in place in pressure contact with existing wells. Although the relatively laterally continuous facies in the I-92 reservoir indicate a high degree of connectedness between reservoir sandstones, the cross-cutting relations of the distal channel facies may create some reservoir compartmentalization, providing a target for gas reserve growth. In addition, lower permeabilities than reservoirs in La Gloria field may limit the drainage radius of some wells.

Estimate of potential for gas reserve growth

The I-92 reservoir of the Julian North field is geometrically representative of the Frio deltaic play and is thus characterized by a depositional and structural style that is distinct from Frio fluvial reservoirs. Comparison of the estimates of natural gas reserve growth of the three reservoirs studied, therefore, adds to the understanding of factors that influence the magnitude of reserve additions from infill drilling.

Production and development history

The first well in the I-92 reservoir was drilled and completed in October 1974, but production did not begin until May 1975. Since 1975, five wells have produced 15.3 Bcf of gas and 220 million barrels of condensate from the I-92 sandstone. The first production well designated in the Frio 9300 sandstone also began producing in May 1975. The cumulative gas and condensate production from the two wells in the Frio 9300 sandstone are 1.6 Bcf and 17.7 million barrels, respectively. The total gas and condensate production through May 1988 from the combined I-92–Frio 9300 reservoir, therefore, is 16.9 Bcf of gas and 237.7 million barrels of condensate.

Since discovery, the I-92 reservoir has been produced under pressure depletion drive. The I-92 reservoir has been operated under proration, in which the producing wells were assigned an allowable that limited the maximum production rate to 25 percent of the annual adjusted

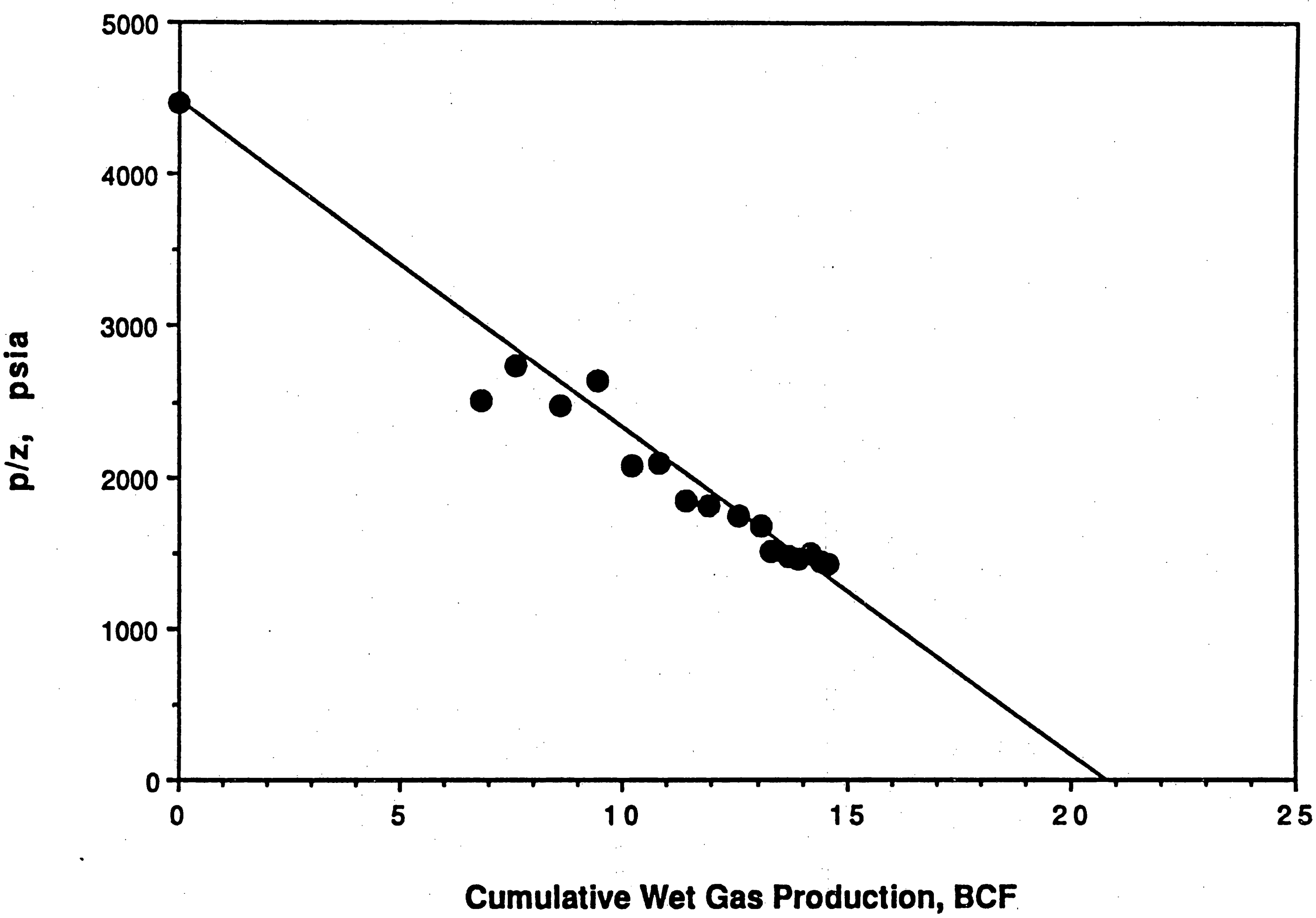


Figure 48. Pressure decline plot for the I-92 reservoir, Julian North field. Material balance estimate of original gas in place in this reservoir is 20.7 Bcf. P = average reservoir pressure; z = compressibility factor for natural gas.

absolute open-flow potential, although most wells have been produced at rates less than their allowable. Production and development statistics for the I-92 reservoir are summarized in table 15.

Data sources

The data sources analyzed for the estimates of gas in place and the productive capacity for the I-92 reservoir are the same as those used for the Brooks and Jim Wells reservoirs, except that operator-supplied data were not available.

Estimates of key reservoir properties

Data from the above sources were reviewed and analyzed to estimate key reservoir properties (table 16). Unlike the Brooks and Jim Wells reservoirs, produced gas from the I-92 reservoir was not reinjected into the reservoir under a gas cycling program. Therefore, the terms "initial conditions" and "original gas in place" refer to those existing at reservoir discovery.

Average and facies-specific reservoir properties

The reservoir properties for the five facies types of the I-92 reservoir were assessed by integrating the geologic maps, geophysical logs, and core data. Facies-specific permeability, porosity, and water saturation were calculated from individual well logs and core analyses, and the geologic maps provided information on the distribution and thickness of the facies types.

The analysis shows that the three productive facies constituting the I-92 reservoir (distal channel, reworked delta front, and distal delta front) are similar in the basic engineering properties controlling gas recovery. Permeability ranges from 4 to 27 md, porosity from 15 to 22 percent, and water saturation from 28 to 39 percent. Table 16 summarizes the reservoir properties by facies type.

Table 15. Production and Development Statistics for the I-92 Reservoir, Julian North Field.

Development History

- First production in May 1975
- Seven wells have produced from the reservoir
- Reservoirs produced by pressure depletion since discovery
- Wells produced at maximum of 25 percent open-flow rate

Production History

- Initial Producing Gas-Liquid Ratio (Scf/BBL): 20,000–30,000
- Current Producing Gas-Liquid Ratio (Scf/BBL): >90,000
- Cumulative Gas Production to May 1988 (Bcf): 16.9
- Cumulative Condensate Production to May 1988 (MB): 237.7

Table 16. Key Reservoir Data Summary for the I-92 Reservoir, Julian North Field.

Average Reservoir Properties

Area:	2,645 acres
Average Net Sandstone Thickness:	7.0 feet
Bulk Volume:	18,568 acre-feet
Average Porosity:	20 percent
Connate Water Saturation:	31.6 percent
Depth:	9,200 feet
Reservoir Temperature:	227°F
Initial Reservoir Pressure (1974):	4,300 psia
Current (1988) Reservoir Pressure:	850 psia
Dry Gas Specific Gravity:	0.65 (Air = 1.0)
API Gravity of Condensate:	62 degrees
Initial Gas Formation Volume Factor:	0.004343 Rcf/Scf
Estimated Gas In Place at Discovery:	25.5 Bcf
Average Absolute Permeability:	16.3 md

Facies-Specific Reservoir Properties

Facies Type	Effective Permeability to Gas (md)	Porosity (%)	Water Saturation (%)
Channel Sand	27	22	33
Point Bar Sand	24	15	28
Proximal Splay	18	17	39
Distal Splay	4	21	30
Floodplain	0.1 to 1.0	—	—

On average, the I-92 reservoir has low to moderate permeability (16.3 md), although not low enough to significantly impede gas flow. Average gas-filled porosity is 20 percent. The bulk volume of the reservoir was estimated at 18,568 ft by planimetering the net-sandstone-thickness maps. Reservoir area is 2,645 acres, and average productive sandstone thickness is only 7.0 ft. The initial pressure of the I-92 reservoir was 4,300 psia. Since discovery, the average reservoir pressure has declined to 850 psia (1988).

Original gas in place

The original gas in place (OGIP) for the I-92 reservoir was calculated using the methodology established for the analysis of the Brooks reservoir. The OGIP was derived from average reservoir properties and initial reservoir pressure and temperature (table 16). Since detailed gas composition data were not available for the I-92 reservoir, the initial formation volume factor was calculated using standard industry correlations (Craft and Hawkins, 1959). From these calculations, the OGIP was estimated at 25.5 Bcf.

Gas contact function for the I-92 reservoir

The development of a gas contact function for the I-92 reservoir followed the same methodology previously discussed for the Brooks reservoir. The application of the methodology and the results of the analysis are presented below.

Since discovery, the I-92 reservoir was produced for two periods characterized by relatively constant well spacing. From 1974 through 1979, four wells produced at an average reservoir-wide well spacing of 661 acres per well. As shown in figure 49, these four wells were concentrated in the northern tip of the reservoir. Due to subsequent drilling of two development wells in the southern part of the reservoir, the reservoir was produced at a closer average reservoir-wide well spacing of 441 acres per well from 1980 through the end of 1983.

As in the Brooks reservoir analysis, the production-decline type curves developed by Fetkovich (1980) were used to analyze the individual well production histories of the wells

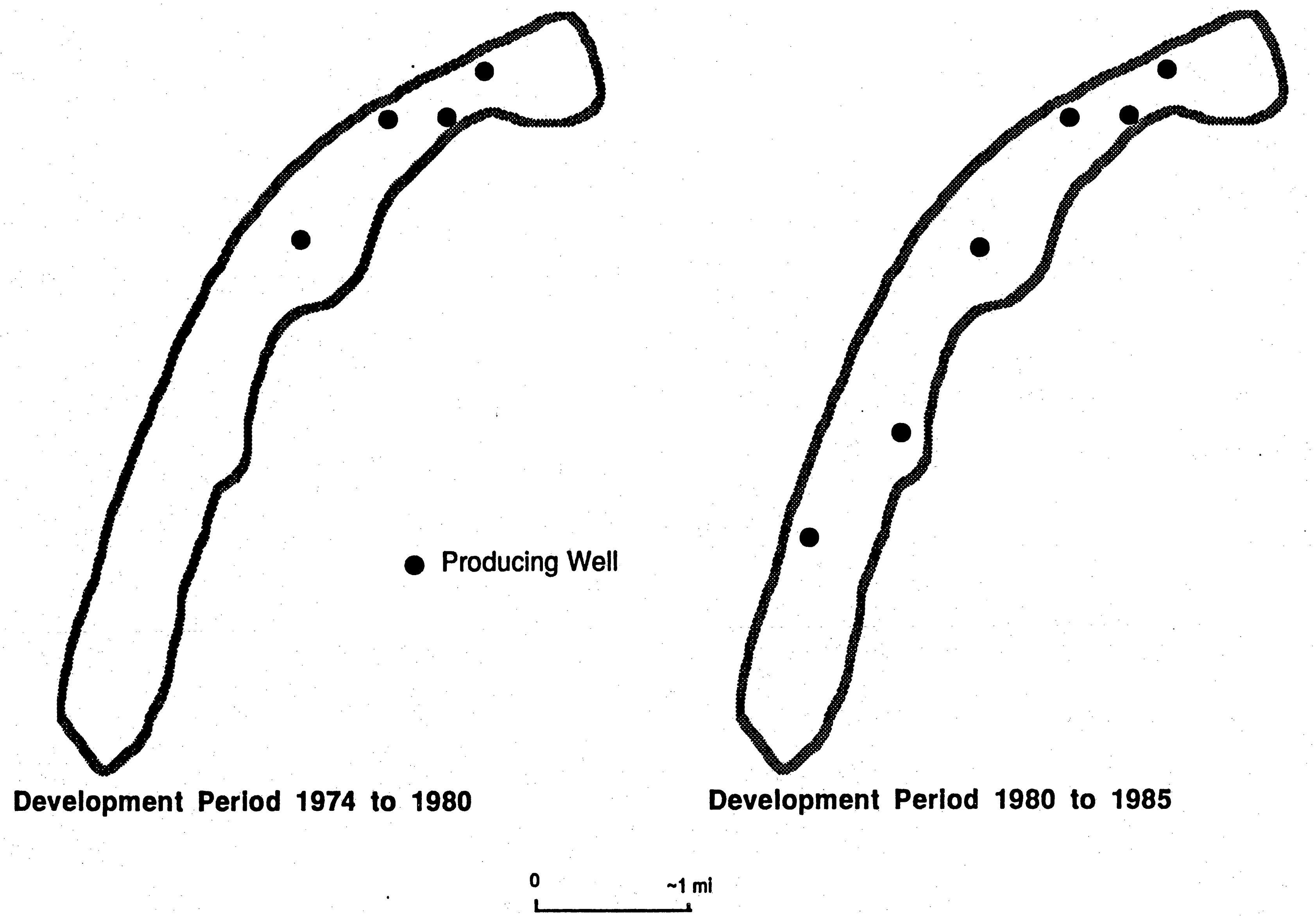


Figure 49. Reservoir development history of the I-92 reservoir, 1974 to 1985.

drilled in the I-92 reservoir. For each of the four wells producing during the first development time period (1974 to 1979), the ultimate gas contacted was calculated by adding the cumulative production and the estimated gas in place remaining in the drainage area. The individual well estimates for ultimate gas contact were summed to derive total gas contacted at the calculated well spacing (661 acres per well) during this first development time period. The process was repeated for each of the six wells producing during the second development time period (1980 to 1983).

For the first development time period, 62.4 percent of OGIP was contacted at a well spacing of 661 acres per well. The drilling of two development wells to reduce the well spacing to 441 acres per well during the second development time period contacted an incremental 24.7 percent of OGIP, bringing the total contacted gas to 87.1 percent of the OGIP (table 17).

The two data points derived from the analysis were plotted against interwell distance, and straight line segments were used to develop a function to relate gas contact as a percentage of original gas in place to interwell distance. This function (fig. 50) was based on two assumptions:

1. 100 percent contact would be achieved at an infinitely small interwell distance (effectively zero on the abscissa).

2. No critical interwell distance was assumed to be present in the I-92 reservoir. This is because the facies are relatively continuous with low depositional heterogeneity at the developmental scale. Thus, the function was assumed to slope steadily to 100 percent. This is a different approach from the facies size cutoff used in La Gloria field, where facies are discontinuous and there is relatively high depositional heterogeneity.

Discussion of the gas contact function

The gas contact function for the I-92 reservoir is shown in figure 50 and is tabulated for typical well spacings in table 18. At an average reservoir-wide well spacing of 640 acres per well (5,280 feet of interwell distance), 64.5 percent of the OGIP is contacted by the producing wells. A

Table 17. Summary of Results of Assessment of Reservoir Heterogeneity for the I-92 Reservoir, Julian North Field.

Development Period One: 1974–1979

• Total Number of Production Wells:	4
• Reservoir Area:	2,645 acres
• Average Well Spacing:	661 acres/well
• Average Interwell Distance:	5,366 feet
• Original Gas In Place:	25.5 Bcf
• Cumulative Gas Production to 1980:	9.6 Bcf
• Total Estimated Ultimate Gas Contacted:	15.9 Bcf
• Ratio of Gas Contact to OGIP:	62.4 percent

Development Period Two: 1980–1983

• Total Number of Production Wells:	6
• Reservoir Area:	2,645 acres
• Average Well Spacing:	441 acres/well
• Average Interwell Distance:	4,383 feet
• Original Gas In Place:	25.5 Bcf
• Cumulative Gas Production to 1984:	14.9 Bcf
• Total Estimated Ultimate Gas Contacted:	22.2 Bcf
• Ratio of Gas Contact to OGIP:	87.1 percent

Table 18. Reservoir Contact as a Percentage of Original Gas In Place for the I-92 Reservoir, Julian North Field.

Well Spacing	Reservoir Contact		Incremental Contact	
(acres/well)	(% OGIP)	(Bcf)	(% OGIP)	(Bcf)
640	64.5	16.4	—	—
320	88.0	22.4	23.5	6.0
160	92.5	23.6	4.5	1.2
80	94.5	24.1	2.0	0.5
very small	100.0	25.5	5.5	1.4

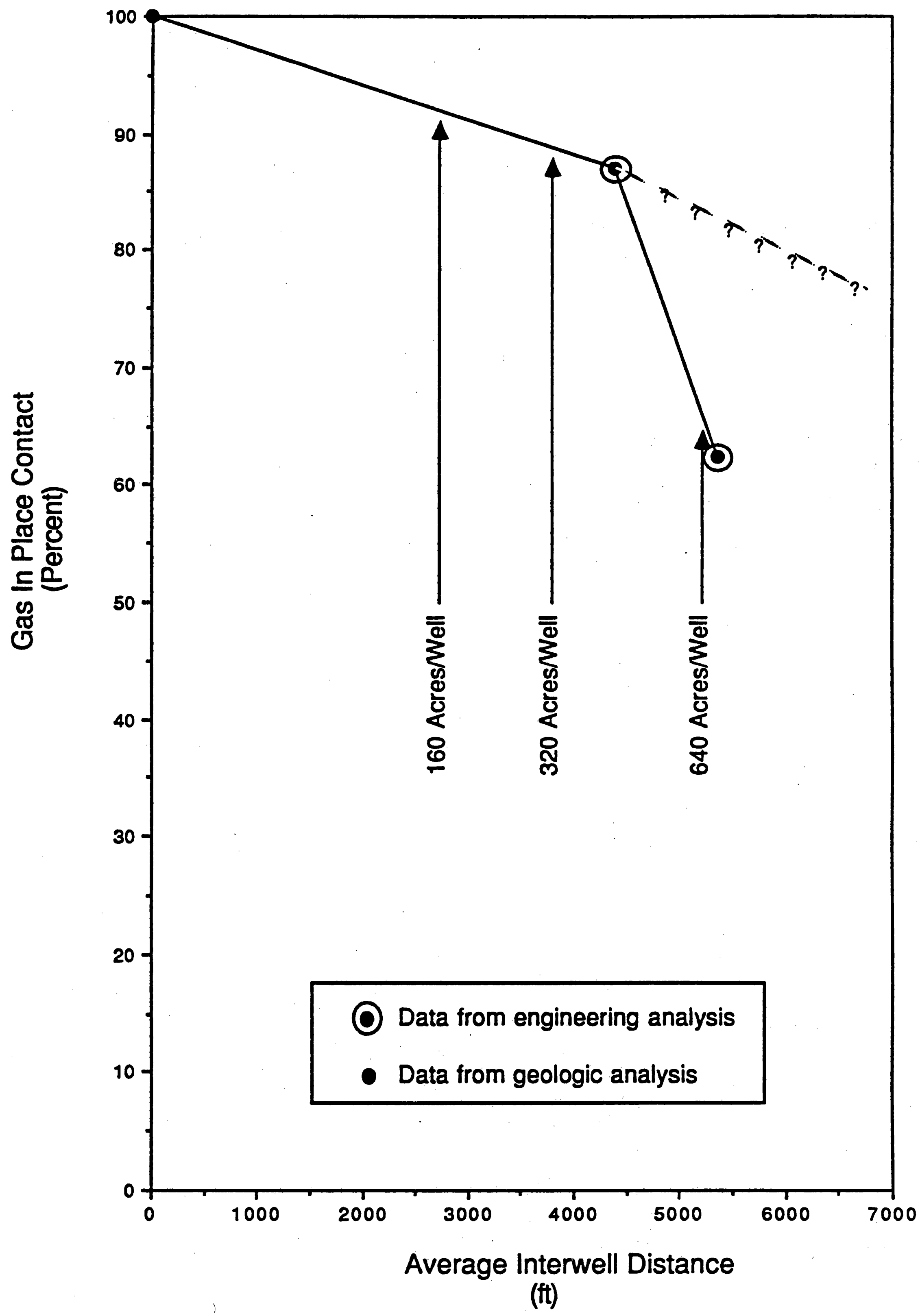


Figure 50. Incremental gas contact function for the I-92 reservoir. Data from the engineering analysis include well spacings of 661 acres per well and 441 acres per well.

decrease in the average reservoir-wide well spacing to 320 acres per well (3,374 ft of interwell distance), contacts an incremental 23.5 percent of the OGIP. This contrasts sharply with an additional reservoir-wide decrease in well spacing to 160 acres per well (2,640 ft of interwell distance), which contacts only 4.5 percent of incremental gas. The total reservoir contact at 160 acres per well is 92.5 percent of the OGIP. The gas contact function, therefore, indicates that infill drilling in this type of depositional setting contacts the bulk of incremental gas available for infill wells with a well spacing decrease of 640 to 320 acres per well.

The relatively high estimates of percentage of OGIP available for infill wells at 320-acre spacing may partially be caused by the development history of the I-92 reservoir. Initially, four wells were concentrated in the northern portion of the I-92 reservoir. The calculated well spacing for the reservoir during this period is 661 acres per well (reservoir area of 2,645 acres divided by four wells). However, if these wells had been evenly spaced over the extent of the reservoir, the initial reservoir contact would have been higher (due to reduced well interference effects) at the same calculated average reservoir-wide well spacing. The resulting gas contact function would predict larger volumes of gas contacted and recovered at initial development well spacings (e.g., 640 acres per well), with corresponding smaller volumes of additional gas available for infill wells. The probable shape of the gas contact function for wells drilled evenly over the reservoir is shown by the dashed line in figure 50. Thus, this analysis of the I-92 reservoir shows that well placement is an important factor in predicting volumes of gas available for infill wells and points to difficulties in the interpretation of average well spacing when existing wells are concentrated in a small part of the field.

<u>Estimate of technically recoverable gas</u>

The data and the results of the analysis of the I-92 reservoir used to estimate technically recoverable gas from infill drilling are discussed below. The details of the methodology are given in the Brooks reservoir discussion.

The I-92 reservoir has an areal extent of 2,645 acres. This surface area was divided into four approximately equal 640-acre grids (fig. 51). The detailed facies maps developed for the geologic model were used in combination with the net-sandstone-thickness maps to calculate reservoir properties for each grid (fig. 52). The average reservoir properties for the four grids show a slight trend toward better reservoir quality moving from north to south: permeability ranges from 11.0 to 19.3 md, porosity from 18 to 21 percent, and water saturation from 30 to 35 percent. Net sandstone thickness ranges from a high of 8.7 ft in Grid 3 to a low of 5.7 ft in the northernmost Grid 1. Based on the original reservoir pressure and temperature, an average gas formation volume factor of 0.004343 Rcf/Scf was estimated for the entire reservoir.

Using the data developed above, the original gas in place was calculated by grid (fig. 53). The gas in place ranges from a high of 12.5 MMcf/acre to a low of 7.6 MMcf/acre. The area of highest gas in place is in Grid 3. Although porosity, permeability, and water saturation show slight increases in this grid, the factor with the greatest influence, having the highest percentage of increase, is net sandstone thickness.

