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Revitalizing a Mature Oil Play: Strategies for Finding and Producing Unrecovered Oil in Frio Fluvial-Deltaic Reservoirs of South Texas

Annual Report
October 1992-October 1993

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EXECUTIVE SUMMARY

Advanced reservoir characterization techniques are being applied to selected reservoirs in the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play of South Texas to maximize the producibility of resources in this mature oil play. This mature play has already produced nearly 1 billion barrels (Bbbl) of oil, yet still contains about 1.6 Bbbl of unrecovered mobile oil and nearly the same amount of residual oil resources. More than half of the reservoirs in this depositionally complex play have already been abandoned, and large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery methods. Primary technical objectives of this project are to develop interwell-scale geological facies models of Frio fluvial-deltaic reservoirs and combine them with engineering assessments and geophysical evaluations in order to characterize the Frio fluvial-deltaic reservoir architecture and flow unit boundaries and to determine the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. These results will lead directly to the identification of specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling.

Progress achieved during the first year of the contract award consisted of (1) screening fields within the Frio Fluvial-Deltaic Sandstone play for currently active reservoirs using detailed production and geologic data bases suitable for detailed characterization studies, (2) developing a regional stratigraphic model of the productive Frio reservoir sequence, (3) selecting two South Texas fields for detailed studies, and (4) gathering data and taking inventory, creating digital data bases, and undertaking initial reservoir studies of each field area.

Reservoir characteristics were screened on a playwide basis, which included the tabulation and statistical analysis of production and engineering data from 346 reservoirs throughout the Frio fluvial-deltaic oil play. Evaluation of these reservoir data resulted in the characterization of reservoir parameters, the frequency distribution for values of individual reservoir attributes, and playwide resource estimates.

In addition to the comprehensive survey and evaluation of engineering data, regional geologic data from the upper Vicksburg through Frio stratigraphic interval in South Texas were compiled and reviewed in order to construct a genetic chronostratigraphic framework for the Frio reservoir interval within the play. This framework will enable individual reservoir zones to be characterized according to their stratigraphic context. This, in turn, will provide a fundamental basis for comparisons of reservoir zones within fields, as well as for the application of specific results of individual reservoir studies to other reservoirs and fields within the play trend.

Two fields were selected for study: Rincon field, near the Mexico border in Starr County, and T-C-B field, in the northern portion of the play trend in Jim Wells County. Project personnel conducted reviews with operators of both fields to discuss research plans and arrange for access to

information on drilling history, perforation intervals, formation and reservoir tops, well logs, core descriptions and analyses, and fluid and pressure test data. Data from over 220 wells have been collected and inventoried from lease blocks in the portion of Rincon field selected for study. Similar data have been gathered for more than 80 wells in T-C-B field. Conventional core from four wells in Rincon field, representing approximately 300 ft in total thickness, has been acquired for detailed study and analysis. No whole core is available for study from T-C-B field, although arrangements have been made for examination of abundant sidewall cores for petrographic analysis.

Preliminary syntheses of reservoir log, core, and production data were undertaken in order to identify individual reservoirs with the greatest additional resource potential to target for detailed reservoir characterization studies. Initial studies of available geologic well data included the selection of representative logs for each field to characterize overall depositional style and illustrate reservoir zones and associated production. Core analysis data from both fields were tabulated, summarized, and evaluated by reservoir to identify and assess reservoir variability within the field. Production histories for individual reservoirs were reconstructed using available completion data.

Summaries of the details of field production history, available geologic and engineering data, and initial reservoir studies are discussed for both T-C-B and Rincon field study areas. The fieldwide stratigraphic and structural framework, along with preliminary compilations of production data and reservoir characteristics for individual reservoir zones, is presented for each field. On the basis of these preliminary investigations and a general assessment of reserve growth potential of reservoirs within each field area, reservoir intervals from Rincon and T-C-B fields have been targeted for detailed characterization studies.

ABSTRACT

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) oil play of South Texas has produced nearly 1 Bbbl of oil, yet still contains about 1.6 Bbbl of unrecovered mobile oil and nearly the same amount of residual oil resources. More than half of the reservoirs in this depositionally complex play have been abandoned, and large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery. Interwell-scale geological facies models of Frio fluvial-deltaic reservoirs will be combined with engineering assessments and geophysical evaluations in order to characterize Frio fluvial-deltaic reservoir architecture and flow unit boundaries and to determine the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. These results will help identify specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling.

Progress achieved during the first year of the contract award consisted of screening production and geologic data bases of fields within the Frio Fluvial-Deltaic Sandstone play to determine fields suitable for detailed characterization studies, selecting two South Texas fields for detailed studies, and performing initial reservoir studies of each field. Tabulation and statistical analysis of production and engineering data from 346 reservoirs throughout the Frio fluvial-deltaic oil play were performed in order to characterize average reservoir parameters, generate frequency distributions for values of individual reservoir attributes, and calculate playwide resource estimates. Two fields were selected for study: Rincon field, near the Mexico border in Starr County, and T-C-B field, in the northern part of the play trend in Jim Wells County. Project personnel conducted reviews with operators of both fields. Data on drilling history, perforation intervals, formation and reservoir tops, well logs, core descriptions and analyses, limited conventional core, sidewall core samples, and fluid and pressure tests were acquired from 220 wells in Rincon field and from more than 80 wells in T-C-B field.

Preliminary syntheses of reservoir log, core, and production data were undertaken to identify individual reservoirs with the greatest additional resource potential to target for detailed reservoir characterization studies. Representative logs for each field were selected to characterize overall depositional style and illustrate reservoir zones and associated production. Core analysis data from both fields were tabulated, summarized, and evaluated by reservoir to identify and assess reservoir variability within the field. Production histories for individual reservoirs were reconstructed using available completion data. On the basis of these preliminary investigations and a general assessment of reserve growth potential of reservoirs within each field area, reservoir intervals from Rincon and T-C-B fields have been targeted for detailed characterization studies.

INTRODUCTION

Summary of Project Objectives

To maximize the producibility of resources in the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) trend of South Texas, we selected two fields in which to apply advanced reservoir characterization techniques. A mature play that has already produced nearly 1 Bbbl of oil, the Frio Fluvial-Deltaic Sandstone still contains about 1.6 Bbbl of unrecovered mobile oil and nearly the same amount of residual oil resources. More than half of the reservoirs in this depositionally complex play have already been abandoned, and large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery methods.

This project will develop interwell-scale geological facies models of Frio fluvial-deltaic reservoirs from selected fields and combine them with engineering assessments to characterize reservoir architecture and flow-unit boundaries and to try to determine the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. Results of these studies should lead directly to the identification of specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling (Table 1).

Table 1. Summary of project objectives.

OBJECTIVE	APPROACH
1. Demonstrate the application of state-of-the-art reservoir characterization to incremental recovery of additional oil in known fields	• Utilize maturely developed fluvial and deltaic sandstone reservoirs as a laboratory for reservoir characterization techniques
2. Integrate geological facies models with petrophysical and engineering data to characterize fluvial-deltaic reservoir heterogeneity and identify controls on the location and volume of unrecovered mobile and residual oil	• Focus on depositional and diagenetic heterogeneity rather than structural complexity
3. Provide examples from selected fields and reservoirs to serve as a guide for other fields and reservoirs	• Characterize major Frio reservoirs in the Vicksburg Fault Zone oil play in the Texas Gulf Coast Basin
4. Define near-term opportunities for infield reserve additions in selected fields by identifying specific targets for strategic infill drilling and well recompletion	• Emphasize practical field-oriented techniques to screen for reserve growth potential and develop approaches to direct strategic targeting of new infill drilling and recompletions to overcome reservoir compartmentalization

Project Description

The project is divided into three major phases (**Figure 1**). The first phase includes (1) the initial tasks of screening fields within the play to select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment (task 1), and (2) performing initial characterization studies on these selected reservoirs in order to identify the potential for untapped, incompletely drained, and new pool reservoirs (tasks 2–4). The second phase will involve advanced characterization of the selected reservoirs in order to delineate incremental resource opportunities. This will include volumetric assessments of untapped and incompletely drained oil, along with an analysis, by reservoir, of specific targets for recompletion and strategic infill drilling. The third and final phase of the project will consist of a series of tasks associated with final project documentation, technology transfer, and the extrapolation of specific results from reservoirs in this study to other heterogeneous fluvial-deltaic reservoirs within and beyond the Frio play in South Texas.

Summary of Progress

This annual report documents technical work completed during the first year of the contract award, from October 1992 through October 1993. Work performed during the reporting period focused on tasks associated with project start-up activities and initial screening of individual fields and reservoirs within the Frio Fluvial-Deltaic Sandstone oil play to assess their suitability for detailed reservoir characterization studies (**Table 2**).

Subtask 1 consisted of initial screening of publicly available field data on reservoirs within the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play. Field summaries were compiled using data from Railroad Commission of Texas hearing files and other public data sources, and these formed the basis for decisions to review additional operator data on specific fields. Fields were screened to identify reservoirs that have a large remaining oil resource, are in danger of premature abandonment, and have geologic and production data in sufficient quantity and of suitable quality to facilitate advanced reservoir characterization studies.

Two fields that met the above criteria were selected for inclusion in this study: Tijerina-Canales-Blucher (T-C-B) field, located in the northern portion of the trend in Jim Wells County, and Rincon field, located to the south in Starr County. Project members met with operators of both fields to review available geologic and production field data, discuss research plans, and collect geological and engineering field data necessary for reservoir characterization and targeted resource addition studies (subtasks 2 and 3). Geologic and production data for both fields have been organized, and initial reservoir characterization studies are currently underway. This first stage of reservoir evaluation has been focused on developing a detailed stratigraphic framework of the productive reservoir intervals in both fields and assessing the additional resource potential of individual reservoir units.

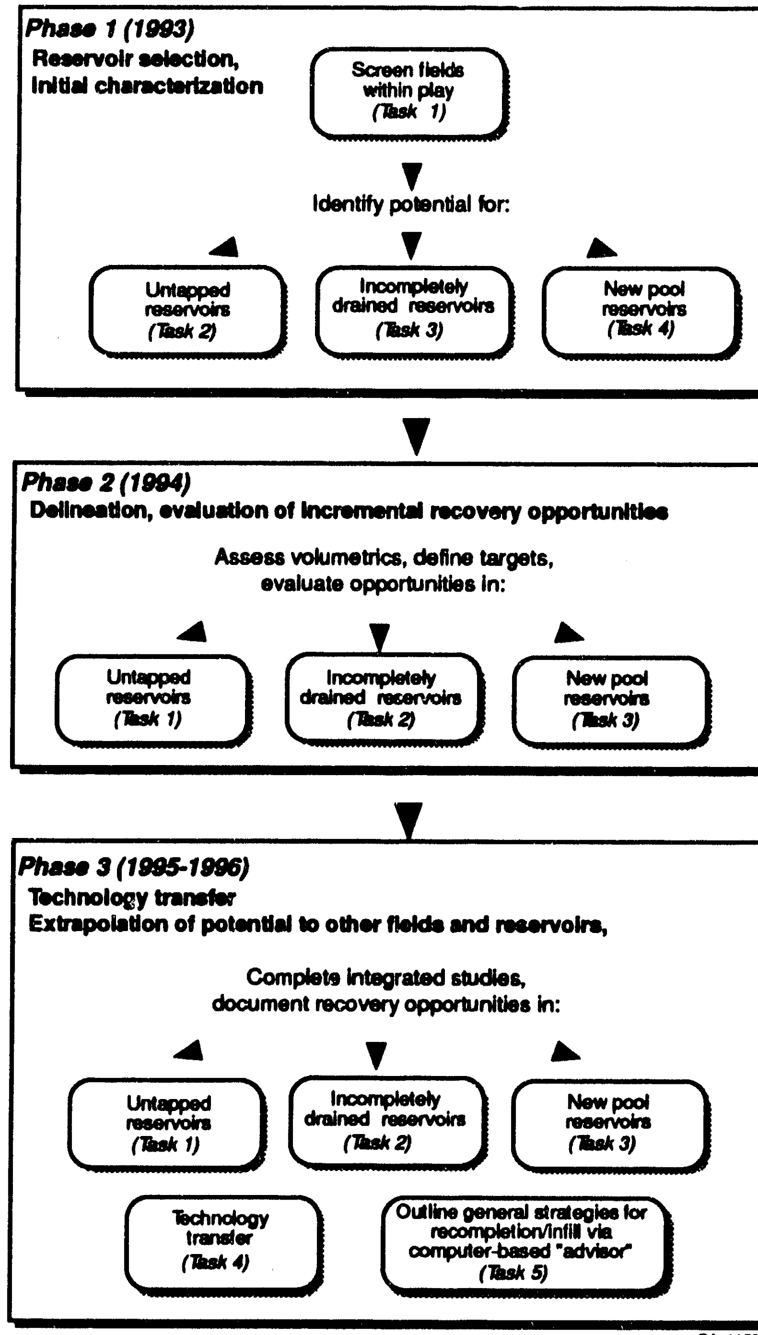


Figure 1. Diagram of work structure for this project illustrating three primary phases and a breakdown of individual tasks associated with each phase of the project. Phase 1 studies were completed during the first project year and are the focus of this report.

Table 2. Significant accomplishments in Project Year 1: 1992–1993.

1. Selection of two South Texas fields for reservoir characterization studies
2. Reviews with field operators, data gathering and inventory
3. Development of digital log data bases
4. Construction of type logs for fields, establishment of regional cross-section framework
5. Preliminary synthesis of reservoir log, core, and production data
6. Synthesis of reservoir pressure and production data
7. Comparison of production histories by reservoir
8. Synthesis of core analyses data by reservoir

RESERVOIR HETEROGENEITY AND RESERVE GROWTH POTENTIAL IN FLUVIAL-DELTAIC SANDSTONES

Stratigraphic Architecture and Scales of Reservoir Heterogeneity

The architecture of sandstones in clastic reservoirs has a direct impact on hydrocarbon recovery. Internal features within reservoir sandstone units define the geometry of fluid pathways that control the efficiency of hydrocarbon migration to the well bore and therefore provide fundamental constraints on the ultimate volume of conventionally recoverable oil and gas that remain in the ground when the reservoir is abandoned (Tyler and others, 1992). Understanding the details of reservoir architecture and its inherent control on fluid migration is critical to efficiently targeting the remaining recoverable oil resource in maturely developed reservoirs.

The internal geometry of sand bodies and the degree of interconnectedness, communication, or compartmentalization between individual reservoir sand bodies are products of the nonuniformity, or heterogeneity, of a rock reservoir (Alpay, 1972). Reservoir structure can be exceedingly complex, containing heterogeneities from scales of kilometers down to scales of less than 1 millimeter (Lasseter and others, 1986). To facilitate studies of the various types of heterogeneities present in rock reservoirs, researchers have arbitrarily divided reservoir heterogeneity into four different classes, or levels, that relate to different scales of investigation (Alpay, 1972; Weber, 1986; Tyler, 1988). These levels of heterogeneity range from the megascopic identification of variations in depositional style and sediment stacking patterns within an entire sedimentary basin sequence, to macroscopic and mesoscopic variations described within an individual depositional unit, to the microscopic study of pore throat variations between grains in a single core (**Figure 2**). The description and characterization of reservoir heterogeneity at each of these scales require separate methodologies, different data types, and the use of various analytical tools designed to measure and detect heterogeneity at different levels of resolution (**Figure 3**) (Worthington, 1991; Jackson and others, 1993).

Megascopic studies of reservoir heterogeneity address large-scale relationships between reservoirs that occur within a play trend or field area (basin scale and field scale) and are controlled by regional variations in base level that occur in response to changes in eustasy, sediment supply, subsidence, and climate (Miall, 1988). An understanding of regional-scale variations in reservoir architecture (for example, connected, laterally amalgamated fluvial channels versus isolated, vertically stacked fluvial channels) is important in identifying reservoir analogs within a play and assessing intrafield variations in reservoir quality and recovery efficiency.

Intermediate scales of reservoir heterogeneity include variations at the macroscale level of the genetic sand unit or depositional facies (for example, point-bar versus crevasse splay deposits) and mesoscale variations within ripple laminae and beds. Microscopic heterogeneity refers to variations at the scale of grains, pores, and pore throats. These small-scale heterogeneities are responsible for

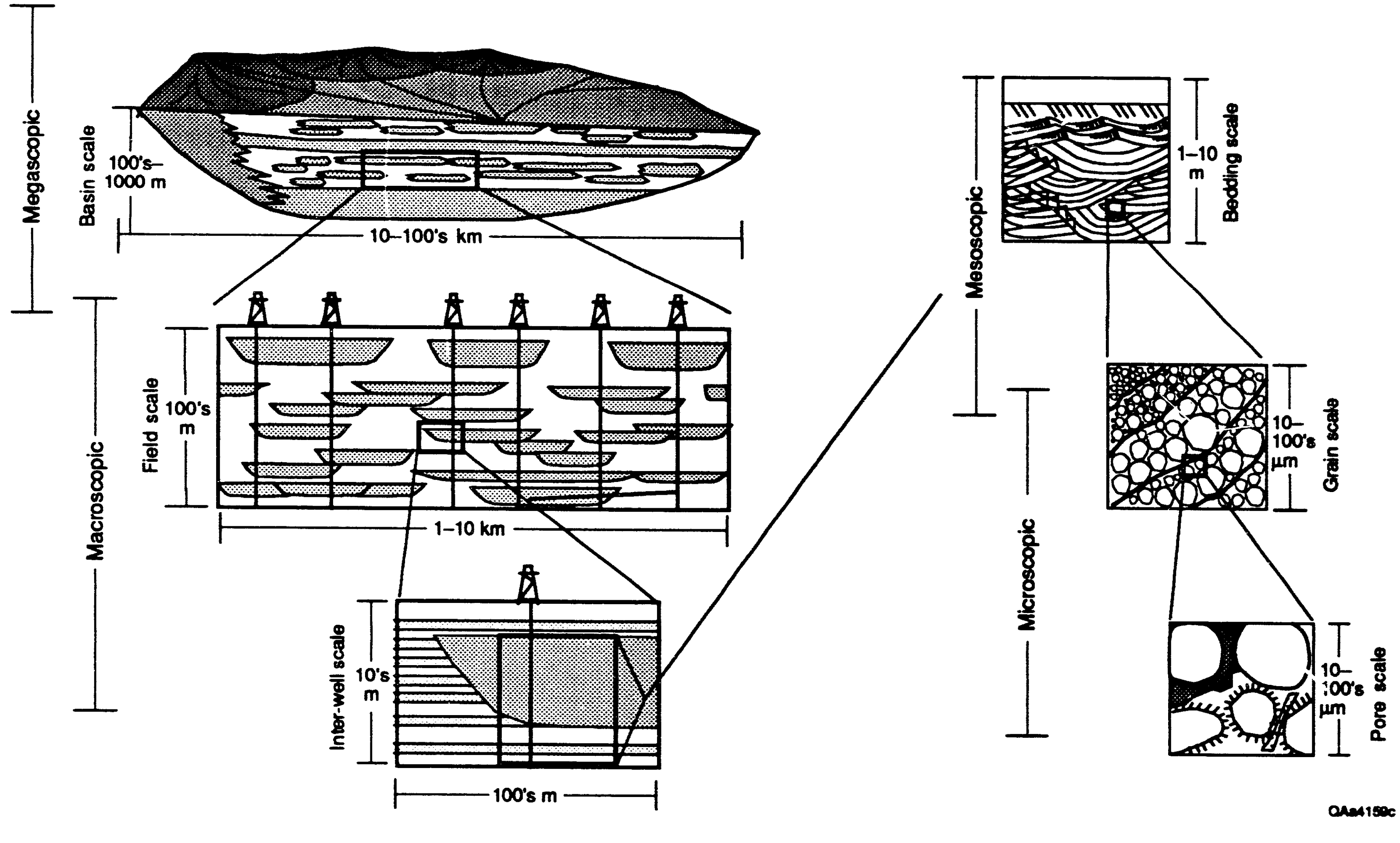


Figure 2. Examples of scales associated with the various levels of heterogeneity present in fluvial-deltaic reservoirs. Compiled from Weber (1986) and Miall (1988).

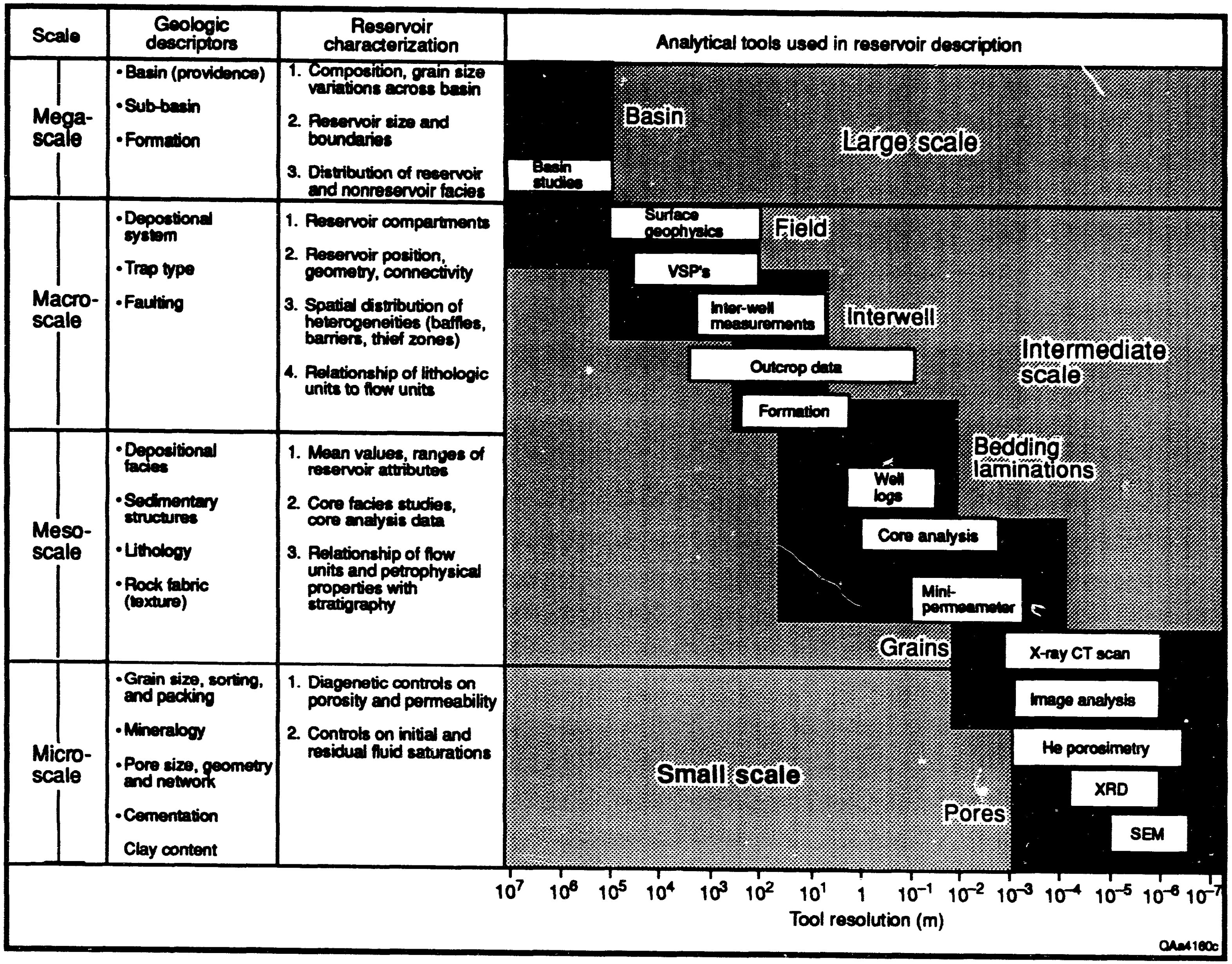


Figure 3. Analytical tools used in the description of reservoir heterogeneity at various scales. Data from Worthington (1991) and Jackson and others (1993).

variations in capillarity and local fluid-flow pathways that control the nature of oil saturation and the retention of residual oil in the vicinity of the well bore. This level of heterogeneity is largely a function of diagenetic processes.

Heterogeneity in fluvial sandstones has also been described in terms of a hierarchy of bounding surfaces of various scales (Miall, 1988). These range from large-scale sixth-order surfaces that separate depositional sequences, to fifth- and fourth-order surfaces defining major reservoir packages and individual channel units at the interwell level, respectively, to smaller fourth- through first-order bounding surfaces, which are small-scale features recognized at the core level, but their limited lateral extent (<25 acres) precludes correlation at the interwell level. A summary of the various scales and nomenclature associated with reservoir heterogeneity is provided in **Table 3**.

Compartmentalization in Fluvial-Deltaic Reservoirs

The scale of heterogeneity that is most critical in controlling fluid flow pathways and is the key to accessing unrecovered mobile oil remaining in the reservoir is the intermediate, interwell, or macroscopic scale of heterogeneity. This level of heterogeneity most closely corresponds to the reservoir flow unit. Macroscale features include variations in depositional and diagenetic facies that serve to compartmentalize a reservoir. Physical bounding elements that define the permeability structure of a reservoir and divide it into separate flow units include both bedding surfaces as well as nonpermeable rock types that act as intrareservoir seals between individual reservoir compartments (Tyler and Finley, 1991). The types of permeability barriers present and the style and extent of reservoir compartmentalization that they create are directly related to the depositional system. LeBlanc (1977) documented many examples of how the distribution, internal characteristics, and continuity of sandstone reservoirs are primarily controlled by the original environment of deposition.

Stratigraphic compartmentalization that is inherent in fluvial-deltaic depositional systems is responsible for the incomplete and inefficient recovery of available oil and gas resources within a developing field. Various categories of infield reservoir compartments, in addition to those currently producing or depleted, are recognized as targets for incremental recovery in mature fields (Levey and others, 1992). These include (1) untapped reservoir compartments, (2) incompletely drained reservoir compartments, and (3) deeper pool targets. Characteristics of these various reservoir targets have been summarized in **Table 4**. Untapped and incompletely drained reservoir compartments are the primary targets that can be identified through detailed depositional facies analysis and the identification of interwell scale heterogeneities that divide reservoir facies into separate flow units. Lithologic heterogeneity and the presence of uncontacted and incompletely drained reservoir compartments located between existing well spacing are illustrated in **Figure 4**. The present level of development within a field, described by current well spacing and the density of completions within reservoir zones, can be used as a relative indicator of remaining untapped potential.

Table 3. Scales of reservoir heterogeneity.

Level of Heterogeneity and Order of Bounding Surface (Miall, 1988)	**Lateral Dimensions (Width)**	**Vertical Dimensions (Thickness)**	**Depositional Unit**	**Subsurface Correlation (Data Types and Mapping Methods)**
Basin Scale *(6th order)*	10-100's km	100's-1000's m	• Formation • Member	• Regional correlation of wireline logs
Field Scale *(5th order)*	1-10 km	100's m	• Channel (Sheet) sandstones • Channel (Ribbon) sandstones	• Intrafield correlation of wireline logs • 2-D seismic data • Closely spaced logs • 3-D seismic data
Interwell (Intrafield) Scale *(4th, 3rd, 2nd orders)*	100's m	10's m	• Macroforms • Bed cosets	• Core studies, facies analysis
Bedding Scale *(1st order)*		1-10 m	• Individual crossbeds	• Core studies
Grain Scale		10-100's mm		• Petrography
Pore Scale		10-100's mm		• Petrography • SEM • X-ray diffraction • Capillary pressure measurements

Table 4. Reservoir compartment terminology.

TYPE	DEFINITION	STRATEGIES FOR IDENTIFICATION
1. UNTAPPED RESERVOIRS	• Not contacted during original field development • Separated vertically or laterally from adjacent producing reservoirs	• Identification by stratigraphic correlation of key shale horizons • Small and narrow channels within a single operational reservoir unit exhibit high degree of variability
2. INCOMPLETELY DRAINED RESERVOIRS	• Not drained when original completions reach an economic limit • May or may not be separated vertically or laterally from adjacent reservoirs	• Correlation of marker horizons within reservoir aids in recognition of separate compartments • Pressure data can be used to identify barriers which inhibit complete drainage of a reservoir
3. DEEPER POOL RESERVOIR	• May have been contacted during original field development, but is at depth below established production	• Regional facies analysis • Development of sequence stratigraphic framework for reservoir systems • Application of field analogs

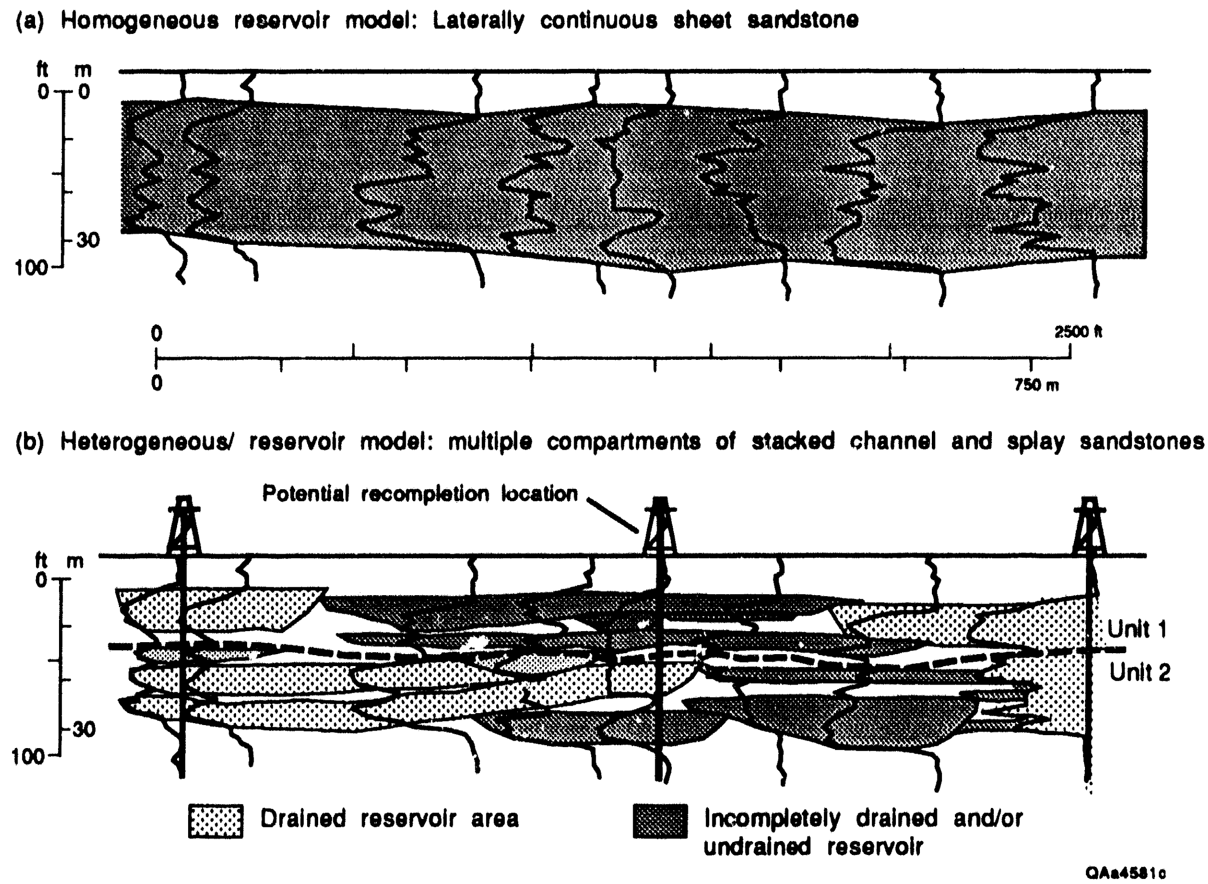


Figure 4. Schematic geological cross section contrasting the generalized interpretation of a sandstone reservoir as a simple, laterally continuous (homogeneous) producing zone (A) with a more detailed interpretation of the same sandstone unit as a complex heterogeneous zone consisting of multiple reservoir compartments (B). In the traditional example of the simple reservoir unit (A), good reservoir continuity suggests that the reservoir can be completely drained at the current well spacing. The complex architecture illustrated in (B) indicates the presence of facies boundaries within the sandstone that create multiple compartments, some of which are only partially drained or are completely untapped at the present well spacing. Modified from Jackson and Ambrose (1989).

In addition to untapped and incompletely drained reservoir targets, there may be additional resource potential present in deeper pool reservoirs, which may exist in reservoir zones already penetrated, but below previously established production. Evaluations of deeper pool targets are based on a much less dense framework of data; therefore, they often require regional facies analysis and sequence stratigraphic studies of reservoir systems to properly assess their recovery potential.

Recovery Potential of Fluvial-Deltaic Sandstone Reservoirs

Estimates of oil recovery from reservoirs in fields across the United States average 34 percent (Tyler, 1988). A recent survey of more than 450 Texas oil reservoirs documented a well-defined trend of declining recovery efficiency with increasing heterogeneity and complexity of reservoir architecture (Galloway and others, 1983). Recovery efficiencies in clastic reservoirs range from a high of nearly 80 percent in the architecturally simple, laterally continuous, wave-dominated delta and barrier-strandplain reservoirs of East Texas, to a low of 8 percent in sand-poor, discontinuous basin-floor turbidite reservoirs in the Permian Basin (Tyler and others, 1984). Fluvial-deltaic reservoirs fall between these extremes, with complex channelization and abrupt facies variation in some fluvial-deltaic reservoir systems responsible for recovery efficiencies as low as 20 percent. This large variation in recovery efficiency is well illustrated for Texas oil reservoirs, because populations of fluvial-deltaic, deltaic, and submarine fan reservoirs contain similar volumes of oil in place but the deltaic reservoirs account for more than 50 percent of total reservoir production (Tyler and Finley, 1991).

Lateral and vertical reservoir heterogeneity is controlled by the depositional processes responsible for creating the reservoir, and this heterogeneity in turn is responsible for developing the reservoir architecture that provides the fundamental control on hydrocarbon recovery efficiency in a given reservoir unit (Tyler and Finley, 1991). Developing a detailed understanding of the processes, styles, and scales of heterogeneity that characterize a particular reservoir type can become a powerful predictive tool in the identification and delineation of additional unrecovered oil and gas resources. Using this approach, major sandstone types can be classified according to their degree of vertical and lateral heterogeneity that can be used to predict recovery efficiencies and the residency of unrecovered mobile oil in the reservoir (Tyler and Finley, 1991) (**Table 5**).

