NEW OIL IN OLD PLACES

by

Robert M. Sneider and John S. Sneider
Sneider Exploration Company Inc.
Houston, Texas

for the

Pratt II Conference
"Petroleum Provinces of the 21st Century"
San Diego, California
January 12-15, 2000

NEW OIL IN OLD PLACES

ABSTRACT

Large reserves are present and economically recoverable in many mature oil fields. Small multidisciplinary teams studied several basins in North America and a few large fields in South America searching for large volumes of low risk reserves in poorly performing fields. The fields studied include those producing by primary recovery with or without secondary recovery potential, and fields undergoing waterflooding. In the United States over 350 mature oil fields were examined from 1981 – 1997 looking for fields to purchase. The majority of the fields were in the USA Permian basin of West Texas/New Mexico and in a coastal portion of the Gulf of Mexico basin. Some large fields were studied for the property owners to rejuvenate or increase production.

Finding large volumes of low risk, presently non-producing reserves within fields involves several steps. First, the teams search in reservoir systems that appear more massive and homogeneous than they are. Second, the geoscience and engineering data is scanned to estimate original oil-in-place, percent recovery, and bypassed reserves. Third, the teams make an economic analysis including improvement costs. Candidate fields for purchase all have new low to moderate risk reserves amounting to at least 5% of the cumulative reserves already produced.

New reserves are found or exploited by applying one or more of the following: (1) improved drilling/completion technology, (2) identification of by-passed pay, especially very low resistivity pay, (3) new 2D and 3D seismic, and (4) sequence stratigraphic concepts. Additional reserves are found in both land-derived clastic and carbonate reservoirs in mature fields.

Forty-six mature fields were purchased in the Permian basin of Texas/New Mexico and in the Gulf of Mexico basin. In the fields purchased, 625 x 10^6 barrels of oil equivalent (BOE) of proved and probable reservoirs were added at a cost of US$ 2.69 per BOE. The average after tax rate of return of the 46 fields is 21 percent.

INTRODUCTION

Exploration is essential to increase hydrocarbon reserves worldwide. Exploration is high risk, high cost and production is highly taxed in many areas. Also the time between discovery and first production can be several years and the size of the reserves discovered is decreasing in many basins. In spite of these hurdles, exploration is critical to finding new hydrocarbons. Another source of increased reserves can be within or adjacent to existing fields, especially in reservoirs producing by depletion or a weak waterdrive. Recoverable reserves in these kinds of fields may be only 12 to 30 percent of the original oil-in-place. In United State basins, except in the deep-water offshore Gulf of Mexico basin, most reserve additions in the recent past are from mature fields. Nehring (1995) showed that in the United States from 1983 to 1992 about 85 percent or 20 billion barrels of proved oil reserve additions were from old fields.

Is there good potential for adding reserves in old fields in mature basins? Our answer is “yes”. The application of new exploration and production technology together with established oil field practices is the driving force behind finding new oil in old places.

This paper presents four examples of reserve additions from mature fields. One example is a revitalized, originally failed waterflood in dolomite reservoirs. The second example shows added reserves in sandstones by applying good engineering practices coupled with field extensions defined by new 2D and 3D seismic. The next example is also in sandstones and shows reserve additions from field extensions defined by geological-geophysical-petrophysical engineering studies and supplemental recovery opportunities from an injection of water alternating with gas (WAG) recovery process. The fourth example is in sandstone and carbonate reservoirs and shows significant reserve additions by infill and horizontal wells and field extensions. Reserve additions in all four examples are a direct result of integrated, multidisciplinary teams of geoscientists and engineers focused on finding new reserves in and around mature fields.

BACKGROUND AND APPROACH

In the 1980s industry downturn our small teams of geoscientists and engineers changed their search for hydrocarbons from exploration ventures to property acquisition. The teams searched for mature fields with large undeveloped oil and gas potential that could be produced profitably. The teams looked for fields that (1) could be waterflooded, (2) had waterfloods that were performing poorly, (3) had unrecognized pay in low resistivity reservoir rocks, (4) had unrecognized reservoir compartments because of structural and/or stratigraphic changes, and (5) had unrecognized field extensions that might be defined by new 2D or 3D seismic surveys.

The team worked mainly in the Permian basin of West Texas-New Mexico and in the Texas-Louisiana Gulf of Mexico basin from onshore to shallow water less than 200 feet (Figure 1). In these two basins, over 350 fields were scanned for acquisition candidates. About 80 of these fields met the reserve/profit/technical criteria, and became potential acquisition candidates. Forty-six potential candidates were purchased in competitive bid sales from major oil companies.

Potential field acquisition candidates were identified using geologic criteria or by production comparisons with analogue fields. We search for economically marginal or near marginal fields with heterogeneous reservoirs that (1) are interpreted as more homogeneous and correlatable by the operator, and (2) are composed of multiple stacked reservoir units that contain thin, continuous fluid flow barriers often below well log resolution. The depositional systems we concentrated on are (a) dolomitized tidal flat sequences, (b) oolite tidal bars, (c) mud-rich deltas and (d) turbidites, especially shingled turbidites in front of deltas. In the Gulf of Mexico basin, we also concentrated on structurally complicated fields associated with growth faulting and intermediate to deep-seated salt. These structural styles often contain undrained reservoir compartments due to faults and facies pinchouts that are difficult to identify with well control and older 2-D seismic.

Production performance from analogue fields guides selection of acquisition candidates. Often bids are based on extrapolation and interpretation of production decline curves as in the Type "A" production curve (Figure 2). Most companies will come up with similar field reserves from these curves. In contrast to this approach, we look for acquisition candidates geologically similar to analogue fields that have production performance like Type "B", Type "C" and Type “D” (Figure 2). Production increases come from new wells in undrained reservoir compartments, infill wells, field extensions, workovers/recompletions, installing a waterflood or simply improving surface equipment, water quality and injection profiles in waterflooded fields. The analogue fields serve as a guide for bidding on the acquisition candidates.

The steps to identify acquisition candidate rapidly, define the potential opportunities and arrive at a bid are detailed in Sneider and Sneider (1998).

Briefly the key steps are: First, the team searches in reservoir systems that appear to be more massive and homogeneous than they are. This includes depositional environments that contain very thin vertical and horizontal flow barriers such as tidal flats, tidal bars, mud-rich deltas and turbidites. Completion intervals are compared with the actual reservoir compartments to identify undrained or poorly drained pay intervals. Real or potential “thief zones” in supplemental recovery projects are identified and remedies are applied to eliminate these zones.

Second, the team organizes the geoscience and engineering data to quickly estimate original oil-in-place, percent recovery and remaining reserves. Rapid scans of representative portions of a field identify undrained or poorly drained reserves. The team identifies workovers, recompletions, infill well locations and ”hidden” pays (e.g., difficult to evaluate low resistivity, low contrast pays). The value of reprocessing existing 2D seismic, acquiring new 2D and 3D seismic and the application of sequence stratigraphic concepts is ascertained. This second step identifies potential reserves.

The third step is an economic analysis that includes recovery cost estimates for missed low risk and high risk reserves. This step also includes an analysis of existing facilities such as platforms, active and inactive wellbores, flow lines, facility consolidation and maintenance to improve operating efficiency, and known potential liabilities (e.g., environmental). Experience from known fields, analogue fields, similar to the fields under consideration and from previously purchased fields in the same or similar trends aids in selecting candidates to purchase. From our experiences, candidate fields have identified new low to moderate risk reserves amounting to at least five percent of the cumulative reserves already produced.

An economic analysis of the candidate field is the final evaluation step before preparing and submitting a final offer. This analysis is based on a cash flow projection and rate of return. The economic analysis includes cost estimates to recover the missed low risk and high risk reserves, the cost of upgrading existing facilities such as maintenance to improve operating efficiency, and known and potential liabilities including abandonment costs. The identification of acquisition candidates is an iterative process conducted by teams composed of geologists, geophysicists, petrophysicists, reservoir engineers, operations and field engineers assisted by lawyers and negotiators.

After purchasing a field, an implementation team executes the workover/recompletion program on previously identified opportunities to increase cash flow and reserves. One or two infill or replacement wells test the technical ideas for increasing reserves. Key intervals are cored and tested to evaluate the new reserve opportunities identified in the detailed field studies. If the new wells are unsuccessful, the field is sold.

The forty-six potential candidates were purchased in competitive bid sale. None of the fields were originally for sale at the time we made an unsolicited bid. The purchase price was slightly higher than our original unsolicited bid price.

OPPORTUNITIES FOR PERFORMANCE IMPROVEMENTS AND RESERVE ADDITIONS

The scan of over 350 fields in the Permian basin and a portion of the Gulf of Mexico basin (Figure 1) identified 82 fields that met reserve/profit/technical criteria and became acquisition candidates. Thirty-six candidate fields were producing by primary recovery without supplemental recovery potential, fourteen fields were producing by primary recovery and had waterflood potential, and thirty-two fields were existing waterfloods. The types of opportunities for reserve additions/performance improvements are shown in Figure 3.

In the fields producing by primary recovery with no supplemental recovery potential (Figure 3a), opportunities are primarily by field extensions (44%) identified by better reservoir characterization defined by geologic studies and new 2D and 3D seismic. Infill wells to produce reserves in undrained reservoir compartments are 29% of the opportunities. Bypassed pays, especially low resistivity/high irreducible water saturation pays and recompletions are 21% of the opportunities. Workovers are 6% of the performance improvements.

In the 14 primary recovery fields with supplemental recovery potential (Figure 3b), the major opportunity (40%) comes from installing a waterflood. Field extensions are 24% of the potential. Infill wells needed for the waterflood and bypassed pays/recompletions represent 15% and 18% of the opportunities respectively. Workovers are 3%.

For fields under an existing waterflood (Figure 3c), the majority of the opportunities to improve performance and add reserves are by infill wells (45%) and flood pattern modification (19%). These changes are to insure injector-producer continuity and uniform sweep of the injected water. Also to insure injected water goes into the appropriate reservoir layers at a rate to maintain a uniform flood front and prevent premature water breakthrough, profile control is essential. Profile control and bypassed pays/recompletions represent 26% of the opportunities for performance improvements and reserve additions.

EXAMPLES

Four examples illustrate the methodology and result of reserve additions and performance improvement in mature fields. Two examples – the “C” waterflood unit in the Permian basin and the “G” field in coastal Louisiana were purchased as part of our property acquisition program. The third example is a based on a joint field study with PDVSA to increase production from a marginal field in Lake Maracaibo, Venezuela. The last example is based on Shell/Esso work in the Auk field area in the North Sea.

"C" waterflood unit, Permian basin

The most effective waterfloods in the Permian basin optimized production by using 20 acre well spacing, 5-spot or 9-spot flood patterns, new injector wells to control injection profiles and opening up additional pays in lower resistivity, lower porosity and higher water saturation intervals. Avoiding or shutting off "thief" zones for injected water, using clean water, and ensuring that injected water connects with producing intervals by avoiding thin flow barriers, all increase waterflood efficiency.

The waterflood candidates to purchase have (1) 40 acre spacing, (2) peripheral or irregular water injector patterns, (3) low secondary recovery to primary recovery ratio (S/P less than 0.75) and (4) low recovery efficiency (primary plus secondary production is less than 25% of the oil-in-place).

Target reservoirs are oolite bars and tidal flats; these environments commonly have thin, continuous impermeable flow barriers that effect connectivity between injectors and producers. The "C" field produces from dolomitized oolite bars on a gentle anticline at a depth of 5000 feet (Figure 4). The operator estimated 49 million barrels of oil-in-place in the 2,500 acre flood unit. Primary development ended in 1960 with 58 producers on 40 acre spacing (Figure 5). Production decline started in 1960 and by 1970 (Time ”A”, Figure 6) the operator obtained approval to initiate a peripheral waterflood, Time “B”. Water injection began in 1974 and a modest increase in production began in 1975. For the next two years, production increased only slightly. The operator injected poorly filtered produced water. Most interior wells did not respond to the peripheral water injection. We estimated a secondary/primary recovery (S/P) ratio of about 0.55 in 1974.

Our field study using logs, well cuttings, rock-log calibration, pressure and production response, shows that the waterflood had significant secondary reserve potential in spite of the poor early response. The field was acquired at the end of 1979.

The "C" field produces from dolomitized oolite bars and tidal channels (Figures 7-9). The original operator correlated the reservoir unit (Figure 7b) as a continuous unit with no continuous flow barrier (Figure 7). Study of well cuttings and two new cores taken after acquisition confirmed that the reservoir consisted of multiple, discrete, oolite bars with tidal channels separated by thin, excellent quality flow barriers of carbonate mud and clay (Figures 7a and 7b). Pressure tests and RFT's confirmed the presence of unswept, low to intermediate pressured oil zones. Only producers located near injectors responded to the peripheral waterflood.

New wells with modern logs and two cores showed the pay cut off used by the original operator was too strict; the operator's pay cut off was 8 percent porosity. Although porosity ranges between 3-12%, permeability depends on dolomite crystal size (Figure 10). Capillary pressure measurements, flood pot tests and field test showed that the lower limit of pay was 4% porosity and 0.1 md. permeability. The new pay cut offs significantly increased San Andres pay (compare Figures 11a and 11b).

Net pay in each subzone (Figures 8 and 9) and the flow barriers were mapped. Additional pay zones identified from the core-log studies and well tests were perforated, clean water was injected, and a small 20-acre, five-spot pilot was initiated (Figure 12). Appropriate volumes of water were selectively injected into the A1, A2, and A3 subzones. Six months after the initiation of the pilot, pressure increased and production increased slightly, Time "C" (Figure 13).

With the encouragement from the pilot, the field was downspaced to 20-acres and a five-spot pattern was developed fieldwide, Time “D” (Figures 14 and 15). Clean water, a mixture of new fresh water and clean produced water, was injected at a pressure of 75% of the formation fracture gradient. To improve sweep efficiency, zones with better permeability, i.e.,“thief” zones, were plugged.

The 20 acre, five-spot pattern flood dramatically increased producible reserves. The S/P ratio increased from 0.55 to 1.75. The recovery efficiency for primary and secondary increased to over 42%. An additional 4 to 6 percent of the oil-in-place may be recoverable from CO_2 flooding based on analogy with CO_2 floods in nearby fields.

Reserve additions and performance improvements in the “C” waterflood unit (Figure 16) are mainly infill wells (36%) and bypassed pays/recompletions (11%). Injection profile control and workovers add 7% and 3%, respectively.

“G” Field, Coastal Louisiana

A major oil company discovered the “G” field in the late 1930’s. At the time of the acquisition scan, the cumulative production of the field was 170 million barrels equivalent of hydrocarbon. The structural trap for the field is a rollover anticline formed by a large growth fault. Large sealing faults subdivide the field into three blocks. Numerous small faults partially or completely offset reservoirs.

The field has a shallower hydropressured interval and a deeper geopressured interval (Figure 17). Before acquisition, all production came from the hydropressured reservoirs deposited in a river-dominated delta complex. Seven wells in the 1940’s drilled through the geopressured section; the wells found thick sands with abundant condensate and gas shows. Completion attempts in the geopressured reservoirs failed. Sands in the geopressured interval appear lenticular and difficult to correlate. Field studies based on new 2D seismic after acquisition suggest that the deeper sands are shingled turbidites with good continuity (Figures 18a and 18b).

The “G” field has 27 reservoirs in the hydropressured interval between 5,000 and 10,300 feet. Since acquisition, new wells identified at least 5 reservoirs in the geopressured interval down to 17,000 feet. .

From 1975 to 1989, the “G” field declined at 12% per year (Figure 19). The field has a solution gas drive with limited water support. At the time of acquisition, production was marginally economic at approximately 1100 barrels per day.

A multidisciplinary geoscience-engineering team quickly identified numerous opportunities before and after acquisition. Increased reserves came from infill wells in undrained or poorly drained reservoir compartments, workovers and recompletions especially of lower resistivity pay zones, and new field extensions. Lateral field extensions and the deeper geopressured reservoirs have significant upside potential.

A year after field acquisition, production increased from 1100 barrels per day to over 4000 barrels equivalent per day following recompletions and workovers of shutin wells. During initial development, only the hydropressured portion of the reservoir system was completed. Thin shale laminations and beds within the reservoir units effectively isolated the reservoir vertically. Wells were recompleted through the entire pay interval. Some of the recompleted wells produced at or near discovery pressure and rate.

Some “wet” zones were actually low resistivity pays. The “X” sands in one well alone added about 1000 barrels a day from a low resistivity (<1.5 ohm-m) zone. The conventional pay in the 9500 ft. “X” sands in this interval went to water eleven years earlier. A new well was drilled and cored (Figure 20). The high resistivity zone that went to water eleven years earlier, was now productive suggesting it had previously coned water.

Analysis of new core and production testing demonstrated that the interval below the high resistivity pay was productive. To demonstrate the production, small intervals were tested. The lower zones produced 990 barrels per day without water and at original pressure on thirty-day tests. The original pay zone produced 3,112 barrels per day. The original pay zone produced approximately 300,000 barrels of oil before watering out again; the low resistivity pay zone continues to produce without significant water. Figure 21 shows the original hydrocarbon distribution mapped on the conventional pay only. Notice pay occurs in one fault block. Figure 22 shows the distribution of hydrocarbons including low resistivity pay. Development of this low resistivity pay added 14 million barrels of proved oil reserves. Newly identified low resistivity pays in several intervals doubled the proved reserves in the field.

The initial redevelopment study increased reserves and increased production to over 5000 bbl per day sustained for several years and is increasing. A new 3D seismic survey run in 1994-1995 delineated numerous deep opportunities in the field. Three significant wells produced from geopressured section now. One well has over 125 net feet of pay.

