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DETAILED EVALUATION OF THE WEST KIEHL ALKALINE-SURFACTANT-POLYMER FIELD PROJECT AND ITS APPLICATION TO MATURE MINNELUSA WATERFLOODS

Final Report

By
Malcolm J. Pitts
Harry Surkalo

March 1995

Performed Under Contract No. DE-AC22-93BC14860

Surtek, Inc.
Golden, Colorado

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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Detailed Evaluation of the West Kiehl Alkaline-Surfactant-Polymer Field Project and It's Application to Mature Minnelusa Waterfloods

Abstract

The combination of an interfacial tension agent and a mobility control agent has the potential to produce additional oil beyond a waterflood. The West Kiehl alkaline-surfactant-polymer project is the first application of this chemical enhanced oil recovery technique. The West Kiehl alkaline-surfactant-polymer flood was initiated in September 1987 as a secondary application after primary recovery. The following analysis of the West Kiehl alkaline-surfactant-polymer flood indicates that incremental oil greater than waterflooding was produced at a cost of less than $2.00 per incremental barrel.

A analysis of approximately 120 Minnelusa oil fields in the Powder River Basin indicates that the total original stock tank oil in place exceeds one billion barrels. If the enhanced oil recovery technology implemented at West Kiehl field could be successfully applied to these fields, the potential incremental oil recovery would approach 130 million barrels.

The goals of "Detailed Evaluation of the West Kiehl Alkaline-Surfactant-Polymer Field Project and It's Application to Mature Minnelusa Waterfloods" are to evaluate both the field performance of the alkaline-surfactant-polymer enhanced oil recovery technology as well as its potential application to other Minnelusa oil fields. The objectives of the project are:

- Evaluate the geological depositional environment of the West Kiehl and of adjacent Minnelusa sand reservoirs with similar fluid and rock characteristics.
- Those reservoir analogs with depositional environments similar to the West Kiehl field will be compared on an engineering basis to define both geological and reservoir performance analogs to the West Kiehl field.
- Compare the production performance results of the best geological and reservoir performance analogs to the West Kiehl field and select two fields for in-depth study. Polymer floods and waterfloods performances were defined.
- Compare the two best field analogs to the West Kiehl field using numerical simulation.
    - History match the results of the laboratory radial coreflood physical simulation the West Kiehl field
    - History match the actual field performance of the alkaline-surfactant-polymer flood at West Kiehl field
    - Forecast the future performance of the West Kiehl project and determine the incremental oil recovery greater than waterflooding
    - History match the actual field performance of the waterflood analog

- History match the actual field performance of the polymer flood analog

- Predict the results of applying the alkaline-surfactant-polymer technology as a tertiary oil recovery technology on the two mature Minnelusa waterflood analog units using classical engineering and numerical simulation.

- Predict the waterflood and polymer flood performance of the West Kiehl field using numerical simulation and the parameters established in the analog field numerical simulations.

Linear and radial coreflood oil recovery by water injection was 56.3% OOIP and 46.6% OOIP, respectively, leaving a waterflood residual oil saturation of 0.343 PV. Injection of alkali plus surfactant plus polymer into the linear corefloods produced an additional 17.3% OOIP for a cumulative oil recovery of 73.7% OOIP with a final residual oil saturation of 0.207 PV. Radial coreflood alkaline-surfactant-polymer oil recovery averaged 61.7% OOIP.
Numerical simulation of the West Kiehl projects the ultimate recovery to be 1,017,000 barrels of oil from alkaline-surfactant-polymer injection and 726,000 barrels from a waterflood. Net incremental oil is 291,000 barrels. This compares with 249,200 to 309,260 barrels of incremental oil by classical reservoir engineering methods. A mobility control polymer flood will produce 885,000 barrels of oil and alkali-surfactant injection will produce 850,000 barrels of oil. Interfacial tension agent (alkali and surfactant) and mobility control agent (polymer) contributions to the total alkaline-surfactant-polymer incremental oil appear to be additive.

After studying 72 fields in a 275 square mile area around the West Kiehl, Prairie Creek South and Simpson Ranch were selected as waterflood and polymer flood analogs. Prairie Creek South numerical simulation predictions of the waterflood is 790,000 barrels of oil or 39.4% OOIP. Classical engineering prediction for the ultimate waterflood recovery is 764,900 to 814,900 barrels of oil or 38.1 to 40.6% OOIP. Alkaline-surfactant-polymer injection is predicted to produce 1,100,000 barrels for 310,000 barrels of incremental oil.
A mobility control polymer flood estimated recovery is 919,000 barrels of oil.

Simpson Ranch classical reservoir engineering analysis indicates the Cat-An® polymer flood will ultimately produce 867,000 to 920,000 barrels of oil or 38.0 to 40.3% OOIP compared to 831,000 predicted by numerical simulation. Numerical simulation predictions for a waterflood and an alkaline-surfactant-polymer flood indicates ultimate oil recovery to be 745,000 and 1,095,000 barrels oil, respectively. Incremental oil for a Cat-An® polymer flood is 86,000 and for an alkaline-surfactant-polymer flood is 350,000 barrels of oil.

If an alkaline-surfactant-polymer project was implemented after a waterflood in the West Kiehl, Simpson Ranch and Prairie Creek South fields the incremental oil recovery predicted by the numerical simulator is 321,000, 323,000, and 272,000 barrels, respectively. The West Kiehl total production by alkaline-surfactant-polymer flood forecast was greater after a waterflood because the Kottabra 25-15 well was on production for the entire alkaline-surfactant-polymer injection period, rather than 6 months.

Actual incremental cost per barrel of oil was less than $1.60. If 1994 prices are applied to the incremental oil recovery potential indicated by the numerical simulation for West Kiehl, Prairie Creek South, and Simpson Ranch, alkaline-surfactant-polymer incremental oil is produced for less than $3.00 per barrel. Incremental oil recovery potential is 130 million barrels of oil in the Minnelusa trend.

Executive Summary

The West Kiehl is the first field to have the combination of alkali plus surfactant plus polymer co-injected to improve oil recovery. The chemical combination injected into the West Kiehl was 0.8 wt% sodium carbonate (Na_2CO_3) plus 0.1 wt% active Petrostep B-100 plus 1,050 mg/l Pusher 700. The Na_2CO_3 and Petrostep B-100 were injected to shift the end point of the relative permeability curve to a lower oil saturation by changing the capillary number. Pusher 700 was injected to improve the mobility ratio so the mobilized oil is displaced effectively.

The West Kiehl field characteristics and production are well documented.[1,2] Classical engineering analysis projects the ultimate oil recovery from the alkaline-surfactant-polymer swept area of the Unit to be 70.1 to 76.1% OOIP or 627,250 to 680,300 barrels of oil, leaving 0.165 to 0.206 PV oil upon completion. The Kottabra 25-15 to the north the Unit was drilled and put on production after approximately two years of alkali plus surfactant plus polymer injection began. As a result, 0.12 PV of alkali plus surfactant plus polymer solution was injected toward the Kottabra 25-15 compared to 0.33 PV into the Unit. The resulting oil recovery from the flooded volume by the Kottabra 25-15 is predicted to be 56.0 to 69.5% OOIP or 249,200 to 309,260 barrels, leaving 0.210 to 0.303 PV oil in place. The Kottabra 25-15 also experienced earlier water break through at 0.11 PV injection compared to the Unit wells at 0.28 PV injected, suggesting poorer oil recovery efficiency.

Laboratory evaluations were performed to provide data to incorporate into the numerical model. Linear coreflood oil recovery by water injection was 56.3% OOIP, leaving a waterflood residual oil saturation of 0.343 PV. Injection of alkali plus surfactant plus polymer produced an additional 17.3% OOIP for a cumulative oil recovery of 73.7% OOIP with a final residual oil saturation of 0.207 PV. Radial coreflood waterflood oil recovery averaged 46.6% OOIP. Mobility control polymer flood oil recoveries averaged 42.8% OOIP and alkali plus surfactant plus polymer flood oil recoveries averaged 61.7% OOIP.

A field history match of the West Kiehl was made and projected to ultimately produce 1,017,000 barrels of oil from the field; 684,000 barrels are projected to be from the three Unit wells and 312,000 barrels are projected from the Kottabra 25-15 and 21,000 from the Kottabra 25-10. Waterflood, mobility control polymer flood, and an alkaline-surfactant-polymer flood are predicted to recover 726,000, 885,000, and 850,000 barrels of oil from the total West Kiehl Field, respectively. Corresponding incremental oil produced by alkaline-surfactant-polymer flooding, mobility control polymer flooding, and alkaline-surfactant flooding are 291,000, 159,000, 124,000 barrels of oil. Interfacial tension agent (alkali and surfactant) and mobility control agent (polymer) contributions to the total alkaline-surfactant-polymer incremental oil appear to be additive.

To define suitable waterflood and polymer flood fields for comparison, a 275 square mile area around the West Kiehl was studied. Seventy two Minnelusa fields were identified. From the 72 fields, 35 were studied in detail to define the waterflood and polymer flood analogs. Each of the fields were mapped and an ultimate recovery estimated using classical engineering and geologic techniques. Two fields selected for detailed study by numerical simulation were Simpson Ranch for the polymer flood and Prairie Creek South for the waterflood. These single injection well fields are too small for a pattern flood and so the volume affected by flooding may be a fraction of the whole field.

Classical engineering analysis of the Prairie Creek South reservoir indicates the waterflood will recover between 809,000 and 846,000 barrels of oil or 40.3 to 42.1% OOIP. Oil saturation at waterflood abandonment will be 0.454 to 0.468 PV. Numerical simulation indicates the ultimate waterflood oil production at the Prairie Creek South will be 790,000 barrels of oil or 39.4% OOIP. Waterflood abandonment oil saturation will be 0.475 PV. The ultimate oil recovery by implementing either an alkaline-surfactant-polymer or a mobility control polymer flood after primary production in Prairie Creek South was determined using numerical simulation. Predicted ultimate oil recovery is 1,100,000 barrels for an alkaline-surfactant-polymer project and 919,000 barrels for a mobility control polymer flood. Incremental oil is 310,000 barrels and 129,000 barrels, respectively.

Simpson Ranch classical engineering analysis indicates the Cat-An® polymer flood will ultimately produce 867,000 to 920,000 barrels of oil or 38.0 to 40.3% OOIP. Final oil saturation upon completion of the polymer flood will be 0.400 to 0.414 PV. Numerical simulation projection for the ultimate Cat-An® polymer flood oil recovery is 831,000 barrels of oil or 36.4% OOIP. Final oil saturation will be 0.424 PV. Numerical simulation of a waterflood and an alkaline-surfactant-polymer flood indicates ultimate oil recovery by the two techniques to be 745,000 and 1,095,000 barrels oil, respectively. Incremental oil for a Cat-An® polymer flood is 86,000 and for an alkaline-surfactant-polymer flood is 350,000 barrels of oil.

Numerical simulation was used to predict the incremental oil which the alkaline-surfactant-polymer technology will produce if implemented after a waterflood in the West Kiehl, Simpson Ranch and Prairie Creek South fields. Total oil production after waterflooding and alkaline-surfactant-polymer flooding from the three fields was 1,047,000, 1,068,000, and 1,062,000 barrels respectively. Corresponding incremental production was 321,000, 323,000, and 272,000 barrels. West Kiehl total production by alkaline-surfactant-polymer flood was greater after a waterflood because the Kottabra 25-15 well was on production for the entire alkaline-surfactant-polymer injection period.

Based on the numerical simulation, 291,000 incremental barrels of oil and the actual incremental cost above the waterflood of $458,015, result in incremental oil production at the West Kiehl for less than $1.60. If 1994 prices are applied to the incremental oil recovery potential indicated by the numerical simulation for West Kiehl, Prairie Creek South, and Simpson Ranch, incremental oil can be produced for less than $3.00 per barrel using the alkaline-surfactant-polymer technology. If the alkaline-surfactant-polymer technology can be applied to all the Minnelusa fields, the incremental oil recovery potential is 130 million barrels of oil.

Introduction

The amount of oil recovered from porous media by fluid injection can be described in equation form by

$$N_o = \frac{E_{VI} E_A E_D S_{oi} N_p}{B_o} \qquad (1)$$

The value of each of the efficiency factors (E_{VI}, E_A, and E_D), the initial amount of oil present (S_{oi}), and the pore volume of the oil zone (N_p) dictates the amount of oil which is produced from an oil bearing porous media.

The displacement efficiency, E_D, can be increased by adding an interfacial tension reducing agent to the injected solution to alter the capillary number. Capillary number is defined as[3]

$$N_{ca} = \frac{\text{viscous forces}}{\text{capillary forces}} = \frac{u \mu_{\text{displacing phase}}}{\gamma_{ow}} \qquad (2)$$

where $\mu_{\text{displacing phase}}$ is the viscosity of the injected phase, u is the darcy velocity of the injected phase and γ_{ow} is the interfacial tension between oil and water. Abrams[4] has demonstrated that capillary number changes of 10^2 to 10^3 are necessary for residual oil saturation to be decreased significantly. Because petroleum reservoirs injection rates and pressures are constrained, increases of $\mu_{\text{displacing phase}}$ or u are limited. Reduction of the interfacial tension between oil and aqueous solution of three or more orders of magnitude are achievable, resulting in a corresponding increase in capillary number and ultimately E_D.

However, adding an interfacial tension agent alone to the injected water can create problems. Viscous instabilities and early break through of the injected fluid can occur.[5] The exacerbated viscous fingering results in decreased reservoir contact efficiency. Including a polymer or mobility control agent in the injected solution can control the viscous fingering.

The chemical enhanced oil recovery project in the West Kiehl Field is the first project in which alkali (sodium carbonate) plus low concentration surfactant (Petrostep B-100) plus polymer (Pusher 700) were co-injected. The co-injection of a mobility control agent plus a combination of interfacial tension agents into the West Kiehl Field was done to improve the three efficiency factors at the same time. Vertical, E_{VI}, and areal, E_A, sweep efficiency factors were increased by the addition of polymer to the injected solution. E_D was increased by adding alkali and surfactant to the injected solution.

The West Kiehl alkaline-surfactant-polymer project is one of only five projects worldwide and the first in the United States in which a mobility control agent (polymer) was co-injected with interfacial tension reduction agent(s) (alkali and surfactant). This project is unique in that low cost chemical combinations were injected. The West Kiehl project is also unique in that it allows the amount of incremental oil produced as a result of the injection of two different volumes of chemical solution to be calculated in the same field demonstration. This is because two wells were drilled in the field north of the West Kiehl Unit 2 years after chemical injection started or 6 months before alkaline-surfactant-polymer ended.

The objective of this project is

- To quantify the incremental oil produced from the West Kiehl alkaline-surfactant-polymer project by classical engineering and numerical simulation techniques.
- To quantify the effect of chemical slug volumes on incremental oil recovery in a field application.
- To determine economics of the application of the alkaline-surfactant-polymer technology.
- To forecast the results of the injection of an alkaline agent plus a low concentration surfactant plus a polymer solution to mature waterfloods in similar reservoirs.
- To provide the basis for independent operators to book and produce additional oil reserves by using the alkaline-surfactant-polymer process.

History of Development of the West Kiehl Field

The West Kiehl Field was discovered in August 1985 by the Terra Resources State 31-36. State 42-36 was drilled and completed in January 1986. State 32-36 was drilled and completed the following month. State 41-36 was drilled in April 1986, but not completed until January 1988 following field unitization in March 1987.

The northern part of the field extends outside the Unit boundary into Section 25 with development starting 21 months after chemical injection was initiated into the Unit. The Kottabra 25-15 was completed in September 1989 and Kottabra 25-10 was completed in July 1990. Kottabra 25-11 was drilled in October 1992 into a water-leg and was completed as a water disposal well. Figure 1 shows the location of these wells on the net porosity-foot isopach.

Geology

The West Kiehl reservoir is a Permian Minnelusa Lower "B" Sand. The Lower "B" Sand is interpreted to be a preserved remnant of a highly dissected coastal eolian dune complex. The eolian sequence including the Lower "B" sand is part of several cycles of transgression and regression of the Wolfcampian seas in the Lusk Embayment to the southeast. The eolian sequences provided outstanding reservoir rock.

Structural contours on top of the lower "B" sand porosity indicate a slight northwest-southeast trending feature. Dip to the southwest primarily reflects regional dip while the very slight indication of the anti-regional dip to the northeast is a result of deposition.

The isopach of the net thickness lower "B" sand as shown in Figure 1 depicts a rather small northwest-southeast sand preservation with thickness ranging from 0 ft to greater than 28 ft (8.7 m). The current mapping of the zero edge surrounding the field reflects, in part, the original depositional topography of the eolian dune complex that constitutes the reservoir for the field. Post Minnelusa erosion may have destroyed a part of the original dune complex, reducing the size of the reservoir.

Injection History

State 31-36 was converted to injection in September 1987. Fox Hills water was injected from mid-September of 1987 to early December 1987 to study the injectivity and response to waterflood. Water injection was 685 bbl/day in early December with a stable well head pressure of 775 psi. The Hall plot demonstrated no injection problems with water.[1]

On December 3, 1987, sodium carbonate injection began with no change in the Hall plot slope, suggesting no damage to the formation by injection of alkali. Surfactant was added to the injection water in addition to the sodium carbonate on December 17, 1987. Co-injection of 15,000 barrels of the alkali-surfactant occurred with a decline in the injectivity factor.[1] The decline in the slope suggests that the residual oil saturation around the well bore was reduced by chemical injection. On January 28, 1988 polymer was added to the alkaline-surfactant solution. Injection of the alkaline-surfactant-polymer solution continued until June 22, 1990 when surfactant was discontinued. Soda ash was discontinued on July 5, 1990. The total alkaline-surfactant-polymer solution injected was 501,063 barrels. Polymer injection continued for 122,926 barrels at the design concentration until April 25, 1991 when a taper of the polymer concentration began. Polymer was injected through December 1991 with water injection beginning in January 1992.

Injection pressure has exceeded formation parting pressure, (estimated to be 0.75 psi/ft) beginning April 1988 or after 158,000 barrels were injected. No change in slope of the Hall plot[1] was observed in April 1988 when injection pressures exceeded 0.75 psi/ft. This would indicate that the fractures were not communicating with other sands or the producing wells. Injection/withdrawal ratios of approximately 1.0 indicate that the injected fluid is staying in zone. The inadvertent limited fracturing may have helped maintain injectivity by increasing the effective wellbore radius. The Hall plot and the injectivity factor plot show no damage to the formation by injection of alkali-surfactant-polymer.

The swept volume is that volume between the injector and the producer contacted by the injected fluids. The volume of alkaline-surfactant-polymer solution injected into the Unit swept area was 0.33 PV and, through December 1991, 0.15 PV of a taper polymer solution was injected. Water injection after the polymer taper began in January 1992. To the north, the area swept by Kottabra 25-15 received 0.12 PV of alkaline-surfactant-polymer solution followed by 0.21 PV polymer.

Production History

The producing wells in the West Kiehl Unit are: State 31-36, State 32-36, State 42-36 and State 41-36. The initial oil production from State 31-36 was 278 bbl/day occurring in October of 1985 with a rapid decline to 34 bbl/day before conversion to injection in September 1987. State 42-36 initially produced 176 bbls/day of oil in February 1986 and declined to 29 bbls/day in September 1987. State 32-36 initially produced 23 bbls/day in March 1986 and declining to 8 bbls/day in

September 1987. The maximum combined primary oil production occurred in February 1986 with 339 bbl/day.

The response to fluid injection beginning in September 1987 was rapid. Unit production increased from a low of 63 bbl/day to a peak of 460 bbl/day in February 1988. Unit production in excess of 400 bbl/day was maintained from February 1988 until February 1989. The Kottabra 25-15 began producing in September 1989. Water production was observed almost immediately upon fluid injection but remained constant at about 2% until May 1990. The Unit oil and water production with and without the two Kottabra wells is shown in Figure 2.

State 32-36 responded rapidly to fluid injection, increasing from 8 bbl/day to 155 bbl/day in February 1988. During injection, the water cut maintained a nearly constant 5% from November 1987 until May 1990. Water production increased rapidly for three months at which time the water cut has stayed between 50% to 65%. Figure 3 depicts the State 32-36 oil and water production. Oil production as of December 1993 was 35.1 barrels/day at an oil cut of 62.2%.

State 42-36 also responded rapidly to fluid injection. Oil production increased from 29 bbl/day in August 1987 to a peak value of 324 bbl/day in February 1988. Initial water break through of about 1 bbl/day occurred in June 1990. The water cuts reached a stabilized value between 50 and 60% between November 1991 and October 1992. Water cuts have increased to 79% in December 1993. Oil production has declined to 34.8 bbl/day. Figure 4 depicts the State 42-36 oil and water production.

State 41-36 began production in January 1988 with a peak oil production of 14 bbl/day in February 1988. Water production began immediately with production from the well. Water cuts began in the 40 to 60% range and by October 1990 had increased to 60 to 75%. Oil production remained essentially constant at 3 to 5 bbl/day from September 1988 until January 1991 when production declined to the 1 to 2 bbl/day range. The well was shut-in in November 1991 but is periodically turned on until production water cut exceeds 80%.

In the northern part of the field, the Kottabra 25-15 began production in September 1989, 21 months after the beginning of alkaline-surfactant-polymer solution injection. It reached peak production of 327 bbl/day in December 1989. Oil production maintained near peak production levels until water break through in May 1990. Water production increased from 2% at break through to approximately 50% in June 1991. Water cut remained constant from June 1991 through April 1992. Water cut has increased to 87% with the corresponding oil production declining to 50.0 bbl/day in December 1993. The Kottabra 25-15 oil and water production are depicted in Figure 5.

Kottabra 25-10 began production in July 1990 and reached peak production values of 35 bbl/day in the same month. The water cut has remained essentially constant from initial production at 33%. Oil production has declined from the initial production level to 10 bbl/day in October 1992. Injection of water into Kottabra 25-11 has increased production to 16 bbls/day in December 1993.

Discussion of Evaluations

West Kiehl Analyses

Geological and Reservoir Analyses West Kiehl

The productive reservoir at West Kiehl consists of a single lower "B" member eolian sand dune complex. The dune is approximately one mile long and less than one-half mile wide with the longitudinal axis trending north north west. The maximum gross sand thickness is 91 ft and maximum net oil sand is 28 ft. The "A" and upper "B" members of the Minnelusa have been eroded at West Kiehl and the unconformable overlying Opeche shale provides the upper seal. The impermeable Minnelusa "C" Dolomite provides the lower seal. The trapping mechanism is entirely stratigraphic and is controlled by the geomorphology of the sand dune.

The effective porosity (over 10%) is developed and preserved in five mappable and conformable horizontal zones. Zones 1 through 5 are labeled on Figure 6 which is a stratigraphic cross section with the top as the Minnelusa "C" dolomite as datum. The zonation is based on the sonic log correlation and porosity variations. Zones 1 through 3 are oil bearing with an oil-water contact at 2,255 ft sub-sea, as determined from log analysis, drill stem tests and completion results. Zones 4 and 5 are below the field oil-water contact, are non-productive and are not perforated. Zone 4 has low porosity and permeability. Figures 7 through 11 show the net oil sand isopachous map for each of the five layers. Figure 7 also shows the wells included in the cross section. Only zones 1 through 3 were used in the numerical simulation.

The productive reservoir at the West Kiehl has a small water leg constituting less than 25% of the total pore volume. There is no discernable gas cap. The primary drive mechanism is entirely solution gas, rock and fluid expansion with no apparent natural water drive.

The West Kiehl has a pore volume of 3,084 Mbbls. The unit pore volume contacted by chemical injection is 1,295 Mbbls and the pore volume contacted by chemical injection to the north toward Kottabra 25-15 is 645 Mbbls. The initial oil saturation in the flood area is 71.8%. The reservoir and production data are summarized in Kiehl West Field Table 1.

Classical Engineering West Kiehl Project Performance

The alkali-surfactant-polymer flood in the West Kiehl Unit was evaluated by analyzing the production from State 32-36 and State 42-36 in a similar manner as discussed by Meyers et. al.[5] The incremental gross swept area between the State 31-36 injection well and the State 32-36 and State 42-36 production wells has a pore volume of 1,295,000 barrels, as determined using the method of Slider.[6] Primary production out of the swept area was 43,364 barrels of oil or 0.033 PV. No water was produced on primary production. Prior to water break through, an additional 361,959 barrels of oil and water or 0.280 PV were produced. Some water was produced almost immediately upon fluid injection from the State 32-36 with the water production continuing at a water cut never exceeding 4% until break through. No water was produced from the State 42-36 until break through. As of December 1993, a total of 526,680 barrels or 0.407 PV of oil have been produced from the gross swept area between the State 31-36 and the State 32-36 plus the State 42-36. Current water cut for the State 32-36 is 62.2% and 78.7% for State 42-36. Based on the water cut and monthly oil production versus cumulative oil produced plots for State 32-36 and State 42-36 (Figures 12 and 13), the ultimate oil recovery from the gross swept area was estimated to be 253,250 to 257,000 barrels of oil from State 32-36 plus 339,450 to 388,800 barrels of oil plus 34,500 barrels of oil from State 31-36 during primary production. Total oil production from the Unit gross swept area is estimated to be 627,250 to 680,300 barrels of oil or 0.484 to 0.525 PV at an economic limit water cut of approximately 92%. Oil saturation in the Unit gross swept area after completion of the project is estimated to be 0.165 to 0.206 PV. The resulting swept volume E_t in the oil recovery equation is 0.701 to 0.761.

The Kottabra 25-15 well started production after chemical injection into the State 31-36 for 21 months. As a result, this well is a good comparison of the State 32-26 and State 42-36 wells performance because the volume of alkaline-surfactant-polymer solution injected was a fraction of the amount injected into the Unit area. The gross swept area of the Kottabra 25-15 has a pore volume of 645,100 barrels. From September 1989 to December 1992, the area received approximately 80,000 barrels or 0.12 PV of alkaline-surfactant-polymer and approximately 135,000 barrels of polymer or 0.21 PV. This compares with 0.33 PV of alkali-surfactant-polymer and 0.15 PV polymer injected into the areas swept by State 32-36 and State 42-36. No primary production occurred from the Kottabra 25-15. Total fluid produced at water break through was 72,643 barrels of fluid or 0.113 PV of which only 221 barrels was water. As of December 1993, 236,996 barrels or 0.367 PV of oil have been produced from the Kottabra 25-15 swept area. Current water cut is 87%. Estimated ultimate oil production is 249,220 to 309,260 barrels of oil from the Kottabra 25-15 plus 17,250 barrels of oil (2,742 m^3) produced during primary by State 31-36 for a total of 266,470 to 326,510 barrels of oil or 0.413 to 0.506 PV. Figure 14 depicts the Kottabra 25-15 water cut and monthly oil versus cumulative oil extrapolation. Oil saturation in the gross swept area after completion of the project is estimated to be 0.209 to 0.303 PV. The E_t of the oil recovery equation calculates to be 0.577 to 0.707. Figure 15 and the following table compare the oil recovery of the West Kiehl Unit with the Kottabra 25-15.

Comparison of Unit and Kottabra 25-15 Oil Recovery

	West Kiehl Unit	**Kottabra 25-15**
Volume Na_2CO_3-Petrostep B-100 -Pusher 700 Injected (PV)	0.33	0.12
Volume of Pusher Drive Injected (PV)	0.15	0.21
Estimated Total Oil Recovery (%OOIP)	0.1 to 76.1	57.7 to 70.7
Final Residual Oil Saturation (PV)	0.165 to 0.206	0.209 to 0.303

The State 41-36 and the Kottabra 25-10 production performance was not evaluated because the volume of fluid produced from both these wells is minimal. Also, the configuration of the Kottabra 25-10 well relative to the State 31-26 and Kottabra 25-15 suggests a minimal impact by the injected fluids on the Kottabra 25-10 performance. Cumulative oil production as of December

1993 was 6,695 barrels of oil from the State 41-36 and 20,579 barrels of oil from the Kottabra 25-10.

To estimate the wateflood incremental oil due to alkaline-surfactant-polymer either the average estimated final oil saturation of 0.403 PV of the 35 field emphasized in the "Geological and Reservoir Analyses of Fields Surrounding West Kiehl" discussed beginning on page 19 or the average of the estimated waterflood residual oil saturation of 0.339 PV from the South Prairie Creek and Simpson Ranch analysis discussed later can be used. The later was used because these fields were felt to be the best reservoir analogs to the West Kiehl of the fields studied. Assuming the waterflood residual oil saturation at the West Kiehl if 0.339 PV, West Kiehl waterflood oil production is 480,000 barrels from the State 32-36 and 42-36 gross swept area and is 238,900 from the Kottabra 25-15 gross swept area. Incremental oil from the State 32-36 plus State 42-36 gross swept area is 147,250 to 200,300 barrels. Incremental oil from the Kottabra 25-15 is 27,570 to 87,860 barrels. Total incremental oil is 174,820 to 288,160 barrels of oil.

West Kiehl Laboratory Evaluations

The initial laboratory evaluation was presented by Clark et. al.[4] The ion content of the Fox Hills injection water and the produced water are listed in the following table. The produced water is from a well drilled in 1992 outside the flood area and is believed to be indicative of the connate water.

West Kiehl Water Analyses

Ion Type	Fox Hills Water	Kottabra 25-11 Produced Water
	Ion Concentration (mg/kg)	
Calcium	1.4	537
Magnesium	0.4	92
Barium	0	5.9
Strontium	0.4	23
Sodium	240	1,490
Potassium	0	60
Iron	0	0
Chloride	15	1,474
Carbonate	37	66
Bicarbonate	446	272
Sulfate	280	4,253
Total Dissolved Solids	838	9,686
pH	8.44	8.33
Resistivity at 21°C (ohm-m)	10.3	1.28

West Kiehl Crude oil is 24 degree API with a viscosity of 17.6 cp at 134°F.

The alkaline plus surfactant plus polymer solution injected into the West Kiehl field was 0.8 wt% Na_2CO_3 plus 0.1 wt% active Petrostep B-100 plus 1,050 mg/l Pusher 700. Interfacial tension measurements were repeated at the design concentration and half the design concentration for the numerical simulation. The solutions were also diluted with produced water. The results are summarized on the following tables.

Interfacial Tension between West Kiehl Crude Oil and Alkali Surfactant

	Interfacial Tension at 134°F (mN/m)	
Na_2CO_3 wt%	**0.05 wt% active Petrostep B-100**	**0.1 wt% active Petrostep B-100**
0.00	18.3	18.3
0.40	0.216	0.024
0.60	<0.001	<0.001
0.80	<0.001	<0.001
1.00	<0.001	<0.001

Produced Water Effect on Interfacial Tension

0.8 wt% Na_2CO_3 plus 0.1 wt% Petrostep B-100 to Produced Water ratio	**Interfacial Tension at 134°F (mN/m)**	
	0.05 wt% active Petrostep B-100	**0.1 wt% active Petrostep B-100**
100:0	<0.001	<0.001
80:20	0.015	0.002
60:40	0.046	0.046
40:60	0.065	0.065
20:60	1.5	1.5

No core was taken at the West Kiehl Field. Therefore, core from near-by Minnelusa Lower "B" reservoirs was used for the laboratory work. The core used were from the Wolf Draw Field, Well Wolf Draw Federal 14-18, and the Guthery Field, Well Brehm #3. Two linear corefloods and seven radial corefloods were completed. Relative permeability analysis indicated the Minnelusa Lower "B" sand is water-wet and the mobility ratio for water-displacing oil averages 2.2. Figure 16 depicts the relative permeability curve. Oil saturation shifts were from 0.788 PV to 0.343 PV, for a recovery of 56.5% of the initial oil saturation. Injection of polymer (Pusher 700) after the waterflood recovered no additional oil. Injection of 0.8 wt% Na_2CO_3 plus 0.1 wt% Petrostep B-100 plus Pusher 700 reduced the oil saturation to 0.207 PV for an additional recovery of 0.136 PV of incremental oil or 39.7% of the waterflood residual oil. Dynamic retention of chemical from the linear corefloods averaged 72,966 lb/acre-ft for Na_2CO_3, 5,123 lb/acre-ft for Petrostep B-100, and 723 lb/acre-ft for Pusher 700 injected with Na_2CO_3 plus Petrostep B-100 and 314 lb/acre-ft when injected dissolved in Fox Hills water prior to alkaline-surfactant-polymer solution. When Pusher 700 dissolved in injection water was injected after the alkaline-surfactant-polymer solution, an additional 49 lb/acre-ft was retained by the Minnelusa sand. Based on resistance factor and chemical retention data of these linear corefloods, an injection concentration of 1,050 mg/l Pusher 700 is sufficient for mobility control if 1 PV of polymer were injected.

Chemical oil recoveries of the radial corefloods using 4 inch radial discs are summarized in the following table. The chemical floods were performed with no waterflood prior to chemical injection with the exception of two corefloods. This is because the West Kiehl Field alkaline-surfactant-polymer project was performed in a secondary application.

Radial Coreflood Waterflood and Chemical Flood Oil Recovery

Chemical Injected	Waterflood Recovery $\%S_{oi}$	Chemical Flood Recovery $\%S_{oi}$	Combined Recovery $\%S_{oi}$
Waterflood followed by 37% PV ASP	45.4	12.6	58.0
Waterflood followed by 13% PV ASP	47.7	5.5	53.2
29% PV ASP - 10% PV Polymer	----	61.2	----
13% PV ASP - 26% PV Polymer	----	52.7	----
94% PV ASP - no Polymer	----	65.9	----
43% PV Polymer	----	40.0	----
35% PV Polymer	----	45.7	----

The average polymer flood performed no better than the average waterflood, 42.8% S_{oi} versus 46.6% S_{oi}, respectively. However, injection of 0.8 wt% Na_2CO_3 plus 0.1 wt% Petrostep B-100 plus 1,050 mg/l Pusher 700 recovered an additional 15% S_{oi}. Additional oil was recovered when more ASP slug was injected. Reducing the volume of alkaline-surfactant-polymer slug injected to 13% PV lowered the incremental oil production to 5.5% S_{oi}.

Numerical Simulation

The West Kiehl alkaline-surfactant-polymer flood area was modeled using the GCOMP reservoir simulator. This simulator provides black-oil, compositional, pseudo miscible, or chemical matching and forecasting capabilities. The chemical phase of the simulator accounts for in-situ surfactant generation or saponification of oil by alkali, the partitioning of surfactant into the oil and water phases, the adsorption and desorption of chemicals onto rock surfaces, increased aqueous phase viscosity by polymer addition based on resistance factor data, and the shift in the residual oil saturation dependant upon contact with the alkaline-surfactant solution and the concentration of each species in solution.

Numerical Simulation - West Kiehl Radial Coreflood History Match

The coreflood history match is performed to verify values for chemical adsorption, resistance factor and capillary number response that result in the oil recovery observed during the coreflood.

Three radial corefloods were matched to calibrate the chemical portion of the model. The first was a waterflood followed by chemical injection and the second and third were polymer and alkali plus surfactant plus polymer injection after injection of 0.043 PV of water. The chemical systems injected were 1,050 mg/l Pusher 700 and 0.8 wt% Na_2CO_3 plus 0.1 wt% Petrostep B-100 plus 1050 mg/l Pusher 700.

The coreflood simulation consists of 5 uniform thickness layers of 5 radial grid blocks each of equal porosity. The permeability of the bottom layer is about 1/10th that of the top 4 layers. The core dimensions, pore volume, and porosity are the same as the average values for radial corefloods.

The coreflood matches are depicted in Figures 17 through 19. Polymer rheologic parameters and alkali plus surfactant capillary number parameters were identical for all three corefloods. The overall oil recovery and oil cut matches of the radial corefloods were good. The comparative oil recovery data are listed in the following table.

Numerical Simulation and Coreflood History Match

Source of Data	Initial Saturation (PV)	Final Saturation (PV)	Total Oil Recovery $\%S_{oi}$
coreflood 3			
Waterflood - actual	0.588	0.321	45.4
Waterflood - simulation	0.589	0.323	45.1
coreflood 3			
ASP - actual	0.321	0.247	58.0
ASP - simulation	0.323	0.244	58.6
coreflood 5			
ASP - actual	0.673	0.261	61.2
ASP - simulation	0.674	0.282	58.1
coreflood 8			
Polymer - actual	0.733	0.398	45.7
Polymer - simulated	0.733	0.400	45.4

Oil recovery in the layers varied from 40% OOIP to 70% OOIP for the alkaline-surfactant-polymer floods and 30 to 55% for the polymer flood.

Figures 17 through 19 also depict the produced chemical concentrations. No Na_2CO_3 was produced in either coreflood and Petrostep B-100 was only produced at low concentrations in coreflood 5.

Numerical Simulation - West Kiehl History Match

Data Used for Simulation - The basic reservoir description for the West Kiehl Field was determined by geological and reservoir engineering interpretation as described earlier. Other data were obtained from various reports and data about the West Kiehl. These include:

- the "Secondary Recovery Feasibility Study" Engineering Committee Report for the West Kiehl Field dated October 1986

- well testing reports for the following wells

State 31-36	State 32-36	State 42-36
State 41-36	Kottabra 25-10	Kottabra 25-15
Kottabra 25-11		

- well logs and log analyses providing depth, porosity, water saturation and completion intervals for the following wells

Argentine 33-25	Flo State 21-36
Kottabra #1	Kottabra 25-10
Kottabra 25-15	Kottabra 32-25
State 31-36	State 32-36
State 41-36	State 42-36
Waliszek 25-14	Kottabra 25-11

- monthly oil and water production from all producing wells through December 1993

- daily injected volume, pressure, and chemical concentration for State 31-36

- isopachs including the following

top of structure	gross sand
net porosity foot	hydrocarbon pore volume

- Routine core analysis from other Minnelusa lower B reservoirs in the vicinity of the West Kiehl field

- reservoir fluid study for State 42-36

Fluid Properties - The properties of the West Kiehl reservoir oil and gas were obtained from the "Reservoir Fluid Study for Terra Resources, Inc. State 42-36 Well Wildcat."[7] These data are compiled in Table 2. Figure 20 shows the crude oil viscosity versus pressure and Figure 21 depicts the oil density and volume factor versus pressure. The reservoir oil is essentially a dead oil. A reservoir water viscosity of 0.635 cp with a density of 1.023 g/ml and a compressibility of 2.95×10^{-6} vol/vol/psi were used.

The physical properties of the chemical solutions injected at West Kiehl were also required for the simulation. The resistance factor and residual resistance factor data and non-newtonian rheological solution properties are used to calculate the viscosity of the polymer solution during the simulation. The viscosity data for the polymer solutions injected at the West Kiehl Field are depicted in Figure 22.

Relative Permeability - The relative permeability data were developed in the linear corefloods as depicted in Figure 16. Wolf Draw core was used. A compilation of 18 relative permeability evaluations conducted on Minnelusa Lower "B" core shown in Figure 23 indicates that the relative permeability using the West Kiehl fluids is typical. The relative permeability data in Figure 23 was used for the reservoir model.

Permeability and Porosity - No core was available from the West Kiehl Field. In order to provide permeability information for numerical simulation, data from an adjacent lower "B" Minnelusa field were used. The permeability for the simulator was obtained from a cross-plot of permeability versus porosity. The data, representing measurements from 5 Minnelusa routine core analyses using a 10% porosity cut-off, are presented in Figure 24. The line shown is the correlation used in the models.

Grid Data - The study area was divided into a grid spacing of 13 by 33 with 3 layers for a total of 1,287 grid blocks. Figure 25 shows the grid system and well locations. The three zones included in the numerical model are shown in the diagrammatic structural cross section shown in Figure 26.

Various properties were assigned to each grid block. The porosity for each layer was obtained by estimating porosity for each zone from the logs and averaging the porosity tabulated for the interval. The resulting porosity maps can be seen as Figures 27 through 29. The greatest porosity for the reservoir was seen for layer 3 and was the greatest around well Kottabra 25-15. Note layer 2 has very low porosity and represents ineffective porosity.

The permeability for each grid block was initially derived from the permeability versus porosity data of Figure 24. Permeability is the parameter for which there is the least information and, as a consequence, is the value that is most manipulated to provide a history match.

Because the model takes into account gravitational forces, the orientation of the structure was also needed. The elevation (sub-sea) of each grid block is determined from the top of structure, and the sum of the thickness of layers for overlain grids.

Initial Conditions - The initial oil and water saturation conditions were obtained by determining an oil-water contact. From the individual well log analyses, the depth of the oil-water contact averaged 2,255 ft sub-sea. The oil saturation below this depth was then set to zero and above this depth at the endpoint of the relative permeability curve, 0.718 PV. Because of the orientation of the structure and the occurrence of an oil water contact, much of the northwest portion of the reservoir is underlain by water. Drilling of the Kottabra 25-11 into this area in October 1992 verified the area to be wet.

Drill stem testing on well State 31-36 indicated an initial reservoir pressure of about 2,200 psi, which was used for the numerical simulation.

West Kiehl Field History Match

The performance of the alkaline-surfactant-polymer flood is matched through December 1993. During the history match, the actual injection rates and oil plus water production rates are the limiting criteria for the simulation. The proportions of water to oil are dictated by the relative permeabilities, the chemical model parameters, and grid saturations. The pressure within a grid block is dictated by the pressure in adjoining grid blocks and the transmissivity between grid blocks. The transmissivity is a function of the thickness, porosity, and effective permeability of the grid blocks. The effective permeability of the fluids depends upon the grid saturation. The pressure of a grid block containing a well depends upon the rate at which fluids are injected or withdrawn from the well, the pressure of adjoining grid blocks and the transmissivity between grid blocks.

To facilitate a history match and honor the oil saturation calculated from the logs, the pore volume of the West Kiehl had to be increased from 3.1 million barrels to 3.7 million barrels. The net pay was increased in layers 1 and 3 between Kottabra 25-15 and State 42-36 to the east of State 31-36.

Three key wells for the history match are State 32-36 and State 42-36 which are in the West Kiehl Unit and Kottabra 25-15. Figure 30 compares the actual cumulative oil, cumulative water, and oil cut for each of the three wells, the combination of 32-36 and 42-36, and the total field. The history match of 32-36 water break through was delayed while 42-36 was early. The combination of 32-36 and 42-36 history match was essentially exact as is the Kottabra 25-15 and the total field.

West Kiehl Chemical Flood Predictions

Predictions were made to extend the current water injection after the alkaline-surfactant-polymer flood and to simulate a waterflood, an alkaline-surfactant flood and a mobility control polymer flood. For the mobility control polymer flood, polymer was injected at the same concentration and over the same time period as the alkaline-surfactant-polymer flood. The alkaline-surfactant flood injection volume was equal to the actual alkaline-surfactant-polymer injection volume. Water was injected after the alkaline-surfactant solution as a drive fluid.

The chemical injection periods for the polymer flood and alkaline-surfactant flood were identical to the corresponding chemical injection of the alkaline-surfactant-polymer flood history match. The injection rates for each quarter year were identical to actual injection rates through December 1993 for the waterflood and polymer flood predictions. Injection into State 31-36 and Kottabra 25-11 after December 1993 for each of the predictions were at a pre-set level equal to the average of 1993 with the actual rate dictated by a pressure limit equal to parting pressure. The chemical flood predictions were:

West Kiehl Numerical Simulation Chemical Consumption

Flood Description	Dates of Injection	---Cumulative Pounds--- --Chemical Injected x 10^{-3}-- Na_2CO_3	Petrostep B-100	Pusher 700
Alkali-surfactant-polymer	January 1988-July 1990	1,547	193	254
polymer drive	July 1990-December 1991			
Alkali-surfactant	January 1988-July 1990	1,362	170	-----
Polymer	January 1988-December 1991	-----	-----	207

Time at which wells were put on production were identical to the actual occurrence.

Figure 31 depicts the cumulative oil, cumulative water and oil cut prediction for the total field of continued injection of the water injection behind the alkaline-surfactant-polymer and polymer drive. Each well was produced to an economic limit of 12 oil bbls/day per well. Figure 32 shows the predicted production for the combination of 32-36 and 42-36. Figure 33 depicts the Kottabra 25-15 predictions. Figures 31 through 33 also depict the waterflood, polymer flood, and alkaline-surfactant-polymer flood predictions. The volume of incremental oil is summarized in the following table.

West Kiehl Numerical Simulation Predicted Oil and Water

Flooding Process	Cumulative Oil MSTB	Cumulative Water MSTB	Incremental Oil MSTB	Project Ending Date
Total Field				
Waterflood	726	1,332	------	4-1998
Mobility Control Polymer	885	1,287	159	10-2000
Alkaline-Surfactant	850	1,119	124	7-1997
Alkaline-Surfactant-Polymer	1,017	1,683	291	10-2002
West Kiehl Unit (Combination of 32-36 and 42-36)				
Waterflood	412	397	------	
Mobility Control Polymer	538	419	126	
Alkaline-Surfactant	498	404	86	
Alkaline-Surfactant-Polymer	609	653	197	
Kottabra 25-15				
Waterflood	218	896	------	
Mobility Control Polymer	273	879	55	
Alkaline-Surfactant	248	684	30	
Alkaline-Surfactant-Polymer	312	989	94	

The majority of incremental oil was produced from the West Kiehl Unit. This is due to volume of alkaline-surfactant-polymer and polymer injected into the Unit versus toward the Kottabra

25-15 well to the North. Based on the simulation pore volume, 0.12 PV of ASP was injected into the area swept by Kottabra 25-15 and 0.23 PV was injected into the area swept by the State 32-36 and 42-36 wells.

Incremental oil was produced by mobility control polymer flooding and alkaline-surfactant flooding. Again, the West Kiehl Unit produced the greatest amount of incremental oil due to the volumes of chemical injected into the respective swept areas. Incremental oil due to the mobility control polymer portion of the solution and the interfacial tension reduction portion of the solution are additive.

In Figures 31 through 33 c (bottom) plots, notice the delay in water break through for the chemical floods relative to the waterflood. The 32-36 plus 42-36 combination showed a delay of water break through of approximately 100,000 bbls. Kottabra 25-15 difference is less than 25,000 barrels. The difference between alkaline-surfactant-polymer flood and either the polymer flood or the alkaline-surfactant flood is the rate of oil cut decline after water break through. This is especially noticeable for the 32-36 plus 42-36 combination which received a larger volume of alkaline-surfactant-polymer injection.

Figure 34 shows the incremental oil over waterflood for the total field, the combination of 32-36 plus 42-36, and for Kottabra 25-15 when different volumes of alkaline-surfactant-polymer solution were injected. For these predictions, the total volume of mobility control fluid injected was kept constant by altering the polymer drive volume. Zero alkaline-surfactant-polymer injection is the mobility control polymer flood. Actual injected volume was 565,000 bbls of alkaline-surfactant-polymer. Kottabra 25-15 production began after 412,000 bbls of alkaline-surfactant-polymer injection. Figure 34 indicates the following:

- Incremental oil due to alkali and surfactant addition to a polymer flood is not significant until sufficient quantity of chemical has been injected to satiate chemical adsorption.

- Kottabra 25-15 produced oil beyond a polymer flood when alkaline-surfactant-polymer solution injection was terminated prior to the well being turned on due to injection of alkaline-surfactant-polymer to the north of State 31-36.

Figure 35 shows the incremental oil over waterflood for the total field, the combination of 32-36 and 42-36, and Kottabra 25-15 if the polymer drive had been continued. In each case, the volume of alkaline-surfactant-polymer injected was 565,000 bbls. Actual polymer drive injection volume was 296,000 bbls. Lengthening the polymer drive would have benefitted the Kottabra 25-15 but not the wells in the West Kiehl Unit.

Figure 36 shows the predicted produced chemical concentrations for continuation of the current chemical flood. Actual produced chemical concentrations are also shown. As of December 1993, only polymer has been produced at the different wells and the simulation prediction suggests polymer will be the only chemical produced in measurable quantities for the remainder of the project life. Predictions of produced chemical indicate that peak chemical concentrations will be produced at State 42-36 and Kottabra 25-15. Predicted peak polymer production will be 8 mg/l, peak Na_2CO_3 production will be 0.04 wt% and peak Petrostep B-100 production will be less than 0.01 wt%.

Geological and Reservoir Analyses of Fields Surrounding West Kiehl

A study area around the West Kiehl field, located in Sections 25 and 36, Township 53 North, Range 68 West, Crook County, Wyoming, was selected to encompass a number of productive Minnelusa oil fields. The area selected includes:

Twp 52N - Rge 67W	Sections 4 to 9
Twp 51N - Rge 68W	Sections 1 to 12
Twp 51N - Rge 69W	Sections 1 to 5 & 8 to 17
Twp 52N - Rge 67W	Sections 4 to 9, 16 to 21 & 28 to 33
Twp 52N - Rge 68W	All
Twp 52N - Rge 69W	Sections 1 to 3, 10 to 15, 22 to 27 & 34 to 36
Twp 53N - Rge 67W	Sections 4 to 9, 16 to 21 & 28 to 33
Twp 53N - Rge 68W	All
Twp 53N - Rge 69W	Sections 1 to 3, 10 to 15, 22 to 27 & 34 to 36
Twp 54N - Rge 67W	Sections 4 to 9, 16 to 21 & 28 to 33
Twp 54N - Rge 68W	All
Twp 54N - Rge 69W	Sections 1 to 3, 10 to 15, 22 to 27 & 34 to 36
Twp 55N - Rge 67W	Sections 28 to 33
Twp 55N - Rge 67.5W	Sections 25 & 36
Twp 55N - Rge 68W	Sections 25 to 36
Twp 55N - Rge 69W	Sections 25 To 27 & 34 to 36

Over 1,600 Minnelusa penetrations have been drilled in this 275 square mile study area at depths ranging from 2,000 feet in the northeast to over 7,000 feet in the southwest. Seventy-two separate Minnelusa oil fields have been developed within this area from 1960 through 1993 with projected ultimate recoverable oil reserves ranging from 2,100 to 6,632,600 barrels. Log suites for the Permian section (top Minnekahta formation through Upper Minnelusa formation) were retrieved from the Denver Earth Resources Library on all of the 1,600 plus wells. These log suites consisted of an induction and a sonic log covering the interval from the top of the Permian Minnekahta formation to total depth or 500 feet below the top of the Minnelusa, which ever is less. In the absence of sonic logs, density or micro logs were substituted, if available. On a few wells, the only available log was a gamma ray-neutron.

An east-to-west and north-to-south stratigraphic cross section grid of the Permian Minnekahta, Opeche and Upper Minnelusa formations was constructed on an approximate two mile grid spacing (ten east-to-west and four north-to-south). The system boundary lines as defined by Fryberger[8,9] were incorporated into this correlation grid with some modification. Fryberger utilized a designation system which subdivided the Upper Minnelusa into the A, B, C, and D units, each representing an episode of off-shore progradation of eolian sand dunes into the evaporitic carbonate sedimentary province of the Lusk Embayment. Within this study area, the B zone was further subdivided into an Upper B and a Lower B, each representing a separate episode. The marine dolomite which overly the A, Upper B, Lower B and C zones and represent the final stages of transgression were designated by the name of the underlying sand. Thus, the dolomite separating the Lower B and the C sand is designated the C dolomite. The top of the Minnelusa C dolomite was utilized as a datum for the regional cross sections.

