IDENTIFICATION OF REMAINING OIL RESOURCE POTENTIAL IN THE FRIO FLUVIAL/DELTAIC SANDSTONE PLAY, SOUTH TEXAS

Topical Report

by

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ABSTRACT

The Frio Fluvial/Deltaic Sandstone (Vicksburg Fault Zone) oil play of South Texas has produced nearly 1 billion stock tank barrels (BSTB) of oil, yet still contains about 1.2 BSTB of unrecovered mobile oil and an even greater amount of residual oil resources (1.5 BSTB). 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 incompletely drained and untapped 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, flow unit boundaries, and 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.

Reservoir attribute data were statistically analyzed from oil and gas fields throughout the geographic area covered by the Frio Fluvial/Deltaic Sandstone oil play. General reservoir attributes analyzed in detail included porosity, initial water saturation, residual oil saturation, net pay, reservoir area, and fluid characteristics. Statistical analysis of variance demonstrated no difference between oil reservoir attributes and gas reservoir attributes, indicating that oil and gas reservoirs are subsets of a larger genetically similar population. Probability functions that describe attribute frequency distributions were determined for use in risk adjusting resource calculations. Different functions were found to be most applicable for the various petrophysical reservoir attributes.

Reservoir volumetric probability distributions are best modeled by the Weibull function, in contrast to convention that generally assumes a lognormal distribution. Statistical tests indicate that the Weibull function most accurately represents the frequency distribution of original oil

in place, original mobile oil in place, and residual oil in place. The Weibull distribution illustrates that Frio fluvial/deltaic reservoirs have a higher probability for the in-place oil resource to be below an average calculated value.

The Frio Fluvial/Deltaic Sandstone play was found to contain significant volumes of remaining oil. The volumetric probability distribution between 5- and 95-percent probability for original oil in place ranges from 3.8 to 5.6 BSTB, original mobile oil in place ranges from 2.5 to 3.6 BSTB, and residual oil ranges from 1.5 to 2.3 BSTB. The remaining mobile oil may be as high as 3.5 BSTB (5-percent probability), with a 95-percent probability that it is at least 1.2 BSTB. Additionally, the untapped oil resource (sand bodies not connected to a well bore) may be 10 percent of the original oil in place, or 380 million stock tank barrels (MMSTB).

INTRODUCTION

This topical report presents results from tasks conducted during the first project year of an overall resource assessment of the Frio Fluvial/Deltaic Sandstone oil play to evaluate the suitability of individual fields and reservoirs for detailed reservoir characterization studies. Project goals for this initial phase of the project were to (1) assess the oil resources within the play, (2) screen data from fields within the play, (3) assess the suitability of reservoirs for detailed characterization studies, and (4) select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment. Later stages of the project will involve advanced characterization of individual Frio reservoirs from selected fields in order to delineate near-term incremental recovery opportunities and identify specific targets for recompletion and strategic infill drilling. Results from reservoirs in this study will have the potential to be extrapolated to other heterogeneous fluvial/deltaic reservoirs within and beyond the Frio play in South Texas.

Recovery Efficiency in Fluvial/Deltaic Sandstone Reservoirs

Oil recovery estimates from reservoirs in fields across the United States average 34 percent (Tyler, 1988). Using Texas oil reservoirs as an example, recovery efficiencies in clastic reservoirs range from 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 Finley, 1991). 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. Recent estimates indicate that more than 34 billion barrels (Bbbl) of unrecovered oil resources are present in fluvial/deltaic reservoirs in fields throughout the United States. This substantial remaining oil resource is in serious danger of remaining unproduced unless advanced reservoir characterization techniques can be developed to locate unrecovered oil within these reservoirs.

The fundamental constraint on the ultimate recovery efficiency of conventionally recoverable oil and gas is reservoir architecture (Tyler and others, 1992). The internal structure, or architecture, of sandstones defines the geometry of fluid pathways that directly control the migration efficiency of hydrocarbons to the well bore. Lateral and vertical reservoir heterogeneities responsible for the internal architecture of a reservoir unit are products of a wide variety of depositional processes. Characterization of these depositional processes and the styles and scales of heterogeneity that control reservoir architecture is a powerful tool that can be used to predict ultimate recovery efficiency and to locate the residency of unrecovered mobile oil in the reservoir (Tyler and Finley, 1991). Fluvial and fluvial-dominated deltaic reservoirs are characterized by low to very low recovery efficiencies on the basis of their high degree of lateral heterogeneity and low to high degree of vertical heterogeneity. For these same reasons, these stratigraphically complex reservoirs possess excellent potential for incremental recovery of additional mobile oil that resides in undeveloped reservoirs.

Stratigraphic complexity inherent in fluvial/deltaic depositional systems is directly responsible for the incomplete and inefficient recovery of available oil and gas resources within a developing field. Significant volumes of mobile oil are isolated in underdeveloped or undeveloped reservoir sand bodies. The relative geometric positioning of wells and low density of perforations within a stratigraphic interval lead to incompletely drained and untapped reservoir sand bodies. These incompletely drained and untapped reservoir sand bodies 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 (fig. 1). The present level of development within a field and the estimated recovery efficiency can be used as relative indicators of remaining oil potential.

In addition to untapped and incompletely drained reservoir targets, additional resource potential may be present in deeper reservoirs not yet discovered, existing in stratigraphic zones already penetrated but below previously established production. Prediction of deeper reservoir targets is based on a much less dense framework of data and commonly requires regional facies analysis and sequence stratigraphic studies of reservoir systems in order to properly assess their recovery potential.

Summary of Objectives

The Frio Fluvial/Deltaic Sandstone (Vicksburg Fault Zone) play of South Texas is a depositionally complex play that has already produced nearly 1 BSTB of oil, yet still contains about 1.2 BSTB of unrecovered mobile oil and nearly the same amount of residual oil resources. More than half of the reservoirs in this mature 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. The primary goals of this report are to describe characteristics of Frio fluvial/deltaic reservoirs and to provide a detailed oil resource assessment of the play.

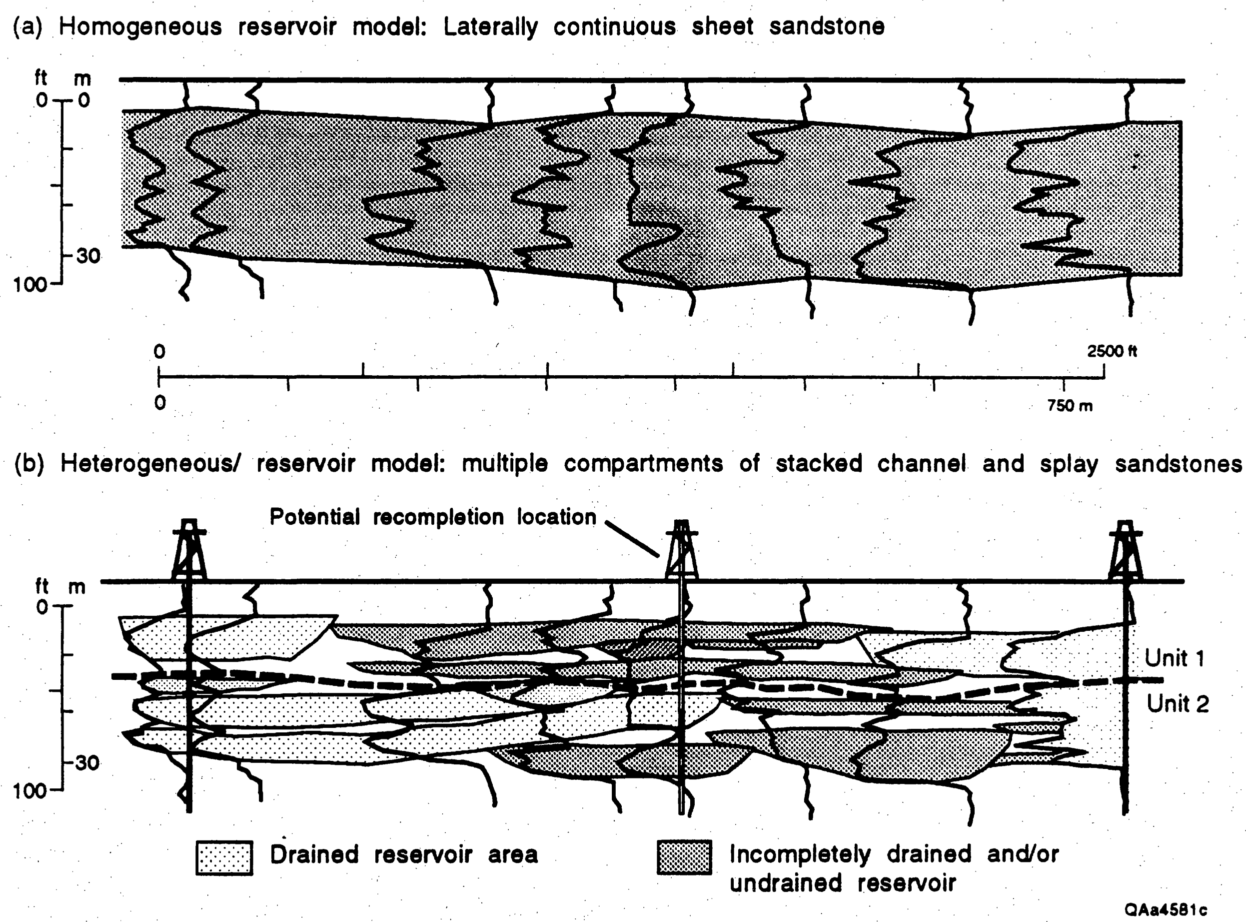

Figure 1. Schematic geological cross section contrasting the generalized interpretation of a sandstone reservoir as a simple, laterally continuous (homogeneous) producing zone (a) with a more detailed interpretation of the same sandstone unit as a complex heterogeneous zone consisting of multiple reservoir 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).

To accurately determine oil resource volumes within a play, each reservoir attribute applied in resource volume calculations must be well characterized. The more data analyzed, the better the understanding of each attribute. The amount of data can be increased if the number of reservoirs analyzed is increased by testing for statistically significant differences between the attributes of oil and gas reservoirs. A combined-data set of both oil and gas reservoirs would be larger overall and would thus produce a more representative characterization. An objective of this study was to determine whether the main reservoir attributes of oil and gas reservoirs are similar enough to be combined into a general characterization of oil and gas reservoirs throughout the Frio Fluvial/Deltaic Sandstone play.

Statistical analysis produces critical information for proper reservoir attribute characterization. Holtz (1993) described the statistical analyses needed in accurate resource evaluation. These analyses included descriptive statistics, covariant determination, and determination of descriptive probability functions. Descriptive statistics illustrate the overall spread of attribute data, give average and most likely values, and demonstrate a data set's relationship to a normal probability distribution. Covariant determination demonstrates the interrelationships between a reservoir's attributes. Determination of descriptive probability functions allows modeling of the likelihood of occurrence of an attribute value. Determination of the best fitting probability function facilitates risk adjusting of volumetric calculations and allows calculation of reservoir volumes with incomplete data. An objective in this study was to ascertain all salient statistical characteristics producing a more accurate resource assessment.

The final objective in the study was to determine reservoir volumetric characteristics and produce an assessment of oil resources. The critical volumetric characteristic is the probability of occurrence for a given value of the oil resource. A typical 40-acre well spacing is the equivalent of a 1-millionth percent sampling size. Certainly at this minute size a better understanding of reservoir volumes is gained by perceiving the resource as a probability distribution. It is typically assumed that this distribution is lognormal; however, this may just be a relict of outdated analysis procedures. In this study we test for the best fitting function. These functions can then be applied by operators to better assess the value of properties within the Frio Fluvial/Deltaic Sandstone play. Additionally, these probability functions allow a more accurate assessment of the original and remaining oil resource within the play.

METHODOLOGY

Recovery opportunities in mature reservoirs of the Frio Fluvial/Deltaic Sandstone Play are being pursued using a two-part approach. First, production data and engineering attributes from reservoirs throughout the play have been screened and analyzed. Volumetric assessments of total original oil in place, remaining mobile oil, and residual oil have been calculated using playwide data to demonstrate the presence of a large remaining oil resource in the play. Incompletely drained oil potential for the play was assessed. A preliminary evaluation of the untapped oil potential for the entire play was based on a statistical model incorporating the average number of producing reservoirs in a field, the number of producing sands in a reservoir, and the completion probability within individual reservoir zones.

The second step will involve detailed studies of a few selected reservoirs from within the play to determine how reservoir architecture controls the drainage of oil and flow of indigenous and injected waters. Geological models based on detailed mapping and stratigraphic correlations will be used to characterize interwell heterogeneity and to identify intrareservoir facies variations and bounding surfaces that create partial or complete barriers to flow that control the location of the incremental oil resource. These models will be combined with reservoir volumetric assessments to identify specific target locations with high potential for containing a large incompletely drained and untapped oil resource that may be recovered by recompletion and infill drilling. This topical report presents the results from this initial phase of the project.

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 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 and Resource 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. Covariance was tested between each combination of parameters, and statistical F and t tests were applied in an analysis of variance (ANOVA) in order to identify statistical differences or similarities between oil and gas reservoir populations. Finally, each of the engineering parameters was analyzed to determine what type of probability function best represents the data distribution. All data were treated as being nondiscrete, and 18 different functions were tested. Three best fit tests were applied, including the chi-square, Kolmogrov-Smirnov (K-S), and Anderson-Darling (A-D) tests (Lindgren, 1976), along with graphical outputs of the data.

Oil volume was stochastically simulated by applying the best fitting probability functions of the individual engineering attributes. Stochastic simulations of oil volume generated the probability of occurrence of original oil in place (OOIP), original mobile oil in place (OMOIP), and residual oil in place (OROIP). These oil volume probability distributions were generated by substituting the attribute probability functions into the equations below. Stochastic simulations were then run to produce probability distributions for each of the oil volume parameters. The resulting oil volume probability distributions were then analyzed by applying the aforementioned best fit tests to determine which function best models the particular distribution.

$$\text{OOIP} = 7758 \times f(\phi) \times f(h) \times f(A) \times (1 - f(S_w))$$

$$\text{OMOIP} = 7758 \times f(\phi) \times f(h) \times f(A) \times (1 - f(S_w) - f(S_{or}))$$

$$\text{OROIP} = \text{OOIP} - \text{OMOIP}$$

where

$f(\phi)$ = porosity probability function,

$f(h)$ = net-pay probability function,

$f(A)$ = reservoir acreage probability function,

$f(S_w)$ = initial water saturation probability function, and

$f(S_{or})$ = residual oil probability function.

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.

GEOLOGIC SETTING

Structural and Stratigraphic Setting

The Frio Fluvial/Deltaic Sandstone (Vicksburg Fault Zone) play is located in South Texas and extends from Starr County northeastward to Jim Wells and Nueces Counties, Texas (Galloway and others, 1983) (fig. 2). 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 having large displacements commonly in excess of hundreds of feet. Faulting mainly offsets the Vicksburg Formation but also locally affects the lower portions of the overlying Frio Formation.

