BED-ISOLATION TREATMENTS OF A MATURE WELL IN THE BLUEBELL FIELD OF THE UINTA BASIN, UTAH, THAT HAS UNDERGONE NUMEROUS HIGH-VOLUME SHOTGUN COMPLETIONS

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Class I Field Demonstration Program contract number DE-FC22-92BC14953 (1993-1999) entitled *Increased oil production and reserves from improved completion techniques in the Bluebell field, Uinta Basin, Utah,* Contracting Officer Representative Dan Ferguson NPTO, Tulsa Oklahoma.

ABSTRACT

The purpose of the Class I field demonstration program was to increase primary oil production and reserves through improved completion techniques in the Bluebell field, Uinta Basin, Utah. Significant hydrocarbon reserves are believed to remain untapped due to insufficient characterization of the reservoir properties and less-than-optimal well-completion practices. Over one-quarter of the wells drilled in the Bluebell field have been abandoned, and the well abandonment rate is expected to increase as water production increases and oil production declines.

Wells in the Bluebell field typically have been completed in a shotgun fashion where 40 or more beds are perforated within a 1,500-foot vertical section of the Tertiary Green River and Colton Formations. During the life of most wells, additional perforated intervals are added and shotgun acid stimulations are applied to all the perforations every few years. The large acid jobs are expensive and the financial return generally declines with each successive treatment.

Part of the well demonstration program involved analyzing a mature well using dual burst thermal decay time (TDT) and dipole shear anisotropy (anisotropy) cased-hole logs and then acidizing four beds individually, attempting to avoid treating oil-depleted water-producing beds. Anisotropy and isotope tracer logs were run for post-treatment analysis. The first two acid treatments resulted in communication with intervals above and below the test interval. Swab tests recovered acid water from both intervals. The third and fourth treatments were confined within the test intervals, and oil and water were recovered during swab testing. A bridge plug was placed between the second and third test intervals, eliminating the first two (lowermost) intervals from production. The daily oil production rate was doubled and reservoir modeling indicates that 27,000 barrels of oil was added to the recoverable reserves from a previously perforated but nonproductive bed.

This project found the bed-isolation completion technique can be an effective and economic treatment if good cased-hole data are gathered, especially for older wells where the potential incremental increase in oil production no longer justifies the expense of the larger shotgun acid completion. Beds should be selected for treatment using anisotropy and TDT logs to identify beds that are fractured and have relatively low water saturation. The bed-isolation completions should be conducted using a dual packer tool to reduce cost. Both the upper and lower packer should be placed between perforated beds with at least 50 feet of vertical separation between them to reduce the risk of communication behind the casing during the treatment. The isotope tracer log can be useful in evaluating the mechanical aspects of the acid treatment, identifying thief beds, and detecting communication problems behind the casing which can be avoided in future treatments.

INTRODUCTION

The Bluebell field demonstrations were intended to test techniques to complete new wells and recomplete old wells in order to increase primary production and extend the life of many wells that might otherwise be prematurely abandoned. While the Bluebell field has produced large amounts of oil, indications are that significant reserves remain untapped due to lack of detailed characterization of the reservoir properties and current completion practices. More than one quarter of the wells drilled have been abandoned, and as water production increases and oil rates decline, the abandonment rate is expected to increase.

Wells in the Bluebell field are typically completed by perforating 40 or more beds over 1,000 to 3,000 vertical feet (300-900 m), then stimulating the entire interval with a single hydrochloric acid treatment. This technique is often referred to as a "shotgun" completion. The shotgun technique is believed to leave many potentially productive beds damaged and/or untreated, while allowing water-bearing and low-pressure (thief) zones to communicate with the wellbore. This practice has been used primarily because of the difficulty in identifying fracture zones and correlating reservoirs between wells.

Dual-porosity, dual-permeability, single-well, numerical simulation modeling indicate that fracturing is essential for good reservoir performance in the Bluebell field. Model sensitivity analyses of block size, fracture porosity, fracture frequency, and fracture permeability were conducted. Increased fracture porosity and frequency resulted in increased gas production. Increasing the fracture permeability increased the oil and gas production from a well for fracture permeabilities up to 5 milliDarcys (mD). Fracture permeability above 5 mD has less of an effect because the production is limited by the matrix permeability.

Two recompletion techniques were tested, a staged-completion, and bed-isolation completion technique. The staged-completion technique involves acidizing the entire productive interval (typically 1,500 feet [450 m] or more) in stages of about 500 vertical-feet (150 m) each. When the treatments are applied in stages, more of the perforated beds receive acid. Larger intervals or single stage treatments do not effectively get acid into all of the perforated beds. The large staged-completion technique becomes less effective as a well matures and many of the perforated beds become depleted of oil and increase in water production. The bed-isolation completion technique involves isolating and acidizing only beds with remaining oil potential. Cased-hole logs are effective tools for identifying changes in reservoir properties and remaining oil potential over the life of a well.

Identification of The Problems

The Bluebell field study was developed after extensive consultation with Uinta Basin operators and service companies on what completion and production problems are believed to be the most significant in the Uinta Basin oil fields. The consensus opinion identified the following problems:

1. A larger than necessary gross interval is typically perforated because of a lack of detailed understanding of the properties in the highly heterogeneous, multiple-reservoir complex spanning the Green River and Colton Formations.

2. Perforating a very large gross interval opens up water zones, thief zones, and low- to non-productive beds.

3. Effective treatments are difficult to design because of the large gross perforated interval, and the complex heterogeneity of the multiple reservoirs opened to the wellbore.

4. Heavy drilling mud, necessitated by overpressured reservoirs, invades the producing beds causing formation damage and reducing near-wellbore permeabilities.

Approach and Project Description

A two-year characterization study of the Bluebell field consisted of 12 separate, yet related tasks. The characterization tasks were: (1) well log analysis and petrophysical investigations, (2) outcrop studies, (3) cuttings and core analysis, (4) subsurface mapping, (5) acquisition and analysis of new logs and cores, (6) fracture analysis, (7) geologic characterization synthesis, (8) analysis of completion techniques, (9) reservoir analysis, (10) best completion technique identification, (11) best zones or areas identification, and (12) technology transfer.

The objective was to improve the geologic characterization of the producing formations, and develop completion techniques for specific producing beds or facies as opposed to the non-specific shotgun approach of stimulating all the beds with a single acid treatment. The characterization did not identify predictable-facies or predictable-fracture trends within the vertical stratigraphic column as hoped. But much was learned about the Green River and Colton reservoirs that is applicable to other individual wells, and when combined with advanced cased-hole logs may help to improve completions of new wells, and recompletion of old wells.

A three-well demonstration was developed. First, two different completion techniques on older wells; then one of the methods was selected for use in completing a new well. The recompletion of the Michelle Ute 7-1 well (section 7, T. 1 S., R. 1 W., Uintah Baseline and Meridian) (figure 1) was the first demonstration. The Michelle Ute 7-1 recompletion was designed as a three-stage, high-diversion, high-pressure, acid treatment. Each stage covered about a 500-foot (150-m) vertical interval with over 10 perforated beds. The Michelle Ute 7-1 treatment failed because of mechanical problems during the recompletion attempt. The second well demonstration was a recompletion of the Malnar Pike 17-1 well (section 17, T. 1 S., R. 1 E.). The Malnar Pike 17-1 recompletion was designed to be an acid treatment at the bed scale, by isolating and treating four individual beds. The third demonstration was the completion of a new well, the John Chasel 3-6A2 (section 6, T. 1 S., R. 2 W.), using the staged completion technique.

GEOLOGIC SETTING

The Uinta Basin is a topographic and structural trough encompassing an area of over 9,300 square miles (24,000 km^2) (Osmond, 1964). The basin is sharply asymmetrical with a steep north flank bounded by the east-west trending Uinta Mountains and a gently dipping south flank bounded by the northwest-plunging Uncompahgre and north-plunging San Rafael uplifts. The basin is bounded on the east by the north-plunging Douglas Creek arch and on the west by the north-south-trending Wasatch Mountains (figure 2). The dominant regional fracture systems trend northwest to southeast and west to east, parallel to the major structural features that border or extend into the basin (Stearns and Friedman, 1972). Faults with large displacement and anticlinal folds are uncommon within the Uinta Basin.

