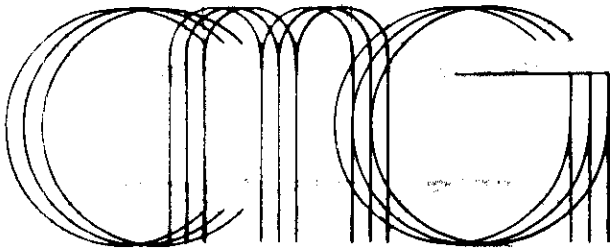
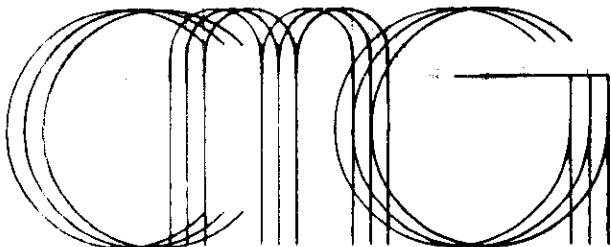
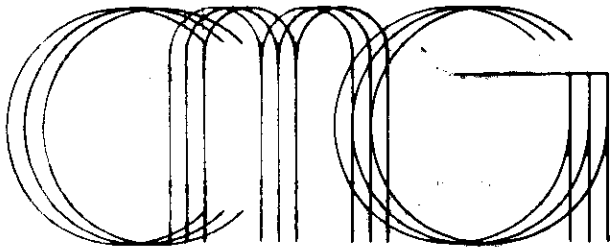
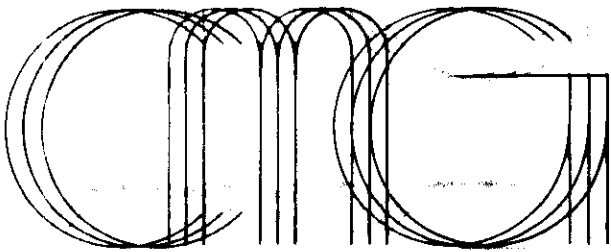
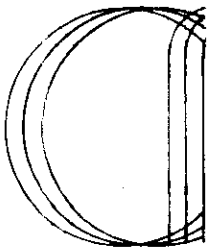


CONFIDENTIAL



COMPUTER MODELLING GROUP



MEMORANDUM

Date: October 3, 1985

To: George Patey
Bob Beamish

From: Richard Brekke

Re: 1985 Waskada Reservoir Model Study
Lower Amaranth A Pool

The purpose of this memo is to highlight some of the important points contained in the 1985 Waskada Reservoir Model Study report.

1) Model Input Data

- the inverted nine spot pattern surrounding well 13A-24-1-26 WPM was chosen to represent the reservoir.
- in order to obtain good reservoir definition a 15X15X4 grid system was used.
- the model study area contained 25 wells which allows a more realistic representation of the boundary conditions around the injection pattern.
- ϕ and h values were calculated by the Exploration Department.
- k_H values were obtained from a field average ϕ/k crossplot.
- k_V values were assumed to be $0.1 \times k_H$
- three different rock types were used assuming $SW_{IRR} = 37\%, 50\%, 60\%$ and $S_{OR} = 20\%, 15\%, 15\%$ respectively.
- initial water saturations were determined from capillary pressure data.

The differences in input data between this study and the previous model study consist of a different study area, an updated ϕ/k crossplot and three rock types instead of a single rock type. A comparison of average reservoir properties used in the two studies indicates that the initial water saturation in the reservoir is greater than the irreducible water saturation in both cases.

	1985 Model Study	1983 Model Study
SW_{IRR}	0.37 - 0.60	0.44
S_{OR}	0.15 - 0.20	0.15
Average ϕ	0.15	0.13
Average k	2.96	3.7
Average Sw	0.61	0.71
OOIP (km^3)	1423.0	836.1

The significance of this factor is that if it is true the OOIP in the Lower Amaranth is less than has been previously calculated. Since, the initial water saturation values are dependent on the calculation method used (logs, capillary pressure, oil base core) it is essential that the best method be used. Therefore it has been recommended that several oil base cores be obtained.

2) History Match

- individual well histories were adequately matched for all the wells.
- the error in total study area oil and water production was essentially zero.
- the total study area gas production has an error of 12% which can be explained by the inaccuracy of field gas measurements during the early life of the pool.
- in order to achieve the final history match, modifications to the rock compressibility, relative permeability curves and several grid block transmissibilities were required.
- Figures 19, 21 and 23 illustrate the adjustments made to the oil/water relative permeability curves; the effect of the adjustments tend to increase the mobility of oil at higher water saturations.
- Figures 20, 22 and 24 illustrate the adjustments made to the gas/oil relative permeability curves; the effect of the adjustments tend to increase the mobility of gas over the full range of liquid saturations.
- Figure 39 contains a schematic diagram of the permeability modifications incorporated into the model; these modifications confirm that the reservoir is heterogeneous in nature.

The failure of the gasflood in Waskada Unit No. 4 may be explained by the previously mentioned history match modifications. Increased gas mobility as well as the increased grid block transmissibilities usually accelerate gas channelling which eventually results in premature gas breakthrough.

3) Predictions

- all oil recovery values shown are based on actual recoveries (less influx) inside an inverted nine spot pattern with a given OOIP; thus fieldwide scaling is accomplished by simply using an original oil in place ratio
- during each prediction a well was shut in if it had a minimum oil rate $< 0.5 \text{ m}^3/\text{d}$, a watercut of 99% or a GOR of $2500 \text{ m}^3/\text{m}^3$.
- three different prediction cases were run; primary depletion (avg k) waterflood (avg k) and waterflood (low k)
- Figures 57 to 60 contain graphical comparisons of the three cases. These figures show that waterflooding definitely improves ultimate recovery; a small increase in total oil production can be expected following the implementation of a waterflood; typical waterflood characteristics should consist of stable oil rates, a slowly increasing WOR and a low GOR; the ultimate oil recovery in low permeability areas may be similar to the higher permeability areas but will require much more time to produce.
- when calculating company reserves 20 year oil recoveries should be used due to inherent inaccuracies in the assumptions beyond this point.

A comparison of prediction results obtained from the current study and the previous study indicates that the peak oil rate will be lower, the reservoir life will be longer and the ultimate oil recoveries could be higher.

	1985 Model Study	1983 Model Study
Primary (Avg. k)	9.1%OOIP/6 yr. life	12.2%OOIP/10 yr. life
Waterflood (Avg. k)	26.7%OOIP/20 yr. life 38.2%OOIP/41 yr. life	28.4%OOIP/15 yr. life
Waterflood (Low k)	19.6%OOIP/20 yr. life 36.5%OOIP/58 yr. life	N/A
Gasflood (Avg. k)	N/A	22.3%OOIP/12 yr. life

A preliminary waterflood prediction run was also run for a low permeability/high viscosity oil case as seen in the NW portion of the reservoir. Results of this run indicate very low oil rates and a lower ultimate recovery. Due to the economic impact of these results an additional PVT study has been initiated.

In conclusion, The 1985 Reservoir Model Study results support the existing D & S Group recoverable reserve estimates for the Waskada Lower Amaranth pool, however, it should be noted that the reservoir parameters used to arrive at recoverable reserves are quite different. As shown below, a difference in initial water saturations combined with a difference in recovery factors compensate for one another and result in a similar reserve estimate.

	1985 Model Study	D & S Group
Sw	0.61	0.45
Primary RF	9.1% OOIP	2.0 - 10.0% OOIP
Waterflood RF (@ 20 yrs.)	19.6 - 26.7% OOIP	10.0 - 20.0 OOIP
Primary RF X (1-Sw)	0.035	0.011 - 0.055
Waterflood RFx (1-Sw)	0.076 - 0.104	0.055 - 0.110

It is essential that prior to the next reserve review we resolve the question of initial water saturation in order that the company does not overestimate its oil reserves in Waskada.

c.c. T.J. Hall





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TELEPHONE (403) 261-0743

October 29, 1985

Manitoba Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. Bob Dubrieul

Dear Sir:

Re: Waskada Lower Amaranth Secondary Recovery
1985 Reservoir Model Study

Enclosed are two (2) copies of the recently completed "1985 Waskada Lower Amaranth Reservoir Model Study" for your review. We will contact you in the near future to set up a meeting to discuss the waterflood forecasts for the existing pressure maintenance areas which are still outstanding.

Yours truly,

OMEGA HYDROCARBONS LTD.

A handwritten signature in dark ink, appearing to read "R.A. Beamish", is written over the typed name.

R.A. Beamish, P. Eng.
Manager - Engineering

RAB:vb
Encl.

c.c. Waskada (LAm) Waterflood
Approvals File

**WASKADA MODEL STUDY
LOWER AMARANTH POOL**

for

OMEGA HYDROCARBONS LIMITED

by

**A. Siu and J. Flores
COMPUTER MODELLING GROUP**

September 1985

TABLE OF CONTENTS

	<u>Page</u>
SUMMARY	ii
CONCLUSIONS	iv
RECOMMENDATIONS	v
MODEL DEVELOPMENT	1
Grid System and Well Locations	1
Geology	1
Reservoir Rock Data	2
Relative Permeability	3
Capillary Pressure and Water Saturation	3
Fluid Properties	4
Initial Conditions	4
Flowing Bottomhole Pressures	5
History Match	5
Waterflood Prediction	7
SENSITIVITY CASES	9
Primary Depletion - Average Permeability	9
Waterflood - Average Permeability	10
Waterflood - Low Permeability	11
Sensitivity Case Comparison	13
REFERENCES	14
List of Figures	
List of Tables	
APPENDICES	
A - Sample Calculations of the Adjusted Oil Rates for the Main Pattern Area	
B - Reservoir Pressures and Saturations at the End of Simulation	

SUMMARY

SUMMARY

The purpose of this study was to update the previous Lower Amaranth waterflood predictions based on 3½ years of production and injection history, and to evaluate the sensitivity of several parameters on oil recovery.

The study area was restricted to Township 1, Range 26 W1M and Sections 23, 24, 25 and 26. It includes 9 wells defining the main pattern area (full 9-spot) in the center, and 16 additional wells at the boundaries. The specific study area that was chosen is considered representative of the reservoir, and has had the longest production history.

Rock compressibility, well fractions, well skin factors, well block saturations, transmissibility values at the grid block interfaces and the shape of the relative permeability curves were adjusted on a trial-and-error basis to match the historical average reservoir pressures, flowing bottomhole pressures, water-cuts and gas-oil ratios. The history match error in cumulative oil and water production is minimal. The cumulative gas production has an error of 12% which is good considering the inaccuracy of gas measurements in the field during the early life of the pool. The flowing bottomhole pressure, the water-cut and gas-oil ratio have also been adequately history matched for each individual well.

A waterflood prediction run as an extension of the history was performed. The oil recoveries at 20 years and at the economic limit are 25.3% OOIP and 39.7% OOIP, respectively. The total reservoir life for this case is estimated to be 42 years.

In order to apply the main pattern waterflood results to fieldwide predictions, it is necessary to examine the effect on oil recovery by several important parameters. For comparison a primary depletion run was made to analyze the merit of waterflooding. Two waterflood cases were then studied. The first case examined the effect of timing (the time at which water injection was initiated) and the second case analysed the effects of lower permeability. An additional sensitivity run using different PVT values will be made at a later date based on actual data from an area of the reservoir which appears to have different oil properties.

Results for these three sensitivity cases are summarized below.

	<u>Primary</u>	<u>Waterflood</u> <u>Average</u> <u>Permeability</u>	<u>Low</u> <u>Permeability</u>
Recovery at 20 years,			
10^3 m^3	40.4	118.6	86.8
% OOIP*	9.1	26.7	19.6
Extrapolated Ultimate Recovery,			
10^3 m^3	40.4 [§]	168.9	161.6
% OOIP	9.1 [§]	38.2	36.5
Oil Bank Peak Rate,			
m^3/d	-	19.5	7.5
Reservoir Life to Economic Limit,			
years	6	41	58

* OOIP = $443 \times 10^3 \text{ m}^3$

§ calculated ultimate recovery

CONCLUSIONS

CONCLUSIONS

1. Some wells have shown a dramatic decrease in both oil and water production rates indicating that the decrease in oil production rate is not related to high water-cut or high producing GOR but to a complete loss of fluid productivity. This loss of productivity may be explained by rapid primary depletion within a small drainage area, fracture healing, plugging or other mechanical problems.
2. The current average reservoir pressure in the study area is about 5 000 kPa. This pressure is only 780 kPa higher than the bubble point pressure.
3. The waterflood predictions indicate an extrapolated ultimate recovery of 38.2% OOIP, which is substantially higher than 9.1% OOIP as predicted for primary depletion. This increased oil recovery is the result of a less severe decline of oil rate.
4. The ultimate oil recovery under waterflood does not seem to depend on how early waterflood is initiated as long as it is implemented before the reservoir pressure drops below the bubble point. However, early waterflood implementation will generate higher initial oil rates.
5. When the average reservoir permeability decreases from 3 mD to 1 mD, the ultimate oil recovery is lowered from 38.2% OOIP to 36.5% OOIP and the reservoir life is lengthened from 41 years to 58 years under waterflood.
6. The economic limit has a significant effect on the ultimate recovery (e.g. the recovery for the average permeability case increases from 38.2% OOIP to 43.7% OOIP if the minimum oil rate for the main pattern is lowered from 4.0 m³/d to 1.1 m³/d).

RECOMMENDATIONS

RECOMMENDATIONS

1. A continuous monitoring program should be implemented to ensure optimum well productivity and to identify potential problems as early as possible.
2. To maximize ultimate oil recovery in this reservoir water injection should be implemented before the average reservoir pressure drops below the bubble point pressure.
3. Water injection pressures in this relatively low permeability reservoir should be maintained just below the fracture pressure of 18 000 kPa (bottomhole) to obtain an average reservoir pressure of about 9 000 kPa. This strategy will help to maintain higher levels of oil productivity and to drain additional oil from low permeability regions.
4. In order to better understand the performance of this reservoir the following additional reservoir and fluid data should be obtained,
 - a) rock compressibility
 - b) a porosity/water saturation relationship using an oil base core
 - c) a PVT analysis for the higher density oil areas
 - d) residual oil, critical gas and irreducible water saturation values
5. To increase the reliability of the model predictions in terms of absolute recoveries and reservoir lives, an updated model study is recommended when additional waterflood history becomes available.

ENVIRONMENTAL DEVELOPMENT

MODEL DEVELOPMENT

Grid System and Well Locations

The model study area was chosen because it is a representative portion of the reservoir, and it has had the longest production history. The study area includes 9 wells defining the main pattern area (full 9-spot) in the center, and 16 additional wells at the boundaries as shown in Figure 1. The extent of the main pattern area is bounded by the broken line.

A three-dimensional reservoir model was developed for the study area. The model study area which contains 256 ha, was first overlaid with a 15 x 15 grid. Then based on geological divisions, 4 reservoir layers were used to give good vertical definition. This grid system yields a total of 900 grid blocks. Block dimensions in the Y direction are the same as in the X direction. The grid locations of the 25 wells in the study area are listed in Table 1. Based on symmetry, the wells at the boundary were initially defined as $\frac{1}{2}$ or $\frac{1}{4}$ wells, depending on their locations.

Geology

The Waskada Field is located approximately 110 km southwest of the City of Brandon, Manitoba in Township 1 and 2, Ranges 25 and 26 W1M. The model study area is restricted to Township 1, Range 26 W1M and Sections 23, 24, 25 and 26. The Waskada Lower Amaranth Pool is at a depth of about 900 m KB. The sand is usually poorly developed with porosities and permeabilities uniformly low. The sand contains abundant thinly interbedded tight stringers. Figure 2 shows a typical well log of the Lower Amaranth formation. There is no gas-oil contact and the oil-water contact is currently estimated at 465 m subsea. The sand dips very gently in a southwesterly direction and the hydrocarbon traps occur independently of the structure. The structure map on top of the Lower Amaranth formation for the study area is shown in Figure 3.

Reservoir Rock Data

Cores and log data were analyzed by Omega for all the wells in the study area to provide the required control points⁽¹⁾. These control data points provided the basis for assigning depth, net pay and porosity distributions. Interpolation of properties between wells was performed using a built-in routine in CMG's IMEX adaptive implicit black oil simulator⁽²⁾. Permeabilities were generated using a permeability-porosity relationship. A summary of the average reservoir rock properties for each layer in the study area is given in Table 2.

Porosities in the study area vary from 11 to 17%. Porosity distribution for each of the layers is shown in Figures 4 to 7. Table 3 shows the initial porosity values for each grid block in the model. For the wells where a layer was missing, a 0.0 value was input.

Net pay thicknesses for the layers in the study area vary from 0 to 12 m. The net pay distribution for each of the layers is shown in Figure 8 to 11. Table 4 contains the net pay values for each grid block in the model.

From core samples taken throughout the field an average correlation of permeability with porosity was developed using wells 16-18-1-25, 2-31-1-25, 15-8-2-25, 3-3-2-26, 5-24-1-26 W1M⁽³⁾. This correlation is shown in Figure 12. Due to the relative large amounts of shale and anhydrite present in the cores, the correlation shows a large degree of scatter in the value of permeability at a given porosity. The horizontal permeability distribution for each of the layers is depicted in Figures 13 to 16. Table 5 shows the horizontal permeability values for each grid block in the model.

Following a review of all the existing core data a K_v/K_h ratio of 0.1 was incorporated in the model. Table 6 contains the vertical permeability values for each grid block in the model.

Relative Permeability

Using the oil base core data reported for well 3-25-1-26 W1M⁽⁴⁾, a relationship between porosity and irreducible water saturation as a function of rock permeability was constructed and is shown in Figure 17. The irreducible water saturations, as estimated from Figure 17 for permeabilities ranging from 1 mD to 20 mD, vary from 37% to 60%. Based on this range of irreducible water saturations three sets of relative permeability curves were developed for the model area.

Figure 18 shows the laboratory measured water-oil relative permeability ratios for wells 16-22 and 3-25-1-26 W1M⁽⁵⁾. The water-oil relative permeability curves were constructed based on these relative permeability ratios, and they were adjusted to reflect the overall well performances. Gas-oil relative permeability curves were derived from laboratory determined values⁽⁵⁾. These curves are shown as broken lines in Figures 19 to 24. The curves have 37%, 50% and 60% as irreducible water saturations, 20%, 15% and 15% as residual oil saturations, and 1% as critical gas saturations, respectively. It is recommended that additional laboratory measurements of residual oil saturations be obtained to improve the modeling of fluid movement.

Capillary Pressure and Water Saturation

Using the available capillary pressure data⁽⁵⁾ a set of fluid distribution curves was developed and is shown in Figure 25. Water saturations were calculated as a function of laboratory capillary pressure and the rock permeability⁽⁶⁾. The laboratory capillary pressure is determined from the depth-capillary pressure relationship shown in Figure 26. Based on an estimated initial oil-water contact of 465 m subsea, the free-water level in the Lower Amaranth Pool is 468 m subsea. Details of the development of the fluid distribution curves is given in the 1983 Waskada Model Study⁽⁷⁾. The water saturation distribution for each of the layers is shown in Figures 27 to 30.

The hydrocarbon pore volume distribution for each of the layers is depicted in Figures 31 to 34. Figure 35 shows the composite hydrocarbon pore volume distribution for the entire study area.

Fluid Properties

The Waskada Lower Amaranth reservoir fluid is an undersaturated hydrocarbon system having a bubble point pressure of 4 220 kPa at a reservoir temperature of 45.0°C⁽⁸⁾. This bubble point pressure is about 4 700 kPa lower than the initial reservoir pressure of 8 900 kPa.

Reservoir oil viscosities vary from a minimum of 1.3 mPa·s at the bubble point pressure to a maximum of 2.9 mPa·s at atmospheric pressure. The initial solution gas-oil ratio is about 44 m³/m³. Oil, water and rock compressibilities used in the model were 1.2 x 10⁻⁶ kPa⁻¹, 4.4 x 10⁻⁷ kPa⁻¹ and 1.34 x 10⁻⁶ kPa⁻¹, respectively. Water viscosity, determined from correlations⁽⁹⁾, was input as 0.7 mPa·s at reservoir conditions. The water formation volume factor and density used were 1.007 m³/m³ and 1000 kg/m³.

Table 7 shows the PVT data used in this model study. Average formation volume factors and solution GOR were obtained from flash and differential liberation data⁽¹⁰⁾.

Initial Conditions

The initial pressure, determined from pressure build-up analysis, in the study area is 8 900 kPa at a datum of 440 m subsea, and initial pressure, oil and water saturation distributions are shown in Tables 8 to 10. Since the reservoir fluid is undersaturated, the initial gas saturation is 0.0. A summary of the fluids-in-place in the model is as follows:

	<u>Study Area</u>	<u>Main Pattern</u>
Pore Volume, 10 ³ res m ³	4 186	1 347
Hydrocarbon Pore Volume, 10 ³ res m ³	1 659	508
Original Oil-In-Place, 10 ³ m ³	1 451	443
Solution Gas-In-Place, 10 ⁶ m ³	64	20
Water-In-Place, 10 ³ m ³	2 500	834

Flowing Bottomhole Pressures

Figure 36 shows a plot of flowing bottomhole pressure versus liquid productivity. This correlation was developed from current fluid level measurements taken at wells 9-23, 16-23, 11-24, 12-24, 14-24, 3-25, 4-25 and 1-26-1-26 W1M. The bottomhole pressures for those wells which were not measured, are estimated from this correlation based on their current productivities. The estimated and measured flowing bottomhole pressure for each well are listed in Table 11.

History Match

The study area contains twenty-five wells. The first well was brought on production in September 1981. The other 24 wells were drilled and put on production or injection at later dates. To maintain reservoir pressure, water injection was initiated in February 1983. Gas injection was initiated at wells 7-23, 5-24 and 7-24-1-26 W1M in May 1984. In this study historical production data up to the end of March 1985 was used. In summary, the study area underwent one and a half years of primary production, and was then followed by two years of combined water and gas injection.

Figure 37 depicts the pressure decline for the study area. The production history for the main pattern wells is shown in Figure 38. Based on production to date the oil decline rate is found to be about 44% per year. One of the reasons for the high decline rate is that there are currently high fluid levels in some of the wells which suggests that the oil production has not been maximized.

To match the pressure decline of the study area while under primary production, it was found necessary to use a rock compressibility of $1.34 \times 10^{-6} \text{ kPa}^{-1}$, which is two times larger than the value used in the previous report⁽⁷⁾. This value falls within the acceptable range of existing rock compressibility correlations⁽⁹⁾. It is recommended that rock compressibility data be obtained for the Waskada Lower Amaranth formation to verify this change.

Because of the heterogeneity of this reservoir, one should not expect that the injection and production volume fraction for a well at the model boundary be exactly equal to its geometrical value. The actual volume fractions for the edge wells, instead, have to be derived using a trial-and-error method which honors the production characteristics of the neighboring producing wells. Table 12 contain the final history matched volume fractions for all the wells.

Well block saturations, transmissibility values at grid block interfaces, and the shape of the relative permeability curves for oil, gas and water were also adjusted in order to match the water-cut and gas-oil ratio performance of the producing wells. The new sets of relative permeability curves for the oil-water, and gas-oil systems are shown as solid lines in Figures 19 to 24. The changes in the well block saturations were so small that the fluids in place remained the same. Locations of transmissibility multipliers are depicted in Figure 39. A high transmissibility path was required between injector 13-24 and producer 9-23 to model the pressure response, and it is consistent with geological data. To match the high GOR observed at 11-24, it was necessary to reduce the transmissibility around producer 11-24, and channel the gas from injector 7-24 to 11-24 through producer 6-24. The modified horizontal (T_x , T_y) and vertical transmissibilities (T_z) are presented in Tables 13 to 15.

The estimated flowing bottomhole pressures at the end of the history were matched by adjusting the skin factors. Table 16 contains the history matched skin factor for all the wells.

Table 17 summarizes the combined history match results for all the wells. The errors in oil and water productions are minimal for the study area. The gas production has an error of 12% which is good considering the inaccuracy of gas measurements in the field during the early life of the pool. Figures 37 and 38 contain the history matched study area pressure and main pattern area production history match. The individual well matches for all the wells contained inside the main pattern area are displayed in Figures 40 to 48. It is felt that the trends of the water-cut and gas-oil ratio are adequately matched. A high GOR due to gas

breakthrough was measured at wells 8-23, 6-24 and 10-24. This behavior was matched and the individual well matches are shown in Figures 49 to 51.

Reservoir pressure, oil, gas and water saturations at the end of the history are presented in Tables 18, 19, 20 and 21 respectively.

Waterflood Prediction

A waterflood prediction was run assuming the continuation of water injection after the existing production and injection history. Gas injectors 7-23, 5-24 and 7-24 were converted into water injectors as has been done in the field. All the injectors were allowed to inject water at their maximum capacity with flowing bottomhole pressure of 18 000 kPa. The producers were allowed to produce at a constant flowing bottomhole pressures of 690 kPa (100 psi) with a maximum total liquid rate of 31.85 m³/d (220 STB/d). During simulation a producing well was shut-in if any one of the following three constraints was violated,

- (i) minimum oil rate of 0.5 m³/d (3 STB/d),
- (ii) water-cut of 99%,
- (iii) gas-oil ratio of 2 500 m³/m³

Since oil from the surrounding area is also produced through the main pattern wells, this amount of oil must be subtracted in order to estimate the amount of oil actually produced from the main pattern area. An example of this calculation is shown in Appendix A. These adjusted oil rates are referred to simply as the oil rates in this report, unless otherwise stated.

A recovery of 36.1% OOIP is obtained at the end of 35 years, and it represents a total oil production of 160.0 x 10³ m³ from the eight producers in the main pattern area with average permeability (3 mD). In this waterflood prediction case 475.4 x 10³ m³ of water was injected to keep the reservoir pressure above the bubble point.

The reservoir performance for this prediction run is shown in Figure 52. The reservoir pressure continued to rise steadily indicating that the instantaneous voidage replacement ratio is greater than one. An oil bank, which peaked at $16.7 \text{ m}^3/\text{d}$ in the eleventh year, is observed in the oil rate curve. The oil rate then declined gradually to $6.5 \text{ m}^3/\text{d}$ at the end of 35 years. In response to water injection, the WOR increases with time but drops sharply as the high water-producing well 9-23 is shut-in at the 21st year. The WOR curve drops again in the 28th year when well 16-23 is shut-in due to high water-cut. The maximum WOR was about 3.0. The gas-oil ratio remained at the solution gas-oil ratio of $44 \text{ m}^3/\text{m}^3$ throughout the prediction due to a reservoir pressure greater than the bubble point pressure.

SENSITIVITY CASES

SENSITIVITY CASES

In order to apply the main pattern waterflood results to fieldwide predictions, it is necessary to analyze the effect on oil recovery by several important parameters. For comparison a primary depletion run was made to examine the merit of waterflood. Two waterflood cases were then studied. The first case examined the effect of timing (the time at which water injection was initiated) and the second case analyzed the effects of lower permeability.

In these three sensitivity runs all the wells that were producing prior to February, 1983 during the actual history were assumed to start producing at a constant bottomhole pressure of 690 kPa (100 psi) at time zero. Waterflooding was initiated, in the two waterflood cases, before the average reservoir pressure dropped to the bubble point pressure of 4 220 kPa. At this time, all the remaining producers were turned on and produced at a bottomhole pressure of 690 kPa, and water was injected into all injectors at a bottomhole pressure of 18 000 kPa. A maximum total liquid rate of 31.85 m³/d (220 STB/d) was also imposed on all the producers as a realistic equipment limitation. During the prediction a producing well was shut-in if any one of the following three constraints was violated,

- (i) minimum oil rate of 0.5 m³/d (3 STB/d),
- (ii) water-cut of 99%,
- (iii) gas-oil ratio of 2 500 m³/m³

An additional sensitivity run using different PVT values will be made at a later date based on actual data from an area of the reservoir which appears to have different oil properties.

Primary Depletion - Average Permeability

It took 9 months of primary production for the average reservoir pressure in the average permeability reservoir (3 mD) to drop to near the bubble point pressure of 4 220 kPa. At this point, all the remaining wells were opened and produced at a

bottomhole pressure of 690 kPa. The main pattern area became uneconomical to operate due to minimal oil rate after 6 years of continuous production. A recovery of 9.1% OOIP is obtained, and it represents a total oil production of $40.4 \times 10^3 \text{ m}^3$ from nine producers.

Figure 53 depicts the reservoir performance of this case. It is observed that the gas-oil ratio rises sharply as soon as the reservoir pressure drops below the bubble point pressure. The gas-oil ratio reaches $580 \text{ m}^3/\text{m}^3$ at abandonment conditions. The oil rate, on the other hand, decreases monotonically. The water-oil ratio increases slightly with time, but never exceeds 2.0. Reservoir pressure decline is rapid in the first year. However, the decline becomes less severe as time goes on due to the expansion of free gas in the reservoir.

The yearly and the cumulative fluid production forecasts for this case are presented in Tables 22 and 23, respectively. Appendix B contains the detailed pressure and saturation distributions at the end of the simulation.

Waterflood - Average Permeability

The purpose of this waterflood case, which injects the largest volume of water at the earliest possible time, is to determine if the timing of water injection affects the ultimate oil recovery. In the waterflood continuation prediction, water was injected at less than maximum volumes during the first $3 \frac{1}{2}$ years of production history. The results of the prediction are plotted as a dotted line shown Figure 54. The waterflood - average permeability results are also presented for comparison. It is observed that by extrapolating the oil rate curves, the cumulative oil productions are 177×10^3 and $168 \times 10^3 \text{ m}^3$ for the continued prediction and sensitivity cases, respectively, at the adjusted oil rate economic limit of $4.0 \text{ m}^3/\text{d}$. Since the oil recoveries do not differ significantly, this suggests that the waterflooding strategy is not that critical as long as waterflooding is initiated before the average reservoir pressure reaching the bubble point pressure. Furthermore, these cumulative oil productions are very sensitive to the oil rate economic limit (e.g. at an economic limit of $1.1 \text{ m}^3/\text{d}$ both curves give identical recovery of $194 \times 10^3 \text{ m}^3$).

In this case the average permeability reservoir model (3 mD) was produced under primary production for 9 months. Water was then injected into all the injectors at a bottomhole pressure of 18 000 kPa. This prediction was allowed to run for 35 years.

A recovery of 35.2% OOIP is obtained at the end of 35 years, and it represents a total oil production of $155.8 \times 10^3 \text{ m}^3$ from eight producers. In an effort to maintain voidage and increase the model average pressure, $564.0 \times 10^3 \text{ m}^3$ of water was injected into the reservoir.

Figure 55 displays the oil, water and gas performance for this case. A distinctive oil bank, an indication of a successful waterflood, appears in the oil rate curve. The maximum oil rate was $19.5 \text{ m}^3/\text{d}$. Note also that the oil decline rate is much less severe when compared to the primary depletion case. The water-oil ratio rose steeply at the end of the tenth year (i.e. the tailing end of the oil bank). The water-oil ratio reached 6.8 after 35 years. The gas-oil ratio remained at the solution gas-oil ratio of $44 \text{ m}^3/\text{m}^3$ throughout the prediction.

Tables 24 and 25 provide the yearly and the cumulative fluid production forecasts, respectively. The detailed pressure and saturation distributions at the end of simulation are shown in Appendix B.

Waterflood - Low Permeability

The Lower Amaranth Pool is a very heterogeneous reservoir of varying porosity and permeability. In this sensitivity case a tighter portion of the reservoir was selected. The porosity-permeability correlation for this case was taken from well 16-18-1-25 W1M, and is expressed as

$$\log_{10} K = .1480 \phi - 2.5241$$

With the new porosity-permeability correlation the average permeability of the study area was reduced to 1.02 mD from 2.96 mD. Assuming that the initial

water saturation does not change, the OOIP remained the same. Table 26 presents the average rock properties for a low permeability area.

The adjusted model was able to produce for 13 months under primary production before the reservoir pressure dropped to near the bubble point. However, for the sake of consistency, the model was only allowed to produce for 9 months under primary. At this point in time, water injection was initiated into all the injectors at a bottomhole pressure of 18 000 kPa. This prediction was allowed to run for a total of 50 years.

A recovery of 34.3% OOIP is obtained at 50 years, and it represents a total oil production of $151.9 \times 10^3 \text{ m}^3$ from eight producers. Total water injection amounted to $468.9 \times 10^3 \text{ m}^3$.

The reservoir performance for the low permeability case (1 mD) is displayed in Figure 56. Because of the lower permeability reservoir, the reservoir pressure took longer to build up to 8 000 kPa (40 years compared with 10 years for the average permeability case), and the average oil production rate was lower. The oil bank is only slightly noticeable. The maximum oil rate of the oil bank was $7.5 \text{ m}^3/\text{d}$. Between the second and sixth years the WOR rose sharply accompanying an abrupt decline of oil rate. Both the WOR and the oil rate became relatively stable thereafter. The WOR dropped abruptly from 4.3 to 1.0 in the 32nd year when well 9-23 was shut-in due to high water-cut. The maximum WOR obtained was 4.6. The GOR reached a maximum at about $90 \text{ m}^3/\text{m}^3$ in the fifth year. As the pressure around the producers rose above the bubble point pressure, the producing GOR decreased gradually to the solution GOR of $44 \text{ m}^3/\text{d}$.

Tables 27 and 28 present, respectively, the yearly and the cumulative fluid production forecasts. The detailed pressure and saturation distributors at the end of simulation are listed in Appendix B.

Sensitivity Case Comparison

Figure 57 compares the oil rate vs cumulative oil production curves for all three sensitivity cases. At the adjusted oil rate economic limit of $4.0 \text{ m}^3/\text{d}$, the extrapolated ultimate recoveries for the primary depletion, waterflood - average permeability and waterflood - low permeability cases are $40.4 \times 10^3 \text{ m}^3$, $168.9 \times 10^3 \text{ m}^3$ and $161.6 \times 10^4 \text{ m}^3$, respectively. This comparison illustrates the obvious need for pressure maintenance within the Waskada Lower Amaranth reservoir.

The oil rate vs time curves for the three cases are shown in Figure 58. At the adjusted oil rate economic limit of $4.0 \text{ m}^3/\text{d}$, the extrapolated reservoir life for waterflood - average permeability and waterflood - low permeability cases are 42 and 54 years, respectively. These results show how different the rate of oil recovery will be depending on the permeability of the area under waterflood.

A comparison of the oil recovery vs time is presented in Figure 59. The oil recoveries after 20 years for the waterflood - average permeability and waterflood - low permeability cases are 26.7% OOIP and 19.6% OOIP, respectively.

The water injection rate profiles for the two waterflood cases are depicted in Figure 60. The amount of water injection in the waterflood - low permeability case is smaller because of the lower total fluid production volume.

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REFERENCES

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FIGURES

LIST OF FIGURES

Figure

- 1 Model Areal Grid and Well Location
- 2 Typical Well Log
- 3 Structure Map on Top of the Lower Amaranth
- 4 "A" Sand Porosity Contour Map (Top)
- 5 "B" Sand Porosity Contour Map
- 6 "C" Sand Porosity Contour Map
- 7 "D" Sand Porosity Contour Map (Bottom)
- 8 "A" Sand Net Pay Contour Map (Top)
- 9 "B" Sand Net Pay Contour Map
- 10 "C" Sand Net Pay Contour Map
- 11 "D" Sand Net Pay Contour Map (Bottom)
- 12 Permeability-Porosity Correlation
- 13 "A" Sand Permeability Contour Map (Top)
- 14 "B" Sand Permeability Contour Map
- 15 "C" Sand Permeability Contour Map
- 16 "D" Sand Permeability Contour Map (Bottom)
- 17 Porosity-Water Saturation Relationship
- 18 Average Water-Oil Relative Permeability Ratio
- 19 Oil-Water Relative Permeability/Irreducible Water Saturation = 0.37
(Rock Type 2)
- 20 Gas-Oil Relative Permeability/Irreducible Water Saturation = 0.37
(Rock Type 2)
- 21 Oil-Water Relative Permeability/Irreducible Water Saturation = 0.5
(Rock Type 1)
- 22 Gas-Oil Relative Permeability/Irreducible Water Saturation = 0.5
(Rock Type 1)

Figure

- 23 Oil-Water Relative Permeability/Irreducible Water Saturation = 0.63
(Rock Type 3)
- 24 Gas-Oil Relative Permeability/Irreducible Water Saturation = 0.63
(Rock Type 3)
- 25 Fluid Distribution Curves
- 26 Depth vs Laboratory Capillary Pressure
- 27 "A" Sand Water Saturation Map (Top)
- 28 "B" Sand Water Saturation Map
- 29 "C" Sand Water Saturation Map
- 30 "D" Sand Water Saturation Map (Bottom)
- 31 "A" Sand Hydrocarbon Pore Volume Map (Top)
- 32 "B" Sand Hydrocarbon Pore Volume Map
- 33 "C" Sand Hydrocarbon Pore Volume Map
- 34 "D" Sand Hydrocarbon Pore Volume Map (Bottom)
- 35 Composite Hydrocarbon Pore Volume Map
- 36 Flowing Bottomhole Pressures vs Liquid Productivity
- 37 Study Area Pressure History
- 38 Main Pattern Area Production History
- 39 Location of Transmissibility Multipliers in the Areal Plane
- 40 Well Production History/9-23-1-26 W1M
- 41 Well Production History/16-23-1-26 W1M
- 42 Well Production History/11-24-1-26 W1M
- 43 Well Production History/12-24-1-26 W1M
- 44 Well Injection History/13-24-1-26 W1M
- 45 Well Production History/14-24-1-26 W1M
- 46 Well Production History/3-25-1-26 W1M
- 47 Well Production History/4-25-1-26 W1M

Figure

- 48 Well Production History/1-26-1-26 W1M
- 49 Well Production History/8-23-1-26 W1M
- 50 Well Production History/6-24-1-26 W1M
- 51 Well Production History/10-24-1-26 W1M
- 52 Reservoir Performance for the Continued Waterflood Prediction
- 53 Reservoir Performance for Primary Depletion - Average Permeability
- 54 Comparison of Ultimate Oil Recovery under Different Waterflood Strategies/Average Permeability
- 55 Reservoir Performance for Waterflood - Average Permeability
- 56 Reservoir Performance for Waterflood - Low Permeability
- 57 Oil Rate vs Cumulative Oil Production/Sensitivity Case Comparison
- 58 Oil Rate vs Time/Sensitivity Case Comparison
- 59 Oil Recovery vs Time/Sensitivity Case Comparison
- 60 Water Injection Rate vs Time/Sensitivity Case Comparison

Figure 1
MODEL AREAL GRID AND WELL LOCATION
Waskada Lower Amaranth Pool
TWP.1 R.26 W1M