Individual fields within the play produce oil from multiple reservoir sandstones in an approximately 2,000-ft-thick stratigraphic interval of the Oligocene Frio Formation. The Frio Formation is one of seven major progradational wedges in the lower Gulf coastal plain of South Texas that records a major depositional offlap episode of the northwestern shelf of the Gulf of

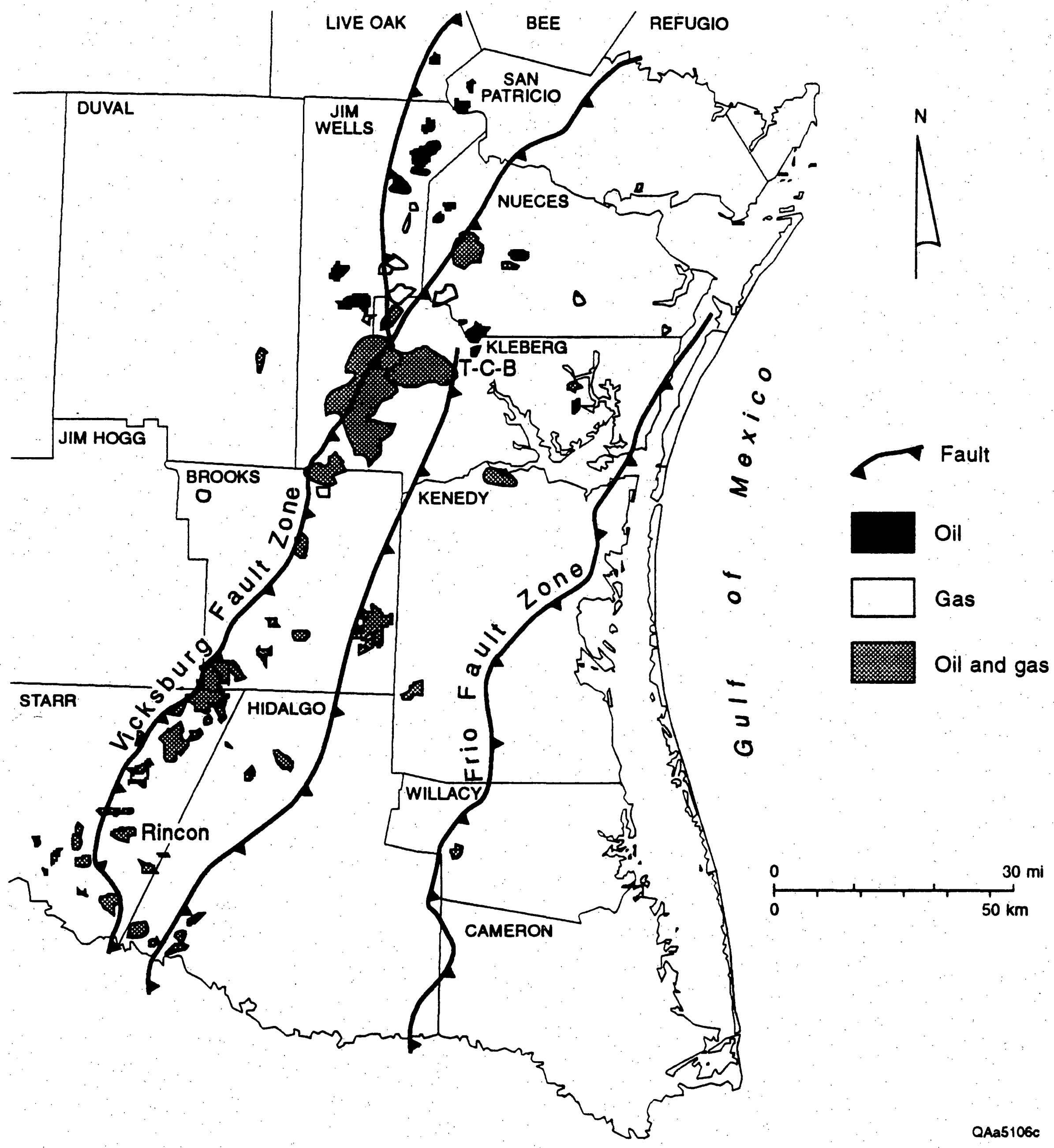

Figure 2. Map of South Texas showing location of fields within the Frio Fluvial/Deltaic Sandstone play along the Vicksburg Fault Zone.

Mexico Basin (figs. 3 and 4). Onshore oil and gas reservoirs commonly lie in the proximal portions of these progradational wedges where sands intertongue with more basinward shales (Galloway, 1989). Frio sedimentation records the entry of a major extrabasinal river into the Gulf Coast Basin along the axis of the Rio Grande Embayment. This ancient fluvial/deltaic complex consists of the Gueydan fluvial and Norias delta systems (Galloway and others, 1982). The entire productive reservoir interval consists of a stacked series of 20 to 40 separate fluvial and deltaic sandstone reservoirs. In general, lower Frio sands represent deltaic facies of the ancestral Norias delta system, and middle and upper Frio sands predominantly reflect deposition in fluvial channels of the Gueydan fluvial system (Galloway and others, 1982).

The Norias delta system constitutes the main Frio depocenter in the South Texas coastal plain (Galloway and others, 1982) and produced the Frio progradational wedge. Thousands of feet of sandstone and shale accumulated in fluvial to fluvial-dominated deltaic and wave-modified deltaic environments (Duncan, 1983). The geometry of the Frio progradational wedge developed in response to pronounced subsidence of the extensive, unstable platform margin (Winker, 1982; Winker and Edwards, 1983). As a result of this rapid subsidence and the reduced marine redistribution of sand, shelf-edge delta sequences in the lower Frio display a fluvial-dominated geometry in plan view (Galloway and others, 1982).

Later stages of Frio deposition near the Vicksburg Fault Zone represent a return to aggradational fluvial deposition (fig. 3) as the Norias delta system continued to prograde farther to the east and to deposit a thick sequence of massive, sandy, shoal-water, arcuate deltas and wave-modified lobate deltas that extended eastward from the Vicksburg Fault Zone to the present position of the Frio Fault Zone (Galloway and others, 1982). Table 1 summarizes the major geologic characteristics of the upper Vicksburg, lower Frio, and middle and upper Frio.

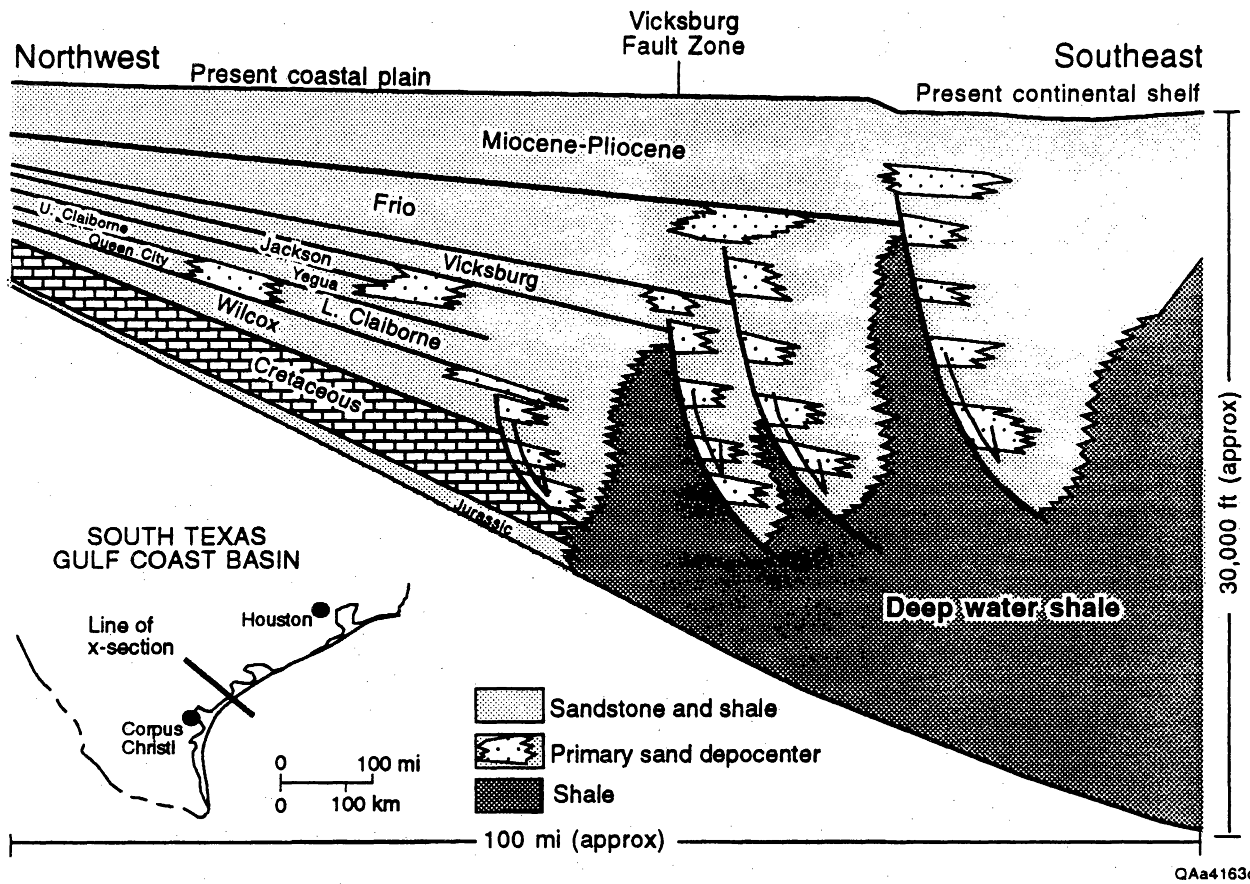

Figure 3. Schematic cross section of the South Texas Gulf Coast Basin. Modified from Bebout and others (1982).

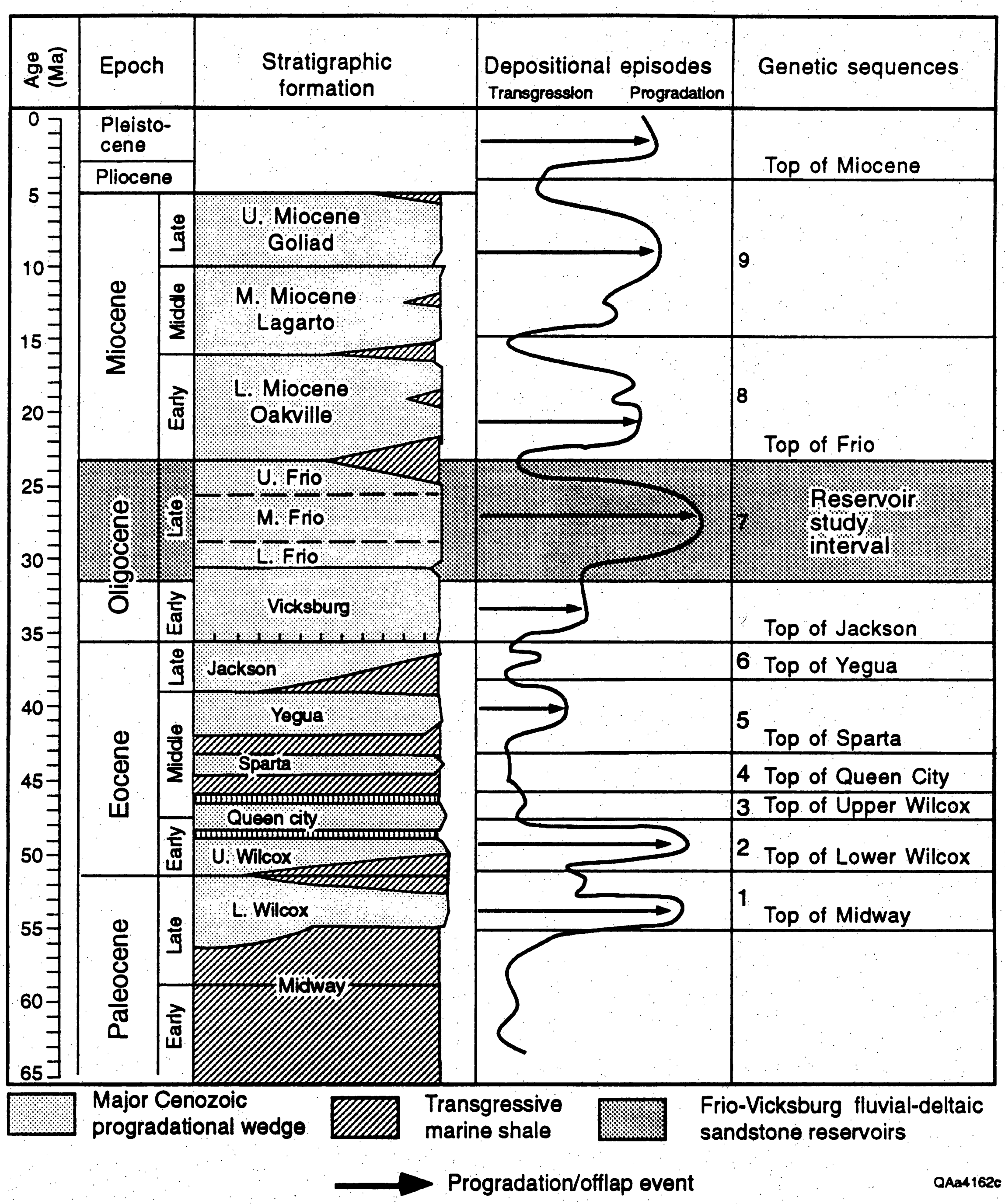

Figure 4. Stratigraphic column of Cenozoic sediments of the South Texas Gulf Coast. The sedimentary succession has been divided into a series of large-scale depositional episodes that represent major periods of progradation that occurred throughout the Cenozoic (Galloway, 1989). Reservoirs in the Frio Fluvial/Deltaic Sandstone play are part of a larger Frio-Vicksburg genetic sequence.

Table 1. 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 South 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 Formation	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

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 thick, 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

Middle and upper Frio sediments were deposited by bedload and mixed-load streams of the Gueydan fluvial system. The large Gueydan fluvial system originated in the Desert Southwest and flowed down the axis of the Rio Grande Embayment across South Texas. Early studies of Frio deposition indicated that the semiarid climate of the Oligocene, combined with the destruction of vegetation by ash deposited from the active volcanic terrane of northwestern Mexico, favored the evolution of low-sinuosity bedload channels flanked by broad, ash-laden crevasse splays in the proximal reaches of the Gueydan fluvial system in South Texas (Galloway, 1977; Galloway and others, 1982). More recent studies using 3-D seismic data in Seeligson field, located in the Frio Fluvial/Deltaic Sandstone play, indicate that Gueydan fluvial deposition in the vicinity of the Vicksburg Fault Zone was characterized by well-developed levees, which allowed for increased sinuosity and the development of relatively narrow channels (Kerr and Jirik, 1990; Ambrose and others, 1992).

Reservoir facies of the Gueydan fluvial system consist of channel-fill and point-bar sandstones (fig. 5). Nonreservoir facies, which commonly separate reservoir units, are 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).