The basin contains as much as 32,000 feet (7,960 m) of sedimentary rock ranging in age from Late Precambrian to Oligocene (figure 3). More than half of the sedimentary sequence (>16,000 feet [3,980 m]) consists of Paleocene- and Eocene-aged rocks (Anders and others, 1992). In Paleocene to Eocene time, the Uinta Basin downwarped relative to the rising Uinta Mountains. The basin had internal drainage forming ancestral Lake Flagstaff and Lake Uinta. Deposition in and around the lakes consisted of open- to marginal-lacustrine facies that make up the Green River Formation. Alluvial redbed deposits that are laterally equivalent and intertongue with the Green River, make up the Colton and Wasatch Formations.

The Uinta Basin of northeast Utah is the most prolific petroleum province in the state. More than 439 million barrels (61,000 MT) of oil and 1 trillion cubic feet (28,000,000 m^3) of gas have been produced from deposits in the Paleocene/Eocene Green River and Colton (Wasatch) Formations. The 104 fields in the basin range in size from the giant Altamont-Bluebell-Cedar Rim field complex (three contiguous fields each with a defined legal boundary) in the northwest and north-central part, to scattered single-well fields throughout the basin (figure 1).

In the Altamont-Bluebell-Cedar Rim field area, the Green River and Colton Formations contain an oil-bearing section up to 8,000 feet (2,400 m) thick of which 2,500 feet (750 m) is locally overpressured. Production occurs from multiple, generally low matrix porosity, thin-bedded sandstone deposited in and around the shores of Lake Flagstaff and Lake Uinta during Paleocene through Eocene time. Permeability is commonly enhanced by vertical fractures.

The Bluebell field has produced over 141 million barrels (19,700,000 MT) of high gravity (38-42 degrees API) oil. The field was discovered in 1959 and is the third largest oil field (based on cumulative production) in Utah with more than 300 active wells. Approved well spacing is two wells per square mile, but much of the field is still produced at one well per square mile.

The Bluebell, Altamont, and Cedar Rim fields are located in the north-central portion of the Uinta Basin, near the structural axis (figures 1 and 2). The generation of hydrocarbons in the low-porosity and low-permeability rocks of the Flagstaff Member of the Green River Formation resulted in an overpressured, fractured, Colton/Flagstaff reservoir. Shallower, hydrostatically pressured hydrocarbon accumulations are found in the upper and lower Green River reservoirs These reservoirs are enhanced by tectonic fractures which commonly make them more porous than the Colton/Flagstaff reservoir.

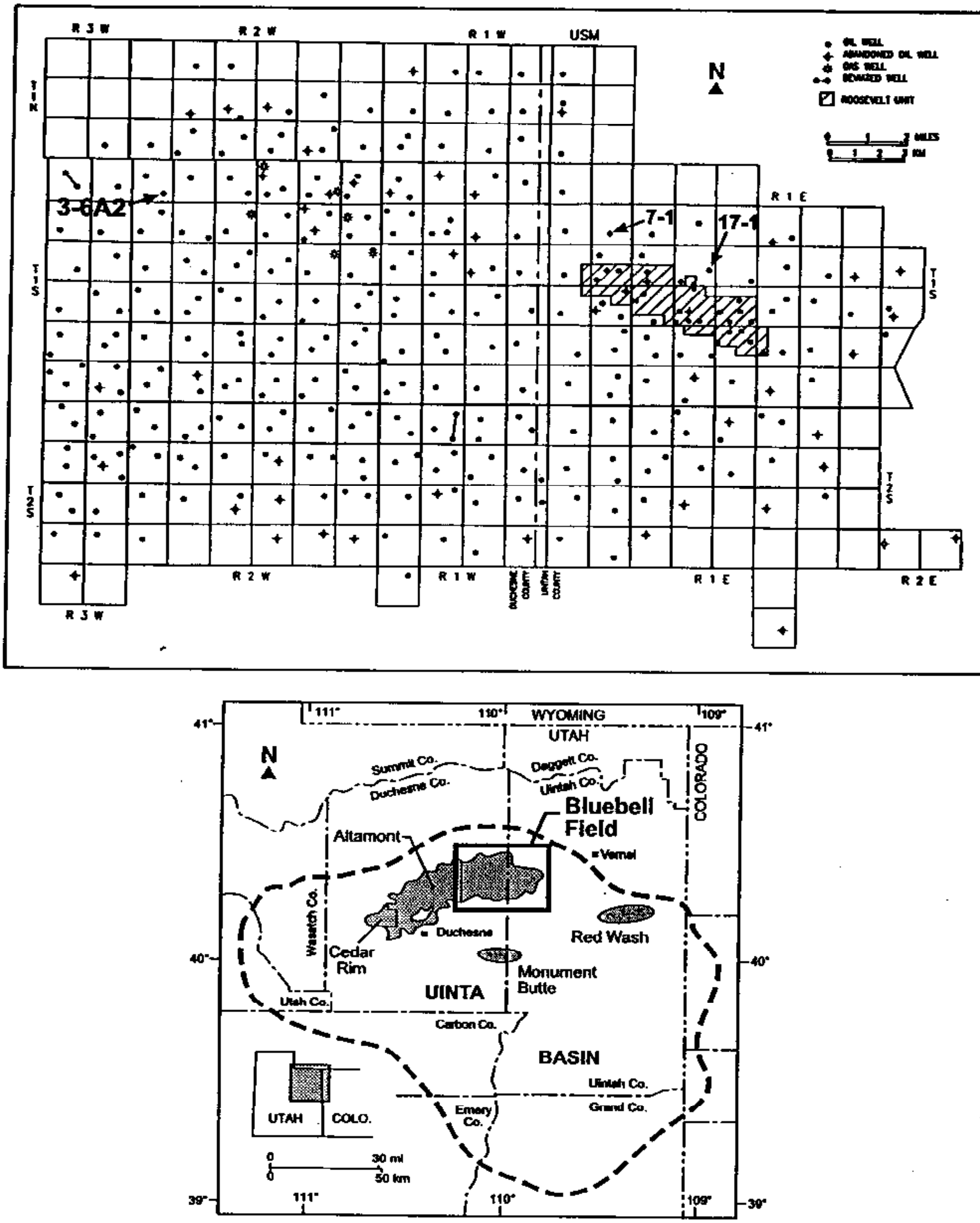


Figure 1. Index map of the Uinta Basin showing major oil fields producing from Tertiary-aged reservoirs. Dashed line approximating the basin extent is the base of the Tertiary-aged rocks. Enlarged map is the Bluebell field with the location of the three demonstration wells labeled, 7-1, 17-1, and 3-6A2.

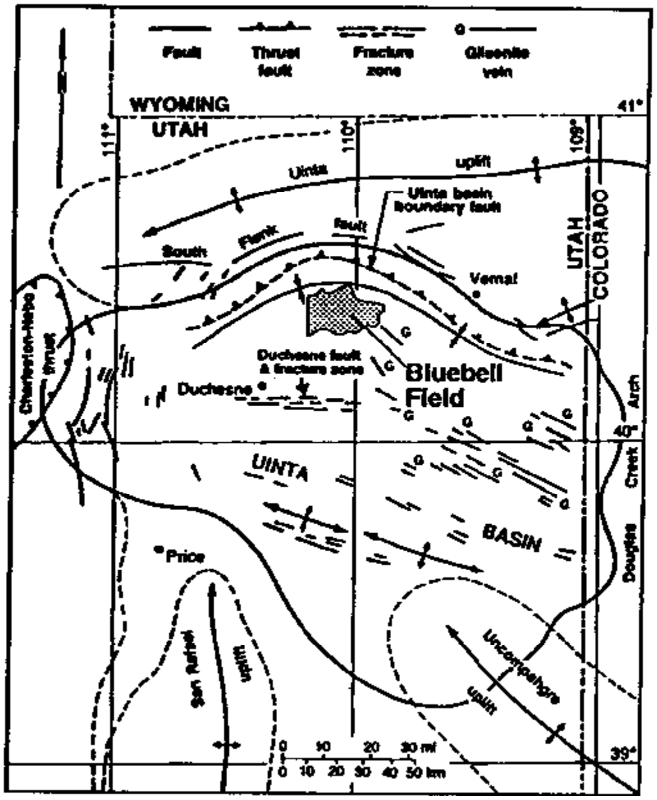


Figure 2. Major structural features, surface faults, and gilsonite veins, in and around the Uinta Basin.

