KOLA BAKKEN 'A' POOL OIL FORMATION
MANITOBA

RESERVOIR SIMULATION STUDY

JUNE, 1994

PREPARED FOR

TUNDRA OIL AND GAS LTD.

PREPARED BY

SCIENTIFIC SOFTWARE-INTERCOMP

KOLA BAKKEN 'A' POOL OIL FORMATION
MANITOBA

RESERVOIR SIMULATION STUDY

JUNE, 1994

PREPARED FOR

TUNDRA OIL AND GAS LTD.

PREPARED BY

SCIENTIFIC SOFTWARE-INTERCOMP

TABLE OF CONTENTS

TABLE OF CONTENTS Cont'd

LIST OF TABLES

Table No.

LIST OF FIGURES

Figure No.

LIST OF FIGURES Cont'd

Figure No.

LIST OF FIGURES Cont'd

Figure No.

LIST OF FIGURES Cont'd

Figure No.

LIST OF FIGURES Cont'd

I. INTRODUCTION

Tundra Oil and Gas Ltd. (Tundra) as an operator of a number of Bakken oil reservoirs in Manitoba commissioned this reservoir simulation study in March 1994. The purpose of this study is to conduct a generic reservoir simulation of a typical Bakken reservoir to determine the optimum well spacing under primary depletion and to determine the optimum well spacing and injection pattern under waterflood. The study comprises a review of well data, analysis of fluid and rock properties and the creation and calibration of a simulation model. Seven depletion prediction simulations including primary, waterflood and horizontal well development were conducted to explore the various depletion scenarios.

The study is based on a 772 ha sector (1,908 acres or 3 square miles) of the Kola Bakken 'A' Pool located approximately 32 kilometers west of Virden, Manitoba within Township 10 Range 29 W1M. The field was discovered in 1985 with the drilling of 13-21. Approximately 37 wells have been drilled in and around the field covering approximately seven sections. The three section model area includes 25 wells with current field production of 17 m^3/day and 45 per cent watercut from 13 wells. Five wells in the model area were drilled and abandoned. Seven wells are no longer producing and are now shut-in. Well 13-21 was converted from a producer to a water injector.

The Kola Bakken 'A' Pool contains 42° API gravity crude having a formation volume factor of 1.14 m^3/m^3 and a initial solution GOR of 17.7 m^3/m^3 with very little gas production. The initial reservoir pressure is estimated to be 8874 kPa (absolute) Bakken 'A' Pool produces from a 1 to 2 m thick fine to medium grained dolomitic sandstone developed at the base of the Middle Bakken member at about 870 m depth, 340 m sub sea.

The study was originally to be applied as a generic reference for other Bakken reservoirs having average reservoir properties, layering, oil rates and reservoir size similar to the Kola Bakken 'A' Pool. This study is now site specific considering the unique history match required with water production via fractures into the overlying wet Lodgepole formation.

II. SUMMARY

This report presents the results of a reservoir simulation study of the Kola Bakken 'A' Pool oil formation in Manitoba. The scope of the study included reviewing the geological and engineering data provided, constructing a sector simulation model of the pool, calibrating the model against historical well performance data and using the calibrated model to investigate a number of pool depletion strategies.

Tundra Oil and Gas Ltd. initiated the study and provided the geological properties and engineering data. The reservoir was initially categorized by Tundra into two productive sands, the Upper Middle Bakken and the Lower Middle Bakken which are separated by the Middle Middle Bakken of limited quality.

Relative permeability data were made available from a study on a composite core of three plugs in series from a well in the study area. Fluid properties for the simulation were based on a recombined sample from the study area. A constant composition expansion test was initiated by the study on a different sample from the study area to establish GOR and bubble point.

There was assumed to be no gas cap and no measured gas/oil contact as the original pressure was above the bubble point. There was assumed to be no underlying aquifer nor any water/oil contact.

The sector model of the Kola Bakken 'A' Pool was constructed using five layers and 2200 total grid cells. The top layer of the model was the overlying Lodgepole aquifer.

The model was calibrated using the overlying Lodgepole formation as the source of water when wells were fractured. A Carter-Tracy limited acting oil aquifer was applied to the boundary of all active cells in the lower sand. The original oil in place was established by Tundra and constrained to 461.8 $10^3 m^3$. The boundary oil aquifer resulted in 38.0 10^3m^3 of oil influx, or 8 per cent of the OOIP at the end of the history match.

Two prediction simulation cases were investigated to compare continuing production from the end of the history match February 1, 1994 for a period of 20 years. The first case or base case assumed 13-21 was not converted to an injector. The second case recognized the 13-21 well being converted to an injector in October 1993 and remained so for the prediction period.

Four predictions were conducted starting from October 1985, the time of initial pool production and run until 2014. The following cases were evaluated: The pool was developed on 32 hectare spacing with no injection; The pool was developed with high-graded locations on an average 32 hectare spacing and no injection; The pool was developed on 32 hectare spacing with 3 injectors on a partial 5 spot pattern; and finally the pool was developed on 16 hectare spacing, as originally developed, with a horizontal well replacing 4 producers early in the field life. The study confirms that 32 hectare provides the highest primary recovery on an individual well basis. One prediction case was run from January 1994 with the addition of a horizontal well to the existing wells.

The study indicates further expansion of the waterflood in the Kola Bakken 'A' Pool should be considered only if satisfactory economic performance is obtained from accelerated production in response to injector 13-21. It was shown selective development with technically supported locations on 32 hectare spacing increases the ultimate recovery to 10.5 10^3m^3 per producing well. The development plan yielding the highest ultimate recovery was the addition of a horizontal well in 1994 to the existing operation. This case resulted in the recovery of 25.9 10^3m^3 of oil from the horizontal well and field ultimate recovery of 152.1 10^3m^3 oil or 33 per cent of the OOIP. Tables 1 and 2 summarize the recoveries for the various prediction cases.

The results from this study are recommended to be used only for the Bakken 'A' pool. Because of the unique nature of the model developed it is suggested that site specific models should be developed for other Bakken reservoirs.

III. CONCLUSIONS

1. The history match challenged the initial geological and engineering interpretation of the Kola Bakken 'A' Pool. The drive mechanism and energy source for the reservoir is estimated to be circumferentially from a thin horizontal extension of the lower middle sand that floods oil into the pool.

2. The limited pressure data that was made available provided a larger degree of freedom than normal in conducting the history match and therefore may impact the accuracy of the resultant model.

3. A good history match of the available data was achieved and historical performance was duplicated.

Analysis of the results of the prediction cases led to the following :

4. Primary production of the existing wells, assuming 13-21 was not converted to an injector, resulted in an ultimate recovery of 137 10^3m^3, or 30 per cent of the OOIP by the year 2014, the end of the 20 year prediction period.

5. The 13-21 injector is estimated to provide increased oil production rates until the year 2000 after which the rates drop lower than estimated under primary production with 5.0 10^3m^3 lower ultimate recovery than having not converted 13-21 to an injector. Therefore, based on the current study, the 13-21 injector is only providing rate acceleration.

6. Predictions of the original field development from October 1985 on 32 hectare spacing (as opposed to the actual 16 hectare spacing) and assuming there was no 13-21 waterflood, resulted in ultimate field recovery of only 87 10^3m^3 or 19 per cent of the OOIP by the year 2014. This is only 64 per cent of that recovered by primary production on 16 hectare spacing. However, under coarser well spacing the average recoveries increased

from 6.85 10^3m^3 per producing well (excluding D&As) on 16 hectares to 8.7 10^3m^3 per producing well for the 32 hectare case. Pending economic support, 32 hectare spacing appears to be more attractive than 16 hectare spacing because of higher oil recovery from individual producers.

7. Concentration of wells in more prolific areas of the field while excluding marginal wells on the pool edge under the previous 32 hectare case, further increased average recovery to 10.5 10^3m^3 per producing well.

8. Predictions of the original field development from October 1985 on 32 hectare spacing (as opposed to the actual 16 hectare spacing) and converting 3 producers to a partial 5 spot waterflood in 1994 resulted in reducing the ultimate field recovery to 75 10^3m^3 or 16 per cent of the OOIP. This case also resulted in lower oil rates after the start of the flood compared to the primary 16 hectare case. This option would not have been a viable development strategy for the Kola Bakken 'A' Pool.

9. Predictions of the original field development from October 1985 on 16 hectare spacing and replacing 4 producers with a horizontal well in the north central area of the field in December 1986, resulted in higher oil rates and an ultimate field recovery of 150 10^3m^3 or 32 per cent of the OOIP. This is the highest recovery studied. The horizontal well recovered 39 10^3m^3 of oil by the end of the prediction period which is 5.5 times greater than average recovery from a vertical well on 16 hectare spacing. The horizontal well produced at a rate of 2.5 times the initial combined oil rates from wells 5-28 and 6-28 over which area the horizontal well produced. Pending economic analysis this case is extremely attractive as the horizontal well costs offset production from 5.5 equivalent vertical wells.

10. Predictions of the existing wells from January 1994 with a horizontal well in the same location as in Case 6 resulted in the highest recovery studied with an ultimate field recovery of 152 10^3m^3 or 33 per cent of the OOIP. The horizontal well recovered 25.9 10^3m^3 of oil by the end of the prediction period. The horizontal well water-cut increased to 73 per cent by the end of the 20 year prediction. Pending economic analysis, with consideration for the risks of high water, the drilling of a horizontal well is extremely attractive.

IV. RECOMMENDATIONS

The simulation study of the Kola Bakken 'A' Pool oil formation has resulted in the following recommendations:

1. Caution should be taken in extrapolation of the results from this study to other Bakken reservoirs because the unique nature of the model developed here has challenged the initial geological and engineering interpretation of the Kola Bakken.

2. Investigate the implications of the history match indicating the source of energy and resultant oil influx is from a thin horizontal extension of the oil leg. The influxing oil may be also in part due to a down dip aquifer.

3. Development of Bakken reservoirs should be pursued on 32 hectare spacing in conjunction with sound technical evaluations to select the best locations and maximize recovery per well. Reduce blanket development on 16 hectare spacing.

4. Horizontal drilling should be considered an optimum initial development strategy in conjunction with 32 hectare spacing for fields similar to the Kola Bakken 'A' Pool.

5. Drilling a horizontal well in the Kola Bakken 'A' Pool should be considered as a development strategy. Development economics should include consideration for risk of high water production.

6. Further expansion of the waterflood in the Kola Bakken 'A' Pool should be considered only if satisfactory economic performance is obtained from accelerated production in response to injector 13-21.

7. Waterflooding of other similar Bakken areas should be considered carefully before any such program is implemented.

8. Conduct pressure surveys on a regular basis for conducting reservoir engineering evaluations.

9. Water injection rates should be monitored carefully so as to not exceed the fracture gradient in the Kola Bakken 'A' Pool.

V. RESERVOIR FLUID PROPERTIES

5.1 OIL AND GAS PROPERTIES

A reservoir fluid study conducted by Chemical & Geological Laboratories Ltd.(1) (C&G Labs) in February, 1988 was supplied for use in the study. The laboratory study was based on a recombined sample of reservoir oil and gas taken from the well Newscope et al Daly 3-28-10-29 W1M. Comparison of the lab data by SSI with data derived from standard correlations resulted in similar formation volume factor and gas-oil ratio (GOR) profiles but the correlated data was substantially steeper than the lab PVT data. Additionally the gas gravity of 1.1 seemed excessive and resulted in a combination not consistent with Standings correlations. Because of the differences, SSI recommended obtaining a new PVT analysis. SSI also recommended a production test to confirm solution GOR so the recombination is done with the right amount of gas.

A second fluid study was conducted by C&G Labs(2) in February 1994 and was also supplied for this study. GOR values are difficult to accurately measure when very low gas production is available as in the Bakken. Rigorous sampling procedures ensured that all fluids flowed up the tubing and that the sample remained above the bubble point. The wellhead samples were taken at 7,000 kPa. A constant composition expansion test was conducted on the pressurized sample to establish bubble point. Two GORs were measured on this and a companion sample.

Oil produced from the Kola Bakken Kola Field is a light crude oil with a relative density of 42° API. The C&G Labs February 1994 fluid study indicated a bubble point of 2,376 kPa (abs) and an average gas-oil ratio at the bubble point of approximately 17.7 m^3/m^3.

Table 3 and Figure 1 lists the oil fluid properties used in the simulation model. Table 4 and Figure 2 show the gas fluid properties used. These data were generated using standard correlations in SSI's **Petroleum WorkBench**. Standing's correlations were used for the oil formation volume factors and gas-oil ratios and Lee-Gonzales-Eakin correlations were used for gas viscosity. Table values for saturation pressures above the bubble point are required to allow repressurization to pressures above the original bubble point. Localized high reservoir pressures can occur under water re-injection conditions.

A gas gravity of 0.9 was used in generating the fluid properties. This was reduced from the 1.1 in the C&G Labs February 1988 report to provide gas-oil ratios as measured in the 1994 analysis.

The formation volume factor and viscosity for under-saturated oil were assumed to vary linearly from the bubble point in the under-saturated region based on constant oil compressibility and constant viscosity slope, respectively. The following values were taken from the C&G Lab February 1988 report.