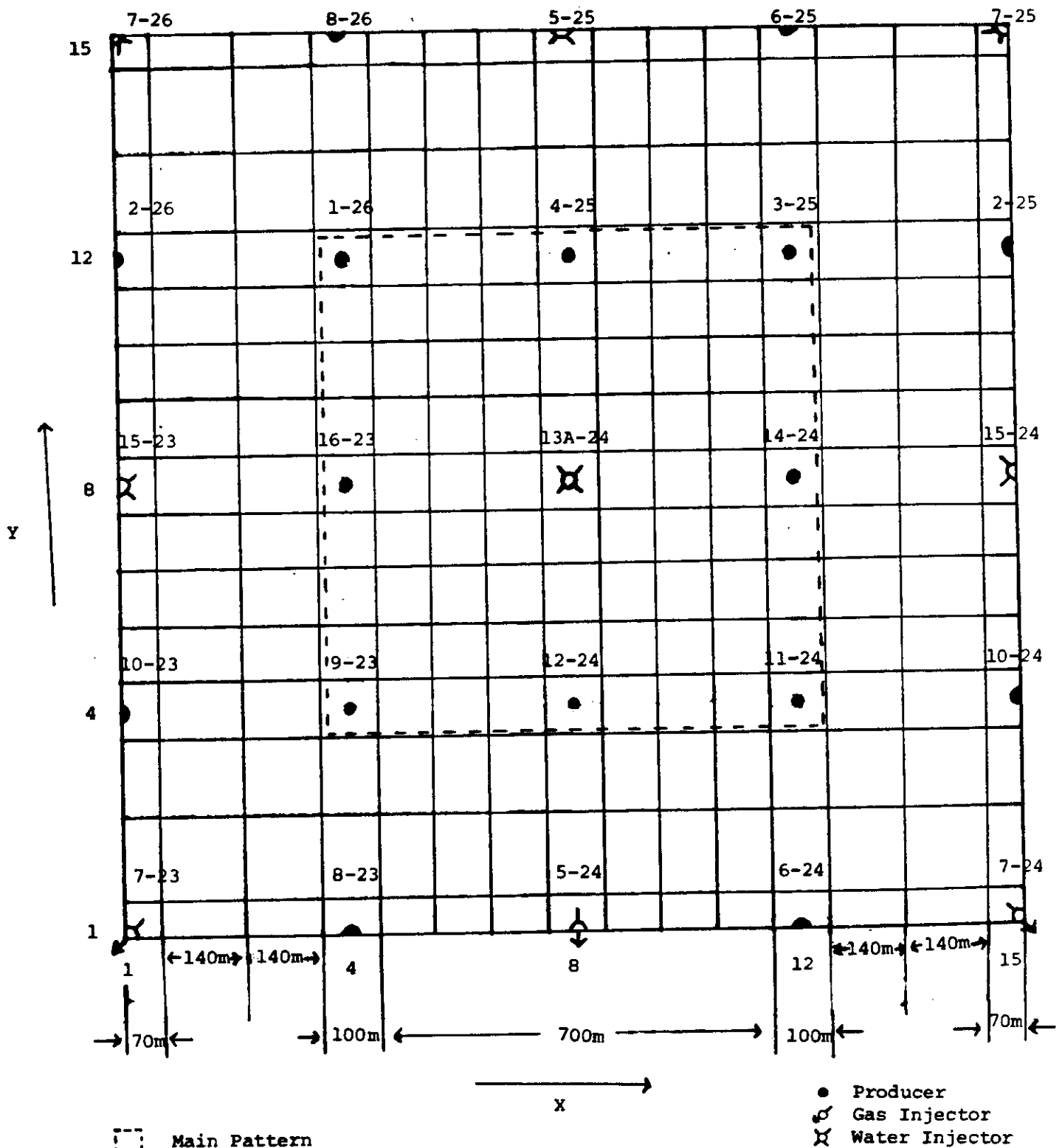


Figure 2
TYPICAL WELL LOG
Waskada Lower Amaranth Pool
11-24-1-26 W1M

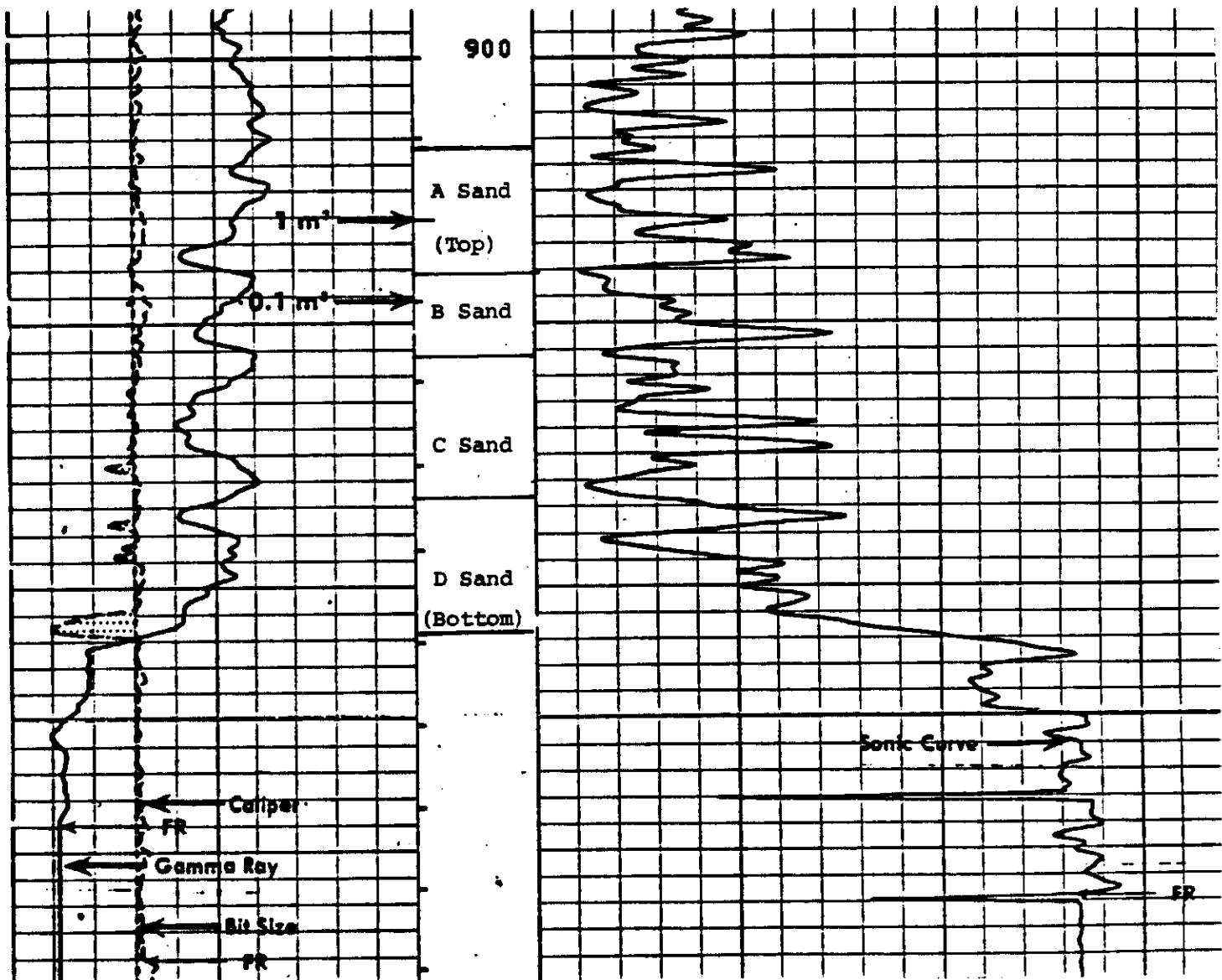


Figure 2 (Continued)
TYPICAL WELL LOG
Waskada Lower Amaranth Pool
11-24-1-26 WIM

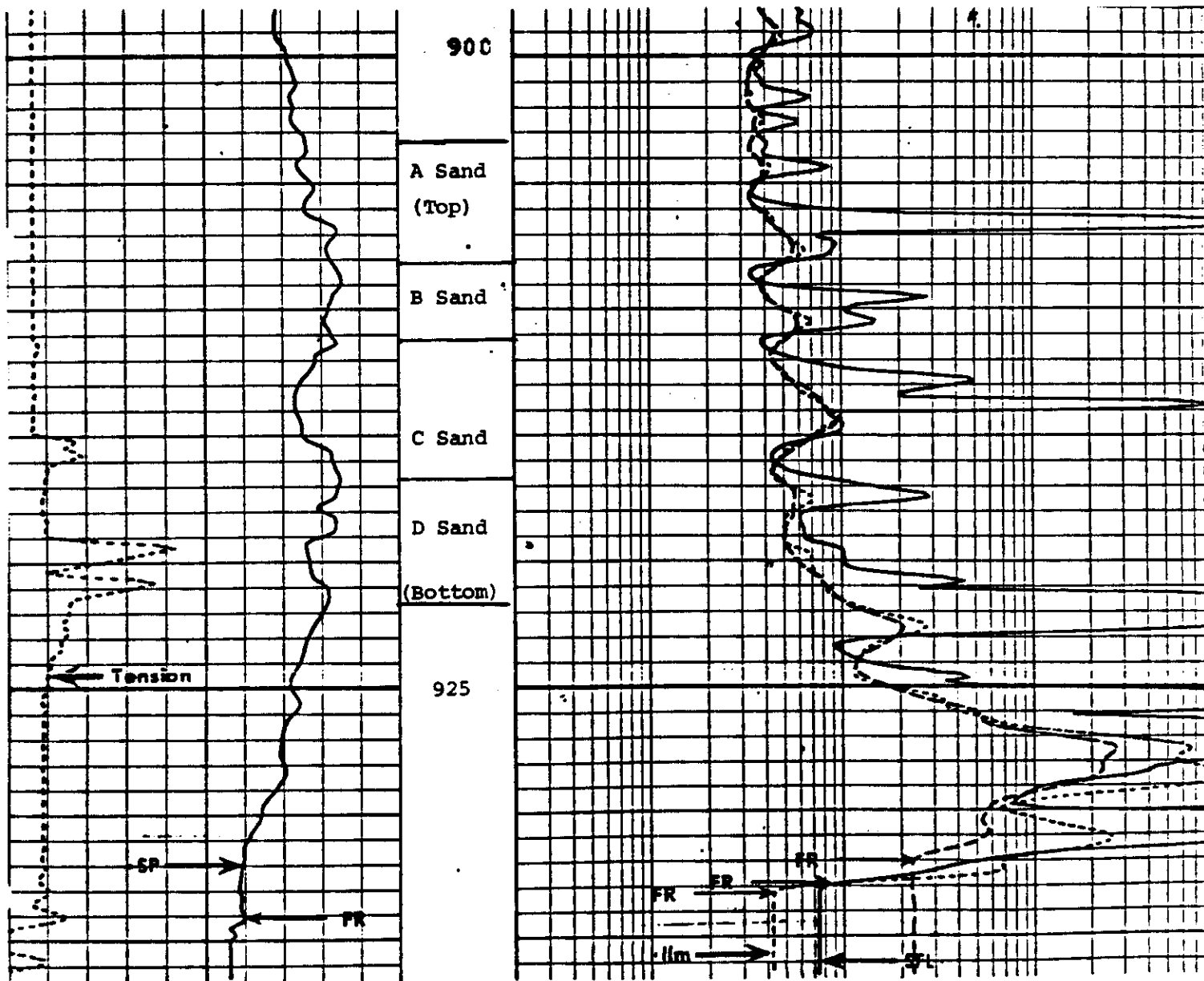


Figure 3
 STRUCTURE MAP ON TOP OF THE LOWER AMARANTH
 (Contour Interval = 1.0)
 Waskada Lower Amaranth Pool

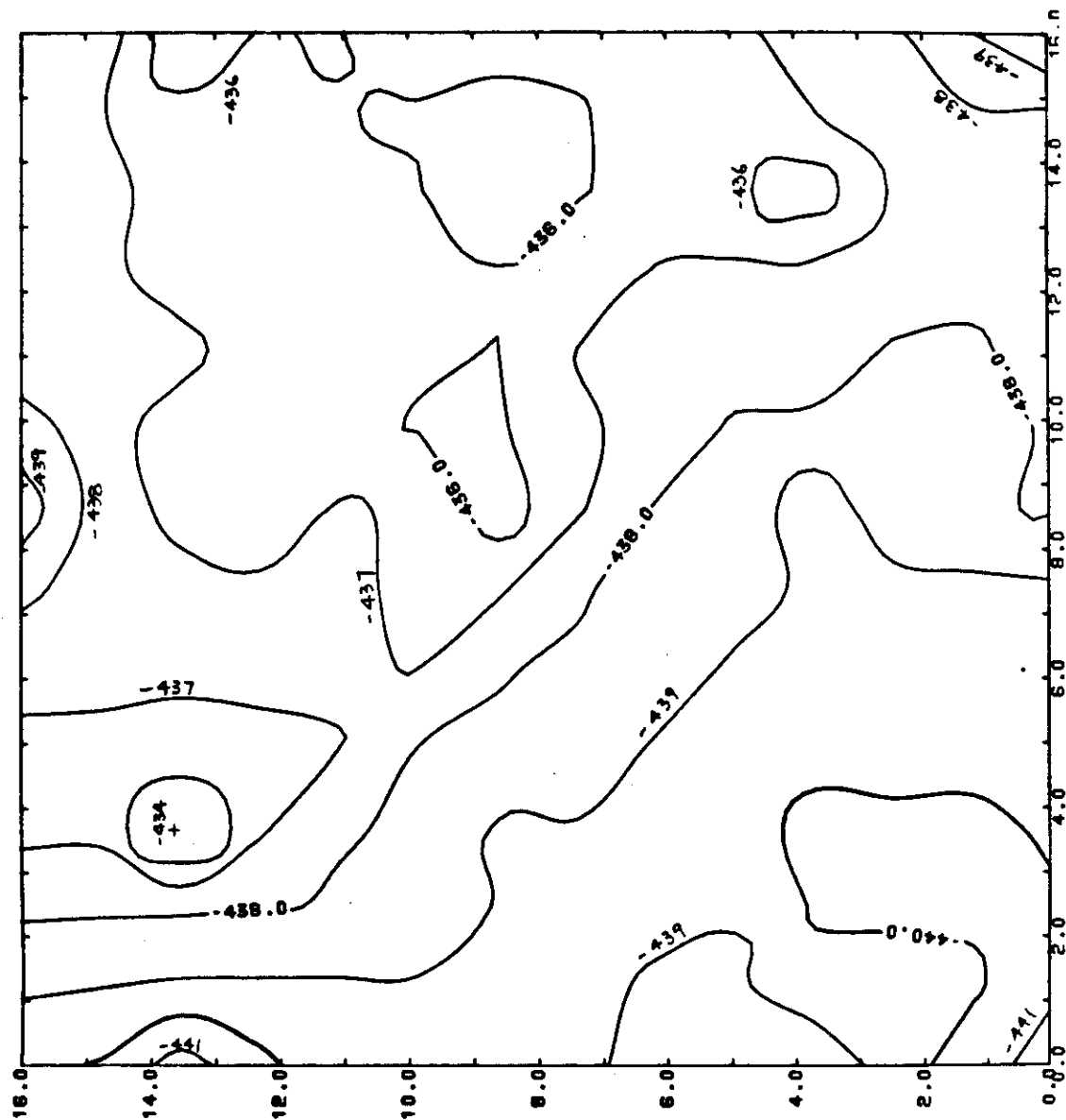


Figure 4
"A" SAND POROSITY CONTOUR MAP (TOP)
(Contour Interval = 0.01)
Waskada Lower Amaranth Pool

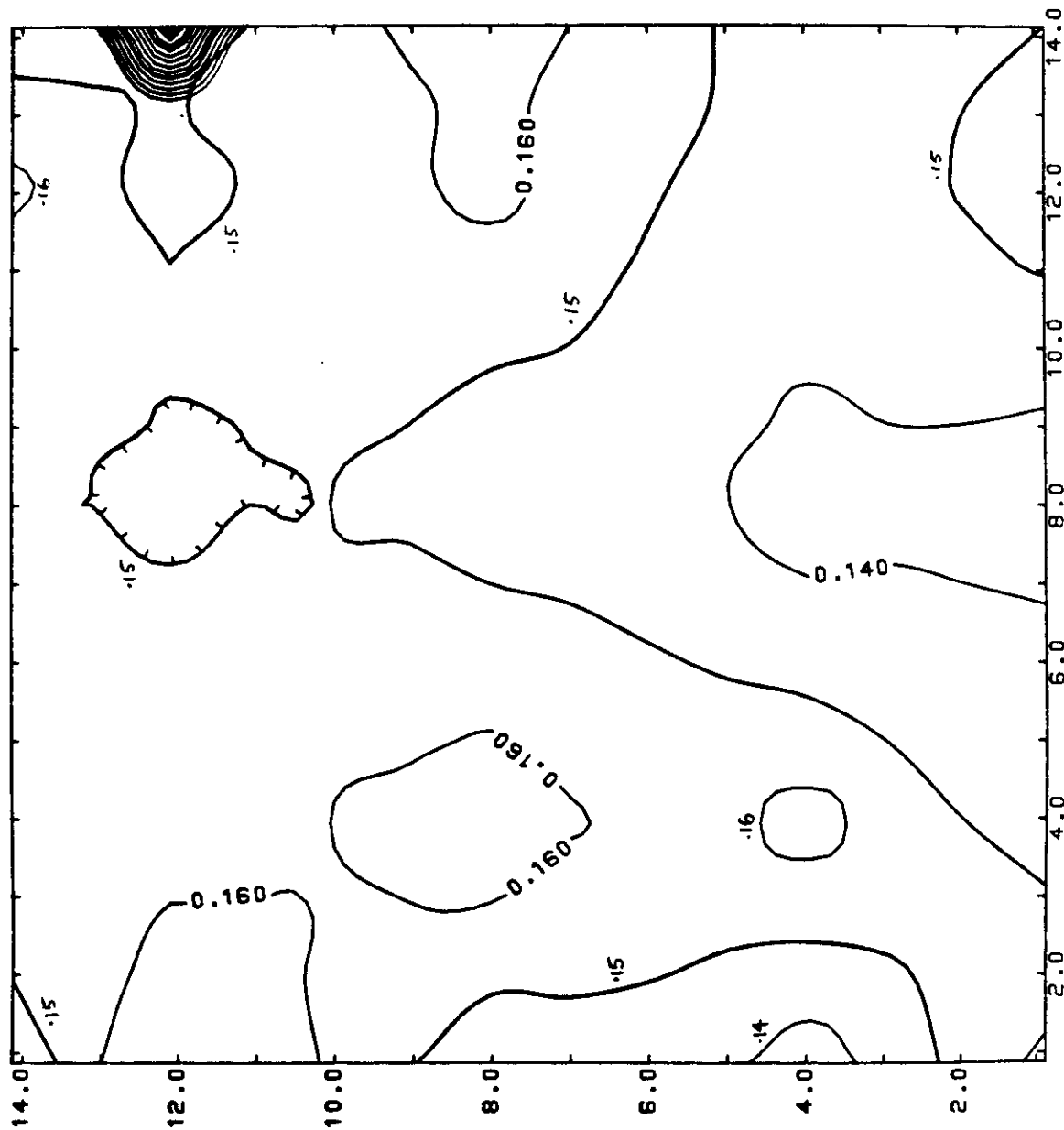


Figure 5
"B" SAND POROSITY CONTOUR MAP
(Contour Interval = 0.01)
Waskada Lower Amaranth Pool

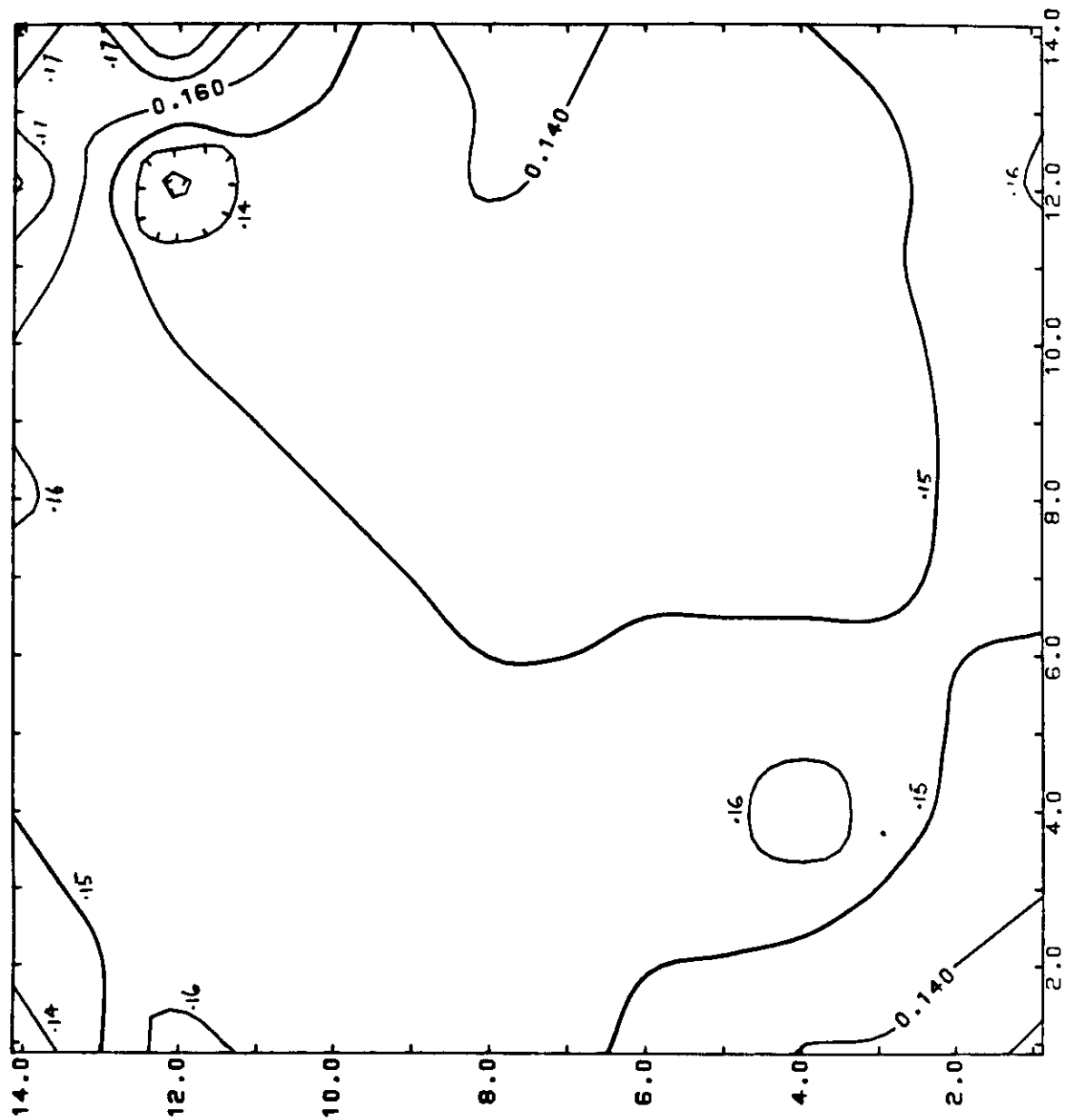


Figure 6
"C" SAND POROSITY CONTOUR MAP
(Contour Interval = 0.01)
Waskada Lower Amaranth Pool

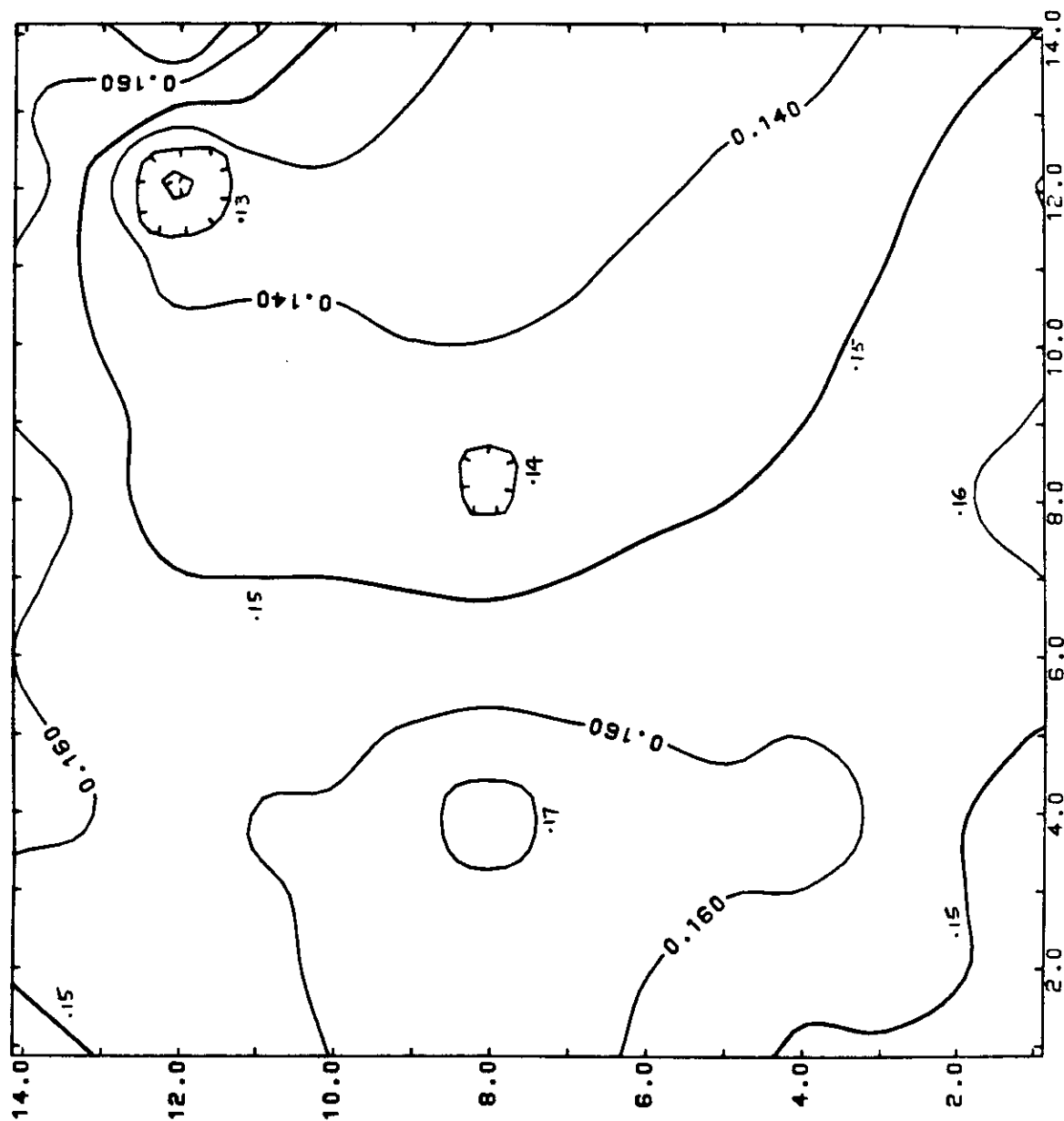


Figure 7
"D" SAND POROSITY CONTOUR MAP (BOTTOM)
(Contour Interval = 0.01)
Waskada Lower Amaranth Pool

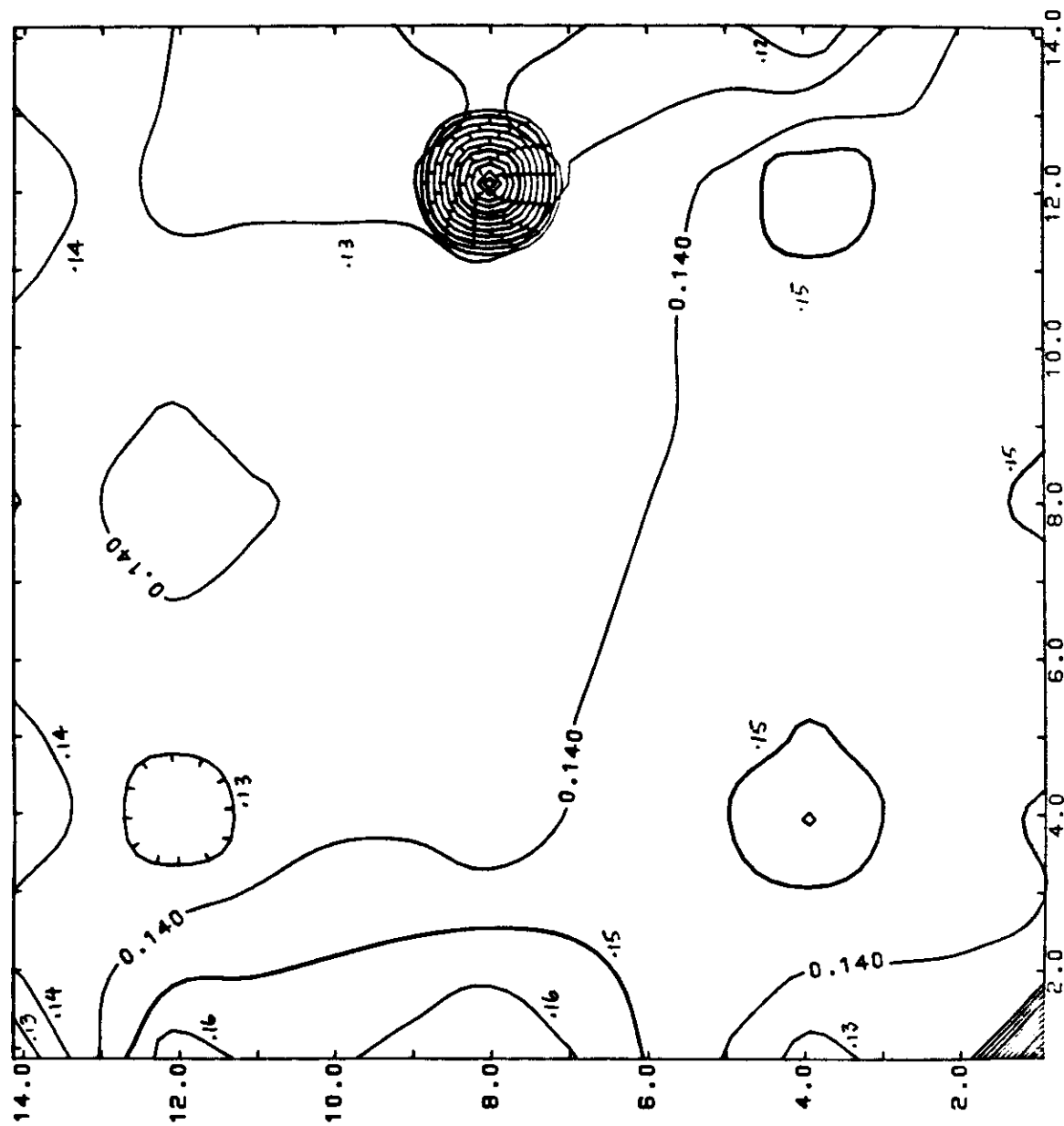


Figure 8
"A" SAND NET PAY CONTOUR MAP (TOP)
(Contour Interval = 0.2)
Waskada Lower Amaranth Pool

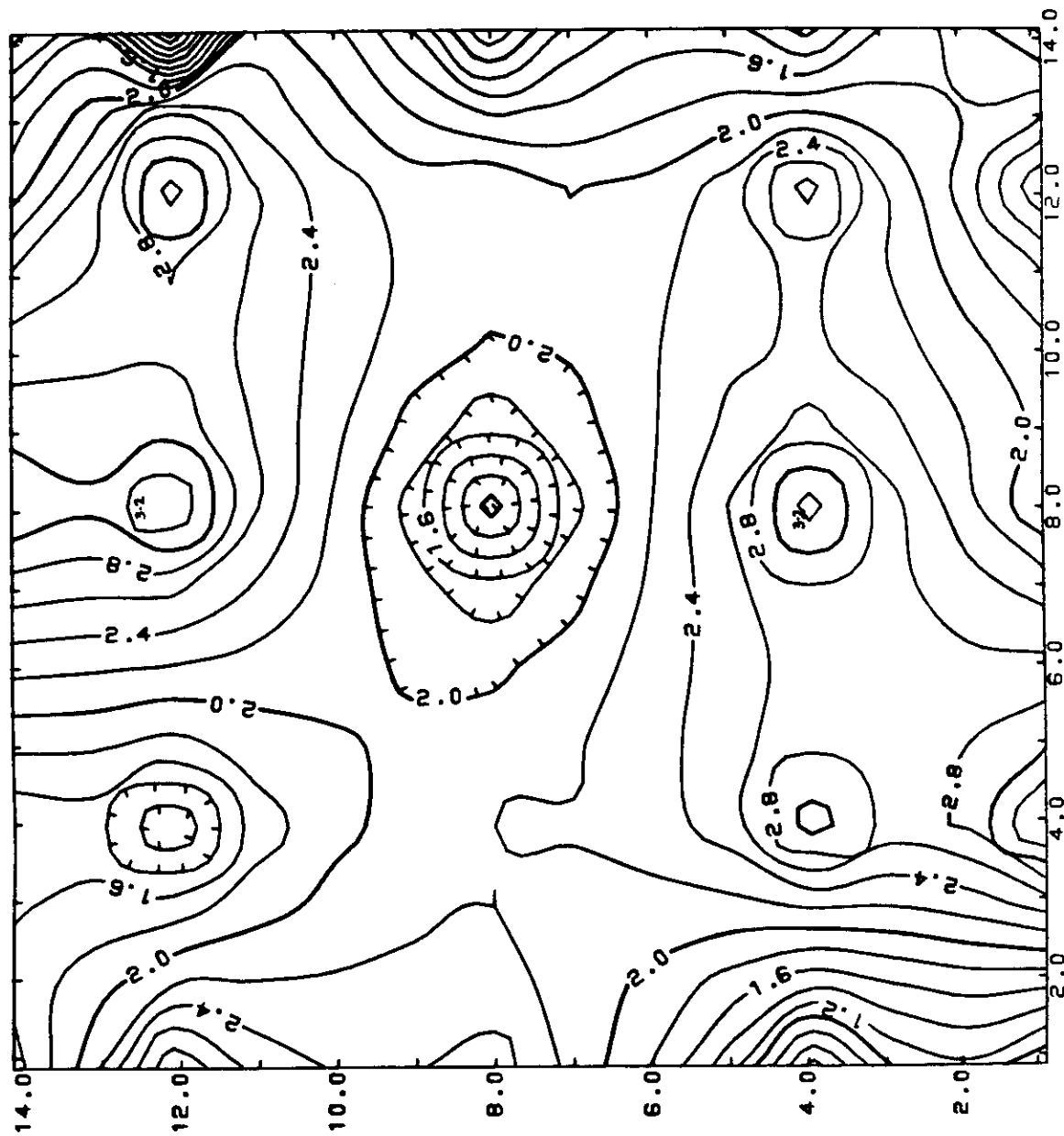


Figure 9

"B" SAND NET PAY CONTOUR MAP

(Contour Interval = 0.2)

Waskada Lower Amaranth Pool

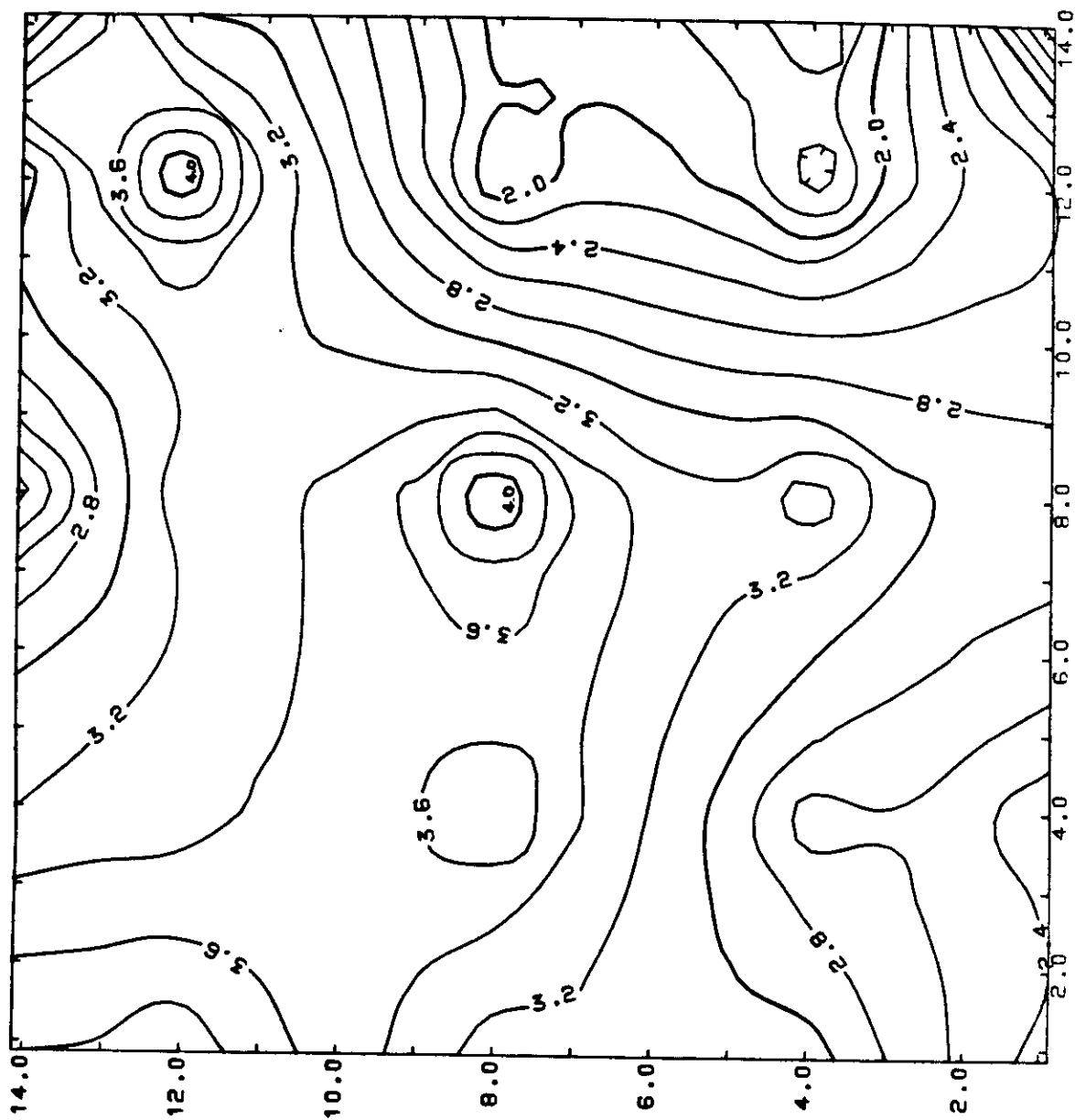


Figure 10

"C" SAND NET PAY CONTOUR MAP

(Contour Interval = 0.2)

Waskada Lower Amaranth Pool

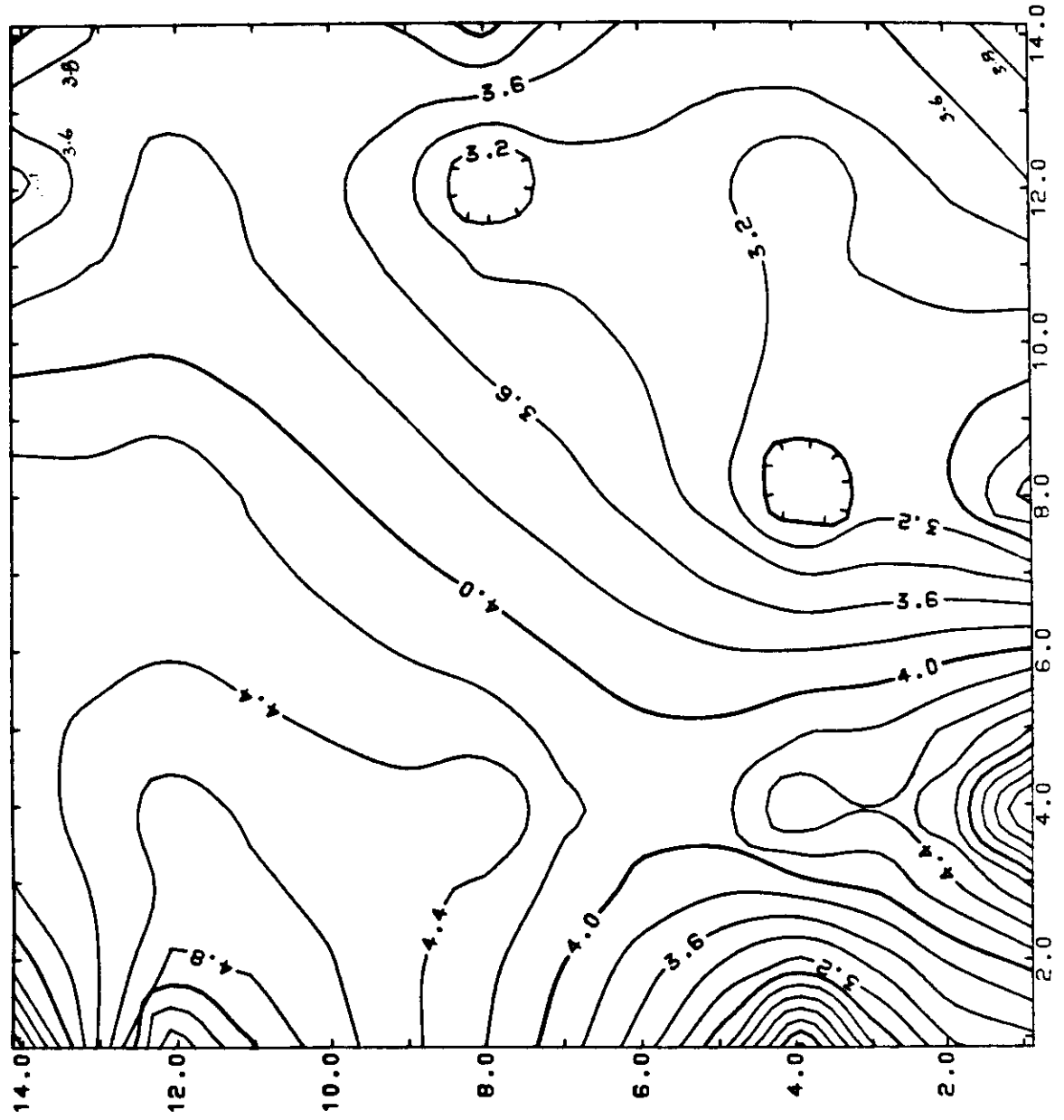


Figure 11
"D" SAND NET PAY CONTOUR MAP (BOTTOM)
(Contour Interval = 0.2)
Waskada Lower Amaranth Pool

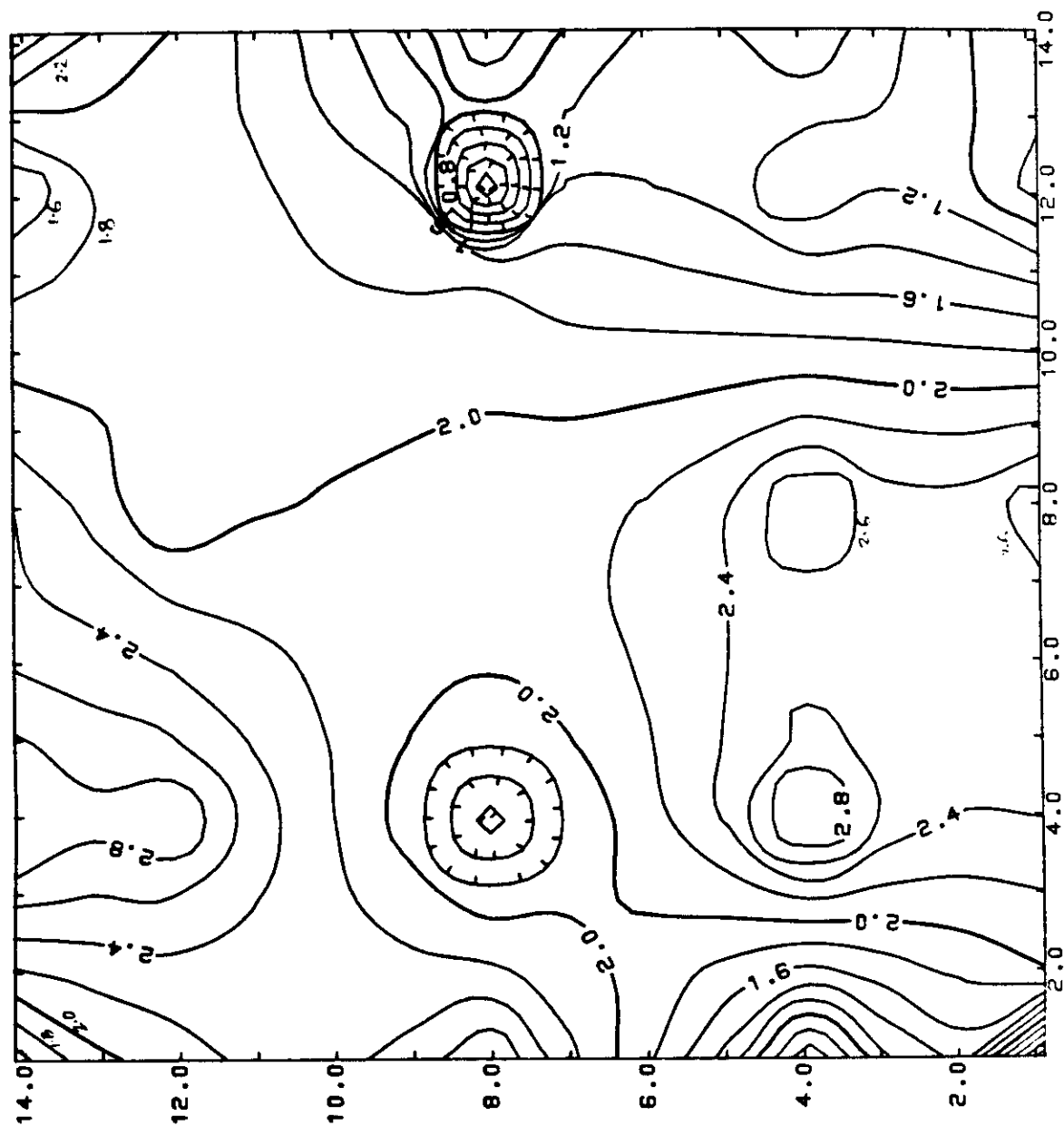


Figure 12
FIELD AVERAGE PERMEABILITY - POROSITY CORRELATION
Waskada Lower Amaranth Pool