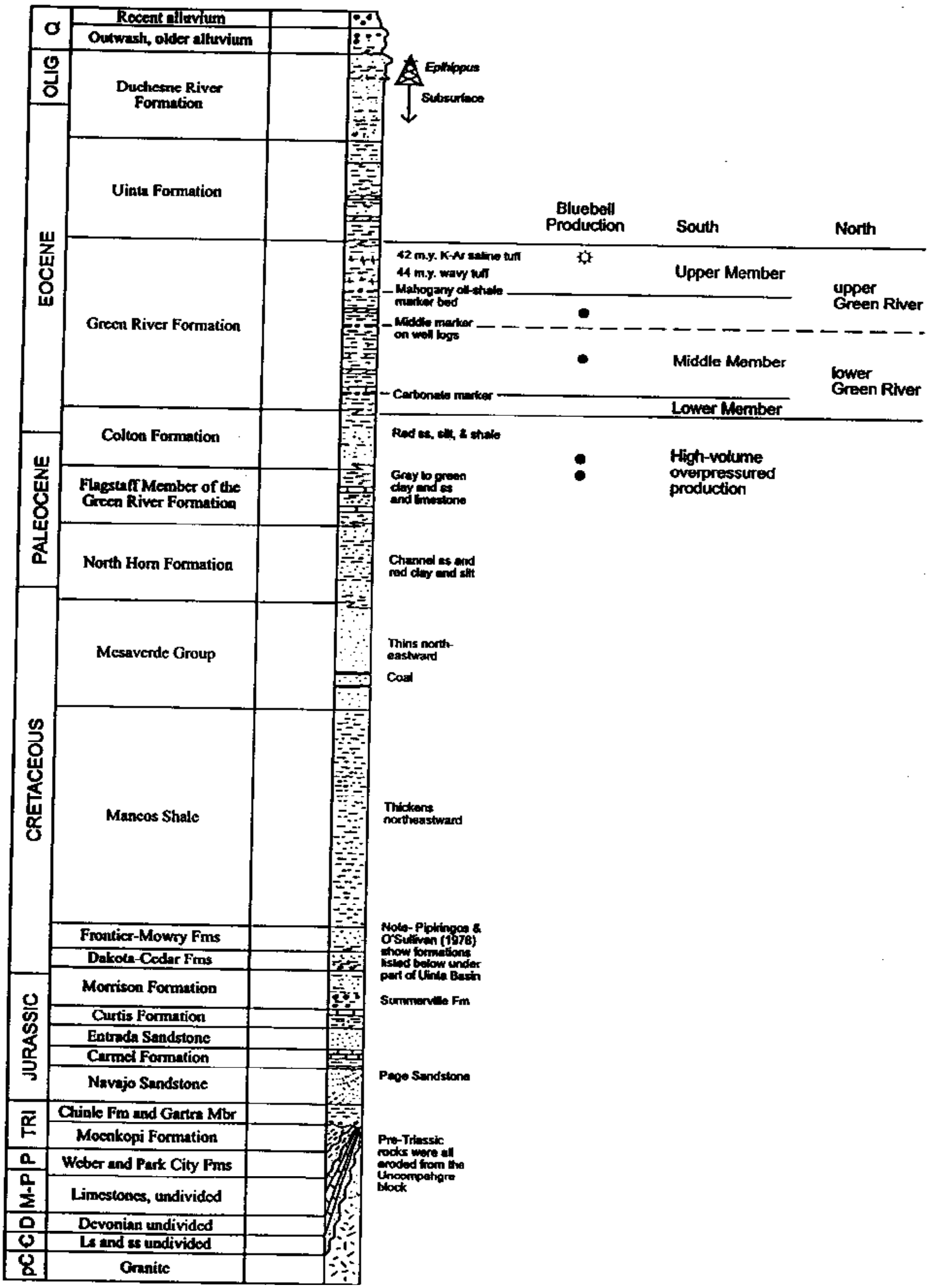


Figure 3. Stratigraphic section of the Uinta Basin modified from Hintze, 1988. The section illustrates the stratigraphic locations of the upper and lower Green River Formation as well as the Colton Formation and Flagstaff Member of the Green River which make up the Colton/Flagstaff reservoir.

SINGLE-WELL NUMERICAL SIMULATION MODELS

Single-well models were developed for both the Michelle Ute 7-1 and Malnar Pike 17-1 wells. The perforated intervals span thousands of feet in both the wells. Geological properties were calculated for all the perforated beds. The information was used to develop models for both wells, but only the Malnar Pike model is discussed here. These were comprehensive models since they took into account all the perforated beds.

Model Parameters

The Malnar Pike 17-1 well is perforated in 55 beds. The model was developed for a 40 acre (16.2 h) (1,320 feet [402.3 m] in the x and y directions) area surrounding the well. The reservoir properties observed at the well bore were assumed to be continuous over the entire 40-acre (16.2-h) area surrounding the well. The numerical values used for various parameters are listed in table 1.

The model was divided into 64 blocks with length and width dimensions of 165 feet (50.3 m). Low-porosity, low-permeability blocks separated the blocks representing perforated beds. This resulted in 109 layers in the vertical direction for the Malnar Pike 17-1 model. The thickness of the grid blocks varied according to the log calculated thickness data. The initial saturation of the perforated beds varied according to the values calculated from logs. The initial reservoir pressure was varied with depth using a gradient of 0.5 pounds-per-square-inch per foot (psi/foot) (115 grams/cm^2/m). The bottom-hole pressure was 3,000 psi (21,000 kPa) for the first year of production and 2,000 psi (14,000 kPa) in subsequent years of production. The initial gas-oil-ratio (GOR) was set to the average GORs observed during the first month of actual production in the well.

Initial Production History Match

The perforating history of the well was duplicated in the production history match model. Even though the well was perforated in multiple beds, all the beds were not perforated at the same time. This factor was incorporated into the model by opening up the respective beds at appropriate times. However, it is not clearly understood which of the perforated beds in the well are responsible for the oil production. The permeabilities of the grid blocks representing the perforated beds were adjusted to match the field oil and gas production. Initially, only the permeabilities of the beds perforated at that time were adjusted until the next set of perforations were added. When the new set of perforations were added, only the permeabilities of newly perforated beds were adjusted. The permeabilities of the set of perforations previously open were not changed. In order to match the production data, the overall permeabilities were reduced after the last set of perforations were added for the well. As a result, the overall permeabilities were reduced to one percent of the original value.

The model predictions for the cumulative oil and gas productions for the Malnar Pike 17-1 well were compared with the field data The model predictions were in close agreement with the field data. The oil production match is better than the gas production, though the gas production predictions are not significantly different than the field data.

The permeabilities and the fracture properties used to obtain the history match are listed in table 1. Extremely low permeability values were needed to obtain the production history match. The matrix permeability for the Malnar Pike 17-1 model varied between 0.1 and 2.5 mD, and the fracture porosity was only 0.02 percent of the reservoir volume. The fracture frequency was 1 per 125 feet (38.1 m). The fracture permeability varied between 0.02 and 0.22 mD. These were adjusted when evaluating the performances of treatments in the well.

The numerical models (four-section, as well as the single-well) do a reasonably good job of matching the field production data. The numerical parameters used for the rock matrix permeability and the fracture properties are extremely low. The low values of the matrix permeability are close to the experimentally observed values. Other researchers also have observed extremely tight (low porosity and low permeability) reservoir rocks in the Bluebell Field (Bredehoeft and others, 1994; Lucas and Drexler, 1976). Because of the tight nature of the reservoirs, production from the Altamont and Bluebell fields is dependent on naturally occurring fracture networks (Bredehoeft and others, 1994; Lucas and Drexler, 1976; Narr and Currie, 1982). The low fracture permeabilities in the model suggests that the fractures are not fully contributing to the production. Wagner (1996) analyzed fractures in some of the cores from the Bluebell field and found that a large number of the fractures were filled with calcite, pyrite or clay. Another reason for non-contributing fractures could be formation damage near the wellbore caused by the frequent acid treatments. The overall permeability values in the model had to be reduced significantly to match the production. The permeability reductions were applied only to the wellbore blocks and not to the entire model. The values were reduced after the final sets of perforations were added to the well. These extreme reductions in the permeability values (99 percent for the Malnar Pike 17-1) suggest that the near-wellbore formation has been damaged over the life of the well. The reductions required can be used to quantify the level of damage.