Reservoir Characterization within a Sequence Stratigraphic Framework

Application of sequence-stratigraphic concepts has made important contributions in many recent reservoir characterization studies. These concepts provide a chronostratigraphic framework in reservoir studies that is useful in delineating the structure of reservoir flow units and also provide a means of transporting results of reservoir studies to other fields in analogous stratigraphic settings. There are several examples of the application of sequence stratigraphy (see, for example, Vail, 1987; Van Wagoner and others, 1988) in the megascale characterization of reservoirs that takes place within exploration of frontier and emerging basins, but sequence stratigraphy also is becoming increasingly more common as a tool in the detailed reservoir characterization of mature fields. Construction of a reservoir framework at the sequence and parasequence scales provides for the natural packaging of strata into genetic units that correlate well to petrophysically defined units at the interwell scale (Tyler and others, 1992). Definition of lithologic and diagenetic reservoir flow-unit architecture of fluvial-deltaic sandstones within the context of a well-defined sequence-stratigraphic framework can provide a model to predict the distribution and continuity of permeable zones in other reservoirs deposited in analogous depositional settings (**Table 6**).

The development of a detailed regional stratigraphic and structural context for a reservoir is viewed as a critical step in evaluating its potential for secondary hydrocarbon recovery. Specific

Table 5. Spectrum of reservoir heterogeneity and resulting recovery potential in clastic reservoirs (adapted from Tyler and Finley, 1991).

	LOW		MODERATE	HIGH	
VERTICAL HETEROGENEITY	*Depositional Environment*	*Recovery Potential*	*Depositional Environment*	*Depositional Environment*	*Recovery Potential*
LOW	Wave-dominated delta Barrier core Barrier shoreface Sand-rich strandplain	Very high recovery efficiency	Delta-front mouth bar Proximal delta front Tidal deposits Mud-rich strandplain	Meander belt (*single story*) Fluvial-dominated delta (*single story*) Back barrier (*single story*)	Low recovery efficiency Mobile oil compart-mentalized, uncontacted, and laterally bypassed
MODERATE	Eolian Wave-modified delta (distal)		Shelf bars Alluvial fan Fan delta Lacustrine delta Wave-modified delta (proximal)	Braided stream Tide-dominated delta	
HIGH	Basin-floor turbidites	Low recovery efficiency Mobile oil vertically bypassed		Back barrier (*stacked units*) Fluvial-dominated delta (*stacked units*) Fine-grained meander belts (*stacked units*) Submarine fans (*stacked units*)	Very low recovery efficiency Mobile oil uncontacted and bypassed

Table 6. Hierarchy of stratal units used in sequence stratigraphy, their geometric dimensions, time scales associated with formation, and applied relevance to reservoir studies (adapted from Van Wagoner, 1990).

Unit	Operational Definition	*Vertical* Thickness Range (ft)	*Lateral* Width Range (sq. miles)	Time Span of Deposition	Relationship to Reservoir Studies
Sequence	Succession of genetically related strata bounded by unconformities and their correlative conformities	100's–1000's	100's–10,000's	10^5-10^6 years	Reservoir framework
Parasequence Set	Succession of genetically related parasequences forming a distinct stacking pattern (usually progradational) and commonly bounded by marine flooding surfaces and their correlative surfaces	10's–100's	10's–1000's	10^4-10^5 years	Total reservoir interval
Parasequence	Succession of genetically related beds and bed sets bounded above and below by marine flooding surfaces and their correlative surfaces	10's	10's-1000's	10^2-10^4 years	Basic reservoir mapping unit (related to flow units)
Bedset	Succession of genetically related beds bounded by surfaces of erosion, non-deposition, or their correlative conformities	1-10's	1-100's	1-10^3 years	
Bed	Succession of genetically related laminae or lamina sets bounded by bedding surfaces of erosion, non-deposition, or their correlative conformities	0.1-10's	1-100's	minutes to years	
Lamina set	Succession of genetically related laminae bounded by surfaces of erosion, non-deposition, or their correlative conformities	0.01-1	0.1-10	minutes to days	
Lamina	Smallest megascopic layer	0.01-0.1	<1	minutes to hours	

architectural styles of reservoirs deposited in fluvial-deltaic environments are a function of varying rates of sediment supply, subsidence rates, eustatic sea-level change, and other extrabasinal factors (Miall, 1988). Different rates of coastal plain aggradation control the stacking geometry and connectivity of channel sandstones. Laterally stacked and connected channel systems are developed during slow net aggradation, whereas vertically stacked and isolated channel systems occur during relatively rapid aggradation (Kerr and Jirik, 1990; Kerr and others, 1992). Previous detailed work on the regional geology of the Frio depositional sequence (Galloway and others, 1982, 1986; Galloway, 1989) and several recent reservoir characterization studies of Frio gas reservoirs (Jirik, 1990; Kerr, 1990; Kerr and Jirik, 1990; Levey and others, 1992) provide an excellent context in which to study individual facies components of oil-bearing reservoirs in the Fluvial-Deltaic Sandstone play of South Texas.

Integrated Geologic and Engineering Evaluation of Reservoir Heterogeneity

Advanced recovery approaches in fluvial-deltaic reservoirs depend on characterization that integrates geological facies models with engineering assessments of reservoir behavior and production histories. Identification and production of incremental mobile oil resources depend on determining which parts of the reservoir have not been effectively contacted or swept because of depositional heterogeneity and the resultant reservoir compartmentalization. Assessing the potential for incremental reserve growth in mature fields requires identifying the location and volume of the remaining resource in the reservoir.

An evaluation of operator drilling and development history, including basic data on reservoir completion and perforation spacing, defines the basic level of field development and is an important factor in determining the potential for additional recovery within a field (Figure 5). Analysis of production trends and compilation of well history information commonly provide direct information on the spatial location, productivity, and volumes of additional reserves. Variations in the number of reservoirs per square mile, the number of completions per reservoir per square mile, and ratios of cumulative production per completion can provide important insights into areas of the field or reservoir zones with additional potential. In addition, different fields often employ different definitions of the term "reservoir"; in some fields a reservoir refers to individual sandstone bodies less than 30 feet thick; in other fields, reservoir zones define a much thicker composite interval (often >100 ft) consisting of multiple isolated sandstone bodies interbedded with mudstone (Ambrose and others, 1992). Careful tabulation of reservoir production and completion data is necessary in order to accurately compare reservoir production between different fields and, in some cases, within a single field. These methods were employed as a first step in screening data from various fields throughout the play and in comparing the levels of production of reservoirs within a single field.

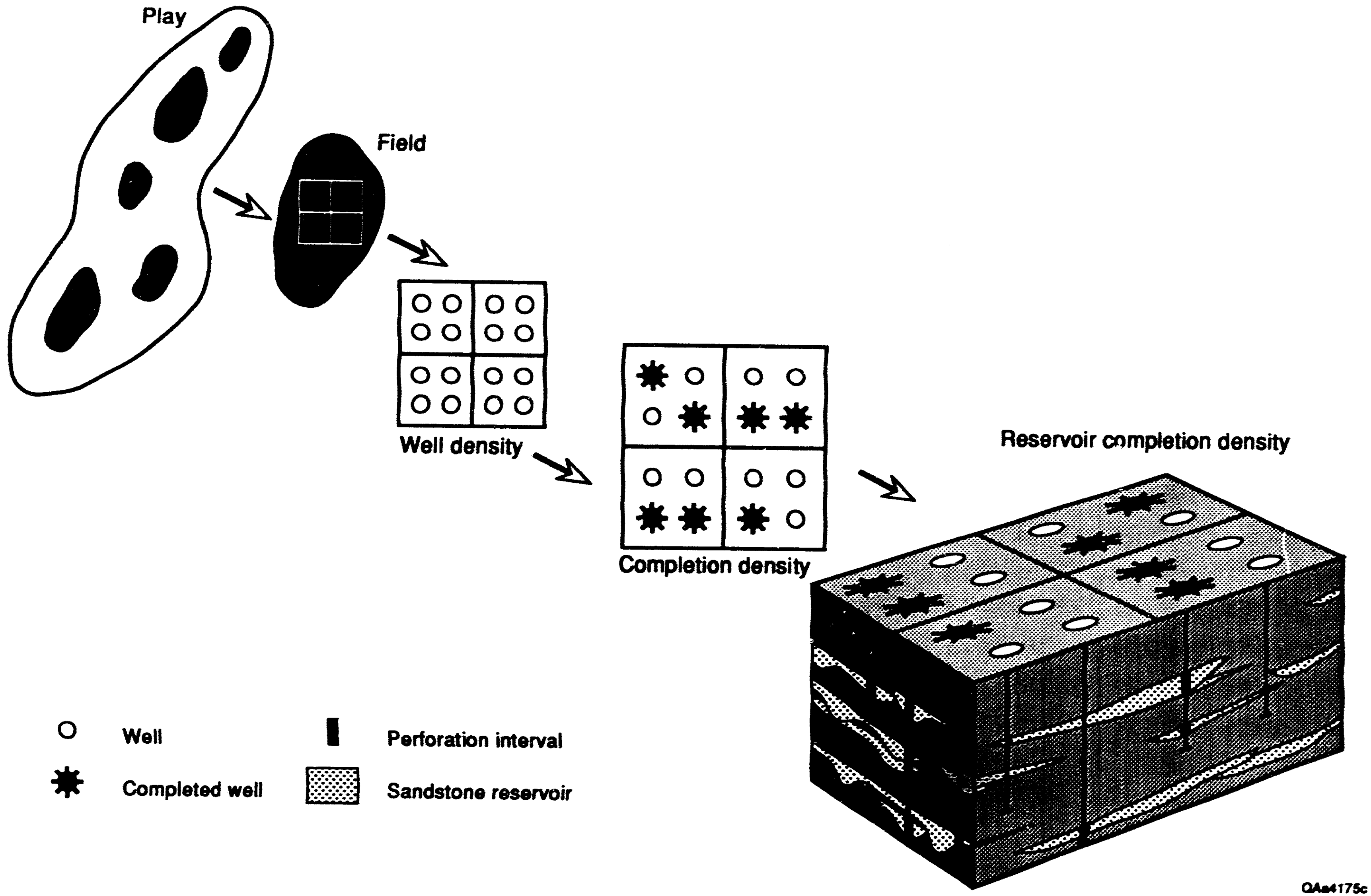


Figure 5. Illustration of various field and reservoir production parameters that can be used in the evaluation of reservoir infill potential within a play, field, or reservoir. Density of completions is identified within a field area and subsequently for individual reservoir zones. The distribution of completions per reservoir is used to identify which zones have lower completion densities and therefore higher potential for incremental recovery of additional reserves. In the example shown here, reservoir B has a lower completion density than that of zones A and C and may possess greater potential for containing untapped or partially drained reserves.

FRIO FLUVIAL-DELTAIC SANDSTONE PLAY OVERVIEW

Location and Characteristics of Fields within the Play

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play (**Figure** 6) is located in South Texas and extends from Starr County northeastward to Jim Wells and Nueces Counties, Texas (Galloway and others, 1983). Fields in the play produce oil from heterogeneous fluvial and deltaic sandstones of the Oligocene Frio and upper Vicksburg Formations on the eastern, downthrown side of the Vicksburg Fault Zone. Oil-bearing traps consist predominantly of shallow rollover anticlines that formed during later stages of fault movement along the fault zone (Jackson and Galloway, 1984; Tyler and Ewing, 1986). Deeper structures are characterized by synthetic and antithetic faults with large displacements commonly in excess of hundreds of feet. Individual fields within the play produce from a stratigraphic interval that averages 2,000 ft in thickness and consists of 20 to 40 separate sandstone reservoirs that are interbedded with mudstone (Stanley, 1970).

Production History

The Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) has produced nearly 1 Bbbl of oil equivalent from 129 reservoirs in fields throughout the play in South Texas (Galloway and others, 1983; Kosters and others, 1989). Total original oil in place estimates, however, are in excess of 4 Bbbl, of which 1.6 Bbbl is classified as unrecovered mobile oil, and nearly the same amount is attributed to residual oil resources (**Figure** 7).

The development status of the play is classified as mature to supermature, because most of the major fields in the play were discovered in the late 1930's and early 1940's (**Figure 8a**). Reservoir abandonment rates increased significantly during the time period from 1987 to 1989 (**Figure 8b**). The number of producing wells in the play showed a precipitous decline of over 50 percent during a 5-yr period from 1974 to 1978. The play has been experiencing a steady decline in both overall production and individual well flow rates throughout the 1980's (**Figure 8c**). By 1989, over one-half of the 129 reservoirs included in the play were no longer producing. Annual production from 376 active wells in 1989 was approximately 1.2 MMbbl. Average daily production rates from these wells had declined to 8.9 bbl/d.

Oil and natural gas reservoirs produce from the same stratigraphic interval. Production drive mechanism is dominantly gas-cap expansion. Most fields have large gas caps and have been unitized to properly develop and maintain pressure in the complex sandstone reservoirs. In many cases, produced natural gas has been cycled back into some of the reservoirs to maintain production of oil.

Engineering attributes for Frio reservoirs throughout the play are described in the next section. The typical reservoir is a dip-oriented fluvial or distributary-channel sandstone draped over a northeast-trending anticlinal structure. Individual sandstone reservoirs range from 10 to 50 ft in

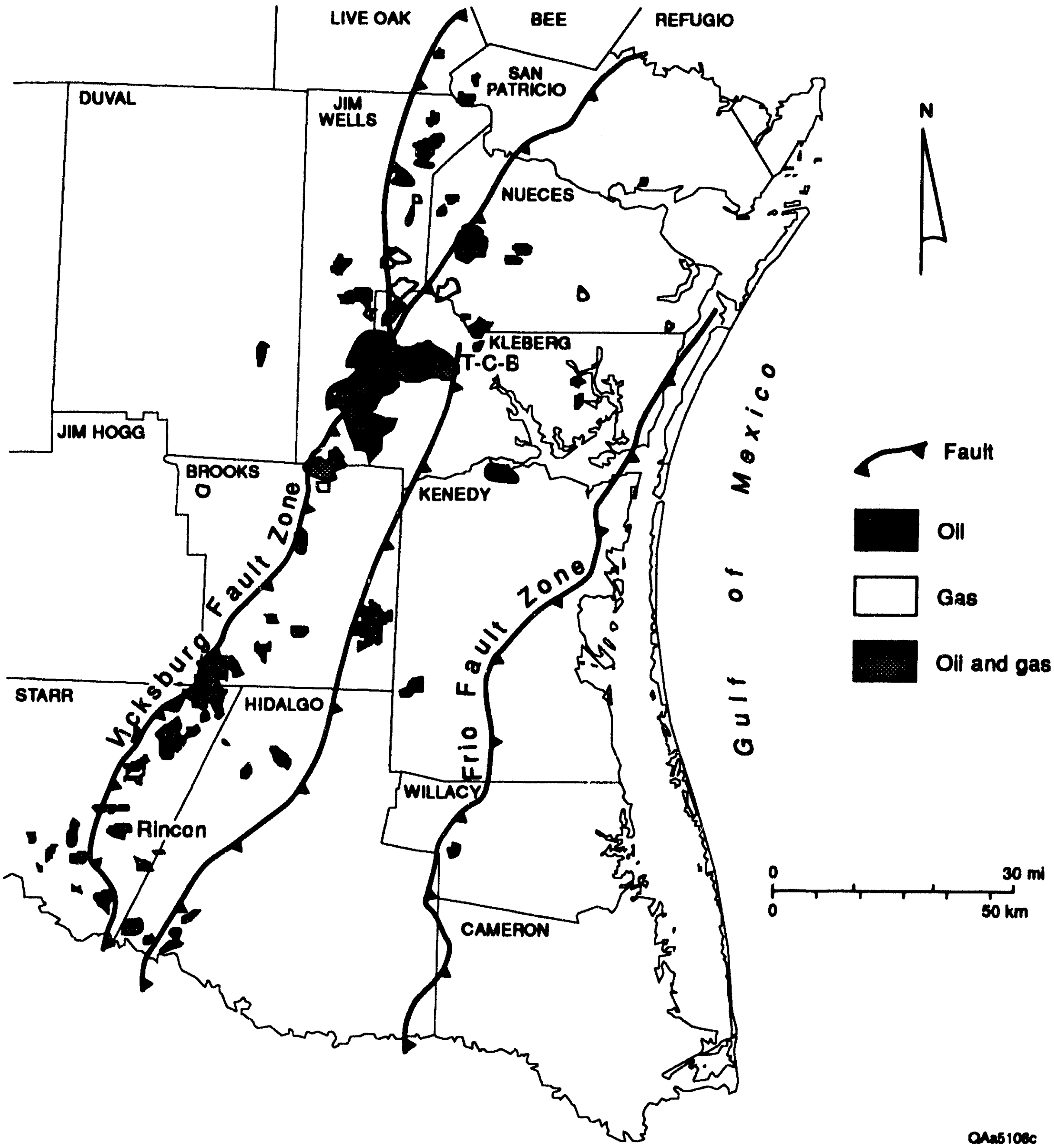


Figure 6. Map of South Texas showing location of fields within the Frio Fluvial-Deltaic Sandstone play along the Vicksburg Fault Zone. Fields shown include those which have produced more than 1 million barrels (1 MMbbl) of oil. Modified from Galloway and others (1983) and Kosters and others (1989).

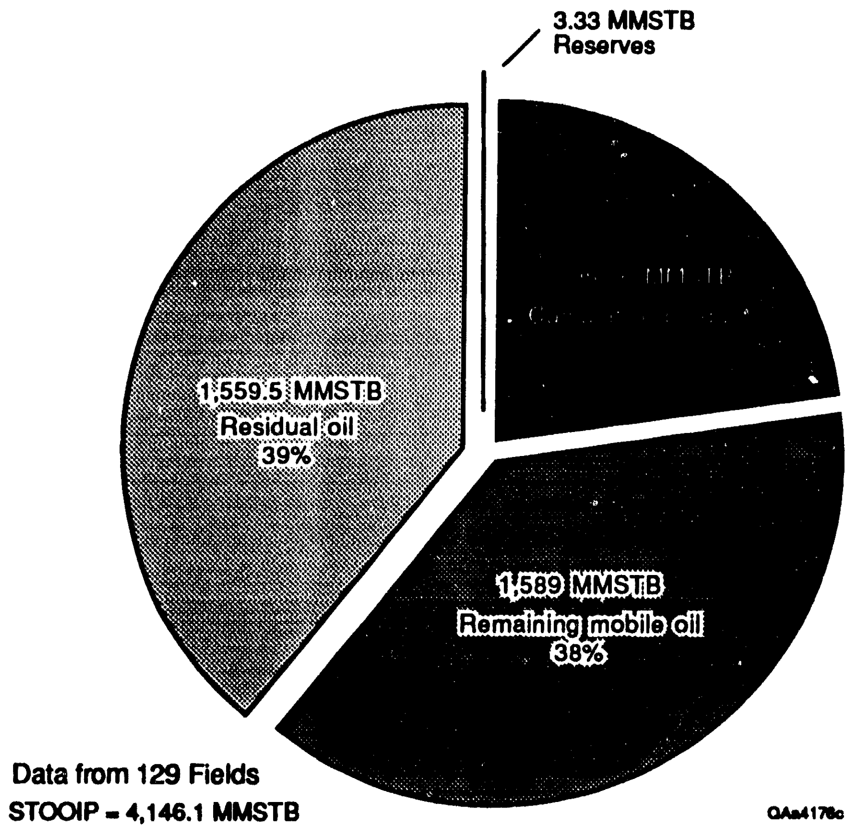


Figure 7. Distribution of the location of oil resources within reservoirs of the Frio Fluvial-Deltaic Sandstone play in South Texas. Nearly 1 billion barrels (1 Bbbl) have been recovered in the play, but nearly two-thirds of the estimated original oil in place, including more than 1.5 Bbbl of remaining mobile oil, remains in the reservoirs.

thickness and consist of individual or multiple amalgamated sand bodies. Porosity and permeability values average 25 percent and 430 md, respectively, and the average API gravity of produced oil is 41°. Reservoirs are internally compartmentalized by permeability baffles and barriers caused by mud-filled channel plugs, by mud drapes and rip-up-clast zones located between channel-on-channel contacts, and by more laterally extensive floodplain mudstone facies located in interchannel areas.

Regional Geology of the Frio Reservoir Interval

Structural and Stratigraphic Setting

Fields in the Frio Fluvial-Deltaic Sandstone play are located on the downthrown side of the large Vicksburg Fault Zone, a major down-to-the-coast listric normal growth fault system that parallels the Gulf coastline for over 100 mi. These faults mainly offset the Vicksburg Formation but also affect the lower portions of the overlying Frio Formation.

The play produces from a stratigraphic interval within the Oligocene Frio Formation, which is one of seven major progradational wedges in the lower gulf coastal plain of South Texas that

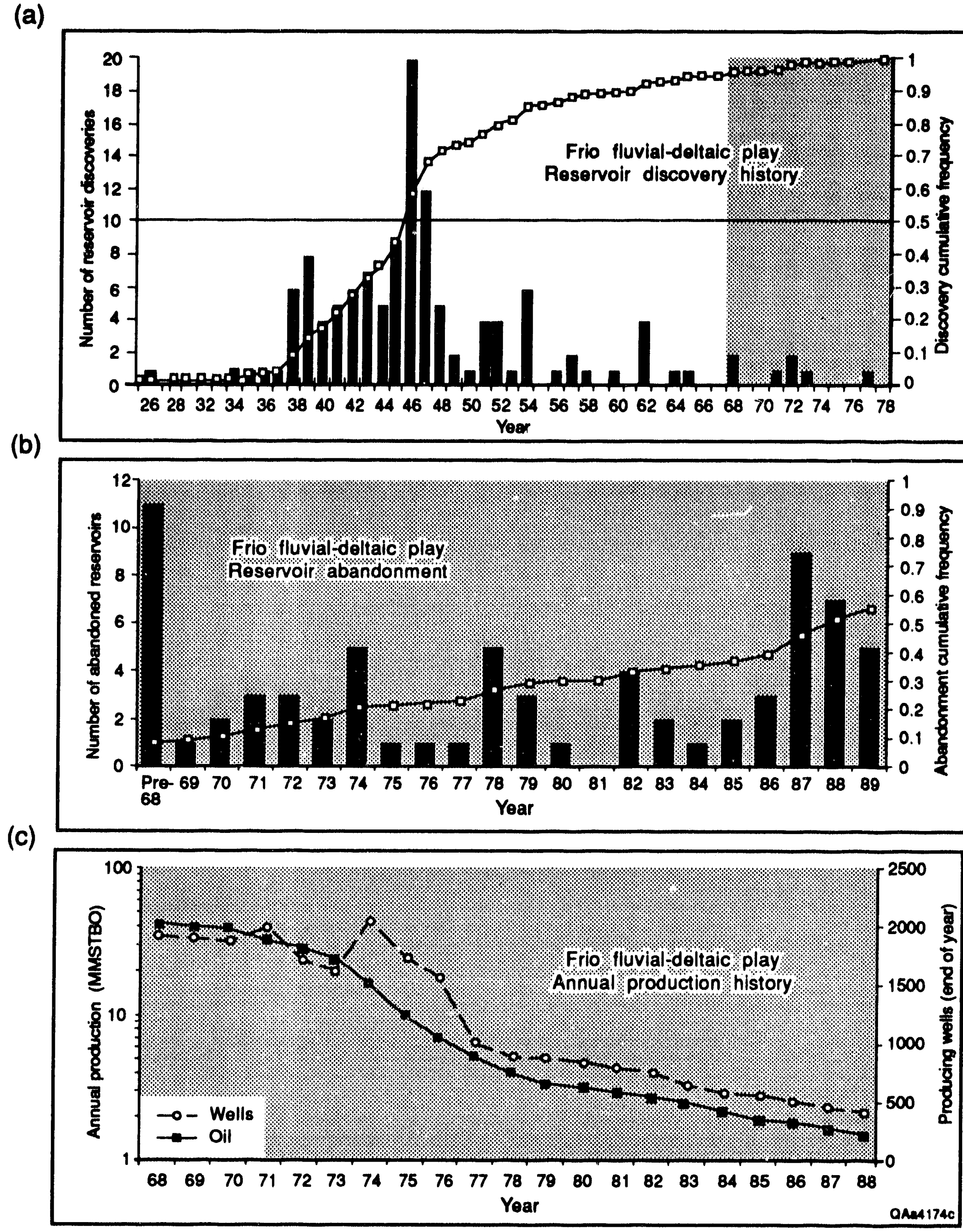


Figure 8. Histograms illustrating trends in reservoir discovery (A), reservoir abandonment (B), and decline in annual production (C) in the Frio Fluvial-Deltaic Sandstone oil play. Oil production in the play has steadily declined since 1968, and as of 1991, nearly 60 percent of all producing reservoirs had been abandoned.

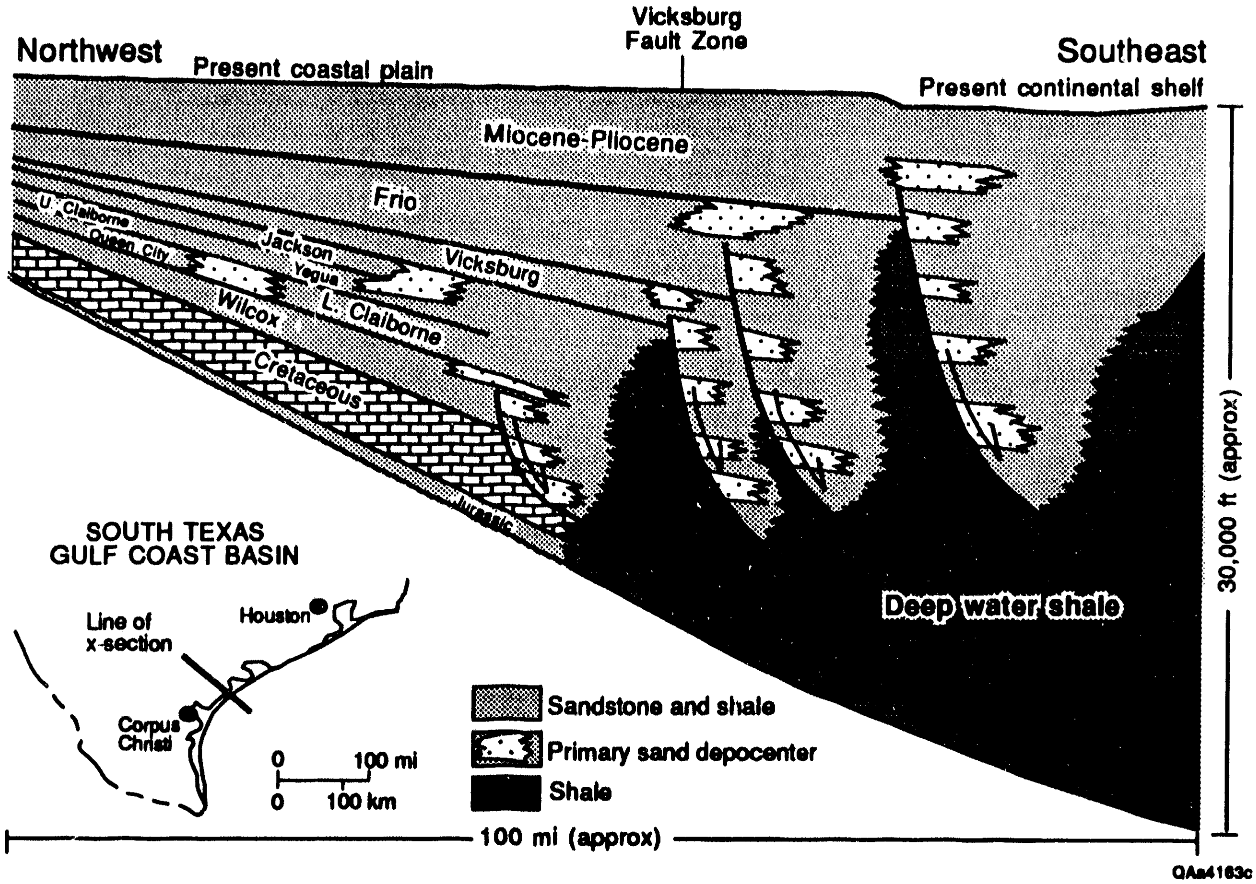


Figure 9. Schematic cross section of the South Texas Gulf Coast Basin. Modified from Bebout and others (1982).

represents the sedimentary record of a major depositional offlap episode of the northwestern shelf of the Gulf of Mexico Basin (Figures 9 and 10). Fields in the play occupy a transitional area between the Norias delta system and the Gueydan fluvial system (Galloway and others, 1982). The majority of productive oil reservoirs is found in progradational, fluvial-dominated deltaic depositional facies within the lower Frio interval and in aggradational fluvial facies in the middle Frio (Figure 11).

Upper Vicksburg–Frio Genetic Stratigraphic Sequence

The entire productive Frio reservoir interval in this play is part of a larger genetic depositional sequence that reflects a series of depositional events that include strata from both Vicksburg and Frio Formations. These depositional events produce an overall genetic stratigraphic stacking pattern that consists of episodes of seaward-stepping deltaic progradation, vertically stacked fluvial aggradation, and landward-stepping retrogradation followed by a transgressive event (Figure 12, Table 7).

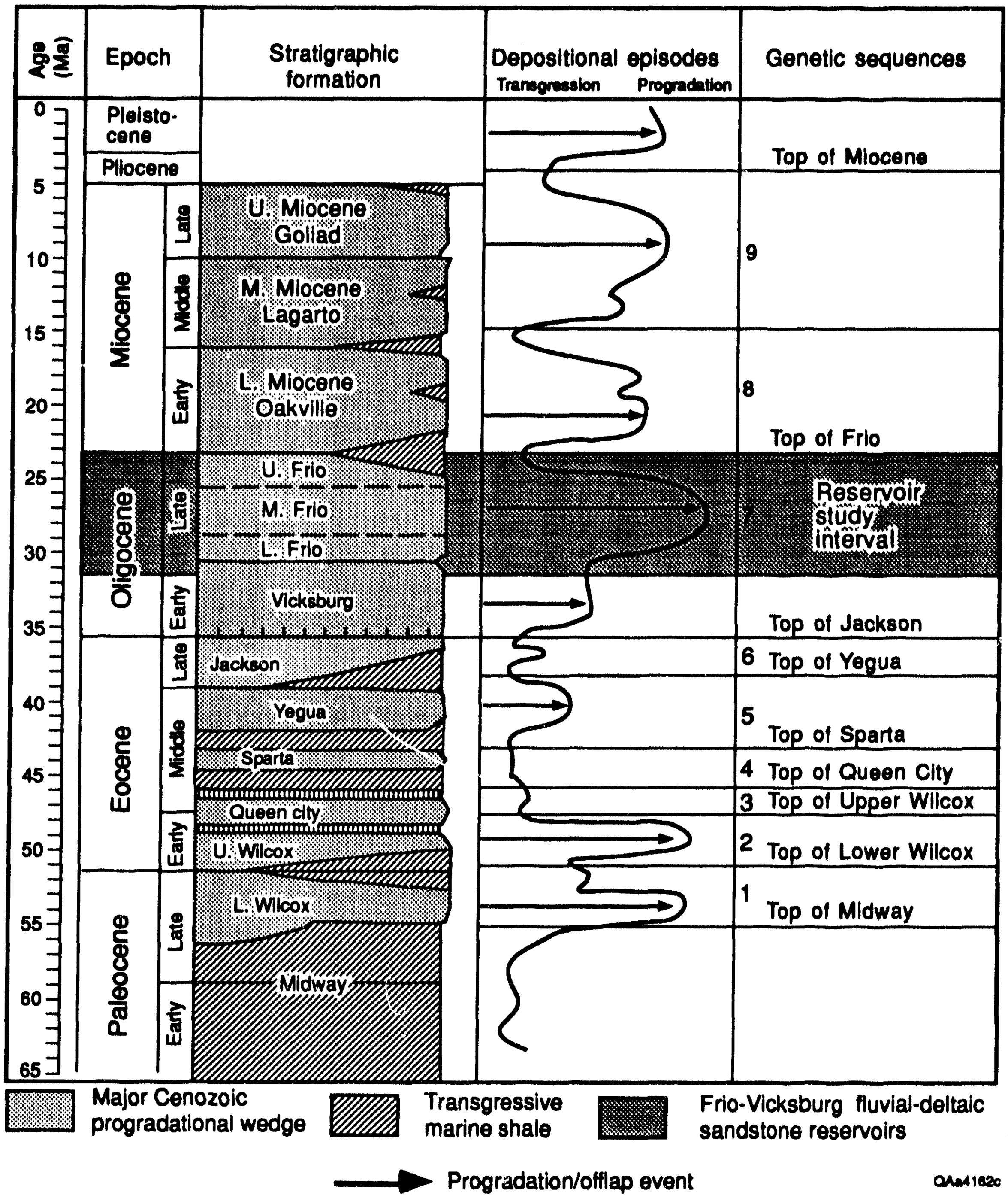


Figure 10. Stratigraphic column of Cenozoic sediments of the South Texas Gulf Coast. The sedimentary succession has been divided into a series of large-scale depositional episodes that represent major periods of progradation that occurred throughout the Cenozoic (Galloway, 1989). Reservoirs in the Frio Fluvial-Deltaic Sandstone play are part of a larger Frio–Vicksburg genetic sequence.