Viscosity slope:	1.585 E-05 1/kPa
Constant oil compressibility:	1.202 E-06 1/kPa

5.2 WATER PROPERTIES

No analysis of water from the Bakken Formation was made available for this study. A single set of water properties was used. The following characteristics of water at reservoir conditions were taken from the Kola Field Pressure Maintenance Application[3] referencing a water salinity of 90,000 ppm:

RESERVOIR WATER PROPERTIES
@ 101.325 Kpa and 15° C

Reservoir conditions	8874kPaa, 31° C
Density:	1.06 gm/cc
FVF:	1.001 Rm^3/m^3
Viscosity:	0.85 cp
Compressibility:	4.5 E-07 1/kPa

In the absence of test data, 90,000 ppm water has been assumed for the reservoir water as well as injected water.

VI. ROCK PROPERTIES

6.1 GENERAL

The June 23 1993 Hycal Energy Research Laboratories Ltd. (Hycal) Relative Permeability Study[4] contained the results of measured water-oil relative permeability on a composite core stack consisting of three plugs in series from well 4-28-10-29 W1M. The shapes of the water-oil relative permeability curves indicates a predominantly water-wet system.

6.2 RELATIVE PERMEABILITY

The Hycal water oil relative permeability curves were based on a reference to the absolute liquid permeability. For the purposes of this study, all relative permeability is referenced to the absolute air permeability. The plugs were assumed to have the same length and using a linear beds in series equation, the average air permeability for the composite core sample was calculated from the individual Hycal air permeabilities to be 17.4 md.

Only one set of water-oil relative permeability curves were presented by Hycal and were used directly. All relative permeability data referenced to oil were converted to be relative to air permeability by multiplying by:

$$K_{\text{reference to oil}} / K_{\text{reference to air}}$$

No gas-oil relative permeability tests were measured on any of the samples. Gas-oil relative permeability curves were generated within **Petroleum WorkBench**. Consistent end points are required in the model. In the simulator the relative permeability to oil for a gas-oil curve at irreducible water saturation K_{rogc} must equal the water-oil value for the relative permeability to oil K_{rocw}. The water-oil value was used as it was available. The critical gas saturation was assumed to be zero. The residual liquid saturation to gas displacement, SLR, is defined as the irreducible water saturation, S_{wi}, plus the residual oil saturation to gas displacement S_{org}. Since no gas data was available, the residual oil saturation to water displacement S_{orw} was used instead of S_{org}. The residual liquid saturation to gas SLR was thus 0.578 plus 0.197 or 0.775. The gas relative permeability was assumed to have a maximum value of 1.

Figure 3 shows the water-oil relative permeability simulation input curves and Figure 4 shows the gas-oil relative permeability curves. Tables 5 and 6 detail the simulation input values used in the study.

6.3 CAPILLARY PRESSURE

The Relative Permeability study conducted by Hycal[4] did not include any capillary pressure tests. For the purposes of this study capillary pressures were generated from **WorkBench**.

The use of oil-water capillary pressures has little impact on the results of the model if there is no underlying water. The capillary pressure data was added when the model was constructed because water production suggested underlying water. The capillary pressure data was left in the model because of the large amounts of water being produced.

The phenomenon of capillary pressure occurs in reservoirs and determines the initial distribution of fluids within the reservoir. The capillary pressure-saturation characteristics of the rock determine the shape of the water-oil and gas-oil transition zones and irreducible water saturation. The model was initialized without an underlying aquifer or an oil-water contact. The maximum estimated capillary pressure was based on generating a transition zone height of 3 m or 10 feet.

Capillary pressure data is included in Table 5.

Initial field pressure was above the bubble point with no free gas. The 2,376 kPa (abs) bubble point is much lower than the 8,874 kPa (abs) initial reservoir pressure so the gas-oil capillary pressure was assumed to be zero and no gas-oil capillary pressure curves were included in the study.

6.4 FORMATION ROCK COMPRESSIBILITY

The formation rock compressibility used in the study was based on standard correlations for pools of this rock type:

Rock Compressibility: 5.8 E-07 1/kPa

VII. MODEL CONSTRUCTION

Simulations for the Kola Bakken 'A' Pool were developed through the use of **SSI's Petroleum WorkBench** Black Oil reservoir simulator.

7.1 GRID SELECTION

The final grid was configured as a three-dimensional oil-gas-water system with 22 cells in the x direction by 20 cells in the y direction areally and 5 layers for a total of 2200 cells covering approximately 770 ha (3 square miles). Cells dimensions of 130 m by 135 m were used with approximately 12 cells to the mile. The simulation gridding is shown in Figure 5 with the structure top shown as 5 m above the upper middle Bakken or the top of layer 1, the Lodgepole.

7.2 LAYERING

The reservoir was initially categorized by Tundra into two productive sands within the middle Bakken of the Bakken formation. The upper and lower productive Bakken members are separated by the relatively unproductive, predominantly argillaceous section. The Lodgepole formation sits above the Bakken and is believed by Tundra to be the source of water in the Bakken through excessive stimulation or fracturing. The top layer of the model was used to represent the Lodgepole formation. The second layer of the model was used for the upper middle Bakken zone. The third layer represented the lower quality middle Bakken and layers 4 and 5 equally divided the more productive lower middle Bakken member.

7.3 GENERATION OF ARRAYS

Pore volume and flow capacity maps were provided by Tundra for the total middle Bakken as well as the upper and lower Bakken members. Open hole logs, gross pay intervals and some core data were also provided. The procedure for constructing the grid layer arrays is outlined below.

1. All open hole logs were analyzed across the middle Bakken in conjunction with the available core data to determine net pay and porosity values.

2. Porosity and permeability core data was reviewed from the top of the upper middle Bakken to the bottom of the lower middle Bakken. Unsuitable samples that were fractured or broken were excluded. The remaining samples were used to build a porosity to permeability transform as shown in Figure 6. At the request of Tundra the transform was forced to pass through 1 md permeability and 15 per cent porosity representing the cutoff for no flow. The transform honoured all data above the cutoff.

3. Tundra's Bakken structure top and pore volume (porosity net thickness) maps for the upper and lower Bakken zones were digitized into **Petroleum WorkBench**. In each case where contours were digitized, the well point values were also digitized in.

4. Tundra's individual well gross pay values and the log analyses porosity values were digitized into **Petroleum WorkBench** for upper, middle and lower zones.

5. Based on the input contours and well point values, **Petroleum WorkBench** generated cell array values for structure top, gross pay, porosity and porosity net thickness.

6. Using **Petroleum WorkBench** transform functions, the porosity net thickness arrays were divided by the log derived porosity arrays to give net pay arrays. This was done for both the upper and lower zones. For the middle Bakken zone the net pay was initially set equal to the gross pay.

7. **Petroleum WorkBench** transform functions were used to convert log porosity arrays to permeabilities arrays using the core data porosity to permeability transform, Figure 6 from step 2.

8. The lower middle Bakken net and gross pay arrays were equally divided between layers 4 and 5. The lower zone porosity and permeability arrays were the same for layers 4 and 5.

9. The unproductive layer 3 middle Bakken was assigned net pay arrays equal to 5 per cent of the gross pay.

10. The Lodgepole aquifer layer 1 was assigned uniform gross and net pay arrays of 5 meters, uniform permeability arrays of 1000 md and uniform porosity arrays of 25 per cent.

11. The y-direction permeability arrays were set equal to the kx arrays. There was no evidence that horizontal permeability showed any anistrophy.

12. The vertical z-direction permeability arrays were set equal to ten per cent of the kx arrays from the core data.

In the first pass at building the array values, the Tundra map derived porosity net thickness arrays were divided by the SSI log derived net thickness arrays to get porosity arrays. This method resulted in porosity values less than the cutoff limits and thus low permeability values. This discrepancy highlights the difficult geology and interpolations associated with the Bakken. The array building process was repeated using the log derived porosity arrays to calculating the net pay arrays. The log porosities were used because they are compatible with the core and are above the cutoffs for producing wells and result in more representative permeabilities.

Figures 7 and 8 show the net thickness contours for layers 2 and 4. Inactive cells are shaded gray.

7.4 AQUIFER

A Carter-Tracy infinite-acting aquifer was applied to the outside edge of layer 1 (Lodgepole formation) to provide a continuous source of water. A vertical transmissibility barrier was applied between the first and second layers to prevent uncontrolled water influx. Selective reductions in vertical transmissibility allow for water encroachment.

7.5 ROCK TYPES

The model was assumed to have a single rock type array linking each grid cell with a common relative permeability data set.

7.6 EQUILIBRIUM REGIONS

The simulation model was established with two equilibrium regions. One region was assigned to layer 1 with the oil water contact at the top of layer 1 making it 100 per cent wet. The second region was assigned to layers 2 through 5, the Bakken. The water/oil contact for the Bakken region was set well below the model's lowest cell and the Bakken region was initialized with no underlying aquifer. There was no initial gas/oil contact as initial reservoir pressure was above the bubble point.

7.7 FLUIDS-IN-PLACE

Tundra's maps of porosity, net thickness and structure were used to form the basis of the simulation model reserves.

Table 1 lists the original volumes in place ultimately used in the history matching process. The OOIP was fixed at 461 $10^3 m^3$.

VIII

VIII. HISTORICAL RESERVOIR PERFORMANCE

8.1 GENERAL

The Kola Bakken 'A' Pool has been on primary production since October 1985 and waterflooding was initiated in October 1993. At the start of the study a total of 25 wells have been drilled in the study area and following 13 are currently producing.

9-20-10-29 W1M
10-20-10-29 W1M
16-20-10-29-W1M
5-21-10-29 W1M
12-21-10-29 W1M
15-21-10-29 W1M
1-28-10-29 W1M
2-28-10-29 W1M
3-28-10-29 W1M
4-28-10-29 W1M
11-28-10-29 W1M
12-28-10-29 W1M
9-29-10-29 W1M

Five wells never produced commercially. They are 15-20, 16-21, 7-28, 1-29 and 8-29. Seven wells no longer produce and are now shut-in. They are 08-20, 10-21, 11-21, 13-21, 14-21, 5-28 and 6-28. Well 13-21 was converted from a producer in an injector.

8.2 PRODUCTION

As of 30 January, 1994, cumulative oil production from wells in the study area is 61 10^3m^3 which is only 13 per cent of the estimated 461 10^3m^3 of original oil in place.

The wells average 40 per cent watercut. There is no underlying aquifer and Tundra advises the water is a result of fracturing into the overlying Lodgepole formation. The wells shut in are a result of high water production.

Monthly production reports of oil and water production were made available by Tundra at the start of the study. This data covered the period 1 October, 1985 to 31 January, 1994. This data formed the basis of the well history used to calibrate the simulation model. The monthly oil and water production records for each well were used as the target production rates for the simulated wells. No gas production data was available because the wells exhibit low GORs and gas volumes are not measured.

8.3 RESERVOIR PRESSURE

Under primary production, reservoir pressure has been declining. The initial reservoir pressure 8,874 kPa (abs), has declined to approximately 6,500 kPa (abs) and remained above the bubble point pressure, 2,376 kpa (abs). Table 7 summarizes the available pressure data. The DST pressure analyses were conducted by Tundra and used as provided. Acoustic well sounder data and corresponding wellhead pressures were provided by Tundra on 4 wells.

The 4 acoustic tests taken in 1992 were analyzed and their results are included in the Appendices section of this report. The intent of the analyses were to establish average reservoir pressure at the time of the test for history matching purposes in the simulation. Well 11-28 had sufficient data to do a standard MBH analysis. The derivative curve is well defined establishing a rectangular boundary drainage area resulting in a high quality pressure point. Well 6-28 with less data is just starting to show the boundary effects and the resultant pressure has a greater uncertainty. A standard MBH analysis was conducted on 16-20 however no boundary effects are evident from the test data. The closed boundary was based on the inter-well drainage distance and the resultant reservoir pressure has a high uncertainty. Even so, the 16-20 pressure falls within the range of the other data. The standard MBH analysis on 4-28 was inconclusive as test data was of insufficient duration to provide meaningful results and the pressure was not used in the simulation study.

Three of the wells shown are outside the study area. Well 16-17 to the south was DST'd in March 1986. Its high initial pressure provides no evidence of communication and could indicate a separate pool confirming the closure of the mapping to the south. The 16-29 and 1-32 pressures are just outside the study area to the north. Both wells were drilled and tested in 1993 and their pressures indicate depletion supporting 'A' Pool extension to these recently drilled northern wells.

Reservoir pressure is a key component in the history matching process. Having high quality pressure data over the duration of the simulation period generally results in better models and thus better predictions. Buildup tests of sufficient duration should be conducted on a regular basis to allow for proper reservoir engineering and ongoing pool management. With only six Bakken pressures available for all the wells in the study, the limited data provided a larger degree of freedom than normal in conducting the history match and therefore may impact the accuracy of the resultant model.

8.4 INITIAL RESERVOIR PRESSURE

The Kola Bakken 'A' Pool initial reservoir pressure of 8,853 kPa (abs) was based on the DST from 13-21-10-29 W1M, the initial completion in the pool (Table 7). A complete analysis was not available for this DST so the initial 60 minute shut-in after a 5 minute preflow of 8,580 kPa (ga) was grossed up by 2 per cent based on a similar preflow and buildup from the well 5-21 DST analysis.

8.5 WELL COMPLETIONS

Tundra supplied completion intervals for all wells. All wells were taken to be fully completed in layers where completed. Table 8 details the completion data. Fractures into the Lodgepole are identified in Table 8 as well as the X-Y location of wells in the model.