With the cross sections as a reference, sequence boundaries, stratigraphic unit tops and porous intervals within the productive portion of the Upper Minnelusa formation were determined and tabulated for all 1,600 wells. The Minnelusa D sequence was penetrated in a few wells with no indication of hydrocarbons. No attempt was made to map this zone. A data table was prepared for all of the retrieved reservoirs (Table 3). The data table includes the subsea tops and bases of all the correlated sand units, the porous intervals, drill stem tests, completion results and current production history through January 1992. Figure 37 is a regional map depicting the field and well locations.

A series of geological work maps and correlation sections were constructed utilizing the data table over all seventy-two Minnelusa oil fields to clearly define the sequence boundaries and the reservoir geometry of each productive unit. The geomorphic trap is the principal type of oil trap in the Upper Minnelusa within the 275 square mile study area. Each of the four members mapped, the A, Upper B, Lower B and C represents an episode of progradation of eolian sand dunes and each episode is terminated and separated by the deposition of a marine dolomite reflecting the maximum marine transgression of the sea to the north and west over the dune deposits. Within the study area, the thickness of the complex within each of the four members varies from less than 20 feet to over 100 feet. The dune complexes have an areal extent ranging from 160 to over 640 acres. A period of regional uplift followed the deposition of the Upper Minnelusa eolian sands. A series of non-marine erosional channels, conforming roughly to the depositional topography of the underlying eolian deposits were incised into the Upper Minnelusa. These varied in width from a few hundred feet to several miles and reached a depth of over 100 feet. The channels were filled with the non-marine Opeche shale, which was subsequently overlain by the Minnekahta dolomite during a period of widespread marine transgression.

The sand dune complexes within the Upper Minnelusa Formation provide the reservoir for oil entrapment. Within the 275 square mile study area, most of the Minnelusa oil accumulations were the result of relatively simple geomorphic traps where the depositional topography of the dune complex was the primary factor controlling oil accumulation. The regional structural setting within the study area consists of a simple monocline with little or no structural closure. Either the conformably overlying marine shale or the unconformably overlying Opeche shale formed the upper seal and the underlying marine shale the lower seal for most productive traps. A few of the oil accumulations were controlled by diagenic facies changes or a combination of facies and geomorphology.

From the data tabulated and the maps and sections constructed for the 72 separate Minnelusa fields, 35 fields, including the West Kiehl, were selected for more rigorous and thorough reservoir analysis. Table 4 lists the 35 fields. The selection process involved eliminating smaller fields with fewer than two producing wells and more complex fields with multiple facies traps.

For the 35 selected fields, net oil pay isopachous maps were constructed for each of the productive eolian sands within the field boundary. Net pays were determined from sonic (or density) logs using a porosity cutoff of 10 per cent. Field oil-water contacts, if present, were established using a combination of conventional log analysis and analysis of drill stem, completion and production tests. The oil columns for each reservoir were planimetered and a reservoir volume (acre-ft) was calculated using the average of three methods. A weighted field average for porosity and true resistivity within the productive zone was calculated by analyzing the logs of all wells penetrating the producing zone. Water resistivities were generally determined from water analyses obtained from early drill stem or production tests. Water resistivities were also "backed out" by analyzing the logs of water-wet Minnelusa sand sections well below the established field oil water contacts. Irreducible field water saturations were then calculated using a Schlumberger nomograph.[10] These calculated values for water saturation probably represent the most sensitive aspect of determining original oil in place. The method used should result in a maximum value for water saturation with the resulting oil in place estimates representing a conservative value.

Field production histories for each of the 35 fields were retrieved from Dwight's Energydata, Inc. production data file. Decline rates were extrapolated for both primary and waterflood portion of the field decline history. Water injection history was retrieved from the State of Wyoming Oil and Gas Commission hard copy production files in Casper, Wyoming and was incorporated into the field production analysis. All of the 35 fields selected are mature enough to provide established decline rates within a margin of error of only a few per cent.

Data tables were prepared for each of the thirty-five selected fields incorporating the data from both the reservoir analyses and the production decline analyses. The table of each field as well as a plot of oil and water production versus time are included with the net pay and well location Figures in the Appendix of the First Annual Report of this study.[11] These select summary tables were utilized to establish ranges of oil recovery from analogous Minnelusa oil fields as a function of stratigraphic interval, primary drive mechanism, and secondary drive mechanism.

The range of pore volume of the 35 selected fields is 1,5400,600 to 30,250,00 barrels while the range of projected ultimate oil recoveries in terms of pore volume ranges from a low of 0.070 PV to a high to 0.379 PV. The weighted average estimate remaining oil in place after primary and waterflood (including waterflood) is 0.403 PV with a range of 0.303 to 0.626 PV.

The breakdown of fields by stratigraphic interval is as follows:

Minnelusa A and Upper B Zones (combined)	4
Minnelusa Upper B Zone	15
Minnelusa Lower B Zone	14
Minnelusa C Zone	2

The breakdown by primary drive mechanism is as follows:

Solution Gas Drive (or rock and fluid expansion)	20
Partial Water Drive	4
Water Drive	11

The breakdown by secondary drive application is as follows:

Waterflood	16
Polymer Augmented Waterflood	10
ASP Augmented Water Flood	2
No secondary recovery	7

Analysis of the 35 fields categorized by either stratigraphic producing horizon or by secondary drive mechanism indicate comparable ranges of reservoir and fluid properties and of recovery factors in terms of oil in place and pore volume. Neither the stratigraphic interval nor the secondary drive mechanism appears to provide any criteria for subdivision or classification of the reservoirs as a function of recovery efficiency. Projected ultimate oil recovery in terms of original oil in place ranges from a low of 10.2% to a high of 50.7% or in terms of pore volume from a low of 0.027 PV to a high of 0.315 PV. Estimated remaining oil in terms of pore volume ranges from 0.303 PV to 0.626 PV. These wide ranges of variation in recovery factors appear to be independent of the stratigraphic reservoir or the secondary drive mechanism, nor do they appear to be a function of reservoir and fluid properties such as pay thickness, average porosity, oil gravity or water salinity.

A primary drive mechanism was assigned to each of the 35 fields based on reservoir geometry and the primary decline history. Solution gas drive (or rock and fluid expansion) reservoirs are defined as reservoirs where the ratio of the volume of oil column to water column is less than 1.0. A plot of the monthly oil rate versus cumulative oil in terms of pore volume for solution gas reservoirs shows a steep, almost linear decline to a maximum of 0.08 PV. Oil to water ratio are characteristically high throughout the primary production history and a plot of total fluid produced also shows a steep, almost linear decline during the primary phase. Nineteen of the 35 selected reservoirs have solution gas (rock and fluid expansion) primary drive mechanisms using these criteria. Of the fields currently being waterflooded, 10 have polymer augmentation and 2 have alkaline-surfactant-polymer augmentation. Water drive primary production reservoirs are defined as reservoirs where the ratio of the volume of the oil column to the water column is less than 0.33. A plot of monthly oil rate versus cumulative oil production in terms of pore volume for water drive reservoirs shows a gradually decreasing decline projected to 0.28 to 0.50 PV with a corresponding decrease in oil cut. A plot of total fluid produced levels out to virtually no decline after the first two or three years. Ten of the 35 fields have water drive primary producing mechanisms using these criteria. Three of these fields are being waterflooded. Reservoirs with a ratio of the volume of the oil column to the volume of the water column is between 1.0 and 0.33 are designated as partial water drives. The plot of monthly oil rate versus cumulative production in terms of pore volume for partial water drive reservoirs shows an initial steep decline with a gradual flattening to about 0.18 PV with a correspondingly gradual decrease in oil cut. Six of the 35 reservoirs are classified as having partial water drive primary production mechanisms. Four of the partial water drive reservoirs are being waterflooded and 1 is being polymer flooded.

In terms of reservoir geometry and the ratio of oil column to water column and the shape of the monthly oil rate versus cumulative oil recovery in pore volumes curve, the West Kiehl field shows all the characteristics of a typical solution gas drive primary production mechanism. Two additional fields were selected for reservoir simulation from the solution gas primary drive reservoirs. The first field, Prairie Creek South, was selected from the waterflooded solution gas reservoirs. The second field, Simpson Ranch, was selected from the solution gas reservoirs among the 10 polymer augmented water floods. The reasons for selecting these fields were similarities in reservoir size and well density and spacing as well as primary drive mechanism. All three field are relative simple geomorphic traps representing a single dune sand complex. Calculations of original oil in place for the three fields ranges from 2,005,200 to 3,106,000 barrels. West Kiehl field has 4 oil producers and 2 water injectors over 145 acres. The second water injector was completed in 1993 and did not play an integral role in the alkaline-surfactant-polymer project. Prairie Creek South has 2 oil producers and 1 water injector over 94 acres and Simpson Ranch has 3 oil producers and 1 water injector over 172 acres.

Prairie Creek South Analyses

Geological and Reservoir Analyses Prairie Creek South

Prairie Creek South Field is located in Section 16 Township 53N Range 68W and produces from the Minnelusa Upper B Zone. As at West Kiehl, the productive zone is subdivided into three units on the basis of stratigraphic correlation. Oil water contacts were determined and the respective isopachous maps were planimetered to calculate the rock volumes. Again porosity variations were defined on separate maps for each unit. Figure 38 depicts the Prairie Creek South net pay isopach and shows the well locations.

The effective porosity (over 10%) is developed and preserved in three mappable and conformable horizontal zones. Zones 1 through 3 are oil bearing and are labeled on Figure 39 which depicts the cross section. The zonation is based on the sonic log correlation and porosity variations. A oil-water contact exists at 2,559 ft subsea which was determined from log analysis, drill stem tests and completion results. Figures 40 through 42 show the net thickness isopachous map for each of the three layer layers.

The primary drive mechanism is entirely solution gas, rock and fluid expansion with no apparent natural water drive. There is no discernable gas cap.

Prairie Creek South has a pore volume of 2,682 Mbbls. The initial oil saturation is 77.0% or 2,005,000 bbls. The reservoir and production data are summarized in Table 5.

Classical Engineering Prairie Creek South Project Performance

Prairie Creek South was discovered in September 1985 with the drilling of State #1 Prairie Creek. Initial production was 85 barrels of oil per day and 40 barrels of water. Prairie Creek B-1 drilled in November 1985 was the first offset drilled and was located due north of the discovery well. Initial production was 81 barrels oil per day. The final productive well in the field, Prairie Creek A-1, was drilled in December 1985 to the east of Prairie Creek B-1 with initial production of 290 barrels of oil per day and 15 barrels of water per day.

A waterflood began in May of 1988 with injection into the State #1 Prairie Creek.

Figures 43 through 45 depict the barrels of oil per day versus cumulative oil produced for the entire field and Wells A-1 and B-1. Oil rates increased rapidly to levels close to initial production rates, typical of Minnelusa reservoirs.

Extrapolating the actual production to 12 barrels of oil per day using oil rate and water cut plot, the ultimate production at Prairie Creek South is:

Classical Engineering Prairie South Ultimate Oil Recovery Projection

	---Ultimate Cumulative Oil Production---	
Well	**BOPD Extrapolation**	**Water Cut Extrapolation**
State #1 Prairie	15,667	15,667
A-1	662,800	625,700
B-1	136,400	123,500
Total Field	814,867	764,867

Monthly oil and water cut regression plots of Wells A-1 and B-1 are depicted in Figures 46 and 47. Total oil production as of December 1993 is 694,561 barrels of oil.

The gross swept volume of the Prairie Creek South field is 1,621,000 barrels, as determined by Slider.[6] Original oil in place is 1,248,200 barrels within the gross swept area. Estimated ultimate waterflood oil recovery varies between 52.4 and 56.4% OOIP from the gross swept area. Final waterflood residual oil saturation varies between 0.335 to 0.366 PV.

Numerical Simulation - Prairie Creek South History Match

Data Used for Simulation - The basic reservoir description for Prairie Creek South was determined by geological and reservoir engineering interpretation as described earlier. Reservoir fluid properties and rock properties were from "South Prairie Creek Minnelusa Unit, Crook County, Wyoming, Waterflood Feasibility Study and Unitization Parameters" dated October 15, 1986. Monthly production data was from Dwight's Energydata, Inc. Monthly water and oil of Well B-1 were altered to match current production values and to correct obvious errors in reporting.

The same composite of 18 Minnelusa relative permeability effective permeabilities curve shapes and ending values used for West Kiehl, shown in Figure 23, were used for Prairie Creek South. The immobile water saturation was shifted to 0.23 PV. Porosity for each layer was contoured from log derived values. Permeability was derived from the same cross-plot of permeability versus porosity used in the West Kiehl analysis (see Figure 24).

Grid Data - The study area was divided into a grid spacing of 9 by 3 with 3 layers for a total of 351 grid blocks. The three zones included in the numerical model are shown in the diagrammatic structural cross section shown in Figure 48. Figure 49 shows the grid system and well locations with the net thickness of layer 1.

Initial Conditions - The initial oil and water saturation conditions were obtained by determining an oil-water contact. From the individual well log analyses, the depth of the oil-water contact averaged 2,559 ft sub-sea. The oil saturation below this depth was then set to zero and above this depth at the endpoint of the relative permeability curve, 0.770 PV. Some bottom water was placed around Prairie Creek South State #1.

Drill stem testing on well State #1 indicated an initial reservoir pressure of about 2,581 psi, which was used for the reservoir model.

Prairie Creek South Field History Match

The performance of the alkaline-surfactant-polymer flood is matched through December 1993. During the history match, the actual injection rates and oil plus water production rates are the limiting criteria for the simulation with proportions of water to oil determined in an identical manner as the West Kiehl. Permeability changes were all that was required to facilitate a history match and honor the oil saturation calculated from the logs.

The history match of the two producing wells and the total field is shown in Figure 50. Well B-1 history match is not as close due to the poor quality of the available production data.

Prairie Creek South Chemical Flood Predictions

Predictions were made to extend the current waterflood and to simulate an alkaline-surfactant-polymer flood and a mobility control polymer flood. For the alkaline-surfactant-polymer flood and the mobility control polymer flood, chemical solutions were injected for approximately the same pore volume as the West Kiehl. Chemical solution injection for the predictions began in May 1988. Injection rates were identical to the actual waterflood through December 1993.

Figure 51 depicts the cumulative oil, cumulative water and oil cut prediction for the total field of continued water injection, injection of an alkaline-surfactant-polymer solution and a mobility control polymer flood. Each well was produced to an economic limit of 12 oil bbls/day per well. Figure 52 shows the predicted production for Well A-1 and Figure 53 shows Well B-1. The data are summarized in the following table.

Prairie Creek South Numerical Simulation Predicted Oil and Water

Flooding Process	Cumulative Oil MSTB	Cumulative Water MSTB	Incremental Oil MSTB	Project Ending Date
Total Field				
Waterflood	790	1,144	------	12-1998
Mobility Control Polymer	919	1,090	129	2-2005
Alkaline-Surfactant-Polymer	1,100	1,075	310	11-2002
Well A-1				
Waterflood	635	936	------	
Mobility Control Polymer	866	1,088	231	
Alkaline-Surfactant-Polymer	948	892	313	
Well B-1				
Waterflood	139	207	------	
Mobility Control Polymer	37	1	-101	
Alkaline-Surfactant-Polymer	137	182	-3	

Total oil recovery predicted by the numerical simulator is 25,000 barrels more than the ultimate predicted by the water cut regression and is 25,000 barrels less than the oil rate extrapolation. Well A-1 is the dominant well in the field and as a result has all the incremental oil production. Adding mobility control to the injected solutions reduced the fluid flow to Well B-1.

Plots c of Figures 51 through 53 also demonstrate a difference in water break through. Water break through is earlier for the waterflood than the chemical floods. The rate of oil cut decline is less for polymer flood than a waterflood and the alkaline-surfactant-polymer flood is less than the polymer flood.

Numerical simulation predictions of produced chemical suggest that peak polymer production at A-1 will be 23 mg/l, peak Na_2CO_3 production will be 0.1 wt% and peak Petrostep B-100 production will be .02 wt%.

Simpson Ranch Analyses

Geological and Reservoir Analyses Simpson Ranch

Simpson Ranch is located in Section 15 Township 51N Range 69W and produces from the Minnelusa Upper B Zone. The productive zone is subdivided into five units on the basis of stratigraphic correlation. The bottom three zones are not productive. No oil water contact exists. Figure 54 depicts the Simpson Ranch net pay isopach and well locations.

The effective porosity (over 10%) is developed and preserved in eight mappable and conformable horizontal zones. Zones 1 through 5 are oil bearing and are labeled on Figure 55 which depicts the cross section. The zonation is based on the sonic log correlation and porosity variations.

Figures 56 through 60 show the net thickness isopachous map for each of the five layer layers, the well locations and the simulation grid.

The primary drive mechanism is entirely solution gas, rock and fluid expansion with no apparent natural water drive. There is no discernable gas cap.

Simpson Ranch has a pore volume of 3,682 Mbbls. The initial oil saturation is 65.0% or 2,280,000 bbls of stock tank oil. The reservoir and production data are summarized in Table 6.

Classical Engineering Simpson Ranch Project Performance

Simpson Ranch was discovered in June 1977 with the drilling of the #1 Hilda. Initial production was 460 barrels of oil per day with no water. The second well in the productive zone was the #1 Hamm Twin Federal which was drilled in October 1977. Initial production was 160 barrels/day of oil with no water. The third well in the field was the #3 Hilda drilled in April 1978 with an initial production of 27 barrels of oil per day with no water. The last well drilled in September 1984 was the #4 Simpson Ranch Unit. Initial production was 54 barrels/day of oil and 1 barrel/day of water. #1 Hilda was shut-in August 1985. Figure 61 shows the total field monthly oil and water production.

Water was initially injected into Hilda #3 beginning in February 1979. A total of 36,074 barrels of water was injected prior to beginning a polymer flood. A Cat-An® polymer flood began in Simpson Ranch in June 1979.[12] A total of 2,500 lbs of cationic polymer was injected in June and July 1979 in 25,513 barrels of water. In July 1979, anionic polymer-aluminum cross link agent injection sequence began. 61,700 lbs of anionic polymer and 74,500 lbs of aluminum citrate were injected in 612,579 barrels of water ending in October 1983. Water injection continues to the present.

The injection of water into Hilda #3 resulted in a immediate increase in oil production in both the Hilda #1 and the Hamm Twin Federal #1 before polymer injection. The Hilda #1 oil production increased from 1,585 barrels of oil in January 1980 to 3,210 barrels by June of 1979. It reached the peak production level of over 7,000 barrels of oil a month in December of 1979. Hamm Twin Federal #1 showed a similar response reaching the peak production level of about 4,000 barrels of oil a month in December 1979. Figures 62 and 63 depict the barrels of oil per day versus cumulative oil produced for the two wells. Figure 64 shows the monthly production for the Simpson Ranch South Well - Unit #4.

Extrapolating the actual production to 12 barrels of oil per day using oil rate and water cut plot, the ultimate production at Simpson Ranch is:

Classical Engineering Simpson Ranch Oil Recovery Prediction

Well	—Ultimate Cumulative Oil Production— BOPD Extrapolation	Water Cut Extrapolation
Hilda #1	334,934	334,934
Hilda #3	4,864	4,864
Hamm Twin Fed #1	354,300	323,200
Unit #4	226,300	204,000
Total Field	920,398	866,998

Monthly oil and water cut regression analysis are shown in Figures 65 and 66 for the Hamm Twin Federal #1 and Simpson Ranch Unit #4. Hilda #1 and Hilda #3 are not shown because the former was shut-in and the later converted to an injector. Actual production through December 1993 is 812,041 barrels of oil.

The gross swept volume of the Simpson Ranch field is 2,264,000 barrels, as determined by Slider.[6] Original oil in place is 1,471,200 barrels. Estimated ultimate waterflood oil recovery varies between 58.0 and 61.7% OOIP from the gross swept area. Final waterflood residual oil saturation varies between 0.249 to 0.281 PV.

Numerical Simulation - Simpson Ranch History Match

Data Used for Simulation - The basic reservoir description for the Simpson Ranch was determined by geological and reservoir engineering interpretation as described earlier. Reservoir fluid properties and rock properties were from a proprietary study performed by Surtek, from the data developed for the West Kiehl and from a prior publication discussing Simpson Ranch.[12] Monthly production data was from Dwight's Energydata, Inc.

The same relative permeability effective permeabilities curve shapes and ending values used for West Kiehl, shown in Figure 23, were used for Simpson Ranch. The immobile water saturation was changed to 0.35 PV. Porosity for each layer was contoured from log derived values. Permeability was derived from the same cross-plot of permeability versus porosity used in the West Kiehl analysis, see Figure 24.

Grid Data - The study area was divided into a grid spacing of 9 by 12 with 5 layers for a total of 540 grid blocks. The five zones included in the numerical model are shown in the diagrammatic structural cross section shown in Figure 67. Figure 68 shows the grid system and well locations. To give the grid and well locations meaning, the grid is shown with the net thickness of layer 2.

Initial Conditions - The initial oil and water saturation conditions were obtained by from the relative permeability curve. The oil saturation was set at the endpoint of the relative permeability curve, 0.650 PV. No oil-water contact was present and the initial reservoir pressure was 3,050 psi.

Chemical Characteristics and Volume of Chemical Injected - For the Cat-An® flood polymers adsorption and rheological data were from proprietary information from a variety of Minnelusa flood studies performed by Surtek. The actual chemical injection sequence was obtained from Chemical Oil Recovery Program Progress Reports.[13] The sequence of injection and volume of chemical injected in the simulation run was:

Simpson Ranch Chemical Injection

Dates of Injection	Injected Fluid	Cumulative Pounds x 10^3 —Polymer Injected— Cationic	Anionic
February 1979-June 1979	Water	----	----
June 1979-July 1979	Cationic Polymer	2.73	----
July 1979-October 1983	Anionic Polymer	----	62.48

Water was injected after October 1983.

Simpson Ranch Field History Match

The performance of the Cat-An® polymer flood is matched through December 1993. During the history match, the actual injection rates and oil plus water production rates are the limiting criteria for the simulation with proportions of water to oil determined in an identical manner as the West Kiehl. Permeability changes were all that was required to facilitate a history match and honor the oil saturation calculated from the logs.

The history match of the four producing wells and the total field is shown in Figure 69. History match is close for all the wells as well as the total field.

Simpson Ranch Chemical Flood and Waterflood Predictions

Predictions were made to extend the current polymer flood and to simulate an alkaline-surfactant-polymer flood and a waterflood. For the alkaline-surfactant-polymer flood, chemical solutions were injected for the same volume as the West Kiehl. Chemical adsorption, interfacial tension, and rheological characteristics were identical to the West Kiehl data. For the Cat-An® flood polymer's extension, data were consistent with the history match information.

Chemical solution injection for the polymer flood history match and prediction and the alkaline-surfactant-polymer prediction began in June 1979. Injection rates were identical to the actual polymer flood through December 1993.

Figure 70 depicts the cumulative oil, cumulative water and oil cut prediction for the total field of continued water injection after the polymer flood, injection of an alkaline-surfactant-polymer solution and a waterflood. Each well was produced to an economic limit of 12 oil bbls/day per well. Figure 71 shows the predicted oil production for Hilda #1. Hamm Twin Federal #1 prediction oil production is shown in Figure 72 and Simpson Ranch Unit #4 is shown in Figure 73.

Simpson Ranch Numerical Simulation Predicted Oil and Water

Flooding Process	Cumulative Oil MSTB	Cumulative Water MSTB	Incremental Oil MSTB	Project Ending Date
Total Field				
Waterflood	745	2,544	------	3-1996
Cat-An Polymer	831	1,090	86	3-1996
Alkaline-Surfactant-Polymer	1,095	2,175	350	3-2003
Well Hilda #1				
Waterflood	320	379	------	
Cat-An Polymer	335	262	15	
Alkaline-Surfactant-Polymer	501	184	181	
Well Hilda #3				
Waterflood	5	0	------	
Cat-An Polymer	5	0	0	
Alkaline-Surfactant-Polymer	5	0	0	
Well Hamm Twin Federal #1				
Waterflood	278	1,082	------	
Cat-An Polymer	319	1,228	41	
Alkaline-Surfactant-Polymer	385	950	107	
Well Simpson Ranch Unit #4				
Waterflood	142	1,082	------	
Cat-An Polymer	173	1,014	31	
Alkaline-Surfactant-Polymer	203	1,041	61	

Total oil recovery predicted by the numerical simulator is 36,000 barrels less than the ultimate predicted by the water cut regression and is 89,400 barrels less than the oil rate regression.

Plots c of Figures 70 through 73 demonstrate a difference in oil cut decline. The oil cut declines more rapidly for the waterflood and for the Cat-An® polymer flood than for the alkaline-surfactant-polymer flood. The Cat-An® polymer flood oil cut decline is slightly delayed relative to the waterflood.

Numerical simulation indicates some polymer will be produced during the Cat-An® polymer flood. Peak polymer concentration is predicted to be 1 mg/l with a total of 350 lbs of polymer produced. Peak chemical concentrations during the alkaline-surfactant-polymer flood are predicted to occur in Hamm Twin Federal #1 fluids. Peak chemical concentrations will be 12 mg/l for polymer, 0.08 wt% for Na_2CO_3 and 0.01 wt% for Petrostep B-100. Total chemical produced is 357,000 lbs of Na_2CO_3, 56,740 lbs of Petrostep B-100, and 5,280 lbs of Pusher 700.

Application of Alkaline-Surfactant-Polymer to Mature Minnelusa Floods

Numerical Simulation after Waterflood and Polymer Flood

To estimate the amount of incremental oil an alkaline-surfactant-polymer project will recover in mature Minnelusa reservoirs, the injection of an alkaline-surfactant-polymer solution after a waterflood was numerically simulated for West Kiehl, Prairie Creek South and Simpson Ranch. Conditions for each reservoir were identical to the prior numerical simulations. Waterfloods and polymer floods had reached the 12 barrel per day economic limit prior to alkaline-surfactant-polymer injection. The volume of alkaline-surfactant-polymer solution injected was approximately equal to that injected in the West Kiehl project.

Mature Minnelusa Alkaline-Surfactant-Polymer after Waterflood
Numerical Simulation Predicted Oil and Water

Flooding Process	Cumulative Oil MSTB	Cumulative Water MSTB	Incremental Oil MSTB	Additional Project Years
Total Field				
West Kiehl				
Waterflood	726	1,332	------	0
Alkaline-Surfactant-Polymer	1,047	4,465	321	19.25
Prairie Creek South				
Waterflood	790	1,144	------	0
Alkaline-Surfactant-Polymer	1,062	2,739	272	10.25
Simpson Ranch				
Waterflood	745	2,544	------	0
Alkaline-Surfactant-Polymer	1,068	5,647	323	15.5

West Kiehl incremental oil recovery due to alkaline-surfactant-polymer injection after waterflood increased by 20,000 barrels. The change in incremental oil production is due to an increase in incremental oil at Kottabra 25-15 of 37,000 barrels (349,000 versus 312,0000 barrels) and a decrease in oil production at the State 32-36 and State 42-36 wells of 9,000 barrels (600,000 barrels versus 609,000 barrels). The incremental oil production change is due to the Kottabra 25-15 well being on production for the entire alkaline-surfactant-polymer injection period. In the actual flood, the Kottabra 25-15 was on production for only 6 months of alkaline-surfactant-polymer injection.

Simpson Ranch and Prairie Creek South show a 23,000 and 38,000 barrel respective decrease in oil recovery compared to injecting the alkaline-surfactant-polymer solution in a secondary mode. From an ending waterflood oil cut of about 95% (12 barrels per day), peak oil cuts increased to 12% ,20% and 25% due to alkaline-surfactant-polymer injection for West Kiehl, Simpson Ranch, and Prairie Creek South, respectively.

Estimated Ultimate Recovery Potential

Incremental oil produced from the combination of West Kiehl, Simpson Ranch, and Prairie Creek South was 906,000 barrels after waterflood and 951,000 barrels in a secondary mode from 10,000,000 barrels of pore space. The Minnelusa trend has approximately 120 reservoirs with an estimated total pore space of 1.4 billion barrels. If the oil recovery efficiency of the West Kiehl is applied to all these fields, the incremental oil recovery potential is 130 million barrels of oil. Since the alkaline-surfactant-design technology has advanced considerably since 1985 (date of the West Kiehl design), this number may be low.

Economic Evaluation

At the West Kiehl, $376,119 was spent for chemicals and $81,986 was spent for a laboratory feasibility study and incremental facilities cost. Incremental oil production of 291,000 barrels of oil predicted from the numerical simulation for alkaline-surfactant-polymer injection in a secondary mode gives an incremental cost per barrel of oil of $1.57.

1994 costs for chemicals are higher than the actual purchase price at West Kiehl. 1994 costs for chemicals delivered to the Minnelusa area are: Polyacrylamide polymer $1.35/lb, Petrostep B-100 $0.95 per active pound, and Na_2CO_3 $0.065 per pound. Incremental facilities cost is estimated to be $100,000 and laboratory feasibility cost and numerical simulation cost are estimated to be $125,000. When these costs are applied to the incremental oil recovery due to alkaline-surfactant-polymer in the West Kiehl, Prairie Creek South, and Simpson Ranch, the cost per incremental barrel of oil are calculated in the following table.

Cost per Incremental Barrel of Oil for Alkaline-Surfactant-Polymer Minnelusa Projects

Fields Name	Numerical Simulation Chemical Cost	Incremental Oil Produced (barrels)	Incremental Cost per Barrel ($/barrel)
West Kiehl			
Secondary	$ 884,500	291,000	$3.03
after Waterflood	$ 904,948	321,000	$2.82
Prairie Creek South			
Secondary	$1,157,600	310,000	$3.73
after Waterflood	$ 886,700	272,000	$3.25
Simpson Ranch			
Secondary	$ 994,550	350,000	$2.84
after Waterflood	$1,032,400	323,000	$3.19

Conclusions

1. Incremental oil was produced at the West Kiehl due to injection of an alkaline-surfactant-polymer solution. Estimated ultimate incremental oil is 291,000 barrels of oil produced at a cost of $1.57 per incremental barrel.

2. Incremental oil can be produced at similar Minnelusa oil reservoirs if the alkaline-surfactant-polymer technology is applied. Incremental oil potential by the alkaline-surfactant-polymer technology is approximately 10% PV based on numerical simulation analysis of West Kiehl, Prairie Creek South and Simpson Ranch Fields.

3. Incremental oil can be produced by implementing an alkaline-surfactant-polymer flood from Minnelusa oil reservoirs which have been waterflooded and are approaching their economic limit.

4. Estimated 1994 chemical costs per incremental barrel is $3.00 or less using the alkaline-surfactant-polymer technology.

5. If the alkaline-surfactant-polymer technology can be applied to the other Minnelusa reservoirs, a potential 130,000,0000 barrels of incremental oil can be produced.

Future Research

Logical extension of this work would be to apply the alkaline-surfactant-polymer technology to a Minnelusa field which is either at or close to the waterflood economic limit.

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Table 1

Kiehl West Field – Data Summary

Producing Zone:	Minnelusa Lower B	Oil Gravity	24.0
Location:	Crook County, Wyoming	Oil Viscosity, cp	19.5
	TWP 53 – RGE 68W	Water Viscosity, cp	0.6
	Sections 25 & 36	Depth, feet	6,671
Drive Mechanism:	ASP Waterflood	Formation Temperature, degrees F	134
Discovered:	1985	Rw @ Formation Temperature	0.25
Unitized:	1987		

		Reservoir Properties	
Current Production – 1/1 to 12/31/92		Volume, acre feet	2,086
Oil, bbls	76,000	Area, acres	145
Water, bbls	126,075	Average Net Pay, feet	14.4
		Average Porosity	19.1%
Cumulative Production – thru 12/31/92		Average S_w	27.5%
Oil, Mbbls	783	FVF Factor	1.030
Water, Mbbls	242		
Injection, Mbbls	1,073	Pore Volume, Mbbls	3,084
		Oil in Place, Mbbls	2,170
Current Rates		Est. Ult. Recovery Factor, %OOIP	46.2%
Oil, bopd	208	Current Recovery Factor %OOIP	36.1%
Oil Cut, %	37.6%	Current Depletion Factor %	78.0%

Waterflood Decline Analysis		**Primary Deline Analysis**	
Economic Cutoff		Economic Cutoff	
Oil, bopd	40	Oil, bopd	20
Oil Cut		End of Primary Decline	08/87
Estimated Decline	25.0%	Estimated Decline	35.0%
Proj. Ultimate Recovery, Mbbls	1,003	Projected Ult. Recovery, Mbbls	96
Proj. Remaining Reserves, Mbbls	220	Primary Recovery Factor %OOIP	4.4%
Estimated Remaining Life, Years (from 1/93)	5.3		
		Cumulative Oil: Pore Volume	0.254
		Cumulative Water: Pore Volume	0.079
OOIP: Pore Volume	0.704	Cumulative Injection: Pore Volume	0.348
Ultimate Recovery: Pore Volume	0.325	Production – Injection Difference: PV	0.015
Remaining O.I.P.: Pore Volume	0.379		

		-------- to 1/93	--------	
Production Location	Name	Cum Oil, bbls	Cum Wtr, bbls	Status
NWSE 25–53–68	Kottraba #10	14,542	6,625	Pump–Oil
SWSE 25–53–68	Kottraba #15	214,805	139,580	Pump–Oil
NENE 36–53–68	State #41	6,551	4,911	SI–Oil
NWNE 36–53–68	State #31	69,071	33	Injection
SWNE 36–53–68	State #32	176,043	53,381	Pump–Oil
SENE 36–53–68	State #42	303,171	37,871	Pump–Oil

		1992 Year	to 1/93	
Injection Location	Name	Curr Inj, bbls	Cum Inj, bbls	Status
NWNE 36–53–68	State #31	220,821	1,072,540	Injection

West Kiehl Oil PVT Properties

Table 2

		SATURATED OIL						RESERVOIR OIL					
PRES	RS	FVF	VISC	DENS	CO	COMPOSITION		FVF	VISC	DENS	CO	COMPOSITION	
PSIA	CF/SB	RB/STB	CP	LB/CF	1/PSI	GAS	ST-OL	RB/STB	CP	LB/CF	1/PSI	GAS	ST-OL
14.6	0	1.0800	9.96	52.13		0.000	1.000	1.0800	9.96	52.13		0.000	1.000
					1449.3						1449.3		
31.6	0	1.0550	9.86	53.37		0.001	0.999	1.0550	9.86	53.37		0.001	0.999
					18.6						18.6		
114.7	0	1.0540	10.03	53.42		0.001	0.999	1.0540	10.03	53.42		0.001	0.999
					7.3						5.0		
514.7	1	1.0520	10.50	53.52		0.001	0.999	1.0519	11.01	53.53		0.001	0.999
					7.8						5.0		
1010.7	1	1.0493	11.21	53.66		0.002	0.998	1.0493	12.23	53.66		0.001	0.999
					5.6						5.0		
2014.7	2	1.0445	12.61	53.92		0.004	0.996	1.0440	14.70	53.93		0.001	0.999
					5.3						5.0		
3014.6	2	1.0393	14.62	54.19		0.006	0.994	1.0388	17.16	54.20		0.001	0.999
					4.7						5.0		
4014.6	3	1.0346	16.48	54.44		0.007	0.993	1.0336	19.62	54.47		0.001	0.999
					8.9						5.0		
5514.6	3	1.0210	18.35	55.17		0.008	0.992	1.0259	23.31	54.88		0.001	0.999

Minnelusa Field Production – ASP Study Table 3, Page 1

TWP 51N to 55N – RGE 67W to 69W

Listing of all known Minnelusa Reservoirs in study area

Field	Minnelusa Producing Zone	Drive Mechanism	Location SEC	Location TWP	Location RGE	Average Net Pay Feet	Average Porosity %	Average S_w %	Volume acre ft	Area acres	Pore Volume Mbbls	Original O. I. P. Mbbls	Pore Volumes OOIP	Pore Volumes Ult Oil Rec	Pore Volumes Cum Oil Rec	Pore Volumes Cum Wtr Rec	Pore Volumes Cum Inj	Pore Volumes Balance	Pore Volumes abd O.I.P
Alpha	C	Polymer	1,2&11	51N	69W	35	16.6%	33.0%	13,922	394	17,929	11,449	0.639	0.281	0.215	0.076	0.229	–0.062	0.358
American	Upper B	Polymer	5&6	52N	68W	15	17.6%	27.0%	3,024	205	4,124	2,867	0.695	0.070	0.059	0.020	0.082	0.003	0.625
Ammo	Upper B	Polymer	16&17	52N	68W	13	20.1%	21.7%	988	76	1,541	1,168	0.751	0.132	0.112	0.297	0.422	0.013	0.618
Art Creek	A & Upper B	Waterflood	8	51N	67W				3,950		5,932	3,953	0.666	0.161	0.146	0.121	0.291	0.024	0.505
Ash	Upper B	Waterflood	27&28	52N	69W	22	16.8%	15.5%	2,086	96	2,715	2,264	0.833	0.236	0.100	0.001	0.008	–0.093	0.597
Berger Hill	Lower B	Water Drive	6	53N	67W	17	25.0%	40.0%	3,079	184	5,971	3,445	0.577	0.162	0.154	1.775			0.415
Bertha	Lower B	Water Drive	23	54N	69W	6	13.6%	30.0%	473	77	497	331	0.667	0.030	0.030	0.152			0.637
Bracken	Upper B	Polymer	12&13	52N	69W	15	17.4%	25.0%	3,092	200	4,181	2,986	0.714	0.191	0.113	0.064	0.353	0.176	0.524
Bracken South	C	Water Drive	13	52N	69W	14	21.2%	39.0%	1,300	94	2,137	1,242	0.581	0.119	0.081	1.178			0.462
Breaks	Lower B	Waterflood	26	52N	69W	31	23.0%	29.0%	6,357	205	11,333	7,663	0.676	0.320	0.157	0.164	0.142	–0.179	0.356
Breaks South	Lower B	Aug Wtr Dr	35	52N	69W	22	21.1%	43.0%	3,559	155	5,827	3,163	0.543	0.037	0.034	0.319			0.506
Brislawn	Lower B	Water Drive	13	54N	68W	8	25.6%	32.0%	702	89	1,393	920	0.660	0.057	0.069	0.699			0.603
Brousa Draw	Upper B	Water Drive	8	53N	67W	11	28.0%	50.0%	421	38	915	448	0.490	0.242	0.161	0.258			0.248
Cambridge	Upper B	ASP	28	53N	68W	23	20.2%	32.0%	5,066	218	7,947	5,247	0.660	0.296	0.027	0.004	0.000	–0.031	0.364
Cardinal	C	Water Drive	28	51N	69W	15	15.6%	45.0%	1,849	124	2,236	1,171	0.524	0.094	0.083	0.514			0.430
Carr Creek	Upper B	Water Drive	25	55N	67.5W	15	13.9%	40.0%	1,859	127	2,000	1,165	0.583	0.170	0.185	1.918			0.412
Corral Creek	Upper B	Water Drive	26&35	55N	68W	16	25.6%	41.0%	2,451	153	4,875	2,792	0.573	0.092	0.116	1.084			0.481
County Line	Lower B	Water Drive	31	52N	68W	20	24.6%	40.0%	2,769	141	5,290	3,023	0.571	0.274	0.192	0.707			0.297
Deadman Creek	Lower B	Polymer	18&19	53N	67W	25	18.1%	24.0%	5,461	266	7,656	5,595	0.731	0.289	0.210	0.225	0.713	0.278	0.441
Edsel	Upper B	Waterflood	25,26,35&36	54N	68W	27	22.5%	32.0%	10,060	376	17,575	11,603	0.660	0.286	0.242	0.425	0.697	0.029	0.374
Guthery	A & Upper B	Waterflood	3	51N	67W				8,338		13,670	8,544	0.625	0.300	0.289	0.415	0.709	0.005	0.325
Gurthery North	U & L B	Solution Gas	2&3;34&35	51&52N	68W				2,981		3,972	2,482	0.625	0.063	0.061	0.006			0.562
Guthery Northwest	Upper B	Solution Gas	34	52N	68W	14	15.3%	38.0%	1,650	122	1,959	1,168	0.596	0.014	0.014	0.003			0.582
Heath	C	Water Drive	8&9	52N	68W	28	18.5%	45.0%	6,845	248	9,825	5,146	0.524	0.084	0.073	0.279			0.440
Heath North	Lower B	Water Drive	4&5	52N	68W	20	26.9%	40.0%	2,060	88	4,291	2,452	0.571	0.187	0.159	0.237			0.385
Hilda	Lower B	Water Drive	36	51N	69W	11	22.5%	35.0%	871	77	1,520	941	0.619	0.273	0.072	0.050			0.346
Hoover Gulch	Upper B	Waterflood	24	52N	69W	14	16.7%	24.0%	2,078	124	2,697	1,952	0.724	0.243	0.130	0.157	0.082	–0.205	0.481
JB	Lower B	Water Drive	20	53N	68W	25	22.2%	45.0%	3,086	125	5,322	2,788	0.524	0.008	0.007	0.064			0.516
Jewel	Lower B	Water Drive	7	54N	67W	23	25.7%	45.0%	2,176	96	4,343	2,319	0.534	0.204	0.175	0.591			0.330
Kiehl	Upper B	Polymer	30&31	53N	68W	35	22.1%	23.0%	10,621	307	18,210	13,613	0.748	0.260	0.139	0.037	0.179	0.003	0.488
Keihl West	Lower B	ASP	25&36	53N	68W	14	19.1%	27.5%	2,086	145	3,084	2,170	0.704	0.325	0.254	0.079	0.348	0.015	0.379
Lad	A & Upper B	Waterflood	17,18&19	54N	67W	28	21.2%	35.0%	8,912	323	13,501	8,520	0.631	0.211	0.197	0.140	0.346	0.009	0.420
Lad South	C	Water Drive	20	54N	67W	12	18.1%	38.0%	1,013	87	1,421	856	0.602	0.113	0.030	0.410			0.489
Lily	A & Upper B	Waterflood	26,27,34&35	54N	68W				5,077		9,240	6,841	0.740	0.234	0.211	0.157	0.364	–0.004	0.506
Little Missouri	Lower B	Polymer	5;31,32	54&55N	67W	19	19.2%	23.0%	5,284	278	7,858	5,875	0.748	0.253	0.126	0.025	0.156	0.005	0.495
Little Mitchell Creek	Lower B	Waterflood	11,14	52N	69W	29	20.4%	25.0%	19,077	664	30,250	21,607	0.714	0.339	0.313	0.118	0.419	–0.013	0.375
Little Mo	Lower B	Water Drive	23	53N	68W	16	20.8%	30.0%	696	43	1,121	755	0.673	0.357	0.356	1.279			0.316
Little Mo South	Lower B	Water Drive	26	53N	68W	14	21.2%	35.0%	850	59	1,394	871	0.625	0.320	0.313	0.503			0.305
Lone Cedar	Upper B	Polymer	8,9,16&17	51N	69W	28	20.7%	15.0%	7,219	261	11,593	9,385	0.810	0.379	0.224	0.176	0.431	0.032	0.431
M–D	Lower B	Water Drive	6;1;25&31,36	52&53N	68&69W	18	16.3%	30.0%	13,778	765	17,370	11,580	0.667	0.318	0.314	0.800			0.348
Mellott Ranch	A & Upper B	Waterflood	2,10&11	52N	68W				14,172		21,174	15,135	0.715	0.297	0.293	0.997	1.275	–0.014	0.418
Missouri	Upper B	Solution Gas	26	53N	68W	12	16.7%	30.0%	651	55	842	572	0.680	0.051	0.050	0.001			0.629
Moorcroft East	A	Water Drive	6	51N	67W	8	24.8%	30.0%	351	43	675	459	0.680	0.021	0.053	1.179			0.658

Minnelusa Field Production – ASP Study
TWP 51N to 55N – RGE 67W to 69W
Listing of all known Minnelusa Reservoirs in study area

Field	Minnelusa Producing Zone	Drive Mechanism	Location SEC	Location TWP	Location RGE	Average Net Pay Feet	Average Porosity %	Average S_w %	Volume acre ft	Area acres	Pore Volume Mbbls	Original O. I. P. Mbbls	Pore Volumes OOIP	Pore Volumes Ult Oil Rec	Pore Volumes Cum Oil Rec	Pore Volumes Cum Wtr Rec	Pore Volumes Cum Inj	Pore Volumes Balance	Pore Volumes abd O.I.P
Moorcroft North	Upper B	Solution Gas	24	52N	68W	8	16.0%	48.0%	813	107	1,009	510	0.505	0.001	0.009	0.010			0.504
Moorcroft Northeast	A	Water Drive	31	52N	67W	15	23.7%	45.0%	1,040	68	1,911	1,021	0.534	0.139	0.140	0.231			0.395
Moorcroft West	A	Waterflood	12	51N	68W	7	18.0%	33.0%	353	49	493	321	0.650	0.295	0.150	0.000	0.167	0.016	0.356
Morel	Lower B	Water Drive	17	53N	68W	19	23.3%	24.0%	1,679	89	3,035	2,218	0.731	0.145	0.087	0.084			0.586
Mule Herder	Lower B	Water Drive	32	52N	68W	8	26.9%	40.0%	367	46	765	437	0.571	0.168	0.143	3.469			0.403
Oshoto	Lower B	Water Drive	22&27	53N	68W	14	22.0%	34.0%	3,471	250	5,927	3,762	0.635	0.272	0.198	0.249			0.363
Oshoto North	Lower B	Water Drive	22	53N	68W	26	22.0%	36.0%	2,755	107	4,701	2,893	0.615	0.312	0.221	0.169			0.303
Oshoto South	C	Water Drive	27	53N	68W	16	18.8%	28.0%	1,282	78	1,870	1,294	0.692	0.067	0.067	2.726			0.625
Ponderosa Ridge	Upper B	Water Drive	21	53N	67W	8	30.0%	25.0%	226	27	526	391	0.743	0.000	0.005	0.144			0.743
Prairie Creek South	Upper B	Waterflood	16	53N	68W	18	20.9%	23.0%	1,651	94	2,682	2,005	0.748	0.286	0.243	0.050	0.327	0.034	0.462
Reynolds Ranch	Upper B	Water Drive	6;1	52N	67&68W	21	26.6%	40.0%	1,840	88	3,797	2,212	0.583	0.256	0.315	2.878			0.326
Rule	Lower B	Waterflood	15	52N	69W	30	17.1%	33.7%	2,577	87	3,419	2,179	0.638	0.191	0.114	0.000	0.082	−0.032	0.447
Scribner	Lower B	Solution Gas	10	53N	69W	9	15.0%	16.0%	222	26	259	207	0.800	0.238	0.233	0.000			0.562
Scribner South	Lower B	Water Drive	10	53N	69W	6	13.0%	31.0%	100	18	101	66	0.657	0.010	0.021	0.122			0.647
Semlek	Lower B	Water Drive	27	52N	68W	25	21.2%	27.0%	6,438	253	10,588	7,432	0.702	0.322	0.304	0.473			0.380
Semlek North	Lower B	Aug Wtr Dr	16&21	52N	68W	19	16.8%	32.0%	3,846	207	5,016	3,280	0.654	0.304	0.287	0.098	0.177	−0.208	0.350
Semlek West	Upper B	Aug Wtr Dr	28&29	52N	68W	27	18.7%	35.0%	15,284	574	22,209	13,881	0.625	0.272	0.261	0.704	0.557	−0.408	0.353
Sidner Draw	A	Water Drive	17	53N	67W	15	24.0%	25.0%	597	40	1,112	810	0.728	0.058	0.046	0.207			0.670
Simpson North	Lower B	Water Drive	10	51N	69W	17	21.3%	35.0%	769	45	1,269	786	0.619	0.320	0.286	0.247			0.299
Simpson Ranch	Upper B	Polymer	15	51N	69W	21	18.0%	35.0%	3,587	172	5,017	3,106	0.619	0.173	0.158	0.377	0.548	0.013	0.446
Simpson Ranch N	A	Solution Gas	15	51N	69W	13	17.8%	35.0%	1,478	112	2,040	1,263	0.619	0.155	0.086	0.001			0.464
Spirit	A	Waterflood	26&35	54N	68W	18	20.0%	30.0%	827	45	1,284	881	0.686	0.328	0.276	0.011	0.193	−0.094	0.358
Terrace	Lower B	Water Drive	11,12	51N	69W	33	23.5%	23.0%	8,886	268	16,213	11,890	0.733	0.357	0.224	0.176			0.376
Terry Draw	Upper B	Water Drive	2	54N	68W	8	13.0%	42.0%	185	24	186	105	0.563	0.012	0.040	0.293			0.551
Texas Trail	Lower B	Aug Wtr Dr	14&23	53N	68W	16	22.0%	30.0%	5,752	354	9,835	6,620	0.673	0.386	0.241	0.155	0.220	−0.176	0.287
Trava	A	Waterflood	16&21	52N	67W	14	24.3%	34.0%	861	60	1,625	1,052	0.647	0.021	0.021	0.000			0.626
Wagonspoke	Lower B	Waterflood	3;34	52&53N	69W	24	19.6%	24.0%	6,296	258	9,573	6,929	0.724	0.295	0.305	0.780	1.425	0.340	0.429
Wildfire	U & L B	Water Drive	21	53N	68W				2,252		3,901	2,163	0.554	0.051	0.046	0.084			0.503
Wolf Draw	Upper B	Polymer	18;24	52N	68&69W	16	17.3%	23.0%	4,436	296	5,958	4,369	0.733	0.210	0.085	0.016	0.087	−0.013	0.523
Totals									272,208		423,730	282,607	0.667	0.248	0.199	0.382			0.419

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TWP 51N to 55N -- RGE 67W to 69W
Listing of all known Minnelusa Reservoirs in study area