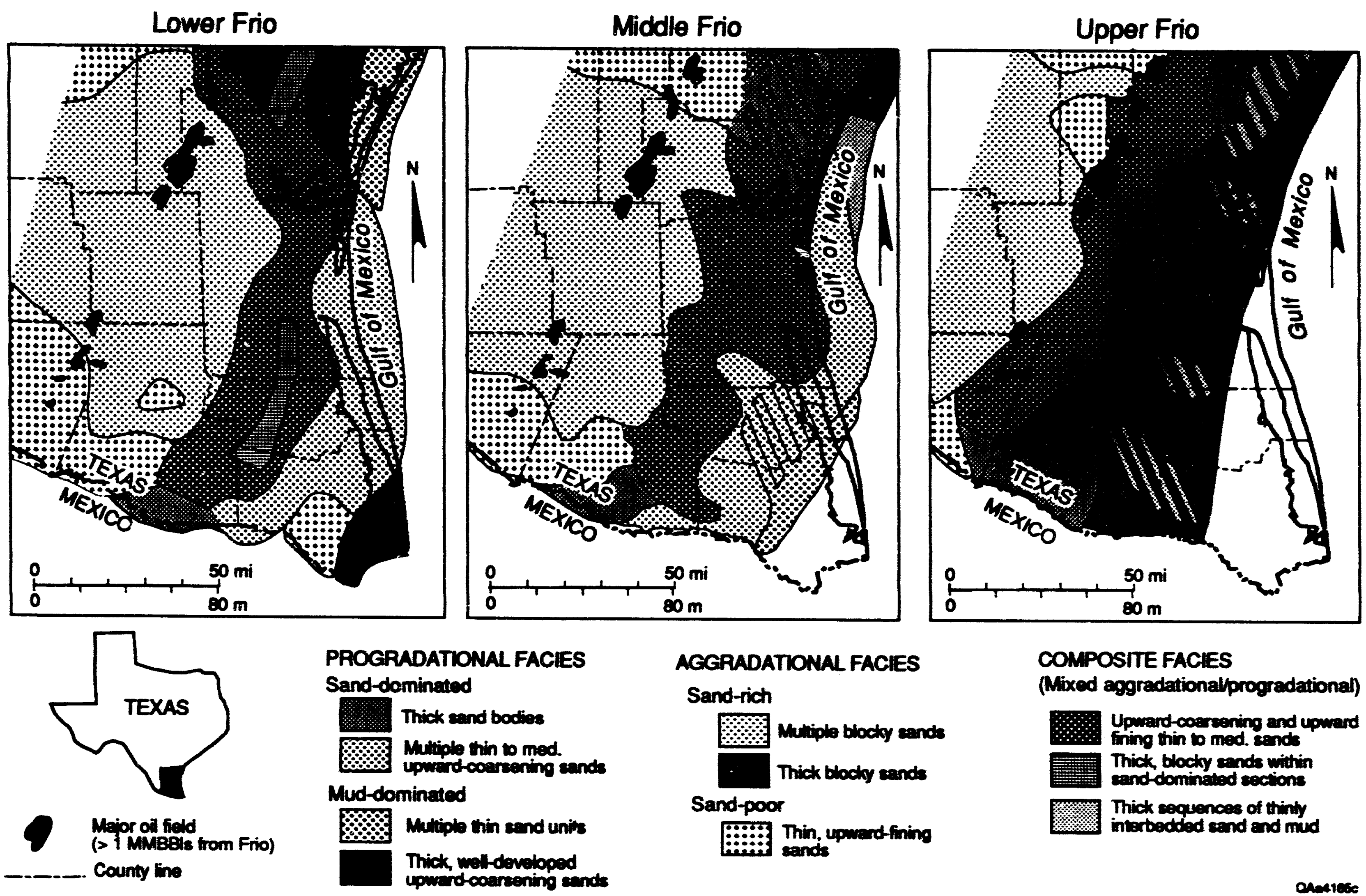


Figure 11. Distribution of aggradational and progradational sequences of the Frio Formation along the Vicksburg Fault Zone oil play (map distribution from Galloway and others, 1982). The Frio sediments near the Vicksburg Fault Zone were deposited primarily in moderate- to high-sinuosity mixed-load stream environments of the Gueydan fluvial system. Based on log facies maps by Galloway and others (1982).

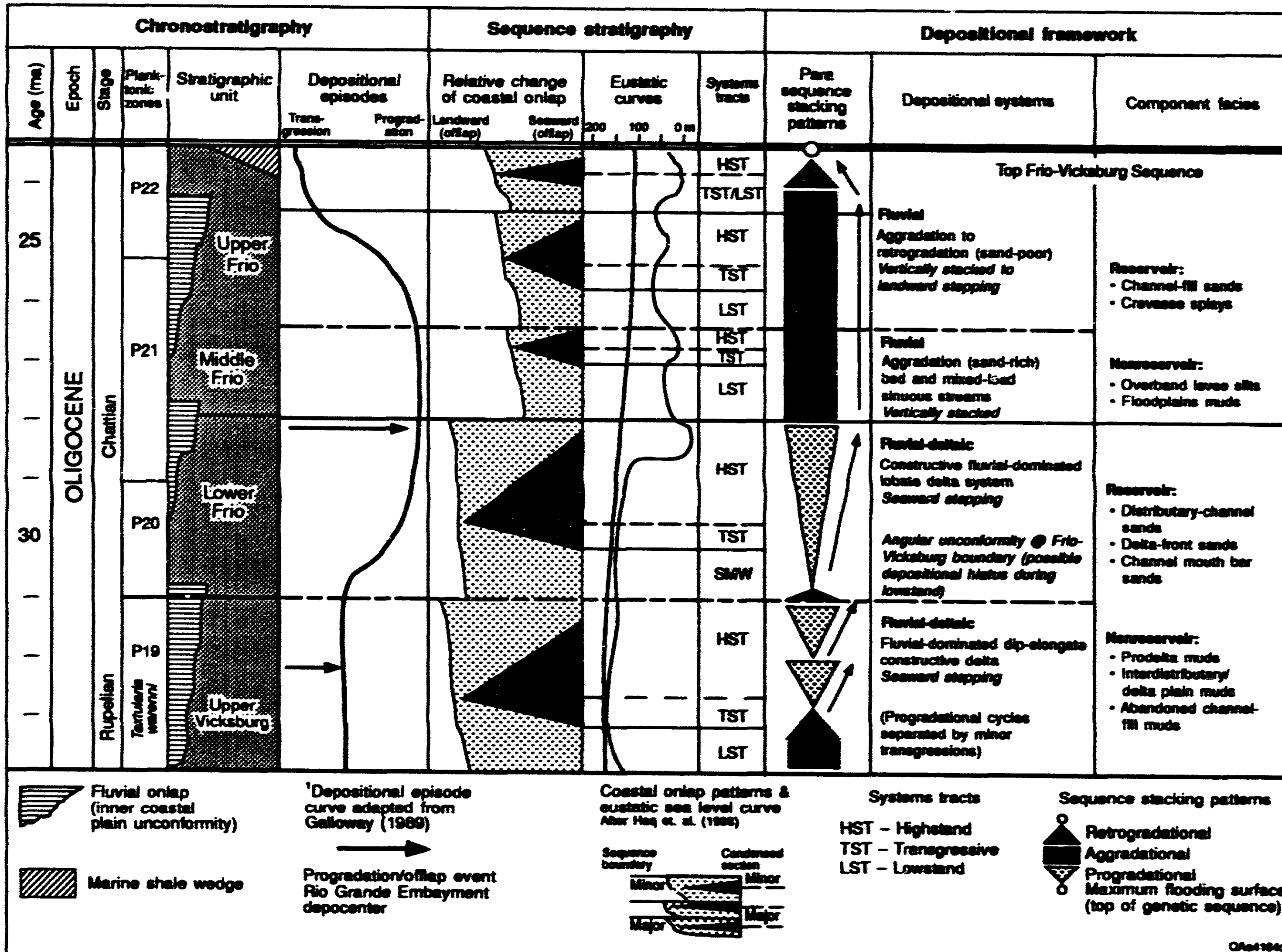


Figure 12. Chronostratigraphic, sequence-stratigraphic, and sediment stacking pattern relationships of the upper Vicksburg–Frio genetic stratigraphic interval in the lower Gulf Coast of South Texas. The relative degree of sediment progradation versus marine transgression illustrated on the depositional episode curve constructed by Galloway (1989) is compared with the relative coastal onlap and offlap patterns and eustatic sea-level curve for the Middle and Late Oligocene (from Haq and others, 1988). Comparison of the period of maximum progradation of the Vicksburg–Frio delta sequence identified on the depositional episode curve with the major sea-level drop in the middle Oligocene suggests an offset of at least a few million years and is interpreted to reflect a significant tectonic imprint on sedimentation (Galloway, 1989). Stratigraphic data from Galloway (1977), Galloway and others (1982), Coleman and Galloway (1990), and Xue and Galloway (1991).

Table 7. Operational stratigraphic subdivisions of the upper Vicksburg–Frio stratigraphic interval.

	UPPER VICKSBURG	LOWER FRIO	MIDDLE and UPPER FRIO
GENERAL LITHOLOGY	Laterally extensive thick sandstones and interbedded mudstone	Laterally extensive sandstones with interbedded mudstone	Interstratified mudstones and lenticular sandstones
INDIVIDUAL SAND THICKNESS	50-150' thick sands separated by 50-100' mudstones	Sands 0-40' thick	Individual channels: 10-30' Amalgamate into units as much as 100' thick; 1000-2500' wide
LOG PROFILE	Stacked upward-coarsening sandstone intervals	Coarsening-upward log profile	Fining-upward log profile of individual channel sands
DEPOSITIONAL SYSTEM	Norias delta	Norias wave-dominated delta	Gueydan fluvial system
DEPOSITIONAL SETTING	Upper Vicksburg is retro-gradational delta system. Lower Vicksburg is landward-stepping package deposited during transgression of S. Texas coast	Deposited in lower coastal plain to inner shelf setting. Strandplain sandstones interbedded with coastal plain and inner shelf mudstones	Coarse-grained meander-belt system with mixed sediment load. Channel-fill and point-bar sandstones flanked by widespread crevasse splay deposits and floodplain muds and silts
STACKING PATTERN	Progradational (Seaward-stepping)	Progradational (Seaward-stepping)	Aggradational (Vertically Stacked)
TOTAL THICKNESS	Greatly influenced by Vicksburg fault zone; 5000-8000' across fault	Approximately 500'	Ranges from 2000-2500'
CONTACT	Unconformity at Vicksburg–Frio boundary; local erosional relief and angular discordance. Conformable with underlying shales of Jackson Fm	Angular unconformity with underlying Vicksburg inferred from dipmeter logs, changes in resistivity and density log responses, seismic sections.	Transitional with lower Frio over few hundred feet
STRUCTURAL SETTING OF RESERVOIR INTERVAL	Structurally complex. Correlations very difficult	Locally structurally complex. Correlations difficult in faulted areas	Relatively unstructured. Stratigraphic correlations difficult in faulted areas
CONTROLS ON RESERVOIR HETEROGENEITY	Reservoir heterogeneity controlled by faults as well as stratigraphy	Reservoir heterogeneity locally controlled by faults, mostly due to stratigraphic complexity	Reservoir heterogeneity controlled by stratigraphic complexity

A brief summary of the main stratigraphic components of the upper Vicksburg–Frio depositional sequence is provided here to place the productive Frio reservoirs that are the focus of this study into a regional stratigraphic and genetic context.

The upper Vicksburg Formation represents the initial progradational phase of the larger Vicksburg–Frio genetic stratigraphic interval (Coleman and Galloway, 1991; Xue and Galloway, 1991). Upper Vicksburg sediments consist of thick progradational (seaward-stepping) deltaic sandstone deposits (Han, 1981; Han and Scott, 1981) that occur in packages 50 to 150 ft thick and are separated by 50- to 150-ft-thick intervals of mudstone. The Vicksburg Formation in South Texas has been strongly affected by movement along faults associated with the development of the Vicksburg Fault Zone (Coleman, 1990; Coleman and Galloway, 1991). Reservoir compartmentalization in these structurally complex reservoirs of the upper Vicksburg is controlled to a very large degree by faults, and stratigraphic correlations necessary to document depositional and diagenetic heterogeneity are very difficult.

The contact between upper Vicksburg strata and sediments of the lower Frio is recognized as an unconformity throughout the lower Gulf Coast. Evidence for the unconformable nature of the contact has been documented in several field studies; it is often recognizable on seismic sections, by deflections on dipmeter data, and by pronounced changes in resistivity and density log responses observed on well logs (Galloway and others, 1982). In addition to lithology, the index foraminifer *Textularia warreni* has been used to distinguish the upper Vicksburg from the overlying Frio Formation (Bebout and Agagu, 1975; Bebout and others, 1978). In South Texas, lowermost sandstones of the Frio have been observed to contain *Textularia warreni*, but for the most part, the nonmarine nature of the bulk of the Frio sequence precludes the exclusive use of foraminifera in differentiating the Frio section.

In southernmost areas of the Rio Grande Embayment in Starr County, genetic sequence analysis suggests that lower Frio deposition was initiated by an aggradational episode of sedimentation that followed a progradational phase represented by upper Vicksburg deposition (Coleman and Galloway, 1991). Farther to the north, in a position along the central axis of the embayment, regional well-log correlations suggest that upper Vicksburg sediments may reflect a period of retrogradation and a subsequent very short period of transgression. In this area, the base of the lower Frio represents a maximum flooding surface, which is then followed by the onset of another progradational phase of sedimentation. Examination of well logs along a cross section in the northernmost area of the Rio Grande Embayment indicates that the progradational event spans both upper Vicksburg and lower Frio sections, but the base of the lower Frio marks a change to a slower rate of progradation (Coleman and Galloway, 1991). Additional stratigraphic analysis focused within selected areas across the Frio Fluvial-Deltaic Sandstone play trend will be required to resolve these differences in sediment accumulation dynamics that mark the transition between Vicksburg and Frio strata.

Lower Frio deposition caused the development of a thick sequence of laterally continuous strandplain sandstone reservoirs and interbedded coastal plain mudstones and inner shelf mudstones in the central Gulf Coast, but it was a relatively short-lived event in the vicinity of fields in the Frio Fluvial-Deltaic Sandstone play in South Texas (Galloway and others, 1982). The location of the shelf edge at the beginning of lower Frio deposition was approximately coincident with the eastern extent of the present-day location of the Vicksburg Fault Zone (Galloway and others, 1982). Deltaic sediments prograded rapidly out over the preexisting unstable shelf margin during early Frio time, and by the beginning of middle Frio deposition, the shelf edge had extended seaward to the location of the present-day Frio Fault Zone. As a result, most deposition of Frio sediments in fields along the Vicksburg Fault Zone consisted of a prolonged aggradational phase of deposition of nonmarine middle and upper Frio sediments of the Gueydan fluvial system.

The contact between middle and upper Frio strata in sediments present in fields along the Vicksburg Fault Zone is not obvious. Upper Frio sedimentation is characterized for the most part as representing a retrogradational phase of sedimentation that is a precursor to a regional marine transgressive event that marks the end of the Vicksburg–Frio genetic depositional sequence (Galloway and others, 1982). This event occurs at the base of the Miocene and is represented by deposition of the marine Anahuac shale (Figure 10). The upper Frio section deposited in fields along the Vicksburg Fault Zone is well landward of this transgressional episode, however, and the location of this maximum flooding surface that serves as the depositional sequence boundary must be extrapolated into the updip, purely nonmarine Frio section. The base-level rise that accompanies retrogradational sedimentation and shoreline retreat favors the accumulation of substantial shore zone and coastal plain deposits (Galloway and others, 1986). This in turn favors the preservation of channel-fill sandstones in the updip portions of the fluvial system. Sandy channel-fill facies that characterize upper Frio sediments in Seeligson field, located in the northern part of the Vicksburg Fault Zone trend, are locally observed to truncate middle Frio strata (Ambrose and others, 1992).

Lower Frio Reservoirs

Reservoir facies of the lower Frio consist predominantly of delta-plain distributary-channel and delta-front channel-mouth-bar sandstones. Delta-flank strandplain and barrier-island sandstones are also present as reservoirs, but their development in the Frio section deposited along the Vicksburg Fault Zone is limited. Distributary channels deposited within delta-plain facies are distributed as elongate, dip-parallel belts (Jackson and Ambrose, 1989). Individual, upward-fining channel sand packages range from 5 to 20 ft in thickness, but commonly stack and produce amalgamated units that have vertical thicknesses of 20 to 60 ft and are 1 to 3 mi wide (Nanz, 1954). In more fluvial-dominated settings, such as in the Frio of South Texas, sand-body continuity is commonly poor, because distributary channel-fill sandstones are flanked laterally by sand-poor interdeltaic facies.

Delta-front facies consist of channel-mouth-bar reservoir sandstones that are interbedded with prodelta mudstone and siltstone. Individual upward-coarsening channel-mouth-bar deposits are generally less than 50 ft thick in the updip regions of the delta system, whereas in deeper distal settings they stack to produce repetitive cycles that are commonly several hundred feet thick (Galloway and others, 1982).

Nonreservoir facies in the lower Frio consist mainly of prodelta mudstones, which grade updip into delta-front sands, interdistributary and delta-plain mudstones, and muddy abandoned channel-fill facies. These low-permeability mud facies locally encase and therefore compartmentalize or isolate individual reservoir sands. Reservoir compartments in isolated, narrow distributary-channel sandstones encased in low-permeability mudstone facies and in channel-mouth-bar sandstones that pinch out into finer grained delta-front facies are the primary targets for additional oil recovery in lower Frio sandstones of the Norias delta system.

Middle and Upper Frio Reservoirs

Reservoir facies of the middle and upper Frio consist of channel-fill and point-bar sandstones (**Figure 13**). Nonreservoir facies, which commonly separate reservoir units, include levee siltstones and floodplain mudstones. Channel-fill deposits exist mainly as dip-elongate belts of sandstone that attain individual thicknesses ranging from 10 to 30 ft, but they are commonly stacked into composite units as thick as 100 ft. Most individual channel-fill belts are 1,000 to 2,000 ft wide but commonly coalesce into combined widths of more than 1 mi (Galloway and others, 1982). Low-permeability subfacies within the channel fill are responsible for the development of multiple reservoir compartments that represent a significant opportunity for additional recovery within channel-fill reservoir facies.

Crevasse splay deposits that flank channel-fill facies and pinch out into floodplain mudstones and siltstones are an additional important reservoir facies. The limited areal extent of splay deposits and their lateral separation from channel-fill reservoir facies by low-permeability facies make them potential targets for additional recovery of compartmentalized reserves.

SCREENING OF FIELD AND RESERVOIR DATA

Overview

Frio fluvial-deltaic sandstones in fields along the Vicksburg Fault Zone in South Texas are prolific oil and gas reservoirs. To maintain production and reservoir data statistics, fields within the Frio Fluvial-Deltaic Sandstone play have been classified as belonging to the oil play, to the gas play, or to both the oil and gas plays in those fields that have produced abundant oil and gas. Oil and gas

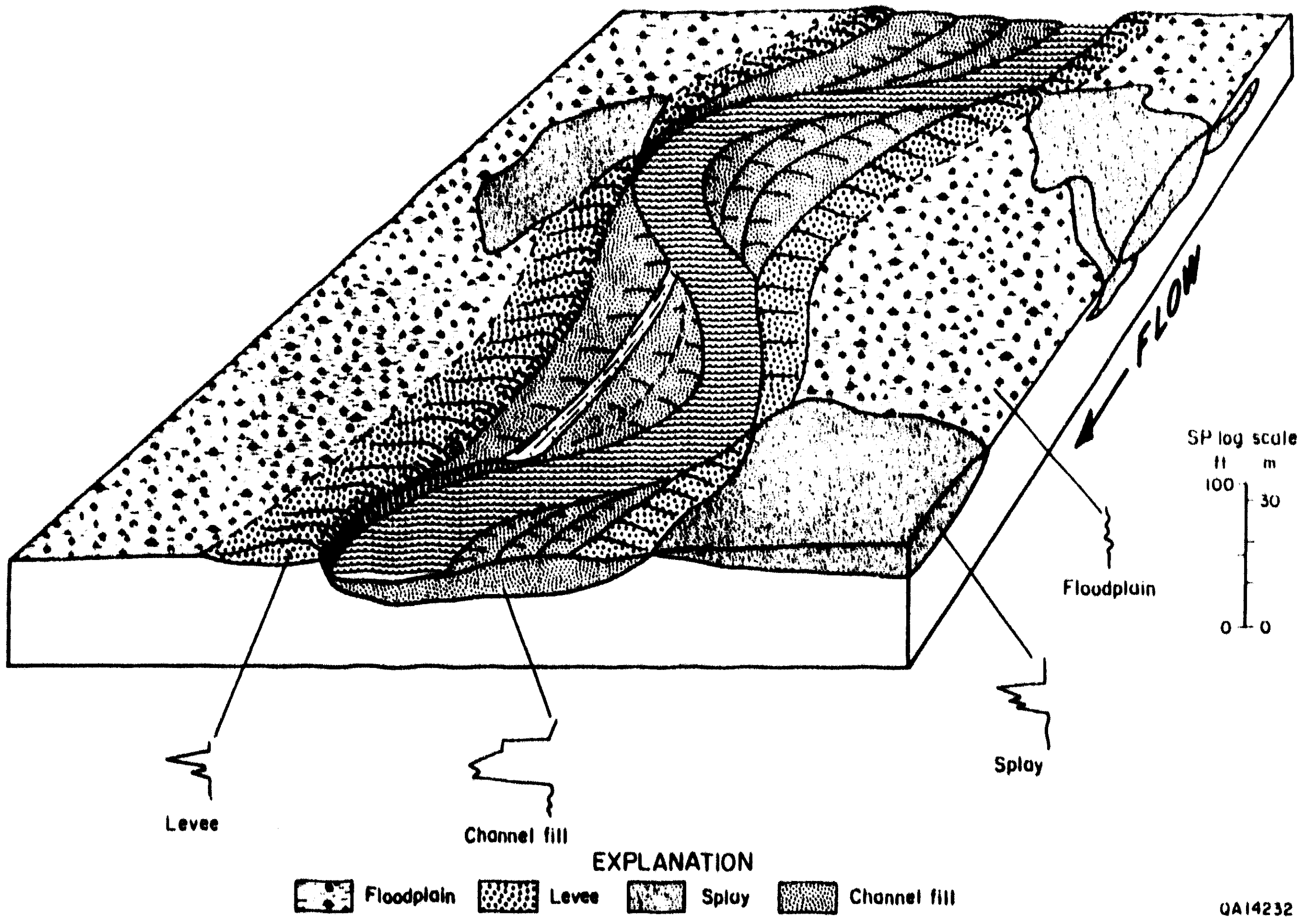


Figure 13. Schematic block diagram illustrating general three-dimensional relationships and characteristic SP log responses in fluvial reservoir and nonreservoir facies. Modified from Galloway (1977).

reservoirs in fields throughout the play consist of sandstone units that overlap geologically. A reservoir interval that produces mainly oil in one field may be stratigraphically correlative with a prolific gas-producing interval in an adjacent field. In other words, much of the data available from oil and gas reservoir groups may represent two subsets of a single large population of reservoirs. Because of the extensive amount of data available for gas reservoirs from fields in the Frio Fluvial-Deltaic Sandstone play trend compared with the amount available for oil reservoirs (282 gas reservoirs, 64 oil reservoirs), data were collected and analyzed for both oil and gas reservoir groups. Statistical analysis was used to characterize reservoir attributes from both oil and gas reservoirs from the Frio Fluvial-Deltaic Sandstone play and to test if data from the two groups represent statistically different populations. If tests reveal data from both oil and gas reservoirs represent a single population of reservoirs, the larger, more inclusive data set of reservoir attributes from combined oil and gas reservoir groups can then be used to better characterize and predict reservoir characteristics throughout the play.

Descriptive and central tendency statistics were determined for average porosity, initial water saturation, residual oil saturation, net-pay thickness, and reservoir size. These parameters were analyzed to determine what type of probability function best represents the distribution of data. Probability distributions generated for each of the reservoir attributes provide a basis for estimating attribute values for reservoirs with incomplete petrophysical data. Engineering attributes were used to simulate volumes and create probability distributions of original oil in place, original mobile oil in place, and residual oil in place for individual oil reservoirs. Individual reservoir oil volumes from fields within the play were then simulated together to produce a risk-adjusted total resource for the Frio Fluvial-Deltaic Sandstone play.

Methodology

Data Sources

Information used in this statistical evaluation came from multiple sources. Hearing files of the Railroad Commission of Texas were a major source of data. Files on unitization, maximum efficient recovery (MER), field rules, and discovery proved particularly informative. Additional sources of numerical and descriptive data include the following:

1. Oil and gas reservoir files compiled by the U.S. Department of Energy (DOE), Energy Information Agency, Dallas Field Office.
2. Compilations of field studies published by various regional geological societies, the American Association of Petroleum Geologists, and the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers.
3. Publications of the Railroad Commission of Texas, including annual reports and surveys of secondary and enhanced recovery operations.
4. Annual reservoir production data and cumulative production data were obtained from Dwight's Energydata and supplemented or modified from Railroad Commission of Texas information. Reservoir location data were mapped by the Bureau of Economic Geology (BEG) and supplemented by latitude and longitude values from Dwight's Energydata.
5. Data were supplemented with information provided by individual operating companies.

Different sources commonly gave different values for the same type of data. Where great discrepancies existed, values were selected on the basis of known geologic criteria and within the context of the overall data base of the play. Data were weighted in favor of records that reflected greater geological and engineering research efforts.

Data Analysis

A rigorous statistical analysis of reservoir characteristics was performed on three separate data sets: oil reservoirs, gas reservoirs, and the two groups combined. The data represent 346 producing reservoirs from throughout the play. Descriptive and central tendency statistics were determined for each of the engineering parameters that influence the calculation of oil volume. These parameters include average porosity, initial water saturation, residual oil saturation, net pay, and reservoir size. Next, each of the engineering parameters was analyzed to determine what type of probability function best represents the data distribution. All data were treated as nondiscrete, with a total of 18 different functions tested. Three best-fit tests were applied, including the Chi-square, Kolmogrov-Smirnov (KS), and Anderson-Darling (A-D) tests, along with graphical outputs of the data. Covariance was tested between each combination of parameters, and statistical F and t tests were applied in order to identify statistical difference or similarity between oil and gas reservoir populations.

Characteristics of the individual engineering parameters were used to simulate oil volume. Stochastic simulations of oil volume provide characteristics of original oil in place, original mobile oil in place, and residual oil in place. Stochastic simulations produced probability distributions for each of the oil volume parameters. These probability distributions were then analyzed to determine which function best describes the particular distribution.

Oil resources of the entire Frio Fluvial-Deltaic Sandstone play were risk adjusted to reflect these volumetric stochastic simulations, and oil volume probability distributions were generated for individual reservoirs. Attributes from reservoirs with incomplete petrophysical data were estimated using the probability functions. Oil volumes calculated for single reservoirs were then risk adjusted by the playwide variability. A risk-adjusted total resource for the Frio Fluvial-Deltaic Sandstone play was then simulated using combined results from the individual reservoir volumes.

Statistical Characteristics of Reservoir Attributes

Reservoir attribute characteristics analyzed for the determination of hydrocarbon volumes included porosity, initial water saturation, residual oil saturation, net-pay thickness, and reservoir area. Statistical analysis of variance (ANOVA) and descriptive statistics were followed by fitting probability functions to the data distributions.

Porosity

Descriptive statistics and ANOVA demonstrate little difference between oil and gas reservoir porosity characteristics. Comparing average reservoir porosities for both populations shows little difference between the two groups. The average between oil and gas reservoirs differs by only 1-percent porosity, and minimum and maximum values differ by only 2-percent porosity (Table 8). Both oil and gas reservoirs are positively skewed and have positive kurtosis. ANOVA tests calculate an F value of 3.76, smaller than the 3.91 F critical value (Table 8), indicating no significant statistical difference between the mean porosity values of oil and gas reservoirs.

Table 8. Statistics for reservoir parameters grouped by oil, gas, and combined data sets.

	Porosity (%)	Initial water saturation (%)	Residual oil saturation (%)	Net pay (ft)	Reservoir area (acres)
Oil reservoirs					
Count	64	48	29	64	65.00
Minimum	20	18	10	5	133.00
Maximum	32	54	39.8	146	7,607.00
Range	12	36	29.8	141	7,474.00
Mean	25.33	30.57	26.98	22.81	2,170.89
Standard deviation	2.67	7.36	5.84	25.96	1,890.17
Coefficient of Variation	0.11	0.24	0.22	1.14	0.87
Skewness	0.37	1.35	-0.29	3.17	1.29
Kurtosis	0.38	2.32	2.31	10.99	0.94
Gas reservoirs					
Count	282	283		178	89.00
Minimum	19	11.5		4	40.00
Maximum	30	68		245	26,000.00
Range	11	56.5		241	25,960.00
Mean	23.89	32.25		24.81	2,826.65
Standard deviation	1.40	5.10		30.37	3,383.35
Coefficient of Variation	0.06	0.16		1.22	1.20
Skewness	0.05	3.37		4.81	4.15
Kurtosis	6.37	24.74		27.45	25.16
Oil and gas combined					
Count	346	331		242	154.00
Minimum	19	11.5		4	40.00
Maximum	32	68		245	26,000.00
Range	13	56.5		241	25,960.00
Mean	24.16	32.00		24.28	2,549.87
Standard deviation	1.79	5.50		29.23	2,860.77
Coefficient of Variation	0.07	0.17		1.20	1.12
Skewness	0.86	2.63		4.53	4.23
Kurtosis	4.47	16.73		25.16	29.68

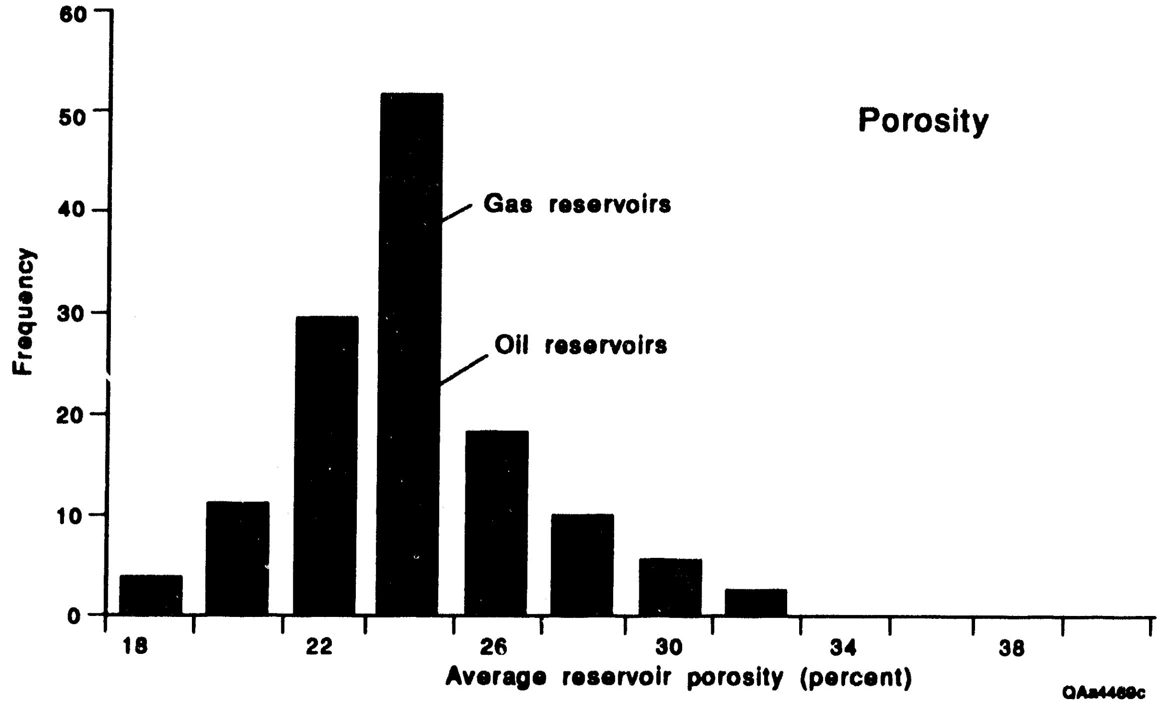


Figure 14. Histogram illustrating distributions for values of reservoir porosity from reservoirs throughout the play.

Average values of reservoir porosity are 25 percent for oil reservoirs and 24 percent for gas reservoirs. Both sets of reservoir values are tightly distributed around the mean. Standard deviation does not exceed 2.7 and is less than 2 for the combined population group. Sixty-eight percent of the reservoirs have values between 22 and 26 percent; at ± 1 standard deviation, the porosity is only 8 percent different from the mean. Standard deviation is highest for oil reservoirs and lowest for gas reservoirs. Both exhibit about the same range, with gas reservoirs slightly more positively skewed (Figure 14). The high positive kurtosis of gas reservoirs also indicates the narrow variation in porosity. This suggests that porosity may not be the largest contributor to hydrocarbon volume variability.

Porosity in gas reservoirs displays a weak negative covariant relationship to reservoir depth (correlation coefficient of -0.52). Deeper reservoirs tend to have lower porosity. Decrease in porosity with depth is an expected phenomenon that reflects increased compaction and diagenesis. Gas reservoirs have a wider depth range and generally occur at greater depths than oil reservoirs.

Initial Water Saturation

ANOVA indicates that there is no statistically significant difference between mean values of initial water saturation in oil and gas reservoirs. A difference of just over 2 percent exists between

Table 9. Results of ANOVA testing, indicating that most parameter means between oil and gas reservoirs are not significantly different.

	F statistic	Critical F
Porosity	3.76	3.91
Initial water saturation	0.08	3.94
Net Pay	0.42	3.88
Acreage	4.24	3.92

the two means. The ANOVA F statistic is 0.08, with an F critical value of 3.9 (Table 9), demonstrating no statistical difference between the means. Therefore, oil and gas reservoirs are likely to belong to the same populations.

Reservoir initial water saturation is highly variable for both oil and gas reservoirs. Both the range and standard deviation demonstrate this high degree of variability. Initial water saturation in oil reservoirs exhibits a range of 36 percent, varying from 18 to 54 percent. Oil reservoirs have a standard deviation of 7 around a mean of 31 percent. Therefore at ± 1 standard deviation, the water saturation is 23 percent different from the mean value. Initial water saturation values in gas reservoirs show even greater variability. Gas reservoirs have a range of 46 percent, from 11 to 57 percent (Table 8).

Mean values derived from distributions of initial water saturation are poor predictors of likely values. Oil reservoirs have a mean value of 31 percent, but the median is just over 23 percent (Table 8). This is due to a long tail of higher values (Figure 15). This characteristic is also true for gas reservoirs, where the mean is 32 percent and the median is just over 22 percent. For the combined population of both reservoir groups, 90 percent of the reservoirs have initial water saturation values less than the mean. The tail of large values also causes the distributions of oil, gas, or combined reservoir groupings to be positively skewed.

Residual Oil Saturation

Analyzed populations of reservoir residual oil saturations demonstrate moderate variance and moderate negative skewness, with low and high statistical outliers. One outlier is found at 10 percent and two outliers are found at 36 and 38 percent. Both groups are disconnected from the main body, which may be partly due to the smaller data sample. The mean value for residual oil saturation is 27 percent, and the standard deviation is 6. A value of 1 standard deviation away from the mean is therefore 22 percent different from the mean. Fifty percent of the reservoirs have residual oil saturation values that lie between 24 and 30 percent, a 6-percent range. The distribution is slightly negatively skewed because of the 10-percent outlier value (Table 8; Figure 16).