The reservoir contact function developed for the I-92 reservoir was used to estimate the incremental gas available for infill wells. For each grid, the percentages derived from the gas contact function were multiplied by the volumetric gas in place to assess the gas available for an infill well at a specific well spacing. For example, a decrease in well spacing from 640 to 320 acres results in an incremental contact of 23.5 percent of OGIP. This percentage was multiplied by the grid-specific gas in place to calculate the incrementally available gas. The incremental gas available in the I-92 reservoir for a decrease in well spacing from 640 acres per well to 320 acres per well is shown in figure 54. This shows that the largest volumes of incremental gas, coincident with the highest values of net sandstone thickness, are available in the south (Grids 3 and 4).

The question remains whether the addition of wells in the southernmost two grids represents conventional practice or actual infill drilling targeted toward incremental unrecovered resources. Given a structurally low position of the wells, the probable

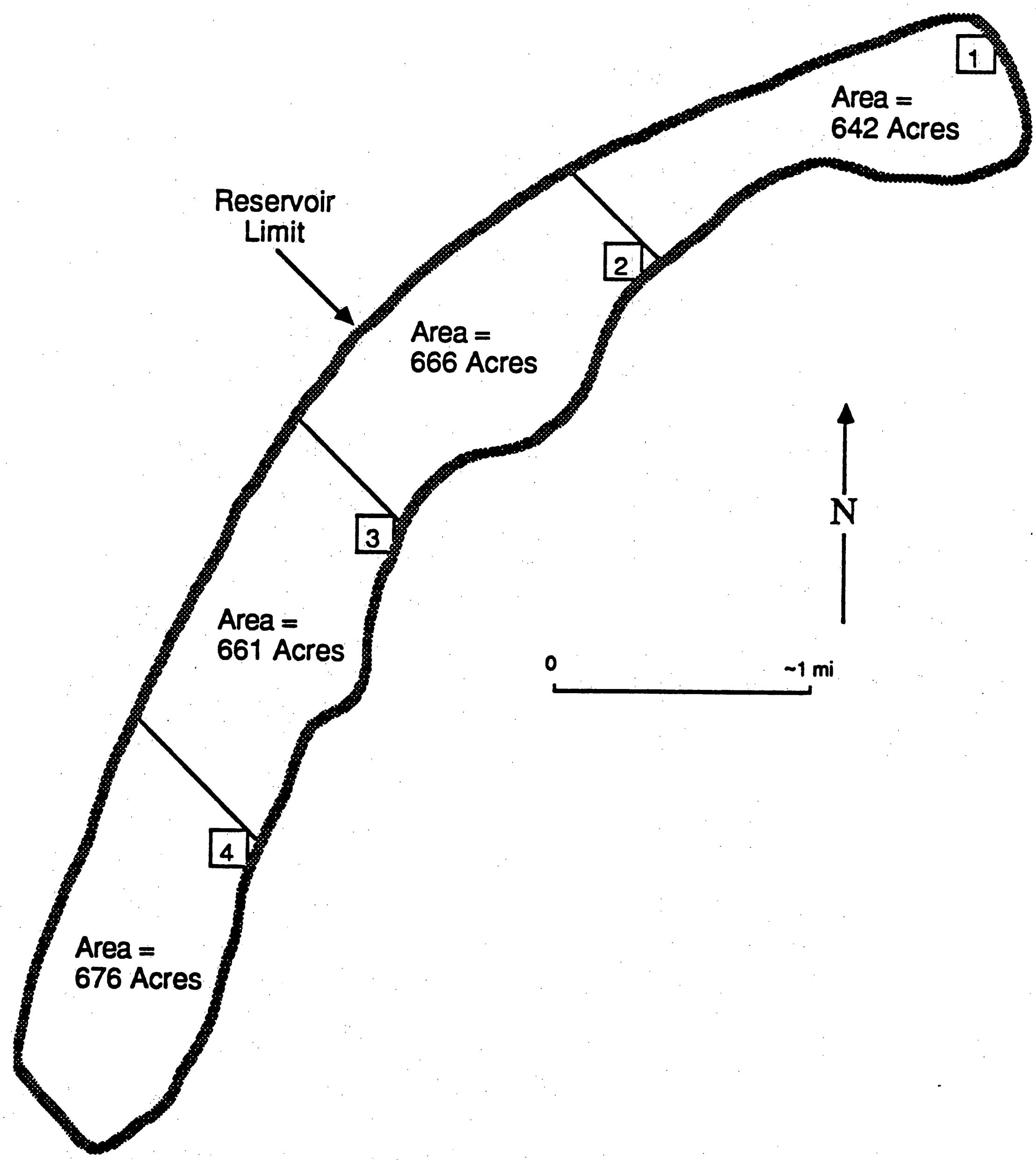


Figure 51. Grid divisions used in the well production model of the I-92 reservoir. Four grids were used, approximating 640-acre spacing. Grid numbers in this and all subsequent figures are shown in the upper right corner of each grid.

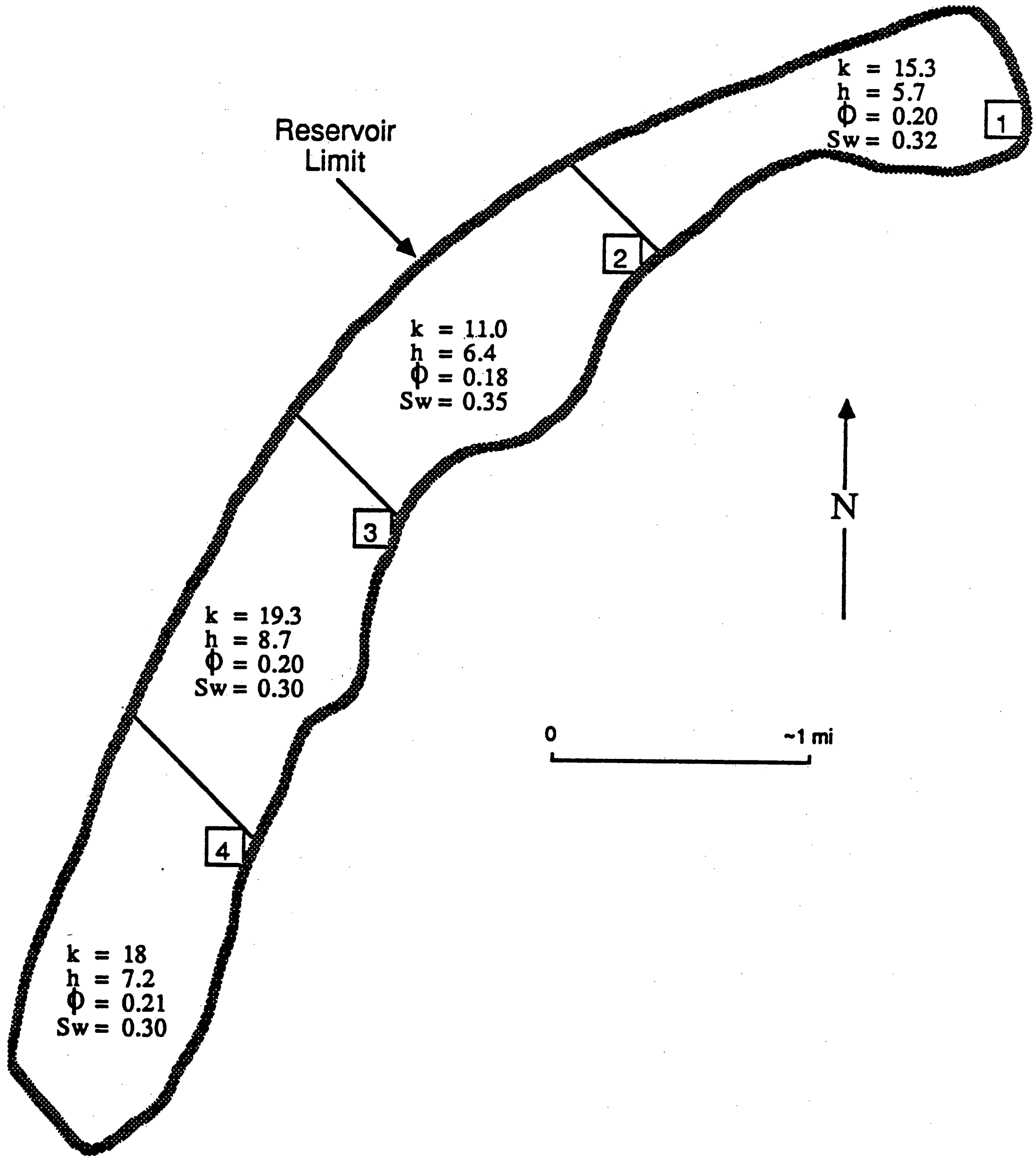


Figure 52. Average grid-specific reservoir properties of the I-92 reservoir at 640-acre grid spacing. Symbols include k, permeability in millidarcys; h, net sandstone thickness in ft; ø, fractional porosity; and S_w, fractional connate water saturation.

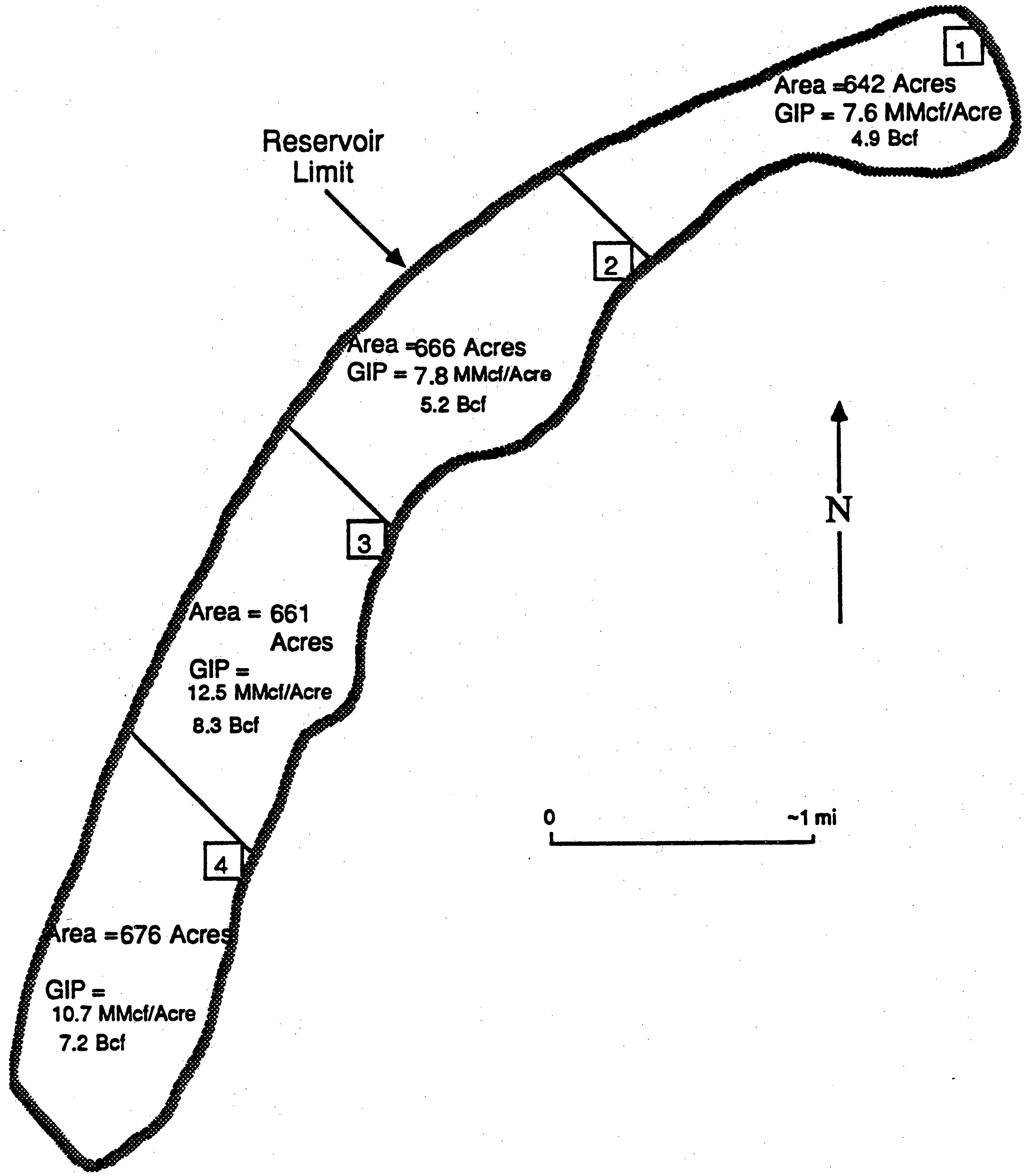


Figure 53. Original volumetric gas in place in the I-92 reservoir. Initial reservoir pressure is estimated at 4,300 psia.

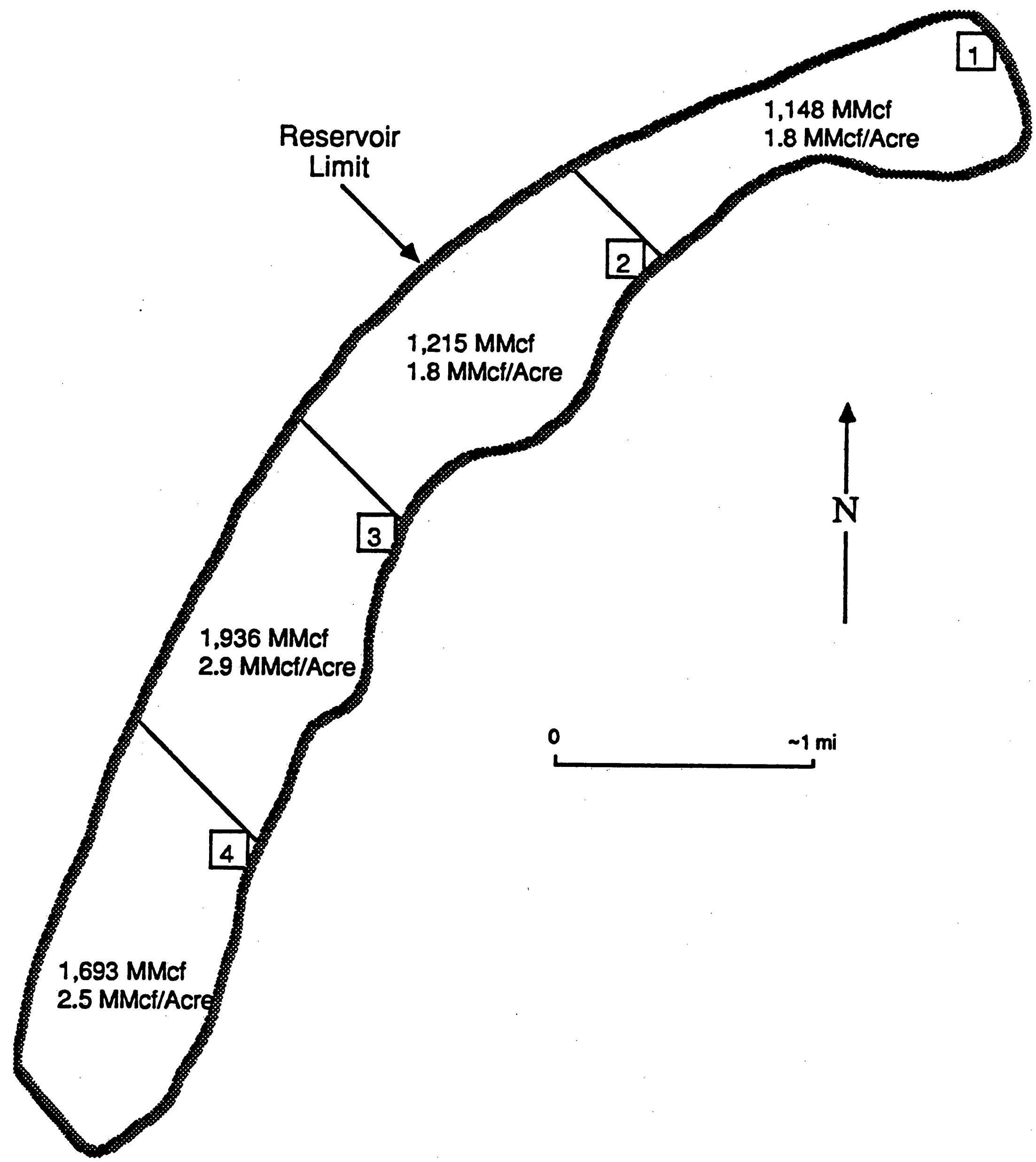


Figure 54. Calculated incremental available gas in the I-92 reservoir for infill drilling from 640- to 320-acre spacing at a reservoir pressure of 4,300 psia.

stratigraphic character of the trap, and lower permeability of the reservoir, the drilling of these wells probably represents development concepts beyond conventional practice. The unusual shape of the reservoir area argues against defining these wells as strategically directed infill wells. However, the existence of these wells and their timing late in the period of development may allow the I-92 reservoir to be used as an example of the incremental contact that can occur with the addition of such wells.

The results of the analysis are presented in table 19 for the four grids in the I-92 reservoir. The volume of technically recoverable incremental gas available in each grid is shown for two infill development strategies—reductions in well spacing from 640 to 320 acres per well and from 320 to 160 acres per well. Based on an original gas in place of 25.5 Bcf and a reservoir pressure at the time of infill drilling of 50 percent initial reservoir pressure, the analysis shows that infill drilling in the I-92 reservoir from an initial development pattern of 640 acres per well to 320 acres per well could recover an additional 4.7 Bcf of natural gas. This represents 78 percent of the incrementally contacted gas of 6.0 Bcf. Further infill drilling to 160 acres per well recovers 1.0 Bcf of the 1.2 Bcf of additionally contacted gas. Infill drilling the two southernmost grids (Grids 3 and 4) would recover the largest volumes of incremental gas, representing nearly two-thirds of the total amount recovered from infill drilling in all four grids.

Conclusions

The geologic analysis of the I-92 reservoir in the Julian North field demonstrates the high sandstone-body continuity that is expected in this type of deltaic reservoir. Diagenetic variations may trap gas additional to that obtained in traditional development practice, but based on facies maps alone, there are few opportunities to complete in partially isolated compartments. The engineering analysis shows that infill drilling can add gas reserves in the deltaic depositional setting. Because of the high sandstone-body continuity, however, most of

Table 19. Technically Recoverable Incremental Gas (MMCF) from Infill Drilling, I-92 Reservoir, Julian North Field.

	Grid Identification Number* 1	2	3	4	Reservoir Total
Volumetric Gas in Place	4,885	5,169	8,237	7,205	25,496
Total Gas Contact at 640 Acres/Well	3,151	3,339	5,313	4,647	16,450
Development Strategy 640 to 320 Acres/Well (One Infill Well)					
Incremental Gas Contact	1,148	1,215	1,936	1,693	5,992
Technically Recoverable Incremental Gas	898	957	1,520	1,327	4,702
Development Strategy 320 to 160 Acres/Well (Two Infill Wells)					
Incremental Gas Contact	220	233	371	324	1,148
Technically Recoverable Incremental Gas	199	205	340	294	1,038

* See Figure 54 for grid location.

the reservoir is contacted at moderate (320-acre) well spacing. Technically recoverable incremental gas amounts to 6.0 Bcf at 320-acre spacing and 1.0 Bcf at 160-acre spacing.

Additionally, the I-92 reservoir provides an example of the importance of field development on gas reserves. The I-92 reservoir was originally developed at an average reservoir-wide well spacing of 661 acres per well; however, the producing wells were concentrated in the northern part of the reservoir. If the wells had been spaced more evenly across the reservoir, the initial gas contact would have been greater (as shown in fig. 50) due to decreased well interference effects and corresponding greater per-well drainage areas. Thus, the analysis of the I-92 reservoir indicates that gas contact can be improved (and reserves maximized) by the timing and location of well placement (i.e., well placement strategies). Indeed, in more laterally continuous deltaic reservoirs, it would be expected that efficient drainage could be achieved at the outset with relatively widely spaced wells.

Conclusions of Detailed Reservoir Studies

The goal of this work was to understand reservoir heterogeneities and compartmentalization in gas fields as an initial basis to assist in developing techniques to add gas reserves through infill drilling. Detailed geologic analyses were combined with an initial methodology for estimating gas contacted by infill wells to provide estimates of natural gas reserve growth from infill drilling in fluvial and deltaic Frio reservoirs.

The first step of the methodology involved detailed geologic mapping of sandstone thickness and distribution of facies types in a reservoir, and identification of geologically located infill completion prospects. The second step combined the facies-specific reservoir properties and net-sandstone-thickness data with well-by-well reservoir engineering analyses to estimate the volume of gas that is contacted by wells. From this, an empirical function was developed to relate well spacing and interwell distance to reservoir contact. Reservoir modeling was used to estimate the volume of recoverable gas at 320- and 160-acre well spacings.

The combination of geologic and engineering analyses provides an integrated approach to identification of gas reserve growth potential. Net-sandstone-thickness and log-facies maps identify partially or totally isolated pockets of gas, and the existence of this additional gas is suggested by the reservoir engineering analyses.

Applying this methodology to the Brooks and Jim Wells reservoirs of La Gloria field and the I-92 reservoir of the Julian North field demonstrates that more intensive reservoir development can appreciably improve gas reserves. Facies-based (strategic) delineation of infill drilling prospects is appropriate in reservoirs with sufficient lateral and vertical heterogeneity. In reservoirs without significant heterogeneity, an optimum drilling strategy would target infill wells in areas of the reservoir having the greatest sandstone thickness. This can be inferred from the findings for the reservoirs studied, although the intent of the operator in drilling the wells studied was not explicitly investigated and was not necessarily strategic infill drilling.

Gas contact can be improved (and reserves maximized) by establishing more efficient well completion and placement strategies. The volume of gas initially contacted at wide (640 acres per well) well spacing is partially determined by well placement and pay zone completion relative to the distribution of facies types. Wells placed strategically as a result of full understanding of reservoir facies types and distribution will contact the greatest percentage of gas in place and will efficiently drain the partially isolated lower permeability facies.

This study found that gas reserve additions result from improved contact with components of the sandstone reservoir which are not effectively drained during the economic lifetime of a production well. These findings confirm the importance of flow restrictions and reservoir compartmentalization in gas reservoirs as factors in reserve growth. Although these geologic factors are equally important in oil reservoirs, the depletion-drive production mechanism in gas reservoirs implies different strategies than those used for oil reservoirs, where delineation of reservoir compartmentalization and sweep efficiency are the objectives for oil recovery through infill drilling.

More analysis is required to understand the correlation between geologic description and natural gas reserve growth. Because of the high mobility of gas and the interaction of geologic and development factors in controlling gas reserves growth, reserve growth analysis must be approached on the basis of an understanding of geologic reservoir heterogeneity, engineering analysis, and the additional information on reservoir geometry that can be provided by geophysical methods.

The methods developed to estimate gas reserve growth in these Frio reservoirs can be applied to other gas reservoirs. The results of this study demonstrate that reservoir analyses which integrate geologic description with specialized reservoir engineering modeling will best assess the effects of reservoir heterogeneity and well placement strategies on gas reserve growth.

ESTIMATE OF ASSOCIATED NATURAL GAS RESERVE GROWTH POTENTIAL

Introduction

Tyler and others (1984) and Fisher and Finley (1986) have demonstrated that 35 billion barrels of unrecovered mobile oil remain in existing reservoirs in Texas. This resource is beyond the amount reported as proved reserves for the State, which was 7.1 billion barrels in 1987. These estimates of unrecovered mobile oil were based on analysis of the geologic and engineering parameters of 450 oil reservoirs listed in Galloway and others (1983). Approximately one-half of the mobile oil and a considerable volume of associated gas remaining in these relatively mature reservoirs can be recovered chiefly through field extension and geologically based infill drilling (Fisher and Finley, 1986). In the onshore United States during the 1950's and 1960's, these development techniques contributed 66 percent of total reserve additions; from 1976 to 1986 the contribution has been 76 percent, and in mature Texas basins, 87 percent. In the complex reservoirs in the Permian Basin, which represented nearly 80 percent of the total Texas reserve additions from 1976 to 1986, extension and infill drilling have contributed 93 percent of this growth, compared with 6 percent from tertiary recovery projects over this same time period (Fisher and Finley, 1986).