IX

IX. MODEL CALIBRATION

9.1 OBJECTIVES

Any reservoir simulation model needs to be calibrated (or history matched) to historically measured field performance before reliable predictions of future performance can be made with confidence. The model calibration phase of the project provides an important perspective on whether the geological and petrophysical basis of the model really support the actual well production. The modification of parameters which are required to make the simulation model match historical performance can often lead to important discoveries about the geological and petrophysical basis of the original model.

The primary objective of the model calibration phase in this project was to check the validity of the geological interpretation and to ensure that the oil, gas and water production from the wells in the model matched the wells in the field. Because performance predictions on a variety of operating scenarios were required including the conversion of existing wells to water injection and/or the addition of new wells, it was important to match historical production well by well. An additional objective of the history matching model calibration phase was to match the average reservoir pressure history, because this indicates an overall match of reservoir energy.

9.2 METHODOLOGY

The model was constructed on the basis of the latest geological and petrophysical understanding of the field supplied by Tundra. The history matching period spanned from initial production 1 October, 1985 to 31 January, 1994.

During the simulated history matching period, wells in the model were opened and shut-in according to the monthly operational history of the wells. While on production, each well in the model produced at an average calendar day production rate over the month. The quality of the history match was determined by comparing simulation performance with well measured performance for the following:

- oil production rate;
- well pressure;
- water production and
- GOR data.

The initial model conditions were modified to obtain the history match. Because many wells lacked pressure data it was not feasible to always match well pressures. When test pressure data was available, observed well pressures were compared with simulated well pressures. Gas production volumes were not measured and assumed to remain constant at the initial solution GOR.

9.3 PERMEABILITY

To achieve a history match, it was found necessary to change the effective horizontal permeability in specific areas of the field. All changes were accomplished through the use of multiplication modifiers applied to the original arrays, which remained unchanged. The horizontal permeability was increased in the lower sand, layers 4 and 5 only. The permeability was increased individually around wells as required to maintain the producing pressure above the bubble point. Table 9 details the layer 2 grid block X direction permeability after history matching and Table 10 the layer 4 final permeabilities. Permeabilities in layer 4 and 5 were identical.

9.4 POROSITY

Grid block porosities for layers 2 and 4 are shown in Tables 11 and 12. No changes were made to the porosity values.

9.5 AQUIFER

The Carter-Tracy infinite acting aquifer applied to the outside edge of layer 1 was reduced in size to a limited acting aquifer so the aquifer pressure would drop along with the oil pressure. This was done to prevent the producing cell pressure from measuring the aquifer pressure in layer 1.

9.6 OIL AQUIFER

A Carter-Tracy limited acting boundary oil aquifer was added to the model and applied to the outside edge of all cells representing the lower sand, layers 4 and 5. This oil aquifer provided the energy necessary to maintain the final reservoir pressure at the 6,500 kpa level.

9.7 TRANSMISSIBILITY

Changes to vertical transmissibility were required as a result of the history matching process. Vertical transmissibility was increased in cells containing wells at the time they were fractured to allow flow between the upper and lower sands, layers 2 through 5. Vertical transmissibility windows were opened between layers 1 and 2 for each well at the time of fracturing to allow water influx for water production.

No changes to horizontal transmissibility were included.

9.8 PORE VOLUME

No additional pore volume multipliers were used as a history matching parameters. The original pore volume as established by Tundra remained fixed.

9.9 INACTIVE CELLS

The initialized model contained two areas of lower sand inactive cells in layers 4 and 5 that required modifications. Five cells around 7-28 and 4 cells around 12-28 were inactive based on the maps provided. One of the inactive cells by 7-28 was activated with similar parameters to the surrounding cells. This cell was necessary to finalize a history match with 2-28. The 4 cells around 12-28 were activated with similar parameters to surrounding cells to facilitate the 12-28 history match.

9.10 RESULTS AND DISCUSSION

Individual well history match simulation plots are shown in Figures 9 through 28. In each of these figures, discrete data symbols represents measured data and solid, dashed or stepped lines represents the simulation results. Figure 29 shows the history match injection pressure for 13-21 and Figure 30 shows the history match water injection volumes for 13-21.

The lack of pressure data in this study detracted from the uniqueness of the solution and introduced more degrees of freedom than normal in replicating the history match. Even so, the simulation match to individual well oil rates, GOR and pressure data is good and the Bakken has been successfully history matched using the limited data available.

A number of unsuccessful attempts were made to capture a match.

Pore volume increases over the model area required reserves greater than 10 times the OOIP. Pore volume increases along the northern edge of the model required as much pore volume and substantial permeability increases to get a match. Both of these indicated that oil expansion alone was not the primary drive mechanism. This is not surprising with the low GOR found in the Bakken.

The overlying Lodgepole aquifer, reported the source of water production, was attempted to provide pressure support by means of a dump flood through fractures unintentionally opened. The water preferentially went to the perforations and was produced in almost all cases making this an unlikely option.

With no reported underlying aquifer by Tundra nor any seen on the logs to provide pressure support nor conclusive geological information indicating a larger oil pool nor likelihood of the Lodgepole aquifer maintaining the reservoir pressure, the history match was not possible given the limited data provided. At this point the oil reserves were fixed eliminating one degree of freedom. A boundary edge oil aquifer was added to the lower sand suggesting a thin horizontal extension of the oil leg that was being driven by water forces. Geologically, the sand exists beyond the established pool boundaries, however permeability and porosity are too low for economic rates. The history match suggests the recognized pool is in communication with this extension allowing for influx of oil into the model providing pool pressure support. During the history matching period 38 10^3m^3 oil (8 per cent of the OOIP) influxed into the model.

The history matching process has challenged the initial geological interpretation. This change should be investigated further by Tundra.

Only known fractures were included in the history matching process. Some anomolies exist in this interpretation. Well 16-20 may well have been fractured in mid 1990 but was modeled with the known fracture in 1992. Well 2-28, the hardest well to history match, has no recorded fracture nor was it modeled with any. Water production records indicate 2-28 may have been fractured in early 1990 at the time of a substantial oil rate increase. Well 2-28 has been modeled with 5 per cent water-cut verses the 25 per cent actual water-cut. Additionally, 4-28 has no record of fracture and was not modeled with any. Well 4-28 may have been fractured in early 1991 or mid 1992. Modeled water-cut rates of 5 per cent are lower than the 25 per cent actual rates.

Well 13-21 was converted to an injector in October 1993. The well was successfully history matched as a producer but was unable to sustain the actual injection volumes when converted to an injector. The maximum injection pressure was set at 15,000 kpa as were the PVT tables. Additional permeability modification was required to get the injector to take all the water. Tundra estimates from experience that the fracture pressure is 8,960 kpa wellhead for a 17,500 kpa bottom hole breakdown pressure. This works out to 2 times the original bottom hole pressure. Fracture pressures of as low as 1.5 times the original bottom hole pressure are possible with sands at this depth. Additionally with tight formations, very clean water is required to prevent plugging pore throats, reducing injectivity forcing up bottom hole pressure and increasing the likelihood of a fracture. As a result the 15,000 kpa pressure limit was kept in place for 1.7 times the original reservoir pressure. Reductions in injectivity beyond the history match can be explained by fracturing and water moving out of the oil area possibly into the Lodgepole. There is no way to verify the water movement for the simulation.

X. DISCUSSION OF RESULTS

10.1 GENERAL

This chapter reviews the results of the seven prediction cases and draws some comparisons where warranted. Prediction Case 1 is taken as the reference case or Base Case for making many of the comparisons.

Cases 1 and 2 forecasted Bakken behaviour into the future from the end of the history match. Cases 3 to 6 forecasted Bakken behaviour from the beginning of the history match as well as into the future assuming the field had been developed differently under a variety of operating scenarios. The purpose was to examine the Bakken under these different operating strategies and to identify waterflood potential and the most efficient operating scheme the field could have been developed on. Case 7 forecasted Bakken behaviour into the future with the addition of a horizontal well. This report was designed to answer pool performance questions only. The selection of the optimal operating strategy for the pool also requires an economic analysis of each of the prediction cases. This report does not encompass any economic analysis.

10.2 PREDICTION CASES

The following six prediction cases were simulated:

Case 1 **Base Case.** Continue producing from the end of the history match, February 1, 1994, with the existing wells producing as drilled on 16 hectare well spacing under primary production. Well 13-21 which was converted to an injector in October 1993 is assumed to have not been converted and remained as a producer.

Case 2 Continue producing from the end of the history match as in Case 1 with the existing wells producing on 16 hectare well spacing. Well 13-21 is assumed to be converted to an injector and remained as an injector for the prediction case.

Case 3 Restart the simulation and prediction at the beginning of the history match in October 1985. Half of the original producing wells are shut-in and not produced resulting in an even 32 hectare spacing. Well 13-21 is not converted to an injector and remained as a producer for the duration of the prediction case.

Case 4 Restart the simulation and Prediction at the beginning of the history match as in Case 3 except producers are selected on a technical basis by Tundra. The overall spacing remained at 32 hectares but the well density is increased in the more prolific central and north central areas of the pool while lower quality wells are dropped around the edge.

Case 5 Prediction Case 5 is restarted at the beginning of the history match and is similar to Case 3 with 32 hectare spacing. In Case 5 three wells, 13-21, 15-21 and 5-28, are converted to water injectors on February 1, 1994 for a partial 5 spot injection pattern.

Case 6 Prediction Case 6 is similar to prediction Case 1 with the original 16 hectare well spacing. The Case 6 prediction is restarted at the beginning of the history match. Case 6 forecasts the performance as if the field had been originally developed with a horizontal well. Four of the existing wells are never produced; 5-28, 6-28, 11-28 and 12-28. They are replaced with the horizontal well coming on production in December 1986.

Case 7 Prediction Case 7 is similar to Prediction Case 2. Case 7 commences from 1994 at the end of the history match and assumes a horizontal well is added in the same location as Case 6. It also assumed that the well 13-21 remained an injector while producers 5-28 and 6-28 were shut-in.

10.3 CONSTRAINTS

The six prediction simulation cases were made with a number of parameters in common. The purpose was to allow the results of the cases to be compared under identically controlled conditions wherever possible.

10.3.1 Predicted Period

Prediction Cases 1, 2 and 7 were started effective February 1, 1994 the end of the history matching period. Cases 1 and 2 were reported yearly on the 1st of February for a period of 20 years. Prediction Cases 3 to 6 were started at the beginning of the history matching period October 1, 1985 and were reported at the end of each year through the history matching period and for an additional 20 years.

10.3.2 Minimum Bottom Hole Pressure

At the end of the history matching period, all wells were calibrated to actual bottom hole pressures assuming the wells were continuously pumped off as reported by Tundra. The pressure drop from the model to the well bottom hole pressure was adjusted to give the final rate at the end of the history matching period under pumped off conditions. The wells were recalibrated for prediction Cases 3 through 6 to ensure they produced at the historical values. This required a number of calibration modifications over the history to match the production. This was required under the assumption the wells were continuously pumped off during the history and produced at deliverability. No data was available on this assumption. The wells could have been plugging up over time thus requiring continuous calibration.

The wells in all cases were not constrained by rate limitations. They produced at the minimum bottom hole pressure unable to maintain constant rates and thus continuously declined.

10.3.3 Maximum Bottom Hole Pressure

A maximum bottom hole pressure of 15,000 kPaa was imposed on all water injection wells in the prediction cases where water injection was used. This value was based on 1.7 times the original reservoir pressure of 8,874 kPaa to keep the pressure below Tundra's estimated fracture pressure of 17,500 kPa.

Simulated injection wells were operated at their assigned injection rate unless the flowing bottom hole pressure climbed to the maximum value specified. The injection wells continued to inject after the flowing BHP reaches the maximum, but the injection rates were reduced to maintain the BHP at or below the maximum.

It is possible the 13-21 water injector has fractured into the overlying Lodgepole because of how easily these wells fracture, how close the injection pressure is to the fracture pressure and how tight the formation is. There is no verification of this available so no fractures on injectors were included.

10.3.4 Minimum Oil Well Rate

In the prediction simulations wells were shut-in to reflect abandoned wells.

10.3.5 Maximum Water-Cut

The maximum water cut was specified as 98 per cent. The chosen value reflects the economic limit at which producing wells would be considered watered out and abandoned.

10.3.6 Injection Wells - New Completions

All injection wells were assumed completed in the same layers as previously completed as producers. The horizontal well was assumed completed in layer 4 only.

10.3.7 Facility Constraints

All required oil production, water injection and gas conservation was assumed capable of being handled by the surface facilities. The actual surface facilities now and in the future were not part of this simulation study.

10.4 CASE 1 - BASE CASE

Prediction Case 1 is the base case and is used as a reference for comparing the other cases. This case represents a continuation of the existing operation with wells drilled on 16 hectare well spacing under primary depletion. Well 13-21, which was converted to an injector in October 1993, was assumed to have not been converted and remained as a producer. The wells were not imposed with any rate restrictions and were assumed continuously pumped off and produced at deliverability.

10.4.1 Case 1 Results

Field reserves are tabulated in Table 1. The overall field simulation plots are shown in Figure 31 and presented in Table 13. The individual well plots of prediction Case 1 are presented in Figures 32 through 46. Individual well recoveries at the end of the history match and at the end of the prediction case are listed in Table 2. Layers 2 and 4 pressure distribution maps for the upper middle and lower middle Bakken are shown in Figures 46 and 47.