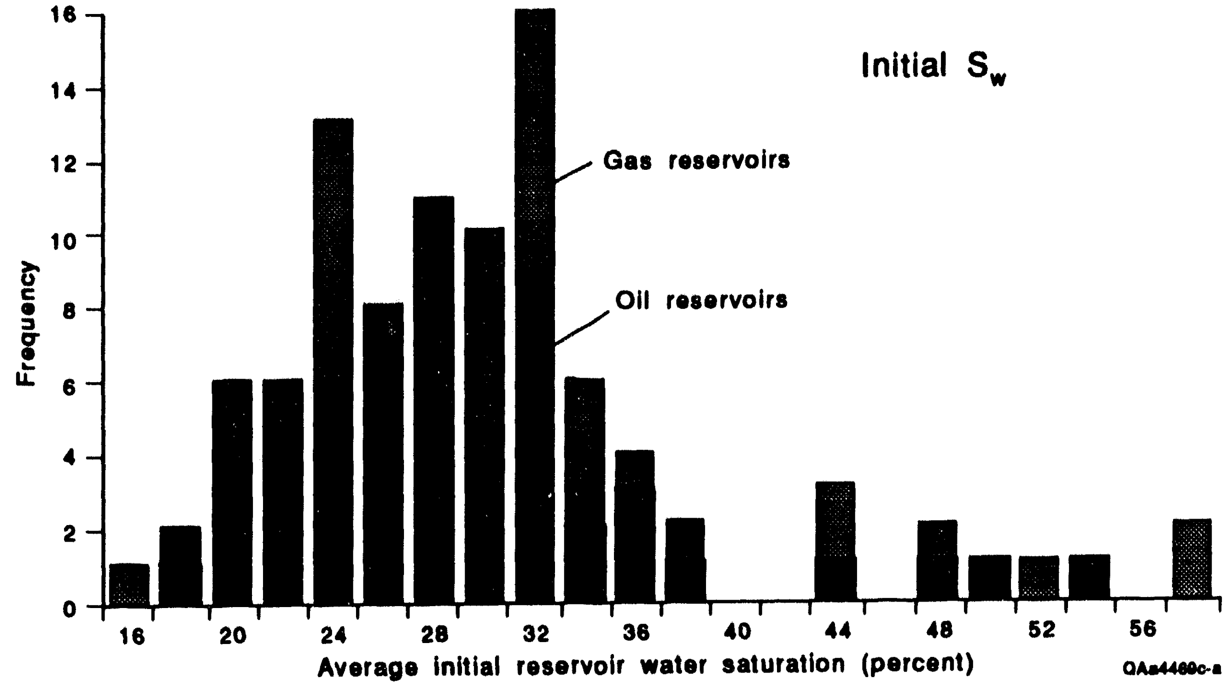


Figure 15. Histogram illustrating distributions for values of reservoir initial water saturation throughout the play.

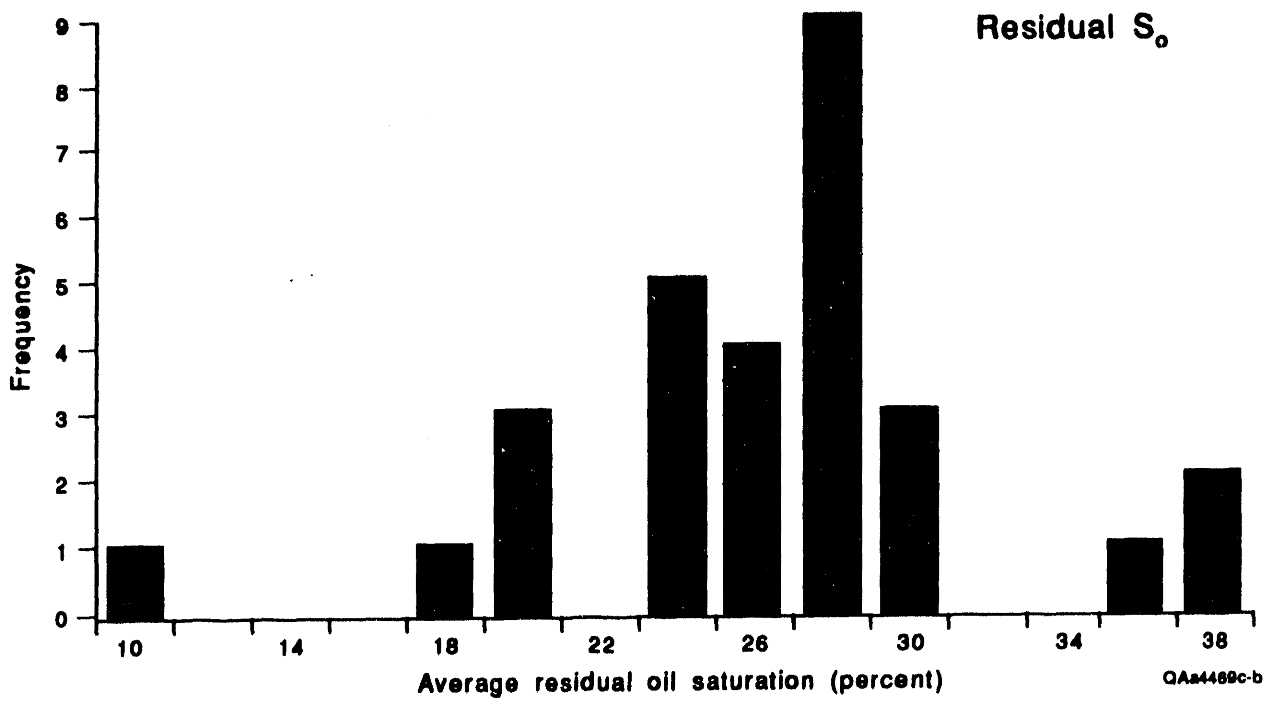


Figure 16. Histogram illustrating distributions for values of reservoir residual oil saturation throughout the play.

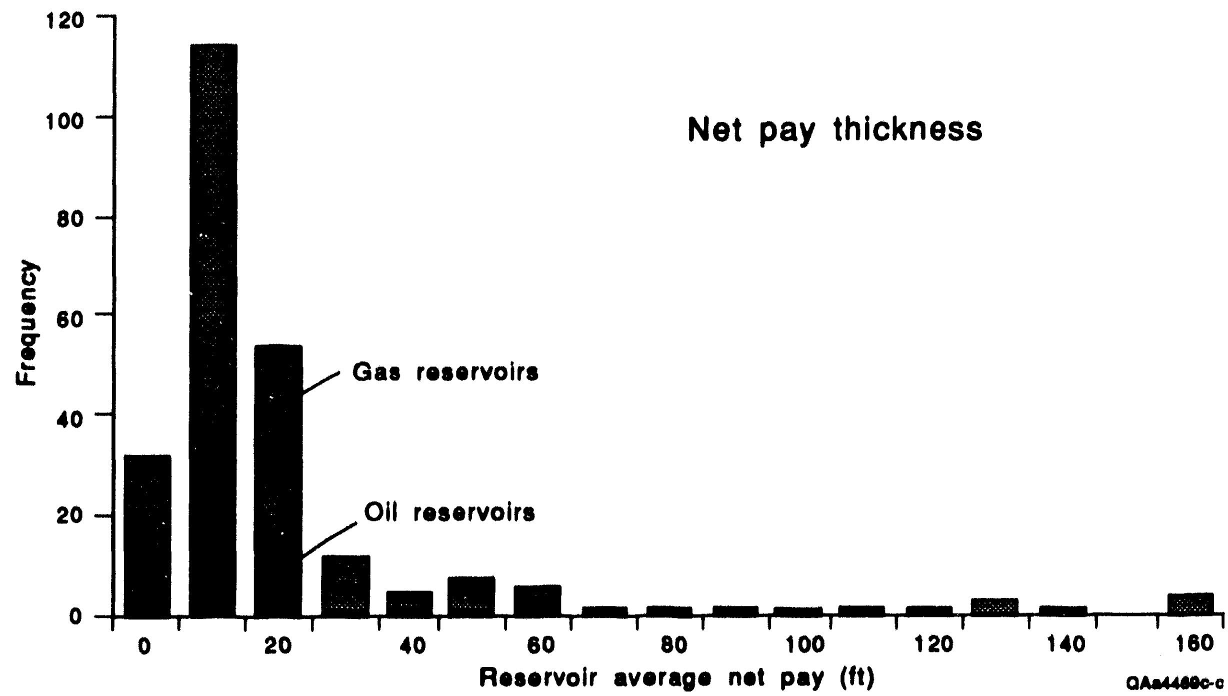


Figure 17. Histogram illustrating distributions for values of reservoir net pay throughout the play.

In addition to these central tendency characteristics, residual oil saturation exhibits a weak covariance with initial oil saturation. The correlation coefficient between residual oil saturation and initial water saturation is -0.46, indicating this weak negative covariant relationship. As initial water saturation increases, residual oil decreases. This relationship could be because higher initial water saturations correspond to reservoirs that are mostly in the oil-water transition zone. The oil that is in this zone would have less tendency to be in contact with the rock and would thus be held in place by surface tension. Also, because the transition zone has low capillary pressure with respect to oil, oil would not be forced into small pore throats, thus reducing the residual oil saturation.

Net Pay

Net-pay thicknesses appear to exhibit the same probability characteristics for both oil and gas reservoirs. Oil reservoirs have a mean value of 23 ft, and gas reservoirs have a mean value of 25 ft, a difference of only 2 ft (Table 8). The F statistic is 0.42, whereas the critical F statistic is 3.88 (Table 9), demonstrating that no significant difference exists between these two means. Because the means are very close to the same values and the ANOVA shows no significant difference between means, gas and oil reservoirs in the Frio Fluvial-Deltaic Sandstone appear to belong to a single population.

Net-pay thicknesses from both oil and gas reservoirs have low variability and are positively skewed, with a high positive kurtosis (**Figure** 17). A full 85 percent of both oil and gas reservoirs have net-pay values ≤20 ft, and the median and mode are 10 ft. The large range and standard deviation are due to a long tail of a few large reservoirs. Gas reservoirs demonstrate wider variability. Net-pay thicknesses in gas reservoirs have a range of 241 ft and a standard deviation of 30. The range and standard deviation of net pay in oil reservoirs are 141 ft and 26, respectively. One standard deviation away from the mean represents a 122-percent change (coefficient of variation) from the mean value for gas reservoirs; for oil reservoirs this difference is 114 percent. Minimum values are the same, although gas reservoirs have wider variability because of a longer tail on the high side. This tail creates a larger standard deviation of net-pay values in gas reservoirs, which is coincident with the fact that gas reservoirs that can produce at lower permeability have the possibility of thicker net pay (Table 8). Skewness and kurtosis are strongly positive for the oil, gas, and combined reservoir data sets, also indicating the tight grouping at thin values and the long tail of few large values.

Thickness of net pay tends to increase with increasing area in gas reservoirs. Net pay demonstrates a weak, positive covariant relationship with reservoir area, with a correlation coefficient of 0.44. Neither oil reservoirs nor the combined group data show this relationship. Because this positive covariant relationship between net pay and area exists only for gas reservoirs, the relationship may be due to the greater mobility of gas.

Reservoir Area

Reservoir area values display a difference between oil and gas data sets. The mean gas reservoir size of 2,827 acres is 656 acres larger than the 2,171-acre mean for oil reservoirs (Table 8). ANOVA demonstrates that the difference between the means is statistically significant, with a generated F statistic value of 4.24, compared with the critical F value of 3.92 (Table 9). The F-test results suggest that oil and gas reservoir size could be sampled from different populations. The difference between the oil and gas reservoirs shows up at the tails of the distributions, where there are fewer small gas reservoirs and more large gas reservoirs (**Figure 18**).

Gas reservoirs tend to have greater variability and be more positively skewed. The range, standard deviation, and coefficient of variation are larger for gas reservoirs than for oil reservoirs. The range for gas reservoirs is 25,960 acres, in contrast to 7,474 acres for oil reservoirs. The coefficient of variation indicates that at 1 standard deviation the area of gas reservoirs is 120 percent larger, whereas for oil reservoirs the area is only 87 percent larger. Both reservoir sets are positively skewed, although gas reservoirs are about four times more skewed. Oil reservoirs display little kurtosis, while in contrast gas reservoirs are highly kurtosic (Table 8). The greatest overall difference between the two groups is caused by the presence of only a few large gas reservoirs.

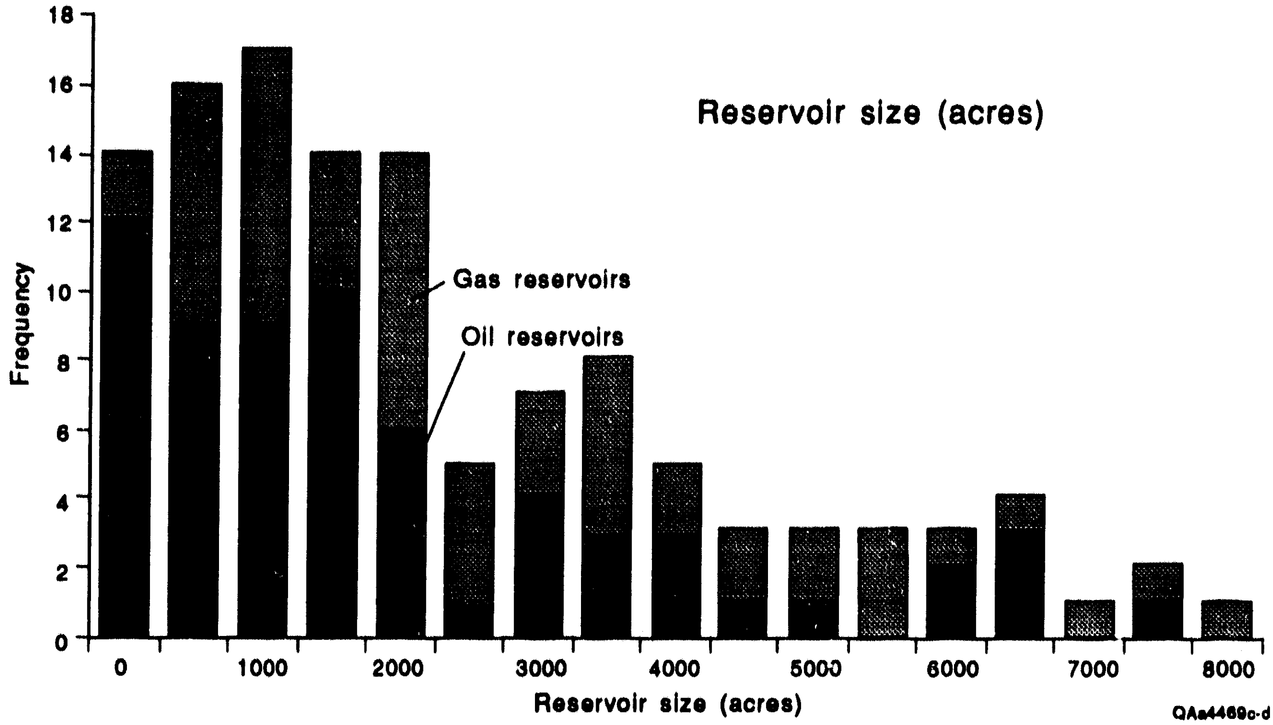


Figure 18. Histogram illustrating distributions for values of reservoir area throughout the play.

Potential for Reserve Growth in the Frio Fluvial-Deltaic Sandstone Oil Play

Reservoir attributes used to simulate volumes and create probability distributions of original oil in place, original mobile oil in place, and residual oil in place for individual reservoirs throughout the Frio Fluvial-Deltaic Sandstone play were combined to produce a risk-adjusted total resource for the play. Probability distributions generated for each of these oil volumes suggest a possible range of estimates for the oil resource remaining in the play as a whole. A preliminary assessment of the oil remaining in incompletely drained and untapped compartments in reservoirs throughout the play is based on these probability distributions.

Incompletely Drained Oil Resource

A large volume of incompletely drained oil resides in the Frio Fluvial-Deltaic Sandstone play. Original oil in place ranges from 3.8 BSTB at 95-percent probability to 5.6 BSTB at 5-percent probability. This probability distribution is skewed positively (Figure 19). Original volumes of mobile oil range from 2.5 to 3.6 BSTB and are also positively skewed.

The incompletely drained resource is represented by both the remaining mobile oil and the residual oil. A minimum of 1.2 BSTB of remaining mobile oil and 1.5 BSTB of residual oil still lies

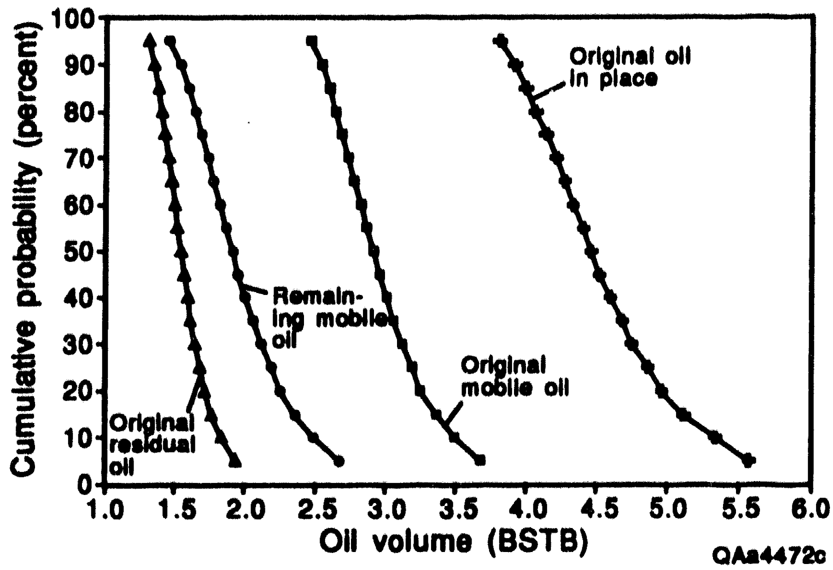


Figure 19. Probability distribution curves illustrating the cumulative probability of original oil in place, original residual oil, original mobile oil, and remaining mobile oil for the Frio Fluvial-Deltaic Sandstone play.

within this play. Maximum volumes may be as high as 3.5 BSTB for mobile oil and 2.3 BSTB for residual oil. No precedent has been set in the Frio for enhanced oil recovery that employs a method for producing residual oil. However, reservoir characterization, coupled with proper reservoir management techniques, can recover additional remaining mobile oil. There exists a 95-percent probability that at least 1.5 BSTB of remaining mobile oil lies within this play and a 5-percent probability that as much as 2.7 BSTB may still reside in these reservoirs (Figure 19). This large volume of remaining mobile oil represents the upside potential for the incompletely drained oil resource.

Untapped Oil Resource

Untapped resource potential within the Frio Fluvial-Deltaic Sandstone play as a whole has been modeled by combining the probability of original oil in place calculated for an individual sand reservoir with the probability of occurrence of a reservoir sand and the probability of completion of a reservoir sand. The probability of a given sand's original oil in place was described by the play probability distribution of original oil in place per acre and the size distribution of an individual sand, or reservoir. Original oil in place per acre was modeled by the Weibull equation, where $a = 1.6$ and $b = 24{,}500$. The areal extent of a reservoir sand was modeled using the distribution of reservoir sands in Rincon field. An exponential fit (b value of 651) was found to best model the variability of the sand area.

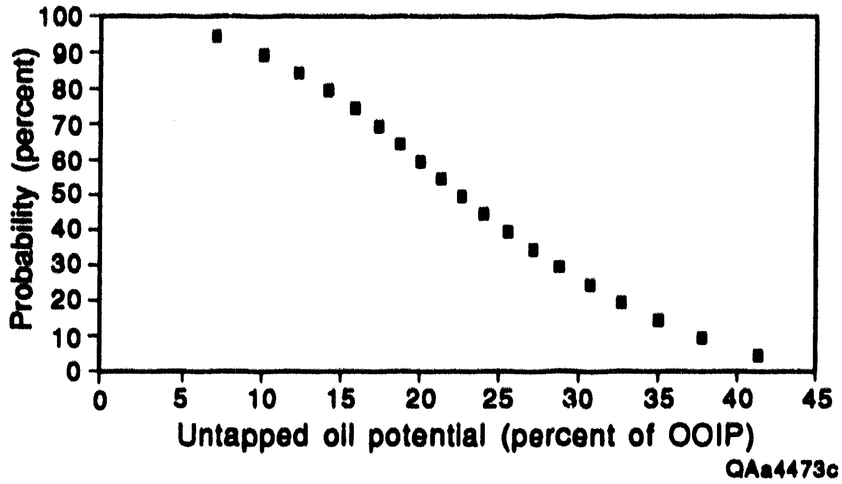


Figure 20. Modeled cumulative probability distribution curve illustrating potential of untapped oil in reservoirs within the play.

The number of sands within a field was estimated by identifying both pay zones and sand occurrences. The range and most likely values for the number of pay zones within a field and the number of sands within a pay zone were the parameters used to model sand occurrence with a triangular probability distribution. A pay zone was defined as a set of sands confined by thick shales above and below that extend over the entire field area. The number of pay zones roughly describes the stacking sequence and vertical facies distribution of reservoir zones within a field area. Using Rincon field as an example, the number of pay zones varies from 1 to 11, with 5 being the most likely number of occurrences. The number of sand occurrences within a single pay zone is interpreted to reflect lateral facies changes and internal heterogeneity within a reservoir. In Rincon field, the number of sands within a reservoir zone varies from 1 to 7, with a most likely value of 4.

The final step in modeling untapped oil potential was to add completion probability into the model and generate a distribution of untapped oil potential as a percentage of original oil in place. Completion probability was modeled as a triangular distribution, where 50 percent was the minimum number of perforated or tapped sands, 80 percent was the most likely number, and 100 percent was the maximum number of completions. Completion probability was combined stochastically with the net-pay zone occurrence, sand within a pay zone occurrence, and original oil in place distributions to generate an estimate of overall probability of untapped oil as a percentage of original oil in place within a field (Figure 20). At a 90-percent probability, 10 percent of the original oil in place is untapped, and at a 10-percent probability, 37 percent of the original oil in place represents the untapped resource. This distribution is fairly normally distributed, with a skewness of only 0.19. The mean percentage of untapped oil represents 23.3 percent of the total in-place resource. These estimates imply that nearly one-quarter of the original oil in place in the Frio Fluvial-Deltaic Sandstone play may be residing in, as yet, untapped reservoir compartments.

Table 10. Screening criteria for field selection.

1. Amount, quality, and type of field data
2. Structural complexity of field
3. Availability of conventional core
4. Completion density
5. Operator commitment to further drilling

SELECTION OF FIELDS FOR CHARACTERIZATION STUDIES

Screening Criteria

Initial screening of fields and reservoirs in the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play was accomplished using publicly available data from (1) hearing files at the Railroad Commission of Texas (RRC), (2) the Bureau of Economic Geology (BEG) Texas Oil Reservoirs data base, (3) commercially available production data from Dwight's Energydata and Petroleum Information, (4) well-log data from BEG and RRC files, (5) trade and technical literature, and (5) some additional private data contributed by companies. Data were compiled in the form of field summaries for several of the largest fields within the Frio Fluvial-Deltaic Sandstone play.

Criteria that formed the basis for field/reservoir selection were established (Table 10). The fundamental considerations for the selection of Frio fluvial-deltaic reservoirs suitable for detailed study focused on both the quality of the field/reservoir data and the potential for identifying additional reserves. Those fields possessing an extensive geological, petrophysical, geophysical, and production data base, coupled with the best possibilities for infield reserve growth, are the most attractive candidates for further study. Infield reserve growth is being analyzed by determining current reservoir recovery efficiency.

Criteria for the selection of specific South Texas Frio reservoirs (Table 11) for detailed study were established at the onset of this project. Reservoirs from fields with large infield reserve potential and sufficient data to provide the means for identifying additional reserves were deemed to be the most suitable candidates for detailed study. Specific considerations in our field selection process included the (1) size of reservoir-producing area, (2) density of well completions in individual reservoirs, (3) quality and quantity of existing geologic and production data, (4) availability of 2-D or 3-D seismic coverage, and (5) current level of drilling activity. Fields that contain reservoirs with large producing areas and numerous well bores with a relatively wide completion spacing are excellent candidates for this project because they present good possibilities

Table 11. Key criteria for reservoir selection.

KEY CRITERIA	*BENEFITS*
1. Current drilling activity within reservoir	opportunities for new data collection
2. Large producing area	increased opportunity for infill potential
3. Completions with a long production history	provide basis for historical comparison, modeling of production
4. Stratigraphically complex and structurally simple	more likely to contain untapped compartments; heterogeneity a function of depositional and diagenetic variability, not structure

for the identification of bypassed and untapped reservoir compartments. Fields with abundant high-quality geologic, geophysical, and production data, including conventional core and core analysis data, modern well logs, 3-D seismic coverage, and complete reservoir production histories, will provide the best chance of success for identifying additional reserve potential through advanced reservoir characterization techniques. Recent drilling activity in a field is an indication of an operator's current strategy for reservoir reexploration and additional field development and therefore highlights fields with the best potential for near-term implementation of recommendations resulting from this project.

Overview of Fields Screened in the Frio Fluvial-Deltaic Sandstone Play

Data were screened from productive Frio reservoirs distributed among fields along the entire play trend in South Texas (Figure 21). There are currently 59 producing reservoirs within at least 26 fields in the play. Initial data screening was limited to the subset of fields that have produced more than 1 MMSTB from the Frio and that have wells currently producing oil from Frio zones. Geologic, engineering, and production data from 14 major fields in the play, from Garcia field in southern Starr County northeastward to Agua Dulce field in Jim Wells and Nueces Counties, were examined (Table 12). Data that were summarized and compared between fields included the number and sizes of individual Frio reservoirs, cumulative past production, the present status of Frio production, and where available, completion densities for individual Frio reservoir units. Completion densities for several of the major producing fields in the play were determined from Railroad Commission of Texas proration schedules and are used as a gross estimate of remaining reserve potential in various fields. Preliminary estimates of potential infield reserve growth were analyzed by determining current reservoir recovery efficiencies.

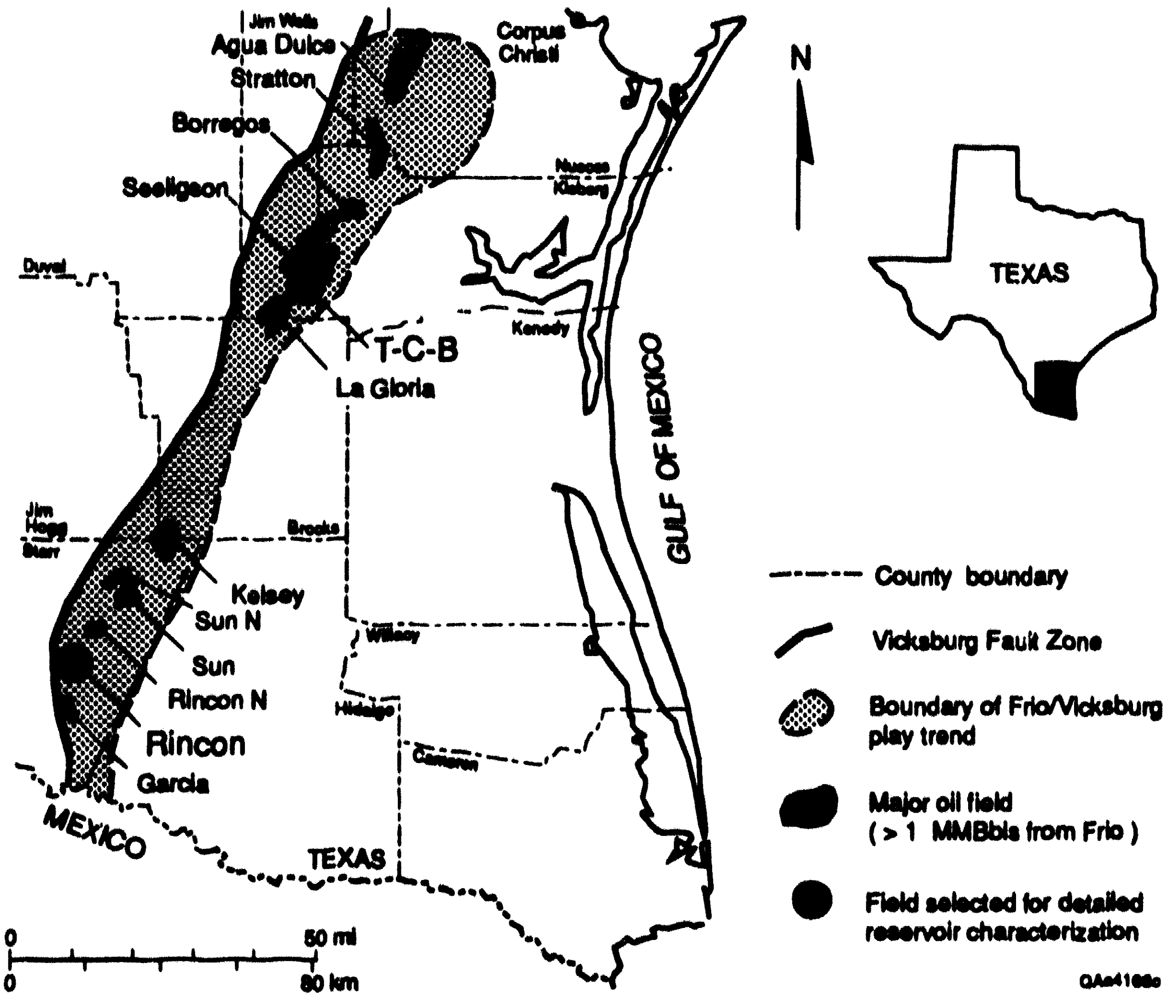


Figure 21. Location map of major fields in the Frio Fluvial-Deltaic Sandstone oil play that were considered for detailed reservoir characterization studies.

Rationale for Field Selection

Our screening criteria significantly reduced the number of oil fields in the Frio Fluvial-Deltaic Sandstone (Vicksburg Fault Zone) play suitable for detailed reservoir characterization studies (Table 12). On the basis of our preliminary assessments of additional reserve growth potential and the availability of abundant geologic and production data, we selected two field areas for inclusion in this project: the western portion of the Tijerina-Canales-Blucher (T-C-B) field, located in Jim Wells County and operated by Mobil, and Rincon field, located in Starr County and operated by Conoco.

Table 12. Major oil fields still producing in the Frio Fluvial-Deltaic Sandstone play in South Texas.

County	Field Name	Operator	Disc. year	Depth Top	1991 Prod. (MSTB)	Prod. Wells (1990)	Cum. Prod. (MSTB)	Well Spacing (acres)	No. of Active Res. Zones
Starr	Rincon	Conoco	1938	4000	23.7	15	40025	20	4 zones
Starr	Rincon North	Oryx	1940	4400	14.9	8	7523	40	2 zones
Starr	Garcia	Oryx	1942	3800	61.5	6	29181	40	4 zones
Starr	Sun	Oryx	1941	4300	18.7	7	26119	20,40	2 zones
Starr	Jay Simmons	Energy	1947	5770	25.3	13	6060	20	1 zone
Brooks	Alta Mesa	Mestena	1936	2485	15	12	9380	20	1 zone
Kleberg	T-C-B	Mobil	1944	7109	3.3	10	22912	40	4 zones
Kleberg	Borregos	Exxon	1945	7040	142.5	37	109463	40 acres	comb.
Jim Wells	Seeligson	Oryx	1942	5675	114.6	30	147021	40	4 zones
Nueces	Stratton	UPRC	1938	6500	10.6	11	10503	40	4 zones
Nueces	Agua Dulce	UPRC	1928	6970	30.9	16	44447	40	1 zone

INITIAL RESERVOIR STUDIES OF SELECTED FIELDS

Introduction

Initial geological and engineering studies were undertaken in Rincon and T-C-B fields. The objective of these investigations was an initial evaluation of the interwell reservoir heterogeneity in the fields as a basis for selection of individual reservoir zones for further analysis to delineate stratigraphic heterogeneities in detail and identify specific targets for recovering additional reserves.

Operators from both fields have provided base maps and access to existing completion records, reservoir production histories, and extensive well data files. Available well data include information on drilling history, perforation intervals, formation and reservoir tops, well logs, core descriptions and analyses, and fluid and pressure test data. Data from 190 wells have been collected and inventoried from lease blocks in the portion of Rincon field selected for study. Similar data have been gathered for more than 80 wells in T-C-B field. Most well logs from both fields are of pre-1950 vintage and typically include only SP and resistivity curves. A very limited number of wells (less than 5 percent) from the northern study area in Rincon field have sonic, density, and porosity logs. More complete log suites are available for many of the recently drilled wells in the T-C-B field. Porosity, sonic, and dipmeter data exist for approximately 15 percent of the wells in the T-C-B study area. None of the log data from either field is available in digital format.

Conventional core from four wells in Rincon field has been loaned for study by Conoco. Total core thickness is approximately 300 ft, which includes sections from four different reservoir intervals from the Frio. Detailed core descriptions and conventional core analysis data (porosity, permeability, and oil and water saturations) for more than 100 wells in Rincon field have been compiled. These represent more than 1,300 individual core analyses over 34 individual reservoir intervals and approximately 4,000 ft of total core thickness. No whole core is available from T-C-B field, but there are limited core analysis data from eight of the older wells in the fields. Sidewall cores from eight additional wells are also accessible for study. A summary of available data from both fields is presented in **Table 13**.

Summaries of the field production histories and available data are presented for both T-C-B and Rincon field areas. The fieldwide stratigraphic and structural framework, along with preliminary compilations of production data and reservoir characteristics for individual reservoir zones, is presented for T-C-B field. A more complete assessment of the stratigraphy and production data from reservoirs in Rincon field is provided because these data were made available earlier in the research year.

Table 13. Summary comparison table of Rincon and T-C-B fields.