We expected development during the next few years to increase production to over 11,000 barrels equivalent per day through field extensions and in newly defined prospects in the deeper geopressured reservoirs (Figure 19).

Performance improvements and reserve additions are principally from field extensions (61%), bypassed pays/recompletions (18%) and infill wells (12%) (Figure 23).

VLC-363, Block III Field, Lake Maracaibo, Venezuela

The VLC-363 is a supergiant field located in eastern Lake Maracaibo that produces from the Eocene, Lower C reservoir from 63 wells (Figure 24). The field was found in the 1960's and had an original oil-in-place (OOIP) greater than 1.7 billion barrels. It has already produced around 200 million barrels of retrograde condensate and an indeterminate amount of gas and it will recover 12 to 13% of the OOIP by primary recovery. The remaining potential is greater than 200 million barrels.

A rejuvenation project started in 1994 by a team of geologist, geophysicists, petrophysicists and engineers from PDVSA and US consultants. (Sneider, et al, 1999).

The structure was mapped using a low resolution a 3D seismic survey and well logs. The well logs were extremely important in identifying the faults because of the low resolution of the seismic. Seismic could not fully resolve most of the faults.

The hydrocarbons are trapped in an upthrown faulted anticline on a down to the northeast fault (Figure 25). The field location is between two major strike-slip faults. A major strike-slip fault bounds the eastern edge of the field. The other strike-slip fault is located about 15-20 km to the west of the field. The field has been through at least 3 different periods of structural evolution including both extensional and strike-slip deformations.

There are more than 22 small faults with <150 feet of throw within the field. None of these small faults were previously mapped (Figure 26). The faults subdivide the field into four distinct production regions (Figure 27).

The new structural interpretation explained several previously unexplained production anomalies such as water producing above oil and large differences in the producing water level across the field (Figure 28). The north-south fault in the center of the field separates a producing water level that is more than 350 feet different from the east to the west (13,025 feet to the east and 13,375 feet to the west). The throw along this fault varies from approximately 125 feet in the south to less than 40 feet in the north.

The small east-west fault separating Production Area 2 from Production Area 4 has about 50 feet of throw, but is associated with a production anomaly. It is clear from the pressure data, that this fault leaks. Shortly after this map was made, the four wells to the south of the fault were worked over and production increased to more than a 1,000 barrels per day in all four wells. The wells up structure to the north of the fault produced at low rates with very high water cuts, and the wells were shutin.

Faults act as barriers and baffles to production (Figure 29). Production data indicate that faults with throw less than 100 feet leak. These small faults still affect production, and have left parts of the field poorly drained. Additionally, these small faults will greatly affect any enhanced recovery project because individual reservoirs are usually less than 50 feet thick.

The Eocene C deposits consist of higher frequency depositional cycles superimposed on an overall transgression (Figure 30). The lower part of the section from the C455 to the Guasare is predominately fluvial deltaic and rests unconformably on a major regional unconformity. The upper part of the section from the C440 to the C448 is predominately marine.

The field contains 16 major flow units. Some of these flow units were further subdivided for reservoir simulation. The major pay intervals are the C448, C455 and C460.

The depositional environment has a major impact on reservoir and flow barrier distribution. Thin flow barriers have a major impact on the primary and secondary recovery process, and result in poor vertical communication in the field. The reservoirs contain numerous barriers and baffles (leak) to vertical flow. The shales between the flow units can support several 1000 psi differences in pressure. The ratio of vertical to horizontal permeability (Kv/Kh) in the sandstones is ~0.6, but the effective Kv/Kh ratio is less than <0.001 when considering the thin shale laminations scattered within the sandstones. This means that there will be poor vertical communication within the reservoirs.

The field went below the bubble point in the mid 1980's. This has caused numerous problems because the hydrocarbon is a retrograde condensate; therefore, there is 1) significant oil shrinkage, 2) formation of numerous secondary gas caps underlying flow unit boundaries and 3) insufficient free gas available to significantly swell oil upon re-pressuring with water.

The extensive reservoir depletion results in very little waterflood movable oil. Without repressuring, gas injection will result in very little oil recovery although with repressuring the reservoir system could become miscible. Without re-pressuring, injected gas will stream through existing high gas saturation regions.

There are four main development opportunities with significant reserve potential: enhanced recovery, new wells in underdeveloped fault blocks, workovers and re-completion in lower resistivity zones. There are about 87 million barrels of potential reserve additions with primary recovery and 400 million barrels of potential reserve additions with enhanced recovery (Figure 31).

A waterflood would recover less than 5% of the OOIP and is uneconomic (Figure 32). A gas injection would have similar results. If the field is filled with water, and then gas is injected, there is an increase recovery of 11% of the OOIP or 187 mmbbls. A 2:1 WAG (water alternating with gas) with the existing wells recovers an additional 16% of the OOIP or 272 million barrels. If infill wells are drilled to produce a better pattern, 23% OOIP or 391 million barrels of additional reserves are possible.

There are at least 3 possible field extensions to the northeast, the southwest and the possibility the southeastern flank of the field (Figure 33).

The northeast extension is in a separate fault block from the main field with one well (VLC-750) drilled in it (Figure 34). This well produced up to 500 barrels per day and produced 200,000 barrels of oil, which is only 3% of the OOIP in the small fault sliver, area 3. The entire reservoir interval was saturated with hydrocarbons and the well had a 16% water cut at abandonment. There are two additional structures isolated from the VLC-750 well (Figure 25). The area to the northwest of the fault block is more than 200 feet above the VLC-750. The structure in area 1 contains about 7 million barrels of recoverable oil by depletion.

The hydrocarbon pore volume map of the main reservoir shows that reservoir quality decreases to the east (Figure 35). The VLC-750 is in the area of poorer reservoir quality. To the west in the fault block, the reservoir quality should improve. All the wells across the fault to the south produced more than a million barrels, with some producing more than 20 million barrels. Also, there are many recompletion opportunities in lower resistivity intervals that have not been completed.

Significant reserves and potential reserves were added to this field by 1) understanding the rock types and pay classification, 2) mapping horizontal flow barriers mainly faults but also facies changes, 3) recognizing vertical flow barriers and changing completion practices or recompeting zones, and 4) integrating the reservoir simulation with the reservoir performance and the geoscience in an iterative way not a linear way.

Auk Field, Central Graben, North Sea

In the North Sea, many of the fields found in the late 1960's and 1970 have reached maturity by primary recovery. Reserve additions and performance improvements in these mature fields have resulted from the application of new production technologies including horizontal or multilateral wells. A good example is the Shell/Esso Auk Field (Figure 36). The field went on production in 1975, had peak production during 1977 – 1979 of about 40,000 bopd and rapidly declined to less than 10,000 bopd in 1988 (Frazer 1998). The estimated ultimate recovery in 1988 was 93 million barrels or about 13 million barrels remaining (Trewin and Bramwell 1991). The estimated ultimate recovery in 1998 is about 180 million barrels or about twice the 1988 estimate.

A major share of the reserve additions at Auk is from a large field extension (Auk North) found previously by seismic, but considered uneconomic for many years. Previous work by Shell/Esso showed Auk North production was not feasible to develop from a satellite platform or from extended reach wells from existing Auk platforms. Improvement in economics that make Auk North development now possible for Shell/Esso comes from the use of multilateral wells from existing Auk development wells and the use of electric submersible pumps deployed and retrieved on coil tubing without the need of a semi-submersible rig. The employment of these engineering advances plus the drilling of new wells and infill wells raises the recovery factor from 17 percent to 30 percent of the oil-in-place.

POTENTIAL FOR RESERVE ADDITIONS

What is the reserve growth potential in and around aging marginal fields? Nehring (1995) showed that about 85 percent (20 billion oil barrels) of proved oil reserve additions in the United States between 1982 and 1992 were from mature fields. Schollnberger (1998) estimated that future additional reserves of about 400 billion barrels of oil and 600 trillion cubic feet, of natural gas are expected from mature fields. Schollnberger estimates are based on Master's 1994 USGS report.

Our estimate of additional reserves in and around mature fields we studied in the Permian basin and a portion of the Gulf of Mexico basin (Figure 1) is more than 6 billion barrels of oil equivalents. This estimate is for fields that have produced at least 25 million barrels and have a potential for adding at least five percent of the cumulative production.

Hundreds of mature fields in the United States and Canada have undergone some type of redevelopment. The potential for future reserve additions still appears excellent in many of these mature basins. Worldwide, adding reserve in and around mature fields is being recognized as an important source of low risk and profitable reserve additions.

ECONOMICS OF RESERVE ADDITIONS

How profitable is adding reserves in and around mature fields? Our experience with the forty-six fields purchased gives some indication of profitability. Figures 37 and 38 show the after tax rate of return (ATROR) for all 46 properties.

The twenty-seven properties producing by primary recovery are more profitable than the nineteen waterflood fields. The average ATROR for all 46 properties is 21%. Forty-one properties have an ATROR of 12 to 41 percent. Three properties, all waterfloods, had 5-7 ATROR, which is acceptable economically. The two waterfloods with 0-1% ATROR are unprofitable. These two projects failed economically because thief zones could not be plugged and a uniform flood front could not be maintained.

Payout or the time in years required to recover the after tax total investment from the net cash flow for the 46 properties is:

27 Primary Production Properties	1.0 – 3.1 years
17 Waterflood Properties	2.0 – 5.8 years
2 Uneconomic Waterfloods	8.0 – 12.8 years

Proved and probable reserves added in the 46 fields is 625 million barrels of oil equivalent at an average cost of US$ 2.69 per barrel equivalent. We expect that some additional reserves will be added in all the properties as a result of improved recovery methods, CO_2 flooding or field extensions.

CONCLUSIONS

Exploration is the key to finding large reserves. Redevelopment of many mature fields is an important source of reserve additions at a good profit. Not all mature fields can be redeveloped profitably. Environmental liabilities and the cost to fix and replace boreholes/producing facilities may exceed the value of proved and potential reserves.

We have been responsible for purchasing and initially redeveloping forty-six properties for several oil companies. Forty-four field redevelopments are profitable, and two are economic failures. The total proved and probable reserves for the fields are 625 million barrels of oil equivalent at an average cost of US$ 2.69 per barrel equivalent. The after tax rate of return is 21 percent for all forty-six properties.

REFERENCES CITED

Frazer, F., 1998, Shell applying new research to marginal prospects, Offshore, August, p. 46 and 50.

Masters, C.D., et al., 1994, World petroleum assessment and analysis, Proceedings 14th World Petroleum Congress, John Wiley and Sons, p. 529-541.

Nehring, R., 1995, The impending crisis in U.S. oil production: What can be done about it, in 1995 SPE Hydrocarbon Economics and Evaluation Symposium, SPE Paper 30059, 7 p.

Schollnberger, W.W., 1998, Projections of the world's hydrocarbon resources and reserve depletion in the 21st century, November Houston Geological Society Bulletin, p. 31-37.

Sneider, J.S., R.M. Sneider, C. Coll, B. Cortiula, G. Gonzales, J.T. Kulha, J.D. Loren, D.Shaughnessy, and M.R. Todd, 1999, Rejuvenating a Mature Supergiant Field VLC-363, Block III Field, Lake Maracaibo, Venezuela- Reservoir Characterization, in Extended Abstracts, AAPG International Conference, Birmingham, England, September 1999, p. 462-467.

Sneider, R.M. and J.S. Sneider, 1998, Rejuvenating marginal, aging oil fields: is it profitable?, Petroleum Geoscience, Vol. 4, p. 303-315.

Trewin, N.H. and M.G. Bramwell, 1991, The Auk field, Block 30/16, UK North Sea, Abbotts, I.L. (ed.) In: United Kingdom Oil and Gas Fields, 25 years Commemorative Volume, Geological Society Memoir No. 14, P. 227-236.

ADDITIONAL REFERENCES

Loren, J.D., R.M. Sneider and L. Rondón, 1998, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Introduction, 1998 AAPG Annual Convention Poster Session, May 1998.

Sneider, J.S., D. Shaughnessy, R.M. Sneider, G. González and B. Cortiula, 1998, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Geologic Framework, 1998 AAPG Annual Convention Poster Session, May 1998.

Loren, J.D., J.T., Kulha and C. Coll, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Petrophysical Evaluation, 1998 AAPG Annual Convention Poster Session, May 1998.

Sneider, J.S., G. González and B. Cortiula, 1998, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Reservoir Characterization, 1998 AAPG Annual Convention Poster Session, May 1998.

Farina, J.R., J.T. Kulha and E. Arzola, 1998, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Reservoir Performance and Observations, 1998 AAPG Annual Convention Poster Session, May 1998.

Sneider, J.S., G. González, J.T. Kulha and D. Shaughnessy, 1998, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Development Opportunities, 1998 AAPG Annual Convention Poster Session, May 1998.

Todd, M.R. and E. Arzola, 1998, Rejuvenating a mature supergiant field, VLC-363, Block III field, Lake Maracaibo, Venezuela: Numerical Simulation, 1998 AAPG Annual Convention Poster Session, May 1998.

LIST OF FIGURES

Figure 10. Cross plot of porosity versus permeability for different Archie rock types. Note that for the same porosity, permeability increases as dolomite crystals size increases. Dolomite crystal size reflects the size of the original limestone particles. The new lower limit of net pay is 4% porosity and 0.1 MD of permeability based on field and laboratory tests.

Figure 11. (a) Gamma-ray and resistivity logs of an original field well (1956), San Andres “C” waterflood unit, Permian basin, Texas. Net pay is 7 m. (b) Gamma-ray neutron porosity and resistivity logs of a 1988 well drilled and cored in the same unit, about 9 m from the 1956 well. Net pay in this well is about 20 m.

Figure 12. Map showing the location of 20-acre 5-spot pilot flood. The peripheral flood pattern of injectors and producers is the same as that in Figure 5. San Andres “C” waterflood unit, Permian basin, Texas.

Figure 13. Graph showing oil production during primary recovery and secondary peripheral waterflood production and the 20-acre, 5-spot pilot flood until December 1980. San Andres “C” waterflood unit, Permian basin, Texas.

Figure 14. Map showing the expanded 20-acre, 5-spot waterflood injection pattern beginning in late 1980. San Andres “C” waterflood unit, Permian basin, Texas.

Figure 15. Graph illustrating primary and secondary waterflood production, San Andres “C” waterflood unit, Permian Basin, Texas. Note the significant increase in production starting at Time “D” which resulted from a 20-acre, 5-spot pattern waterflood and perforating all pay zones.

Figure 16. Opportunities for reserve additions and performance improvements, “C” waterflood unit, Permian basin, Texas.

Figure 17. Composite type log of the “G” field, coastal Gulf of Mexico basin, Louisiana.

Figure 18. (a) Stratigraphic cross-section across the “G” field based on 6 deep wells, palaeo-data and 3D seismic data. (b) Sequence stratigraphic correlation of shallow and deep reservoir units based on well logs, 3D seismic data and some palaeo-data, “G” and “B” fields, coastal Gulf of Mexico basin. Only two deep 1950s wells penetrated the

sections below 3000 m. Both wells had gas condensate shows and were recompleted in the normally pressured prograding complex reservoirs.

Figure 19. Graph of “G field daily production in BOEPD. The field was acquired in 1989 and a field redevelopment study was initiated. The production increase started in 1990 resulting from workovers and recompletions. A 1994-95 3D seismic survey documented additional shallow and deep new well opportunities and field extensions.

Figure 20. Well logs of the 9500 ft. reservoir sand in a 1989 well, “G” field, coastal Gulf of Mexico. This new cored well is less than 10 meters from a 1940s well that produced from the upper 20 ft. of the 9500 sand. The low resistivity interval below the 7 _m interval was never tested because it was interpreted as wet. This low resistivity interval production tested about 1000 BOPD. Each individual flow test was 30 days.

Figure 21. Structure map on top of the 9500 ft. sand showing its original distribution of oil and gas, “G” field coastal Gulf of Mexico, Louisiana.

Figure 22. Structure map on top of the 9500 ft. sand showing the new distribution of oil and gas resulting from recompleting the low resistivity intervals in the sand, “G” field, coastal Gulf of Mexico, Louisiana.

Figure 23. Opportunities for reserve additions and performance improvements, “G” field, Gulf of Mexico basin, coastal Louisiana

Figure 24. Location of VLC-363, Block III field, Lake Maracaibo, Venezuela.

Figure 25. Structure map on the top of the C455 reservoir based on well logs and 3D seismic, VLC-363, Block III field.

Figure 26. 1960s structure map on the top of the C4 reservoir based on well logs, VLC-363, Block III field.

Figure 27. Sealing and partially sealing faults divide the field into four major production zones, VLC-363, Block III field.

Figure 28. Daily production, hydrocarbon distribution and well status in July 1995 superimposed on the C455 structure map, VLC-363, Block III field.

Figure 29. Map showing faults that are completely sealing that act as barriers to fluid flow and faults that leak but act as partial barriers to fluid flow, VLC-363, Block III field.

Figure 30. Type log for the VLC-363 Block III field showing detailed correlation units that separate flow units and showing the sequence stratigraphic interpretation.

Figure 31. Diagrams showing a) distribution of reserve additions and opportunities for production improvements with primary recovery and b) distribution of reserve additions and performance improvements including enhanced recovery, VLC-363, Block III field.

Figure 32. Plot showing recovery in time after water or WAG (water alternating with gas) injection in years versus the cumulative oil recovery as fractions of OOIP, VLC-363, Block III field.

Figure 33. Location of some field extension areas, VLC-363, Block III field.