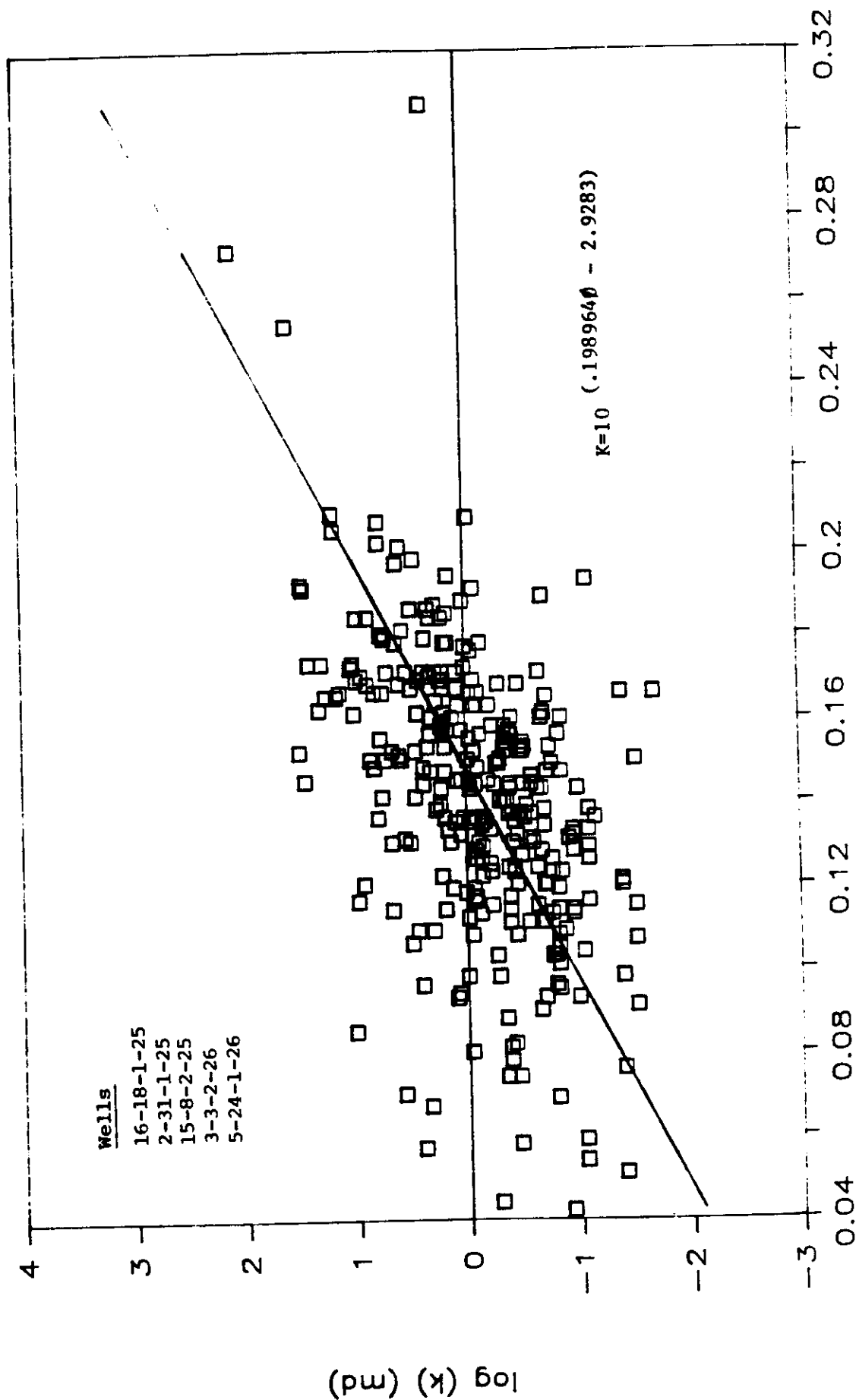


Figure 13
"A" SAND PERMEABILITY CONTOUR MAP (TOP)
(Contour Interval = 1.0)
Waskada Lower Amaranth Pool

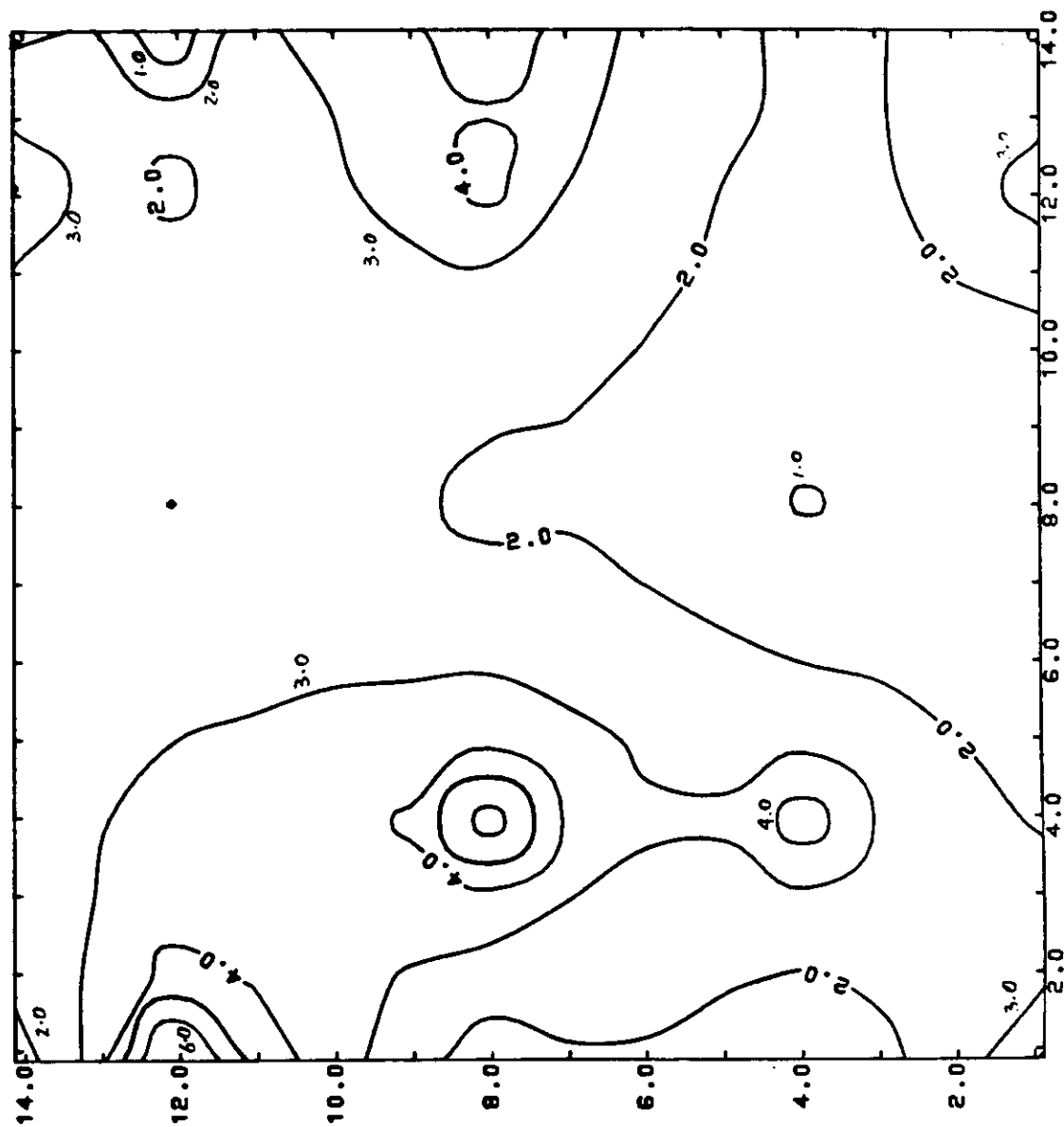


Figure 14
"B" SAND PERMEABILITY CONTOUR MAP
(Contour Interval = 1.0)
Waskada Lower Amaranth Pool

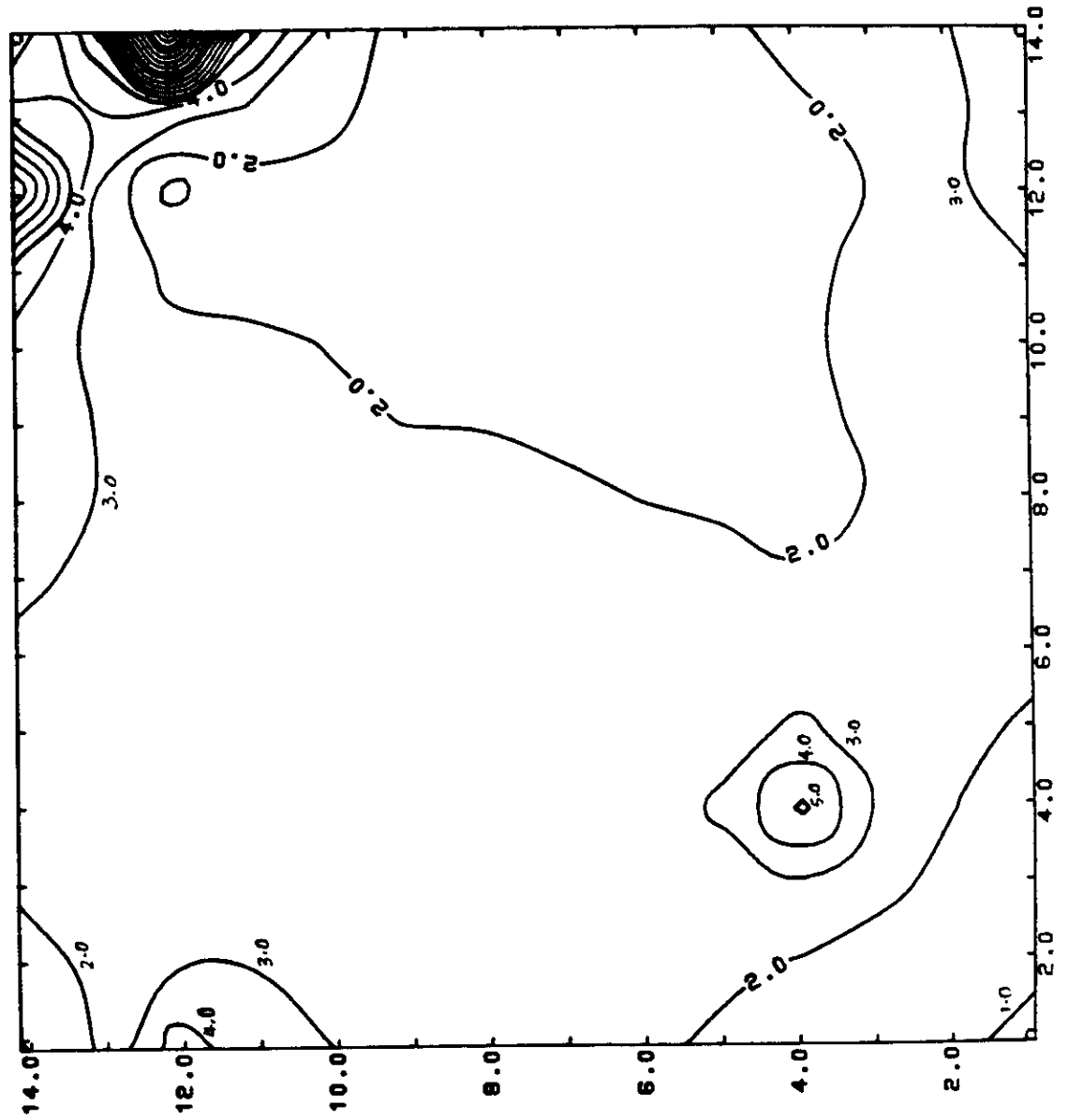


Figure 15
"C" SAND PERMEABILITY CONTOUR MAP
(Contour Interval = 1.0)
Waskada Lower Amaranth Pool

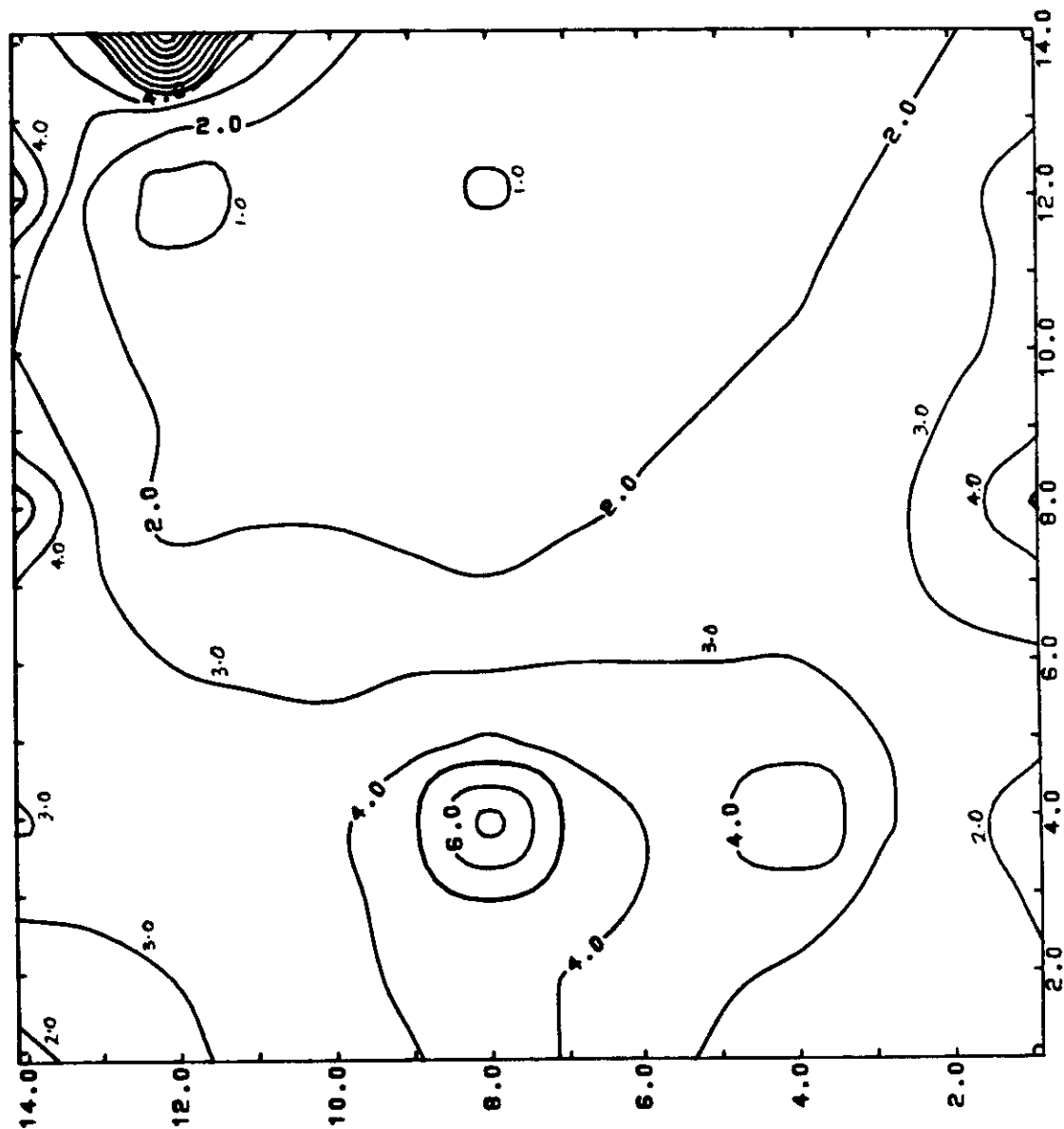


Figure 16
"D" SAND PERMEABILITY CONTOUR MAP (BOTTOM)
(Contour Interval = 1.0)
Waskada Lower Amaranth Pool

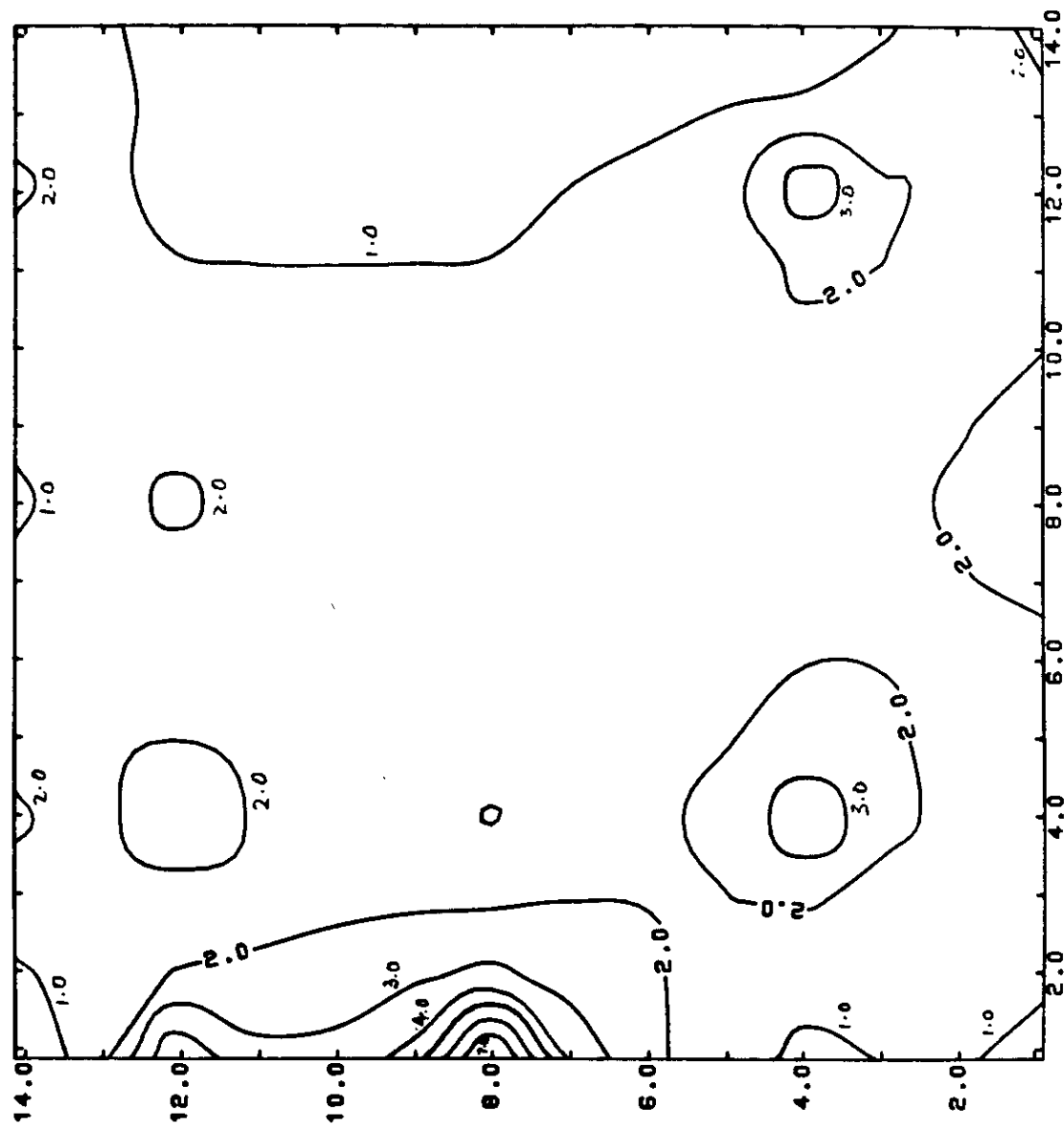


Figure 17

POROSITY-WATER SATURATION RELATIONSHIP

Waskada Lower Amaranth Pool

3-25-1-26 W1M

Oil Base Core

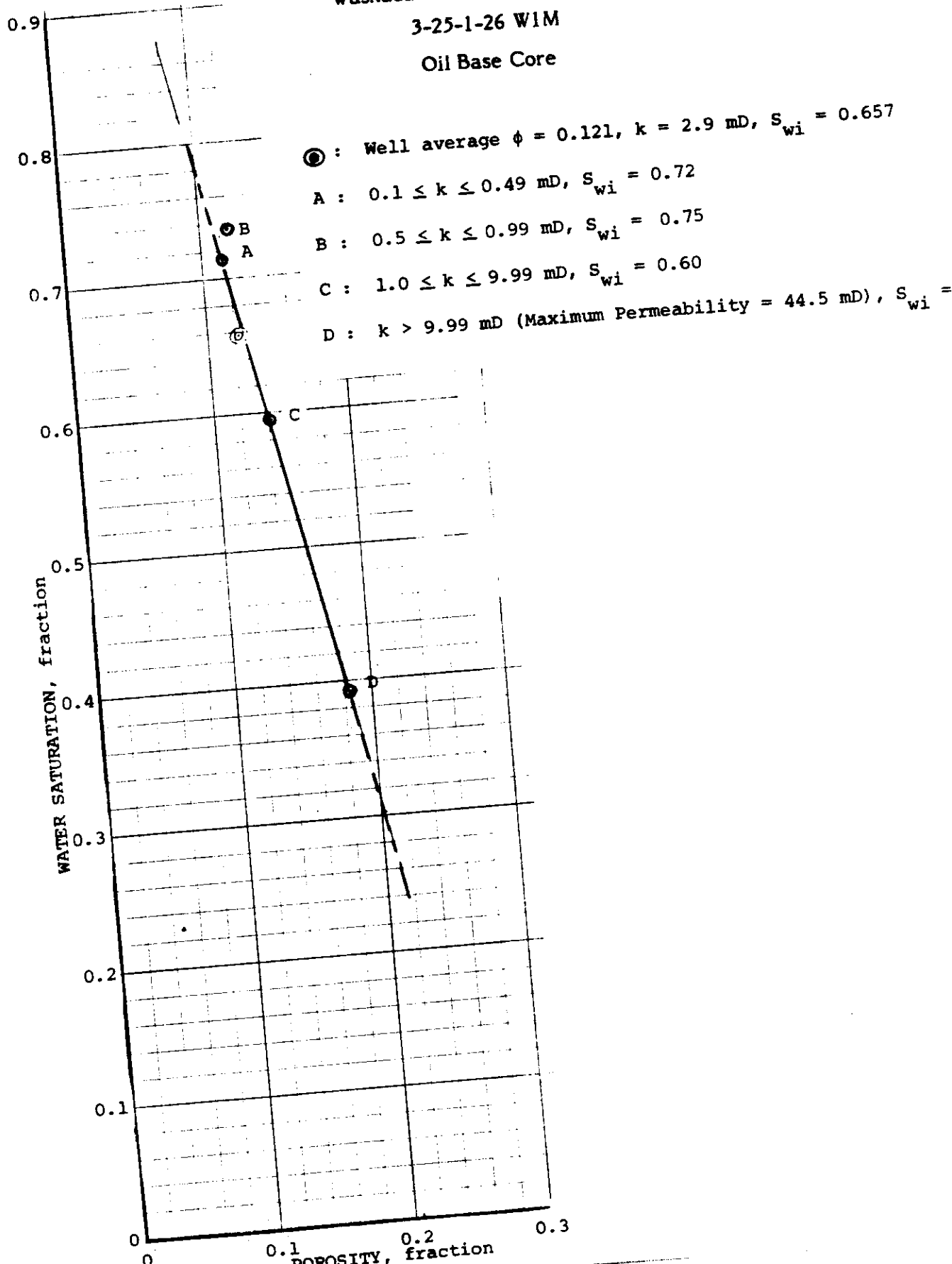


Figure 18
AVERAGE WATER-OIL RELATIVE PERMEABILITY RATIO
Waskada Lower Amaranth Pool

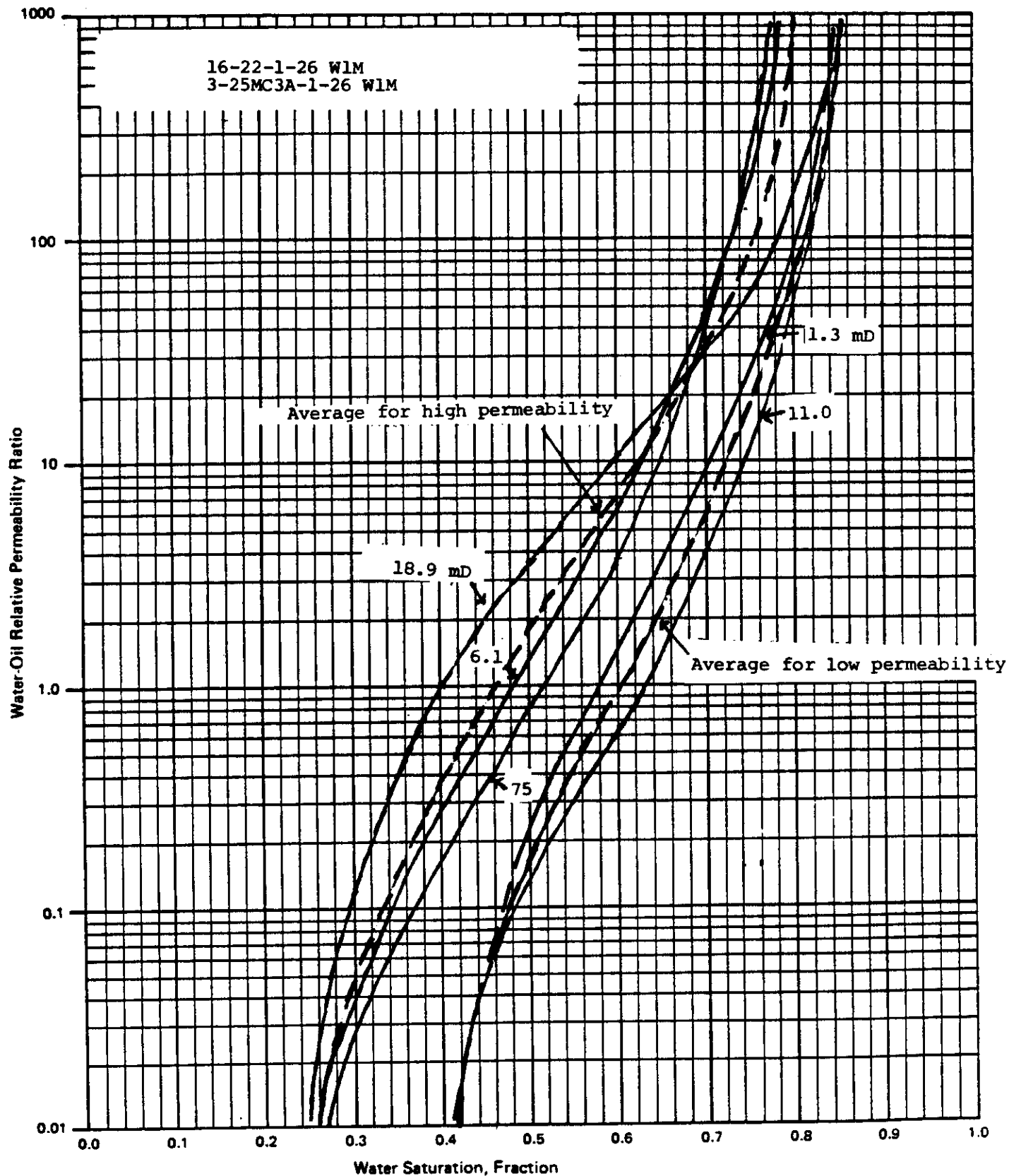


Figure 19
OIL-WATER RELATIVE PERMEABILITY
Waskada Lower Amaranth Pool
Irreducible Water Saturation = 0.37
Rock Type 2

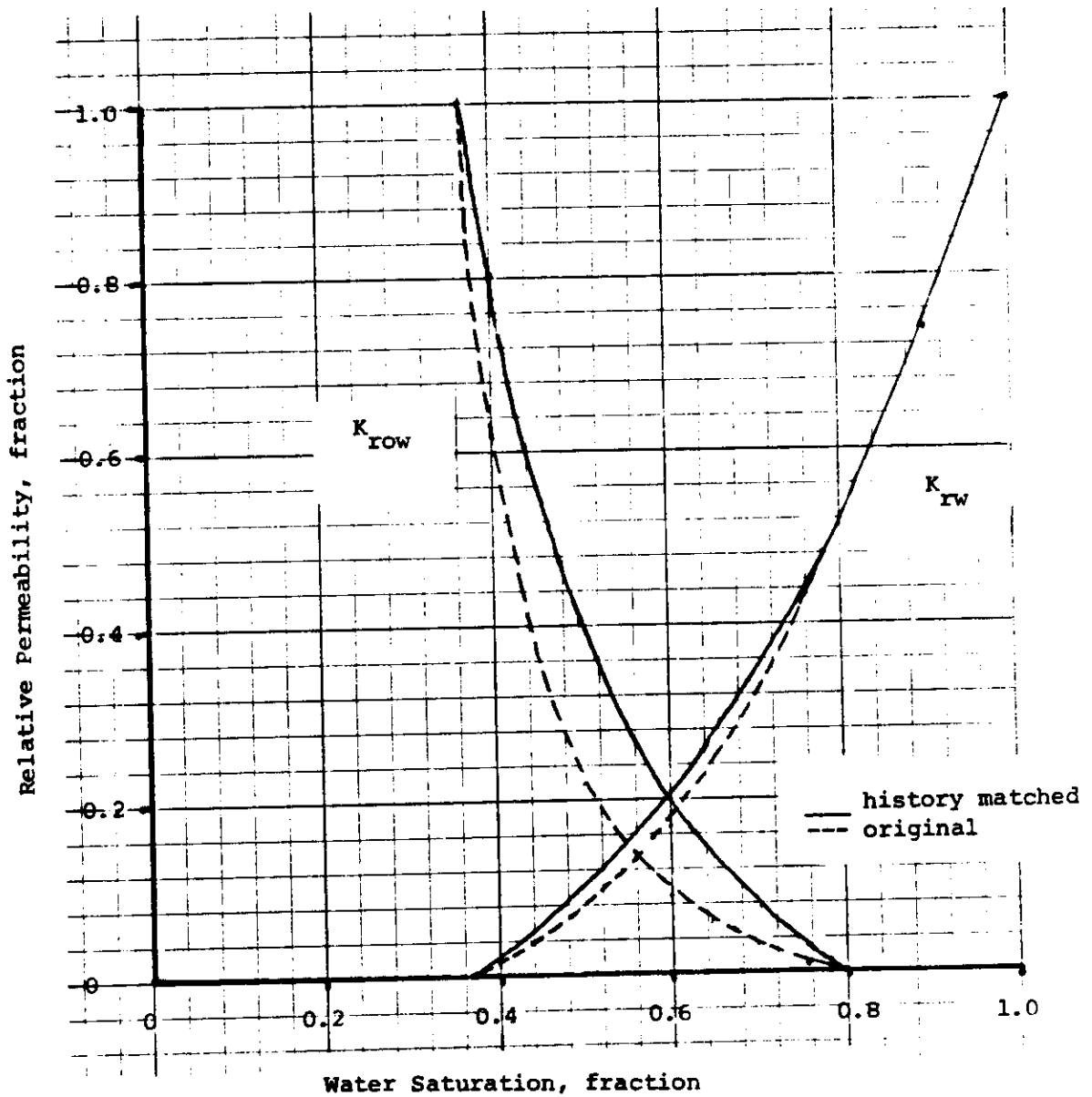


Figure 20
GAS-OIL RELATIVE PERMEABILITY
Waskada Lower Amaranth Pool
Irreducible Water Saturation = 0.37
Rock Type 2

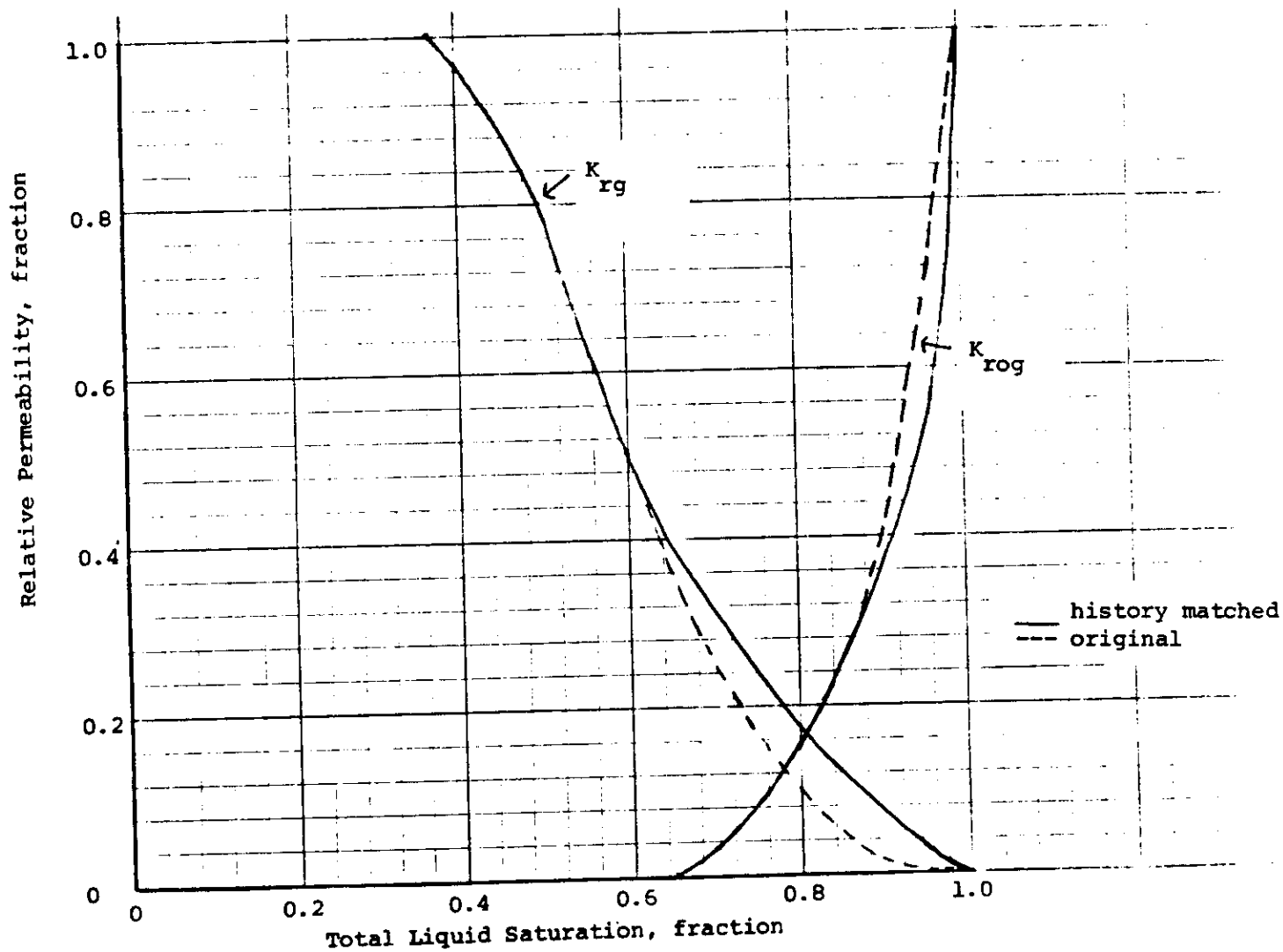


Figure 21
OIL-WATER RELATIVE PERMEABILITY
Waskada Lower Amaranth Pool
Irreducible Water Saturation = 0.5
Rock Type 1

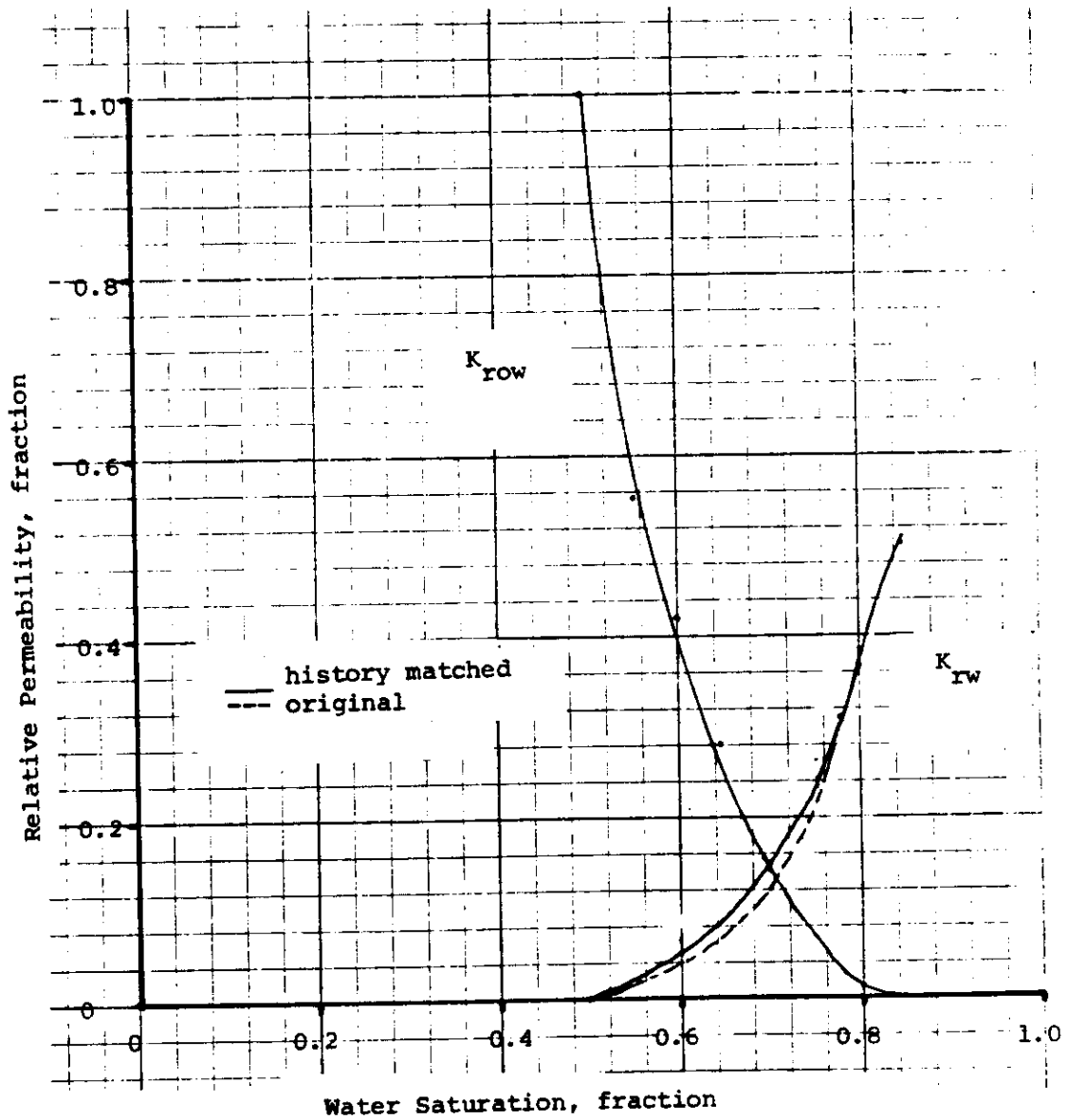


Figure 22
GAS-OIL RELATIVE PERMEABILITY
Waskada Lower Amaranth Pool
Irreducible Water Saturation = 0.5
Rock Type 1

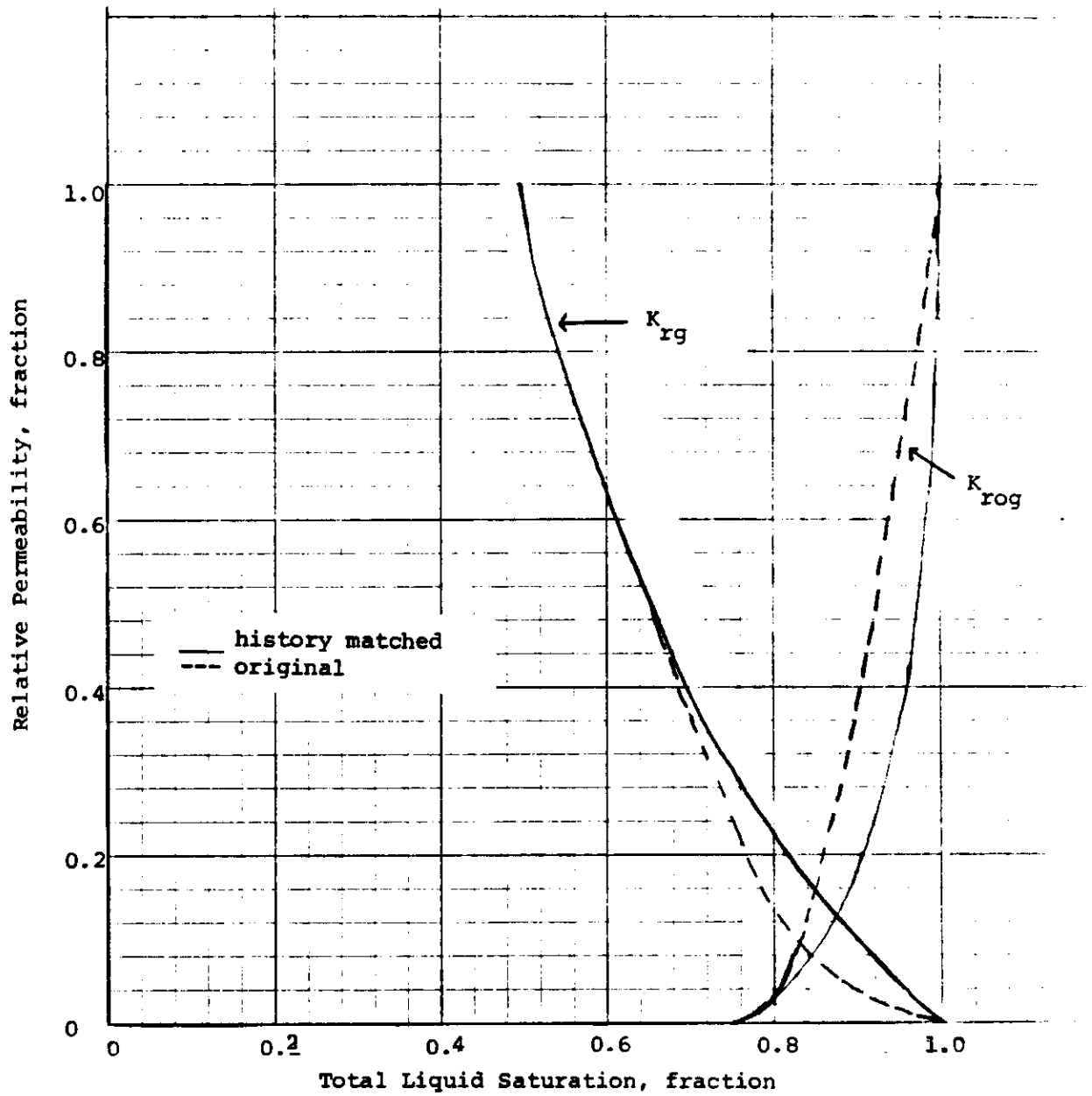


Figure 23
OIL-WATER RELATIVE PERMEABILITY
Waskada Lower Amaranth Pool
Irreducible Water Saturation = 0.63
Rock Type 3

