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COALINGA POLYMER DEMONSTRATION PROJECT

Third Annual Report, July 1977—July 1978

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Shell Oil Company
Ventura, California

U. S. DEPARTMENT OF ENERGY

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COALINGA POLYMER DEMONSTRATION PROJECT

Third Annual Report
for the Period
July 1977-July 1978

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SUMMARY

The Coalinga Field is located on the northern end of the San Joaquin Valley in Central California. The field has produced primary oil since 1901. The loss of solution gas during the early primary years of production has increased the viscosity of the oil. As a result, waterflood projects in the field have been only marginally successful. There appears to be a significant potential for enchanced oil recovery pending the development of mobility control technology.

The Coalinga Polymer Demonstration Project has been designed to test polymer flooding as an enhanced waterflooding technique to increase oil recovery through water displacement mobility control. This project will also provide a direct comparison between waterflooding and polymer flooding in a representative portion of the Temblor Zone II reservoir of the East Coalinga Field. The major objective of the project is to determine if the added expense of polymer flooding over conventional waterflooding is economically justified.

The demonstration project has been organized into five phases which are: (1) Evaluation Phase, (2) Development Phase, (3) Water Injection Phase, (4) Polymer Injection Phase, and (5) Production Monitoring Phase. Field testing and the selection of the pilot site were completed during the Evaluation Phase. The drilling of new wells, the reconditioning of wells, and the installation of injection and porduction facilities were completed during the Development Phase.

The Water Injection Phase began in June, 1976, with the injection of 5,400 barrels per day into four 18-acre inverted five-spot injection patterns. This water injection case has been maintained for the major portion of this phase. The area being monitored for response also includes an updip area (with no injection wells) because of the unconfined nature of the project. During water injection, the gross production rate increased from 1200 BD to 2300 BD. The oil production rate increased to a plateau of approximately 410 BD, an increase of approximately 100 BD over the estimated primary rate. The production response which has been observed is significantly lower than the original estimates.

The Polymer Injection Phase began in May, 1978, and is expected to continue for approximately two to three years. The minimum time required to evaluate the polymer flood performance is the period necessary to establish a decreasing water cut trend.

The Production Monitoring Phase will follow and consist of one year of data gathering and reporting to complete the demonstration project. Additional water injection will follow the polymer slug for approximately eight years. The evaluation of the degree of mobility control attained with the polymer will be made during this phase. If the demonstration project is successful, the economics of a full scale expansion of this recovery project will be evaluated.

RESERVOIR DESCRIPTION

GEOLOGY

The Coalinga Field is located on the northern end of the San Joaquin Valley in Central California (Figure 1). The Polymer Pilot Area, Sections 26 and 27, is located on a southeasterly plunging asymmetrical anticline (Figure 2). The reservoir under investigation is the Temblor Zone II, which dips 13 to 14 degrees to the southeast in the pilot area, as shown on Figure 3. The top of Zone II, designated as the Black Shale, is found at depths ranging from 1,900 feet to 2,400 feet within the pilot area.

The Temblor Zone II reservoir consists of about 125 net feet of pay distributed among ten sands within a 350-foot gross interval. There are ten distinct sand intervals, each of which consists of several sand stringers, as shown by the type log on Figure 4. Geological control does not permit mapping individual sand stringers, but the sand intervals are correlative across the pilot area. The two upper sand intervals, E and F, were deposited in a marine deltaic environment and are of floodable quality only in the pilot area. The remaining sands were deposited in a nonmarine alluvial channel environment and will be the major objective of any future expansion.

Outcrop excavation and subsurface studies of the alluvial sands in Zone II have established the direction of deposition from the northwest to southeast. Sand continuity can be expected over long distances in the direction of stream flow. But, clay drapes or shale deposits which formed as the channels accreted in a northeasterly direction can seriously disrupt sand continuity. These interchannel clay drapes and channel boundaries are barriers to fluid flow, and have had a pronounced effect on the primary and waterflood performance within the pilot area. Barriers either identified or inferred in the major sand intervals are shown on Figures 5 to 13. No sand barriers have been inferred in either the E/F or G_c sand intervals. Barrier "C", also shown on Figures 5 to 13, is an established impermeable barrier not related to the depositional genesis. This barrier is believed to be caused by cemented fractures which are completely sealing (2).

A detailed discussion of the geologic history and sedimentary genesis of the Temblor formation Zone II is contained in the previous annual reports (1,2).

PETROPHYSICAL

The petrophysical description of the Temblor formation Zone II within the pilot area, has been updated. The basic petrophysical parameters evaluated for each of the major sand intervals were porosity, net feet of permeable sand, and fluid saturations. Sixteen wells, each of which contained a complete suite of logs, were included in the evaluation. In addition, cores obtained from a number of those wells were analyzed and used to calibrate the logs.

Porosity - Density and/or neutron logs were used in obtaining formation porosity. The porosity of each interval was obtained by averaging the porosity of the sand stringers which comprise the interval. A matrix rock density of 2.65 grams per cubic centimeter and a fluid density of 0.992 grams per cubic centimeter were used to calculate the porosity from the density logs using the following equation (see Table 1 for nomenclature):

$$\phi = \frac{\rho_m - \rho_b}{\rho_m - \rho_f}$$

The calculated porosities, tabulated in Table II, ranged in value from 18 to 30.3 percent.

Gas Saturation - The wells with both density and neutron logs were evaluated for desaturation using gas saturation crossplots. Table III lists the net feet and percentage of gas saturation in each interval. Nearly all intervals in the updip Section 27 area were partially desaturated; however, desaturation did not extend into the downdip Section 26 area.

Water Saturation - Water saturations were calculated using the Waxman-Smits shaly sand equation:

$$\frac{R_t}{R_o} = S_w^{-n^*} \left[\frac{1 + R_w B Q_v}{1 + R_w B Q_v / S_w} \right]$$

Where:

$$R_o = \frac{\phi^{-m^*} R_w}{1 + R_w B Q_v}$$

Shale content (Q_v) was determined for each interval from core analyses. The determined values for shale content range from 0.06 to 0.46 milliequivalent per milliliter of pore space (Table IV). The cementation (m^*) and saturation (n^*) exponent values of 1.69 and 1.8, respectively, were also determined from core analyses.

Formation resistivity (R_t) and porosity (ϕ) of the individual intervals were obtained from log measurements. Formation water resistivity (R_w) was determined from water salinity analyses of produced water samples from the individual or nearby wells. The salinity of the individual intervals within a well are assumed to be equal, as the production fluids are commingled within the wellbore. The chemical composition of original formation water has been altered by dump-flooding which has occurred in mechanically defective wells (1,2). As a result, produced water from Zone II varies in salinity from 2200 ppm to 9000 ppm (Table V).

The water saturations calculated for the individual intervals represent a net thickness weighted average of the sand stringers which comprise the interval. Talbe VI is a tabulation of the calculated water saturations, which range in value from 12 to 69 percent. The overall calculated average water saturation within the immediate pilot area is 41.9 percent. This value is higher than the previously assumed value of 35 percent, which will reduce the potential oil recovery from the pilot area.

The water saturations were calculated using single or averaged value(s) of shale content, saturation exponent, cementation exponent and formation water resistivity. As a result of the small sample size, the calculated water saturations have an associated degree of uncertainty. The sensitivity of the calculated water saturation to the shal content and formation water resistivity are shown on Figures 14 and 15, respectively.

RESERVOIR

P-V T Analysis - Surface oil samples were collected from two wells within the pilot area, 276-27 and 4-14-26. The samples were submitted for P-V-T analyses to better define the oil properties within the Temblor formation Zone II. The results from the analyses, pertinent to the numerical simulation, are listed on Table VII. A small amount of solution gas, approximately 10 cubic feet per barrel, was measured in the oil samples. The introduction of solution gas into the numerical simulation will effect the compressibility of the system. Also, the oil viscosity of the two samples were lower than indicated by previous measurements. (Wells 12-7-27, 99-27, and 295-27) Additional oil samples were obtained from two pilot wells (Wells 1-8-26 and 3-8-26) and from the stock tank and the viscosity of the oil measured (Figure 16). The estimated oil viscoisty of the gas free crude at reservoir temperature and atmospheric pressure has been reduced from 25 cp to 20.4 cp.

Relative Permeability Endpoints - Endpoint permeabilities have been re-examined to include new core analyses measurements from Well 16-6-27. The measured endpoint relative permeabilities from 34 samples have been grouped and analyzed according to individual sand intervals (Table VIII). The average endpoint permeability values have been calculated, using an arithmetic average and a geometric average. The calculated permeabilities, using the geometric average, are slightly lower, and are believed to better approximate the behavior of a heterogeneous sand interval (3). Additional data measurements are planned for core samples from well 16-6-27.

Permeability vs Salinity - Fresh water sensitivity tests were conducted on core plugs, from the G_c and H_x intervals from Well 16-6-27. The purpose of the tests was to determine the sensitivity of the reservoir permeability to the salinity of the injected fluid. This is of particular importance as there is an insufficient amount of produced brine available in the field for a full scale expansion of the pilot. As a result, the use of fresh water is also being tested in the pilot area along with a chemical treatment to protect the near wellbore from fresh water damage (1).

Two methods were used to represent permeability changes due to water and polymer flooding with fresh water. The salinity reduction methods used should simulate the salinity changes encountered in the flooding processes. Prior to beginning salinity reduction, core plugs were reduced to residual oil saturation using 35,000 ppm brine at flow rate of 1.3 feet per day. This flow rate corresponds to the lowest rate that could be obtained with the equipment used and approximates flow rates expected in the reservoir. The first method of salinity reduction utilized step rate changes, with a 24-hour flow period for each salinity step. Thirteen steps were used to reduce the salinity from 35,000 ppm to 300 ppm. A reversal of these steps to measure the permeavility recovery was also followed. The second method of salinity reduction involved the continuous reduction of salinity from 35,000 ppm to distilled water. Permeability measurements were calculated at various points in the cycle.

Figure 17 displays the results from both testing methods. Over 98 percent of the original permeability was lost in the sample that was subjected to the step change method. The major portion of the permeability loss occurred when the salinity was reduced from 3000 to 2000 ppm. Only a slight permeability recovery was observed when the salinity was increased back to 35,000 ppm. Similar permeability losses were observed using the continuous salinity reduction method. The major portion of the permeability loss occurred when the salinity was reduced from 1720 to 1160 ppm. Further tests are planned to determine if the salinity at which the majority of the permeability loss occurs is a function of the method of salinity reduction or the amount of the clay present.

WATERFLOOD PERFORMANCE

Overall Performance - The production response to water injection has been significantly lower than originally forecast. The performance curve from the immediate pilot area is shown on Figure 18. The water injection rate has been maintained at 5400 BD for the major portion of the 22 month water injection phase. The rate was lowered in March, 1978, in preparation for polymer injection which began in May, 1978. During the waterflood period, the gross production rate gradually increased from a primary rate of 1200 BD to a rate of 2300 BD. During the same period, oil production rate increased to a plateau of approximately 410 BD, an increase of approximately 100 BD over the estimated primary rate. A sharp decline in oil production occurred in March, 1978, when the injection rate was decreased.

Injection Well Completions - All four pilot injection wells were completed with casing cemented through Zone II, and the major sand intervals jet perforated. Each sand interval was treated using an oil wetting treatment to protect the fresh water sensitive formation clays from damage caused by fresh water injection (1). Individual intervals, in each injection well, were selectively stimulated with mud acid to obtain the desired injection profile prior to beginning full scale water injection.

Injection Well Performance - Injection of fresh water into the pilot wells began in June, 1976. In order to monitor the performance of the injection wells, injection rate and bottom hole pressures were continuously recorded, and injection profile surveys periodically obtained. The overall injection performance has been good in essentially all respects. The injection rate was maintained at 1350 barrels per day per well during the water injection phase, while injection pressure gradually increased. The performance curves for the four injection wells are shown in Figures 19 through 22.

A summary of the cumulative injection into the six major sand intervals in each of the four injection wells is given on Table IX. The overall balance of injection, both by individual well and by sand interval, has been within acceptable limits. On a movable pore volume basis, the H_x interval has taken a significantly larger volume of injection than the other five intervals.

Producing Well Completions - Seven of the nine pattern producers were completed using an open hole underreamed gravel pack completion technique. A protective casing string was cemented at the top of Zone II. The formation was then underreamed and a liner gravel packed, as shown on Figure 23. The two remaining pattern producers and the majority of the nonpattern producers were completed using a slotted liner. A protective casing string was cemented above Zone II. The formation was then drilled through and a slotted liner placed across the formation, as shown on Figure 24.

Producing Well Performance - The performance curves of the pattern production wells are shown on Figure 25. The most pronounced response to waterflooding has been observed in the updip wells, and wells within the interior of the five spot patterns. A majority of the updip response has been observed in Wells 273-27, 274-27, and 276-27, which are adjacent to the southwest pattern. The interior wells which have shown response are Wells 34-37, 58-27, and 92-27. The central and downdip wells have shown little response to waterflooding.

Figure 26 is an isobaric map constructed from pressure surveys obtained in the pattern producing wells. The datum selected for construction of the map was the base of the H_w interval. The low pressures observed in Wells 285A-27 and 3-11-26 indicate that a flow barrier exists in a majority of the sand intervals between these wells and the remainder of the pilot area.

Production Well Treatments and Stimulations - All pattern producing wells, with the exception of 4-6-26, were subjected to an oil wetting treatment to protect the fresh water sensitive clays prior to initiating injection (1).

Because response to waterflooding was slow, a majority of the wells were stimulated to remove or reduce suspected impairment. Two stimulation methods were attempted to treat for suspected bacterial debris and/or unhydrated polymer, associated with polymer in drilling fluid. A combination bacteria destruct and hydrochloric acid treatment failed to improve response in Wells 14-7-27, 1-8-26 and 3-8-26. A sodium hypochlorite treatment, to oxidize suspected unhydrated polymer, also failed to improve response in Well 14-7-27.

Mud acid treatments also failed to increase production. Conventional mud acid treatments were used in Wells 1-8-26 and 284-27, and deep penetrating mud acid treatment was used in 3-11-26.

The two northern pattern producers, Wells 1-5-2 and 4-6-26, have produced at high water rates since they were drilled in 1975. Two conventional cement squeeze operations were conducted in each well in an attempt to eliminate the extraneous water production. Recent inflow survey indicate that neither well is producing significant amounts of water at or near the casing shoe, although water production has not decreased. It is suspected that localized dump-flooding occurred in this area prior to the abandonment of older wells.

Sampling Observation Well Completions - The Sampling observation wells were completed with casing cemented through Zone II. Each well was then jet-perforated in three individual five foot sand stringers to allow fluid sampling without distorting the reservoir flow patterns. Each of the intervals was then gravel packed using an inner liner and a liner jam-on packer for zonal isolation. Figure 27 is a schematic of one of the observation well completions.

Sampling Observation Well Performance - Data from the sampling observation wells has not been as definitive as expected toward monitoring the flood performance. The low producing rates observed in many of the producing intervals indicates the producing zones may not be responding to water injection. In addition, adjacent zones within the same well often produce at similar rates and salinities, indicating zonal communication. A summary of the performance of the individual observation wells is a follows:

Well 1-7-26

F Sand - The production performance of this interval changed in September, 1977. The production rate increased from 6 BDW to 14 BDW, and the salinity decreased from 4700 ppm to 2400 ppm. This performance indicates the advance of a water bank into this interval. No oil production has been obtained from this interval.

Gc Sand - The production performance of this zone has been erratic. The production rate and salinities have fluctuated between test periods. The well is currently producing 45 BDW with a salinity of 840 ppm, which is similar to the performance of the H_w interval.

Hw Sand - This interval watered out in August, 1976. The production rate has averaged 46 BDW, with a salinity of 600 ppm.

Well 1-9-26

F Sand - Because of the low production rates, this zone has not been sampled since June, 1977.

Gc and Gd Sands - These zones are believed to be in communication based on similar production rates, salinities, and zonal pressures. A production inflow log run in June, 1977, indicated that a majority of the produced fluids were entering from the G_c sand. As a result, the production from both zones has been commingled. The production rate has averaged 12 BDW and 1 BDO, with a salinity of 1200 ppm.

Well 15-8-27

Gc Sand - As a result of the low production rates, this interval was sampled only once during the past year. The production rate was 1 BDW during May, 1978, with a salinity of 7700 ppm. This production rate is similar to those observed during previous test periods. No waterflood response has been observed from this zone.

Gd and Hw Sands - The production from both zones was commingled in December, 1977, as a result of the low production rates. Production has since averaged 7 BDW and 4 BDO, with a salinity of 10,000 ppm. No waterflood response has been observed from either zone.

Well 16-7-26

Gc Sand- Because of low production rates, this interval was sampled only once during the past year. The production rate was 1 BDW during May, 1978, with a salinity of 7700 ppm. This rate and salinity are similar to those observed during previous test periods. No waterflood response has been observed from this zone.

Hw Sand - The production rate from this zone varied from 1 to 17 BDW during the past year. The salinity of the produced water also varied from 7900 to 9300 ppm. The salinity fluctuations may be indicative of minor fluid movements in this interval.

Hx Sand - The production rate from this interval averaged 4 BDW, while the salinity varied from 6900 to 8900 ppm during the past year. The production from both zones has been commingled. The production rate has averaged 12 BDW and 1 BDO, with a salinity of 1200 ppm.

Logging Observation Well Completion - The logging observation well, 16-6-27, was completed using a protective string of casing cemented above Zone II. A nonconductive fiberglass liner was cemented across Zone II, as shown on Figure 28.

Logging Observation Well Performance - Well 16-6-27 is a focal point to monitor fluid saturation changes within the reservoir as the waterflood and polymer flood progress. Resistivity log devices have been run periodically throughout the waterflood phase. No significant changes of resistivity have occurred in any of the sands within the past year, indicating a lack of waterflood response. The logging frequency has been reduced to one run per month. Resistivity changes, which occurred during the first year of waterflooding, were documented in the Second Annual Report (2).

RESERVOIR SIMULATION

Full Scale Pilot Simulation Model - A three-dimensional numerical simulator is being used to model the project performance. The grid pattern selected is variable in the horizontal (x-y) and in the vertical (variable thickness) directions, as shown on Figure 29. The size of the grid blocks in the horizontal plane vary in dimensions from 200' X 200' to 600' X 1200'. The smaller grid blocks used in the Immediate Pilot Area assures that only one well is located in a grid block. Wells are placed in the center of the grid block, regardless of the actual position. Larger grid blocks are used outside the Immediate Pilot Area, as less definition is required. Where more than one producing well is located in a grid block, the wells are combined into one psuedo well. To model the updip area of high gas saturation, it was necessary to include a row of large grid blocks, not shown on Figure 29.

The ten sand intervals have been combined into six layers to simplify the simulation. The layers being used are as follows:

Layer	Sand Interval(s)
1	E/F Sands
2	G_c Sand
3	G_d Sand
4	$X/Y/H_w$ Sands
5	H_x Sand
6	J_s/J_v Sands

The minor X and Y sands are in sand-to-sand contact with the major H_w sand in many places and were combined. The E and J_v sands are of lesser importance and have been combined with the F and J_s sands, respectively.

The primary performance of the pilot area has been simulated using this model. Areas within the pilot have, on primary production, produced anomalous amounts of water which is believed to have been the result of dump-flooding. To simulate this type of performance, six fictitious water injection wells were included in the model. The overall preliminary match (Figure 30) is close, but to match the performance of key project wells, further adjustments of the reservoir parameters will be required. Attempts to simulate the waterflood performance are continuing.

Sensitivity Study - To aid in the full scale simulation study, a single layer model was constructed and used to determine the sensitivity of various key parameters to a water injection process. The physical parameters, used in the model, were typical of those used in the large three-dimensional model.

To simplify the problem, a liquid-filled system was used with uniform oil and water saturations. The relative permeability curves were expressed in terms of a single shape exponent parameter as suggested by Hirasaki (4). The model was tilted 13 degrees and consisted of a downdip producer, an updip producer and an injection well midway between the two producers.

A base waterflood case was established using these assumed parameters. To determine the sensitivity of various parameters, the assumptions used in the base case were held constant and one parameter was varied at a time. The parameters investigated were the shapes of the relative permeability curves, the system compressibility, oil viscosity, absolute permeability, wellbore skin, and the strength of partial barriers between the injector and the downdip producer.

Two of the variables investigated had a marked effect on oil recovery per unit of injection. These were the shape of the relative permeability curves and the system compressibility. The shapes of the relative permeability curves were varied by changing the exponent used in the exponential equations. As shown on Figure 31, the oil recovery decreased as the value of the shape parameter was decreased. It is believed that the lower values ot the shape parameter will approximate the average relative permeability curves resulting from individual layer heterogeneities. The system compressibility was varied by changing the rock compressibility to approximate various in-situ gas saturations. As shown on Figure 32, larger rock compressibilities (higher gas saturation) resulted in lower oil recoveries.

Reducing the formation permeability or increasing the wellbore skin increased the length of time required to complete the waterflood since the fluids did not move as readily. But for a unit of injection, there is little change in the unit of production. Increasing oil viscosity will result in a higher mobility ratio and a slightly lower recovery per unit of injection. For partial barriers to be effective in reducing recovery in a closed system, the ratio of restricted flow to unrestricted flow must approach 0.10 or less. The results from the sensitivity study will be used to adjust parameters in the full scale simulation model.

Polymer Slug Design - The numerical model used to design the polymer slug is shown in Figure 33. As in the large simulation model, six noncommunicating layers tilted at 13 degrees were modeled. In this model, the individual layers were assumed to be of constant thickness, permeability and porosity. The thickness of each layer was based on the average thickness of the sand intervals in the four five-spot patterns in the pilot area. The permeability, porosity, and fluid saturations were based on petrophysical analyses discussed previously. As in the large simulation model, a large updip grid block in each of the layers was included to model the updip area of high gas saturation. Three production and two injection wells were located to approximate the structural position of the pilot pattern production and injection wells. This model approximates, but is not, a true element of symmetry for the pilot.

All simulation runs covered a period which began in 1972 and terminated in 1995. The waterflood injection began in mid-1976. Injection rates were held constant at 1,350 barrels per day per well and the producing wells were pressure or liquid constrained to net more than 900 barrels per day per well to approximate the performance of the pilot. The oil production performance for continued primary and waterflooding is shown on Figure 34.

A polymer grading scheme was used in all simulated polymer displacement processes. The spearhead polymer slug was assumed to be 26.4 percent of the total slug size and was followed by four equally sized polymer grading steps. The adsorption of polymer onto the rock surface was assumed to be 3.2 micrograms per gram. Polymer injection was assumed to start in mid-1978.

To analyze the effect of slug size on recovery, the viscosity of the spearhead was selected to yield a mobility ratio of 1.0. The slug size was varied from 0.26 to 1.03 polymer movable pore volumes $(MPV)_{PF}$. The results of the simulation runs are displayed on Figure 35. Incremental oil production of polymer flooding over waterflooding, as a function of slug size, is shown on Figure 36. The optimum slug size was determined to be approximately 0.5 $(MPV)_{PF}$. The incremental benefit of increasing the slug size above optimum is small, whereas decreasing the slug size to less than optimum would result in significantly less oil recovery.

The effect of mobility ratio on recovery was also investigated using a constant slug size of 0.50 $(MPV)_{PF}$ and varying the mobility ratios from 0.8 to 2.0. The results from the simulations are displayed on Figure 37. Greater peak responses were observed at earlier times as the mobility ratio was successively reduced. The incremental oil recovery of polymer flooding over waterflooding, as a function of mobility ratio, is shown on Figure 38. Although the optimum mobility ratio appears to be less than one, the injection of a more viscous polymer would prolong the field test. For this reason the optimum mobility ratio was selcted to be one. Pertinent data from the simulation runs are listed on Table X.