Field	Disc Date	Unit Date	Oil Gravity	Depletion Factor %	1992 Production Oil bbls	1992 Production Water bbls	Cum Prod thru 1992 Oil Mbbls	Cum Prod thru 1992 Water Mbbls	Injection 1992 Mbbls	Injection Cum Thru 1992	Est Pri Tot Rec Mbbls	Est Pri Rec % OOIP	1992 Rate bopd	Oil Cut %	Proj Rem Rec Mbbls	Proj Tot Rec Mbbls	Est Rem Life Months	Est Ult Rec % OOIP
Alpha	1986	1989	25.3	76.6%	854,237	538,832	3,856	1,355	1,468,500	4,108	1,894	16.5%	2,340	61.3%	1,179	5,036	60	44.0%
American	1986	1988	20.9	84.0%	28,505	24,156	244	84	63,028	340	73	2.5%	78	54.1%	47	291	26	10.1%
Ammo	1985	1988	19.9	84.8%	15,207	93,019	173	458	168,160	650	39	3.4%	42	14.1%	31	204	40	17.5%
Art Creek	1981	1985	22.3	90.8%	40,069	80,935	868	715	262,700	1,725	401	10.2%	110	33.1%	88	957	49	24.2%
Ash	1987	1992	20.0	42.5%	12,754	1,171	272	3	21,378	21	281	12.4%	35	91.6%	368	640	60	28.3%
Berger Hill	1975		19.0	95.1%	35,407	1,019,955	921	10,600			969	28.1%	97	3.4%	48	969	20	28.1%
Bertha	1984		25.4	100.0%	0	0	15	75			15	4.5%	0		0	15	0	4.5%
Bracken	1983	1986	21.4	59.1%	80,977	52,108	471	269	422,655	1,477	148	4.9%	222	60.8%	326	798	117	26.7%
Bracken South	1981		27.0	67.8%	31,986	720,635	172	2,517			254	20.4%	88	4.2%	82	254	35	20.4%
Breaks	1976	1990	21.0	48.9%	329,751	357,216	1,775	1,855	745,305	1,604	1,947	25.4%	903	48.0%	1,854	3,629	176	47.4%
Breaks South	1976	1989	27.0	92.4%	8,773	141,663	197	1,860	531,134	1,816	219	6.9%	24	5.8%	16	214	24	6.8%
Brislawn	1988		23.0	122.0%	9,207	163,700	97	974			79	8.6%	25	5.3%	(17)	79	0	8.6%
Brousa Draw	1988		16.0	66.3%	25,551	107,901	147	236			221	49.4%	70	19.1%	75	221	76	49.4%
Cambridge	1989	1993	20.2	9.2%	38,195	10,409	217	33	0	0	316	6.0%	105	78.6%	2,139	2,356		44.9%
Cardinal	1966		19.6	88.6%	4,700	45,630	186	1,150			210	17.9%	13	9.3%	24	210	81	17.9%
Carr Creek	1984		26.1	108.7%	36,123	768,310	371	3,837			341	29.3%	99	4.5%	(30)	341	0	29.3%
Corral Creek	1962		25.0	125.5%	7,423	174,934	564	5,282			450	16.1%	20	4.1%	(115)	450	0	16.1%
County Line	1974		26.0	70.0%	75,078	555,463	1,016	3,739			1,451	48.0%	206	11.9%	435	1,451	116	48.0%
Deadman Creek	1973	1979	22.0	72.5%	79,229	219,374	1,607	1,726	526,574	5,461	268	4.8%	217	26.5%	609	2,216	202	39.6%
Edsel	1981	1984	21.0	84.7%	208,157	1,671,895	4,260	7,469	1,895,200	12,244	817	7.0%	570	11.1%	769	5,029	63	43.3%
Guthery	1963	1968	21.0	96.2%	118,734	962,914	3,946	5,676	1,037,399	9,688	789	9.2%	325	11.0%	157	4,103	57	48.0%
Gurthery North	1963		21.0	97.3%	8,833	1,418	243	24			250	10.1%	24	86.2%	7	250	10	10.1%
Guthery Northwest	1982		21.0	100.1%	1,681	0	28	7			28	2.4%	5	100.0%	(0)	28	0	2.4%
Heath	1980		22.0	87.1%	24,872	177,234	716	2,740			822	16.0%	68	12.3%	106	822	81	16.0%
Heath North	1987		22.0	85.4%	131,282	506,119	684	1,018			801	32.7%	360	20.6%	117	801	25	32.7%
Hilda	1987		22.0	26.4%	31,644	20,118	109	76			415	44.1%	87	61.1%	305	415	160	44.1%
Hoover Gulch	1971	1986	19.0	53.5%	32,643	44,140	350	423	43,580	220	126	6.5%	89	42.5%	305	655	173	33.5%
JB	1986		23.4	94.2%	7,212	93,665	39	343			41	1.5%	20	7.1%	2	41	65	1.5%
Jewel	1961		21.3	85.8%	13,131	131,314	762	2,568			888	38.3%	36	9.1%	126	888	163	38.3%
Kiehl	1973	1985	21.8	53.4%	300,759	383,664	2,524	678	810,300	3,264	789	5.8%	824	43.9%	2,202	4,726	238	34.7%
Keihl West	1985	1987	24.0	78.0%	76,000	126,075	783	242	220,821	1,073	96	4.4%	208	37.6%	220	1,003	64	46.2%
Lad	1978	1982	21.3	93.5%	84,534	326,536	2,664	1,890	436,400	4,674	385	4.5%	232	20.6%	184	2,848	42	33.4%
Lad South	1984		23.0	26.7%	15,698	0	43	583			160	18.7%	43	100.0%	117	160	99	18.7%
Lily	1984	1987	21.7	90.1%	181,941	682,172	1,951	1,453	853,503	3,364	768	11.2%	498	21.1%	215	2,166	31	31.7%
Little Missouri	1986	1989	22.9	49.8%	210,902	96,820	989	199	352,364	1,228	304	5.2%	578	68.5%	997	1,986	137	33.8%
Little Mitchell Creek	1966	1969	25.4	92.4%	204,682	340,648	9,481	3,575	576,745	12,666	2,143	9.9%	561	37.5%	785	10,267	115	47.5%
Little Mo	1966		25.0	99.7%	7,299	76,015	399	1,435			401	53.1%	20	8.8%	1	401	3	53.1%
Little Mo South	1966		25.0	97.9%	8,125	69,101	437	701			446	51.2%	22	10.5%	10	446	15	51.2%
Lone Cedar	1984	1987	25.0	59.3%	390,602	828,631	2,601	2,035	1,250,481	5,001	842	9.0%	1,070	32.0%	1,788	4,389	115	46.8%
M-D	1967		24.6	98.5%	117,964	1,120,374	5,446	13,891			5,538	47.8%	323	9.5%	82	5,528	14	47.7%
Mellott Ranch	1960	1965	20.7	98.4%	139,015	1,457,911	6,195	21,110	1,990,428	27,001	992	6.6%	381	8.7%	102	6,297	13	41.6%
Missouri	1987		21.5	98.0%	3,785	64	42	1			43	7.4%	10	98.3%	1	43	3	7.4%
Moorcroft East	1983		22.4	251.2%	4,049	154,694	36	796			14	3.1%	11	2.6%	(22)	14	0	3.1%

Minnelusa Field Production – ASP Study
TWP 51N to 55N – RGE 67W to 69W
Listing of all known Minnelusa Reservoirs in study area

Field	Disc Date	Unit Date	Oil Gravity	Depletion Factor %	1992 Production Oil bbls	1992 Production Water bbls	Cum Prod thru 1992 Oil Mbbls	Cum Prod thru 1992 Water Mbbls	Injection 1992 Mbbls	Injection Cum Thru 1992	Est Pri Tot Rec Mbbls	Est Pri Rec % OOIP	1992 Rate bopd	Oil Cut %	Proj Rem Rec Mbbls	Proj Tot Rec Mbbls	Est Rem Life Months	Est Ult Rec % OOIP
Moorcroft North	1983		22.4	861.3%	899	0	9	10			1	0.2%	2	100.0%	(8)	1	0	0.2%
Moorcroft Northeast	1972		22.4	100.8%	3,614	38,841	268	442			266	26.1%	10	8.5%	(2)	266	0	26.1%
Moorcroft West	1983	1989	22.4	50.9%	11,005	0	74	0	17,365	82	28	8.8%	30	100.0%	71	145	131	45.3%
Morel	1982		23.6	60.0%	25,327	48,106	264	255			440	19.8%	69	34.5%	176	440	136	19.8%
Mule Herder	1986		20.0	85.0%	15,474	143,827	109	2,655			129	29.4%	42	9.7%	19	129	22	29.4%
Oshoto	1983		22.4	72.8%	72,532	165,319	1,173	1,478			1,611	42.8%	199	30.5%	438	1,611	162	42.8%
Oshoto North	1984		22.4	70.7%	83,461	123,286	1,037	792			1,467	50.7%	229	40.4%	430	1,467	136	50.7%
Oshoto South	1981		22.4	100.0%	6,479	438,112	126	5,096			126	9.7%	18	1.5%	0	126	0	9.7%
Ponderosa Ridge	1989		12.0		0	0	2	76			0	0.0%	0		(2)	0	0	0.0%
Prairie Creek South	1985	1988	21.2	85.1%	50,772	115,159	653	135	185,784	878	133	6.6%	139	30.6%	114	766	52	38.2%
Reynolds Ranch	1974		24.0	123.0%	24,617	972,161	1,197	10,928			973	44.0%	67	2.5%	(223)	973	0	44.0%
Rule	1985	1991	25.0	59.7%	88,668	0	389	0	205,805	280	425	19.5%	243	100.0%	263	652	70	29.9%
Scribner	1988		24.0	98.0%	3,603	0	60	0			62	29.8%	10	100.0%	1	62	0	29.8%
Scribner South	1982		24.0	208.0%	0	0	2	12			1	1.5%	0		(1)	1	4	1.5%
Semlek	1962		22.6	94.5%	44,841	320,062	3,224	5,010			3,411	45.9%	123	12.3%	188	3,411	69	45.9%
Semlek North	1975	1988	22.6	94.2%	51,661	118,919	1,438	492	185,754	889	1,051	32.0%	142	30.3%	88	1,526	60	46.5%
Semlek West	1962		23.0	95.8%	128,646	1,285,470	5,791	15,637	536,708	12,369	5,297	38.2%	352	9.1%	256	6,047	33	43.6%
Sidner Draw	1988		22.0	78.2%	15,410	21,640	51	230			65	8.0%	42	41.6%	14	65	18	8.0%
Simpson North	1988		22.0	89.5%	26,788	114,759	363	313			406	51.7%	73	18.9%	43	406	37	51.7%
Simpson Ranch	1977	1990	21.0	91.0%	21,741	242,655	792	1,891	243,195	2,749	130	4.2%	60	8.2%	79	870	78	28.0%
Simpson Ranch N	1971		21.0	55.3%	10,751	3,897	175	2			316	25.0%	29	73.4%	141	316	261	25.0%
Spirit	1985	1992	21.0	84.0%	54,428	13,936	354	15	190,328	248	312	35.4%	149	79.6%	67	421	47	47.8%
Terrace	1985		20.2	62.7%	419,311	585,989	3,631	2,847			5,792	48.7%	1,149	41.7%	2,161	5,792	147	48.7%
Terry Draw	1982			328.2%	0	0	7	54			2	2.2%	0		(5)	2	0	2.2%
Texas Trail	1974	1982	25.1	62.4%	169,997	223,916	2,371	1,527	277,147	2,162	1,389	21.0%	466	43.2%	1,426	3,797	240	57.4%
Trava	1985	1992	22.6	97.4%	4,164	0	34	0	38,123	38	35	3.3%	11	100.0%	1	35	3	3.3%
Wagonspoke	1972	1978	28.0	103.2%	36,635	1,192,634	2,916	7,467	1,102,741	13,640	1,124	16.2%	100	3.0%	(91)	2,825	0	40.8%
Wildfire	1985		19.0	90.7%	16,308	46,473	181	326			200	9.2%	45	26.0%	19	200	22	9.2%
Wolf Draw	1988	1992	21.5	40.3%	121,299	7,752	504	92	515,628	516	461	10.5%	332	94.0%	747	1,251	114	28.6%
Totals					5,545,147	20,569,846	85,090	163,485	17,175,233	131,477	53,127		15,192		22,146	107,236		37.2%

Minnelusa Field Production
TWP 51N to 55N – RGE 67W to 69W
Listing of Select Minnelusa Reservoirs in Study Area

Field	Minnelusa Producing Zone	Drive Mechanism	Location SEC	Location TWP	Location RGE	Average Net Pay Feet	Average Porosity %	Average S_w %	Volume acre ft	Area acres	Pore Volume Mbbls	Original O. I. P. Mbbls	Pore Volumes: OOIP	Pore Volumes: Ult Oil Rec	Pore Volumes: Cum Oil Rec	Pore Volumes: Cum Wtr Rec	Pore Volumes: Cum Inj	Pore Volumes: Balance	Pore Volumes: abd O.I.P
Alpha	C	Polymer	1,2&11	51N	69W	35	16.6%	33.0%	13,922	394	17,929	11,449	0.639	0.281	0.215	0.076	0.229	−0.062	0.358
American	Upper B	Polymer	5&6	52N	68W	15	17.6%	27.0%	3,024	205	4,124	2,867	0.695	0.070	0.059	0.020	0.082	0.003	0.625
Ammo	Upper B	Polymer	16&17	52N	68W	13	20.1%	21.7%	988	76	1,541	1,168	0.758	0.132	0.112	0.297	0.422	0.013	0.626
Art Creek	A & Upper B	Waterflood	8	51N	67W	27	19.3%	31.2%	3,950	145	5,932	3,953	0.666	0.161	0.146	0.121	0.291	0.024	0.505
Ash	Upper B	Waterflood	27&28	52N	69W	22	16.8%	15.5%	2,086	96	2,715	2,264	0.834	0.236	0.100	0.001	0.008	−0.093	0.598
Berger Hill	Upper B	Water Drive	6	53N	67W	17	25.0%	40.0%	3,079	184	5,971	3,445	0.577	0.162	0.154	1.775			0.415
Bracken	Upper B	Polymer	12&13	52N	69W	15	17.4%	25.0%	3,092	200	4,181	2,986	0.714	0.191	0.113	0.064	0.353	0.176	0.524
Breaks	Upper B	Aug Wtr Dr	26	52N	69W	31	23.0%	29.0%	6,357	205	11,333	7,663	0.676	0.320	0.157	0.164	0.142	−0.179	0.356
Cambridge	Upper B	Polymer	28	53N	68W	23	20.2%	32.0%	5,066	218	7,947	5,247	0.660	0.296	0.027	0.004	0.000	−0.031	0.364
Deadman Creek	Upper B	Polymer	18&19	53N	67W	25	18.1%	24.0%	5,461	266	7,656	5,595	0.731	0.289	0.210	0.225	0.713	0.278	0.441
Edsel	Upper B	Waterflood	25,26,35&36	54N	68W	27	22.5%	32.0%	10,060	376	17,575	11,603	0.660	0.286	0.242	0.425	0.697	0.029	0.374
Guthery	A & Upper B	Waterflood	3	51N	67W	38	21.2%	35.0%	8,338	217	13,670	8,544	0.625	0.300	0.289	0.415	0.709	0.005	0.325
Heath	C	Water Drive	8&9	52N	68W	28	18.5%	45.0%	6,845	248	9,825	5,146	0.524	0.084	0.073	0.279			0.440
Heath North	Lower B	Water Drive	4&5	52N	68W	20	26.9%	40.0%	2,060	88	4,291	2,452	0.571	0.187	0.159	0.237			0.385
Hoover Gulch	Upper B	Waterflood	24	52N	69W	14	16.7%	24.0%	2,078	124	2,697	1,952	0.724	0.243	0.130	0.157	0.082	−0.205	0.481
Kiehl	Upper B	Polymer	30&31	53N	68W	31	22.1%	23.0%	10,621	307	18,210	13,613	0.748	0.260	0.139	0.037	0.179	0.003	0.488
Kiehl West	Upper B	ASP	25&36	53N	68W	14	19.1%	27.5%	2,086	145	3,084	2,170	0.704	0.325	0.254	0.079	0.348	0.015	0.379
Lad	Upper B	Waterflood	17,18&19	54N	67W	28	21.2%	35.0%	8,912	323	13,501	8,520	0.631	0.211	0.197	0.140	0.346	0.009	0.420
Lily	A & Upper B	Waterflood	26,27,34&35	54N	68W	24	21.3%	23.0%	5,077	213	9,240	6,841	0.740	0.234	0.211	0.157	0.364	−0.004	0.506
Little Missouri	Lower B	Polymer	5;31,32	54&55N	67W	19	19.2%	23.0%	5,284	278	7,858	5,875	0.748	0.253	0.126	0.025	0.156	0.005	0.495
Little Mitchell Creek	Lower B	Waterflood	11,14	52N	69W	29	20.4%	25.0%	19,077	664	30,250	21,607	0.714	0.339	0.313	0.118	0.419	−0.013	0.375
Lone Cedar	Upper B	Polymer	8,9,16&17	51N	69W	28	20.7%	15.0%	7,219	261	11,593	9,385	0.810	0.379	0.224	0.176	0.431	0.032	0.431
Mellott Ranch	A & Upper B	Waterflood	2,10&11	52N	68W	27	21.6%	24.5%	14,172	518	21,174	15,135	0.715	0.297	0.293	0.997	1.275	−0.014	0.417
Oshoto	Lower B	Water Drive	22&27	53N	68W	14	22.0%	34.0%	3,471	250	5,927	3,762	0.635	0.272	0.198	0.249			0.363
Oshoto North	Lower B	Water Drive	22	53N	68W	26	22.0%	36.0%	2,755	107	4,701	2,893	0.615	0.312	0.221	0.169			0.303
Prairie Creek South	Upper B	Waterflood	16	53N	68W	18	20.9%	23.0%	1,651	94	2,682	2,005	0.748	0.286	0.243	0.050	0.327	0.034	0.462
Reynolds Ranch	Upper B	Water Drive	6;1	52N	67&68W	21	26.6%	40.0%	1,840	88	3,797	2,212	0.583	0.256	0.315	2.878			0.326
Rule	Lower B	Waterflood	15	52N	69W	30	17.1%	33.7%	2,577	87	3,419	2,179	0.638	0.191	0.114	0.000	0.082	−0.032	0.447
Semlek	Lower B	Water Drive	27	52N	68W	25	21.2%	27.0%	6,438	253	10,588	7,432	0.702	0.322	0.304	0.473			0.380
Semlek North	Lower B	Aug Wtr Dr	16&21	52N	68W	19	16.8%	32.0%	3,846	207	5,016	3,280	0.654	0.304	0.287	0.098	0.177	−0.208	0.350
Semlek West	Upper B	Aug Wtr Dr	28&29	52N	68W	27	18.7%	35.0%	15,284	574	22,209	13,881	0.625	0.272	0.261	0.704	0.557	−0.408	0.353
Simpson Ranch	Upper B	Polymer	15	51N	69W	21	18.0%	35.0%	3,587	172	5,017	3,106	0.619	0.173	0.158	0.377	0.548	0.013	0.446
Terrace	Lower B	Water Drive	11,12	51N	69W	33	23.5%	23.0%	8,886	268	16,213	11,890	0.733	0.357	0.224	0.176			0.376
Wagonspoke	Lower B	Waterflood	3;34	52&53N	69W	24	19.6%	24.0%	6,296	258	9,573	6,929	0.724	0.295	0.305	0.780	1.425	0.340	0.429
Wolf Draw	Upper B	Polymer	18;24	52N	68&69W	16	17.3%	23.0%	4,436	296	5,958	4,369	0.733	0.210	0.085	0.016	0.087	−0.013	0.523
Totals									209,920	8,404	327,398	223,418							
Average (weighted)						24	20.1%	29.0%	5,998	240	9,354	6,383	0.682	0.273	0.215	0.343	0.388	0.170	0.409
Maximum						38	26.9%	45.0%	19,077	664	30,250	21,607	0.834	0.379	0.315	2.878	1.425	0.340	0.626
Minimum						13	16.6%	15.0%	988	76	1,541	1,168	0.524	0.070	0.027	0.000	0.000	−0.408	0.303

Minnelusa Field Production
TWP 51N to 55N – RGE 67W to 69W
Listing of Select Minnelusa Reservoirs in Study Area

Field	Disc Date	Unit Date	Oil Gravity	Depletion Factor %	1992 Production Oil bbls	1992 Production Water bbls	Cum Prod thru 1992 Oil Mbbls	Cum Prod thru 1992 Water Mbbls	Injection 1992 Mbbls	Injection Cum Thru 1992	Est Pri Tot Rec Mbbls	Est Pri Rec % OOIP	1992 Rate bopd	Oil Cut %	Proj Rem Rec Mbbls	Proj Tot Rec Mbbls	Est Rem Life Months	Est Ult Rec % OOIP
Alpha	1986	1989	25.3	76.6%	854,237	538,832	3,856	1,355	1,469	4,108	1,894	16.5%	2,340	61.3%	1,179	5,036	60	44.0%
American	1986	1988	20.9	84.0%	28,505	24,156	244	84	63	340	73	2.5%	78	54.1%	47	291	26	10.1%
Ammo	1985	1988	19.9	84.8%	15,207	93,019	173	458	168	650	39	3.4%	42	14.1%	31	204	40	17.5%
Art Creek	1981	1985	22.3	90.8%	40,069	80,935	868	715	263	1,725	401	10.2%	110	33.1%	88	957	49	24.2%
Ash	1987	1992	20.0	42.5%	12,754	1,171	272	3	21	21	281	12.4%	35	91.6%	368	640	60	28.3%
Berger Hill	1975		19.0	95.1%	35,407	1,019,955	921	10,600			969	28.1%	97	3.4%	48	969	20	28.1%
Bracken	1983	1986	21.4	59.1%	80,977	52,108	471	269	423	1,477	148	4.9%	222	60.8%	326	798	117	26.7%
Breaks	1976	1990	21.0	48.9%	329,751	357,216	1,775	1,855	745	1,604	1,947	25.4%	903	48.0%	1,854	3,629	176	47.4%
Cambridge	1989	1993	20.2	9.2%	38,195	10,409	217	33		0	316	6.0%	105	78.6%	2,139	2,356		44.9%
Deadman Creek	1973	1979	22.0	72.5%	79,229	219,374	1,607	1,726	527	5,461	268	4.8%	217	26.5%	609	2,216	202	39.6%
Edsel	1981	1984	21.0	84.7%	208,157	1,671,895	4,260	7,469	1,895	12,244	817	7.0%	570	11.1%	769	5,029	63	43.3%
Guthery	1963	1968	21.0	96.2%	118,734	962,914	3,946	5,676	1,037	9,688	789	9.2%	325	11.0%	157	4,103	57	48.0%
Heath	1980		22.0	87.1%	24,872	177,234	716	2,740			822	16.0%	68	12.3%	106	822	81	16.0%
Heath North	1987		22.0	85.4%	131,282	506,119	684	1,018			801	32.7%	360	20.6%	117	801	25	32.7%
Hoover Gulch	1974	1986	19.0	53.5%	32,643	44,140	350	423	44	220	126	6.5%	89	42.5%	305	655	173	33.5%
Kiehl	1973	1985	21.8	53.4%	300,759	383,664	2,524	678	810	3,264	789	5.8%	824	43.9%	2,202	4,726	238	34.7%
Kiehl West	1985	1987	24.0	78.0%	76,000	126,075	783	242	221	1,073	96	4.4%	208	37.6%	220	1,003	64	46.2%
Lad	1978	1982	21.3	93.5%	84,534	326,536	2,664	1,890	436	4,674	385	4.5%	232	20.6%	184	2,848	42	33.4%
Lily	1984	1987	21.7	90.1%	181,941	682,172	1,951	1,453	854	3,364	768	11.2%	498	21.1%	215	2,166	31	31.7%
Little Missouri	1986	1989	22.9	49.8%	210,902	96,820	989	199	352	1,228	304	5.2%	578	68.5%	997	1,986	137	33.8%
Little Mitchell Creek	1966	1969	25.4	92.4%	204,682	340,648	9,481	3,575	577	12,666	2,143	9.9%	561	37.5%	785	10,267	115	47.5%
Lond Cedar	1984	1987	25.0	59.3%	390,602	828,631	2,601	2,035	1,250	5,001	842	9.0%	1,070	32.0%	1,788	4,389	115	46.8%
Mellott Ranch	1960	1965	20.7	98.4%	139,015	1,457,911	6,195	21,110	1,990	27,001	992	6.6%	381	8.7%	102	6,297	13	41.6%
Oshoto	1983		22.4	72.8%	72,532	165,319	1,173	1,478			1,611	42.8%	199	30.5%	438	1,611	162	42.8%
Oshoto North	1984		22.4	70.7%	83,461	123,286	1,037	792			1,467	50.7%	229	40.4%	430	1,467	136	50.7%
Prairie Creek South	1985	1988	21.2	85.1%	50,772	115,159	653	135	186	878	133	6.6%	139	30.6%	114	766	52	38.2%
Reynolds Ranch	1974		24.0	123.0%	24,617	972,161	1,197	10,928			973	44.0%	67	2.5%	(223)	973	0	44.0%
Rule	1985	1991	25.0	59.7%	88,668	0	389	0	206	280	425	19.5%	243	100.0%	263	652	70	29.9%
Semlek	1962		22.6	94.5%	44,841	320,062	3,224	5,010			3,411	45.9%	123	12.3%	188	3,411	69	45.9%
Semlek North	1975	1988	22.6	94.2%	51,661	118,919	1,438	492	186	889	1,051	32.0%	142	30.3%	88	1,526	60	46.5%
Semlek West	1962		23.0	95.8%	128,646	1,285,470	5,791	15,637	537	12,369	5,297	38.2%	352	9.1%	256	6,047	33	43.6%
Simpson Ranch	1977	1990	21.0	91.0%	21,741	242,655	792	1,891	243	2,749	130	4.2%	60	8.2%	79	870	78	28.0%
Terrace	1985		21.0	62.7%	419,311	585,989	3,631	2,847			5,792	48.7%	1,149	41.7%	2,161	5,792	147	48.7%
Wagonspoke	1972	1978	28.0	103.2%	36,635	1,192,634	2,916	7,467	1,103	13,640	1,124	16.2%	100	3.0%	(91)	2,825	0	40.8%
Wolf Draw	1988	1992	21.5	40.3%	121,299	7,752	504	92	516	516	461	10.5%	332	94.0%	747	1,251	114	28.6%
Totals					4,762,638	15,131,340	70,291	112,376	16,121	127,130	37,887		13,048		19,086	89,377		
Average (weighted)			22.1	78.6%	136,075	432,324	2,008	3,211	597	4,709	1,082	17.0%	373	23.9%	545	2,554		40.0%
Maximum			28.0	123.0%	854,237	1,671,895	9,481	21,110	1,990	27,001	5,792	50.7%	2,340	100.0%	2,202	10,267		50.7%
Minimum			19.0	9.2%	12,754	0	173	0	0	0	39	2.5%	35	2.5%	(223)	204		10.1%

Table 5

Prairie Creek South Field – Data Summary

Producing Zone:	Minnelusa Upper B
Location:	Crook County, Wyoming
	TWP 53N – RGE 68W
	Section 16
Drive Mechanism:	Waterflood
Discovered:	1986
Unitized:	1988

Current Production – 1/1 to 12/31/92

Oil, bbls	50,772
Water, bbls	115,159

Cumulative Production – thru 12/31/92

Oil, Mbbls	653
Water, Mbbls	135
Injection, Mbbls	878

Current Rates

Oil, bopd	139
Oil Cut, %	30.6%

Waterflood Decline Analysis

Economic Cutoff	
Oil, bopd	
Oil Cut	5.0%
Estimated Decline	30.0%
Proj. Ultimate Recovery, Mbbls	766
Proj. Remaining Reserves, Mbbls	114
Estimated Remaining Life, Years (from 1/93)	4.3
OOIP: Pore Volume	0.748
Ultimate Recovery: Pore Volume	0.286
Remaining O.I.P.: Pore Volume	0.462

Oil Gravity	21.2
Oil Viscosity, cp	22.0
Water Viscosity, cp	0.6
Depth, feet	6,992
Formation Temperature, degrees F	120
Rw @ Formation Temperature	0.09

Reservoir Properties

Volume, acre feet	1,651
Area, acres	94
Average Net Pay, feet	17.6
Average Porosity	20.9%
Average S_w	23.0%
FVF Factor	1.030
Pore Volume, Mbbls	2,682
Oil in Place, Mbbls	2,005
Est. Ult. Recovery Factor, %OOIP	38.2%
Current Recovery Factor %OOIP	32.5%
Current Depletion Factor %	85.1%

Primary Deline Analysis

Economic Cutoff	
Oil, bopd	20
End of Primary Decline	07/90
Estimated Decline	35.0%
Projected Ult. Recovery, Mbbls	133
Primary Recovery Factor %OOIP	6.6%
Cumulative Oil: Pore Volume	0.243
Cumulative Water: Pore Volume	0.050
Cumulative Injection: Pore Volume	0.327
Production – Injection Difference: PV	0.034

Production Location	Name	-------- to 1/93 Cum Oil, bbls	Cum Wtr, bbls --------	Status
NWNE 16–53–58	State A #1	532,080	113,099	Pump–Oil
NENW 16–53–58	State B #1	104,757	19,507	Pump–Oil
SENW 16–53–58	Prairie Creek #1	15,667	2,780	Injection

Injection Location	Name	1992 Year Curr Inj, bbls	to 1/93 Cum Inj, bbls	Status
SENW 16–53–68	Prairie Creek #1	174,861	878,231	Injection

Simpson Ranch Field – Data Summary

Producing Zone:	Minnelusa Upper B
Location:	Campbell County, Wyoming TWP 51 – RGE 69W Section 15
Drive Mechanism:	Polymer Waterflood
Discovered:	1977
Unitized:	1978

Current Production – 1/1 to 12/31/92

Oil, bbls	21,741
Water, bbls	242,655

Cumulative Production – thru 12/31/92

Oil, Mbbls	792
Water, Mbbls	1,891
Injection, Mbbls	2,749

Current Rates

Oil, bopd	60
Oil Cut, %	8.2%

Waterflood Decline Analysis

Economic Cutoff	
Oil, bopd	
Oil Cut	5.0%
Estimated Decline	10.0%
Proj. Ultimate Recovery, Mbbls	871
Proj. Remaining Reserves, Mbbls	79
Estimated Remaining Life, Years (from 1/93)	7.6

OOIP: Pore Volume	0.619
Ultimate Recovery: Pore Volume	0.236
Remaining O.I.P.: Pore Volume	0.383

Oil Gravity	21.0
Oil Viscosity, cp	15.7
Water Viscosity, cp	0.4
Depth, feet	7,883
Formation Temperature, degrees F	120
Rw @ Formation Temperature	0.20

Reservoir Properties

Volume, acre feet	2,633
Area, acres	183
Average Net Pay, feet	14.4
Average Porosity	18.0%
Average S_w	35.0%
FVF Factor	1.050
Pore Volume, Mbbls	3,682
Oil in Place, Mbbls	2,280
Est. Ult. Recovery Factor, %OOIP	38.2%
Current Recovery Factor %OOIP	34.7%
Current Depletion Factor %	90.9%

Primary Deline Analysis

Economic Cutoff	
Oil, bopd	20
End of Primary Decline	04/79
Estimated Decline	45.0%
Projected Ult. Recovery, Mbbls	130
Primary Recovery Factor %OOIP	5.7%

Cumulative Oil: Pore Volume	0.215
Cumulative Water: Pore Volume	0.514
Cumulative Injection: Pore Volume	0.747
Production – Injection Difference: PV	0.018

		-------- to 1/93	---------	
Production Location	Name	Cum Oil, bbls	Cum Wtr, bbls	Status
SENW 15–51–69	Hilda #3	4,864	72	Injection
SWNE 15–51–69	Hilda #1	334,934	365,241	TA–Oil
NWSE 15–51–69	Hamm Twin–Fed #2	310,581	854,022	Pump–Oil
NENWSE 15–51–69	Unit #4	145,056	675,447	Pump–Oil

Injection Location	Name	1992 Year Curr Inj, bbls	to 1/93 Cum Inj, bbls	Status
SENW 15–51–69	Hilda #3	243,195	2,676,909	Injection

Figure 1

West Kiehl Net Pay Isopach with Well Locations

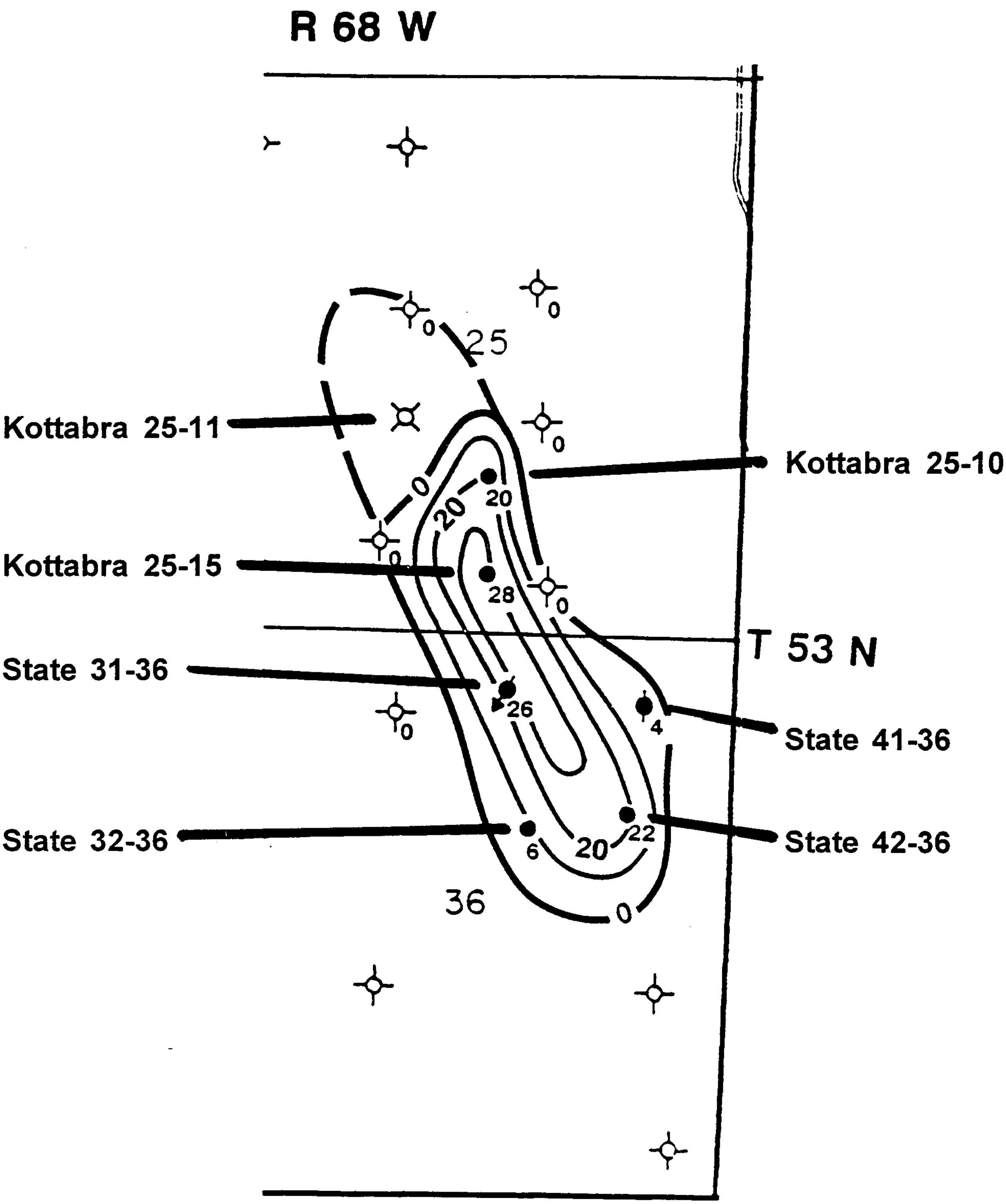


Figure 2

Production Performance of the West Kiehl Alkaline-Surfactant-Polymer Flood

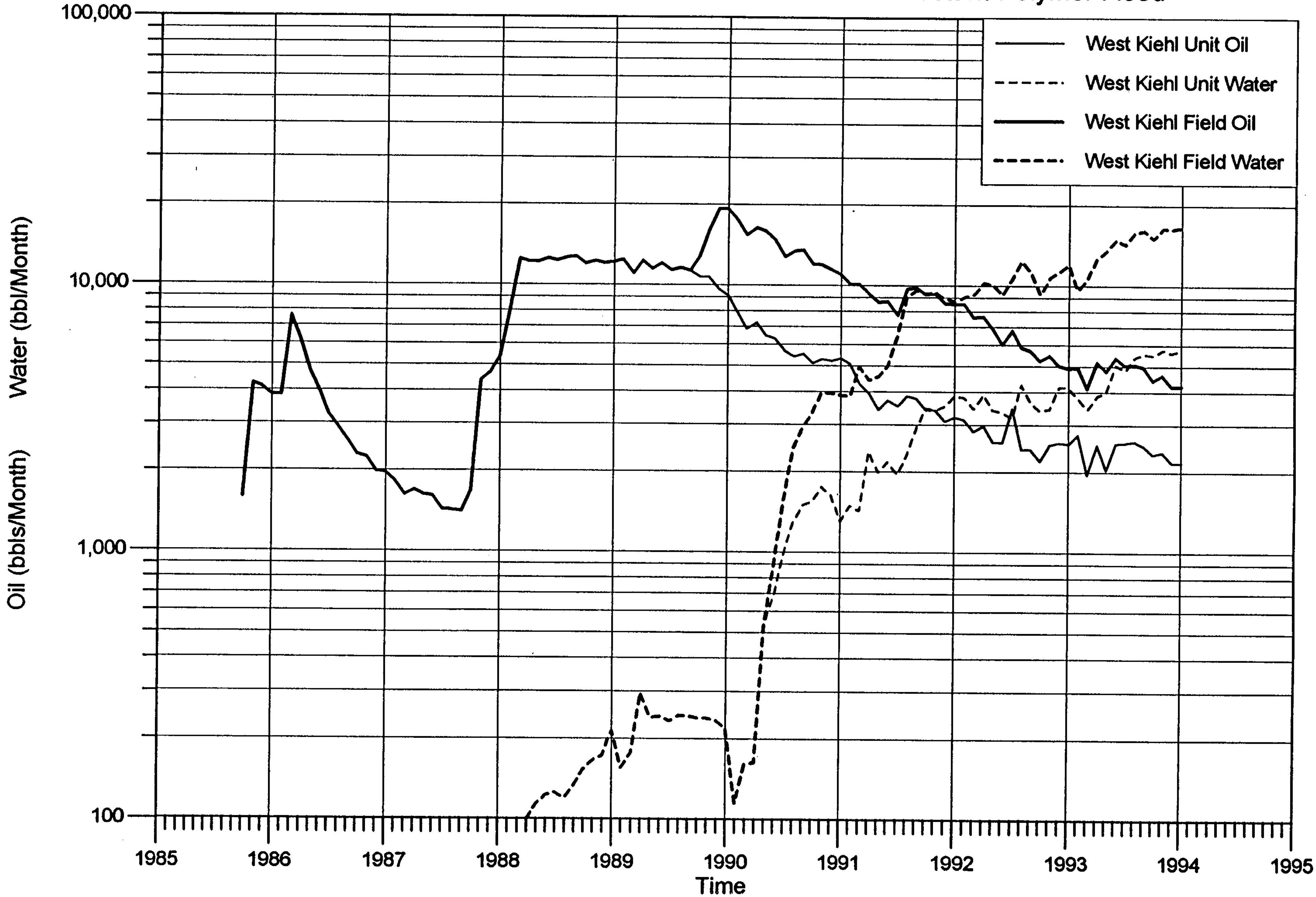


Figure 3

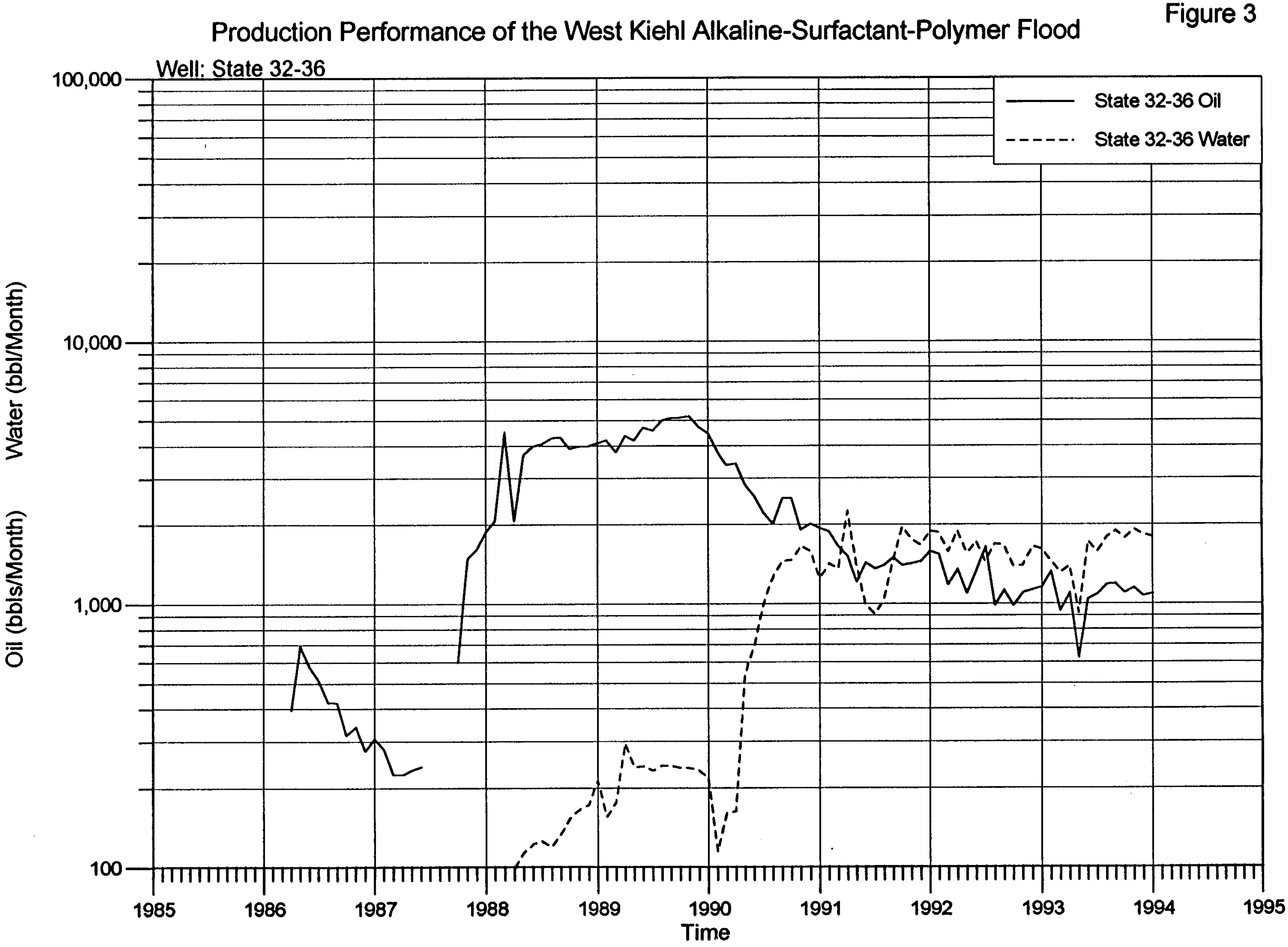

Production Performance of the West Kiehl Alkaline-Surfactant-Polymer Flood
Well: State 32-36
State 32-36 Oil
State 32-36 Water
Water (bbl/Month)
Oil (bbls/Month)
100,000
10,000
1,000
100
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Time

Figure 4

Production Performance of the West Kiehl Alkaline-Surfactant-Polymer Flood

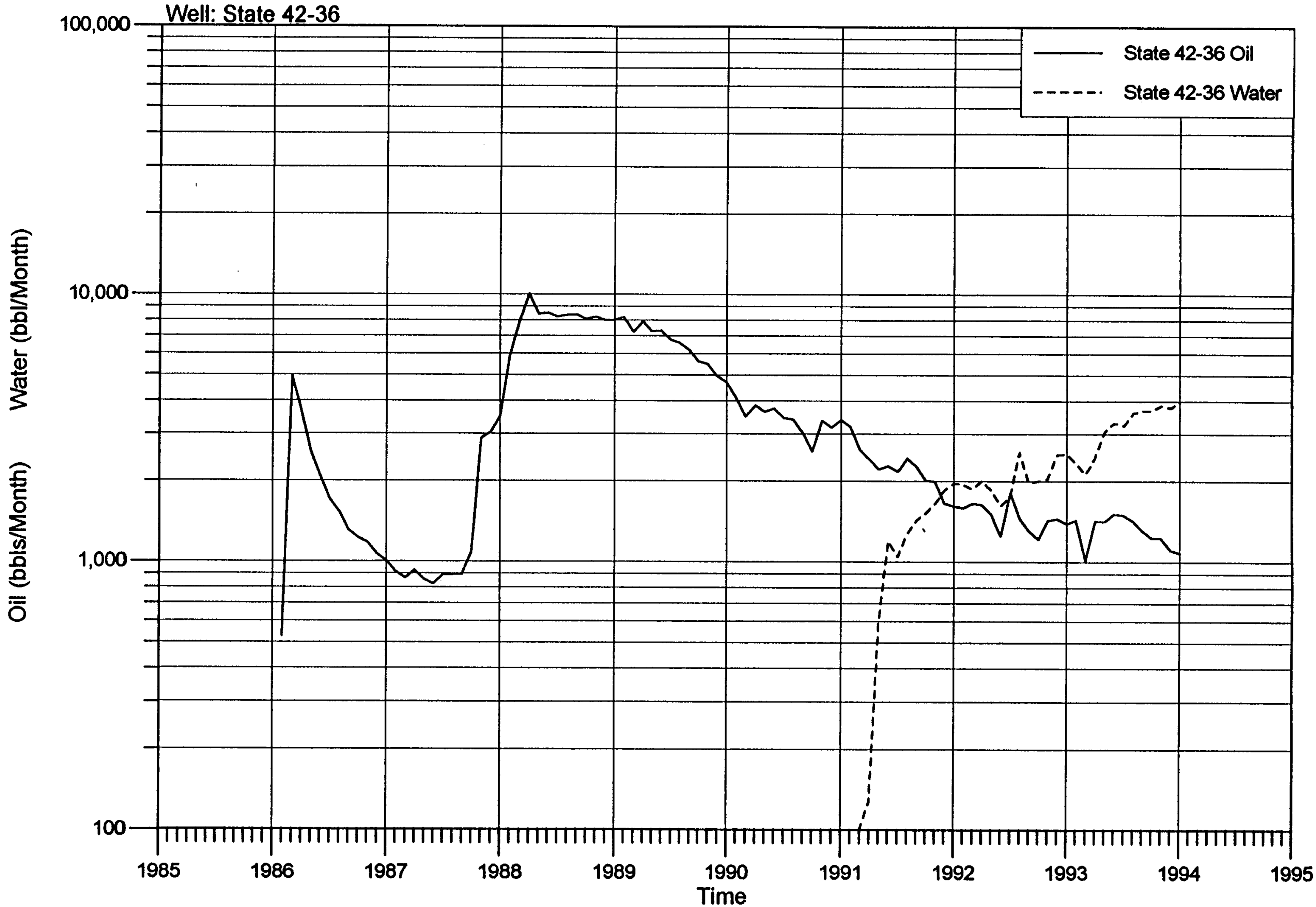
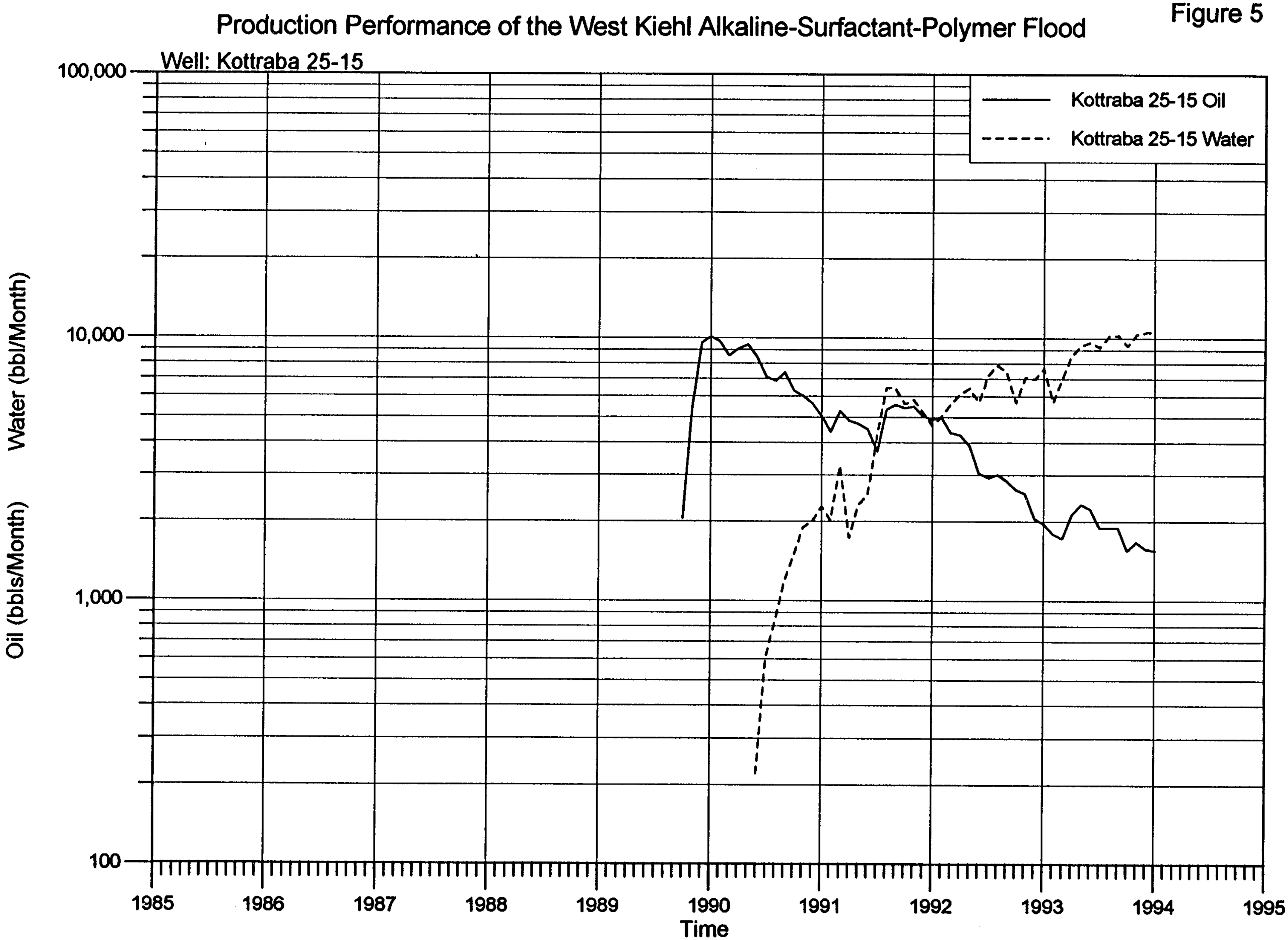


Figure 5


Production Performance of the West Kiehl Alkaline-Surfactant-Polymer Flood
Well: Kottraba 25-15
Kottraba 25-15 Oil
Kottraba 25-15 Water
100,000
10,000
1,000
100
Water (bbl/Month)
Oil (bbls/Month)
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Time