Table 1. Parameters for the comprehensive models for the Malnar Pike 17-1 well.

PARAMETER	***Malnar Pike 17-1***
Reservoir extent (ft)	9,582-14,360
Grid size	8*8*99
Grid block size (x and y) (ft)	165
Porosity	0.0-0.21
Matrix permeability mD	0.1-2.5
Fracture porosity	0.000002
Fracture frequency	1 per 125 ft
fracture permeability	0.02-0.22
Pressure (psi/ft)	0.5
Oil gravity (API)	35
Gas gravity	0.75
Initial GOR (scf/stb)	1100
Initial bubble point pressure (psi)	4,795
Initial oil saturation	0.1-1.0
Bottom hole pressure (psi)	3,000

RECOMPLETION OF THE MALNAR PIKE 17-1 WELL

The recompletion of the Malnar Pike 17-1 well was the second step in the three-well field demonstration. The Malnar Pike 17-1 recompletion involved isolation, stimulation, and testing of much smaller intervals than normal, treating at the bed scale, or as close to bed scale as was practical. The intervals were isolated using a bridge plug at the base and a packer at the top of the test interval.

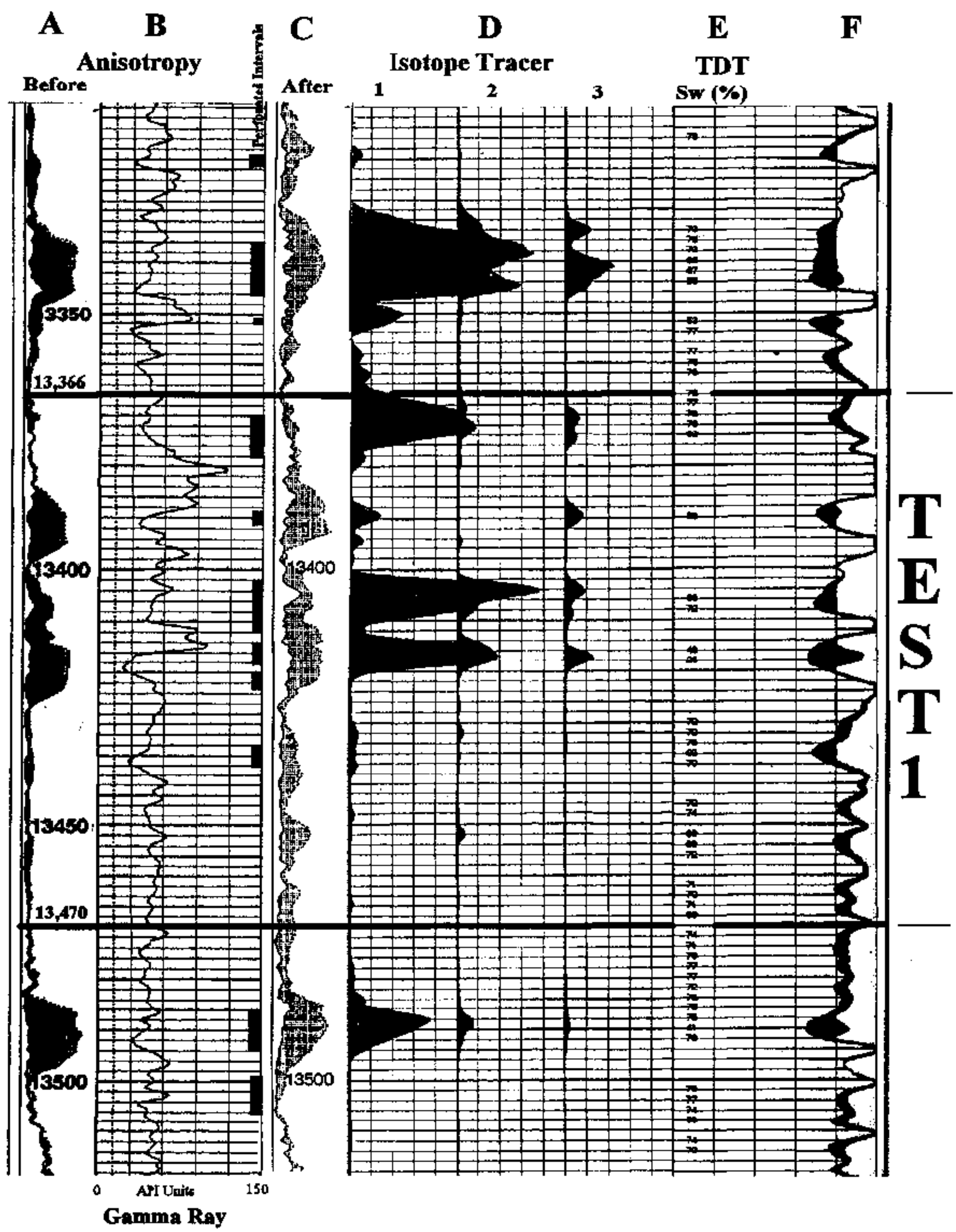
Four separate acid treatments and tests were applied. The first two treatments resulted in communication above and below the test interval. Swab tests recovered acid water from both intervals after the treatment. The third and fourth treatments were mechanically sound and resulted in an increase in the daily oil production.

The TDT log was run before the treatment, anisotropy logs were run before and after the treatment, and an isotope tracer log was run after the treatment. These logs were used to identify beds for treatment and for post-treatment testing and evaluation.

Test Number 1

The first interval stimulated and tested was at a log depth from 13,366 to 13,470 feet (4,073.9-4,105.7 m) (figure 4a). A temperature and spinner survey run early in the life of the well, showed the perforations from 13,434 to 13,438 feet (4,094.7-4,095.9 m) were responsible for 17 percent of the oil production at that time. The TDT log shows this bed has a water saturation from 63 to 79 percent. The pre-treatment anisotropy log shows little to no fracturing in this bed. The perforated intervals 13,402 to 13,412 feet (4,084.9-4,087.9 m), and 13,486 to 13,494 feet (4,110.5-4,112.9 m), were identified as thief zones by the earlier temperature and spinner survey. The pre-treatment anisotropy log shows good fracture development in both thief zones. The perforated bed 13,414 to 13,418 feet (4,088.6-4,089.8 m), has a water saturation of 25 to 40 percent. All the other perforated beds in the test interval have water saturation ranging from 62 to 79 percent as indicated on the TDT log.

Figure. 4A-4D. Portions of the cased-hole logs ran in the Malnar Pike 17-1 demonstration well. Column A is a portion of the dipole shear anisotropy log ran before acid treatment. The greater the separation of the two lines (shaded in) the greater the density of fractures. Column B is a gamma-ray curve for correlation and bed identification. Column C is the anisotropy log ran after the acid treatments. Column D is from the isotope tracer log with the different tracers labeled 1, 2, and 3. The larger the curve, the more isotope left behind the casing, which helps determines where the acid went. The TDT log shows percent water saturation (Sw) in column E and column F diagrammatically shows oil (black) and water (white) in the pore volume of the rock. (4A) test number 1, (4B) test number 2, (4C) test number 3, and (4D) test number 4.



A
B
Anisotropy
Perforated Intervals
C
D
Isotope Tracer
E
TDT
F
Before
After
1
2
3
Sw (%)
3350
13,366
13400
13450
13,470
13500
0
API Units
150
Gamma Ray
TEST 1

Figure 4A.