Based on the results from this model, a spearhead viscosity of 5.4 centpoise was selected to begin injection into the pilot area. This viscosity will yield a mobility ratio of approximately 1.0. The number of grading steps necessary to obtain optimum recovery will be investigated further using this model. The volume of each grading step will be based on the reservoir volume being swept, which has not yet been determined.

POLYMER FACILITIES
AND PRODUCT SPECIFICATIONS

Kelco Xanflood (R) Biopolymer has been selected for use in the Coalinga Polymer Demonstration Project. The selection of the polymer and the design of the mixing and injection facilities were discussed in previous annual reports (1, 2). Ongoing laboratory and field testing have lead to minor facility modifications, the establishment of quality control criteria, and the selection of a biocide for the protection of the polymer.

Polymer Concentrate Mixing Facilities - A 500 gallon retention tank was added downstream of the polymer concentrate mixer to eliminate the use of the mixer as a retention tank (Figure 39). The addition of this tank doubles the capacity of the mixer, and more importantly provides a polymer concentrate reserve volume should mixer downtime occur.

The installation of an automatic liquid enzyme feed system has eliminated the necessity of manually adding the enzyme to each batch of polymer concentrate. The enzyme has been changed from the dry powder Alcalase (R) 6.0 to liquid Alcalase (R) 1.9 for ease of handling.

The shear applied to the polymer concentrate, downstream of the retention tank, has been increased from 300 psig to 900 psig pressure drop. This increase in shear has resulted in a slight increase in filterability of the polymer solution, without a decrease in viscosity.

Blending Facilities - The control system to proportion the polymer concentrate and USBR water has been modified to minimize variation of concentration of the polymer solution. The new proportioning control device meters the flow rates of both the blended polymer solution and the polymer concentrate, and adjusts the flow rates of the respective streams as required. An alarm system has been installed that will shut down the plant if the desired concentration of polymer solution is not produced.

Storage Facilities - Circulation pumps were added to each of the four 500 barrel polymer solution storage tanks to minimize stagnant areas in the tanks.

Product Variability - Product variation between batch lots received from the manufacturer had been observed. As a result, Shell and the manufacturer have established polymer testing specifications and testing procedures to assure acceptable product quality prior to shipment. All batch lots are now dry blended prior to packaging, which will further reduce product variation.

Biocide Selection - Acrolein (Aqualin (R)) has been selected for use as the biocide for the project. Based upon laboratory tests, this biocide was found to be both compatible with the polymer and stable at the existing reservoir temperatures and pressures. Core flow studies determined that adsorption onto the formation rock and partitioning into the oil phase by the biocide were minimal. Acrolein was also found to protect the polymer under surface conditions while maintaining biocidal activity.

Polymer Product Specifications - Quality control and monitoring specifications have been established to maintain the desired viscosity and prevent impairment of injection wells. The specifications currently used are as follows:

1. 10-15 ppm excess sulfite upstream of the biocide injection point.
2. Less than 100 ppb dissolved oxygen.
3. 30 ppm active Acrolein biocide.

4. Less than 0.5 ppm total iron.

5. Viscosity of polymer solution within 10 percent of those shown on Figure 40.

6. Greater than 2500 milliliters filterability.*

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*Filterability is defined as the filtrate volume passing through a 1.2 micron Millipore membrane in five minutes at a pressure differential of 20 psi.

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APPENDIX I

TABLES

TABLE I
NOMENCLATURE

SYMBOL	
B	Equivalent conductance of clay counter ions, (1/equiv/ohm-m)
C_r	Rock compressibility, (volume/volume/psi)
k_{oi}	Permeability to oil, (md)
k_{ro}	Relative permeability to oil
k_{rw}	Relative permeability to water
k_w	Permeability to water, (md)
m*	Cementation exponent for shaly sands
MPV	Movable pore volume, (bbls)
MR	Mobility Ratio
n*	Saturation exponent for shaly sands
OOIP	Original oil in place
P-V-T	Pressure-Volume-Temperature
Q_v	Quantity of cation exchangeable clay present, (meq/ml of pore space)
R_o	Resistivity of water saturated rock, (ohm-m)
R_t	Formation Resistivity, (ohm-m)
R_w	Formation Water Resistivity, (ohm-m)
SS	Slug size, (bbls)
S_o	Oil saturation, fractional pore volume
S_{or}	Residual oil saturation, fractional pore volume
S_w	Water saturation, fractional pore volume
S_{wc}	Connate water saturation, fractional pore volume
WFMO	Waterflood movable oil, (bbls)
ϕ	Porosity, fractional bulk volume
ρ	Density, (g/cc): ρ_b = Bulk rock density: ρ_m = Matrix rock density: ρ_f = Fluid density

TABLE II
COALINGA POLYMER PILOT
SUMMARY OF LOG CALCULATED POROSITIES*

	SAND INTERVAL									
WELLS	E	F	Gc	Gd	X	Y	Hw	Hx	Js	Jv
1-5-26	.245	.245	.229	.221	.245	-	.237	-	.260	
1-7-26	.261	.270	.230	.243	-	.248	.240	-	.244	
1-8-26	.255	.282	.248	.263	.233	.278	.248	.251	-	
2-9-26	.28	.257	.230	.27	.26	.26	.25	.25	.267	
3-8-26	.227	.223	.222	.220	-	-	.203	-	.220	
3-11-26	.234	.223	.24	.23	.245	-	.215	.195	.18	.236
4-6-26	.264	.261	.239	.264	.231	-	.223	.239	.245	
4-13-26	.211	.216	.22	.255	.197	-	.23	.18	.25	
12-7-27	.243	.223	.261	.227	-	.247	.28	.27	.215	
14-7-27	.274	.278	.265	.263	-	.286	.270	.252	-	
15-8-27	.24	.27	.232	.244	.194	-	.239	.206	-	
15-9-27	.24	.26	.25	.26	.24	.26	.25	.25	.245	
16-6-27	.262	.267	.243	.261	-	-	.256	.272	.257	
16-7-27	.254	.284	.25	.258	.26	.268	.257	.228	.224	
256A-27	.227	.259	.261	.227	-	.288	.23	.29	.18	.284
285A-27	.26	.249	.18	.25	.23	-	-	.250	.247	
2-7-26	.236	.273	.224	.265	.233	.22	.234	.23	.23	
12-26	.278	.212	.182	.227	.242	.258	.23	.258	.245	
74-27	.242	.248	-	.18	-	.25	.20	.224	.212	
92-27	.288	.285	.27	.285	.30	-	-	-	-	
93-27	.288	-	.242	-	-	.258	.221	.212	.242	
114-27	.303	.261	.273	.258	-	-	-	.218	.242	
115-27	.267	.267	.261	-	-	.25	.212	.215	.20	
117-27	.300	.258	-	-	-	-	.227	.212	.20	
118-27	.218	-	.215	.227	.245	.261	.20	.212	.212	
182-27	.273	.218	.212	.212	-	-	-	-	-	
15-6-27	.233	.232	.238	.25	.235	.235	.229	.221	.225	
37-26			.242	.239	.197	.212	.212	.258	.197	
32-26			.273	.30	-	-	-	-	-	
6-10-26			.23	.24	.25	-	-	.255	.26	
10-26			.25	.264	.255	-	.275	.218	.25	
187X-27			.225	.225	.225	-	.225	.20	.225	
120-27			.252	.245	.273	.258	.275	.20	.215	
9-7-27			.28	-	-	-	.30	.28	-	
75-27			.30	.225	-	-	-	-	.20	
121-27				.20	-	.25	.30	.22	.21	
265-27				.20	-	-	-	-	-	
95-27							.25	.225	-	
152-27								.20		
AVERAGE	.256	.253	.241	.242	.240	.255	.241	.232	.228	.260

*Interval porosity shown is a net thickness weighted average of the stringers comprising the interval

TABLE III
COALINGA POLYMER PILOT
SUMMARY OF LOG CALCULATED GAS SATURATIONS*

(Net Feet Containing Desaturation / In-Situ Gas Saturation)

WELL	E	F	Gc	Gd	X	Y	Hw	Hx	Js	Jv
10-26	--	--	--	--	--	--	Z11/100	--	3/25	--
9-7-27	5/57	4/39	5/25	22/73	--	10/84	25/62	--	6/32	16/69
12-7-27	14/37	7/39	32/100	5/65	--	12/100	19/53	27/71	16/28	25/27
14-7-27	10/22	37/23	11/25	12/9	--	15/5	32/14	13/10	32/10	11/24
15-6-27	3/19	2/7	6/18	1/9	--	--	7/23	--	4/12	--
15-8-27	8/12	26/33	--	--	--	--	--	--	--	--
15-9-27	5/20	4/5	--	9/16	--	--	--	--	--	4/7
16-6-27	--	5/12	8/13	--	--	--	--	--	--	5/5
16-7-27	--	4/6	2/27	--	--	--	2/7	--	5/3	--
75-27	--	--	6/30	3/72	--	7/73	10/100	23/97	8/11	6/13
256A-27	4/18	--	21/80	12/43	--	4/48	31/72	15/70	--	8/49
285A-27	4/22	9/37	6/33	11/16	7/46	--	--	23/78	--	4/24

* No desaturation was observed in the following wells:

1-5-26	2-9-26
1-7-26	2-7-26
1-8-26	3-8-26
1-9-26	4-6-26

TABLE IV

COALINGA POLYMER PILOT

SAND INTERVAL SHALE CONTENT MEASURED FROM CORE ANALYSIS

(Milliequivalents per milliliter of pore volume)

WELL	SAND INTERVAL									
	E	F	Gc	Gd	X	Y	Hw	Hx	Js	Jv
3-11-26			.15	.19	.34		.14	.30	.16	.23
4-13-26	.10	.10	.37	.32			.12	.18	.13	
12-7-27	.27	.07	.13	.30		.12	.06	.12	.29	.23
16-6-27		.46	.26	.20			.18	.10	.09	.42
256A-27			.17	.15		.15	.17	.20	.30	.23
285A-27	.20	.33	.31	.17	.15			.13	.09	.39

TABLE V
COALINGA POLYMER PILOT
SALINITY OF PRODUCED WATER USED IN LOG EVALUATION

	WELL	SALINITY (ppm)
Updip		
	71-27	6200
	113-27	7300
	115-27	8800
	117-27	2900
	120-27	2400
	121-27	2550
	152-27	2200
	165-27	7500
	172-27	4700
	274-27	7200
	275-27	5200
	276-27	5700
	282-27	3000
	284-27	6100
Central		
	34-27	3800
	58-27	3600
	91-27	6300
	176-27	3200
	187X-27	3650
	265-27	3600
	265A-27	4650
	294-27	4000
	15-9-27	4400
	1-26	4100
	29-26	5300
	1-5-26	4900
	1-6-26	4650
Downdip		
	137-26	5800
	3-8-26	8000
	3-11-26	9000
	4-6-26	4800

TABLE VI

COALINGA POLYMER PILOT
SUMMARY OF LOG CALCULATED WATER SATURATIONS

	SAND INTERVAL									
	E	F	Gc	Gd	X	Y	Hw	Hx	Js	Jv
A. UPDIP WELLS										
15-8-27	.28	.25	.32	.37	.38	-	.45	-	-	-
14-7-27	.50	.32	.26	.38	-	.48	.43	.67	.46	.39
15-9-27	.50	.37	.18	.32	.47	-	.38	.69	.32	-
12-7-27	.44	.36	.12	.19	-	.29	.39	.21	.60	.40
UPDIP AVERAGE	.43	.33	.22	.32	.43	.39	.41	.52	.46	.40
B. CENTRAL WELLS										
1-8-26	.45	.23	.31	.34	-	.34	.43	-	-	-
1-7-26	.35	.23	.42	.52	-	.69	.49	-	-	-
16-7-27	.51	.21	.52	.52	.56	.38	.49	-	-	-
16-6-27	.50	.37	.41	.52	-	-	.43	.45	.64	-
1-5-26	.55	.34	.40	.39	.54	-	.42	-	.38	-
2-9-26	.51	.49	.48	.59	.63	-	-	.62	.49	-
285A-27	.67	.45	.54	.46	.65	-	.46	-	-	-
CENTRAL AVERAGE	.51	.33	.44	.48	.60	.47	.45	.54	.50	-
C. DOWNDIP WELLS										
3-11-26	.59	.28	.40	.63	.38	-	.35	.48	.27	.55
3-8-26	.53	.36	.38	-	-	-	.28	-	.60	-
4-6-26	.33	.32	.40	.69	.65	-	-	-	.60	-
4-13-26	-	-	.21	.38	-	-	.27	.45	.38	-
DOWNDIP AVERAGE	.48	.32	.35	.57	.52	-	.30	.47	.46	.55

TABLE VII

COALINGA POLYMER PILOT
P-V-T DATA SUMMARY

Well	276-27	4-14-26
Depletion Study Temperature, (°F)	110	110
Saturation Pressure, (psia)	116	68
Compressibility of Reservoir Oil @ 110°F (Vol/Vol/Psi x 10^6)	10.540	10.075
Specific Gravity of Saturated Oil @ 110°F	.8450	.8937
Viscosity, centipoise	10.648(*)	12.662(**)
Formation Volume Factor, (Bbls/Bbl)	1.082	1.068
Solution Gas-Oil Ratio , (Cu.Ft./BBL)	9.1	7.4

* Viscosity of gas free samples at atmospheric pressure and 110°F was 12.512 CP.

** Viscosity of gas free samples at atmospheric pressure and 110°F was 14.507 CP.

TABLE VIII

COALINGA POLYMER PILOT

SUMMARY OF ENDPOINT PERMEABILITY DATA

				ARITHMETIC MEAN		GEOMETRIC MEAN	
SAND (S)	NO. SAMPLES	$\bar{S}$WC	$\bar{S}$W AT SORW	KOI AT SWC	KW AT SORW	KOI AT SWC	KW AT SORW
GC	6	.405	.749	350.3	105.2	332.4	84.9
GD	3	.343	.800	212.9	89.7	190.7	73.9
X, Y, HW	8	.377	.773	373.8	130.5	188.4	87.6
HX	5	.464	.762	349.5	113.5	207.0	43.5
JS, JV	12	.348	.751	337.2	119.6	228.0	76.4
ALL DATA	34	.382	.762	339.0	116.1	249.9	73.8

TABLE IX

CUMULATIVE INJECTION BY INTERVAL - 6/76 TO 2/78

(M BBLS.)

SAND INTERVAL	WELL 2-7-26	WELL 2-9-26	WELL 15-6-27	WELL 15-9-27	TOTAL	INJECTION AS A PERCENTAGE OF MOVABLE PORE VOLUME (MPV[1])
E/F	156	170	156	210	692	38.1
G_c	40	115	77	140	372	42.9
G_d	6	47	81	89	223	33.3
X-Y-H_w	352[2]	12[2]	116	288	767	60.5
H_x	123	202	288	40	653	97.4
J_s / J_v		51	52	0	103	22.6[3]
TOTAL	677	597	770	767	3082	

---

1. $\text{MPV} = 7758\ AH\phi\,(1 - S_{or} - S_{wc})$
2. EXCLUDES 92.2M AND 179.4 M BARRELS OF INJECTION INTO THIEF SAND IN WELLS 2-7-26 AND 2-9-26 RESPECTIVELY
3. EXCLUDES PORE VOLUME IN 2-7-26 PATTERN WHICH IS NOT BEING INJECTED INTO BECAUSE OF A HIGH WATER SATURATION.

TABLE X

RESULTS OF POLYMER SLUG DESIGN SIMULATION
(NOT SCALED MODEL)

TOTAL PORE VOLUME	9,169,000 BBLS.
ORIGINAL OIL IN PLACE (OOIP)	4,435,000 STB.
PRIMARY RECOVERY	1,098,600
PERCENT OF OOIP	24.8%
WATERFLOOD RECOVERY	1,709,000
PERCENT OF OOIP	38.5%
POLYMER FLOOD RECOVERY	1,944,000
PERCENT OF OOIP (0.5 MPV - 5.4 CP)	43.8%

APPENDIX II

FIGURES

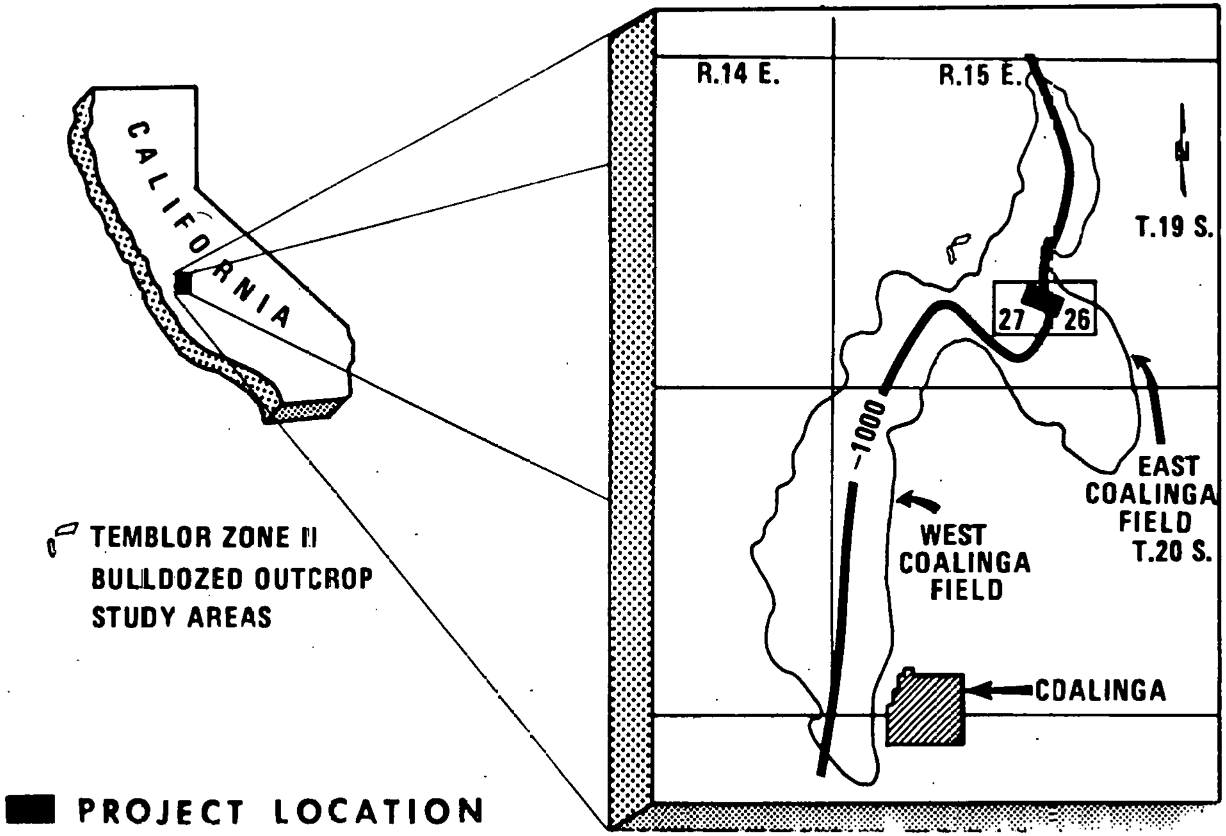
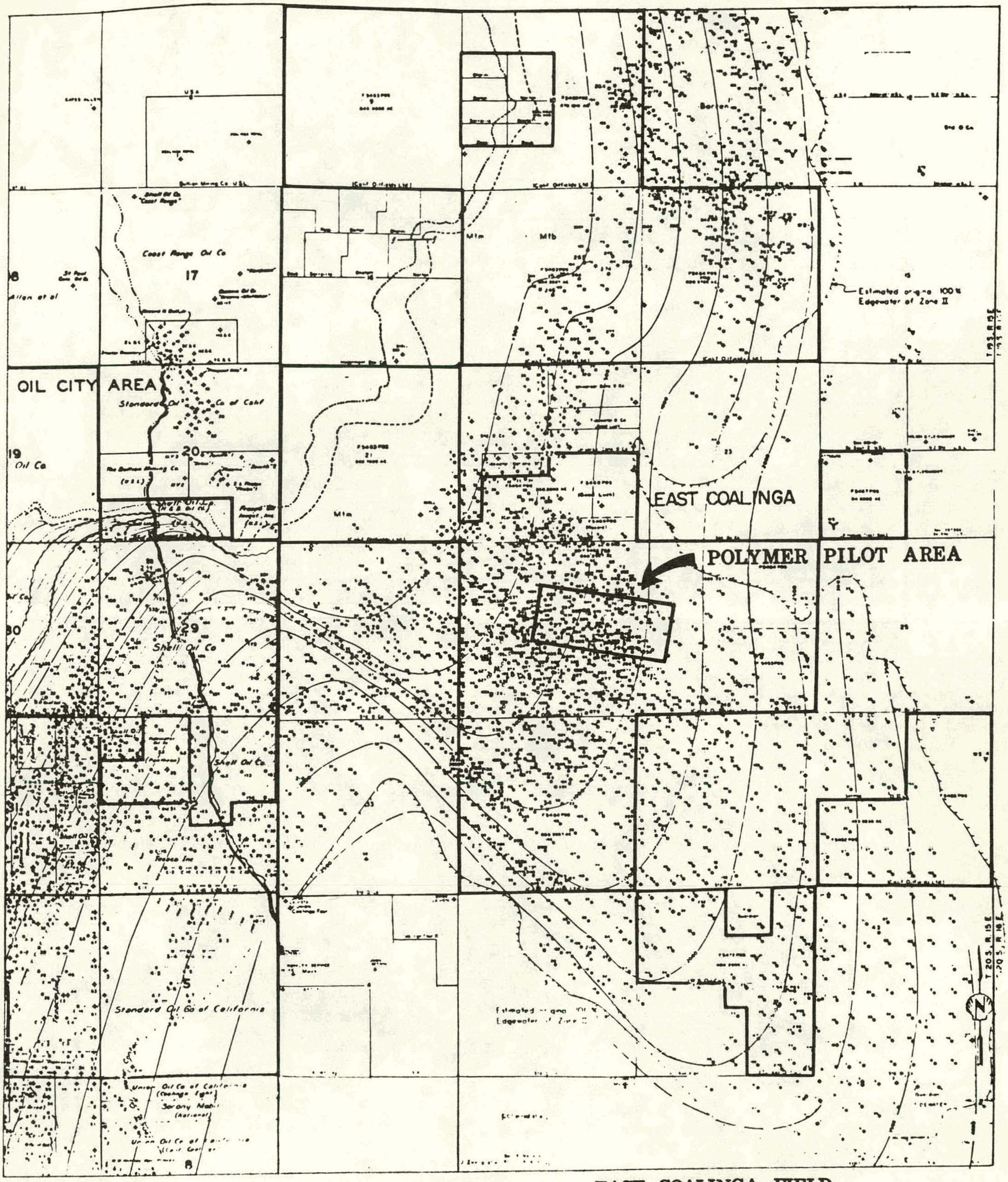


FIGURE 1
COALINGA FIELD INDEX MAP
POLYMER DEMONSTRATION PROJECT

FIGURE 2



EAST COALINGA FIELD

CONTOUR TOP BLACK SHALE

C.I. = 500'