Pressure and production data from many recent in-field development wells indicate that many oil and associated gas reserve additions in Texas have been from previously untapped or poorly drained reservoir compartments. Reservoir complexity and recovery efficiency are largely controlled by the three-dimensional facies framework, although diagenesis, existing well spacing, drive mechanism, and production practices are contributing factors (fig. 55).

Galloway and others (1983) divided the major oil reservoirs of Texas that had produced at least 10 million barrels to 1981 into 48 plays. Reservoirs in these plays share similar depositional setting, hydrocarbon source, and trapping style. Tyler and others (1984)

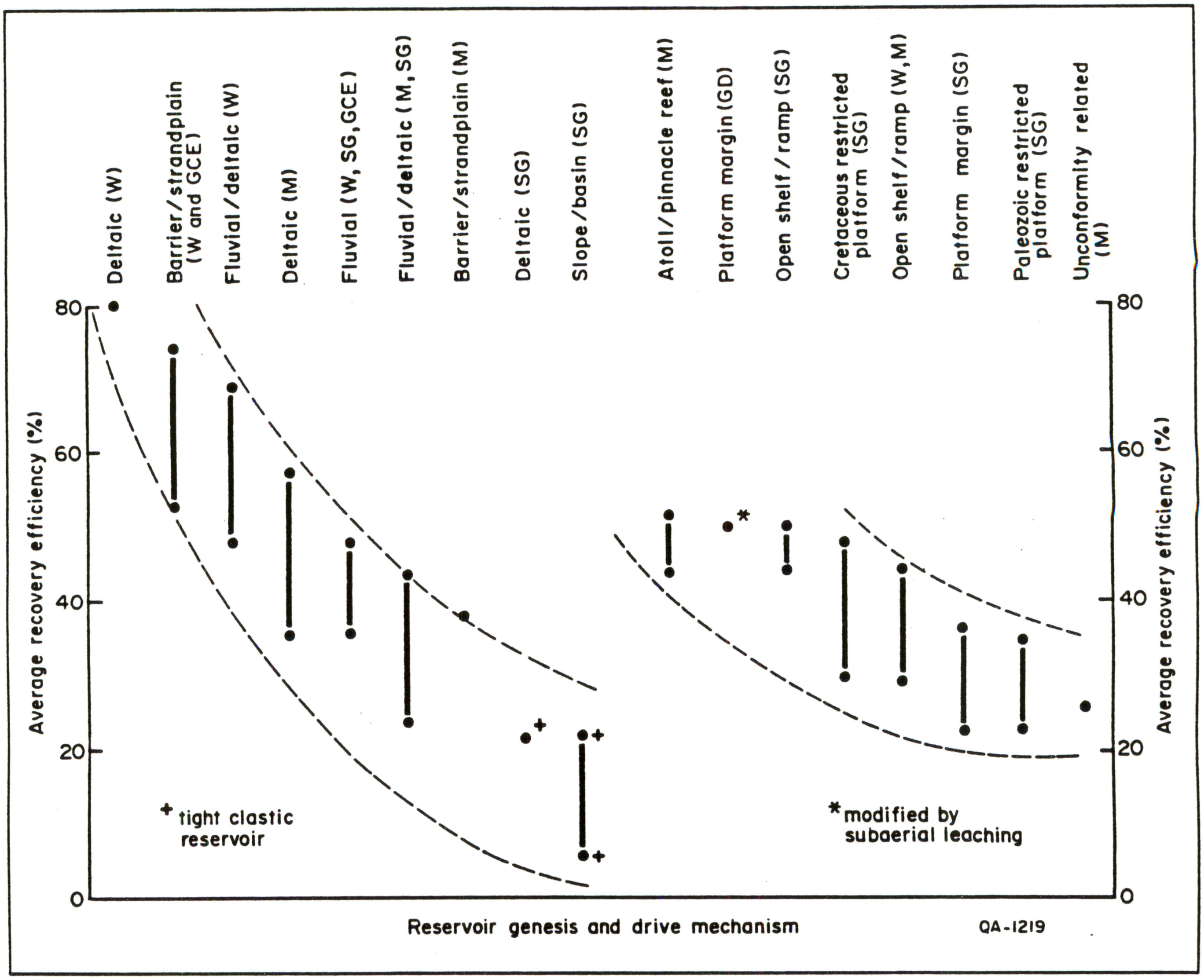


Figure 55. Recovery efficiency versus depositional systems and drive mechanism for major clastic and carbonate reservoirs in Texas. Drive mechanisms: W = water, GCE = gas-cap expansion, GD = gravity drainage, SG = solution gas, M = mixed (combination of W, GCE, and SG). From Tyler and others (1984).

calculated the remaining mobile oil resource in each of these plays on the basis of residual oil saturation, water saturation, estimated ultimate recovery, percentage of unrecovered oil, and original oil-in-place data and showed that the percentage of of unrecovered mobile oil in each of these plays could be related to depositional setting. Besides depositional setting, other factors contribute to remaining mobile oil resource, including current spacing, drive mechanism, traditional production practices, field unitization, and economic conditions.

Oil and Associated Gas Reserve Growth Potential of Important Texas Plays

Tyler and others (1984) and Fisher and Finley (1986) have demonstrated that most of the unrecovered mobile oil (23.7 billion barrels) and associated gas resource in Texas is in carbonate reservoirs in the Permian Basin, chiefly in restricted-platform deposits in plays such as the San Andres/Grayburg Carbonate in the Central Basin Platform (fig. 56). Restricted-platform deposits originated on shallow-water platforms under arid climatic conditions. Diagenesis of original sediments produced extensive beds of dolomite that typically exhibit low porosity and permeability values. These deposits are highly stratified and have low recovery efficiencies, resulting in large volumes of trapped oil that is unrecovered after primary and secondary operations.

The Gulf Coast region of Texas contains 4.6 billion barrels of unrecovered mobile oil and has the second highest reserve growth potential of oil-producing regions in the state (Fisher and Finley, 1986). The Frio barrier/strandplain play, an important play in the Gulf Coast, contains 46 reservoirs that collectively contain 4.2 billion barrels of original oil in place (fig. 57). Clastic barrier/strandplain systems are typified by well-sorted, laterally continuous sandstones. They exhibit high recovery efficiencies in massive barrier-core sandstones, although stratigraphic entrapment of oil can occur in tidal-inlet and backbarrier sandstones. In contrast with restricted-platform carbonates, which have an average recovery efficiency of

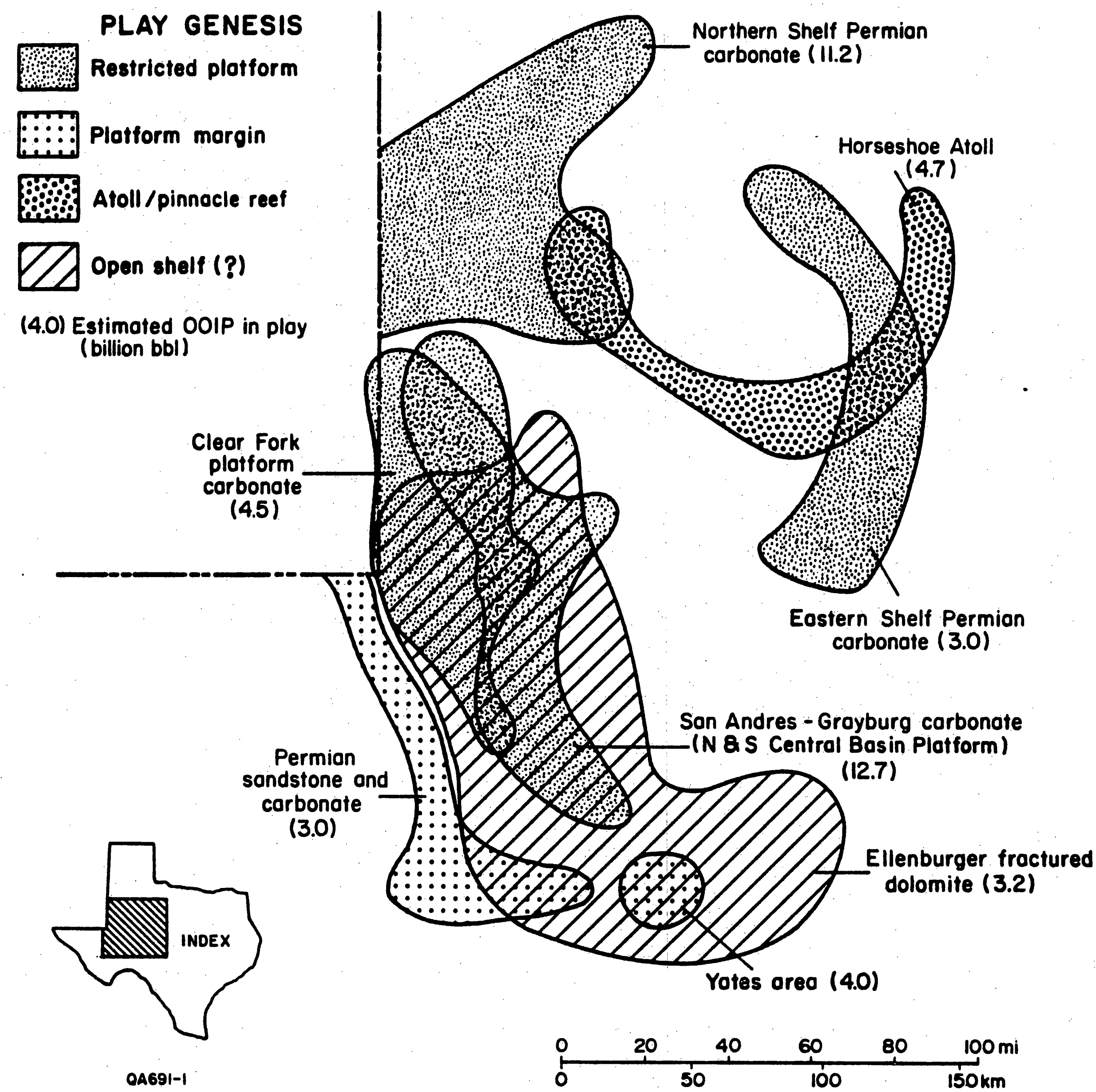


Figure 56. Major carbonate oil plays of the Permian Basin. Enormous volumes of oil have been concentrated in restricted-platform carbonates in the Central Basin Platform. From Tyler and others (1984).

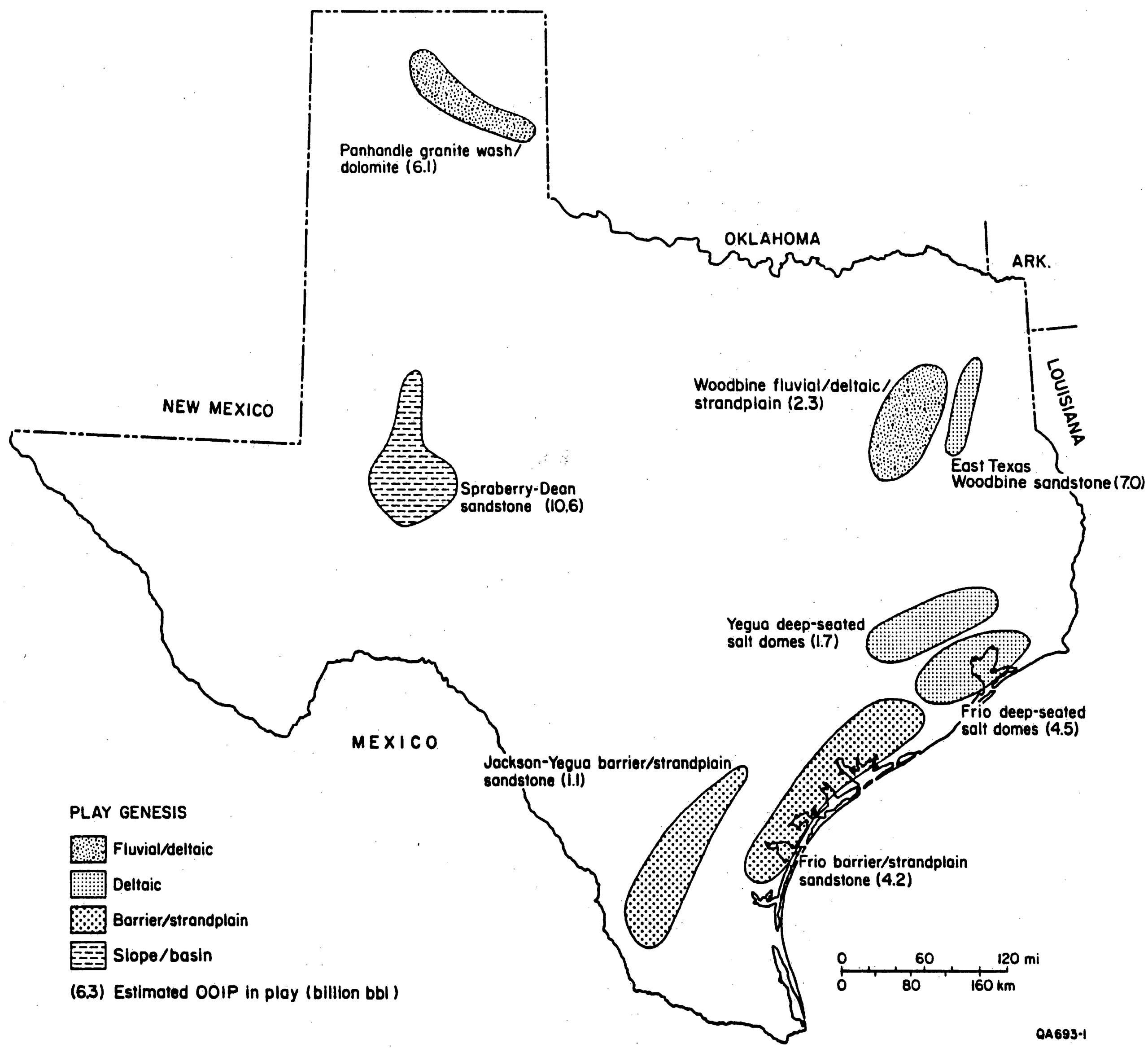


Figure 57. Main clastic plays of Texas that contain more than 1 billion barrels of OOIP. The Frio barrier/strandplain play is the largest of the 48 plays in Texas and contains 4.2 billion barrels of oil. Modified from Tyler and others (1984).

32 percent, barrier/strandplain reservoirs have a high average recovery efficiency of 50 percent (Tyler and others, 1984).

Oil and Associated Gas Reservoir Studies

Detailed geological and engineering studies were made of three reservoirs representative of the volumetrically important San Andres/Grayburg (South Central Basin Platform), Frio barrier/strandplain, and Clearfork Platform Carbonate plays in Texas. Reservoirs chosen for detailed study in these plays were Dune (Grayburg) in the San Andres/Grayburg South Central Basin Platform play, Robertson North (Clearfork) in the Clearfork Platform Carbonate play, and the West Ranch (41-A) reservoir in the Frio barrier/strandplain play. The purpose of these studies was to determine the amounts of oil and associated gas that can be economically recovered in each of these reservoirs by infill drilling. In each study, the reservoir analyzed in detail was assumed to be geologically analogous to the other reservoirs in the play and, by extrapolation, could provide a reasonable estimate of the economic potential of infill drilling in the play. The reserve growth potential of both blanket-infill drilling, where infill wells were drilled on a regular grid pattern to a minimum pattern spacing economically justified, and geologically based infill drilling, where wells are geologically targeted to the more productive portions of reservoirs, were determined for the Dune field, Section 15 (Grayburg), and for West Ranch (41-A) reservoir. Only a blanket-infill study was conducted for the Robertson North (Clearfork) reservoir, because Barbe and Schnoebelen (1987) had previously documented the geologic heterogeneity and performance of infill wells in the Robertson North (Clearfork) reservoir.

The oil and associated gas reserve growth potential of the Dune (Grayburg) and West Ranch (41-A) reservoirs through strategic, or geologically based, infill drilling was based on pay-continuity functions for each of the major facies in these reservoirs. The pay-continuity functions based on logs, cores, other geologic data, historical production data, and engineering analyses relate reservoir continuity to horizontal distance between existing well pairs.

Different methods, described in later sections of this report, were used to derive pay-continuity functions for the Dune (Grayburg) and West Ranch (41-A) reservoirs. These pay-continuity functions were used with volumetric and reservoir properties to estimate the amount of recoverable oil and associated gas in each reservoir.

Estimates of the recoverable oil and associated gas in the two plays (San Andres/Grayburg [South Central Basin Platform] and Frio barrier/strandplain) were projected from analyses of the Dune (Grayburg) and West Ranch (41-A) reservoirs, respectively. To determine the oil and associated gas recoverable through strategic infill drilling, these reservoirs were divided into their primary facies, and the volume of reservoir corresponding to each major facies was determined. Pay-continuity functions specific to each of these facies were developed. The determination of recoverable mobile oil remaining in each reservoir was made by weighting the fraction of each major facies in the reservoir and the pay continuity established for each facies.

San Andres/Grayburg (South Central Basin Platform) Play

Production History

The San Andres/Grayburg (South Central Basin Platform) play is the most productive of the three Texas plays that produce from the Upper Permian San Andres and Grayburg Formations. The other two plays are the North Central Basin Platform play and Ozona Arch play (fig. 58). These San Andres/Grayburg plays are some of the most prolific in Texas, and collectively contain over 15 billion barrels of oil and 6.3 Tcf of original associated gas in place (Galloway and others, 1983). Large volumes of unproduced oil and gas will remain in place in these reservoirs even after secondary recovery, thereby providing the incentive for strategic infill drilling to potentially increase reserves.

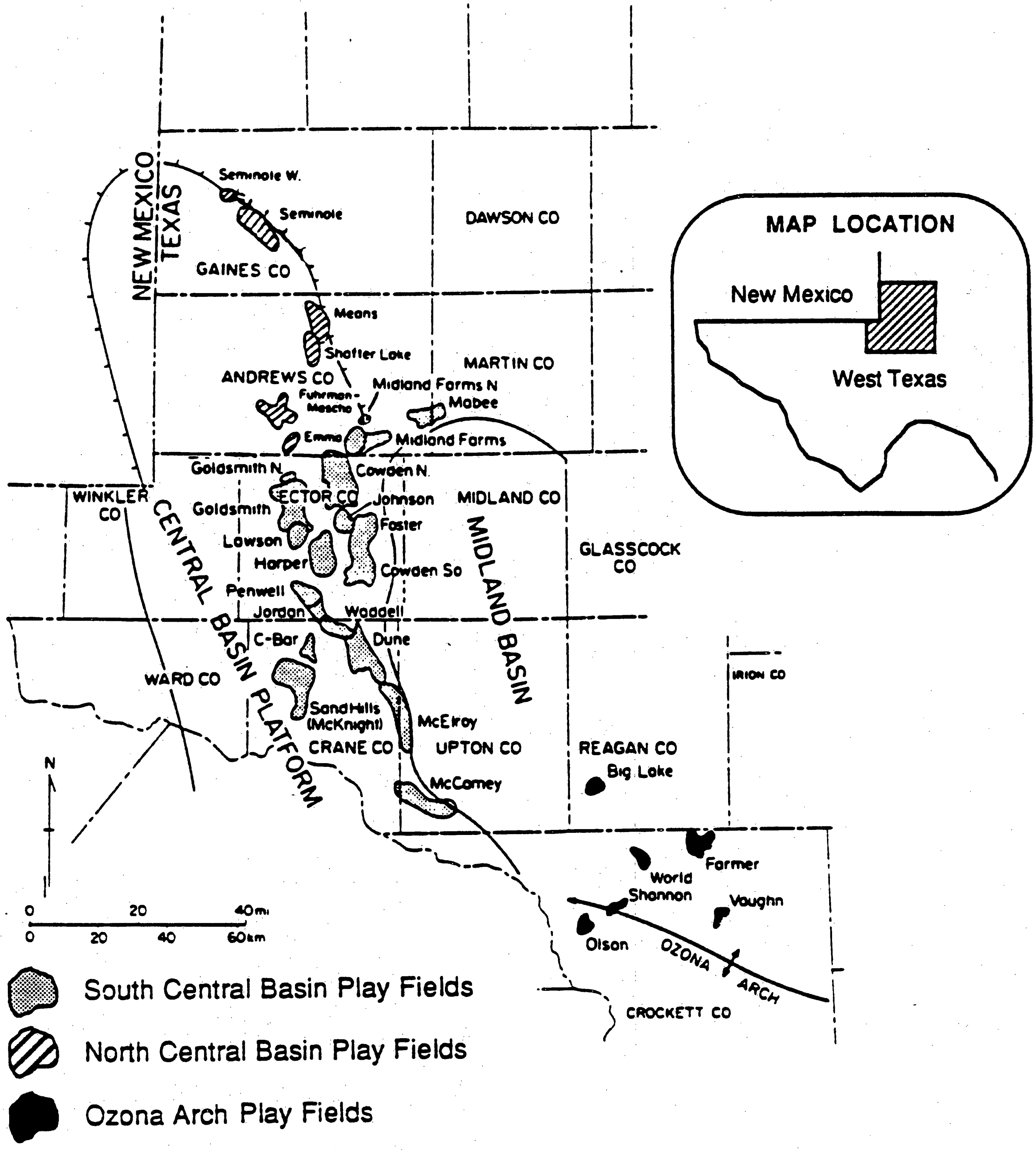


Figure 58. Location of the three San Andres/Grayburg platform plays in the Permian Basin (South Central Basin Platform, North Central Basin Platform, and Ozona Arch). Carbonate reservoirs in these plays are extremely heterogeneous and will contain large volumes of unproduced oil and associated gas in place after primary and secondary recovery. Modified from Godec and others (1989a), after Galloway and others (1983).

Depositional and Structural Setting

Carbonate strata of the San Andres and Grayburg Formations were deposited along the eastern margin of the Central Basin Platform in a semirestricted, platform-margin setting. Numerous fluctuations in relative sea levels in this part of the Permian Basin, caused by a combination of local subsidence, shelf-margin progradation, and eustatic sea-level changes, resulted in landward and seaward shifting of depositional environments and facies tracts for many miles on the low-relief platform.

During periods of high sea level, subtidal carbonate oolite and skeletal grainstone bars accumulated on the shelf (fig. 59). During periods of low sea level, mixed clastic and carbonate tidal-flat and sabkha deposits, consisting of anhydrite, dolomitic lime mud, and terrigenous siltstone and sandstone migrated basinward over the shallow-marine carbonate deposits. Many regressive-transgressive cycles in San Andres/Grayburg strata resulted in stacked, cyclic sequences of interbedded shallow-marine and arid tidal-flat deposits.

The main reservoir facies in the San Andres/Grayburg (South Central Basin Platform) play are dolomitized grainstone bars consisting of oolites, sponges, and algae with leached secondary porosity. These reservoir facies pinch out laterally into low-porosity fusulinid wackestones and mudstones. These subtidal reservoir facies are systematically replaced landward and are bounded vertically by nonproductive, anhydrite-cemented supratidal tidal-flat and sabkha facies. Oil also occurs in a few vugs in the nonporous tidal-flat facies, but no significant volume of hydrocarbons have been found (Bebout and others, 1987).