Over the 20 year prediction period the individual well pressures remained above the bubble point. The field wide pressure shown on Figure 31 and other field plots represents an average of all cells in the model including the aquifer in layer 1 and is of little value. Individual well pressures better represent the pressure response.

By the year 2014 at the end of the prediction period, the pool rate had dropped to 7.9 m^3/day from 15.7 m^3/day at the end of the history match.

After shutting in 10-20 in 1995 because of high water production, the water-cut increased from 40 per cent to 52 per cent by the end of the prediction.

Remaining recoverable oil at the end of the history match, February 1, 1994, was 76 10^3m^3 or 16 per cent of the OOIP. Ultimate oil recovery was 137 10^3m^3 or 29.7 per cent of the OOIP.

10.5 CASE 2

Prediction Case 2 is also a continuation of the existing operation on the original 16 hectare well spacing. Well 13-21 was converted to an injector in October 1993 and remained so for the duration of the prediction. The wells were not imposed with any rate restrictions and were assumed continuously pumped off and produced at deliverability. The intent of this case was to establish the effectiveness of the existing waterflood compared to having developed the field with primary production only.

10.5.1 Case 2 Results

Field reserves are tabulated in Table 1. The overall field simulation plots are shown in Figure 48 and presented in Tables 14 and 15. The individual well plots of prediction Case 2 are presented in Figures 49 through 61. Individual well recoveries at the end of the history match and at the end of the prediction case are listed in Table 2. Figure 62 shows well 13-21 water injection volumes. Layers 2 and 4 pressure distribution maps at the end of the prediction are shown in Figures 63 and 64. Water saturation distribution maps for layers 2 and 4 are shown in Figures 65 and 66.

Over the 20 year prediction period, the individual well pressures stayed above the bubble point.

At the beginning of the prediction period the oil rate was 17.3 m^3/day, 1.6 m^3/day higher than the primary rates in Case 1. Case 2 waterflood oil rates remained above the Case 1 primary rates until the year 2000. By the year 2014 at the end of the prediction period, the pool rate had dropped to 5.6 m^3/day.

After shutting in 10-20 in 1985 because of high water production, the watercut increased from 38 per cent to 79 per cent by the end of the prediction as compared to only 52 per cent watercut for Case 1. No wells were required to be shut-in from high water as a result of the flood.

Remaining recoverable oil at the end of the history match, February 1, 1994, was 72 10^3m^3 or 15.6 per cent of the OOIP. Ultimate oil recovery was 132 10^3m^3 or 29 per cent of the OOIP, slightly less than Case 1 under primary production.

Case 2 shows the conversion of 13-21 to an injector recovered 5.7 10^3m^3 more oil than primary Case 1 by the year 2000. By the end of the prediction period, Case 2 lost the gain and a further 5.0 10^3m^3 compared to Case 1. Initially the rates responded quickly to the flood providing incremental recovery. Ultimately the rates went lower than primary production as the water-cut increased resulting in the reduced recovery. Therefore, the 13-21 injector is only providing rate acceleration.

10.6 CASE 3

Prediction Case 3 was started at the beginning of the history match in October 1985. Half the existing wells were not produced resulting in 32 hectare spacing. Well 13-21 was not converted to an injector and remained a producer.

10.6.1 Case 3 Results

Field reserves are tabulated in Table 1. The overall field simulation plot is shown in Figure 67 and presented in Table 16. The individual well plots of prediction Case 3 are presented in Figures 68 through 77. Individual well recoveries at the end of the history match and at the end of the prediction case are listed in Table 2. Layer 2 and 4 pressure distribution maps at the end of the prediction are shown in Figures 78 and 79.

Over the 20 year prediction period, the individual well pressures stayed above the bubble point.

By the year 2014 at the end of the prediction period the pool rate had dropped to 6 m^3/day.

Wells 11-21 and 5-28 were assumed fractured and shut-in as a result of high water cut as they were in the history match for Cases 1 and 2.

Cases 3 through 6 were compared to the Case 1 total as well as compared to the individual wells from Case 1. This is detailed in Table 2.

At the end of Case 1 history match, February 1 1994, only those wells in Case 1 that were in Case 3 produced 27.6 10^3m^3 oil or 45 per cent of the 61 10^3m^3. At the end of the prediction, the same wells in Case 1 produced approximately the same percentage. This shows the 32 hectare wells selected are a good representation of half the production from the 16 hectare case.

Case 3 resulted in 87.4 10^3m^3 or 18.9 per cent of the OOIP, ultimate recoverable reserves. This falls below the total Case 1 ultimate recoverable of 137 10^3m^3. Only those wells in Case 1 that were in Case 3 predicted 63.5 10^3m^3 ultimate recoverable reserves or 13.8 per cent of the OOIP.

Case 3 increased 32 hectare well spacing results in 64 per cent of the recovery from the 16 hectare spacing Case 1. Case 3 incremental recovery over the same wells in Case 1 is 38 per cent at the end of the prediction.

Although the coarser well spacing results in less overall oil recovery, the average recovery per well increases from 6.85 10^3m^3 per producer for the 16 hectare spacing Case 1 to 8.7 10^3m^3 per producer for the 32 hectare spacing Case 3. Pending economic support, 32 hectare spacing provides more oil recovery than 16 hectare spacing on an individual well basis even though reducing overall field recoveries.

10.7 CASE 4

Prediction Case 4 is similar to Case 3 with the prediction taken from the beginning of the history using 32 hectare well spacing. Well 13-21 was also assumed to remain a producer. Case 4 producers were selected on a technical basis by Tundra. The overall spacing remained at 32 hectares but the well density was increased in the more prolific central and north central areas of the pool while lower quality wells were dropped around the edge.

10.7.1 Case 4 Results

Field reserves are tabulated in Table 1. The overall field simulation plot is shown in Figure 80 and presented in Table 17. The individual well results of prediction Case 4 are presented in Figures 81 through 90. Individual well recoveries at the end of the prediction and at the end of the prediction case are listed in Table 2. Layers 2 and 4 pressure distribution maps at the end of the history match are shown in Figures 91 and 92.

Over the 20 year prediction period, the individual well pressures stayed above the bubble point.

By the year 2014 at the end of the prediction period the pool rate had dropped to 6.4 m^3/day.

Wells 11-21 and 5-28 were assumed fractured and shut-in as a result of high water cut as they were in the history match for Cases 1 and 2.

At the end of the Case 1 history match, February 1 1994, only those wells in Case 1 that were in Case 4 produced 41.7 10^3m^3 oil or 68 per cent of the 61 10^3m^3. At the end of the prediction, the same wells in Case 1 produced approximately the same percentage. This shows the 32 hectare wells selected are better than average.

Case 4 resulted in 105.0 10^3m^3 or 22.8 per cent of the OOIP, ultimate recoverable reserves. This falls below the total Case 1 ultimate recoverable of 137 10^3m^3. Only those wells in Case 1 that were used in Case 4 predicted 92.8 10^3m^3 ultimate recoverable or 20.1 per cent of the OOIP.

Case 4 recognizing increased 32 hectare well spacing with technically preferred wells results in 77 per cent of the oil recovery realized from the 16 hectare spacing in Case 1. Case 4 incremental recovery over the same wells in Case 1 is only 13 per cent verses 38 per cent for Case 3. This illustrates by selecting the better wells a higher overall recovery is obtained but not higher incremental recovery for reduced spacing.

Although the coarser well spacing results in less overall oil recovery, Case 4 shows that the average recovery per well increases from 6.85 10^3m^3 per producer for the 16 hectare spacing Case 1 to 10.50 10^3m^3 per producer for the 32 hectare spacing Case 4. Pending economic support, 32 hectare spacing appears to be more attractive than 16 hectare spacing with higher productivity from individual wells.

10.8 CASE 5

Case 5 represents a waterflood on 32 hectare spacing Case 3. The prediction was started at the beginning of the history match as in Case 3. Three wells, 13-21, 15-21 and 5-28 were converted to injectors on February 1, 1994 for a partial 5 spot injection pattern.

10.8.1 Case 5 Results

Field reserves are tabulated in Table 1. The overall field simulation plot is shown in Figure 93 and presented in Tables 18 and 19. The individual well plots of prediction Case 5 are presented in Figures 94 through 103. Individual well recoveries at the end of the history match and at the end of the prediction case are listed in Table 2. Water injection volumes are shown in Figures 104 through 106. Layers 2 and 4 pressure distribution maps at the end of the prediciton are shown in Figures 107 and 108. Water saturation distribution maps for layers 2 and 4 are shown in Figures 109 and 110.

Over the 20 year prediction period, the individual well pressures stayed above the bubble point.

By the year 2014 at the end of the prediction period the pool rate had dropped to 3.2 m^3/day.

Wells 11-21 and 5-28 were assumed fractured and shut-in as a result of high water cut as they were in the history match for Cases 1 and 2.

Case 5 resulted in 74.8 10^3m^3 or 16.2 per cent of the OOIP, ultimate recoverable reserves. This falls below the 87.4 10^3m^3 or 18.9 per cent of OOIP that was not waterflooded in Case 3. Thus the waterflood results in an overall decrease in recovery.

The waterflood resulted in there being no years where the oil rate under waterflood was higher than the oil rate in Case 3 with no waterflood. The loss of oil production from the best producers in the field when they were used as injectors could not be replaced by flooding lower quality wells.

Case 5 confirms the results of Case 2 and that pending actual field performance from the initial area and economic support, waterflooding should be considered carefully before any expansion is considered.

10.9 CASE 6

Case 6 was similar to prediction Case 1 on the original 16 hectare well spacing. The Case 6 prediction was started at the beginning of the history match. Four of the existing wells were never produced; 5-28, 6-28, 11-28 and 12-28. They were replaced with a horizontal well coming on production in December 1986 the same time as 5-28 went on production. The horizontal well was drilled 650 m from 5-28 to 6-28 with the pump being located at 5-28. Well 13-21 remained a producer as in Case 1.

10.9.1 Case 6 Results

Field reserves are tabulated in Table 1. The overall field simulation plot is shown in Figure 111 and presented in Table 20. The individual well results of prediction Case 6 are presented in Figures 112 through 127. The horizontal well performance is presented in Figure 128 and Table 21. Individual well recoveries at the end of the prediciton and at the end of the prediction case are listed in Table 2. Layer 2 and 4 pressure distribution maps at the end of the history match are presented in Figures 129 and 130.

Over the 20 year prediction period the individual well pressures remained above the bubble point.

Case 6 resulted in 149.7 10^3m^3 or 32 per cent of the OOIP, ultimate recoverable reserves. This is higher than Case 1 which recovered 137.1 10^3m^3 or 30 per cent of the OOIP. Case 6 recovered 12.6 10^3m^3 more oil than Case 1 or 2 per cent of the OOIP.

The horizontal well recovered a total of 39.1 10^3m^3 of oil by the end of the prediction which is 5.5 times greater than the average recovery of a vertical well on 16 hectare spacing. The horizontal well initially produced at 16.5 m^3/day, 2.5 times the combined rate of 5-28 and 6-28. This ratio remained the same for the first year. After 2 years the horizontal well was producing 3.9 times the combined rates of 5-28 and 6-28.

By the year 2014 at the end of the prediction period, the pool rate had dropped to 7.9 m^3/day from 15.7 m^3/day at the end of the history match.

After shutting in 10-20 in 1995 because of high water production, the water-cut increased from 34 per cent to 46 per cent by the end of the prediction.

The horizontal well resulted in increased rates and recoveries for the overall field as compared to the Base Case. Pending economic support, the drilling of a horizontal well is very attractive as the horizontal costs offset up to 5.5 vertical wells. The horizontal well case was the best development of all those considered in this study.

The horizontal well oil production rates are 2.5 to 4 times higher than the combined well rates because of a larger reservoir contact area and because this is a thin reservoir with low permeability.

10.10 CASE 7

Case 7 was similar to Case 2. The prediction period commenced at the end of the history match, February 1994. A horizontal well was drilled in the same location as Case 6 and commenced production at the beginning of the prediction period. Well 13-21 was assumed to remain an injector as in Case 2. In contrast to Case 6, however, the two producers, 5-28 and 6-28, were assumed to have been drilled, hydraulic fracture stimulated, produced during the history period and replaced by the horizontal well during the prediction period.

10.10.1 Case 7 Results

Field reserves are tabulated in Table 1. The overall field simulation plot is shown in Figure 131 and presented in Tables 22 and 23. Individual well results are presented in Figures 132 through 144. Water injection is presented in Figure 145. The horizontal well performance is presented in Figure 146 and Table 24. Individual well recoveries at the end of the prediction period are listed in Table 2. Layers 2 and 4 pressure distribution maps at the end of the prediction are presented in Figures 147 and 148. Layers 2 and 4 water saturation distribution maps at the end of the prediction are presented in Figures 149 and 150.

Case 7 resulted in 153 $10^3 m^3$ or 33 per cent of the OOIP, ultimate recoverable reserves. This is the highest of all cases studied.

The horizontal well recovered a total of 25.9 10^3m^3 of oil by the end of the prediction with only 66 per cent of that recovered by the horizontal well in Case 6. This is mainly a reflection of the drop in the reservoir pressure by the start of the prediction and the increased water production.