COALINGA POLYMER PILOT

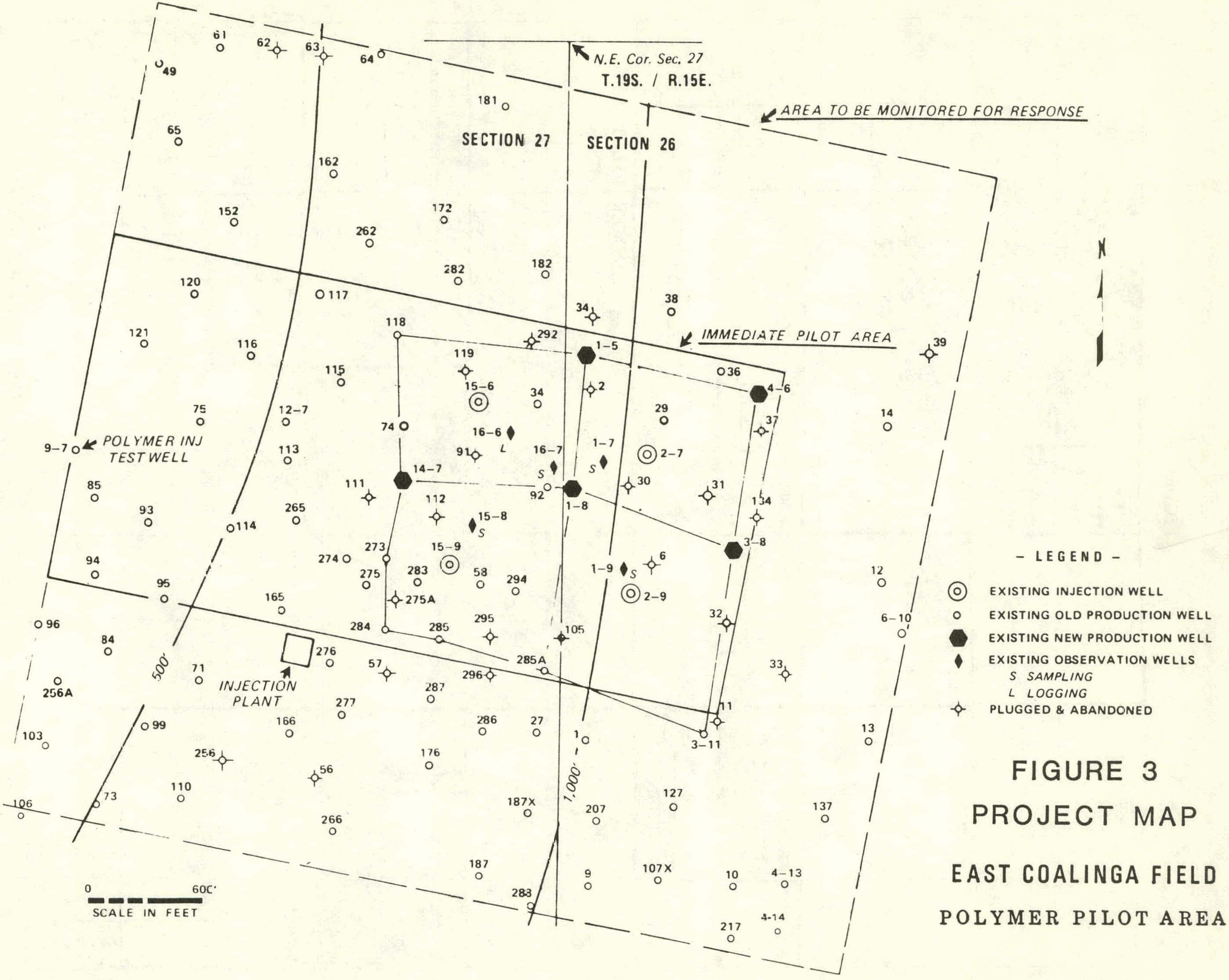
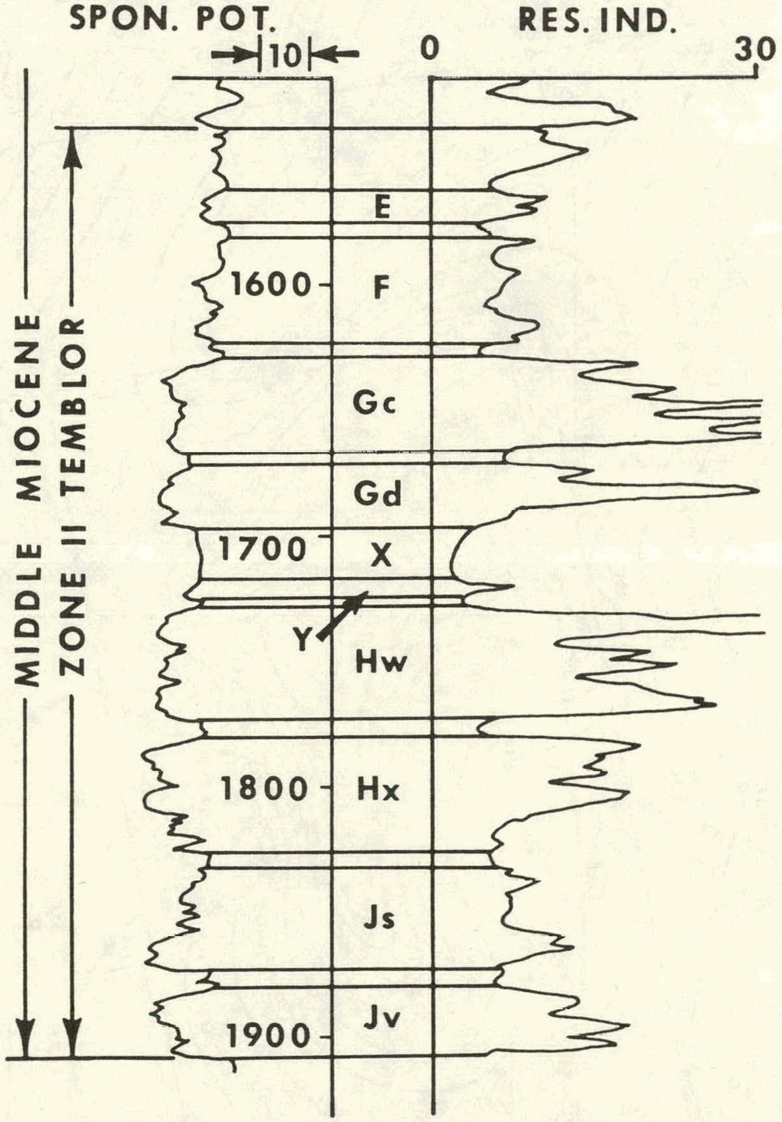


FIGURE 3
PROJECT MAP
EAST COALINGA FIELD
POLYMER PILOT AREA

FIGURE 4

TYPE LOG
COALINGA FIELD
ZONE II RES.



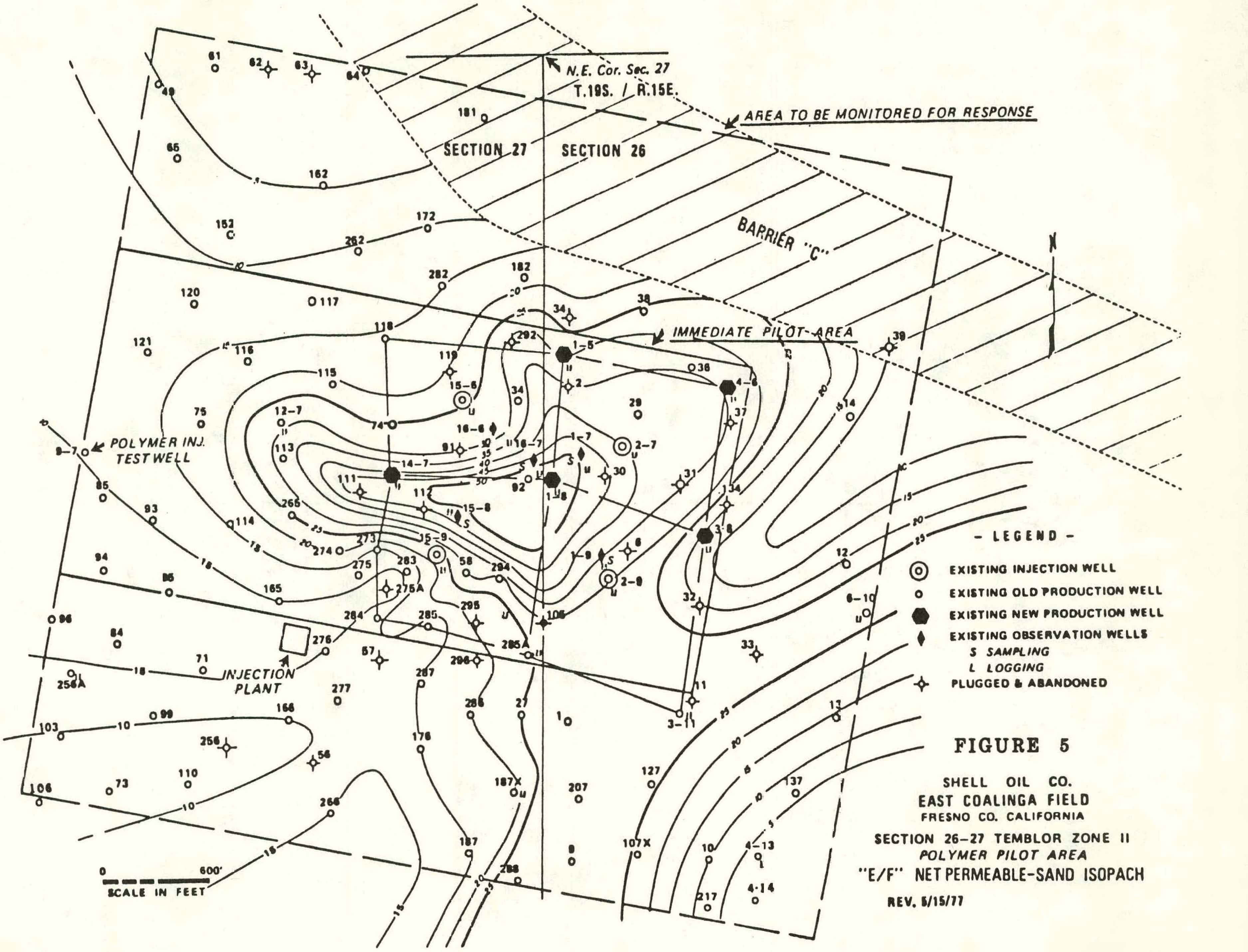


FIGURE 5

SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA
SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA
"E/F" NET PERMEABLE-SAND ISOPACH
REV. 5/15/77

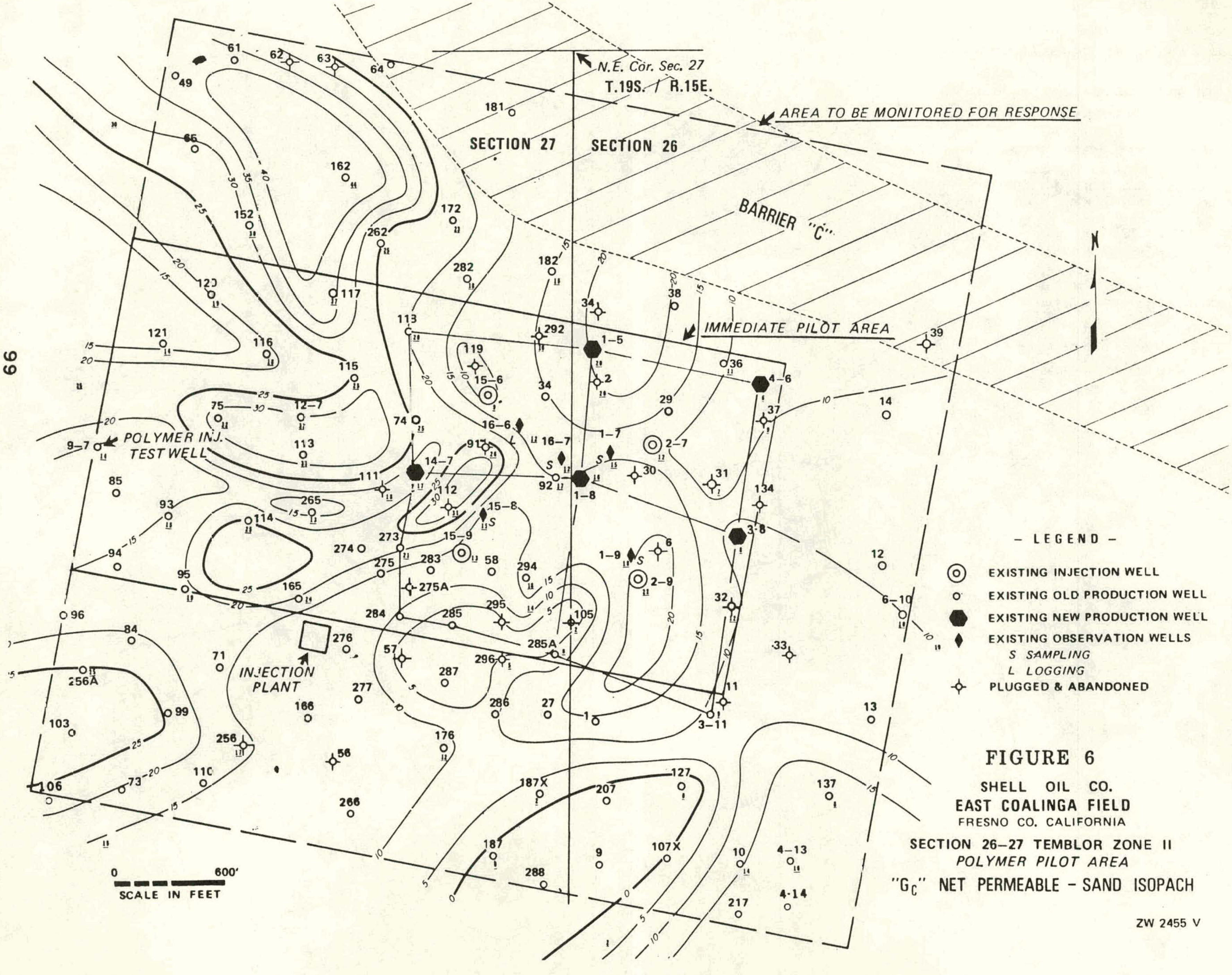
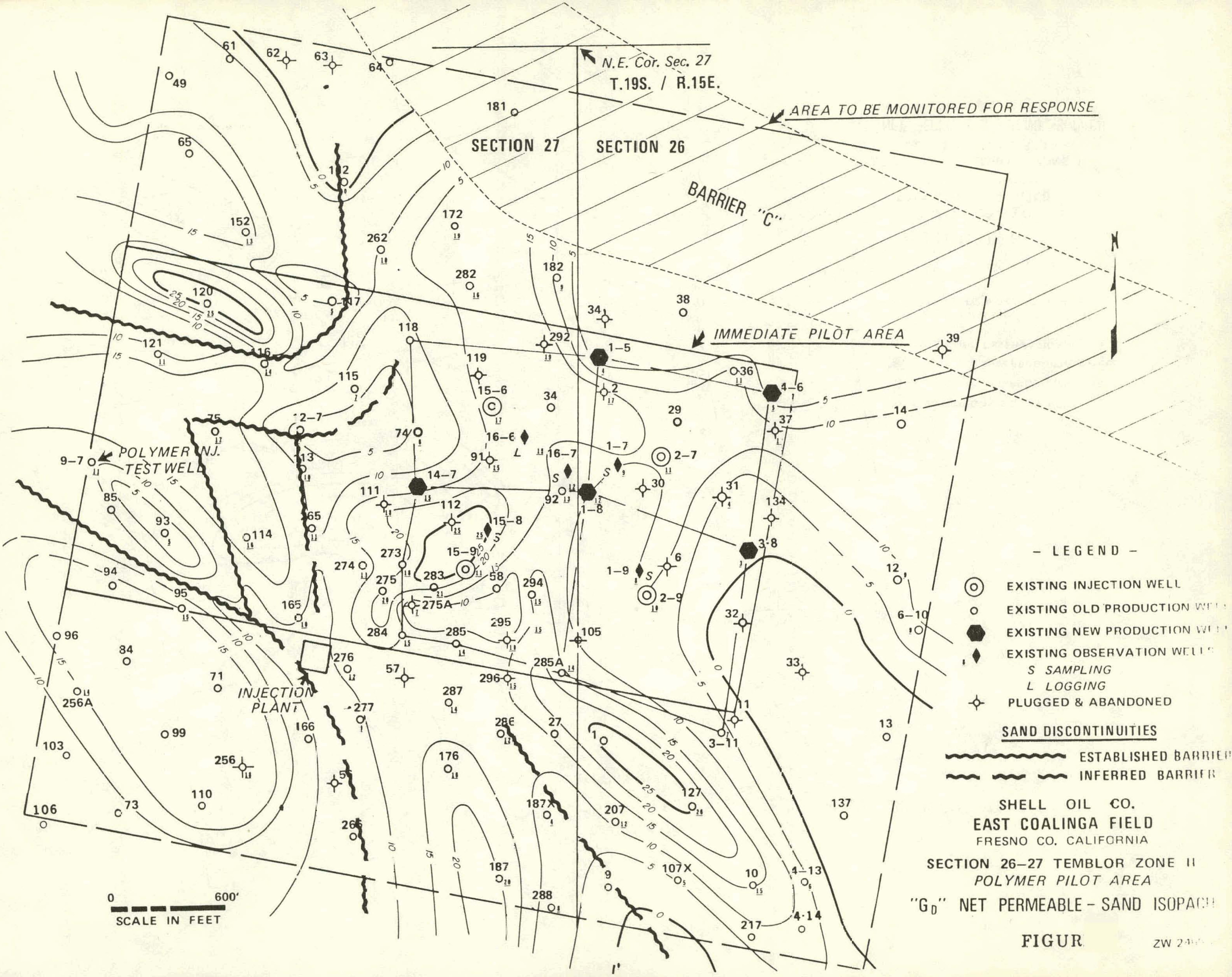


FIGURE 6

SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA
SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA
"G_C" NET PERMEABLE – SAND ISOPACH

ZW 2455 V

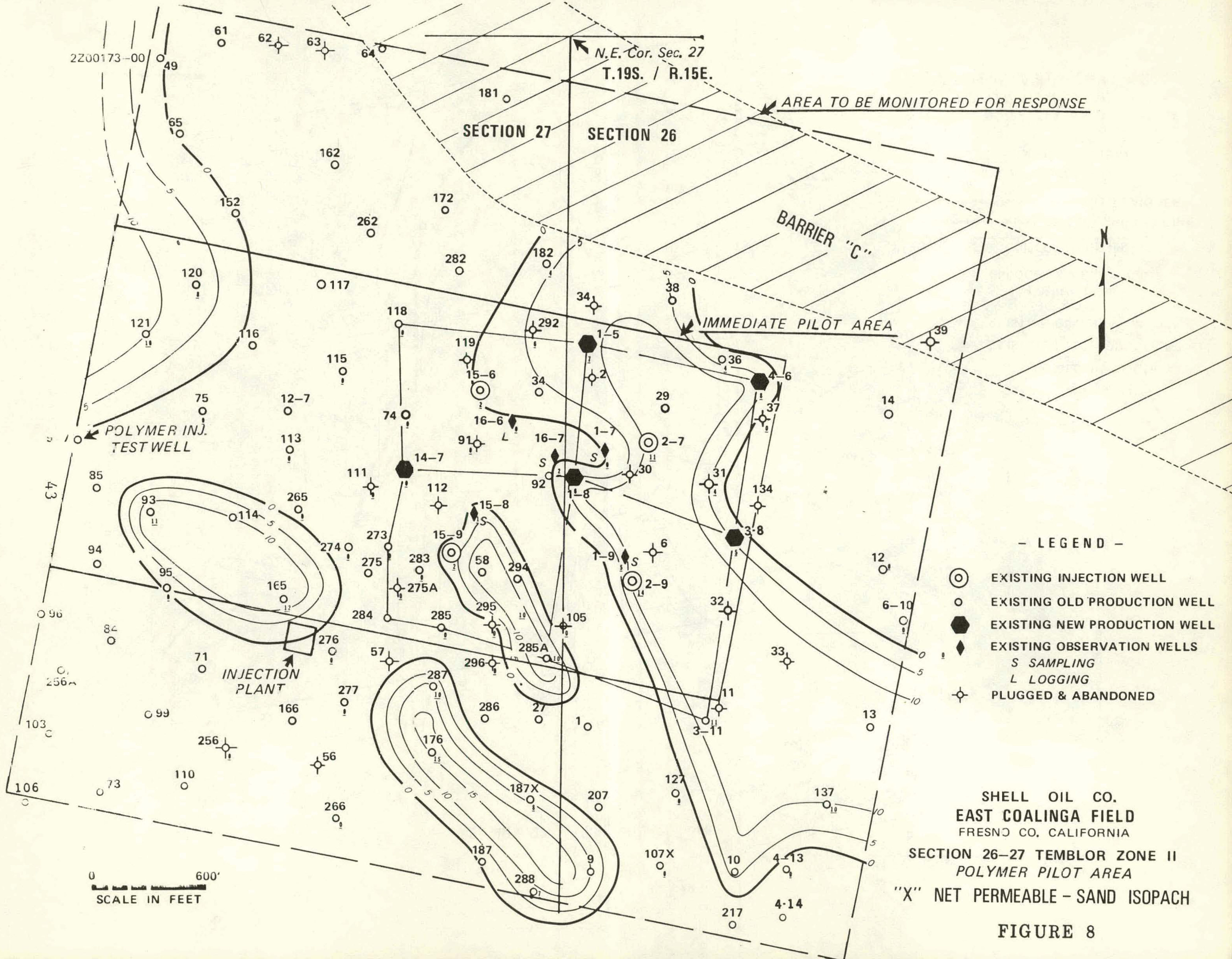


SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA

SECTION 26-27 TEMBLOR ZONE II
POLYMER PILOT AREA
"G_D" NET PERMEABLE - SAND ISOPACH

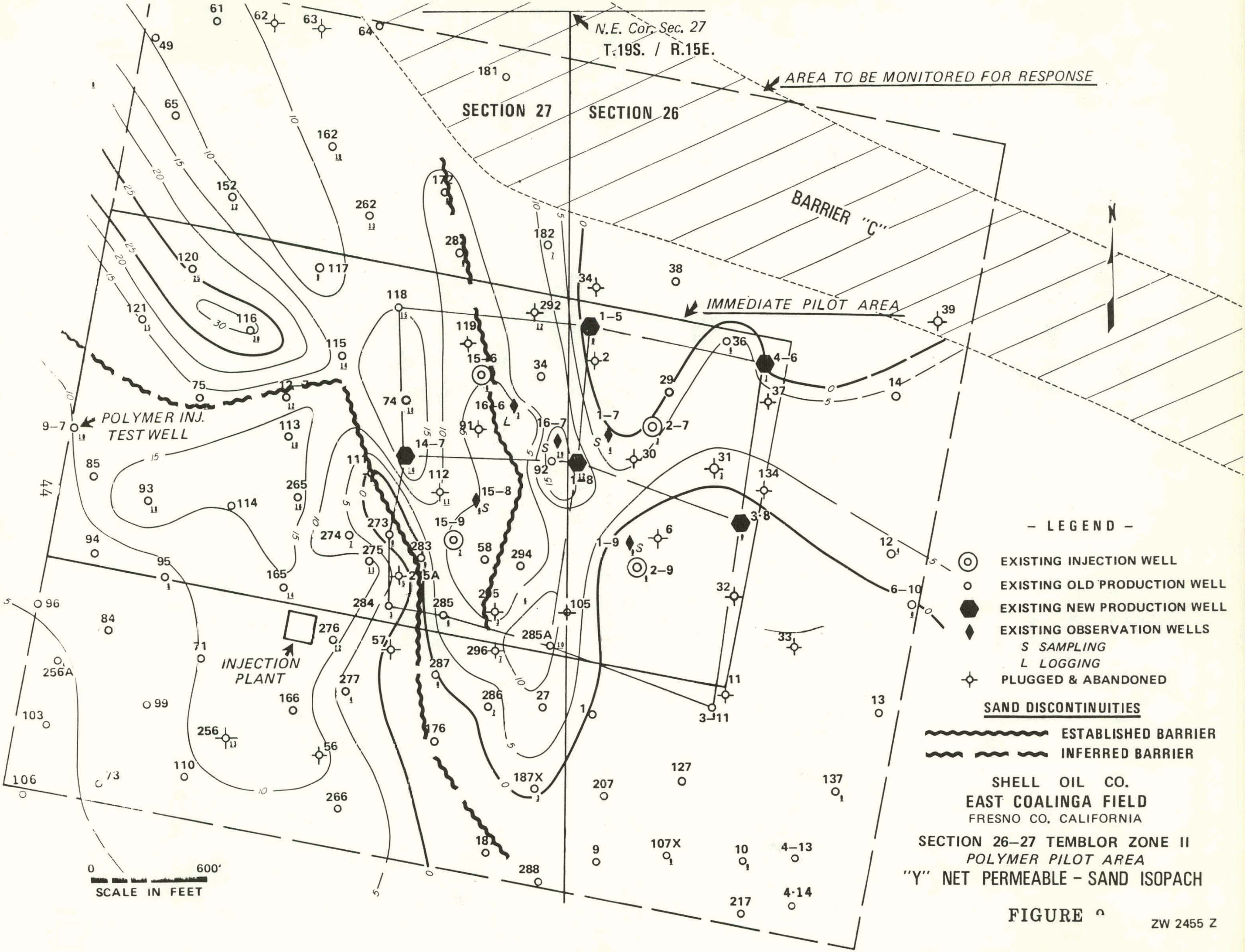
FIGUR

ZW 24



SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA
SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA
"X" NET PERMEABLE – SAND ISOPACH