Most traps in the play are combinations of structure and stratigraphic features, consisting of drape closure or offset along northwest-trending faults caused by Pennsylvanian tectonic activity on the platform margin (Galley, 1958; Ward and others, 1986). Productive limits for areally extensive, fault-bounded anticlines in the play are controlled by the extent and quality of the reservoir. For example, Sand Hills (McKnight) reservoir, located on

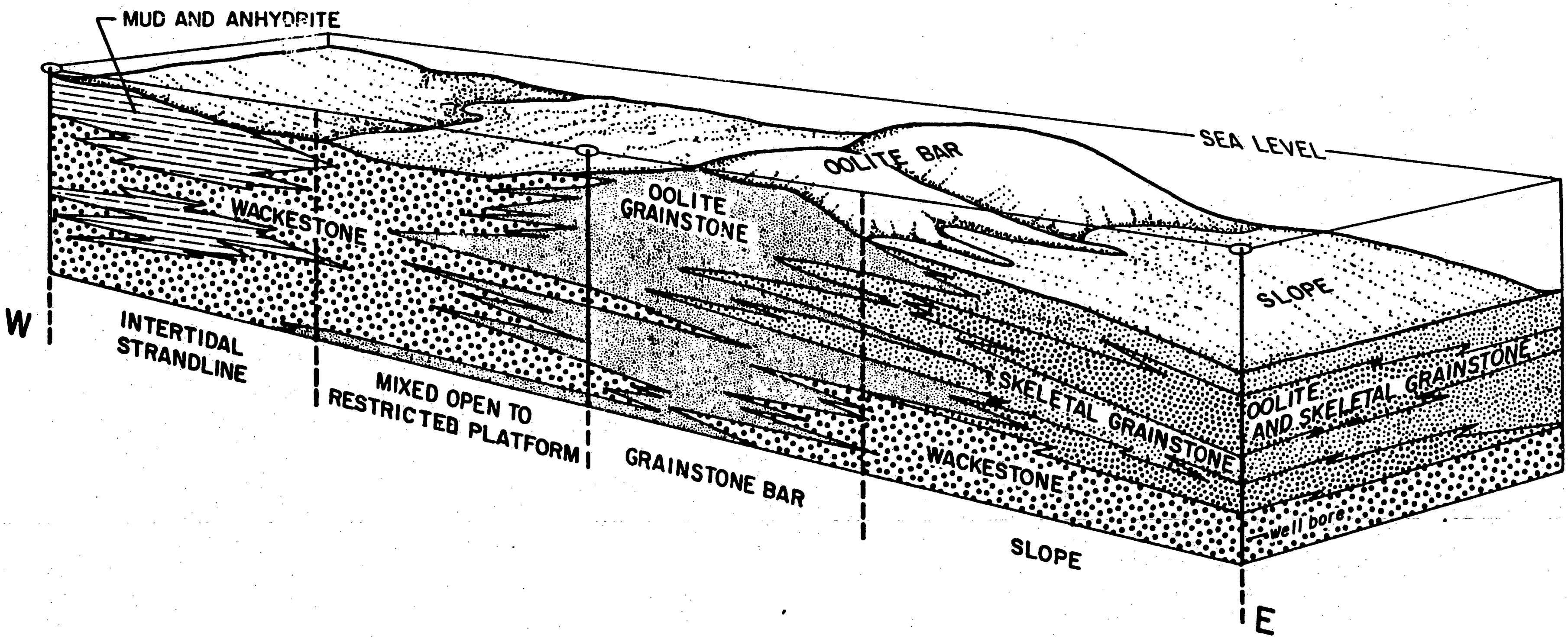


Figure 59. Schematic block diagram of shallow-marine carbonate depositional environments in the San Andres and Grayburg Formations in the Central Basin Platform. Modified from George and Stiles (1978).

figure 58, is productive on the east, basinward side but unproductive on the west margin because of local pinching out of permeable facies (fig. 60).

Because of the many regressive-transgressive, mixed clastic and carbonate cycles on the Central Basin Platform, San Andres and Grayburg reservoirs are highly stratified and complex. The reservoirs typically contain many individual permeable layers commonly less than 15 ft thick that pinch out abruptly from well to well. Recovery efficiencies in the play are low, averaging 26 percent, because of poor lateral and vertical reservoir continuity and weak solution-gas drives. Large, unitized waterflood and gas-injection programs have been instituted in most of the reservoirs to overcome the effects of reservoir heterogeneity and early, long-sustained primary depletion (Galloway and others, 1983).

Dune field

Grayburg reservoirs in Dune field, selected for reserve-growth analysis as representative of the San Andres/Grayburg (South Central Basin Platform) play, are located on the eastern margin of the Central Basin Platform (fig. 61). The reservoir trap results from updip and downdip porosity pinch-outs from facies changes along the flanks of a fault-bounded anticlinal structure (Bebout and others, 1987). The most productive facies in Dune field are multiple, stacked crinoid packstone/grainstone bars that are bounded laterally by nonporous fusulinid wackestones and vertically by nonporous, anhydrite-cemented mudstones and siltstones. These bars are developed into belts oriented northwest to southeast, subparallel to depositional strike. The vertical and lateral distribution of these packstone/grainstone bars results in considerable heterogeneity in the field (fig. 62).

A square-mile, 640-acre area in Dune field (Section 15, fig. 61) was selected for detailed facies and pay-continuity analysis of four carbonate zones that collectively contain approximately 31 MMbbl of oil distributed in net pay from 40 ft (9 m) to over 160 ft (36 m) thick (Bebout and others, 1987). A northwest-southeast-trending belt of net pay thicker than 110 ft (33.5 m) that occupies the central part of Section 15 corresponds to a facies tract dominated by

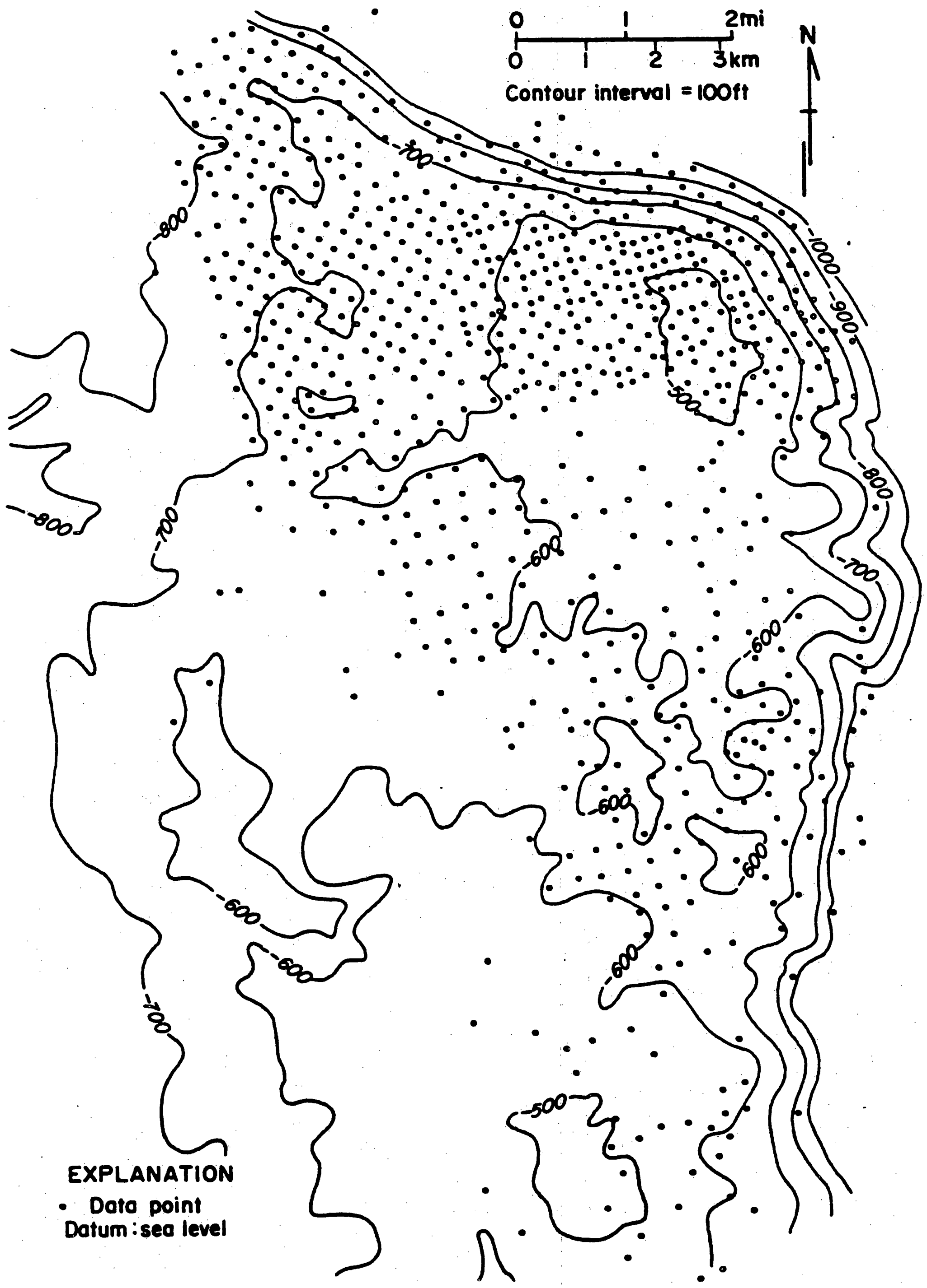


Figure 60. Structure map, contoured on a San Andres marker in Sand Hills (McKnight) field, located in the San Andres/Grayburg South Central Basin Platform play (fig. 70). Most of the west half of the field is nonproductive because of updip pinch-out of shallow-marine carbonate reservoir facies into nonporous sabkha anhydrites. From Galloway and others (1983).

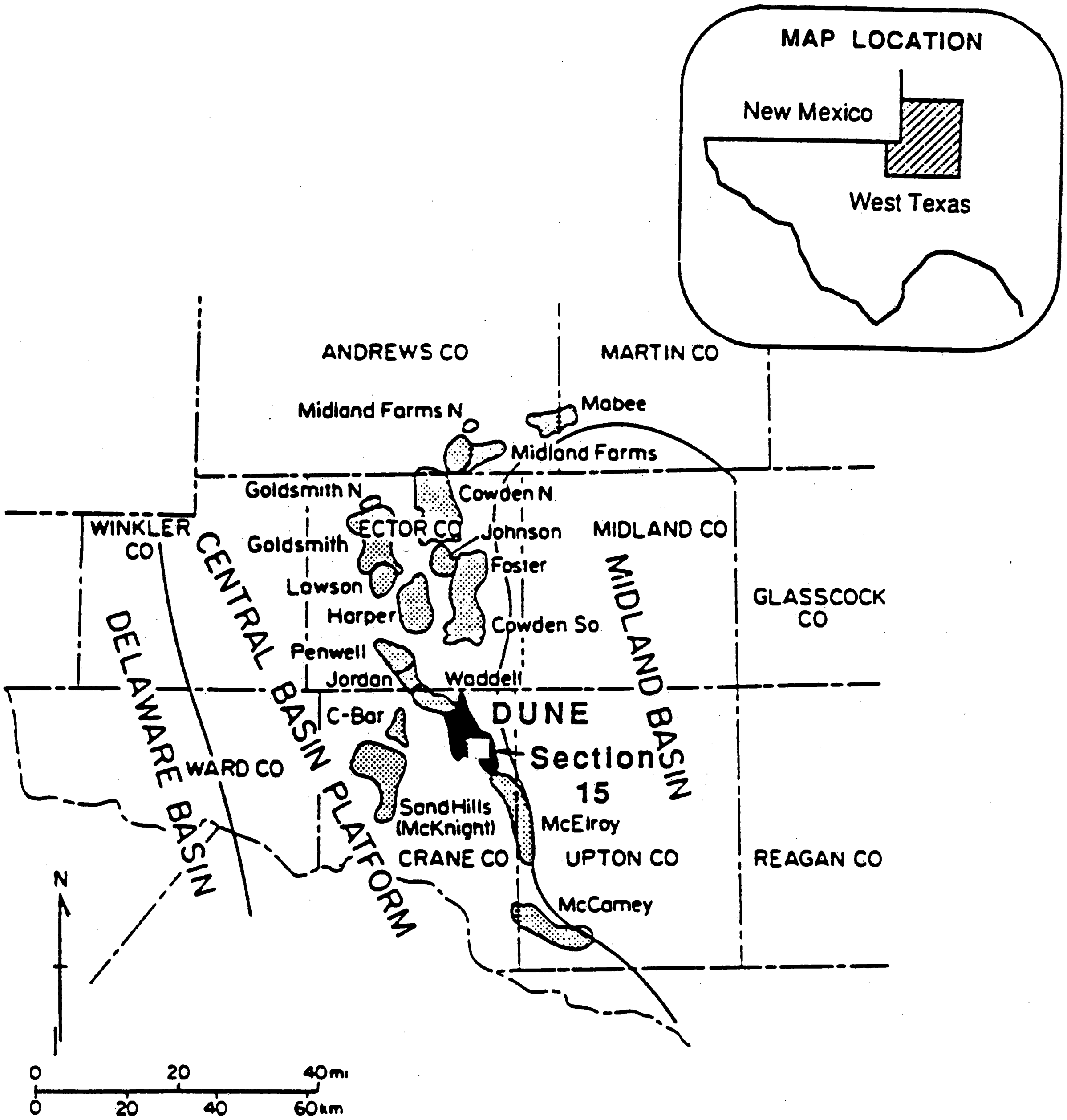


Figure 61. Location of Section 15 in Dune field, selected as the study area representative of the San Andres/Grayburg South Central Basin Platform Play. The reservoirs in this play occur in porous packstone/grainstone bars developed within anticlinal structures on the margin of the Central Basin Platform. Modified from Godec and others (in preparation), after Galloway and others (1983).

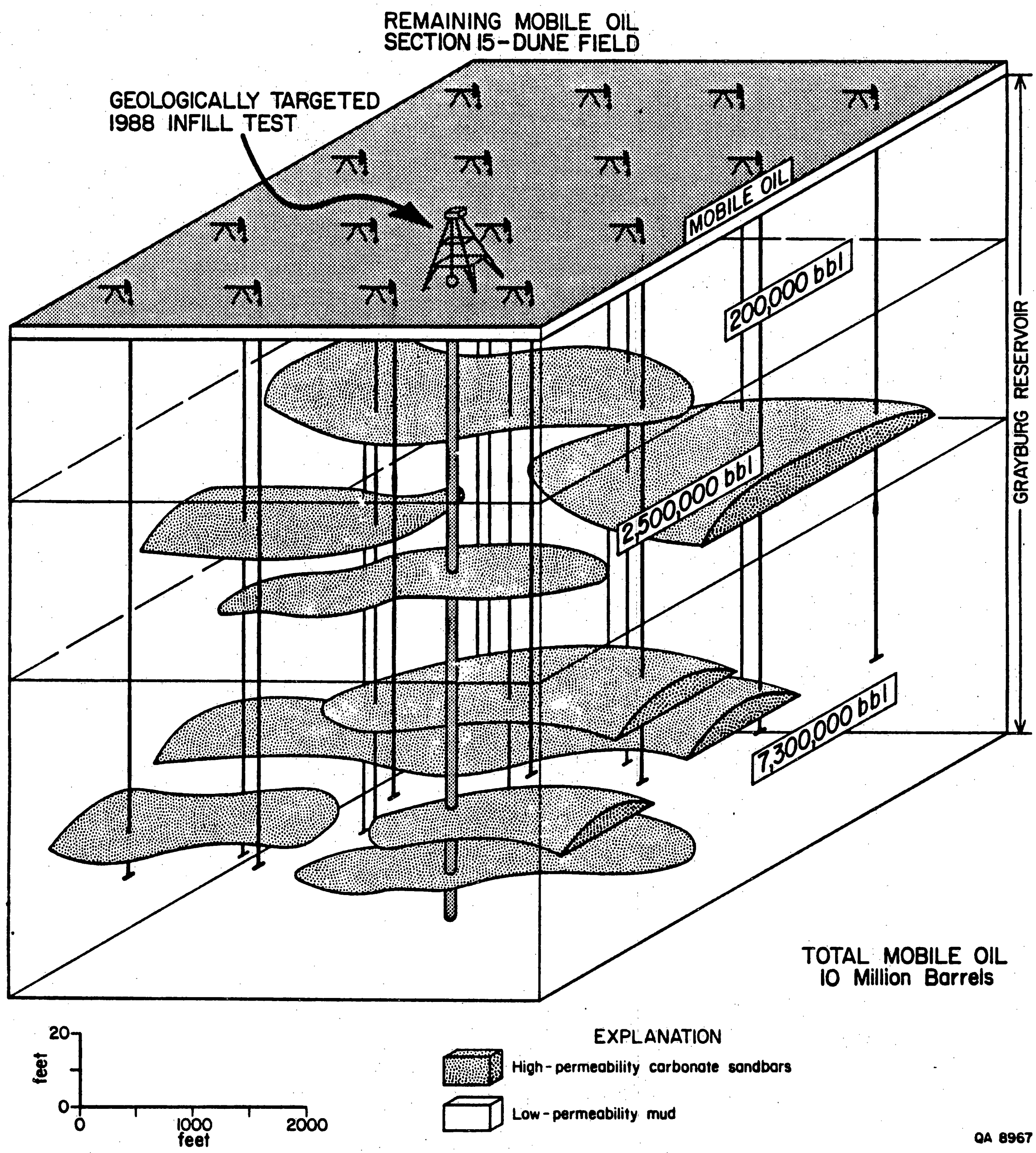


Figure 62. Reservoir heterogeneity in Section 15 in Dune field results from the three-dimensional distribution of numerous lenticular grainstone bars encased in low-permeability wackestones. Geologically based infill wells contact several of these bars in the same well bore, resulting in higher-than-average incremental production. From Lucia (1988).

productive grainstones that have an average porosity of 11.5 percent (fig. 63). In contrast, the northeast and southwest corners of Section 15 contain less than 110 ft of net pay within wackestones that have an average porosity of only 9.3 percent. Geologic and engineering analyses clearly indicate that greater oil and gas recovery potential are associated with the grainstone belt in Section 15.

Pay-continuity functions

A semi-quantitative method of relating pay continuity to reservoir facies, originally developed by Stiles (1976) for carbonate reservoirs in Fullerton field in West Texas, was applied to Section 15 of Dune field. The Stiles (1976) method calculates pay continuity by dividing the cross-sectional area of pay zones that are continuous between a well pair by the total cross-sectional area of both continuous and discontinuous zones between the well pair (fig. 64). Bebout and others (1987) defined pay zones in Dune field as all strata having a permeability value of 0.1 md or more. Permeability values were derived from relationships observed between porosity values obtained from low-temperature whole-core analysis, and sonic, resistivity, and neutron-density log responses. Lucia (1983) has previously demonstrated methods for obtaining porosity-permeability relationships in carbonate rocks of the type present in Dune field.

Pay zones were correlated across one strike and two dip sections in Section 15. Pay-continuity values, obtained from well pairs on these sections, were plotted against horizontal distance between well pairs. Pay-continuity functions for each of the two main facies (grainstone and nongrainstone) were developed for a strategic, or geologically based, case of oil-reserve growth in Section 15 of Dune field (Godec and others, 1989a; fig. 65). These pay-continuity functions were used to determine the incremental mobile oil that could be contacted and flooded at closer well spacing in each facies. The amount of remaining mobile oil in place in Section 15 had previously been calculated by Bebout and others (1987) by

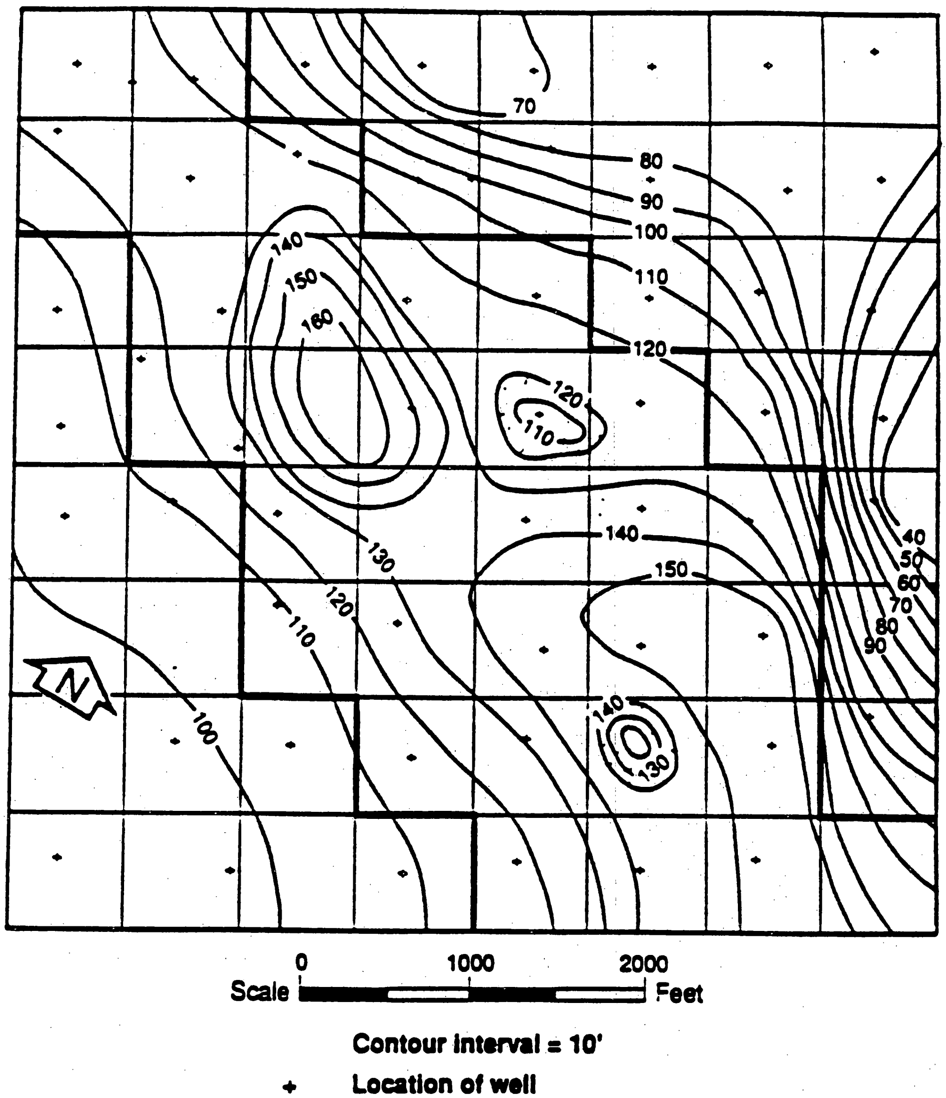
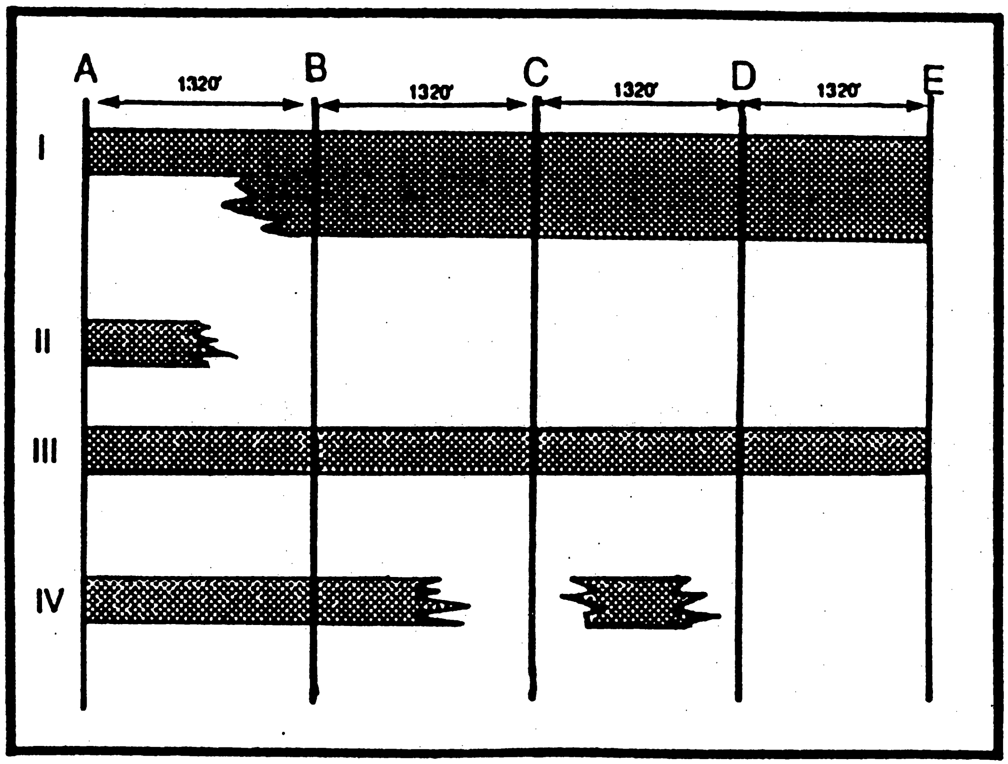


Figure 63. Aggregate net-pay isopach in Section 15 of Dune field. A northwest-southeast-trending belt of net pay, referred to as the grainstone-dominant area, is 110 ft (33.5 m) or more in thickness. The nongrainstone area is limited to the northeast and southwest corners of Section 15 and is generally less than 110 ft thick. Modified from Godec and others (in preparation a).



$$\% \text{ Continuity} = \frac{\text{Effective Porous Volume}}{\text{Total Porous Volume}} \qquad \% \text{ Continuity Well Pair A-B} = \frac{\text{BED I + III + IV}}{\text{BED I + II + III + IV}}$$

Figure 64. Illustration of the Stiles (1976) method used for calculating pay continuity in San Andres/Grayburg reservoirs in Section 15 in Dune field. Cross-sectional areas of continuous net pay (defined by permeabilities of 0.1 md or more in Dune field) between well pairs are summed and then divided by the combined cross-sectional area of continuous and discontinuous net pay between the well pairs.