Figure 34. Location map of the northeast fault block prospect. Area 1 contains 456 acres and 34.6 mmbbl OOIP, Area 2 contains 278 acres and 22.6 mmbbl OOIP, and area 3 contains 152 acres and 7.5 mmbbl OOIP, VLC-363, Block III field.

Figure 35. Hydrocarbon pore volume map for the C455 reservoir, VLC-363, Block III field.

Figure 36. Production history and field development, Auk-Auk North field, central graben, North Sea.

Figure 37. Value of 19 waterflood fields purchased in the Permian basin, Texas and New Mexico. Value is expressed at the percent after tax rate of return (ATROR). The two unprofitable fields were fractured and water injection could not be controlled.

Figure 38. Value of 27 fields purchased in the Texas-Louisiana coastal Gulf of Mexico basin. Value is expressed as the ATROR%.

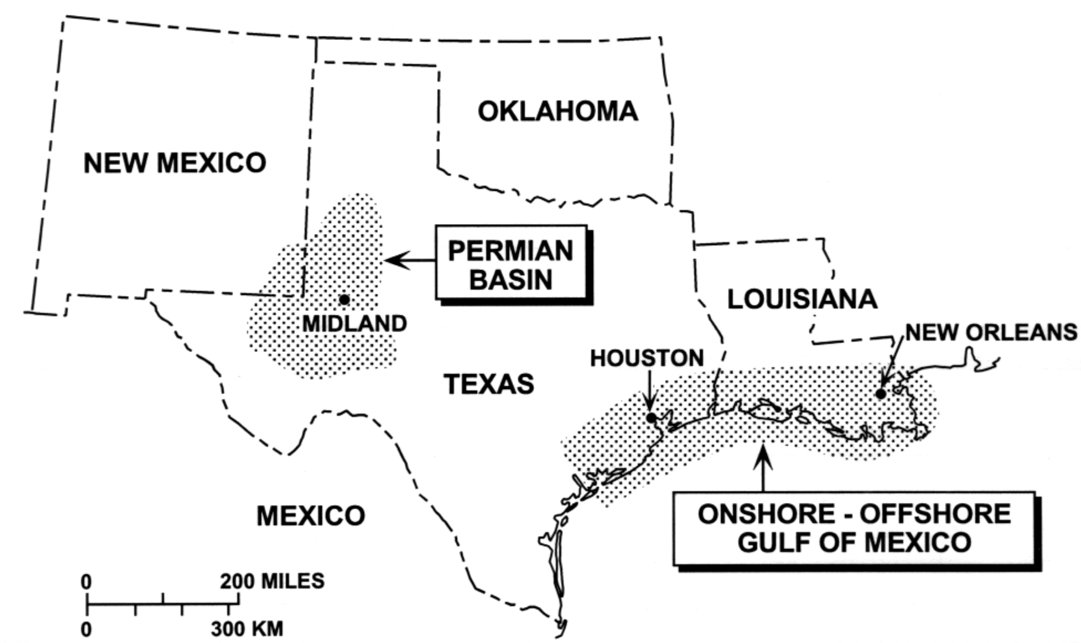

Figure 1. Location of basins where field were acquired in West Texas, New Mexico and onshore-offshore Texas and Louisiana.

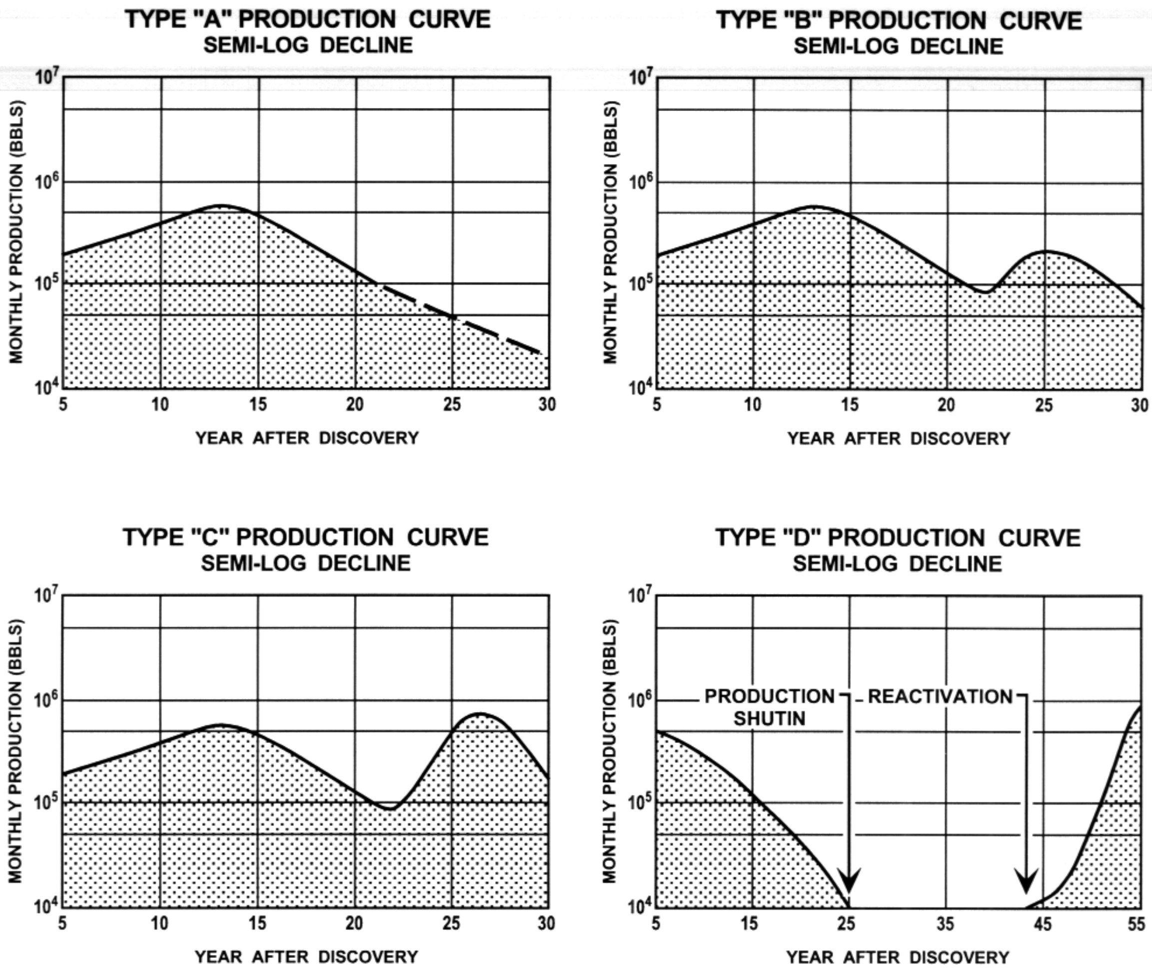

Figure 2. Type “A” graph illustrates a typical production decline curve of a depletion reservoir. Type “B” production decline shows a secondary production increase resulting from infill drilling, recompletions, workovers and/or flooding. Type “C” production curve shows the secondary production is higher than the initial production rate. Type “D graph is typical of a rejuvenated marginal field. Production increases are the result of operations similar to Type “B” and Type “C”.

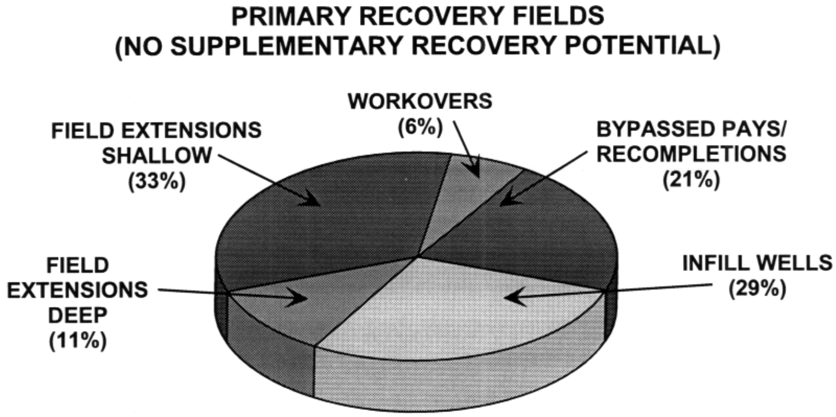

Figure 3a.

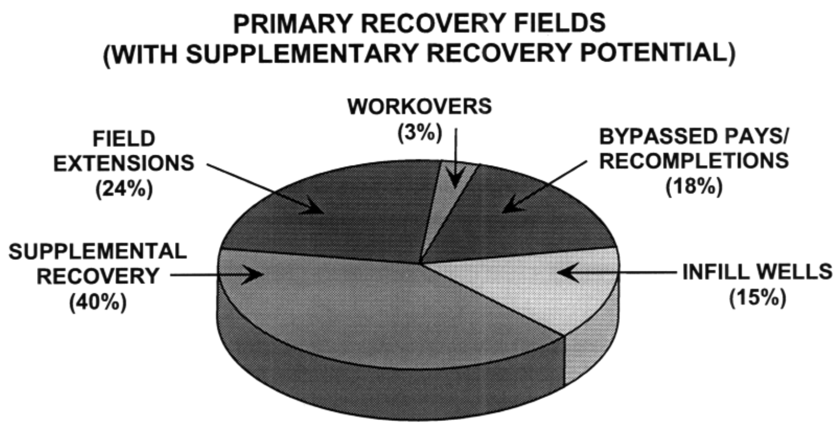

Figure 3b.

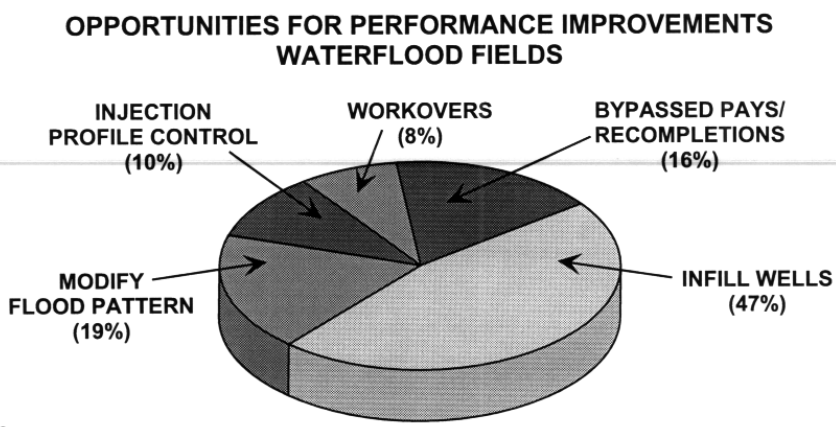

Figure 3c.

Figure 3. Opportunities for reserve additions and performance improvements. (a) primary recovery fields with no supplemental recovery potential, (b) primary recovery fields with supplemental recovery potential, (c) waterflood fields.

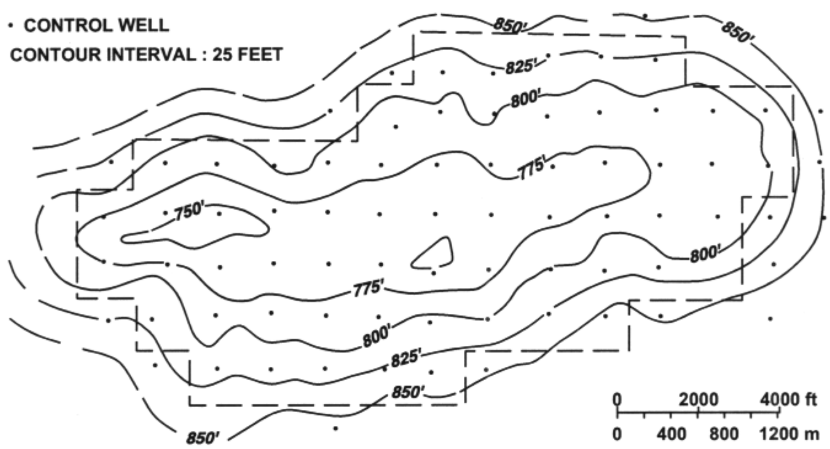

Figure 4. Structure map on top of the San Andres Reservoir, “C” waterflood unit, Permian basin, Texas. Note the gentle anticline with four-way closure.

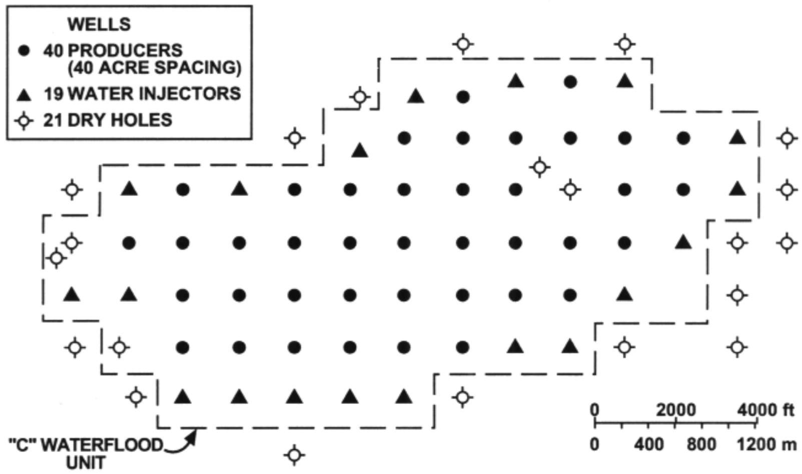

Figure 5. Map showing the location of injectors and producers at the start of the peripheral waterflood, San Andres “C” waterflood unit, Permian basin, Texas.

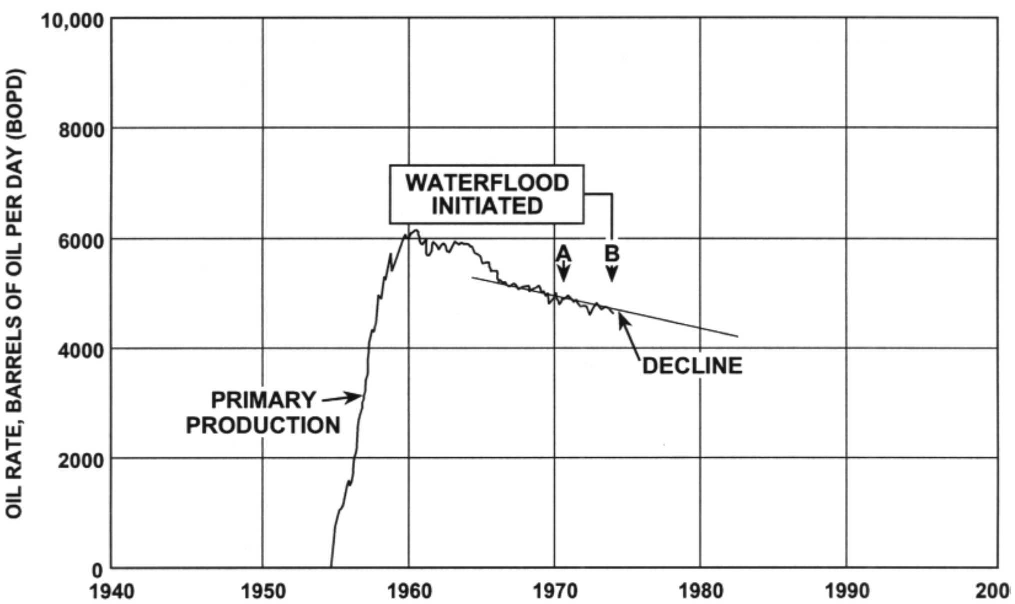

Figure 6. Graph showing primary production. The peripheral waterflood was initialed at Time “B”, San Andres “C” waterflood unit, Permian basin, Texas.