FIGURE 8

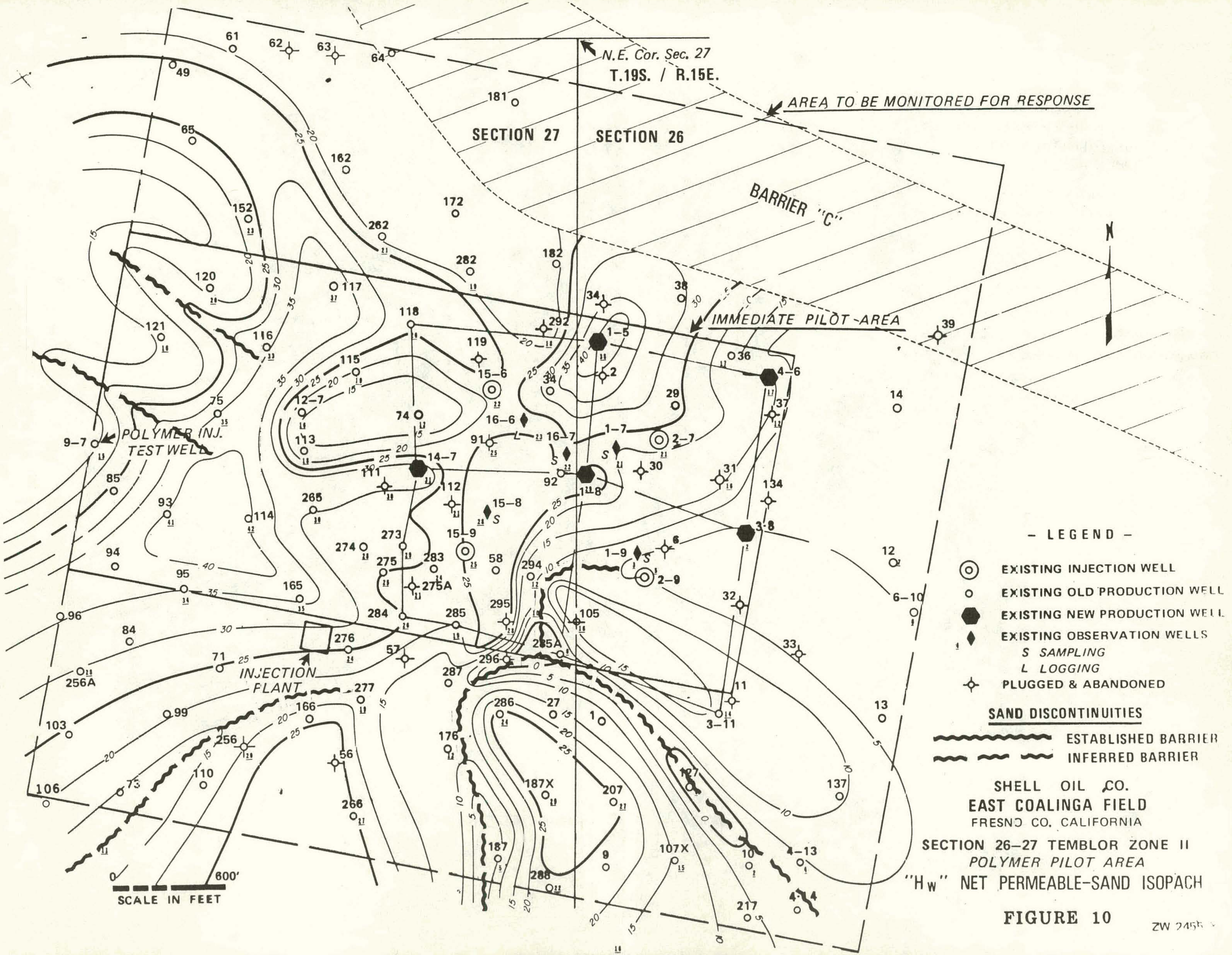


SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA

SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA
"Y" NET PERMEABLE – SAND ISOPACH

FIGURE 9

ZW 2455 Z



SHELL OIL CO.

EAST COALINGA FIELD

FRESNO CO. CALIFORNIA

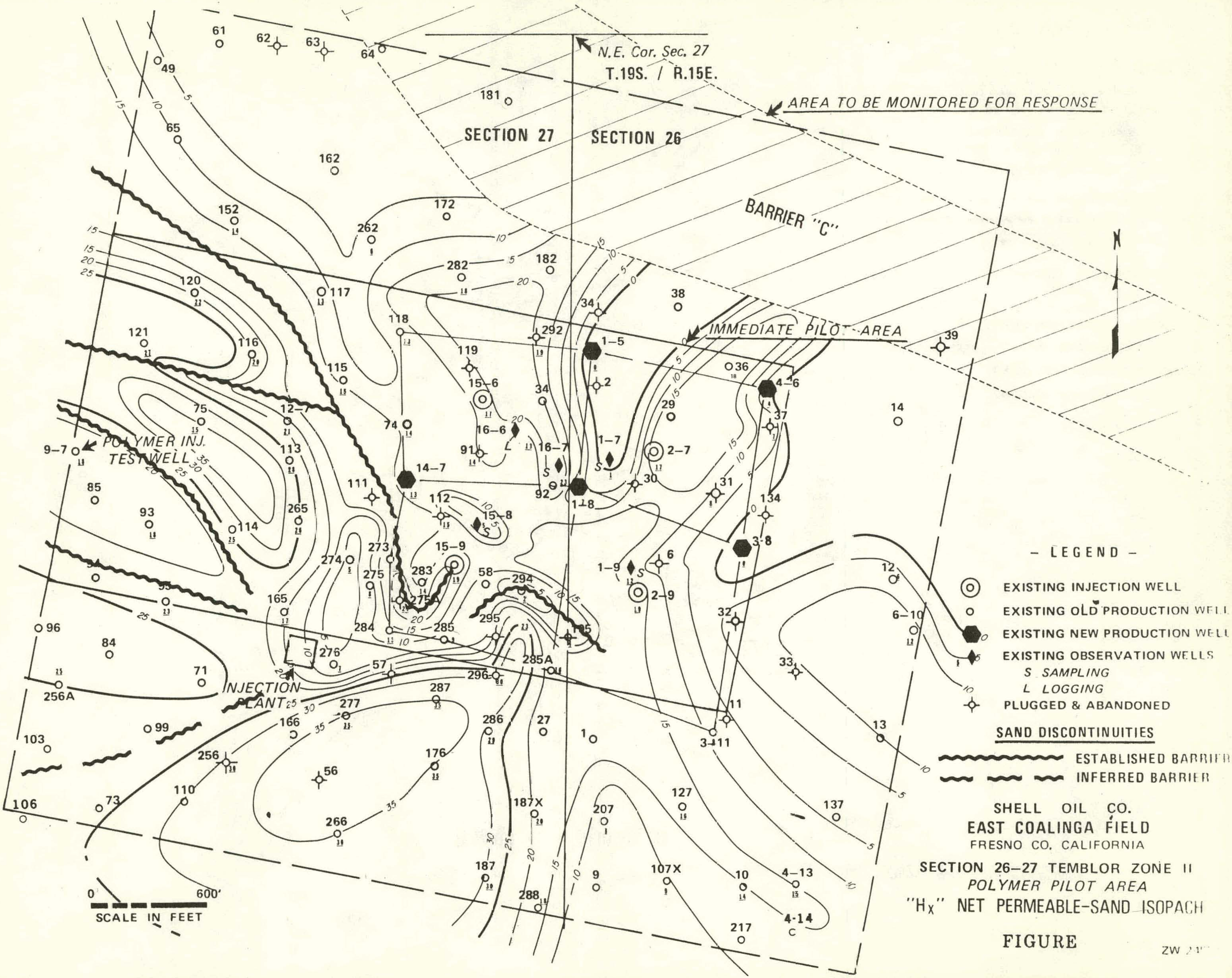
SECTION 26–27 TEMBLOR ZONE II

POLYMER PILOT AREA

"H_W" NET PERMEABLE-SAND ISOPACH

FIGURE 10

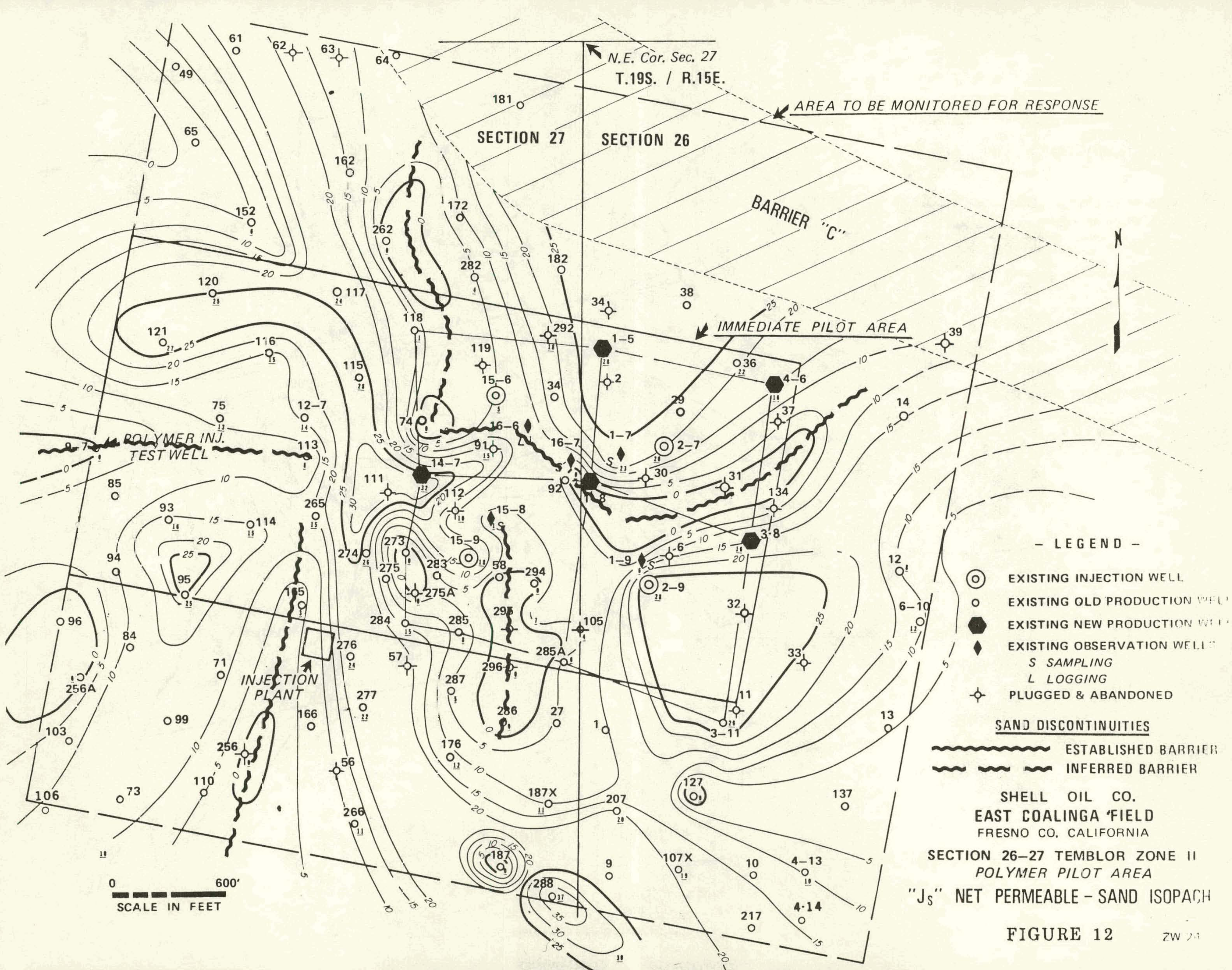
ZW 2455



SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA

SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA
"H_X" NET PERMEABLE-SAND ISOPACH

FIGURE

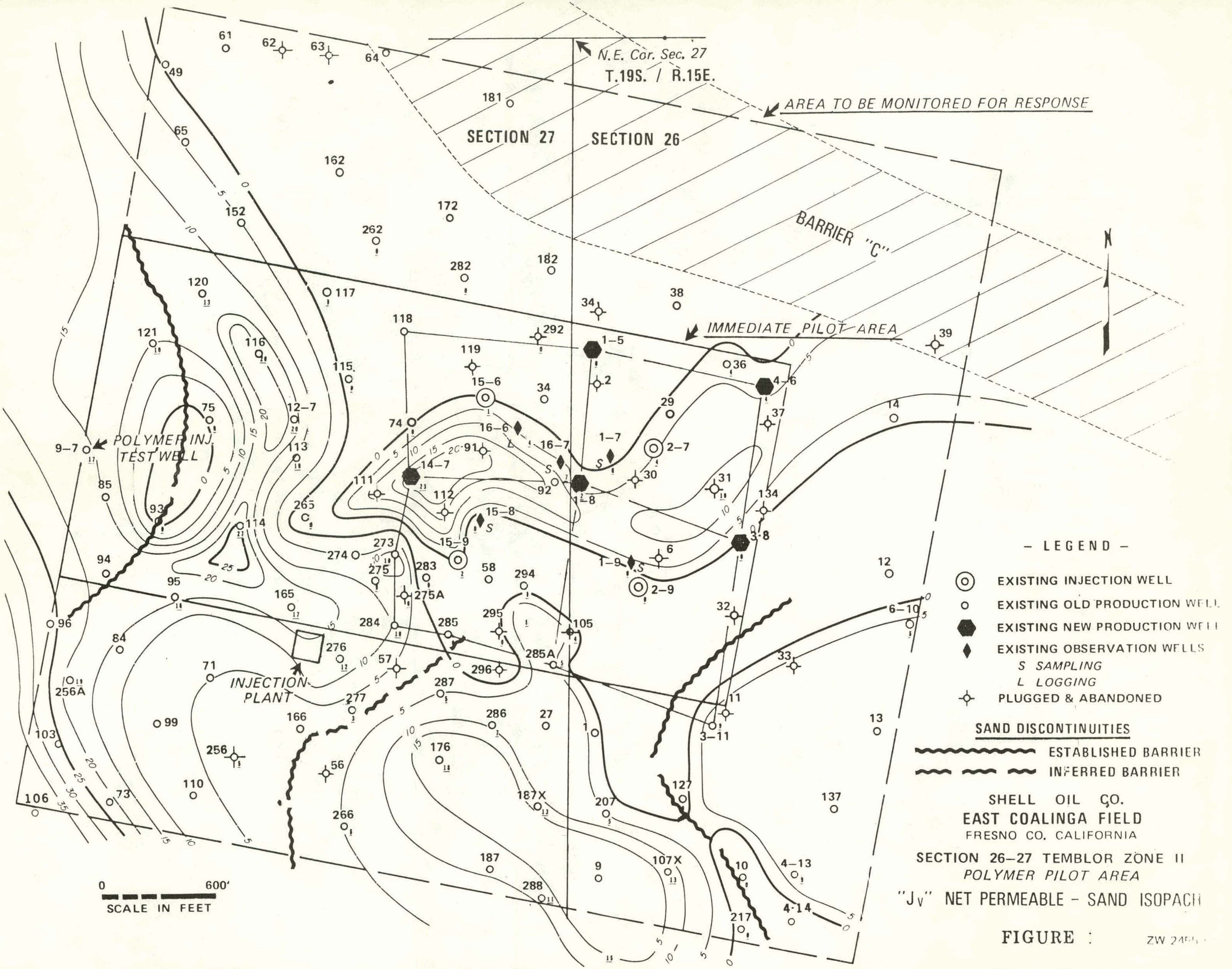


SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA

SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA

"J_S" NET PERMEABLE - SAND ISOPACH

FIGURE 12



SHELL OIL CO.
EAST COALINGA FIELD
FRESNO CO. CALIFORNIA

SECTION 26–27 TEMBLOR ZONE II
POLYMER PILOT AREA
"Jv" NET PERMEABLE – SAND ISOPACH

FIGURE :

ZW 24[illegible]