The horizontal well watercut in Case 7 increased to 73 per cent and was observed to be significantly higher than the 12 per cent predicted in the Case 6 horizontal well. These elevated levels of water production, compared to Case 6, have been attributed to the communication with the overlying Lodgepole through hydraulic fracture stimulations of wells 5-28 and 6-28 and the water injection into the well 13-21. Wells 10-20 and 4-28 were both subsequently shut-in as a result of high water production.

Pending economic support, the drilling of a horizontal well is a very attractive development. However, the risks of high water production should be considered prior to any horizontal development in the Kola Bakken 'A' Pool where the presence of hydraulically fractured wells could have established communication with the overlying Lodgepole horizon. The vertical wells 5-28 and 6-28 that were replaced by the horizontal well, both watered after fracture stimulations. This suggests there is a high probability that the horizontal well will produce at a high watercut where communication with the Lodgepole has been established.

XI

XI. REPORT PREPARATION

Scientific Software-Intercomp technical staff member responsible for the preparation of this report entitled "***KOLA BAKKEN 'A' POOL OIL FORMATION MANITOBA, RESERVOIR SIMULATION STUDY***" is:

Brien M. Farrell, P. Eng.

Court C. Fortems, P. Eng.
VP Consulting

PERMIT TO PRACTICE
Intercomp Resource Development & Engineering Ltd.,
Operating as Scientific Software-Intercomp
Signature
Date 94/6/16
PERMIT NUMBER: P 510
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

005994

XII. REFERENCES

1. Reservoir Fluid Study Newscope et al Daly 3-28-10-29 W1M, Chemical & Geological Laboratories Ltd., Calgary, 11 February, 1988.

2. Constant Composition Expansion, Tundra Daly 8-32-10-29 W1M, Chemical & Geological Laboratories Ltd., Calgary. Report No. C94-9545, February, 25, 1994.

3. Kola Field Bakken 'A' Pool Pressure Maintenance Application, July 1993; Tundra Oil and Gas Ltd.

4. Tundra Bakken 'A' Pool Relative Permeability Study Well 4-28-10-29 W1M, Hycal Energy Research Laboratories Ltd. Calgary, Alberta 93-028 June 23, 1993.

TABLES

TABLES

TABLE 1

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA - RESERVOIR SIMULATION STUDY

PREDICTION CASE RESERVES

	Case 1 from Feb. 1, 1994 Base Case No Injection	**Case 2** from Feb. 1, 1994 13-21 Injection	**Case 3** from Oct 1, 1985 32 ha Spacing No Injection	**Case 4** from Oct 1, 1985 Upgrade location 32 ha Spacing No Injection	**Case 5** from Oct 1, 1985 32 ha Spacing 3 Injectors	**Case 6** from Oct 1, 1985 Horizontal Well 16 ha Spacing No Injection	**Case 7** from JAN 1, 1994 Horizontal Well 16 ha Spacing 13-21 as Injector
OOIP (E3M3)	461	461	461	461	461	461	461
Cumulative Production to Feb 1, 1994 (E3M3)	61	60	36	45	36	69	60
Cumulative Production to Feb 1, 1994 (% of OOIP)	13%	13%	8%	10%	8%	15%	13%
Incremental Production to Feb 1, 2014 (E3M3)	76	72	51	60	39	81	92
Incremental Production to Feb 1, 2014 (% of OOIP)	16%	16%	11%	13%	8%	18%	20%
Ultimate Recovery to Feb 1, 2014 (E3M3)	137	132	87	105	75	150	152
Ultimate Recovery to Feb 1, 2014 (% of OOIP)	30%	29%	19%	23%	16%	33%	33%

TABLE 2

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA - RESERVOIR SIMULATION STUDY
PREDICTION WELL RESERVES

Well	Case 1 Base Case from Feb. 1, 1994 No Injection		Case 2 from Feb. 1, 1994 13-21 Injection		Case 3 from Oct 1, 1985 - 32 ha spacing: Comparison of Case 1 Well Productions		Case 3 Wells		Case 4 from Oct 1, 1985 - 32 ha spacing Upgraded Locations: Comparison of Case 1 Well Productions		Case 4 Wells	
	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14
8-20	1.7	1.7	1.7	1.7	-	-	-	-	-	-	-	-
9-20	4.4	6.8	4.4	+ 9.6	4.4	6.8	6.4	11.2	4.4	6.8	5.1	7.9
10-20	0.3	0.4	0.3	0.4	-	-	-	-	-	-	-	-
16-20	6.5	17.9	6.5	-15.5	-	-	-	-	6.5	17.9	7.1	19.9
5-21	1.1	3.3	1.1	3.2	1.1	3.3	1.2	2.7	-	-	-	-
10-21	1.0	1.0	1.0	1.0	-	-	-	-	-	-	-	-
11-21	0.7	0.7	0.7	0.7	0.7	0.7	1.1	1.1	0.7	0.7	1.1	1.1
12-21	2.6	7.7	2.6	+13.1	-	-	-	-	-	-	-	-
13-21	11.9	22.1	11.6	11.6	11.9	22.1	14.6	33.6	11.9	22.1	12.0	24.6
14-21	0.7	0.7	0.7	0.7	-	-	-	-	-	-	-	-
15-21	0.3	3.1	0.3	3.4	0.3	3.1	0.3	4.0	0.3	3.1	0.3	3.9
1-28	0.3	4.4	0.3	4.5	0.3	4.4	0.3	5.0	-	-	-	-
2-28	8.3	19.8	8.3	+ 21.7	-	-	-	-	-	-	-	-
3-28	4.8	13.5	4.8	+ 15.0	4.8	13.5	6.8	21.2	4.8	13.5	6.2	18.5
4-28	7.2	16.1	7.2	− 12.1	-	-	-	-	7.2	16.1	7.7	17.6
5-28	1.9	1.9	1.9	1.9	1.9	1.9	2.5	2.5	1.9	1.9	1.9	1.9
6-28	2.2	2.2	2.2	2.2	-	-	-	-	-	-	-	-
11-28	0.8	3.1	0.8	2.9	0.8	3.1	1.0	2.7	-	-	-	-
12-28	2.6	6.1	2.6	6.0	-	-	-	-	2.6	6.1	2.8	6.0
9-29	1.4	4.6	1.4	4.3	1.4	4.6	1.4	3.4	1.4	4.6	1.4	3.5
Horiz. 5-28	-	-	-	-	-	-	-	-	-	-	-	-
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Total	60.7	137.1	60.4	131.5	27.6	63.5	35.6	87.4	41.7	92.8	45.6	104.9
% of OOIP	13%	30%	13%	29%	6%	14%	8%	19%	9%	20%	10%	23%

TABLE 2 Cont'd

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA - RESERVOIR SIMULATION STUDY
PREDICTION WELL RESERVES

	Case 5 from Oct 1, 1985 - 32 ha spacing 3 Injectors				Case 6 from Oct 1, 1985 - 16 ha spacing Horizontal Well				Case 7 from Jan 1, 1994 - 16 ha spacing Horizontal Well	
	Comparison of Case 1 Well Productions		Case 5 Wells		Comparison of Case 1 Well Productions		Case 6 Wells		Comparison of Case 2 Well Productions	Case 7 Wells
Well	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb 1/94	Feb 1/14	Feb1/14	Feb 1/14
8-20	-	-	-	-	1.7	1.7	1.9	1.9	1.7	1.7
9-20	4.4	6.8	6.4	16.3	4.4	6.8	4.6	7.1	9.6	9.6
10-20	-	-	-	-	0.3	0.4	0.4	0.5	0.4	0.4
16-20	-	-			6.5	17.9	6.7	17.4	15.5	15.5
5-21	1.1	3.3	1.2	3.4	1.1	3.3	1.2	3.0	3.2	3.7
10-21	-	-	-	-	1.0	1.0	1.2	1.2	1.0	1.0
11-21	0.7	0.7	1.1	1.1	0.7	0.7	1.1	1.1	0.7	0.7
12-21	-	-	-	-	2.6	7.7	2.4	4.5	13.1	13.1
13-21	11.9	22.1	14.5	14.5	11.9	22.1	11.3	20.6	11.6	11.6
14-21	-	-	-	-	0.7	0.7	0.7	0.7	0.7	0.7
15-21	0.3	3.1	0.3	0.3	0.3	3.1	0.3	2.9	3.4	3.2
1-28	0.3	4.4	0.3	5.6	0.3	4.4	0.3	4.3	4.5	4.4
2-28	-	-	-	-	8.3	19.8	8.3	18.3	21.7	20.1
3-28	4.8	13.5	6.8	24.6	4.8	13.5	4.1	9.4	15.0	12.0
4-28	-	-			7.2	16.1	6.5	14.2	12.1	11.0
5-28	1.9	1.9	2.5	2.5	1.9	1.9	-	-	1.9	1.9
6-28	-	-	-	-	2.2	2.2	-	-	2.2	2.2
11-28	0.8	3.1	1.0	2.8	0.8	3.1	-	-	2.9	2.9
12-28	-	-			2.6	6.1	-	-	6.0	5.9
9-29	1.4	4.6	1.4	3.7	1.4	4.6	1.2	3.5	4.3	4.6
Horiz. 5-28	-	-	-	-	-	-	16.8	39.1	-	25.9
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Total	27.6	63.5	35.5	74.8	60.7	137.1	69.0	149.7	131.5	152.1
% of OOIP	6%	14%	8%	16%	13%	30%	15%	32%	29%	33%

TABLE 3

KOLA BAKKEN 'A' POOL OIL FORMATION, MANITOBA

RESERVOIR SIMULATION STUDY

HYDROCARBON OIL PROPERTIES

PRES kPag	GOR m^3/m^3	μO CP	BO Rm^3/Sm^3
.0	.00	3.6500	1.0000
750.0	4.65	3.3811	1.0150
1500.0	10.72	3.0696	1.0350
2250.0	17.47	2.7264	1.0530
2376.0	18.65	2.6901	1.0549
3000.0	24.71	2.4034	1.0709
3750.0	32.33	2.1592	1.0916
4500.0	40.27	1.9790	1.1138
5250.0	48.49	1.8184	1.1373
6000.0	56.95	1.6706	1.1620
6750.0	65.63	1.5361	1.1879
7500.0	74.51	1.4151	1.2149
8250.0	83.58	1.3070	1.2429
9000.0	92.82	1.2107	1.2718
9750.0	102.22	1.1250	1.3018
10500.0	111.76	1.0484	1.3326
11250.0	121.45	.9797	1.3642
12000.0	131.27	.9180	1.3967
12750.0	141.22	.8621	1.4300
13500.0	151.29	.8114	1.4641
14250.0	161.47	.7652	1.4989
15000.0	171.76	.7228	1.5345

TABLE 4

KOLA BAKKEN 'A' POOL OIL FORMATION, MANITOBA

RESERVOIR SIMULATION STUDY

HYDROCARBON GAS PROPERTIES

PRES kPaa	BG Rm^3/Sm^3	VISG CP
.0	.35000	.01015
750.0	.13762	.01019
1500.0	.06636	.01035
2250.0	.04256	.01055
2376.0	.04003	.01059
3000.0	.03063	.01081
3750.0	.02346	.01114
4500.0	.01866	.01155
5250.0	.01522	.01205
6000.0	.01265	.01267
6750.0	.01067	.01345
7500.0	.00911	.01440
8250.0	.00788	.01556
9000.0	.00690	.01694
9750.0	.00615	.01851
10500.0	.00556	.02023
11250.0	.00511	.02202
12000.0	.00476	.02382
12750.0	.00449	.02557
13500.0	.00428	.02725
14250.0	.00411	.02883
15000.0	.00397	.03033

TABLE 5

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA
RESERVOIR SIMULATION STUDY

WATER-OIL RELATIVE PERMEABILITY

End Points

Swi	=	0.5780
Sor	=	0.1980
Krocw	=	0.1445
Krwro	=	0.0312

Sw	Krw	Kro	Cap Pres. kPa
0.5780	0.0000	0.1445	20.690
0.5890	0.0007	0.1243	11.760
0.6010	0.0018	0.1060	7.289
0.6120	0.0029	0.0897	5.511
0.6230	0.0042	0.0751	4.519
0.6340	0.0055	0.0621	3.874
0.6460	0.0069	0.0508	3.417
0.6570	0.0084	0.0409	3.072
0.6680	0.0100	0.0324	2.802
0.6790	0.0115	0.0252	2.583
0.6910	0.0131	0.0191	2.402
0.7020	0.0148	0.0141	2.249
0.7130	0.0165	0.0101	2.118
0.7240	0.0182	0.0069	2.005
0.7360	0.0200	0.0045	1.905
0.7470	0.0218	0.0027	1.816
0.7580	0.0236	0.0015	1.737
0.7690	0.0255	0.0007	1.666
0.7810	0.0273	0.0003	1.630
0.8030	0.0312	0.0000	1.503
1.0000	1.0000	0.0000	1.000

relative to air premeability

TABLE 6

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA
RESERVOIR SIMULATION STUDY