Recent well log and core studies of Gulf Coast Frio sandstone gas reservoirs have documented small-scale heterogeneities that can be used to subdivide channel-fill units into distinct subfacies according to their individual diagnostic porosity and permeability ranges (Kerr, 1990; Kerr and Jirik, 1990; Kerr and others, 1992). The basal subfacies consists of a channel lag composed of clay clasts and has low-porosity and -permeability values, which range from 5 to 20 percent and 0.01 to 10 md, respectively. The highest porosity and permeability values

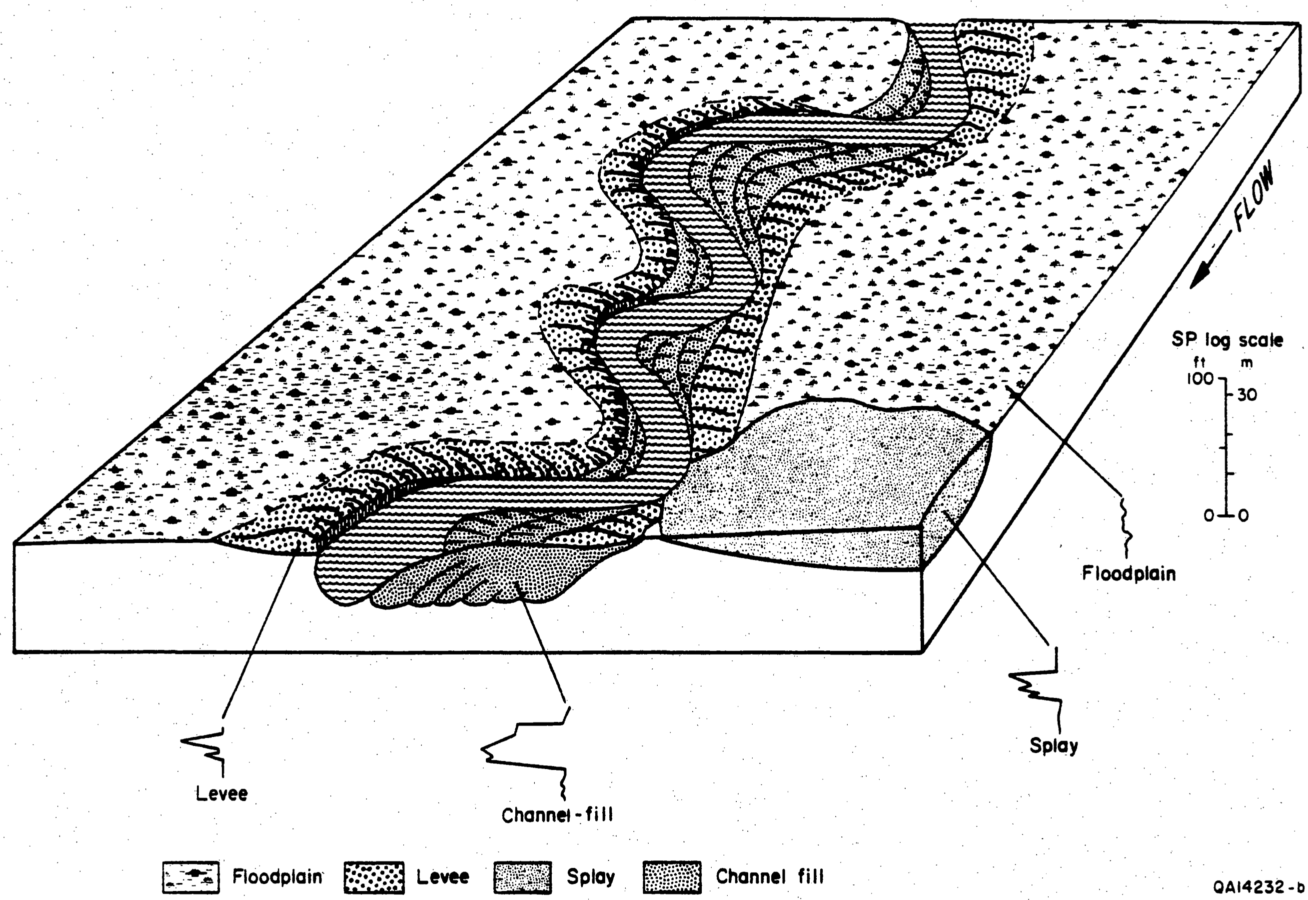

Figure 5. Schematic block diagram illustrating general three-dimensional relationships and characteristic SP log responses in fluvial reservoir and nonreservoir facies. Modified from Galloway (1977).

(20–25 percent, 100–500 md) are measured in crossbedded, medium- to fine-grained sandstones that are present immediately above the basal lag. Plane-bedded and ripple-laminated fine to very fine grained sandstones are observed to contain large variations in porosity and permeability over just a few vertical feet (permeability ranges from 1 to 200 md). The uppermost subfacies of channel-fill deposits consist of intervals of structureless siltstone and mudstone that commonly contain carbonate nodules and root mottling indicative of soil-forming processes. These upper intervals are of poor reservoir quality and act either as baffles or complete barriers to fluid flow. These 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. Splay units consist of a series of individual sandstone beds that represent either multiple flood events from a single crevasse or a complex of splays merging from different crevasse breaks. Splay reservoir facies have a fan or lobate geometry, with vertical thicknesses as great as 20 ft proximal to channel-fill deposits and lateral dimensions that range to as much as 4,000 ft. Porosity and permeability values in splay sandstones vary from reservoir facies with 20-percent porosity and 500 md near the main channel to nonreservoir facies (5-percent porosity and <1 md) that act as flow barriers in distal splay environments (Kerr and Jirik, 1990). 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.

RESERVOIR ATTRIBUTE CHARACTERISTICS

The reservoir attributes that characterize Frio sandstones reflect a combination of depositional and postdepositional controls. Regional structure and large-scale facies variations that affect source rock distribution and hydrocarbon migration combine to control effective reservoir area and the characteristics of trapped fluids. Smaller-scale local depositional features are responsible for variations in porosity, fluid saturation, and net pay. Reservoir attribute characteristics of Frio sandstones analyzed for the determination of hydrocarbon volumes included porosity, initial water saturation, residual oil saturation, net-pay thickness, area, and fluid. Statistical analysis of variance (ANOVA) and descriptive statistics were followed by fitting probability functions to the data distributions.

Reservoir Porosity

Statistical Characteristics

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 2). 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 3).

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 is 2.7 for gas reservoirs and less than 2 for the combined-population group. Sixty-eight percent of the reservoirs have values between 22 and 26 percent, and 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 (table 2). Both exhibit approximately the same range, with gas reservoirs slightly more positively skewed (fig. 6). The high positive kurtosis of gas reservoirs also indicates the narrow variation in porosity, suggesting that porosity may not be the largest contributor to hydrocarbon volume variability.

Porosity in gas reservoirs displays a weak negative covariance relationship to reservoir depth (correlation coefficient of −0.52). Deeper reservoirs tend to have lower porosity.

Table 2. 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

Table 3. 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

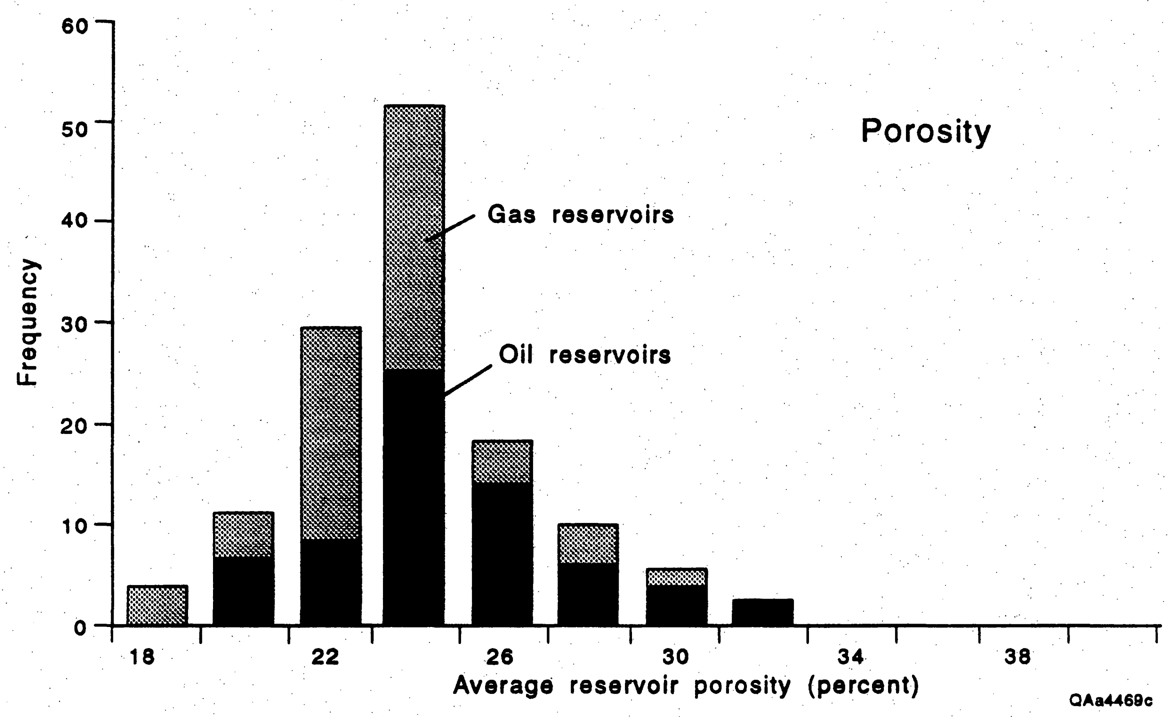

Figure 6. Histogram illustrating distributions for values of reservoir porosity from reservoirs throughout the play.

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.

Descriptive Probability Functions

Average reservoir porosity of Frio fluvial/deltaic reservoirs is best modeled by a normal, gamma, and/or logistic probability density function. For oil reservoirs, the normal, logistic, and gamma probability functions fit the porosity distributions. The normal distribution was the best fit according to the K-S test and fits the smaller values up to the mean the most accurately (fig. 7). The gamma function displayed the second-best fit according to the K-S test, and the A-D test ranked the logistic probability as the best fitting function. Overall, neither of the three functions represents the data very well. For simplicity, a normal probability function will be used to characterize reservoir porosity. The normal density function is given below for oil reservoirs where $\mu = 25.33$ percent and $\sigma = 2.67$ percent:

$$f(\xi) = 1/(2\pi\sigma^2)^{.5}e^{-(x-\mu)^2/\sigma^2}$$

In gas reservoirs, porosity is best modeled by the logistic probability function. Both the K-S and A-D tests indicate that either a logistic or gamma function describes the porosity data well. The K-S test ranks the gamma function as being slightly better, whereas the A-D test ranks the logistic test as being slightly better. The logistic function represents the lower values more accurately and thus is the most useful for modeling porosity. The logistic density function is given below and models gas reservoirs when $\alpha = 23.8$ percent and $\beta = 1.34$:

$$f(x) = z/b(1+z)^2$$

where

$$z = \exp(-(x-a)/b).$$

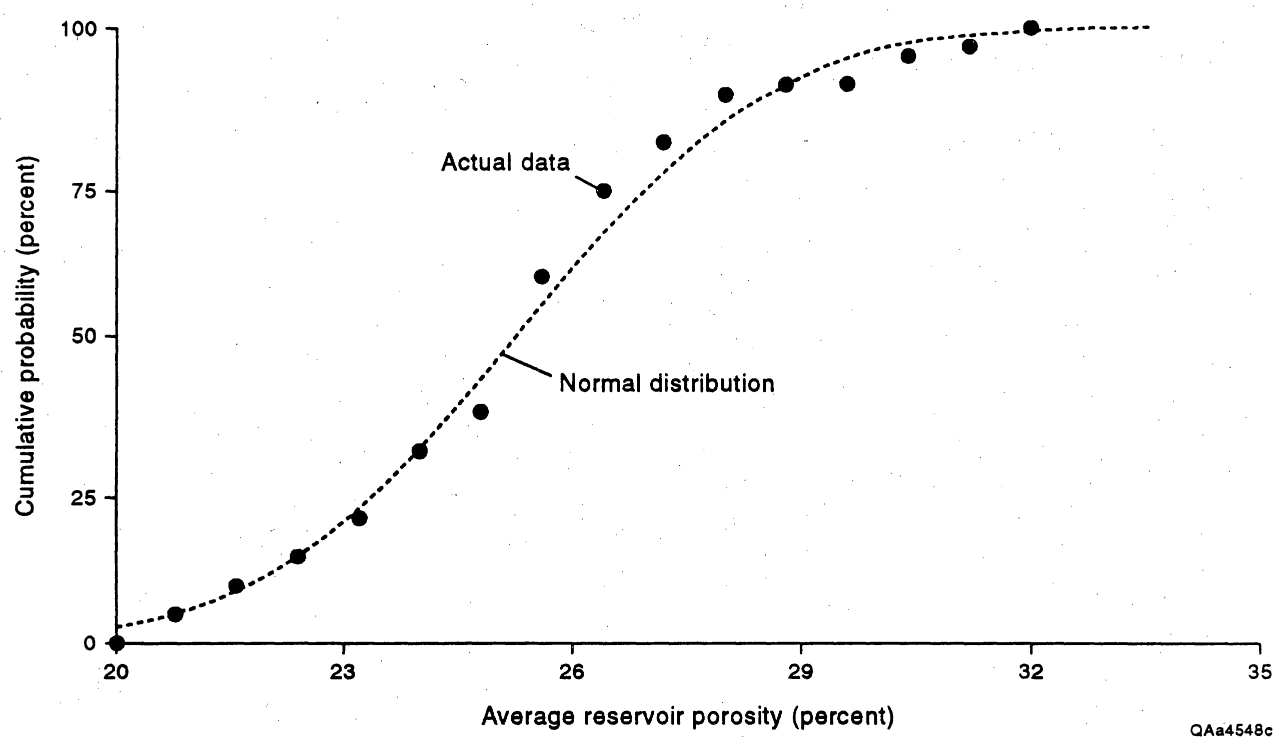

Figure 7. Cumulative frequency comparing actual porosity data with best fitting probability function.

When both oil and gas reservoirs are analyzed together, porosity is best modeled by the logistic probability function. The A-D test chooses the logistic function as the best model, whereas the K-S test points to the gamma function. Neither statistical tests nor visual inspection demonstrate much difference between these two functions. The logistic probability function may be preferable because it was the best fit for gas reservoirs. The logistic density function where $\alpha = 24.55$ and $\beta = 1.45$ best models the combined-data set. Therefore, when volumetric calculations are risk adjusted, a logistic or normal probability function should be applied to model porosity.

Reservoir Initial Water Saturation

Statistical Characteristics

ANOVA indicates that no statistically significant difference exists between mean values of initial water saturation in oil and gas reservoirs. A difference of just over 2 percent exists between the two means, and the ANOVA F statistic is smaller than the critical F value (table 3), demonstrating no statistical difference between the means. Therefore, oil and gas reservoirs are likely to belong to the same population and the characteristics of the combined-data sets are applicable to oil reservoirs.

Reservoir initial water saturation is highly variable for both oil and gas reservoirs, as demonstrated by the range and standard deviation. 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 just as much variability. Gas reservoirs have a range of 46 percent, from 11 to 57 percent, and a standard deviation of 5.1 around a mean of 24 (table 2).

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 2). This is due to a long tail of higher values (fig. 8). 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 that are less than the mean. The tail of large values also causes the distributions of oil, gas, or combined-reservoir groupings to be positively skewed.

Descriptive Probability Functions

The frequency distribution of initial water saturation is nonnormal and is best modeled by beta, gamma, or lognormal probability distribution functions. Individually the oil and gas reservoir groupings appear somewhat bimodel, having a long tail of high-magnitude values. The K-S and A-D tests indicate that a beta probability distribution function best describes the distribution of S_w values in oil reservoirs. For oil reservoirs, initial water saturation probability is modeled where $\alpha = 3.39$ and $\beta = 6.78$, and the resulting function is scaled to percentage by multiplying the result by 36 and adding 18 percent. The gamma distribution is also a good probability model for oil reservoirs. The beta function corresponds best until the high-magnitude value tail is exhibited (fig. 9) and therefore is the most useful model. Gas reservoirs, taken as a group, are also best described by the beta function according to the K-S test (fig. 10). The beta probability function is modeled where $\alpha = 3.39$ and $\beta = 6.78$, and the resulting function is scaled to a percentage by multiplying by 56.5 and adding 11.5 percent. Other functions that are good models include the chi-square and lognormal functions. The chi-square function does not fit the lower values below the mean as well as the beta probability function, and the lognormal function does not fit as well around the mean. The beta density function is written as

$$f(x) = [x^{\alpha-1}(1-x)^{\beta-1}]/B(\alpha,\beta)$$

where $B(\alpha,\beta) = t^{x}2^{-1}(1-t)x2-1\ dt$.