FIGURE 14

COALINGA POLYMER PILOT
SENSITIVITY OF SHALE CONTENT ON LOG CALCULATED WATER SATURATION

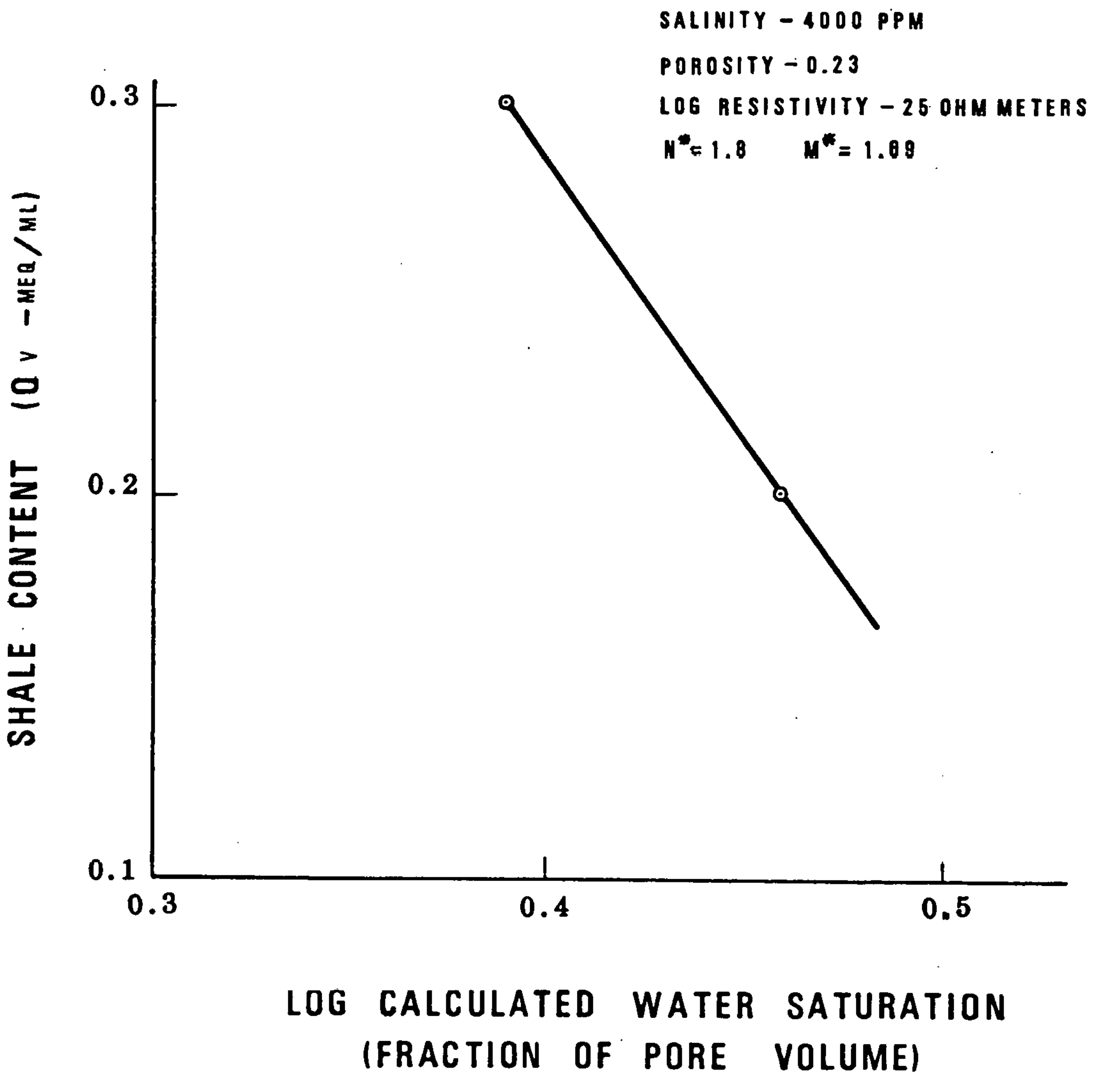


FIGURE 15

COALINGA POLYMER PILOT

SENSITIVITY OF FORMATION WATER SALINITY ON LOG CALCULATED WATER SATURATION

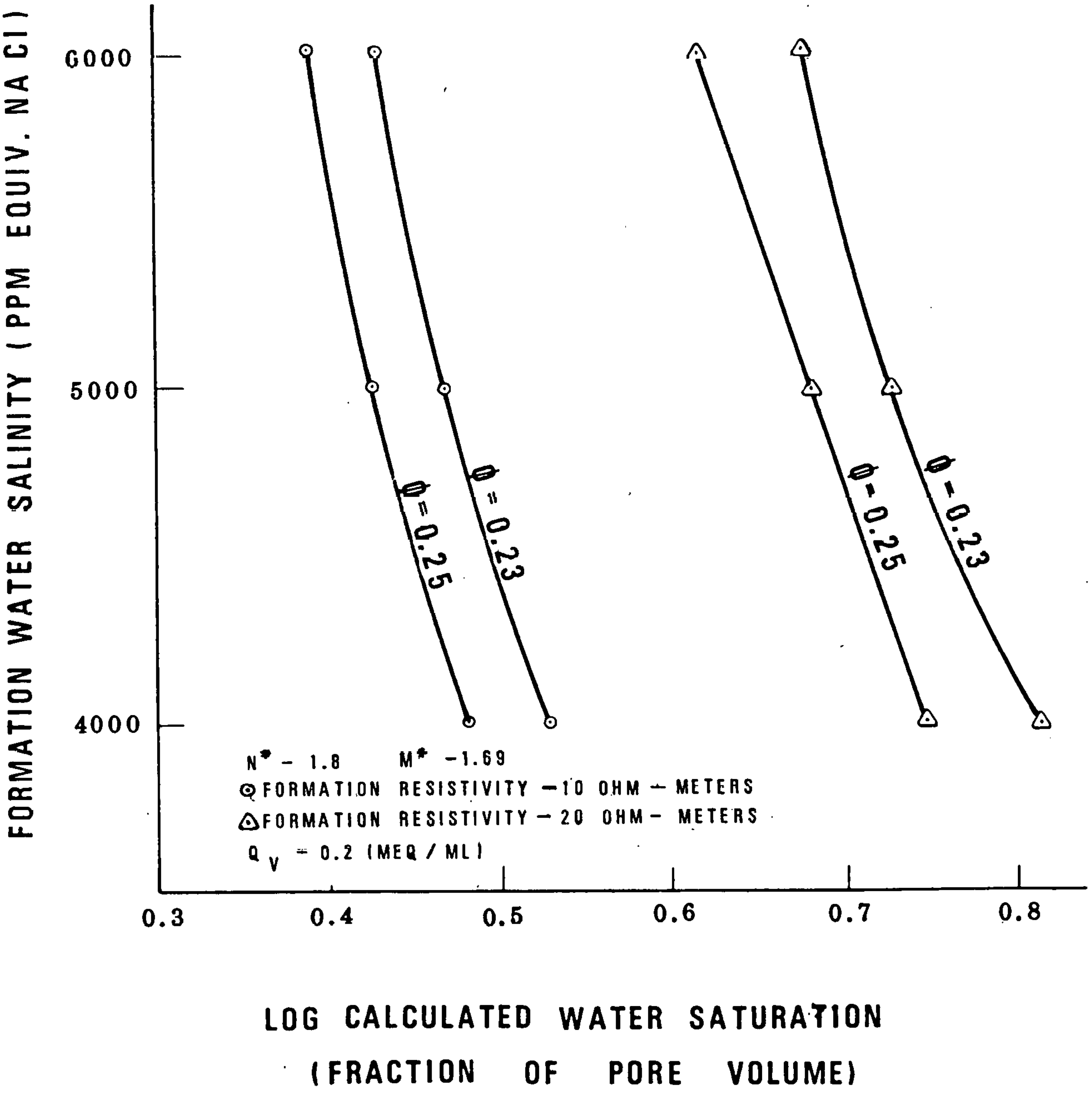


FIGURE 16

COALINGA POLYMER PILOT

CRUDE OIL VISCOSITY
VS.
TEMPERATURE

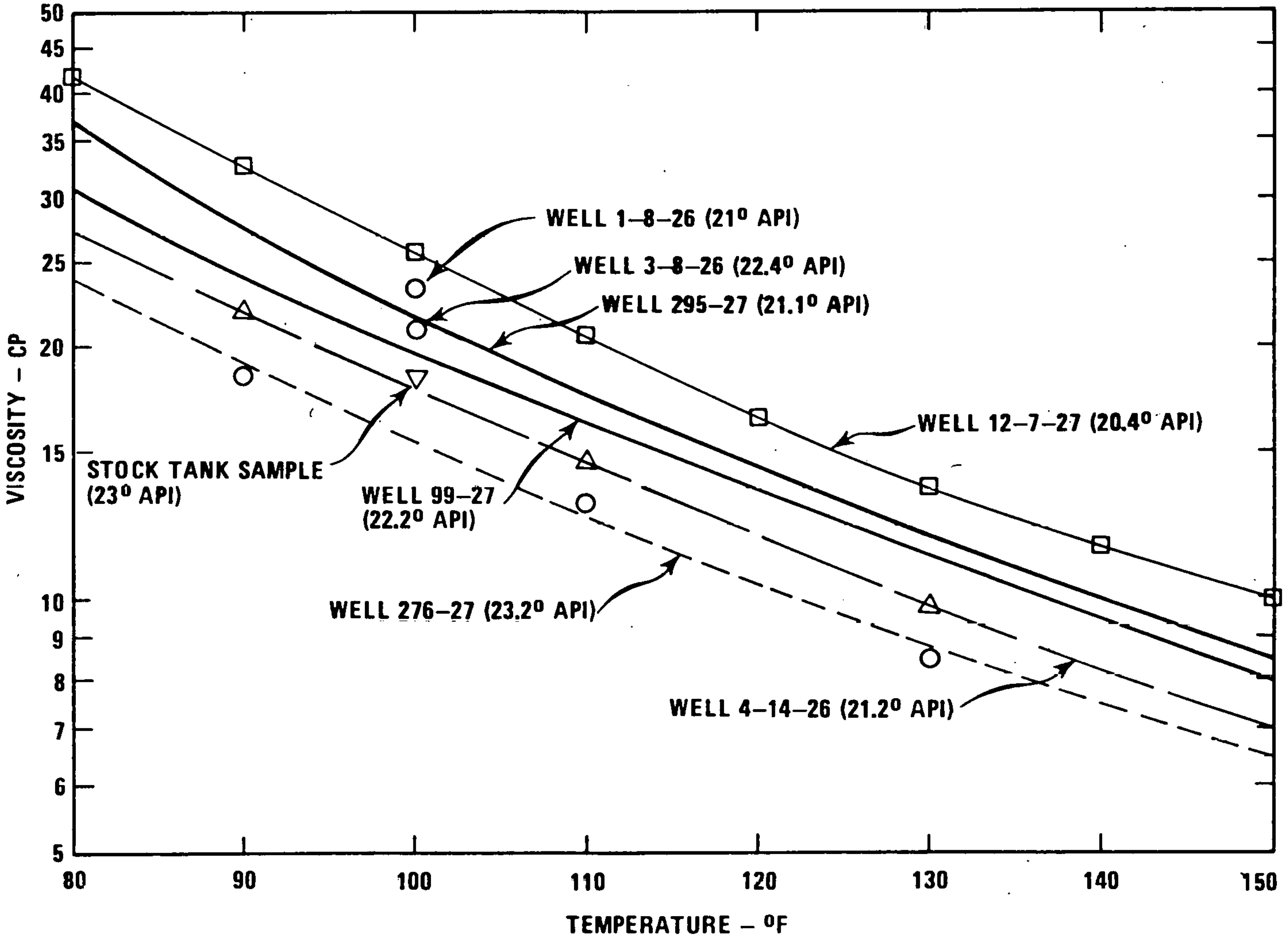


FIGURE 17

COALINGA POLYMER PILOT
CORE PERMEABILITY VS SALINITY

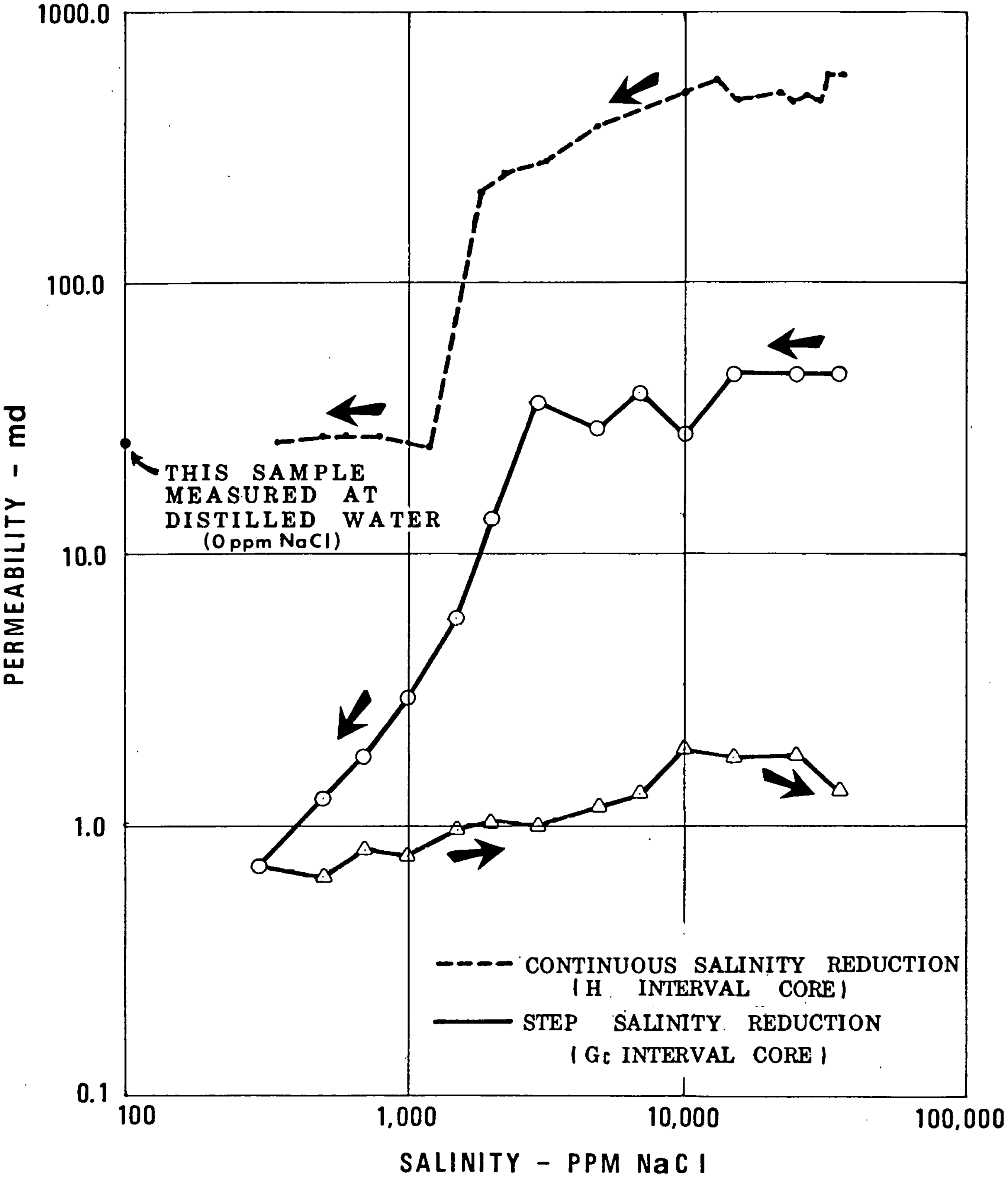


FIGURE 18

COALINGA POLYMER
PILOT PERFORMANCE CURVE
IMMEDIATE PILOT AREA

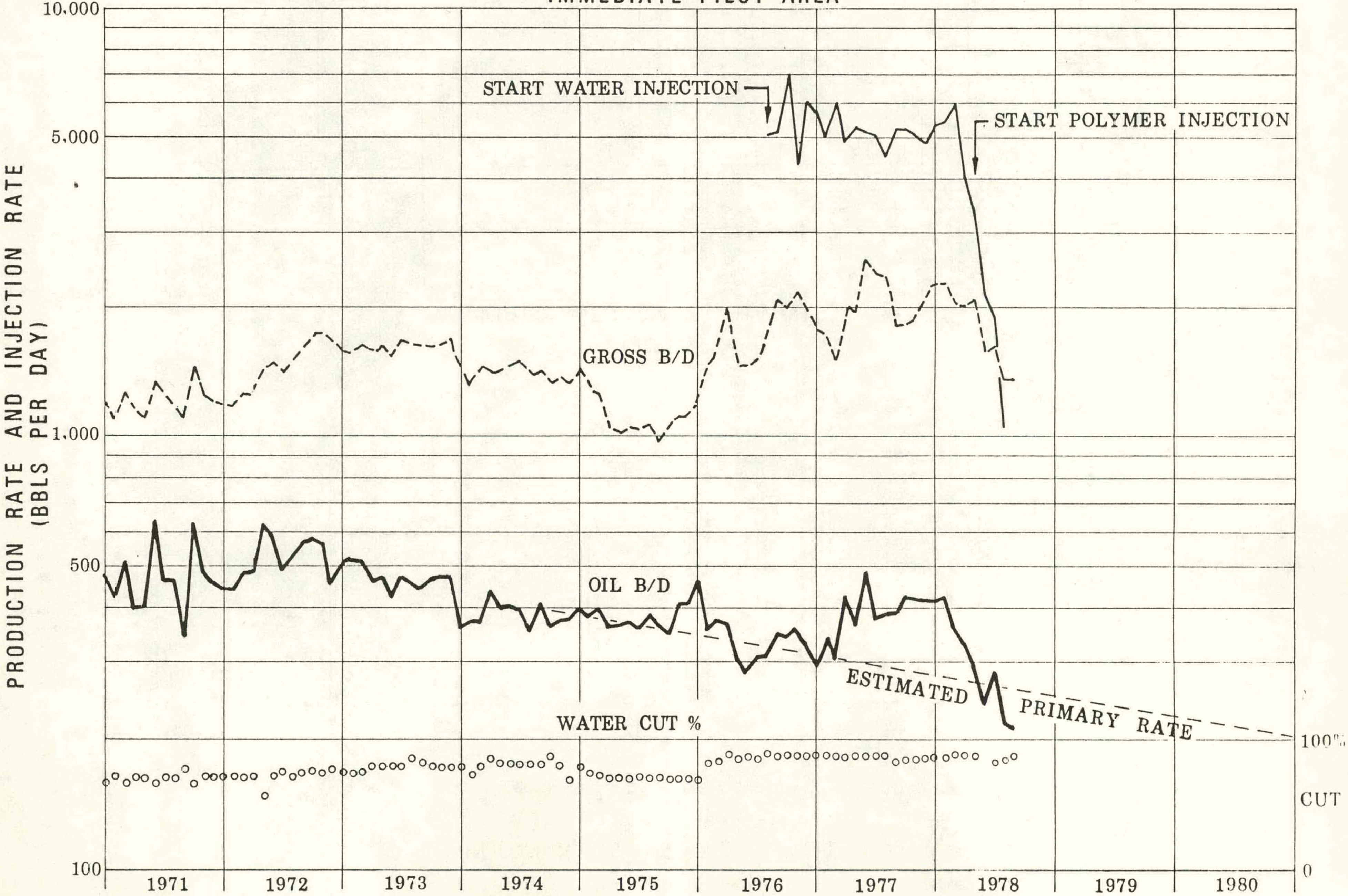


FIGURE 19
INJECTION WELL CURVES - WELL 2-7-26

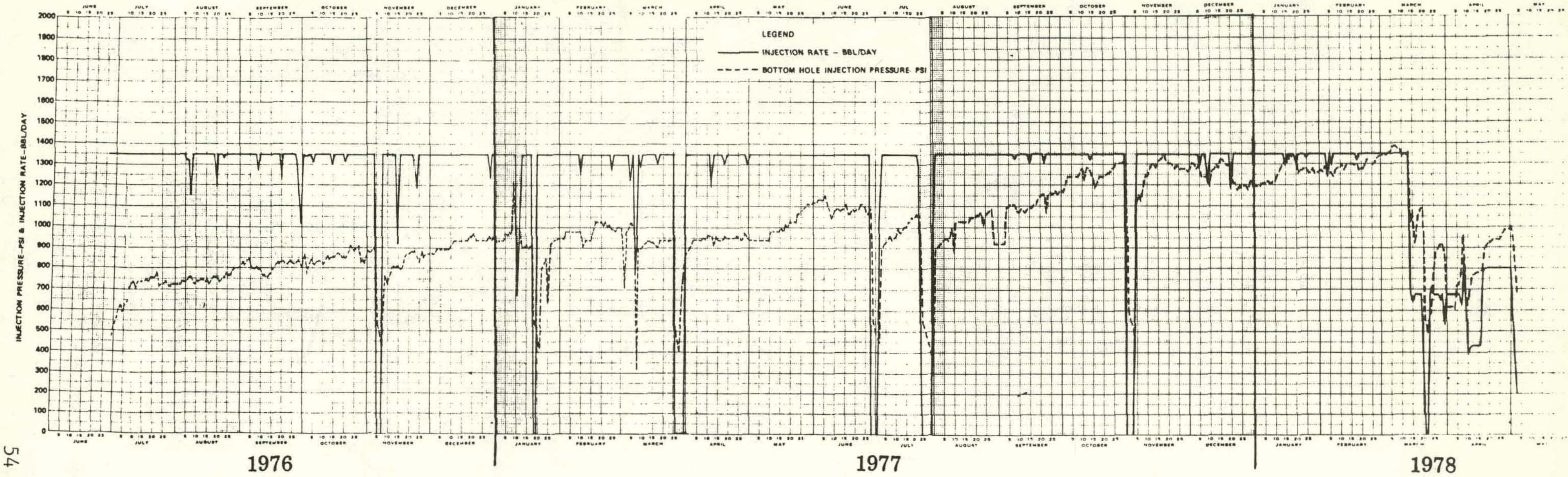


FIGURE 20
INJECTION WELL CURVES - WELL 2-9-26

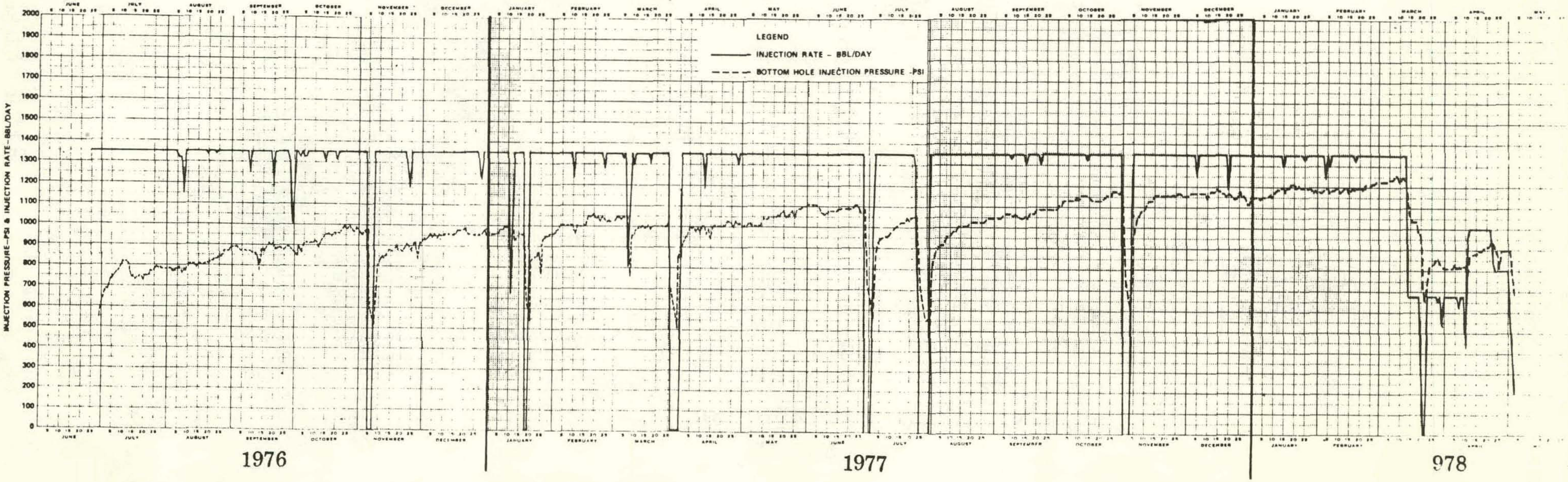


FIGURE 21