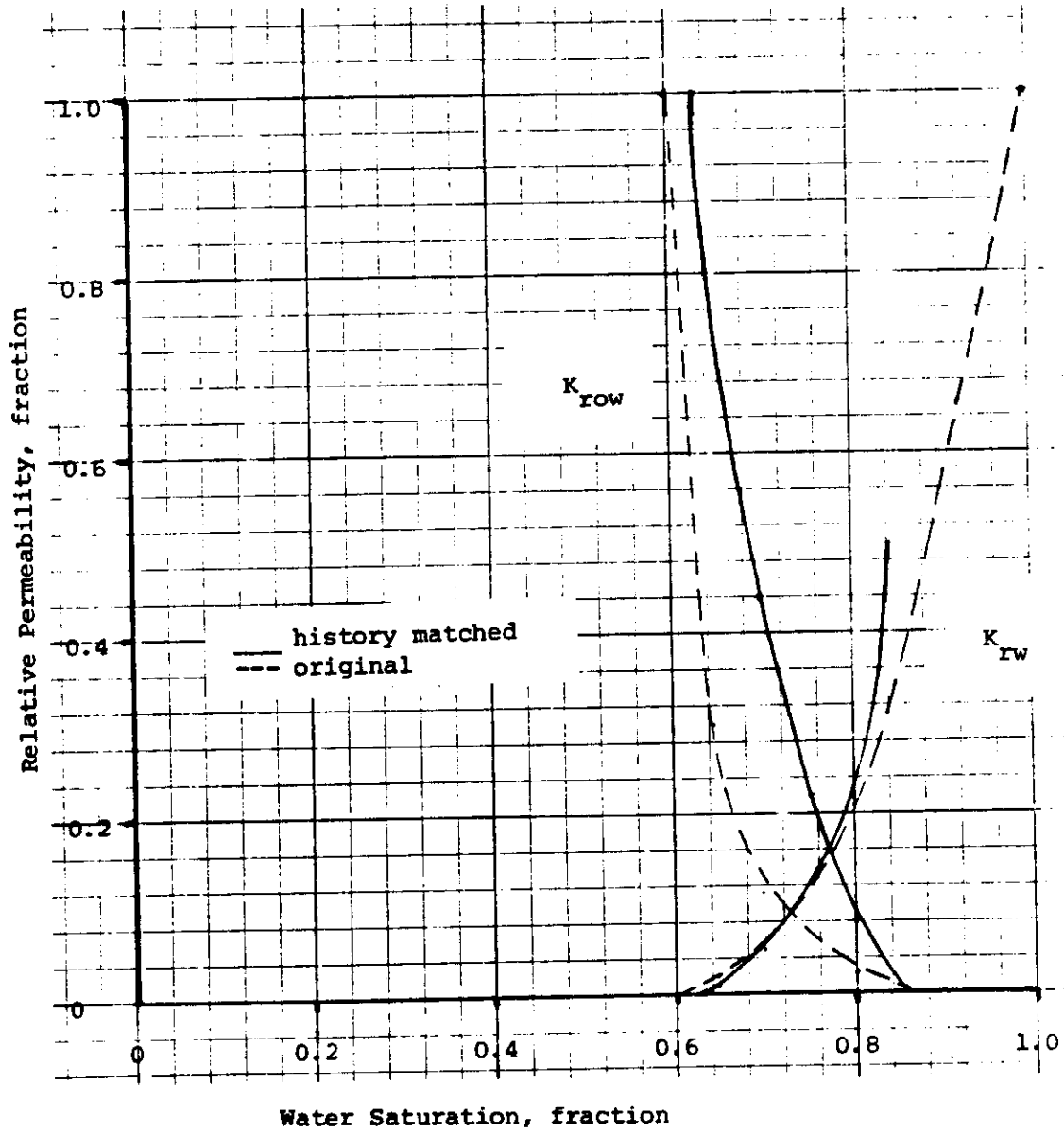


Figure 24
GAS-OIL RELATIVE PERMEABILITY
Waskada Lower Amaranth Pool
Irreducible Water Saturation = 0.63
Rock Type 3

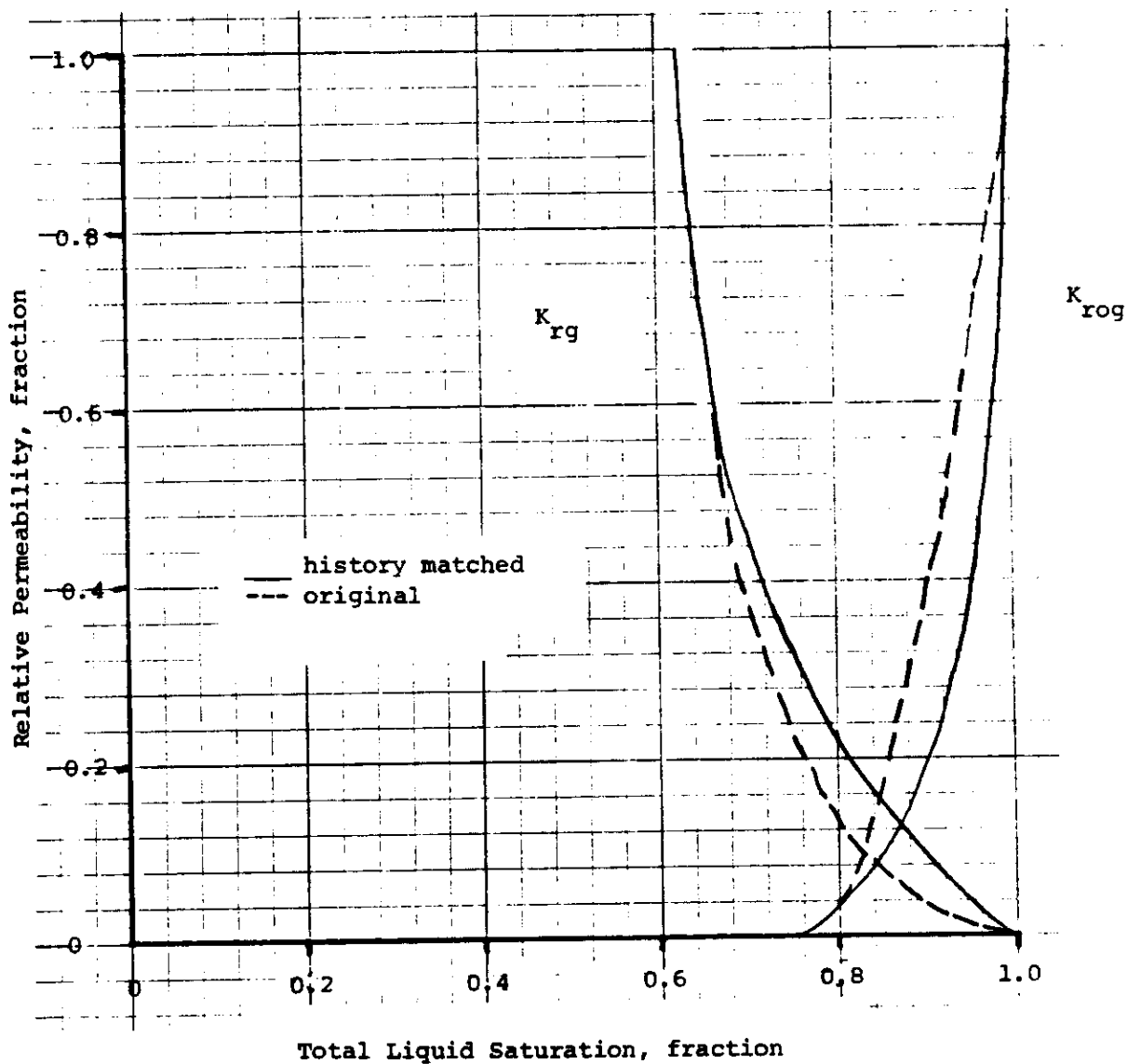


Figure 25
 FLUID DISTRIBUTION CURVES
 Waskada Lower Amaranth Pool

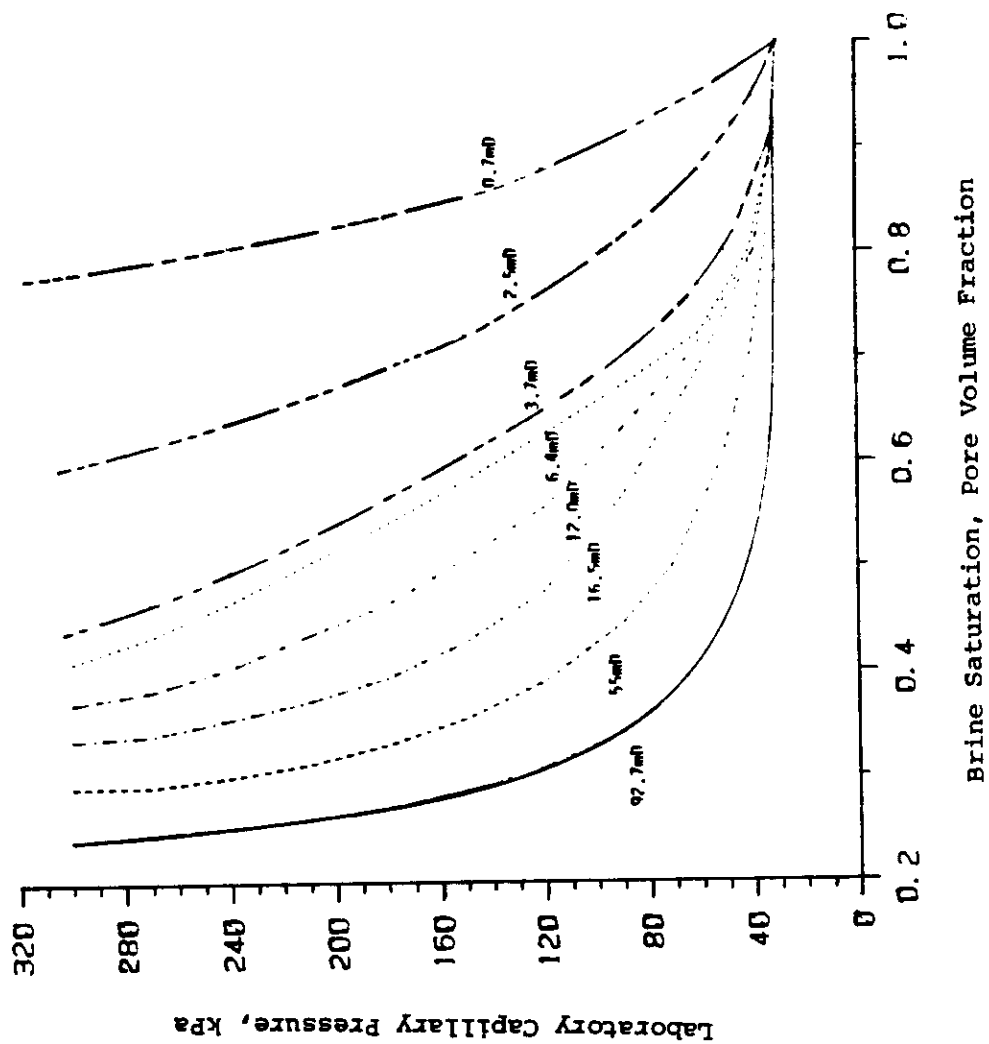


Figure 26
DEPTH VS LABORATORY CAPILLARY PRESSURE
Waskada Lower Amaranth Pool

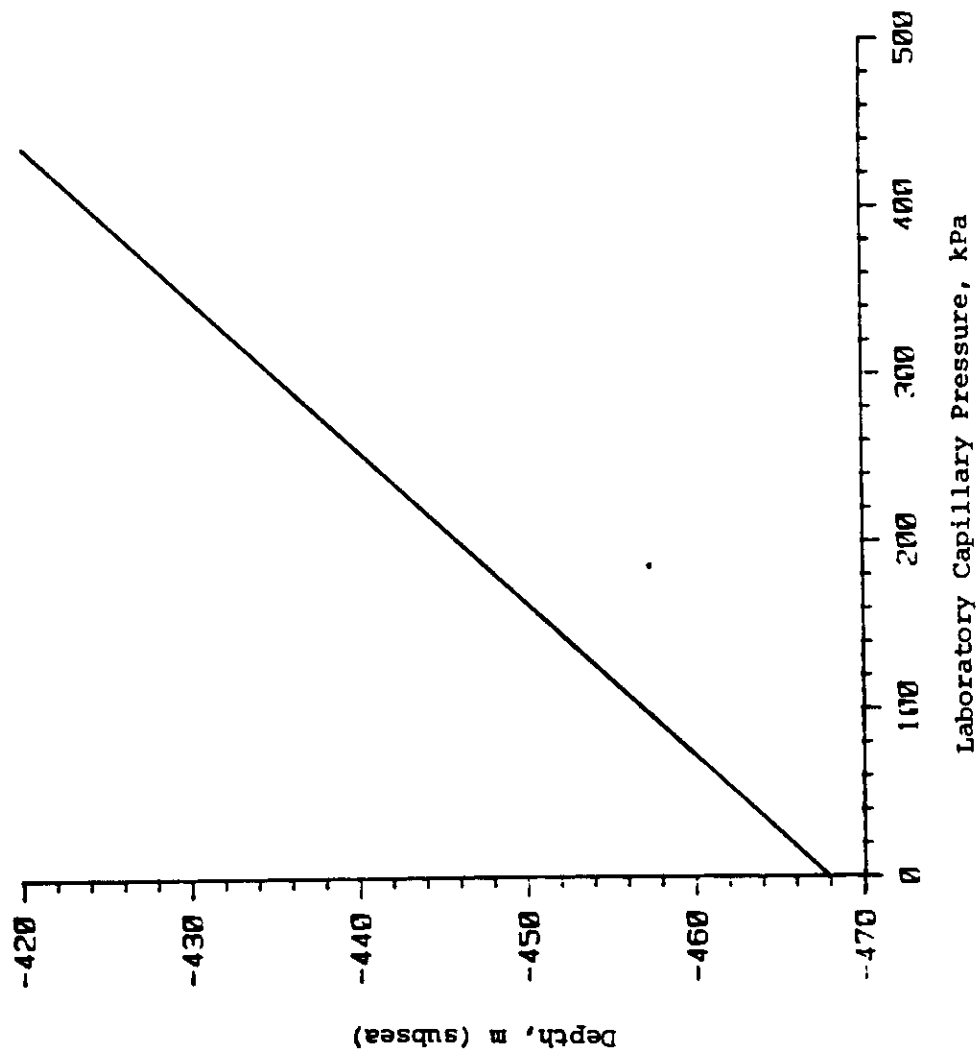


Figure 27

"A" SAND WATER SATURATION MAP (TOP)

(Contour Interval = 0.05)

Waskada Lower Amaranth Pool

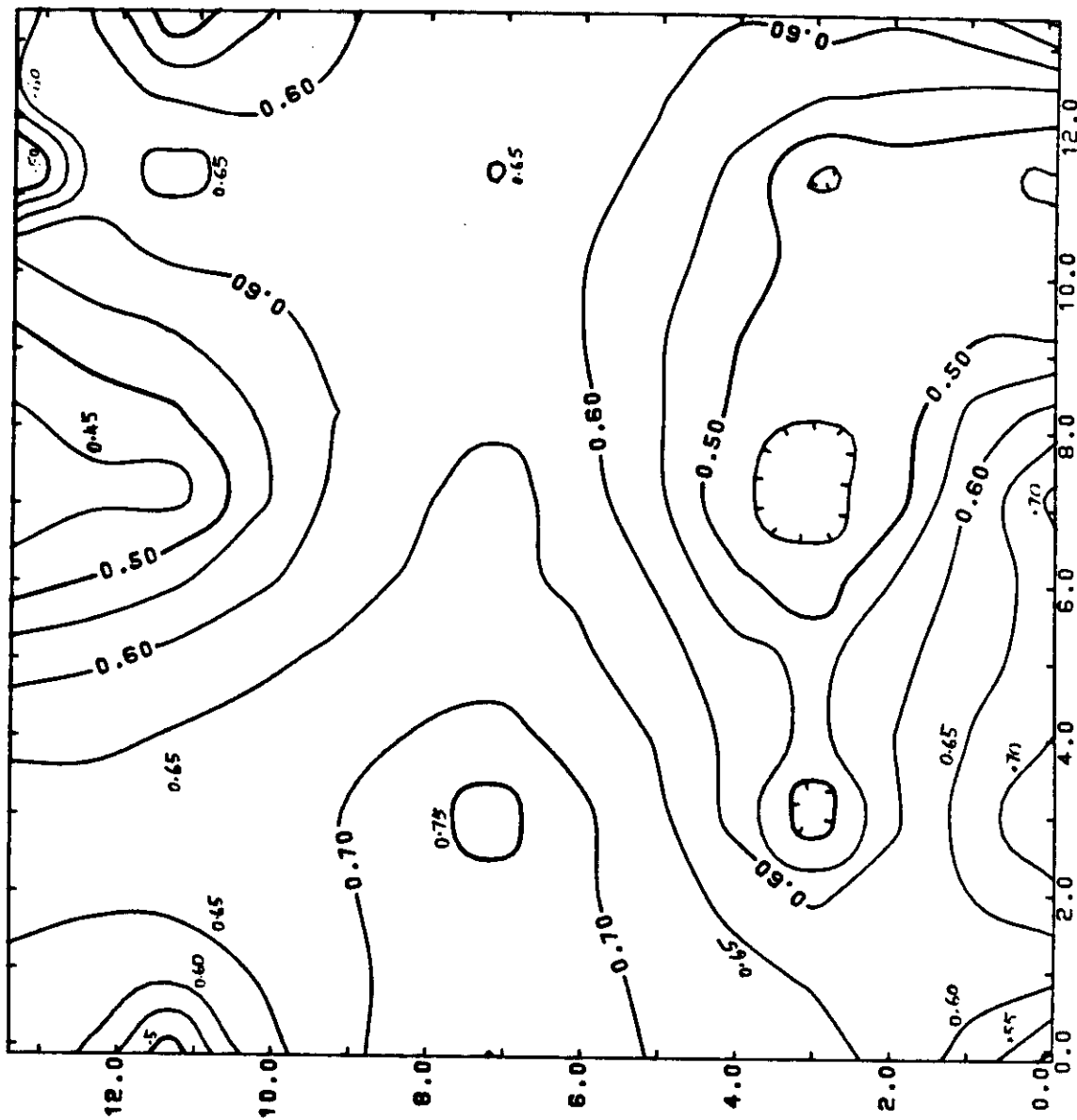


Figure 28
"B" SAND WATER SATURATION MAP
(Contour Interval = 0.05)
Waskada Lower Amaranth Pool

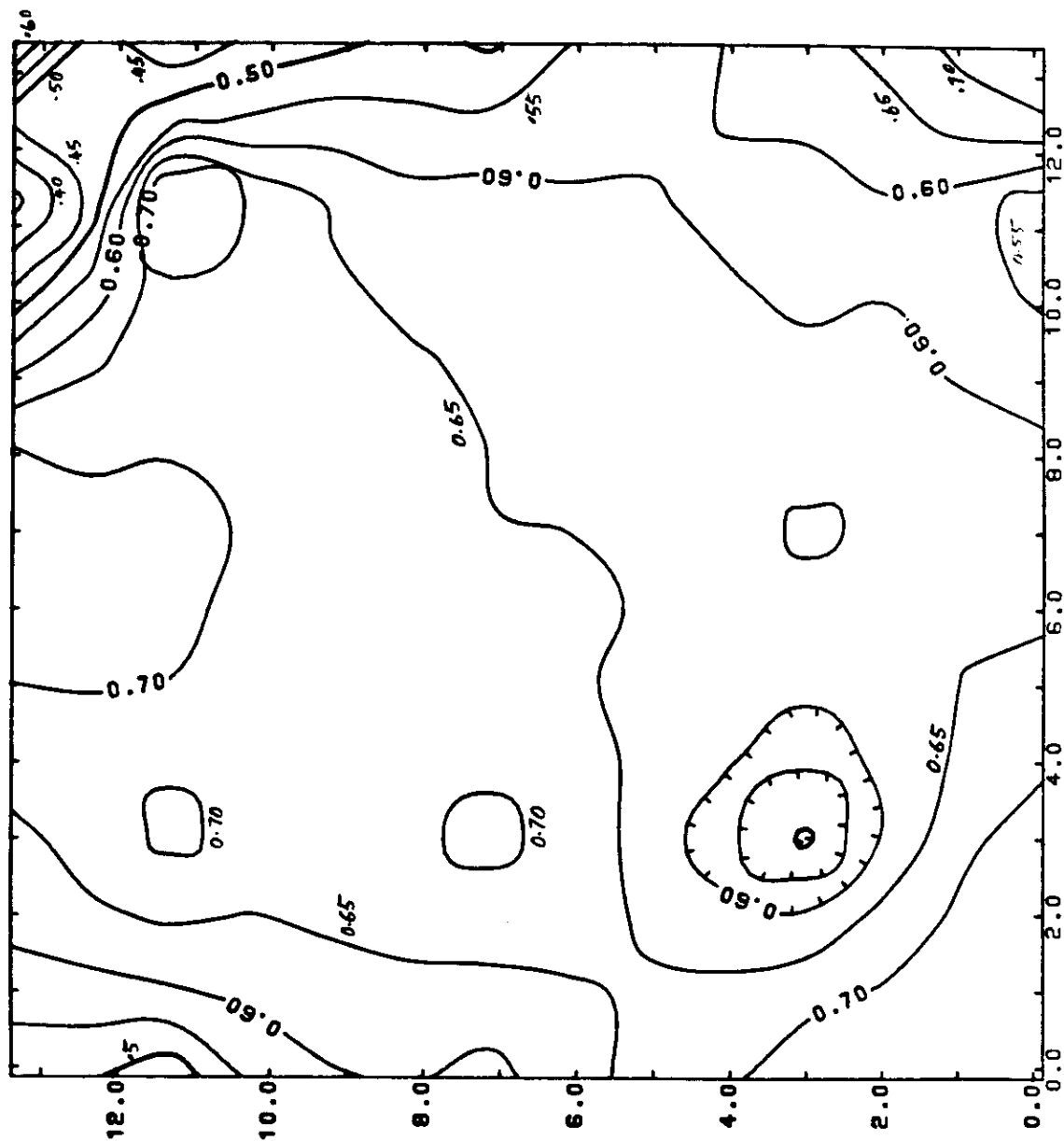


Figure 29

"C" SAND WATER SATURATION MAP

(Contour Interval = 0.05)

Waskada Lower Amaranth Pool

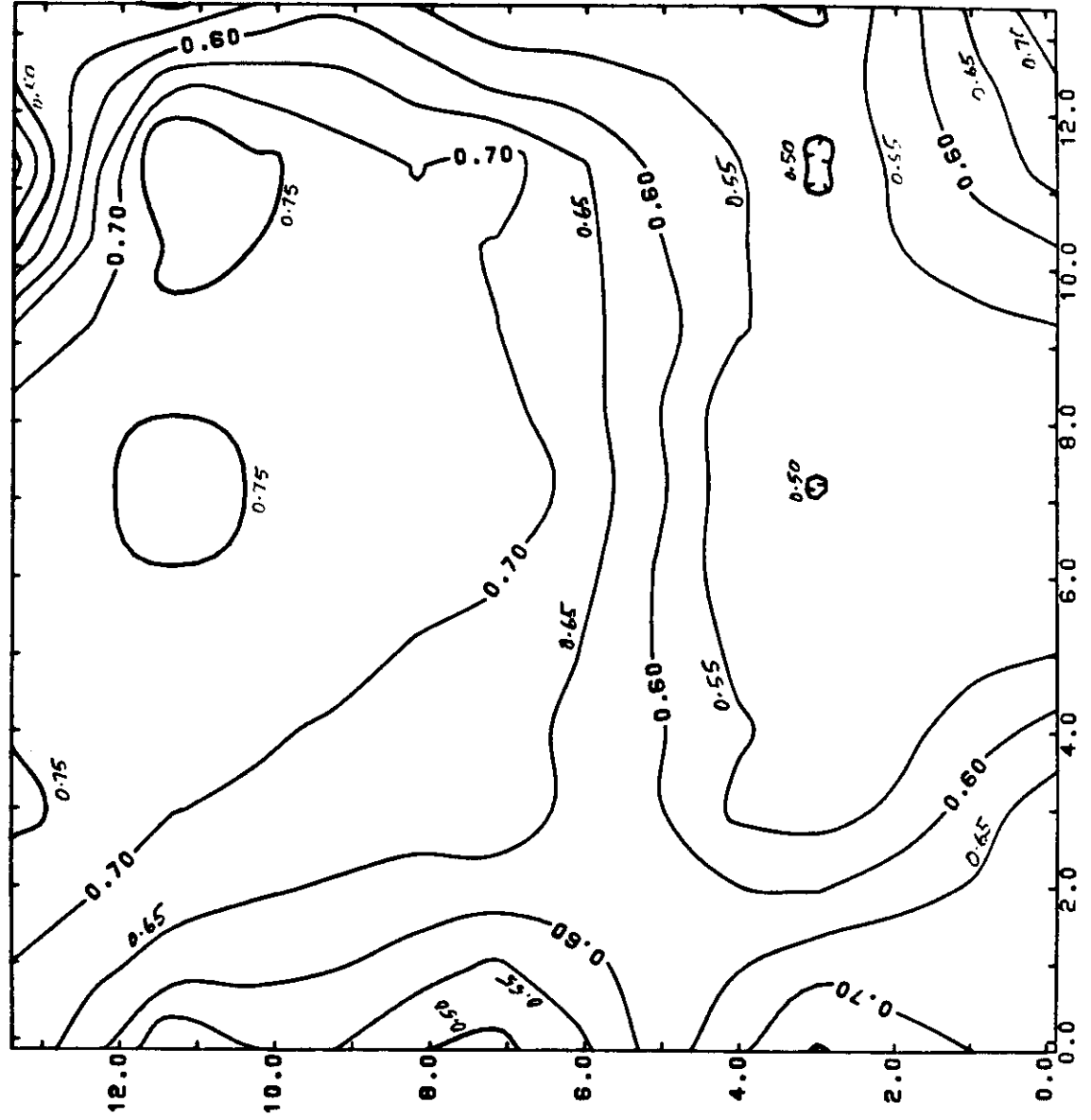


Figure 30
"D" SAND WATER SATURATION MAP (BOTTOM)
(Contour Interval = 0.05)
Waskada Lower Amaranth Pool

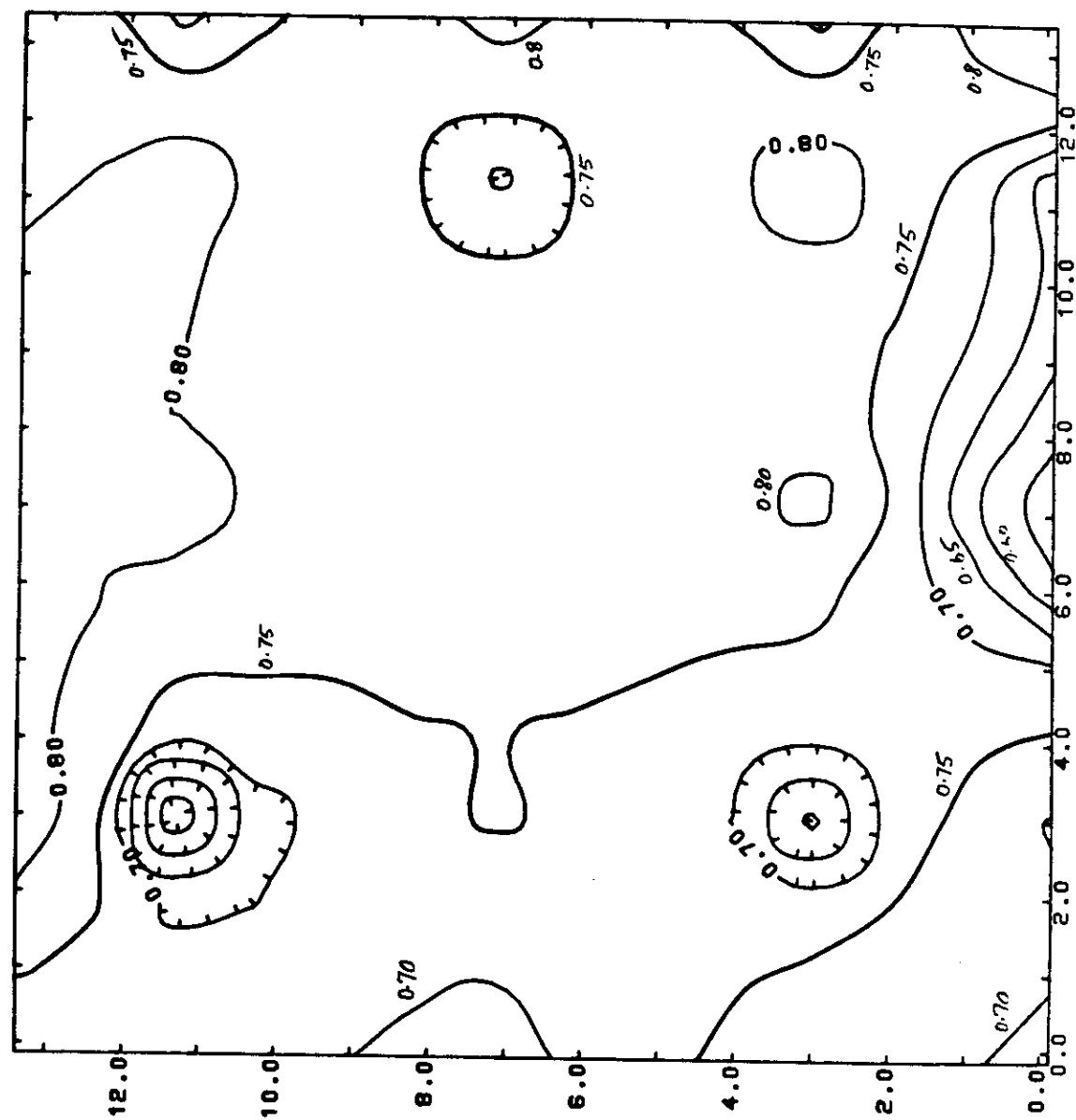


Figure 31
"A" SAND HYDROCARBON PORE VOLUME MAP (TOP)
(Contour Interval = 500.0)
Waskada Lower Amaranth Pool

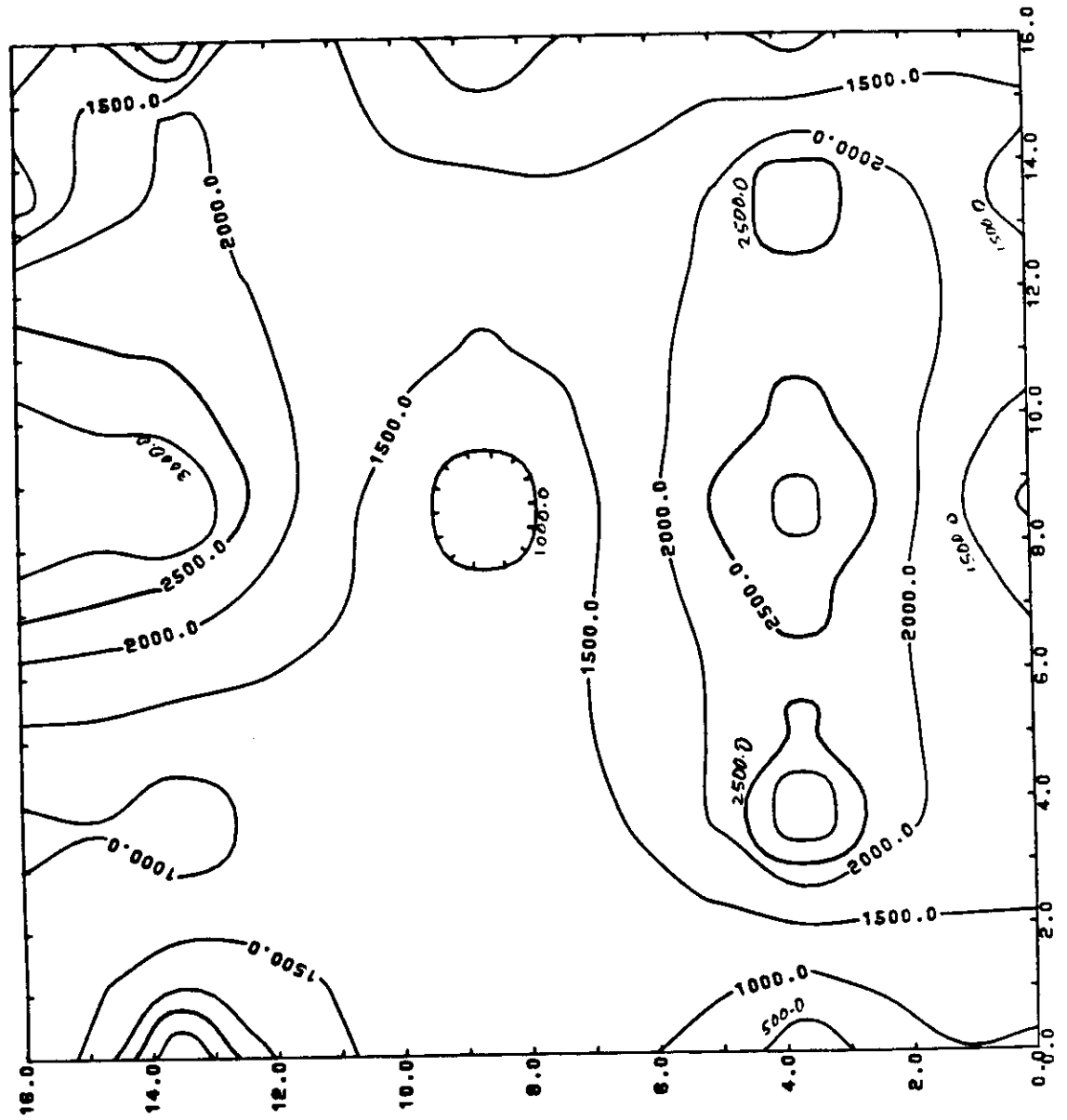


Figure 32
"B" SAND HYDROCARBON PORE VOLUME MAP
(Contour Interval = 500.0)
Waskada Lower Amaranth Pool

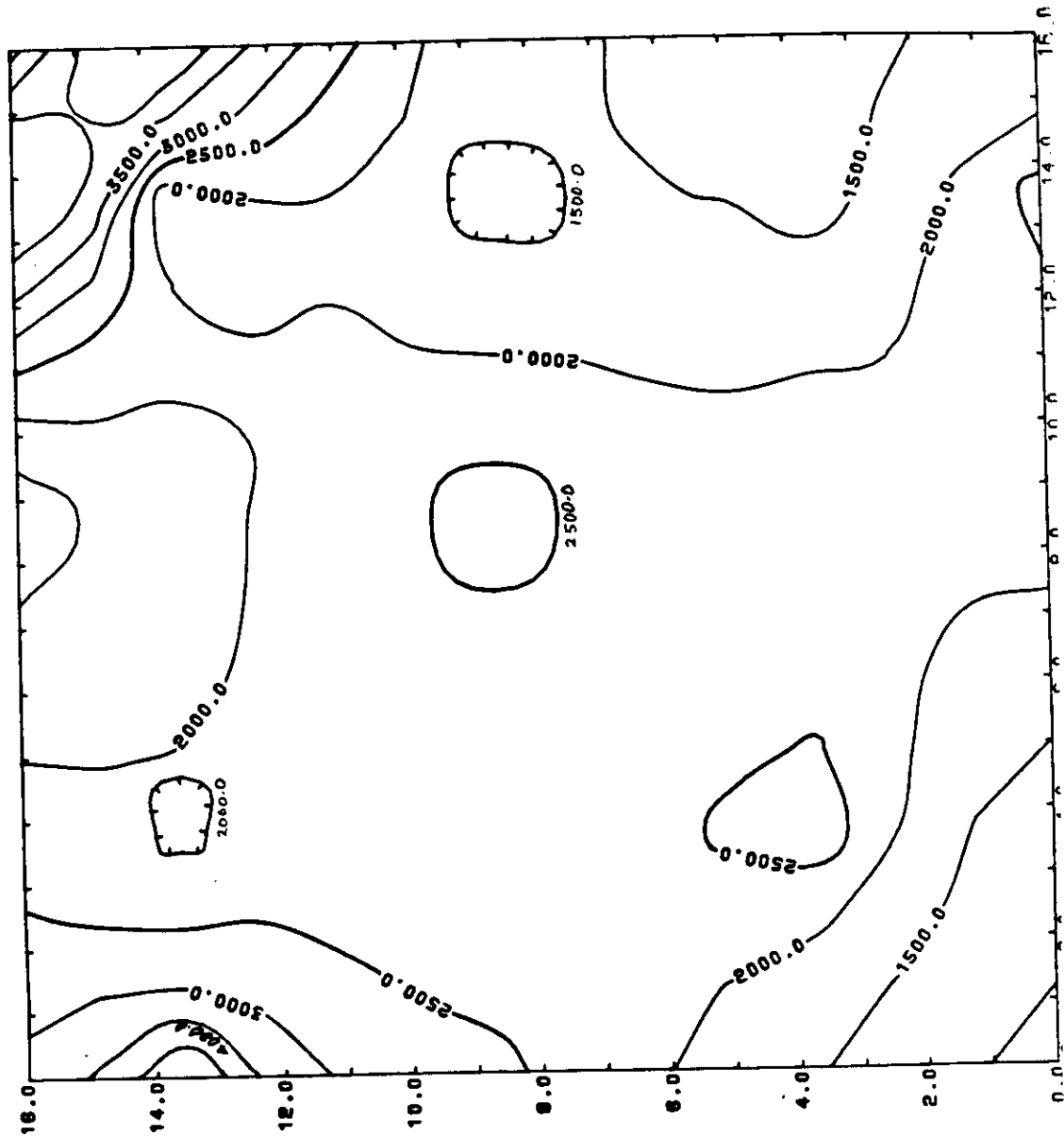


Figure 33
 "C" SAND HYDROCARBON PORE VOLUME MAP
 (Contour Interval = 500.0)
 Waskada Lower Amaranth Pool

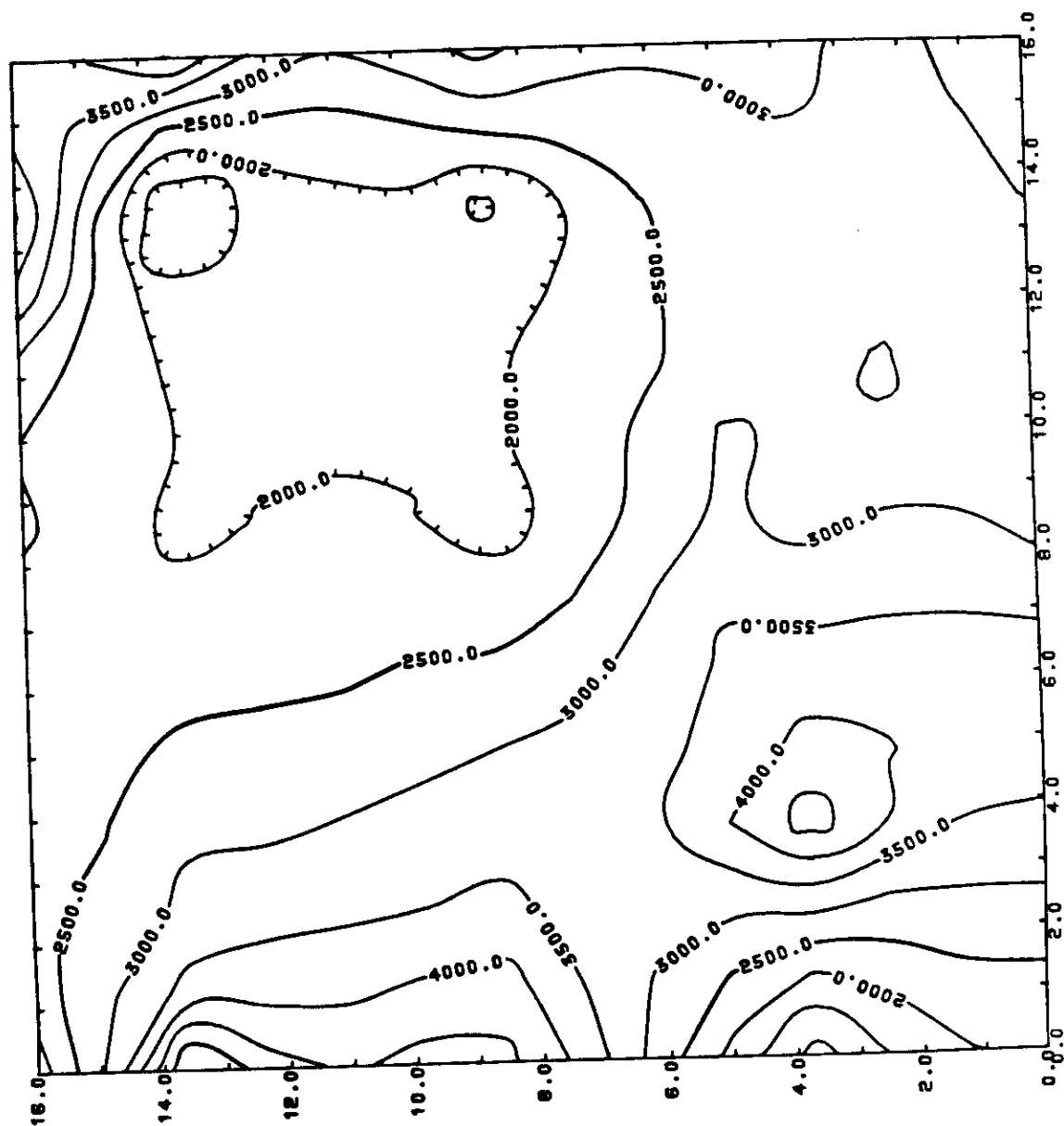


Figure 34
"D" SAND HYDROCARBON PORE VOLUME MAP (BOTTOM)
(Contour Interval = 500.0)
Waskada Lower Amaranth Pool