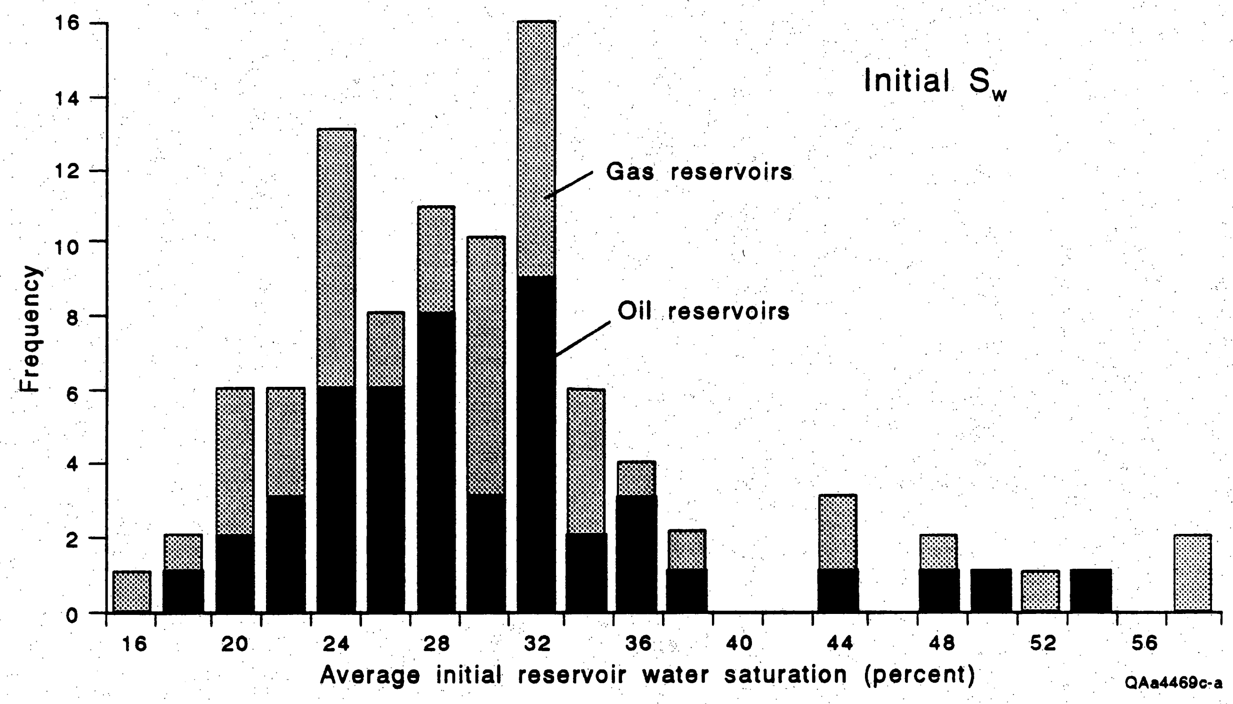

Figure 8. Histogram illustrating distributions for values of reservoir initial water saturation throughout the play.

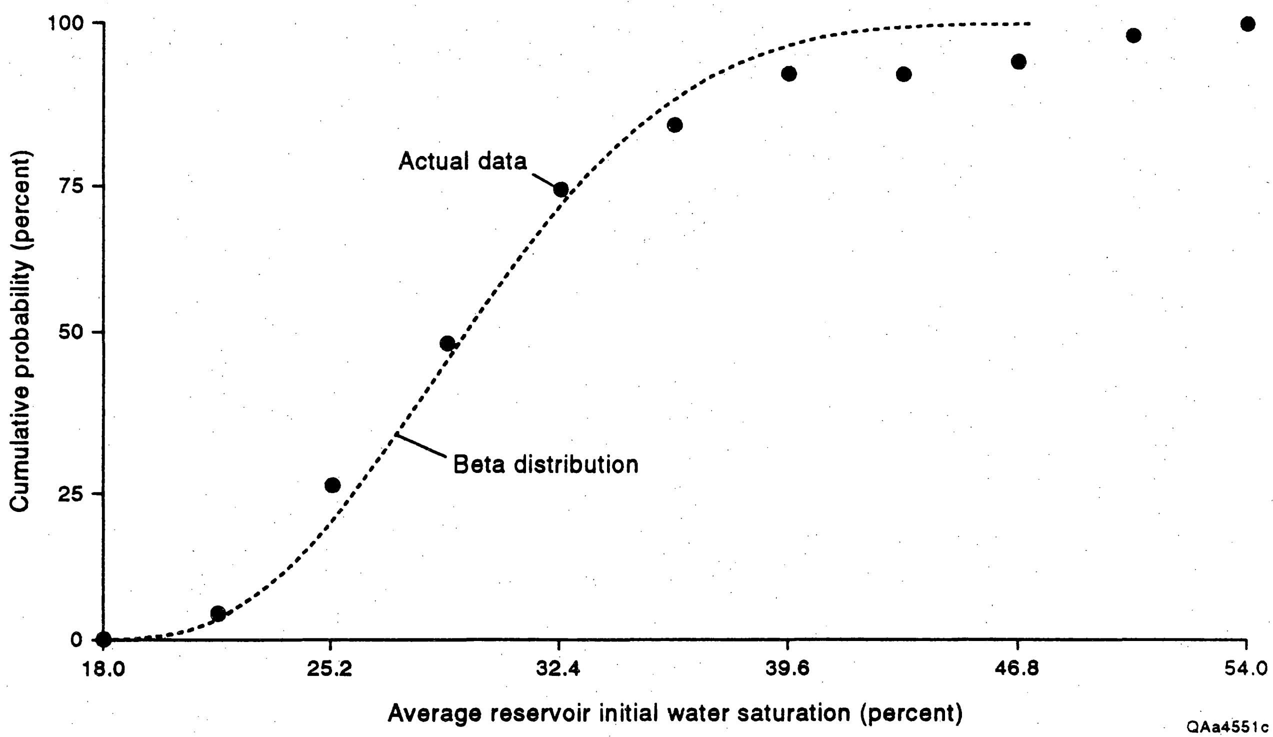

Figure 9. Cumulative probability distribution comparing actual oil reservoir initial water saturation with the beta function fit.

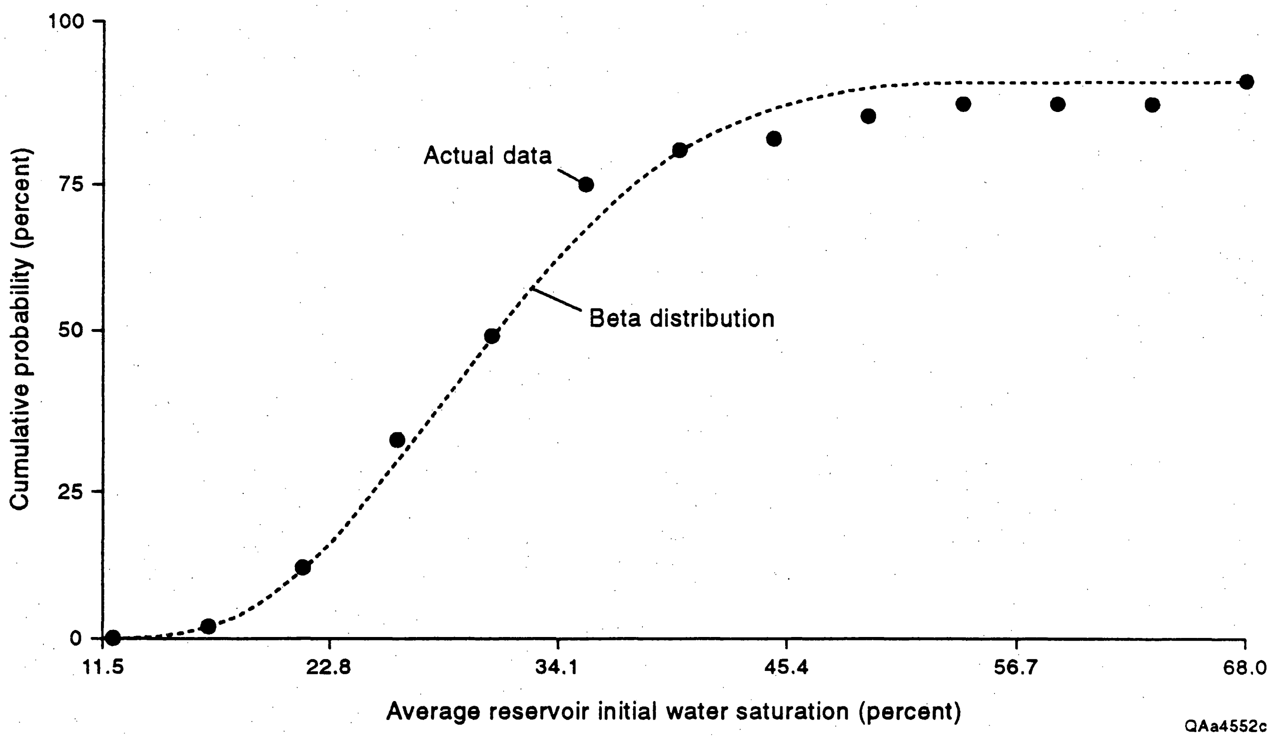

Figure 10. Cumulative probability distribution comparing actual gas reservoir initial water saturation with the beta function fit.

Initial water saturation probability distribution is best modeled by a lognormal or beta function when oil and gas reservoirs are combined. Both the K-S and A-D tests rank the lognormal function as the best representation of initial water saturation. The tests indicate that the beta function is nearly as accurate. Both functions fit the tails well but have some deviation at the sharp drop after the mode of the distribution (fig. 11). The lognormal density function given below models the combined-data set when m = 30.84 and s = 8.75:

$$f(x) = [1/(x(2\pi\sigma^2)^{.5})][\exp((-(\ln(x)-\mu_1)^2)/2\sigma_1^2)]$$

where

$$\mu_1 = \ln(\mu^2/(\sigma^2+\mu^2)^{.5}) \text{ and } \sigma_1^2 = (\ln(\sigma^2+\mu^2)/\mu^2))^{.5}.$$

Therefore, when volumetric calculations are risk adjusted, a beta, gamma, or lognormal probability function should be applied to model initial water saturation.

Reservoir Residual Oil Saturation

Statistical Characteristics

Analyzed populations of reservoir residual oil saturation 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 caused by 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 2; fig. 12).

In addition to these central tendency characteristics, residual oil saturation exhibits a weak negative covariance with initial oil saturation; the correlation coefficient is –0.46. Thus, as initial

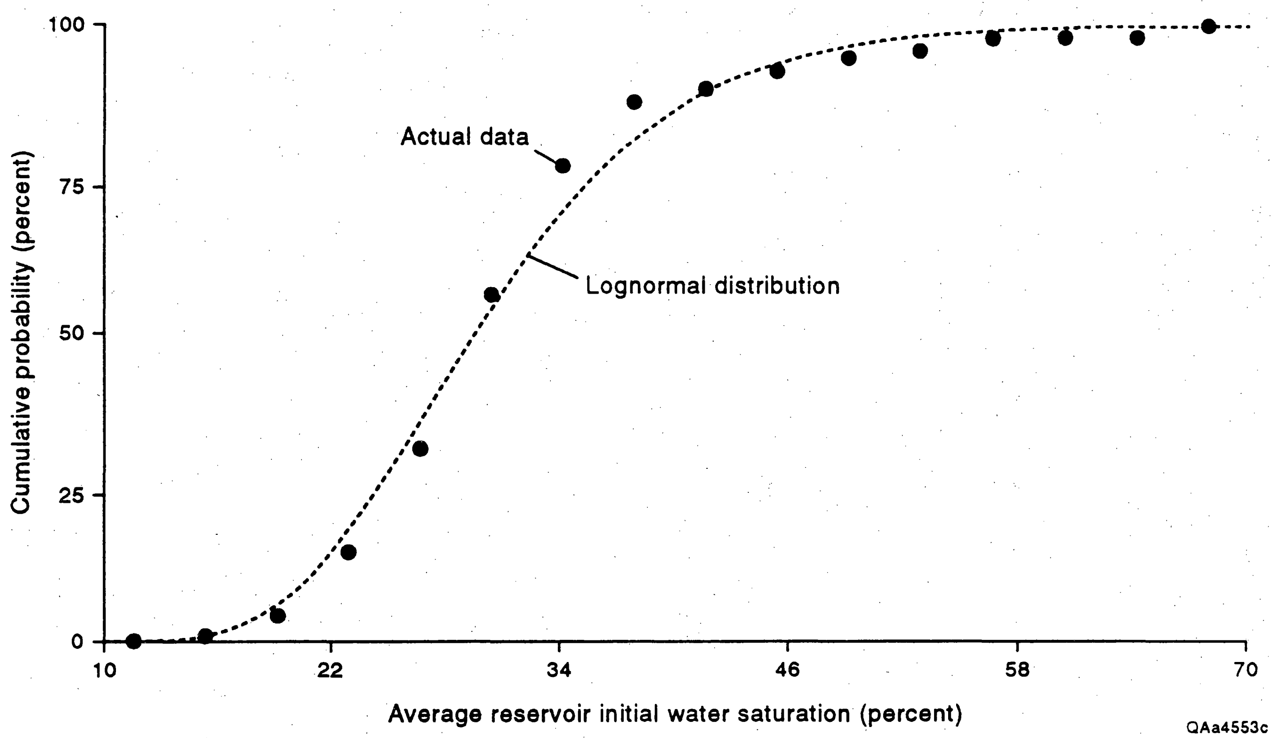

Figure 11. Cumulative probability distribution comparing combined oil and gas reservoir initial water saturation with the lognormal function fit.

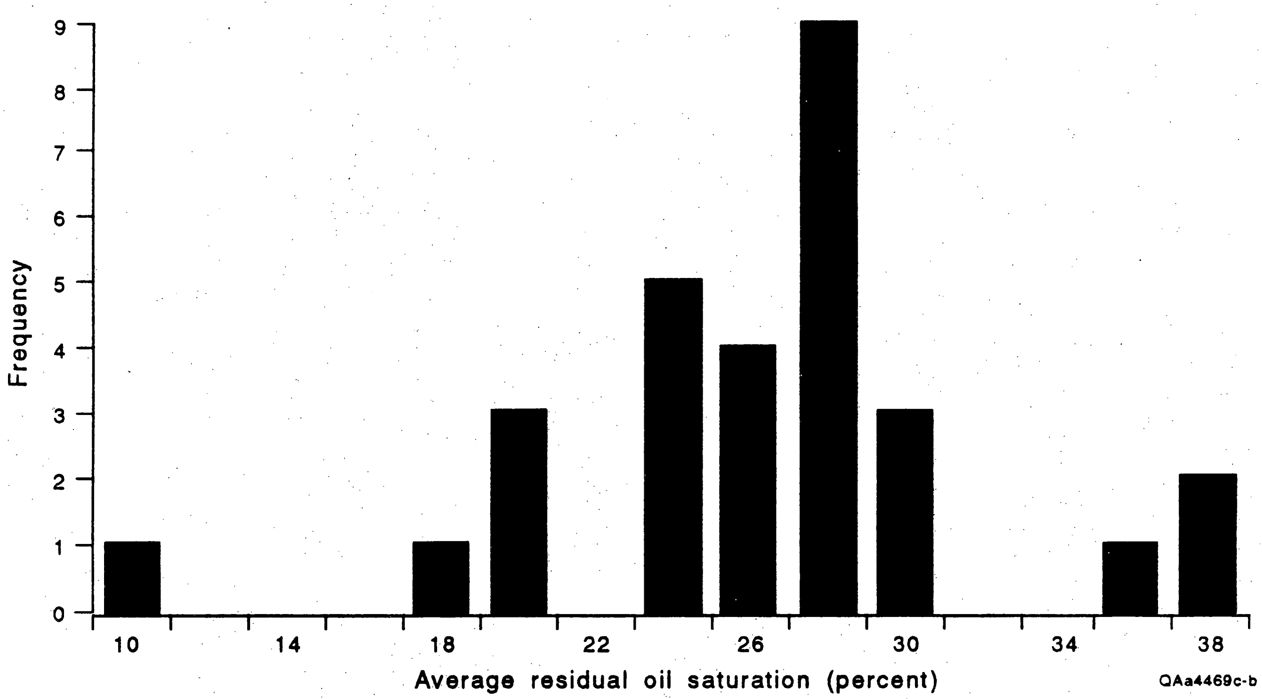

Figure 12. Histogram illustrating distributions for values of reservoir residual oil saturation throughout the play.

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.

Descriptive Probability Functions

The probability distribution of residual oil saturation is best modeled by a logistic or normal probability function. The K-S, A-D, and chi-square tests all point to the logistic probability function as the best choice for modeling residual oil saturation and the normal distribution as the second best. Both functions represent the low values well, the mean values less well, and the larger tail moderately well (fig. 13). The applicability of these functions indicates that residual oil saturation is distributed fairly proportionately around the mean. The equation for applying the logistic model is given when $\alpha = 27.0$ percent and $\beta = 3.22$.

Reservoir Net Pay

Statistical Characteristics

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 2). The F statistic is 0.42, whereas the critical F statistic is 3.88 (table 3), 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.