Basic Information	RINCON FIELD	T-C-B FIELD
Operator	Conoco	Mobil
Discovery Year	1939	1939 (by Shell)
Total Acres	20,520	4800
Wells	640+	80
Reservoir Sands	30	18
Sands >1 MMbbl	14	8
Depth Interval	3000-5000 ft	5500-7700 ft
Cumulative Oil Prod	65 MMbbl	22.9 MMbbl
Active Completions	25 oil, 30 gas	10 oil, 23 gas
Current Rates	373 bopd	300 bopd
	4576 Mcf/d	16,000 Mcf/d
Available Field Data		
Study Area	5400 acres (northern field area)	3500 acres (1 lease)
Number of Wells	173	85
Whole Core	300 ft core	No core
Other Core Data	Analyses from 100+ wells Additional sidewall cores	Limited analyses Sidewall cores from 13 wells

Rincon Field

Location and Structural Setting

Rincon field is located in eastern Starr County, Texas, 120 mi southwest of Corpus Christi and approximately 20 mi north of the United States–Mexico border (**Figure 22**). The field is one of many located within the 240-mi-long Frio Fluvial-Deltaic Sandstone oil and gas play that is downthrown and parallel to the large Vicksburg flexure/growth fault. The structural setting at Rincon field is similar to those of other fields in this highly prolific play. The general structure in the shallow Frio section is characterized by a northeast-trending, downthrown asymmetric rollover anticline that plunges gently to the northeast and is bounded to the west by the Sam Fordyce–Vanderbilt Fault, a major growth fault associated with the large Vicksburg Fault Zone system (**Figure 23**) (Ashford, 1972). Frio production associated with the shallow structure is both stratigraphically and structurally controlled. Hydrocarbons are trapped in zones within the rollover

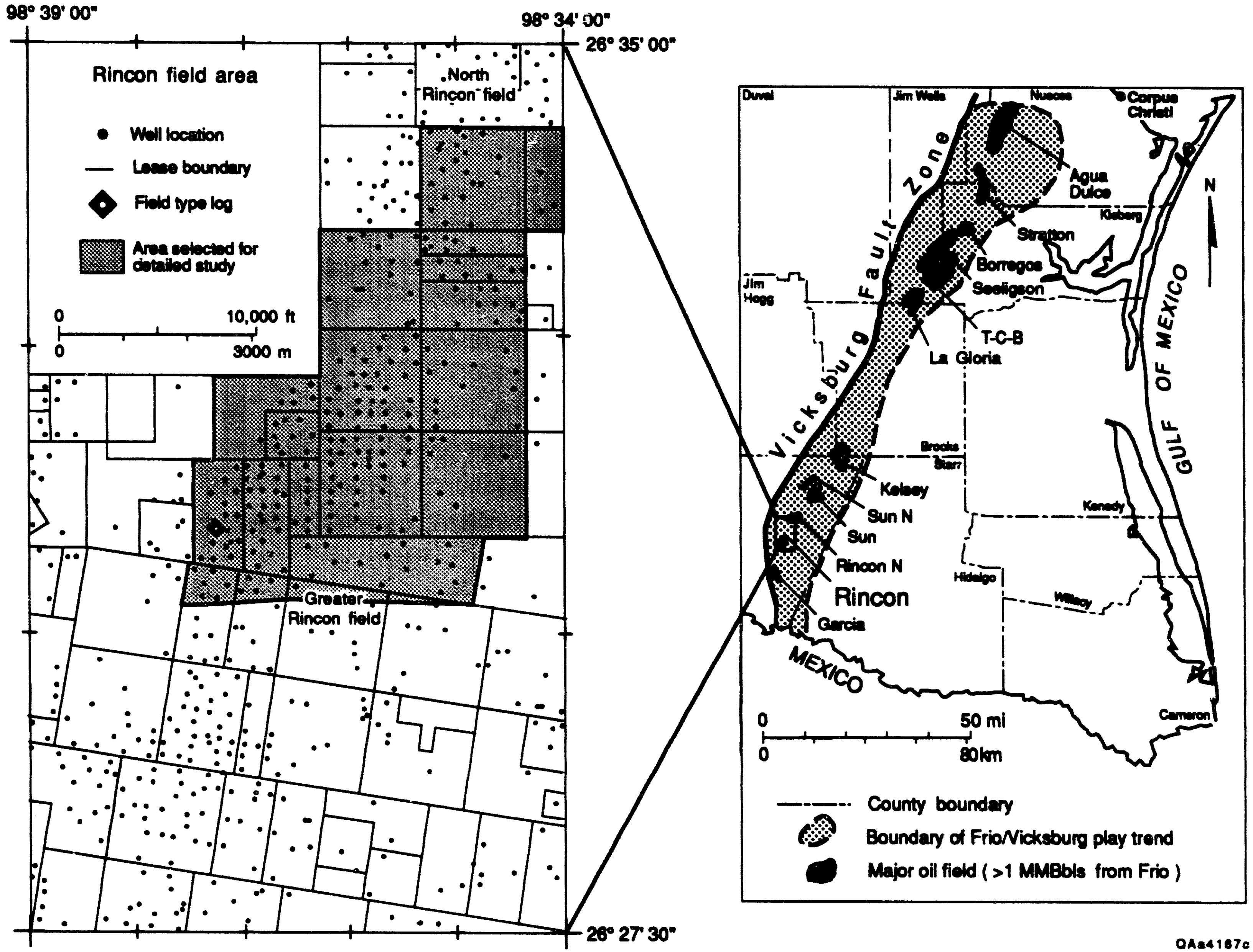


Figure 22. Map showing location of Rincon field and area of field selected for study.

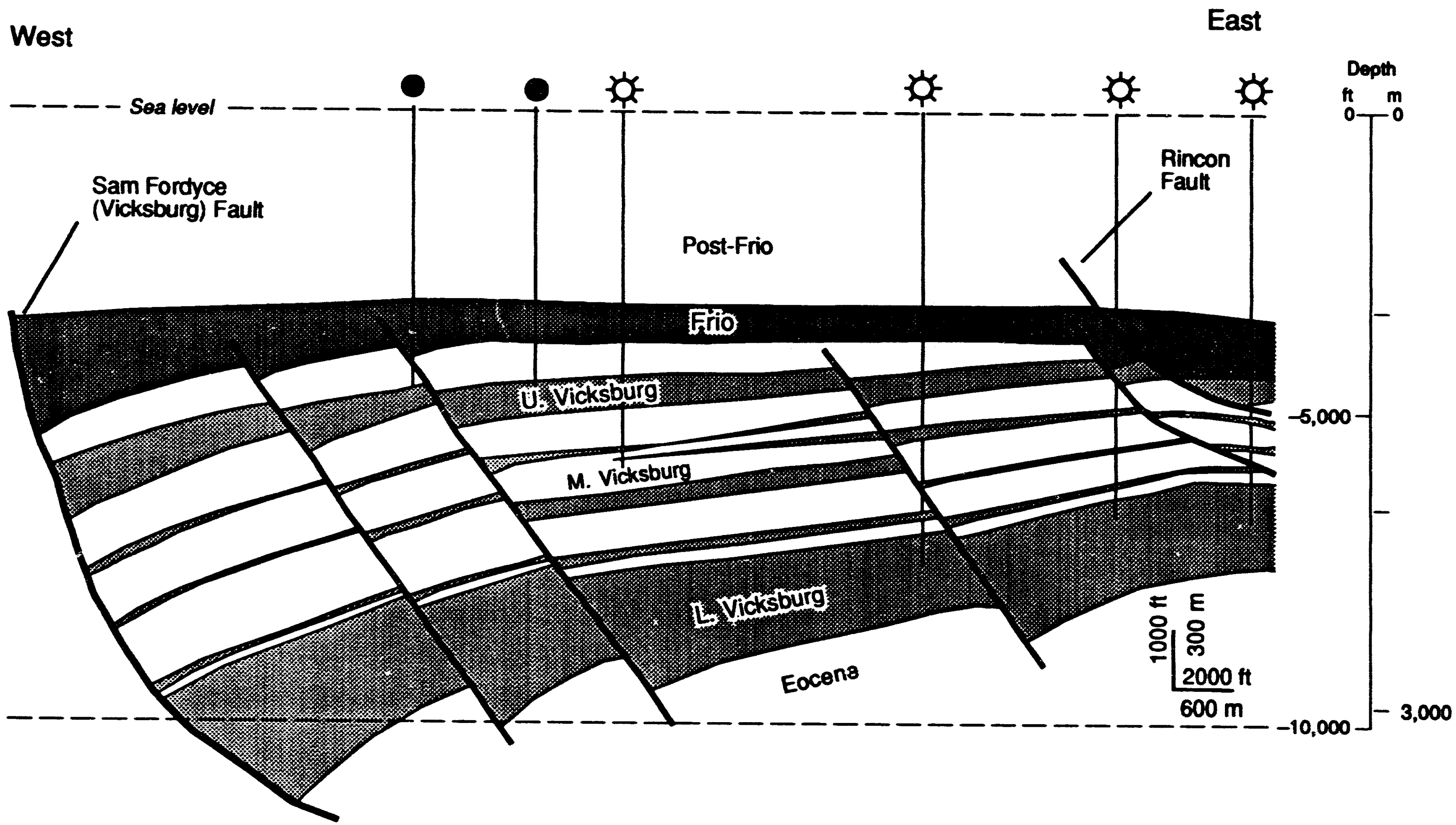


Figure 23. Generalized west to east cross section through Rincon field illustrating structural setting. Adapted from Ashford (1972).

anticline downdip of the major growth fault and exist in multistoried and multilateral sandstone reservoirs that form complex stratigraphic traps draped over an anticlinal nose.

Below a regional unconformity that marks the boundary between the Frio and the Vicksburg Formations, the field structure becomes more complexly faulted and folded. Vicksburg accumulations are primarily controlled by upside fault closures on down-to-the-east faulting and secondarily by stratigraphic truncation. Nine major Vicksburg reservoir zones have produced from multiple fault-separated traps at depths of 5,000 to 8,000 ft. The bulk of oil production is from the first Vicksburg sand, which has produced nearly 35 MMSTB of oil from the west flank of the structure.

Field Development and Production History

The first well in the Rincon field area was a dry hole drilled by Transwestern Oil Company in 1936. The field was discovered in 1939, following the completion of a seismic program. The discovery well was the T. B. Slick B-266 No. 1 well, located in the center of the field. The first oil was produced from shallow Frio objectives in the Slick B-528 No. 2 well. Conoco took over field development in 1940 and is currently the principal operator for most of the Rincon area, which includes producing acreage from the Boyle, Cameron, Rincon-Vicksburg, North Rincon, and Urshel fields, as well as the formerly productive Davenport and East Rincon fields.

The initial phase of Frio development continued through the mid-1940's (Figure 24). Peak production rates occurred in 1944, when production averaged approximately 7,300 bbl/d. An extensive Vicksburg development program occurred from 1950 to 1954, following discovery of the first productive Vicksburg sand in the extreme southern part of the field in 1949. More than 65 MMSTB of oil have been produced from fluvial-deltaic sandstone reservoirs over the combined Frio–Vicksburg stratigraphic interval. By 1990, production from 38 separate Frio reservoirs yielded over 45 MMSTB of oil. Present Frio production has declined to average daily rates of 373 STB of oil and 4,576 Mcf of gas.

Reservoirs in the Frio section have produced under a combined natural water drive and gas-cap expansion. Most of the Frio oil reservoirs had initial gas caps. Gas was often reinjected into the gas caps of many of the larger reservoirs during the early years of field production in order to maintain reservoir pressure and extend the flowing life of the wells. Waterfloods were also performed in several of the larger reservoir zones, including the D-5 sand, E-1 and E-2 sand zones, and G-1 and G-2 sand zones. Some wells were completed concurrently as dual producers in two waterflood units. Production records indicate most of these floods were successful.

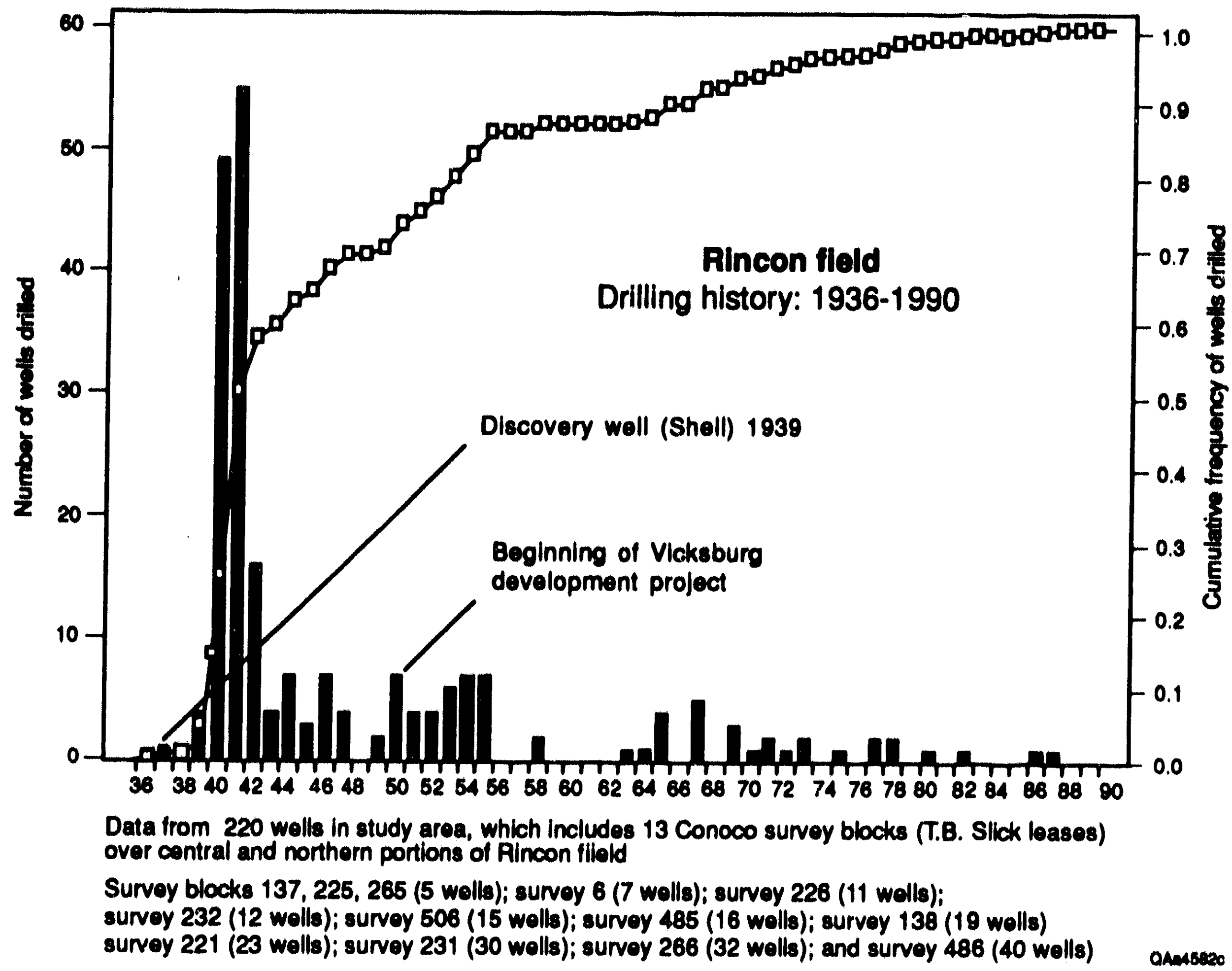


Figure 24. Histogram illustrating chronology of drilling and development in Rincon field from 1936 to 1990.

Study Area and Data Base

The entire Rincon field area covers over 20,000 acres and contains more than 640 wells. A geographic subset of this large field area has been selected for detailed study. The area of investigation will target part of the northern portion of the field (Figure 25). The decision to focus within this area was based on a combination of factors, including the density of available well data, the presence of conventional whole core, extensive core analysis data, and the location of new production wells in the area. Data from the new wells, including complete log suites, will be incorporated into the study as they are made available. Reservoir studies will be limited to productive sand units within the Frio section. Deeper Vicksburg reservoirs are characterized by structural complexity and significantly less well control. Vicksburg reservoir sands do not provide good potential for detailed stratigraphic correlations and studies of lateral facies heterogeneity and will not be a focus of this study.

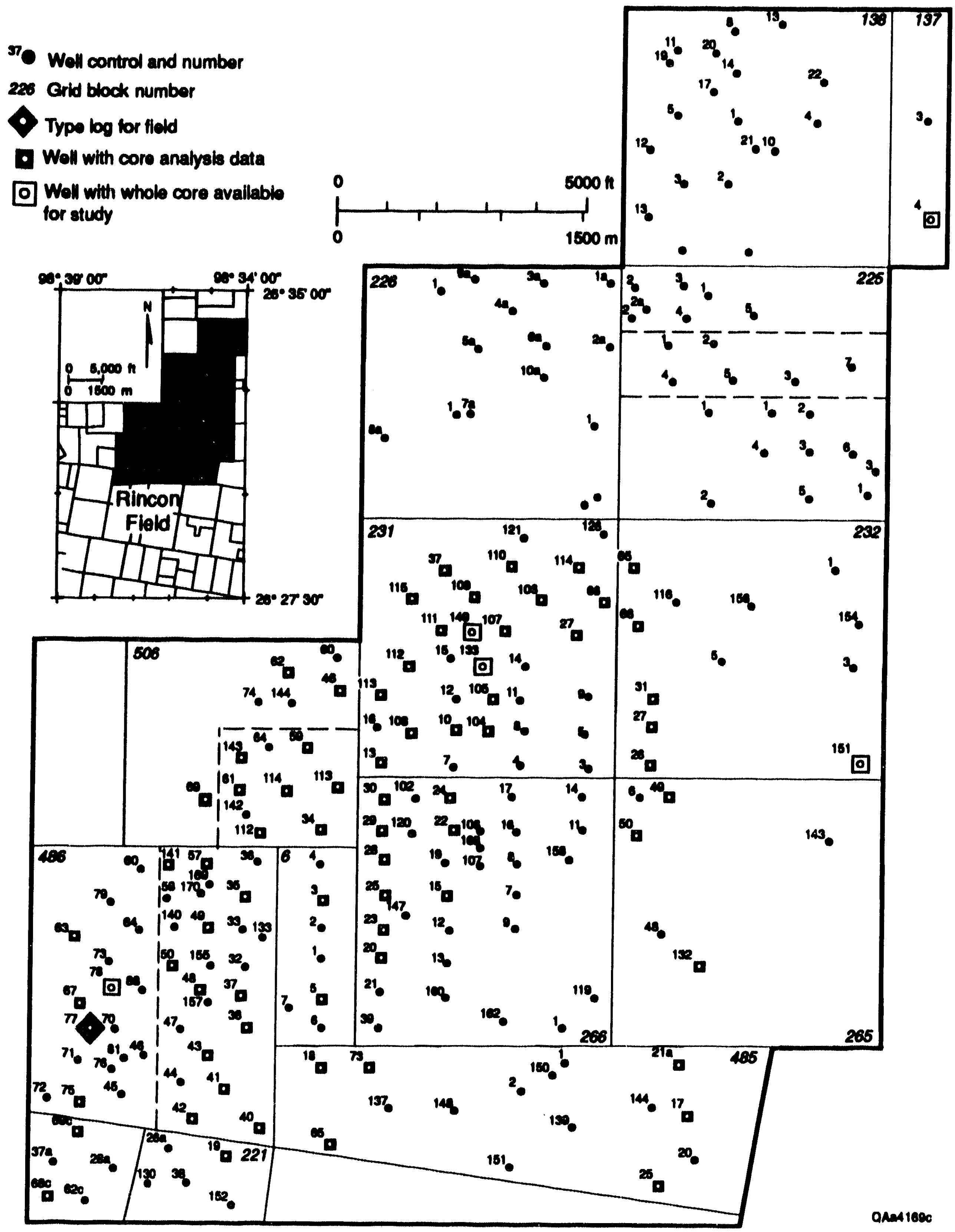


Figure 25. Index map showing distribution of well and core data in Rincon field study area.

Rincon field is densely drilled and has been extensively cored. Approximately 200 wells have been drilled in the central Rincon area, and abundant conventional core analysis data exist for 38 individual reservoir sand intervals within the Frio section. Data from approximately 225 wells have been made available for this study by Conoco. These include well logs and extensive well history information consisting of chronologies of completions, production, and abandonment for individual reservoir zones, production and pressure-test data, extensive wireline core data, and limited reservoir fluid analyses. More than 200 well logs have been imported into a digital data base to facilitate standard well log analysis, detailed formation evaluation, and three-dimensional modeling efforts of selected reservoir intervals.

The large volume of conventional core analysis data and archived core available for study makes this field an excellent candidate for detailed reservoir characterization studies. Flow-unit parameters and permeability architecture of individual reservoir units can be directly quantified by both new measurements and reinterpretation and synthesis of existing subsurface data. The quantity of available core data also provides an excellent opportunity to test and apply outcrop-derived constraints on flow units and permeability structure from analogous fluvial-deltaic reservoirs.

General Stratigraphic Framework

Rincon field is located near the southwestern edge of the Rio Grande Embayment, an area that covers a large part of southwestern Texas and that served as one of the primary depocenters for Gulf Coast sedimentation during the Paleogene and Neogene. The top of the Frio sequence in the Rincon area is at approximately 1,800 ft. The Frio interval consists of 2,500 to 3,000 ft of interbedded sandstone and mudstone. The top of productive Frio reservoirs in Rincon field is found at an average depth of 3,400 ft subsea, and the total thickness of the entire Frio–upper Vicksburg reservoir sequence averages 2,400 ft.

More than 50 individual productive reservoir sands within the stratigraphic interval from 3,000 to 5,000 ft have been identified and mapped across the field by Conoco. These reservoirs range in dimension from only a few acres to complex, interrelated reservoir systems that cover the entire field. Fault displacements in the productive Frio interval are generally minor, and the major cause for reservoir complexity and compartmentalization of hydrocarbons is a result of the multilateral and multistacked nature of the Frio reservoir sands. The variability in sandstone geometries and the complex depositional architecture of these Frio reservoirs provide excellent potential for identifying additional hydrocarbons that have been isolated in untapped and incompletely drained reservoir compartments.

The top of the Vicksburg Formation, located at an average depth of 4,600 ft, is identified by the presence of a regional unconformity surface that is apparent on seismic sections and by changes in resistivity and density log character. It can also be correlated on well-log cross sections. The total thickness of the Vicksburg in the Rincon area is unknown, but the formation extends below a total depth of 9,100 ft (>4,000 ft thick). Production from Vicksburg sands occurs over a depth range from 5,000 to 8,000 ft and comes from multiple fault-separated traps. Upper Vicksburg sandstones consist of 50- to 150-ft-thick progradational packages typically separated by 150- to 300-ft-thick intervals of mudstone (Humphrey, 1986). The thickness and overall log character of individual Vicksburg sand packages are relatively consistent within portions of the field, but fieldwide correlations are complicated by the complex faulting associated with development of the Vicksburg Fault Zone.

Frio Reservoir Geology

The stratigraphic interval that contains the productive Frio and upper Vicksburg reservoir sands for Rincon field is illustrated in a representative type log from a well located in the middle of the study area (Figure 26). The Frio reservoir interval has been divided into 11 zones designated A through K; these zones are further subdivided into a total of 37 individual reservoirs. The Frio–Vicksburg contact is taken to be the top of the L series sands. This contact is indicated by a distinctive change in lithology of the formation as well as by limited paleontological evidence. Upper Vicksburg sandstone reservoirs include L series sands and a thick package of stacked sands referred to as the first Vicksburg sand. The entire Vicksburg series includes reservoir zones of the Vicksburg I, II, and III sands, and each of these contains several subdivisions.

The productive reservoir interval includes strata from both the middle and lower Frio section. Middle and lower Frio reservoirs in Rincon field are located in an aggradational to mixed aggradational and progradational setting within the Gueydan fluvial system (Galloway and others, 1982). Reservoir facies are developed in a combination of broad, dip-elongate fluvial channel-fill sandstone complexes and a smaller number of strike-oriented sandstones that exhibit a bar geometry. Net-sandstone isopach mapping of each of the Frio reservoir sand intervals reveals a recurring pattern of sandstones with dip-elongate and strike-oriented geometries. The primary depositional pattern is characterized by dip-elongate channel deposition that reflects sedimentation dominated by fluvial aggradation and deposition in channel systems flowing along an axis across the low-relief Oligocene Gulf coastal plain toward the shoreline from northwest to southeast. These periods of sedimentation appear to be briefly punctuated by short intervals in which strike-oriented sand bodies are developed. These phases probably reflect periods of decreased aggradation, which allows for minor marine transgression and subsequent reworking and redistribution of the sand originally deposited in dip-elongate channels by wave action. The development of these strike-oriented bar deposits is limited, and isopach mapping indicates that they are laterally discontinuous. They do not form important oil reservoirs.

All of the major productive oil reservoir zones in Rincon field appear to represent deposition in large dip-elongate fluvial systems. These dip-elongate fluvial sandstone reservoirs occur as

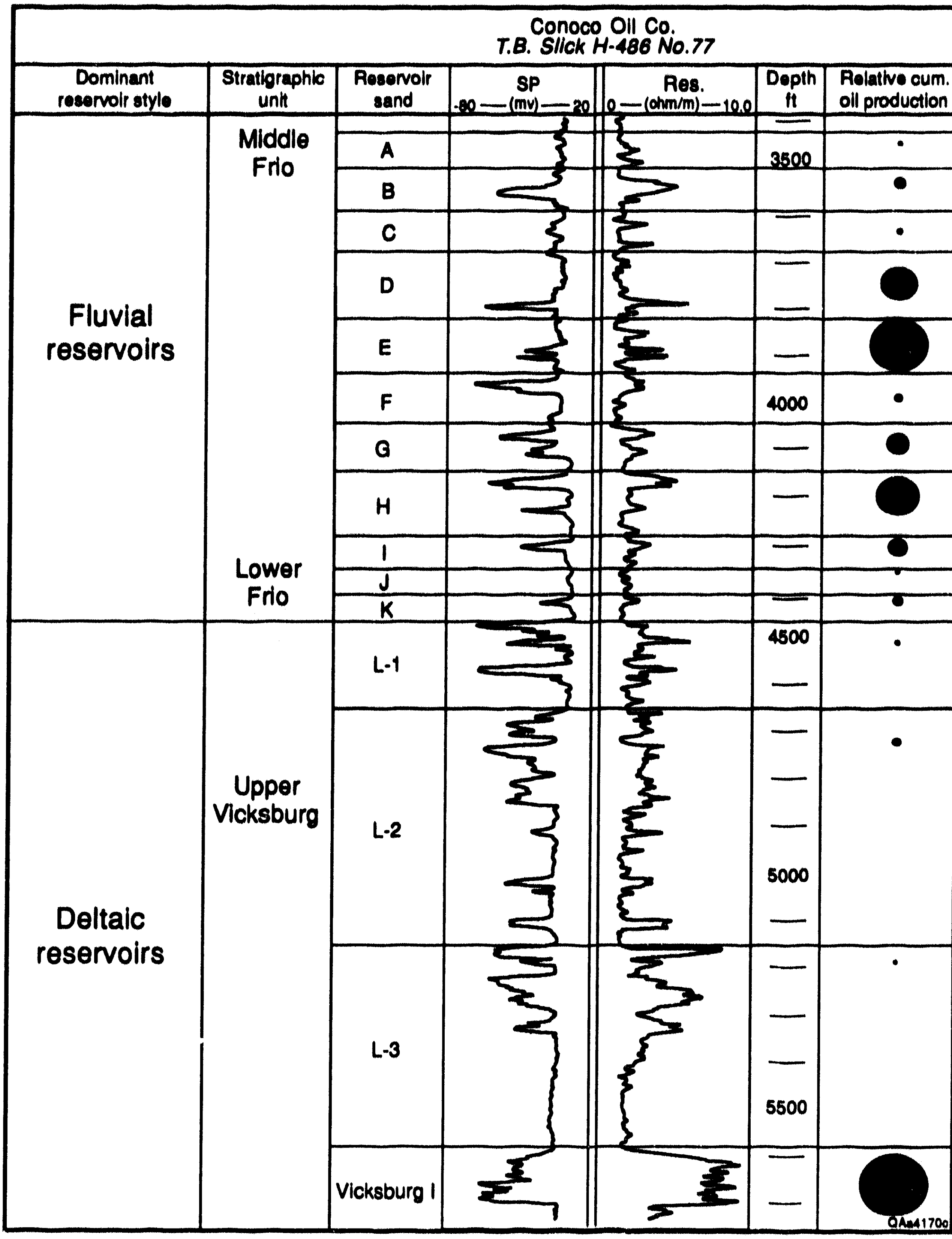


Figure 26. Representative log from Rincon field illustrating general stratigraphy and nomenclature of reservoir sands.

individual narrow channel-fill units isolated vertically and laterally by very low permeability overbank facies and floodplain mudstones and as large channel complexes with multiple sand lobes that combine into a single large communicating reservoir. These reservoir complexes commonly consist of multiple thin sand units that range in gross thickness between 50 and 100 ft and possess a net-sand thickness of 0 to 40 ft.

Survey of Individual Reservoir Zones

Accomplishments during Project Year 1

Studies of Frio reservoirs in Rincon field completed during the first year consisted of a comprehensive screening of available geologic and engineering data in order to assess which productive sandstone zones exhibited the best potential for identifying additional oil reserves through detailed characterization of reservoir heterogeneity. Initial tasks designed to identify reservoir zones that would represent the best candidates for detailed study included (1) compilation and comparison of production data by reservoir, (2) synthesis and evaluation of reservoir core analysis data, (3) review and synthesis of reservoir-specific geologic data supplied by Conoco, and (4) establishment of a stratigraphic cross-section grid across the field study area. Details associated with the first three of these tasks are presented below. Detailed stratigraphic cross sections are currently being developed and will be completed early in the second project year.

Reservoir Development History

The first step in estimating the potential for additional oil resources in Rincon field consisted of a thorough survey of the production history of the various productive reservoir zones. Data sources for this effort consisted of production data available from public sources, including files from the Railroad Commission of Texas, Dwight's Energydata, and Petroleum Information Consultants, as well as extensive well records from Conoco, the field operator. Information acquired from Conoco includes detailed well history records and a computerized production data base with completions and oil and gas production listed by individual reservoir zone for each well in the field (Table 14).

Perforation data for individual reservoir zones in 220 wells were tabulated to provide a chronological history of completions by reservoir. In addition, cumulative oil and gas production for all oil productive reservoir zones was compiled in order to provide comparisons of oil produced by reservoir zone and to illustrate the stratigraphic distribution of oil production. This information is provided in Figure 27. The histogram of completions for Rincon field reservoirs illustrates the mature status of field development, because more than 65 percent of all reservoir completions took

Table 14. Major productive reservoir sandstone zones in Rincon field.

Sand unit name	Average depth (subsea)	Reservoir acres	Number of completions	Acres/ completion	Abandoned zones	Presently active zones*	Number oil wells	Cumulative gas production (Mcf)	Cumulative oil production (MSTB)
B-1	2947	316	31	10	25	6	13	12070	137.6
D-3	3240	468	18	26	17	1	11	1476	749.3
D-4	3248	635	5	127	5	0	2	70	8.5
D-5	3248	2189	81	27	77	4	51	12315	7550.3
D-6	3280	687	5	137	5	0	2	257	3.0
E-1	3390	167	25	7	18	7	17	8288	1802.2
E-2	3390	1360	46	30	36	10	39	14604	6881.6
E-3	3391	931	39	24	39	0	35	4408	4720.7
E-4	3520	505	9	56	8	1	4	1797	660.8
G-1	3586	955	33	29	27	6	20	10068	3151.3
G-2	3570	1180	18	66	16	2	13	5378	1715.5
G-3	3587	280	5	56	5	0	3	1950	488.9
I-1	3660	532	11	48	10	1	17	8729	1314.9
I-2	3655	377	5	75	5	0	6	3556	742.2
J-1	3708	153	7	22	7	0	8	3051	645.0
K-1	3782	184	10	18	10	0	10	5850	419.6

Reservoir acreage, completion data, and cumulative production volumes are from wells within the study area (refer to location map; see Figure 22 for comparison of total field production volumes vs. study area totals)

*Active zones include presently producing completions and shut-in zones

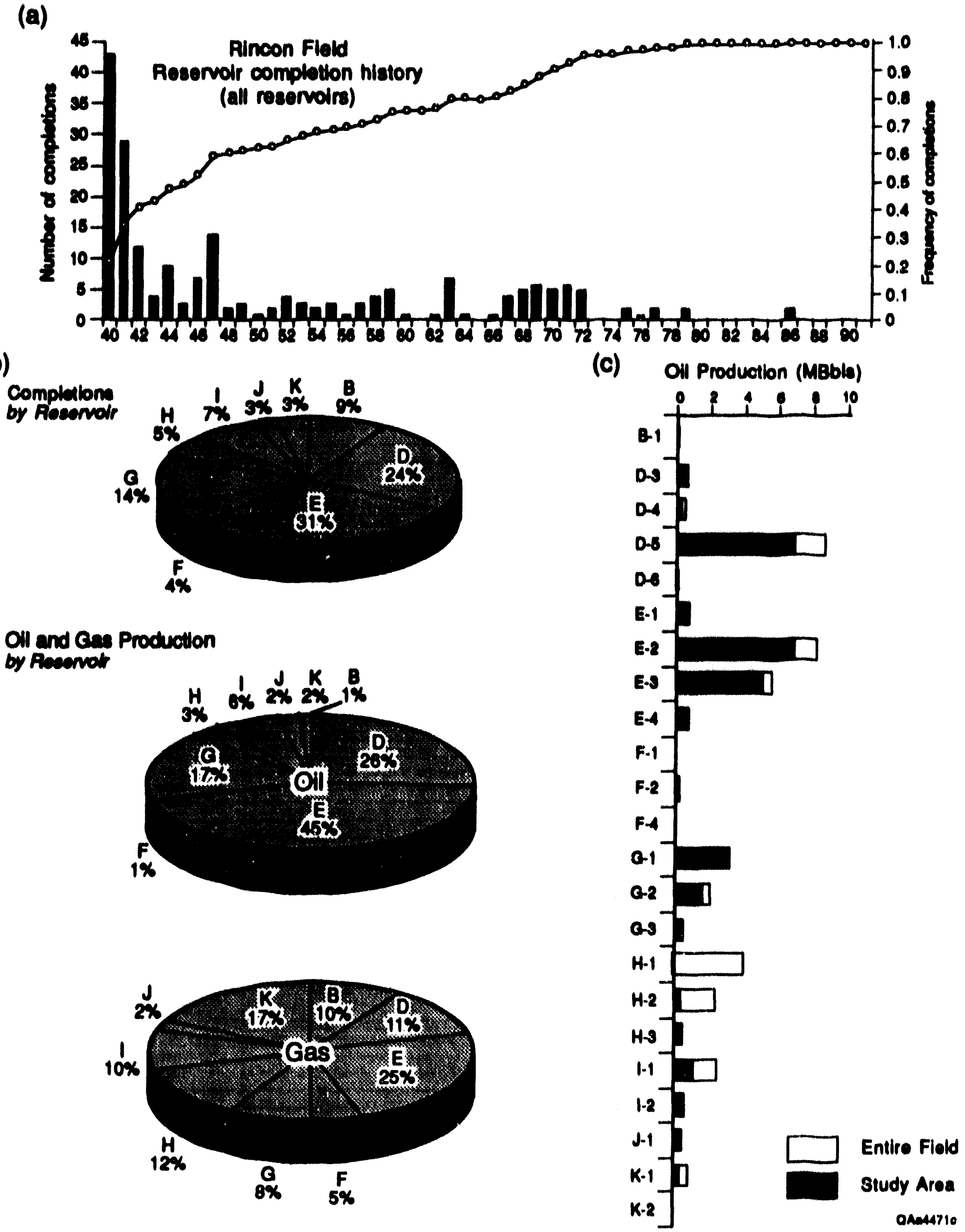


Figure 27. Summary of Rincon field production illustrated by (A) history of reservoir completions, (B) oil and gas production by reservoir, and (C) stratigraphic distribution of productive reservoir zones.

place prior to 1950. The D, E, and G sand series account for 69 percent of all completions and 88 percent of the oil produced in the field area selected for study. The dramatic decline in oil production from these major reservoirs since 1968 (**Figure 28**) is reflected in the significant increase in abandonments of reservoir zones throughout the 1970's (**Figure 29**). As of 1990, there were only 27 oil wells remaining in the field that were producing or had shut-in status (**Figure 30**).