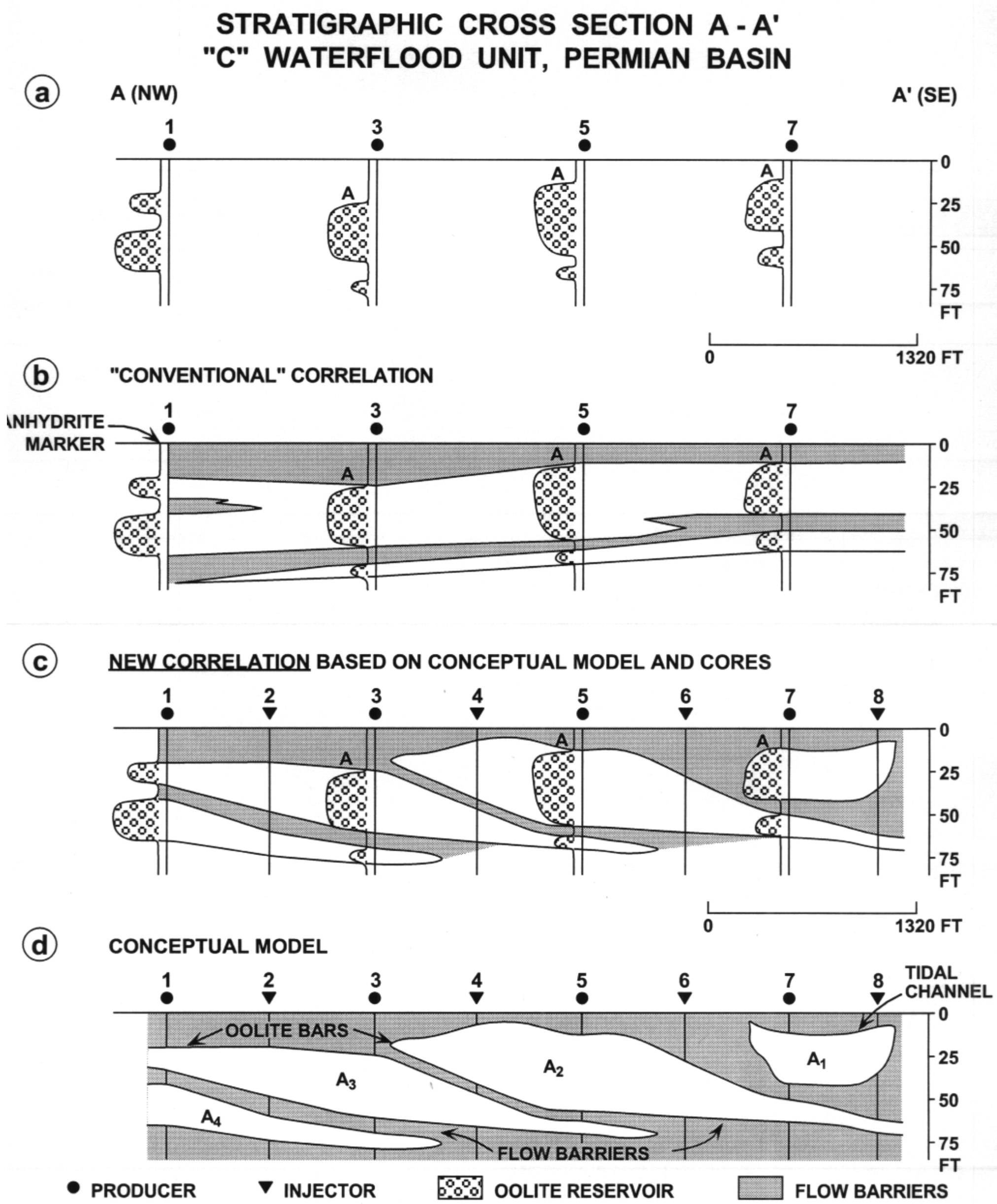

Figure 7. North-south stratigraphic cross-section A-A' showing (a) original gamma-ray log response, (b) original operator's correlation and (c and d) new correlations of reservoirs and flow barriers based on oolite tidal bars and tidal channel models. Infill injector wells are required to effectively flood the reservoir flow units.

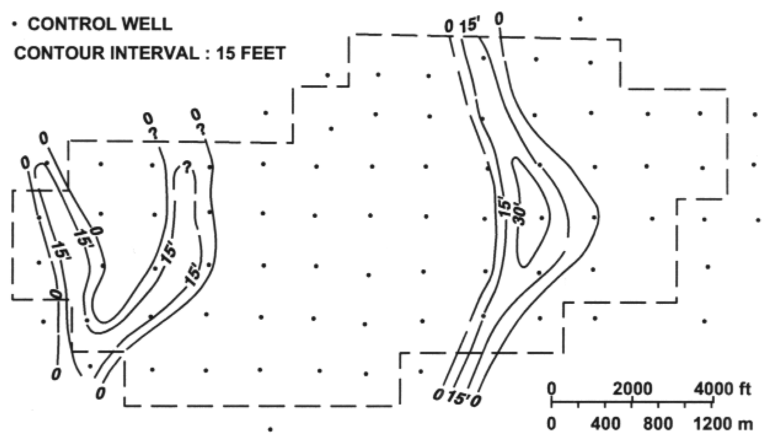

Figure 8. Net pay isopach map of the “A1” zone tidal channels, San Andres Reservoir, “C” waterflood unit, Permian basin, Texas.

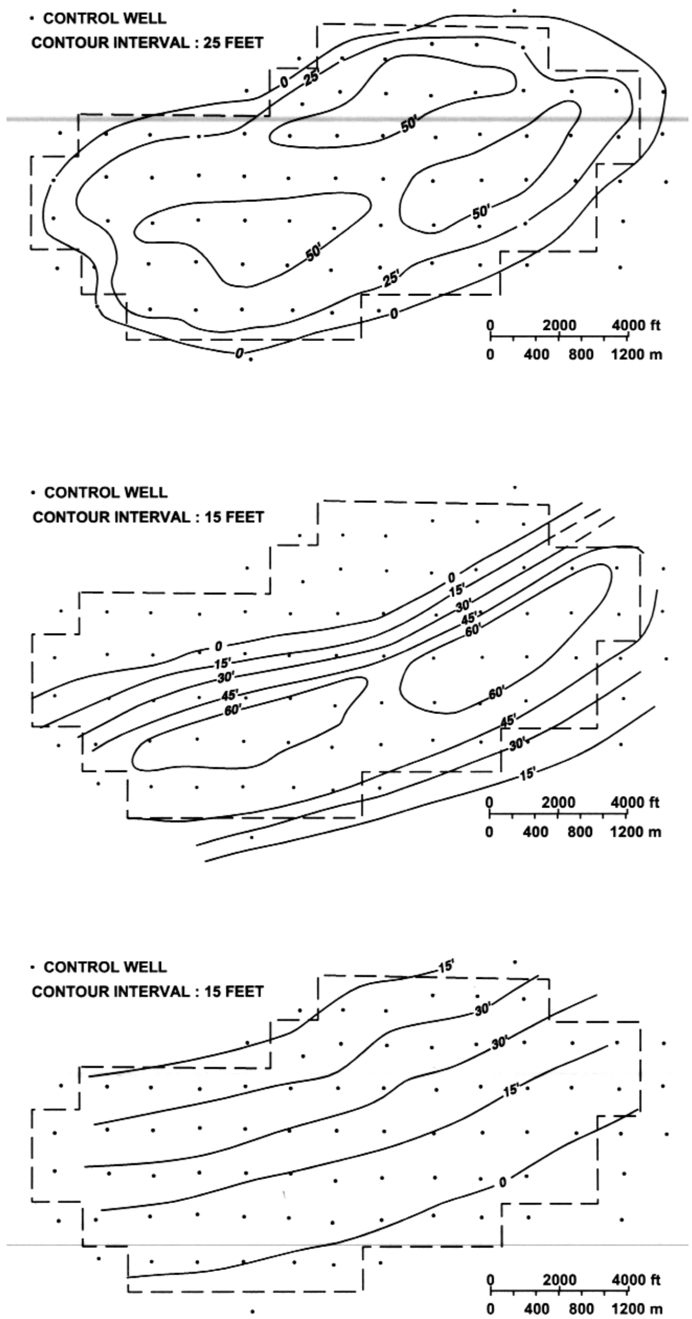

Figure 9. Net pay isopach map of: (a) combined oolite bar subzones “A2” and “A3” are separated vertically by an effective flow barrier of shaly carbonate mudstone (b) “A2” subzone - a shaly carbonate mudstone separates this subzone from the “A3” subzone (c) “A3” subzone. “A2” and “A3” subzones are located in the San Andres Reservoir, “C” waterflood unit, Permian basin, Texas.

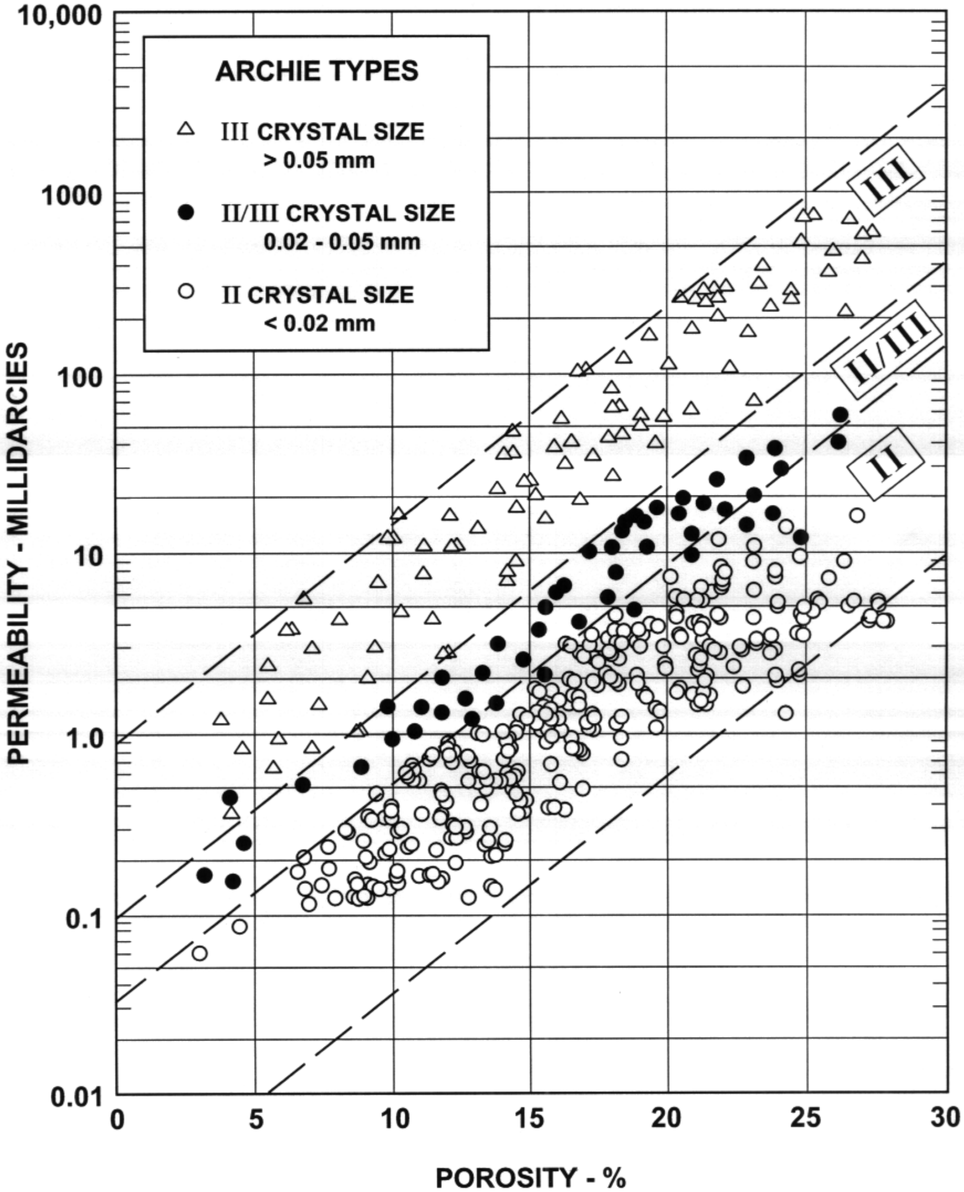

Figure 10. Cross plot of porosity versus permeability for different Archie rock types. Note that for the same porosity, permeability increases as dolomite crystals size increases. Dolomite crystal size reflects the size of the original limestone particles. The new lower limit of net pay is 4% porosity and 0.1 MD of permeability based on field and laboratory tests.

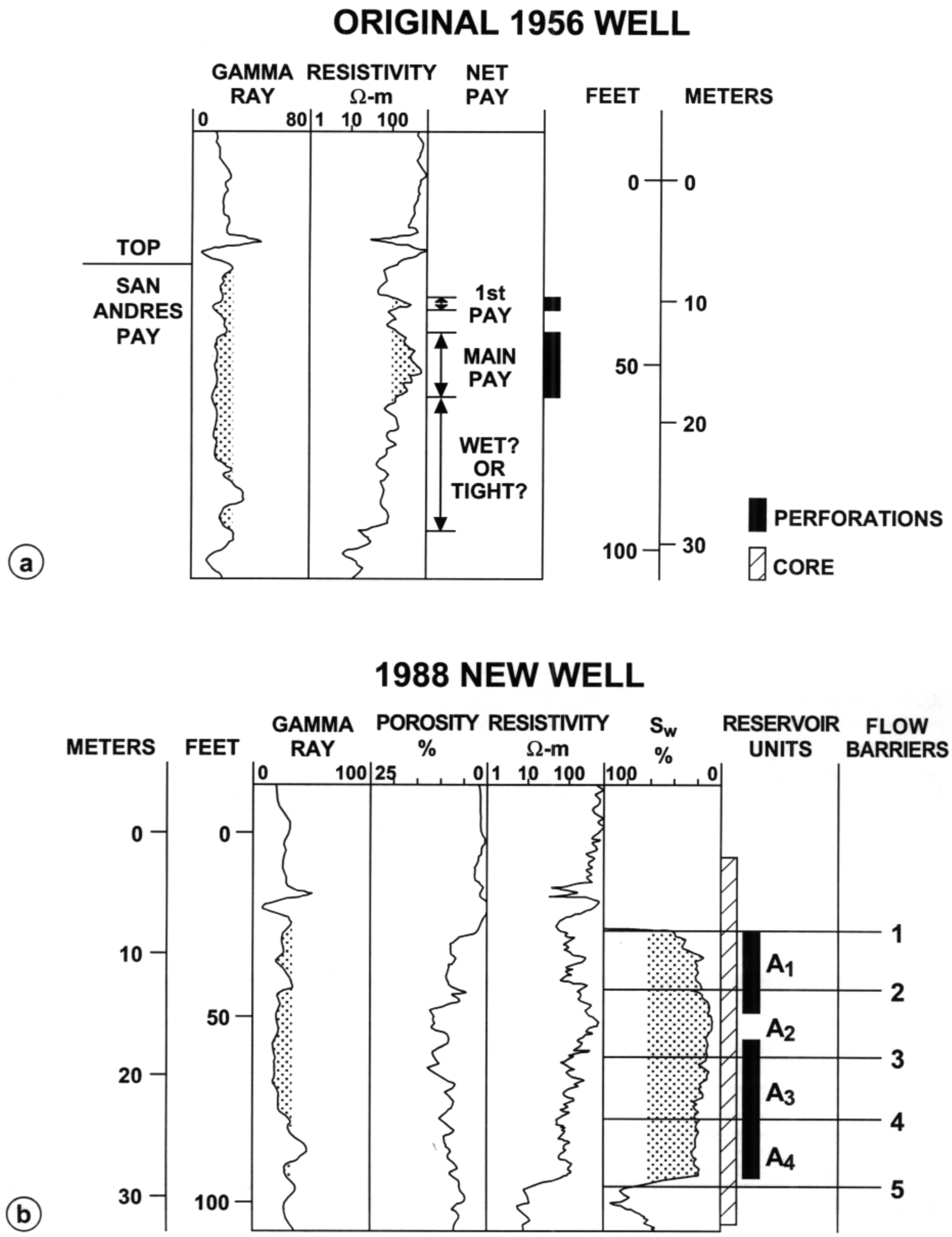

Figure 11. (a) Gamma-ray and resistivity logs of an original field well (1956), San Andres "C" waterflood unit, Permian basin, Texas. Net pay is 7 m. (b) Gamma-ray neutron porosity and resistivity logs of a 1988 well drilled and cored in the same unit, about 9 m from the 1956 well. Net pay in this well is about 20 m.

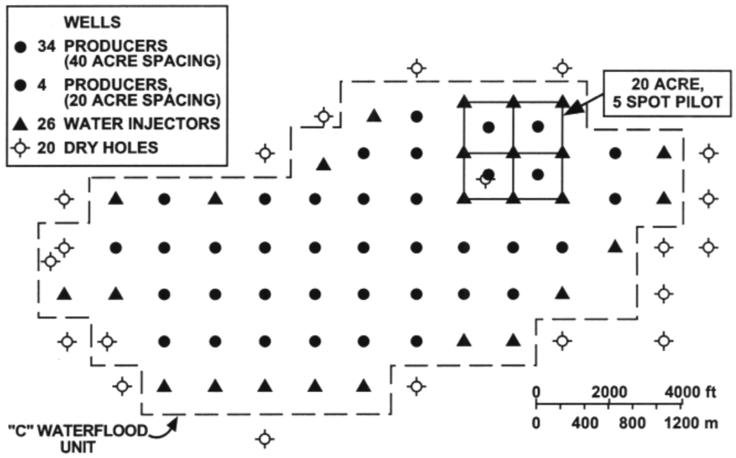

Figure 12. Map showing the location of 20-acre 5-spot pilot flood. The peripheral flood pattern of injectors and producers is the same as that in Figure 5. San Andres "C" waterflood unit, Permian basin, Texas.

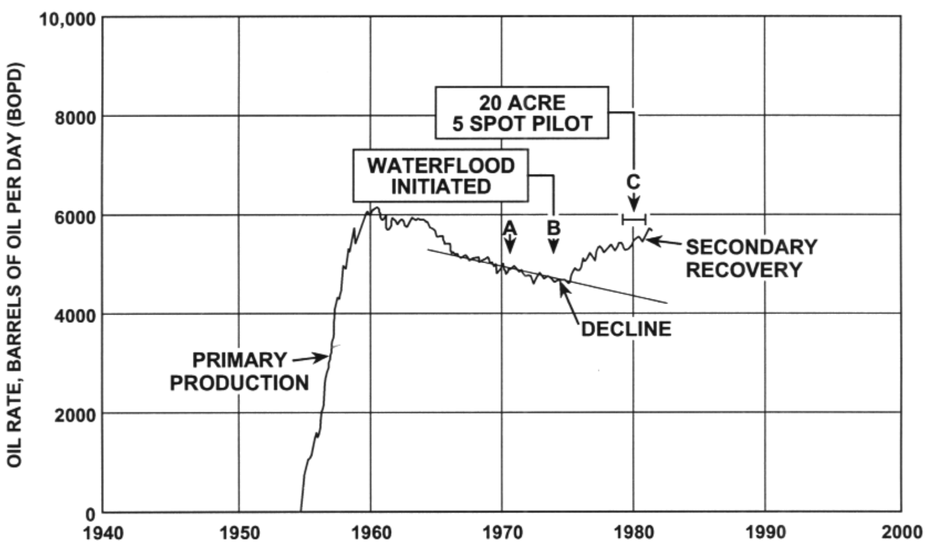

Figure 13. Graph showing oil production during primary recovery and secondary peripheral waterflood production and the 20-acre, 5-spot pilot flood until December 1980. San Andres "C" waterflood unit, Permian basin, Texas.