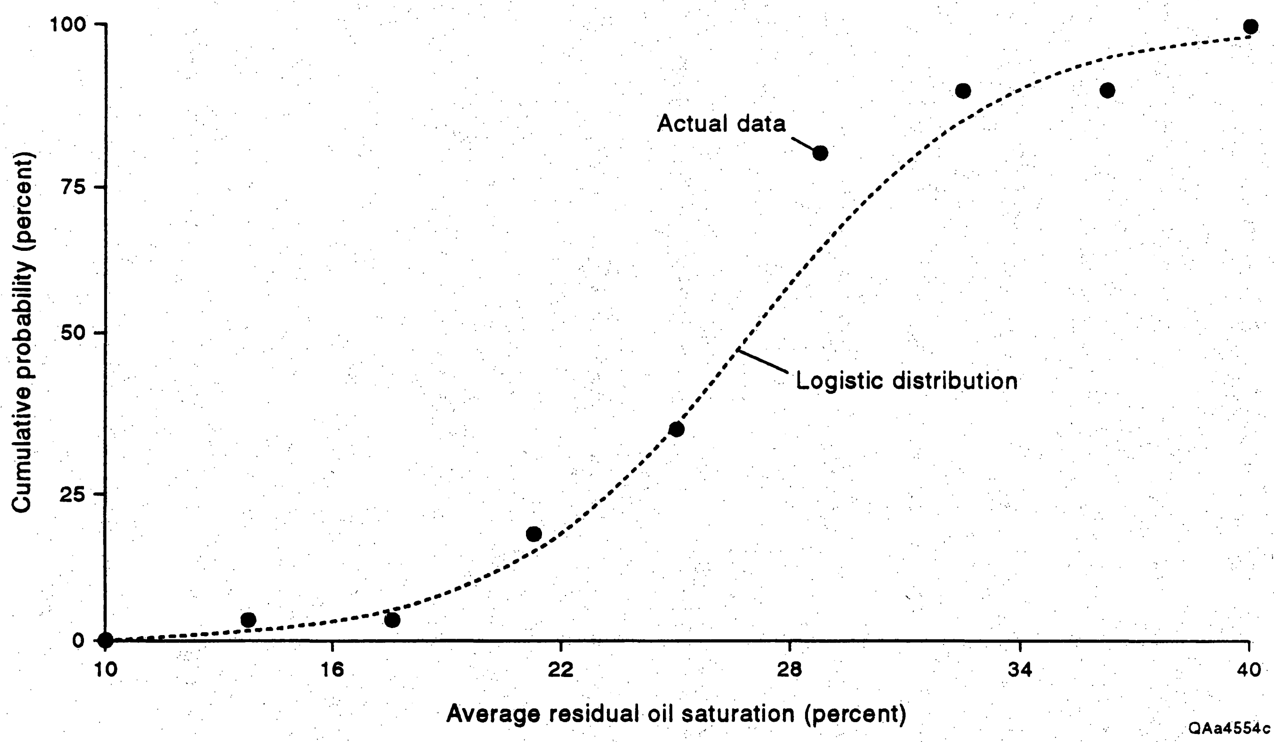

Figure 13. Cumulative probability distribution curves comparing actual reservoir residual oil saturation with a logistic function fit.

Net-pay thicknesses from both oil and gas reservoirs have low variability and are positively skewed, with a high positive kurtosis (fig. 14). A full 85 percent of both oil and gas reservoirs have net-pay values of less than 20 ft, and the median and mode are 10 ft. The large range and standard deviation are due to a long tail created by the presence 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 thickness 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 permeabilities have the possibility of thicker net pay (table 2). 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 weakly positive covariant relationship (correlation coefficient of 0.44) with reservoir area. 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 because the greater mobility of gas allows less permeable rocks to be produced.

Descriptive Probability Functions

A lognormal probability density function best describes the distribution of net-pay values for oil, gas, or combined-data sets. The K-S and A-D tests rank the lognormal function as the superior model for oil, gas, and combined-data sets. Even when the few thick reservoirs are

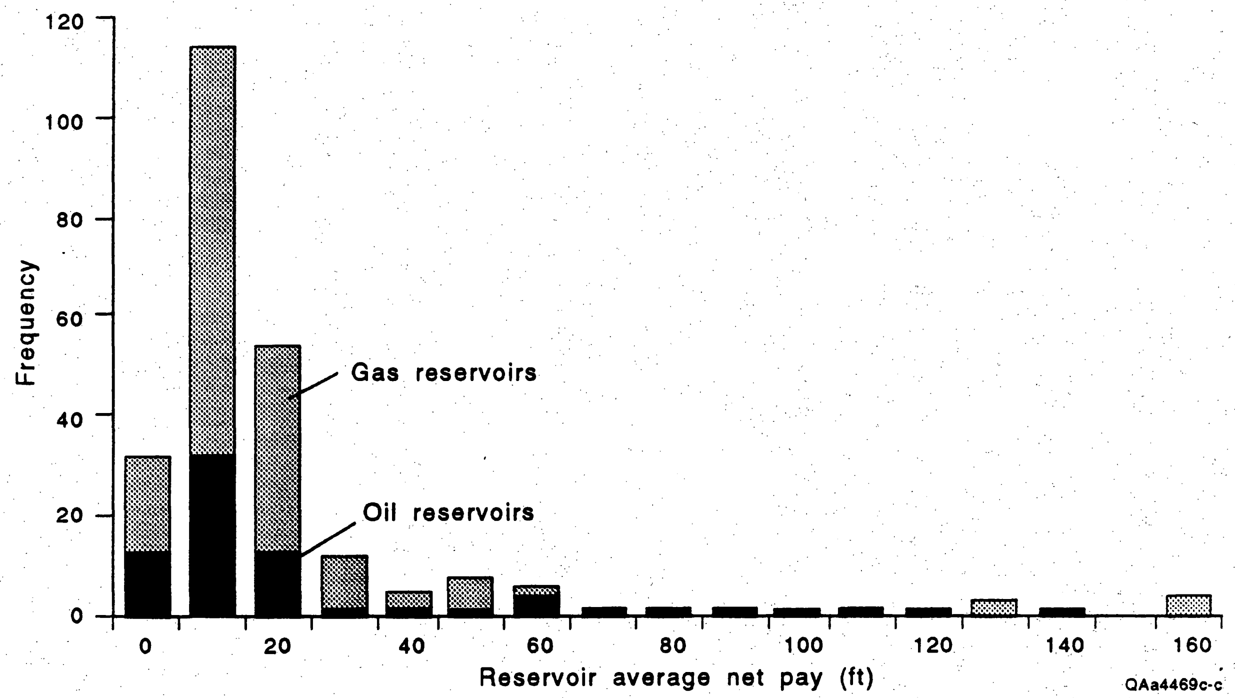

Figure 14. Histogram illustrating distributions for values of reservoir net pay throughout the play.

treated as outliers and are removed, these two tests still indicate the lognormal as the best model. The lognormal function fits the data best at the tails for the oil reservoirs and deviates slightly around the mean (fig. 15). Gas reservoirs and the combined-data sets consistently display a good fit with the lognormal function. For oil reservoirs the lognormal can be applied when $\mu = 19.69$ and $\sigma = 16.37$, gas reservoirs when $\mu = 20.72$ and $\sigma = 15.48$, and the combined-data set when $\mu = 20.63$ and $\sigma = 16.54$. The gamma function is an option that can be used instead of the lognormal function. The chi-square function consistently ranked the gamma function as a better fit to the oil, gas, and combined-data sets. However, the gamma function has discontinuity problems at the tail of large values and is therefore a poor model at these higher values.

Reservoir Area

Statistical Characteristics

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 2). ANOVA demonstrates that the difference between the means is statistically significant, having a generated F statistic value of 4.24 and a critical F value of 3.92 (table 3). 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 (fig. 16).

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 (table 2). 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

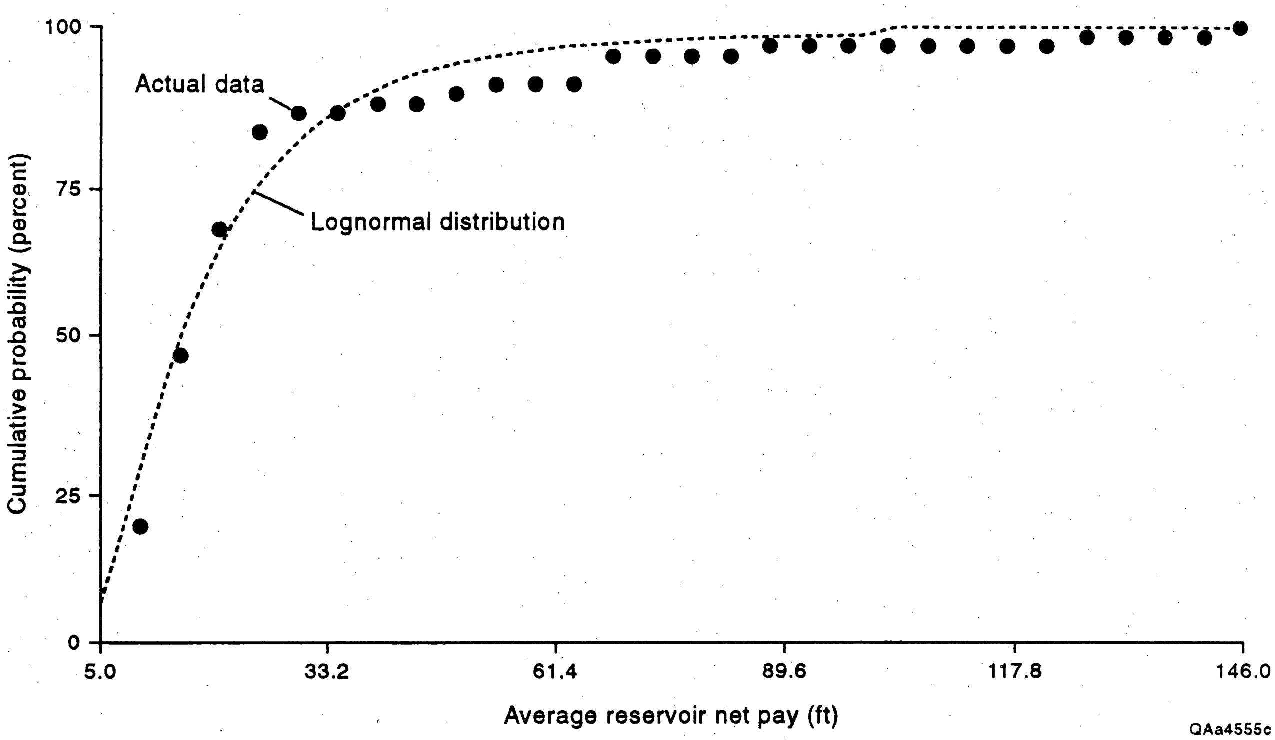

Figure 15. Cumulative probability distribution comparing actual reservoir net-pay values with a lognormal function fit.

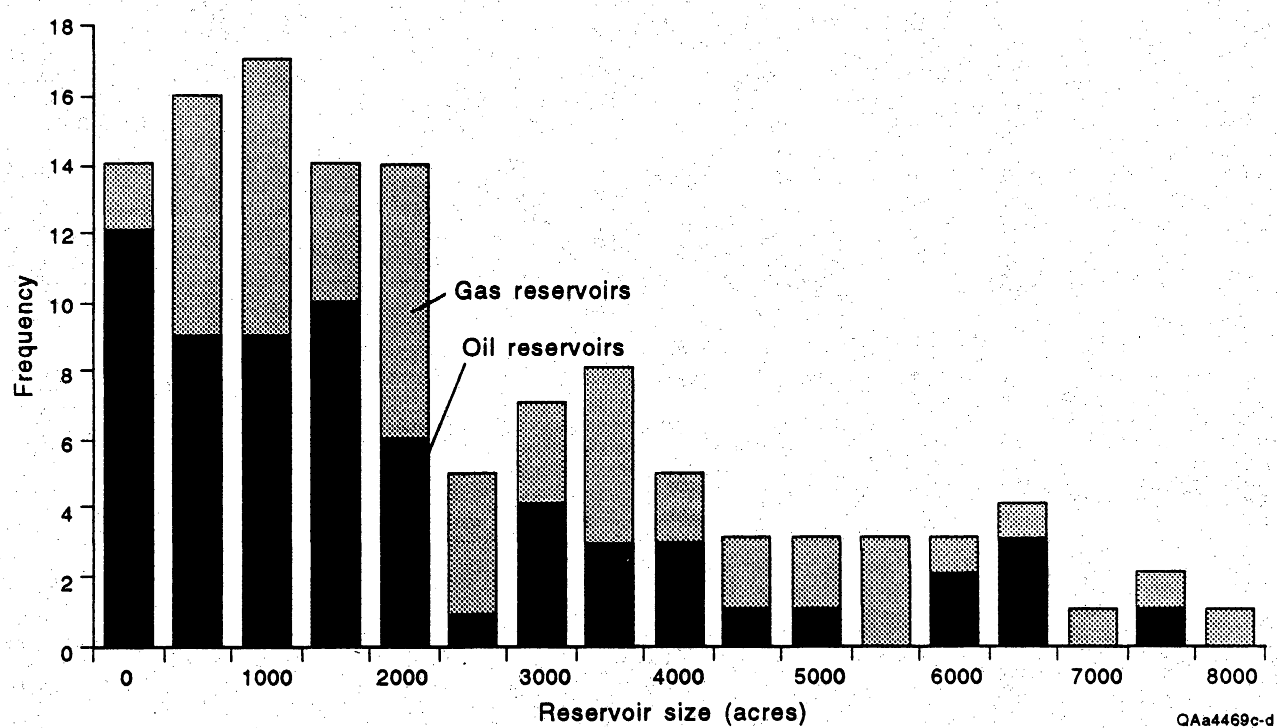

Figure 16. Histogram illustrating distributions for values of reservoir area throughout the play.

skewed. Oil reservoirs display little kurtosis, whereas gas reservoirs are highly kurtosic (table 2). The greatest overall difference between the two groups is caused by the presence of only a few large gas reservoirs.

Descriptive Probability Functions

The probability distribution of reservoir size is best modeled by a lognormal function, with the exponential function as a good second option. Both the K-S and A-D statistical tests indicate that the lognormal function is a good fitting probability density function for gas, oil, and the combined-data set. The lognormal function fit the oil and gas reservoir density distributions very well except for the extreme tail of the large values (fig. 17). For oil reservoirs the lognormal can be applied when $\mu = 2{,}580$ and $\sigma = 3{,}290$, for gas reservoirs when $\mu = 2{,}720$ and $\sigma = 3{,}210$, and for the combined-data set when $\mu = 3{,}250$ and $\sigma = 3{,}310$. The exponential function is also a good model according to the K-S and A-D tests. The exponential function is less accurate at the small-value side of the distribution; however, it fits the large-value tail well. These fitting characteristics also hold true for the combined oil and gas reservoirs data set.

Fluid Characteristics

Fluid characteristics are an important influence on the volume and recovery efficiency of oil. Four salient characteristics, including oil gravity, bubble-point pressure, viscosity, and formation volume factor, were analyzed. Interrelationships between these characteristics and with reservoir depth were also tested. Testing for depth relationships is in part a surrogate test for relationships with temperature and pressure and thus provides easily obtainable information.