GAS-OIL RELATIVE PERMEABILITY

End Points

SLR = 0.7750
Sgc = 0.0000
Kro = 0.1445
Krg = 0.9999

Liquid Saturation SL	Kro	Krg
0.7750	0.0000	1.0000
0.7862	0.000001	0.9002
0.7975	0.000014	0.8019
0.8088	0.000073	0.7062
0.8200	0.0002	0.6144
0.8313	0.0006	0.5273
0.8425	0.0012	0.4459
0.8538	0.0022	0.3707
0.8650	0.0037	0.3024
0.8763	0.0059	0.2412
0.8875	0.0090	0.1875
0.8988	0.0132	0.1412
0.9100	0.0187	0.1024
0.9213	0.0258	0.0707
0.9325	0.0347	0.0459
0.9438	0.0457	0.0273
0.9550	0.0592	0.0144
0.9663	0.0755	0.0062
0.9775	0.0948	0.0019
0.9888	0.1177	0.0002
1.0000	0.1445	0.0000

FIGURE 7

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA
RESERVOIR SIMULATION STUDY

PRESSURE DATA

Well	Test	Date	Pressure kPa (Abs)	KB m	Test Depth m KB	Test Depth m SS	341 m SS Datum Pressure kPa (Abs)	
13-21	DST	29-Sep-85	8,853	537.1	875.5	338.4	8874.4	(1)
16-17	DST	19-Mar-86	11,239	?	906.5	?	?	(2)
5-21	DST	5-Dec-87	8,460	536.8	881.6	344.8	8428.7	
9-29	DST	28-Nov-87	8,458	537.2	868.2	331.0	8540.4	
16-20	AWS	27-May-92	5,968	537.7	882.0	344.3	5940.4	
4-28	AWS	9-Jul-92	4,296	536.7	878.0	341.3	4293.6	(3)
6-28	AWS	13-Jul-92	6,091	534.6	868.0	333.4	6153.6	
11-28	AWS	31-Aug-92	6,451	534.0	867.0	333.0	6516.9	
15-21	DST	13-Feb-93	6,411	533.5	866.7	333.2	6475.3	
16-29	DST	22-Feb-93	7,271	535.7	867.8	332.1	7344.3	(2)
1-32	DST	3-Oct-93	7,716	536.5	869.2	332.7	7784.4	(2)

gradients:	16-20	8.35	kPa/m	
	4-28	8.14	kPa/m	
	6-28	8.24	kPa/m	
	11-28	8.24	kPa/m	
	others	8.24	kPa/m	(at average)

Notes:

(1) Original reservoir pressure. Based on SI after 5 min flow and grossed up by 2 % based on 5-21 analysis and at datum of top of the perfs (top of lower middle zone).

(2) Outside study area.

(3) Insufficient buildup. Unusable data.

TABLE 8

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA

RESERVOIR SIMULATION STUDY

COMPLETION SUMMARY

Well	Upper Middle Layer 2	Middle Middle Layer 3	Upper Lower Middle Layer 4	Lower Lower Middle Layer5	Fractures	Model cell x	Model Cell y
8-20			yes	yes	On initial completion	7	16
9-20			yes	yes	July 1986	7	13
10-20	yes		yes		On initial completion	4	13
16-20			yes	yes	June 1992	7	10
5-21			yes	yes	On initial completion	10	16
10-21			yes	yes		16	13
11-21		yes	yes	yes	On initial completion	13	13
12-21			yes	yes	On initial completion	10	13
13-21			yes	yes		10	10
14-21			yes	yes	Fractured and shut-in	13	10
15-21	yes	yes	yes	yes		16	10
1-28	yes	yes	yes	yes		20	7
2-28			yes	yes		16	7
3-28			yes	yes		13	7
4-28			yes	yes		10	7
5-28			yes	yes	On initial completion	10	4
6-28			yes	yes	Fractured and shut-in	13	4
11-28	yes	yes	yes	yes	January 1993	13	1
12-28			yes	yes	On initial completion	10	1
8-29			yes	yes	December 1987	7	4
9-29			yes	yes	On initial completion	7	1

TABLE 9

KX ARRAY : X-DIRECTION PERMEABILITIES : (MD)

LAYER 2

Y-DIR	1	2	3	4	5	6	7	8	9	10
1					13.4598	10.8778	7.9064	4.6277	2.6262	1.7612
2					11.3761	9.3156	6.9817	4.6369	3.0396	2.2496
3					9.6961	8.0356	6.2561	4.6294	3.5140	2.7925
4					8.1988	6.9053	5.5432	4.3211	3.5160	2.9665
5						5.9693	4.8265	3.6492	2.6749	1.9075
6								3.2256	2.1115	1.3798
7										
8										
9						6.3281				
10					6.6198	7.3184	7.3382	6.1620		
11			8.0151	7.9834	8.1795	8.1560	7.6481	6.7368	5.9574	5.5181
12		10.8807	10.5417	10.2460	9.2971	8.0558	7.0040	6.7791	7.2701	7.8106
13		11.4580	10.8867	10.1039	8.2688	6.4823	5.4145	6.0415	8.1074	11.2074
14		9.1494	8.0835	7.0211	5.6718	4.5309	4.0799	4.7369	6.6020	8.4769
15		5.7967	4.8428	4.0796	3.3595	2.8339	2.7353	3.2600	4.3621	5.3272
16		3.1681	2.6108	2.2064	1.8846	1.6805	5.0000			5.0000
17	1.9881	1.5975	1.3499	1.1798	1.0698					
18	.9037	.7767	.6910	.6384						
19	.4022	.3719	.3526							
20		.1752	.1767							

LAYER 2

Y-DIR	11	12	13	14	15	16	17	18	19	20	21	22
1	1.9316	2.6915	3.8196	4.7116	5.5978							
2	2.0968	2.3475	2.8900	3.5898	4.5431							
3	2.1587	1.9293	2.1132	2.6314								
4	1.8812	1.4436										
5	1.3028											
6							6.4967	10.3148	15.4380	20.9023	25.6169	30.8570
7				1.8272	2.7676	4.1971	6.1056	8.4979	11.4310	14.1968	16.1672	18.5439
8			2.1813	2.7940	3.6531	4.6420	5.5345	6.3257	7.2232	8.1991	9.1223	10.2924
9		3.1556	3.7615	4.2943	4.7955	5.0816	4.8978	4.5422	4.4245	4.6856		
10	4.0357	4.5520	5.3385	5.4902	5.5285	5.1904	4.2691	3.4053				
11	5.2677	5.1873	5.2835	5.3275	5.1718	4.5845	3.6547					
12	6.7105	5.2048	4.3823	4.3167	4.2354	3.7991	3.1088					
13	8.0200	4.9845	3.5474	3.4477	3.4331	3.1711	2.6889					
14	6.8563	4.6288	3.4594	3.1313	3.0077	2.7756	2.4086					
15	5.0298	4.0898	3.3864	3.0384	2.8224	2.5656						
16		3.5261										
17												
18												
19												
20												

TABLE 10

KX ARRAY : X-DIRECTION PERMEABILITIES : (MD)

LAYER 4

Y-DIR \ X-DIR	1	2	3	4	5	6	7	8	9	10
1						43.5900	33.5500	27.3800	20.0000	20.0000
2					22.2200	28.0400	29.5700	30.8400	20.0000	20.0000
3				3.5300	8.5400	15.5800	22.5500	33.0300	52.2100	70.2600
4					2.3400	6.4900	13.6700	29.9200	69.2200	137.5100
5						2.1300	8.0900	24.9100	60.6000	102.4500
6							6.3100	28.7800	64.7600	85.2300
7								75.2000	151.4100	131.3700
8							118.4100	251.0000	251.0000	251.0000
9						7.0000	583.4700	251.0000	251.0000	251.0000
10				.0000	.1000	19.9500	251.0000	251.0000	251.0000	1551.6000
11			.1000	.1000	.1000	44.3000	251.0000	251.0000	251.0000	123.4600
12			.1000	.4400	2.7400	51.5100	212.1000	405.7500	218.4000	118.9400
13		3.6800	13.1900	37.2600	33.7000	70.2000	334.6200	80.7900	59.6400	399.0400
14		22.3800	22.3800	22.3800	22.3800	88.2900	85.8000	41.0100	31.8800	36.0600
15		22.3800	22.3800	22.3800	44.7600	60.9400	29.6000	24.9400	28.7400	17.9900
16	22.3800	22.3800	22.3800	22.3800	44.7600	48.6200	27.1800	23.8800	27.7000	18.0000
17	15.8500	15.8500	15.8500	15.8500	31.7000	36.0800	23.0800	20.7000	23.2200	14.0400
18	15.8500	15.8500	15.8500	15.8500	31.7000	26.4000	18.3000	16.4600	17.6600	10.1200
19		15.8500	15.8500	15.8500	15.8500	9.3800	6.7500	6.0200	6.2400	
20			15.8500	15.8500	15.8500	6.0100	4.4100	3.9400		

LAYER 4

Y-DIR \ X-DIR	11	12	13	14	15	16	17	18	19	20	21	22
1	17.1200	4.3800	4.5795	41.4000	55.8000	45.6000	46.2000	57.0000	26.8000	20.2000	31.4000	49.7000
2	20.9500	12.0700	38.9400	52.3500	61.2000	43.8000	41.7000	51.0000	24.4000	18.8500	29.9500	48.3000
3	55.5000	33.3700	54.1200	378.4500	362.7000	225.0000	201.6000	251.1000	42.0000	33.9000	55.3500	90.9000
4	106.3400	67.6500	119.6100	150.6600	540.0000			158.7600	14.0200	11.7600	19.5500	32.4100
5	103.0400	77.8400	141.8100	195.1200	170.8200			124.3800	22.7200	19.3600	32.1500	53.1400
6	86.5700	69.3700	131.3100	199.7100	202.5000	203.0400	135.3600	94.4100	17.3500	14.6650	23.9750	39.2900
7	98.1500	63.8500	169.2900	178.9200	211.3200	248.6700	182.5200	131.2200	23.9900	19.9450	32.0750	52.2100
8	121.5300	56.0400	86.9700	147.7800	203.4000	277.5600	223.7400	166.0500	29.9700	24.4300	39.0750	63.1550
9	102.9200	43.0300	66.2700	123.8400	96.5700	97.9200	128.1600	197.5500	35.5700	28.2750	44.4300	70.6000
10	67.2600	32.7900	56.3100	38.6700	32.1300	34.1700	46.5600	73.4700	39.7100	30.7300	47.2000	
11	50.6000	29.5200	58.2900	41.5800	34.6500	36.5100	48.7200	74.9100	39.6600	30.6350		
12	75.8800	29.1700	68.2500	49.1100	38.8200	38.3700	49.0500	72.5700	37.3800	28.6000		
13	52.8800	28.3400	40.3200	19.3400	14.3600	26.0000	16.2900	23.2200	34.6100			
14	44.5000	25.9400	25.3600	20.3100	15.9500	14.6300	17.0100					
15	21.4600	23.4800	22.7000	19.6100	16.8000							
16	19.8900	20.4200	19.5900									
17	15.7400											
18												
19												
20												

TABLE 11

PHI ARRAY : GRID BLOCK POROSITIES : (FRACTION)

LAYER 2

Y-DIR \ X-DIR	1	2	3	4	5	6	7	8	9	10
1					.1876	.1846	.1799	.1722	.1640	.1582
2					.1852	.1823	.1781	.1722	.1661	.1617
3					.1829	.1802	.1765	.1722	.1682	.1649
4					.1805	.1780	.1748	.1712	.1682	.1657
5						.1759	.1728	.1687	.1642	.1593
6								.1670	.1608	.1547
7										
8										
9						.1767				
10					.1774	.1788	.1789	.1763		
11			.1801	.1801	.1804	.1804	.1795	.1776	.1758	.1747
12		.1846	.1841	.1837	.1823	.1802	.1782	.1777	.1787	.1798
13		.1853	.1846	.1835	.1806	.1771	.1745	.1760	.1803	.1850
14		.1820	.1803	.1782	.1751	.1719	.1704	.1725	.1773	.1809
15		.1754	.1728	.1704	.1675	.1651	.1646	.1671	.1713	.1742
16		.1667	.1639	.1615	.1592	.1575	.1600			.1500
17	.1599	.1568	.1543	.1524	.1510					
18	.1485	.1463	.1446	.1435						
19	.1368	.1357	.1349							
20		.1248	.1249							

LAYER 2

Y-DIR \ X-DIR	11	12	13	14	15	16	17	18	19	20	21	22
1	.1595	.1643	.1694	.1724	.1749							
2	.1607	.1624	.1654	.1685	.1719							
3	.1611	.1595	.1608	.1640								
4	.1591	.1553										
5	.1538											
6							.1771	.1838	.1896	.1940	.1970	.1996
7				.1587	.1647	.1708	.1762	.1810	.1853	.1884	.1903	.1923
8			.1613	.1649	.1688	.1722	.1748	.1767	.1786	.1805	.1820	.1838
9		.1666	.1692	.1711	.1727	.1735	.1730	.1719	.1715	.1724		
10	.1702	.1719	.1742	.1747	.1748	.1738	.1710	.1677				
11	.1741	.1738	.1741	.1742	.1738	.1720	.1688					
12	.1776	.1739	.1714	.1712	.1709	.1693	.1664					
13	.1801	.1733	.1683	.1679	.1679	.1667	.1643					
14	.1779	.1722	.1680	.1665	.1659	.1648	.1627					
15	.1734	.1704	.1677	.1661	.1650	.1636						
16		.1682										
17												
18												
19												
20												

TABLE 12

PHI ARRAY : GRID BLOCK POROSITIES : (FRACTION)