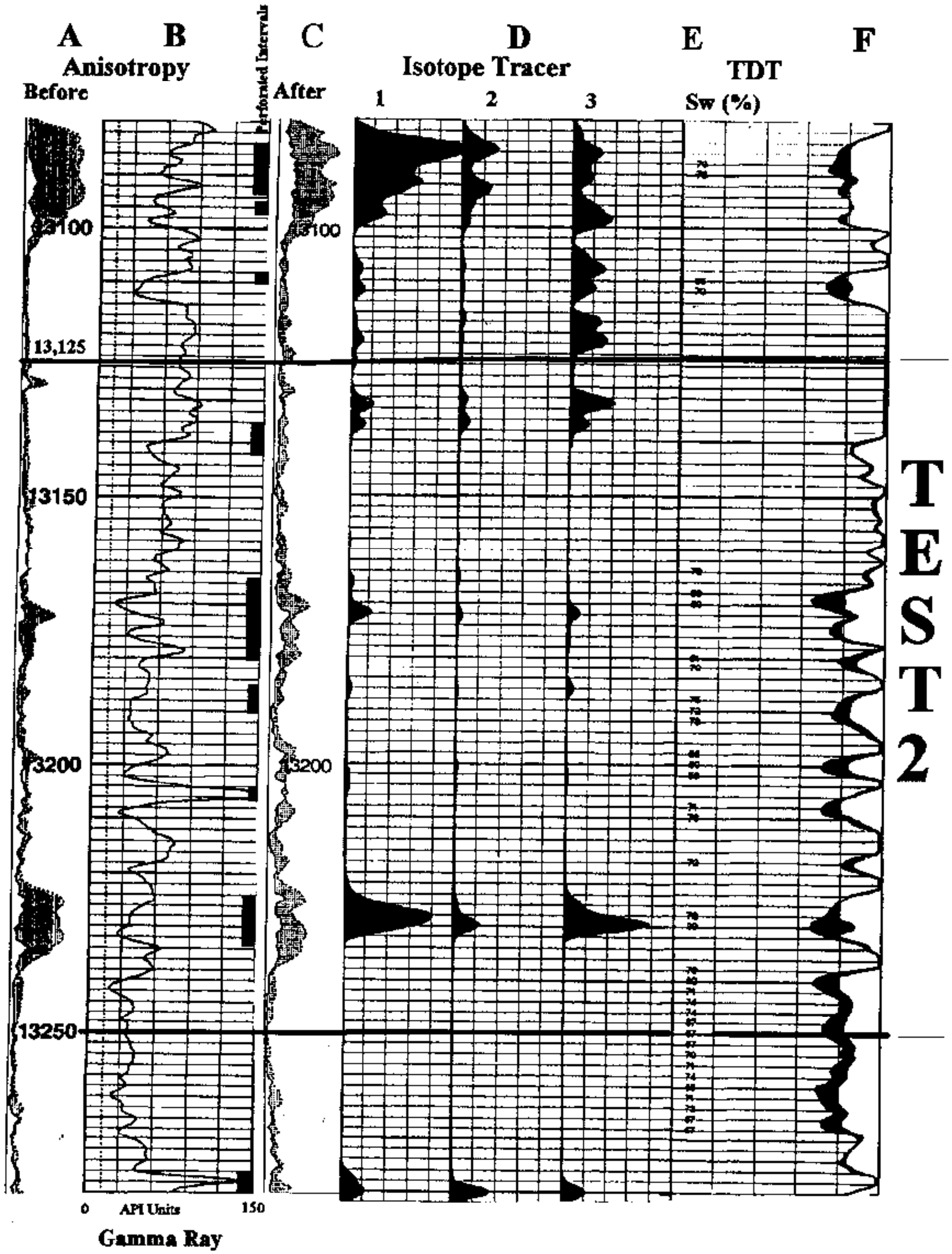

A
B
Anisotropy
Before
Perforated Intervals
C
After
D
Isotope Tracer
1
2
3
E
TDT
Sw (%)
F
13100
13,125
13150
13200
13250
TEST 2
0
API Units
150
Gamma Ray

Figure 4B.

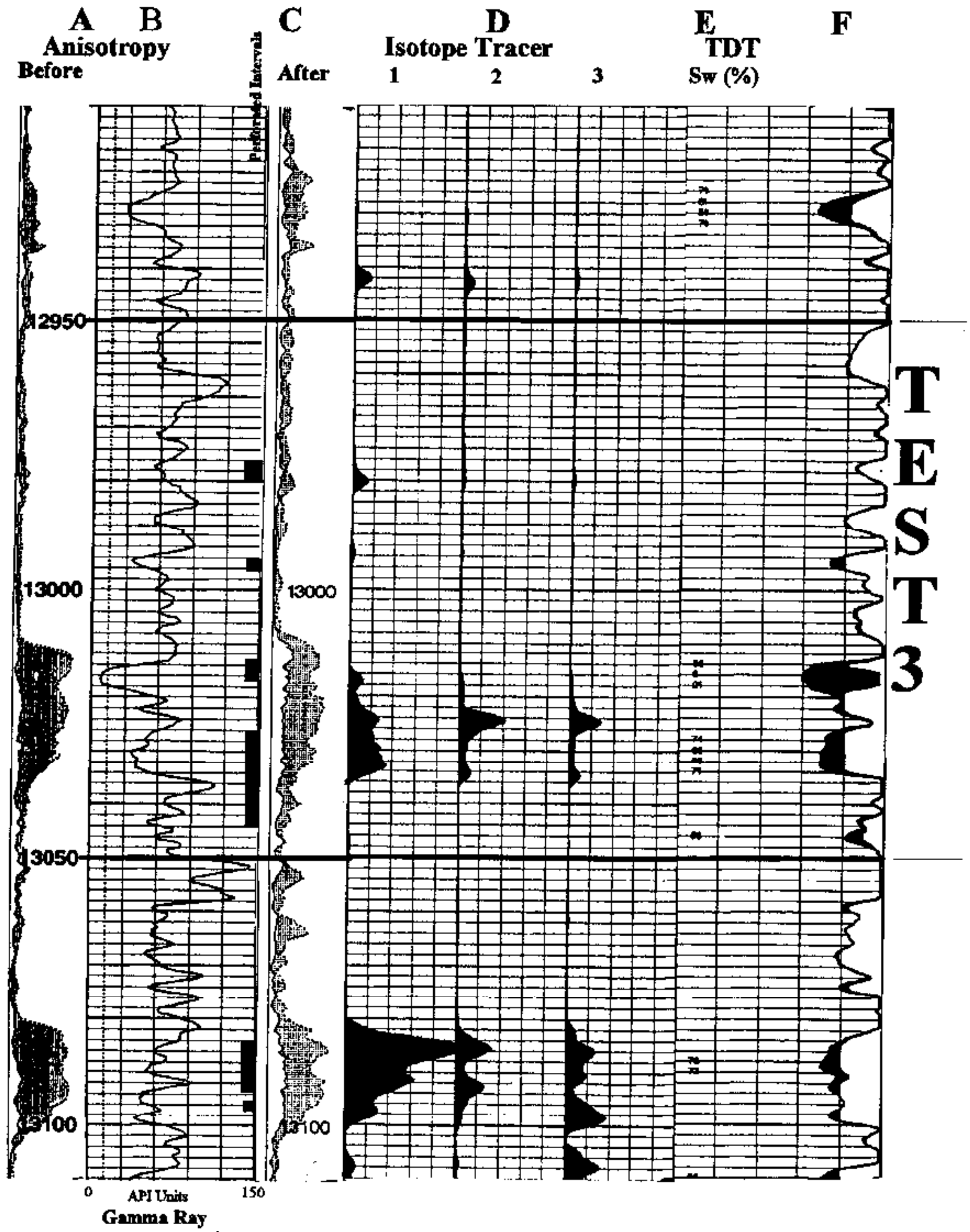

A
B
Anisotropy
Before
Perforated Intervals
C
After
D
Isotope Tracer
1
2
3
E
TDT
Sw (%)
F
12950
13000
13050
13100
TEST 3
0
API Units
150
Gamma Ray

Figure 4C.