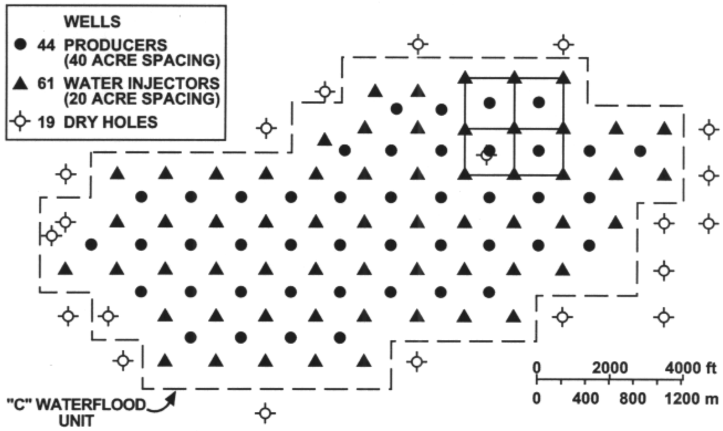

Figure 14. Map showing the expanded 20-acre, 5-spot waterflood injection pattern beginning in late 1980. San Andres "C" waterflood unit, Permian basin, Texas.

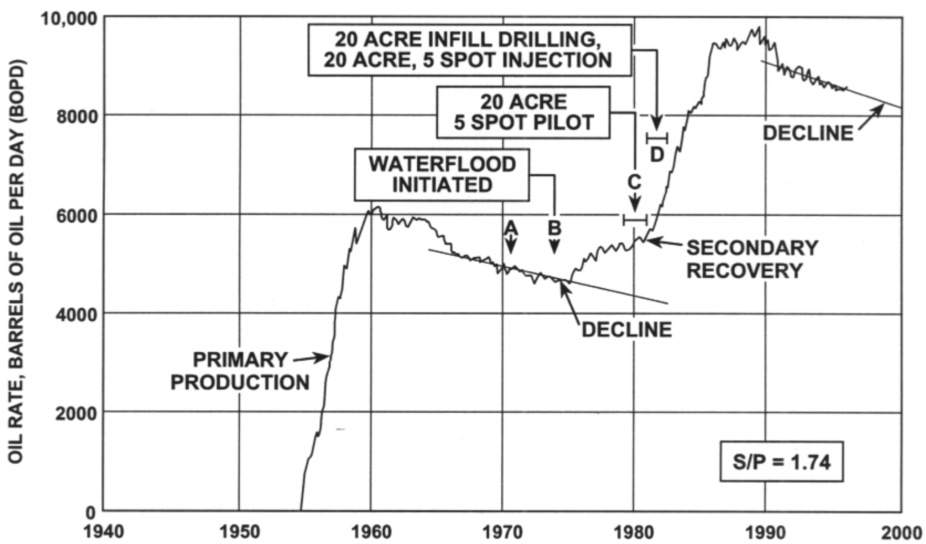

Figure 15. Graph illustrating primary and secondary waterflood production, San Andres "C" waterflood unit, Permian Basin, Texas. Note the significant increase in production starting at Time "D" which resulted from a 20-acre, 5-spot pattern waterflood and perforating all pay zones.

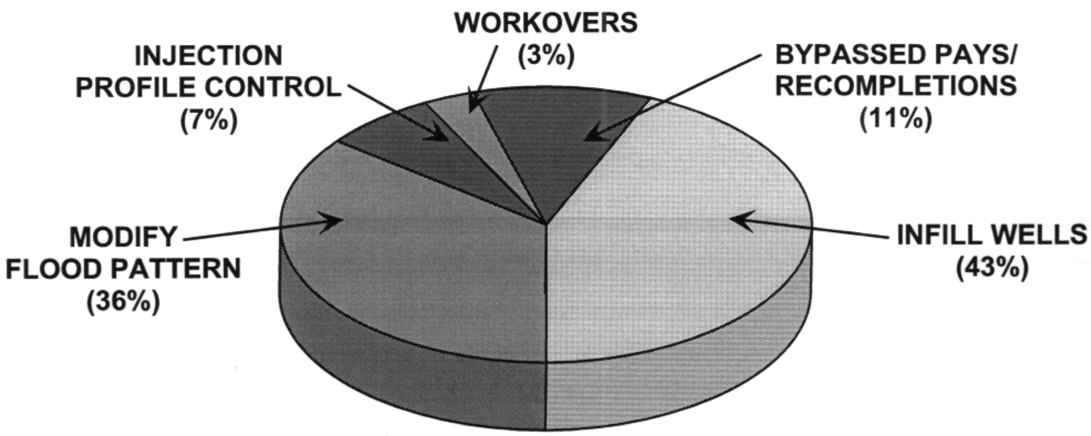

Figure 16. Opportunities for reserve additions and performance improvements, "C" waterflood unit, Permian basin, Texas.

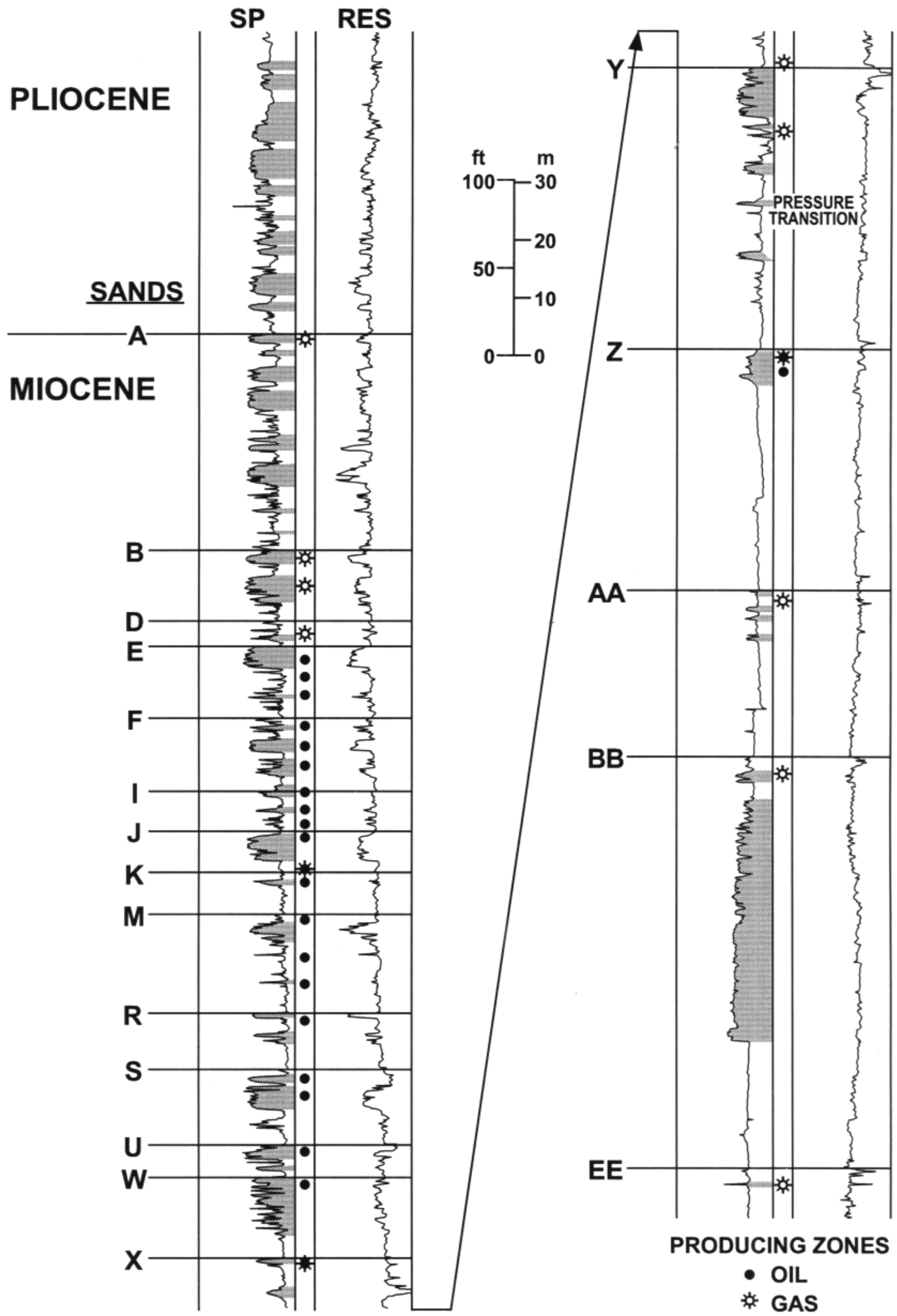

Figure 17. Composite type log of the "G" field, coastal Gulf of Mexico basin, Louisiana.

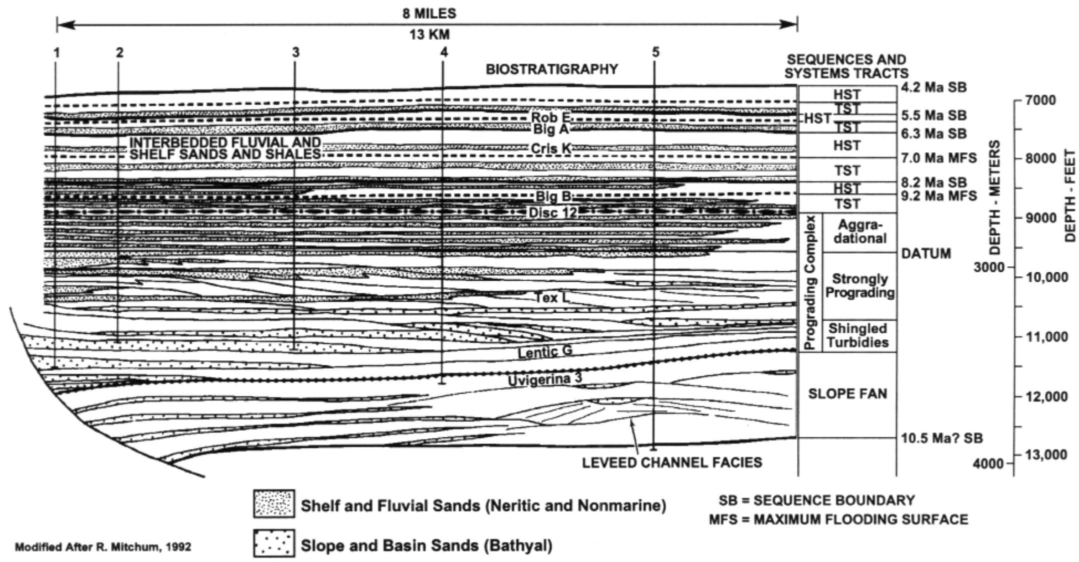

Figure 18a.

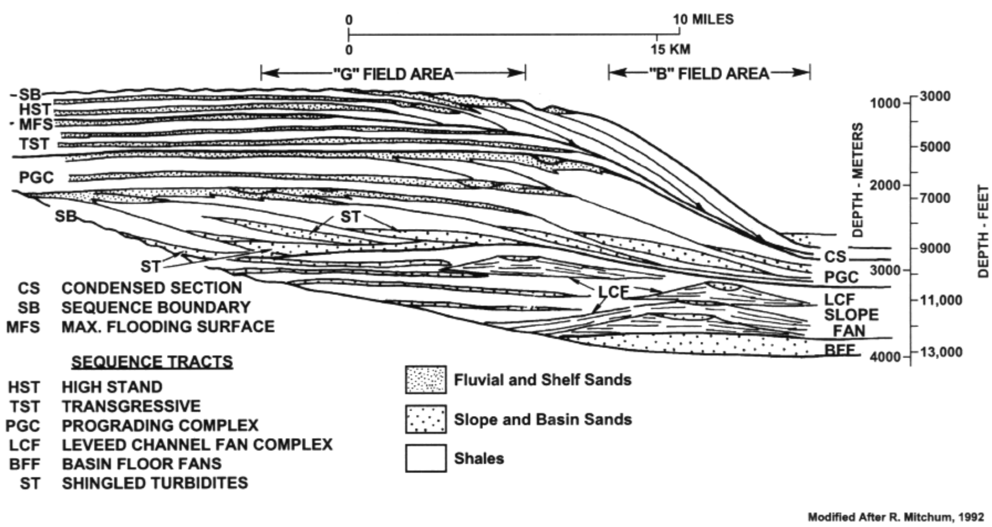

Figure 18. (a) Stratigraphic cross-section across the "G" field based on 6 deep wells, palaeo-data and 3D seismic data. (b) Sequence stratigraphic correlation of shallow and deep reservoir units based on well logs, 3D seismic data and some palaeo-data, "G" and "B" fields, coastal Gulf of Mexico basin. Only two deep 1950s wells penetrated the sections below 3000 m. Both wells had gas condensate shows and were recompleted in the normally pressured prograding complex reservoirs.

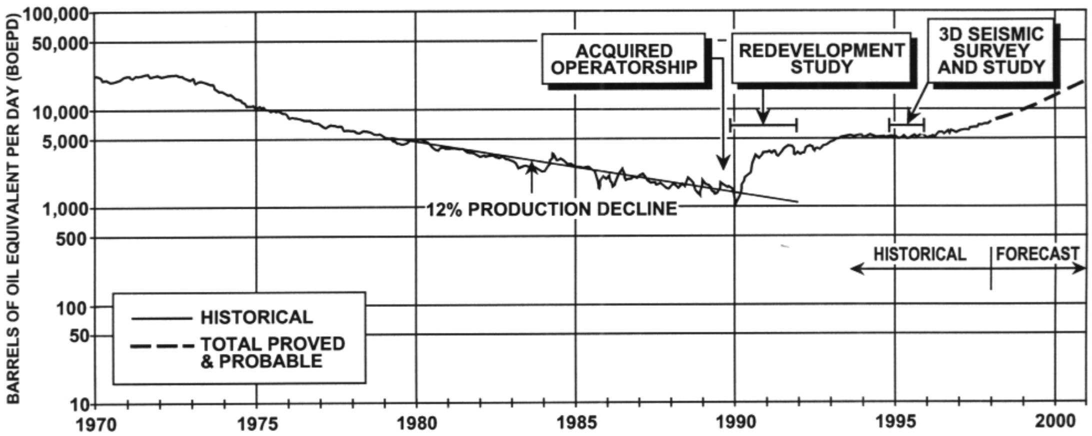

Figure 19. Graph of "G field daily production in BOEPD. The field was acquired in 1989 and a field redevelopment study was initiated. The production increase started in 1990 resulting from workovers and recompletions. A 1994-95 3D seismic survey documented additional shallow and deep new well opportunities and field extensions.

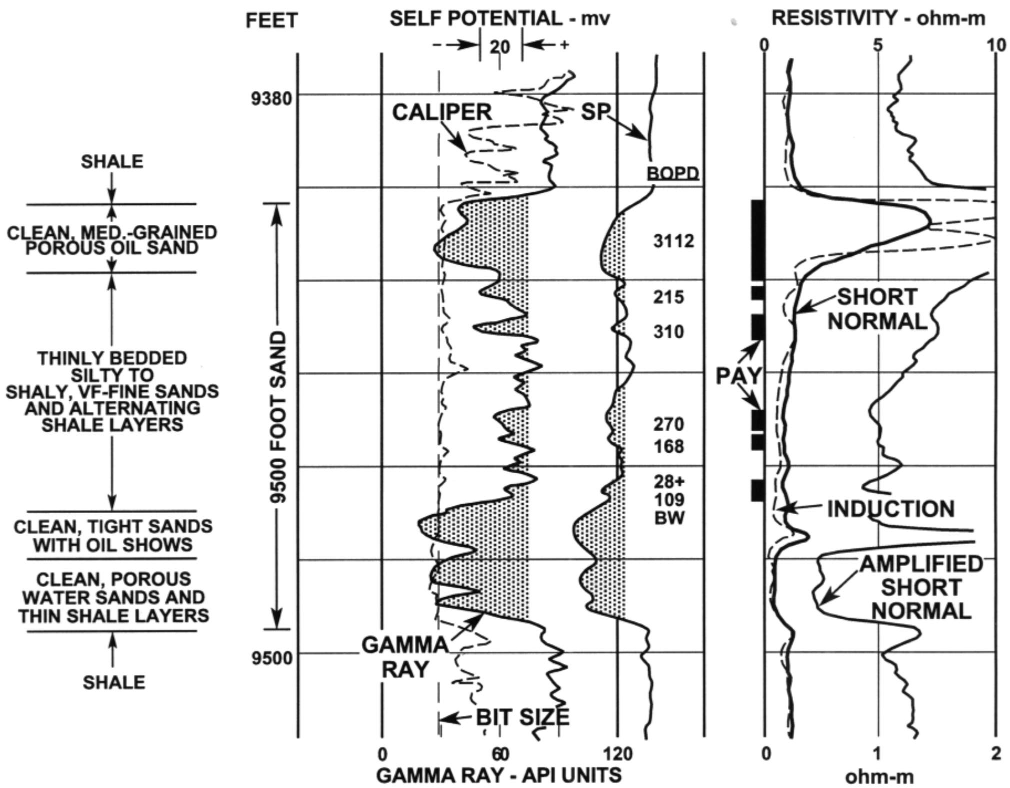

Figure 20. Well logs of the 9500 ft. reservoir sand in a 1989 well, “G” field, coastal Gulf of Mexico. This new cored well is less than 10 meters from a 1940s well that produced from the upper 20 ft. of the 9500 sand. The low resistivity interval below the 7 _m interval was never tested because it was interpreted as wet. This low resistivity interval production tested about 1000 BOPD. Each individual flow test was 30 days.