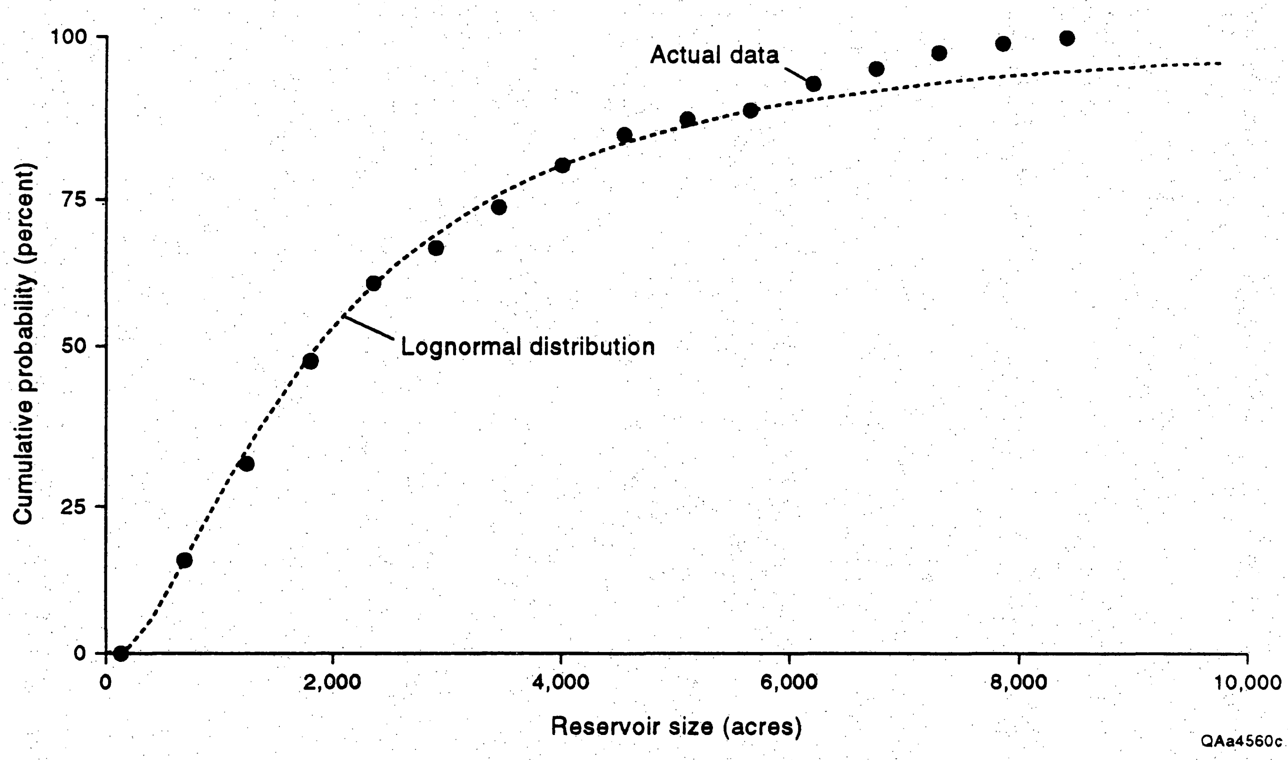

Figure 17. Cumulative probability distribution comparing actual oil and gas reservoir area with a lognormal function fit.

Oil Gravity

Oil in the Frio Fluvial/Deltaic Sandstone play is light in nature. The average gravity is 38.8° API, with a median of 41.3° API and a standard deviation of 7.79. The range is wide (31.5°), with a minimum of 20° API and a maximum of 51.5°; however, the frequency distribution is negatively skewed (-1.2) toward the high side (fig. 18). A slight bimodel distribution is evident because the lower oil gravity is confined mainly to reservoirs of less than 5,000 ft in depth, and the reservoirs between depths of 4,000 and 9,000 ft display higher API values (35° to 51.5°). Although some depth control is evident, no contiguous depth relationship was observed.

Oil Bubble-Point Pressure

Bubble-point pressure (P_b) is easily predictable from reservoir depth and oil gravity. The data for this play range from 1,300 to 3,855 psia, average 2,769 psia, and have a standard deviation of 732 psia. Bubble-point increases with increasing reservoir depth and increases with decreasing oil gravity. Multilinear regression substantiates the relationship between P_b and depth and oil gravity, and together they can be used to predict P_b. The equation below can be applied to calculate P_b . This multilinear regression has a correlation coefficient (r^2) of 0.78 and an F statistic of 26 (critical F is >0.001). These statistical significance tests verify the correlation between P_b, reservoir depth, and oil gravity:

$$P_b = 0.43(\text{reservoir depth}) - 72.0(\text{oil gravity}) + 3{,}212$$

where depth is in feet and oil gravity is in API units.

Oil Viscosity

Oil viscosity displays a moderate bimodel tendency and a weak depth relationship. Viscosity ranges from a minimum of 0.24 centipoise (cp) to a maximum of 1.56 cp, averages 0.41 cp, and has a median of 0.33 cp. The data distribution is positively skewed (3.66) with a

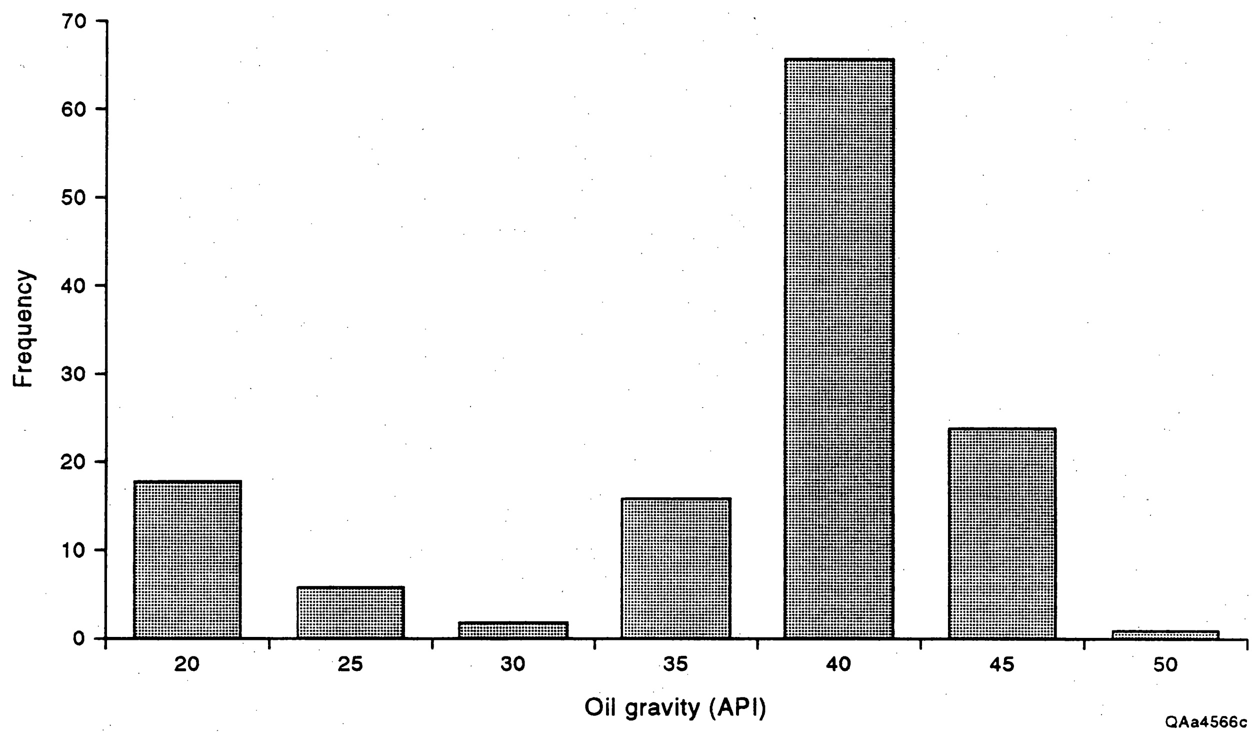

Figure 18. Histogram of oil gravity illustrating the light nature of the oil.

high kurtosis (16.9). The high skewness and kurtosis are due to a grouping of data centered around a 0.3-cp value, whereas the average of 0.41 cp is a result of the combination of this group and a second group centered around a 0.55-cp value (fig. 19). The 0.3-cp group is at a slightly deeper average reservoir depth than the 0.55-cp group, indicating a slight influence of reservoir depth on viscosity.

Oil Formation Volume Factor

Oil formation volume factor (FVF) displays the characteristics of a normal light crude. From the sample reservoirs, FVF ranges from 1.1 to 1.57, averages 1.37, and has a standard deviation of 0.098 and a median of 1.36. The distribution of data is slightly negatively skewed (–0.36) and displays low kurtosis (0.72), therefore demonstrating a fairly normal distribution type. FVF has a moderate correlation with depth and a weak correlation with oil gravity. Together these characteristics can be used to estimate FVF. The equation below is the result of using multilinear regression to predict FVF. The correlation coefficient (r^2) of this equation is low (0.31); however, the F statistic is 10.3 and the critical F is 0.0002, showing that a significant relationship exists. The error in this equation makes the equation useful only for preliminary analysis, and an operator should obtain a fluid sample from a particular lease to use in a final reserve analysis.

$$\mathrm{FVF} = 4.35 \times 10^{-5}(\mathrm{depth}) + 2.9 \times 10^{-3}\,(\mathrm{gravity}) + 0.99$$

where depth is in feet and oil gravity is in API units.

RESERVOIR VOLUME CHARACTERISTICS

Characterization of oil resources was built upon probability functions found to best describe the individual reservoir attributes. The probability density functions that best describe each of the reservoir attributes are very similar between oil, gas, and combined-reservoir data

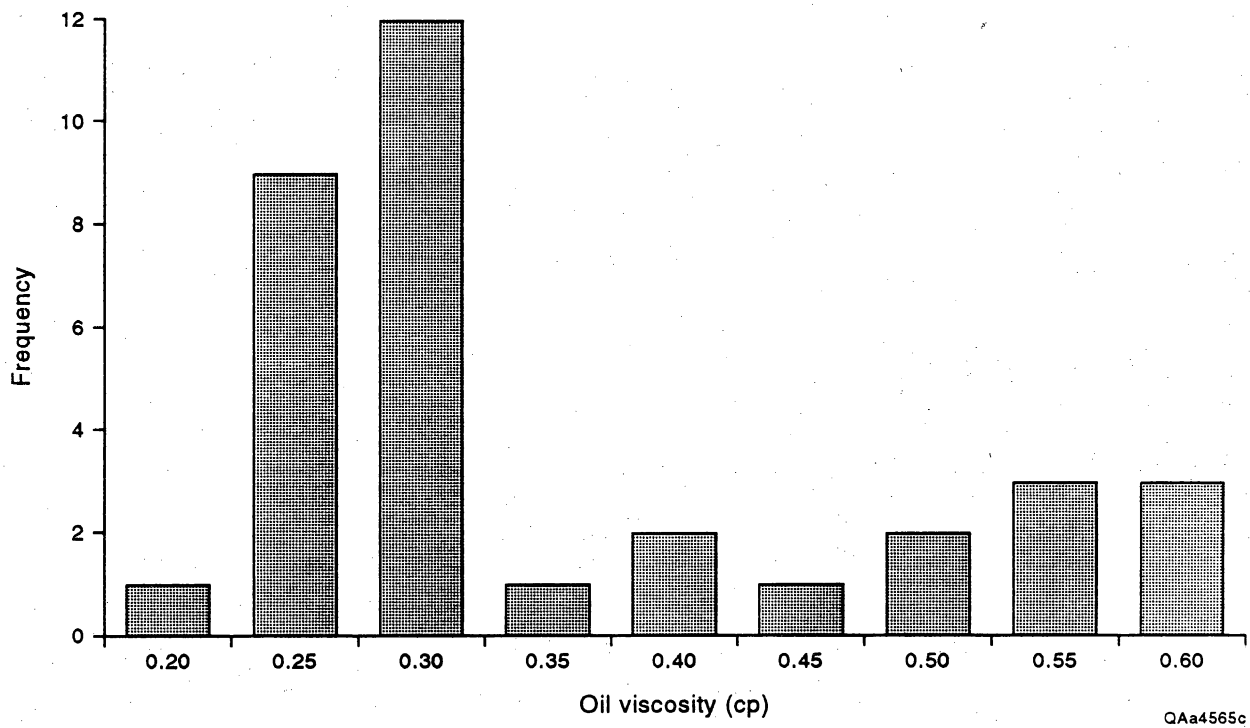

Figure 19. Histogram of oil viscosity illustrating the bimodel distribution.

groupings (table 4). This similarity, along with the ANOVA results and the similarity in the statistical central tendency measurements, signifies that either the oil reservoir data set or the combined-data set characterizes the reservoir parameter variability. Only reservoir acreage displayed any difference. Therefore, the combined-attribute distributions were used in stochastic simulations to develop oil-in-place probability distributions on a per-acre basis. These distributions characterize the oil resource probability of occurrence and are used in assessing the potential for incompletely drained and untapped oil.

Original Oil in Place per Acre

Simulation Results

Original oil in place per acre displays limited variability. The coefficient of variation is 0.83, low in comparison to original mobile or residual oil volumes per acre. There is a 90-percent probability that at least 8,000 STB/acre lie within a reservoir and up to 52,900 STB/acre may exist at a 10-percent probability. The range between 90- and 10-percent probability is 44,900 STB, whereas the range between the upper and lower quartiles is only 21,000 STB. The probability of occurrence is skewed to the low side and displays high positive kurtosis, which also indicates less variability. The median is 20,400 STB, much lower than the mean at 27,104 STB. Because of the skewness, the median is a more representative measure of central tendency.

The simulation results for the two cases, one using oil reservoir data and the other using combined oil and gas data sets, are very similar. The coefficient of variation difference is only 0.01. The 90-percent probability value for the combined-data set is 8,336 STB, which is only 4 percent different from the value for oil-only reservoirs. Median values are also nearly equal, having only a 5-percent difference. At 10-percent probability, the difference is only 1 percent. In addition, both display high positive skewness and kurtosis, illustrating the similarity of

Table 4. Summary of the best probability density functions for modeling the reservoir engineering parameters.

Attribute	Best function	Alternative functions
Porosity		
Oil reservoirs	Normal	Gamma or logistic
Gas reservoirs	Logistic	Gamma
Combined	Logistic	Gamma
Initial water saturation		
Oil reservoirs	Beta	Gamma
Gas reservoirs	Beta	Chi square
Combined	Lognormal	Beta
Residual oil saturation		
Oil reservoirs	Logistic	Normal
Net pay		
Oil reservoirs	Lognormal	Gamma
Gas reservoirs	Lognormal	Gamma
Combined	Lognormal	Gamma
Reservoir area		
Oil reservoirs	Lognormal	Exponential
Gas reservoirs	Lognormal	Exponential
Combined	Lognormal	Exponential

reservoir attributes and reservoir volume characteristics in the two data sets and allowing the volumetric characteristics to be used interchangeably.

Best Fitting Probability Functions for Volume Distributions

The Weibull probability function best models the variability in original oil in place for both the oil reservoir and combined oil and gas reservoir data sets. The K-S test indicates that the Weibull function best represents the combined-data set and is the second-best fitting function for the oil reservoirs. The K-S test indicates that the exponential function best models the oil reservoirs and is the second-best model for the combined-data set. However, because the exponential function is a specific solution for the Weibull function, the Weibull is a more general solution and therefore the best model. The Weibull function fits the actual simulation data best at both tails of the distribution. The Weibull equation, where $\alpha = 1.61$ and $\beta = 24{,}500$, represents the combined-data model (fig. 20).

Residual Oil per Acre

Simulation Results

Residual oil saturation per acre is the smallest, most variable, and most skewed of the three volumetric components. Simulation results produce a probability distribution that has a coefficient of variation of 0.89, a mean of 10,507 bbl, and a standard deviation of 9,359 bbl. The coefficient of variation, which is a dimensionless variation indicator, is larger than the original oil in place or original mobile oil in place values. A 7.5-fold variation exists between the 90- and 10-percent probabilities, and a 2.8-fold variation exists between the upper and lower quartile. This variation is higher than the total oil in place variation. The simulation results produce a positively skewed (2.97) distribution with high kurtosis (18.25), demonstrating that the probability of occurrence is on the low side.