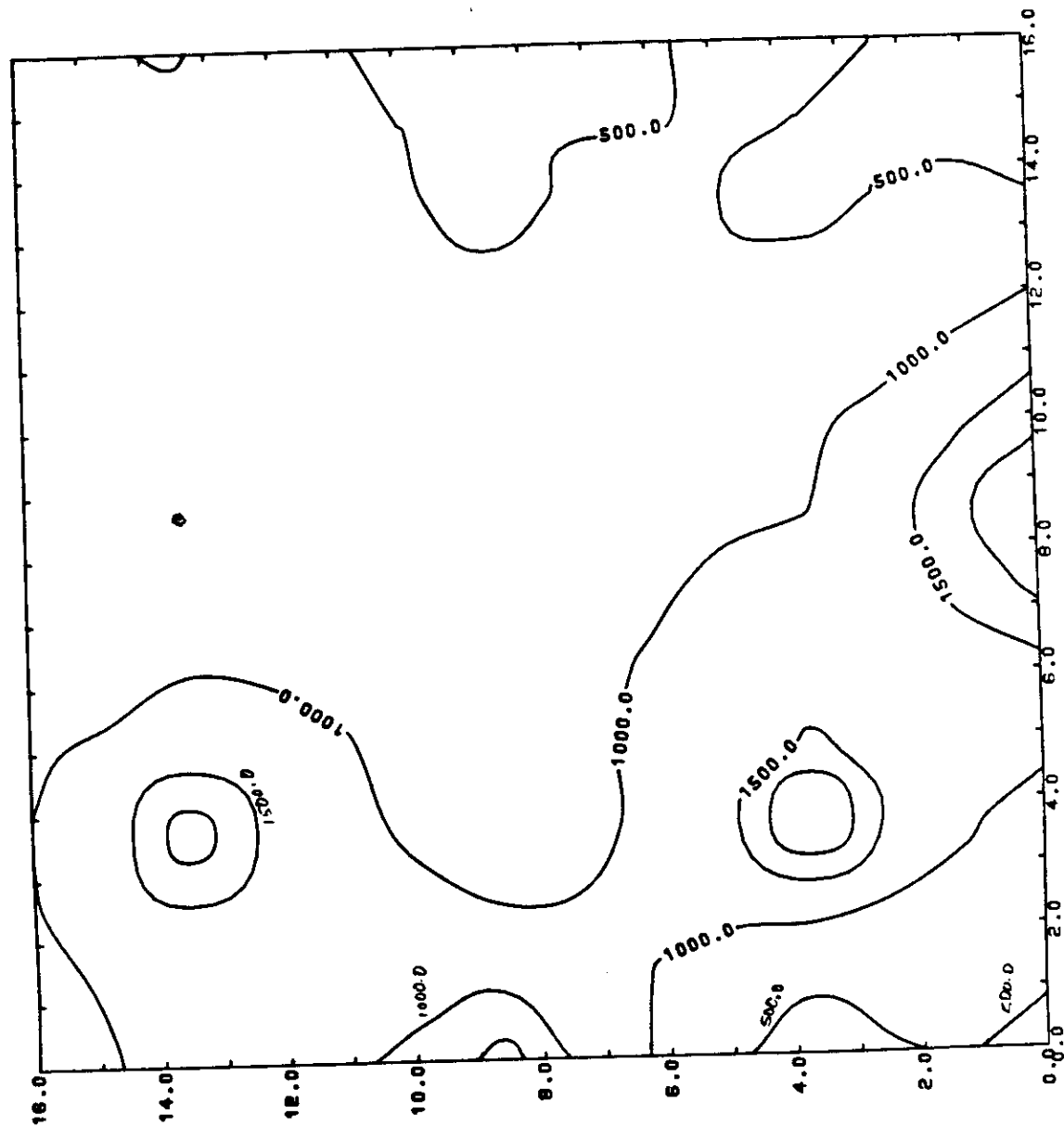


Figure 35
COMPOSITE HYDROCARBON PORE VOLUME MAP
(Contour Interval = 1 000.0)
Waskada Lower Amaranth Pool

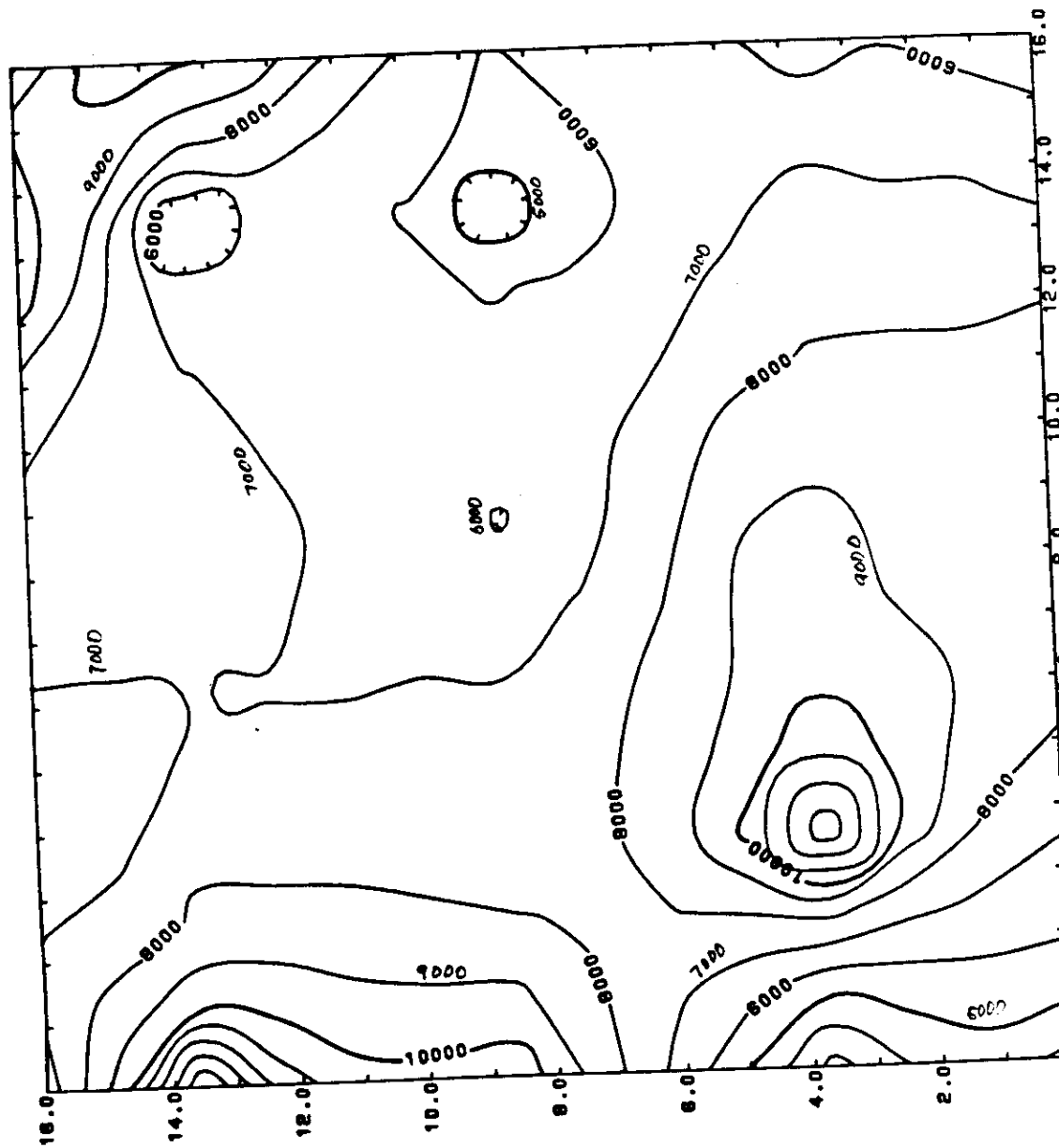


Figure 36
FLOWING BOTTOMHOLE PRESSURES VS LIQUID PRODUCTIVITY
Waskada Lower Amaranth Pool

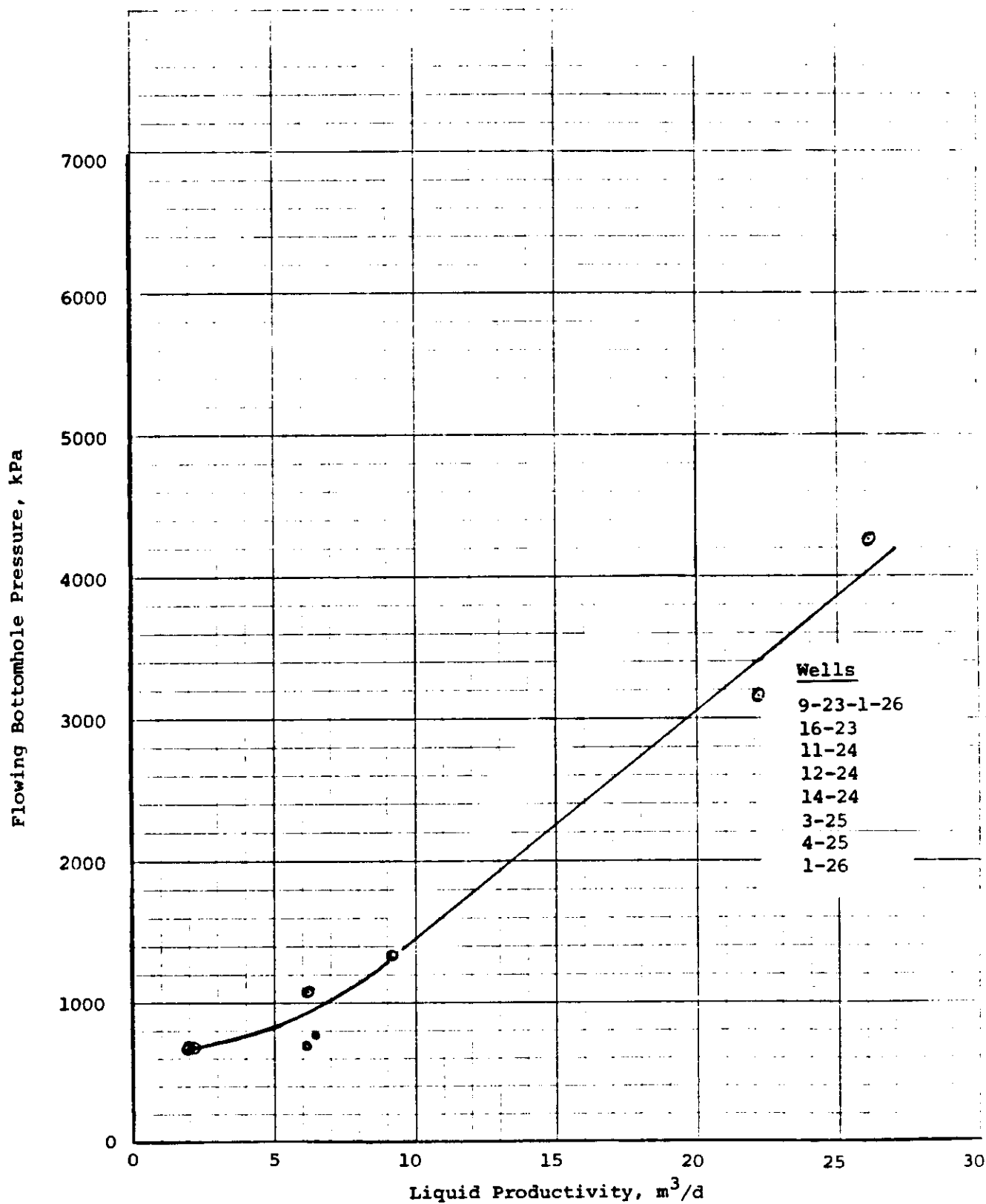


Figure 37
STUDY AREA PRESSURE HISTORY
Waskada Lower Amaranth Pool

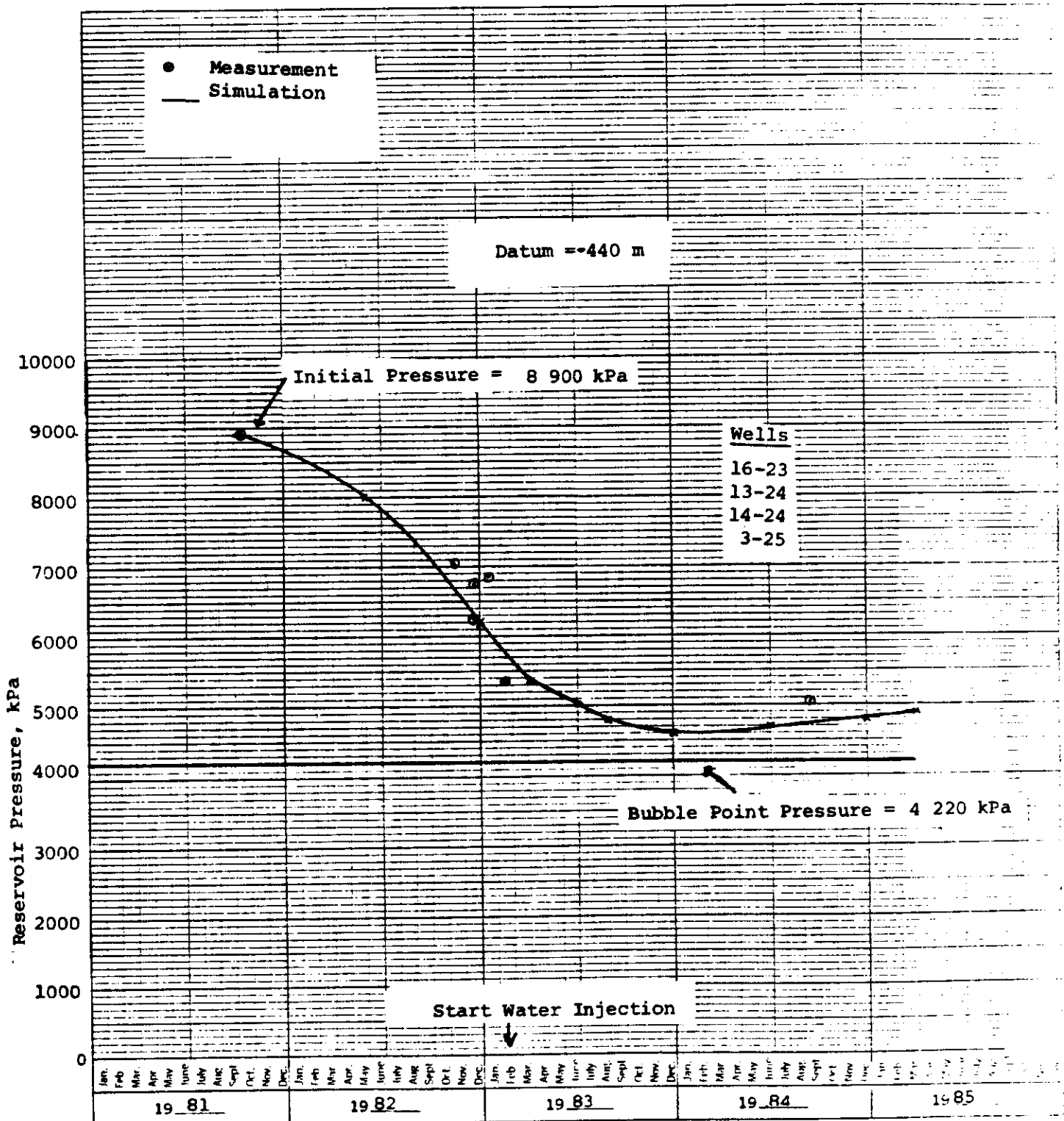


Figure 38
 MAIN PATTERN AREA PRODUCTION HISTORY
 Waskada Lower Amaranth Pool

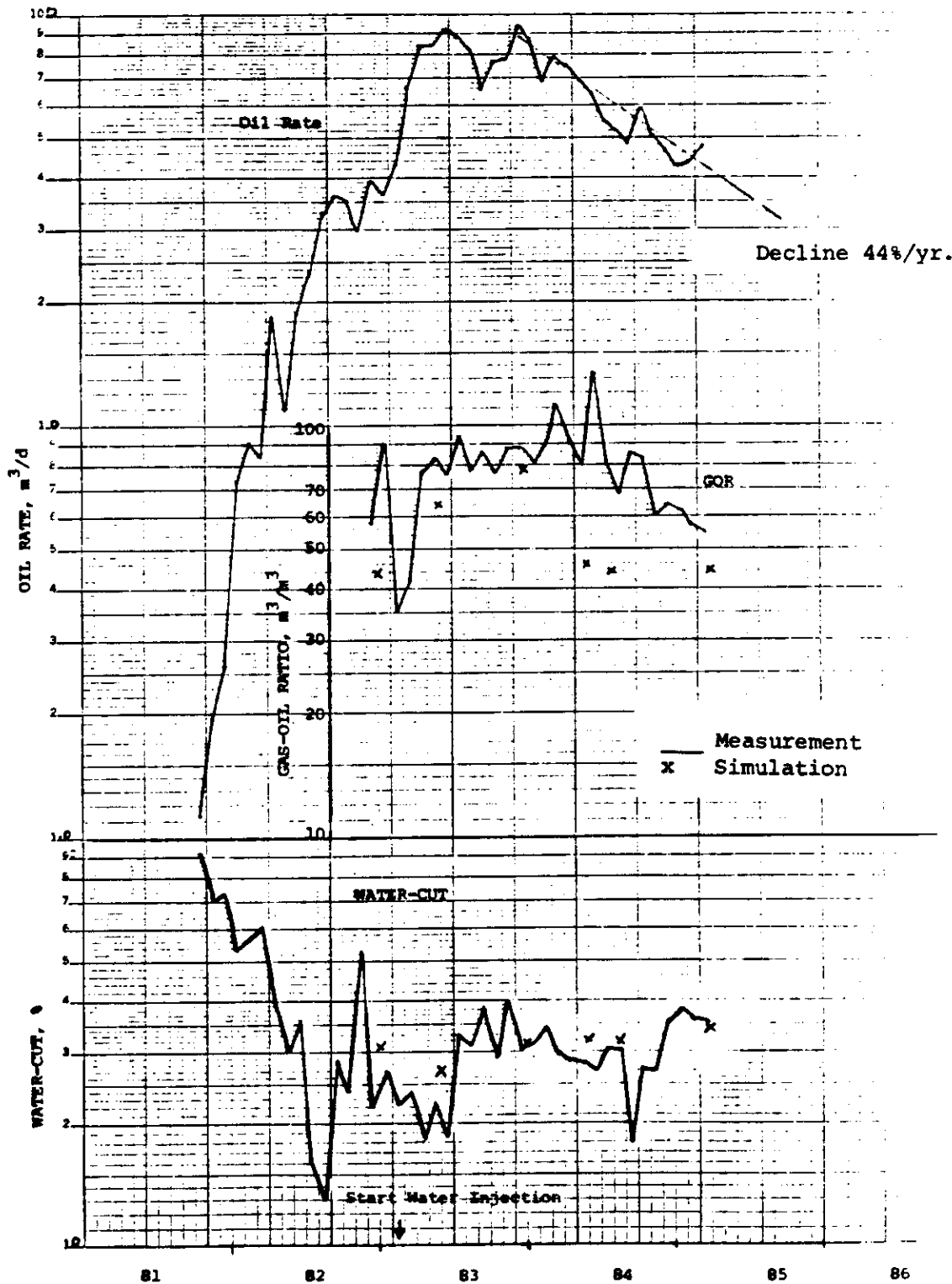
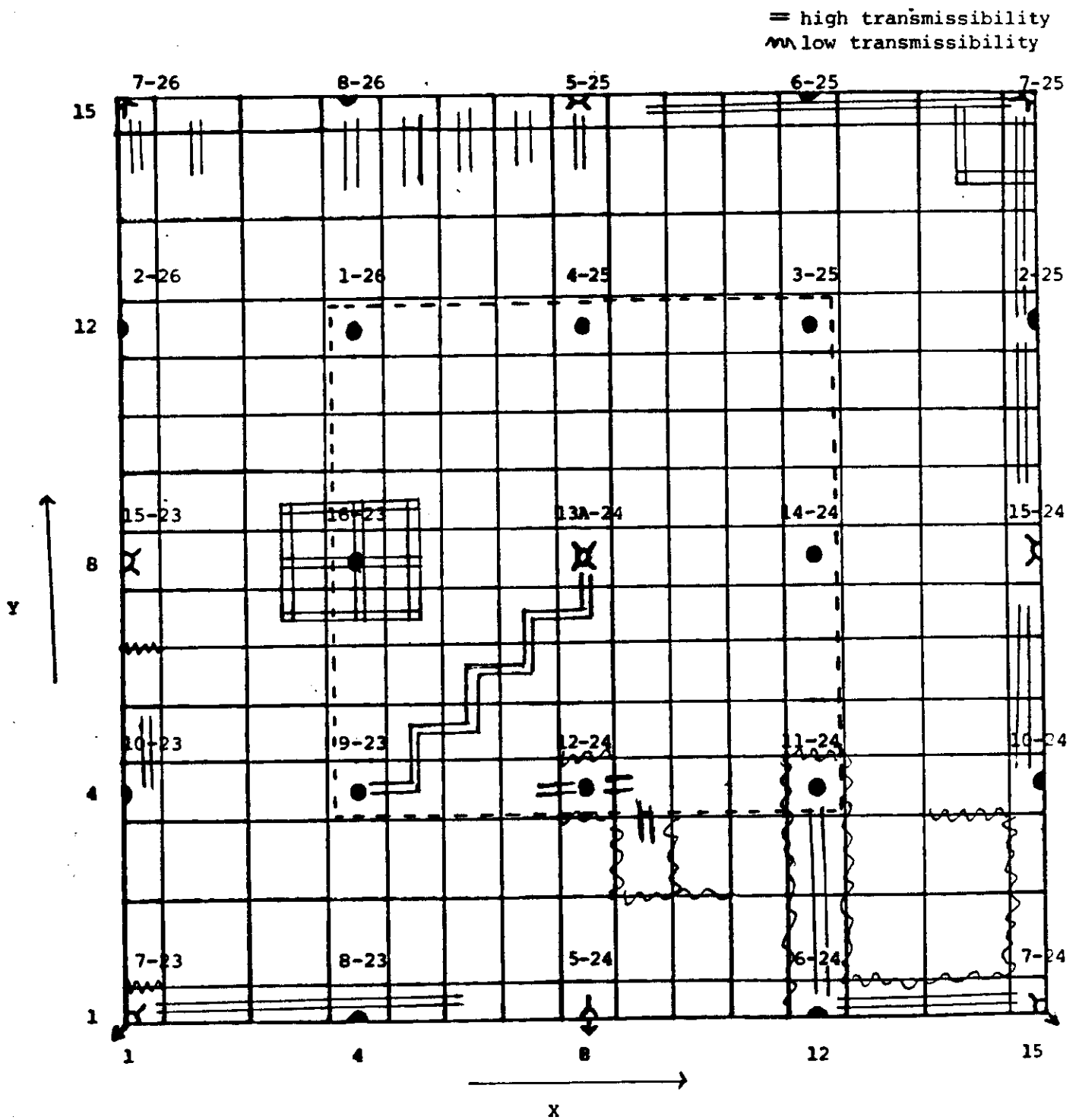


Figure 39
 LOCATION OF TRANSMISSIBILITY MULTIPLIERS IN THE AREAL PLANE
 Waskada Lower Amaranth Pool
 TWP.1 R.26 W1M