GO BACK
TO ORIGINAL
FOR 11" X 17
FOLD-OUT
B. J. ADAMS
OFFICE

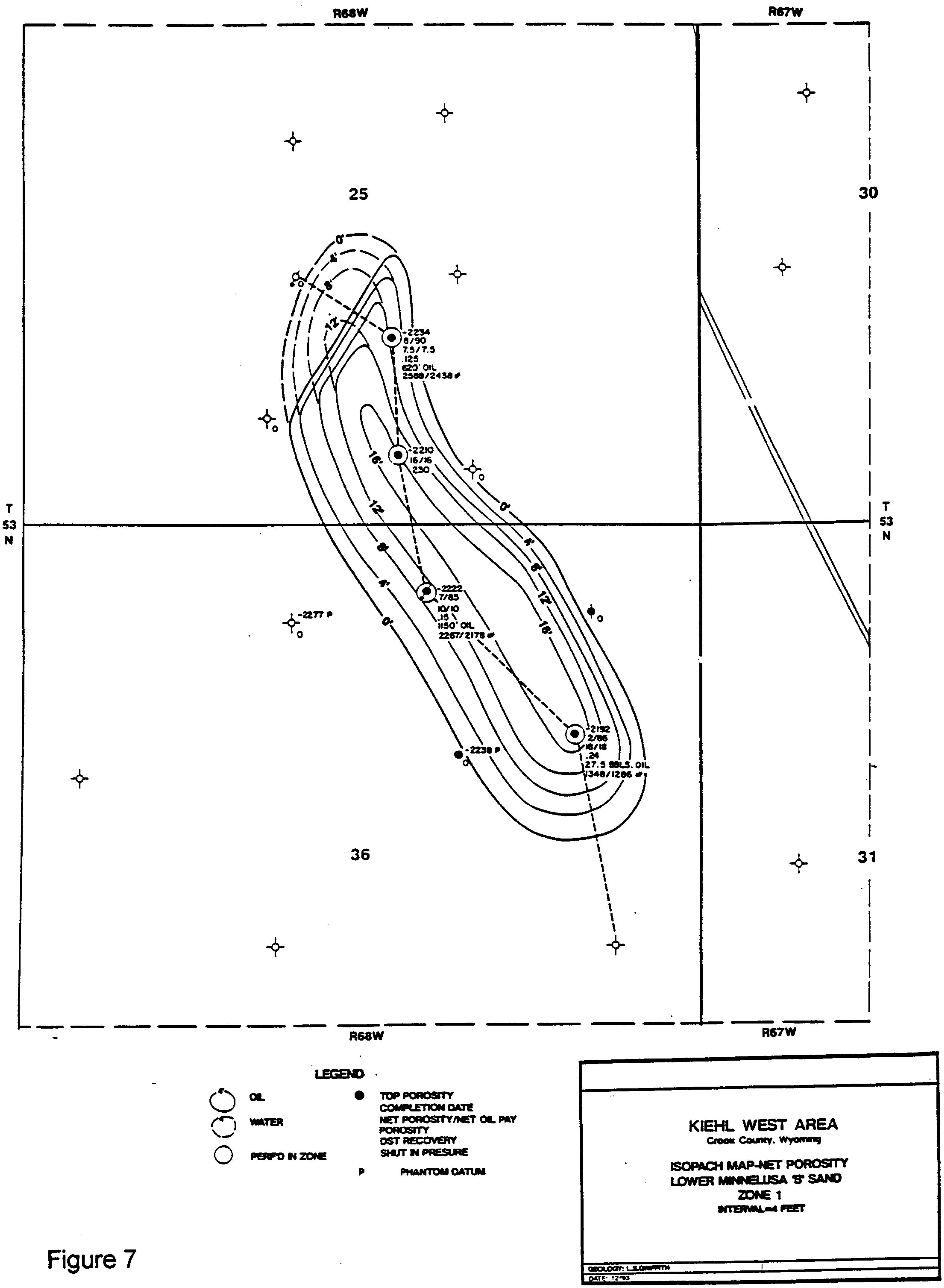
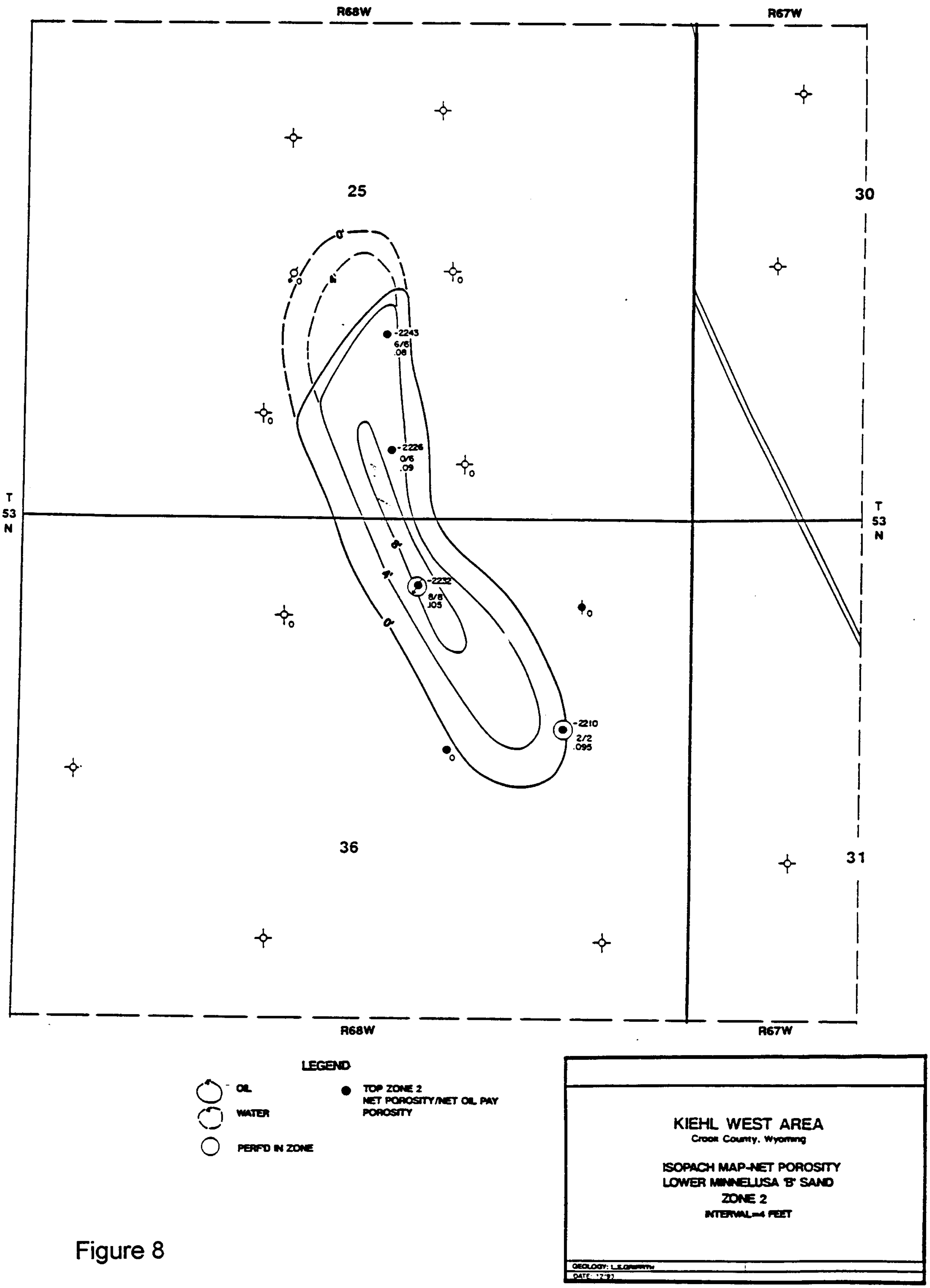
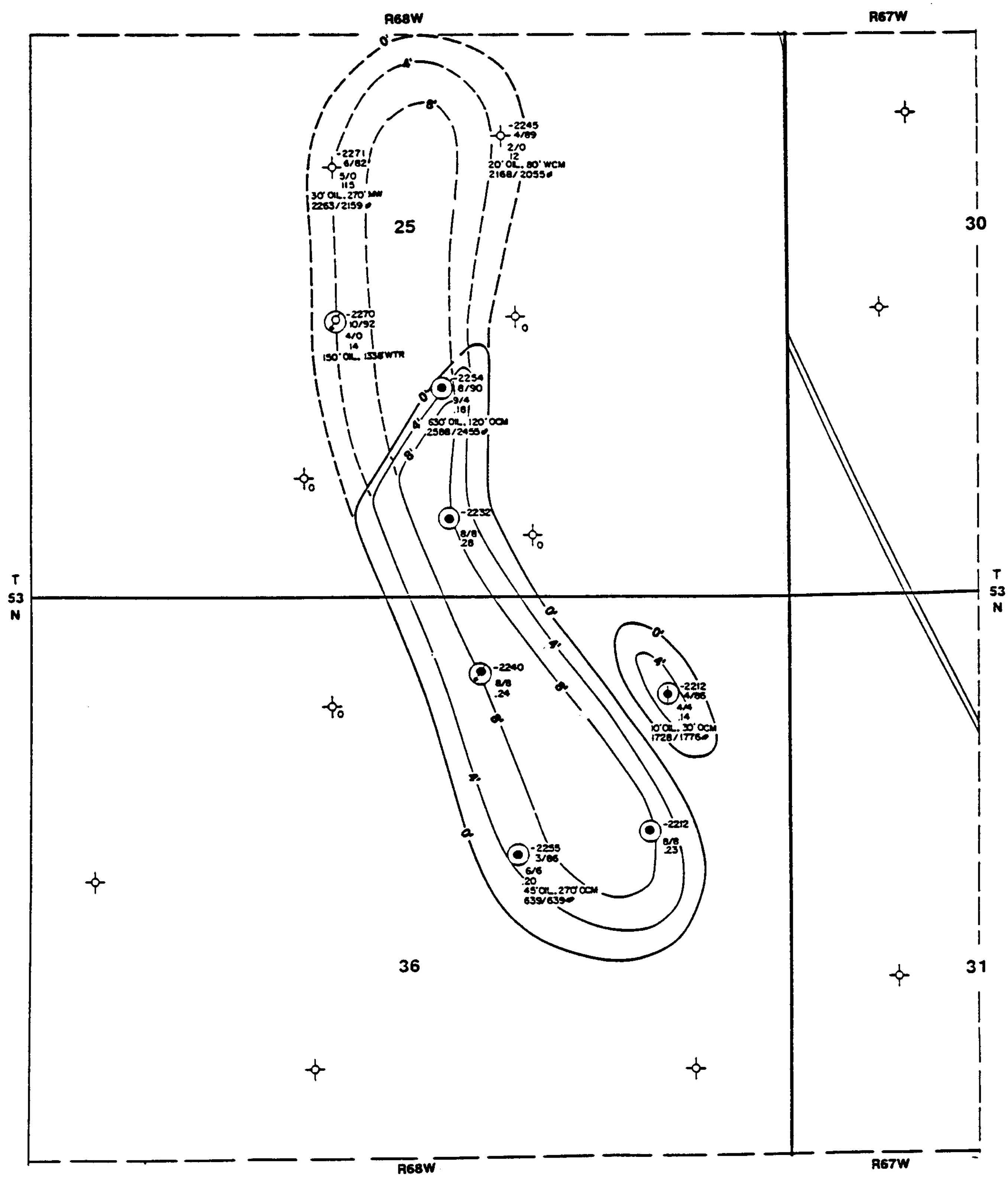

R68W
R67W
25
30
36
31
T
53
N
-2234
8/90
7.5/7.5
.125
620' OIL
2588/2438 #
-2210
16/16
230
-2222
7/85
10/10
.15
1150' OIL
2267/2178 #
-2192
2/86
18/18
.24
27.5 BBLS. OIL
1348/1286 #
-2277 P
-2238 P
LEGEND
OIL
WATER
PERF'D IN ZONE
TOP POROSITY
COMPLETION DATE
NET POROSITY/NET OIL PAY
POROSITY
DST RECOVERY
SHUT IN PRESURE
P PHANTOM DATUM
KIEHL WEST AREA
Crook County, Wyoming
ISOPACH MAP-NET POROSITY
LOWER MINNELUSA 'B' SAND
ZONE 1
INTERVAL=4 FEET
DATE: 12/93

Figure 7



R68W
R67W
25
30
36
31
T
53
N
-2243
6/6
.08
-2226
0/6
.09
-2232
8/8
.105
-2210
2/2
.095
0'
4'
8'
LEGEND
OIL
WATER
PERF'D IN ZONE
TOP ZONE 2
NET POROSITY/NET OIL PAY
POROSITY
KIEHL WEST AREA
Crook County, Wyoming
ISOPACH MAP-NET POROSITY
LOWER MINNELUSA 'B' SAND
ZONE 2
INTERVAL=4 FEET

Figure 8



LEGEND

OIL

WATER

PERF'D IN ZONE

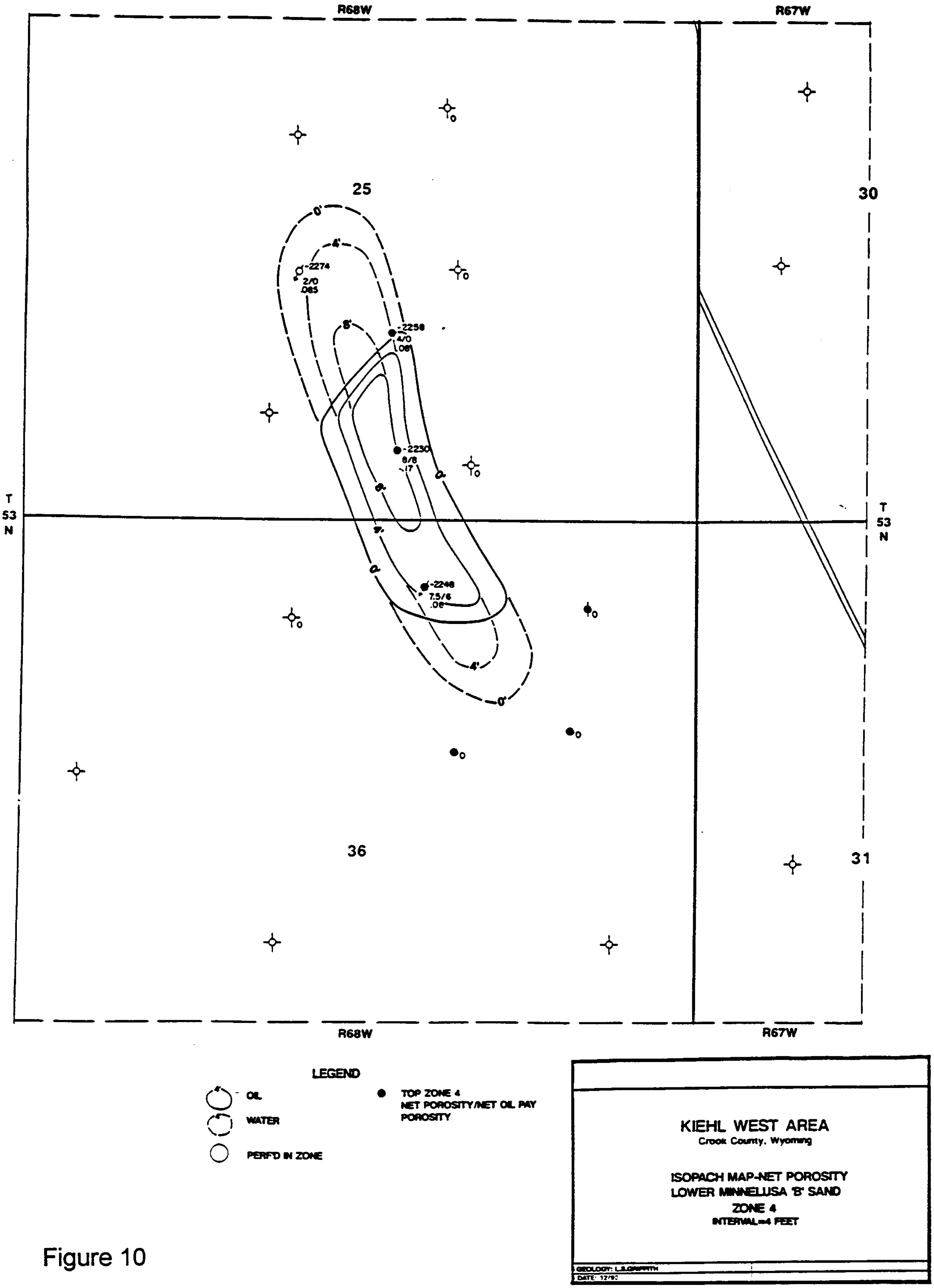
TOP ZONE 3
COMPLETION DATE
NET POROSITY/NET OIL PAY
POROSITY
DST RECOVERY
SHUT IN PRESSURE

KIEHL WEST AREA
Crook County, Wyoming

ISOPACH MAP-NET POROSITY
LOWER MINNELUSA 'B' SAND
ZONE 3
INTERVAL=4 FEET

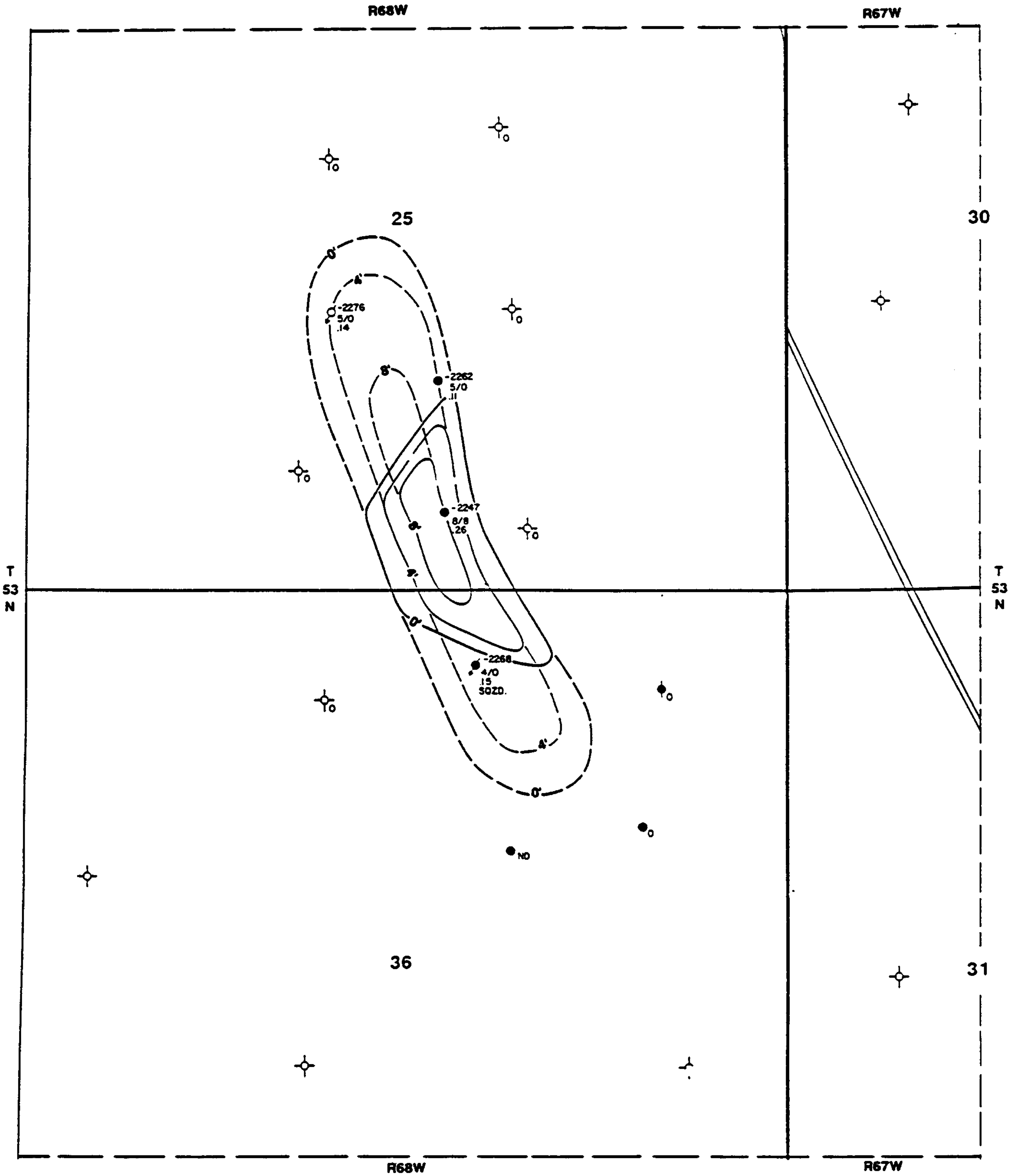
GEOLOGY: L.S.GRIFFITH
DATE: 12/93

Figure 9



R68W
R67W
25
30
-2274
2/0
.085
-2258
4/0
.081
-2230
8/8
.17
-2248
7.5/6
.08
0'
4'
8'
T
53
N
36
31
LEGEND
OIL
WATER
PERF'D IN ZONE
TOP ZONE 4
NET POROSITY/NET OIL PAY
POROSITY
KIEHL WEST AREA
Crook County, Wyoming
ISOPACH MAP-NET POROSITY
LOWER MINNELUSA 'B' SAND
ZONE 4
INTERVAL=4 FEET

Figure 10



LEGEND

OIL

WATER

PERF'D IN ZONE

TOP ZONE 5
NET POROSITY/NET OIL PAY
POROSITY

KIEHL WEST AREA
Crook County, Wyoming

ISOPACH MAP-NET POROSITY
LOWER MINNELUSA 'B' SAND
ZONE 5
INTERVAL=4 FEET

GEOLOGY: L.S.GRIFFITH
DATE: 12/83

Figure 11

Figure 12

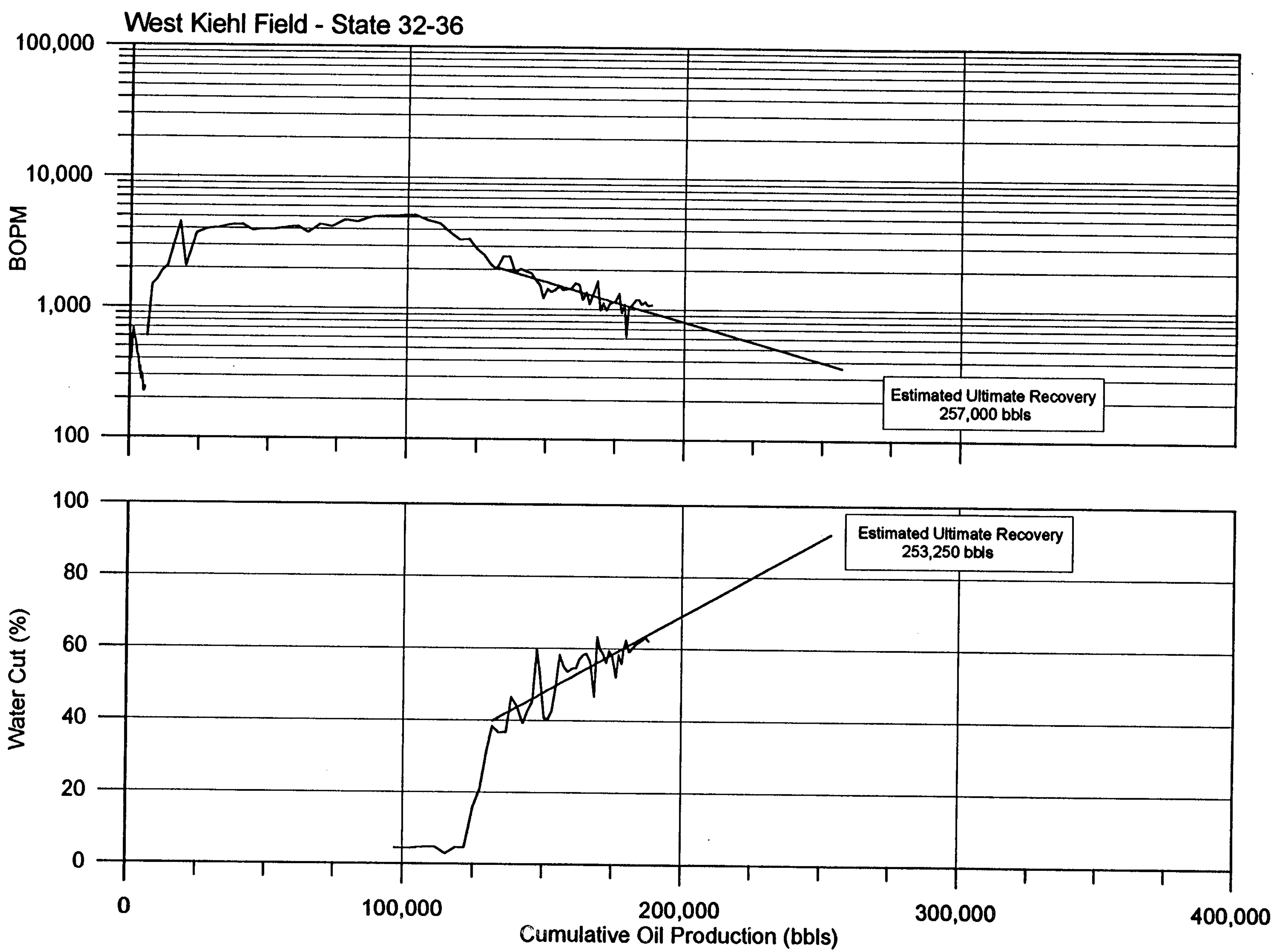

West Kiehl Field - State 32-36
100,000
10,000
1,000
100
BOPM
Estimated Ultimate Recovery
257,000 bbls
100
80
60
40
20
0
Water Cut (%)
Estimated Ultimate Recovery
253,250 bbls
0
100,000
200,000
300,000
400,000
Cumulative Oil Production (bbls)

Figure 13

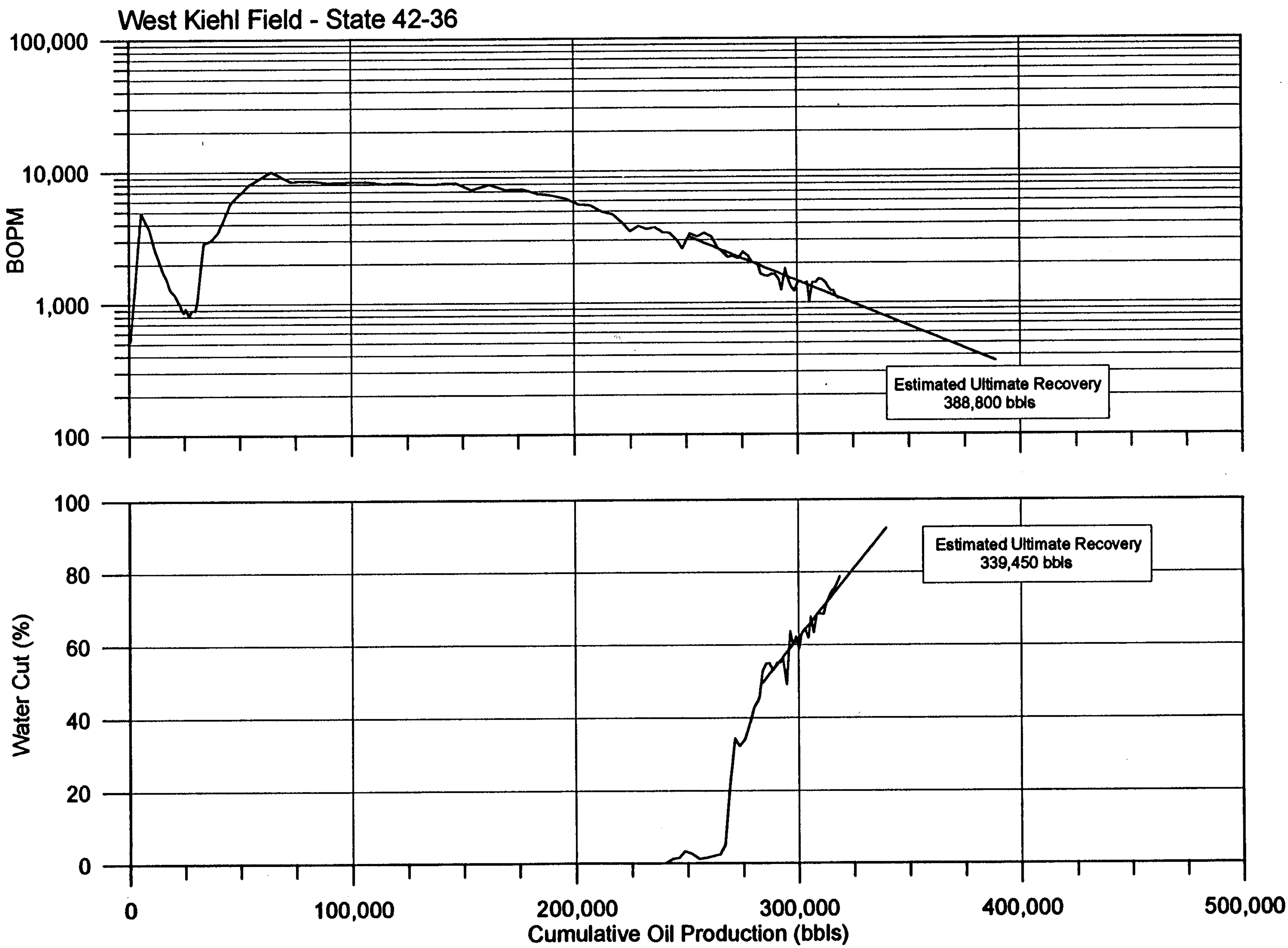
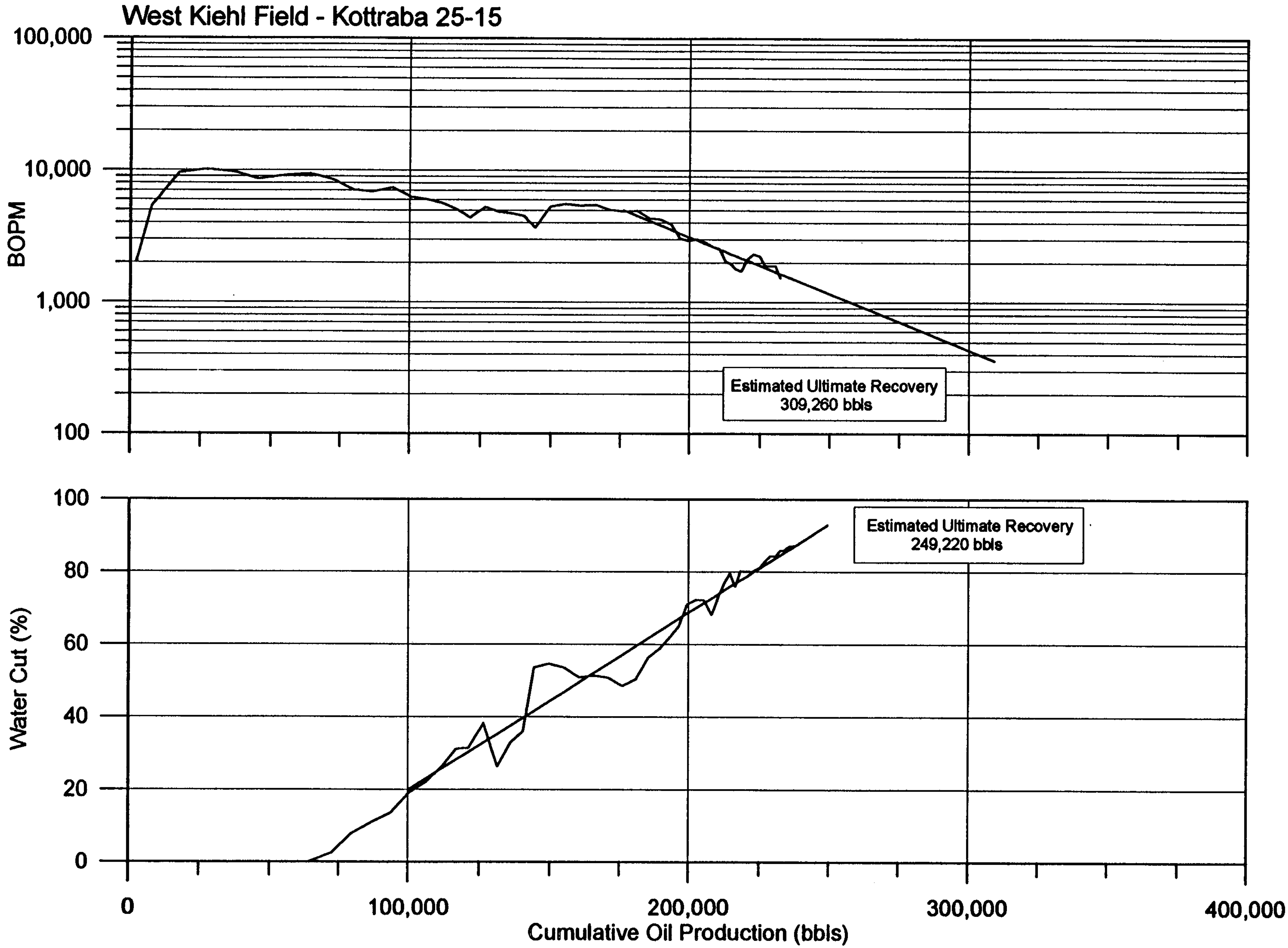

West Kiehl Field - State 42-36
100,000
10,000
1,000
100
BOPM
Estimated Ultimate Recovery
388,800 bbls
100
80
60
40
20
0
Water Cut (%)
Estimated Ultimate Recovery
339,450 bbls
0
100,000
200,000
300,000
400,000
500,000
Cumulative Oil Production (bbls)

Figure 14



West Kiehl Field - Kottraba 25-15
BOPM
100,000
10,000
1,000
100
Estimated Ultimate Recovery
309,260 bbls
Water Cut (%)
100
80
60
40
20
0
Estimated Ultimate Recovery
249,220 bbls
0
100,000
200,000
300,000
400,000
Cumulative Oil Production (bbls)

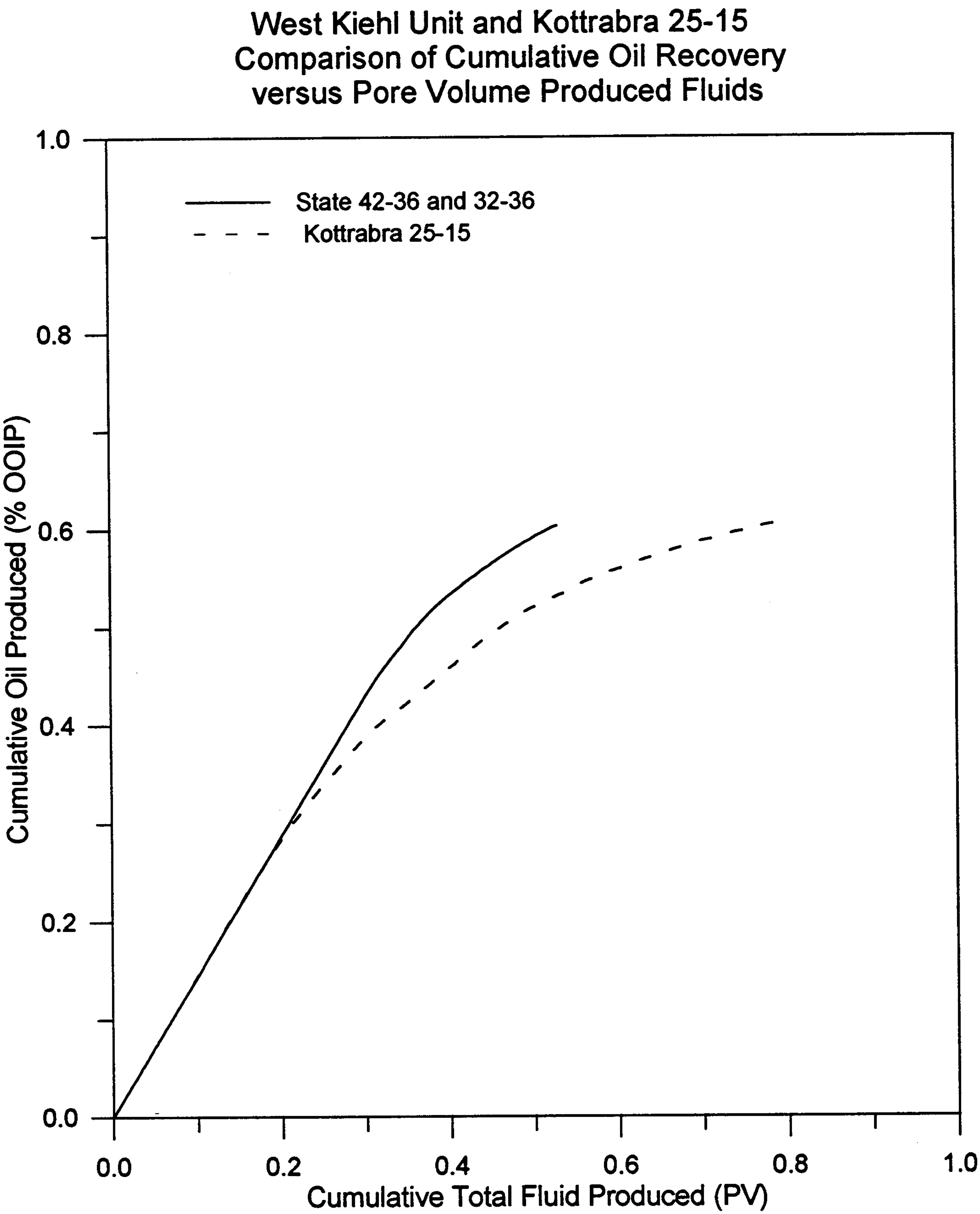
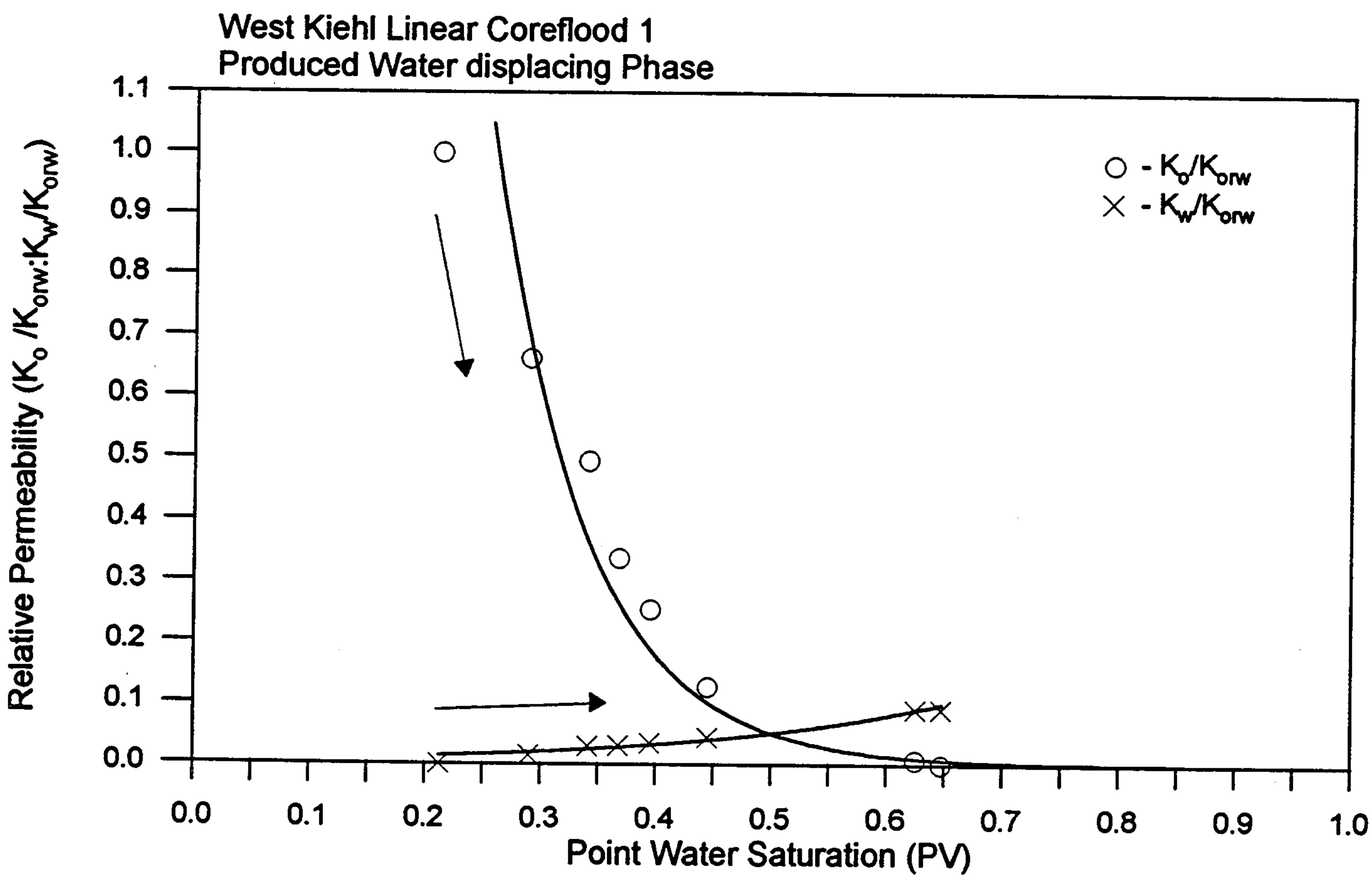

West Kiehl Unit and Kottrabra 25-15
Comparison of Cumulative Oil Recovery
versus Pore Volume Produced Fluids
State 42-36 and 32-36
Kottrabra 25-15
Cumulative Oil Produced (% OOIP)
Cumulative Total Fluid Produced (PV)
0.0
0.2
0.4
0.6
0.8
1.0

Figure 16

West Kiehl Relative Permeability



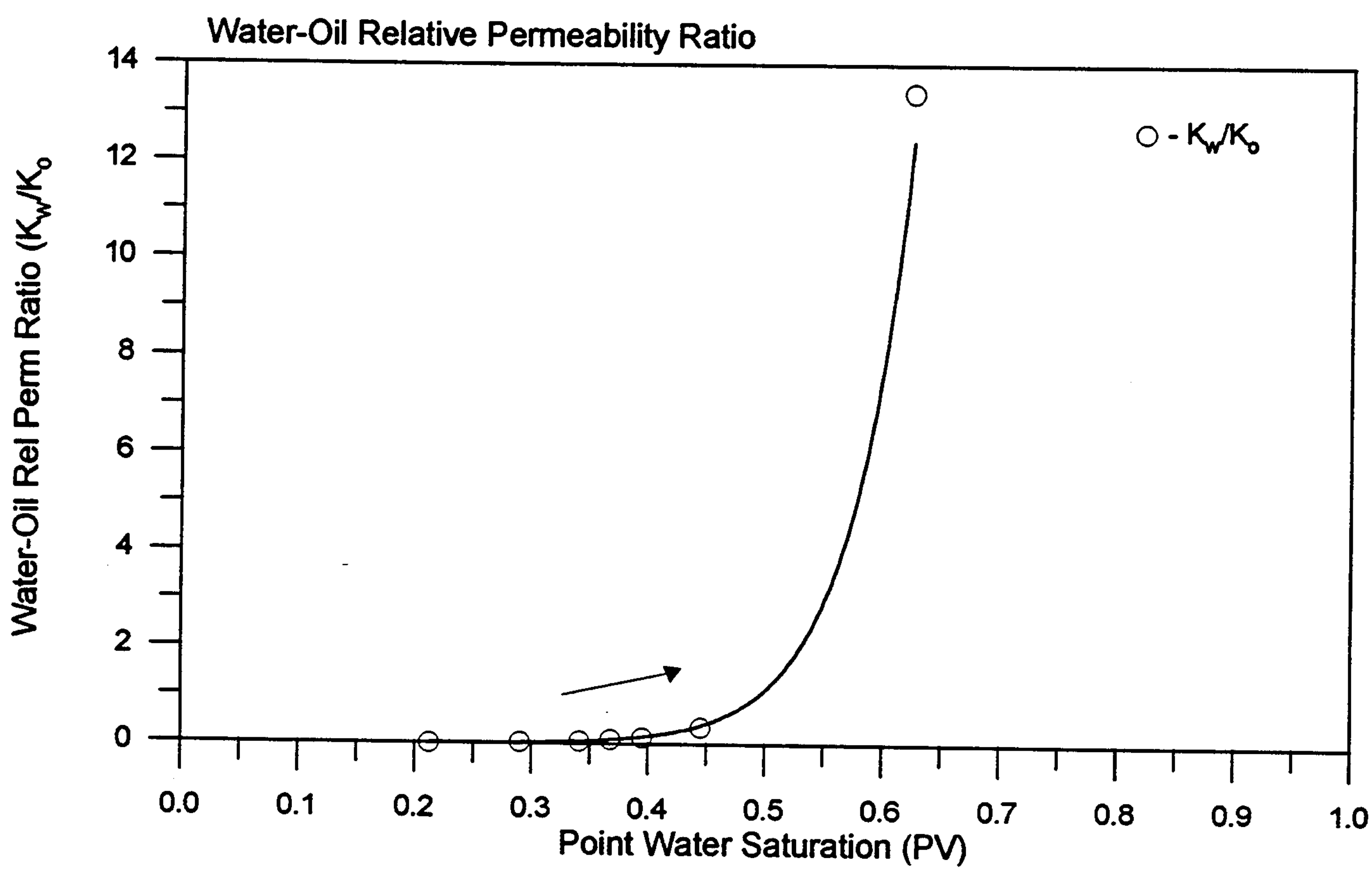
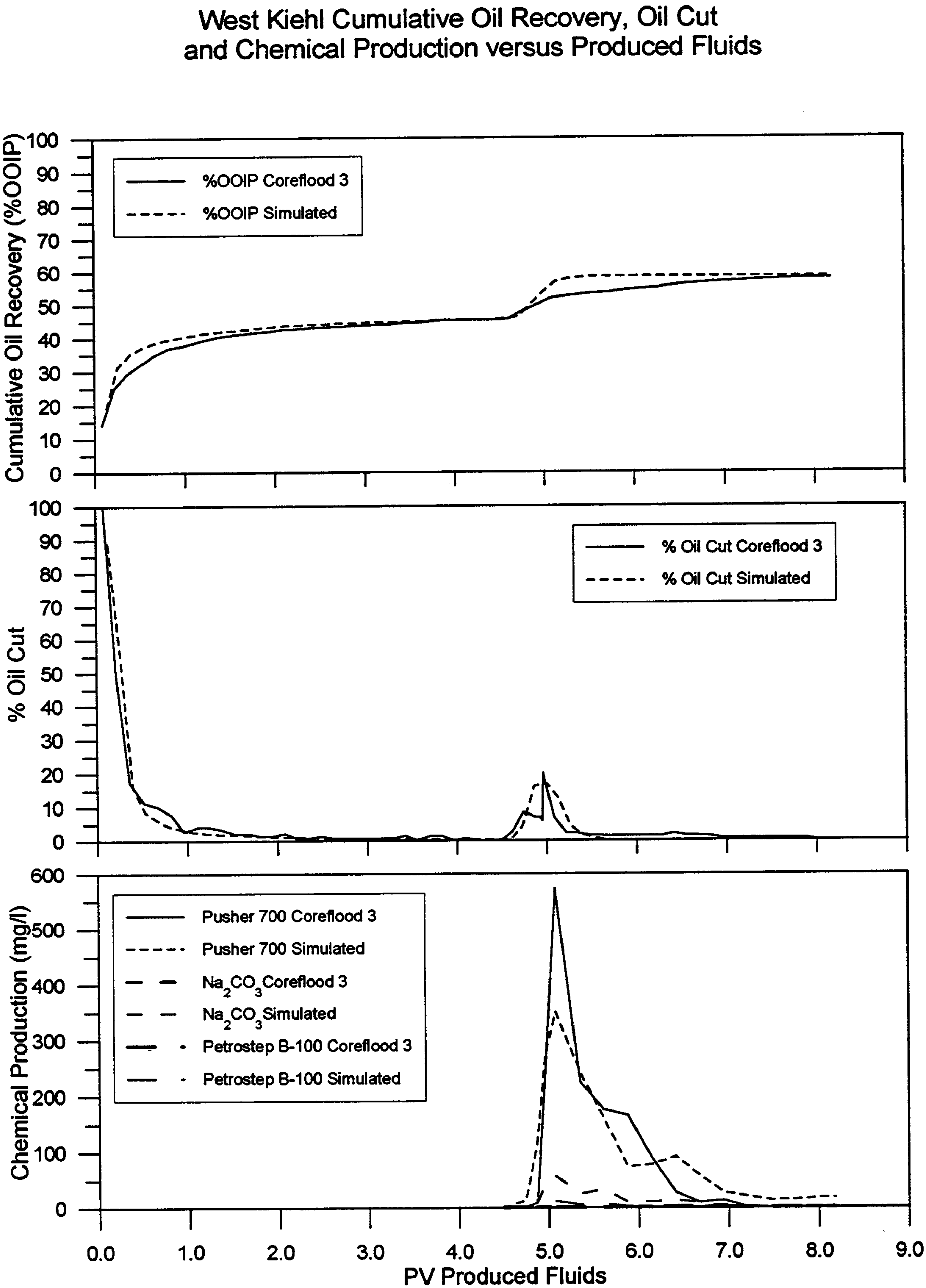


Figure 17



West Kiehl Cumulative Oil Recovery, Oil Cut and Chemical Production versus Produced Fluids
Cumulative Oil Recovery (%OOIP)
%OOIP Coreflood 3
%OOIP Simulated
% Oil Cut
% Oil Cut Coreflood 3
% Oil Cut Simulated
Chemical Production (mg/l)
Pusher 700 Coreflood 3
Pusher 700 Simulated
Na_2CO_3 Coreflood 3
Na_2CO_3 Simulated
Petrostep B-100 Coreflood 3
Petrostep B-100 Simulated
PV Produced Fluids
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0

Figure 18

West Kiehl Cumulative Oil Recovery, Oil Cut and Chemical Production versus Produced Fluids