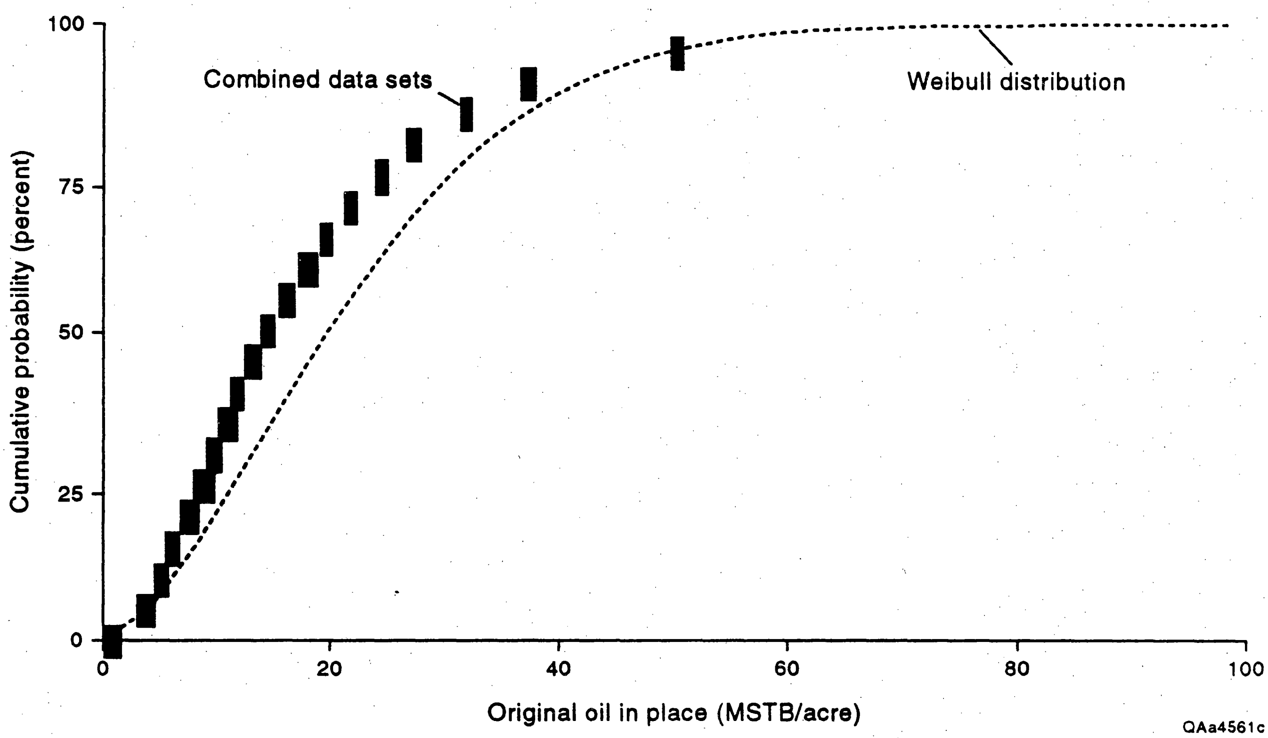

Figure 20. Cumulative probability distribution illustrating the Weibull probability function as the model for the variation of original oil in place per acre.

Best Fitting Probability Functions for Volume Distributions

The beta and exponential functions were found to best represent the probability distribution of residual oil. The K-S test ranked the beta function as the best fitting and the exponential function as a very close second. The chi-square test ranked the exponential function as the best choice and the beta function as a poor choice. Visual inspection revealed that the exponential function overestimated the probability at low values and underestimated probability at high values. Within the statistical tests, the overestimation cancels out the underestimation, giving the perception of an overall superior fit to the beta function. However, the beta function more closely resembles the shape of the simulation data. A good representation of the probability of residual oil volume (fig. 21) is the beta function, written as beta (1.66,17.35) × 79,500 + 474.

Original Mobile Oil per Acre

Simulation Results

Original mobile oil in place is slightly less variable and less skewed than residual oil probability. The mean original mobile oil in place is 16,596 bbl/acre and a standard deviation is 14,203 bbl from simulation results. Variation measures show a coefficient of variation of 0.86 and an approximate three-fold variation between the upper and lower quartile. These variation indicators illustrate that variation of original mobile oil in place is less than that of residual oil volumes. Skewness is 2.60, less than the residual oil value, and kurtosis is 13, also less than the residual oil volume distribution. Because the original mobile oil in place is less variable, less risk is associated with the calculated primary and secondary resource volumes than with the calculated tertiary volumes.

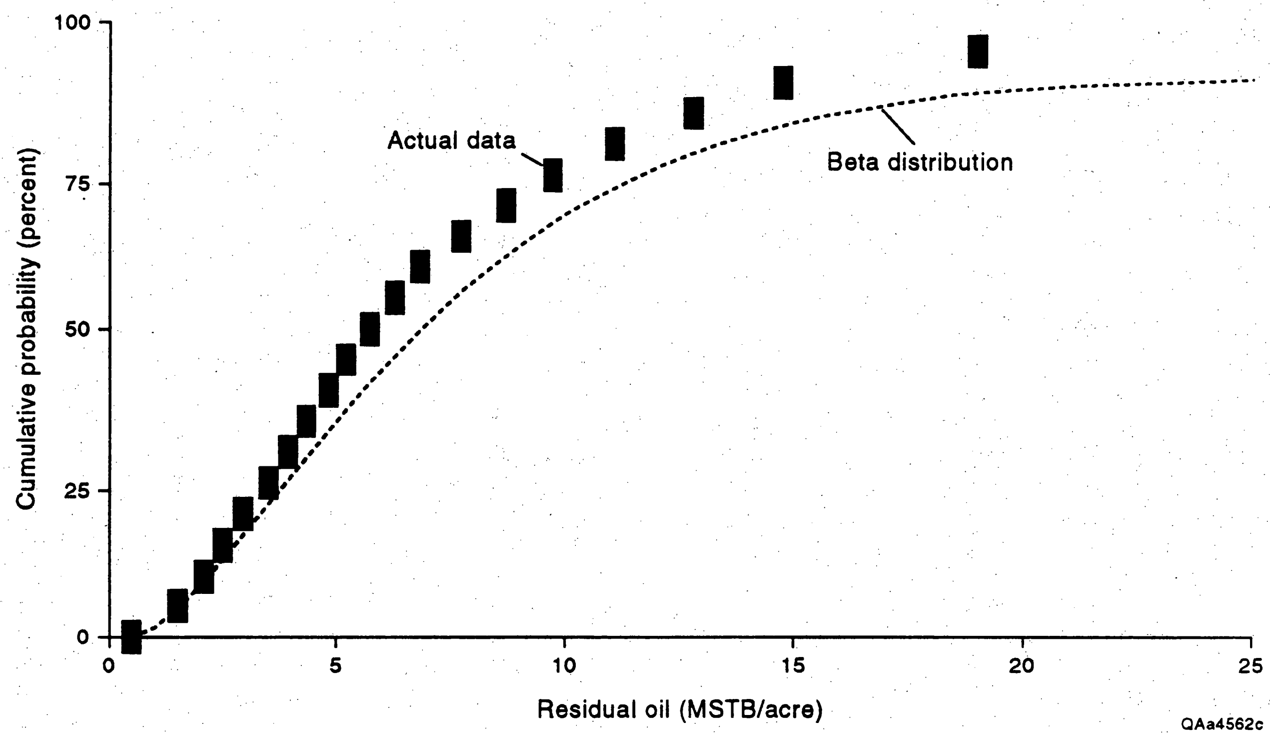

Figure 21. Cumulative probability distribution comparing actual simulation results of residual oil with a best fit beta function model.

Best Fitting Probability Functions for Volume Distributions

The original mobile oil in place is best modeled by a Weibull or exponential probability function. The K-S test ranks the exponential and Weibull identically as being most reliable in predicting the simulation distribution. Lognormal and logistic functions are the next-best fitting functions, respectively. The chi-square test ranks the Weibull as the best fitting function and the exponential as also a very good fit. Visual inspection points to the Weibull function as the best for the probability distribution pattern. The exponential function overestimates the low-end values and underestimates the high-end probability values. The Weibull probability function that best models original mobile oil in place is given by α = 1.64 and β = 16,400 (fig. 22).

Current Reserve Characteristics

Reserve probability characteristics are readily definable because the Frio Fluvial/Deltaic Sandstone is very mature. Currently, 61 percent of the discovered reservoirs have been abandoned. The reservoirs still producing contributed only 0.1 percent of the cumulative production in 1991, and 50 percent of that annual production came from one reservoir. Therefore, the current cumulative production values can be considered as representing the ultimate reserve character of this play.

The distribution of ultimate reserves displays a large number of small-volume reservoirs and a small number of large-volume reservoirs. The average of 5,383 STB is much higher than the median of 2,588 STB. The standard deviation of 8,205 is high, and the coefficient of variation of 1.52 is also high. These high measures of variability are due to the wide range of values (45,597 STB). Although the range is high, the distribution is highly positively skewed (3.47) and highly kurtosic (12.75), indicating a higher probability for smaller volume reservoirs. Figure 23 illustrates the frequency of reserve size and shows the strong tendency toward small reservoirs.

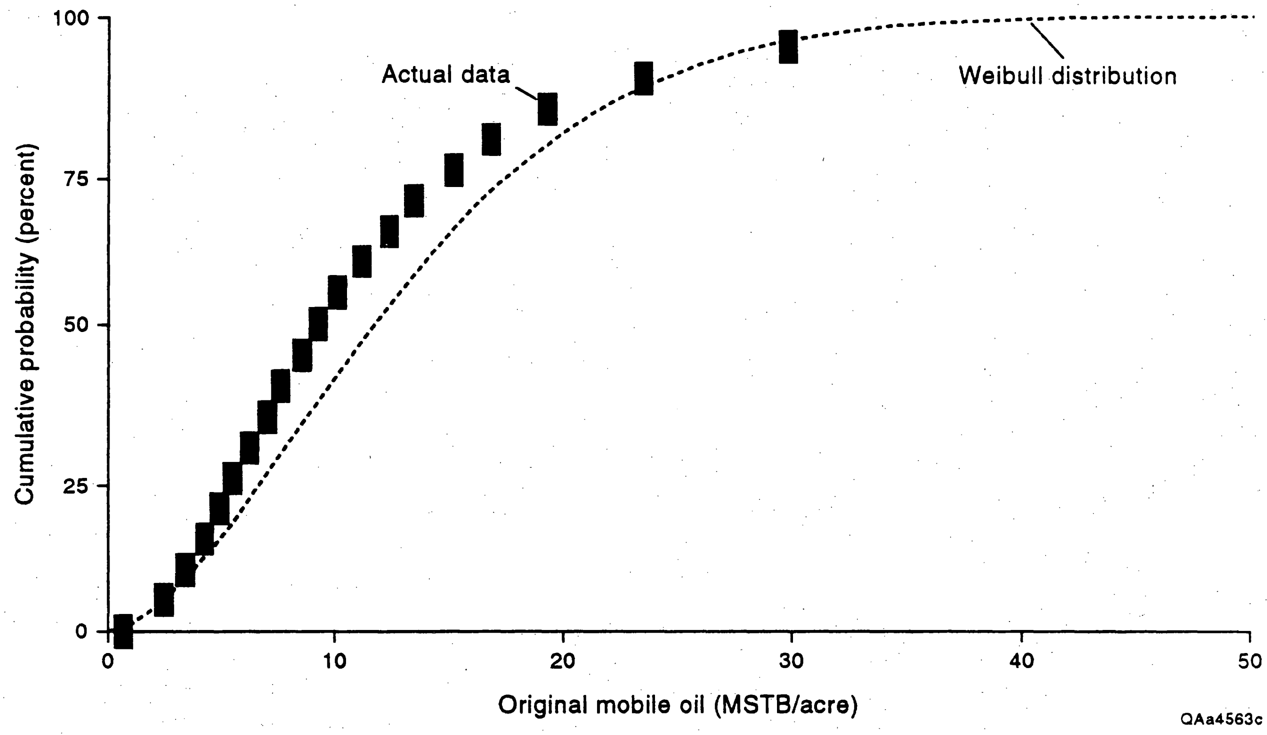

Figure 22. Cumulative probability distribution of original mobile oil in place per acre comparing actual simulation results with the Weibull function model.

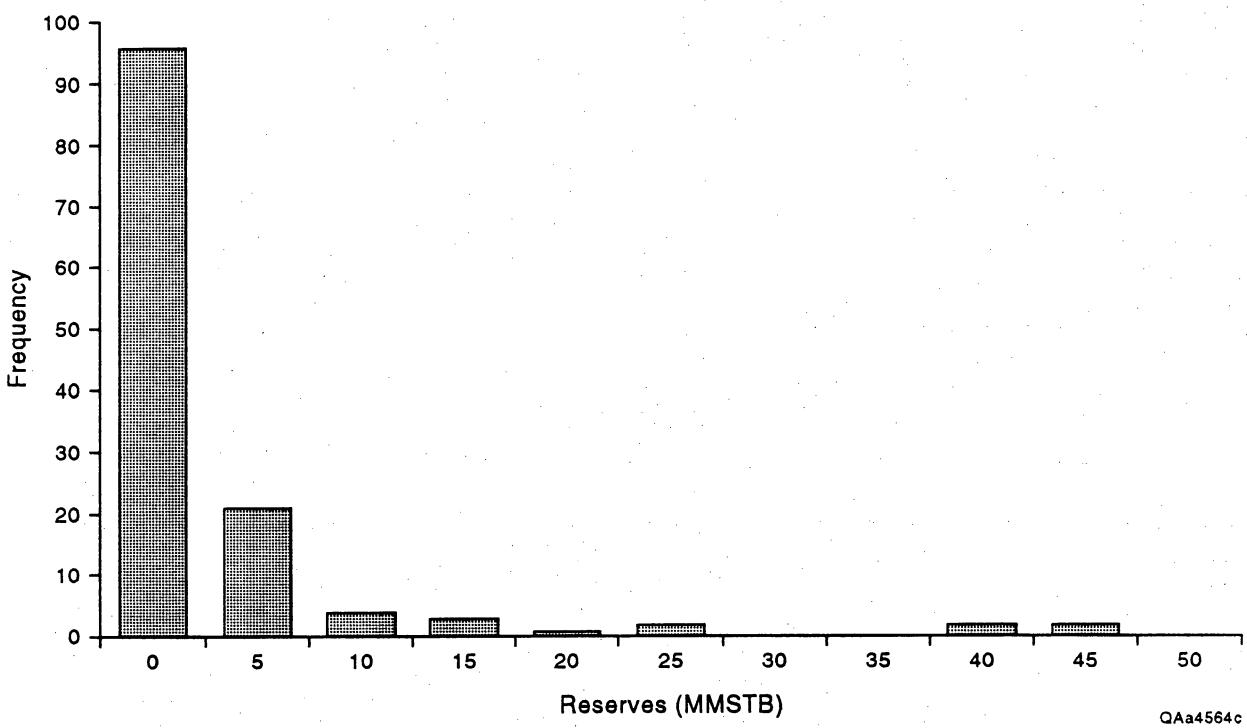

Figure 23. Histogram of ultimate reserves illustrating tendency of most reservoirs to contain small reserves.

A Pareto probability distribution function best models the probability of reservoir reserves, in contrast to traditionally assumed lognormal distribution. The chi-square test indicates that the Pareto is the best fitting function, with gamma, lognormal, and Weibull functions being slightly poorer. The K-S test indicates that the lognormal and Weibull are better fitting functions. However, visual inspection shows that the lognormal function fits poorer for the low values and has a discontinuity at the larger values, and the Weibull function fits poorly at the low-end values. The Pareto function model is given when $\alpha = 1.01$ and $\beta = 1$. Therefore, when risk adjusting reserves of a Frio fluvial/deltaic property, a Pareto probability function should be applied and the average value will be higher than the most likely value.

PRODUCTION AND DEVELOPMENT 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 (Holtz and others, 1991). Total original oil-in-place estimates, however, are in excess of 4 BSTB, of which 1.6 BSTB are classified as unrecovered mobile oil, and nearly the same amount is attributed to residual oil resources.

The development status of this play is classified as mature to super mature, because most of the major fields in the play were discovered in the late 1930's and early 1940's (fig. 24). Reservoir abandonment rates increased significantly during the time period from 1987 to 1989 (fig. 25). The number of producing wells in the play showed a precipitous decline of over 50 percent during a five-year period, 1974 through 1978. The play has been experiencing a steady decline in both overall production and individual well flow rates throughout the 1980's (fig. 26). 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 MMSTB. Average daily production rates from these wells had declined to 8.9 bbl/d.