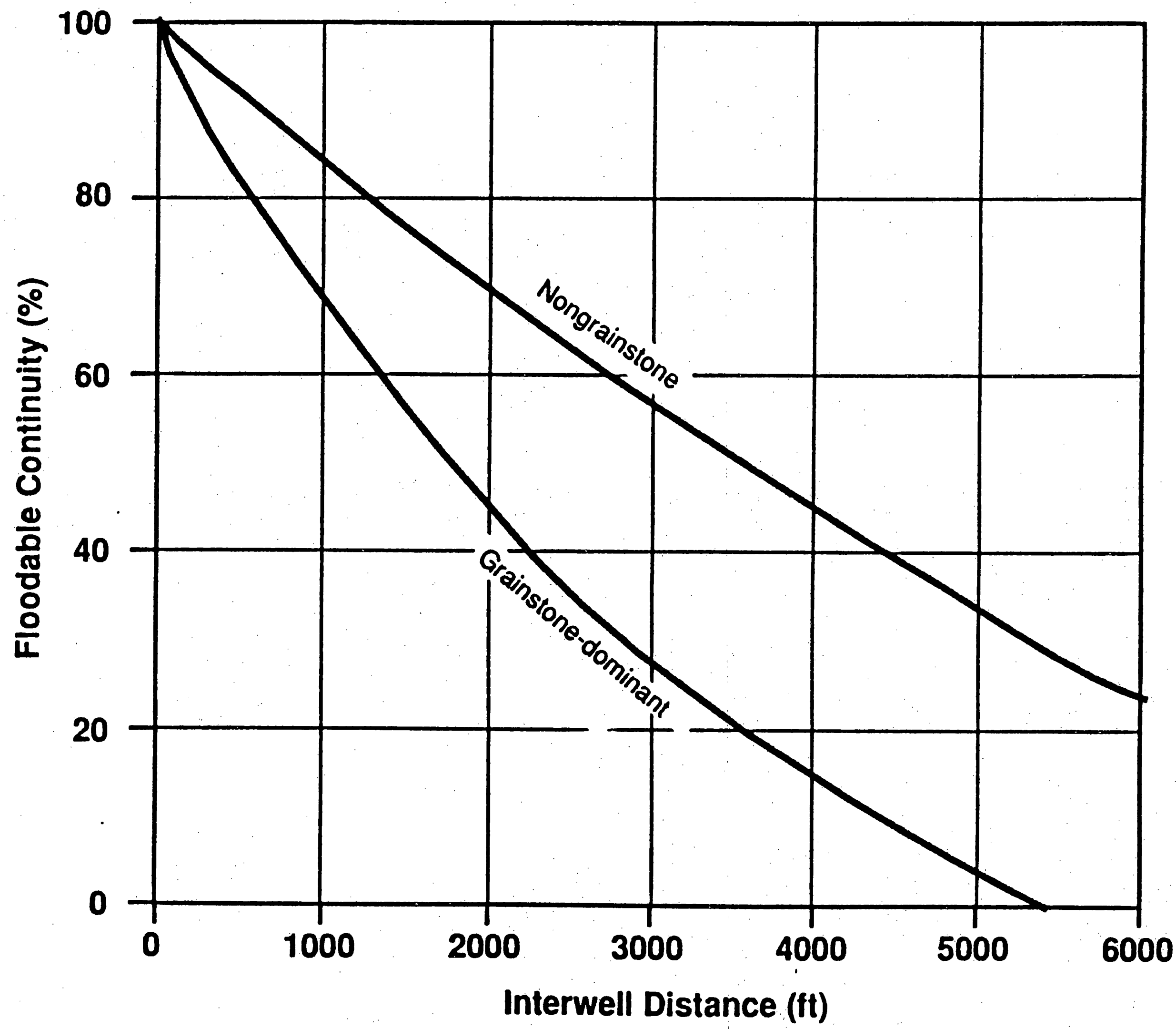


Figure 65. Pay-continuity functions for grainstone and nongrainstone facies in Section 15 in Dune field. Relatively poor pay continuity in the grainstone-dominant trend results from abrupt permeability pinch-outs in laterally discontinuous bars. New infill wells in the grainstone bar facies in Dune field have a greater potential of contacting mobile oil than in the nongrainstone facies, which is characterized by relatively greater pay continuity. From Godec and others (in preparation a).

subtracting the amount of produced oil and residual oil from the amount of original oil in place.

These floodable pay-continuity functions (fig. 65) indicate that the grainstone-dominant facies has less floodable reservoir continuity than the nongrainstone facies at the same well spacing, and therefore this facies should be targeted by new infill wells. For example, the pay-continuity curve for the grainstone-dominant facies indicates that an additional 8 percent of remaining mobile oil in this facies can be contacted by drilling from 20-acre (967-ft) well spacing to 10-acre (660-ft) well spacing in Section 15. This 8 percent was calculated by subtracting the value of 73 percent remaining mobile oil contacted at 20-acre spacing from the value of 81 percent contacted at 10-acre spacing. This additional 8 percent corresponds to 490 thousand barrels of oil recoverable through infill drilling in the grainstone facies in Section 15. In contrast, only an additional 4 percent, or 90 thousand barrels, of remaining mobile oil in the thinner, nongrainstone facies can be contacted by drilling from 20-acre to 10-acre well spacing in Section 15.

Associated gas reserve growth potential

Amounts of oil and associated gas that can be recovered by strategic and blanket infill drilling in Section 15 of Dune field were calculated from the pay-continuity functions developed for each case. These results were extrapolated to the remainder of the field and then to the entire play (table 20). Results indicate that approximately 276 Bcf of associated gas are recoverable in the South Central Basin Platform play by infill drilling from current well spacing to 10-acre spacing. However, approximately 223 Bcf, or 80 percent of this associated gas, can be recovered by strategic infill drilling to 10-acre well spacing in the grainstone-dominant facies only. This clearly demonstrates the control of facies distribution on incremental recovery because current well spacing has failed to contact many of the permeable, discontinuous grainstone bars in the play. Strategic infill drilling based on

Table 20. Recoverable Amounts of Associated Gas (Bcf) from Infill Drilling in the San Andres/Grayburg South Central Basin Platform Play. Data from Godec and others (1989a).

Field	Grainstone Facies	Nongrainstone Facies	Combined Facies
Cowden, N.	24.6	6.1	30.7
Cowden, S.	13.2	3.2	16.4
C-Bar	1.7	0.4	2.1
Dune	14.4	3.6	18.0
Foster	14.4	3.6	18.0
Goldsmith, N.	2.1	0.6	2.7
Goldsmith	60.3	15.4	75.7
Harper	2.7	0.6	3.3
Johnson	4.9	1.1	6.0
Jordan	5.2	1.4	6.6
Lawson	3.1	0.7	3.8
Mabee	2.8	0.7	3.5
McCamey	2.6	0.6	3.2
McElroy	5.6	1.3	6.9
Midland Farms, N.	1.2	0.3	1.5
Midland Farms	15.7	4.1	19.8
Penwell	16.1	3.9	19.0
Sand Hills	18.6	4.3	22.9
Waddell	14.1	3.2	17.3
Play Total	**223.3**	**55.1**	**277.4**

detailed facies maps of each reservoir in the play will be instrumental in economic recovery of the additional oil and associated gas resource.

Economically Recoverable Associated Gas

The associated gas resource potential discussed above represents the total resource recoverable from the South Central Basin Platform Play from infill drilling to 10 acres per producer. The economic viability of producing this gas was assessed under both infill development scenarios (blanket and strategic) (Godec and others, in 1989a). Estimated economically recoverable associated gas from infill drilling from current spacing to 10 acres per producer in the South Central Basin Platform Play is summarized in table 21 for various gas price ranges.

At a gas price of $1.00/Mcf, a program of blanket infill development with ongoing waterfloods in oil reservoirs in the play would result in the economic recovery of 75 Bcf of associated natural gas. A program of strategic infill drilling at the same price would yield 175 Bcf of recoverable gas, or another 100 Bcf of associated gas over that recovered from blanket development.

Up to a price of $5.00/Mcf, slightly more incremental gas (250 compared with 240 Bcf, or 4 percent more) is recovered under a blanket scenario where marginally economic wells are drilled. In the blanket infill case, knowledge of geologic heterogeneity is not applied in selecting from among all available potential infill locations. The result is that the more productive facies (grainstone-dominant) must bear the burden of the less productive facies (nongrainstone) and compensate for the subeconomic performance of the less productive wells.

A volume-weighted average price for gas under blanket and strategic approaches can be calculated for gas prices up to $5.00/Mcf from the data in table 21. A price of $1.00/Mcf was used for the lowest price range, and the midpoint of the price range was used for the other ranges including, but not above, $5.00/Mcf. The result is that under blanket infill drilling the average cost per Mcf for incremental recovery of 250 Bcf is $1.96/Mcf. For strategic infill

Table 21. Economically Recoverable Associated Gas from the South Central Basin Platform Play.

Infill Development Scenario	Incremental Recoverable Gas (Bcf) (at $/Mcf Wellhead Price)				
	<$1.00	$1.00-2.00	$2.00-3.00	$3.00-5.00	>$5.00
Blanket	75	90	40	45	25
Strategic	175	35	15	15	35

drilling the average cost is $1.35/Mcf, or 31 percent less on a cost-per-unit basis. Evaluation of the data in table 21 shows the cost advantages of the strategic approach in producing incremental associated gas at gas prices below $5.00/Mcf.

Frio Barrier/Strandplain Play

Production History, Depositional and Structural Setting

The Frio barrier/strandplain play consists of 46 clastic reservoirs located in the Texas Gulf Coastal petroleum province (fig. 66). This prolific play, which contains 4.2 billion barrels of oil and 2.3 Tcf of associated gas in place (Galloway and others, 1983), is defined by the intersection of the regionally extensive Frio and Vicksburg Fault Zones and sandstones of the Greta-Carancahua barrier-strandplain system of the Oligocene Frio Formation. Recovery efficiencies in the Frio barrier/strandplain play are high, reflecting fair to good reservoir continuity. Approximately 53 percent of original oil in place will be recovered at the end of primary production.

West Ranch (41-A) reservoir

The 41-A reservoir in West Ranch field (fig. 67) was also selected for detailed geologic and engineering analysis (Godec and others, 1989b). The 41-A reservoir is considered to be representative of the other reservoirs in the Frio barrier/strandplain play because it contains all of the barrier-strandplain facies predominant in the play, such as barrier core, tidal inlet, flood-tidal delta, and backbarrier lagoon. Additionally, the values of many key reservoir properties in the 41-A reservoir, such as recovery efficiency, porosity, and residual oil and water saturation, are similar to the average values for the other reservoirs in the play.

Galloway and Cheng (1985) previously mapped the distribution of the three main barrier-island facies in West Ranch field (fig. 68). The 41-A reservoir consists of strike-parallel barrier-core facies that have a tabular geometry, which are eroded by dip-parallel tidal-inlet facies that are lenticular in cross section. Both of these facies, which constitute most of the

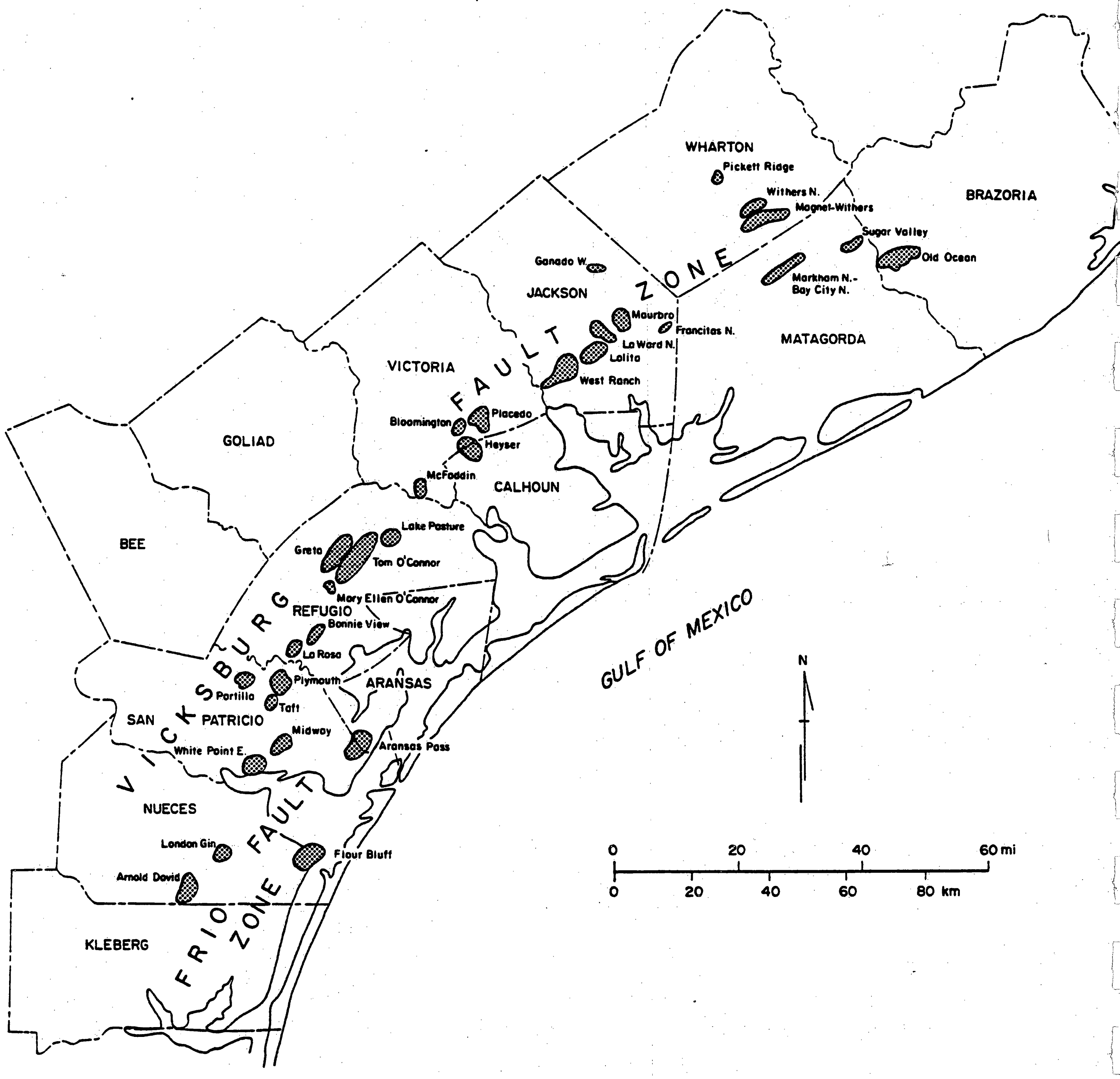


Figure 66. Geographic distribution of reservoirs in the Frio barrier/strandplain play, located on Figure 69. From Galloway and others (1983).

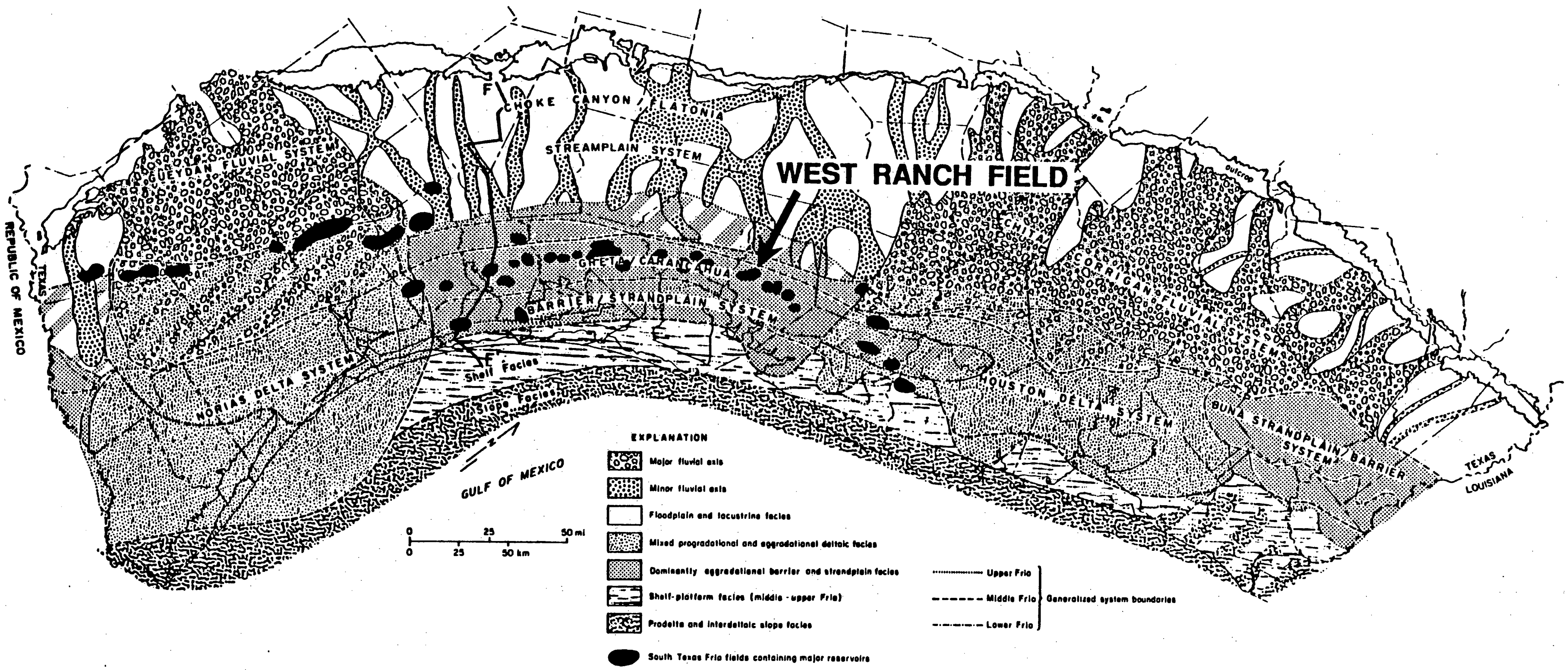


Figure 67. Regional distribution of reservoirs and depositional framework of the Frio barrier/strandplain play, located between deltaic depocenters in South and East Texas, respectively. West Ranch field is located in the northern half of the play. Modified from Galloway and others (1983).

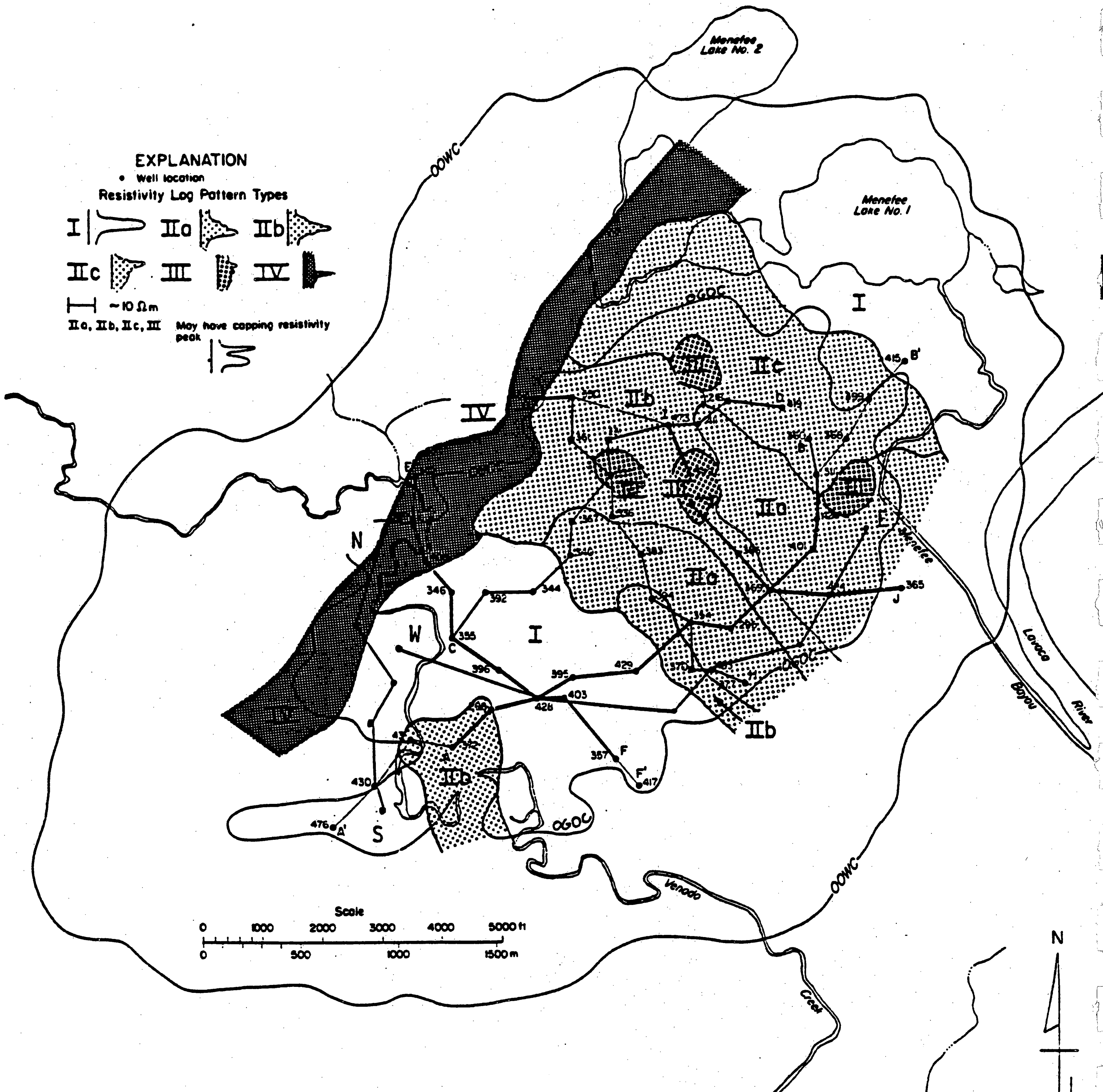


Figure 68. Resistivity log-facies map of the main sandstone in the West Ranch (41-A) reservoir. Dip-parallel tidal-inlet facies, defined by resistivity patterns IIa, IIb, and IIc (upward-fining, symmetrical, and upward-coarsening) cut across barrier-core facies, represented by resistivity pattern I (blocky). Type III (baseline deflection) corresponds to muddy inlet-fill; type IV (serrate and spiky pattern) is associated with muddy backbarrier lagoonal deposits. Pay continuity was calculated between well pairs on the cross sections indicated above. Modified from Galloway and Cheng (1985).

reservoir by volume, grade updip into thin flood-tidal delta and muddy backbarrier lagoonal facies (fig. 69). Although the barrier-core facies is internally homogeneous, the tidal-inlet facies is highly variable in nature and contains large variations in sandstone content and sedimentary structures. Compartments in the 41-A reservoir are located in tidal-inlet facies or where they are in erosional contact with barrier-core facies.