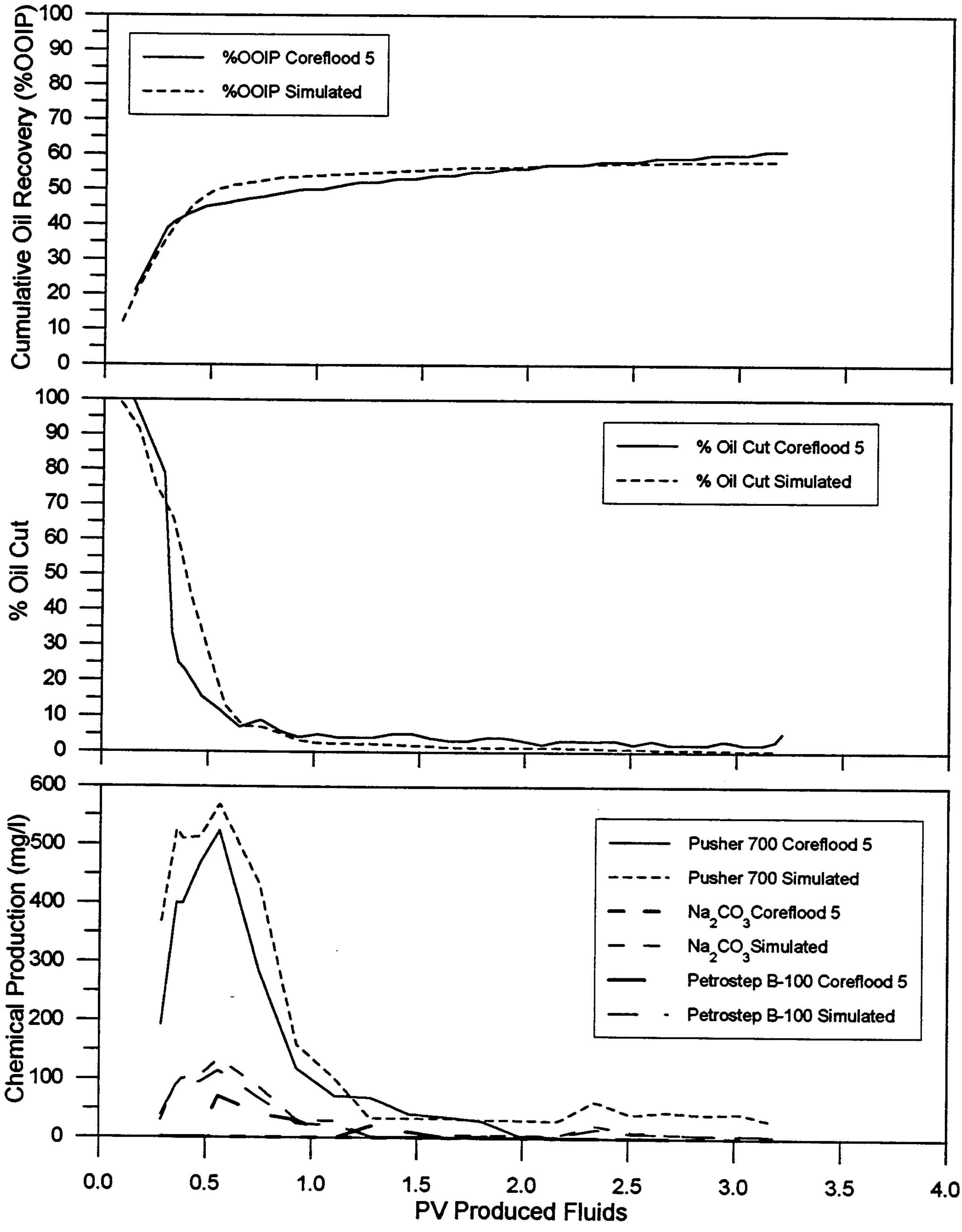


Figure 19

West Kiehl Cumulative Oil Recovery, Oil Cut and Chemical Production versus Produced Fluids

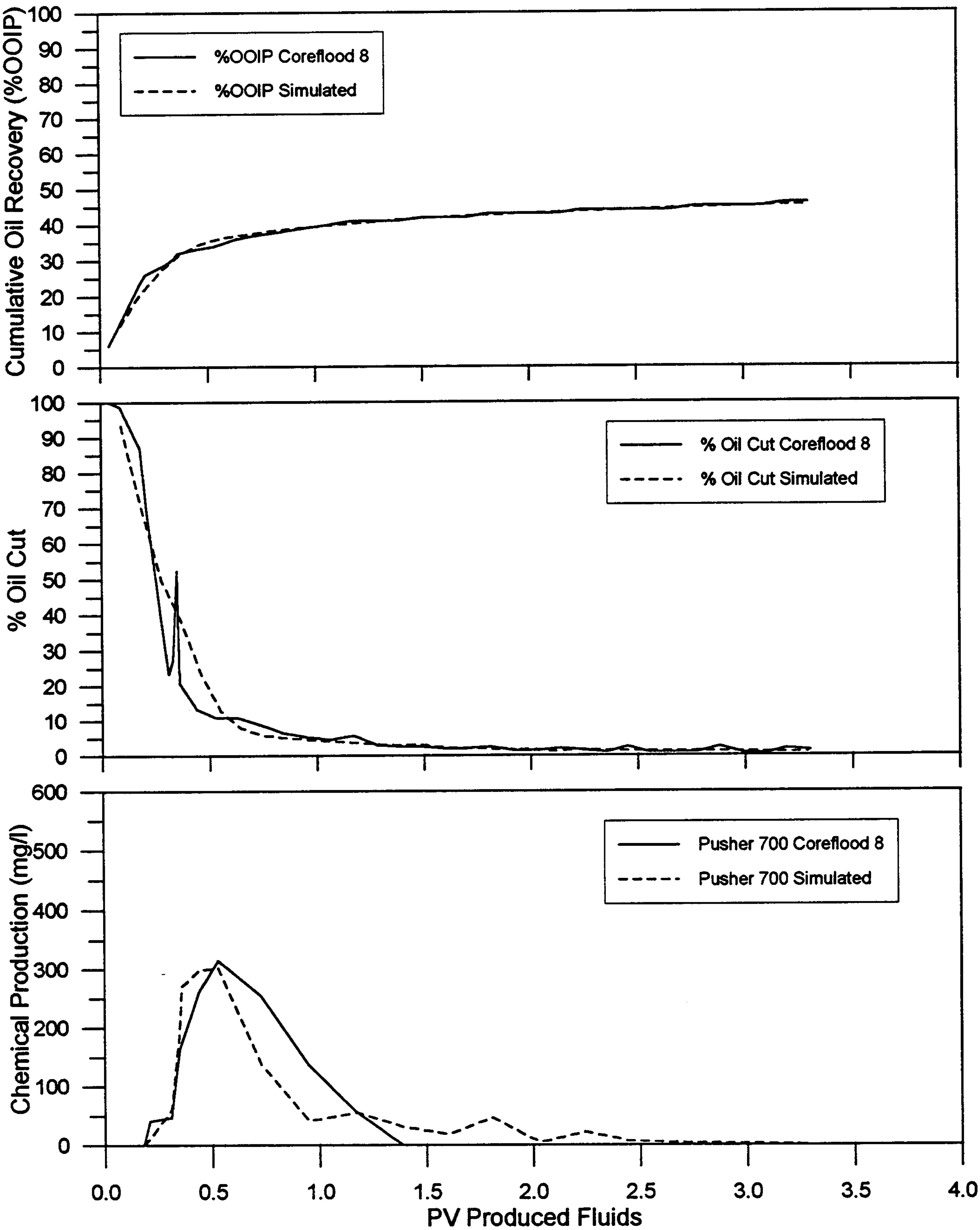
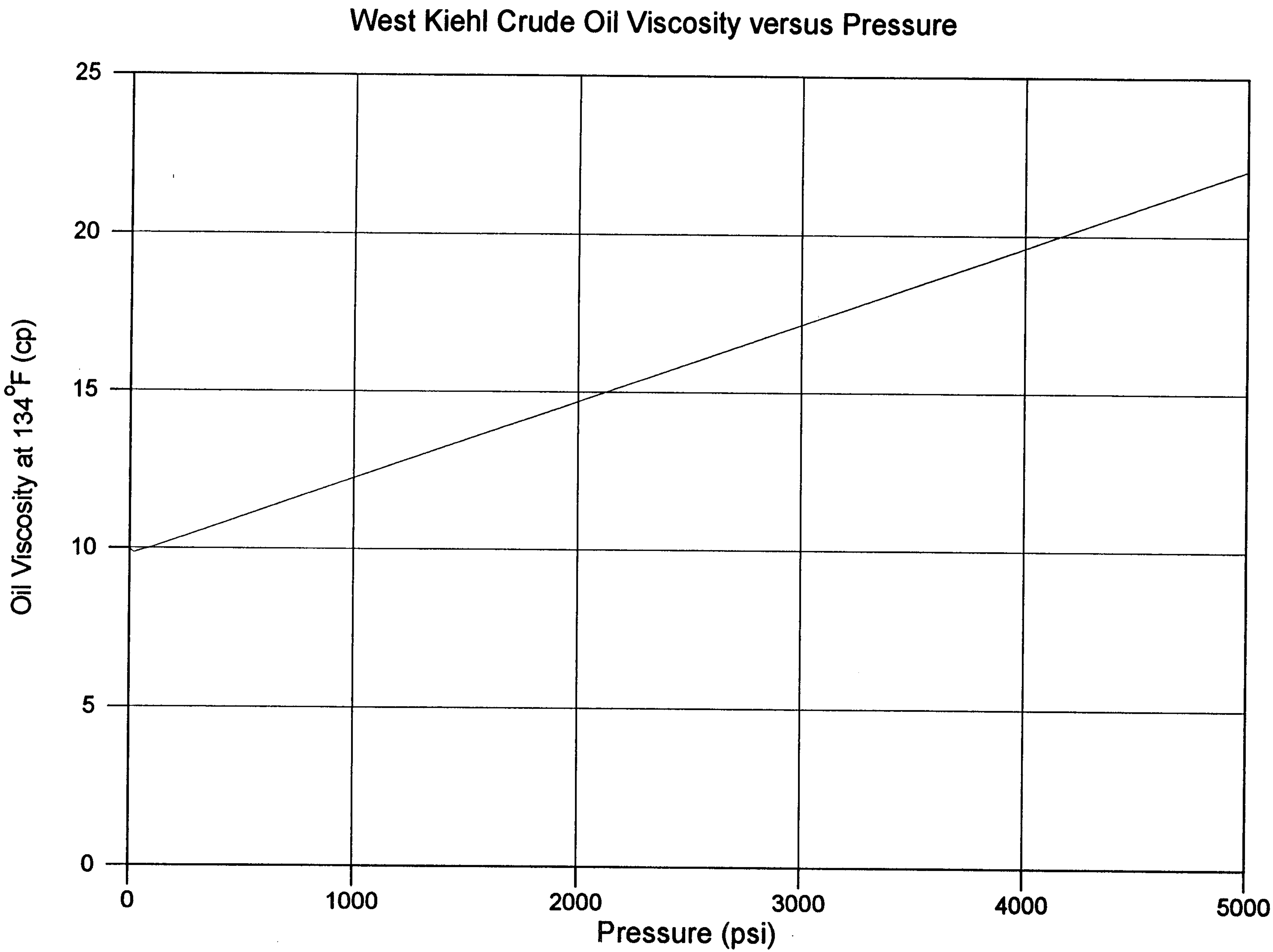


Figure 20



West Kiehl Crude Oil Viscosity versus Pressure
Oil Viscosity at 134°F (cp)
25
20
15
10
5
0
0
1000
2000
3000
4000
5000
Pressure (psi)

Figure 21

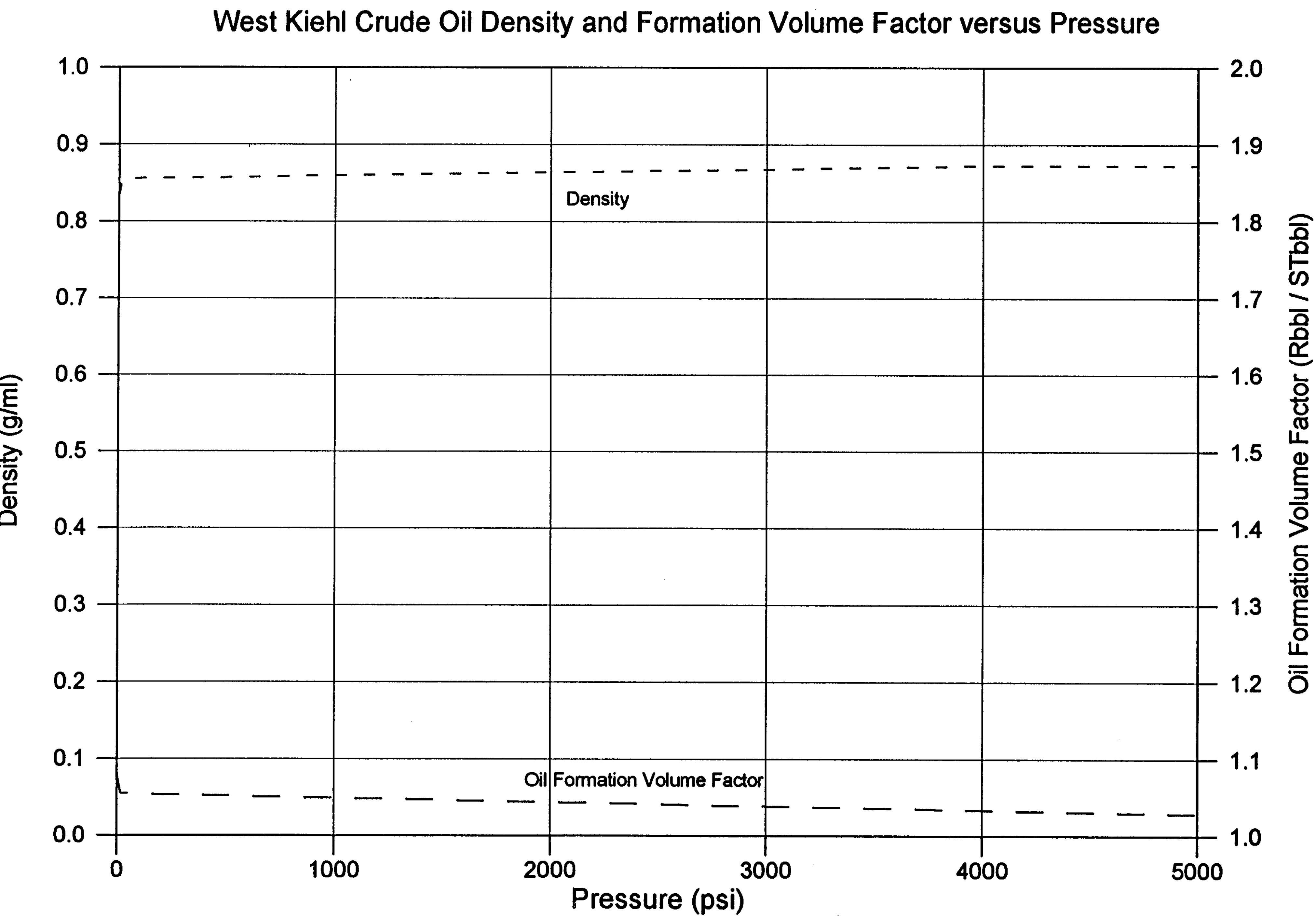

West Kiehl Crude Oil Density and Formation Volume Factor versus Pressure
Density (g/ml)
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Oil Formation Volume Factor (Rbbl / STbbl)
2.0
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.0
Density
Oil Formation Volume Factor
0
1000
2000
3000
4000
5000
Pressure (psi)

Figure 22

Coreflood Model Viscosity versus Polymer Concentration

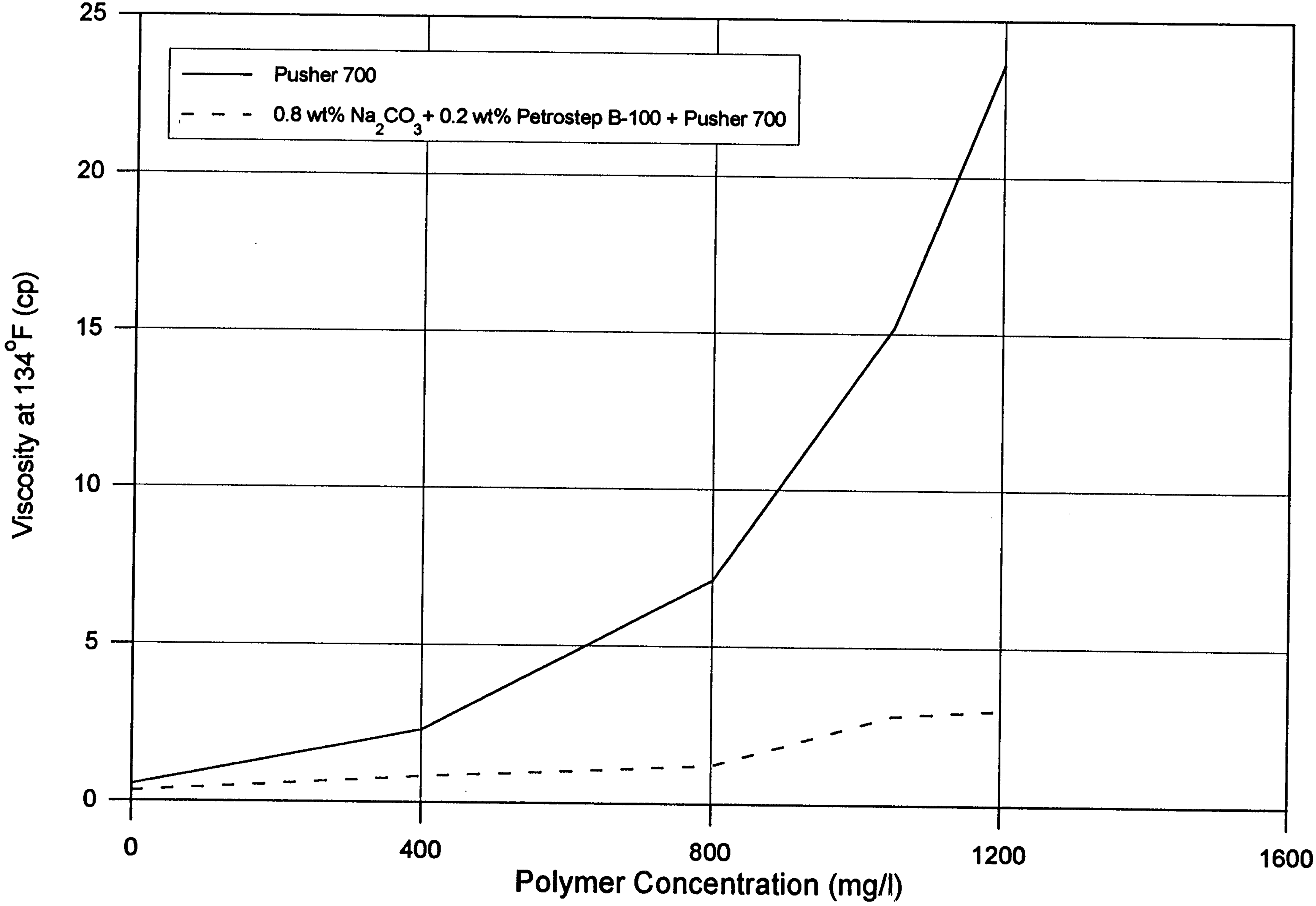


Figure 23

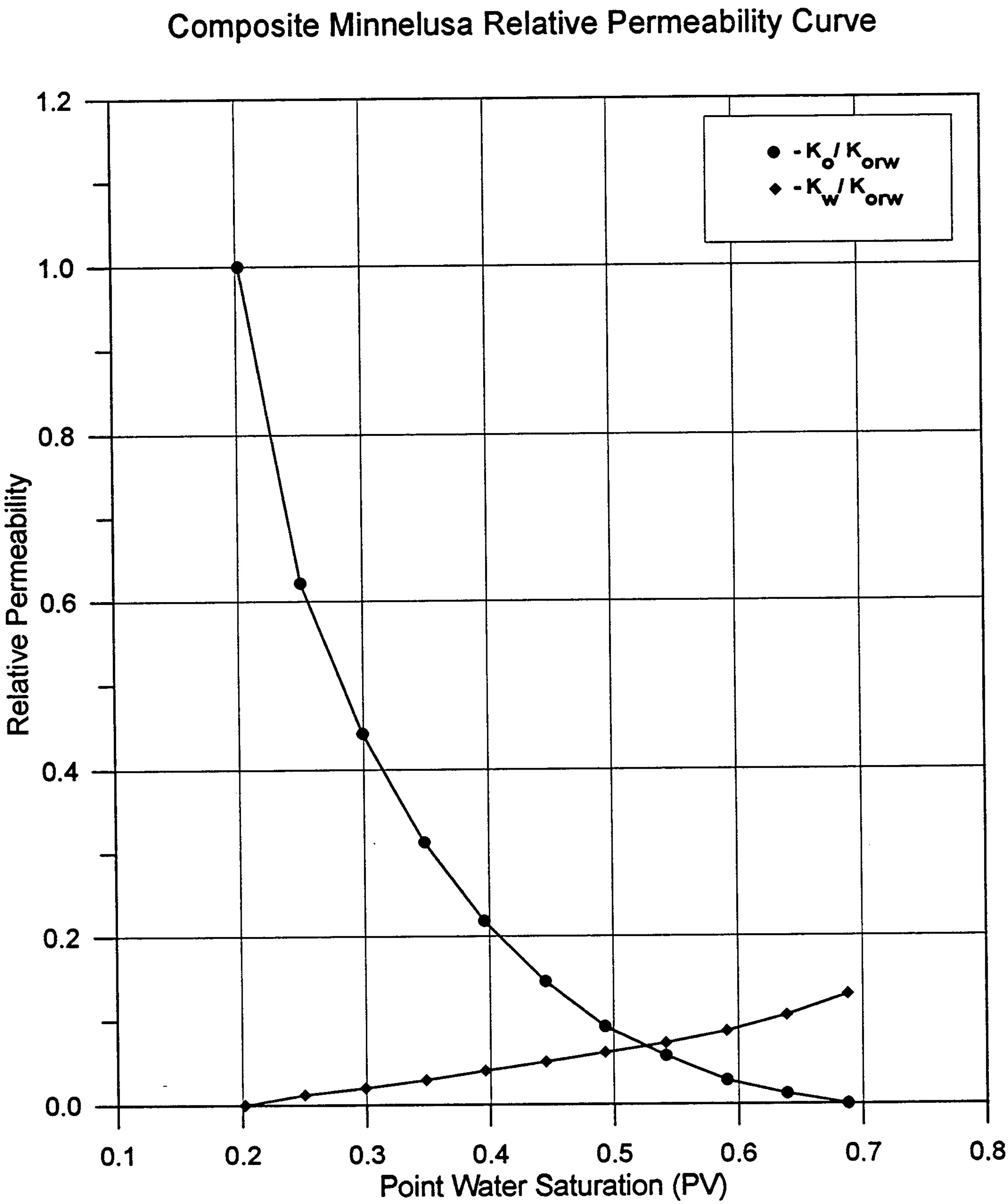
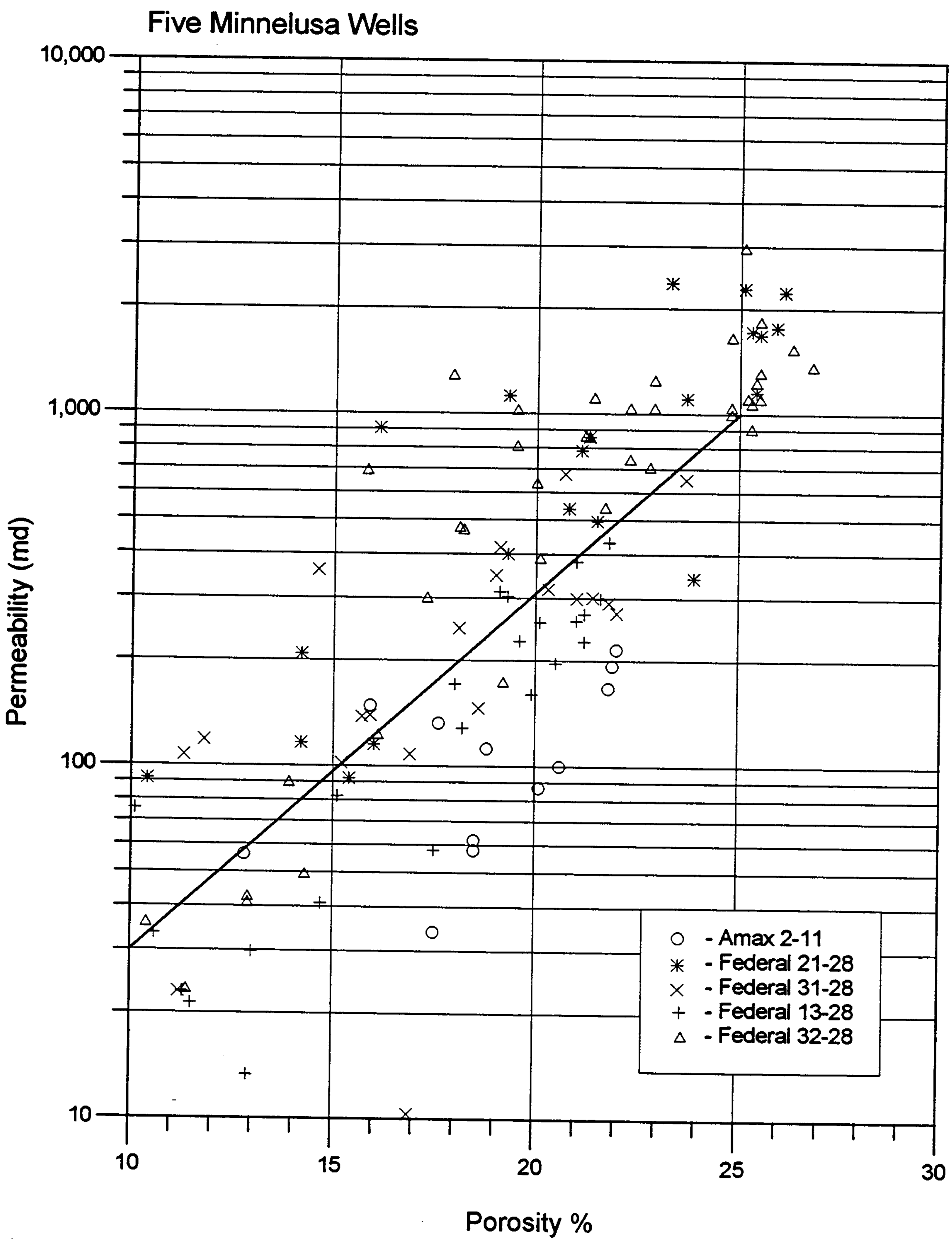

Composite Minnelusa Relative Permeability Curve
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Relative Permeability
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
Point Water Saturation (PV)
- K_o / K_{orw}
- K_w / K_{orw}

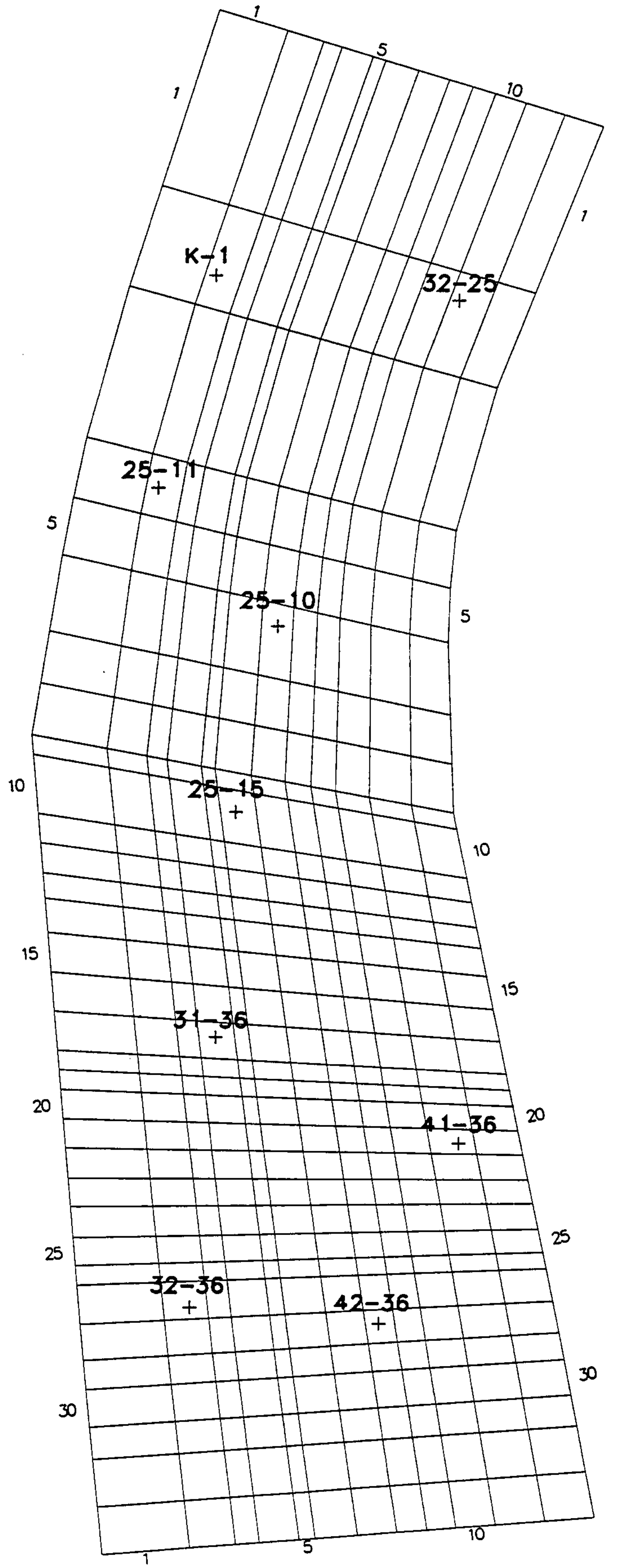
Figure 24

Permeability versus Porosity



West Kiehl Numerical Model Grid

Figure 25



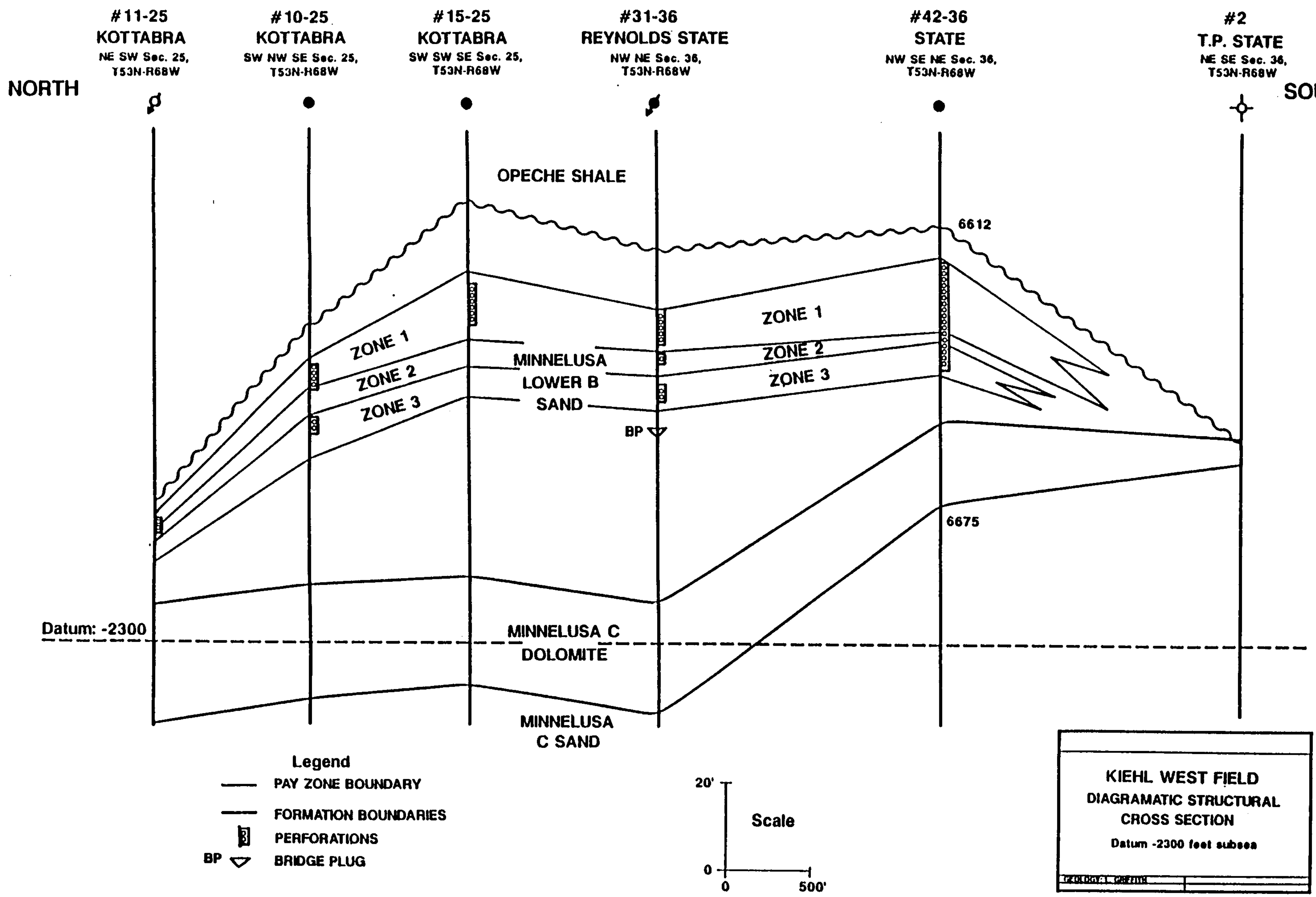
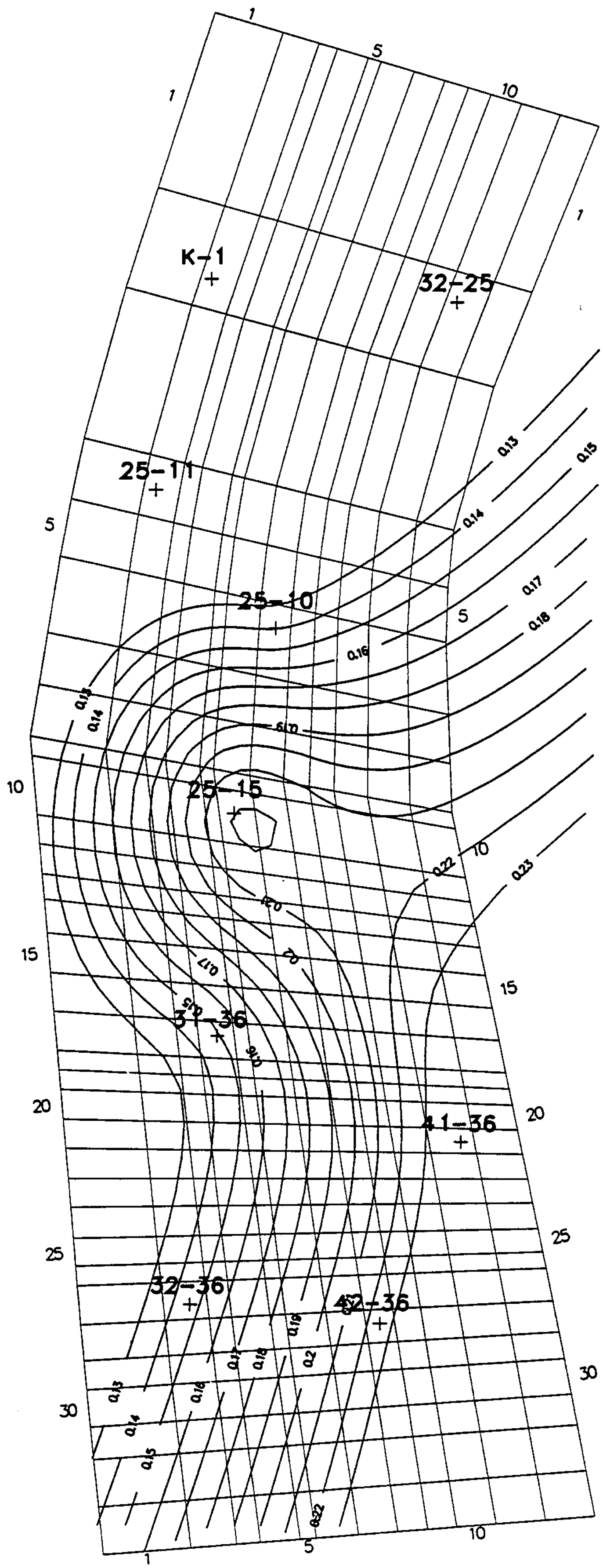

#11-25
KOTTABRA
NE SW Sec. 25,
T53N-R68W
#10-25
KOTTABRA
SW NW SE Sec. 25,
T53N-R68W
#15-25
KOTTABRA
SW SW SE Sec. 25,
T53N-R68W
#31-36
REYNOLDS STATE
NW NE Sec. 36,
T53N-R68W
#42-36
STATE
NW SE NE Sec. 36,
T53N-R68W
#2
T.P. STATE
NE SE Sec. 36,
T53N-R68W
NORTH
SOUTH
OPECHE SHALE
6612
ZONE 1
ZONE 2
ZONE 3
MINNELUSA
LOWER B
SAND
BP
6675
Datum: -2300
MINNELUSA C
DOLOMITE
MINNELUSA
C SAND
Legend
PAY ZONE BOUNDARY
FORMATION BOUNDARIES
PERFORATIONS
BP
BRIDGE PLUG
Scale
20'
0
0
500'
KIEHL WEST FIELD
DIAGRAMATIC STRUCTURAL
CROSS SECTION
Datum -2300 feet subsea

Figure 26

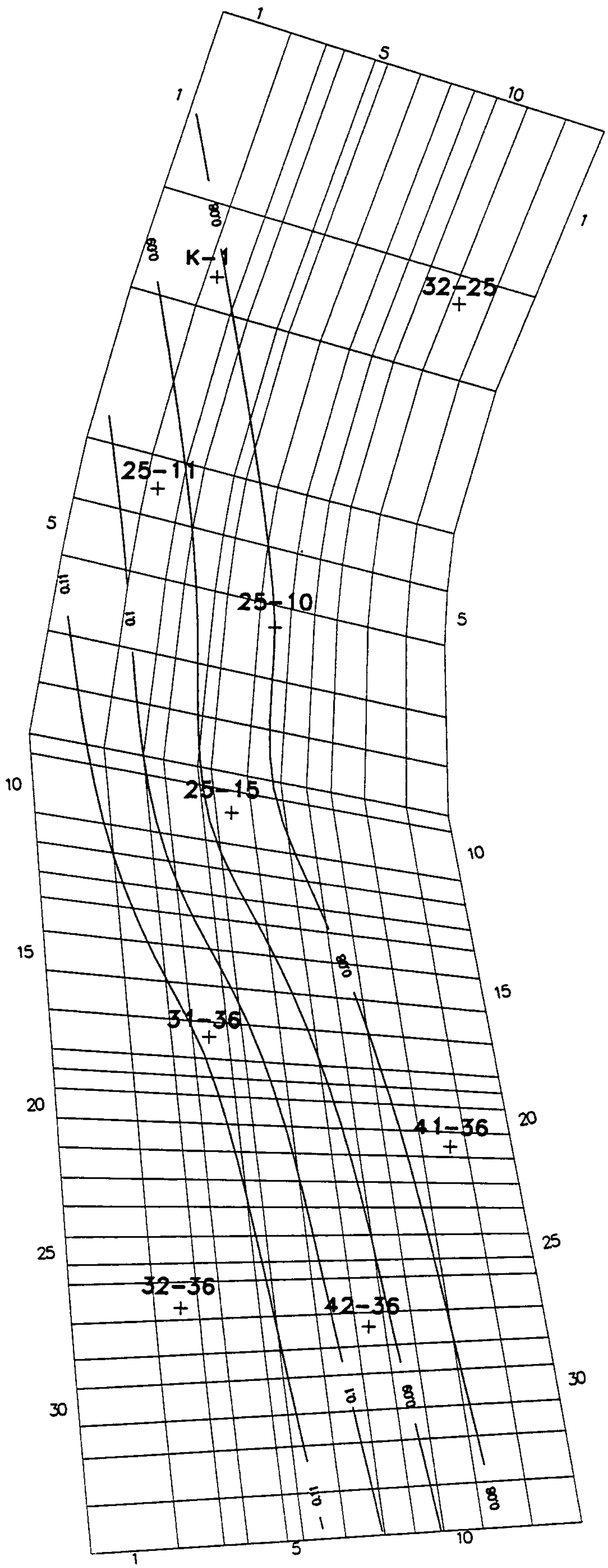
Net Porosity: Layer 1

Figure 27



Net Porosity: Layer 2

Figure 28



Net Porosity: Layer 3 **Figure 29**

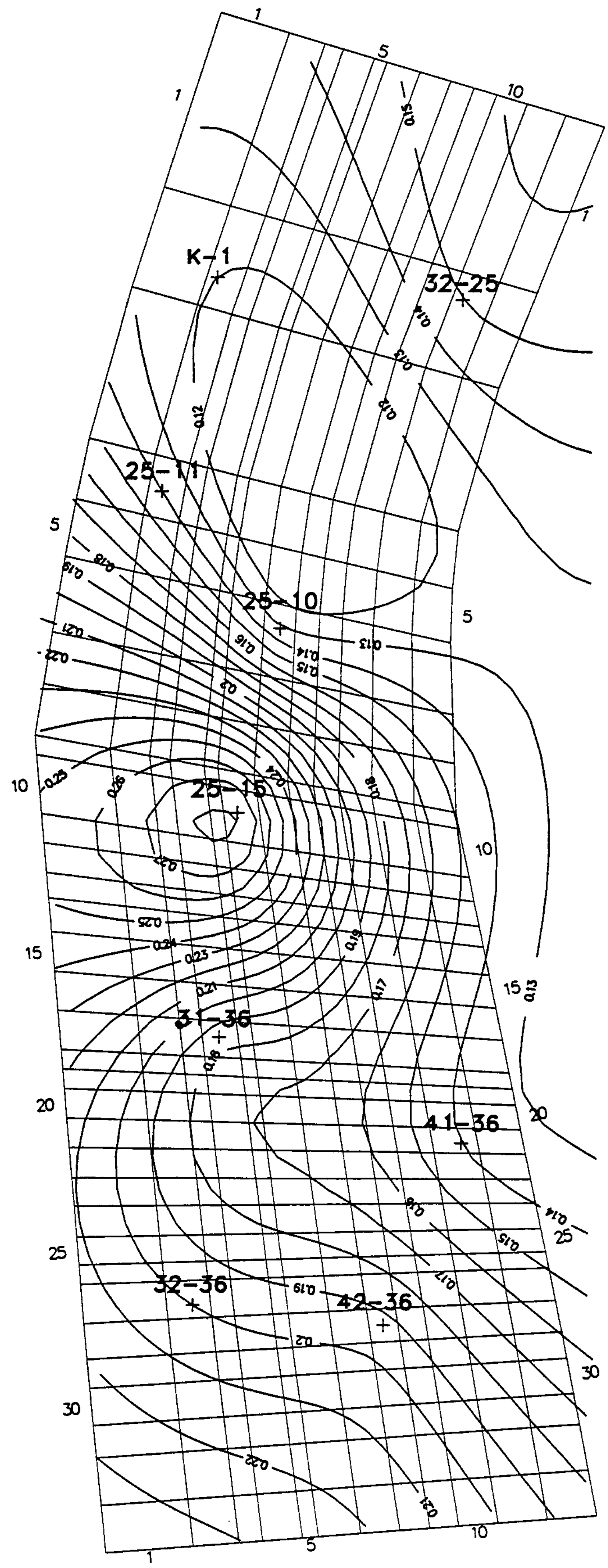


Figure 30

West Kiehl Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

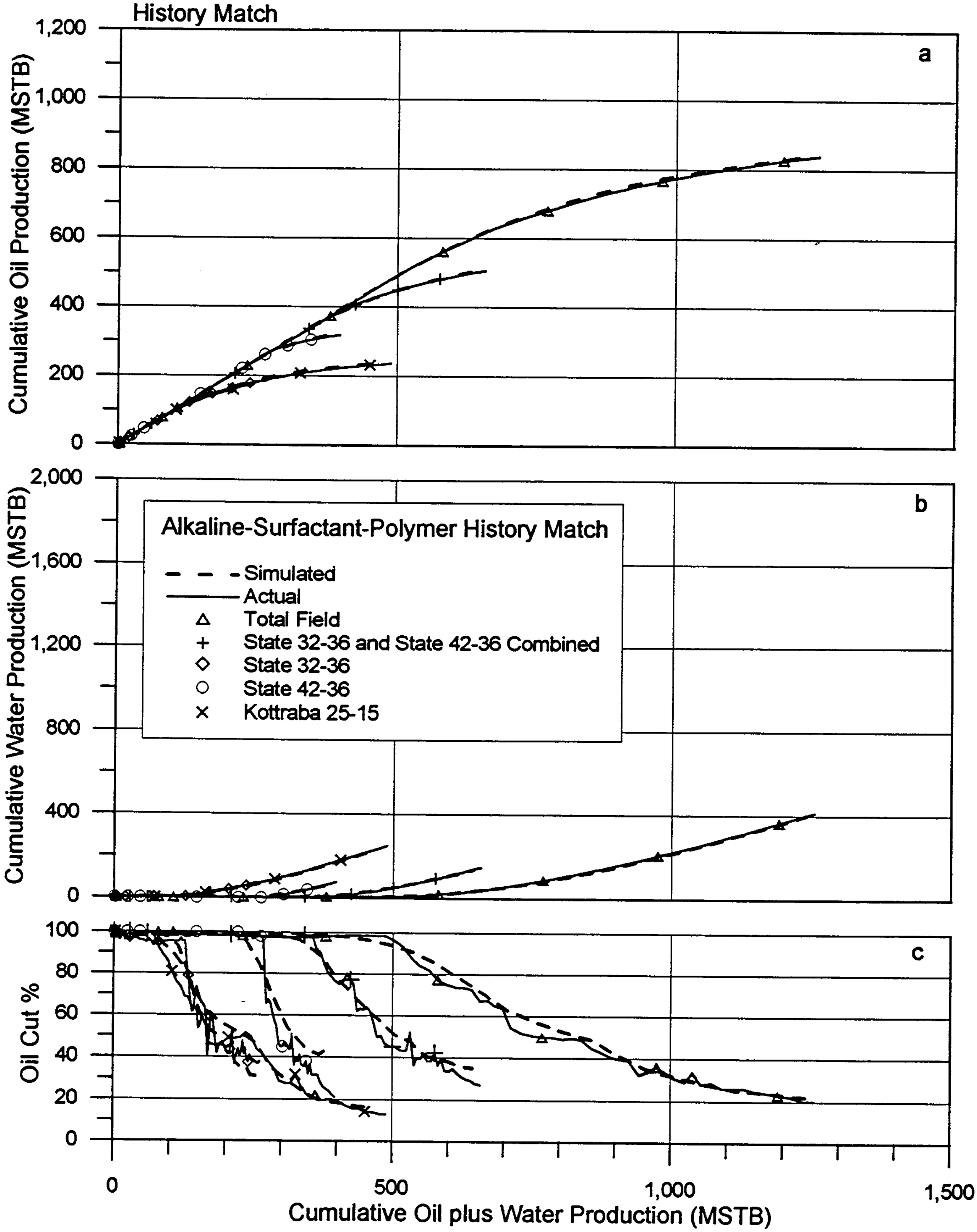
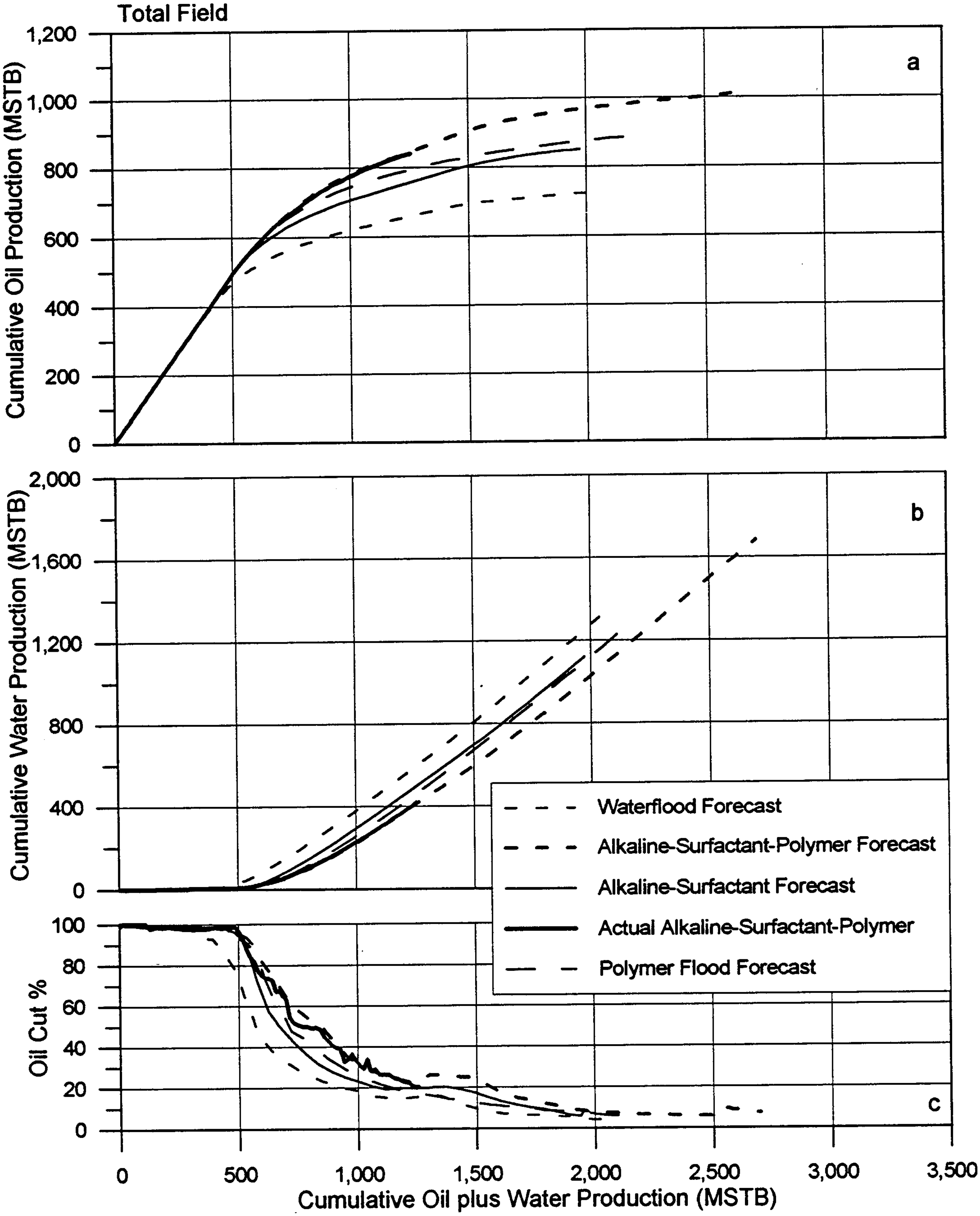