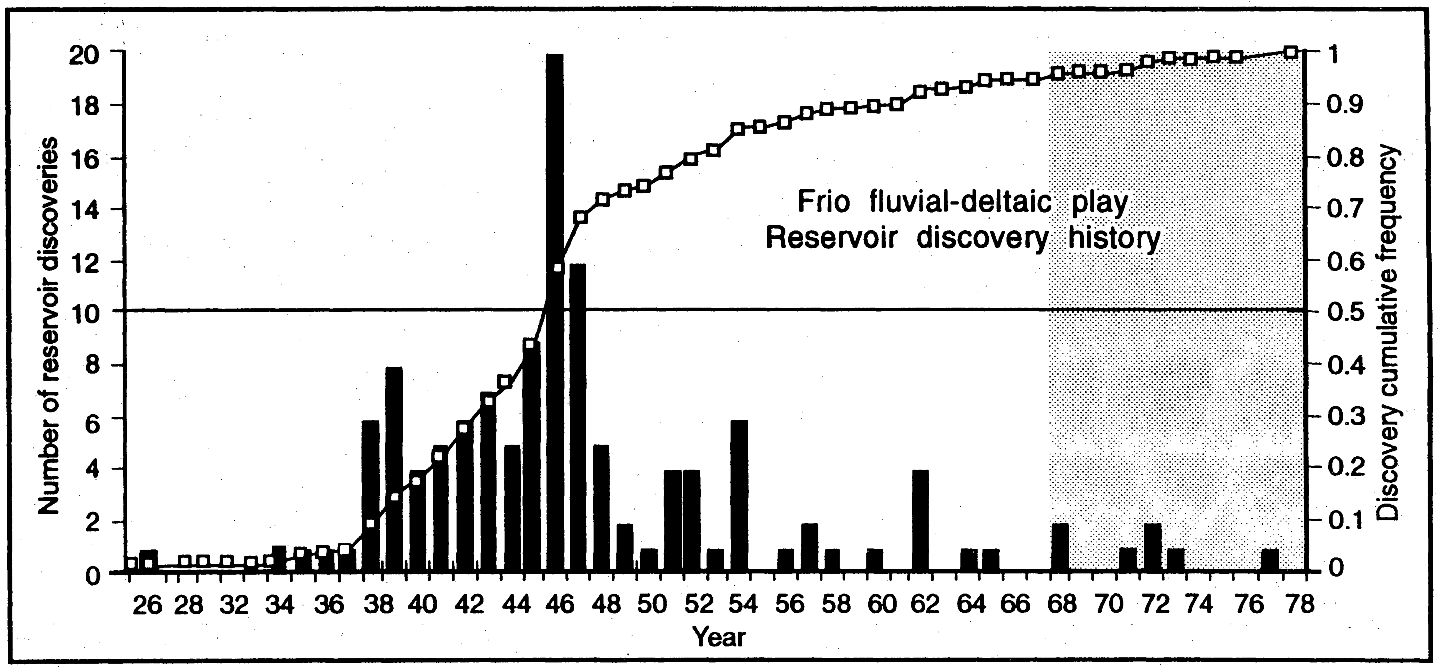

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Figure 24. Histogram illustrating trend in reservoir discovery in the Frio Fluvial/Deltaic Sandstone play.

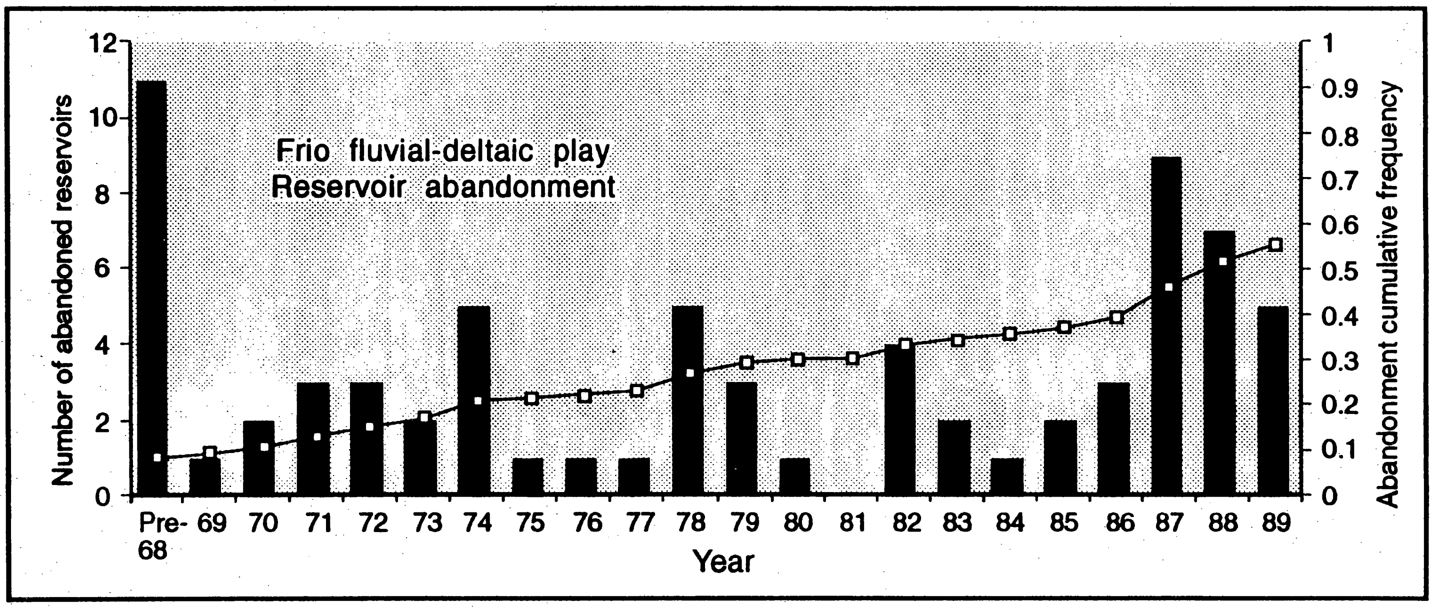

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Figure 25. Histogram illustrating trend in reservoir abandonment in the Frio Fluvial/Deltaic Sandstone play. As of 1991, nearly 60 percent of all producing reservoir had been abandoned.

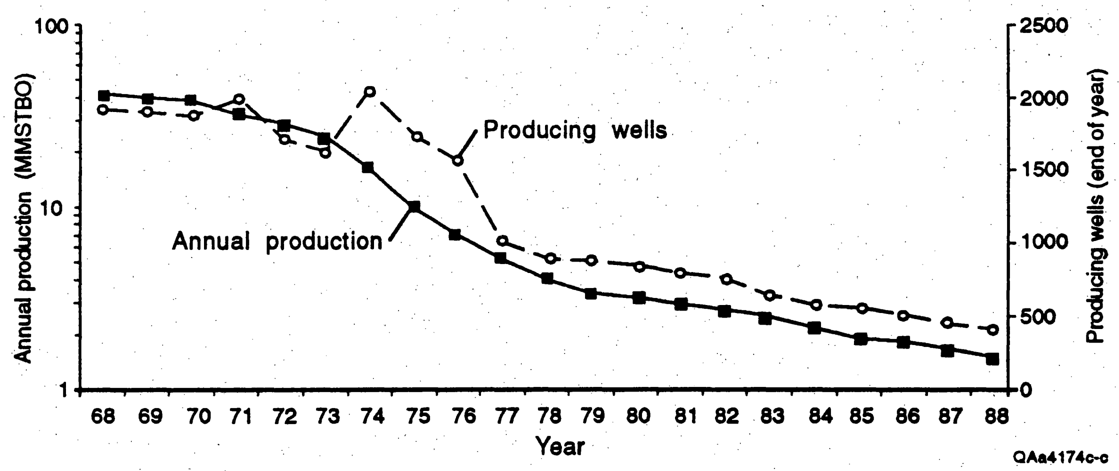

Figure 26. Histogram illustrating trend of decline in annual production in the Frio Fluvial/Deltaic Sandstone play since 1968.

Oil and natural gas reservoirs produce from the same stratigraphic interval. The 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.

POTENTIAL FOR RESERVE GROWTH

The 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 both the location and volume of the remaining resource in the reservoir. The best approach toward incremental recovery in heterogeneous fluvial/deltaic reservoirs is one that integrates geological facies models with engineering assessments of reservoir behavior and production histories.

Reserve growth assessment within the Frio Fluvial/Deltaic Sandstone play in South Texas focused on estimating oil volumes that either have been incompletely drained or have remained untapped. Both assessments were based on the statistical characteristics of reservoir volumes. Analysis of incompletely drained reservoirs was based on a risk-adjusted total resource for the entire Frio Fluvial/Deltaic Sandstone play. Probability distributions generated for remaining oil volumes suggest a possible range of estimates for the incompletely drained resource remaining in the play as a whole. The untapped resource potential is less well defined because it is based on speculation of oil volumes not proven by production. However, because of the large number of individual sand bodies, significant volumes may remain. The statistical probability of the occurrence was used, together with the volumetric probability, to assess the untapped resource.

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 (fig. 27). 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 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. A 95-percent probability exists that at least 1.5 BSTB of remaining mobile oil lies within this play, and a 5-percent probability exists that as much as 2.7 BSTB may still reside in these reservoirs (fig. 27). This large volume of remaining mobile oil represents the upside potential for the incompletely drained oil resource.

Untapped Oil Potential

The untapped resource potential of sand bodies 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 reservoir sand 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 probability distribution of original oil in place per acre and the size distribution of an individual sand or reservoir for the play. Original oil in place per acre was modeled by the Weibull equation, where $\alpha = 1.6$ and $\beta = 24{,}500$. The areal extent of a reservoir sand was modeled using the distribution of reservoir sands in Rincon field. An exponential fit (β value of 651) was found to best model the variability of the sand area.

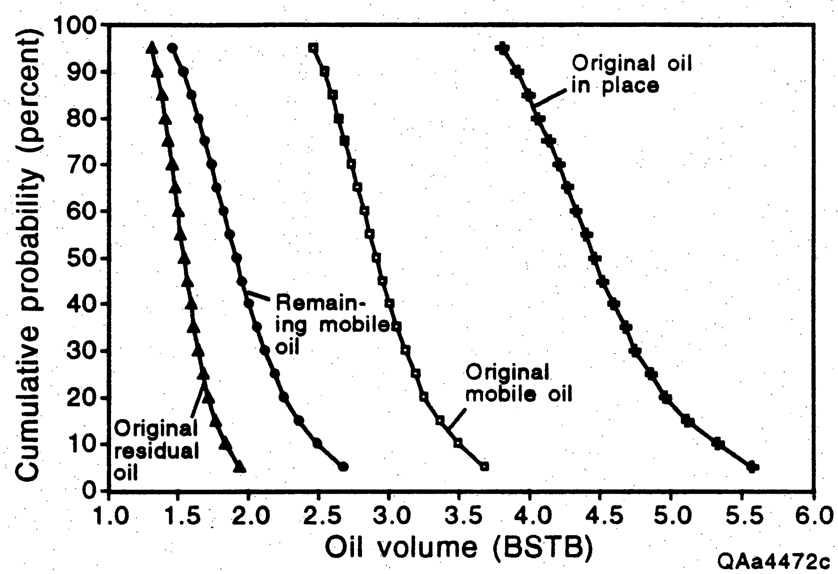

Figure 27. Probability distribution curves illustrating the cumulative probability of original oil in place, original residual oil, original mobile oil, and remaining mobile oil for the Frio Fluvial/Deltaic Sandstone play.

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 above and below by thick shales 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, occurrence of sand units within a pay zone, and original oil in place per acre distributions to generate an estimate of overall probability of untapped oil as a percentage of original oil in place within a field. At a 90-percent probability, 10 percent of the original oil in place is untapped; at a 10-percent probability, 37 percent of the original oil in place represents the untapped resource (fig. 28). This distribution is fairly normally distributed, having 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 untapped reservoir compartments.

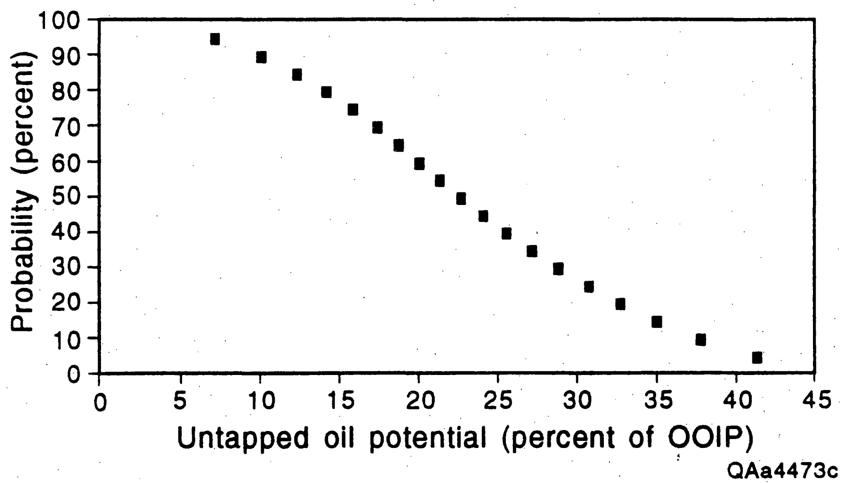

Figure 28. Modeled cumulative probability distribution curve illustrating potential of untapped oil in reservoirs within the Frio Fluvial/Deltaic Sandstone play.

CONCLUSIONS

The reservoir attributes that delineate in-place hydrocarbon volumes should be modeled by different probability functions. The functions that best describe attribute variability include the gamma, exponential, beta, logistic, and lognormal functions. Variability in porosity is best modeled by logistic or gamma functions. Initial water saturation is best modeled by the beta function. Residual oil saturation is best modeled by the logistic function. Net pay and reservoir area are best modeled by lognormal, gamma, or exponential probability functions. Each reservoir attribute can be estimated in risk-adjusted reservoir volumetric calculations by applying the best fitting probability function.

Statistical analysis indicates that Frio oil and gas reservoirs within the Vicksburg fault trend have similar reservoirs attributes and therefore are part of the same reservoir population. ANOVA testing showed that the oil reservoir attributes have means that are not statistically different from those of gas reservoirs. Oil and gas reservoir attributes can therefore be modeled by similar probability functions. The statistical similarity of Frio oil and gas reservoirs suggests their geologic equivalence and supports using the data from both reservoir groups for a more complete analysis of the play as a whole.

Traditionally a lognormal probability distribution has been used to describe the character of reserves and original oil in place. Our analysis, however, generated results to the contrary. A Weibull probability function best describes the distribution for original oil in place and original mobile oil in place. A beta or exponential distribution is the best model for original residual oil in place, and reserve probability is best modeled by a Pareto distribution. Because the exponential probability function is a specific solution for the more general Weibull function, the Weibull function is very powerful for modeling original in-place oil volumes. Importantly, when risk adjusting the in-place oil volumes for reservoirs in this play, a more accurate picture can be obtained by applying the Weibull function.

The probability model for original oil in place is different from the model of ultimate recovery (actual total reservoir reserves). The original oil in place is best modeled by a Weibull probability function, whereas the actual reservoir reserves are best modeled by a Pareto function. If the ultimate production is a direct linear function of the reservoir original oil in place, both should have the same probability distribution. Economic influences are inducing this discrepancy. Because of the economy of scale and the ownership of large reservoirs by major oil companies, these reservoirs have traditionally had higher recovery efficiencies. With the ownership of Texas reservoirs moving from the majors to smaller companies, the inequity of recovery may change.

Significant volumes of oil are present for reserve growth in incompletely drained reservoirs and reservoirs that are untapped. Frio oil reservoirs contain a conservative estimate of 1.2 BSTB of remaining mobile oil and 1.5 BSTB of residual oil. These volumes reside in incompletely drained reservoirs. Statistical modeling of untapped oil resource indicates that a conservative estimate of 10 percent of the original oil in place is untapped and thus will remain unproduced. Together these two targets are a substantial volume of oil for redevelopment and reexploration.

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