INJECTION WELL CURVES - WELL 15-6-27

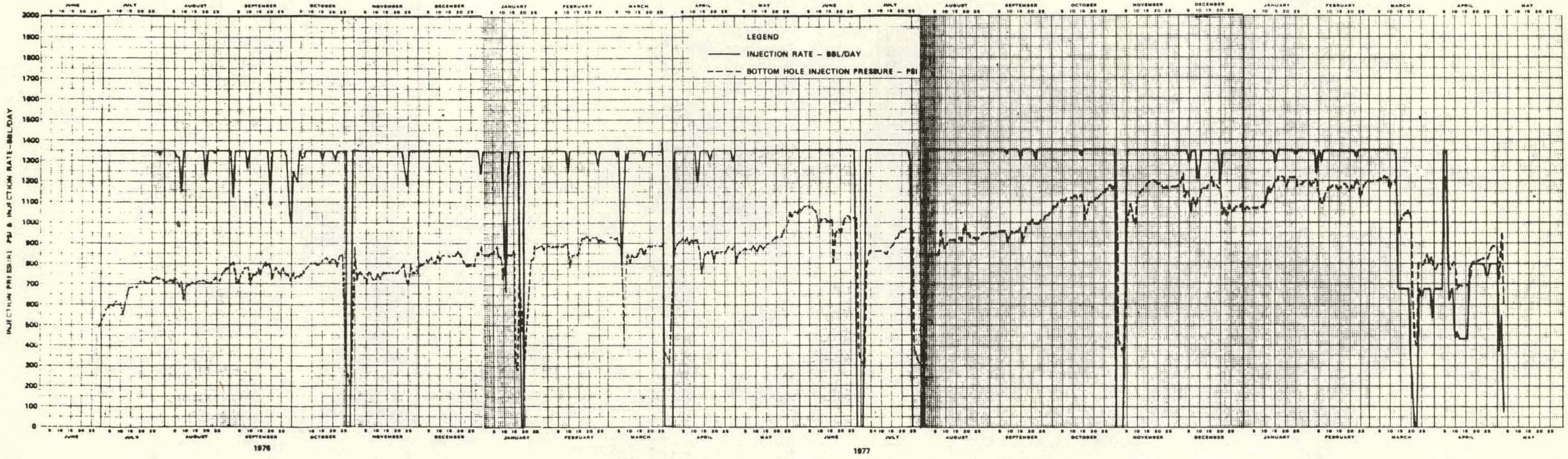


FIGURE 22
INJECTION WELL CURVES - WELL 15-9-27

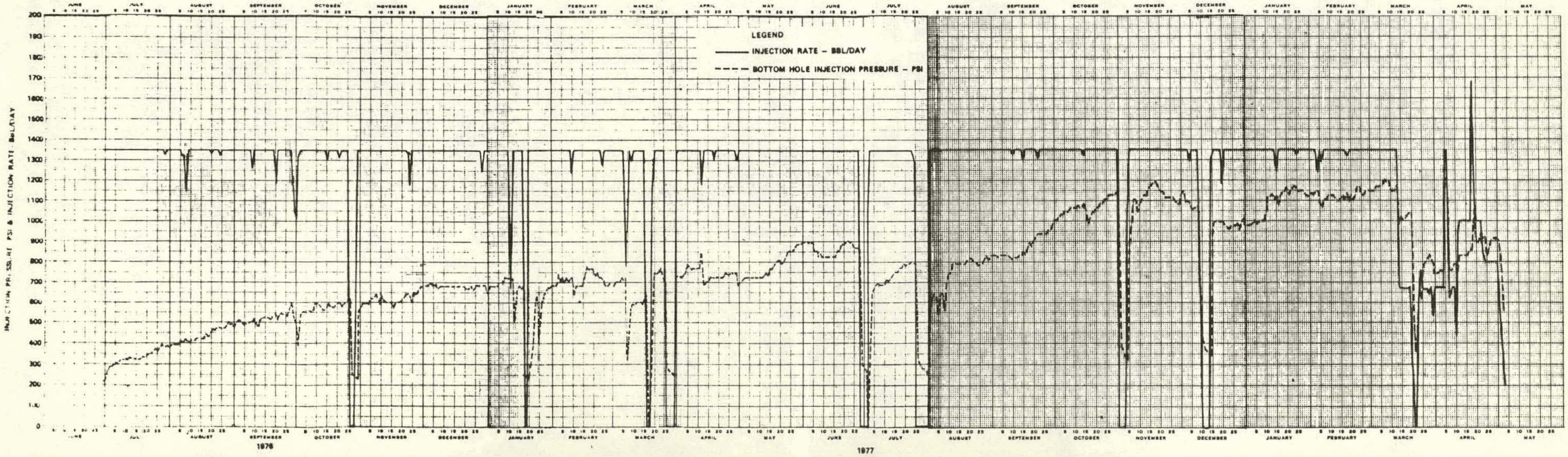


FIGURE 23

PRODUCTION WELL SCHEMATIC
WELL 1-8-26
COALINGA POLYMER PILOT

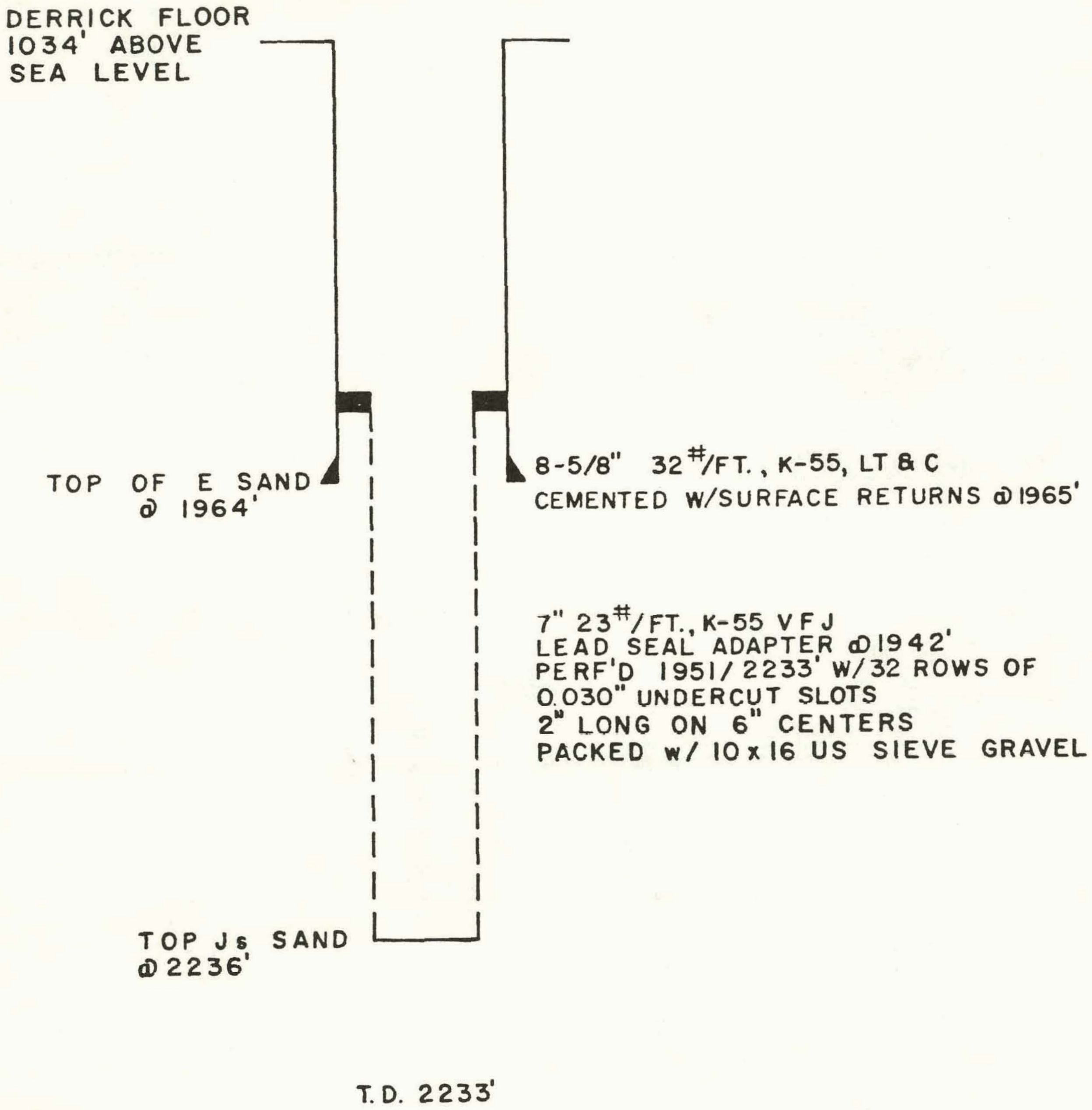
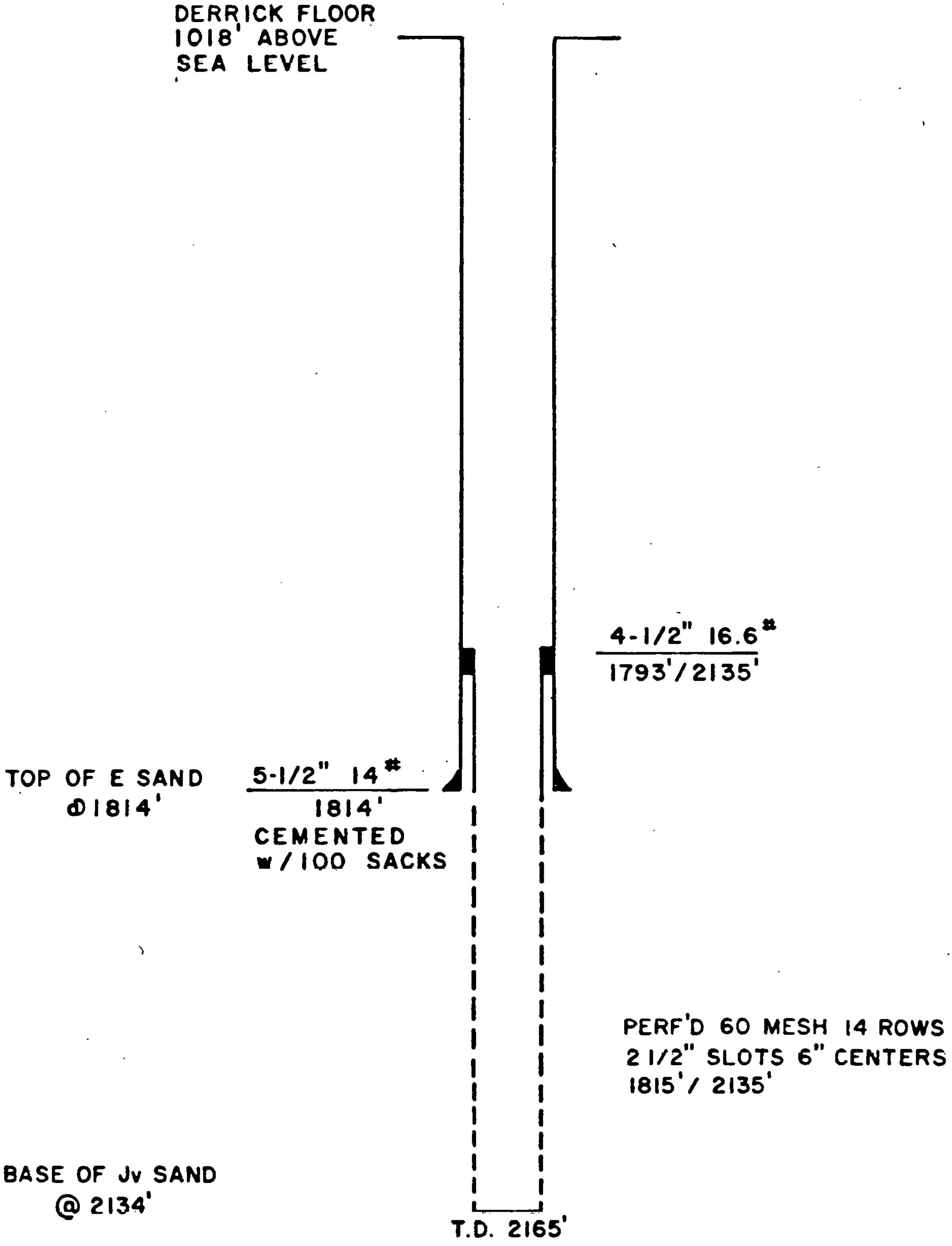


FIGURE 24

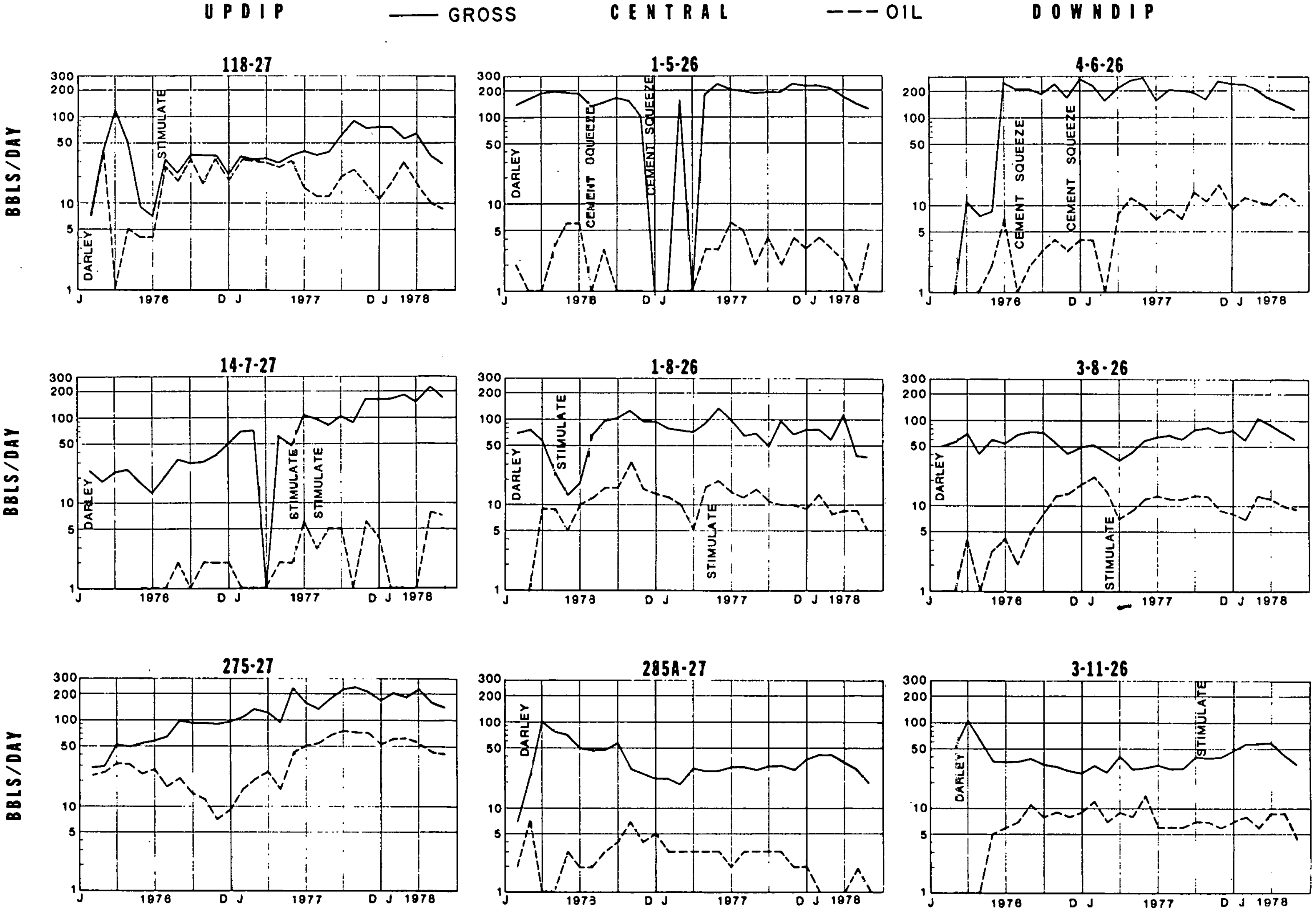
PRODUCTION WELL SCHEMATIC
WELL 285-27
COALINGA POLYMER PILOT



ZV-204 A

FIGURE 25

PRODUCTON PERFORMANCE
PATTERN PRODUCTION WELLS
COALINGA POLYMER PILOT



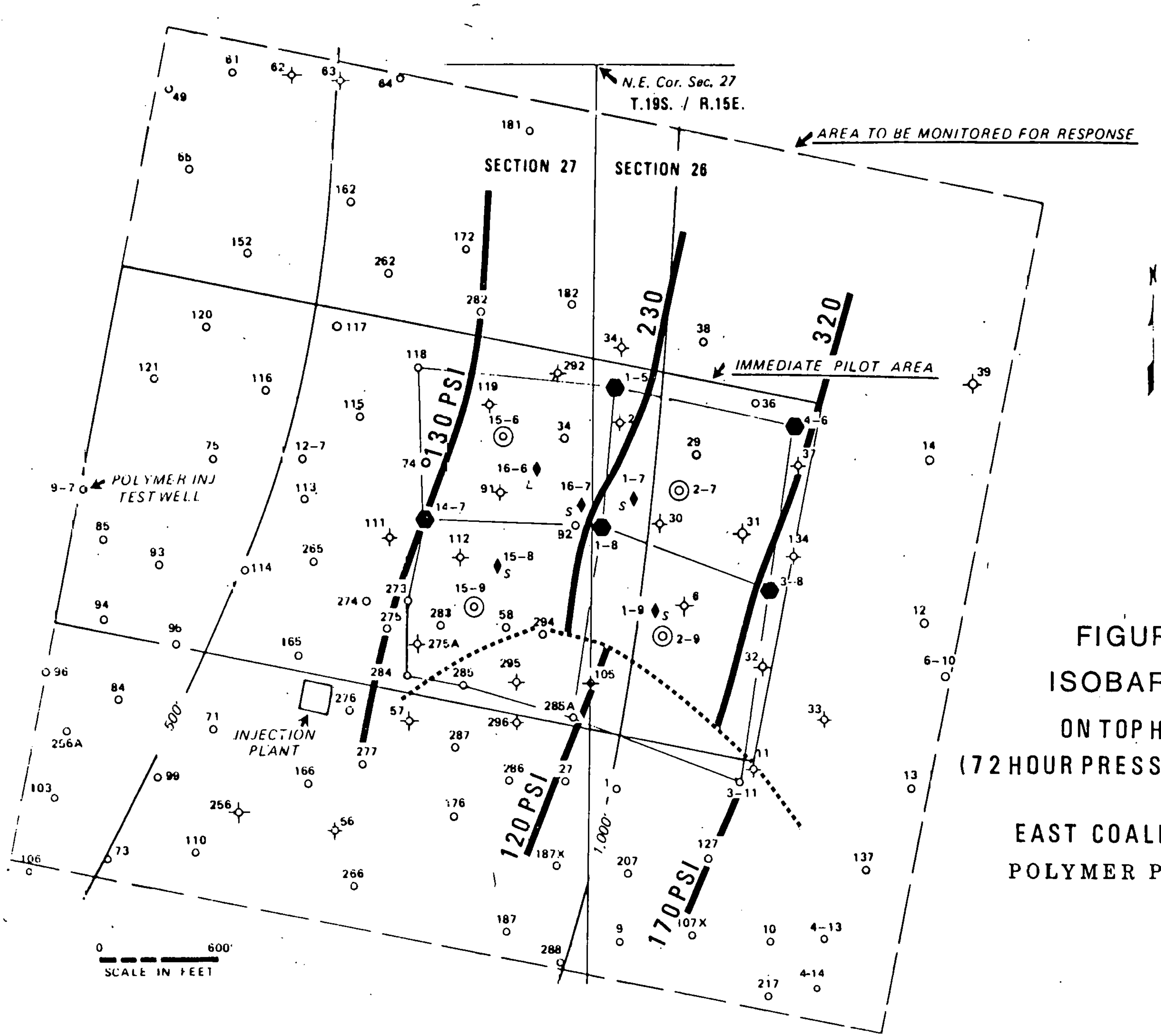


FIGURE 26

ISOBARIC MAP

ON TOP Hw (3/78)
(72 HOUR PRESSURE FALL-OFF)

EAST COALINGA FIELD
POLYMER PILOT AREA

FIGURE 27

SAMPLING OBSERVATION WELL SCHEMATIC
1-7-26
COALINGA POLYMER PILOT

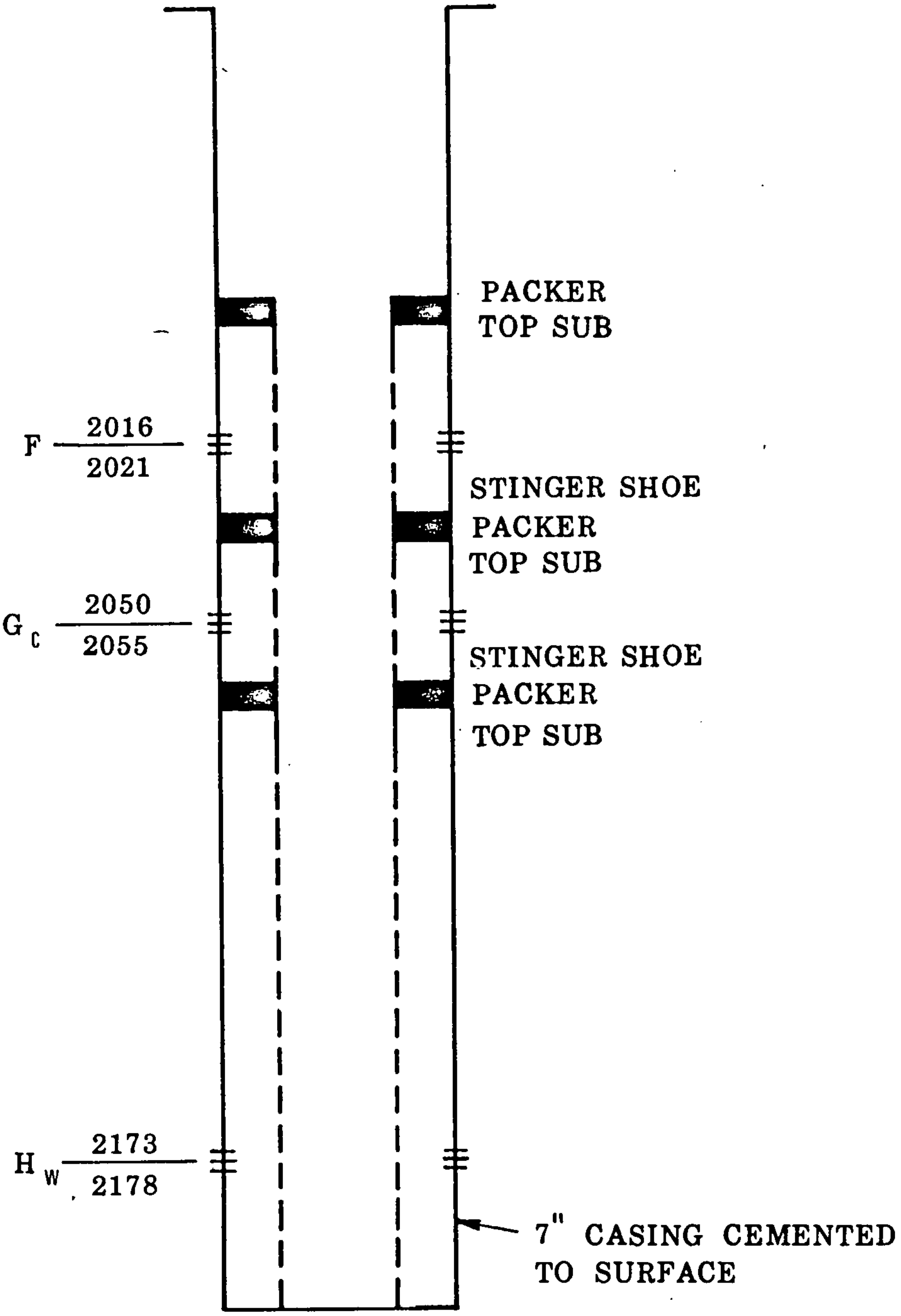
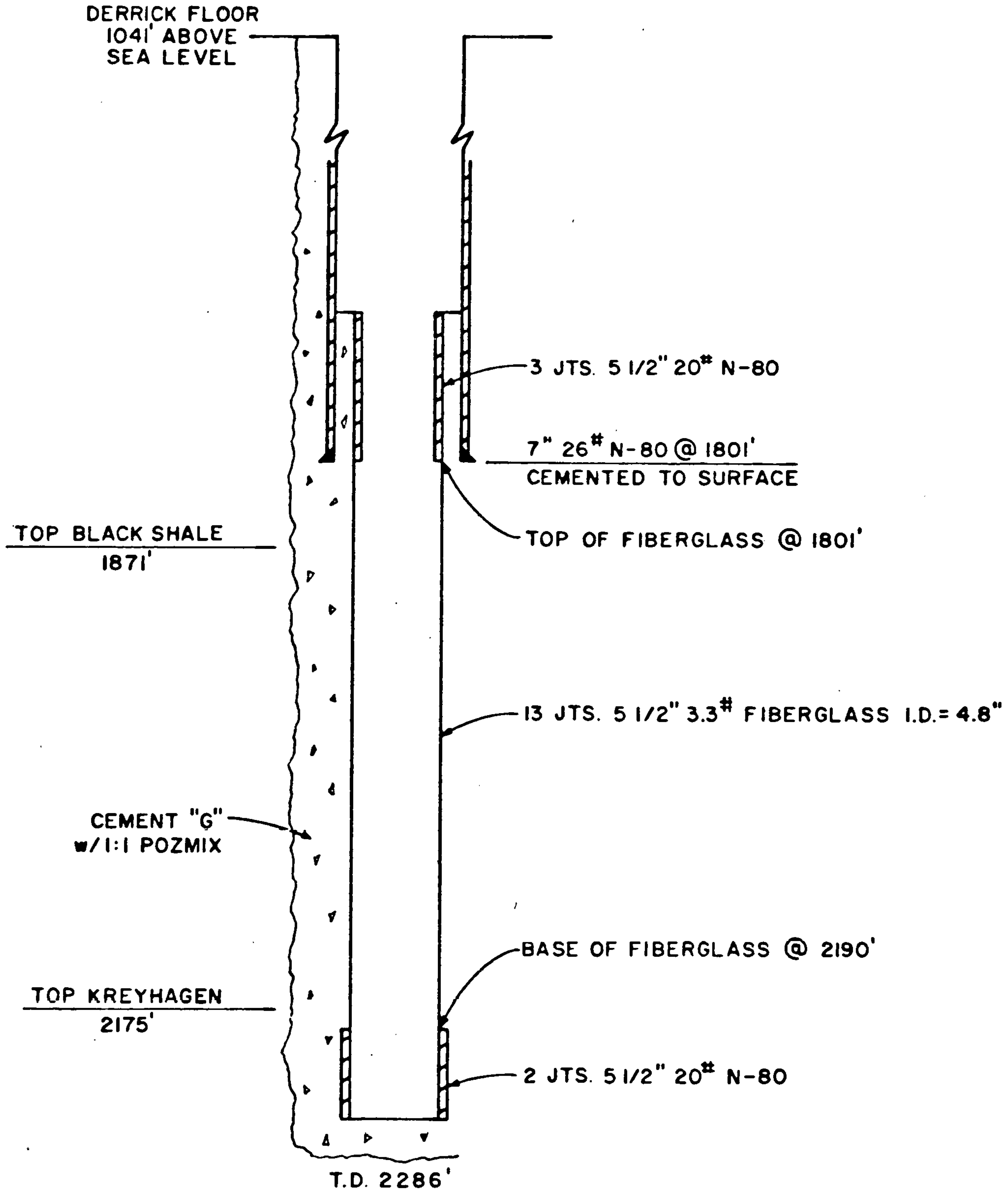