9-23-1-26 WIM



16-23-1-26 WIM

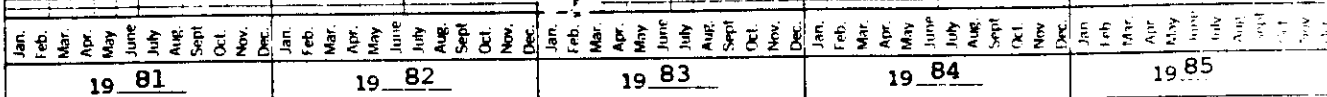


Figure 42

WELL PRODUCTION HISTORY

Waskada Lower Amaranth Pool

11-24-1-26 W1M

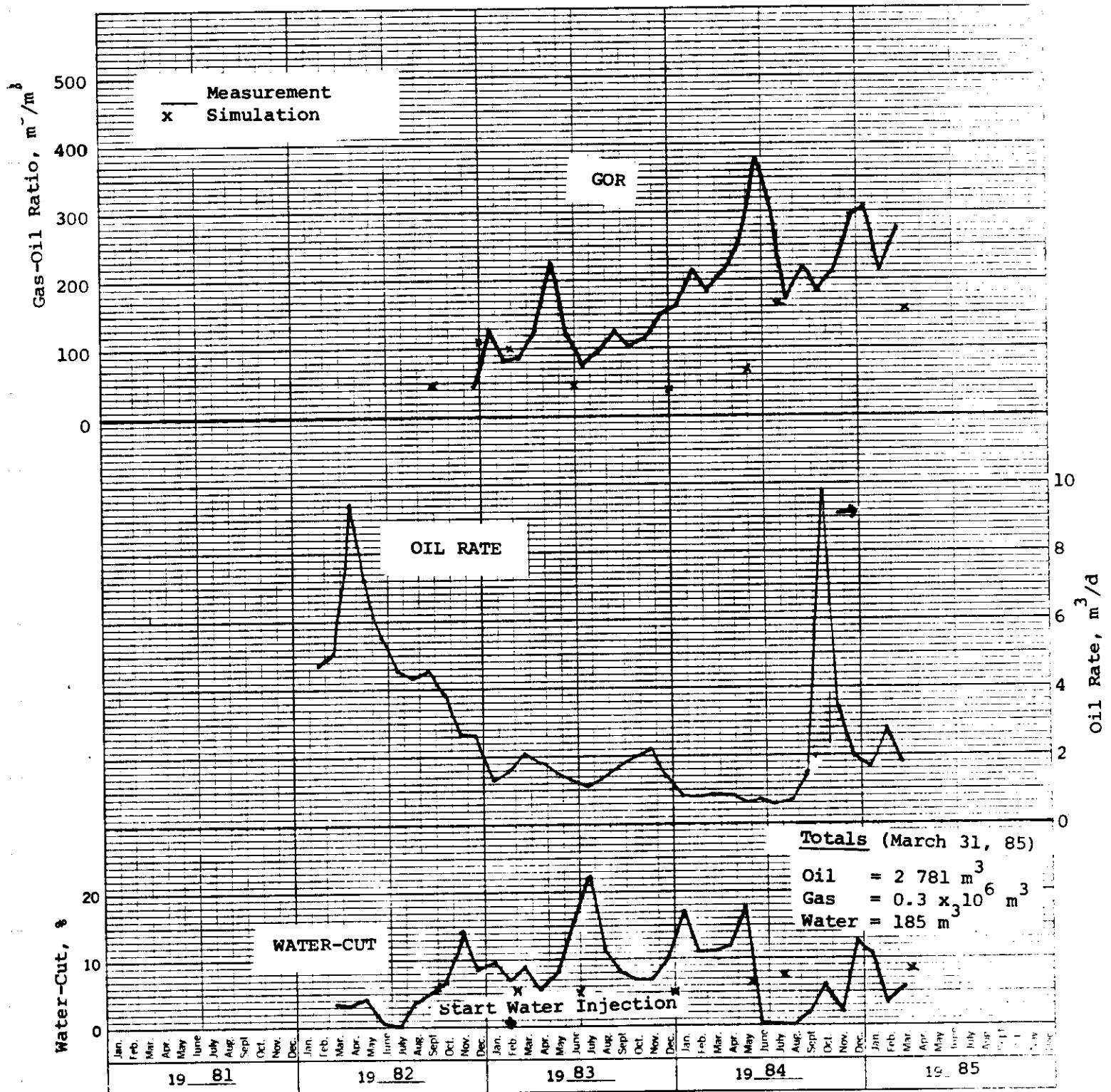


Figure 43
WELL PRODUCTION HISTORY
Waskada Lower Amaranth Pool
12-24-1-26 W1M

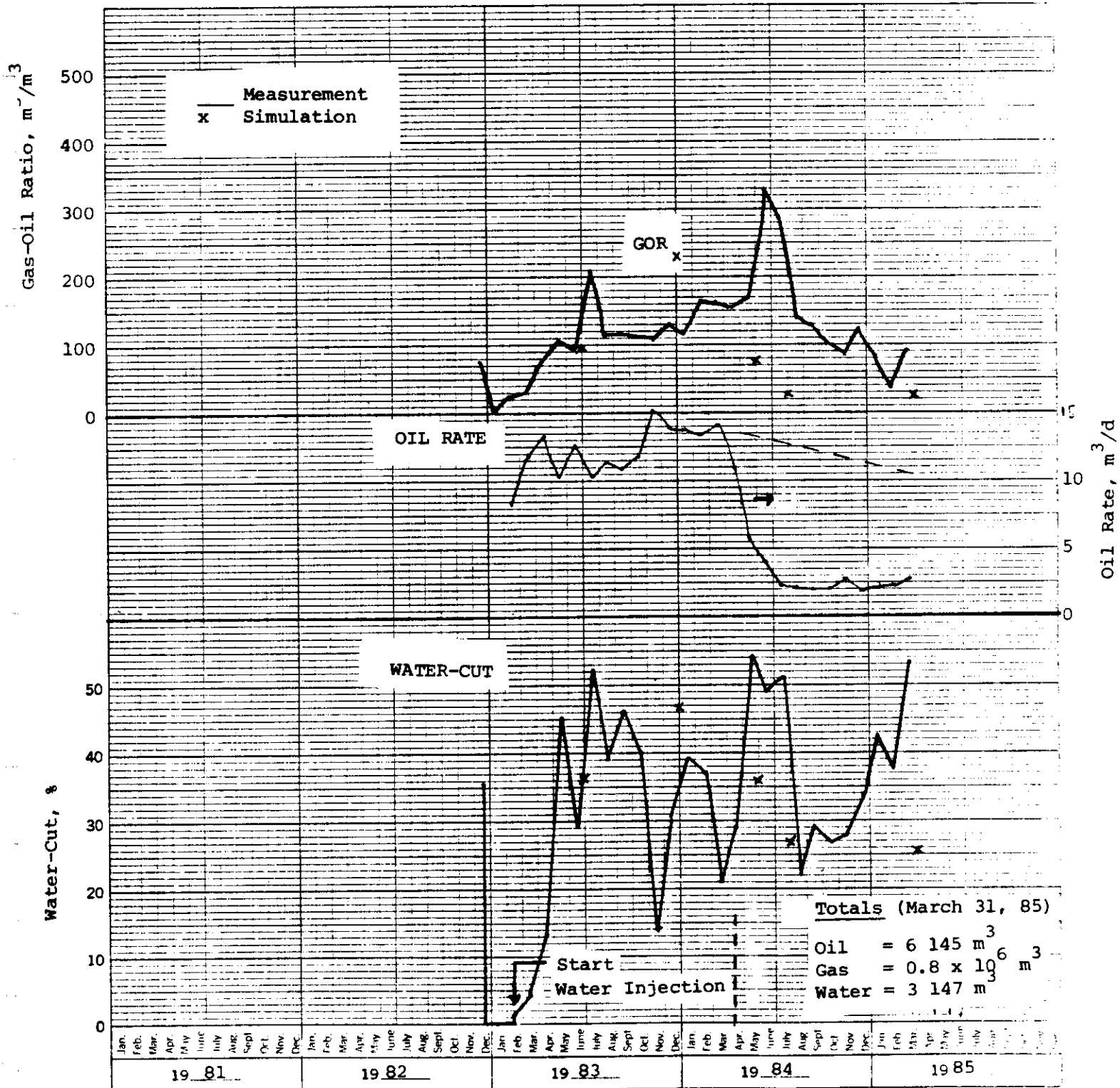


Figure 44
WELL INJECTION HISTORY
Waskada Lower Amaranth Pool
13-24-1-26 WIM

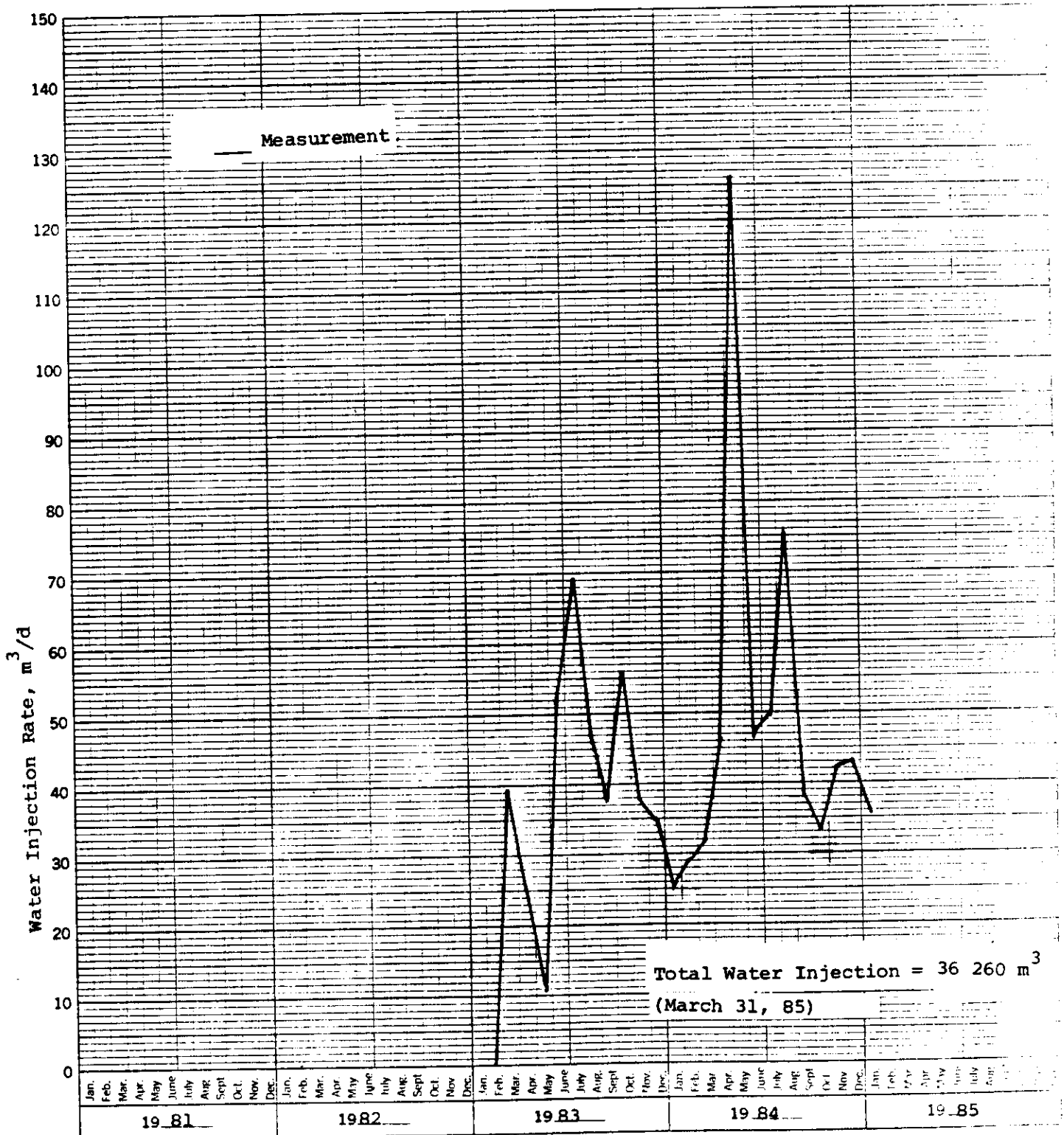


Figure 45
WELL PRODUCTION HISTORY
Waskada Lower Amaranth Pool
14-24-1-26 W1M

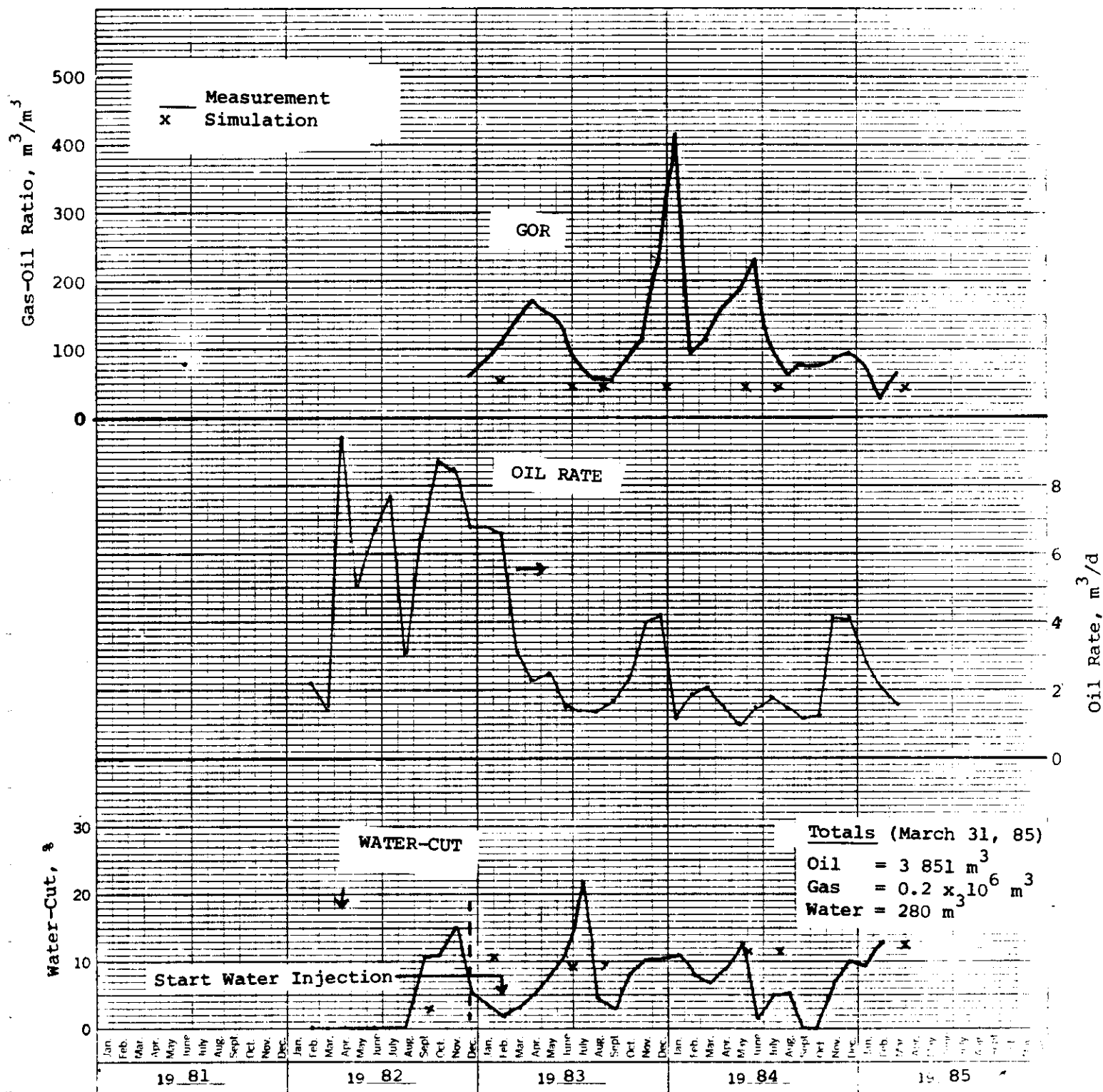


Figure 46
WELL PRODUCTION HISTORY
Waskada Lower Amaranth Pool
3-25-1-26 W1M

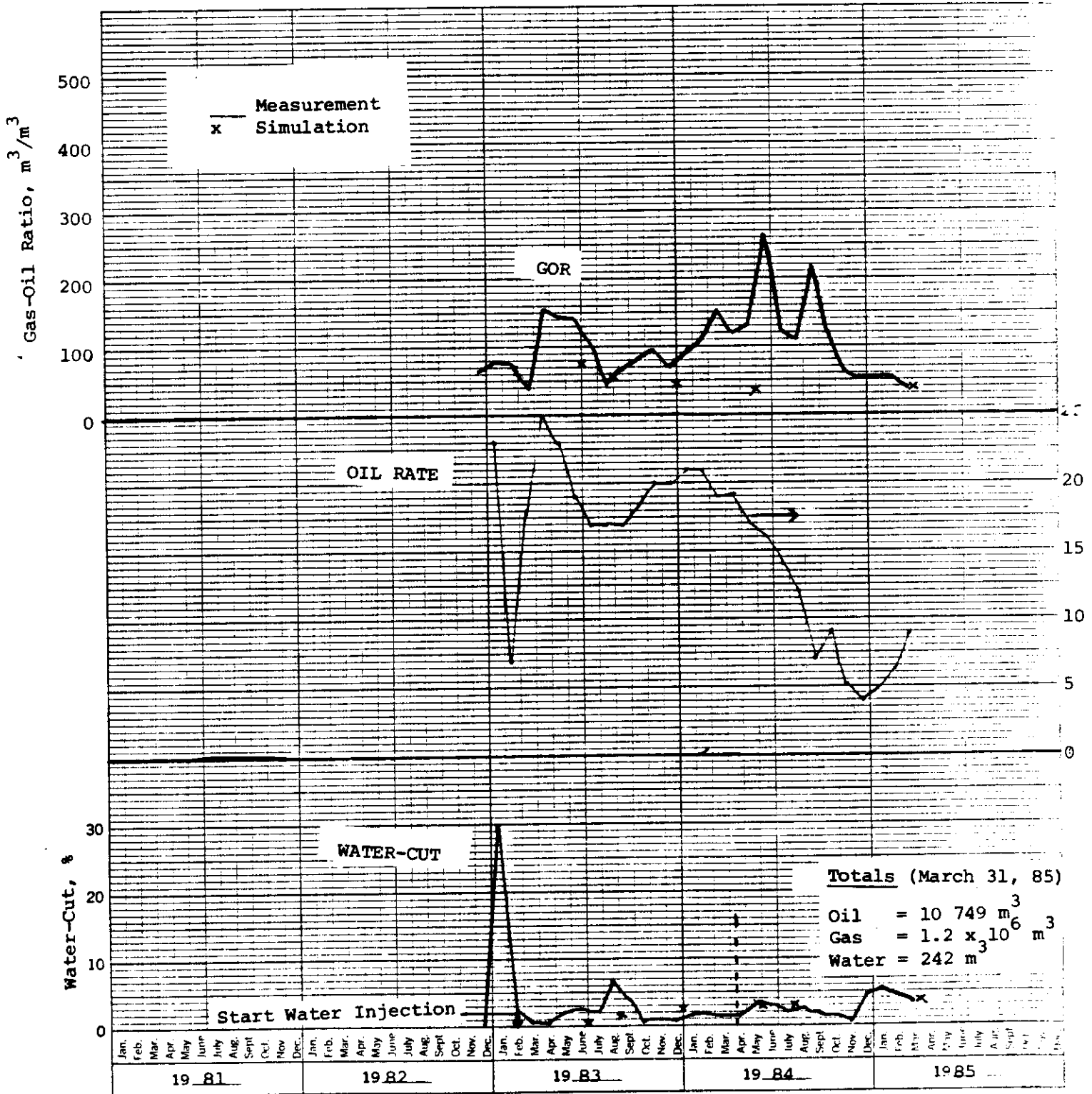


Figure 47

Waskada Lower Amaranth Pool

4-25-1-26 W1M

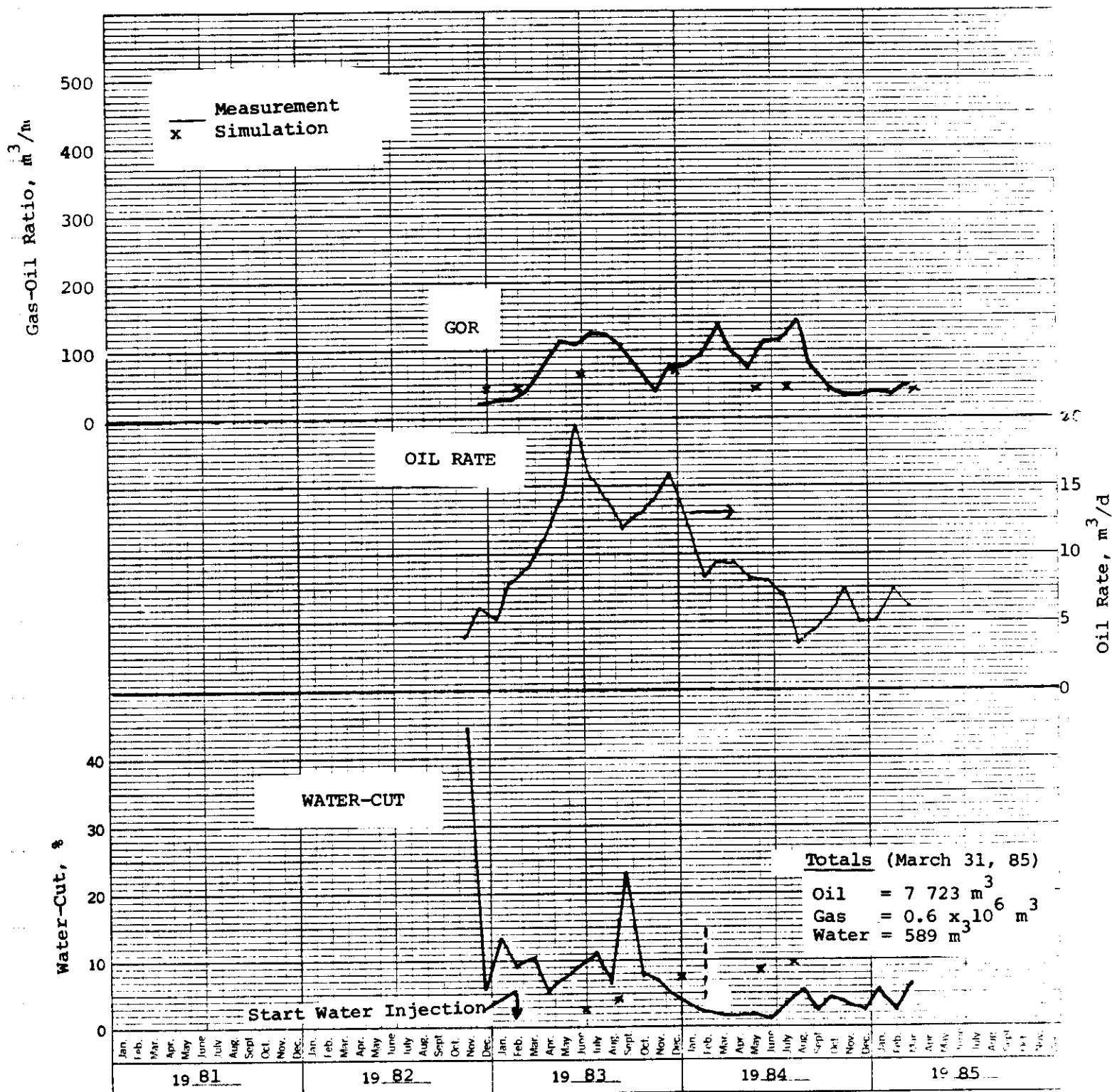


Figure 48
WELL PRODUCTION HISTORY
Waskada Lower Amaranth Pool
1-26-1-26 WIM

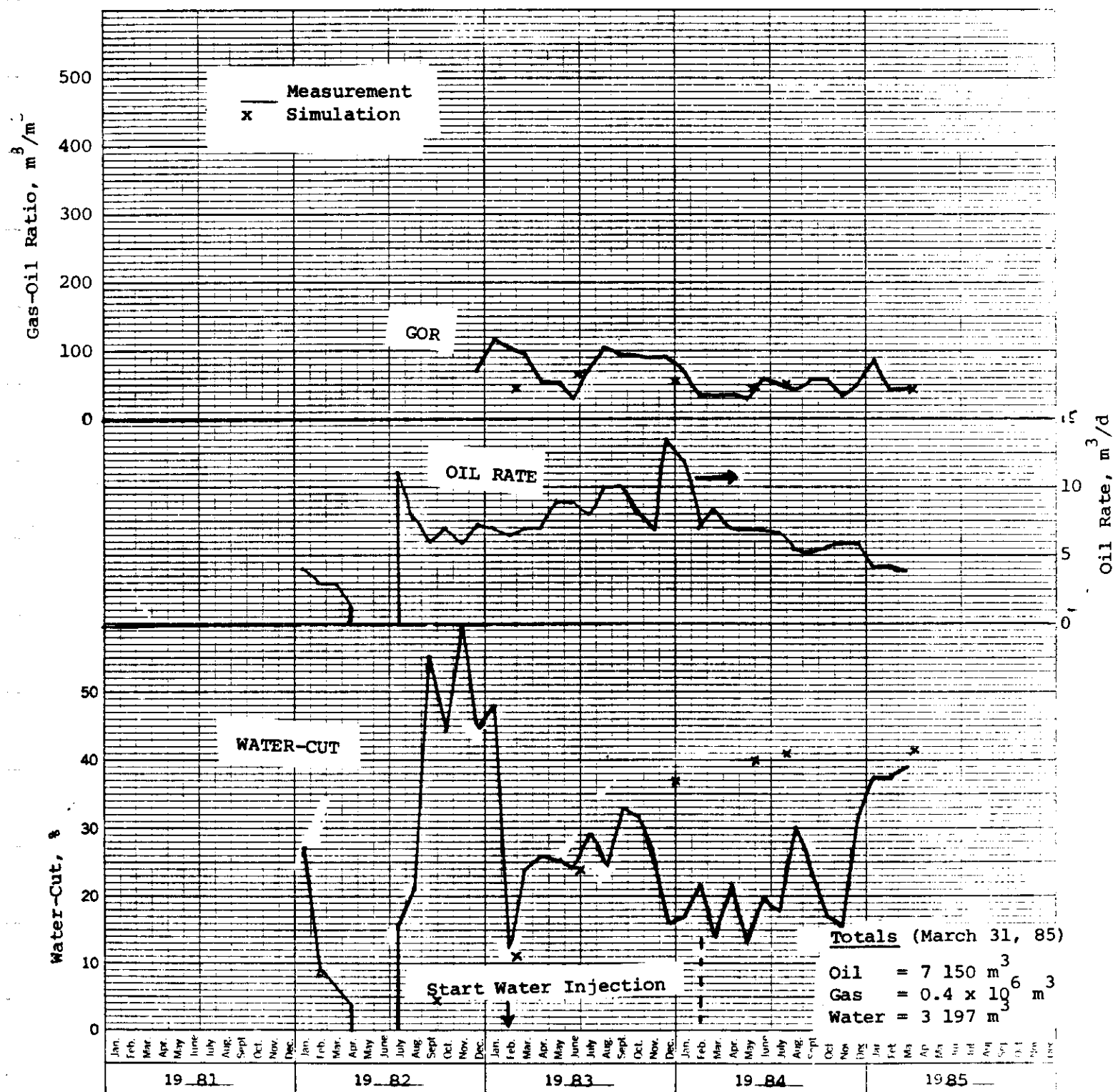
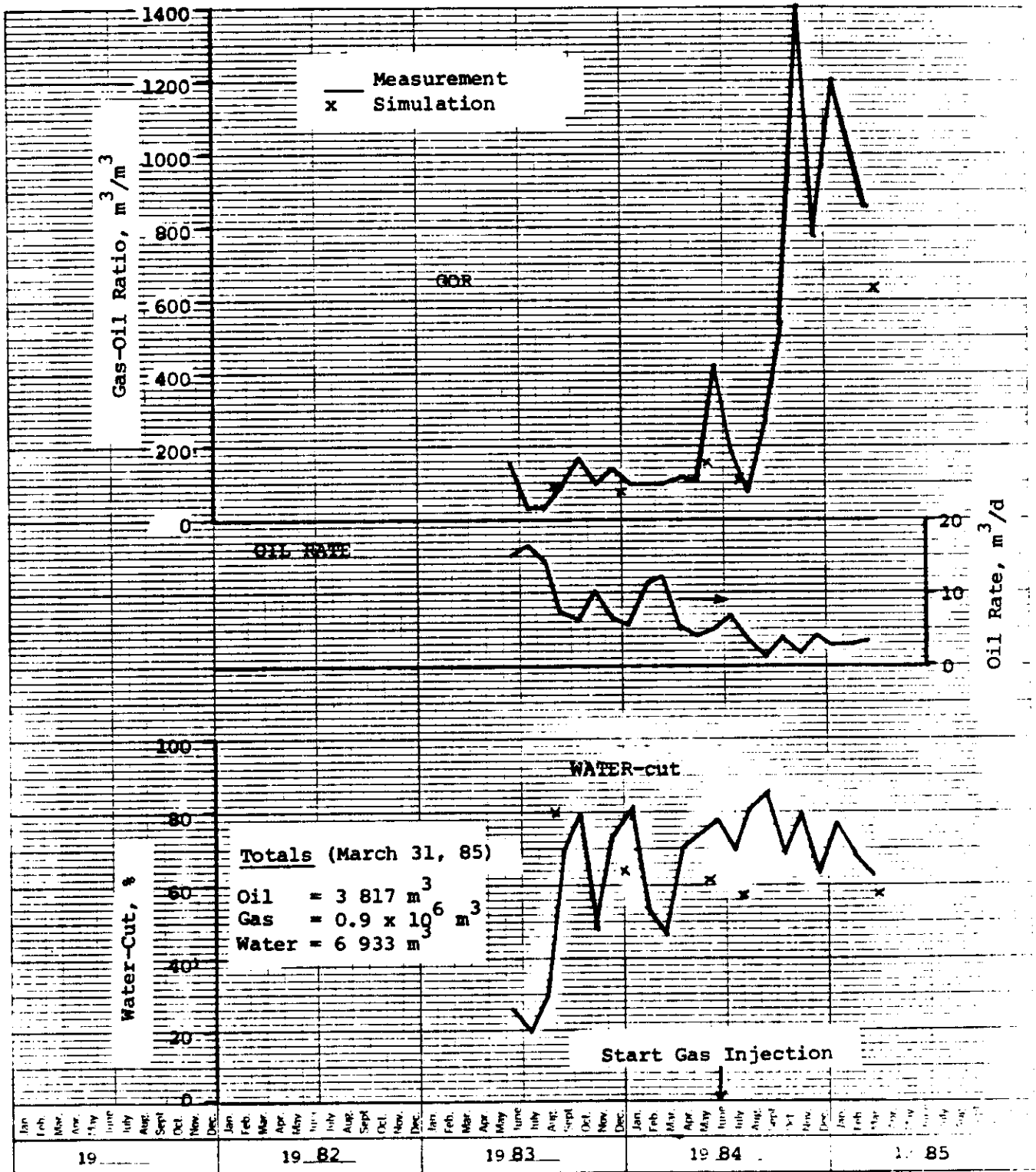


Figure 49
WELL PRODUCTION HISTORY
Waskada Lower Amaranth Pool
8-23-1-26 WIM



6-24-1-26 W1M

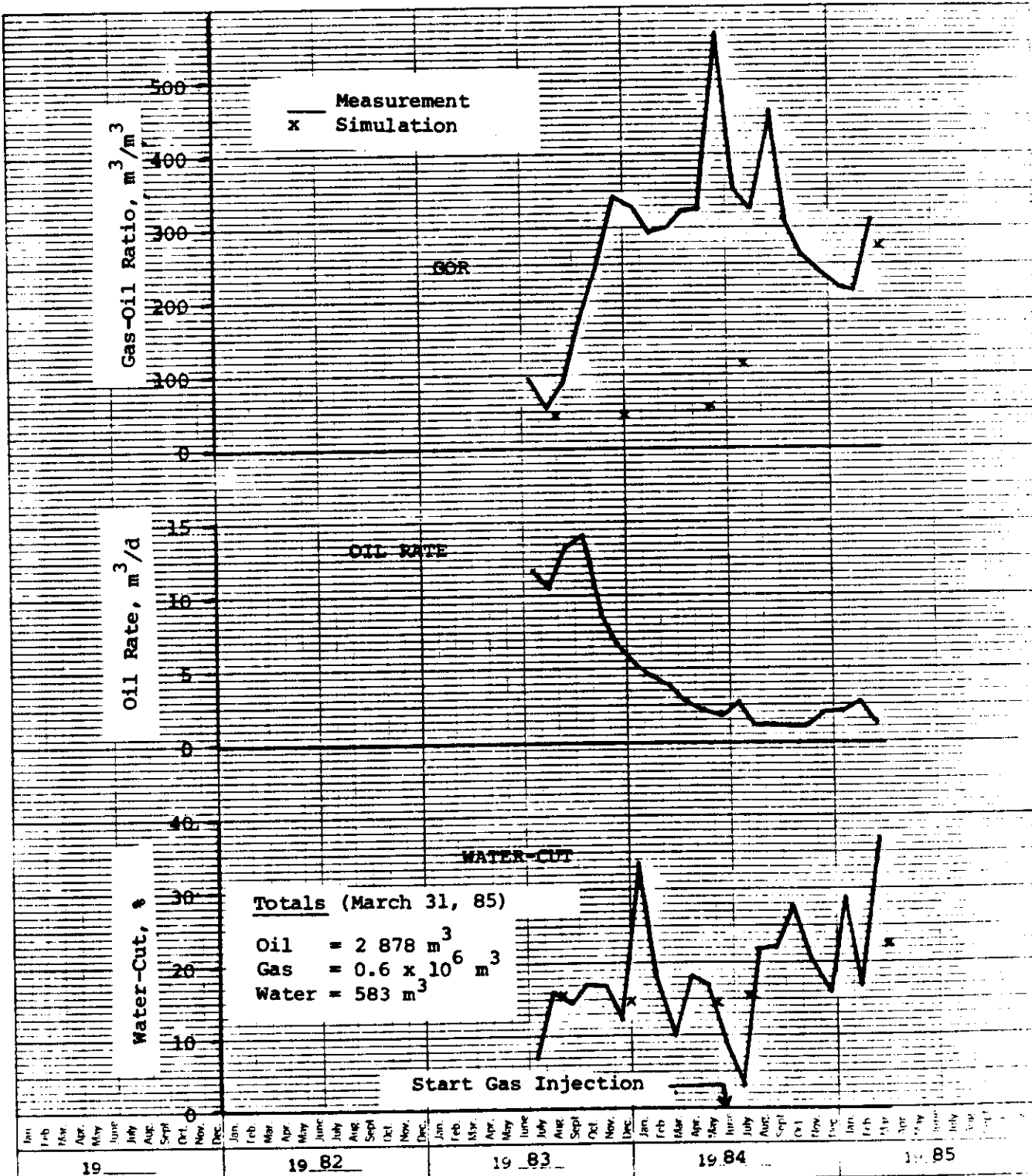


Figure 51
WELL PRODUCTION HISTORY
Waskada Lower Amaranth Pool
10-24-1-26 W1M

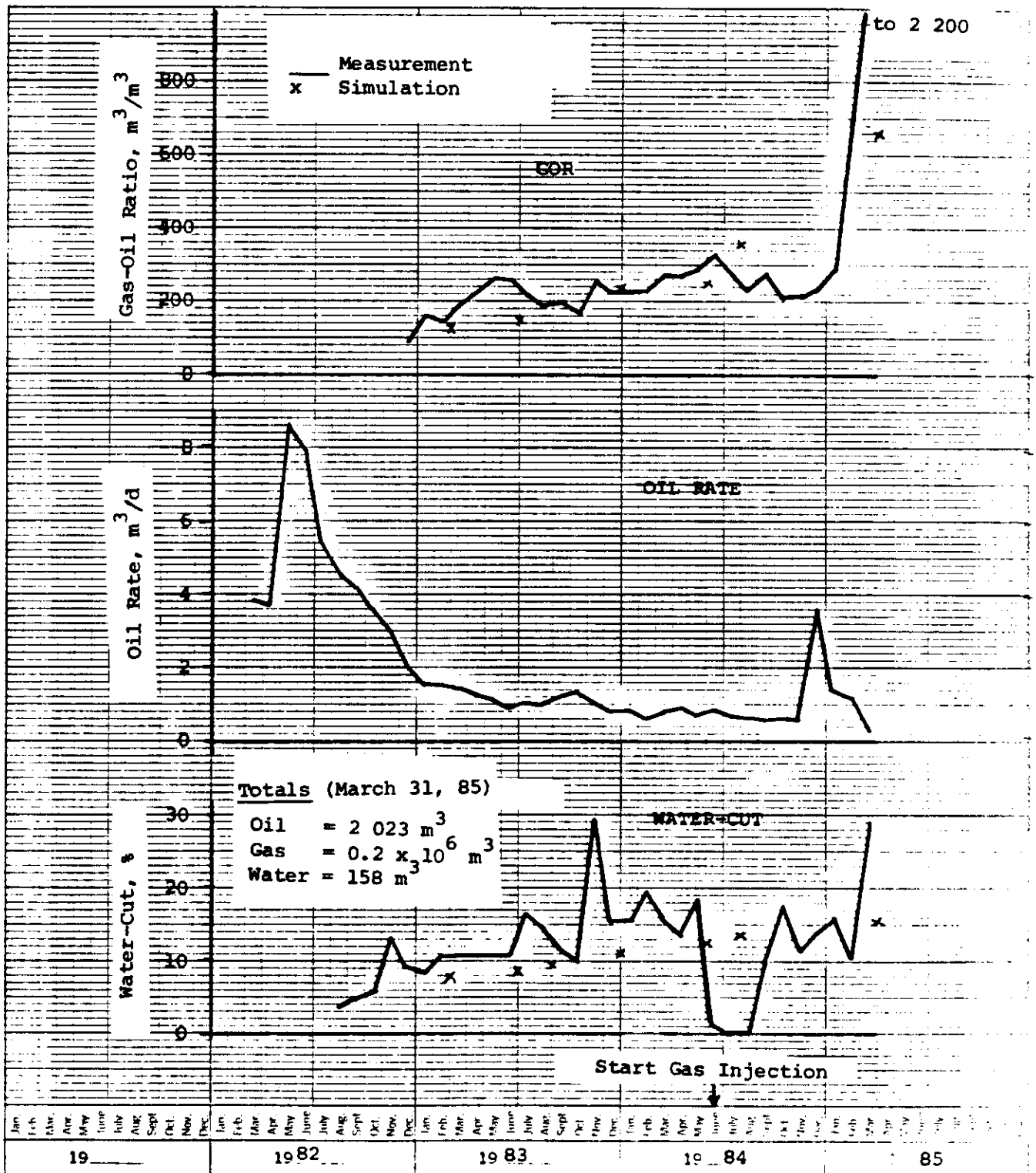


Figure 52

RESERVOIR PERFORMANCE FOR THE CONTINUED WATERFLOOD PREDICTION

AVERAGE PERMEABILITY

Waskada Lower Amaranth Pool

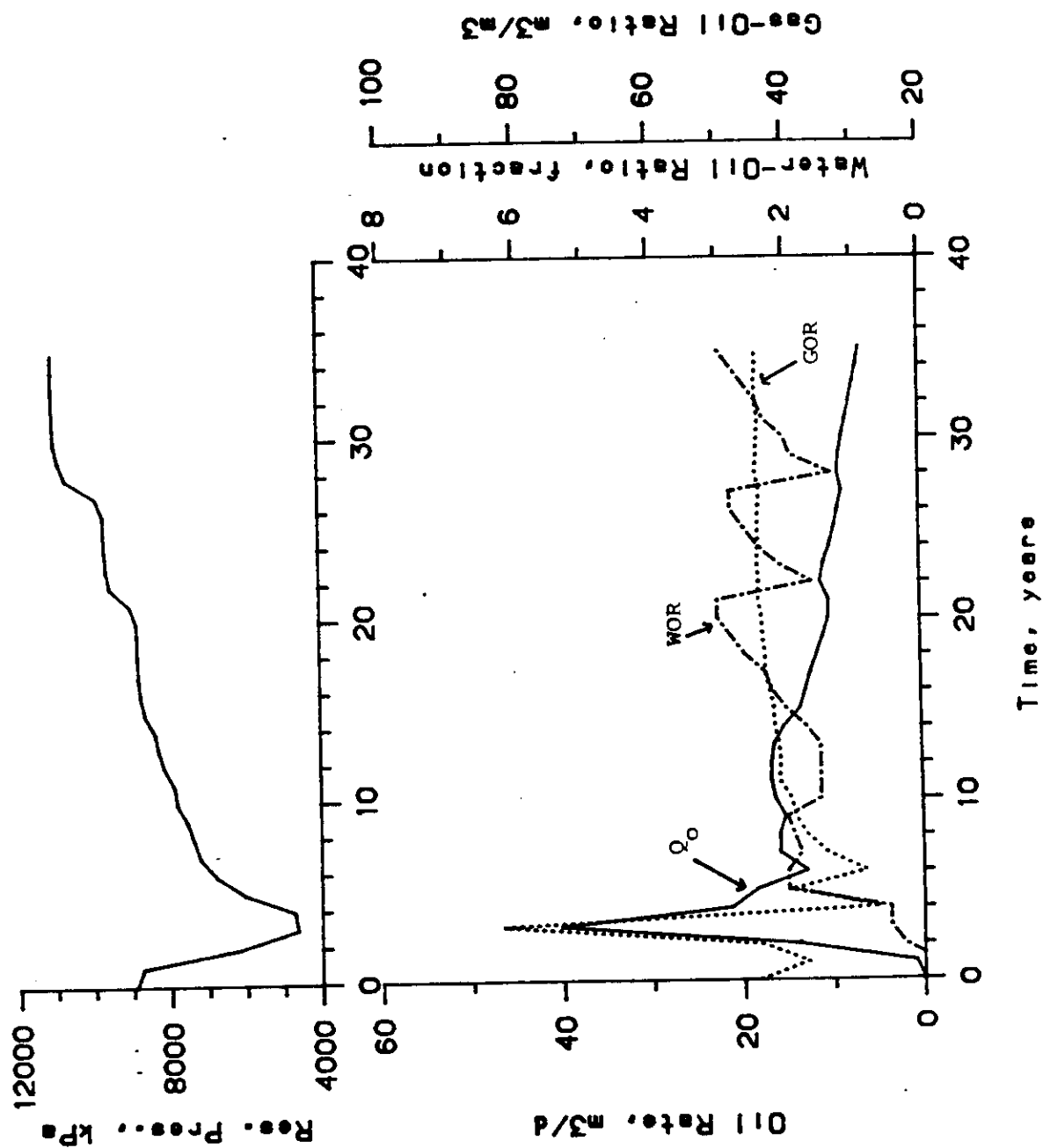


Figure 53
 RESERVOIR PERFORMANCE FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

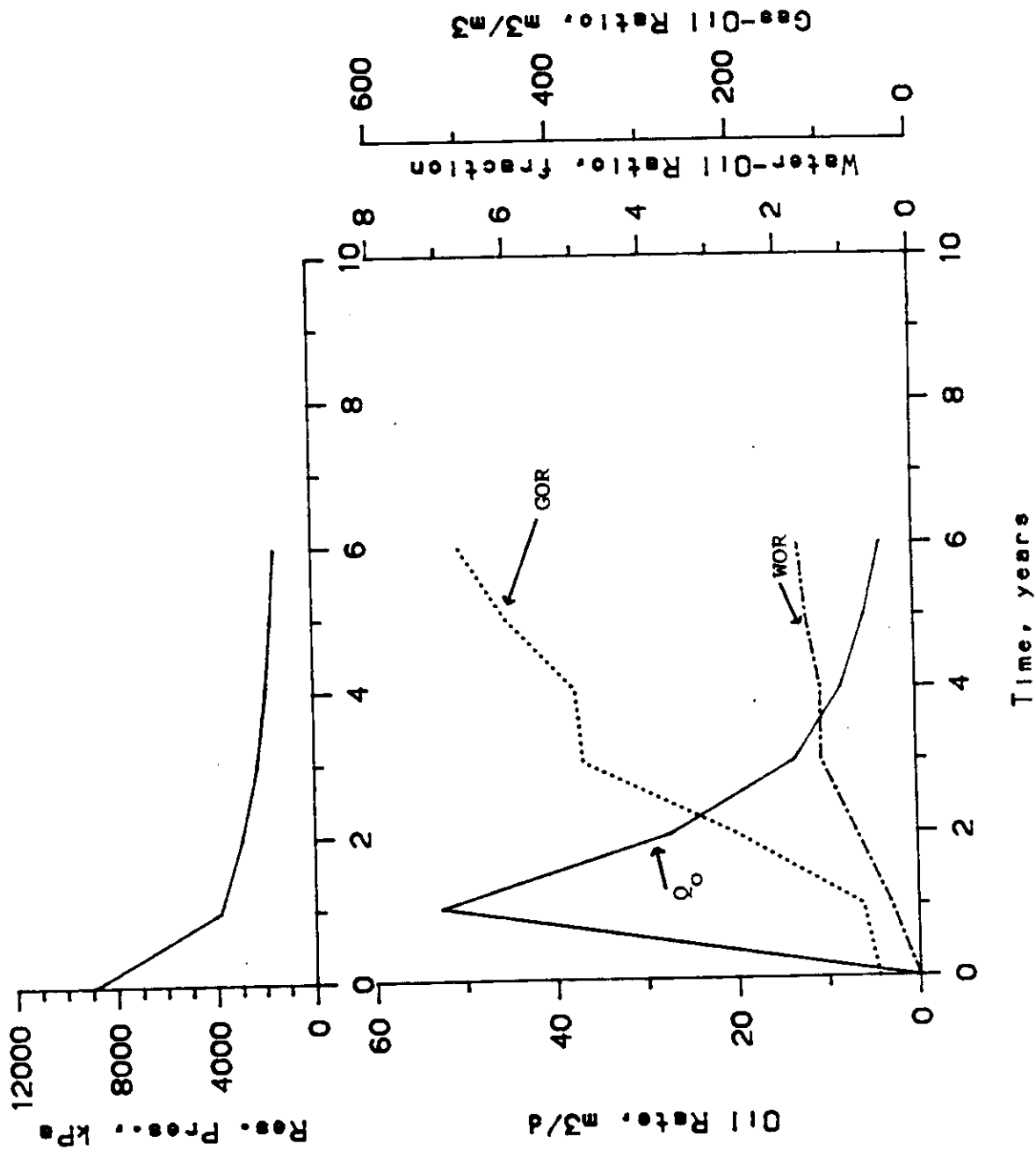


Figure 54

COMPARISON OF ULTIMATE OIL RECOVERY UNDER DIFFERENT WATERFLOOD STRATEGIES

AVERAGE PERMEABILITY

Waskada Lower Amaranth Pool

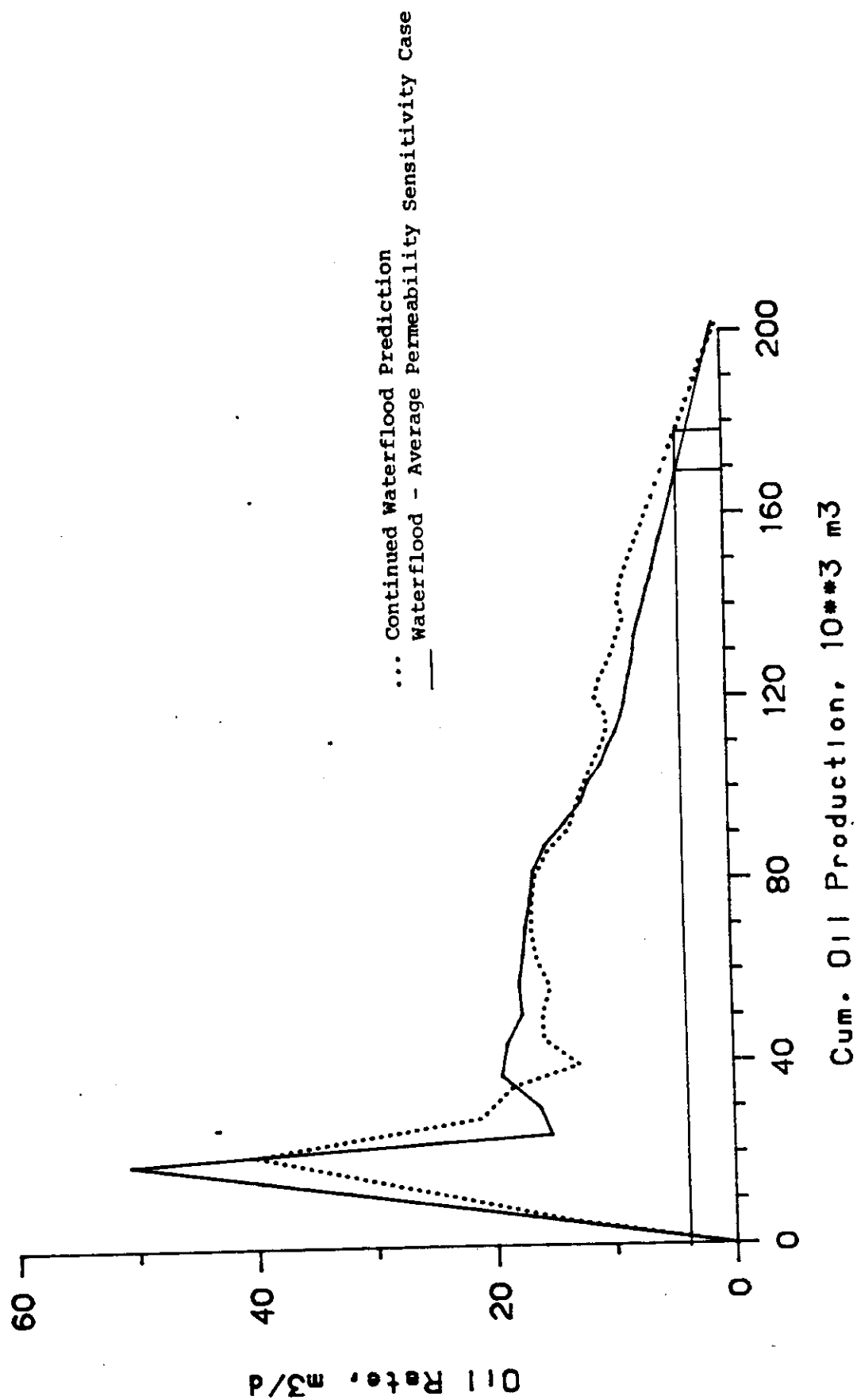


Figure 55

RESERVOIR PERFORMANCE FOR WATERFLOOD - AVERAGE PERMEABILITY

SENSITIVITY CASE

Waskada Lower Amaranth Pool

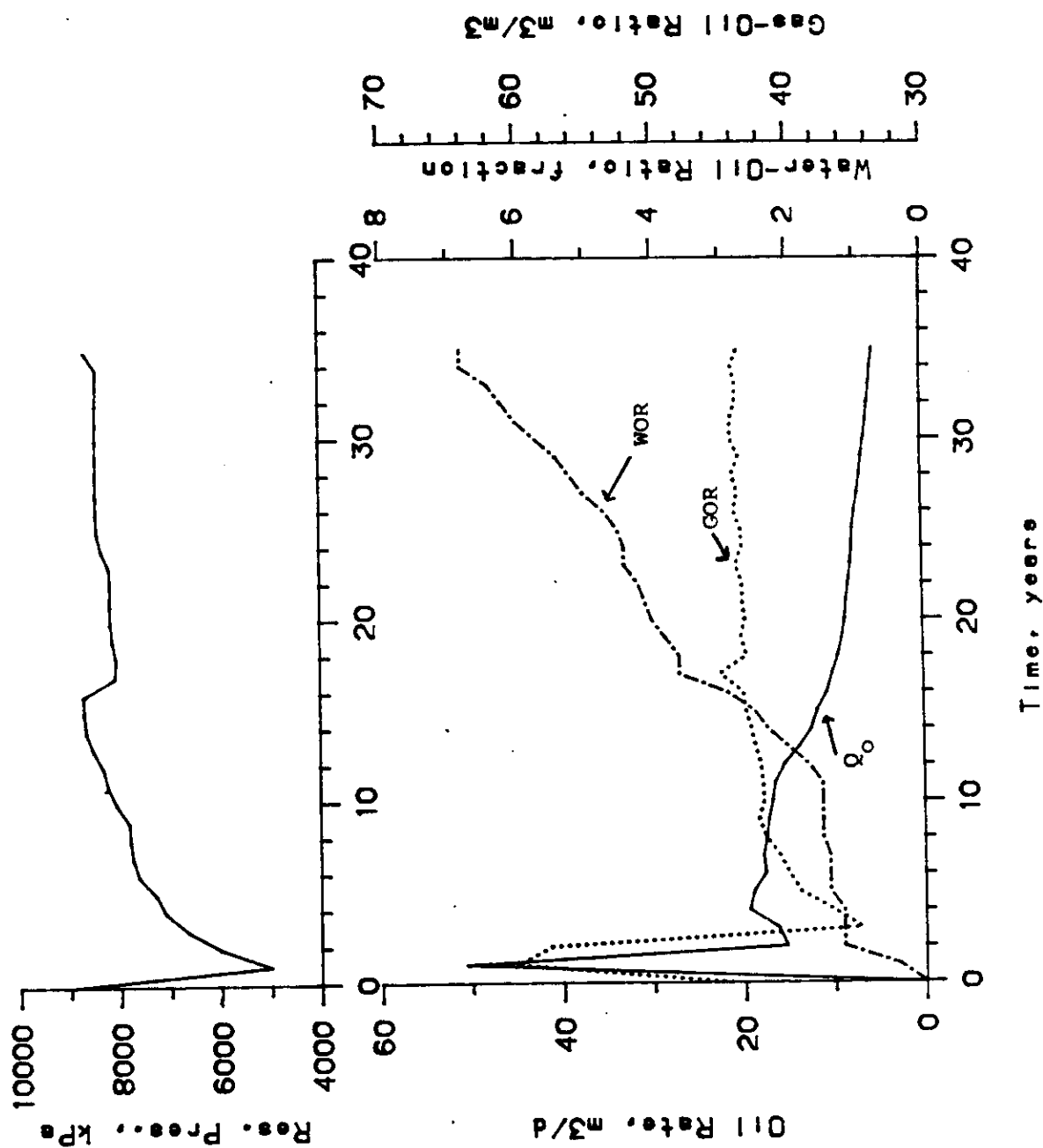


Figure 56
 RESERVOIR PERFORMANCE FOR WATERFLOOD - LOW PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

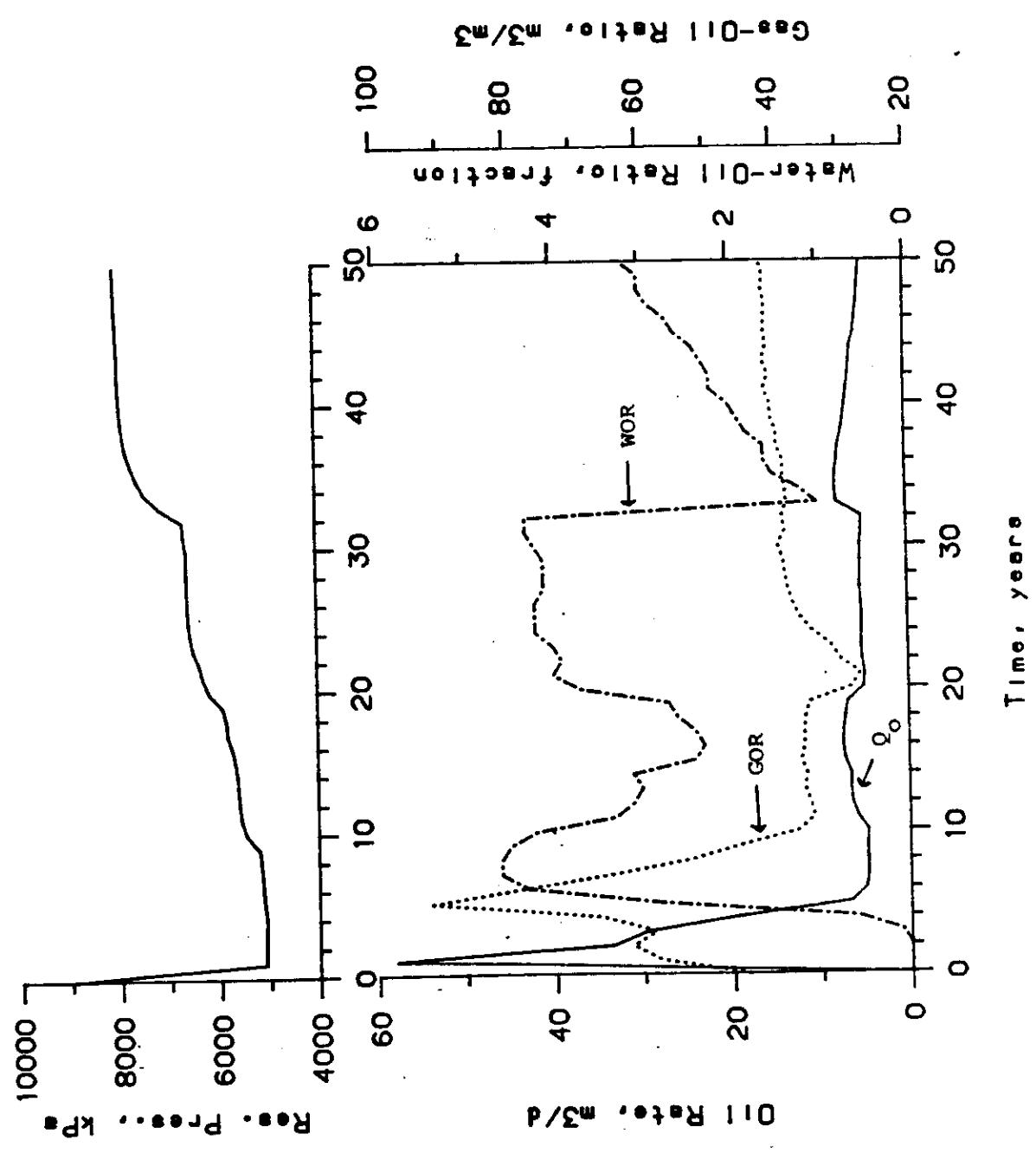


Figure 57

OIL RATE VS CUMULATIVE OIL PRODUCTION
 SENSITIVITY CASE COMPARISON
 Waskada Lower Amaranth Pool

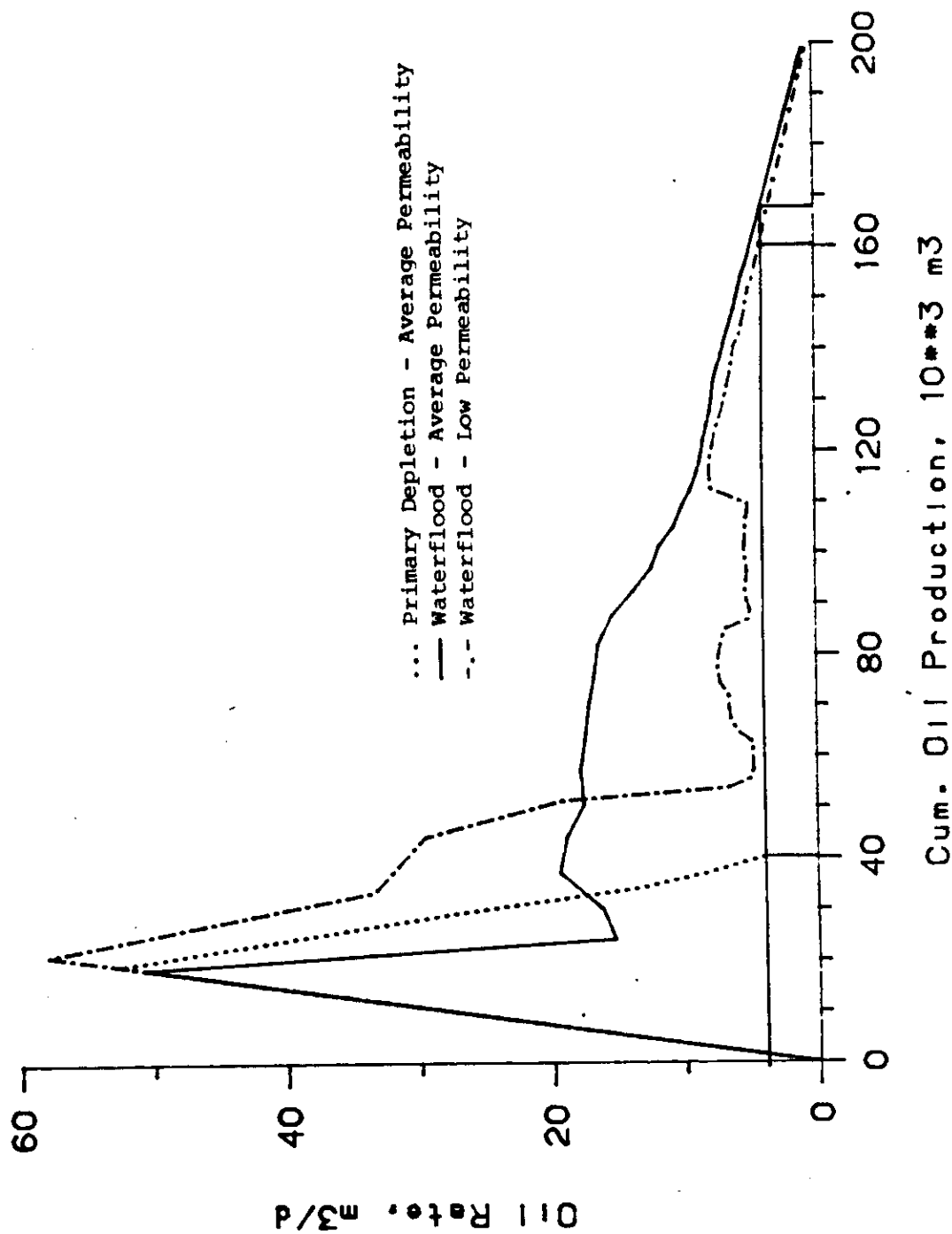


Figure 58
OIL RATE VS TIME
SENSITIVITY CASE COMPARISON
Waskada Lower Amaranth Pool