Pay-continuity functions

The Stiles (1976) pay-continuity method that was used in the analysis of Dune field was initially considered for use in pay-continuity analysis of the 41-A reservoir. However, this method was not applicable to the 41-A reservoir, because it was originally developed for reservoirs in which the pay zones occur as thin, discontinuous stringers. In the relatively unstratified 41-A reservoir, the Stiles (1976) method yielded values of pay continuity that increased with greater distance between well pairs, instead of decreasing in accordance with geologically based expectations.

An alternate method of pay continuity was devised, based on kh (permeability multiplied by pay zone thickness) ratios between adjacent wells. Data from 41 wells on five cross sections that intersect all major facies in the 41-A reservoir were used in the pay-continuity analysis. The kh values in each well were extrapolated from a resistivity-permeability relationship between whole-core data and deep-induction resistivity log response, developed by Galloway and Cheng (1985). For adjacent wells on the cross sections, the pay continuity was defined simply as the kh ratio between the wells. For well pairs separated by large distances, the kh ratios between each intervening well pair were multiplied together sequentially, resulting in decreasing pay continuity over increasing distance between wells. This method is illustrated on figure 70. Approximately 240 data points were generated from the five cross sections. These points were plotted on a graph, and a least-squares curve was fit to the data points.

Individual pay-continuity functions were also constructed for each facies in the 41-A reservoir. Comparison of the pay-continuity functions for all of the main facies in the 41-A

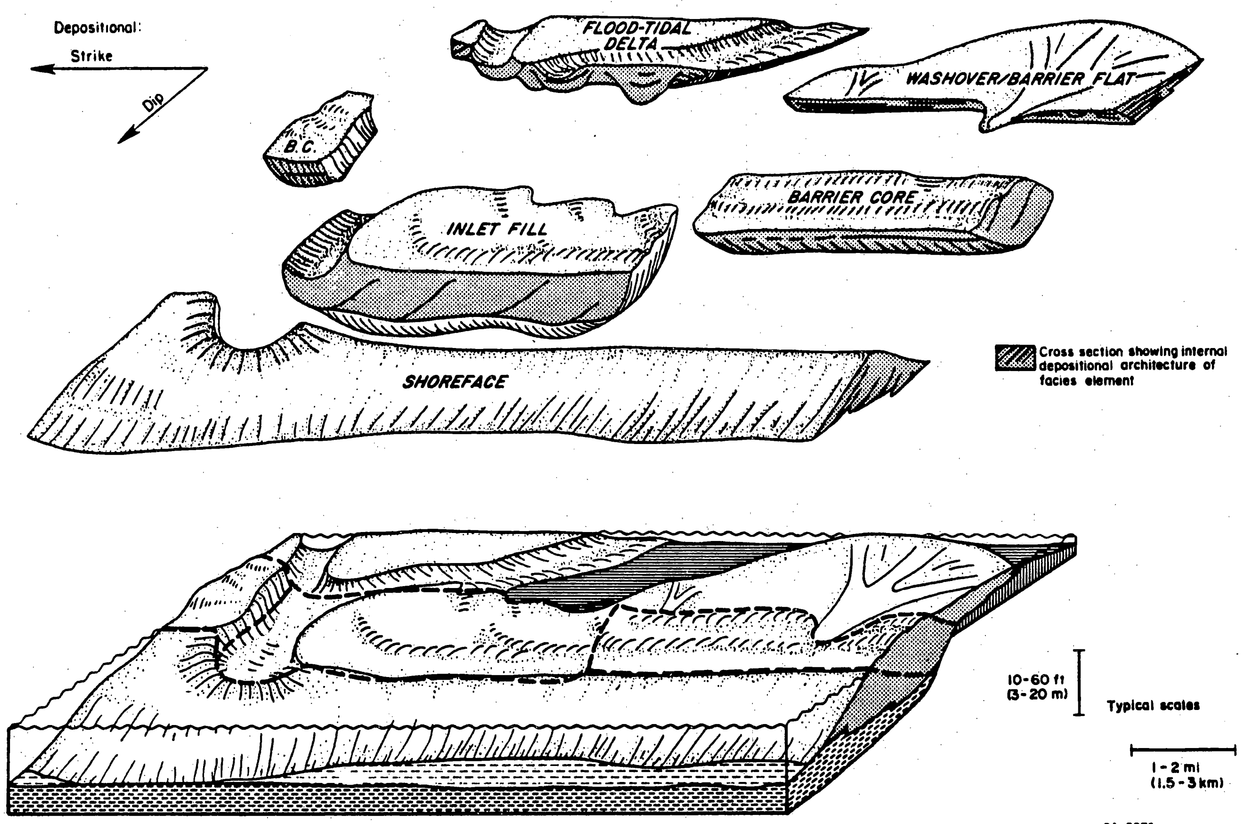
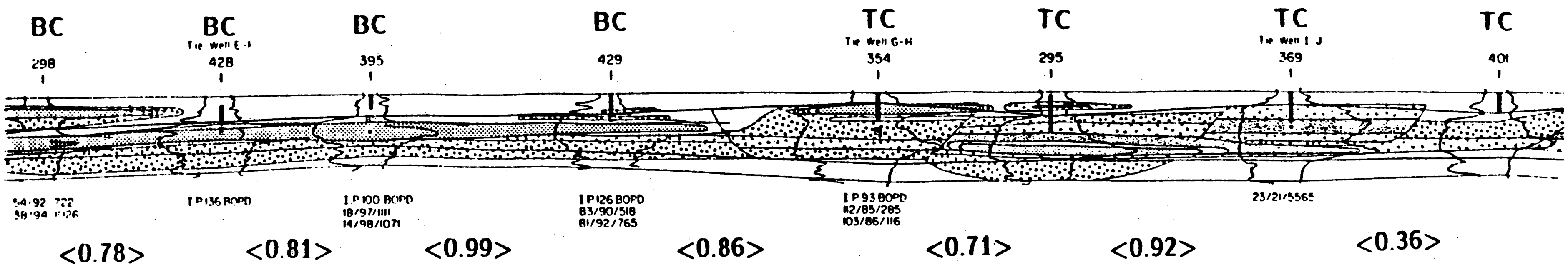


Figure 69. Facies components in barrier-island sand bodies. From Galloway and Cheng (1985).



TC Tidal Channel

BC Barrier Core

< > Kh-ratio between adjacent wells

	Well Pair	Distance (Ft)	Pay Continuity	
BARRIER CORE	298-428	800		0.78
	298-395	1.550	0.78(0.81) =	0.63
	298-429	2.650	0.78(0.81)(0.99) =	0.62
TIDAL CHANNEL	354-295	750		0.71
	354-369	1.700	0.71(0.92) =	0.65
	354-401	2.750	0.71(0.92)(0.36) =	0.24

Figure 70. Illustration of the Kh-ratio method used in determining pay continuity in the West Ranch (41-A) reservoir. Example above is a portion of cross section AB from Figure 80. Kh ratios between pay zones in barrier-core facies in the west part of cross section AB are high, and therefore pay continuity in this facies is high. In contrast, Kh ratios between adjacent tidal-inlet wells vary greatly, resulting in a steep decline in pay continuity with increasing interwell distance. Modified from Galloway and Cheng (1985).

reservoir indicates that the two most heterogeneous barrier-island facies are the backbarrier and inlet-fill facies, whereas the barrier-core facies is the most homogeneous (fig. 71).

Strategic infill wells, drilled in areas where the potential is greatest for recovering uncontacted mobile oil, should be targeted primarily in the tidal-inlet facies, or along the boundary between the tidal-inlet and barrier-core facies. Other infill opportunities can be found along the edge of the backbarrier facies, where tidal-delta and washover-fan sandstones pinch out into lagoonal mudstones. These sites coincide with areas where variations in lateral and vertical permeability are greatest in the reservoir.

Associated gas reserve growth potential

A geologically based case of oil reserve growth in the 41-A reservoir incorporated the concept of strategically located infill wells based on facies heterogeneity in the reservoir. Volumes of the three primary facies in the 41-A reservoir—barrier core, tidal inlet, and backbarrier—were calculated in order to estimate the volumes of uncontacted oil and unproduced associated gas in areas of the field corresponding to each facies. With the reserve growth potential of each major facies characterized in terms of pay continuity and reservoir volume, it was then possible to provide estimates of remaining mobile oil and associated gas that can be produced by new infill wells in each facies.

Extrapolated amounts of uncontacted mobile oil and unproduced associated gas in the Frio barrier/strandplain play were based on a grouping of the 46 reservoirs into six different facies volume-distribution types according to the dominant facies in each reservoir. Determination of facies volume-distribution types in the play was based on a variety of data, including maps, cross sections, electric logs, and drilling and production data obtained from the Railroad Commission of Texas. Relative volumes of the three major barrier-island facies, barrier-core, tidal-inlet, and backbarrier, for the combined-facies and tidal-inlet facies volume-distribution types (table 22) were calculated from detailed log-facies maps of the West Ranch 41-A (fig. 68) and West Ranch Greta reservoirs. Relative facies volumes in reservoirs

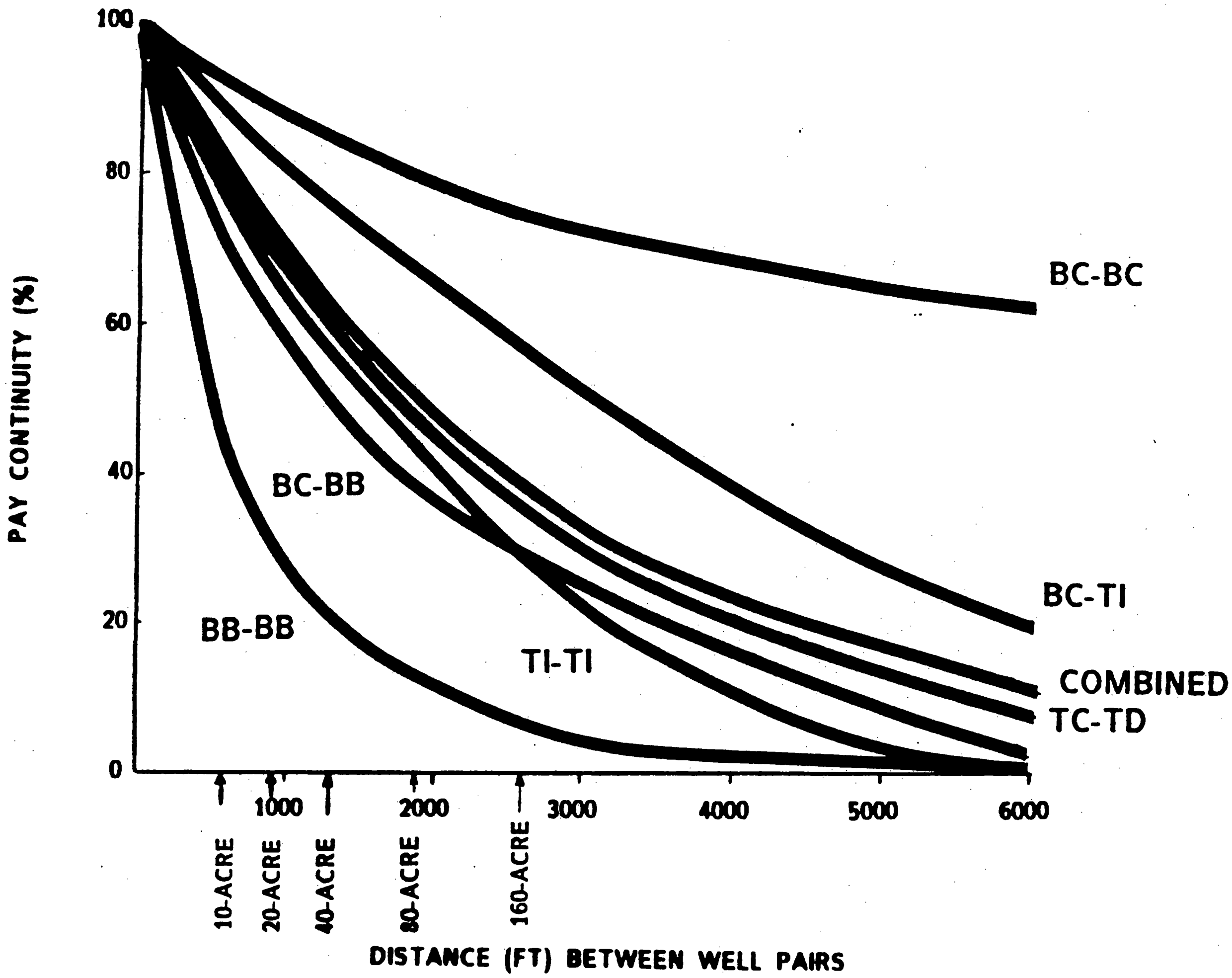


Figure 71. Pay-continuity functions, based on the Kh-ratio method, for each major facies or between facies in the West Ranch (41-A) reservoir. Abbreviations: BC = barrier core; TI = tidal inlet; TC = tidal channel; TD = tidal delta; BB = backbarrier.

Table 22. Pay-Continuity Type Versus Facies Volumes in Reservoirs in the Frio Barrier/Strandplain Play.

Pay-Continuity Type	Reservoir Example	Tidal Inlet	Facies Volume (%) Barrier Core	Backbarrier
Combined	West Ranch 41-A	61	27	12
TI-TI (Tidal inlet)	West Ranch Greta	68	17	15
BC-BC (Barrier core)	NM-NBC* Carlson	20	70	10
TC-TD (Tidal channel and delta)	Heyser 5400	40	20	40
BC-TI (Barrier core and tidal inlet)	Tom O'Connor 4500	45	45	10
BC-BB (Barrier core and backbarrier)	Old Ocean Chenault	20	40	40

* North Markham–North Bay City.

characterized by other facies volume-distribution types in table 22 were estimated from available data on other reservoirs in the play.

Net amounts of uncontacted mobile oil and associated gas that can be obtained by infill drilling will be calculated for each reservoir by weighting separate pay-continuity functions for each facies according to the relative percentage of facies present in each type of reservoir in the play. This two-step process is illustrated by the West Ranch Greta reservoir, identified by the tidal-inlet facies volume-distribution type on table 22. The net amount of uncontacted mobile oil and associated gas that can be recovered from the West Ranch Greta reservoir is based on a pay-continuity curve that is a combination of the TI-TI (tidal inlet), BC-BC (barrier core), and BB-BB (backbarrier) curves (fig. 71) that are weighted 68, 17, and 15 percent, respectively, on the basis of the relative volumes of these three facies. For more homogeneous reservoirs with greater recovery efficiencies, such as North Markham–North Bay City (Carlson), which is identified by the barrier-core facies volume-distribution type, the pay-continuity curve that was used was one weighted 70 percent by the BC-BC (barrier core) function, reflecting the dominance of this homogeneous facies in the reservoir.

The results of the extrapolation process indicate that approximately 137 Bcf of associated gas are recoverable from the Frio barrier/strandplain play by infill drilling from current spacing to 10 acres per producer. Approximately 68 Bcf will come from the tidal-inlet facies, which has the greatest infill potential for the play. An estimated 22 Bcf is recoverable from the barrier-core facies, and another 47 Bcf is recoverable from the backbarrier facies.

Economically Recoverable Associated Gas

The economics of producing this associated gas from the Frio barrier/strandplain play was assessed under both infill development scenarios (blanket and strategic). Estimated economically recoverable associated gas from infill drilling from current spacing to 10 acres per producer in the play is summarized in table 23 for various gas price ranges.

Table 23. Economically Recoverable Associated Gas from the Frio Barrier/Strandplain Play.

Infill Development Scenario	Incremental Recoverable Gas (Bcf) (at $/Mcf Wellhead Price)				
	<$1.00	$1.00-2.00	$2.00-3.00	$3.00-5.00	>$5.00
Blanket	40	45	20	30	0
Strategic	70	30	15	20	0

At a gas price of $1.00/Mcf, a program of blanket infill development implemented in ongoing waterfloods in Frio barrier/strandplain oil fields in the play would result in the economic recovery of 40 Bcf of associated natural gas. A program of strategic infill drilling at the same price would yield 70 Bcf of recoverable reserves, or another 30 Bcf of associated gas over that recovered from blanket development.

A volume-weighted average price for gas under blanket and strategic infill methods can be calculated for gas prices to $5.00/Mcf from the data in table 23. Under blanket infill drilling, the average cost per Mcf for incremental recovery of 135 Bcf is $2.17/Mcf. For strategic infill drilling the average cost is $1.80/Mcf, or 17 percent less on a cost-per-unit basis, clearly indicating that strategic infill drilling should be more economical than blanket infill drilling on a regular grid pattern.

Clearfork Platform Carbonate Play

An analysis of the Clearfork Platform Carbonate play has also been conducted (Godec and others, 1989a) to determine the economics of infill drilling to recover the unswept oil remaining in the play. The analysis was performed using studies available in the literature and data obtained from public sources. The primary source was a report by Barbe and Schnoebelen (1987), which examined the infill development potential of the Robertson North (Clearfork) reservoir, which was considered to be representative of the other reservoirs in the play. The information was examined and analyzed under the same framework developed for the South Central Basin Platform play study, but without detailed geologic characterization and quantified reservoir heterogeneity. In addition, no assessment of the potential of geologically targeted infill development was performed.

The Clearfork Platform Carbonate play, located in the Central Basin Platform in West Texas, produces oil and associated gas from heterogeneous interbedded carbonate and clastic reservoirs in the Leonardian Series of Permian age. The play consists of 13 major reservoirs, which have each produced over 10 million barrels of crude oil as of 1981. The high level of heterogeneity in reservoirs within these fields leads to low recovery efficiencies and therefore considerable quantities of unrecovered mobile oil. All of these reservoirs have reached primary depletion, and secondary recovery programs are currently underway.

The results of the extrapolation of the analysis of the Robertson North (Clearfork) reservoir to the entire play indicate that approximately 187 Bcf of associated gas are recoverable from the Clearfork Platform Play by infill drilling from current spacing to 10 acres per producer. The economic viability of producing this gas from a program of infill drilling from current spacing to 10 acres per producer in the play is summarized in table 24 for various gas price ranges.

At a gas price of $1.00/Mcf, a program of blanket infill development implemented in ongoing waterfloods in Clearfork Platform Carbonate oil fields in the play would result in the economic recovery of 40 Bcf of associated natural gas. Another 45 Bcf are recoverable at a gas price between $1.00 and $2.00 per Mcf, 30 Bcf from $2.00 to $3.00 per Mcf, and 35 Bcf in the price range of $3.00 to $5.00 per Mcf.

Associated Gas Reserves in Texas

An extrapolation of associated gas reserves to the state level was provided initially by identifying the major associated gas plays in Texas from the list of gas plays by Kosters and others (1989). Only those reservoirs that have had at least 10 Bcf of cumulative production were included in Kosters and others' list of gas plays. The major associated gas plays, totaling 15, are listed on table 25. All of these plays correspond to oil plays listed in Galloway and others (1983), except for Mississippian pinnacle reef limestones (MS-2) and Panhandle Missourian-Desmoinesian fluvial-deltaic sandstones (PN-11). Except for these two plays and the Lower/Middle Pennsylvanian sandstone play in the Marietta Basin (PN-8), all of the major associated gas plays in Texas occur in the Permian Basin in West Texas (fig. 4). Reservoirs in Gulf Coast and East Texas gas plays dominantly produce nonassociated gas, although they also contain some associated gas.

Table 24. Economically Recoverable Associated Gas from the Clearfork Platform Carbonate Play.

Infill Development Scenario	Incremental Recoverable Gas (Bcf) (at $/Mcf Wellhead Price)				
	<$1.00	$1.00-2.00	$2.00-3.00	$3.00-5.00	>$5.00
Blanket	40	45	30	35	37
Strategic	Analysis not performed				

Table 25. Volumes of Recoverable Gas (Bcf) in the Major Associated Gas Plays in Texas.

Associated Gas Play	Equivalent Oil Play	Depositional System	Avg. IGOR (SCF/BBL)	Target Oil (MMBBL)	Associated Gas Conserv/Optimum	
Atoka Gp. limestones sand sandstones	Extension of Penn. Platform Carbonate	Open shelf, mounds, and patch reefs	787 p.*	139 p.	41.0	68.4
Clearfork platform carbonates	Clearfork platform carbonate	Open shelf/platform, extensive diagenesis	742	1429	397.6	798.7
Delaware sandstone	Delaware sandstone	Submarine canyon, sandy	649	231.2	56.3	93.8
Ellenburger karst dolomite	Ellenburger fractured dolomite	karstic overprint	954	693.8	248.2	413.7
Lower/middle Penn. deltaic sandstone, Marietta Basin	Extension of Strawn sandstone	Fluvial-dominated deltas	348 p.	273.5	35.7	59.5
Mississippian pinnacle reef ls.	No equivalent	Small atolls, pinnacle reefs	900 p.	1.3 p.	0.6	0.7
Panhandle Missourian-Desmoinesian deltaic sandstones	No equivalent	Sandy submarine canyon and fluvial dominated deltas	240 p.	6.2 p.	0.7	0.9
San Andres/Grayburg platform carbonate	San Andres/Grayburg N.C.B.P., S.C.B.P., No. shelf Perm. Carb.	Open shelf/platform, extensive diagenesis	469	5764	1013.7	1689.6
Siluro-Devonian shelf carbonates-Midland Basin	Siluro-Devonian ramp carbonate	Open shelves and ramps	132	111.8	5.5	9.2
Silurian carbonate pinch-out	Siluro-Devonian South Cen. Basin Platform	Open shelf/platform, extensive diagenesis	1,375	53.8	27.7	46.2
Siluro-Devonian erosional truncation	Siluro-Devonian North Cen. Basin Platform	Open shelf/platform, extensive diagenesis	818	230.4	70.7	117.8
Spraberry/Dean sandstone	Spraberry/Dean sandstone	Submarine fan, silty to muddy	798	4000	1197	1995

Table 25 (cont.)

Associated Gas Play	Equivalent Oil Play	Depositional System	Avg. IGOR (SCF/BBL)	Target Oil (MMBBL)	Associated Gas Conserv/Optimum	
Upper Guadalupian platform sandstones	Permian sandstone and carbonate	Open shelf, mixed ss/carb	395	446.2	66.1	110.2
Upper Pennsylvanian carbonates	Horseshoe Atoll	Atolls, large pinnacle reefs	881	596.7	197.1	328.6
Wolfcamp carbonates	Wolfcamp platform carbonates	Open shelf/platform, extensive diagenesis	739	96.4	26.7	44.5
Total Recoverable Associated Gas					**3384.6**	**5776.8**

* p. = projected

Amounts of target oil, which include uncontacted mobile oil and bypassed mobile oil, were calculated for reservoirs in the oil plays in Galloway and others (1983) that correspond to the associated gas plays in Kosters and others (1989). Critical reservoir properties that were necessary for calculating target oil—residual oil saturation, water saturation, original oil in place, and ultimate recovery—were updated from values used in Tyler and others (1984). Equal percentages of uncontacted mobile oil and bypassed mobile oil as a fraction of original mobile oil in place were estimated for each play, although relative amounts of each vary slightly from play to play (C. R. Hocott, personal communication, 1988). The amount of target oil in associated gas plays that do not correspond directly with an oil play listed in Galloway and others (1983) was extrapolated by comparison with other oil plays characterized by similar depositional environments. For example, the Mississippian pinnacle reef limestones play (MS-2) was compared with the Horseshoe atoll play (Galloway and others, 1983), and the Lower/Middle Pennsylvanian sandstone play in the Marietta Basin (PN-8) was compared with the Strawn sandstone play (Galloway and others, 1983). The amount of target oil in each of these two plays was estimated by comparing the ratios of cumulative production to target oil between plays.