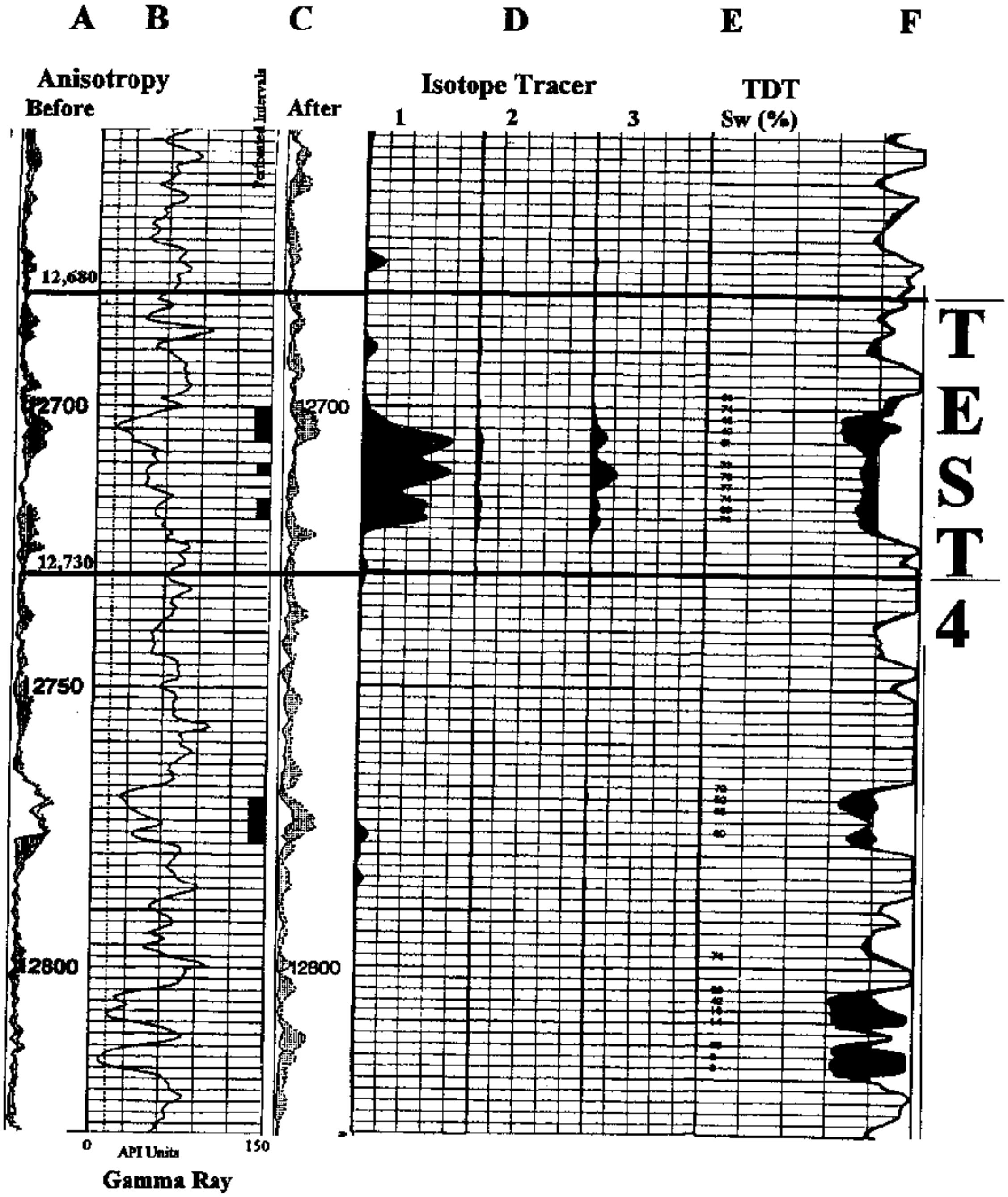

A
B
C
D
E
F
Anisotropy
Before
Perforated Intervals
After
Isotope Tracer
1
2
3
TDT
Sw (%)
12,680
12700
12,730
2750
12800
TEST 4
0
API Units
150
Gamma Ray

Figure 4D.

The interval was treated with 357 bbl (56,800 L) of hydrochloric (HCl) acid pumped at a maximum pressure of 7,214 psi (49,700 kPa), an average pressure of 5,500 psi (38,000 kPa), and at a maximum rate of 10 bpm (1,600 Lpm). Communication occurred behind the casing (probably in the cement between the casing and the formation) above the packer and below the bridge plug. The communication can be identified on the isotope tracer (tracer number 1) and the post-treatment anisotropy logs. The communication greatly reduced the effective delivery of the treatment to the intended beds. Limited swab testing after the treatment recovered acid water.

Test Number 2

The second interval stimulated and tested was at a log depth from 13,125 to 13,250 feet (4,000.5-4,038.6 m) (figure 4b). The pre-treatment anisotropy log showed two perforated intervals with well developed fractures at 13,224 to 13,233 feet (4,030.7-4,033.4 m) and 13,165 to 13,180 feet (4,012.7-4,017.3 m). A two-foot (0.6-m) layer (13,228 to 13, 230 feet [4,031.9-4,032.5 m]) has a water saturation of 39 percent. The other perforated intervals have a water saturation ranging from 59 percent to more than 79 percent based on the TDT log.

The interval was stimulated with 95 bbl (15,100 L) of HCl acid pumped at a maximum pressure of 6,810 psi (46,900 kPa), an average pressure of 6,000 psi (41,000 kPa), and at a maximum rate of 10.2 bpm (1,600 Lpm). Communication occurred behind the casing (probably in the cement between the casing and the formation) above the packer and possibly below the bridge plug. The communication can be identified on the isotope tracer (tracer number 3) and the post-treatment anisotropy logs. The communication greatly reduced the effective delivery of the treatment to the intended beds. Limited swab testing after the treatment recovered acid water.

Test Number 3

The third interval stimulated and tested was at a log depth from 12,950 to 13,050 feet (3,947.2-3,977.6 m) (figure 4c). The perforated interval 13,013 to 13,017 feet (3,966.4-3,967.6 m) has a water saturation ranging from 8 to 56 percent, and the perforated interval 13,026 to 13,044 feet (3,970.3-3,975.8 m) has a water saturation range from 66 to 71 percent based on the TDT log. Although these two perforated intervals appear to be separate beds based on the gamma-ray log, the pre-treatment anisotropy log showed the beds were in communication with each other via fractures. Perforated intervals 12,994 to 12,996 feet (3,960.6-3,961.2 m) and 12,976 to 12,980 feet (3,955.1-3,956.3 m) have more than 80 percent water saturation and no fractures.

The interval was stimulated with 72 bbl (11,400 L) of HCl acid pumped at a maximum pressure of 8,203 psi (57,000 kPa), an average pressure of 6,000 psi (41,000 kPa), and at a maximum rate of

10 bpm (1,600 Lpm). A minor amount of communication occurred below the bridge plug. The communication is identified on the isotope tracer (tracer number 2) and the post-treatment anisotropy logs. The upper perforated intervals do not appear to have taken any acid. The tracer log shows that the perforated intervals 13,013 to 13,017 feet (3,966.4-3,967.6 m) and 13,026 to 13,044 feet (3,970.3-3,975.8 m) are in communication as indicated on the pre-treatment anisotropy log. Limited swab testing after the treatment recovered a minor amount of oil, gas, and acid water.

Test Number 4

The fourth interval stimulated and tested was at a log depth from 12,680 to 12,730 feet (3,864.9-3,880.1 m) (figure 4d). The perforated intervals 12,700 to 12,706 feet (3,870.9-3,872.8 m); 12,710 to 12,712 feet (3,874.0-3,874.6 m); and 12,716 to 12,720 feet (3,875.8-3,877.1 m); are in a coarsing-upward sequence with the best developed fracturing (pre-treatment anisotropy log) and lowest water saturation (TDT [40 to 48 percent] log) near the top of the sequence. The lower portion of the sequence has water saturations ranging from 69 to 78 percent.

The interval was stimulated with 71 bbl (11,300 L) of HCl acid pumped at a maximum pressure of 7,200 psi (49,600 kPa), an average pressure of 6,700 psi (46,200 kPa), and at a maximum rate of 9.6 bpm (1,500 Lpm). The isotope tracer (tracer number 1) and post-treatment anisotropy logs showed little to no communication above or below the test interval. Limited swab testing after the treatment recovered a minor amount of oil, gas, and acid water.