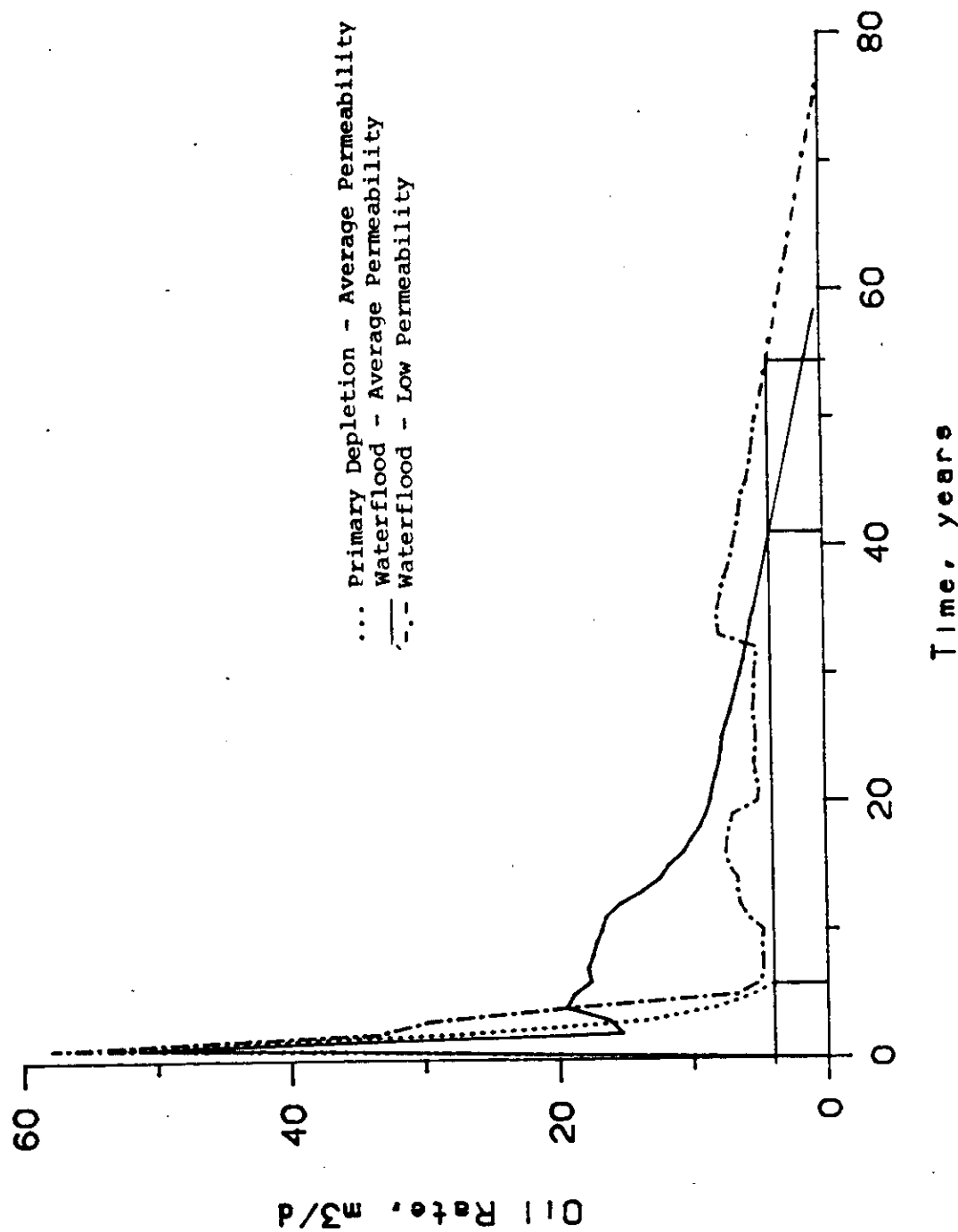


Figure 59
OIL RECOVERY VS TIME
SENSITIVITY CASE COMPARISON
Waskada Lower Amaranth Pool

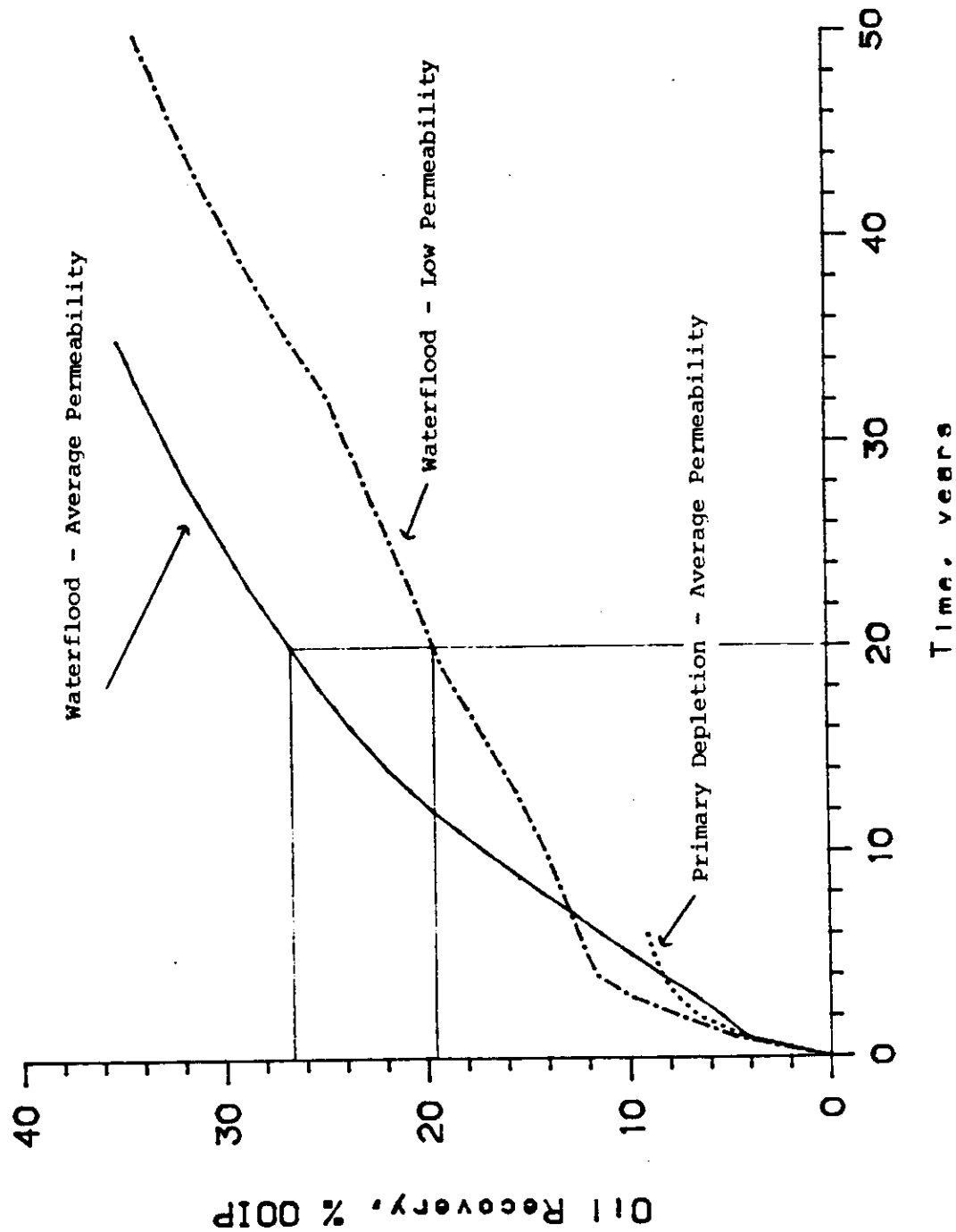
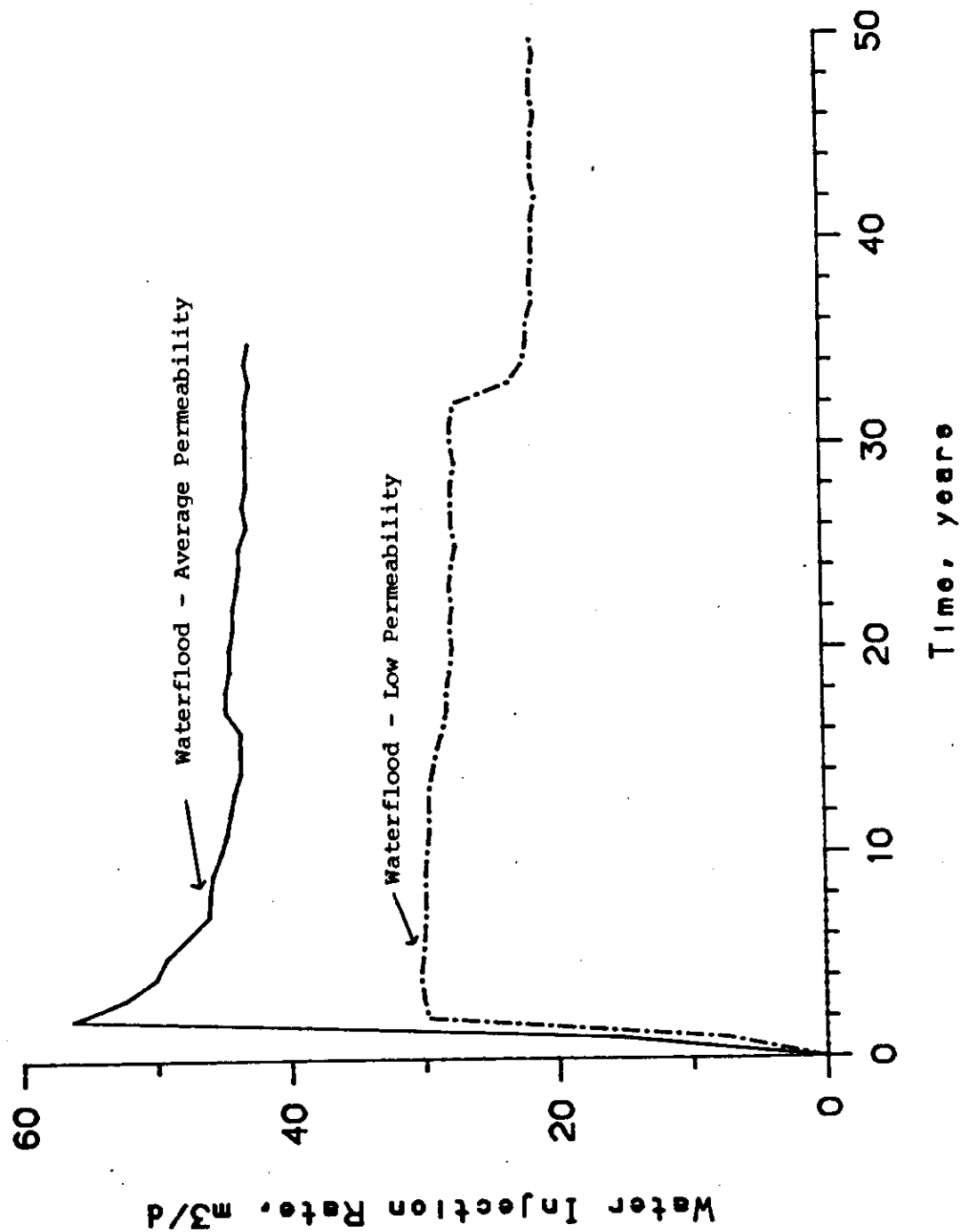


Figure 60
WATER INJECTION RATE VS TIME
SENSITIVITY CASE COMPARISON
Waskada Lower Amaranth Pool



TABLES

LIST OF TABLES

Table

- | | |
|-----------|--|
| 1 | Producers and Injectors in the Study Area |
| 2 | Summary of Average Reservoir Rock Properties |
| 3 | Porosity, Fraction |
| 4 | Net Pay |
| 5 | Horizontal Permeability, mD |
| 6 | Vertical Permeability, mD |
| 7 | PVT Functions |
| 8 | Initial Reservoir Pressure |
| 9 | Initial Oil Saturation |
| 10 | Initial Water Saturation |
| 11 | Flowing Bottomhole Pressures at End of History |
| 12 | Well Volume Fractions after History Match |
| 13 | Transmissibility TX |
| 14 | Transmissibility TY |
| 15 | Transmissibility TZ |
| 16 | Well Skin Factors after History Match |
| 17 | Summary of History Match |
| 18 | Reservoir Pressure at End of History |
| 19 | Oil Saturation at End of History |
| 20 | Gas Saturation at End of History |
| 21 | Water Saturation at End of History |
| 22 | Yearly Fluid Production Forecast for Primary Depletion - Average Permeability |
| 23 | Cumulative Fluid Production Forecast for Primary Depletion - Average Permeability |

Table

24	Yearly Fluid Production Forecast for Waterflood - Average Permeability
25	Cumulative Fluid Production Forecast for Waterflood - Average Permeability
26	Summary of Average Rock Properties for Waterflood - Low Permeability
27	Yearly Fluid Production Forecast for Waterflood - Low Permeability
28	Cumulative Fluid Production Forecast for Waterflood - Low Permeability

Table 1
PRODUCERS AND INJECTORS IN THE STUDY AREA
Waskada Lower Amaranth Pool

<u>Well No.</u>	<u>Well Location</u>		<u>Remarks</u>
	<u>Field</u>	<u>Model (x,y)</u>	
1	7-23-1-26 W1M	(1,1)	Surrounding gas injector (¼ well)
2	8-23	(4,1)	Surrounding producer (½ well)
3	9-23	(4,4)	Main pattern producer
4	10-23	(1,4)	Surrounding producer (½ well)
5	15-23	(1,8)	Surrounding water injector (½ well)
6	16-23	(4,8)	Main pattern producer
7	5-24	(8,1)	Surrounding gas injector (½ well)
8	6-24	(12,1)	Surrounding producer (½ well)
9	7-24	(14,1)	Surrounding gas injector (¼ well)
10	10-24	(14,4)	Surrounding producer (½ well)
11	11-24	(12,4)	Main pattern producer
12	12-24	(8,4)	Main pattern producer
13	13A-24	(8,8)	Main pattern water injector
14	14-24	(12,8)	Main pattern producer
15	15-24	(14,8)	Surrounding water injector (½ well)
16	2-25	(14,12)	Surrounding producer (½ well)
17	3-25	(12,12)	Main pattern producer
18	4-25	(8,12)	Main pattern producer
19	5-25	(8,14)	Surrounding water injector (½ well)
20	6-25	(12,14)	Surrounding producer (½ well)
21	7-25	(14,14)	Surrounding water injector (¼ well)
22	1-26	(4,12)	Main pattern producer
23	2-26	(1,12)	Surrounding producer (½ well)
24	7-26	(1,14)	Surrounding water injector (¼ well)
25	8-26	(4,14)	Surrounding producer (½ well)

Table 2
SUMMARY OF AVERAGE RESERVOIR ROCK PROPERTIES
Waskada Lower Amaranth Pool

<u>Model Layer</u>	<u>Net Pay, m</u>	<u>Porosity, fraction</u>	<u>Permeability, mD</u>	<u>Water Saturation, fraction</u>	<u>OOIP, 10³ m³</u>
1 or A (top)	2.1	0.151	2.89	0.56	312
2 or B	3.0	0.151	3.19	0.59	411
3 or C	3.9	0.152	3.32	0.59	529
4 or D	<u>2.0</u>	<u>0.141</u>	<u>1.99</u>	<u>0.72</u>	<u>171</u>
Total	11.0				1 423
Average		0.150	2.96	0.61	

Table 3

POROSITY, FRACTION

Waskada Lower Amaranth Pool

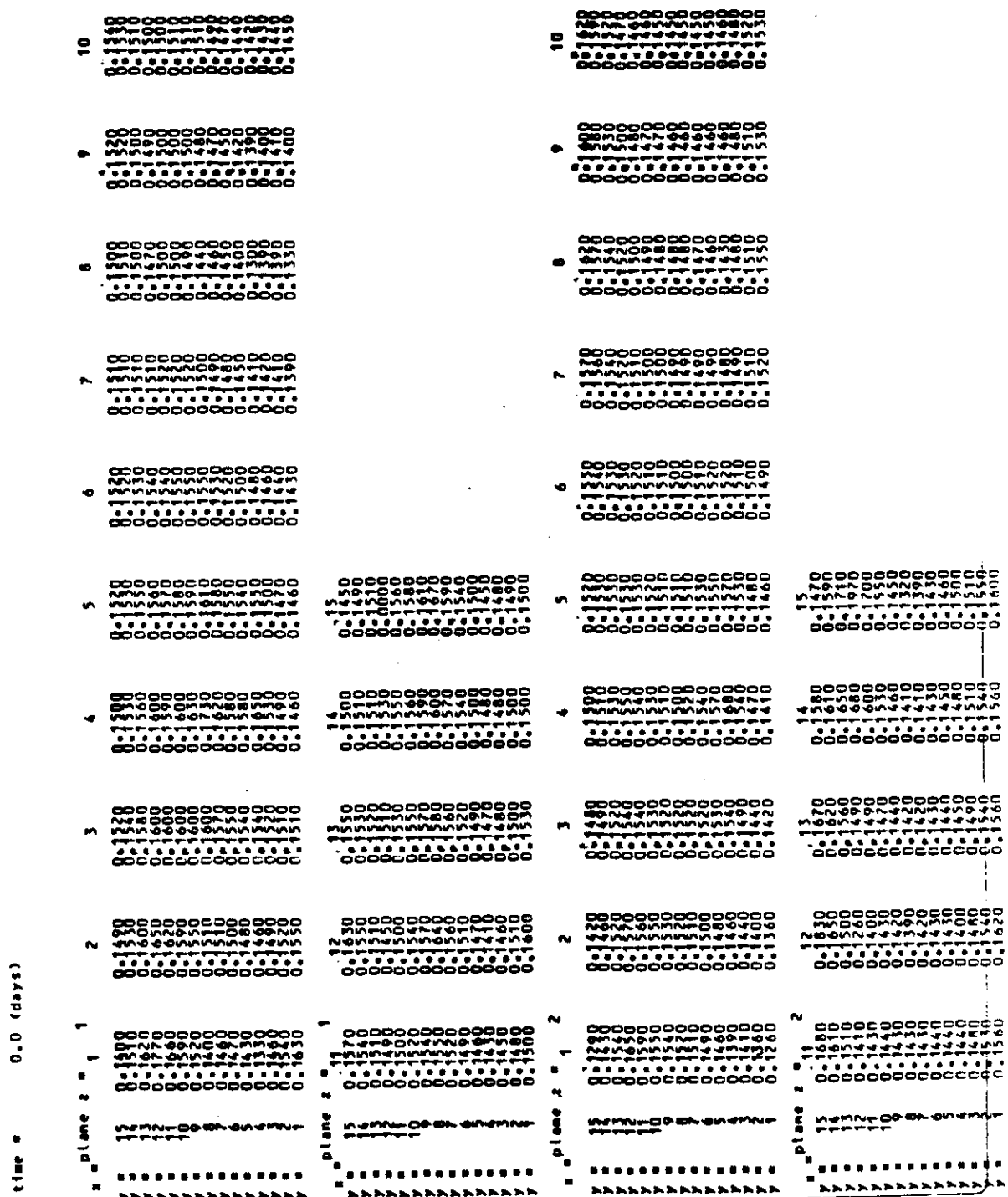


Table 3 (Continued)

POROSITY, FRACTION

Waskada Lower Amaranth Pool

Table 5
HORIZONTAL PERMEABILITY, mD
Waskada Lower Amaranth Pool

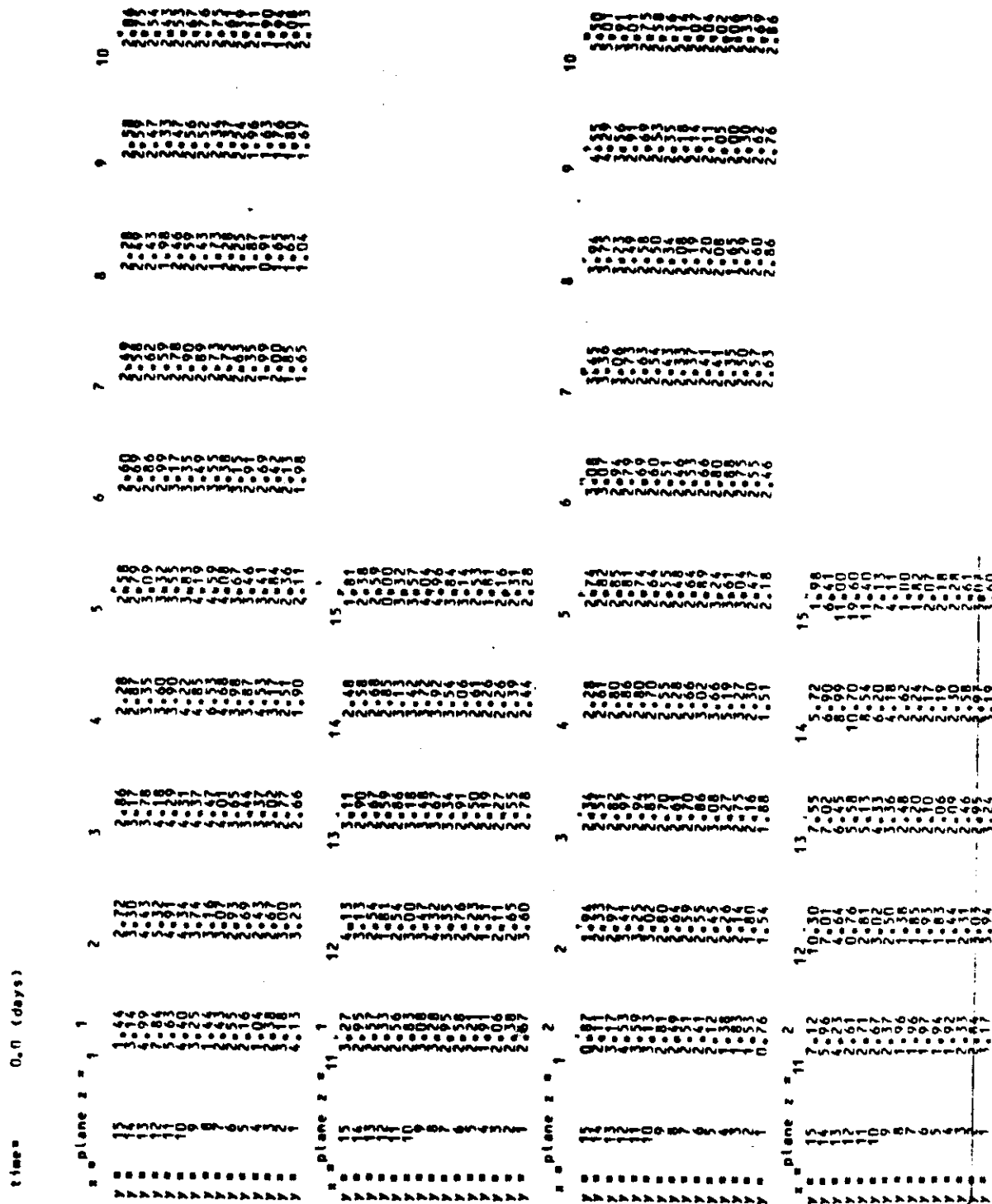


Table 5 (Continued)

HORIZONTAL PERMEABILITY, mD

Waskada Lower Amaranth Pool

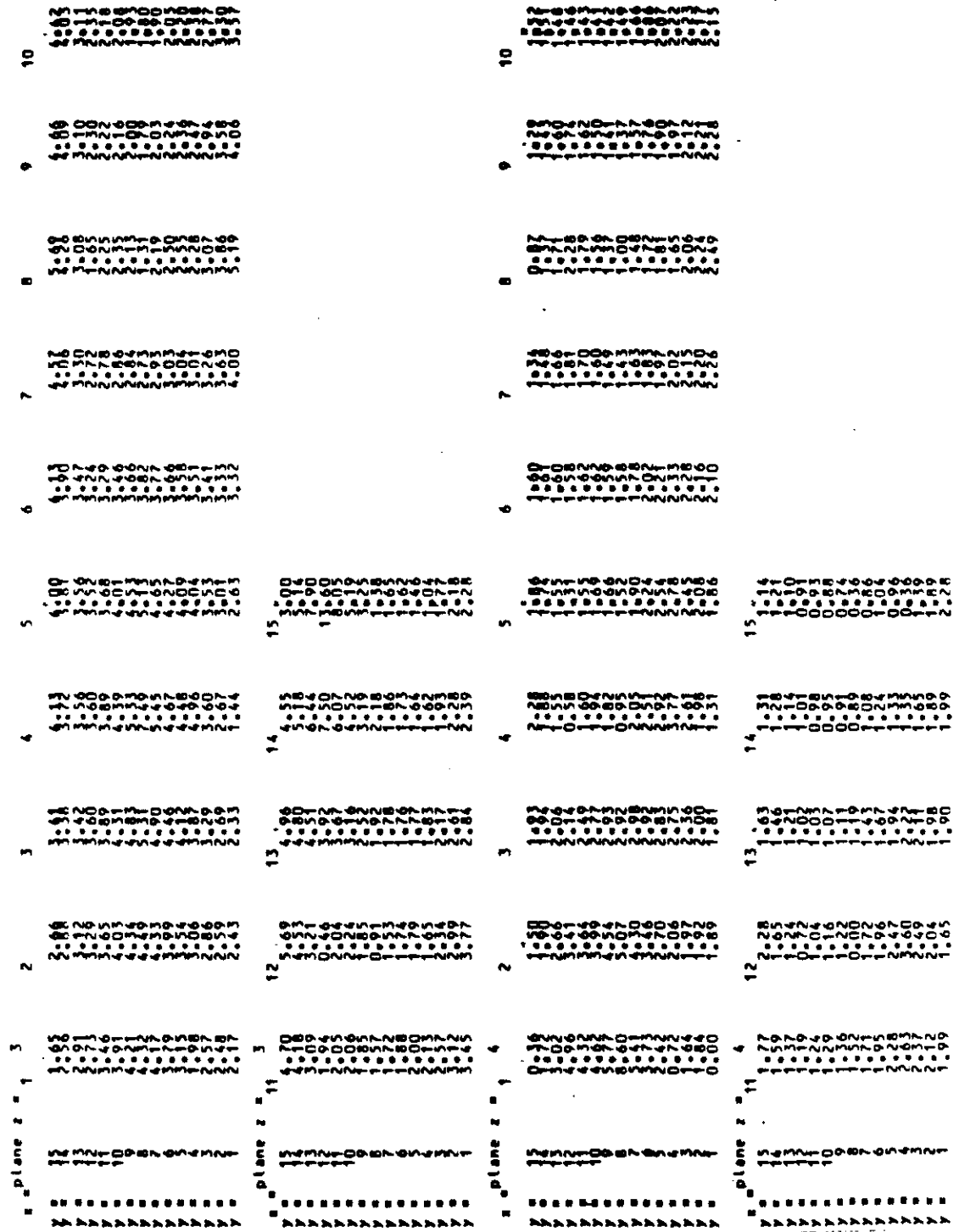


Table 6
VERTICAL PERMEABILITY, mD
Waskada Lower Amaranth Pool

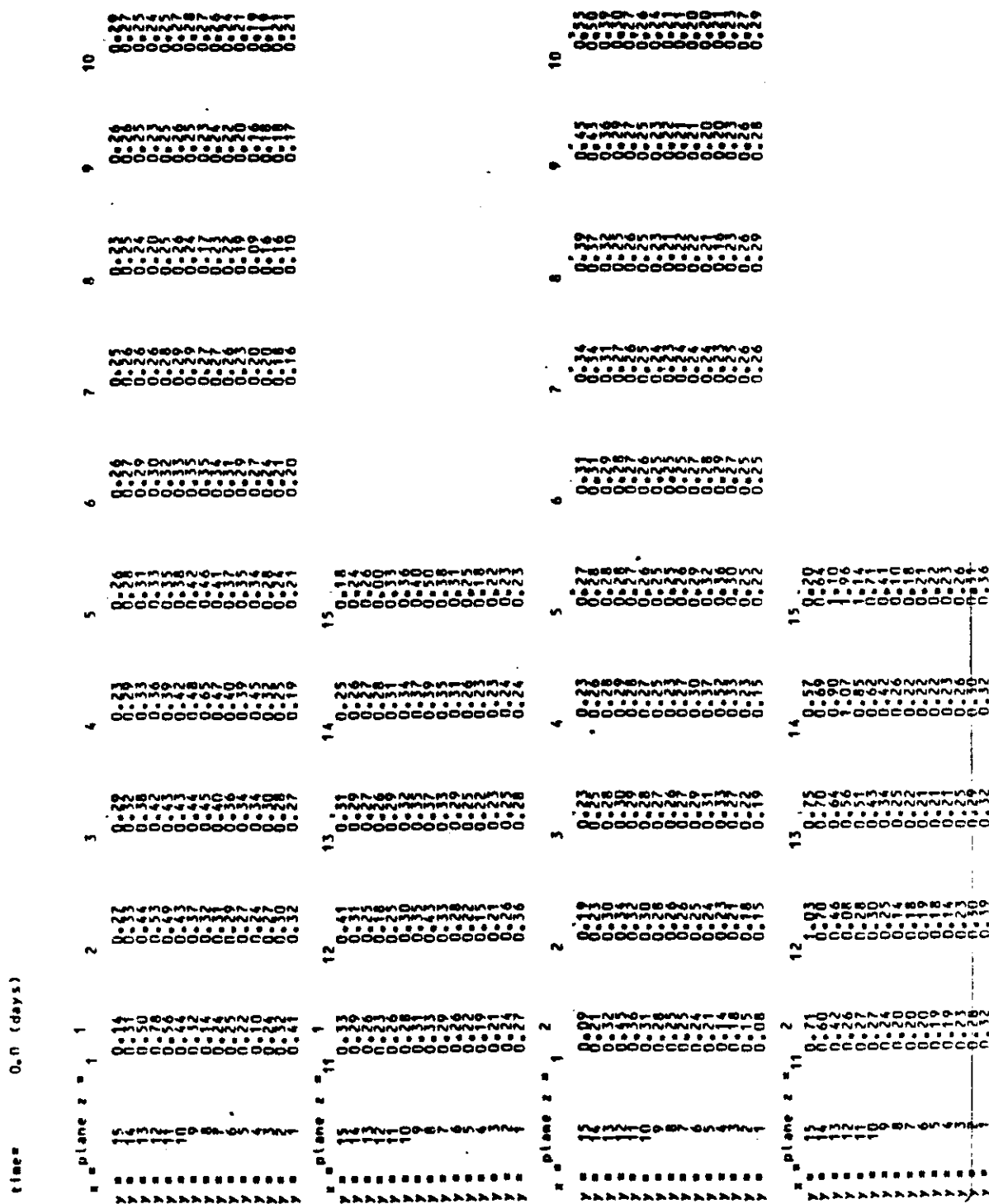
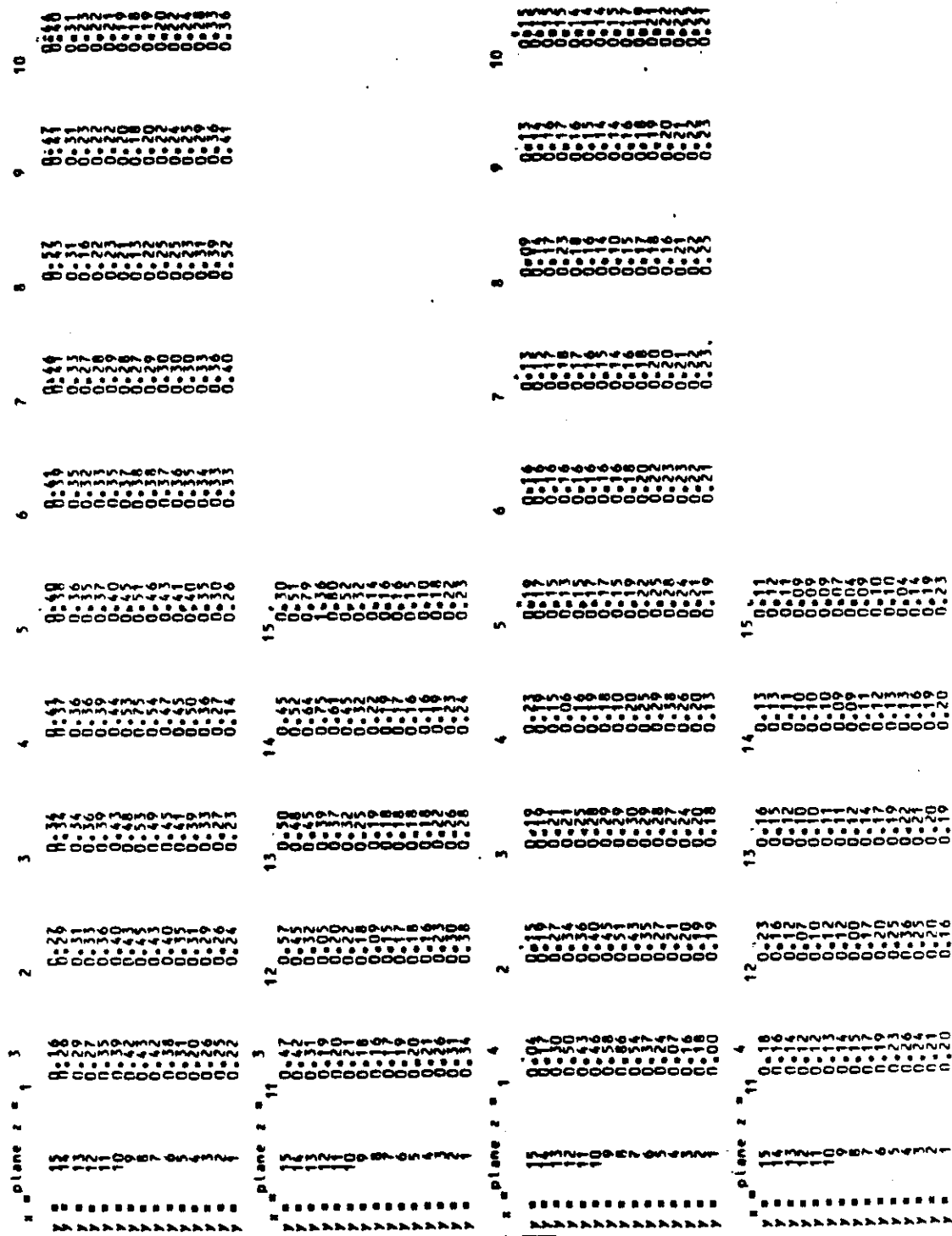


Table 6 (Continued)

VERTICAL PERMEABILITY, mD

Waskada Lower Amaranth Pool



PVT FUNCTIONS

Waskada Lower Amaranth Pool

PVT FUNCTIONS									
pressure kpa	sol'n gas m3/m3	oil fvf m3/m3	gas fvf m3/m3	gas emd m3/m3	oil visc mpas	gas visc mpas	gas emd m3/m3	oil visc mpas	gas visc mpas
0.000	0.000	1.01186	1.10632	0.904	2.904	1.020	0.000	2.904	0.020
50.000	10.706	1.06123	0.27680	3.613	4.500	1.040	0.000	4.500	0.040
100.000	22.337	1.12045	0.10360	5.028	3.400	1.100	0.000	3.400	0.100
150.000	33.735	1.17218	0.04928	6.553	3.200	1.150	0.000	3.200	0.150
200.000	44.695	1.21409	0.03655	8.207	3.000	1.200	0.000	3.000	0.200
250.000	55.132	1.25000	0.02503	9.992	2.800	1.250	0.000	2.800	0.250
300.000	65.000	1.28000	0.01849	12.000	2.600	1.300	0.000	2.600	0.300
350.000	74.345	1.30500	0.01400	14.277	2.400	1.350	0.000	2.400	0.350
400.000	83.205	1.32500	0.00849	16.774	2.200	1.400	0.000	2.200	0.400
450.000	91.585	1.34000	0.00389	20.000	2.000	1.450	0.000	2.000	0.450
500.000	100.000	1.35000	0.00000	25.000	1.800	1.500	0.000	1.800	0.500
550.000	108.345	1.35500	0.00000	30.000	1.600	1.550	0.000	1.600	0.550
600.000	116.685	1.35500	0.00000	35.000	1.400	1.600	0.000	1.400	0.600
650.000	125.000	1.35000	0.00000	40.000	1.200	1.650	0.000	1.200	0.650
700.000	133.205	1.34000	0.00000	45.000	1.000	1.700	0.000	1.000	0.700
750.000	141.585	1.32500	0.00000	50.000	0.800	1.750	0.000	0.800	0.750
800.000	150.000	1.30500	0.00000	55.000	0.600	1.800	0.000	0.600	0.800
850.000	158.345	1.28000	0.00000	60.000	0.400	1.850	0.000	0.400	0.850
900.000	166.685	1.25000	0.00000	65.000	0.200	1.900	0.000	0.200	0.900
950.000	175.000	1.21409	0.00000	70.000	0.000	1.950	0.000	0.000	0.950
1000.000	183.205	1.17218	0.00000	75.000	0.000	2.000	0.000	0.000	1.000

Table 9

INITIAL OIL SATURATION
Waskada Lower Amaranth Pool

time = 0.0 (days)	1	2	3	4
plane	plane	plane	plane	plane
1	1	1	1	1
2	2	2	2	2
3	3	3	3	3
4	4	4	4	4
5	5	5	5	5
6	6	6	6	6
7	7	7	7	7
8	8	8	8	8
9	9	9	9	9
10	10	10	10	10
11	11	11	11	11
12	12	12	12	12
13	13	13	13	13
14	14	14	14	14
15	15	15	15	15
16	16	16	16	16
17	17	17	17	17
18	18	18	18	18
19	19	19	19	19
20	20	20	20	20
21	21	21	21	21
22	22	22	22	22
23	23	23	23	23
24	24	24	24	24
25	25	25	25	25
26	26	26	26	26
27	27	27	27	27
28	28	28	28	28
29	29	29	29	29
30	30	30	30	30
31	31	31	31	31
32	32	32	32	32
33	33	33	33	33
34	34	34	34	34
35	35	35	35	35
36	36	36	36	36
37	37	37	37	37
38	38	38	38	38
39	39	39	39	39
40	40	40	40	40
41	41	41	41	41
42	42	42	42	42
43	43	43	43	43
44	44	44	44	44
45	45	45	45	45
46	46	46	46	46
47	47	47	47	47
48	48	48	48	48
49	49	49	49	49
50	50	50	50	50
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54	54	54	54	54
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89	89	89	89	89
90	90	90	90	90
91	91	91	91	91
92	92	92	92	92
93	93	93	93	93
94	94	94	94	94
95	95	95	95	95
96	96	96	96	96
97	97	97	97	97
98	98	98	98	98
99	99	99	99	99
100	100	100	100	100

Table 10

INITIAL WATER SATURATION

Waskada Lower Amaranth Pool

time = 0.0 (days)

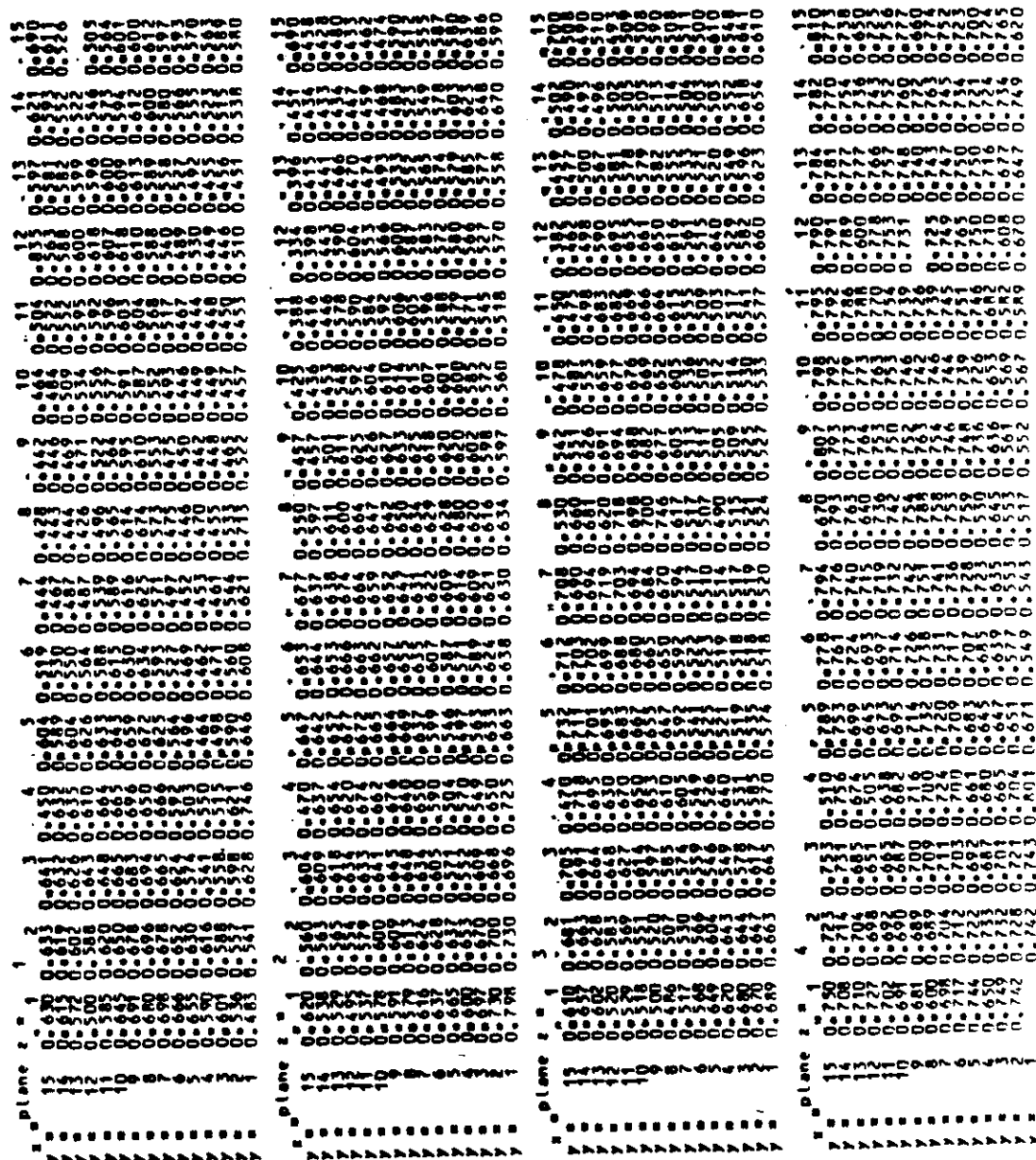


Table 11
FLOWING BOTTOMHOLE PRESSURES AT END OF HISTORY
Waskada Lower Amaranth Pool
(March 31, 85)