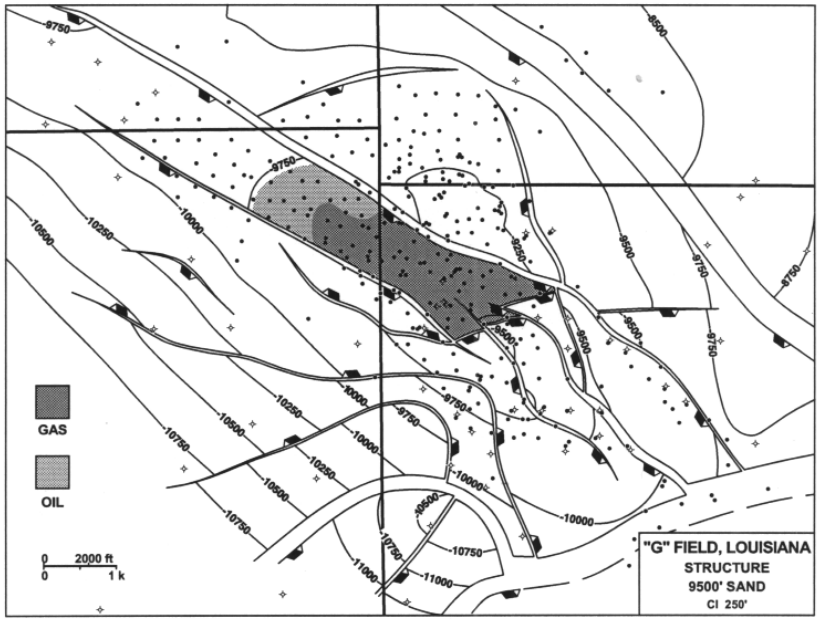

Figure 21. Structure map on top of the 9500 ft. sand showing its original distribution of oil and gas, “G” field coastal Gulf of Mexico, Louisiana.

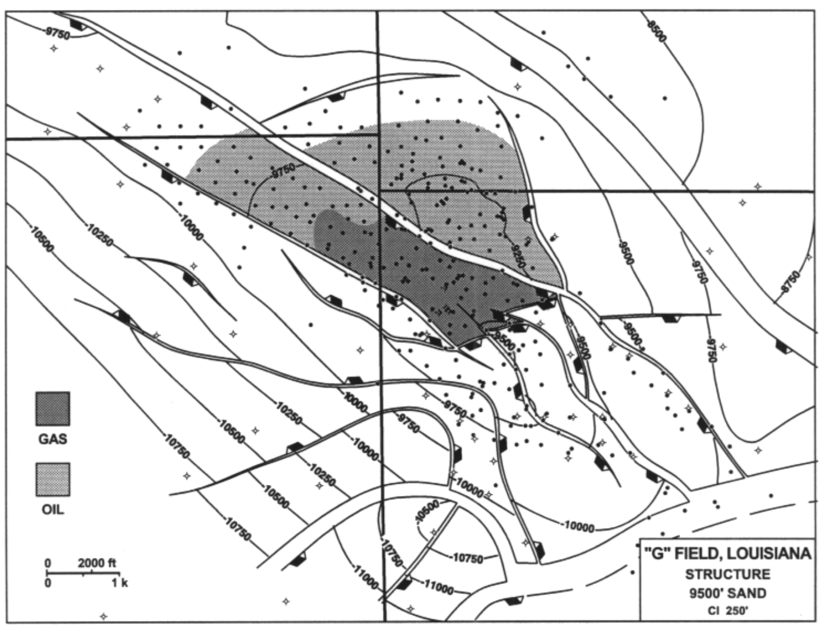

Figure 22. Structure map on top of the 9500 ft. sand showing the new distribution of oil and gas resulting from recompleting the low resistivity intervals in the sand, “G” field, coastal Gulf of Mexico, Louisiana.

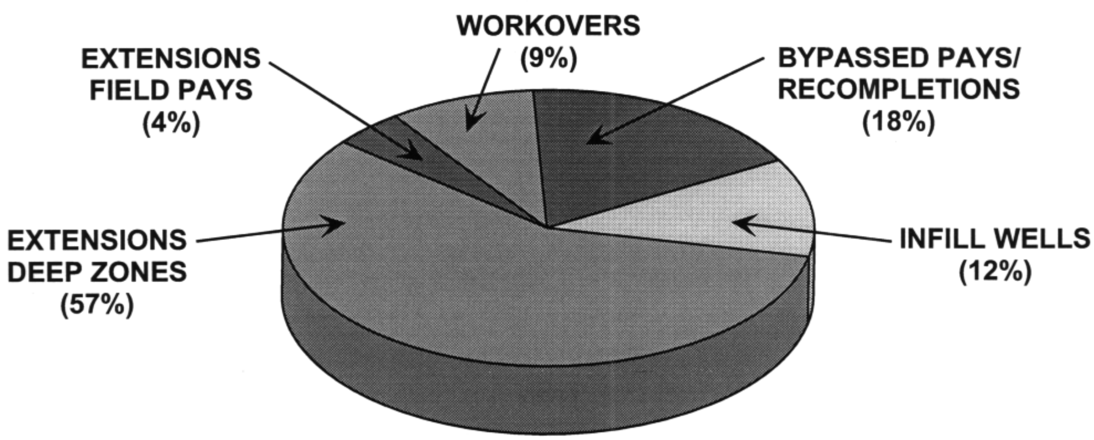

Figure 23. Opportunities for reserve additions and performance improvements, “G” field, Gulf of Mexico basin, coastal Louisiana.

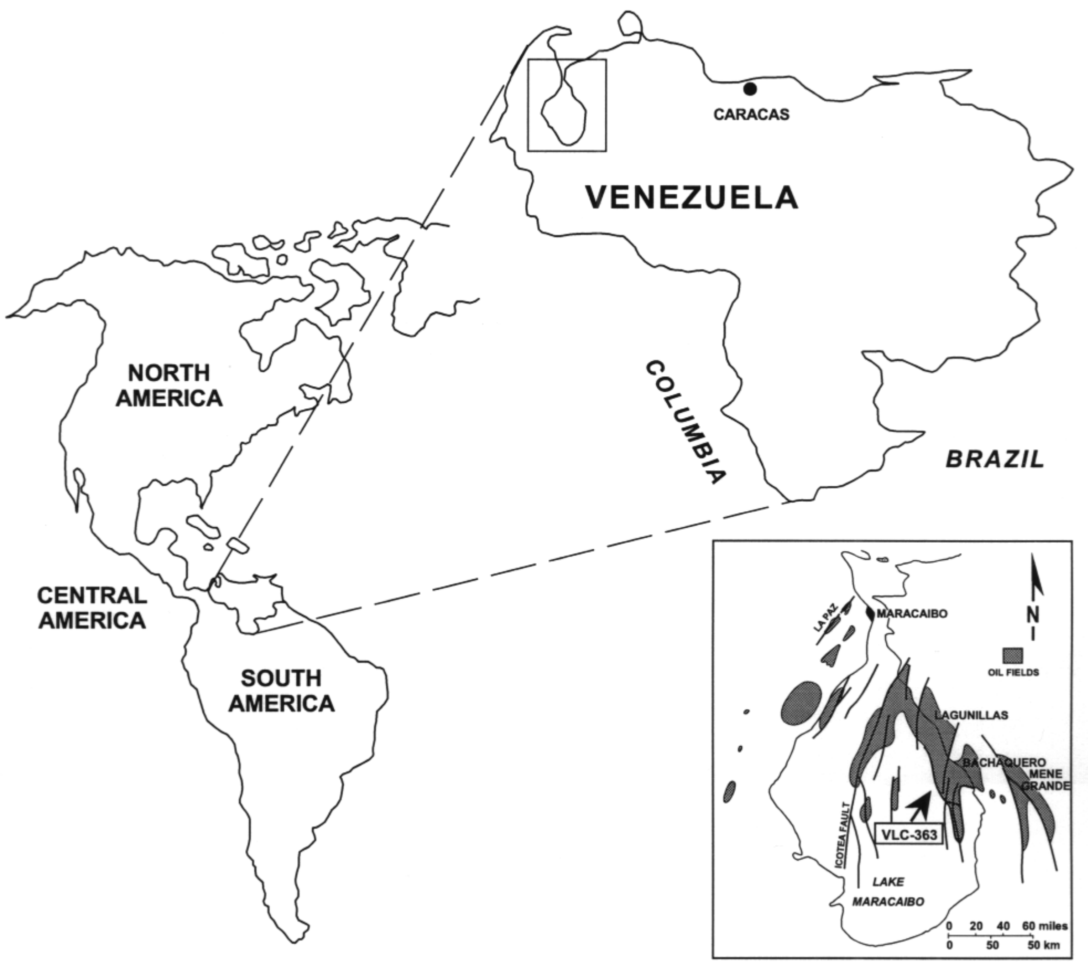

Figure 24. Location of VLC-363, Block III field, Lake Maracaibo, Venezuela.

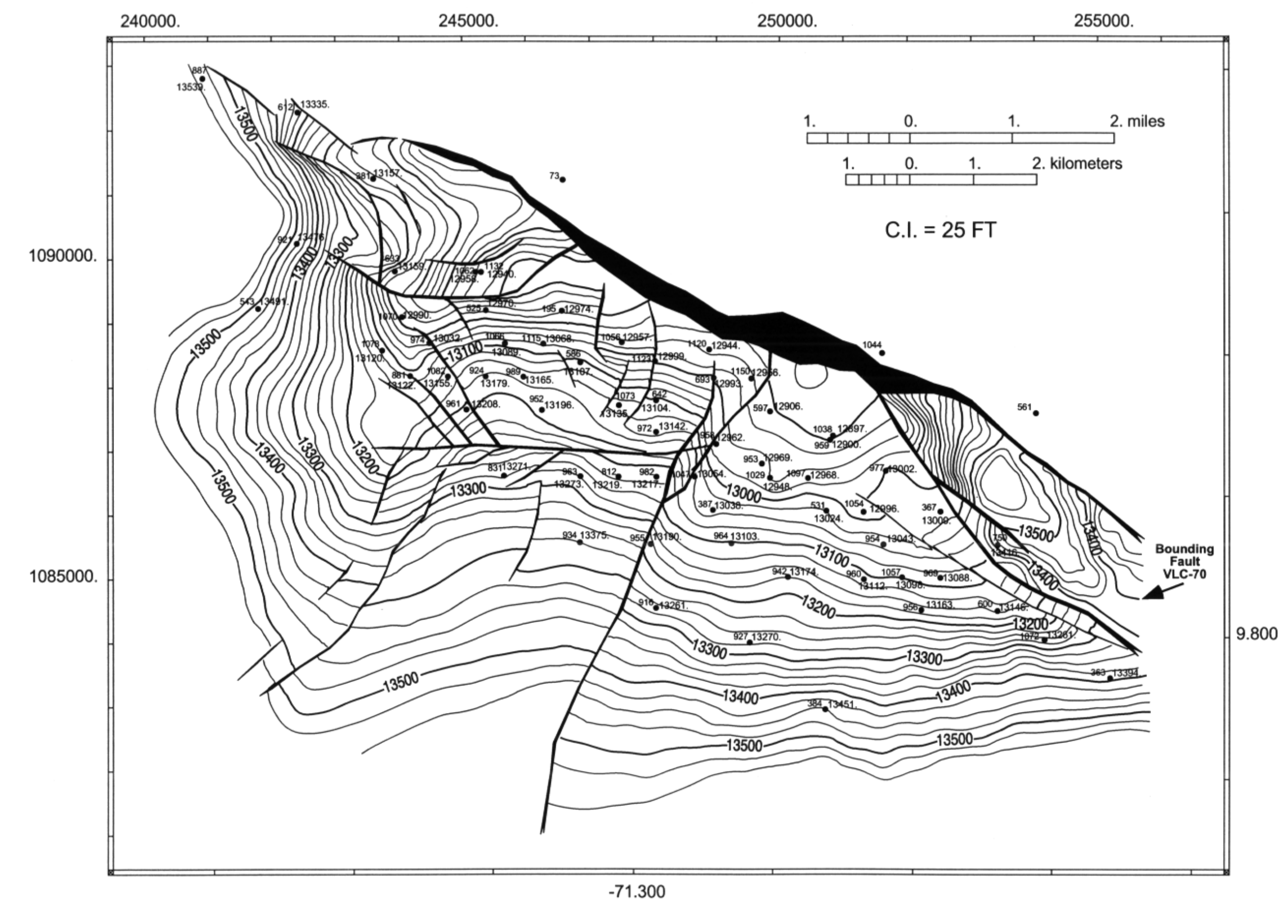

Figure 25. Structure map on the top of the C455 reservoir based on well logs and 3D seismic, VLC-363, Block III field.

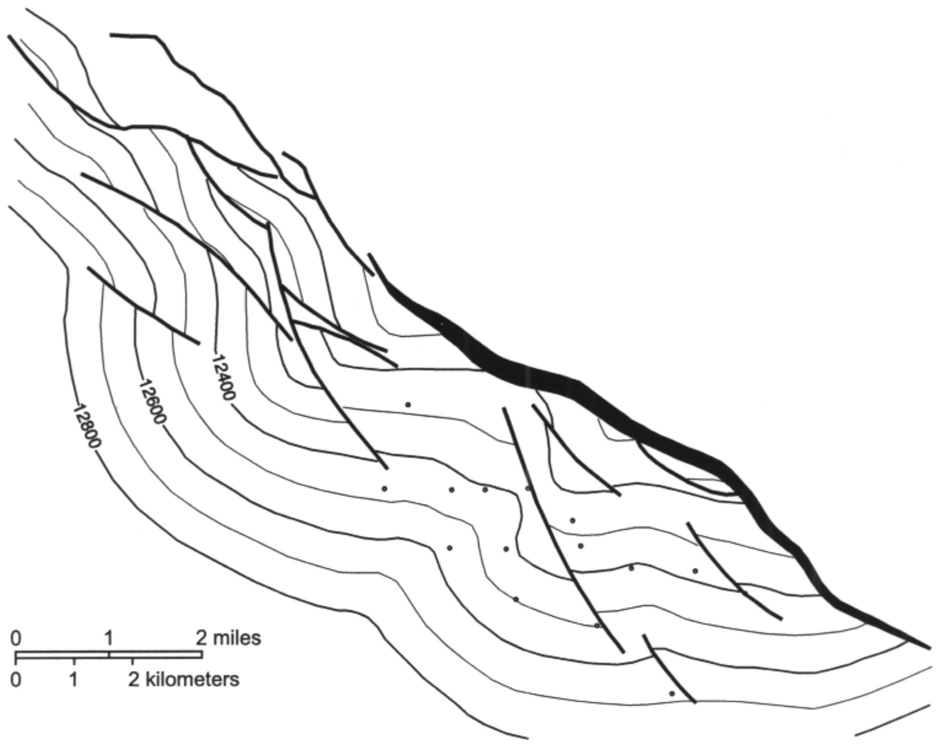

Figure 26. 1960s structure map on the top of the C4 reservoir based on well logs, VLC-363, Block III field.

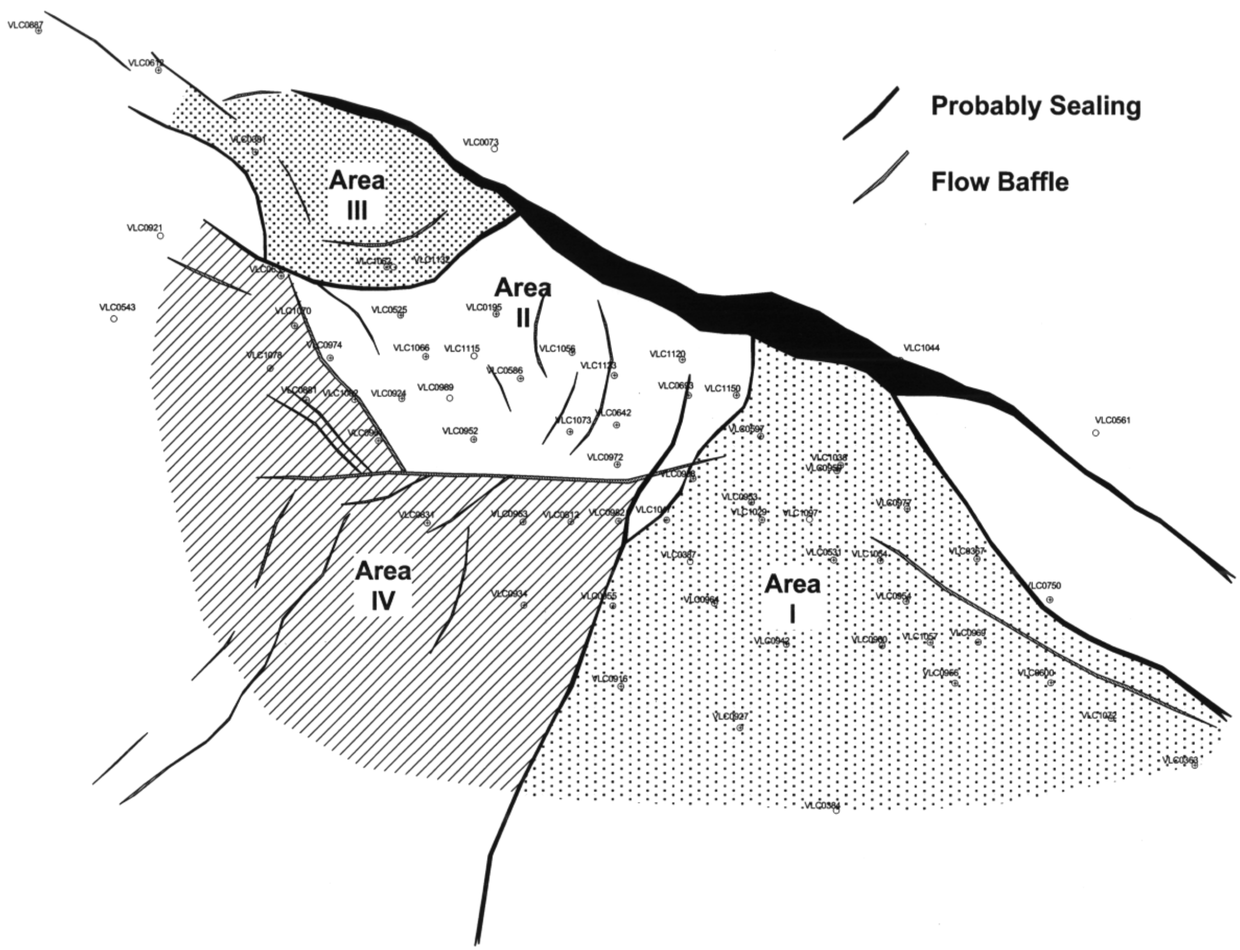

Figure 27. Sealing and partially sealing faults divide the field into four major production zones, VLC-363, Block III field.