Preliminary Production Results

The Malnar Pike 17-1 well was completed in 1987 flowing 640 BOPD (89.6 MT) and 550 MCFGPD (15,600 m^3). The cumulative production before the demonstration (September 31, 1997) was 111,304 BO (15,582.6 MT) and 95,970 MCFG (2,717,900 m^3). The Malnar Pike 17-1 was producing at an average rate of 18 BOPD (2.5 MT) prior to the treatment. After the treatment, a bridge plug was placed at a depth of 13,060 feet (3,980.7 m), above the first and second intervals, because the operator felt they would produce water. The Malnar Pike 17-1 well has produced 20,663 BO (2,892.8 MT) in 17 months since the recompletion, averaging 41 BOPD (5.7 MT).

REVISED NUMERICAL SIMULATION MODEL AND PREDICTION OF THE PERFORMANCE OF THE TREATMENT

The two test intervals producing in the Malnar Pike 17-1 well are test interval three, between 12,950 and 13,050 feet (3,947.2-3,977.6 m), and test interval four between 12,680 and 12,730 feet (3,864.9-3,880.1 m). A bridge plug was set at 13,060 feet (3,980.7 m) so that the perforations below this depth would not contribute to the production. Because of the treatment, oil production increased from about 18 BOPD (2.5 MT) to about 40 BOPD (5.6 MT).

The dual-porosity, dual-permeability model employed previously to match oil and gas production from Malnar Pike 17-1 was modified to assess the treatment. Relevant matrix and fracture properties used in the model are presented in table 1. The aerial extent of the model was 40 (16.2 h) acres. The well intersected 109 layers; 55 oil-bearing layers separated by 54 non oil-bearing layers. Each of the layers were assigned appropriate depths.

When measured water saturations were used in the model, water produced from the model was two times the actual water produced from the well. In order to match the actual water production, relative water permeabilities were altered. The new set of relative permeabilities are shown in table 2. The cumulative oil, gas, and water production to October 1997, as predicted by the model, are compared with the field totals in table 3. As can be seen from the table, the agreement between the model predictions and field data is excellent. Even though the cumulative production match is reasonably good, the monthly oil, gas, and water production results from the model differ considerably from the field results (figures 5, 6, and 7). The oil production from the field is still reasonably well matched; however water and gas predictions could be improved. Considering the complexity of the data set and the interdependency of data types, the history match is reasonable.

The model predicted a total oil rate of 16 BOPD (2.2 MT) in October 1997. Several different strategies were attempted to match the post treatment rate of about 40 BOPD (5.6 MT). Only the properties in the affected zones were changed at the treatment time. All of the strategies and corresponding rates after treatment are listed in table 4. It was hypothesized that the treatment would have increased fracture permeabilities, extent of fracturing and or frequency of fracturing. Each of the options was examined, either in isolation, or in combination with other options, as well as the option of adding a new layer.

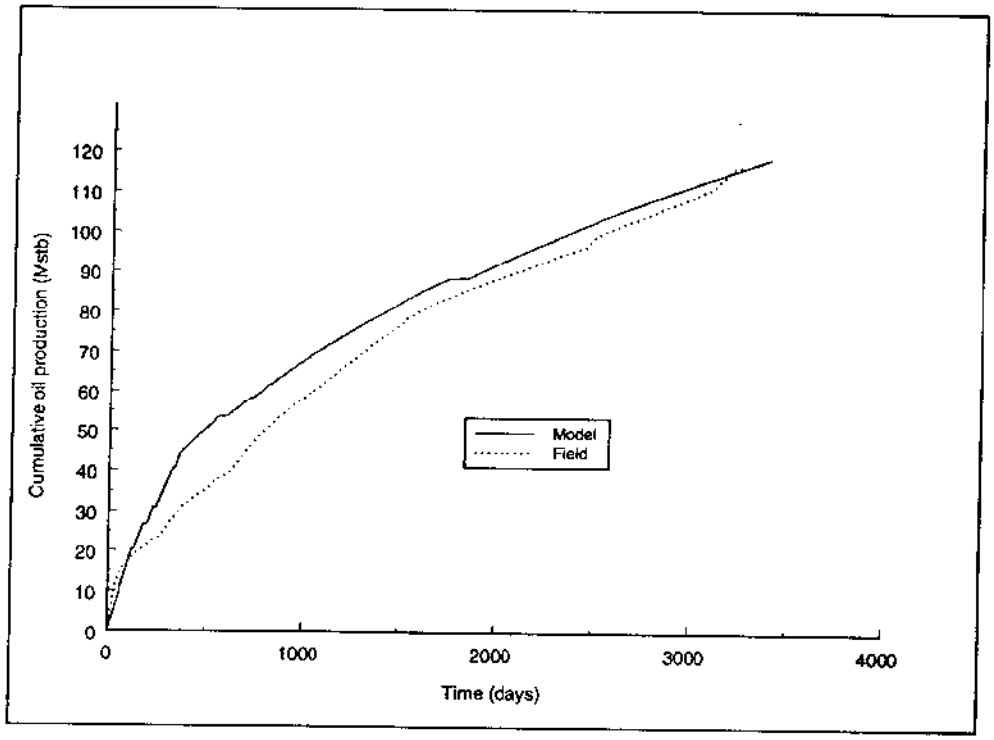


Figure 5. Comparison of cumulative oil production from the Malnar Pike 17-1 well with the modified model predictions.

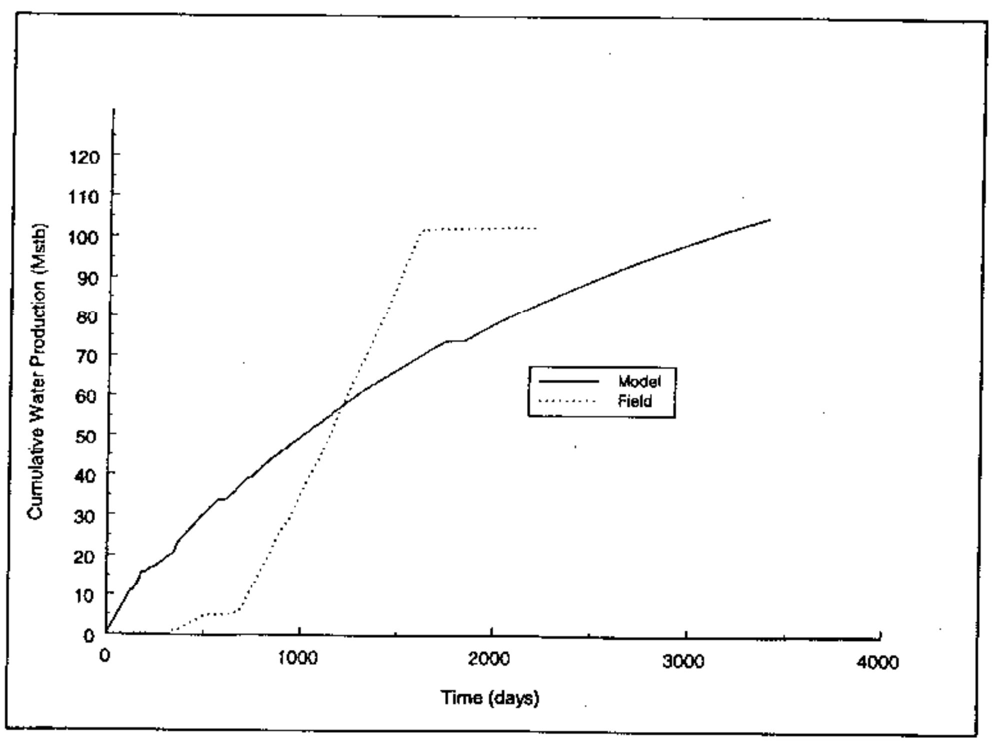


Figure 6. Comparison of cumulative water production from the Malnar Pike 17-1 well with the modified model predictions.