Figure 31

West Kiehl Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water



West Kiehl Cumultive Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

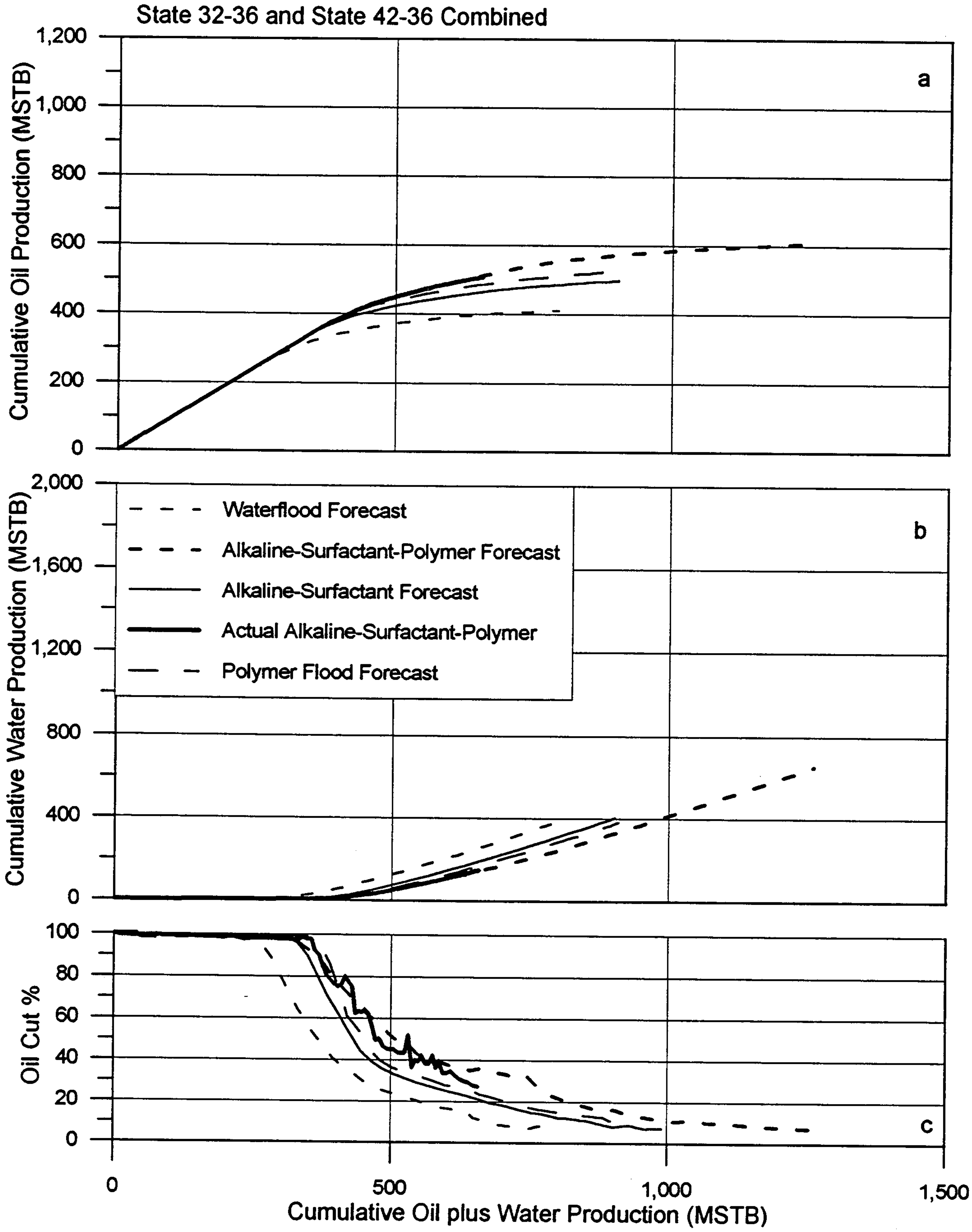


Figure 33

West Kiehl Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

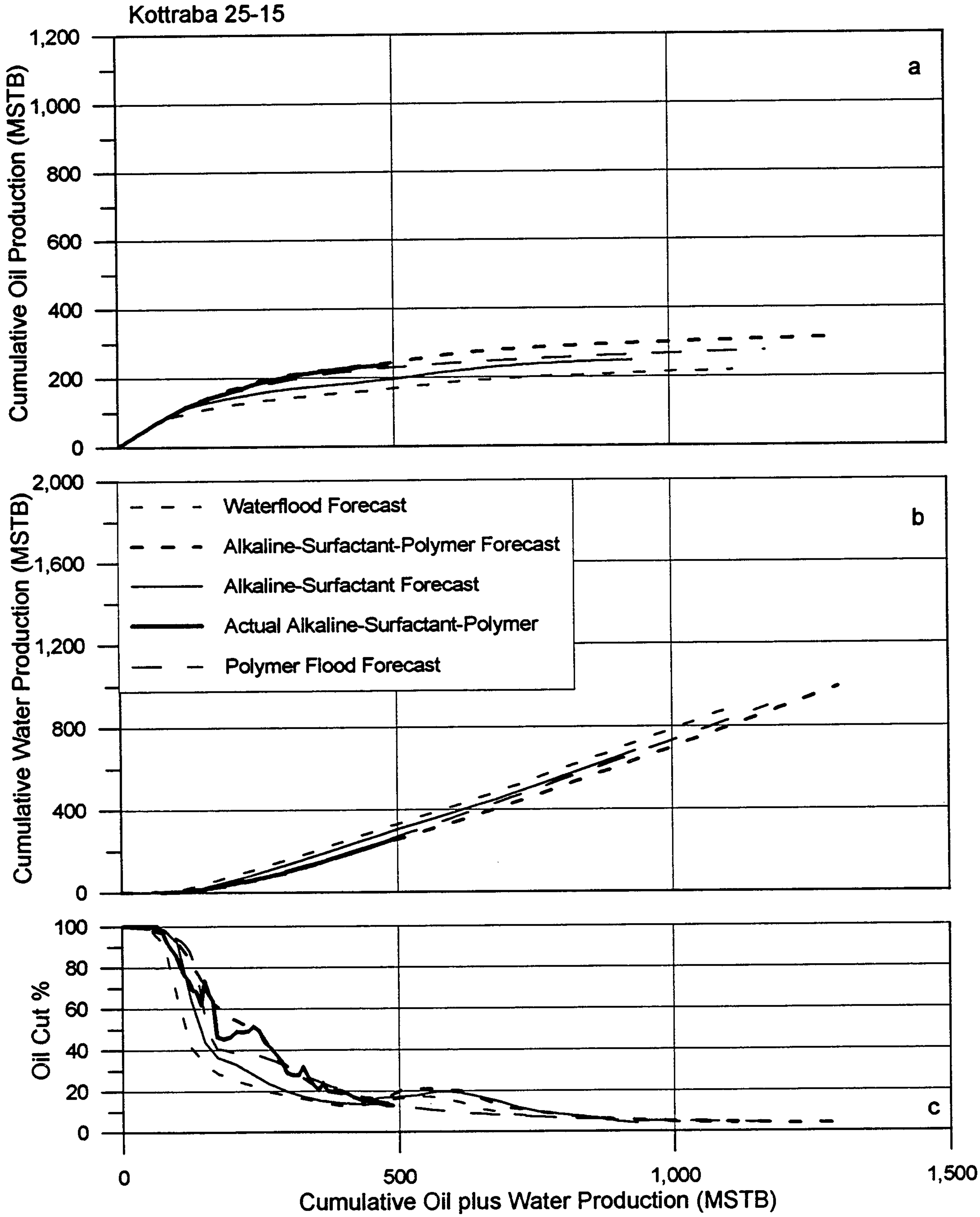


Figure 34

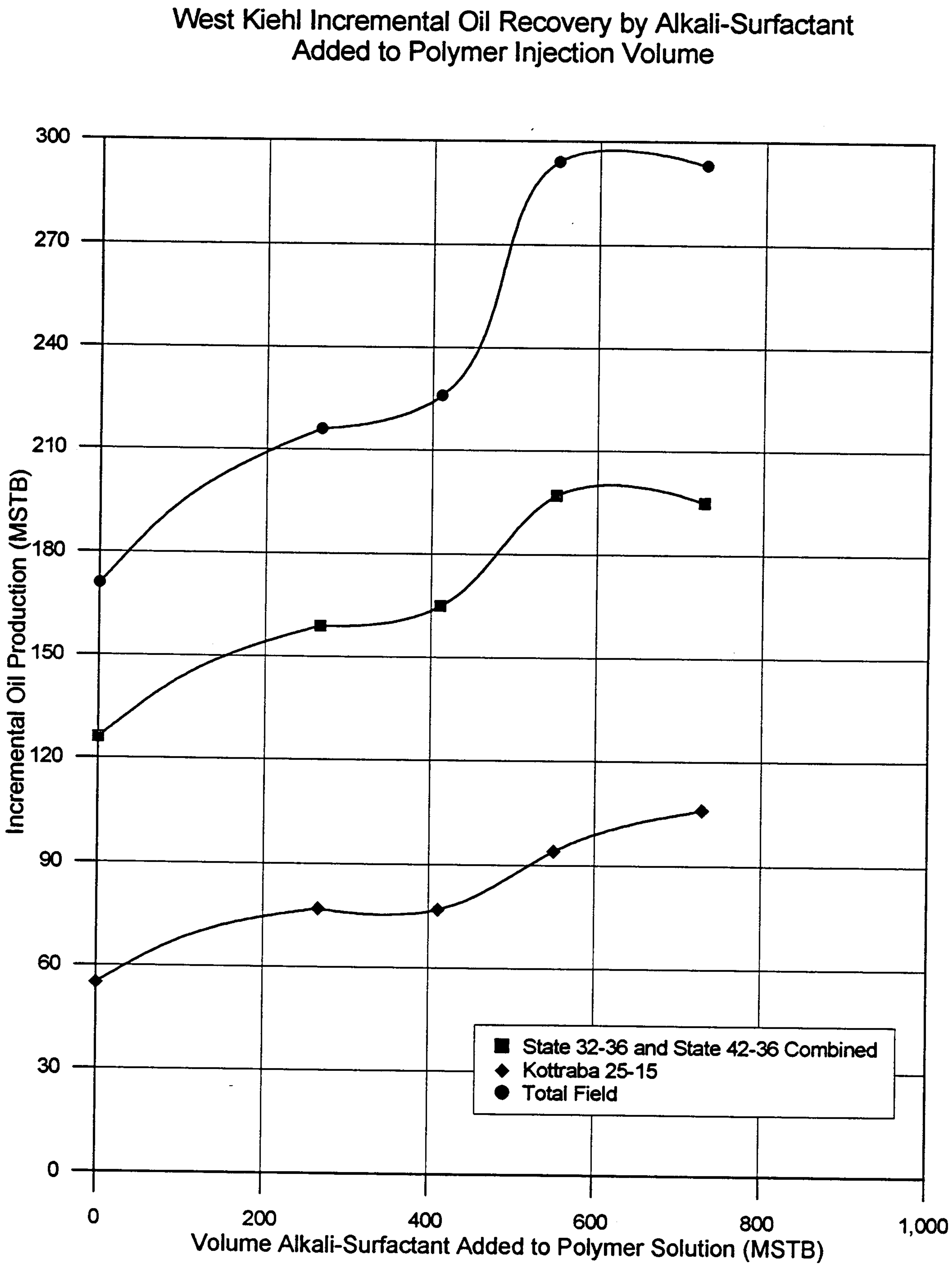

West Kiehl Incremental Oil Recovery by Alkali-Surfactant
Added to Polymer Injection Volume
300
270
240
210
180
150
120
90
60
30
0
Incremental Oil Production (MSTB)
0
200
400
600
800
1,000
Volume Alkali-Surfactant Added to Polymer Solution (MSTB)
State 32-36 and State 42-36 Combined
Kottraba 25-15
Total Field

Figure 35

West Kiehl Incremental Oil Recovery by Alkaline-Surfactant-Polymer versus Volume of Polymer Drive Injection

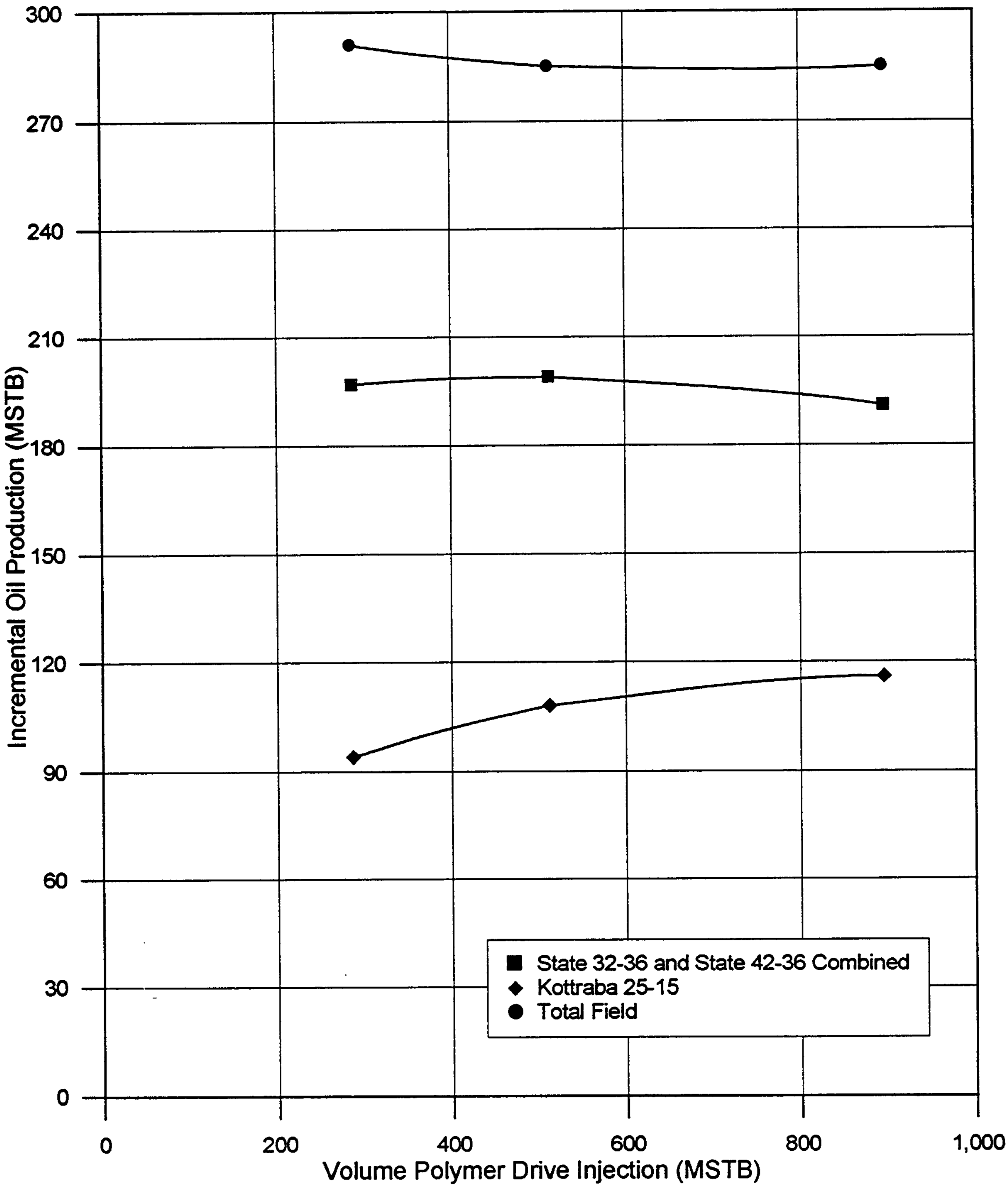
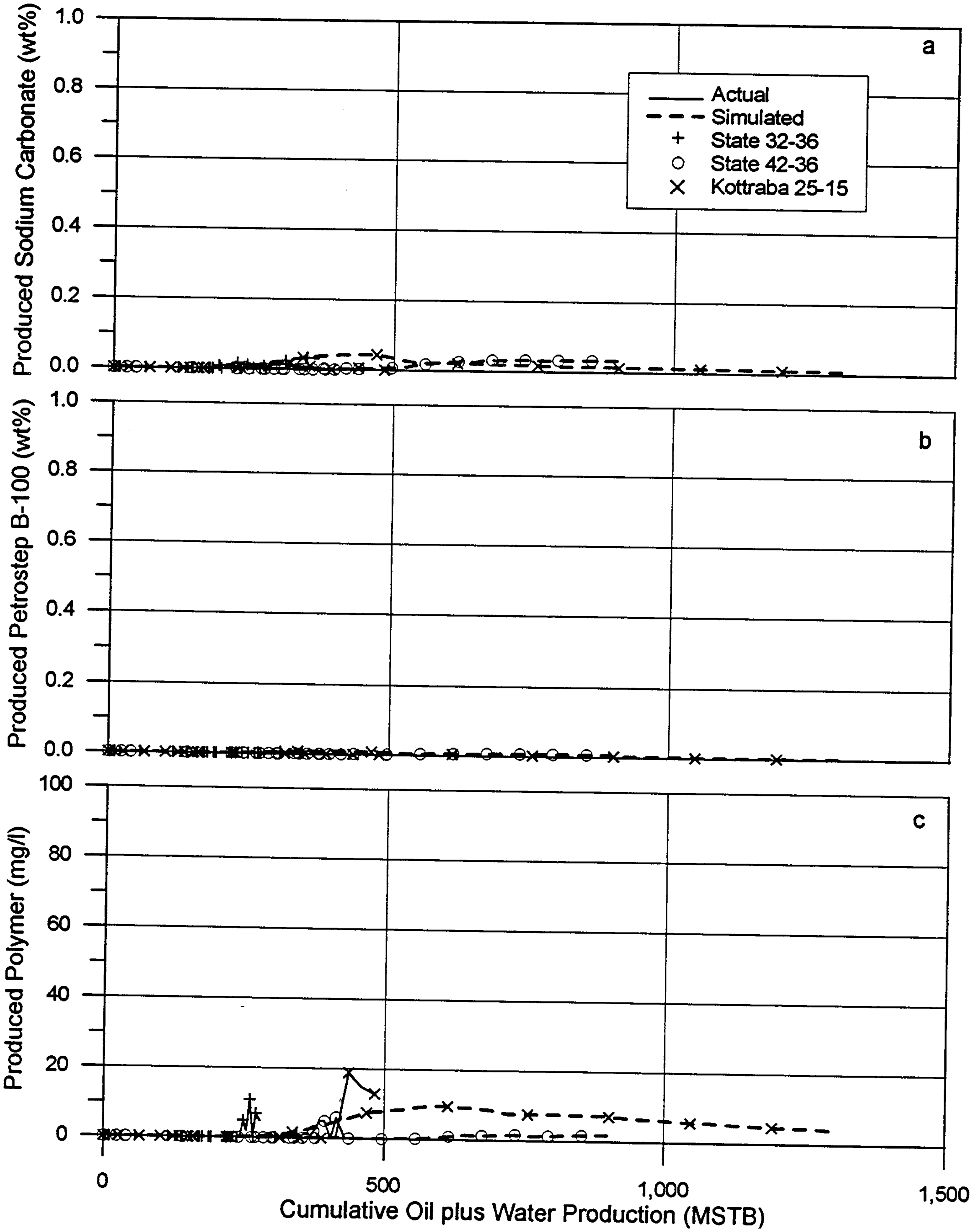


Figure 36

Predicted and Actual Chemical Concentrations
of Alkaline-Surfactant-Polymer Flood at West Kiehl



GO BACK
TO ORIGINAL
FOR 11" X 17
FOLD-OUT
B. J. ADAMS
Office

Figure 38

Prairie Creek South Isopach with Well Locations

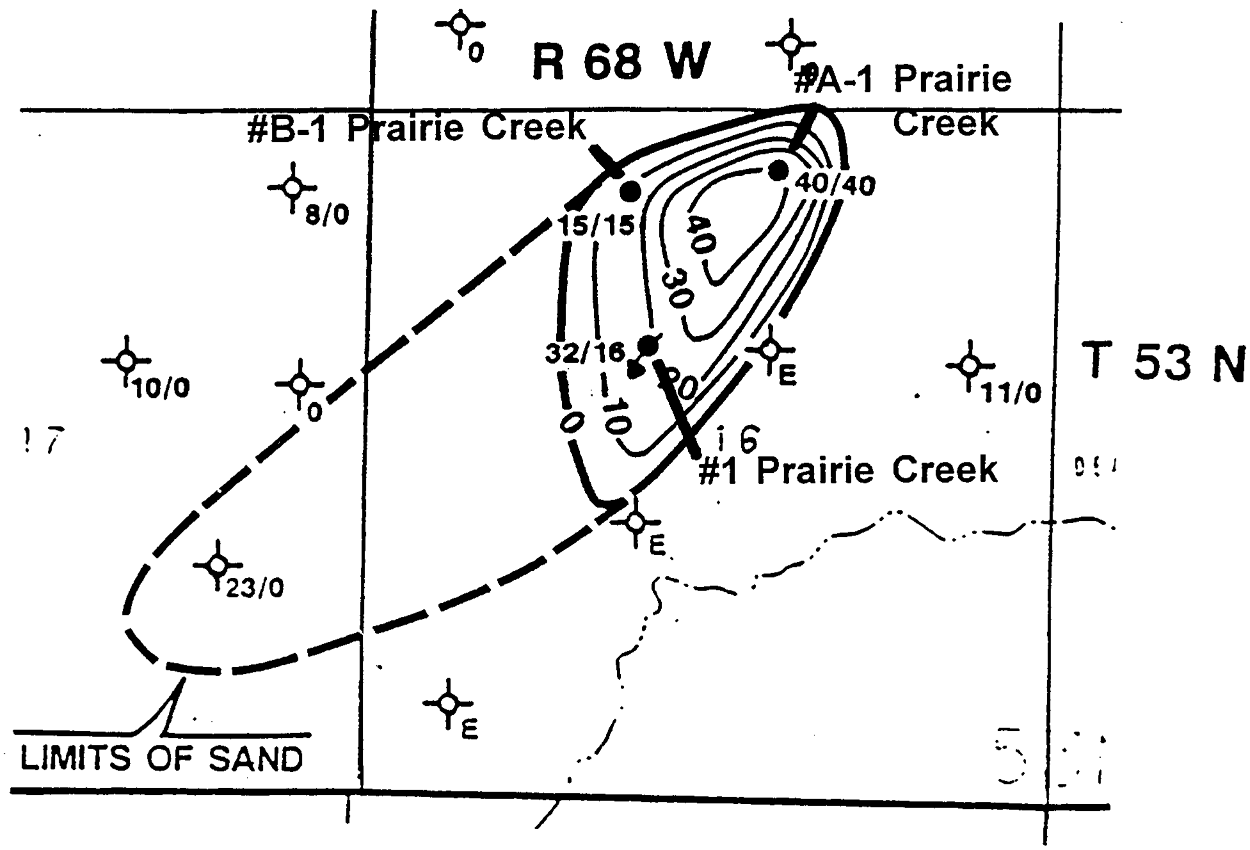
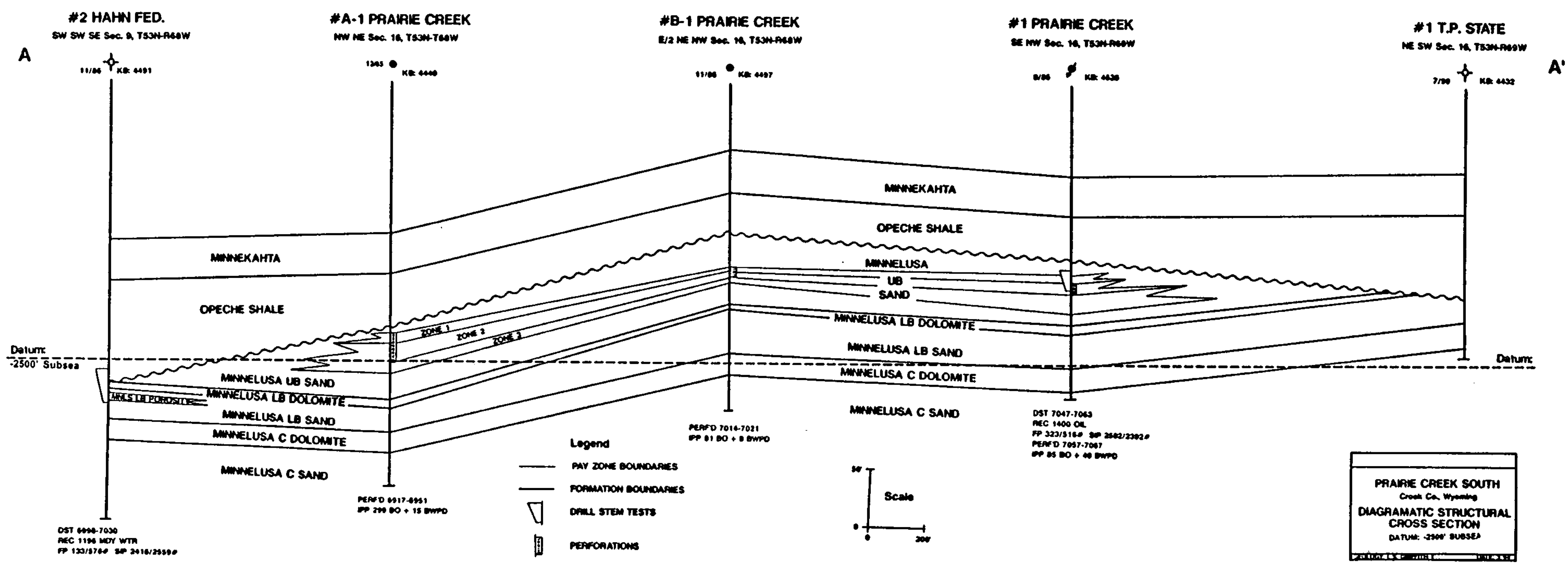


Figure 39



A
A'
#2 HAHN FED.
SW SW SE Sec. 9, T53N-R68W
#A-1 PRAIRIE CREEK
NW NE Sec. 16, T53N-T68W
#B-1 PRAIRIE CREEK
E/2 NE NW Sec. 16, T53N-R68W
#1 PRAIRIE CREEK
SE NW Sec. 16, T53N-R68W
#1 T.P. STATE
NE SW Sec. 16, T53N-R69W
MINNEKAHTA
OPECHE SHALE
MINNELUSA
UB
SAND
ZONE 1
ZONE 2
ZONE 3
MINNELUSA UB SAND
MINNELUSA LB DOLOMITE
MINNELUSA LB SAND
MINNELUSA C DOLOMITE
MINNELUSA C SAND
Datum:
-2500' Subsea
Datum:
Legend
PAY ZONE BOUNDARIES
FORMATION BOUNDARIES
DRILL STEM TESTS
PERFORATIONS
Scale
PRAIRIE CREEK SOUTH
Crook Co., Wyoming
DIAGRAMATIC STRUCTURAL CROSS SECTION
DATUM: -2500' SUBSEA

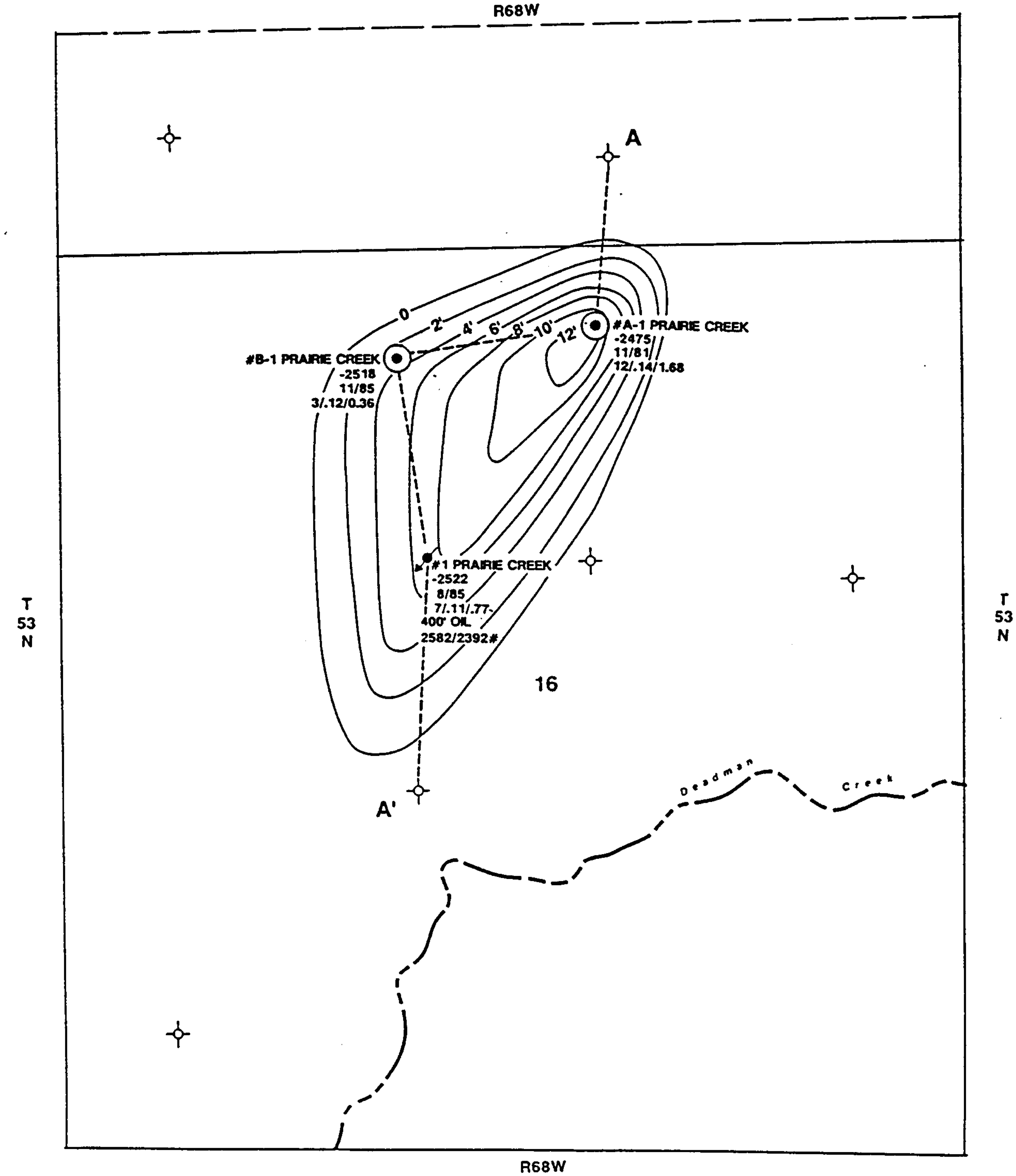


Figure 40

LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

- NO SAND DEVELOPMENT
- COMPLETED IN ZONE
- LINE OF CROSS SECTION

PRAIRIE CREEK SOUTH AREA
Crook County, Wyoming

MINNELUSA UPPER 'B' SAND

ZONE 1
ISOPACH:
NET OIL PAY
INTERVAL = 2 feet

GEOLOGY: L.S. GRIFFITH
DATE DATE: 4/94

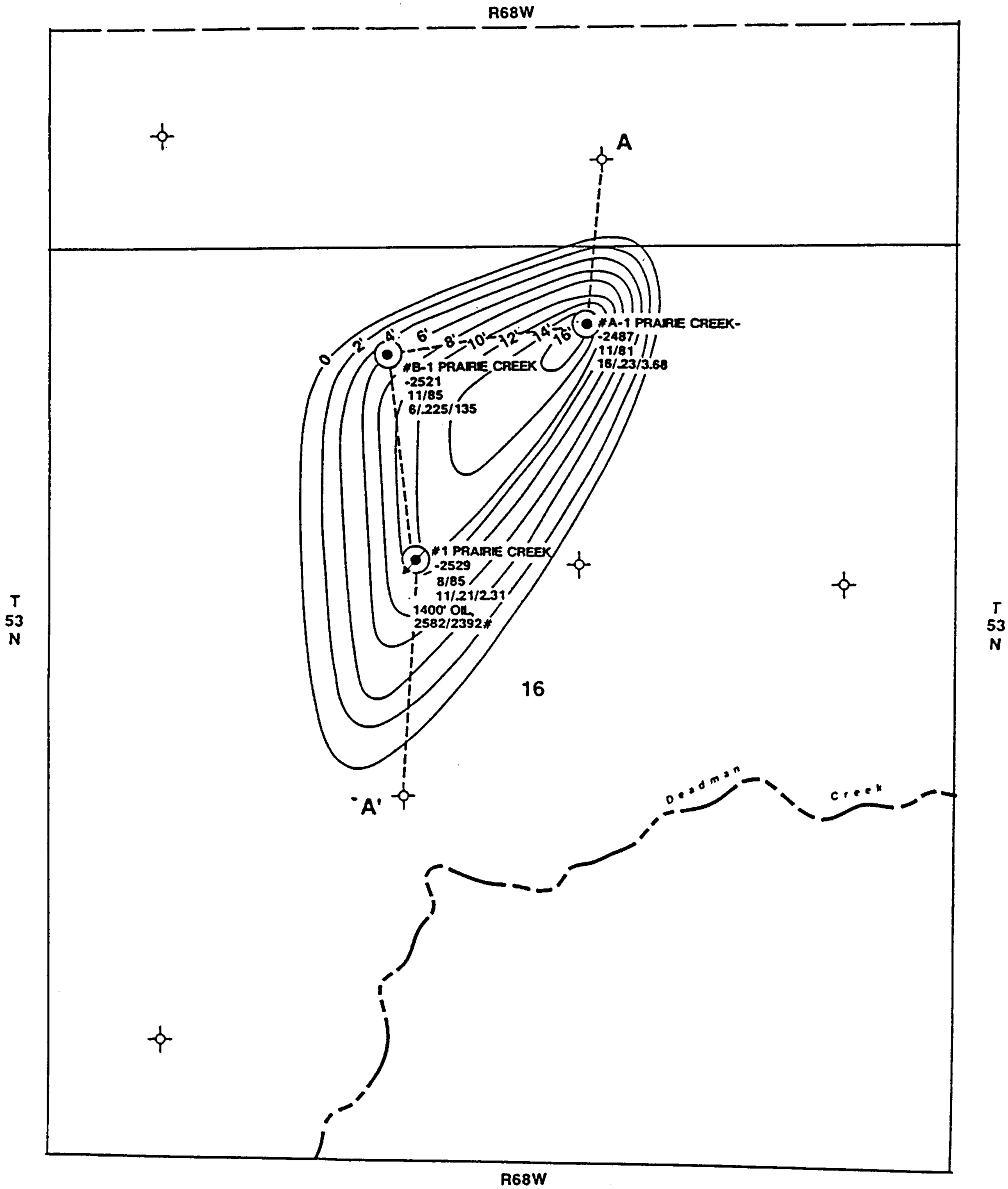


Figure 41

LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

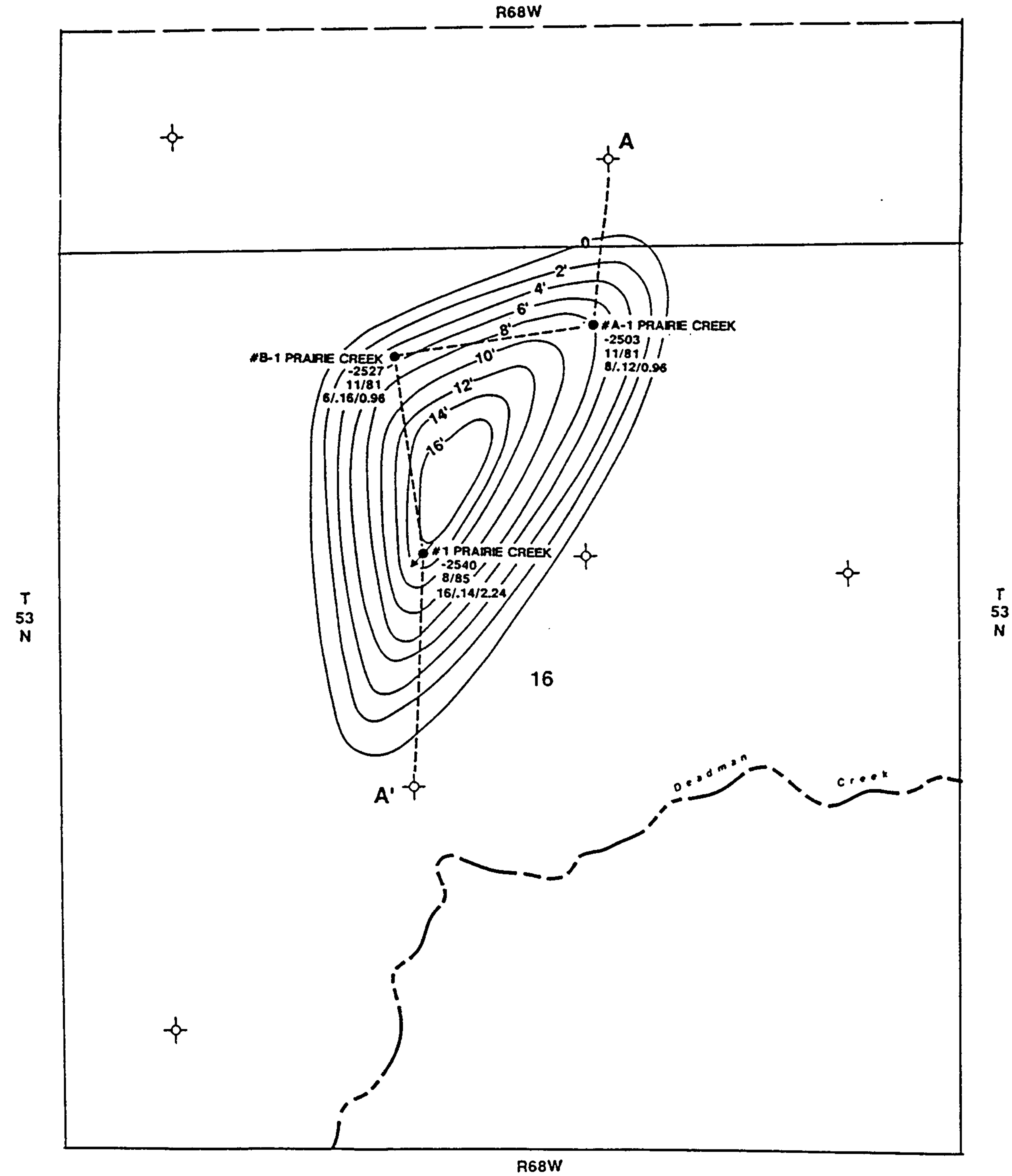
- NO SAND DEVELOPMENT
- COMPLETED IN ZONE
- LINE OF CROSS SECTION

PRAIRIE CREEK SOUTH AREA
Crook County, Wyoming

MINNELUSA UPPER 'B' SAND

ZONE 2
ISOPACH:
NET OIL PAY
INTERVAL = 2 feet

GEOLOGY L.S. GRIFFITH
DATE DATE: 4/94



LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

— NO SAND DEVELOPMENT

COMPLETED IN ZONE

---- LINE OF CROSS SECTION

PRAIRIE CREEK SOUTH AREA
Crook County, Wyoming

MINNELUSA UPPER 'B' SAND
ZONE 3
ISOPACH:
NET OIL PAY
INTERVAL = 2 feet

GEOLOGY: L.S. GRIFFITH
DATE: DATE: 4/94

Figure 42

Figure 43

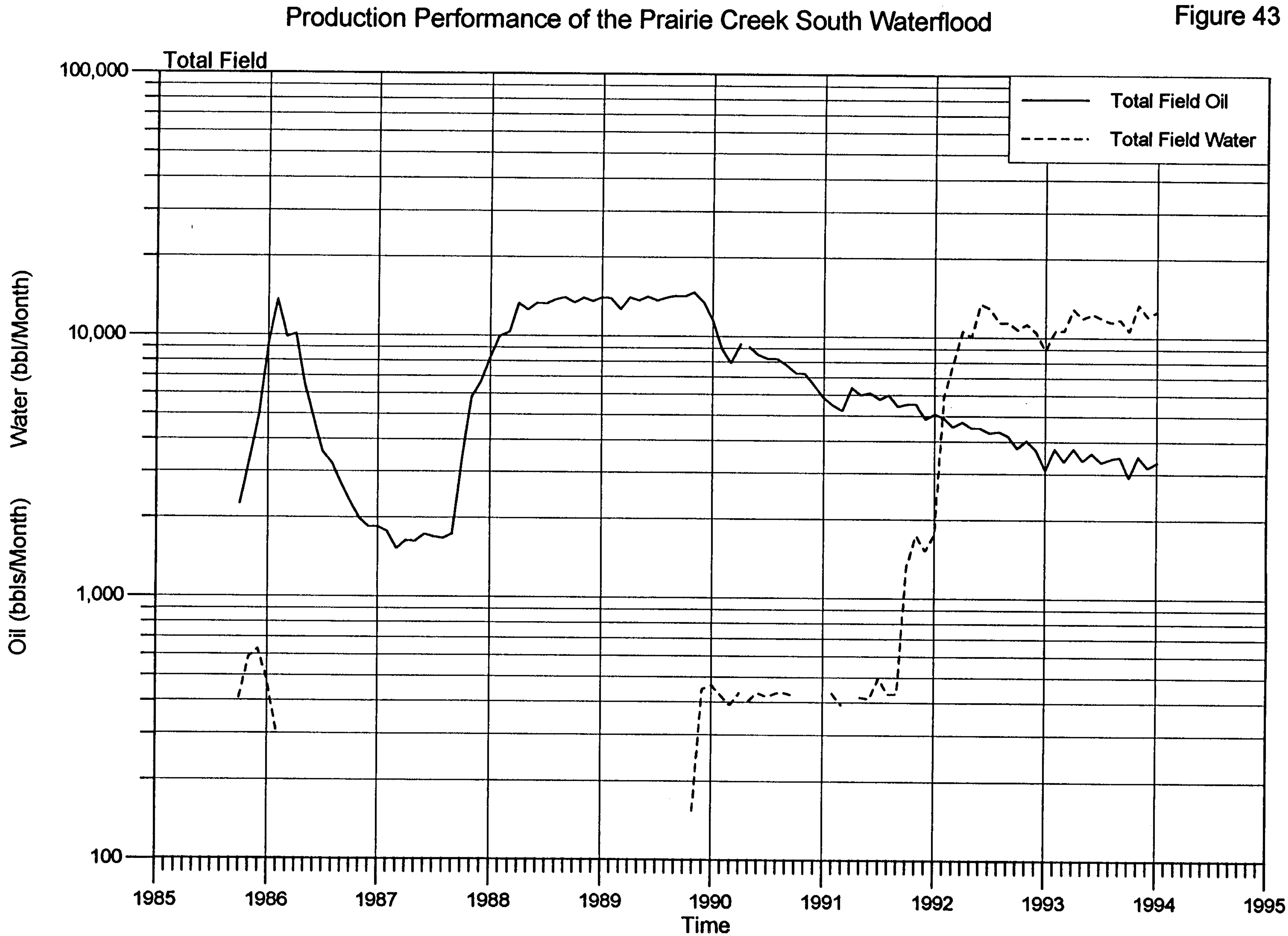
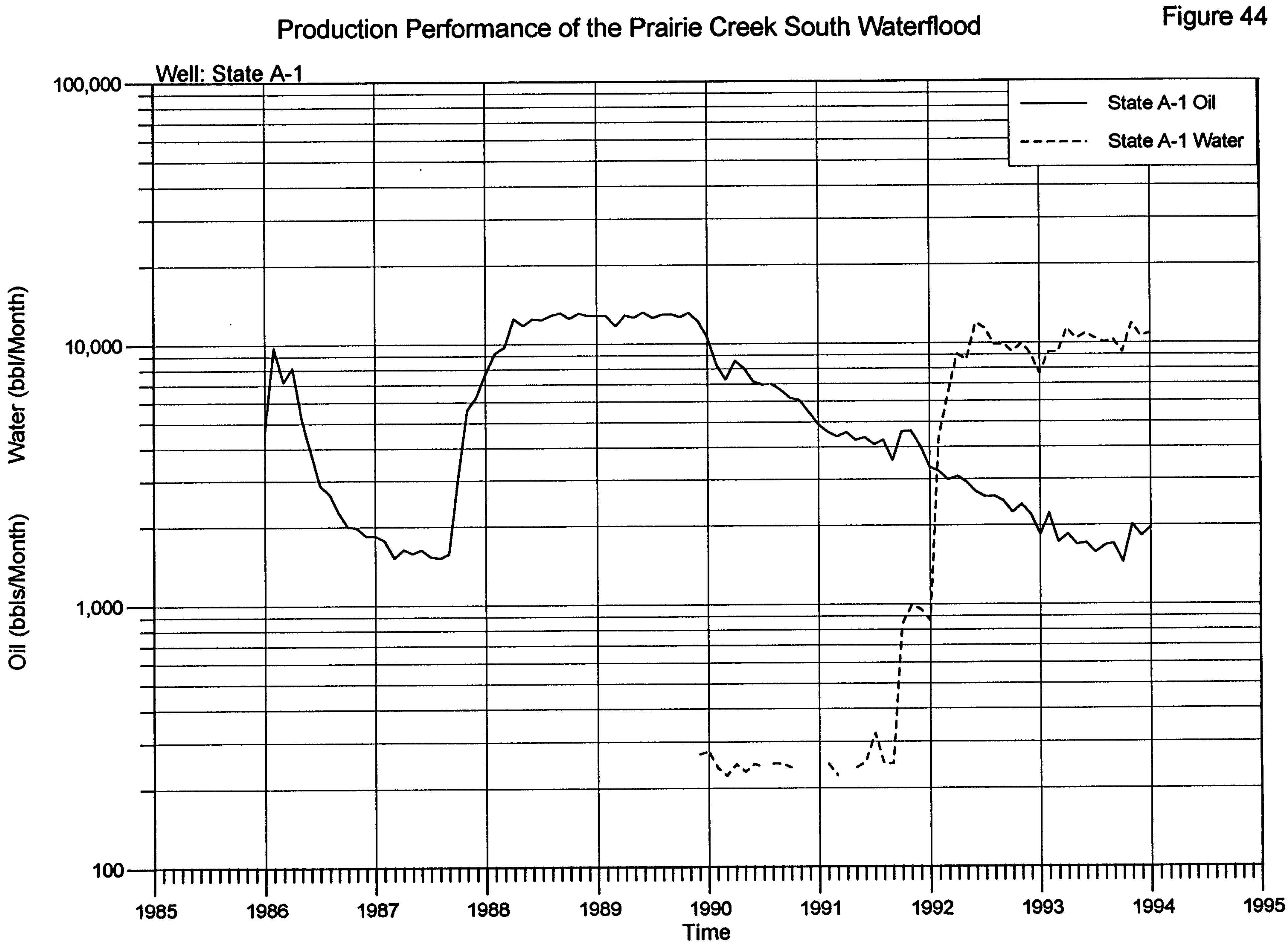

Production Performance of the Prairie Creek South Waterflood
Total Field
Total Field Oil
Total Field Water
Water (bbl/Month)
Oil (bbls/Month)
100,000
10,000
1,000
100
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Time

Figure 44



Production Performance of the Prairie Creek South Waterflood
Well: State A-1
State A-1 Oil
State A-1 Water
Water (bbl/Month)
Oil (bbls/Month)
100,000
10,000
1,000
100
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Time