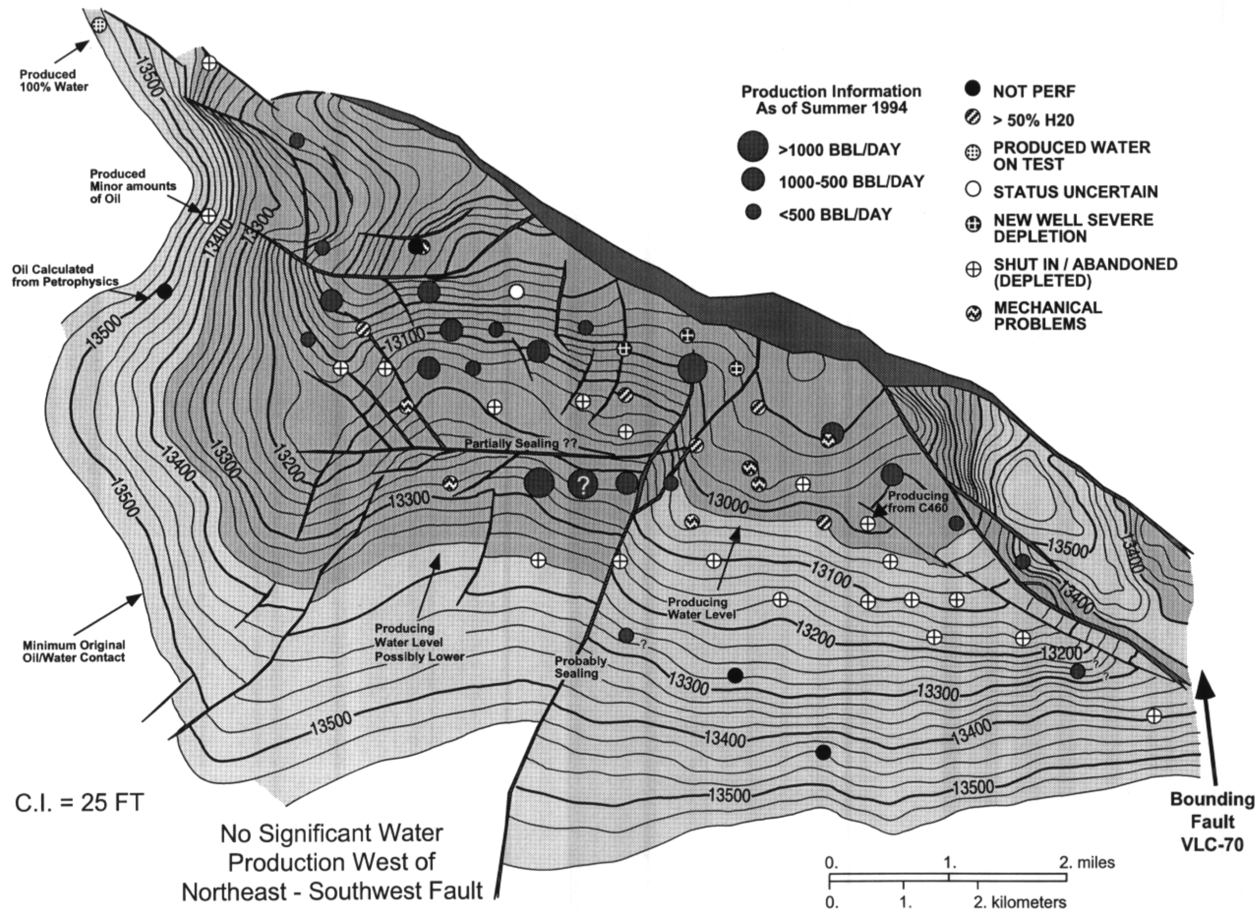

Figure 28. Daily production, hydrocarbon distribution and well status in July 1995 superimposed on the C455 structure map, VLC-363, Block III field.

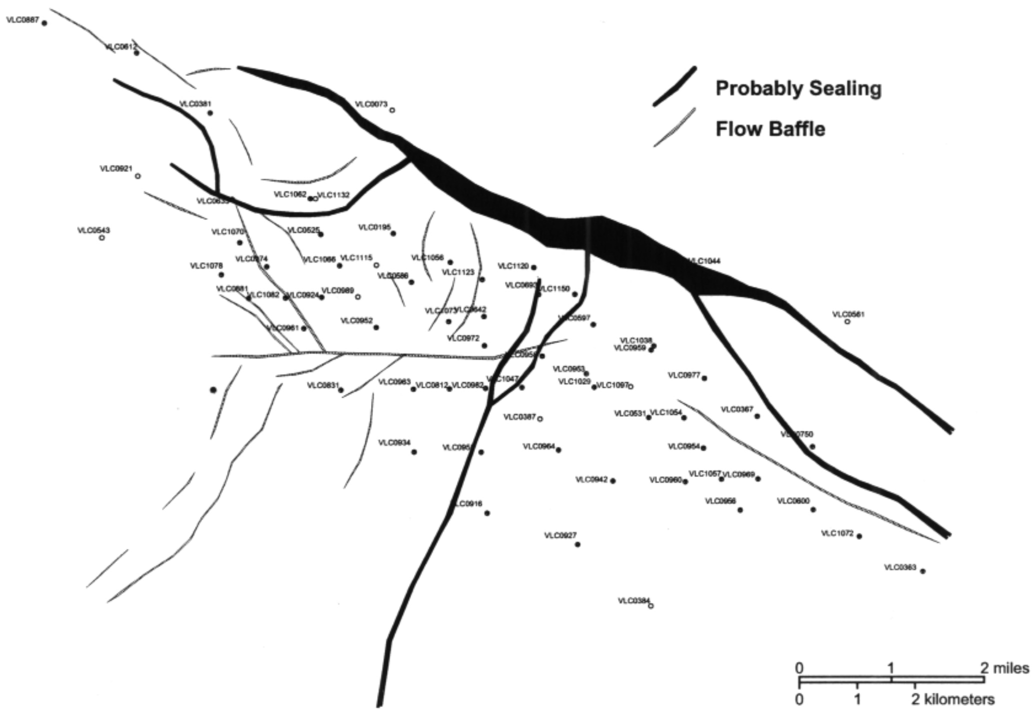

Figure 29. Map showing faults that are completely sealing that act as barriers to fluid flow and faults that leak but act as partial barriers to fluid flow, VLC-363, Block III field.

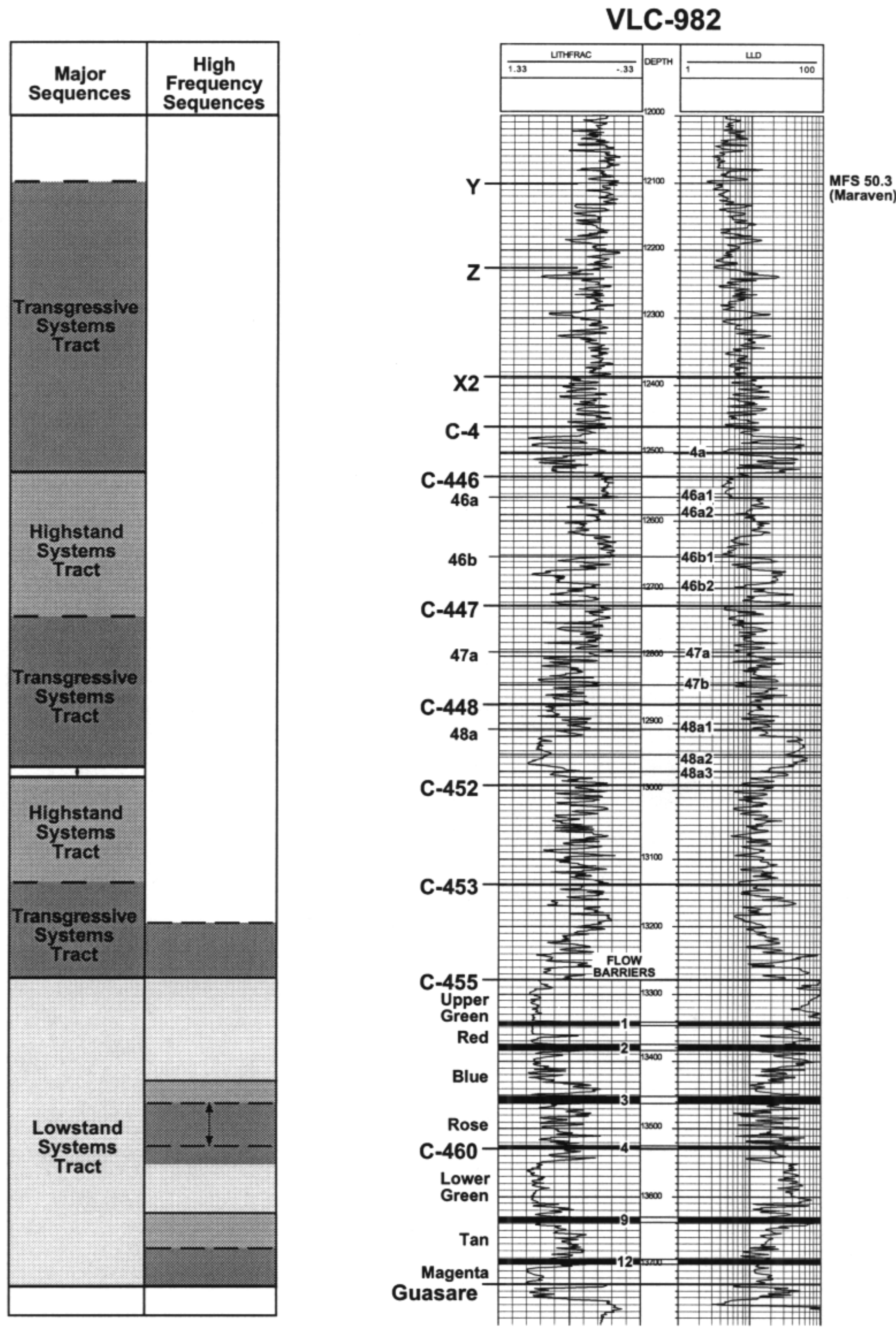

Figure 30. Type log for the VLC-363 Block III field showing detailed correlation units that separate flow units and showing the sequence stratigraphic interpretation.

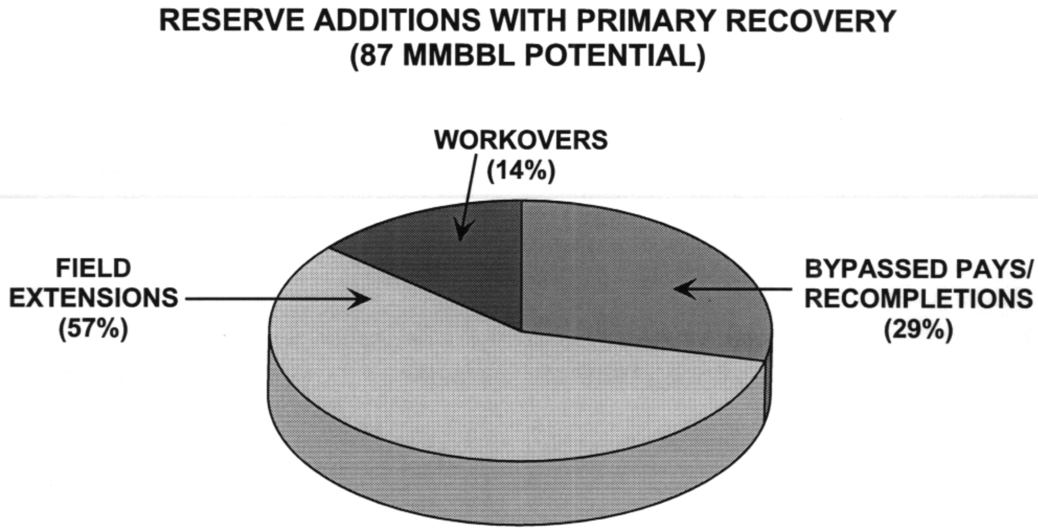

Figure 31a.

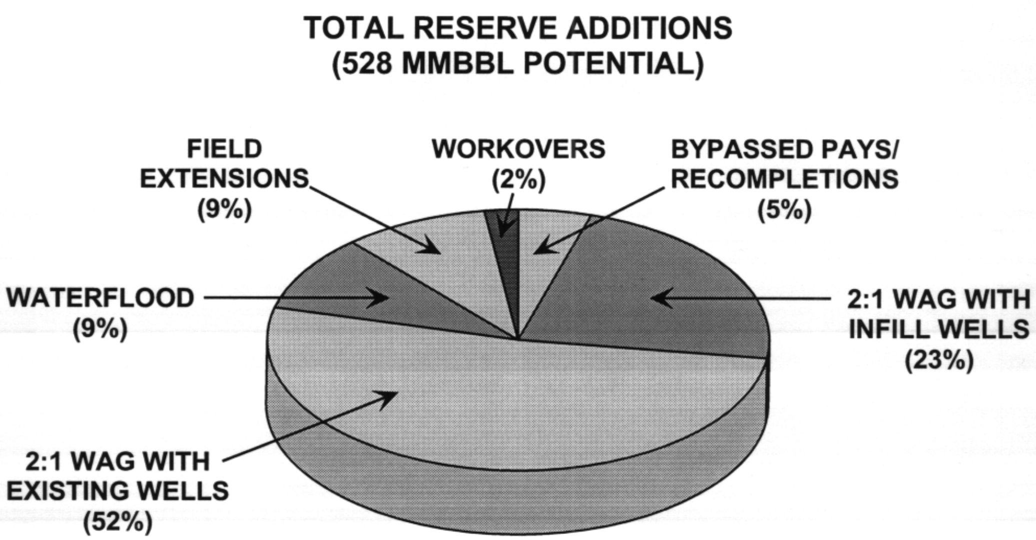

Figure 31. Diagrams showing a) distribution of reserve additions and opportunities for production improvements with primary recovery and b) distribution of reserve additions and performance improvements including enhanced recovery, VLC-363, Block III field.

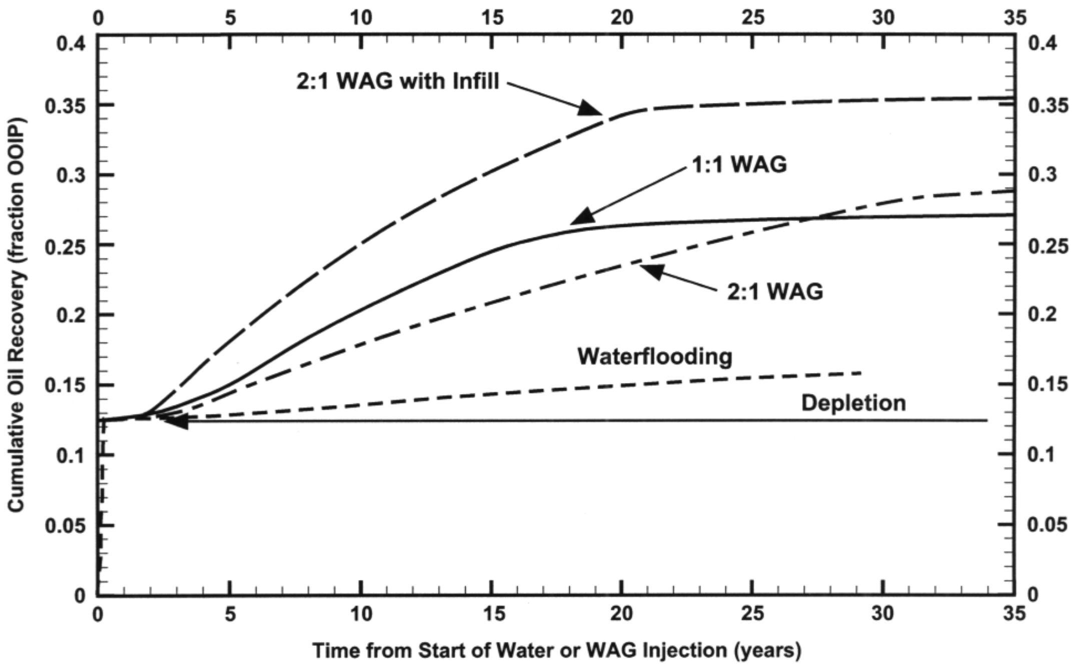

Figure 32. Plot showing recovery in time after water or WAG (water alternating with gas) injection in years versus the cumulative oil recovery as fractions of OOIP, VLC-363, Block III field.