Reservoir Attributes

Abundant wireline core data from more than 100 wells in the Rincon field study area were compiled, sorted by reservoir, and evaluated to develop estimates of reservoir quality for the major Frio reservoir zones. A summary of average porosity and permeability values for each of the Frio reservoir sands is shown in **Table 15**. Porosity and permeability values for individual reservoir sands were also grouped according to reservoir zone (for example, values for Frio E-1, E-2, E-3, and E-4 sands were grouped into the E reservoir zone) and then cross plotted to illustrate the range of reservoir quality for each of the Frio reservoir zones (**Figure 31**). Core data measured from sands in dip-elongate fluvial channel reservoirs exhibit a greater range of values than that of reservoirs mapped as strike-elongate bar sands. This likely reflects the greater range of depositional facies present within the fluvially dominated reservoir zones and may also be partly an artifact of slightly higher textural maturity of the reworked bar sand units.

Reservoirs with High Potential for Incremental Oil Recovery

The Frio D and E sand series are the two most highly prolific reservoir zones in Rincon field. Sandstones within this combined interval have produced more than 22 MMbbl of oil. The stratigraphic complexity of this interval of vertically stacked and laterally coalescing sand lobes provides ideal conditions for the isolation of oil accumulations in multiple reservoir compartments, many of which are now incompletely drained or completely untapped. Significant additional reserves may be identified through integrated geologic and engineering studies that characterize the heterogeneity of various reservoir facies.

The Frio D sand series was discovered in 1940. Total field production from the entire suite of D reservoir sands is more than 10 MMbbl of oil and 17 Bcf of gas. Within the area of this study, D reservoirs have accounted for 8.3 MMSTB oil, with more than 7.5 MMSTB attributed to the D-5 sand zone. The main productive interval consists of four units correlated as the D-3, D-4, D-5, and D-6 sands. These sand units are correlated as individual sands that combine into a complex stratigraphic channel system that covers more than 2,000 acres in the northern half of the field. Pressure and production histories indicate that these sands form a single large communicating reservoir. Data from reservoir mapping, log correlations, and core analyses indicate significant

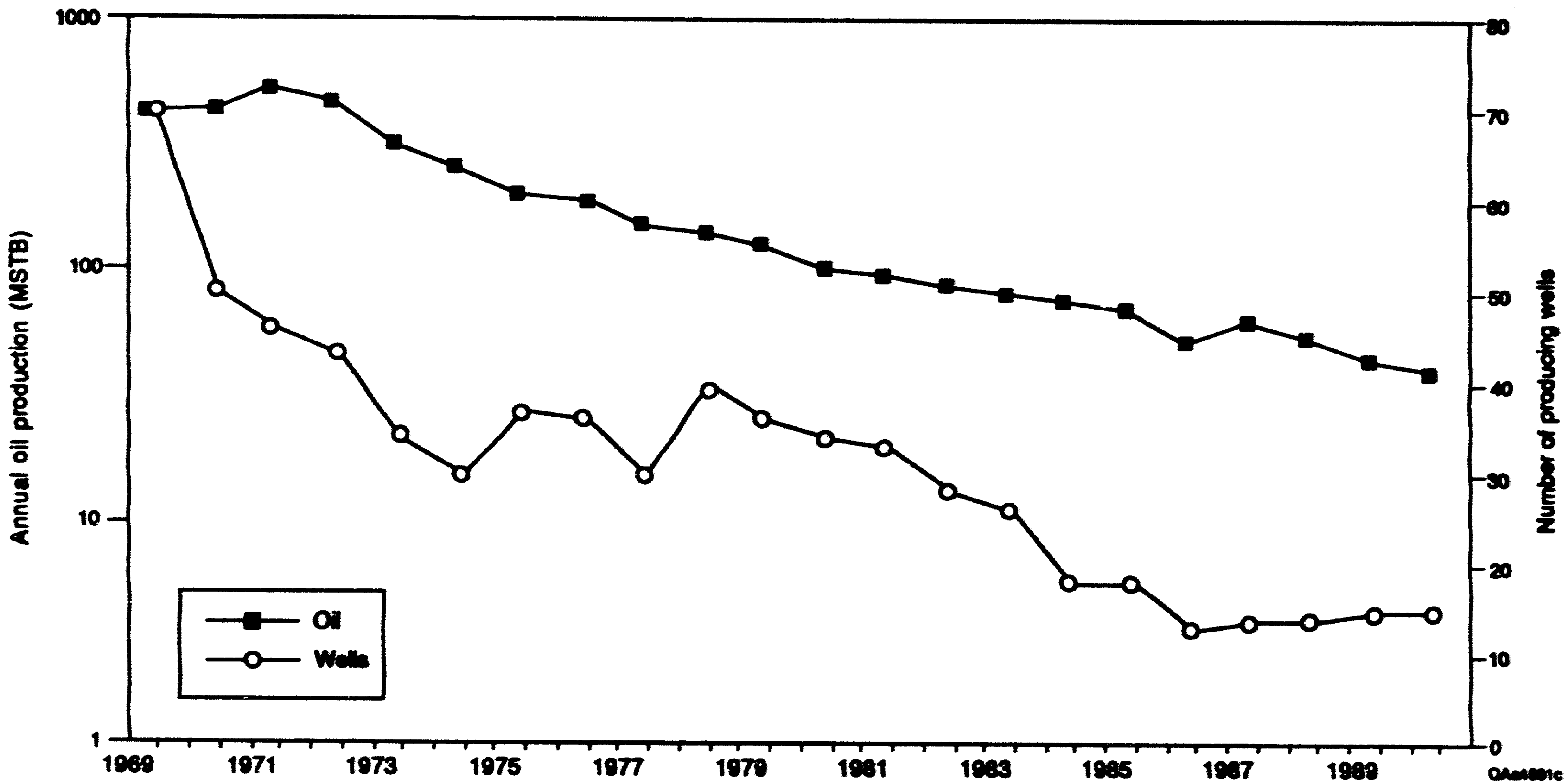


Figure 28. Trends in annual oil production and number of producing wells in Rincon field from 1968 to 1990.

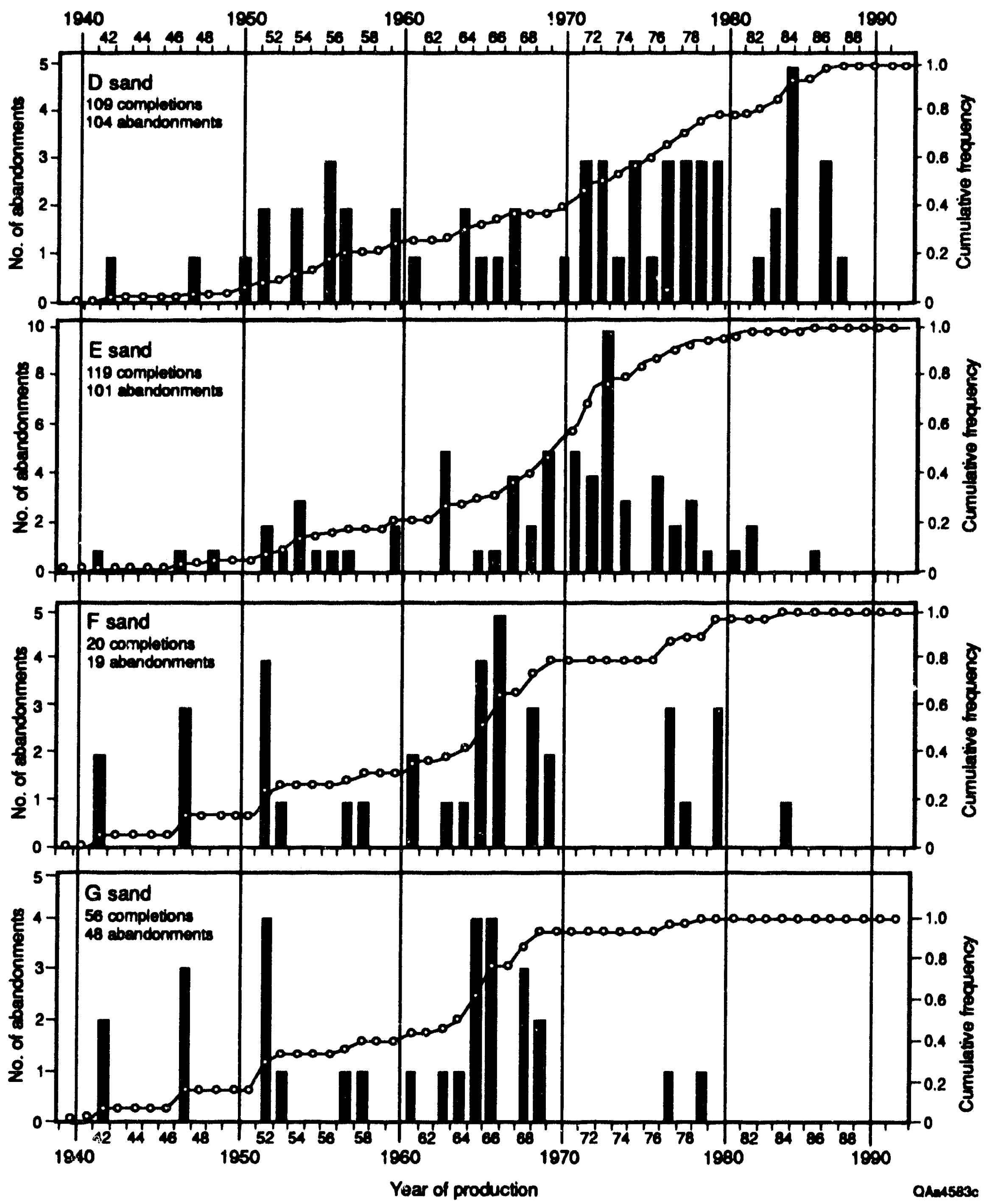


Figure 29. Trends in reservoir abandonment for selected major reservoir zones in Rincon field.

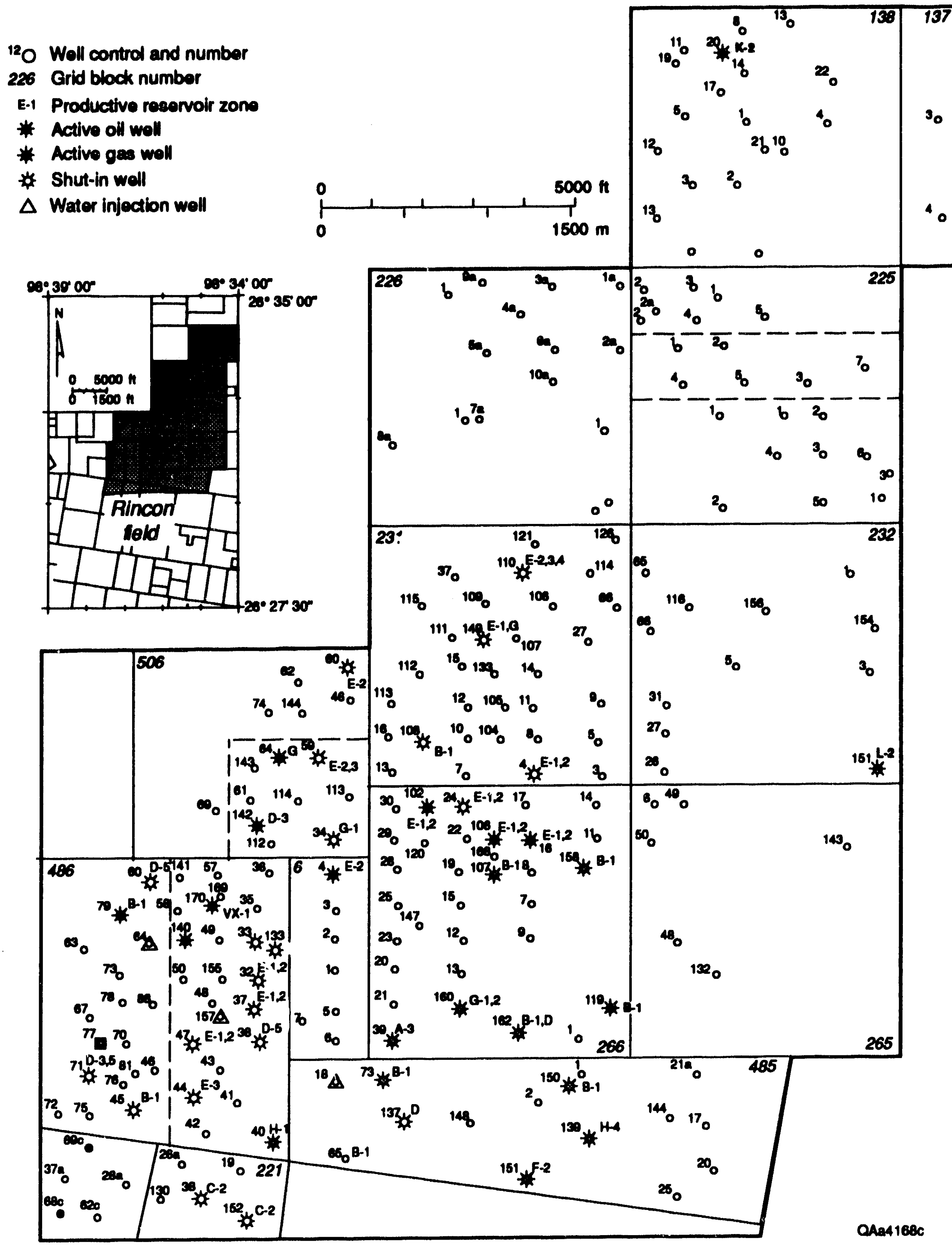


Figure 30. Map showing distribution of active wells and currently productive reservoir zones within Rincon field study area.

Table 15. Summary of reservoir characteristics for individual Rincon reservoir sandstones.

Reservoir Pay Zone	Depositional Environment and Sandstone Geometry	Cored Wells	Core Feet	No. of Samples	Sand Unit	Porosity		Permeability	
						Mean	s.d.	G mean	Median
B zone	Series of strike elongate bars				B-1	26.91	4.98	43.2	55.0
Mid D zone	Several complex channel systems, Mid-Frio D-3,4,5,6 all in communication; thinly NW-SE trending channel in the north	40	1000	262	D-1	28.9	1.78	12.4	12.0
					D-3	24.6	3.64	24.5	16.0
					D-4	24	4.07	46.1	41.5
					D-5	26	4.45	36.9	46.0
D-6 zone	Eroded reworked bar sand trending NS (strike-elongate)				D-6	22.3	3.1	5.5	34.0
E zone	Extensive channel system; E-1 thin channel sands; 2,3,4 E lobes all in communication—1 reservoir—successfully waterflooded	56	1438	386	E-1	25.3	3.92	9.6	18.0
					E-2	26.0	4.69	20.0	25.0
					E-3	29.0	3.18	91.4	107.5
					E-4	22.4	5.62	21.1	34.0
F 1&2 zone	Pair of broad channel complexes trend EW	15	327	109	F-1	27.53	4.49	36.1	54.0
					F-2	24.18	3.76	8.5	18.0
G zone	Large NW-SE trending channel sands complex G-1 & G-2 lobes coalesce into 1 communicating res.; G-3 series of narrow channels, unsuccessful waterflooding	36	968	210	G-1	27.74	4.57	77.3	118.0
					G-2	27.46	4.21	25.2	23.0
					G-3	26.89	3.95	23.9	42.5
H zone	Series of broad NW-SE trending channels; H-1 and H-2 act as 1 NW-SE trending res. H-3—3 isolated strat channel sands, H-4—thin narrow channel sand only in southern portion of field	20	496	98	H-1	28.87	4.94	80.6	99.0
					H-2	27.86	4.23	41.6	75.0
					H-3	27.37	5.28	27.3	49.5
					H-4	28.49	4.14	276.9	270.
I zone	Extensive channel system, several discrete NW-SE trending broad channels	9	70	28	I-1	27	5.28	27.5	52.0
J zone	Narrow channel sand NW-SE	7	104	53	J-1	24.15	8.46	114.7	522.5
K-1 zone	Series of strike-elongate bar sands	5	35	24	K-1	27.42	3.63	42.4	108.0
K-2 zone	Narrow channel EW trending sand, faulted				K-2	21.73	5.55	9.7	12.0

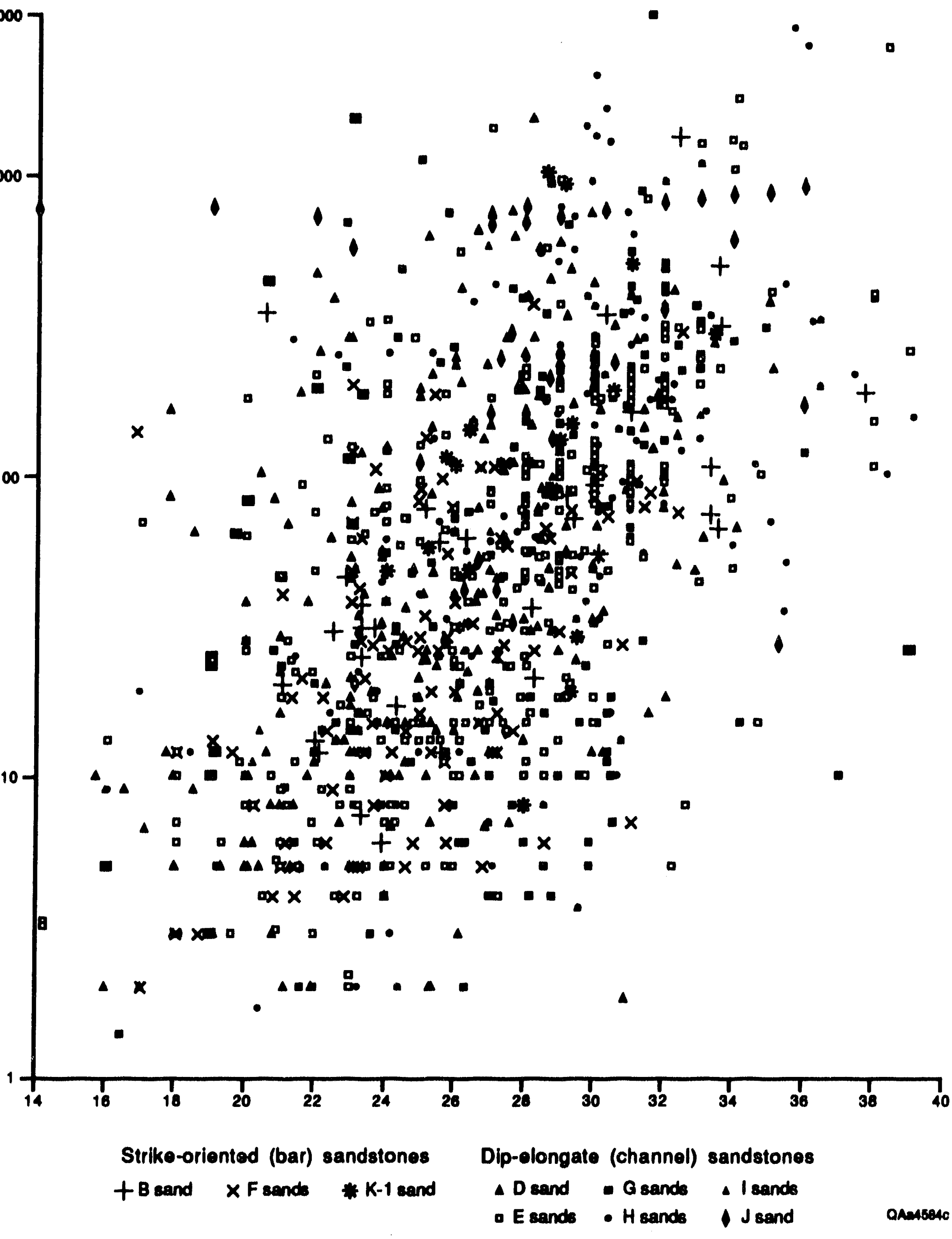


Figure 31. Cross plot of porosity and permeability values measured from wireline cores taken in productive Frio reservoir zones in Rincon field. Sand zones mapped with a strike-elongate distribution indicative of deposition in reworked bars (B-1, F, and K-1 reservoirs) exhibit significantly less variability in porosity and permeability values.

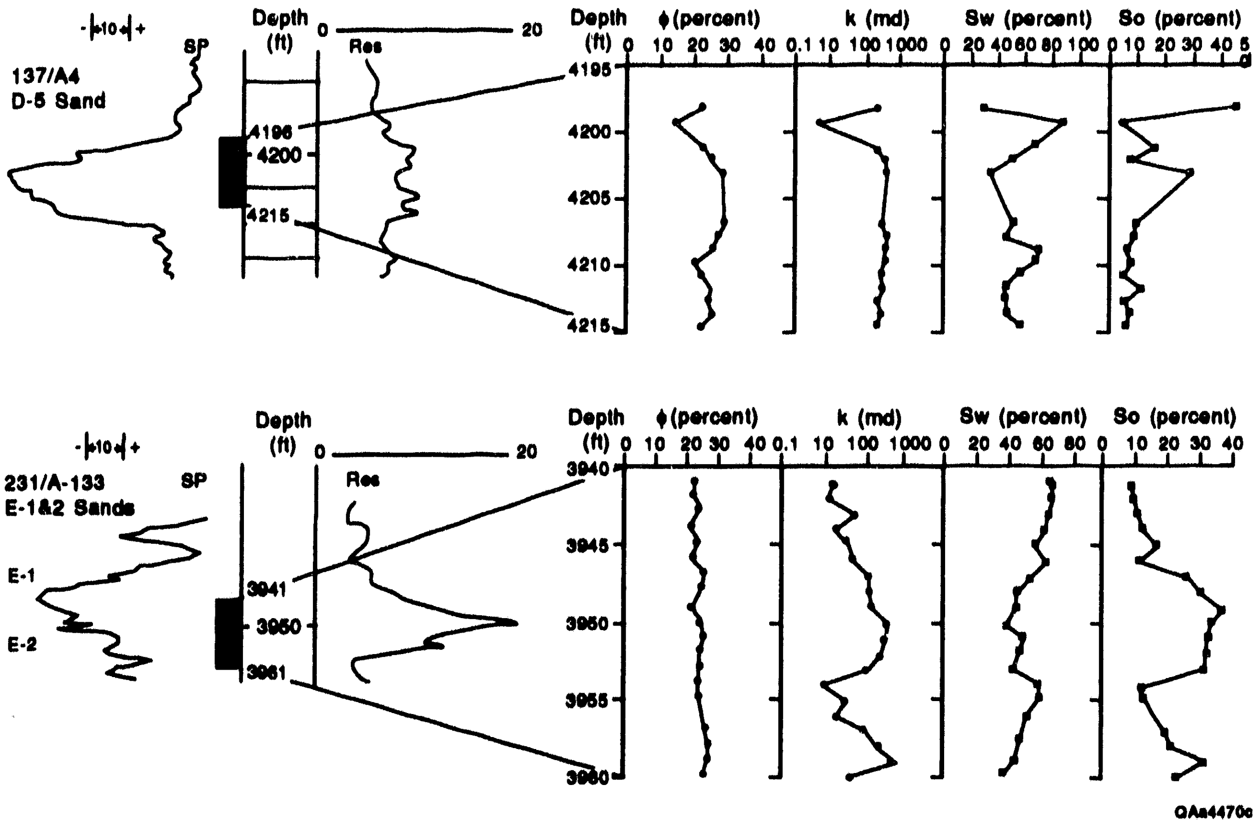


Figure 32. Log signature and porosity/permeability trends across a cored interval through the prolific Frio D and E reservoir interval in Rincon field.

heterogeneity within the D reservoir interval, and permeability barriers have been mapped within the large D-5 sand.

Sands included in the Frio E sand complex have produced in excess of 15 MMSTB of oil and 31 Bcf of gas since discovery in 1940. Production from this reservoir interval in the area of the field chosen for study is more than 14 MMSTB oil, which represents almost 95 percent of the total field production. The E zones are individually mapped as the E-1, E-2, E-3, and E-4 sands. Stratigraphic correlation and production data indicate that the E-1 and E-2 sands are often in fluid communication, as are the E-3 and E-4 sand zones. In some cases, all of the individual reservoir sands have been interpreted to be in communication. The stratigraphic relationships of the interrelated reservoir systems of the Frio D and E reservoirs are very complex and need to be documented through the construction of detailed stratigraphic cross sections. This work is currently under way.

Average reservoir parameters for the D and E reservoir sand zones have been estimated from extensive core analysis data (Figure 32). Average porosity values for D-3 through D-6 sands range from 22 to 26 percent and geometric mean permeability values range from 5 to 37 md permeability. E sands range from 22-percent porosity and 21-md permeability for the E-4 sand to 29-percent porosity and 91-md permeability for the E-3 sand. Cross plots for porosity and permeability values from cores in the D-3 through D-6 and E-1 through E-4 zones illustrate not only the wide overall variability of reservoir quality present in this interval but also distinct groupings within certain reservoir zones (Figure 33). Grouping of core values by individual reservoir subfacies is expected to reveal controls of specific depositional facies on reservoir quality. This work is also in progress.

Tijerina-Canales-Blucher (T-C-B) Field

Location and Structural Setting

The Tijerina-Canales-Blucher (T-C-B) field is located in the lower Gulf Coast Plain of South Texas, approximately 55 mi southwest of Corpus Christi (Figure 34). It covers an area that includes parts of southern Jim Wells and Kleberg Counties. The area of T-C-B field chosen for study consists of the "Blucher" lease, operated by Mobil Exploration and Producing U.S. This part of the field, covering more than 4,800 acres of the western area of the greater T-C-B field, lies in a structural saddle between large rollover anticlinal features to the northeast and southwest that define Seeligson and La Gloria fields, respectively. The main trapping mechanism is the Sam Fordyce Fault, part of the regional Vicksburg growth fault system, which runs for several hundred miles parallel to the coastline and creates the Frio Fluvial-Deltaic Sandstone play trend. Downwarping into the syndepositional fault plane generated dip reversals that in turn formed anticlinal closures that serve as the main hydrocarbon traps in T-C-B field and in many other fields in the Vicksburg Fault Zone play (Stanley, 1970).

Shallow oil-bearing structures within the Frio section in T-C-B field consist of large, gentle rollover anticlines that formed during later stages of movement on the Sam Fordyce Fault zone. Structure developed in the deeper Vicksburg section is more complex and is characterized by multiple synthetic and antithetic faults with large displacements.

Field Development and Production History

Multiple reservoirs in various portions of the field area have been discovered and produced by Sun (now Oryx), Humble (now Exxon), Texaco, and Mobil. Most drilling took place in the 1940's, and intermittent development continued through the 1980's. T-C-B field has produced significant volumes of oil and gas from both Frio and Vicksburg fluvial-deltaic reservoir sands and is still under primary recovery. Cumulative oil production in the greater T-C-B field area from Frio zones alone is more than 50 MMSTB. Oil production from major zones dropped precipitously in the mid-1970's, and the number of producing wells has been on a steady decline since that time (Figure 35).

The western "Blucher" part of the field was discovered in 1939 by Shell Oil Company with the Von Blucher No. 1 well. Shell drilled five wells (two oil, two gas, and one dry hole) before selling

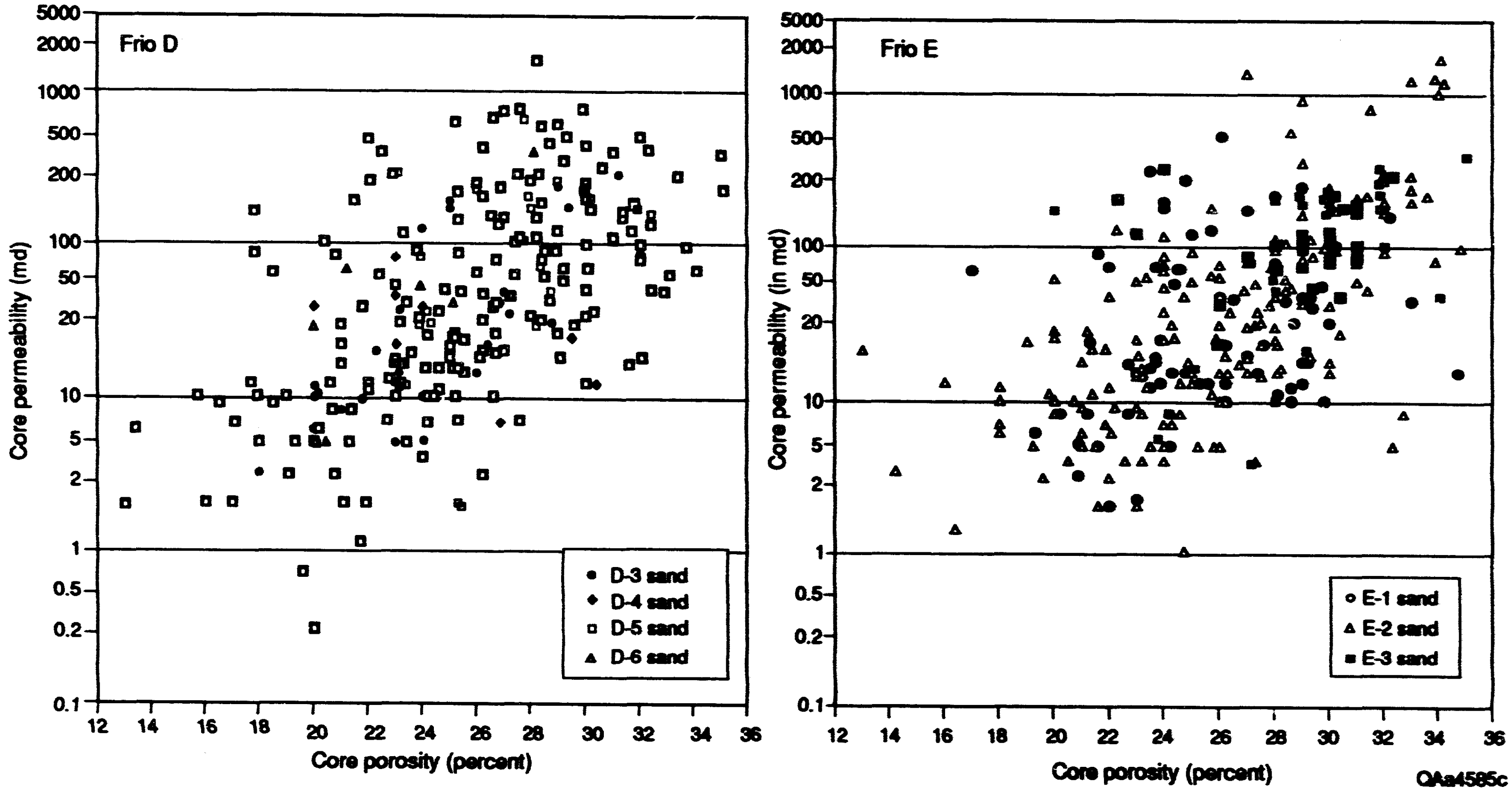


Figure 33. Cross plot of porosity and permeability data from individual sand units within the major Frio D and E reservoir zones in Rincon field.

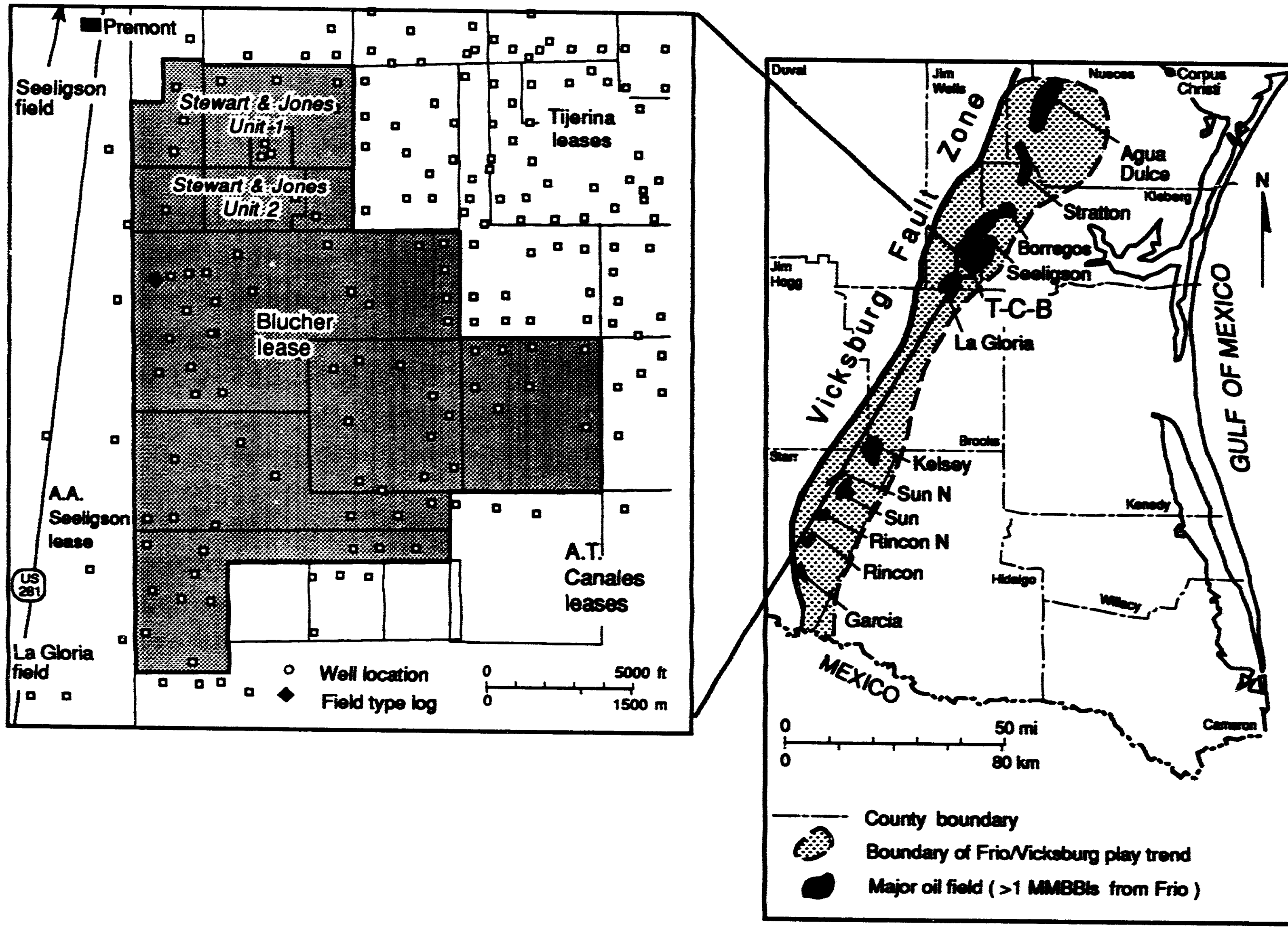


Figure 34. Map showing location of T-C-B field and lease area selected for study.