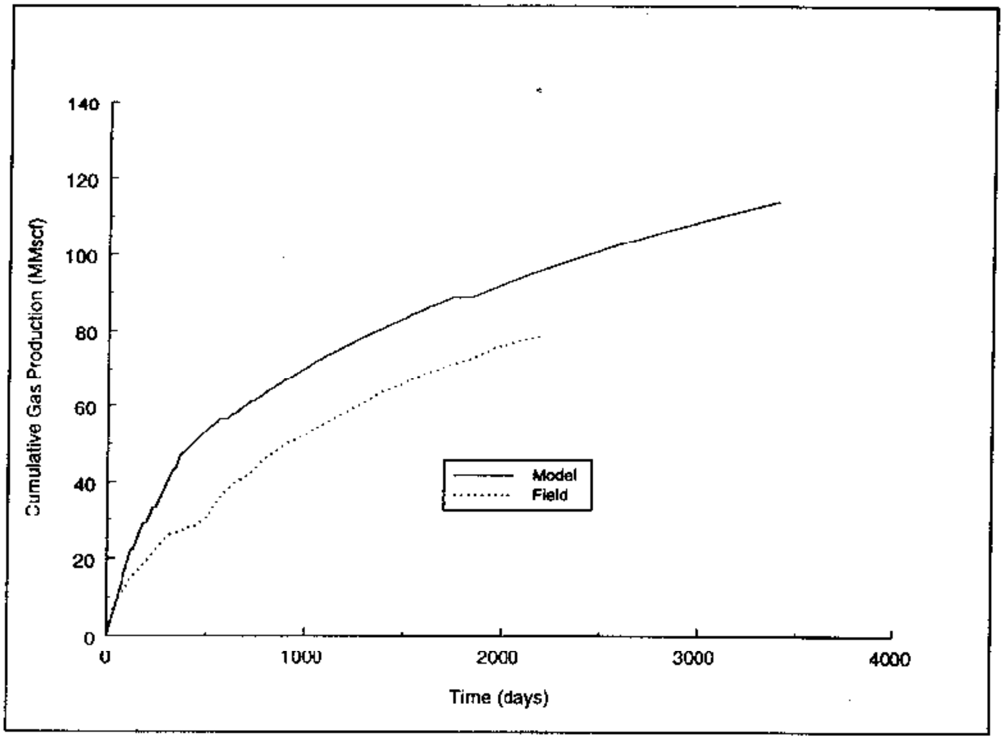


Figure 7. Comparison of cumulative gas production from the Malnar Pike 17-1 well with the modified model predictions.

As seen in table 4, it is possible to realize the gains in production by a variety of methods. Increasing the fracture permeability to 22 mD appeared to provide the most realistic increase in production. However, in most of the strategies examined, the production rate decreased to about 25 BOPD (3.5 MT) after about 6 months. Only in the scenario where an equivalent new layer was added to the reservoir did the production remain steady at around 31 BOPD (4.3 MT) well after the layer was opened. The layer was 30 feet (9.1 m) thick with a porosity of 0.14 and an initial oil saturation of 0.7. The layer had a matrix permeability of 1.5 mD and fracture permeability of 2.2 mD (properties of the older layers). Assuming only three percent recoverable oil from the layer (based on the performance of the well) we calculated that net reserves of about 27,000 BO (3,780 MT) were added to the well.

Table 2. Relative permeabilities used to obtain the history match for the Malnar Pike 17-1 well.

Water Saturation	***Relative Permeability to Water***	***Relative Permeability to Oil***
0.22	0.0	1.0
0.3	0.05	0.1
0.35	0.1	0.05
0.4	0.15	0.0175
0.5	0.5	0.0073
0.6	0.7	0.005
0.8	0.9	0.003
0.9	0.96	0.001
1.0	1.0	0.0

Table 3. Production match between the model and actual data from the Malnar Pike 17-1 well.

	Production as of December 1993		***Production as of October 1997***	
	Actual Production	***Model Prediction***	***Actual Production***	***Model Prediction***
Oil (Mstb)	93	100	113	125
Gas (MMscf)	79	87	96*	119
Water (Mstb)	100	102	122*	110

Mstb = thousand stock tank barrels

MMscf = Million standard cubic feet

* = value extrapolated from available data

Table 4. Different strategies used in emulating the treatment in the Malnar Pike 17-1 well.

Strategy	***Production Rate Immediately after Treatment (Stb/day)***	***Production Rate 4 Months after Treatment (Stb/day)***
1. Increase fracture permeability in affected layers from 2.2 to 22 mD	39	25
2. Increase extent of fracturing in the affected layers from 495 to 660 feet	29	22
3. Combine strategies 1 and 2	35	23
4. Increase fracture frequency to one every 5 feet	41	24
5. Add a new layer 12 feet thick, with 0.1 porosity, and oil saturation of 0.7	39	31

CONCLUSIONS

Dual-porosity, dual-permeability, single-well numerical modeling increased our knowledge of the importance of numerous reservoir properties. Fractures, specifically fracture permeability are essential to good reservoir performance.

Communication above and below the test intervals was a major problem in the Malnar Pike 17-1 well. The Malnar Pike 17-1 well has numerous perforations that have been acidized several times, increasing the potential for communication behind the casing. It is likely that conventional acid treatments (typically a 500- to 1,500-foot [150-460 m] interval) of older wells in the Bluebell field experience a similar problem. Much of the acid may be moving vertically through the cement and into beds other than the targeted (perforated) ones.

Test results from the Malnar Pike 17-1 well generally confirmed the interpretation of the anisotropy and TDT logs. Beds with fractures indicated by the anisotropy log generally took most of the acid while beds without fractures took little to no acid. The low treating pressure of about 7,000 psi [48,000 kPa], versus the normal treating pressure of 10,000 psi [69,000 kPa], was not high enough to hydraulically induce new fractures.

RECOMMENDATIONS

The use of the TDT and anisotropy logs are effective in identifying pay in new and older wells. The data from these logs can reduce the number of beds perforated, reduce potential water production problems, and when combined with isotope tracers, increase the understanding of the effectiveness of an acid treatment.

The bed-scale completion technique used in the Malnar Pike 17-1 well could be effective in older wells nearing depletion where the larger staged completion is no longer economical. Based on the experience of the Malnar Pike 17-1 demonstration, we recommend the following:

1. Use a dual packer tool instead of a retrievable packer and bridge plug to allow several beds to be treated in one day, greatly reducing the cost;

2. set the packers between perforated intervals so that there is at least 50 feet (15 m) between the perforated bed above and below each packer to reduce the risk of communication;

3. use the anisotropy and TDT logs to select beds that are fractured and have relatively low water saturation; and

4. use a treating pressure high enough to fracture the formation, especially if the anisotropy log indicates that some of the beds being treated do not have open fractures.

ACKNOWLEDGMENTS

The field demonstrations were conducted by Quinex Energy Corporation, Bountiful Utah, under the direction of DeForrest Smouse Ph.D., Lewis Wells, and Smokey Payne. The study was funded in part by the U.S. Department of Energy National Petroleum Technology Office in Tulsa Oklahoma. Contract management was the responsibility of Edith Allison, Jerry Castle, Gary Walker, and Dan Ferguson of NPTO over the many years of the project. Funding was also provided by the Utah Office of Energy and Resource Management under the direction of Jeff Burks.

The demonstration was the result of an extensive reservoir characterization study. The following people were active participants or provided valuable advice during the study: M. Lee Allison Ph.D., Roger L. Bon, and J. Wallace Gwynn, Ph.D., Utah Geological Survey, Salt Lake City, Utah: Richard Curtice, Halliburton Energy Services, Vernal Utah; Doug Howard, formerly consulting engineer, now with Flying J Oil and Gas, North Salt Lake, Utah; Richard Jarrard, Ph.D., University of Utah, Department of Geology and Geophysics, Salt Lake City, Utah; Bart J. Kowallis, Ph.D., Thomas H. Morris, Ph.D., and students Ann Garner and MaryBeth Wegner, Brigham Young University, Department of Geology, Provo, Utah; Rajesh J. Pawar Ph.D., graduate student under the Direction of Milind D. Deo, University of Utah, Department of Chemical and Fuels Engineering, Salt Lake City, Utah; David Ponto, Dowell Schlumberger’s in-house engineer for Coastal Oil and Gas, Denver, Colorado; Carol N. Tripp, consulting geologist, Salt lake City, Utah.

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