LAYER 4

Y-DIR \ X-DIR	1	2	3	4	5	6	7	8	9	10
1						.2046	.2009	.1979	.2000	.2000
2					.1949	.1983	.1990	.1996	.2000	.2000
3				.1683	.1810	.1898	.1951	.2006	.2073	.2116
4					.1623	.1771	.1879	.1992	.2113	.2213
5						.1610	.1803	.1965	.2094	.2170
6							.1767	.1986	.2104	.2144
7								.2125	.2227	.2206
8							.2032	.2300	.2300	.2300
9						.1549	.2263	.2300	.2300	.2300
10				.0029	.0800	.1700	.2300	.2300	.2300	.2272
11			.0273	.0604	.1170	.1816	.2300	.2300	.2300	.2197
12			.1126	.1380	.1646	.1912	.2116	.2210	.2179	.2091
13		.1689	.1873	.2024	.2009	.1956	.1923	.1977	.1991	.1966
14		.1950	.1950	.1950	.1950	.1990	.1885	.1879	.1901	.1919
15		.1950	.1950	.1950	.1950	.1995	.1890	.1865	.1886	.1918
16	.1950	.1950	.1950	.1950	.1950	.1962	.1878	.1859	.1881	.1918
17	.1900	.1900	.1900	.1900	.1900	.1919	.1854	.1838	.1855	.1883
18	.1900	.1900	.1900	.1900	.1900	.1874	.1820	.1805	.1815	.1835
19		.1900	.1900	.1900	.1900	.1824	.1776	.1760	.1765	
20			.1900	.1900	.1900	.1760	.1715	.1698		

LAYER 4

Y-DIR \ X-DIR	11	12	13	14	15	16	17	18	19	20	21	22
1	.1811	.1714	.1620	.1547	.1490	.1459	.1461	.1492	.1542	.1602	.1666	.1732
2	.1940	.1861	.1771	.1681	.1603	.1555	.1548	.1577	.1629	.1692	.1759	.1828
3	.2081	.2008	.1919	.1808	.1702	.1632	.1617	.1649	.1708	.1777	.1848	.1920
4	.2176	.2110	.2034	.1908	.1850			.1715	.1782	.1857	.1930	.2004
5	.2171	.2130	.2058	.1945	.1826			.1780	.1852	.1929	.2002	.2075
6	.2146	.2114	.2047	.1949	.1850	.1792	.1792	.1840	.1913	.1989	.2060	.2132
7	.2164	.2102	.2025	.1933	.1857	.1821	.1835	.1888	.1960	.2034	.2102	.2173
8	.2195	.2083	.1987	.1905	.1851	.1837	.1865	.1922	.1992	.2063	.2131	.2200
9	.2171	.2045	.1948	.1880	.1844	.1846	.1884	.1947	.2017	.2084	.2150	.2217
10	.2109	.2005	.1925	.1870	.1843	.1852	.1897	.1963	.2033	.2096	.2158	
11	.2068	.1990	.1930	.1881	.1854	.1862	.1904	.1966	.2033	.2096		
12	.2026	.1988	.1952	.1905	.1871	.1869	.1904	.1961	.2024	.2086		
13	.1974	.1984	.1976	.1929	.1886	.1871	.1904	.1955	.2013			
14	.1949	.1971	.1968	.1936	.1901	.1888	.1910					
15	.1944	.1957	.1952	.1931	.1908							
16	.1933	.1937	.1931									
17	.1899											
18												
19												
20												

TABLE 13

```
*****************************************************************************************************************)
(                     ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c  ))
( W o r k B e n c h   )                                                                                 (  S o f t w a r e  -   ))
(                     )                    FIELD PERFORMANCE - CASE 1                                   (  I n t e r c o m p     ))
*****************************************************************************************************************)
```

Project/Case: Case 1 BASE CASE PREDICTION

TOTAL FIELD

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
114	1FEB1994	3318.0	15.7	60.7	.3	1.1	18.6	22.6	32.9	.5894
126	1FEB1995	3683.0	14.1	66.1	.3	1.2	18.6	23.4	41.3	.6239
138	1FEB1996	4048.0	13.2	71.0	.2	1.3	18.6	9.0	45.9	.4048
150	1FEB1997	4414.0	12.7	75.7	.2	1.4	18.6	9.2	49.2	.4220
162	1FEB1998	4779.0	12.1	80.2	.2	1.5	18.6	9.4	52.6	.4351
174	1FEB1999	5144.0	11.7	84.6	.2	1.6	18.6	9.4	56.1	.4460
186	1FEB2000	5509.0	11.3	88.8	.2	1.7	18.6	9.5	59.5	.4553
198	1FEB2001	5875.0	11.0	92.9	.2	1.7	18.6	9.5	63.0	.4636
210	1FEB2002	6240.0	10.6	96.8	.2	1.8	18.6	9.5	66.4	.4711
222	1FEB2003	6605.0	10.3	100.6	.2	1.9	18.6	9.4	69.9	.4780
234	1FEB2004	6970.0	10.0	104.3	.2	1.9	18.6	9.4	73.3	.4841
246	1FEB2005	7336.0	9.8	107.9	.2	2.0	18.6	9.4	76.7	.4898
258	1FEB2006	7701.0	9.5	111.4	.2	2.1	18.6	9.3	80.2	.4950
270	1FEB2007	8066.0	9.3	114.9	.2	2.1	18.6	9.3	83.5	.4998
282	1FEB2008	8431.0	9.0	118.2	.2	2.2	18.6	9.2	86.9	.5037
294	1FEB2009	8797.0	8.8	121.5	.2	2.3	18.6	9.1	90.3	.5071
306	1FEB2010	9162.0	8.6	124.6	.2	2.3	18.6	9.0	93.6	.5106
318	1FEB2011	9527.0	8.4	127.8	.2	2.4	18.6	8.9	96.8	.5137
330	1FEB2012	9892.0	8.2	130.8	.2	2.4	18.6	8.8	100.0	.5167
342	1FEB2013	10258.0	8.1	133.8	.2	2.5	18.6	8.7	103.2	.5201
354	31JAN2014	10622.0	7.9	136.7	.1	2.5	18.6	8.6	106.4	.5229

TABLE 14

WorkBench — Field Production And Injection Report — (Scientific Software - Intercomp)

FIELD PERFORMANCE - CASE 2

Project/Case: Case 2 WITH 13-21 INJECTOR

TOTAL FIELD

Time Step Number	Date	Cumulative Time DAYS	Oil Production Rate STM3/D	Oil Production Cumulative KSTM3	Gas Production Rate KSM3/D	Gas Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Water Production Rate STM3/D	Water Production Cumulative KSTM3	Water Cut FRACTION
115	1FEB1994	3318.0	17.8	60.5	.3	1.1	18.6	26.0	32.8	.5932
127	1FEB1995	3683.0	18.1	67.1	.3	1.3	18.6	23.8	41.6	.5673
139	1FEB1996	4048.0	16.5	73.4	.3	1.4	18.6	10.2	45.9	.3834
151	1FEB1997	4414.0	14.9	79.1	.3	1.5	18.6	11.9	50.0	.4452
163	1FEB1998	4779.0	13.4	84.2	.2	1.6	18.6	13.5	54.7	.5020
175	1FEB1999	5144.0	12.1	88.8	.2	1.7	18.6	14.7	59.8	.5487
187	1FEB2000	5509.0	11.1	93.0	.2	1.7	18.6	15.7	65.4	.5870
199	1FEB2001	5875.0	10.2	96.9	.2	1.8	18.6	16.6	71.4	.6186
211	1FEB2002	6240.0	9.5	100.5	.2	1.9	18.6	17.3	77.5	.6448
223	1FEB2003	6605.0	8.9	103.8	.2	1.9	18.6	17.8	84.0	.6667
235	1FEB2004	6970.0	8.4	107.0	.2	2.0	18.6	18.3	90.6	.6856
247	1FEB2005	7336.0	8.0	110.0	.1	2.1	18.6	18.7	97.4	.7020
259	1FEB2006	7701.0	7.6	112.8	.1	2.1	18.6	19.1	104.3	.7163
271	1FEB2007	8066.0	7.2	115.5	.1	2.2	18.6	19.5	111.3	.7291
283	1FEB2008	8431.0	6.9	118.1	.1	2.2	18.6	19.8	118.5	.7404
295	1FEB2009	8797.0	6.6	120.6	.1	2.2	18.6	20.0	125.8	.7511
307	1FEB2010	9162.0	6.4	122.9	.1	2.3	18.6	20.3	133.2	.7606
319	1FEB2011	9527.0	6.2	125.2	.1	2.3	18.6	20.4	140.6	.7686
331	1FEB2012	9892.0	6.0	127.4	.1	2.4	18.6	20.6	148.1	.7758
343	1FEB2013	10258.0	5.8	129.6	.1	2.4	18.6	20.7	155.6	.7822
355	31JAN2014	10622.0	5.6	131.6	.1	2.5	18.6	20.8	163.2	.7878

TABLE 15

WorkBench — Field Production And Injection Report — Scientific Software - Intercomp

FIELD PERFORMANCE - CASE 2

Project/Case: Case 2 WITH 13-21 INJECTOR

TOTAL FIELD

Time Step Number	Date	Cumulative Time DAYS	Gas Injection Rate KSM3/D	Gas Injection Cumulative KKSM3	Water Injection Rate STM3/D	Water Injection Cumulative KSTM3	Average Pressure KPA	Oil Recovery (CUM/OOV) FRACTION	Gas Recovery (CUM/OGV) FRACTION
115	1FEB1994	3318.0	.0	.0	20.0	2.4	7627.0	.1312	.1312
127	1FEB1995	3683.0	.0	.0	19.2	9.4	7355.7	.1456	.1456
139	1FEB1996	4048.0	.0	.0	18.9	16.4	7427.1	.1592	.1592
151	1FEB1997	4414.0	.0	.0	18.7	23.3	7413.8	.1716	.1716
163	1FEB1998	4779.0	.0	.0	18.6	30.1	7366.0	.1827	.1827
175	1FEB1999	5144.0	.0	.0	18.4	36.8	7313.2	.1927	.1927
187	1FEB2000	5509.0	.0	.0	18.3	43.5	7259.8	.2019	.2019
199	1FEB2001	5875.0	.0	.0	18.2	50.2	7206.7	.2103	.2103
211	1FEB2002	6240.0	.0	.0	18.1	56.8	7155.1	.2181	.2181
223	1FEB2003	6605.0	.0	.0	18.0	63.4	7104.5	.2253	.2253
235	1FEB2004	6970.0	.0	.0	18.0	69.9	7055.3	.2322	.2322
247	1FEB2005	7336.0	.0	.0	18.0	76.5	7007.4	.2386	.2386
259	1FEB2006	7701.0	.0	.0	18.0	83.1	6960.0	.2448	.2448
271	1FEB2007	8066.0	.0	.0	18.0	89.6	6913.0	.2506	.2506
283	1FEB2008	8431.0	.0	.0	18.0	96.2	6866.8	.2562	.2562
295	1FEB2009	8797.0	.0	.0	18.1	102.8	6821.4	.2616	.2616
307	1FEB2010	9162.0	.0	.0	18.1	109.4	6776.9	.2668	.2668
319	1FEB2011	9527.0	.0	.0	18.1	116.0	6733.2	.2717	.2717
331	1FEB2012	9892.0	.0	.0	18.2	122.6	6690.4	.2765	.2765
343	1FEB2013	10258.0	.0	.0	18.2	129.3	6648.1	.2811	.2811
355	31JAN2014	10622.0	.0	.0	18.2	135.9	6606.4	.2856	.2856

TABLE 16

```
****************************************************************************************************
(                   ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c ))
( W o r k B e n c h )                                                                             (  S o f t w a r e -   ))
(                   )                  FIELD PERFORMANCE - CASE 3                                 (  I n t e r c o m p    ))
****************************************************************************************************
```