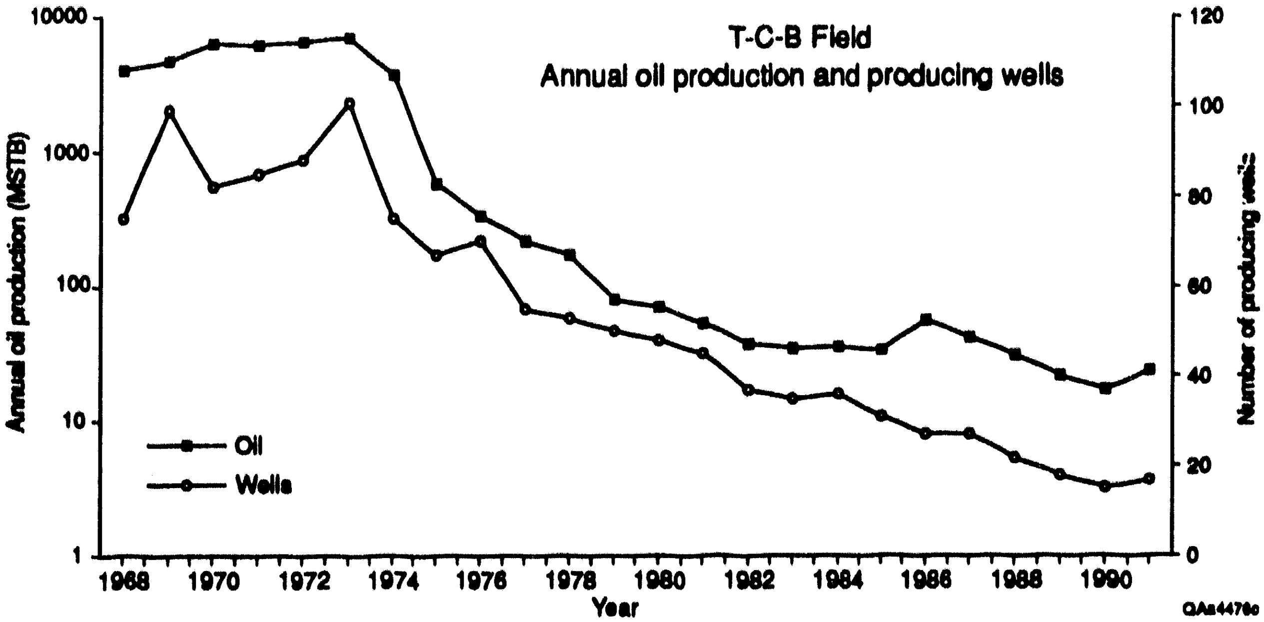


Figure 35. Trends in annual oil production and number of producing wells in major reservoirs within T-C-B field from 1968 to 1991.

their leases to the La Gloria Corporation. La Gloria drilled 53 wells from 1942 to 1967. Mobil purchased the leases from La Gloria in 1967 and has since drilled 30 wells. The first 11 wells were drilled shortly after purchase of the field in the early 1970's. Activity was renewed in 1985, when five additional wells were drilled to include deeper wildcat zones (7,000 to 10,000 ft). Interpretation of an additional seismic line, acquired as part of a large seismic program over Seeligson field in 1986, provided better resolution of the main fault and indicated additional deep-seated faulting. This led to the mapping of deeper sands and the drilling of five new wells. Following the acquisition of additional seismic lines, 9 more wells were drilled from 1988 to 1991, bringing the total wells drilled on Mobil's T-C-B leases to 88. Figure 36 summarizes the historical development activity for Mobil's Blucher-area leases. As of 1992, there were 29 active completions on the Blucher lease (19 gas, 10 oil) in 24 wells, with 12 wells idle.

Although production history of the T-C-B field started in 1939, actual fieldwide oil production by reservoirs before 1950 is not readily available from public sources. Lease-specific production records obtained from La Gloria Corporation after Mobil purchased the properties in 1967 are incomplete, although attempts have been made to re-create the early production history. The leases in T-C-B field overlap nearby fields, and some production within T-C-B may be attributed to La Gloria, Seeligson, and other fields producing from the prolific 21-B reservoir zone. Additionally, attributing production to a specific zone can be difficult because of the proliferation of reservoir zone names. More than 40 zones have been named on Mobil leases alone, with many of these being rough stratigraphic equivalents.

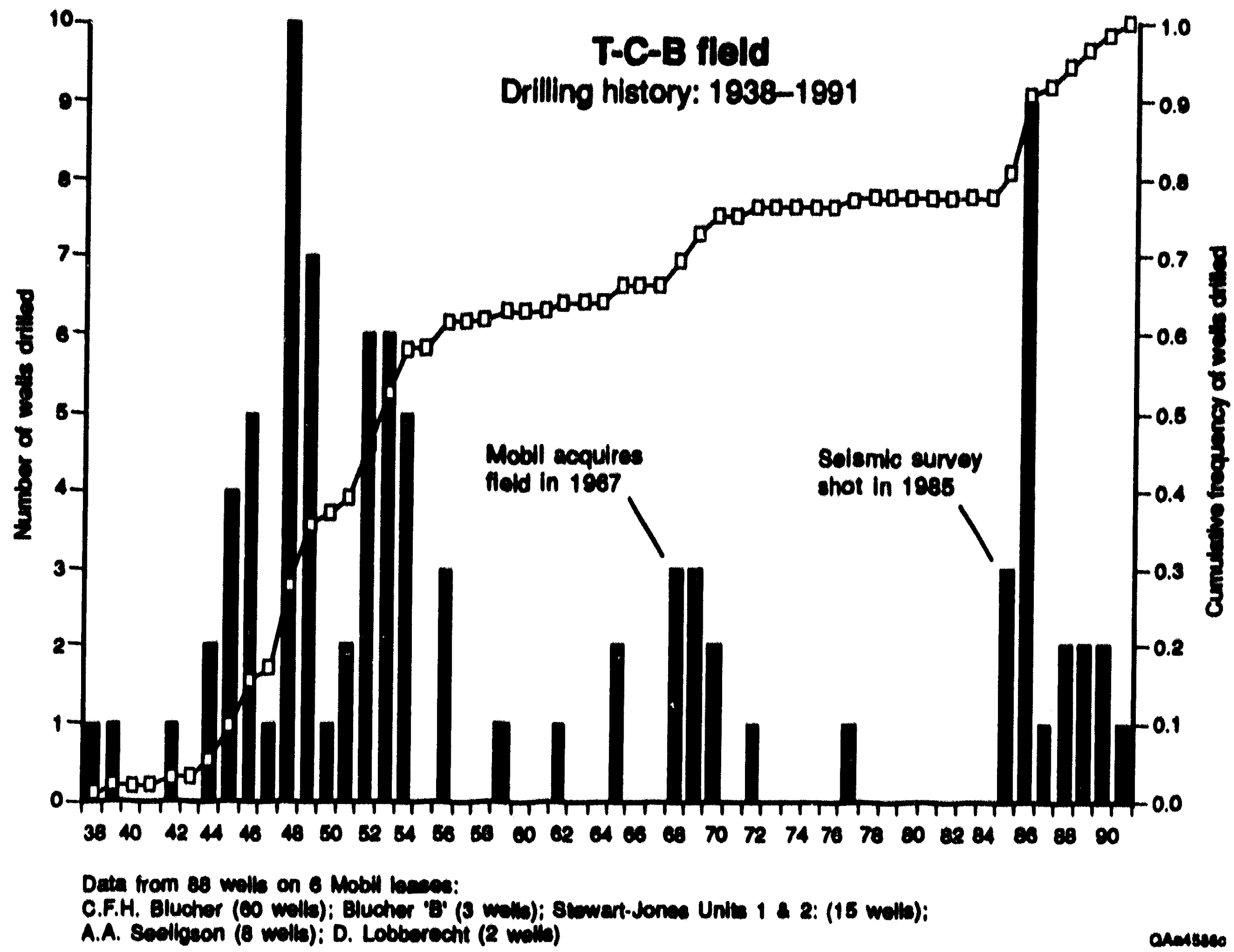


Figure 36. Histogram illustrating chronology of drilling and development in Mobil leases within T-C-B field (1938–1991).

Production data available from public sources indicate that no reservoir has been drilled at closer than 40-acre spacing. This large well spacing suggests that infill potential at T-C-B field may exceed that of many of the other Frio-producing fields in South Texas.

Study Area and Data Base

The area of study in T-C-B field consists of the 3,500-acre Blucher lease, which covers the southwest portion of the field (Figure 37). The Blucher lease is the largest of five leases that compose Mobil's acreage in T-C-B field. Additional data from wells in four adjacent leases have also been made available by Mobil Exploration and Producing U.S.

The primary data set, consisting of more than 65 wells, includes well logs, sidewall cores, wireline and sidewall core analyses, a limited number of structure and net-pay maps,

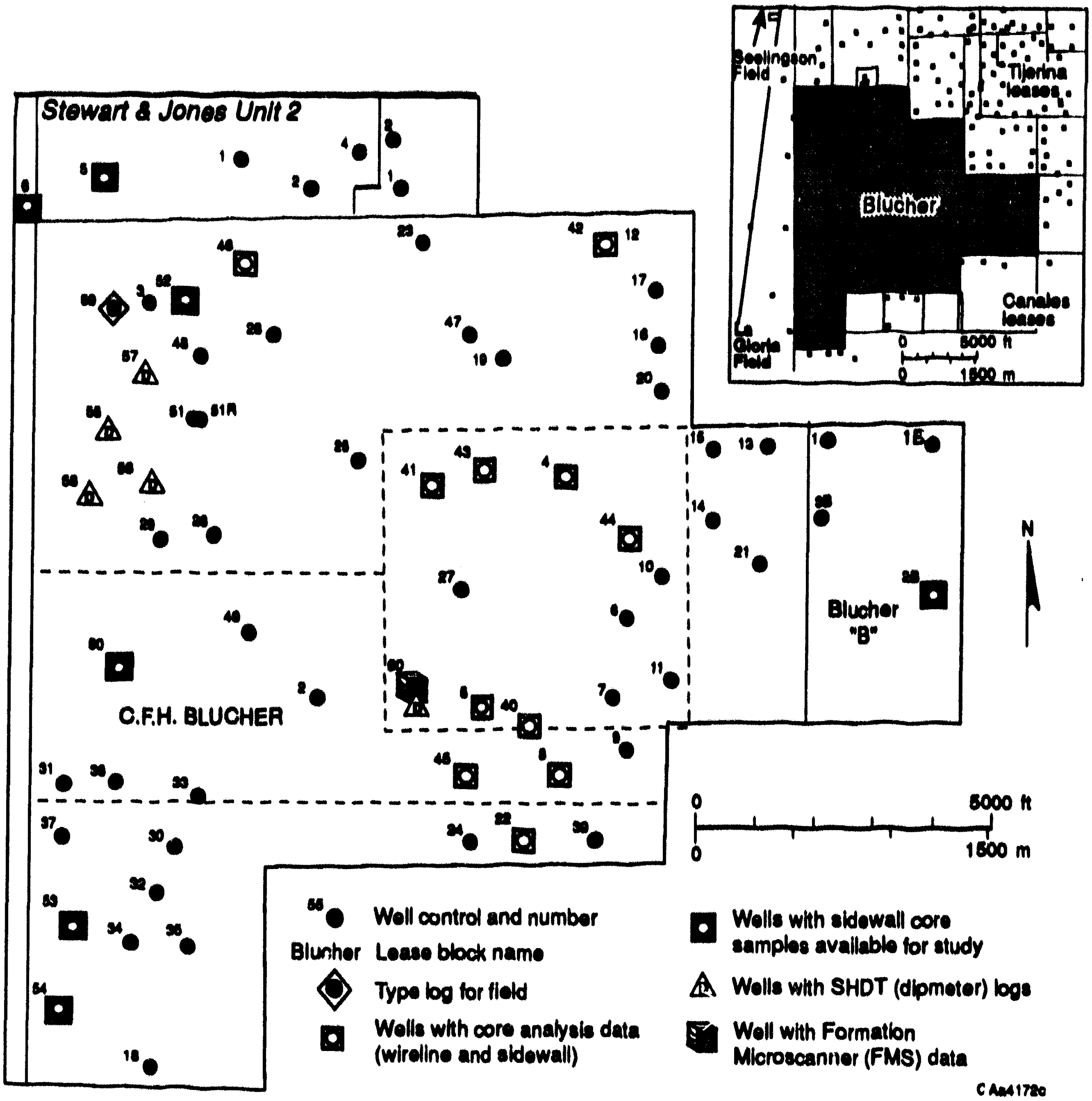


Figure 37. Index map showing distribution of well and core data in T-C-B study area.

biostratigraphic reports, production and pressure data, and reports of petrographic and clay mineralogy studies. Because of Mobil's continued activity in the field, 18 of the well-log suites are of modern vintage (mid-1980's and forward) and include 5 high-resolution dipmeter (SHDT) logs and 1 Formation Microscanner (FMS) data set. Figure 37 documents the spatial distribution of the various types of data and core material available from each well in the study area.

General Stratigraphic Framework

The representative reservoir interval for the Blucher area of T-C-B field is depicted in a type log for the field shown in Figure 38. Hydrocarbon production is obtained from reservoirs in the Oligocene Frio and upper Vicksburg Formations. The Frio reservoir interval in T-C-B field comprises the middle and lower Frio members and consists of a series of sandstone units that occur over the depth interval from 5,500 to 7,600 ft and include the "Maun" through "Lobberecht" sands. The upper Vicksburg reservoir sequence begins at the top of a thick package of stacked sands designated as the "Massive Vicksburg." The total thickness of the entire Frio–upper Vicksburg reservoir sequence in T-C-B field averages 2,600 ft.

The upper Vicksburg Formation consists of thick, massive, progradational deltaic to shallow marine sandstones (Taylor and Al-Shaleb, 1986). The reservoir interval ranges in depth from 7,600 to 11,800 ft, but production in the Blucher area is limited to the upper 400 ft of that interval. Vicksburg sands in T-C-B field are almost exclusively gas reservoirs and will not be a focus of this study.

The lower Frio Formation is a 1,000-ft-thick interval dominated by mudstone, with thin interbedded sandstones as much as 30 ft thick. In the adjacent Seeligson field directly to the northwest of the T-C-B field, the lower Frio rests with angular unconformity on the upper Vicksburg (Ambrose and others, 1992). The lowest reservoir interval in the lower Frio, the Lobberecht, is sandier than the rest of the unit and has previously been interpreted by Mobil as the only "lower Frio" strata in T-C-B field. Correlations applied to the T-C-B field from Galloway and others (1982) and from Jirik (1990) have been used to justify the thicker lower Frio interval used in this report. The lower Frio has been interpreted to contain deltaic sediments from the Norias delta system, based on a study of a single reservoir interval in the eastern portion of T-C-B field (Reistroffer and Tyler, 1991). These sediments include strandplain, barrier bar, and associated sandstones interbedded with lower coastal plain, bay-fill, and inner-shelf mudstones. Well-log patterns and paleontologic evidence of interbedded intervals barren of fossils suggest that fluvial sediments of the upper delta plain are also present in this interval. This indicates that the position of the facies tract alternated through the lower Frio in the vicinity of T-C-B field from the Norias delta plain to the Gueydan fluvial system.

Middle Frio reservoirs are found over a 1,200-ft interval and can be grouped into 100- to 130-ft-thick sand-prone intervals interbedded with sand-poor intervals of similar thicknesses. This much sandier section appears to be in abrupt contact with the underlying lower Frio. Preliminary correlations based on a dip-oriented seismic line suggest that the base of the middle Frio is unconformable and separates growth-faulted strata below from less-faulted units above (Figure 39). Similar observations were made at Seeligson field by Ambrose and others (1992). Log patterns, paleontologic data, and detailed studies of reservoirs in the middle Frio at adjacent La Gloria and Seeligson fields (Jackson and Ambrose, 1989; Ambrose and others, 1992) indicate that reservoir

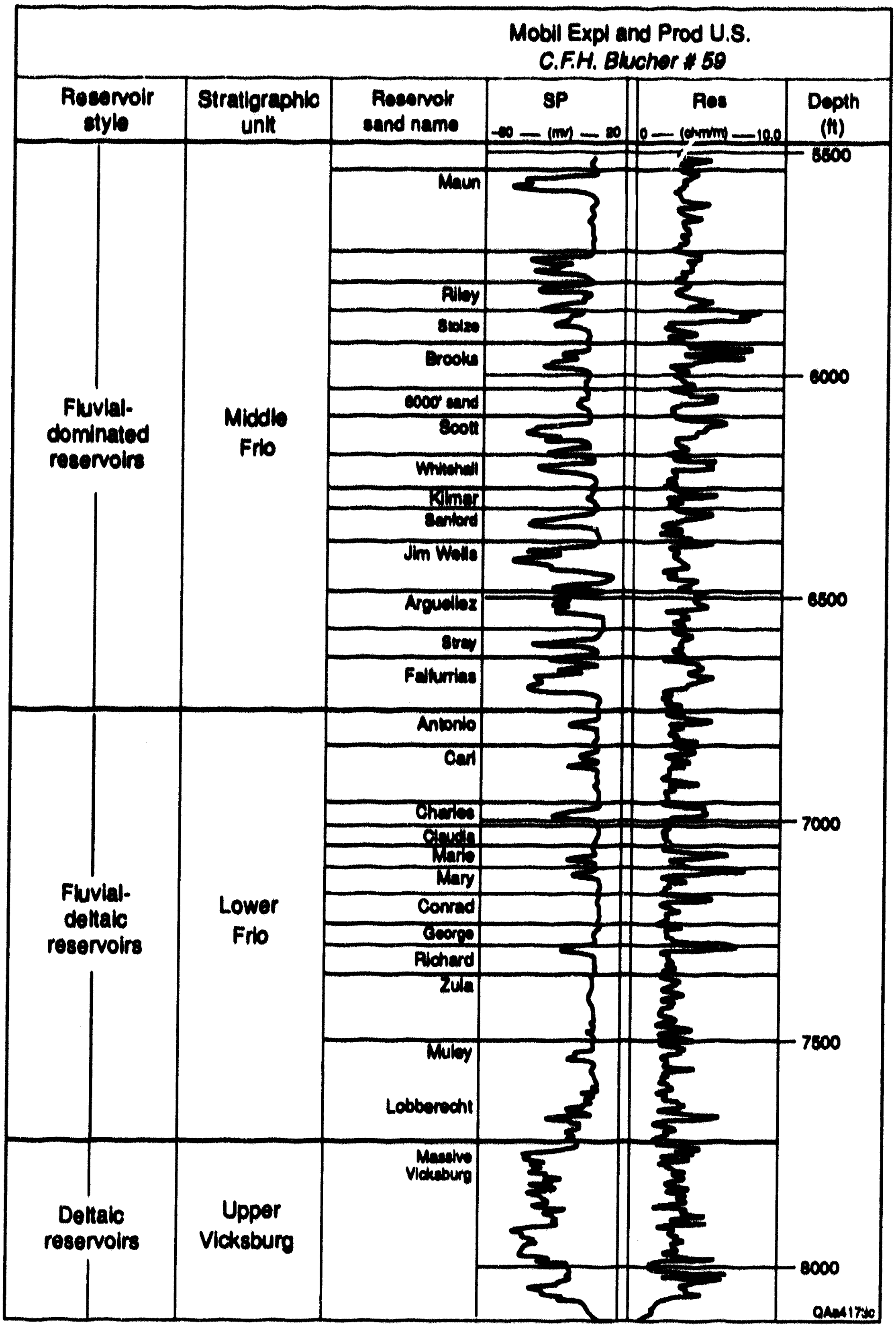


Figure 38. Representative log from T-C-B field illustrating generalized stratigraphy and nomenclature of productive reservoir sands.

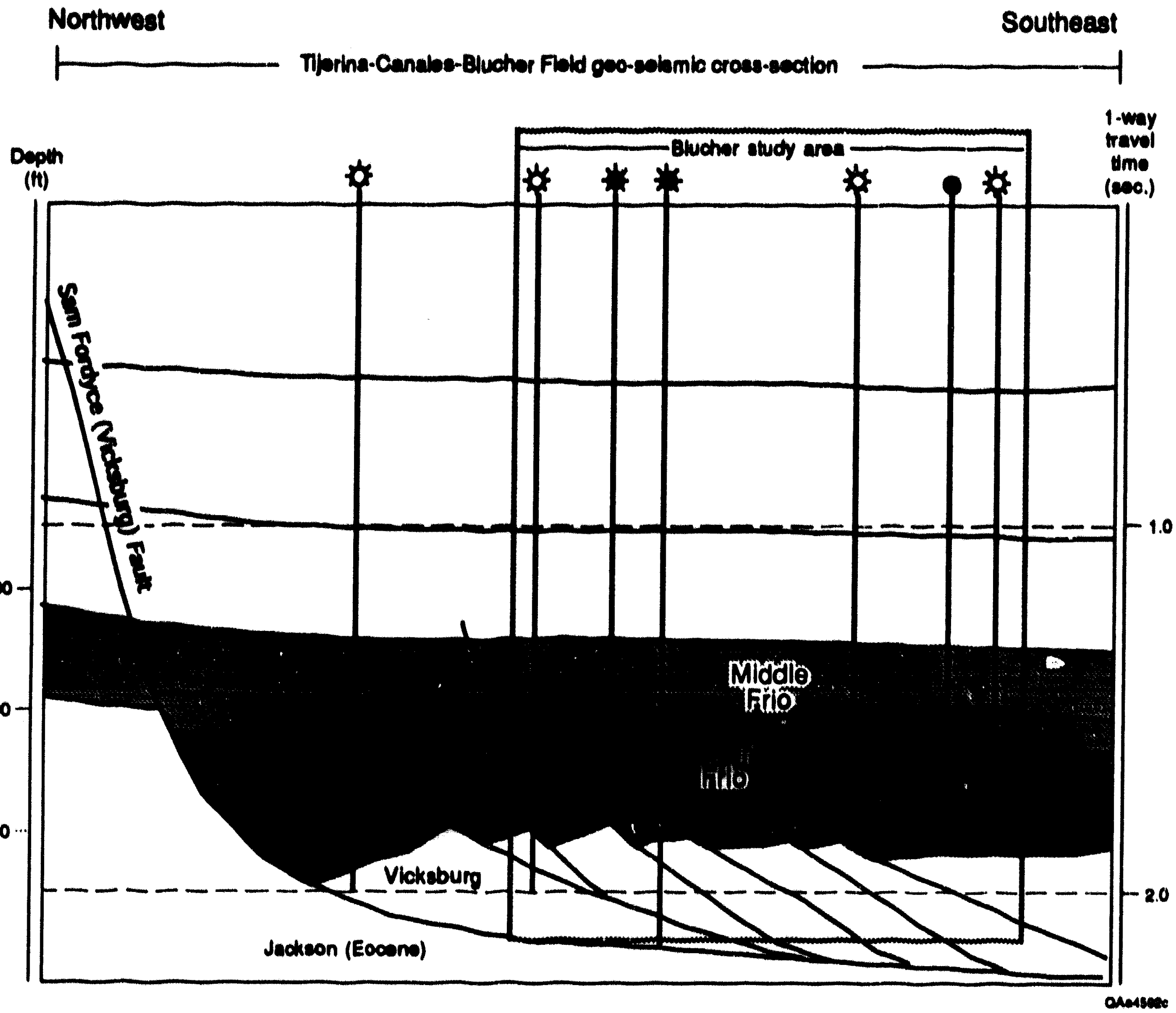


Figure 39. Northwest to southeast geoseismic dip section across T-C-B field illustrating general structural setting of Frio and Vicksburg reservoir sections. The base of the middle Frio Formation is a significant surface separating structurally complicated reservoirs below from less faulted reservoirs above. Seismic interpretation provided by Mobil Exploration and Producing U.S.

sandstones were deposited in fluvial settings of the Gueydan system and include channel-fill, point-bar, and splay facies interbedded with floodplain and overbank mudstones.

Reservoir Geology

On the basis of regional studies within the Frio Formation (Kerr and Jirik, 1990; Levey and others, 1992), a study of the adjacent Seeligson field (Jirik, 1990), and preliminary interpretations within the study area, fluid flow and reservoir drainage in the middle and lower Frio intervals of the

T-C-B field are thought to be affected to varying extents by both structural complications and the architecture of the reservoir sand bodies. Lower Frio reservoirs are predominantly vertically isolated sandstones of moderate lateral continuity that are further compartmentalized by faulting. Middle Frio reservoirs include both vertically stacked and vertically isolated reservoirs of limited lateral extent and are less affected by faulting. As a result, reservoir styles in both the middle and lower Frio of T-C-B field provide many opportunities for uncontacted and poorly drained reservoir compartments.

As mentioned previously, structural complications are interpreted to be more significant in the lower Frio reservoirs. Seismic and well-log correlations in the adjacent Seeligson field (Ambrose and others, 1992) indicate fault throws of up to 200 ft. The dip-oriented seismic line through T-C-B confirms the presence of significant synthetic and antithetic faults below the base of the middle Frio. These faults are anticipated to act as barriers to fluid flow and reservoir drainage. In addition, the lower Frio consists of sandstones deposited in a wide variety of settings, from strandplain to fluvial environments, resulting in a spectrum of reservoir architecture styles and internal heterogeneity. Sand bodies are rarely amalgamated, leading to reservoirs that are vertically isolated from adjacent units by mudstones thicker than 10 ft. This leaves internal heterogeneity as the primary facies-dependent factor controlling reservoir drainage. In deltaic facies such as strandplain and barrier bar sands, vertical and lateral internal heterogeneity is expected to be low, resulting in more thoroughly drained reservoirs (Tyler and Finley, 1991). However, fluvial facies in fine-grained meander belts typically have high lateral heterogeneity. This increased complexity creates greater opportunities for the existence of poorly drained reservoir compartments.

The middle Frio interval at T-C-B field appears to be less affected by faulting. Fault throws in the middle Frio at Seeligson field are less than 30 ft (Ambrose and others, 1992), and the seismic line through T-C-B shows very minor offsets, which occur on a fewer number of faults than cut the lower Frio. As a result, the primary cause of reservoir compartmentalization is thought to be reservoir architecture and internal heterogeneity.

The middle Frio interval is composed of sand-prone sections as much as 130 ft thick that are separated by sand-poor sections 100 to 150 ft thick. Sand-prone sections consist of individual channel-fill and splay sands from 10 to 30 ft thick and 500 to 5,000 ft wide, which are amalgamated vertically and "stacked" laterally. Sands appear to be laterally continuous but are actually a series of separate, stratigraphically equivalent channel-fill or splay events. Kerr and Jirik (1990) referred to this style of fluvial architecture as "laterally stacked" and pointed out that channel-on-channel sand contacts will be common, increasing reservoir drainage efficiency. However, sand-on-sand contacts can be baffles to fluid migration. Levey and others (1992) demonstrated that such a contact was sufficient to compartmentalize a fluvial channel-fill reservoir and would result in an economic infill gas completion at a 40-acre spacing.

Sand-poor sections within the middle Frio are composed of channel-fill and splay sandstones as much as 30 ft thick and separated by more than 5 ft of mudstone. These sands are laterally isolated in that they are not in contact with stratigraphically equivalent channel fills and are limited in lateral extent (500 to 5,000 ft in width). Kerr and Jirik (1990) referred to this as a "vertically stacked" architectural style and indicated that these more completely sealed reservoirs have a higher potential for uncontacted or poorly drained compartments. Levey and others (1992) documented the discovery of such a channel-fill reservoir, which had never been contacted at 320-acre spacing. Considering that many channels in the middle Frio may be less than 1,000 ft wide, significant potential exists for discovery of uncontacted reservoirs in fields such as T-C-B with present well spacings as low as 40 acres.

Survey of Individual Reservoirs

Accomplishments during Project Year 1

Tasks carried out during the first project year at T-C-B field included screening of individual reservoir intervals for their potential to contain uncontacted or poorly drained reservoir compartments. These tasks, consisting of a review and analysis of the geologic and engineering data available through public sources and the field operator, included (1) compilation of individual well histories and cumulative production by zone to identify significant reservoirs, (2) review of regional and field stratigraphy, allowing placement of reservoir zones into a genetic stratigraphic framework, (3) synthesis of available petrophysical and mineralogic data by reservoir to evaluate gross reservoir storage and flow capacity and potential for formation damage, and (4) preparation of a stratigraphic cross-section grid of the study area to further evaluate the potential for facies and architecture-induced compartmentalization. Results of the first three tasks are presented below. Construction of a stratigraphic cross-section grid is in progress and will provide key information by early in the second project year.

Reservoir Development History

Reservoir development throughout the life of T-C-B field was assessed to aid in the screening of reservoirs for infill potential. Insight into the history of individual reservoirs at T-C-B field is limited by incomplete data regarding well histories and accurate cumulative production information. Of the 88 wells on Mobil leases at T-C-B, well completion histories were available for only 31. Additionally, gaps in lease production data prior to 1967 exist. As a result, the total number of completions and the cumulative production per reservoir are not known with certainty. The available data can be used on a relative basis to compare the activity and productivity of each zone.

Reservoir stratigraphy within T-C-B field is complex, with oil and gas production from many vertically and laterally stacked sandstones. More than 40 different zone names exist just within the

Blucher area. Preliminary correlation of these zones is complete, and they have been grouped into 16 reservoir intervals using the concepts of genetic stratigraphy.

Table 16 lists parameters for each reservoir interval that summarize its production history. These parameters include the number of known successful completions, abandonments, active completions, cumulative production from 1967 forward, and successful and unsuccessful completions in the past 10 yr. As a check on the relative values of cumulative production, the number of well years of production (the sum of the number of years each well produced from a given reservoir) prior to 1967 is also listed. As expected, zones with high post-1967 production have a greater history of production prior to 1967, confirming their prolonged importance as reservoirs. Zones that do not follow this trend include the Brooks, Conrad, and Lobberecht, indicating that either they were short-lived reservoirs or that post-1967 production data are incomplete. If the reservoirs were short-lived, they have not been assessed for bypassed potential through modern reservoir characterization techniques.

Figure 40 illustrates the relative importance of zones on the basis of cumulative production. It shows a plot of cumulative oil production and the ratio of gas to oil produced by reservoir interval (high cumulative gas-to-oil ratios indicate reservoirs with large gas caps and thin oil rims). The greatest number of reservoirs lies in the lower Frio, with just a few intervals in the middle Frio section. Oil and gas production is dominated by the Marie and Mary reservoirs, which are part of the prolific 21-B interval. These preliminary data indicate that the Scott and Kilmar intervals in the middle Frio and the Carl, Charles, Conrad, and Richard in the lower Frio are the other major reservoirs.

Reservoirs within T-C-B field are being abandoned with increasing frequency. **Figure 41** shows that over 95 percent of reservoir completions were carried out before 1985, but nearly 20 percent of all abandonments occurred during that year. These abandonments are due to a perception that reservoirs have reached economic depletion, which has resulted in a loss of well bores in which to carry out recompletions or measure critical reservoir data.

Active well completions in the Blucher area are listed in Table 16 and their locations are shown in **Figure 42**. The Richard, Marie, Charles, Scott, and Kilmar intervals are the most active current reservoirs, with more than three completions each. A campaign of recompletion attempts has accompanied the renewed drilling activity in the Blucher area over the past decade. This moderately successful effort has been most productive in the Scott, Carl, Marie, and Richard intervals. Success, especially in the three intervals within the lower Frio, may be the result of increased structural resolution due to the recent seismic program. Certain zones have yielded disappointing results, especially the Arguellez and Lobberecht zones. Assessing the reasons for success and failure in these recent completions will be important in selecting reservoirs for detailed study.

Table 16. Production history of reservoir intervals in T-C-B field.

Reservoir Interval	Average Depth (subsea)	Completions		Abandonments		Completion Density[2] (ac/comp)	Completions (1983 to Present)		Post-1967 Production[3]	
		Total	Active[1]	Total	Percent		Attempt	Success	Gas (MMcf)	Oil (MSTB)
Brooks	6000	4	0	4	100	1200	1	0	113	3
Scott	6100	8	3	5	63	600	4	3	649	120
Kilmar	6200	9	3	6	67	533	2	1	2654	48
Jim Wells	6300	2	0	2	100	2400	2	1	0	0
Arguellez	6500	5	0	5	100	960	7	1	71	9
Falfurrias	6650	2	0	2	100	2400	1	0	0	0
Antonio	6720	4	0	4	100	1200	3	1	2	0
Carl	6820	10	2	3	30	480	4	2	6712	31
Charles	6870	18	4	14	78	267	3	0	13,939	29
Marie	7010	29	6	23	79	166	5	3	26,679	16
Mary	7040	11	1	10	91	436	2	0	21,199	520
Conrad	7100	13	2	11	85	369	0	0	352	22
Richard	7150	11	7	4	36	436	7	5	10,767	77
Zula	7180	7	0	7	100	686	1	0	1252	5
Muley	7220	6	0	6	100	800	0	0	266	23
Lobberecht	7250	5	1	4	80	960	4	0	0	0

(Reservoir acreage completion data and cumulative production volumes are from within the Blucher lease study area.)

[1]Active zones include presently producing completions and shut-in zones
[2]Completion densites calculated using 4800-acre area for the Blucher lease
[3]Pre-1967 by reservoir production data is incomplete

Reservoir Attributes

The present understanding of T-C-B Frio reservoir facies and architecture is based on previous studies in nearby fields, combined with a preliminary assessment of Blucher-area stratigraphy. Three reservoirs in adjacent fields have been assessed by previous Bureau of Economic Geology studies (Jackson and Ambrose, 1989; Jirik, 1990) and reservoir architecture and compartmentalization have been addressed by Kerr and Jirik (1990) and Levey and others (1992). Within the T-C-B area itself, structure and net-pay maps prepared by Mobil over the Blucher lease are available for three reservoir units, and an independent study of the 21-B reservoir interval carried out adjacent to the Blucher lease in the eastern part of T-C-B field provides information on depositional setting and reservoir characterization.