Figure 45

Production Performance of the Prairie Creek South Waterflood

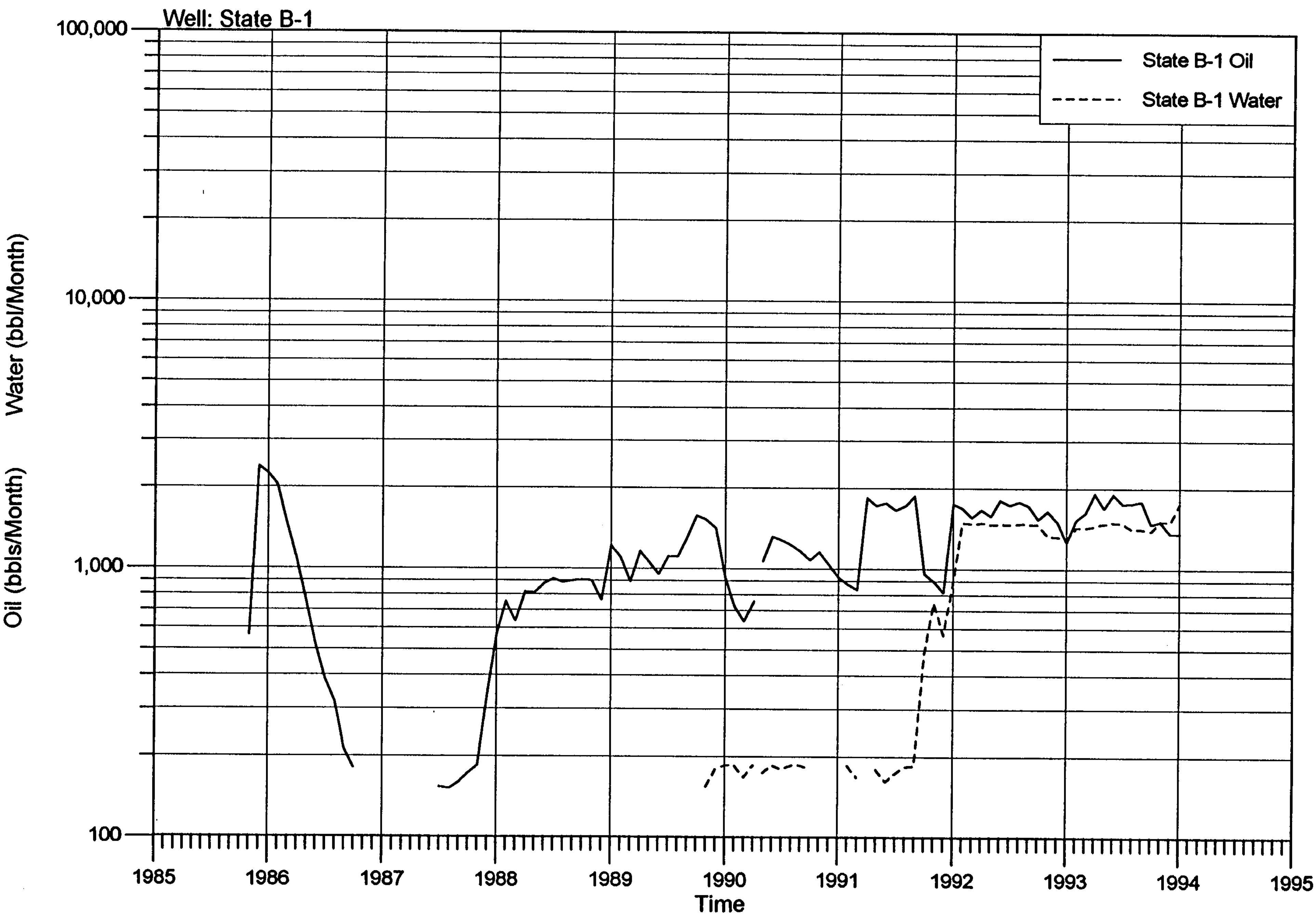
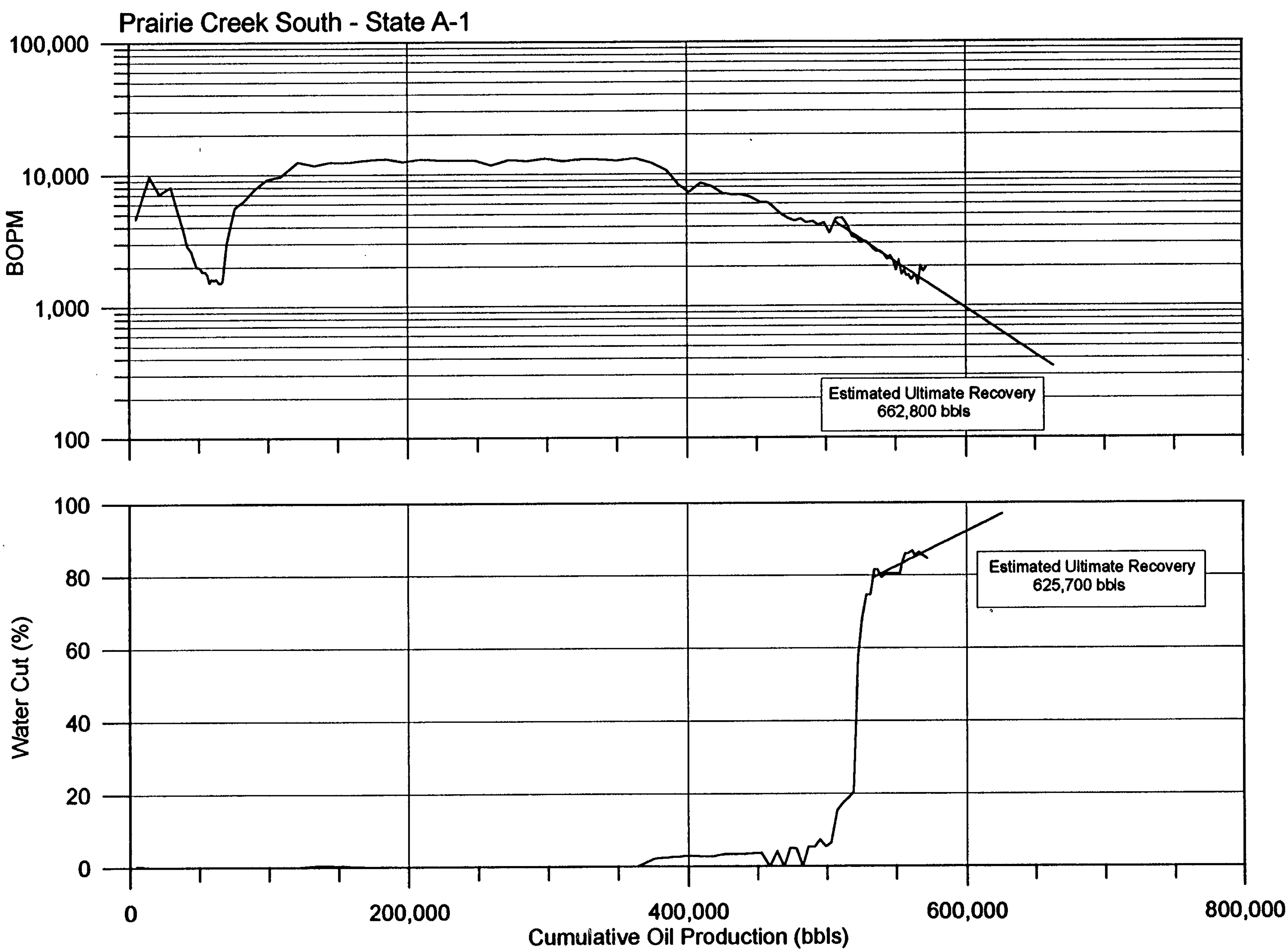
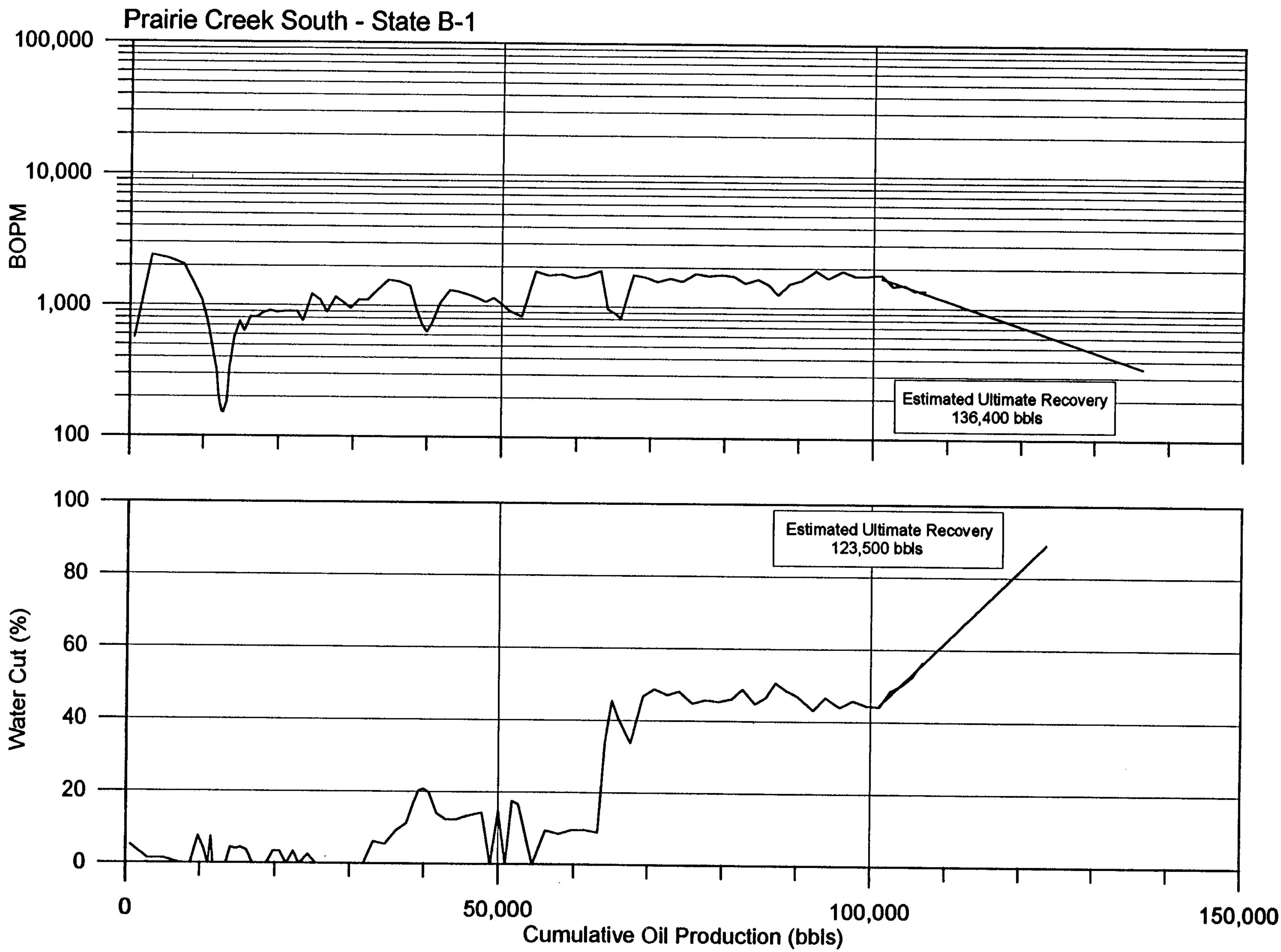


Figure 46



Prairie Creek South - State A-1
100,000
10,000
1,000
100
BOPM
Estimated Ultimate Recovery
662,800 bbls
100
80
60
40
20
0
Water Cut (%)
Estimated Ultimate Recovery
625,700 bbls
0
200,000
400,000
600,000
800,000
Cumulative Oil Production (bbls)

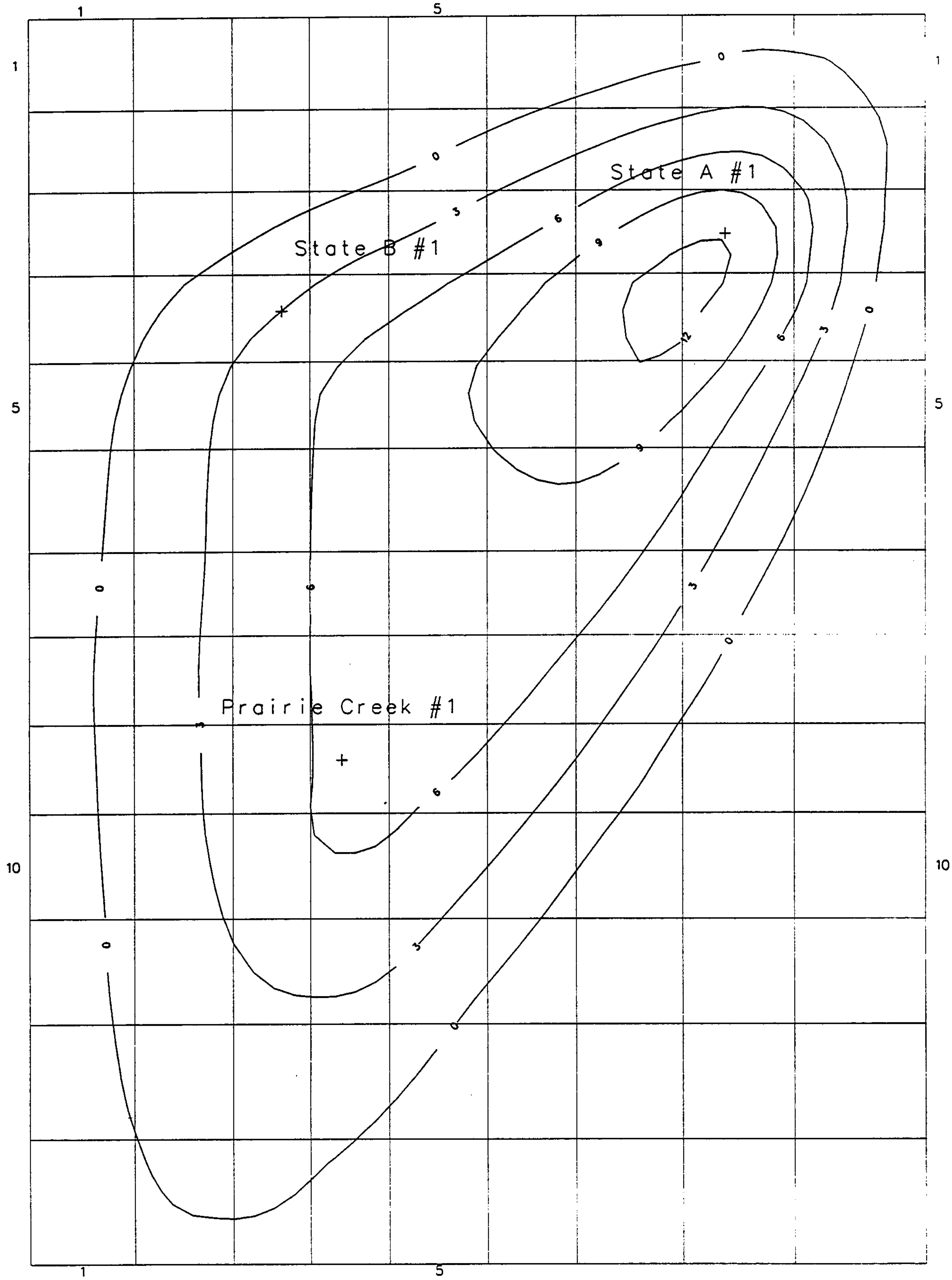
Figure 47


Prairie Creek South - State B-1
100,000
10,000
1,000
100
BOPM
Estimated Ultimate Recovery
136,400 bbls
100
80
60
40
20
0
Water Cut (%)
Estimated Ultimate Recovery
123,500 bbls
0
50,000
100,000
150,000
Cumulative Oil Production (bbls)

Go Back
To Original
For 11" X17
Fold-Out
B. J. Adams
Office

Prairie Creek South
Net Thickness: Layer 1

Figure 49



Prairie Creek South Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

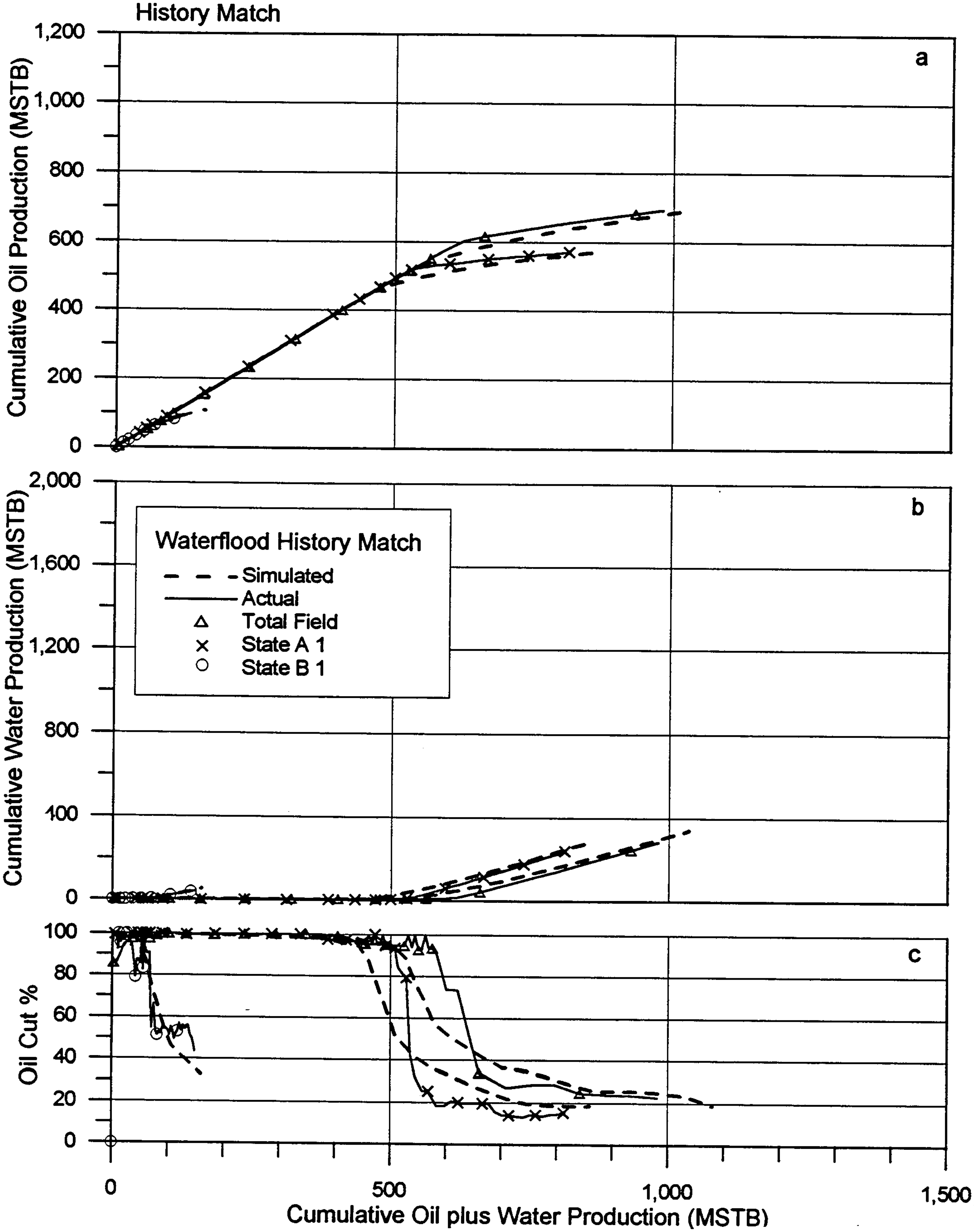


Figure 51

Prairie Creek South Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

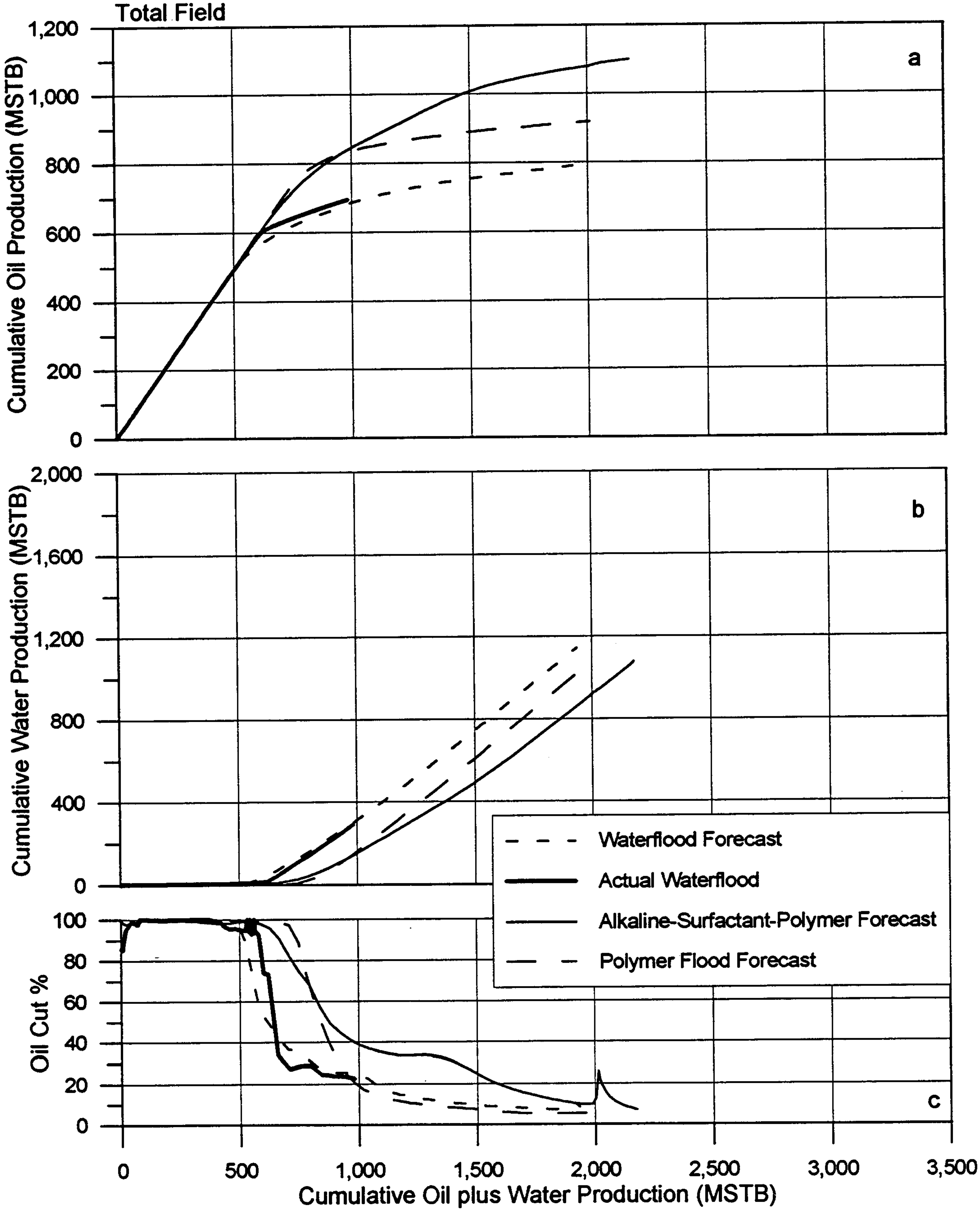


Figure 52

Prairie Creek South Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

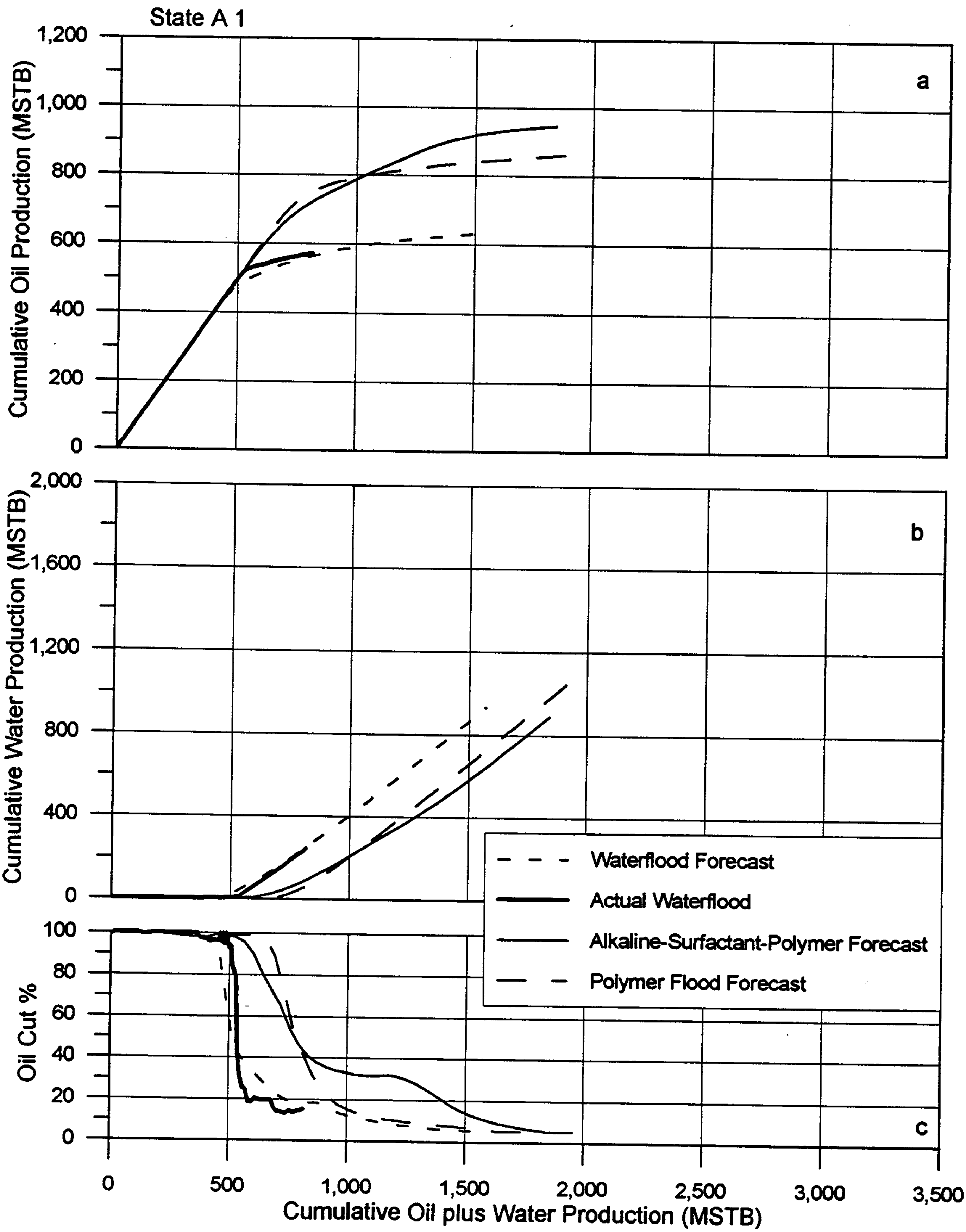


Figure 53

Prairie Creek South Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

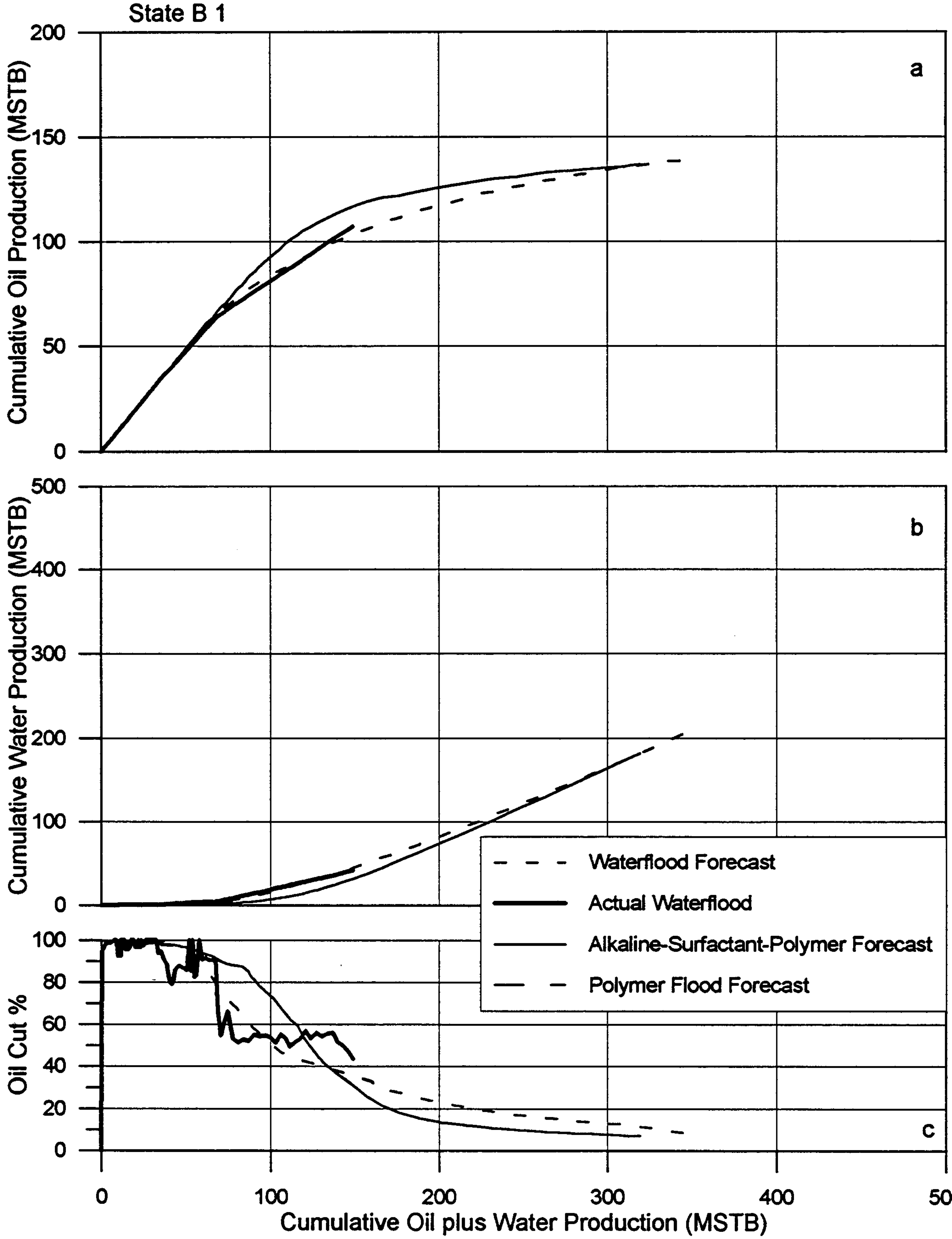


Figure 54

Simpson Ranch Isopach with Well Locations

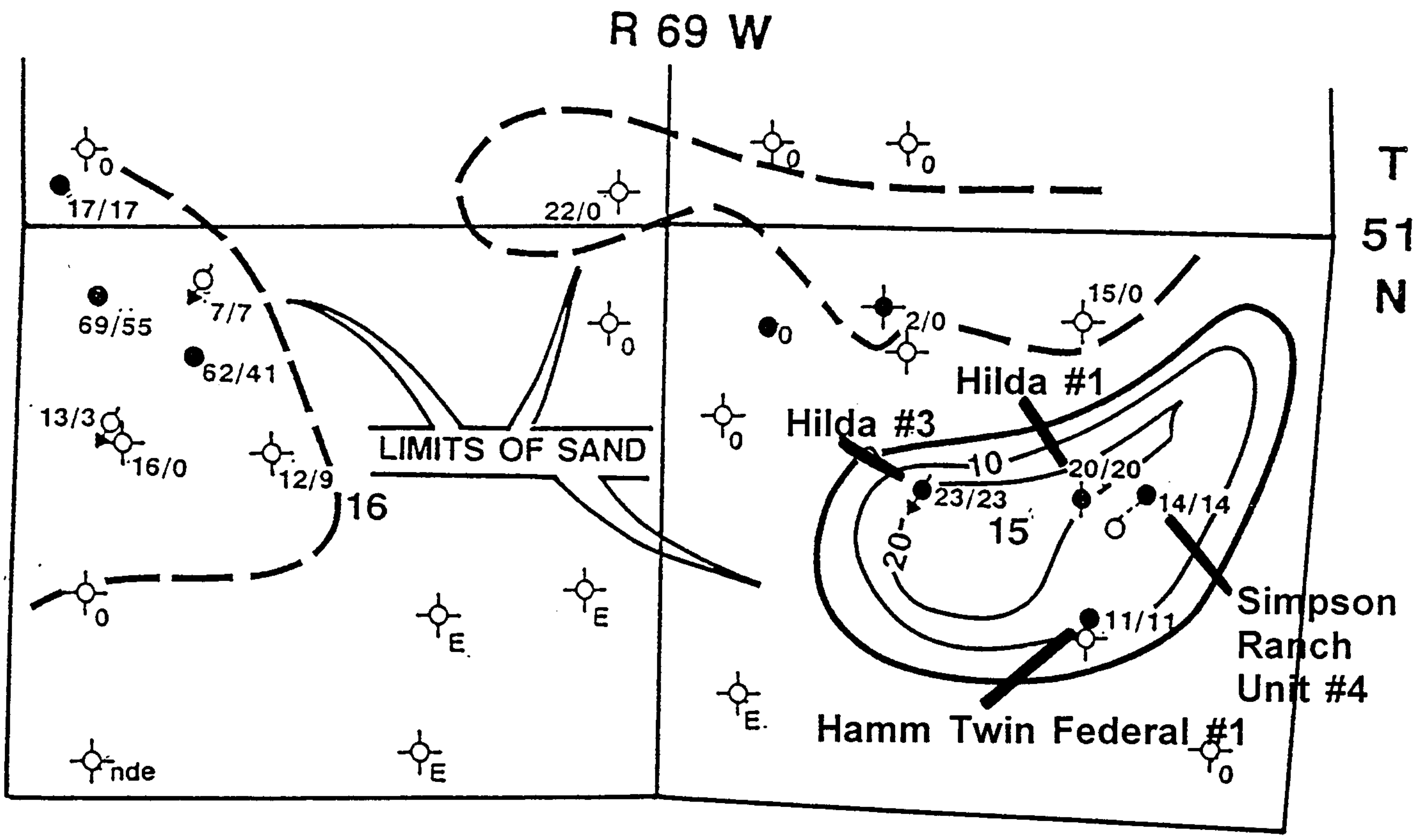
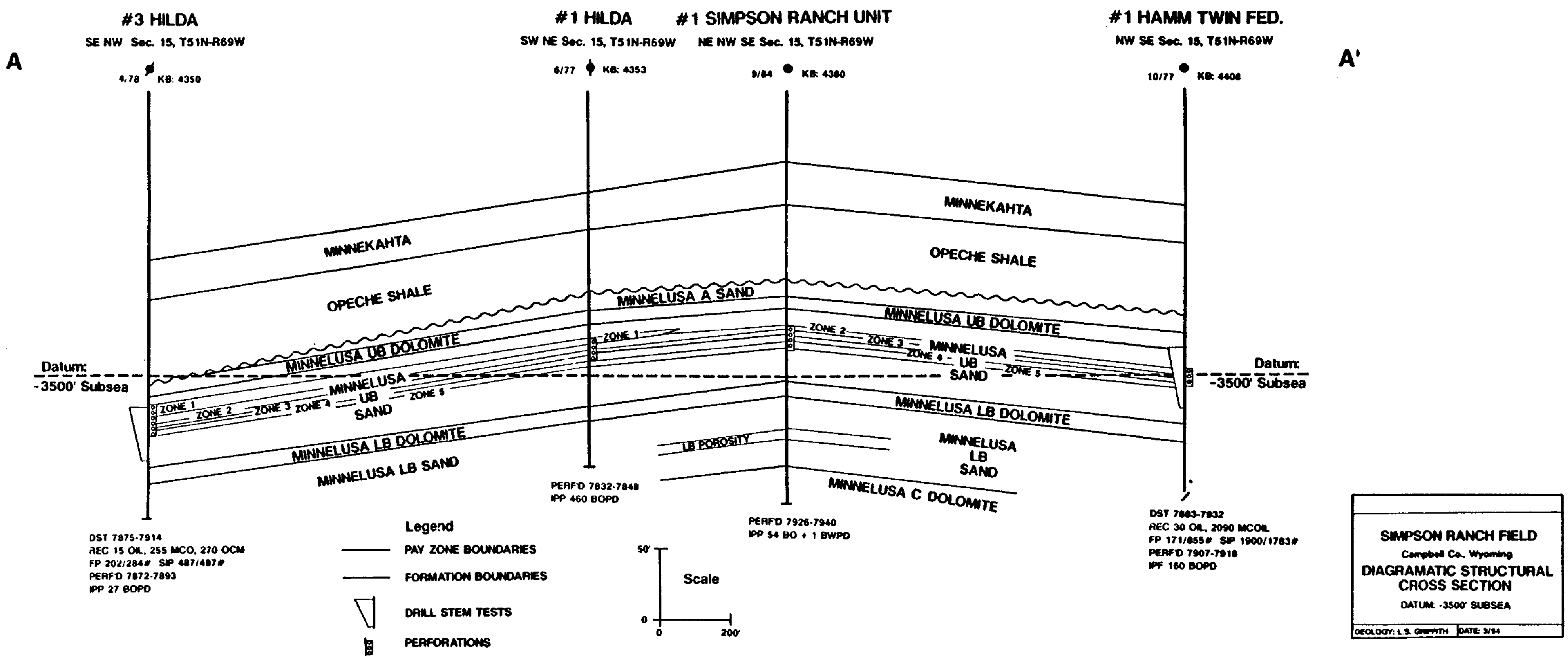


Figure 55


A
A'
#3 HILDA
SE NW Sec. 15, T51N-R69W
4/78 KB: 4350
#1 HILDA
SW NE Sec. 15, T51N-R69W
6/77 KB: 4353
#1 SIMPSON RANCH UNIT
NE NW SE Sec. 15, T51N-R69W
9/84 KB: 4380
#1 HAMM TWIN FED.
NW SE Sec. 15, T51N-R69W
10/77 KB: 4406
MINNEKAHTA
OPECHE SHALE
MINNELUSA A SAND
MINNELUSA UB DOLOMITE
MINNELUSA UB SAND
ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
MINNELUSA LB DOLOMITE
MINNELUSA LB SAND
LB POROSITY
MINNELUSA C DOLOMITE
Datum: -3500' Subsea
DST 7875-7914
REC 15 OIL, 255 MCO, 270 OCM
FP 202/284# SIP 487/487#
PERF'D 7872-7893
IPP 27 BOPD
PERF'D 7832-7848
IPP 460 BOPD
PERF'D 7926-7940
IPP 54 BO + 1 BWPD
DST 7883-7932
REC 30 OIL, 2090 MCOIL
FP 171/855# SIP 1900/1783#
PERF'D 7907-7918
IPF 160 BOPD
Legend
PAY ZONE BOUNDARIES
FORMATION BOUNDARIES
DRILL STEM TESTS
PERFORATIONS
Scale
50'
0
0
200'
SIMPSON RANCH FIELD
Campbell Co., Wyoming
DIAGRAMATIC STRUCTURAL CROSS SECTION
DATUM: -3500' SUBSEA
GEOLOGY: L.S. GRIFFITH
DATE: 3/94

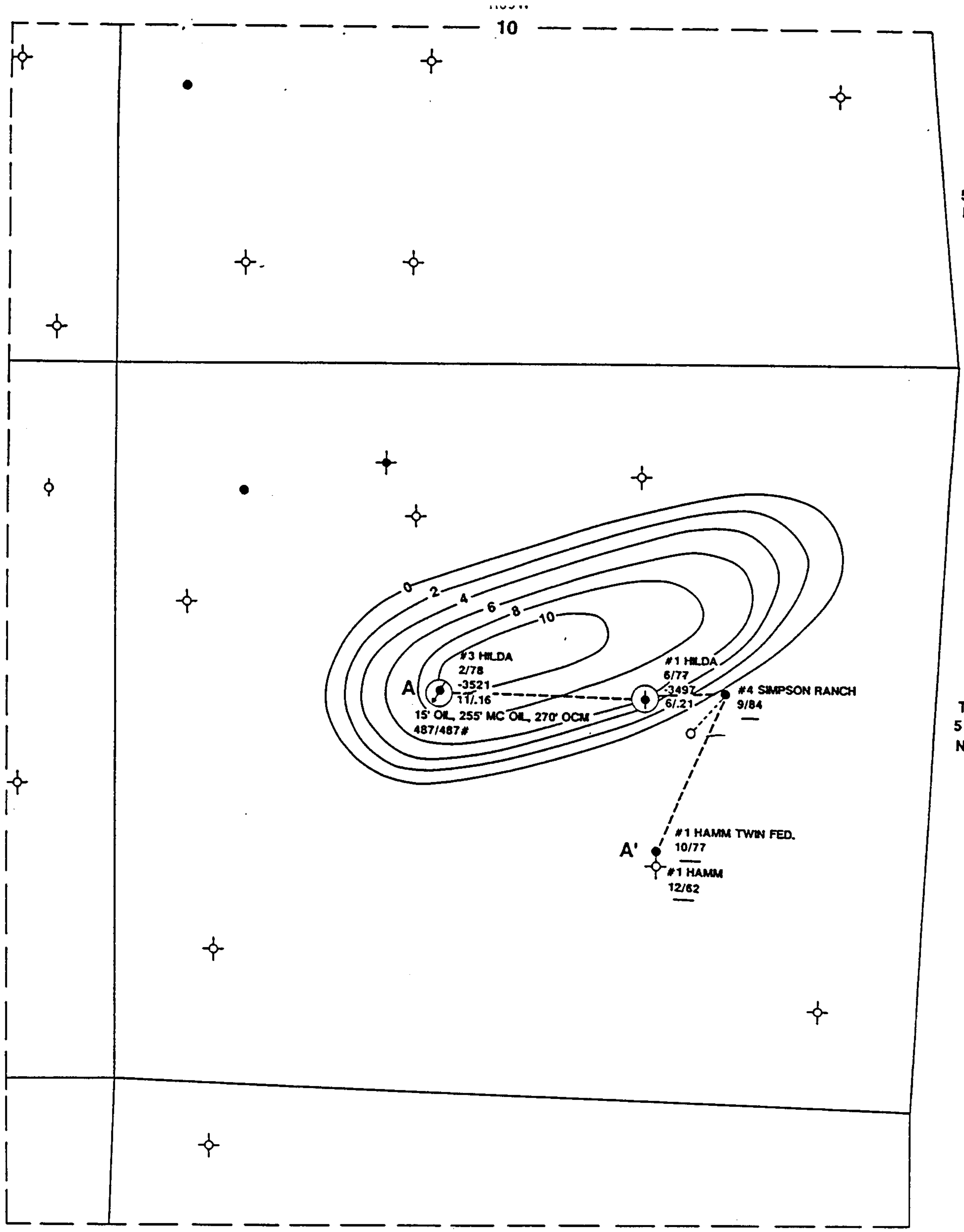


Figure 56

LEGEND

- ● PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
● COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

— NO SAND DEVELOPMENT

○ COMPLETED IN ZONE

---- LINE OF CROSS SECTION

SIMPSON RANCH AREA
Campbell County, Wyoming

ISOPACH MAP-NET OIL PAY
MINNELUSA UPPER 'B' SAND
ZONE 1

INTERVAL=2 FEET

GEOLOGY: L.S. GRIFFITH

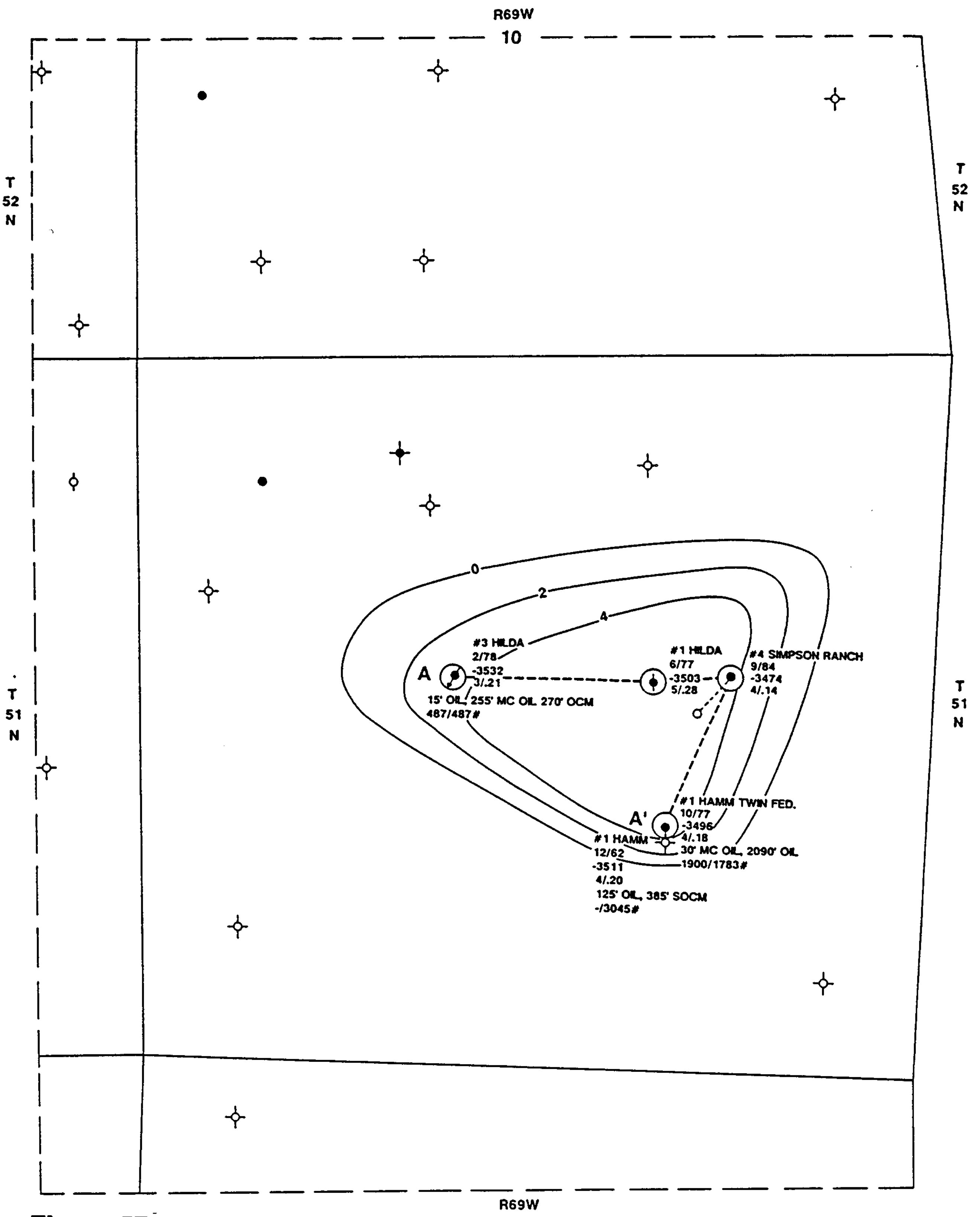


Figure 57

LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

- NO SAND DEVELOPMENT
- COMPLETED IN ZONE
- LINE OF CROSS SECTION

SIMPSON RANCH AREA
Campbell County, Wyoming

ISOPACH MAP-NET OIL PAY
MINNELUSA UPPER 'B' SAND
ZONE 2

INTERVAL=2 FEET

GEOLOGY: L.S. GRIFFITH
3/94

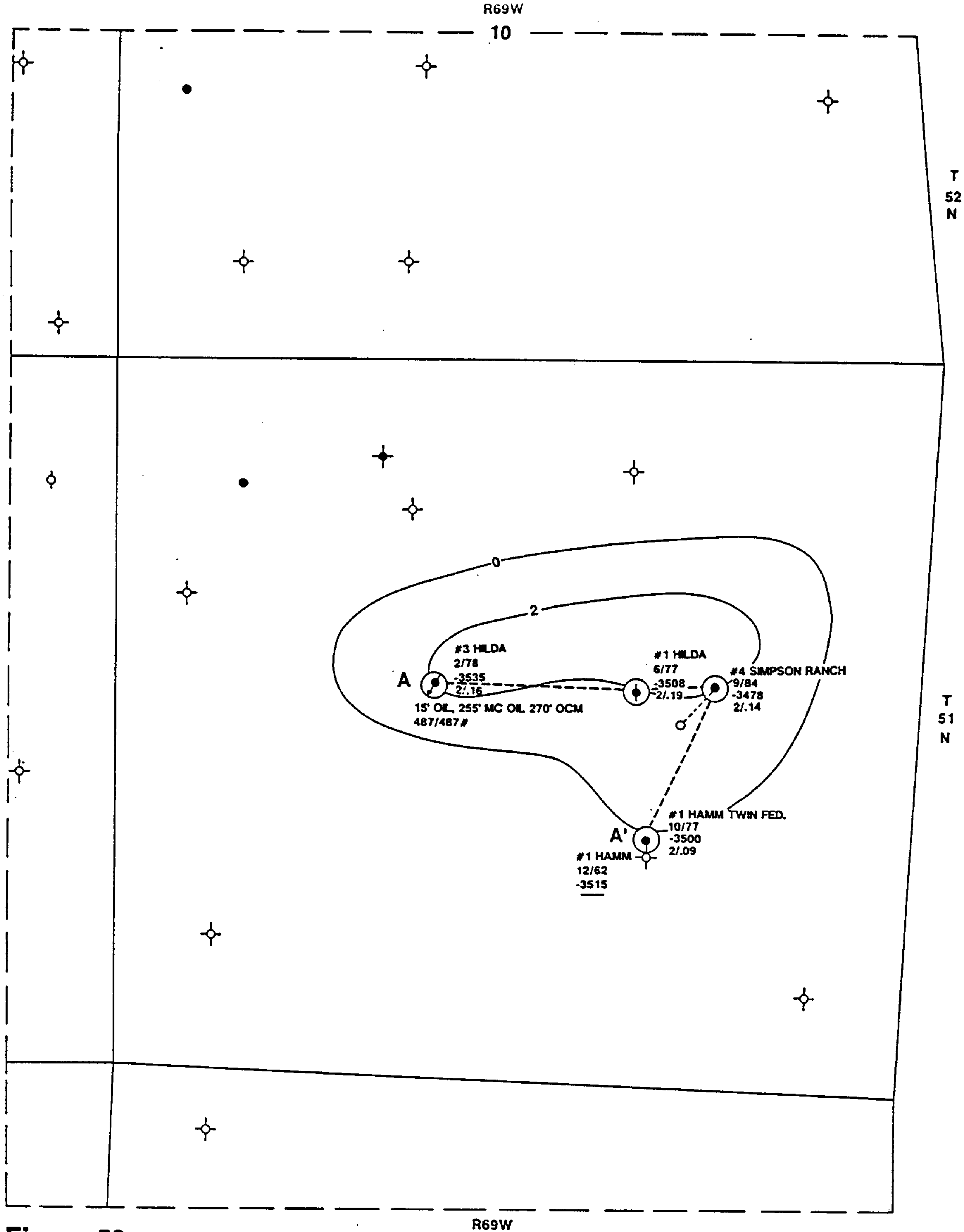


Figure 58

LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

- NO SAND DEVELOPMENT
- COMPLETED IN ZONE
- LINE OF CROSS SECTION

SIMPSON RANCH AREA
Campbell County, Wyoming

ISOPACH MAP-NET OIL PAY
MINNELUSA UPPER 'B' SAND
ZONE 3
INTERVAL=2 FEET

GEOLOGY: L.S. GRIFFITH
3/94

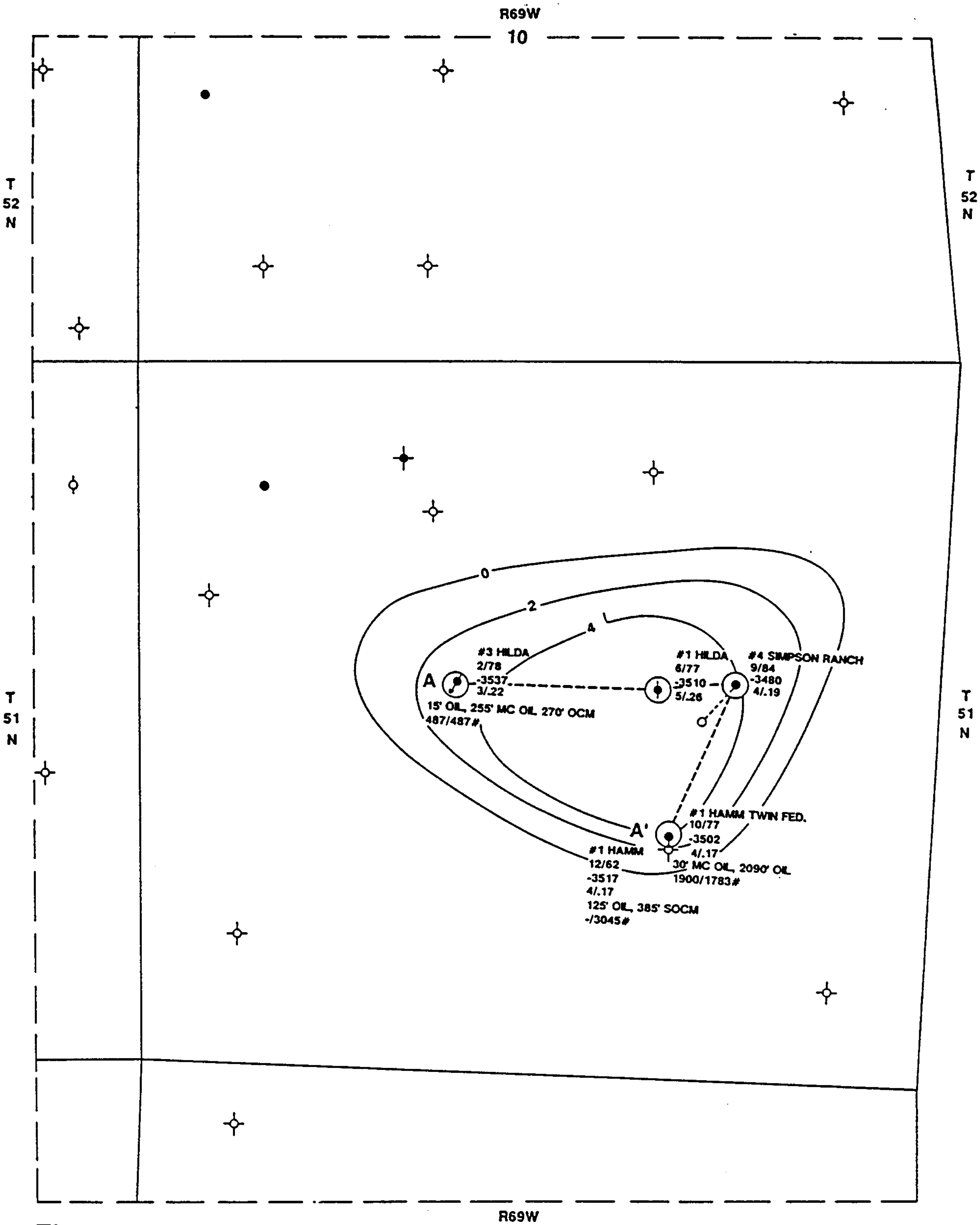


Figure 59

LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
- OIL WELL CONVERTED TO INJECTOR
- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