FIGURE 28

LOGGING OBSERVATION WELL SCHEMATIC
WELL 16-6-27
COALINGA POLYMER PILOT



ZV-204 D

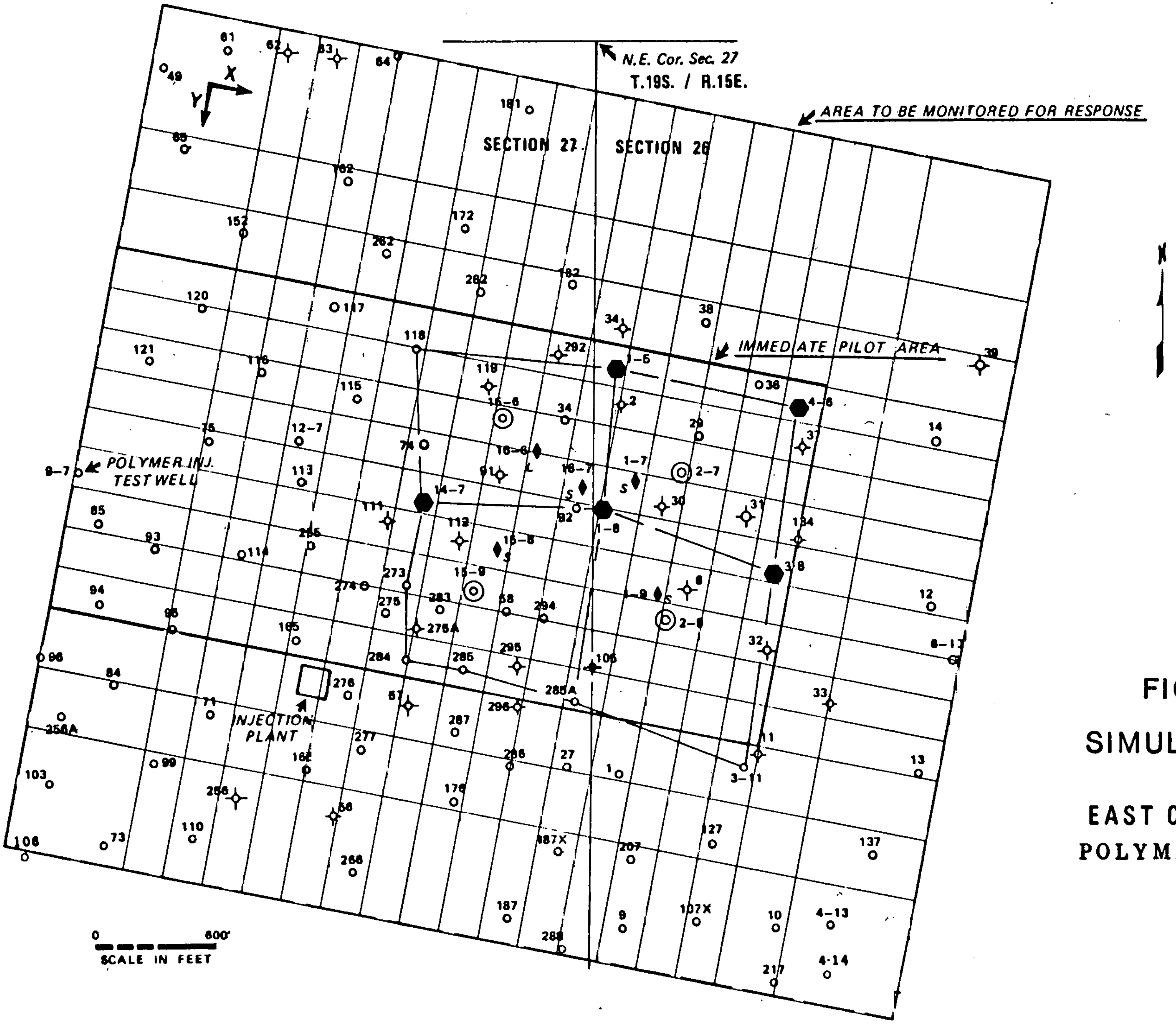


FIGURE 29

SIMULATION GRID

EAST COALINGA FIELD

POLYMER PILOT AREA

FIGURE 30

SIMULATION PRIMARY HISTORY MATCH
COALINGA POLYMER PILOT

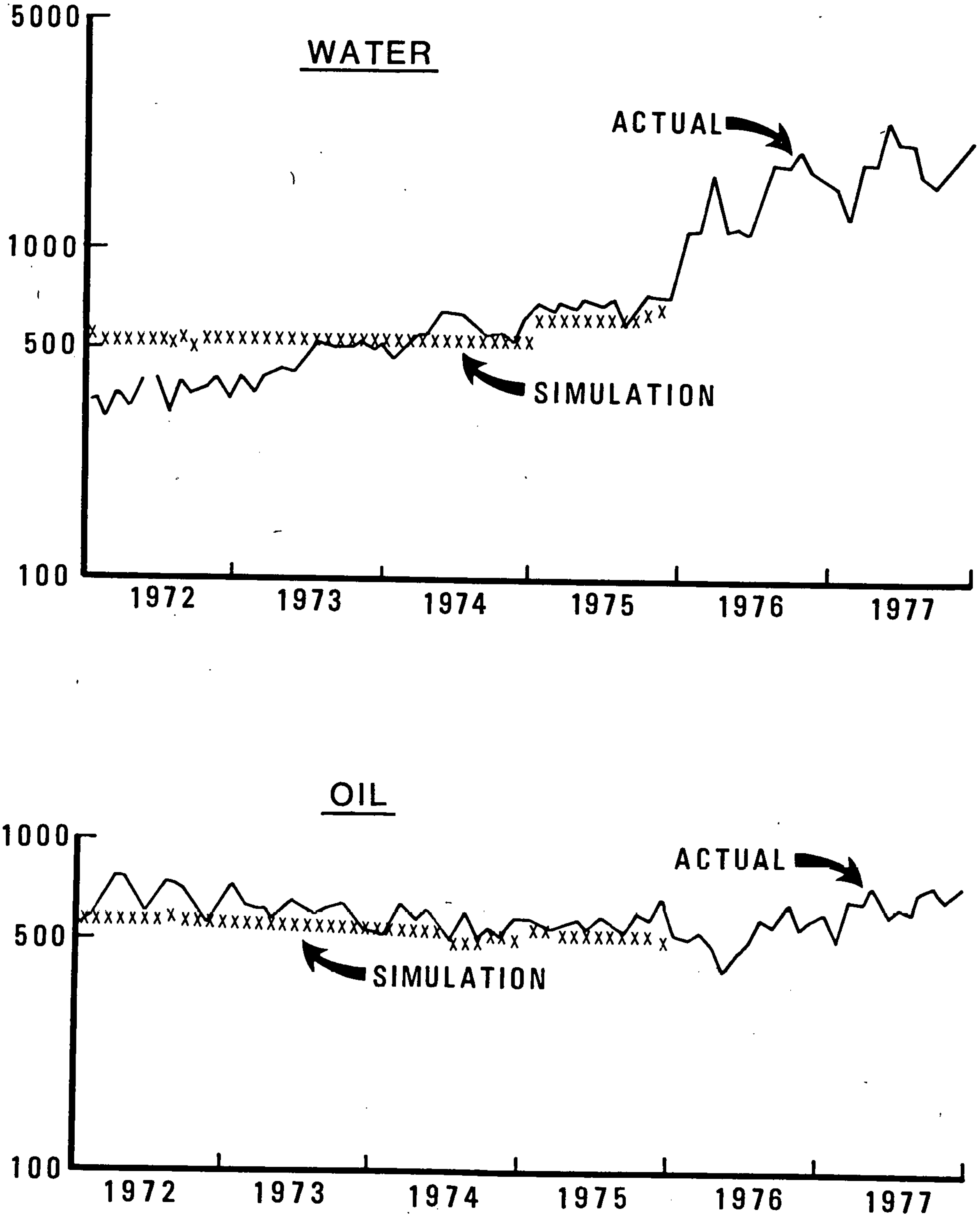


FIGURE 31
SENSITIVITY STUDY
WATERFLOOD PERFORMANCE PREDICTION
VS RELATIVE PERMEABILITY SHAPE
COALINGA POLYMER PILOT

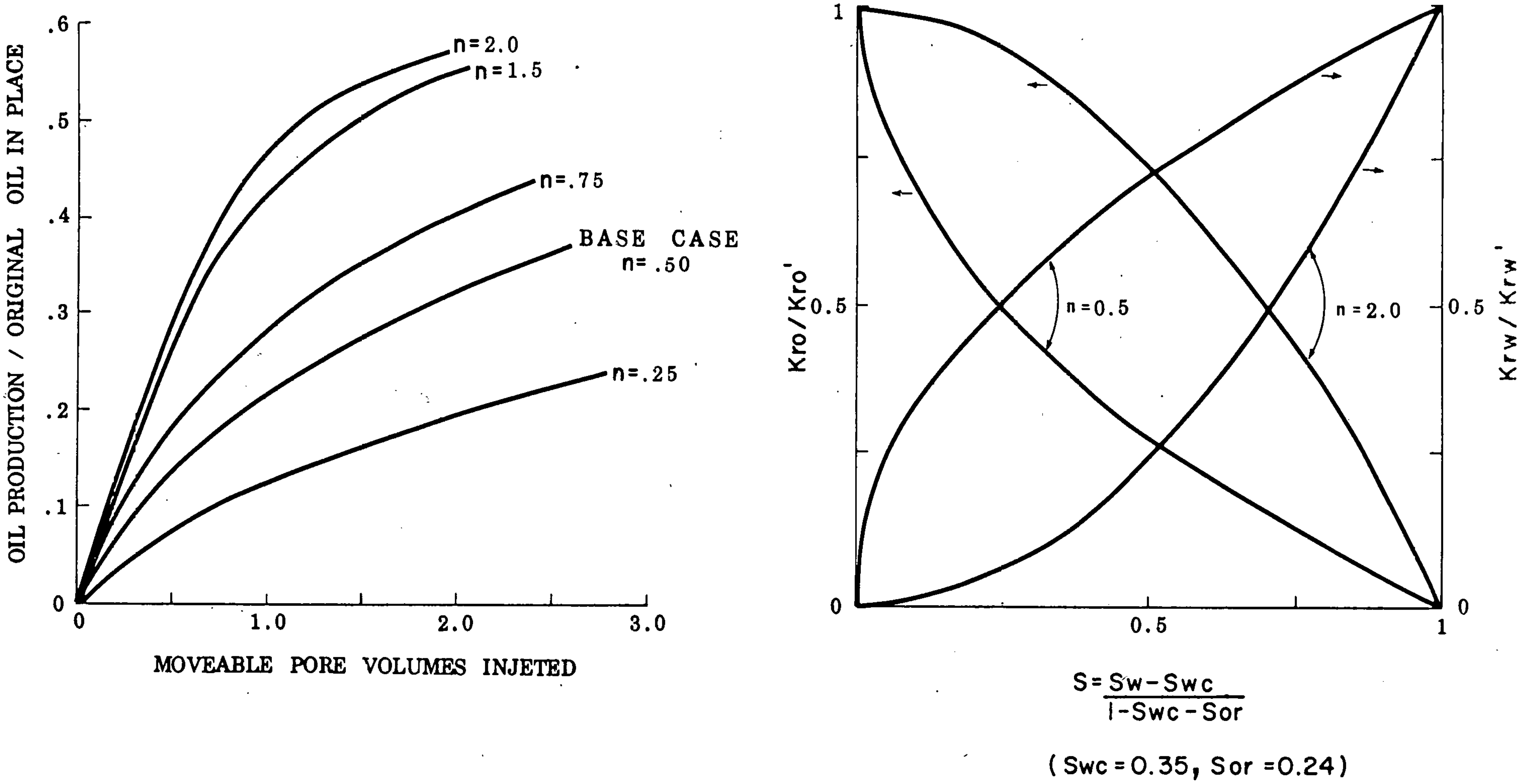


FIGURE 32

SENSITIVITY STUDY
WATERFLOOD PERFORMANCE PREDICTION
VS ROCK COMPRESSIBILITY
COALINGA POLYMER PILOT

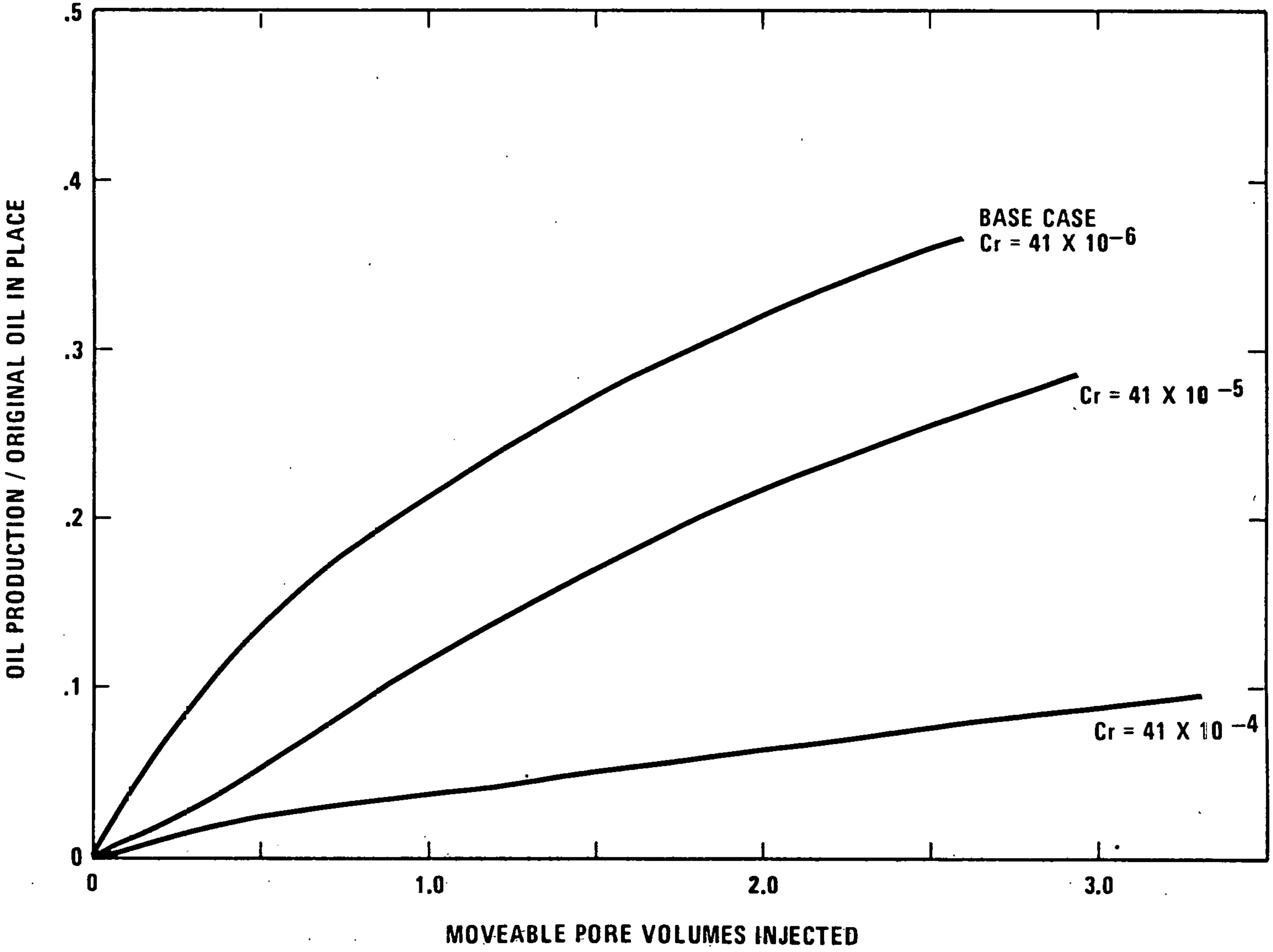
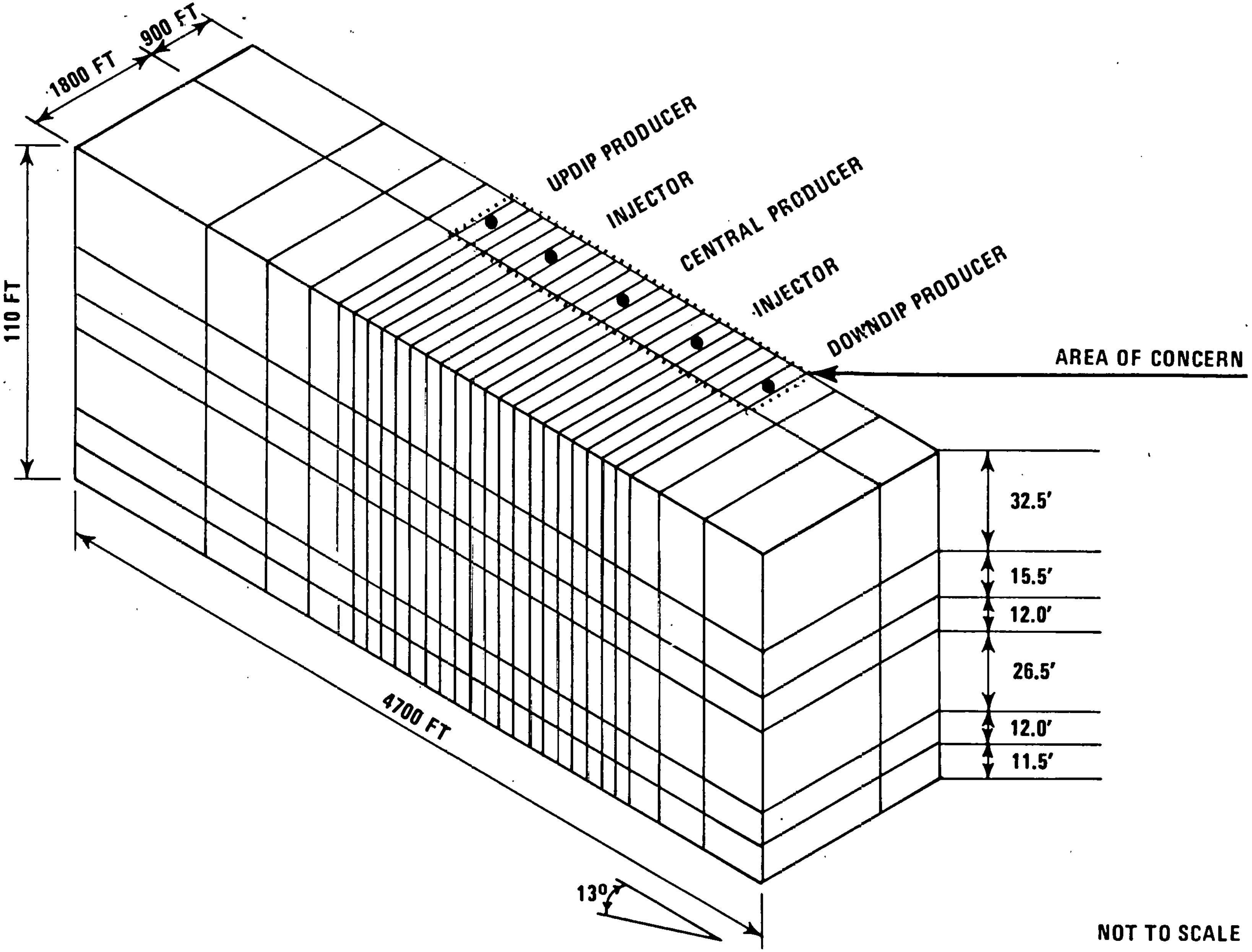