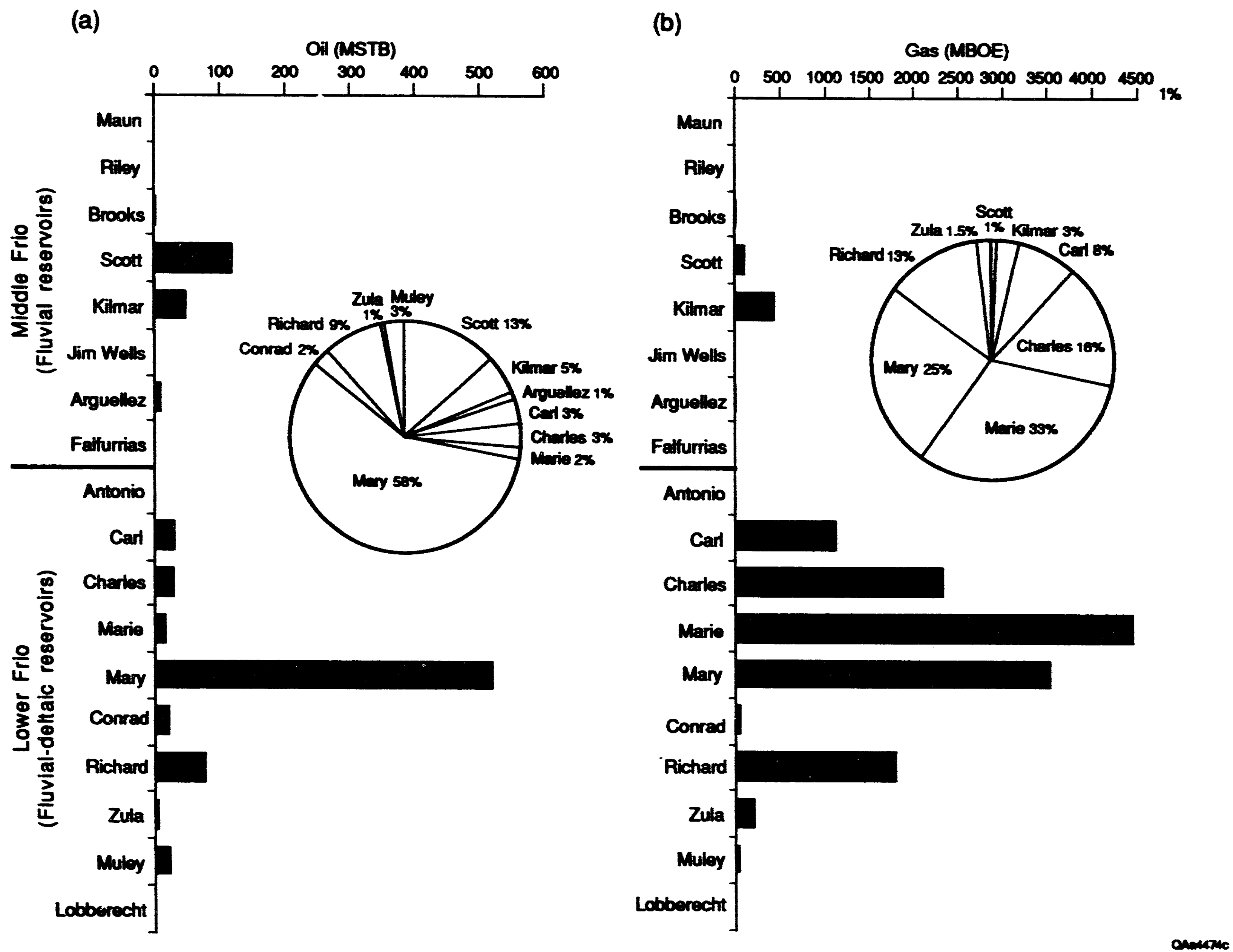
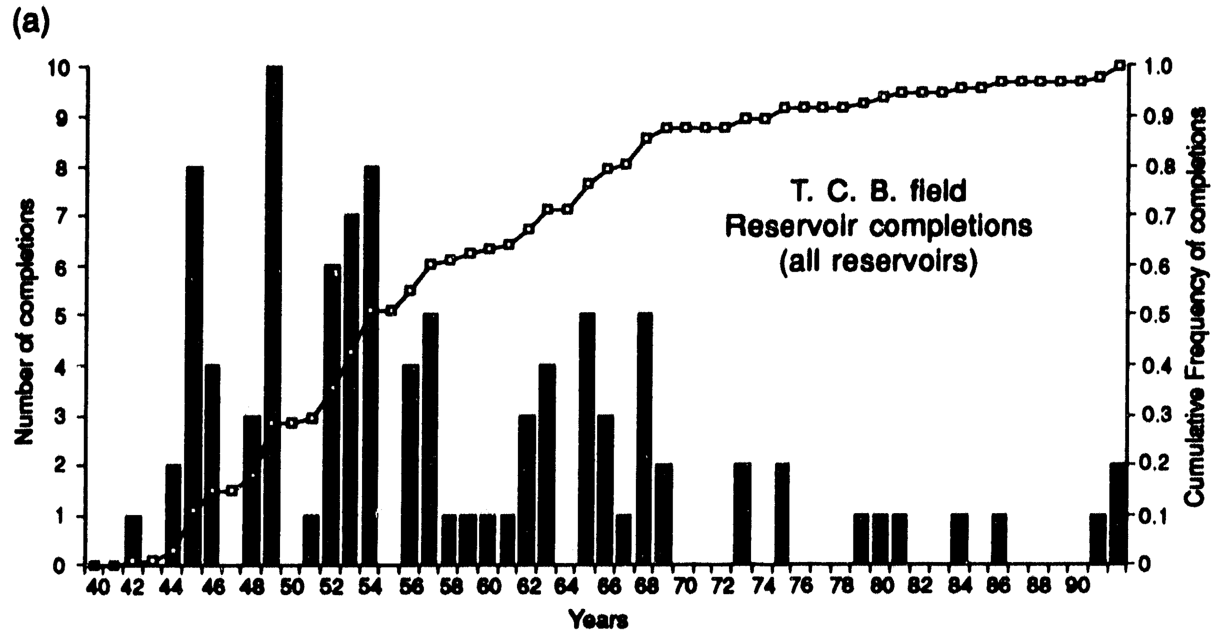


Figure 40. Summary of cumulative (A) oil and (B) gas production from Mobil leases from 1967 to 1992, illustrating the relative importance and stratigraphic position of Frio Formation reservoir intervals. The Marie and Mary sands are equivalent to the prolific 21-B interval, which has produced more than 20 million barrels (MMbbl) of oil throughout the life of the T-C-B field.



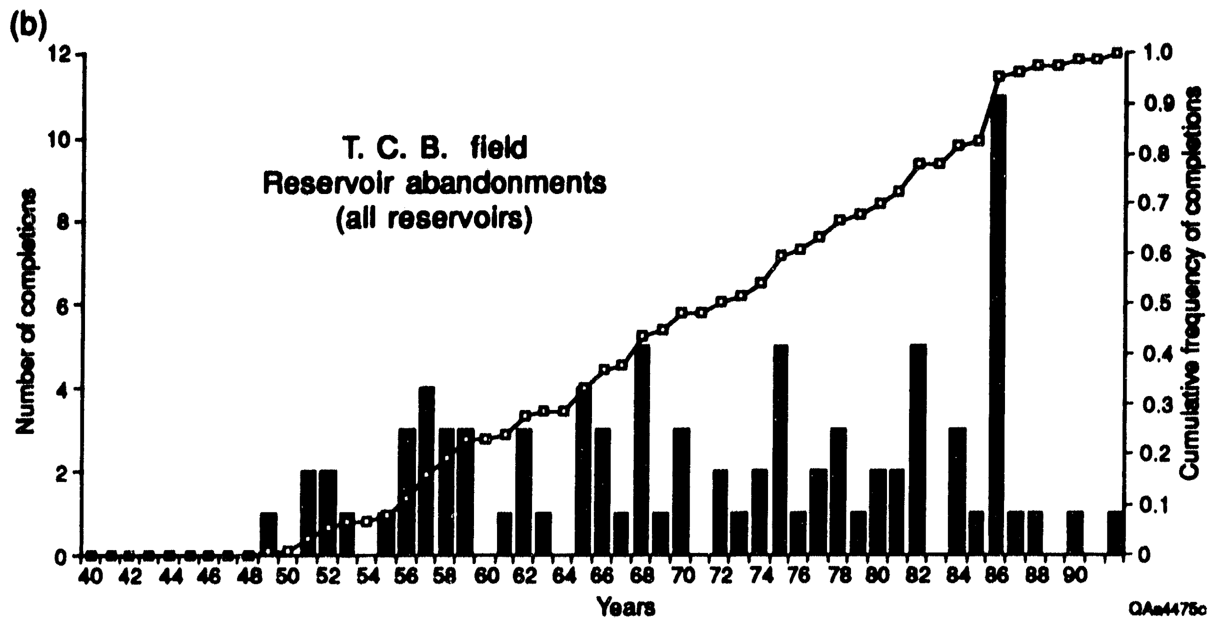


Figure 41. Histograms illustrating trends in (A) completion and (B) abandonment for individual reservoir zones in T-C-B field.

Middle Frio reservoir intervals alternate between sand-prone and sand-poor fluvial sequences. The setting and architecture of units in this interval have been studied by Jackson and Ambrose (1989), who examined the Brooks reservoir in La Gloria field, and by Jirik (1990), who assessed reservoirs equivalent to the Riley and Jim Wells in Seeligson field. A net-pay map supplied by Mobil showing a dip-elongate sand body provides additional confirmation of the fluvial nature of these reservoirs within T-C-B field. The lower Frio consists of thinner intervals of deltaic sands,

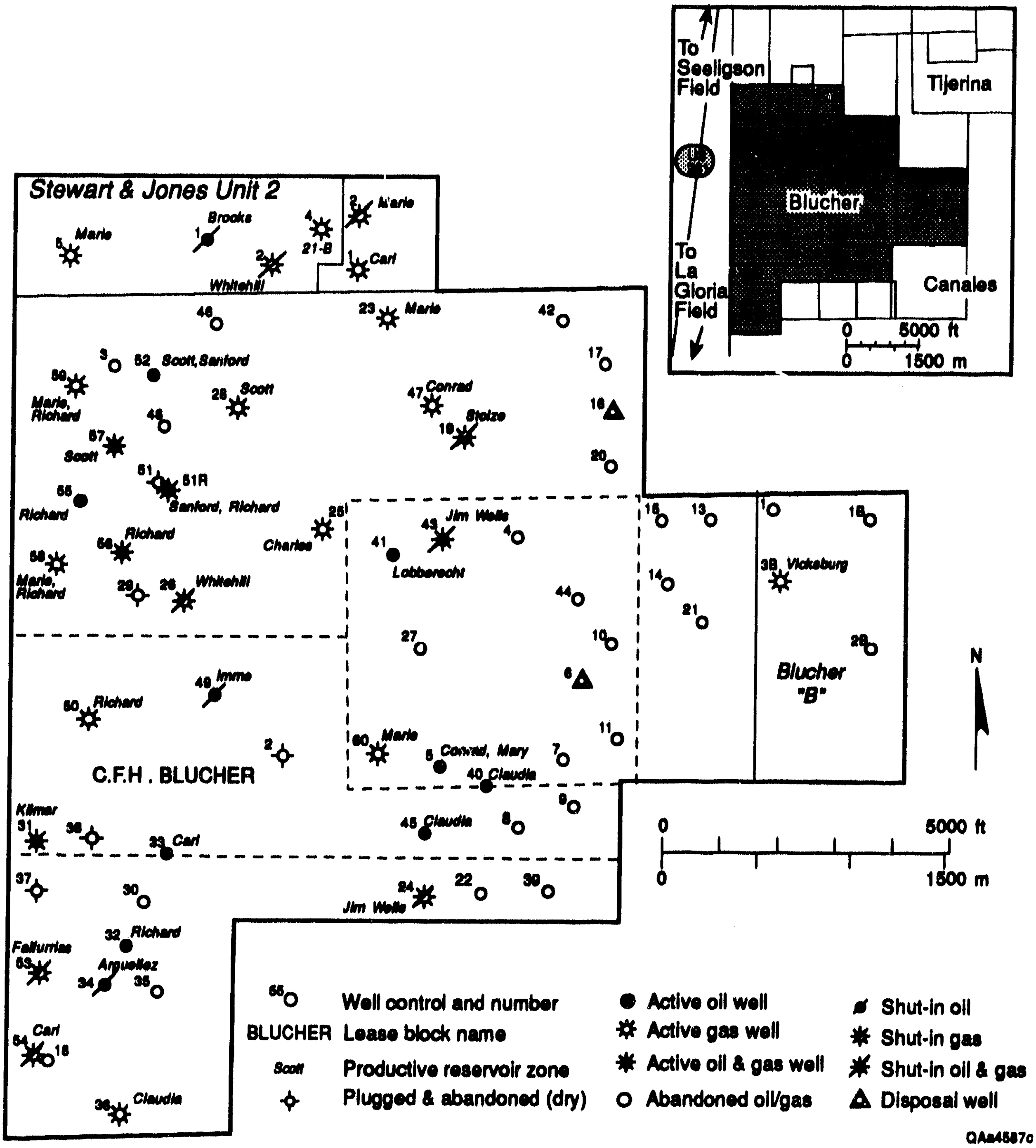


Figure 42. Map of T-C-B field study area showing distribution of active wells and currently producing reservoir zones.

possibly alternating with fluvial sediments, in an overall shalier interval. This interpretation is based on work by Reistroffer and Tyler (1991) that identified 21-B reservoirs as deltaic, along with a net-sand map of the Conrad showing a strike-elongate sand. Abrupt-based, upward-fining SP patterns and no mention of fossils in paleontology reports regarding this interval support the interpretation of a fluvial depositional setting for these reservoir sandstones.

No whole core is available within the study area to assist in depositional facies analysis. Six wireline cores were taken during field development, but none have been preserved. Core analysis data exist for 646 samples, split equally between wireline and sidewall cores, from a total of 14 wells. Other information available to assist in characterization of these reservoirs includes petrographic and clay mineral data of 24 sidewall cores from 7 wells. Known geologic and petrophysical characteristics of individual T-C-B reservoirs are summarized in **Table 17.**

As shown in Table 17, average porosities for Frio reservoirs are good, ranging from 19 to 25 percent, whereas permeability is poor to good, with geometric means of 2 to 77 md and medians of 5 to 168 md. Best permeabilities are limited to lower Frio reservoirs. Cross plots of porosity and permeability for wireline and sidewall cores in middle Frio, lower Frio, Lobberecht, and Vicksburg sands (**Figure 43**) demonstrate the parity of wireline and sidewall data. We conclude that sidewall core analysis data will be accurate enough to use for characterization of T-C-B field reservoirs. Cross plots of data in the middle and lower Frio intervals (**Figure 44**), the intervals most likely to contain reservoirs to be selected for detailed study, show very little scatter in the middle sequence and much wider scatter in the lower interval. Wider scatter in the lower Frio is most likely the result of including data from a greater number of facies, from both fluvial and deltaic associations. The greatest scatter in individual lower Frio reservoirs occurs in the Marie, Mary, and Conrad sands, which are known from previous studies to be dominated by deltaic facies. Further evaluation of these core data will facilitate the detailed characterization of Frio reservoirs.

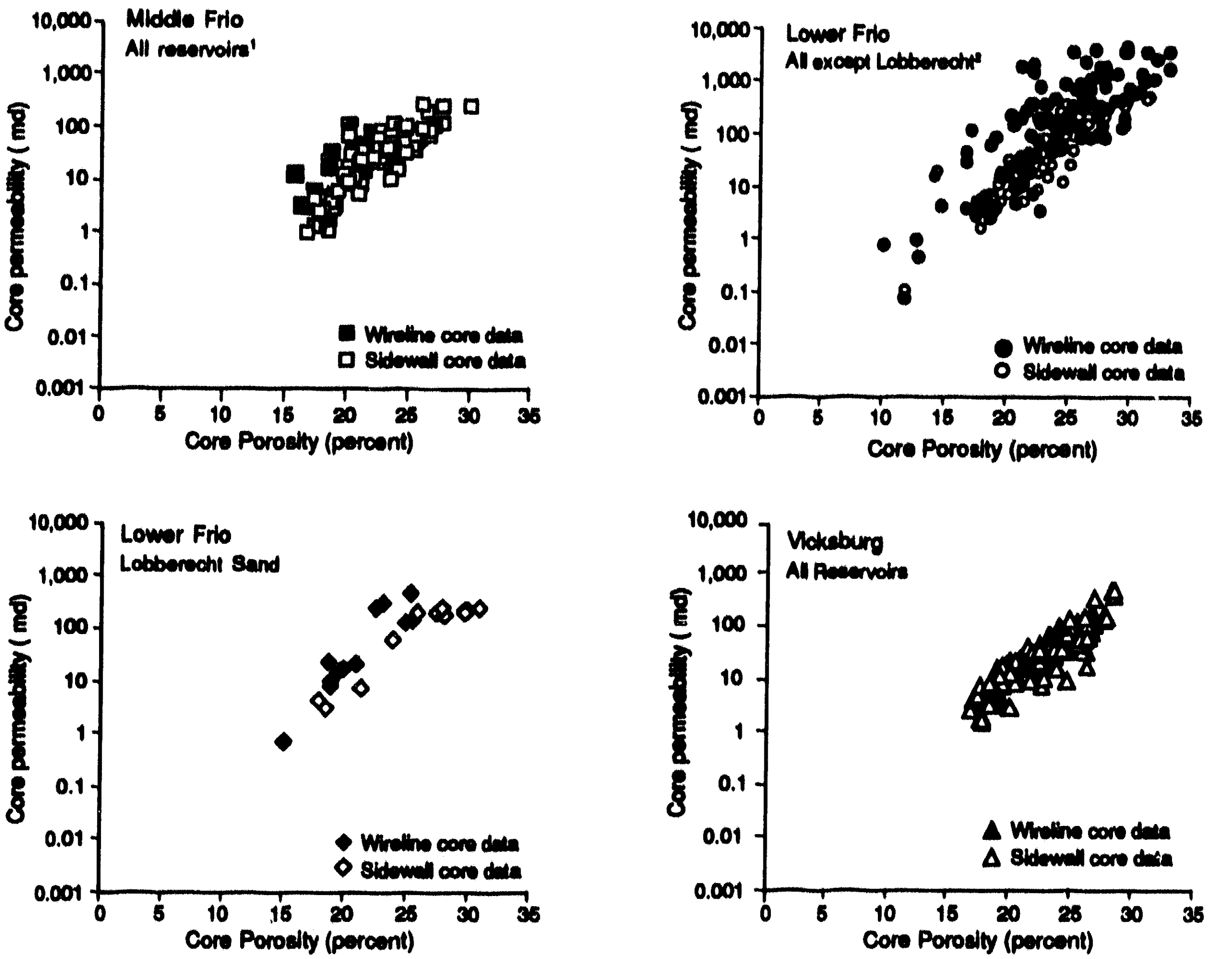
On the basis of analyses by various laboratories of 24 sidewall cores from 7 wells, reservoir sands are shown to have a litharenite to feldspathic litharenite composition, with volcanic and carbonate grains being the primary clast types. Authigenic clays include varying amounts of chlorite, illite, and moderately to highly expandable illite-smectite, with lesser amounts of kaolinite (**Figure 45**). Many of these clays are sensitive to fresh-water-based fluids and hydrofluoric acid, as well as to fines migration. Because recognition of potential formation damage from such interactions is relatively recent, completion practices from the early field life may have resulted in less than optimal production tests. Reservoirs will be reviewed for situations where formation damage may have masked an otherwise economic completion. Further examination of existing mineralogic and petrographic data and sampling and additional analysis of sidewall core material will be necessary to evaluate the importance of diagenesis on reservoir quality. More than 1,000 sidewall cores from 15 wells are available from Mobil, should additional sampling be required.

Reservoirs with High Potential for Incremental Oil Recovery

Geologic and engineering data from the Blucher area of T-C-B field were evaluated to target reservoir zones possessing the best potential for recovering additional oil reserves through detailed characterization studies. Reservoirs with high cumulative production and relatively low completion

Table 17. Summary of geologic and petrophysical characteristics for individual reservoir sandstones in T-C-B field.

RESERVOIR INTERVAL	Producing Unit	Mean Depth	Depositional Environment and Sandstone Geometry	CORE DATA			POROSITY %		PERMEABILITY	
				wells	feet	N	Mean	s.d.	GeoMean	Median
RILEY	Riley	5874	Laterally Stacked Fluvial Channels	3	15	8	22.1	2.6	26	42
	Stolze	6017		2	106	10	21.8	1.9	21	29
BROOKS	Brooks	6144	Vertically Stacked Fluvial Channels	2	60	14	20.3	2.5	7	5
SCOTT	Scott	6137	Laterally Stacked Fluvial Channels	3	102	17	23.0	3.0	3.37	33
	Whitehill	6222		1	69	2	24.5	0.6	39	40
KILMAR	Sanford	6320	Vertically Stacked Fluvial Channels	3	31	12	23.6	3.4	10	43
JIM WELLS	Jim Wells	6365	Laterally Stacked Fluvial Channels	2	112	19	22.9	3.1	22	49
ARGUELLEZ	Arguellez	6646	Vertically Stacked Fluvial Channels	5	273	13	21.6	2.9	16	21
	Stray	6793		0	0	0	23.5	2.4	5	16
FALFURRIAS	Falfurrias	6812	Laterally Stacked Fluvial Channels	7	156	13	20.7	3.1	7	23
ANTONIO	Antonio	6841	No Data	4	109	34	20.9	2.3	2	11
CARL	Carl	6961	No Data	7	56	37	21.6	2.9	65	18
CHARLES	Charles	7003	No Data	10	238	50	22.0	2.4	9	19
	Claudia	7061		2	20	6	19.1	1.1	7	7
MARIE	Marie	7140	Deltaic	8	27.5	26	22.6	4.6	31	29
	Corgey	7058		1	18.5	6	22.5	2.0	5	26
MARY	Mary	7172	Deltaic	8	39	26	25.2	4.8	25	182
CONRAD	Conrad	7224	Deltaic	11	150	88	24.6	3.7	77	106
RICHARD	Richard	7280	No Data	7	57.5	34	24.5	3.2	20	86
	George	7290		4	11.5	21	20.7	3.4	7	5
ZULA	Zula	7308	No Data	5	35.5	16	23.4	2.7	?	43
LOBBERECHT	Lobberecht	7379	No Data	6	135	32	25.2	4.7	57	168
VICKSBURG	Massive Vicksburg	7493	Deltaic	6	114	12	21.1	3.3	2	15



[1] Middle Frio reservoirs at T-C-B refer to stratigraphic interval from approximately 5400–6800 ft depth and include Stray, Riley, Stolze, Brooks, 6000 ft sand, Scott, Sanford, Jim Wells, Arguellez, and Falfurrias sand reservoirs.

[2] Lower Frio reservoirs at T-C-B refer to interval from approximately 6800–7600 ft depth and include Antonio, Carl, Charles, Claudia, Marie, Mary, Conrad, Richard, and Zula sand reservoirs

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Figure 43. Porosity/permeability cross plots of wireline and sidewall core data for middle Frio, lower Frio, Lobberecht, and Vicksburg sand reservoirs.

density provide the best potential for containing a large remaining resource and for possessing undeveloped and untapped reservoir compartments. Facies variability and depositional style of various reservoir zones were taken into consideration to provide an indication of architectural complexity and reservoir heterogeneity. Reservoirs in the T-C-B field study area best meeting these criteria include the Marie and Mary (21-B), Scott, and Kilmar sand zones.

The 21-B zone, composed of the Marie and Mary sands, is by far the most productive interval throughout the greater T-C-B field area and has produced more than 50 MMbbl of oil. Of the 40 completions carried out in 25 wells, only 4 remain open. Preliminary information, based on completions in only 25 wells within the 4,800-acre Blucher lease, suggests that average completion

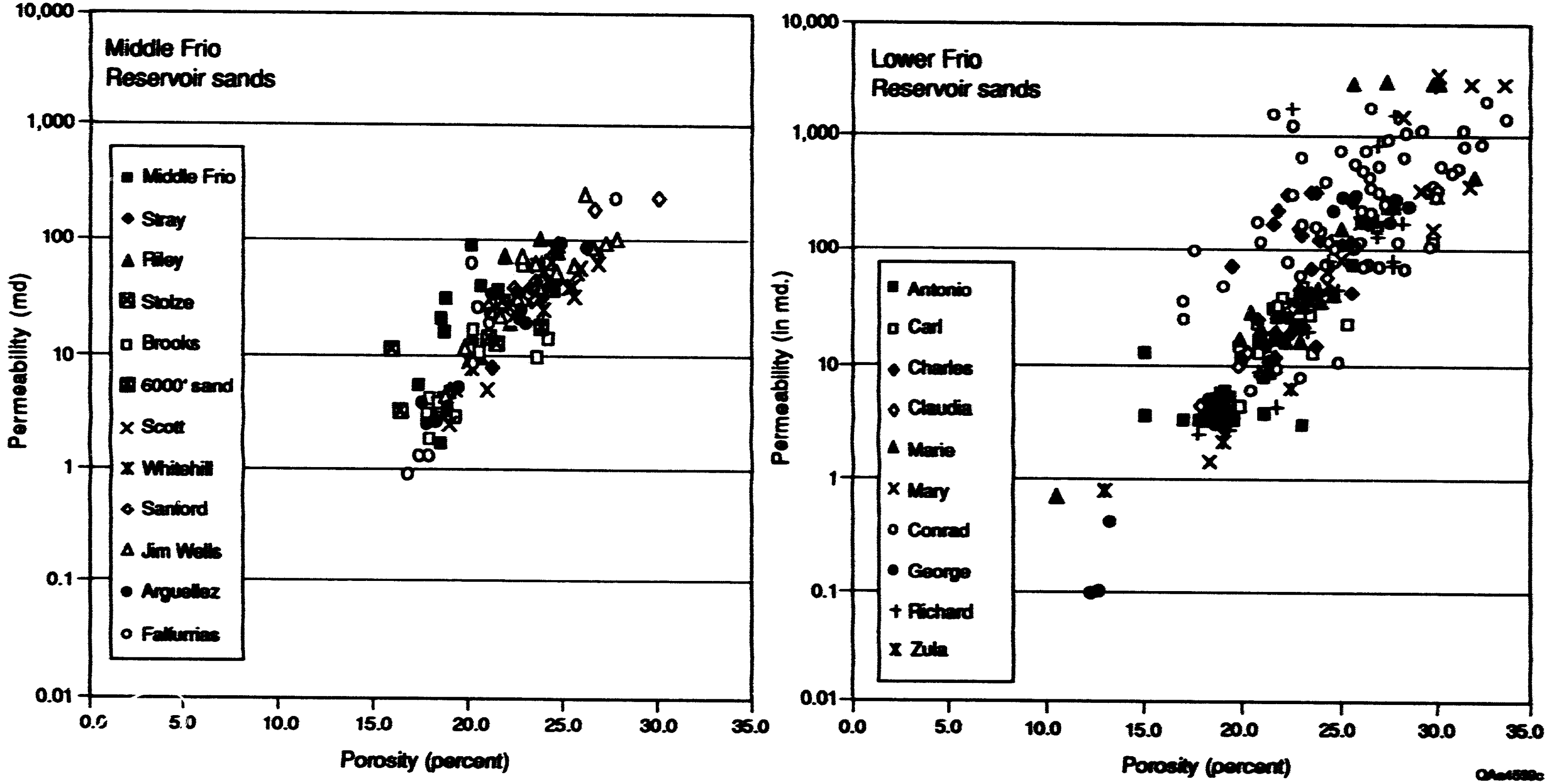

Figure 44. Representative reservoir variability illustrated on a porosity/permeability cross plot for middle and lower Frio zones in T-C-B field.

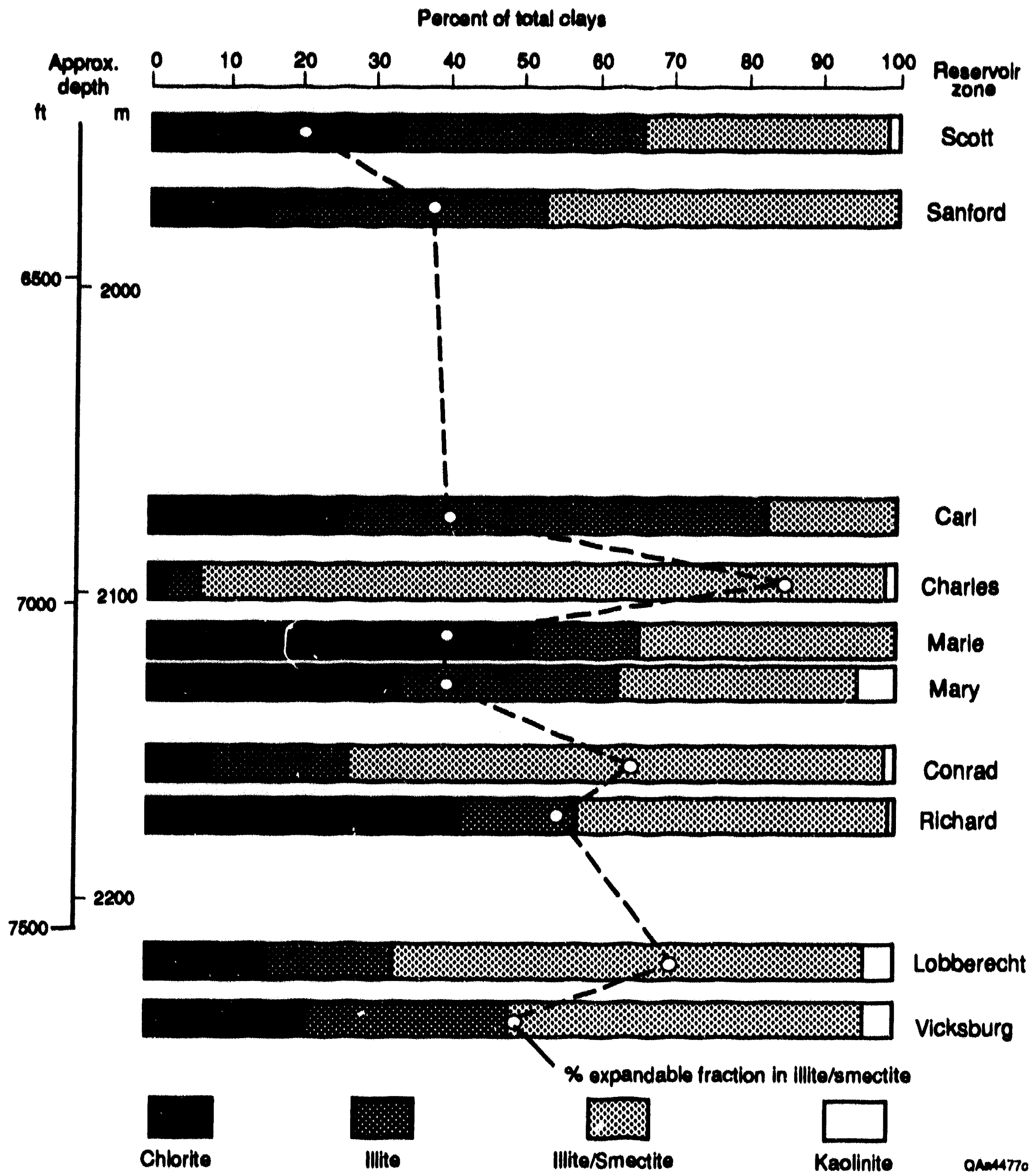

Figure 45. Bar graph illustrating clay mineralogy within the less than 2 μ-size fraction of sidewall core samples from various T-C-B reservoirs. Relative abundances of chlorite, illite, mixed-layered illite-smectite, and kaolinite are plotted, as is the percent of expandable clay in the mixed-layered illite-smectite fraction. The dominance of chlorite and moderately expandable illite-smectite results in reservoirs that are susceptible to damage from drilling and acidizing fluids.

spacing may be as high as 200 acres. Because the 21-B sands were most likely deposited in a lower delta-plain to delta-front setting, a variety of depositional facies, and thus styles of architecture, can be expected.

The Scott interval has produced more than 120 MSTB of oil from the Blucher lease since 1967 and has a significant production history predating this time. Fieldwide production has not been established, but relative cumulative values for the Blucher lease suggest that it is the most significant of the Middle Frio reservoirs. Completion density is very low, with only 8 perforations in 7 well bores over the 4,800-acre area. The Scott interval provides the best opportunity at T-C-B field to characterize a productive, laterally stacked fluvial interval.

The Kilmar reservoir has had low production since 1967 from the Blucher lease (48 MSTB), but it has one of the longest production histories, dating back to the early stages of field development. This suggests that it is a significant interval that had a high level of early activity but is now in danger of abandonment because of low production rates. The Kilmar sands are vertically stacked fluvial bodies that provide excellent opportunities for identifying uncontacted and incompletely drained reservoir compartments.

FUTURE RESEARCH PLANS

The primary objective of phase I of the study was to identify fields and reservoirs in the Frio Fluvial-Deltaic Sandstone play with the greatest potential for uncontacted and incompletely drained reservoir compartments. Reservoirs demonstrating the greatest reserve growth potential will be targeted for detailed reservoir characterization studies in phase II of the project. Reservoir data from throughout the Frio Fluvial-Deltaic Sandstone play were compiled in an effort to characterize reservoir parameters and generate resource estimates, and these formed the basis for assessing the additional uncontacted and incompletely drained potential in the play as a whole. Quantification of the additional resource potential residing in incompletely drained and untapped compartments within specific reservoir zones in Rincon and T-C-B fields is well under way. Synthesis of reservoir log, core, and production data in Rincon and T-C-B fields is nearing completion. Preliminary stratigraphic studies and analysis of reservoir core data have characterized overall depositional style and reservoir variability within each field. Production data in each field are currently being evaluated. Completion density for individual reservoirs has been identified and will be a means to target untapped reservoir potential. Volumetric estimates of produced fluids and remaining reserves will be calculated to identify and delineate the potential remaining in incompletely drained reservoir compartments. Upon completion of initial reservoir studies in each of the fields, suitable reservoirs from each field will be targeted for detailed characterization and delineation of specific opportunities for capturing additional resources.

Phase II studies, encompassing the second year of the project, will focus on delineation of incremental recovery opportunities in Rincon and T-C-B fields. Screening of reservoirs from each field to determine the best candidates for recompletion and infill potential will be complete by early in the second project year. Selected reservoirs will then be assessed from a geologic standpoint to identify reservoir architecture and internal heterogeneity. Engineering methods will be applied to the resulting identified reservoir compartments to quantify remaining oil in place and the potential for economic recovery of those remaining reserves.

Advanced reservoir characterization will consist of analysis of depositional and diagenetic heterogeneities within selected reservoirs and an assessment of reservoir compartmentalization. Stratigraphic studies in both fields will involve the construction of cross sections and maps illustrating distribution of net-sandstone thickness, permeability thickness, and water saturation. Detailed facies maps will be developed for selected reservoir zones using log and core data. Results from these studies will be used to identify primary architecture and internal physical heterogeneity within prospective reservoir zones. Detailed core studies and petrophysical measurements will be carried out on 300 ft of conventional core from Rincon field, and petrographic analyses will be performed on available sidewall core material from T-C-B field. The integration of petrographic and petrophysical core and log studies with reservoir pressure and production data will be used to identify individual reservoir compartments.

Interpretations of interwell-scale reservoir heterogeneity and of the styles and degree of compartmentalization in selected reservoirs may be greatly enhanced by incorporating information on spatial relationships of sandstone geometry, continuity, and permeability distribution available from outcrop studies of an analogous fluvial-deltaic reservoir system. Deliverables from phase II of the project will include the identification of specific opportunities for recovering additional oil reserves from untapped, incompletely drained, and possibly new pool reservoir targets.

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