Both optimistic and conservative estimates of associated gas in Texas were prepared by using various fractions of target oil and different gas-to-oil ratios to furnish a range of expected recoveries of associated gas. The optimistic estimate was based on the assumption that all gas associated with uncontacted mobile oil is recoverable at the initial gas-to-oil ratio, and that at least 25 percent of the bypassed oil contains associated gas at the original gas-to-oil ratio. The conservative estimate assumed that gas associated with the uncontacted mobile oil fraction is characterized by only 75 percent of the initial gas-to-oil ratio because of pressure depletion in the reservoir, and that virtually no gas associated with the bypassed oil fraction remains to be recovered because this gas has been contacted and depleted during primary recovery operations in the reservoir.

Estimates of the amount of recoverable associated gas in Texas from the selected associated gas plays range from 3.4 Tcf (conservative method) to 5.8 Tcf (optimistic method). These estimates are for the selected associated gas plays only, representing about one-third of the oil plays in Texas, and therefore are less than estimates provided by Finley and others (1988), who based their statewide extrapolation of associated gas from 100 percent of the target oil (bypassed and uncontacted mobile oil, at a gas-to-oil ratio of 700 Scf/bbl) in the 48 oil plays listed in Galloway and others (1983). In contrast, the optimistic method presented in this report considers only 62.5 percent of the target oil for each play (25 percent of the bypassed mobile oil and 100 percent of the uncontacted mobile oil) at the initial gas-to-oil ratio, weighted volumetrically. The average initial gas-to-oil ratio, weighted volumetrically, for the 15 selected associated gas plays in Texas is 631.4 Scf/bbl, which is similar to the figure estimated by Finley and others (1988).

A further analysis of associated gas reserve growth and gas/oil ratios may be made using Energy Information Administration data for production and reserve additions. The leading oil producing districts in Texas are districts 8 and 8A in the Permian Basin. Each of these districts accounts for approximately 200 million barrels of production of the total Texas oil production of about 725 million barrels in 1987. Nine years (1979–1987) of data may be reviewed for each district, and the reserves of associated gas and oil added in reserve growth categories (sum of net revisions, extensions, and new reservoirs discovered in old fields) analyzed to yield a gas-oil ratio (GOR). Combining the two districts, 3,231 Bcf of associated gas reserves were added with the addition of 3,556 Mmbbl of oil reserve growth in the period from 1979 to 1987. The resulting GOR is 917 Scf/bbl, which exceeds by about one-third the ratio for the 15 selected plays analyzed and is also greater than the 700 Scf/bbl used in the resource assessment of Finley and others (1988). New field discoveries for associated gas and oil show a GOR of 2,500 Scf/bbl in district 8 and 273 Scf/bbl in district 8A, indicating that reserve growth oil in district 8 is relatively depleted in gas. This depletion is expected in that oil which has been contacted but bypassed and is now being added as reserves and would have preferentially yielded its gas early in the production history of the reservoir. In district 8A the GOR for new oil (273 Scf/bbl) and reserve growth oil (320 Scf/bbl) are comparable. This similarity bears further study, but does not detract from the resource estimates of associated gas reserve growth when viewed from the perspective of expected lower GORs in reserve growth oil.

Conclusions

Considerable amounts of unrecovered mobile oil and associated gas in Texas fields are available through geologically based infill drilling that will produce from uncontacted or poorly drained compartments in complex reservoirs. Detailed geological study of selected reservoirs allows the documentation of the control of facies heterogeneity on oil and gas recovery in important plays in Texas. Pay-continuity functions that relate reservoir continuity to horizontal distance between existing wells can be developed for each major facies in the reservoir. These functions form the basis for projecting the strategic infill oil and associated gas production potential of the reservoir for the remainder of the play.

Projection of the amount of recoverable gas in the major associated gas plays in Texas, identified by Kosters and others (1989), was based on updated amounts of uncontacted and bypassed mobile oil originally calculated by Tyler and others (1984) for each oil play in Texas. Estimates of the amount of recoverable associated gas in these selected associated gas plays range from 3.4 Tcf to 5.8 Tcf. District-wide analysis of GORs suggests that volumes of associated gas reserve growth potential derived based on the GORs of the plays analyzed are not excessive and may be conservative. The greatest recovery potential for this resource in Texas is in carbonate reservoirs in the Permian Basin. These reservoirs, which commonly have solution-gas drives and poorly developed gas caps, have low recovery efficiencies as a result of complex facies architecture. Geologically based infill wells in areas of greatest reservoir heterogeneity can recover much of this unproduced resource.

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APPENDIX

Using Type Curve Analysis to Estimate Gas Contact for Producing Wells

The central analytical technique used in this study to establish a gas reservoir's potential for reserve growth is type curve analysis. For this, production decline type curves were used to estimate the gas contacted by a producing well operating under proration. Ultimate gas contacted by a single well was calculated by summing the cumulative gas produced at the beginning of the production decline with the remaining gas in place as estimated from the type curves. This appendix provides example applications of this method to calculate the gas in place theoretically in contact and producible within the established drainage area of a well.

The type curves selected for this analysis are those developed by Fetkovich (1980). These curves were generated by combining the empirical gas backpressure equation (Rawlins and Schellhardt, 1935) with a linear material balance equation for a volumetric gas reservoir. In addition, these curves model well production at a constant fraction of the annually adjusted open-flow potential, which was the mode of operation in many of the nonassociated gas reservoirs in the Frio fluvial and deltaic plays. Additional information concerning the derivation and use of these type curves is given by Smith (1983).

<u>Example Wells</u>

Two wells producing from the Brooks reservoir in La Gloria field were chosen to illustrate the application of the type curves.

- The South La Gloria Gas Unit 1 (SLGU 1), which began producing in 1941 and continued operation until its abandonment in 1965, was selected as an example of a well analyzed during the first development time period (1956 to 1965). From the end of cycling until abandonment, this well produced a cumulative gas volume of 16.6 Bcf.

- For the second development time period (1965 to 1975), the La Gloria Gas Unit 36 (LGU 36) was selected for illustration of the methodology. This well was drilled and completed in early 1966. From the onset of production until abandonment in 1984, the well produced a cumulative gas volume of 5.4 Bcf.

The entire post-cycling production histories of SLGU 1 and LGU 36 are presented in figures A-1 and A-2, respectively. In addition, the data used to develop these plots are provided in tables A-1 and A-2.

Methodology

A six-step methodology was developed to calculate ultimate gas contacted by a single well:

STEP 1. Prepare Log-Log Plot of Production History of Single Well. Since the production decline type curves were developed for analyzing nontransient flow behavior, only the gas production history during pseudosteady-state flow is plotted. Pseudosteady-state flow behavior happens in reservoirs having closed outer boundaries (i.e., reservoirs in which no external energy, such as water influx from an aquifer or dry gas from an injection well, is being added). The onset of pseudosteady-state flow occurs when the pressure transient from the production well is affected by the closed outer reservoir boundary or by interference from adjacent producers. The pseudosteady-state gas flow data used in the analysis of SLGU 1 are presented in figure A-3 and table A-3, while similar data for LGU 36 are shown in figure A-4 and table A-4. Due to erratic monthly production volumes caused by temporary well shut-ins and pipeline delivery scheduling, gas production rates were averaged over a six-month period, and the corresponding time values were taken at the midpoint of the respective time period. The time variable for the log-log plot is measured from the beginning of the pseudosteady-state production history being analyzed.

STEP 2. Select Specific Type Curves for Analysis. Fetkovich (1980) generated a family of type curves as a function of the ratio of the initial reservoir pressure to the constant backpressure imposed on the well ($x_i = p_i/p_{wf}$). As this ratio increases to infinity, the curves

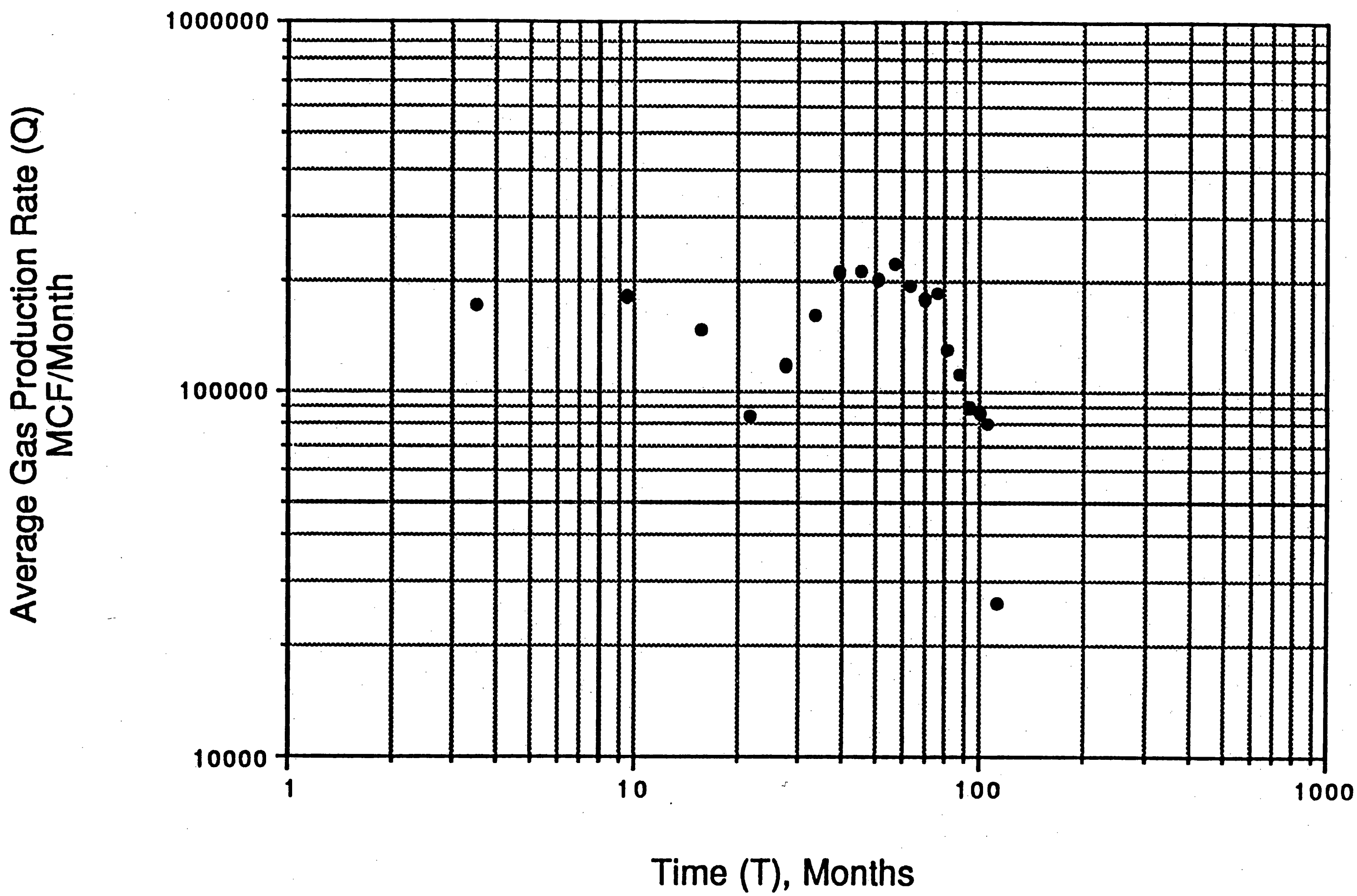

Figure A-1. Log-log plot of post-cycling gas production history of South La Gloria Gas Unit 1, Brooks reservoir, La Gloria field.

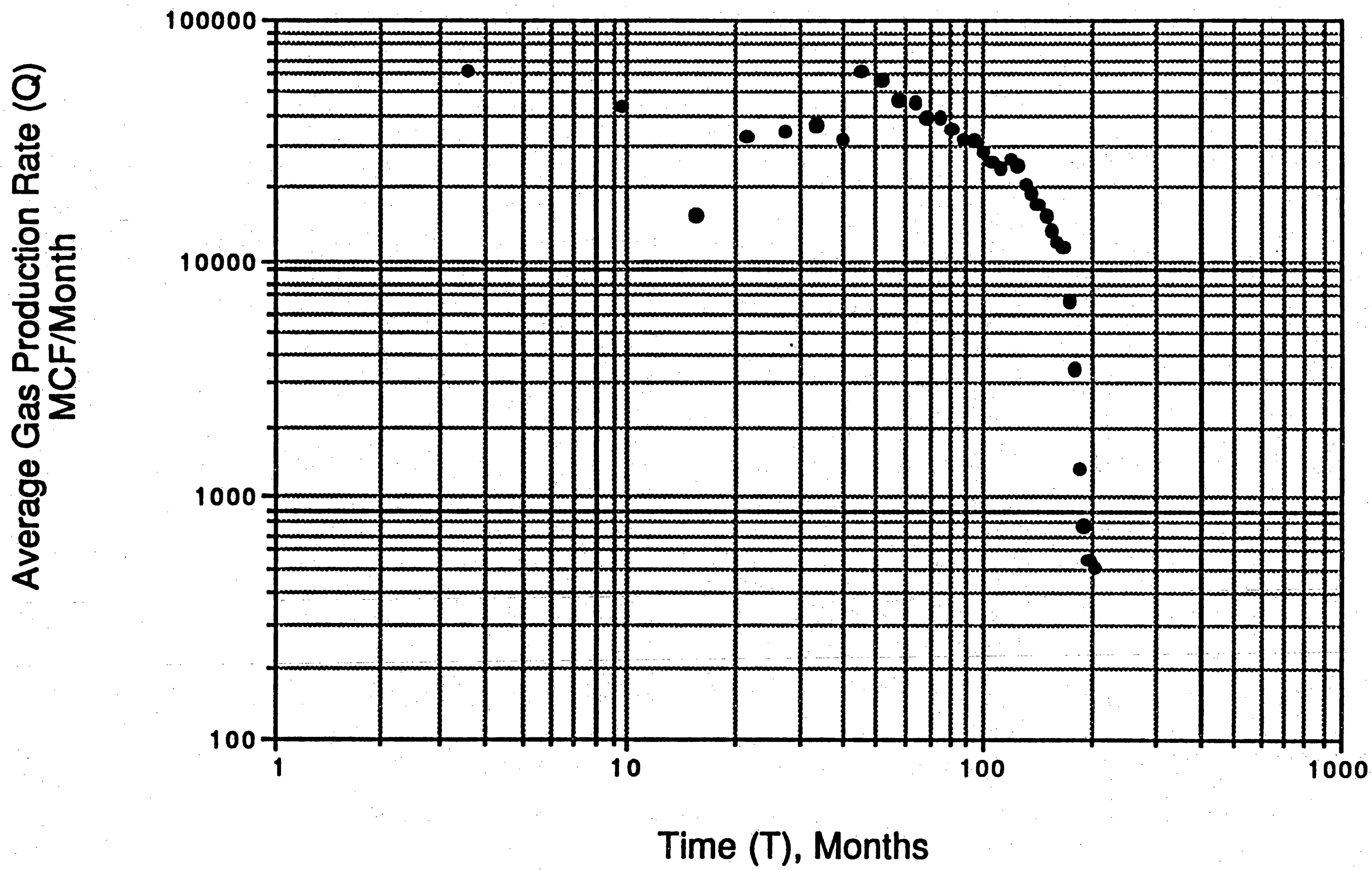

Figure A-2. Log-log plot of post-cycling gas production history of La Gloria Gas Unit 36, Brooks reservoir, La Gloria field.

Table A-1. Summary of Post-Cycling Gas Production History,*
South La Gloria Gas Unit 1, Brooks Reservoir, La Gloria Field.

Producing Time Period	Average Gas Production Rate Mcf/Month**	Cumulative Gas Production (MMCF) at End of Producing Time Period
Jan.-June 1956	172,526	1,035
July-Dec. 1956	179,991	2,115
Jan.-June 1957	146,966	2,997
July-Dec. 1957	85,929	3,513
Jan.-June 1958	116,873	4,214
July-Dec. 1958	160,221	5,175
Jan.-June 1959	209,454	6,432
July-Dec. 1959	213,906	7,715
Jan.-June 1960	201,016	8,921
July-Dec. 1960	224,901	10,270
Jan.-June 1961	192,966	11,428
July-Dec. 1961	176,143	12,485
Jan.-June 1962	185,177	13,596
July-Dec. 1962	129,889	14,375
Jan.-June 1963	110,932	15,041
July-Dec. 1963	90,039	15,581
Jan.-June 1964	86,980	16,103
July-Dec. 1964	81,399	16,591
Jan.-Feb. 1965	26,441	16,644

Cumulative Post-Cycling Gas Production = 16.6 Bcf
Well Shut In March 1965
Well Plugged and Abandoned December 1976

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* Source of data: Texas Railroad Commission gas production ledgers.
** Gas production rates are average values over the producing time period.

Table A-2. Summary of Post-Cycling Gas Production History,* La Gloria Gas Unit 36, Brooks Reservoir, La Gloria Field.

Producing Time Period	Average Gas Production Rate Mcf/Month**	Cumulative Gas Production (MMCF) at End of Producing Time Period
July-Dec. 1966	62,350	374
Jan.-June 1967	44,481	641
July-Dec. 1967	15,353	733
Jan.-June 1968	33,107	932
July-Dec. 1968	34,778	1,140
Jan.-June 1969	37,287	1,364
July-Dec. 1969	32,660	1,560
Jan.-June 1970	62,896	1,937
July-Dec. 1970	57,359	2,282
Jan.-June 1971	46,522	2,561
July-Dec. 1971	46,070	2,837
Jan.-June 1972	39,628	3,075
July-Dec. 1972	39,301	3,311
Jan.-June 1973	36,123	3,527
July-Dec. 1973	32,720	3,724
Jan.-June 1974	31,925	3,915
July-Dec. 1974	29,084	4,089
Jan.-June 1975	26,501	4,249
July-Dec. 1975	24,352	4,395
Jan.-June 1976	26,994	4,557
July-Dec. 1976	25,230	4,708
Jan.-June 1977	21,333	4,836
July-Dec. 1977	19,293	4,952
Jan.-June 1978	17,340	5,056
July-Dec. 1978	15,521	5,149
Jan.-June 1979	13,409	5,229
July-Dec. 1979	11,997	5,302
Jan.-June 1980	11,343	5,370
July-Dec. 1980	6,737	5,410
Jan.-June 1981	3,446	5,431
July-Dec. 1981	1,335	5,439
Jan.-June 1982	763	5,443
July-Dec. 1982	562	5,446
Jan.-Feb. 1983	521	5,449

Cumulative Post-Cycling Gas Production = 5.4 Bcf
Well Shut In February 1983
Well Worked Over in Another Zone March 1984

* Source of data: Texas Railroad Commission gas production ledgers.

** Gas production rates are average values over the producing time period.

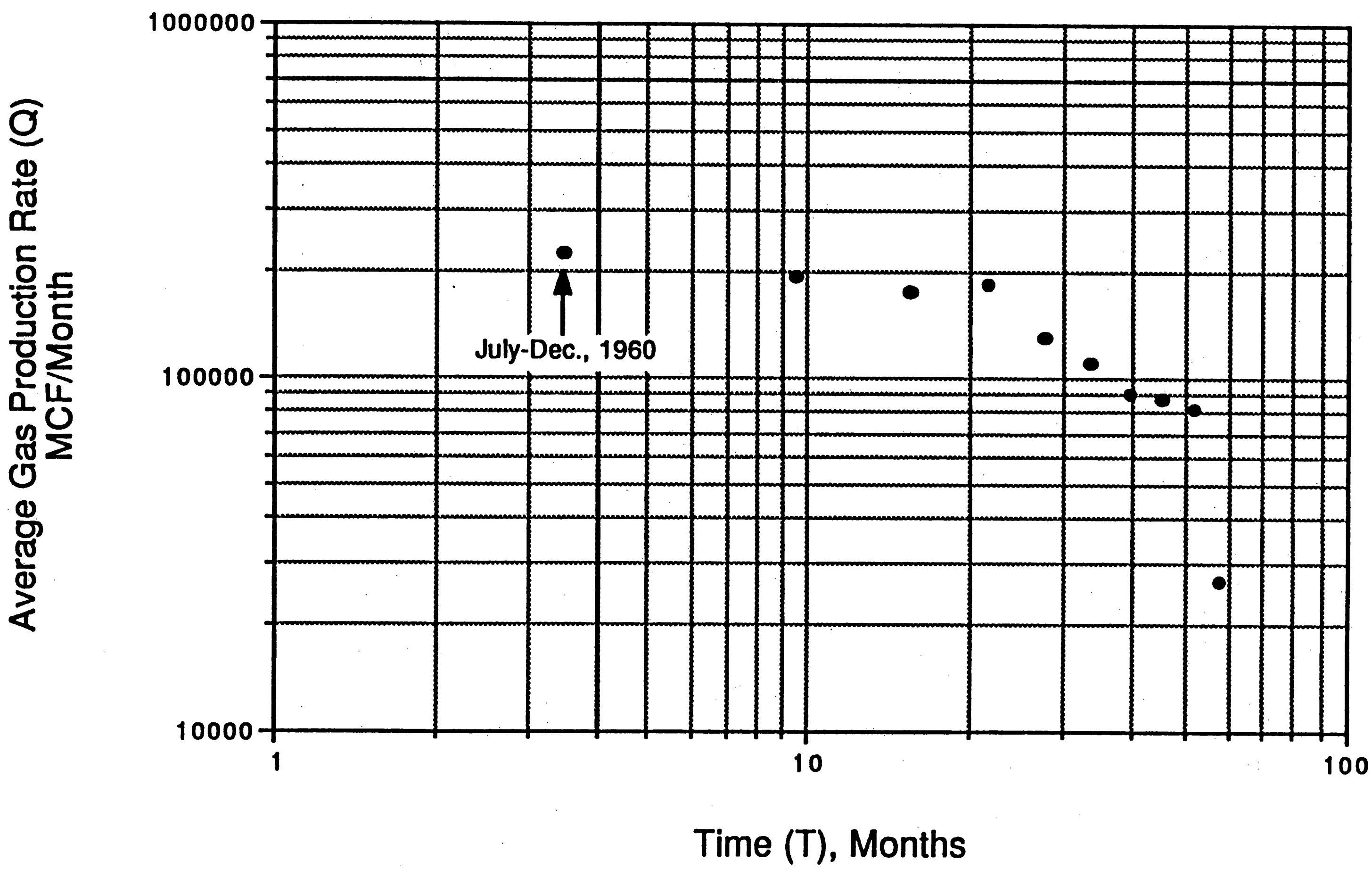

Figure A-3. Log-log plot of post-cycling gas production history used in type curve analysis of South La Gloria Gas Unit 1, Brooks reservoir, La Gloria field.

Table A-3. Summary of Production Data* Used in Type Curve Analysis, South La Gloria Gas Unit 1, Brooks Reservoir, La Gloria Field.