<u>Well No.</u>	<u>Location</u>	<u>Measured Liquid Prod. Rate, m³/d</u>	<u>FBHP, kPa</u>	
			<u>Measured</u>	<u>Correlation</u>
1	7-23-1-26	-	-	-
2	8-23	9.3	-	1 300
3	9-23	26.1	4 250	4 050
4	10-23	9.1	-	1 300
5	15-23	-	-	-
6	16-23	22.2	3 173	3 400
7	5-24	-	-	-
8	6-24	2.2	-	650
9	7-24	-	-	-
10	10-24	0.5	-	600
11	11-24	1.9	642	640
12	12-24	6.2	1 036	1 000
13	13-24	-	-	-
14	14-24	2.1	667	670
15	15-24	-	-	-
16	2-25	10.7	-	1 700
17	3-25	9.3	1 322	1 300
18	4-25	6.6	638	640
19	5-25	-	-	-
20	6-25	20.7	-	4 600
21	7-25	-	-	-
22	1-26	6.4	738	750
23	2-26	7.7	-	1 200
24	7-26	-	-	-
25	8-26	17.2	-	3 600

Table 12
WELL VOLUME FRACTIONS AFTER HISTORY MATCH
Waskada Lower Amaranth Pool

<u>Well Name</u>	<u>Original Well Fraction</u>	<u>History Matched Well Fraction</u>
7-23-1-26 W1M	1/4	1/2*
8-23	1/2	3/4*
9-23	1	1
10-23	1/2	1/2
15-23	1/2	1/2
16-23	1	1
5-24	1/2	3/4*
6-24	1/2	3/4*
7-24	1/4	3/5*
10-24	1/2	1/2
11-24	1	1
12-24	1	1
13A-24	1	1
14-24	1	1
15-24	1/2	1/4*
2-25	1/2	1/2
3-25	1	1
4-25	1	1
5-25	1/2	2/5*
6-25	1/2	1/2
7-25	1/4	1/4
1-26	1	1
2-26	1/2	1/2
7-26	1/4	1/4
8-26	1/2	1/2

* history matched well fraction \neq original well fraction

Table 13

TRANSMISSIBILITY TX

Waskada Lower Amaranth Pool

Waskada Lower Amaranth Pool

[illegible]

Table 15

times n,n (days)

Table 15 (Continued)

TRANSMISSIBILITY T2

Waskada Lower Amaranth Pool

plane 1 = 1	10	9	8	7	6	5	4	3	2	1
plane 2 = 1	10	9	8	7	6	5	4	3	2	1
plane 3 = 1	10	9	8	7	6	5	4	3	2	1
plane 4 = 1	10	9	8	7	6	5	4	3	2	1
plane 5 = 1	10	9	8	7	6	5	4	3	2	1
plane 6 = 1	10	9	8	7	6	5	4	3	2	1
plane 7 = 1	10	9	8	7	6	5	4	3	2	1
plane 8 = 1	10	9	8	7	6	5	4	3	2	1
plane 9 = 1	10	9	8	7	6	5	4	3	2	1
plane 10 = 1	10	9	8	7	6	5	4	3	2	1

Table 16
WELL SKIN FACTORS AFTER HISTORY MATCH
Waskada Lower Amaranth Pool

<u>Well Name</u>	<u>Skin Factor</u>	
7-23-1-26	47.98	(-4.09)+
8-23	-5.26	
9-23	-5.00	
10-23	-5.73	
15-23	1.93	
16-23	-5.07	
5-24	74.13	(-4.76)+
6-24	-3.70	
7-24	67.31	(-4.63)+
10-24	2.70	
11-24	-2.32	
12-24	-4.68	
13A-24	-2.34	
14-24	1.23	
15-24	-4.78	
2-25	4.41	
3-25	-4.89	
4-25	-4.07	
5-25	-4.13	
6-25	-4.48	
7-25	-3.65	
1-26	-4.48	
2-26	1.47	
7-26	-4.80	
8-26	-5.70	

+ skin factor used when the gas injector is converted to water injection in the prediction runs

Time = 3m12 (54p) 0.2051

Time = 3m12 (54p) 0.2051

Table 18 (Continued)

RESERVOIR PRESSURE AT END OF HISTORY

Waskada Lower Amaranth Pool

(March 31, 85)

[illegible]

Table 19

OIL SATURATION AT END OF HISTORY

Waskada Lower Amaranth Pool

(March 31, 85)

Time = 1307.0 (days)

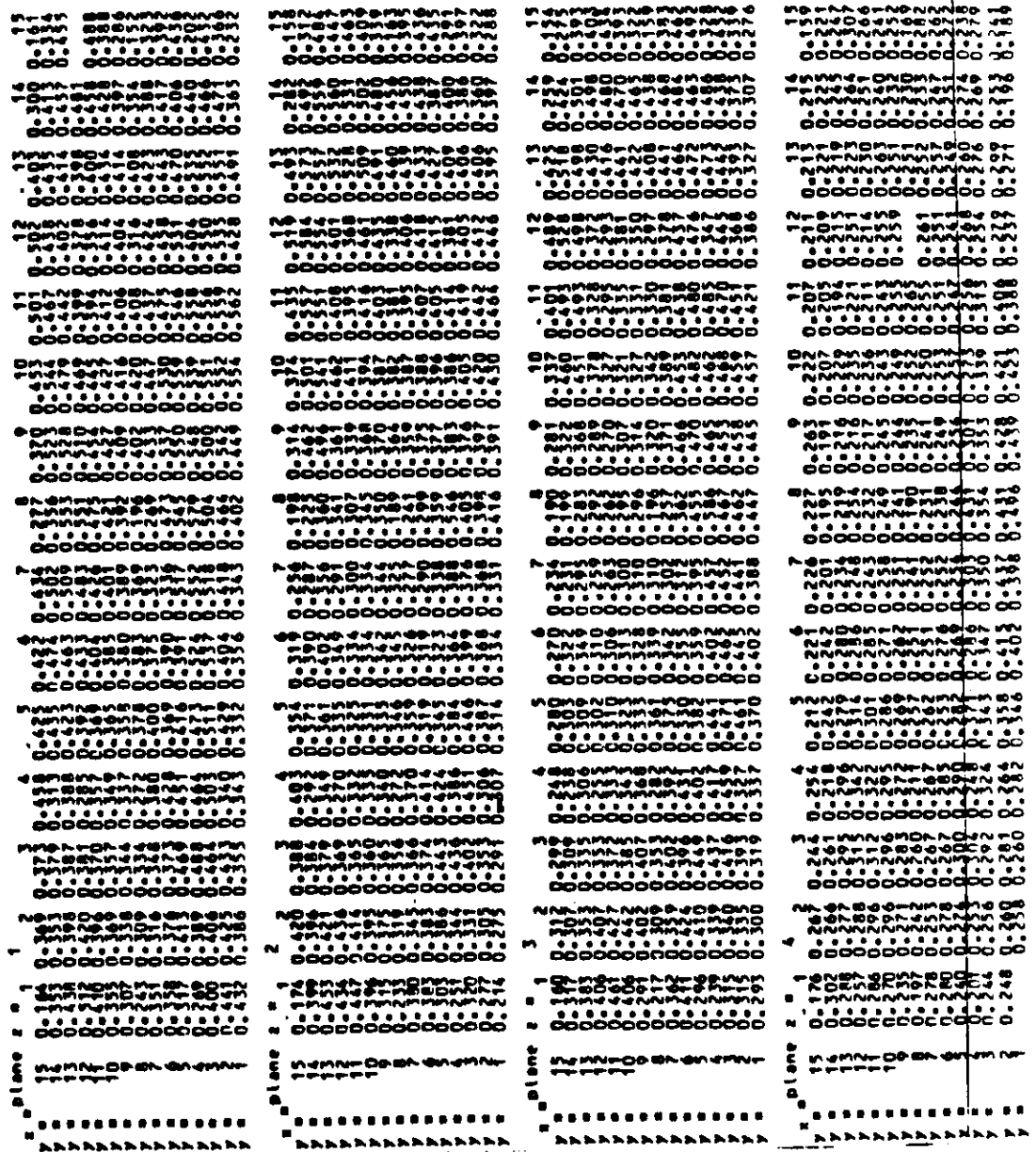


Table 20

GAS SATURATION AT END OF HISTORY

Waskada Lower Amaranth Pool

(March 31, 85)

time = 1307.0 (days)

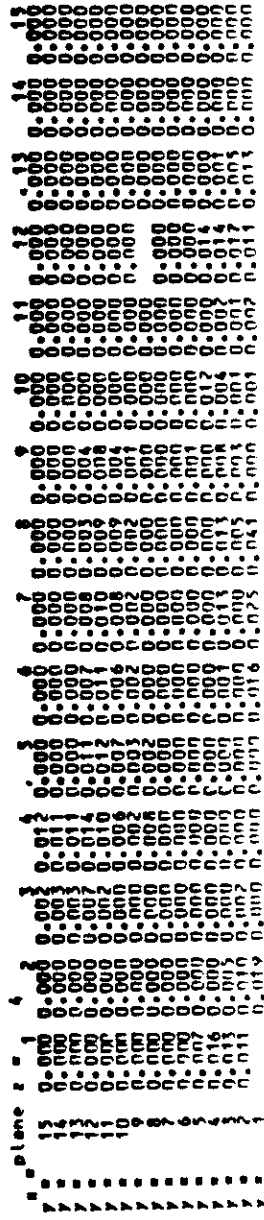
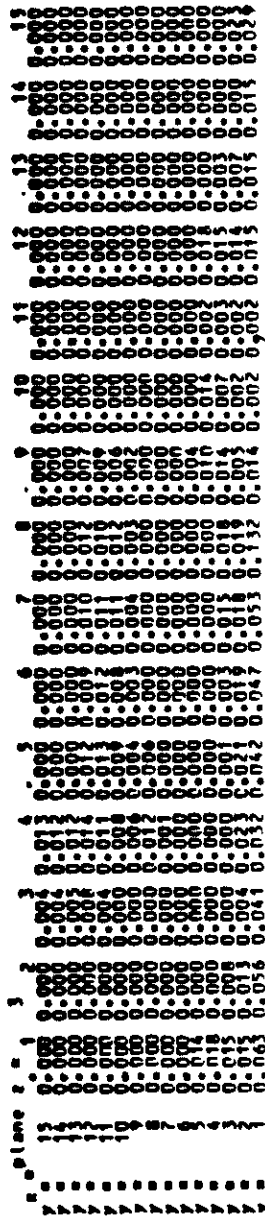
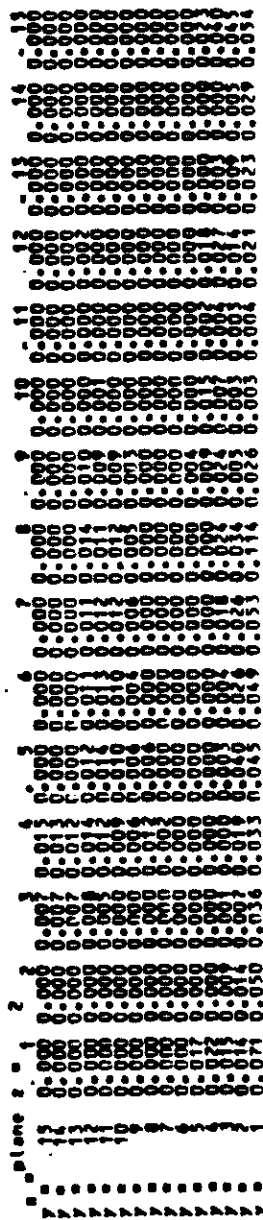
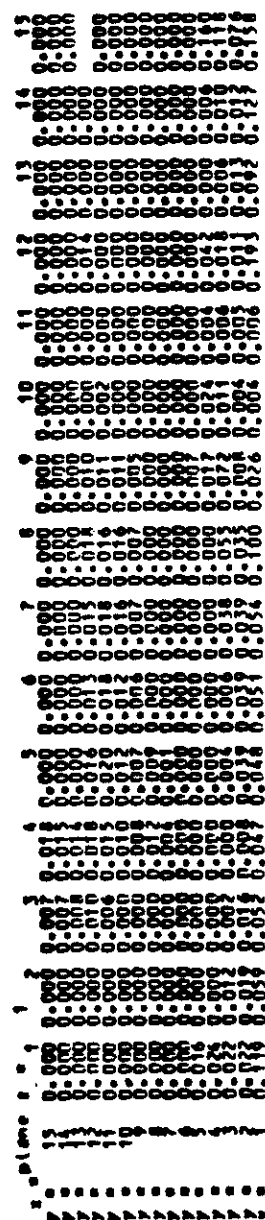


Table 21
WATER SATURATION AT END OF HISTORY
Waskada Lower Amaranth Pool

Time = 1307.0 (days)

(March 31, 85)

plane	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100
plane	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100
plane	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100
plane	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100

Table 22

YEARLY FLUID PRODUCTION FORECAST FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY

SENSITIVITY CASE

Waskada Lower Amaranth Pool

YEAR	OIL PROD m ³	RECOVERY/YR %	WATER PROD m ³	GAS PROD m ³	WOR	GOR	WATER INJ m ³
1	19240.0	4.34	7480.0	1177000.0	0.39	61.2	0.0
2	19980.0	2.25	8870.0	2005000.0	0.89	200.9	0.0
3	4890.0	1.10	6670.0	1804000.0	1.36	368.9	0.0
4	2990.0	0.67	4230.0	1127000.0	1.41	376.9	0.0
5	2010.0	0.45	3230.0	911000.0	1.61	453.2	0.0
6	1330.0	0.30	2320.0	672000.0	1.74	505.3	0.0

* Original Oil in Place = 4.4330E+05 m³

Table 23

CUMULATIVE FLUID PRODUCTION FORECAST FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY

SENSITIVITY CASE

Waskada Lower Amaranth Pool

YEAR	CUM. OIL PROD m ³	RECOVERY %	CUM. WATER PROD m ³	CUM. GAS PROD m ³	CUM. WATER INJ m ³
1	19240.0	4.34	7480.0	1122000.0	0.0
2	29220.0	6.59	16320.0	3182000.0	0.0
3	34110.0	7.69	23020.0	4986000.0	0.0
4	37100.0	8.37	27250.0	6113000.0	0.0
5	39110.0	8.82	30480.0	7024000.0	0.0
6	40440.0	9.12	32800.0	7696000.0	0.0

* Original Oil in Place = 4.4330E+05 m³

Table 25

CUMULATIVE FLUID PRODUCTION FORECAST FOR WATERFLOOD - AVERAGE PERMEABILITY

SENSITIVITY CASE

Waskada Lower Amaranth Pool

YEAR	CUM. OIL PROD m ³	RECOVERY %	CUM. WATER PROD m ³	CUM. GAS PROD m ³	CUM. WATER INJ m ³
1	18490.0	4.17	7115.0	1112000.0	5595.0
2	24070.0	5.43	14070.0	1433000.0	26150.0
3	30000.0	6.77	21350.0	1639000.0	45520.0
4	37100.0	8.37	29940.0	1900000.0	63520.0
5	44010.0	9.93	39670.0	2171000.0	81520.0
6	50950.0	11.85	48920.0	2428000.0	98900.0
7	56930.0	12.85	58120.0	2693000.0	115800.0
8	63330.0	14.20	67550.0	2959000.0	132600.0
9	69910.0	15.70	77080.0	3224000.0	149300.0
10	75740.0	17.09	86080.0	3488000.0	165800.0
11	81760.0	18.47	95040.0	3753200.0	182100.0
12	87420.0	19.72	104520.0	3969000.0	198300.0
13	92940.0	20.87	114520.0	4182000.0	214400.0
14	96940.0	21.84	124900.0	4375000.0	230300.0
15	101230.0	22.71	135710.0	4568000.0	246210.0
16	105110.0	23.53	146030.0	4728000.0	262100.0
17	108780.0	24.31	156770.0	4883000.0	277900.0
18	112450.0	25.07	167190.0	5040000.0	293700.0
19	116160.0	25.74	177740.0	5181000.0	309500.0
20	119930.0	26.41	187740.0	5316000.0	325300.0
21	123490.0	27.08	197290.0	5449000.0	341100.0
22	127130.0	27.69	206590.0	5575000.0	356900.0
23	130330.0	28.29	215600.0	5695000.0	372700.0
24	133810.0	28.80	224900.0	5805000.0	388500.0
25	136860.0	29.28	234580.0	5905000.0	404300.0
26	140090.0	29.73	244610.0	6000000.0	420100.0
27	143320.0	30.16	254980.0	6095000.0	435900.0
28	146770.0	30.57	265780.0	6185000.0	451700.0
29	149930.0	30.96	276100.0	6275000.0	467500.0
30	153580.0	31.33	286740.0	6355000.0	483300.0
31	156840.0	31.68	297780.0	6435000.0	499100.0
32	159930.0	32.01	308310.0	6515000.0	514900.0
33	162580.0	32.32	319300.0	6595000.0	530700.0
34	165840.0	32.61	330780.0	6675000.0	546500.0
35	168490.0	32.88	342780.0	6755000.0	562300.0
36	171230.0	33.13	355310.0	6835000.0	578100.0
37	173930.0	33.36	368380.0	6915000.0	593900.0
38	176740.0	33.57	381900.0	6995000.0	609700.0
39	179490.0	33.76	395980.0	7075000.0	625500.0
40	182230.0	33.93	410510.0	7155000.0	641300.0

* Original Oil in Place = 4.4330E+05 m³

Table 26
**SUMMARY OF AVERAGE ROCK PROPERTIES FOR WATERFLOOD - LOW PERMEABILITY
 SENSITIVITY CASE**
 Waskada Lower Amaranth Pool

<u>Model Layer</u>	<u>Net Pay, m</u>	<u>Porosity, fraction</u>	<u>Permeability, mD</u>	<u>Water Saturation, fraction</u>	<u>OOIP 10³ m³</u>
1 (top)	2.1	0.151	1.06	0.56	312
2	3.0	0.151	1.06	0.59	411
3	3.9	0.152	1.12	0.59	529
4	<u>2.0</u>	<u>0.140</u>	<u>0.74</u>	<u>0.72</u>	<u>171</u>
Total	11.0				
Average		0.150	1.02	0.61	1 423

Table 27
 YEARLY FLUID PRODUCTION FORECAST FOR WATERFLOOD - LOW PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

YEAR	OIL PROD m ³	RECOVERY/YR % OOIP	WATER PROD m ³	GAS PROD m ³	WOR	GOR	WATER INJ m ³
1	21160.0	4.77	394.0	1218000.0	0.02	57.6	2724.0
2	22220.0	2.76	556.0	1754000.0	0.05	61.1	10876.0
3	12081.0	2.44	97.0	629000.0	0.09	58.2	10998.0
4	7040.0	1.33	390.0	494000.0	0.55	66.5	11020.0
5	2440.0	0.33	670.0	241000.0	2.58	91.1	10980.0
6	1810.0	0.39	7970.0	141000.0	4.58	77.4	10930.0
7	1740.0	0.39	7960.0	92000.0	4.57	64.4	10930.0
8	1720.0	0.40	8040.0	80000.0	4.54	53.4	10820.0
9	1720.0	0.43	7000.0	63000.0	4.52	44.4	10800.0
10	23350.0	0.54	7300.0	82000.0	0.63	33.3	10800.0
11	22410.0	0.54	7380.0	86000.0	0.08	33.3	10800.0
12	22450.0	0.54	6280.0	85000.0	0.37	33.3	10700.0
13	22220.0	0.54	6380.0	96000.0	0.35	33.3	10400.0
14	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
15	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
16	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
17	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
18	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
19	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
20	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
21	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
22	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
23	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
24	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
25	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
26	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
27	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
28	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
29	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
30	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
31	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
32	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
33	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
34	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
35	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
36	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
37	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
38	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
39	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
40	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
41	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
42	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
43	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
44	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0
45	22220.0	0.54	6380.0	96000.0	0.35	33.3	10300.0

* Original Oil in Place = 4.4330E+05 m³

Table 28

CUMULATIVE FLUID PRODUCTION FORECAST FOR WATERFLOOD - LOW PERMEABILITY

SENSITIVITY CASE

Waskada Lower Amaranth Pool

YEAR	CUM. OIL PROD. m ³	RECOVERY % OIP	CUM. WATER PROD. m ³	CUM. GAS PROD. m ³	CUM. WATER INJ. m ³
1	21160.0	6.77	394.0	1218000.0	2724.0
2	33380.0	9.53	950.0	1972000.0	13600.0
3	44190.0	9.97	1920.0	2601000.0	24590.0
4	51230.0	11.56	3820.0	3067000.0	35640.0
5	53680.0	12.11	5740.0	3291000.0	46620.0
6	55720.0	12.57	7660.0	3423000.0	57560.0
7	57490.0	12.97	9570.0	3544000.0	68410.0
8	58970.0	13.33	11470.0	3653000.0	79130.0
9	60250.0	13.65	13360.0	3751000.0	90130.0
10	61380.0	13.94	15240.0	3838000.0	101200.0
11	62380.0	14.20	17110.0	3915000.0	112800.0
12	63280.0	14.43	18970.0	3982000.0	124300.0
13	64090.0	14.63	20820.0	4040000.0	135600.0
14	64820.0	14.80	22660.0	4089000.0	146900.0
15	65480.0	14.95	24490.0	4130000.0	158100.0
16	66080.0	15.08	26310.0	4163000.0	169200.0
17	66630.0	15.19	28120.0	4198000.0	180200.0
18	67130.0	15.28	29920.0	4235000.0	191100.0
19	67590.0	15.35	31710.0	4273000.0	201900.0
20	68010.0	15.40	33490.0	4312000.0	212600.0
21	68390.0	15.44	35260.0	4352000.0	223200.0
22	68730.0	15.47	37020.0	4393000.0	233700.0
23	69040.0	15.49	38770.0	4435000.0	244100.0
24	69320.0	15.51	40510.0	4478000.0	254400.0
25	69570.0	15.52	42240.0	4522000.0	264600.0
26	69790.0	15.53	43960.0	4567000.0	274700.0
27	69980.0	15.54	45670.0	4613000.0	284700.0
28	70140.0	15.55	47370.0	4660000.0	294600.0
29	70280.0	15.55	49060.0	4708000.0	304400.0
30	70400.0	15.56	50740.0	4757000.0	314100.0
31	70500.0	15.56	52410.0	4807000.0	323700.0
32	70590.0	15.56	54070.0	4858000.0	333200.0
33	70670.0	15.56	55720.0	4910000.0	342600.0
34	70740.0	15.56	57360.0	4963000.0	351900.0
35	70800.0	15.56	58990.0	5017000.0	361100.0
36	70850.0	15.56	60610.0	5072000.0	370200.0
37	70890.0	15.56	62220.0	5128000.0	379200.0
38	70920.0	15.56	63830.0	5185000.0	388100.0
39	70940.0	15.56	65430.0	5243000.0	396900.0
40	70960.0	15.56	67020.0	5302000.0	405600.0
41	70970.0	15.56	68600.0	5362000.0	414200.0
42	70980.0	15.56	70170.0	5423000.0	422700.0
43	70980.0	15.56	71730.0	5485000.0	431100.0
44	70980.0	15.56	73280.0	5548000.0	439400.0
45	70980.0	15.56	74820.0	5612000.0	447600.0
46	70980.0	15.56	76350.0	5677000.0	455700.0
47	70980.0	15.56	77870.0	5743000.0	463700.0
48	70980.0	15.56	79380.0	5810000.0	471600.0
49	70980.0	15.56	80880.0	5878000.0	479400.0
50	70980.0	15.56	82370.0	5947000.0	487100.0

* Original Oil in Place = 4.4330E+05 m³

APPENDIX A

Appendix A

**SAMPLE CALCULATIONS OF THE ADJUSTED OIL RATES
FOR THE MAIN PATTERN AREA**

Material Balance Equation for the main pattern area is:

$$\text{INFLUX}_F = \text{FIP} + P_F - I_F - \text{OFIP} \quad F=o,g,w \quad (\text{A.1})$$

where

INFLUX_F is the cumulative influx of fluid F, which may be oil, gas or water;

FIP is the current fluid-in-place within the main pattern area;

P_F is the cumulative fluid production from the eight producers;

I_F is the cumulative fluid injection through well 13A-24;

and OFIP is the original fluid-in-place within the main pattern area.

Assuming all the influx is produced immediately, the fluid production rate can be calculated by the following equation

$$Q_F = \frac{(P_F - \text{INFLUX}_F)^n - (P_F - \text{INFLUX}_F)^{n-1}}{\Delta t} \quad (\text{A.2})$$

where the superscript n represents the time level, and Δt denotes the time interval between time levels n and n-1.

Example: Waterflood - Timing - Average Permeability

$$\text{OOIP} = 443.3 \times 10^3 \text{ m}^3$$

$$I_0 = 0 \text{ m}^3$$

<u>Time level</u>	<u>Time, days</u>	<u>OIP, 10^3 m^3</u>	<u>P_o, 10^3 m^3</u>
0	0.0	443.3	0.0
1	365.0	424.8	33.1

$$\text{INFLUX}_0^0 = 0.0 \text{ m}^3$$

$$\text{INFLUX}_0^1 = (424.8 + 33.1 - 0.0 - 443.3) \times 10^3 = 14.6 \times 10^3 \text{ m}^3$$

$$Q_0 = \frac{(33.1 - 14.6) \times 10^3 - (0.0 - 0.0)}{365} = 50.7 \text{ m}^3/\text{d}$$

APPENDIX B

Appendix B

RESERVOIR PRESSURES AND SATURATIONS AT THE END OF SIMULATION

List of Tables

Table

B-1	Final Pressure Distribution for Primary Depletion - Average Permeability
B-2	Final Oil Saturation for Primary Depletion - Average Permeability
B-3	Final Gas Saturation for Primary Depletion - Average Permeability
B-4	Final Water Saturation for Primary Depletion - Average Permeability
B-5	Final Pressure Distribution for Waterflood - Average Permeability
B-6	Final Oil Saturation for Waterflood - Average Permeability
B-7	Final Water Saturation for Waterflood - Average Permeability
B-8	Final Pressure Distribution for Waterflood - Low Permeability
B-9	Final Oil Saturation for Waterflood - Low Permeability
B-10	Final Water Saturation for Waterflood - Low Permeability

Table B-1
 FINAL PRESSURE DISTRIBUTION FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

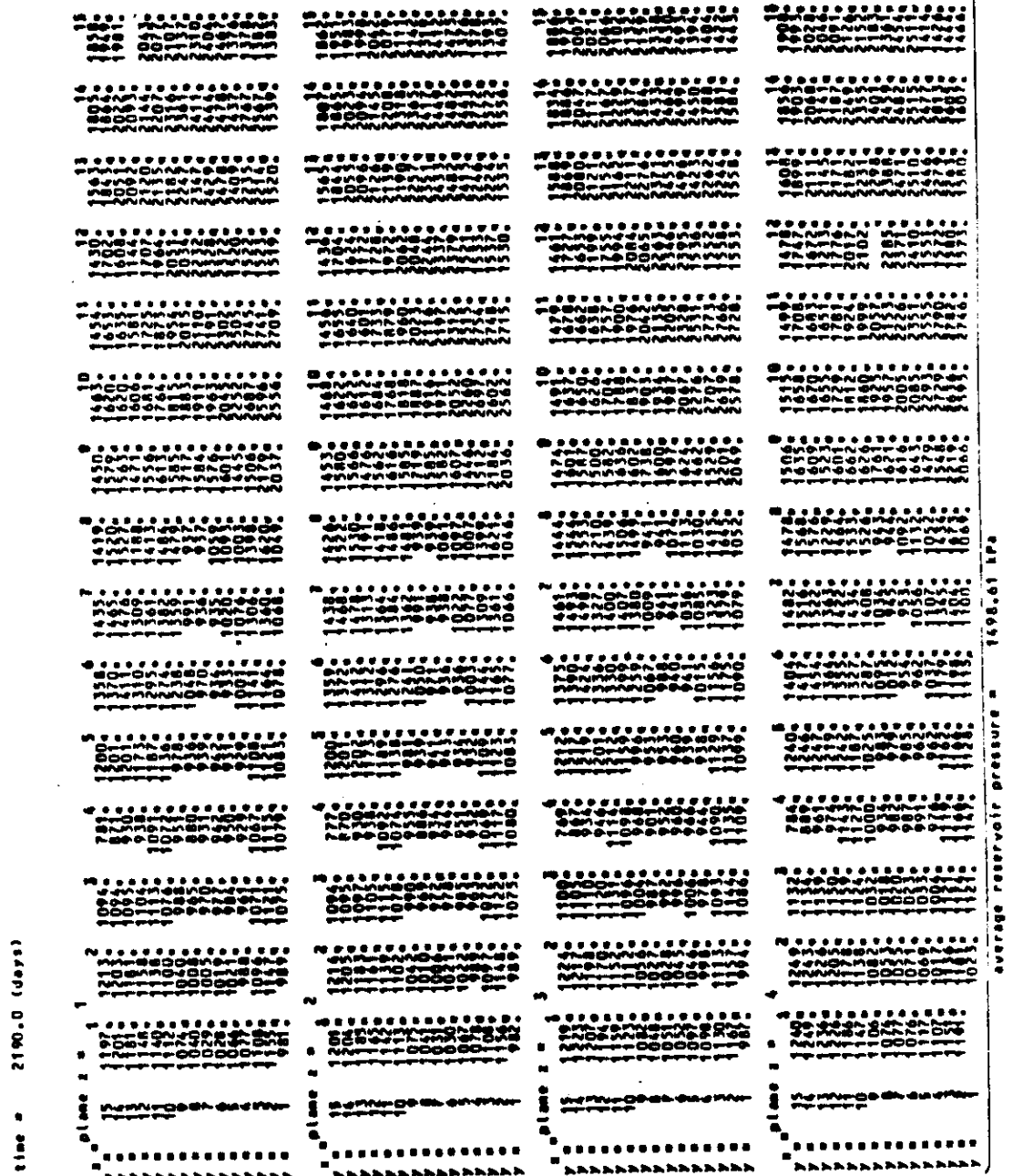


Table B-2
 FINAL OIL SATURATION FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

time = 2190.0 (days)

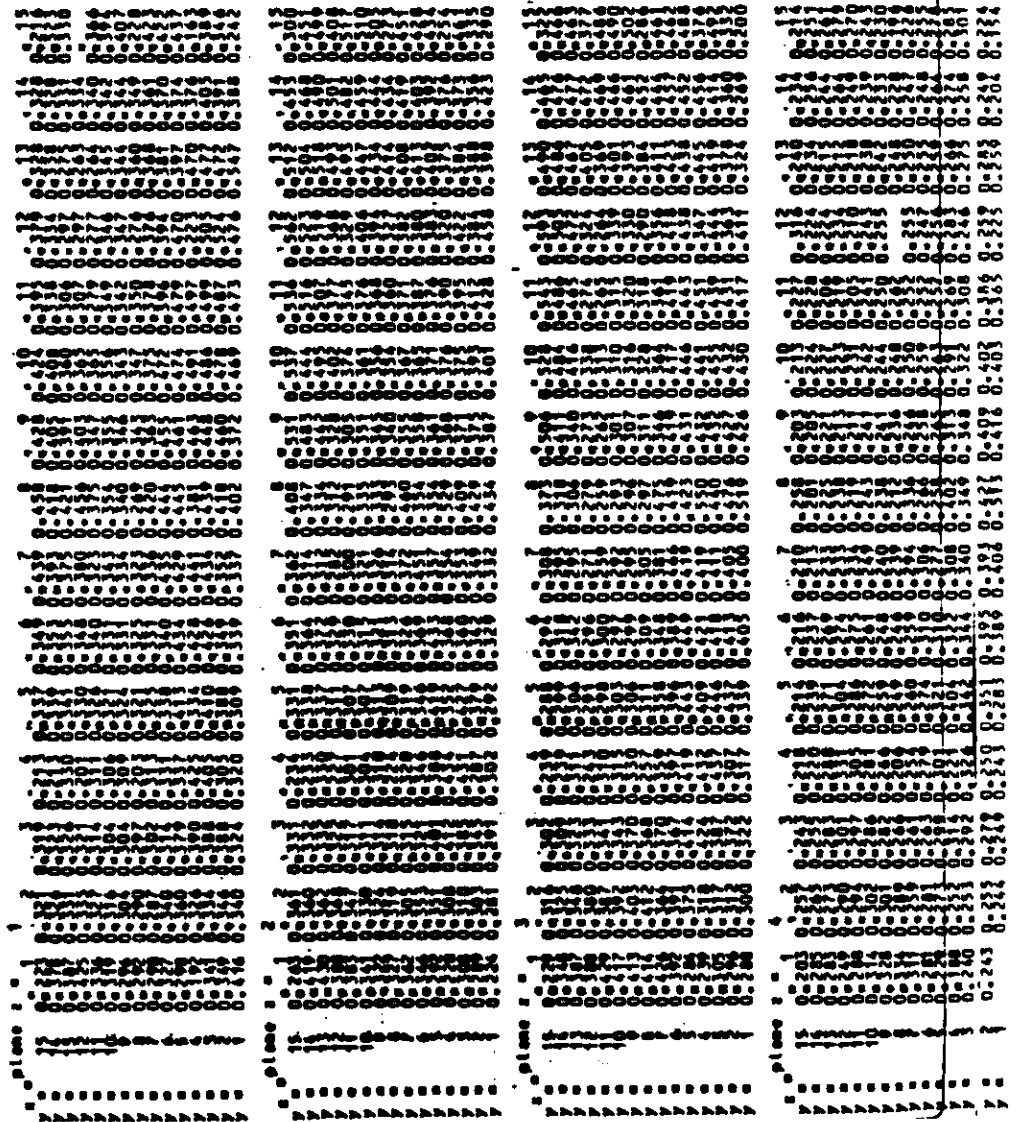


Table B-3
 FINAL GAS SATURATION FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool



Table B-4
 FINAL WATER SATURATION FOR PRIMARY DEPLETION - AVERAGE PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

time = 2100.0 (days)

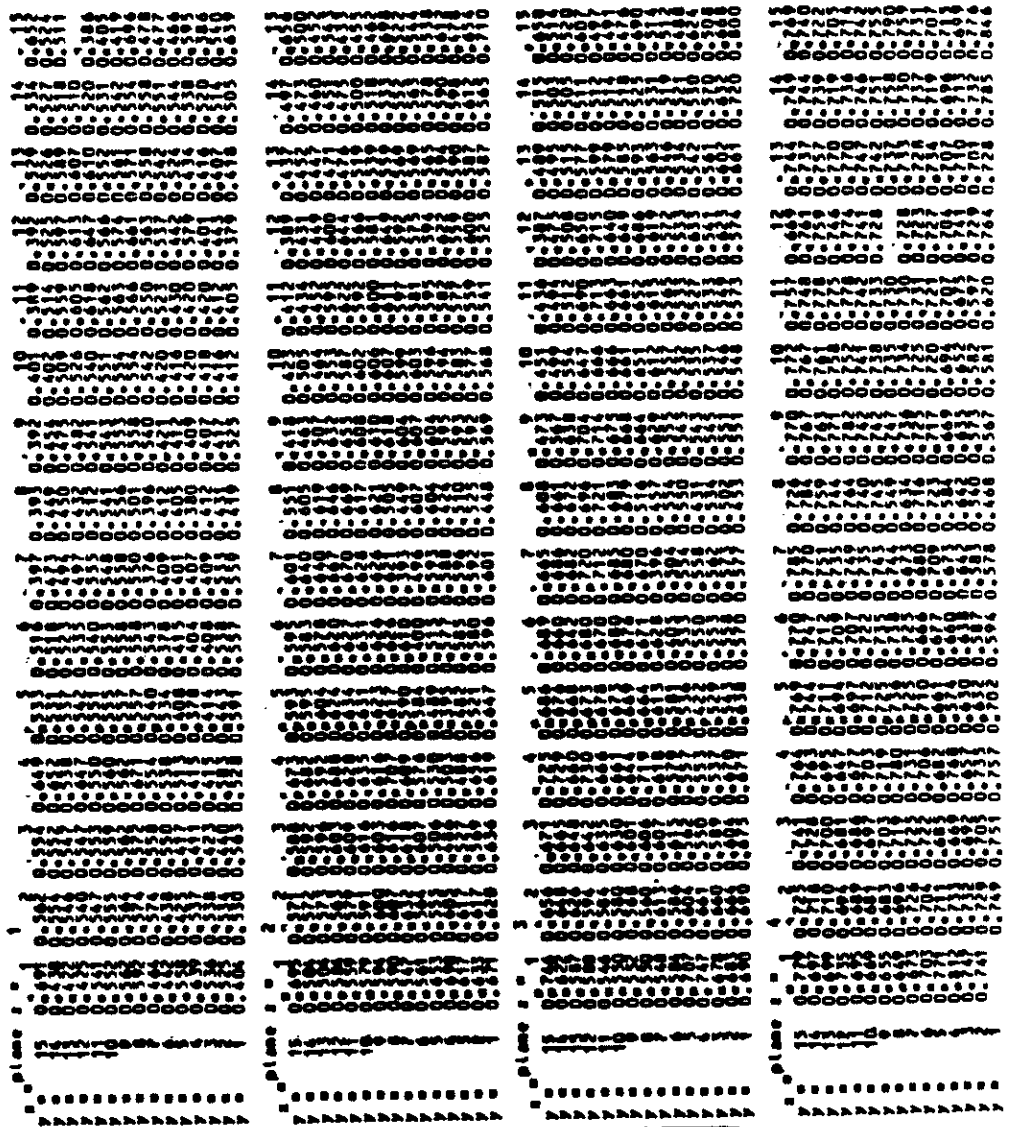


Table B-6
 FINAL OIL SATURATION FOR WATERFLOOD - AVERAGE PERMEABILITY
 SENSITIVITY CASE
 Waskada Lower Amaranth Pool

time = 12775.0 (days)

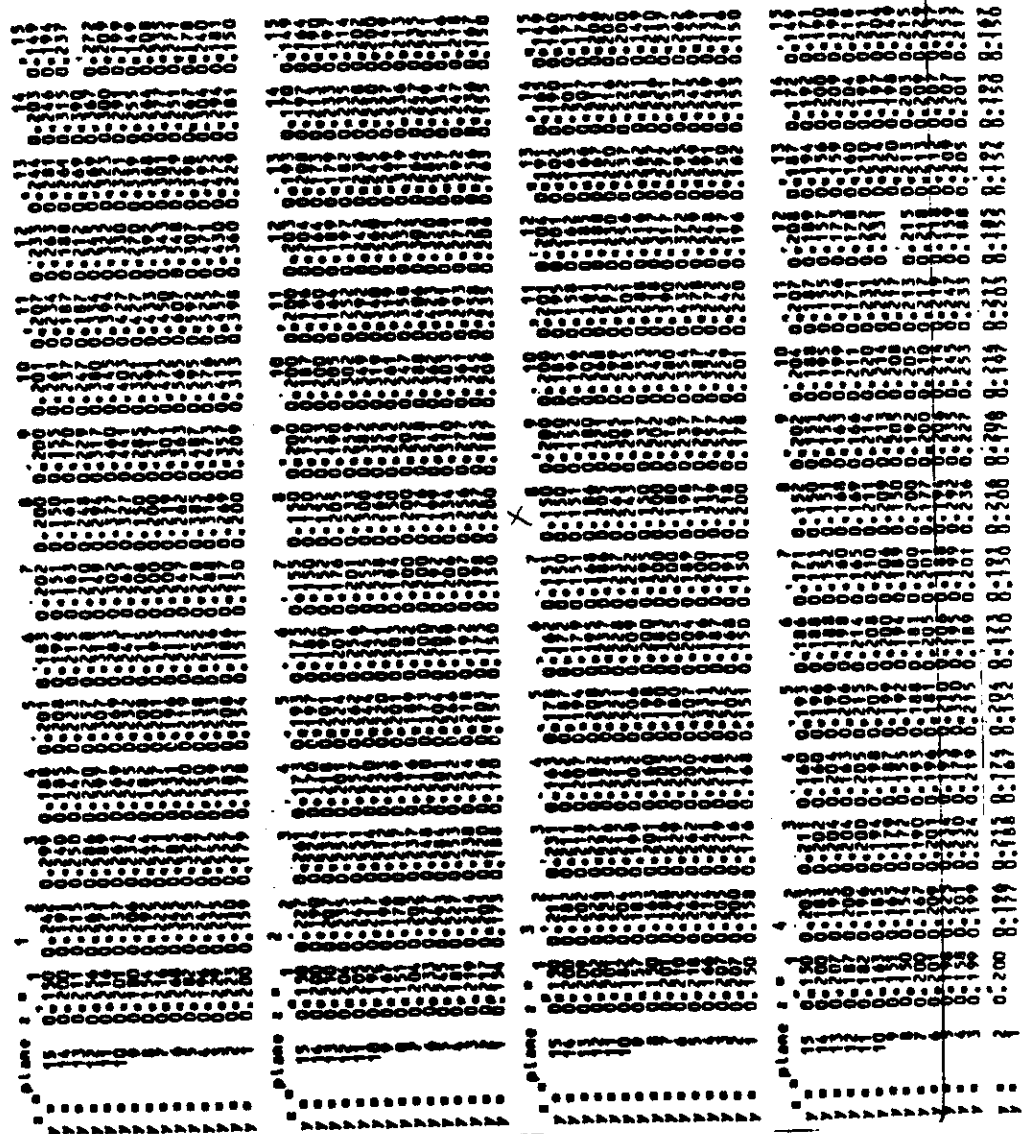


Table B-7
FINAL WATER SATURATION FOR WATERFLOOD - AVERAGE PERMEABILITY
SENSITIVITY CASE
 Waskada Lower Amaranth Pool

time = 12775.0 (days)