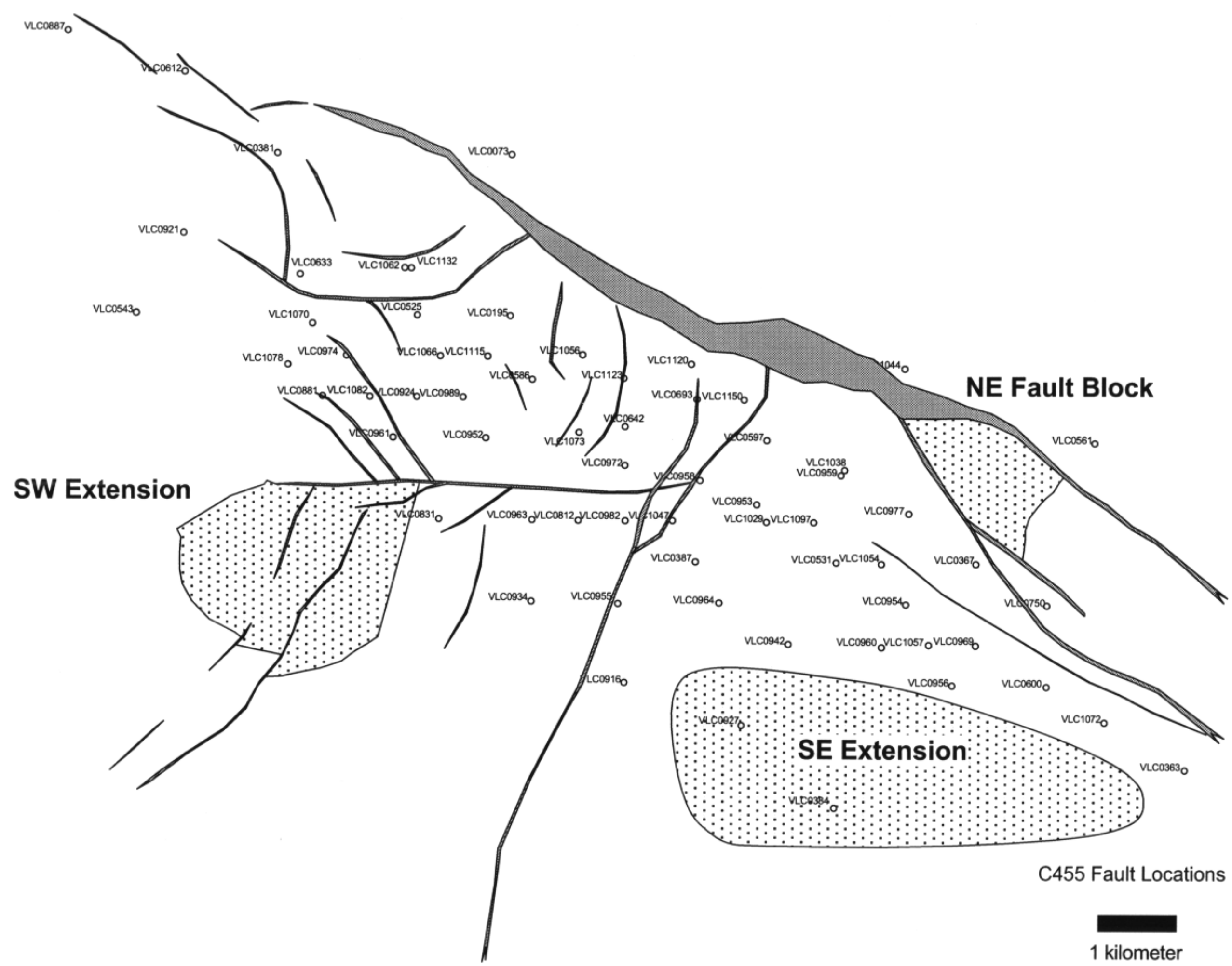

Figure 33. Location of some field extension areas, VLC-363, Block III field.

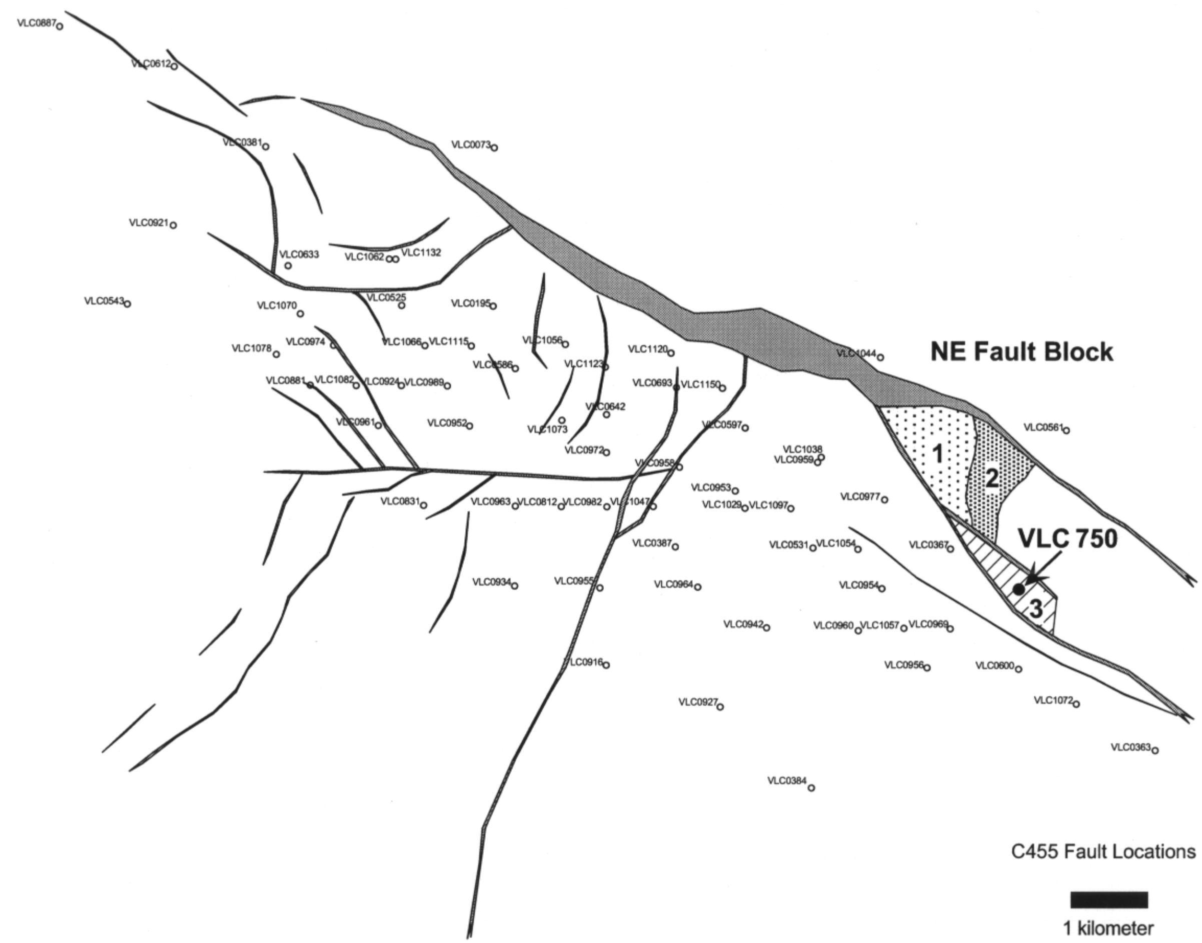

Figure 34. Location map of the northeast fault block prospect. Area 1 contains 456 acres and 34.6 mmbbl OOIP, Area 2 contains 278 acres and 22.6 mmbbl OOIP, and area 3 contains 152 acres and 7.5 mmbbl OOIP, VLC-363, Block III field.

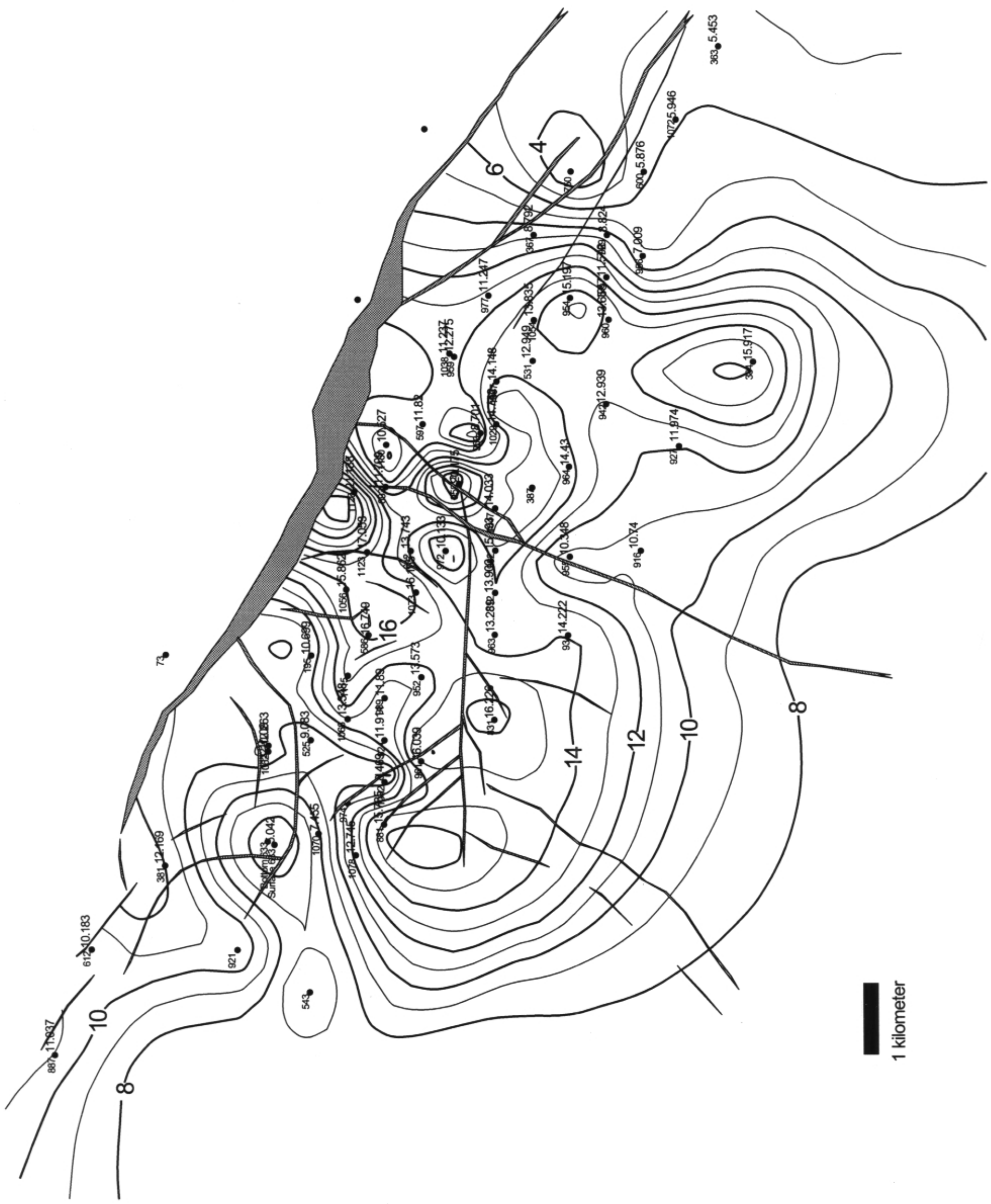

Figure 35. Hydrocarbon pore volume map for the C455 reservoir, VLC-363, Block III field.

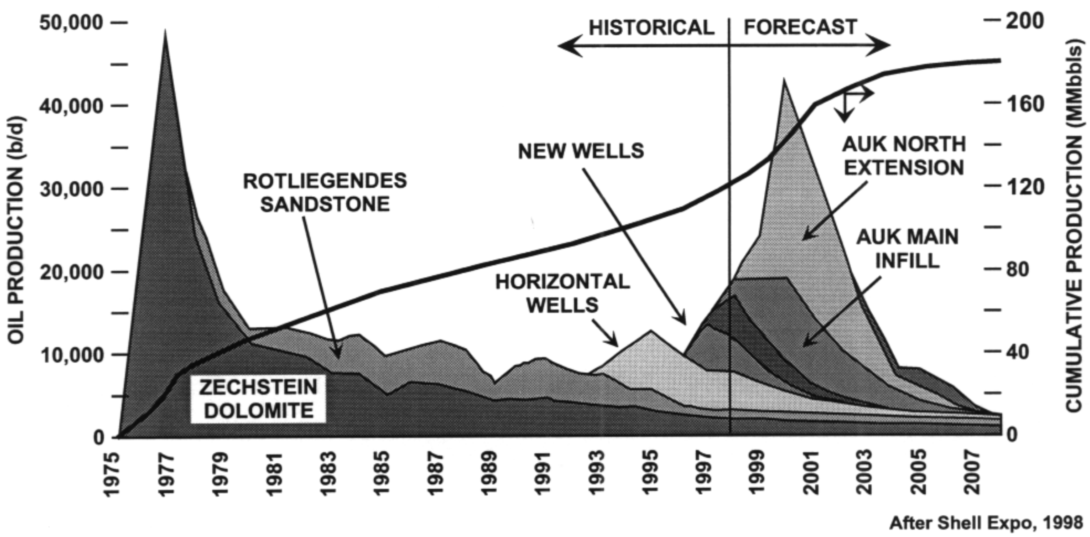

Figure 36.Production history and field development, Auk-Auk North field, central graben, North Sea.

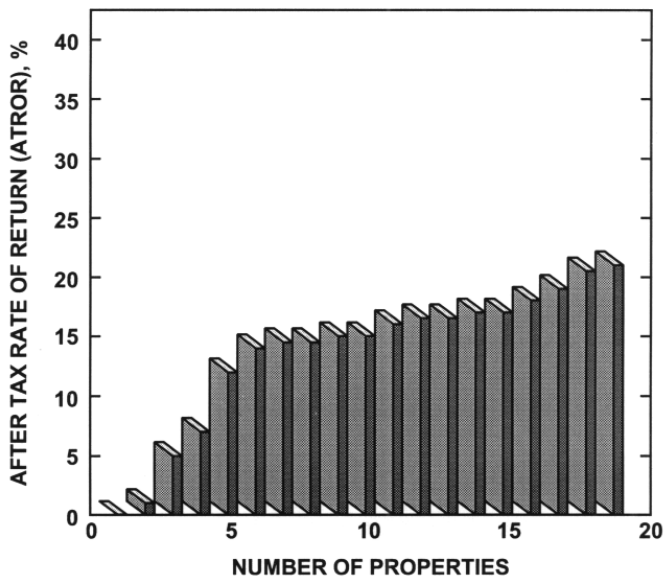

Figure 37.Value of 19 waterflood fields purchased in the Permian basin, Texas and New Mexico. Value is expressed at the percent after tax rate of return (ATROR). The two unprofitable fields were fractured and water injection could not be controlled.

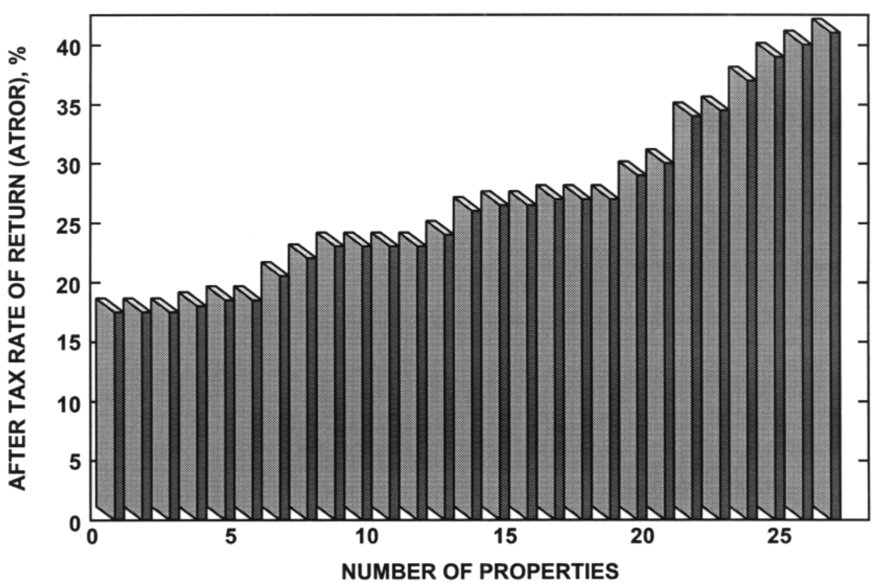

Figure 38.Value of 27 fields purchased in the Texas-Louisiana coastal Gulf of Mexico basin. Value is expressed as the ATROR%.