Producing Time Period	Cumulative Time, Months	Average Gas Production Rate Mcf/Month**	Cumulative Gas Production (MMCF) at End of Producing Time Period
Jan. 1956-June 1960	—	—	8,921
July-Dec. 1960	3.5	224,901	10,270
Jan.-June 1961	9.5	192,966	11,428
July-Dec. 1961	15.5	176,143	12,485
Jan.-June 1962	21.5	185,177	13,596
July-Dec. 1962	27.5	129,889	14,375
Jan.-June 1963	33.5	110,932	15,041
July-Dec. 1963	39.5	90,039	15,581
Jan.-June 1964	45.5	86,980	16,103
July-Dec. 1964	51.5	81,399	16,591
Jan.-Feb. 1965	57.5	26,441	16,644

Cumulative Gas Production from July 1960 through February 1965 = 7.7 Bcf

* Source of data: Texas Railroad Commission gas production ledgers.

** Gas production rates are average values over the producing time period.

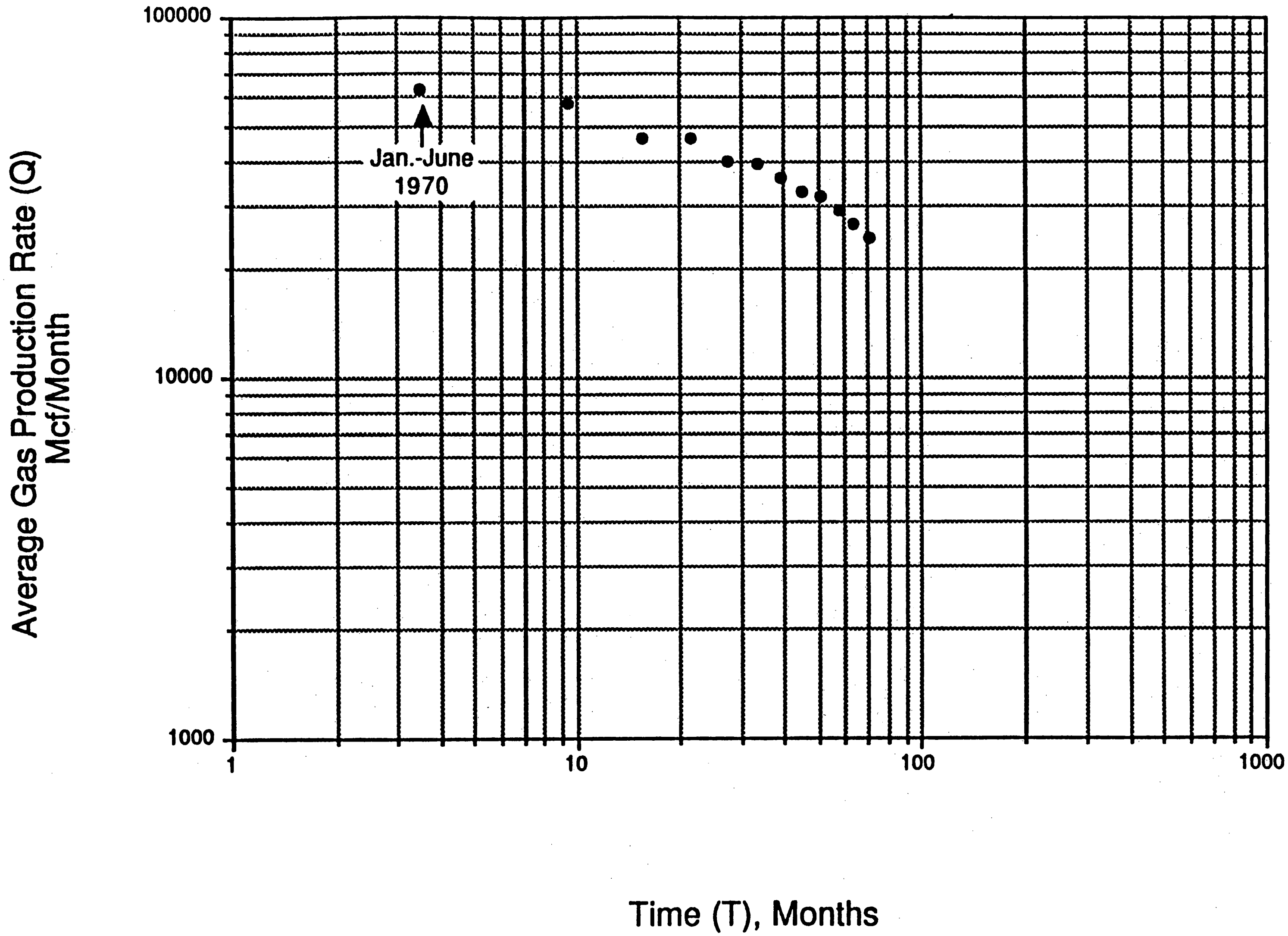

Figure A-4. Log-log plot of post-cycling gas production history used in type curve analysis for La Gloria Gas Unit 36, Brooks reservoir, La Gloria field.

Table A-4. Summary of Production Data* Used in Type Curve Analysis, La Gloria Gas Unit 36, Brooks Reservoir, La Gloria Field.

Producing Time Period	Cumulative Time, Months	Average Gas Production Rate Mcf/Month**	Cumulative Gas Production (MMCF) at End of Producing Time Period
July 1966–Dec. 1969	—	—	1,560
Jan.-June 1970	3.5	62,896	1,937
July-Dec. 1970	9.5	57,359	2,282
Jan.-June 1971	15.5	46,522	2,561
July-Dec. 1971	21.5	46,070	2,837
Jan.-June 1972	27.5	39,628	3,075
July-Dec. 1972	33.5	39,301	3,311
Jan.-June 1973	39.5	36,123	3,527
July-Dec. 1973	45.5	32,720	3,724
Jan.-June 1974	51.5	31,925	3,915
July-Dec. 1974	57.5	29,084	4,089
Jan.-June 1975	63.5	26,501	4,249
July-Dec. 1975	69.5	24,352	4,395

Cumulative Gas Production from January 1970 through December 1975 = 2.8 Bcf

* Source of data: Texas Railroad Commission gas production ledgers.

** Gas production rates are average values over the producing time period.

model well production at a constant fraction of the annually adjusted open-flow potential. In addition, each family of curves was generated for a different value of the gas backpressure exponent, n. This exponent, which is a qualitative indication of the degree of turbulence during gas flow, varies from 0.5 (turbulent) to 1.0 (nonturbulent). For the analyses of the production histories of SLGU 1 and LGU 36, the type curve developed for x_i = infinity and n = 1.0, which is shown in figure A-5, was selected. The well-specific gas backpressure exponents, n, were obtained from the Texas Railroad Commission Files (Form G-1, Gas Well Back Pressure Test, Completion and Recompletion Report and Log).

The type curves are presented in the form of a log-log plot of dimensionless rate (Q_D) against dimensionless time (T_D). The dimensionless variables are defined as follows:

Q_D	=	Q/Q_i
Q_i	=	Gas production rate at onset of pseudosteady-state flow
Q	=	Gas production rate at some time (T)
T_D	=	$Q_i T/G_i$
T	=	Time at which Q is measured
G_i	=	Gas in place in drainage area of well at onset of pseudosteady-state flow

STEP 3. Match Log-Log Plot of Actual Production History with Type Curve. For each producing well the two plots were matched by overlaying the type curve with the plot of the pseudosteady-state gas production history. The log-log plot of the actual data was moved, keeping the vertical and horizontal axes of the two plots parallel, until the actual production data points matched the selected type curve. This process is illustrated in figures A-6 and A-7 for wells SLGU 1 and LGU 36, respectively.

STEP 4. Select Match Points from Each Plot. After the best fit between the actual data and type curve had been obtained, a match point (Q, T) was selected from the actual data plot. Keeping the two plots in the matched position, a corresponding match point (Q_D, T_D) beneath (Q, T) was selected on the plot of the type curves. These match points are listed in tables A-5 and A-6 for the analyses of wells SLGU 1 and LGU 36, respectively.

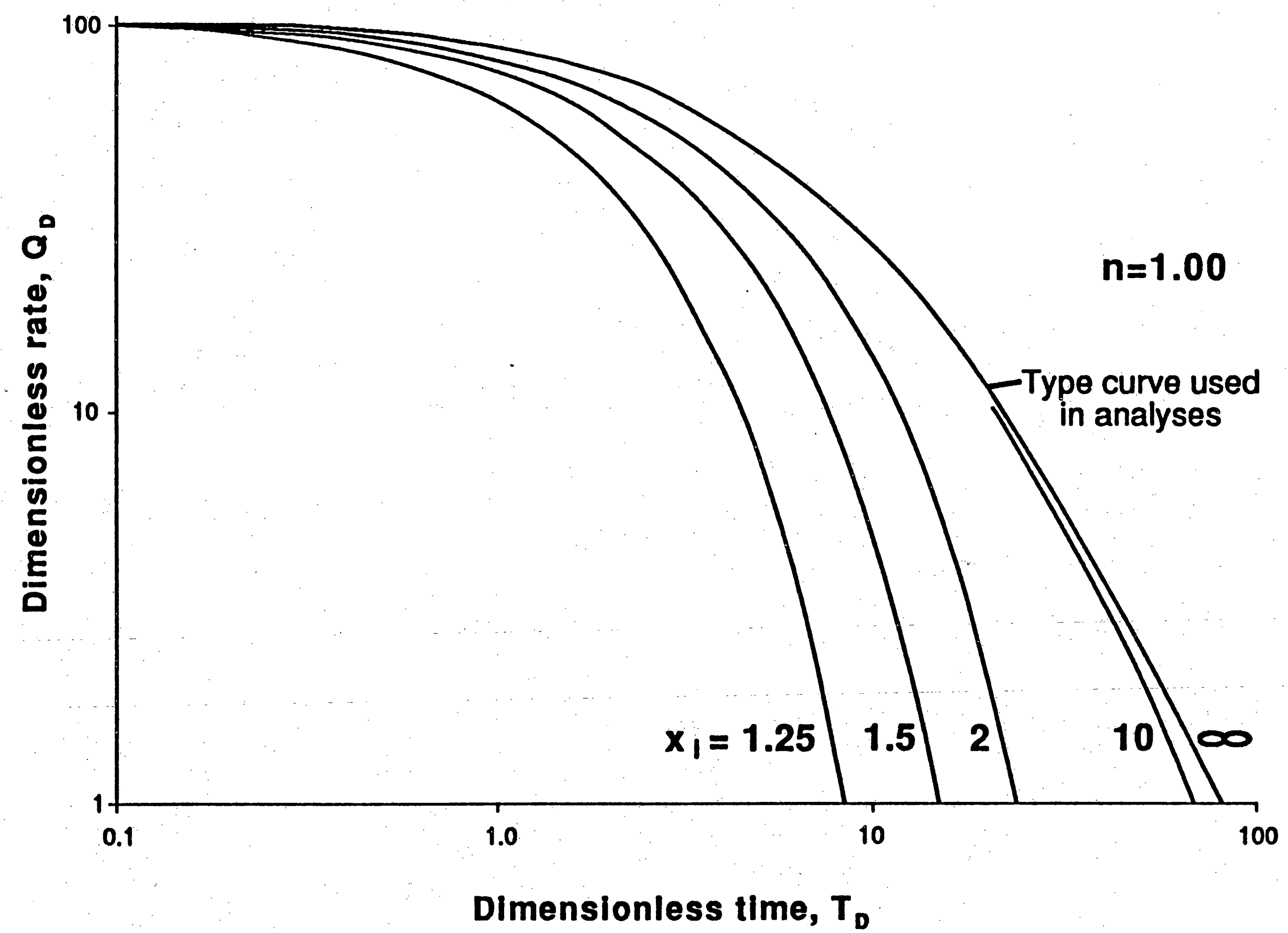

Figure A-5. Production decline type curves used in analysis of South La Gloria Gas Unit 1 and La Gloria Gas Unit 36. After Fetkovitch (1980).

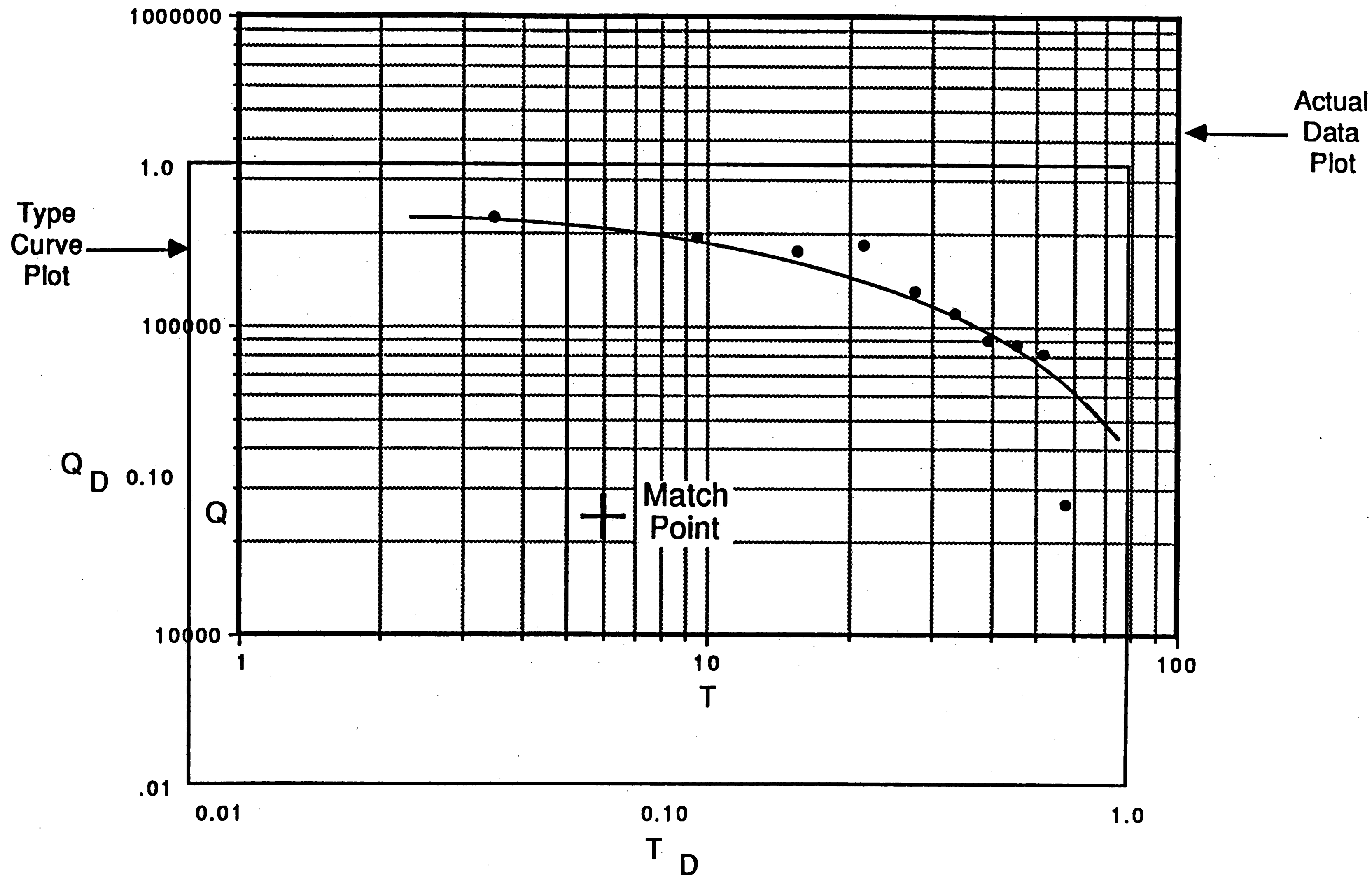

Figure A-6. Match of actual production history with type curve plot for South La Gloria Gas Unit 1, Brooks reservoir, La Gloria field.

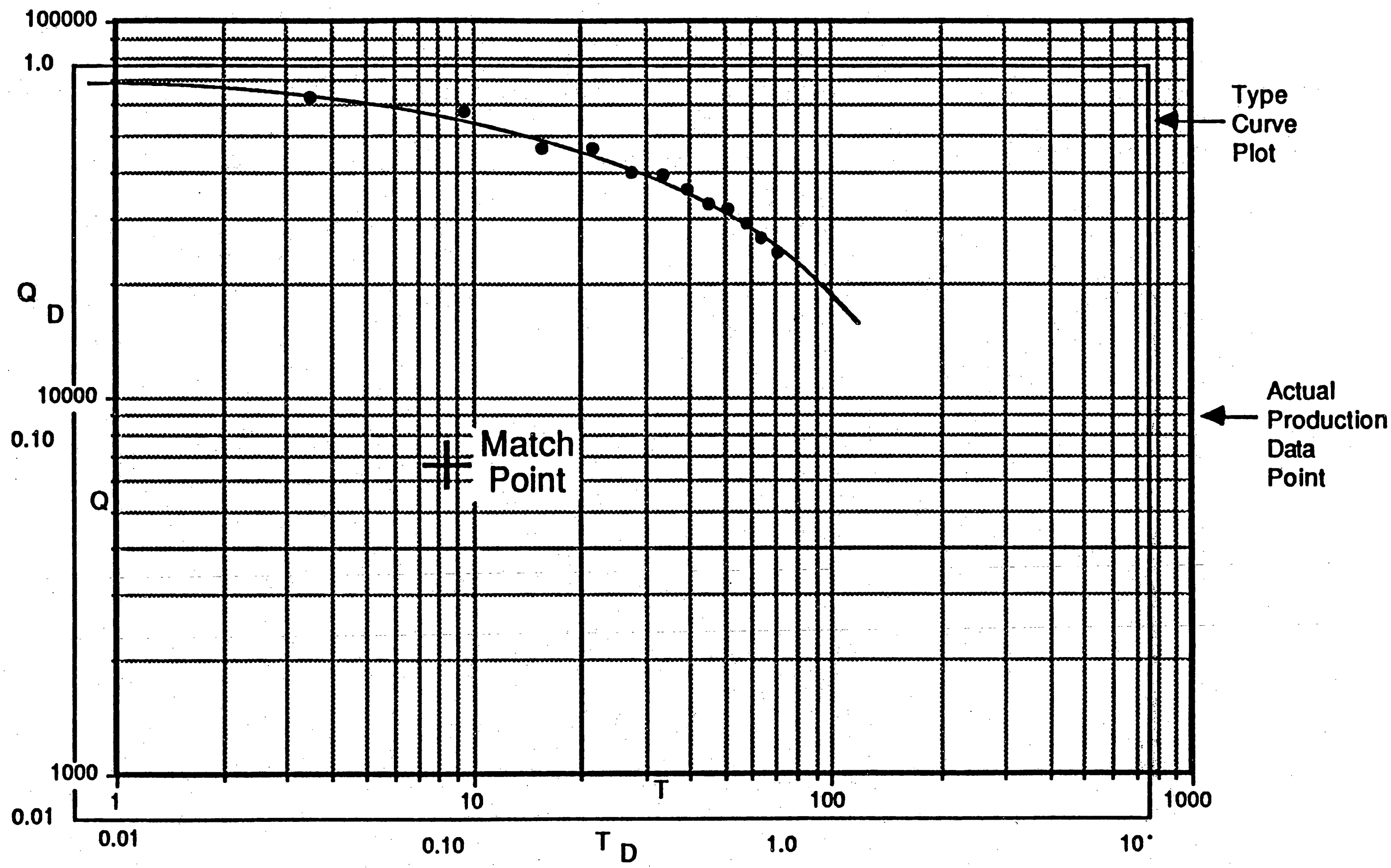

Figure A-7. Match of actual production history with type curve plot for La Gloria Gas Unit 36, Brooks reservoir, La Gloria field.

Table A-5. Summary of Type Curve Analysis to Estimate Ultimate Gas Contacted, South La Gloria Gas Unit 1, Brooks Reservoir, La Gloria Field.

Match Points

Type Curve	Actual Data
$Q_D = 0.1$	$Q = 25{,}000$ Mcf/Month
$T_D = 0.1$	$T = 6.0$ Months

Calculation of Q_i and G_i

$Q_D = Q/Q_i = 0.1,$ or $Q_i = Q/Q_D = 250{,}000$ Mcf/Month

$T_D = Q_iT/G_i = 0.1,$ or $G_i = Q_iT/T_D = 15.0$ Bcf

Calculation of Ultimate Gas Contacted

Cumulative Gas Production to July 1960 = 8.9 Bcf
Gas In Place in July 1960 = 15.0 Bcf
Ultimate Gas Contacted = 8.9 + 15.0 = 23.9 Bcf

Table A-6. Summary of Type Curve Analysis to Estimate Ultimate Gas Contacted, La Gloria Gas Unit 36, Brooks Reservoir, La Gloria Field.

Match Points

Type Curve	Actual Data
$Q_D = 0.1$	$Q = 6{,}600$ Mcf/Month
$T_D = 0.1$	$T = 8.8$ Months

Calculation of Q_i and G_i

$Q_D = Q/Q_i = 0.1,$ or $Q_i = Q/Q_D = 66{,}000$ Mcf/Month

$T_D = Q_iT/G_i = 0.1,$ or $G_i = Q_iT/T_D = 5.8$ Bcf

Calculation of Ultimate Gas Contacted

Cumulative Gas Production to January 1970 = 1.6 Bcf
Gas In Place in January 1970 = 5.8 Bcf
Ultimate Gas Contacted = 1.6 + 5.8 = 7.4 Bcf

STEP 5. Calculate Gas in Place from Match Points. As shown in tables A-5 and A-6, the actual rate match point (Q), the dimensionless rate match point (Q_D) and the definition of dimensionless rate ($Q_D = Q/Q_i$) were used to calculate the gas flow rate (Q_i) at the beginning of the pseudosteady-state flow history being analyzed. Next, the actual time match point (T), the dimensionless time match point (T_D) and the definition of dimensionless time ($T = Q_iT/G_i$) were used to calculate gas in place (G_i).

STEP 6. Calculate Ultimate Gas Contact. The ultimate gas contacted by each well was estimated by summing the cumulative gas produced prior to the beginning of the pseudosteady-state flow history being analyzed and the gas in place in the established drainage area of the well. As shown in table A-5, SLGU 1 contacted 23.9 Bcf of gas during the first development time period, and LGU 36 (table A-6) contacted 7.4 Bcf of gas during the second development time period.

This ultimate gas contacted represents the gas volume that not only has been produced but also is available for production by each well at the average well spacing during their respective development time periods. When this average well spacing changes (i.e., infill wells come on- or off-line), the drainage areas change (i.e., well interference effects), thus changing the ultimate gas contacted by the well.

Discussion

It is important to note that the ultimate gas contacted is not necessarily the gas volume that will be produced but represents the gas available for production. For example, SLGU 1 produced 16.6 Bcf of the 23.9 Bcf contacted, or 69 percent of the ultimate gas contacted, before being shut in at the end of the first development time period (1965). Internal reports obtained from Mobil indicate that this well was producing significant quantities of water between 1963 and 1965. Although the average reservoir pressure was high at this time (about 1,300 psia in 1965), the well could not continue to effectively remove water from the wellbore. Because of its location downdip and adjacent to the reservoir boundary, the water production was probably due to water coning and was not caused by an encroaching aquifer. None of the wells drilled updip and in the center of the geologic structure experienced significant water production or exhibited the effects of a strong water drive.

Similarly, LGU 36 produced 5.4 Bcf of the 7.4 Bcf contacted, or 73 percent of the ultimate gas contacted before being abandoned in 1984. There were no indications that the gas production history of LGU 36 was adversely affected by excess water production. However, the average reservoir pressure at abandonment (in 1984) was less than 300 psia, which suggests that this well was shut in because the remaining 2.0 Bcf of gas could not be economically produced at such low pressures. Using average Brooks reservoir properties (table 2) and an average pressure of 1,200 psia, it was estimated that LGU 36 contacted 14,946 acre-ft of reservoir volume (i.e., a gas volume of 7.4 Bcf). Similar calculations indicate 1.7 Bcf of gas would remain in this contacted reservoir volume at an abandonment pressure of 300 psia. This abandoned volume of 1.7 Bcf of gas compares well with the 2.0 Bcf of abandoned gas volume derived from the combination of type curve analysis for gas in place minus actual gas production data.