FIGURE 33

POLYMER SLUG DESIGN MODEL
COALINGA POLYMER PILOT



NOT TO SCALE

FIGURE 34

POLYMER SLUG DESIGN MODEL
PRIMARY AND WATERFLOOD PREDICTIONS
COALINGA POLYMER PILOT

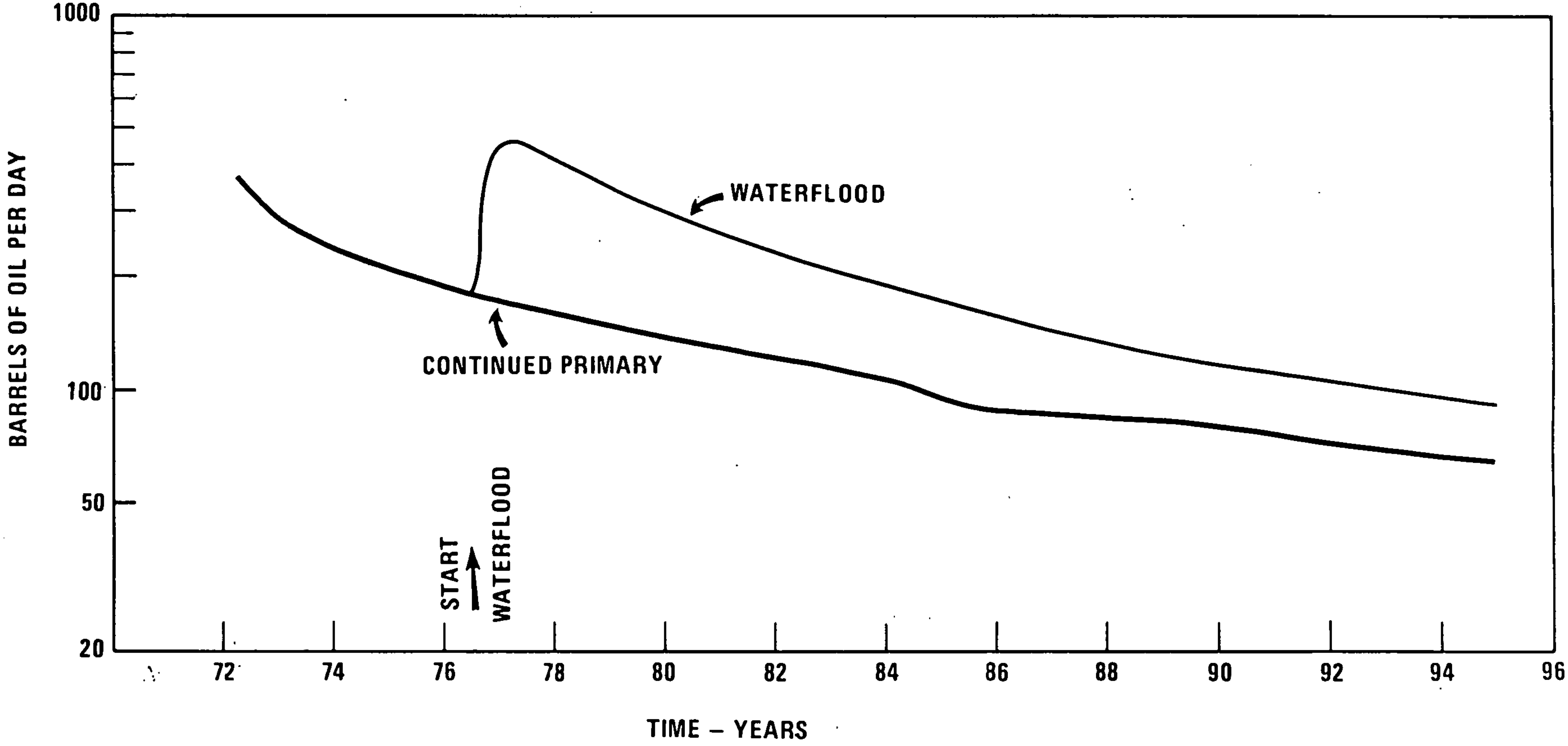


FIGURE 35

POLYMER SLUG DESIGN MODEL
POLYMER RECOVERY PREDICTION VS SLUG SIZE
COLINGA POLYMER PILOT

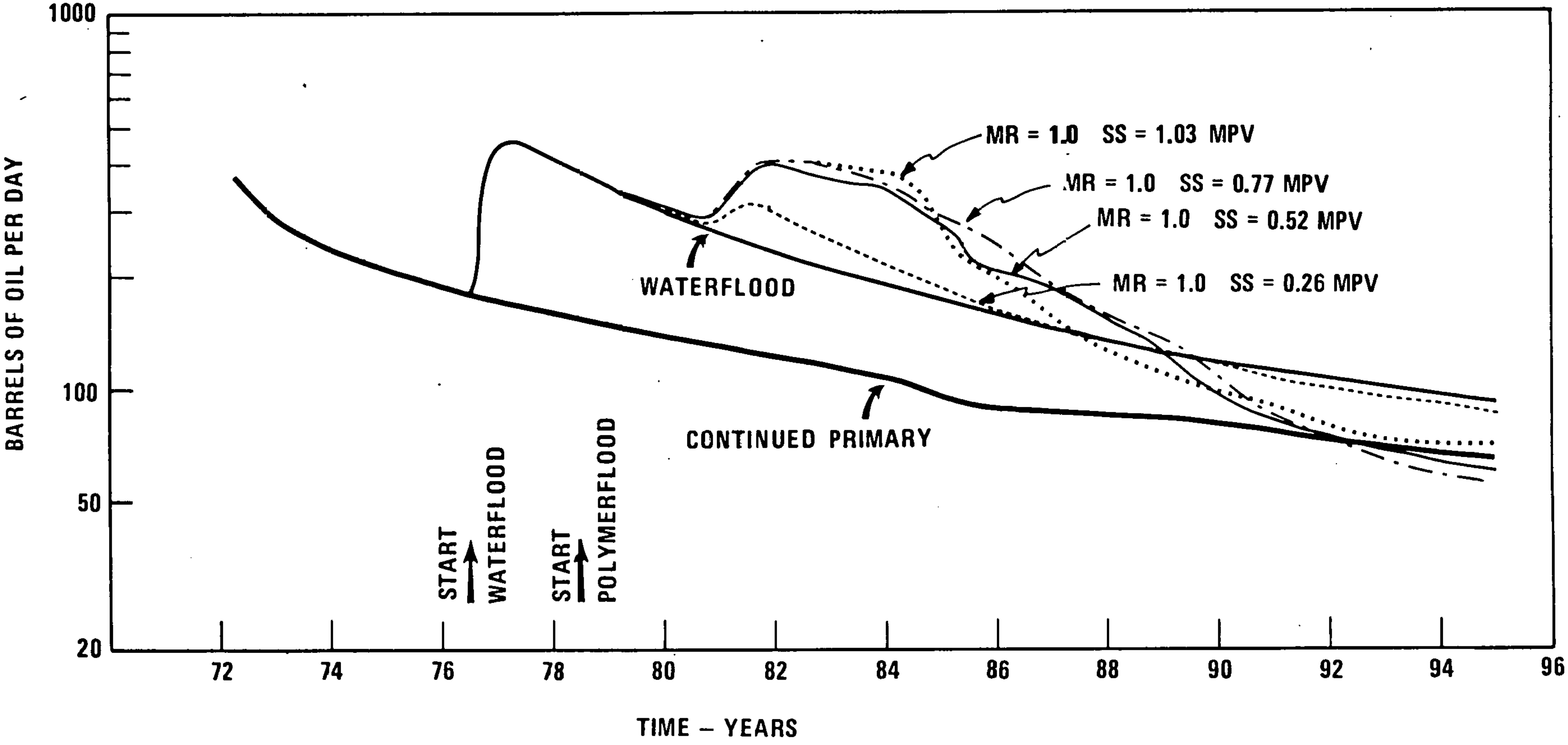


FIGURE 36
POLYMER SLUG DESIGN MODEL
POLYMER INCREMENTAL OIL RECOVERY
VS SLUG SIZE
COALINGA POLYMER PILOT

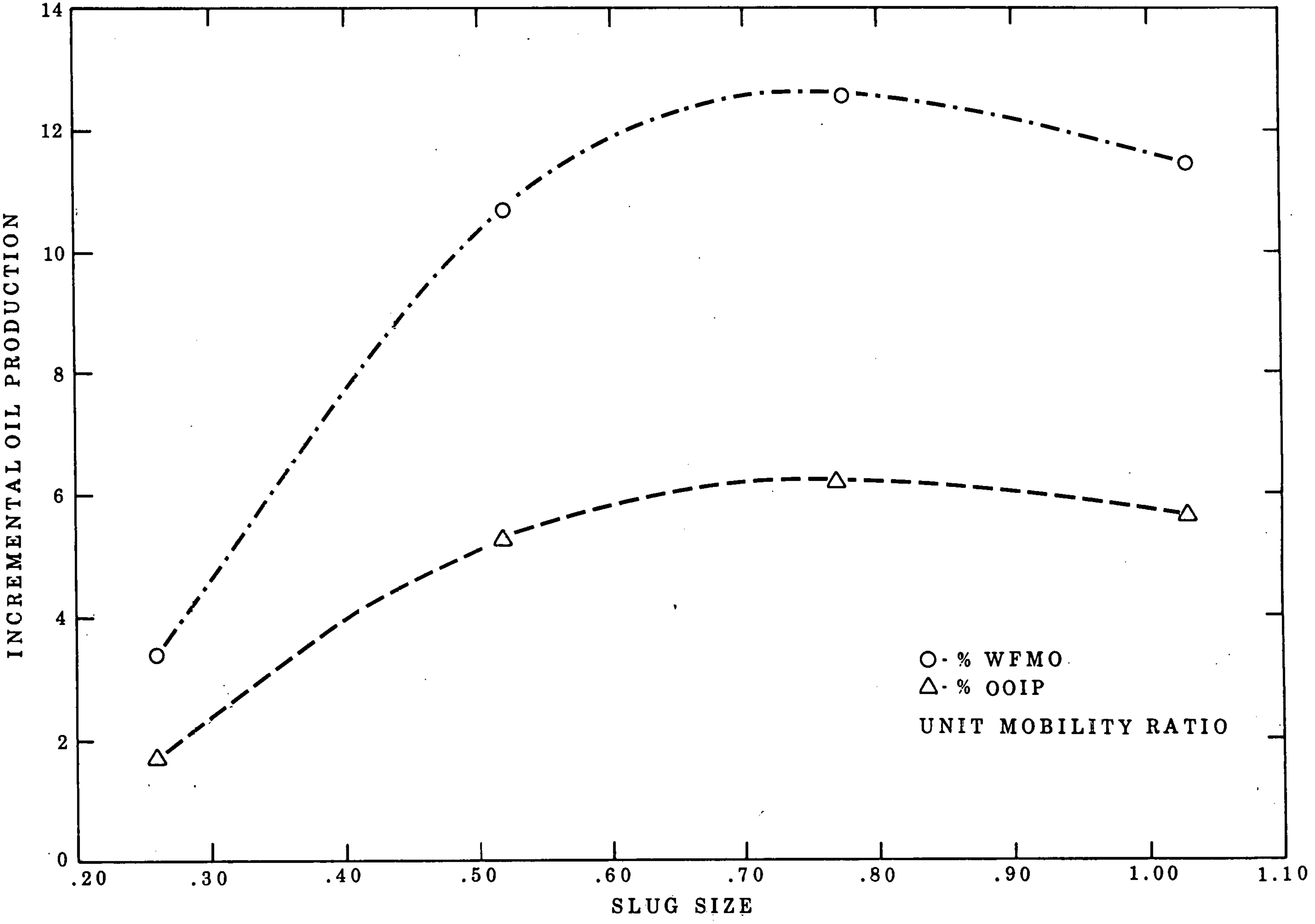


FIGURE 37

POLYMER SLUG DESIGN MODEL
POLYMER RECOVERY PREDICTION VS MOBILITY RATIO
COLINGA POLYMER PILOT

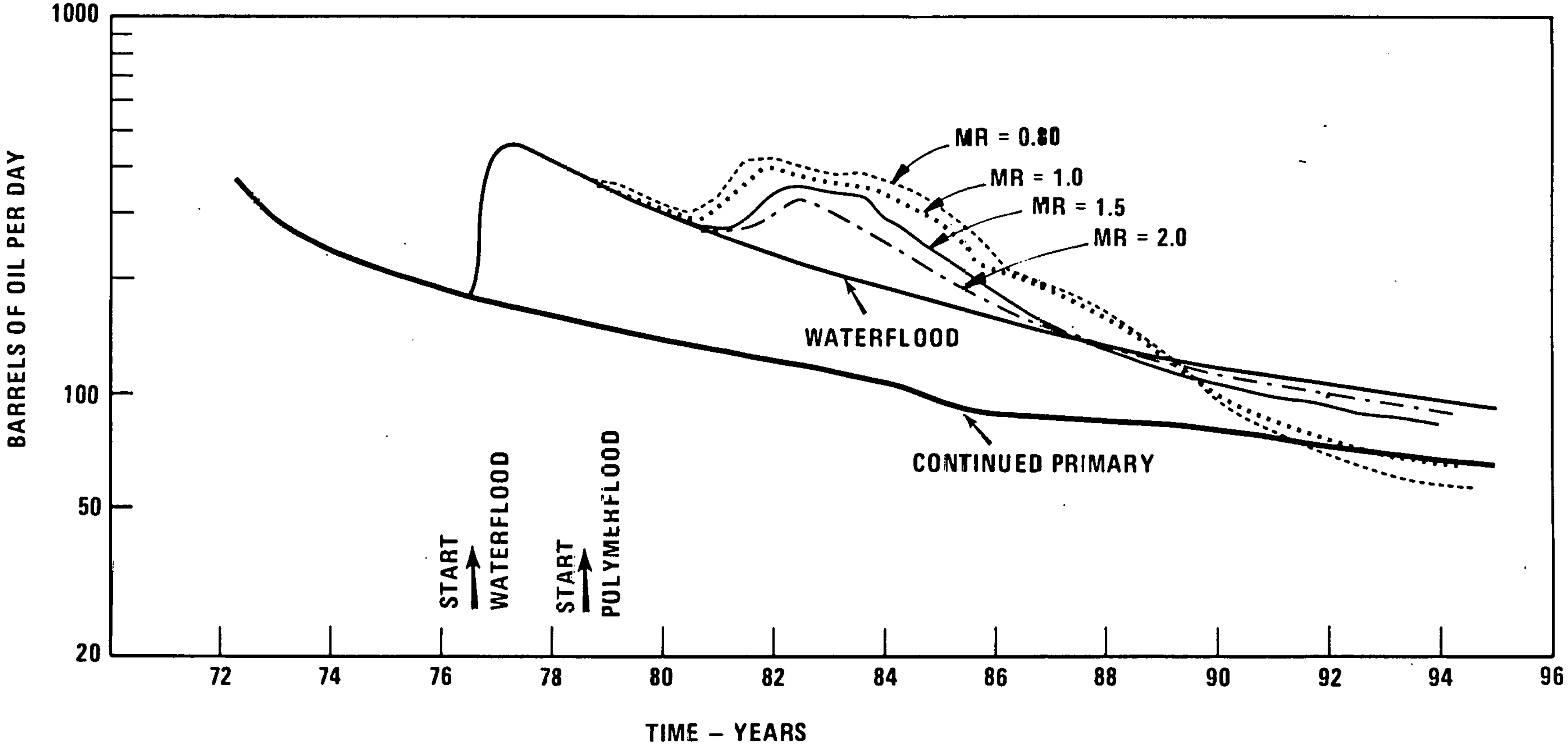
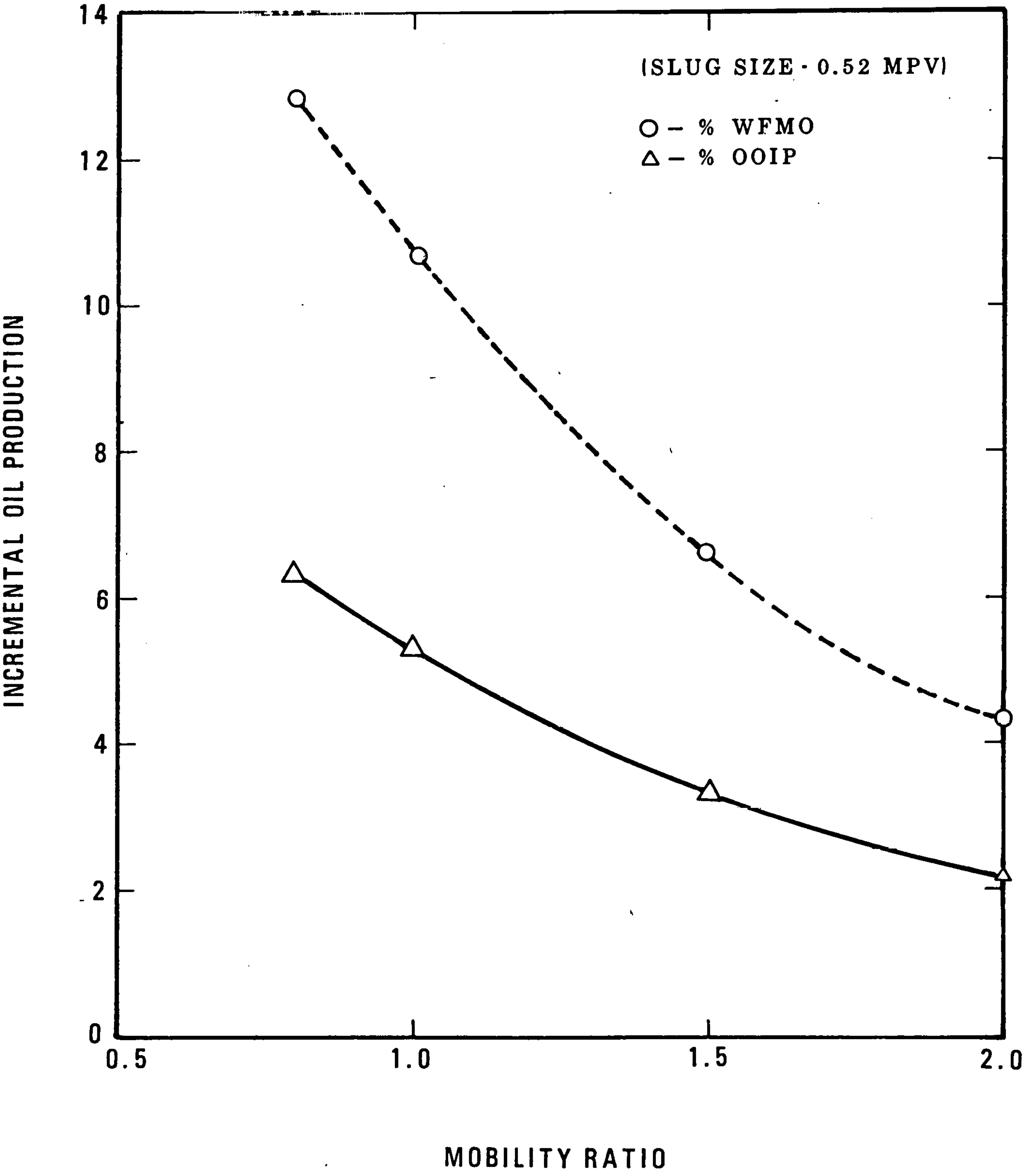


FIGURE 38

POLYMER SLUG DESIGN MODEL
POLYMER INCREMENTAL RECOVERY PREDICTIONS
VS MOBILITY RATIO
COALINGA POLYMER PILOT



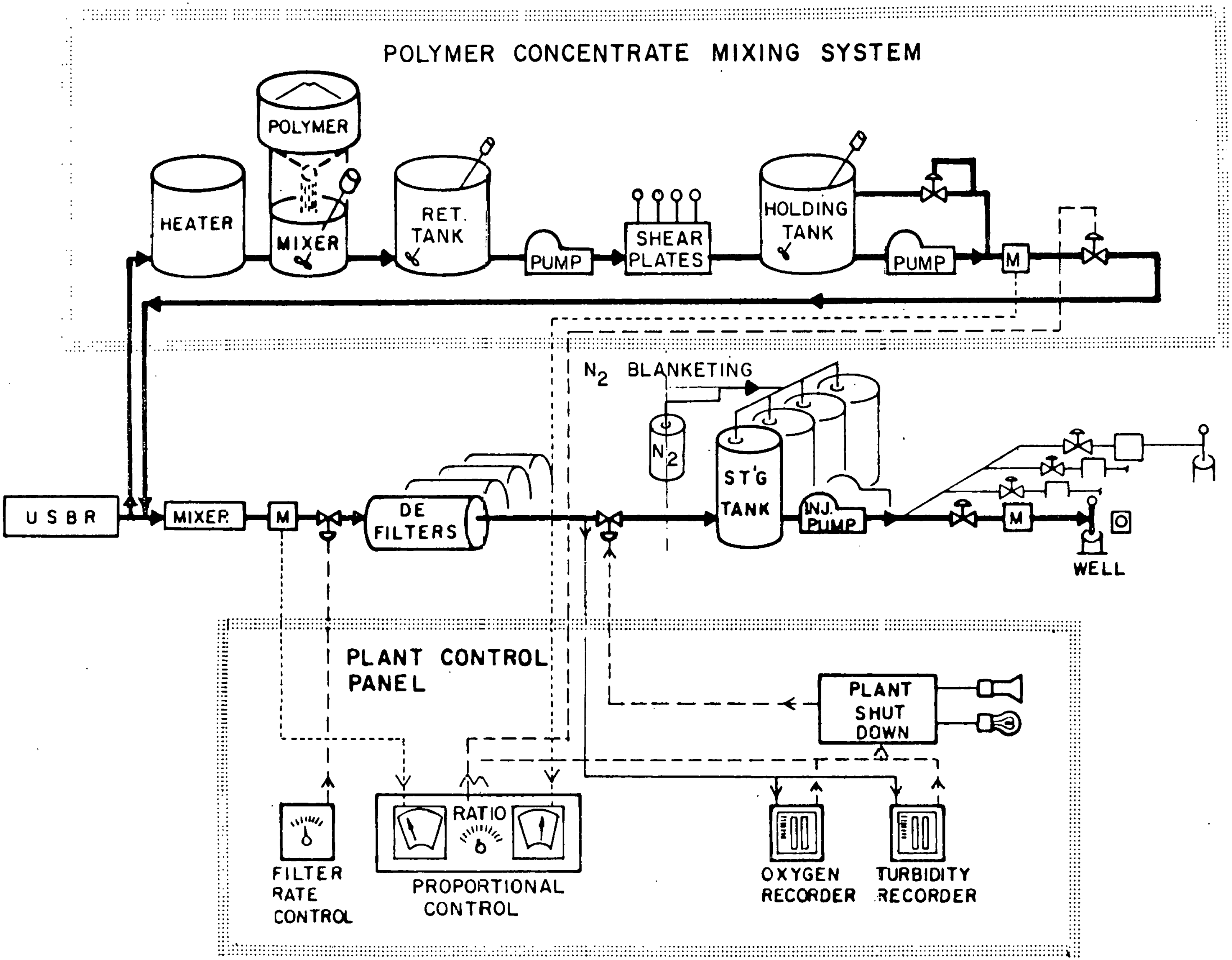


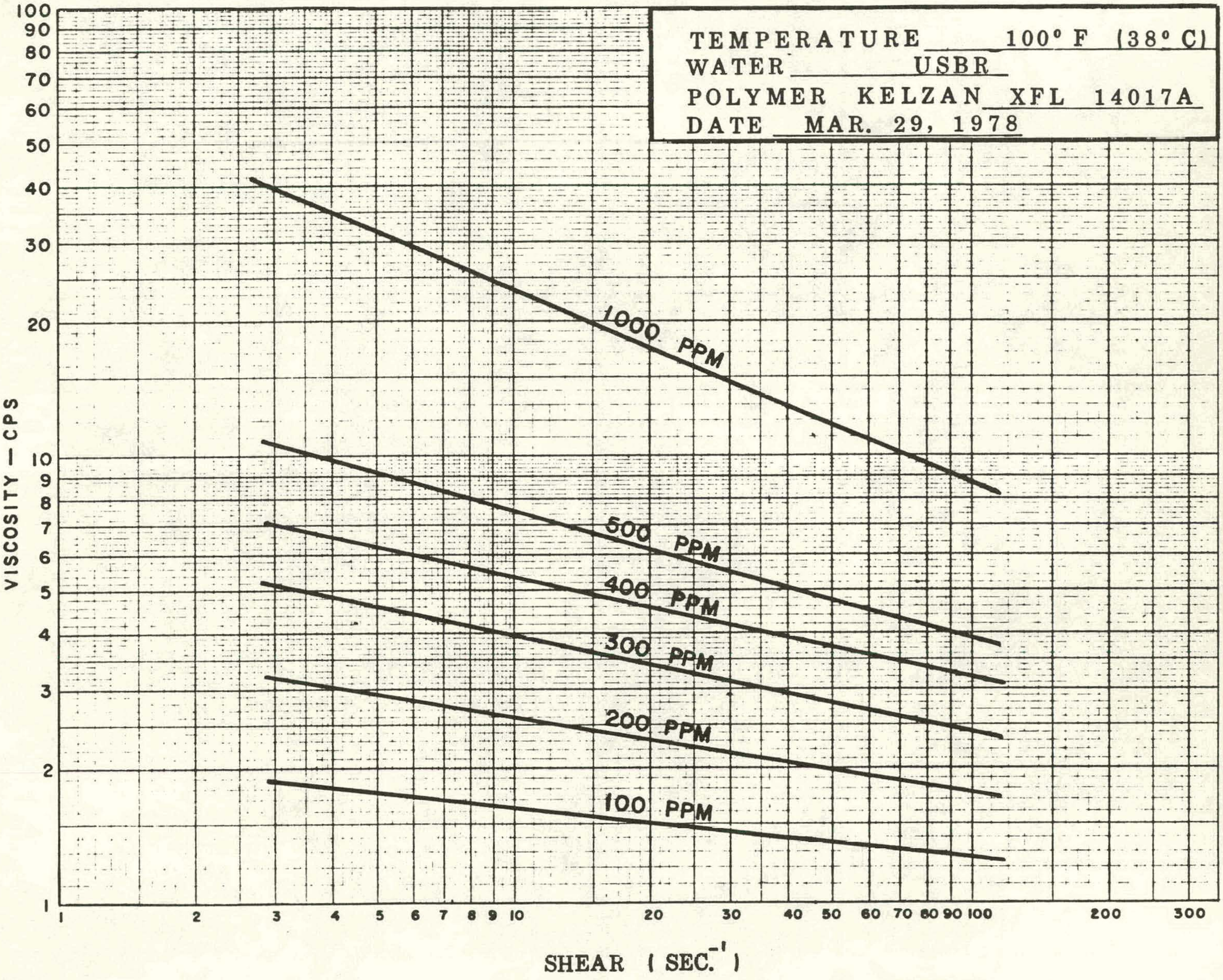
FIGURE 39
POLYMER MIXING AND INJECTING PLANT

ZV-285B

FIGURE 40

VISCOSITY / SHEAR OF POLYMER SOLUTION

COALINGA POLYMER PILOT


TEMPERATURE 100° F (38° C)
WATER USBR
POLYMER KELZAN XFL 14017A
DATE MAR. 29, 1978

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