- NO SAND DEVELOPMENT
- COMPLETED IN ZONE
- LINE OF CROSS SECTION

SIMPSON RANCH AREA
Campbell County, Wyoming

ISOPACH MAP-NET OIL PAY
MINNELUSA UPPER 'B' SAND
ZONE 4

INTERVAL=2 FEET

GEOLOGY: L.S. GRIFFITH
3/94

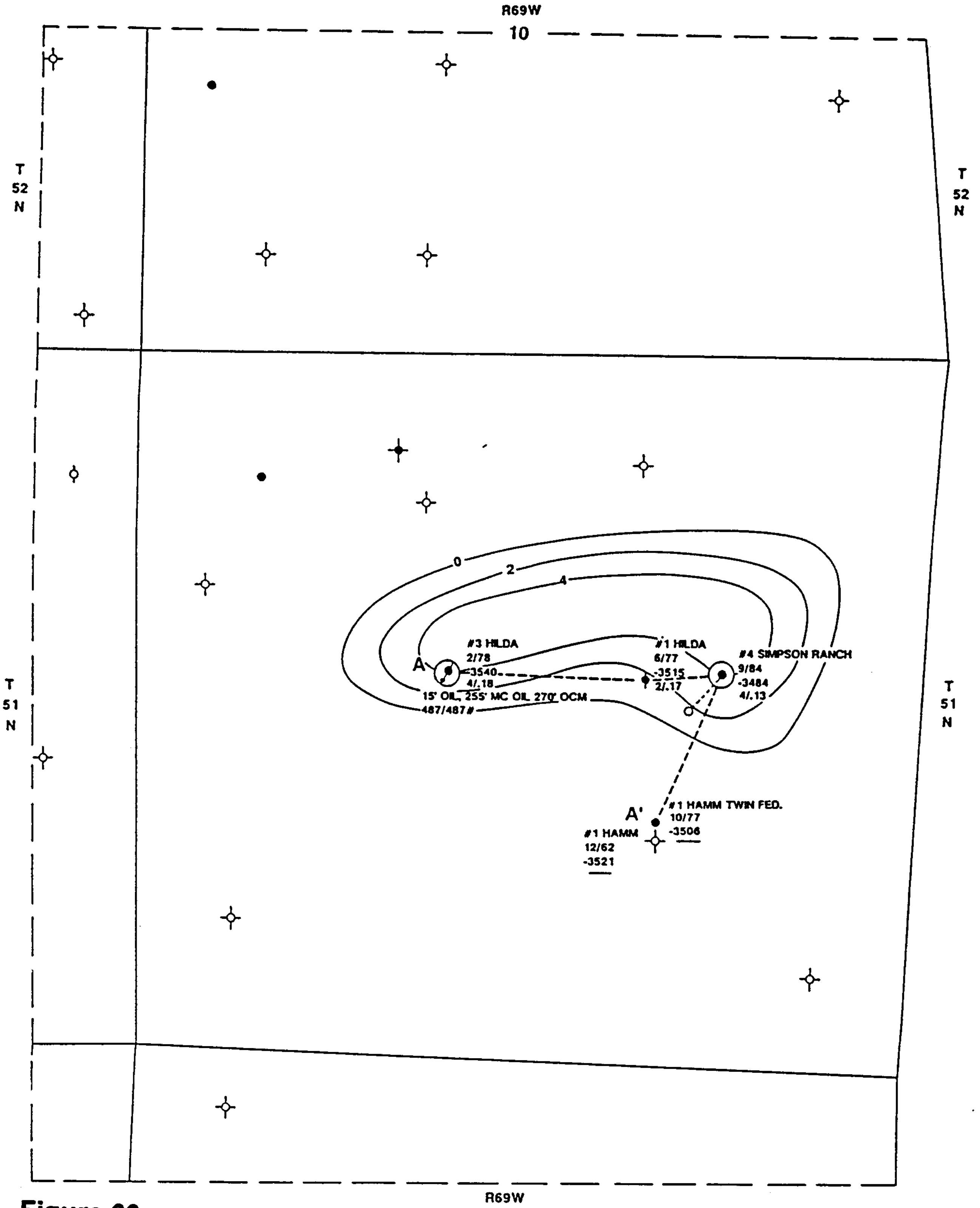


Figure 60

LEGEND

- PROD. OIL WELL
- SHUT IN OIL WELL
- ABND. OIL WELL
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- WATER INJECTOR
- DRY HOLE
- LOCATION
- DEVIATED OIL WELL

WELL NAME
COMPLETION DATE (mo/yr)
TOP POROSITY-SUBSEA
NET OIL PAY/POROSITY
DST RECOVERY
SHUT IN PRESSURE

— NO SAND DEVELOPMENT

COMPLETED IN ZONE

---- LINE OF CROSS SECTION

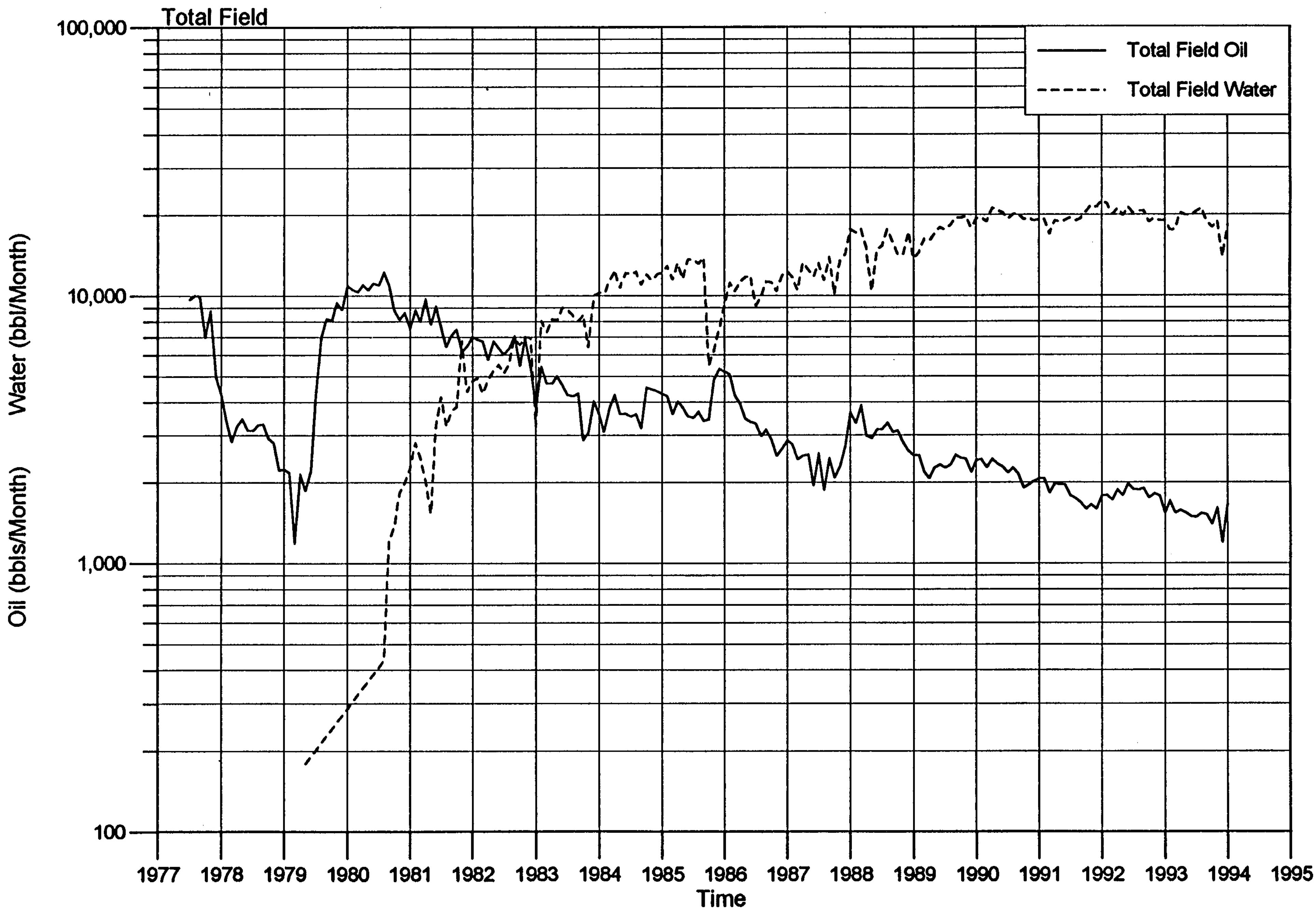
SIMPSON RANCH AREA
Campbell County, Wyoming

ISOPACH MAP-NET OIL PAY
MINNELUSA UPPER 'B' SAND
ZONE 5
INTERVAL=2 FEET

GEOLOGY: L.S. GRIFFITH
3/94

Figure 61

Production Performance of the Simpson Ranch Cat-An Polymer Flood



Production Performance of the Simpson Ranch Cat-An Polymer Flood

Figure 62

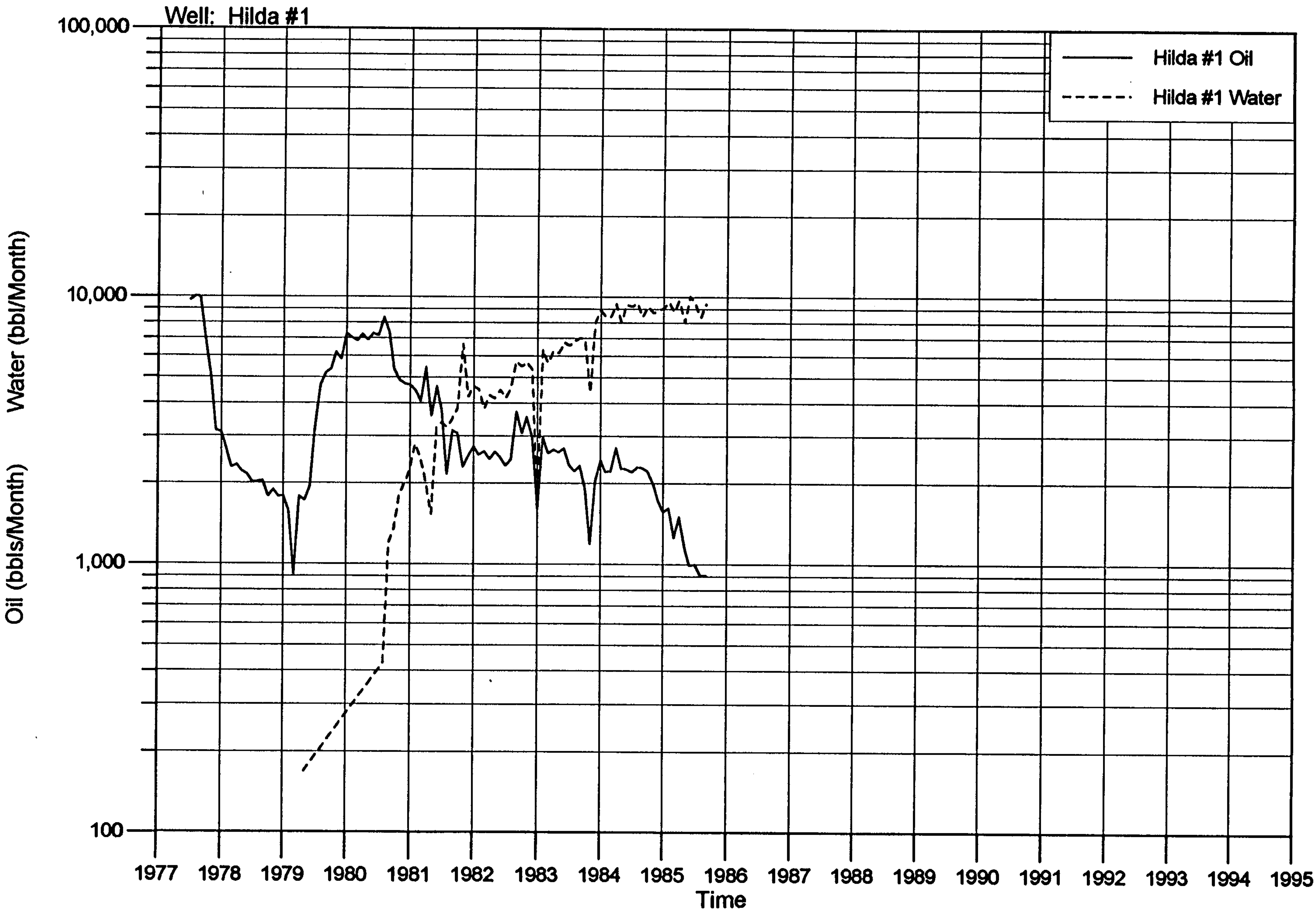
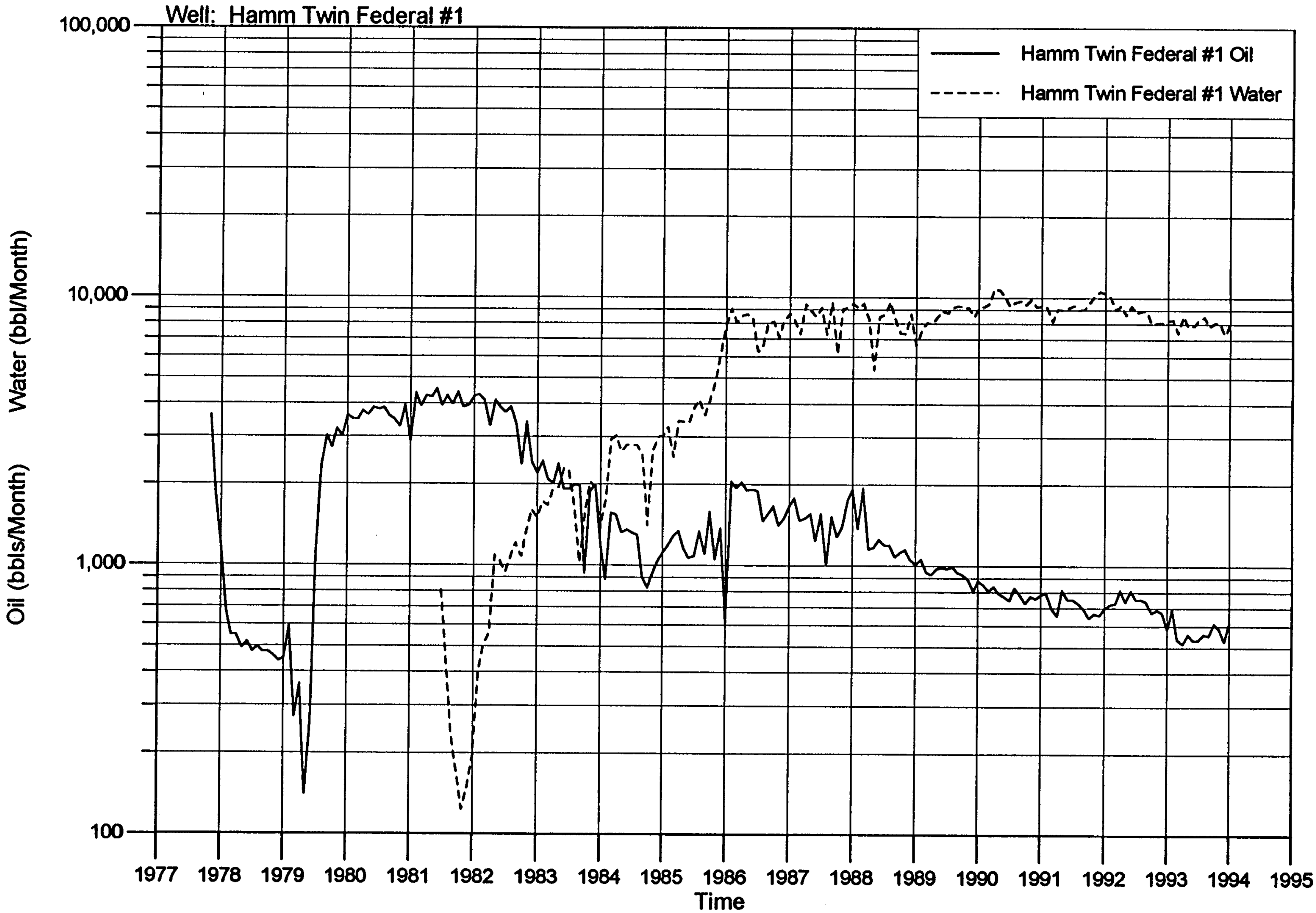


Figure 63

Production Performance of the Simpson Ranch Cat-An Polymer Flood



Production Performance of the Simpson Ranch Cat-An Polymer Flood

Figure 64

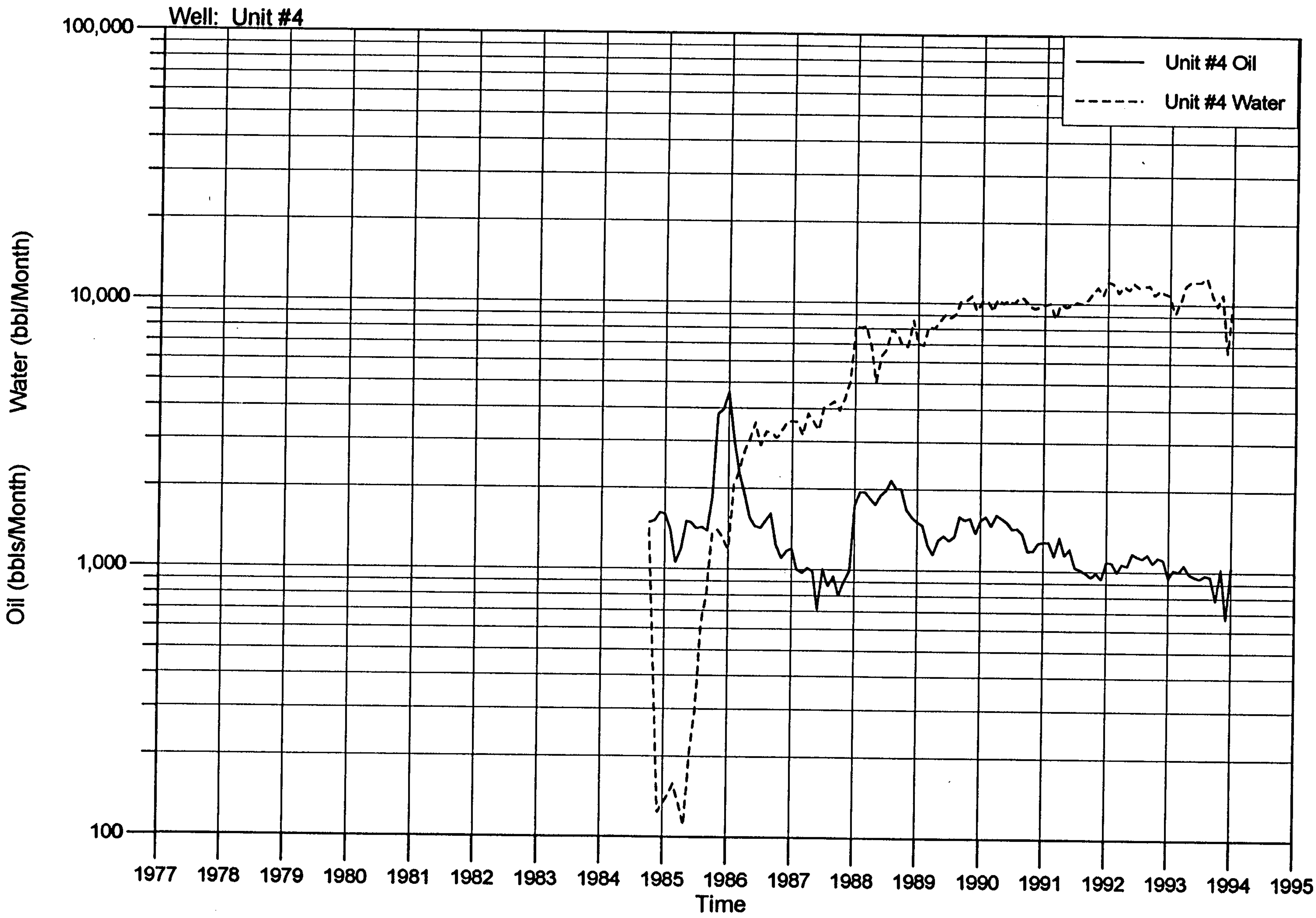


Figure 65

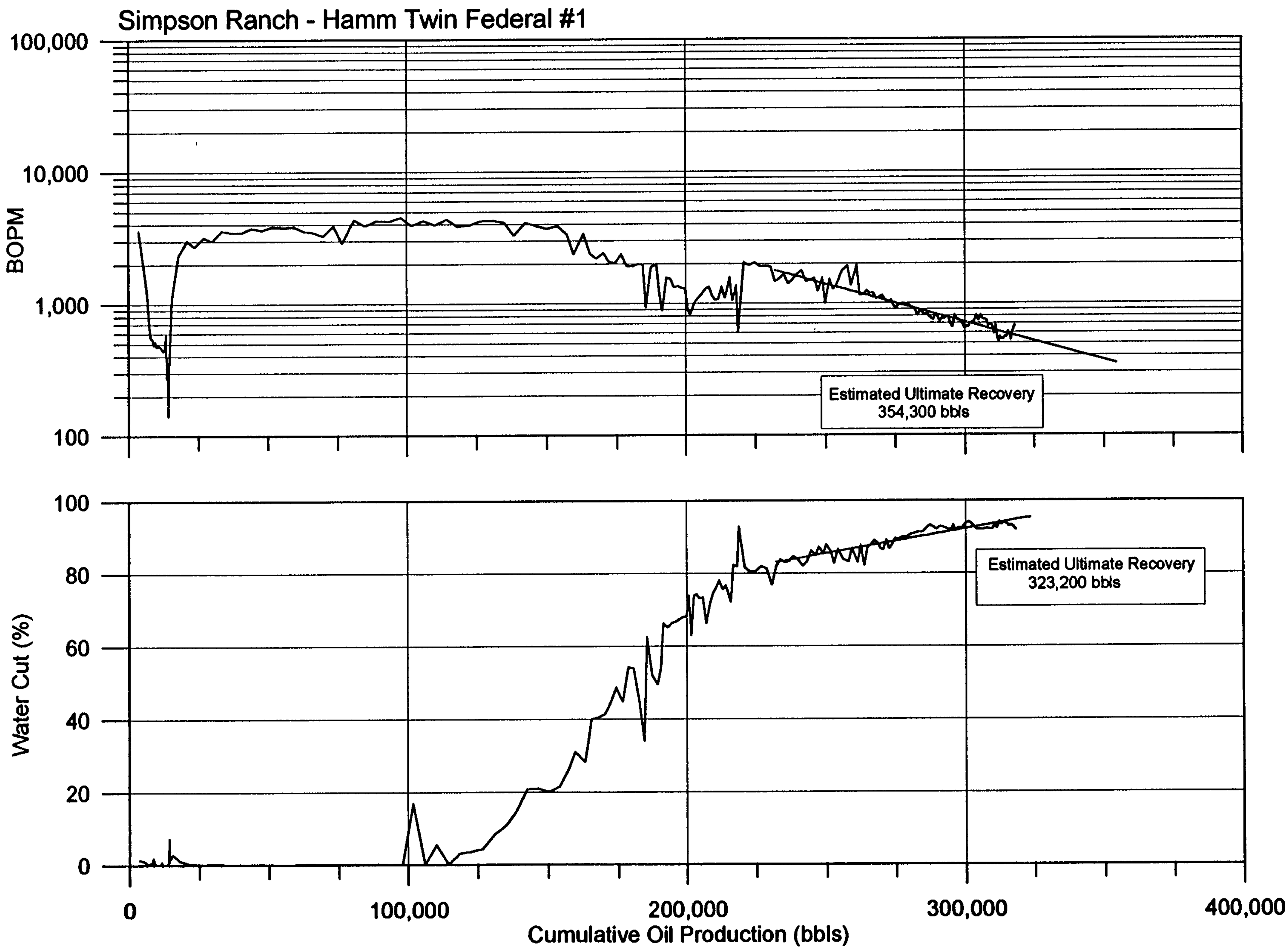
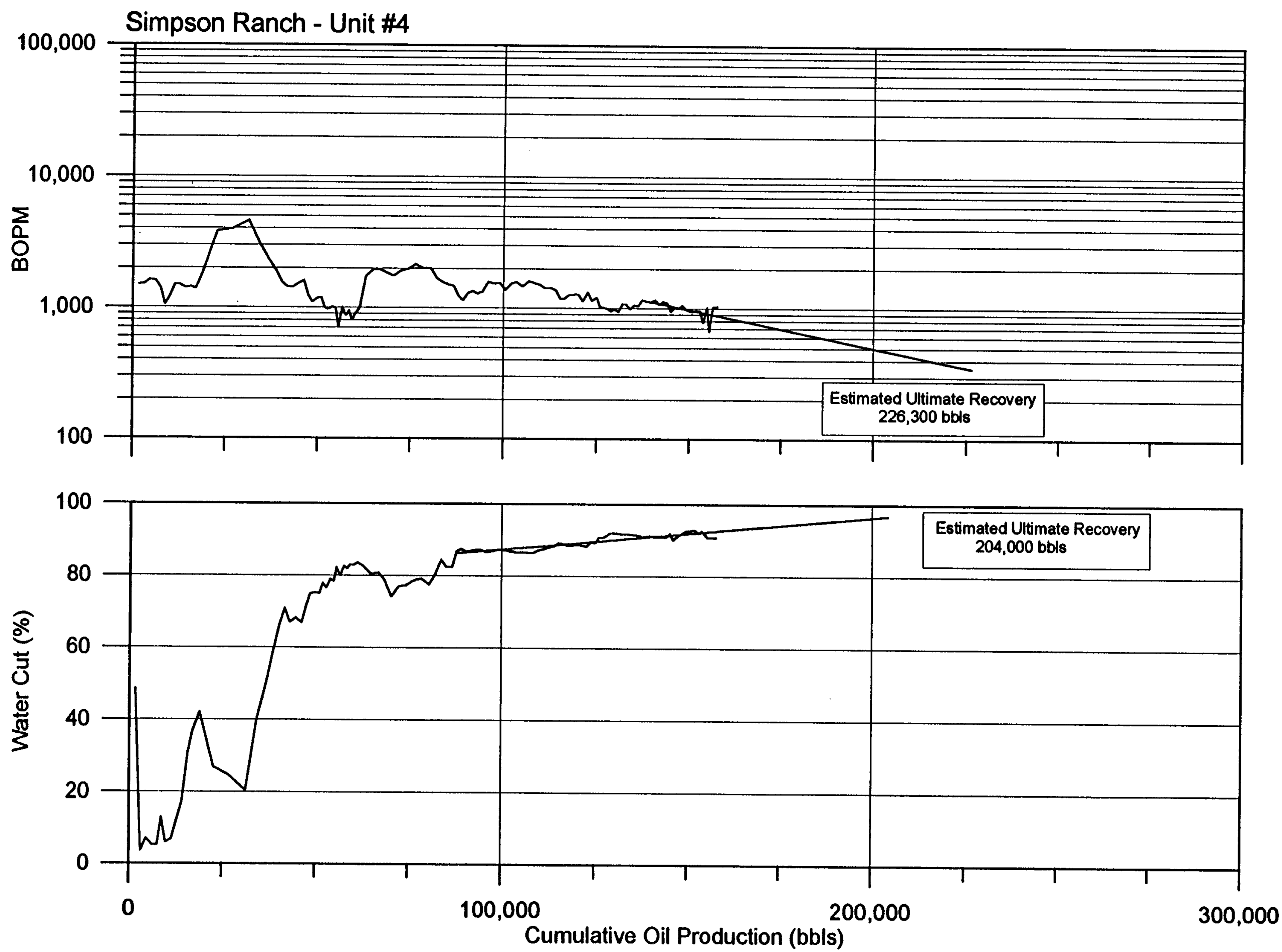

Simpson Ranch - Hamm Twin Federal #1
100,000
10,000
1,000
100
BOPM
Estimated Ultimate Recovery
354,300 bbls
100
80
60
40
20
0
Water Cut (%)
Estimated Ultimate Recovery
323,200 bbls
0
100,000
200,000
300,000
400,000
Cumulative Oil Production (bbls)

Figure 66



Simpson Ranch - Unit #4
100,000
10,000
1,000
100
BOPM
Estimated Ultimate Recovery
226,300 bbls
100
80
60
40
20
0
Water Cut (%)
Estimated Ultimate Recovery
204,000 bbls
0
100,000
200,000
300,000
Cumulative Oil Production (bbls)

GO BACK
TO ORIGINAL
FOR 11" X 17
FOLD-OUT
B. J. ADAMS
office

Simpson Ranch
Net Thickness: Layer 2

Figure 68

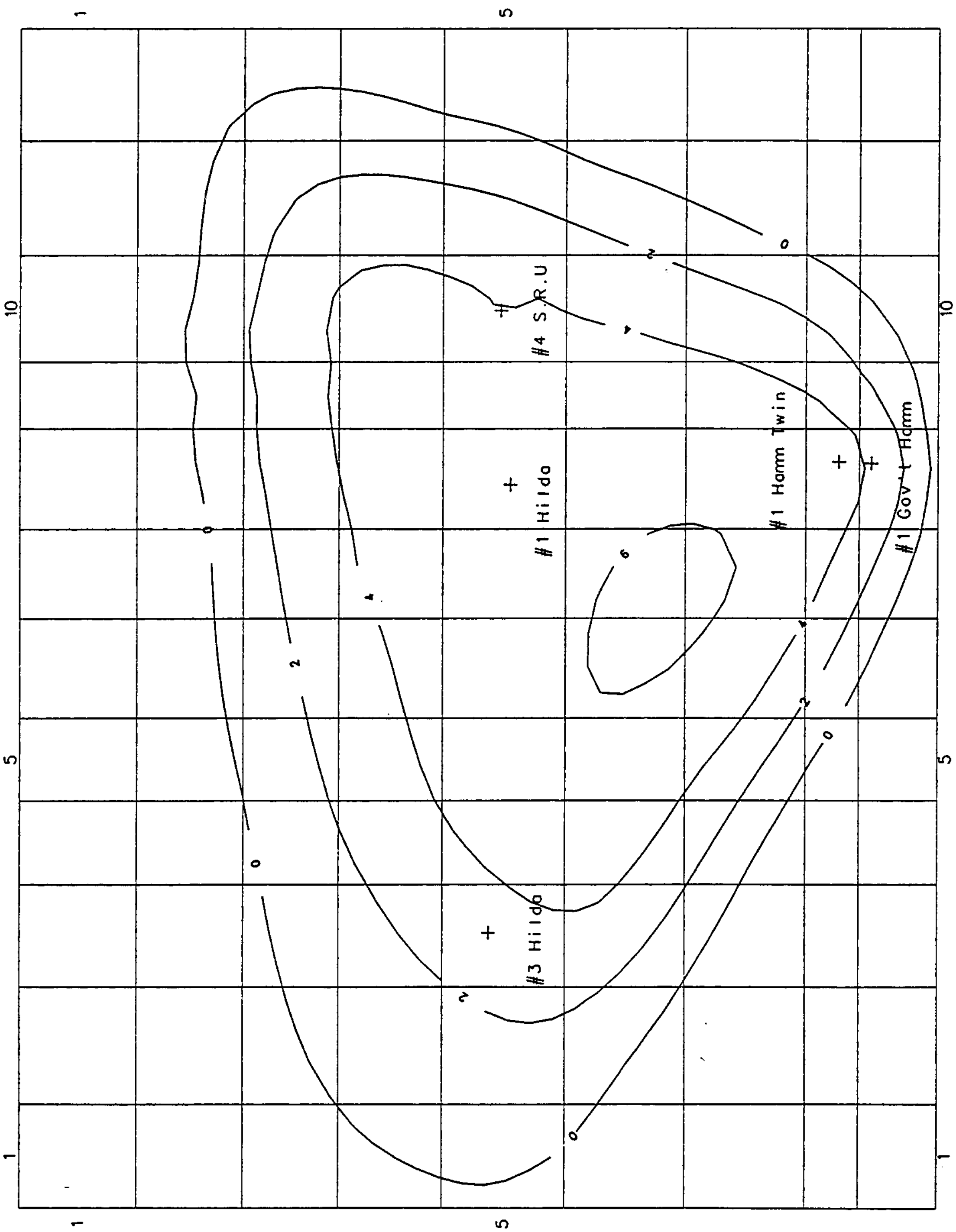


Figure 69

Simpson Ranch Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

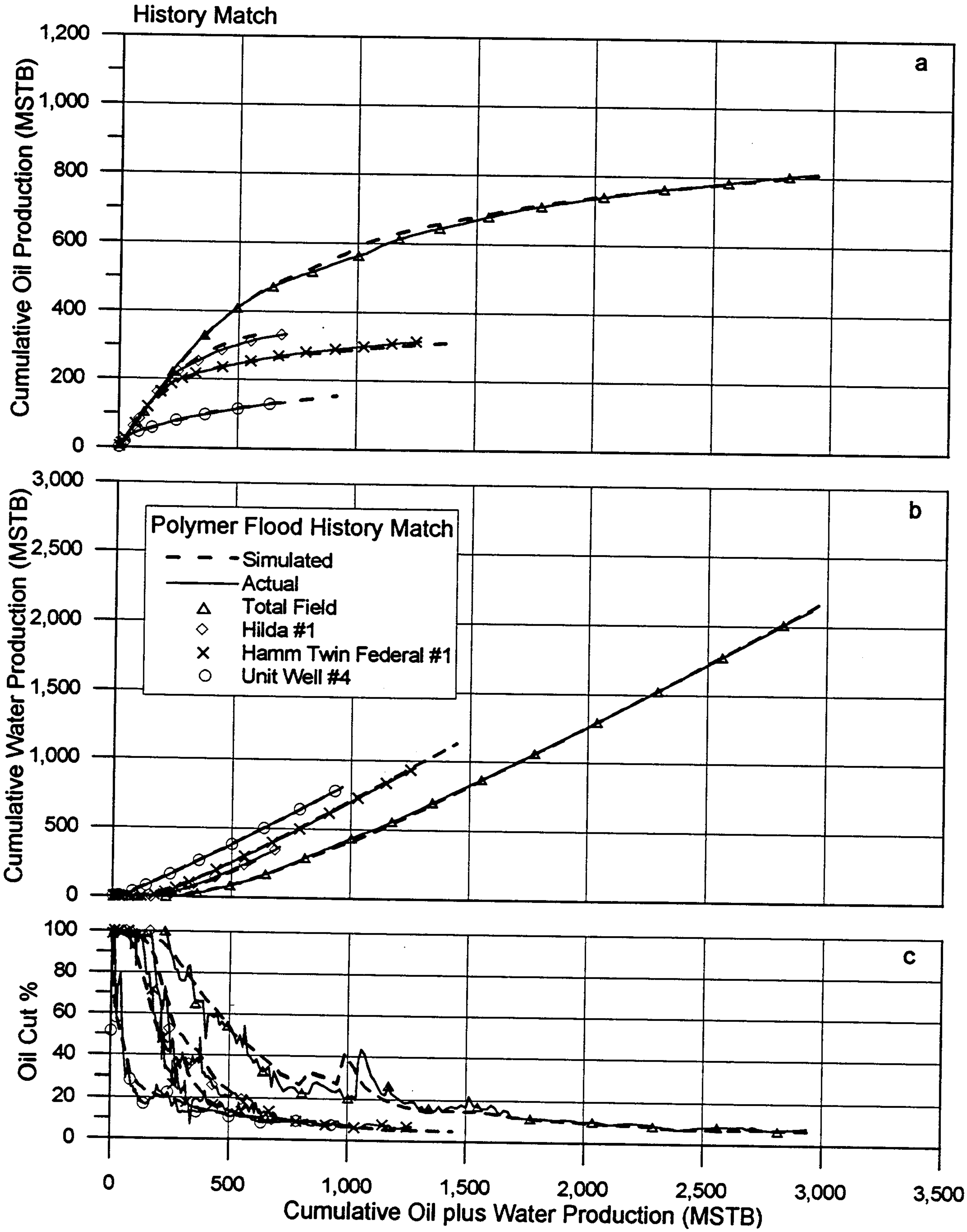


Figure 70

Simpson Ranch Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

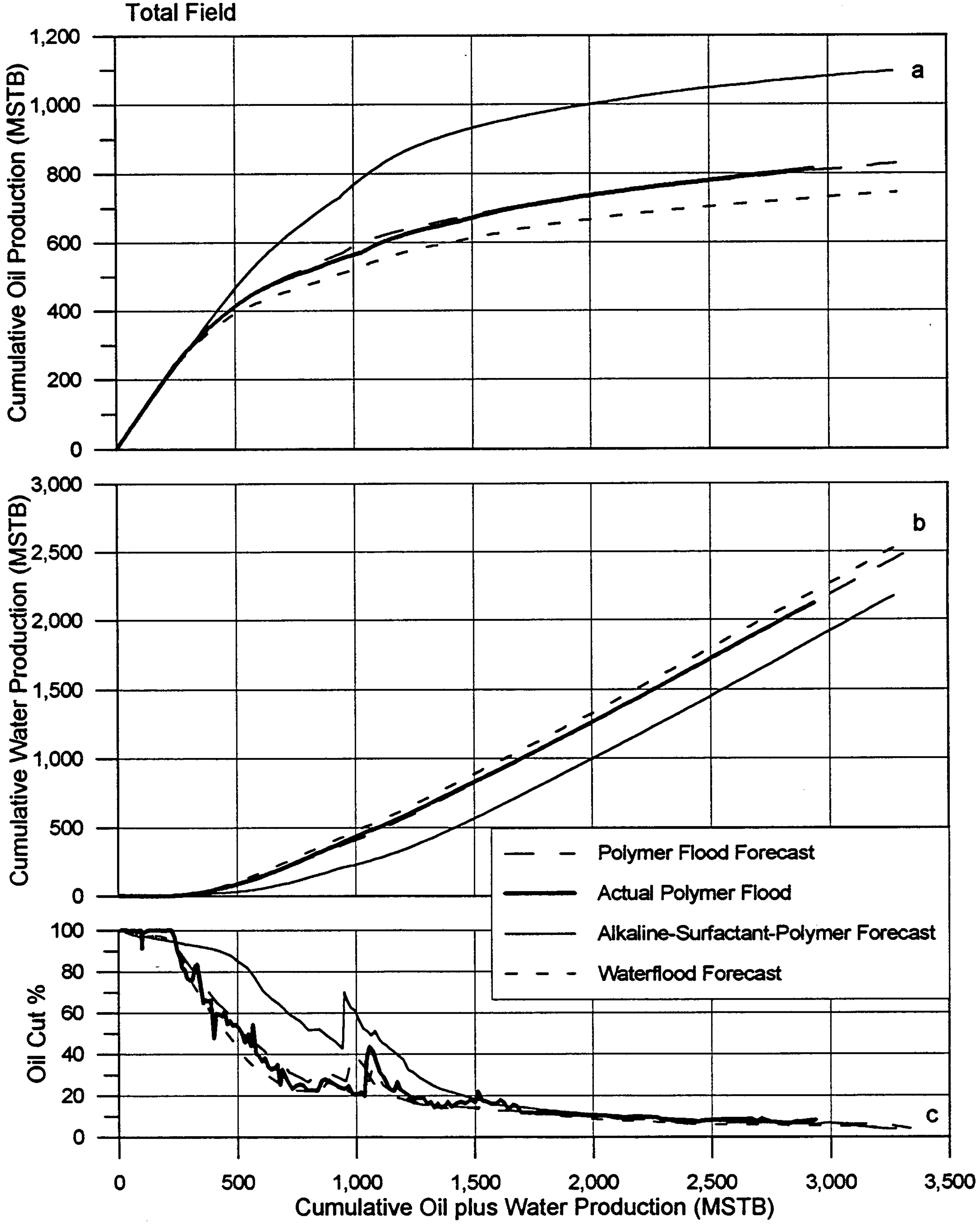


Figure 71

Simpson Ranch Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

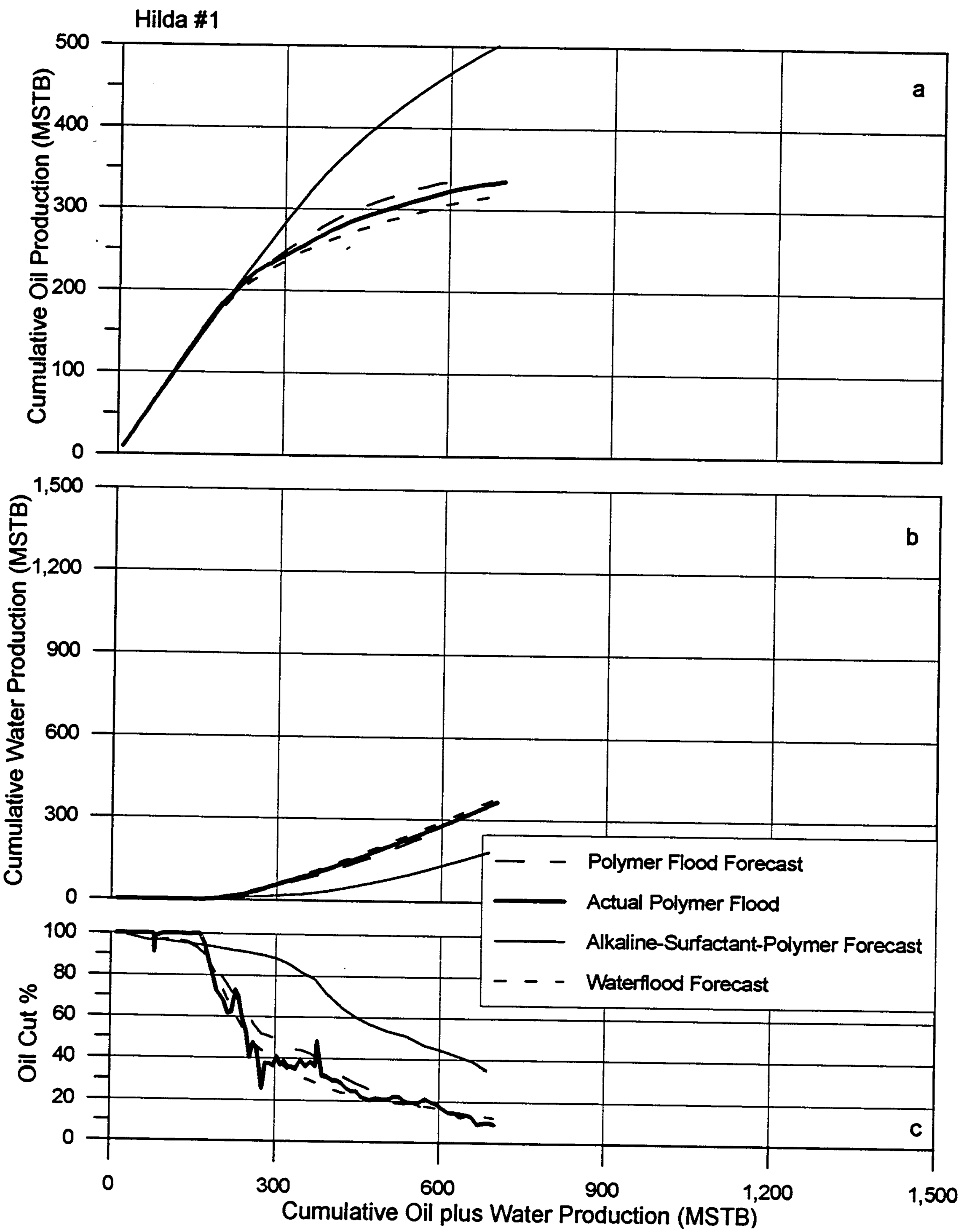


Figure 72

Simpson Ranch Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water

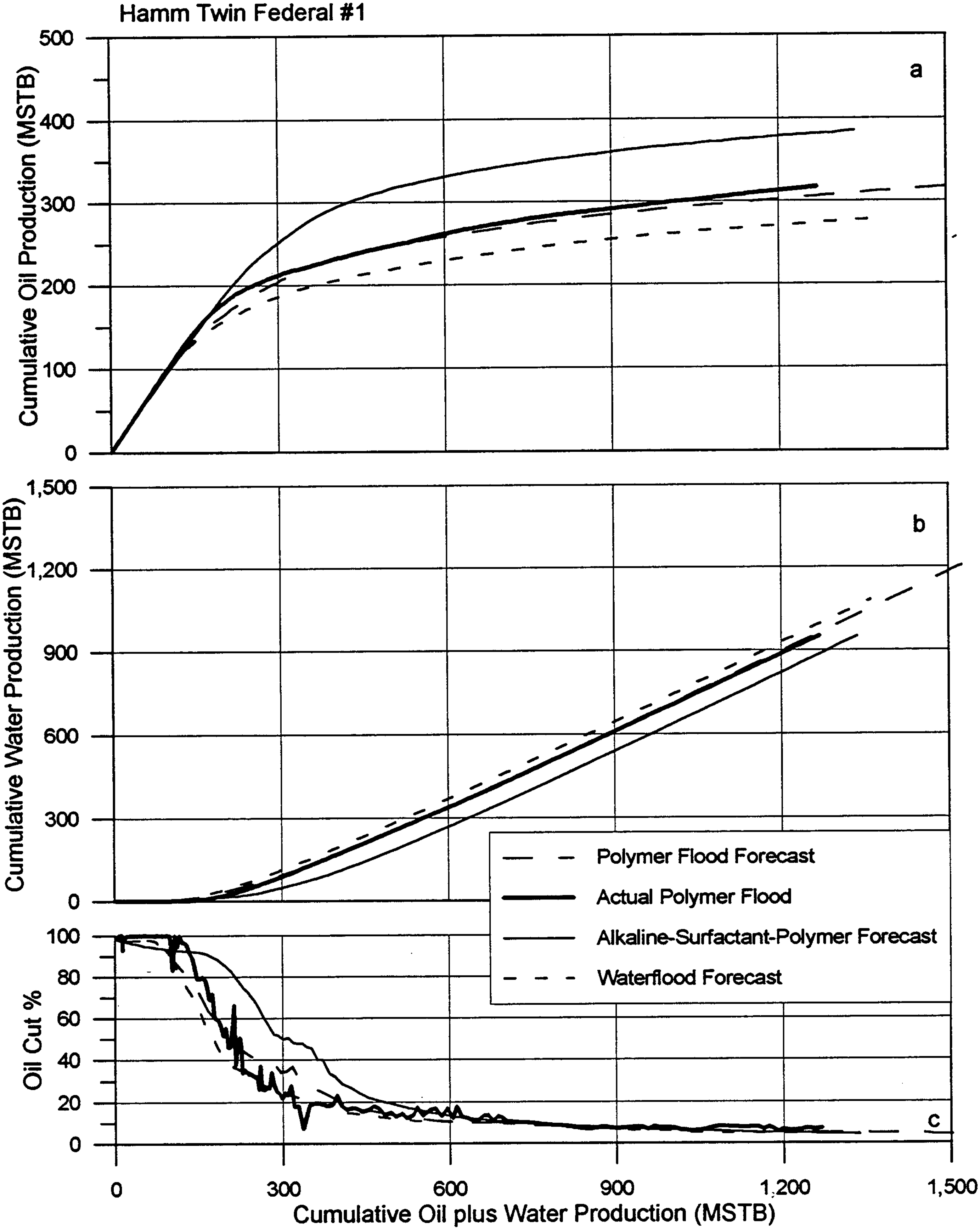
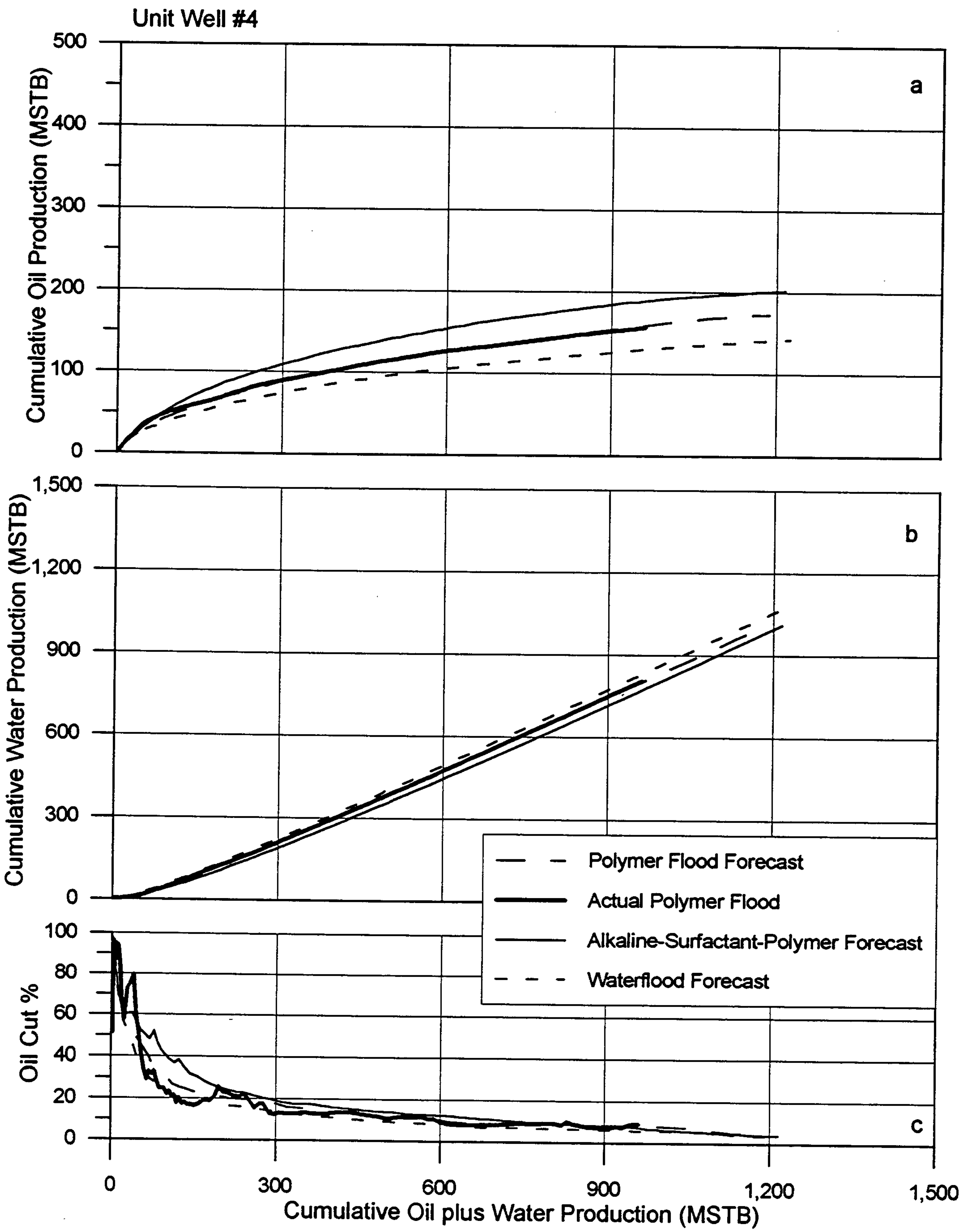


Figure 73

Simpson Ranch Cumulative Oil, Cumulative Water, and Oil Cut versus Cumulative Oil plus Water



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