Project/Case: CASE 3 32 HECTARE SPACING NO INJECTOR

TOTAL FIELD

Time Step Number	Time Step Date	Cumulative Time DAYS	Oil Production Rate STM3/D	Oil Production Cumulative KSTM3	Gas Production Rate KSM3/D	Gas Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Water Production Rate STM3/D	Water Production Cumulative KSTM3	Water Cut FRACTION
13	31OCT1985	303.0	.0	.0	.0	.0	.0	.0	.0	.0000
15	31DEC1985	364.0	9.1	.6	.2	.0	18.6	.0	.0	.0025
27	31DEC1986	729.0	16.0	5.7	.3	.1	18.6	41.6	6.6	.7222
41	31DEC1987	1094.0	20.5	11.0	.4	.2	18.6	3.9	12.1	.1587
53	31DEC1988	1460.0	12.8	16.6	.2	.3	18.6	6.3	14.1	.3294
65	31DEC1989	1825.0	11.2	20.9	.2	.4	18.6	6.9	16.6	.3814
77	31DEC1990	2190.0	10.4	24.8	.2	.5	18.6	7.2	19.2	.4085
89	31DEC1991	2555.0	9.7	28.4	.2	.5	18.6	7.3	21.8	.4310
101	31DEC1992	2921.0	8.0	31.6	.1	.6	18.6	1.6	24.0	.1653
113	31DEC1993	3286.0	9.1	35.3	.2	.7	18.6	2.6	24.8	.2240
114	31JAN1994	3317.0	9.0	35.6	.2	.7	18.6	2.7	24.8	.2283
126	1JAN1995	3652.0	8.6	38.5	.2	.7	18.6	3.0	25.8	.2586
138	1JAN1996	4017.0	8.2	41.6	.2	.8	18.6	3.1	26.9	.2757
150	1JAN1997	4383.0	8.0	44.6	.1	.8	18.6	3.2	28.1	.2873
162	1JAN1998	4748.0	7.8	47.4	.1	.9	18.6	3.3	29.3	.2964
174	1JAN1999	5113.0	7.6	50.3	.1	.9	18.6	3.3	30.5	.3040
186	1JAN2000	5478.0	7.5	53.0	.1	1.0	18.6	3.4	31.7	.3107
198	1JAN2001	5844.0	7.3	55.7	.1	1.0	18.6	3.4	33.0	.3164
210	1JAN2002	6209.0	7.2	58.4	.1	1.1	18.6	3.4	34.2	.3216
222	1JAN2003	6574.0	7.1	61.0	.1	1.1	18.6	3.4	35.5	.3263
234	1JAN2004	6939.0	7.0	63.6	.1	1.2	18.6	3.4	36.7	.3305
246	1JAN2005	7305.0	6.9	66.1	.1	1.2	18.6	3.4	38.0	.3345
258	1JAN2006	7670.0	6.8	68.6	.1	1.3	18.6	3.5	39.2	.3383
270	1JAN2007	8035.0	6.6	71.0	.1	1.3	18.6	3.5	40.5	.3418
282	1JAN2008	8400.0	6.6	73.4	.1	1.4	18.6	3.5	41.8	.3450
294	1JAN2009	8766.0	6.5	75.8	.1	1.4	18.6	3.4	43.0	.3482
306	1JAN2010	9131.0	6.4	78.1	.1	1.5	18.6	3.4	44.3	.3512
318	1JAN2011	9496.0	6.3	80.4	.1	1.5	18.6	3.4	45.5	.3540
330	1JAN2012	9861.0	6.2	82.7	.1	1.5	18.6	3.4	46.8	.3568
342	1JAN2013	10227.0	6.1	85.0	.1	1.6	18.6	3.4	48.0	.3596
354	1JAN2014	10592.0	6.0	87.2	.1	1.6	18.6	3.4	49.3	.3623
355	31JAN2014	10622.0	6.0	87.4	.1	1.6	18.6	3.4	49.4	.3625

TABLE 17

```
*****************************************************************************************************************)
(                 ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c  ))
( W o r k B e n c h )                                                                             (  S o f t w a r e  -  ))
(                 )                    FIELD PERFORMANCE - CASE 4                               (  I n t e r c o m p  ))
*****************************************************************************************************************)
```

Project/Case: CASE 4 32 HECTARE SPACING AND HIGHGRADE LOCATIONS TOTAL FIELD

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
13	31OCT1985	303.0	.0	.0	.0	.0	.0	.0	.0	.0000
15	31DEC1985	364.0	9.1	.6	.2	.0	18.6	.0	.0	.0025
28	31DEC1986	729.0	21.8	7.0	.4	.1	18.6	41.7	6.5	.6561
42	31DEC1987	1094.0	28.4	15.0	.5	.3	18.6	5.1	12.3	.1519
54	31DEC1988	1460.0	15.9	22.2	.3	.4	18.6	7.8	14.8	.3279
66	31DEC1989	1825.0	13.7	27.5	.3	.5	18.6	8.4	17.8	.3802
78	31DEC1990	2190.0	11.7	31.9	.2	.6	18.6	8.5	20.9	.4223
90	31DEC1991	2555.0	10.9	36.2	.2	.7	18.6	8.6	24.0	.4411
102	31DEC1992	2921.0	12.6	40.8	.2	.8	18.6	3.4	26.8	.2123
114	31DEC1993	3286.0	11.2	45.2	.2	.8	18.6	3.8	28.1	.2536
115	31JAN1994	3317.0	11.2	45.5	.2	.8	18.6	3.8	28.2	.2561
127	1JAN1995	3652.0	10.6	49.2	.2	.9	18.6	4.1	29.5	.2773
139	1JAN1996	4017.0	10.1	52.9	.2	1.0	18.6	4.2	31.1	.2928
151	1JAN1997	4383.0	9.7	56.6	.2	1.1	18.6	4.3	32.6	.3050
163	1JAN1998	4748.0	9.4	60.0	.2	1.1	18.6	4.3	34.2	.3152
175	1JAN1999	5113.0	9.1	63.4	.2	1.2	18.6	4.4	35.8	.3241
187	1JAN2000	5478.0	8.8	66.7	.2	1.2	18.6	4.4	37.4	.3322
199	1JAN2001	5844.0	8.5	69.8	.2	1.3	18.6	4.4	39.0	.3396
211	1JAN2002	6209.0	8.3	72.9	.2	1.4	18.6	4.4	40.6	.3465
223	1JAN2003	6574.0	8.1	75.9	.2	1.4	18.6	4.4	42.2	.3528
235	1JAN2004	6939.0	7.9	78.8	.1	1.5	18.6	4.4	43.8	.3586
247	1JAN2005	7305.0	7.7	81.7	.1	1.5	18.6	4.4	45.4	.3641
259	1JAN2006	7670.0	7.5	84.4	.1	1.6	18.6	4.4	47.0	.3692
271	1JAN2007	8035.0	7.4	87.2	.1	1.6	18.6	4.4	48.6	.3741
283	1JAN2008	8400.0	7.2	89.8	.1	1.7	18.6	4.4	50.2	.3788
295	1JAN2009	8766.0	7.1	92.4	.1	1.7	18.6	4.4	51.8	.3833
307	1JAN2010	9131.0	6.9	95.0	.1	1.8	18.6	4.4	53.5	.3876
319	1JAN2011	9496.0	6.8	97.5	.1	1.8	18.6	4.4	55.1	.3917
331	1JAN2012	9861.0	6.7	100.0	.1	1.9	18.6	4.4	56.7	.3956
343	1JAN2013	10227.0	6.6	102.4	.1	1.9	18.6	4.4	58.3	.3995
355	1JAN2014	10592.0	6.5	104.8	.1	2.0	18.6	4.4	59.8	.4032
356	31JAN2014	10622.0	6.4	105.0	.1	2.0	18.6	4.4	60.0	.4035

TABLE 18

```
******************************************************************************************)
(                  ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c  ))
( W o r k B e n c h )                                                                              (  S o f t w a r e -    ))
(                  )                    FIELD PERFORMANCE - CASE 5                                  (  I n t e r c o m p    ))
******************************************************************************************)
```

Project/Case: **CASE 5** **32 HECTARE SPACING - 3 INJECTORS PARTIAL 5 SPOT** TOTAL FIELD

Time Step Number	Date	Cumulative Time DAYS	Oil Production Rate STM3/D	Oil Production Cumulative KSTM3	Gas Production Rate KSM3/D	Gas Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Water Production Rate STM3/D	Water Production Cumulative KSTM3	Water Cut FRACTION
13	31OCT1985	303.0	.0	.0	.0	.0	.0	.0	.0	.0000
15	31DEC1985	364.0	9.1	.6	.2	.0	18.6	.0	.0	.0025
27	31DEC1986	729.0	16.0	5.7	.3	.1	18.6	41.6	6.6	.7222
41	31DEC1987	1094.0	20.5	11.0	.4	.2	18.6	3.9	12.1	.1587
53	31DEC1988	1460.0	12.8	16.6	.2	.3	18.6	6.3	14.1	.3294
65	31DEC1989	1825.0	11.2	20.9	.2	.4	18.6	6.9	16.6	.3814
77	31DEC1990	2190.0	10.4	24.8	.2	.5	18.6	7.2	19.2	.4085
89	31DEC1991	2555.0	9.7	28.4	.2	.5	18.6	7.3	21.8	.4310
101	31DEC1992	2921.0	8.0	31.6	.1	.6	18.6	1.6	24.0	.1653
113	31DEC1993	3286.0	9.1	35.3	.2	.7	18.6	2.6	24.8	.2240
119	31JAN1994	3317.0	5.5	35.5	.1	.7	18.6	2.6	24.8	.3187
132	1JAN1995	3652.0	6.2	37.5	.1	.7	18.6	2.8	25.8	.3108
144	1JAN1996	4017.0	6.6	39.9	.1	.7	18.6	2.8	26.8	.2986
156	1JAN1997	4383.0	6.8	42.3	.1	.8	18.6	2.8	27.8	.2922
168	1JAN1998	4748.0	6.9	44.8	.1	.8	18.6	2.8	28.8	.2891
180	1JAN1999	5113.0	7.0	47.4	.1	.9	18.6	2.8	29.9	.2889
192	1JAN2000	5478.0	6.9	49.9	.1	.9	18.6	2.9	30.9	.2934
204	1JAN2001	5844.0	6.7	52.4	.1	1.0	18.6	2.9	32.0	.3046
216	1JAN2002	6209.0	6.4	54.8	.1	1.0	18.6	3.1	33.1	.3232
228	1JAN2003	6574.0	6.0	57.0	.1	1.1	18.6	3.2	34.2	.3468
240	1JAN2004	6939.0	5.7	59.2	.1	1.1	18.6	3.4	35.4	.3724
252	1JAN2005	7305.0	5.4	61.2	.1	1.1	18.6	3.5	36.7	.3988
264	1JAN2006	7670.0	5.0	63.1	.1	1.2	18.6	3.7	38.0	.4268
276	1JAN2007	8035.0	4.7	64.9	.1	1.2	18.6	3.9	39.4	.4553
288	1JAN2008	8400.0	4.4	66.5	.1	1.2	18.6	4.2	40.9	.4835
300	1JAN2009	8766.0	4.2	68.1	.1	1.3	18.6	4.4	42.5	.5105
312	1JAN2010	9131.0	4.0	69.6	.1	1.3	18.6	4.6	44.1	.5360
324	1JAN2011	9496.0	3.7	71.0	.1	1.3	18.6	4.8	45.8	.5611
336	1JAN2012	9861.0	3.5	72.3	.1	1.3	18.6	4.9	47.6	.5837
348	1JAN2013	10227.0	3.3	73.5	.1	1.4	18.6	5.1	49.4	.6025
360	1JAN2014	10592.0	3.2	74.7	.1	1.4	18.6	5.2	51.3	.6205
361	31JAN2014	10622.0	3.2	74.8	.1	1.4	18.6	5.2	51.5	.6219

TABLE 19

```
*************************************************************************************************************
(                  ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c  ))
(  W o r k B e n c h  )                                                                           (  S o f t w a r e  -  ))
(                  )                    FIELD PERFORMANCE - CASE 5                                (  I n t e r c o m p    ))
*************************************************************************************************************
```

Project/Case: CASE 5 — 32 HECTARE SPACING - 3 INJECTORS PARTIAL 5 SPOT TOTAL FIELD

Time Step Number	Date	Cumulative Time DAYS	Gas Injection Rate KSM3/D	Gas Injection Cumulative KKSM3	Water Injection Rate STM3/D	Water Injection Cumulative KSTM3	Average Pressure KPA	Oil Recovery (CUM/OOV) FRACTION	Gas Recovery (CUM/OGV) FRACTION
13	31OCT1985	303.0	.0	.0	.0	.0	8871.6	.0000	.0000
15	31DEC1985	364.0	.0	.0	.0	.0	8845.2	.0012	.0012
27	31DEC1986	729.0	.0	.0	.0	.0	8262.2	.0124	.0124
41	31DEC1987	1094.0	.0	.0	.0	.0	8205.3	.0239	.0239
53	31DEC1988	1460.0	.0	.0	.0	.0	8223.7	.0360	.0360
65	31DEC1989	1825.0	.0	.0	.0	.0	8177.5	.0452	.0452
77	31DEC1990	2190.0	.0	.0	.0	.0	8113.1	.0537	.0537
89	31DEC1991	2555.0	.0	.0	.0	.0	8047.9	.0616	.0616
101	31DEC1992	2921.0	.0	.0	.0	.0	8026.7	.0686	.0686
113	31DEC1993	3286.0	.0	.0	.0	.0	8017.8	.0767	.0767
119	31JAN1994	3317.0	.0	.0	30.0	1.1	8091.5	.0770	.0770
132	1JAN1995	3652.0	.0	.0	20.1	8.5	8229.0	.0814	.0814
144	1JAN1996	4017.0	.0	.0	19.1	15.6	8240.7	.0865	.0865
156	1JAN1997	4383.0	.0	.0	18.5	22.5	8240.1	.0918	.0918
168	1JAN1998	4748.0	.0	.0	17.8	29.1	8237.0	.0973	.0973
180	1JAN1999	5113.0	.0	.0	17.2	35.5	8232.8	.1028	.1028
192	1JAN2000	5478.0	.0	.0	16.5	41.6	8228.4	.1083	.1083
204	1JAN2001	5844.0	.0	.0	15.9	47.6	8224.5	.1137	.1137
216	1JAN2002	6209.0	.0	.0	15.4	53.3	8221.2	.1189	.1189
228	1JAN2003	6574.0	.0	.0	14.9	58.8	8217.9	.1238	.1238
240	1JAN2004	6939.0	.0	.0	14.4	64.1	8213.9	.1284	.1284
252	1JAN2005	7305.0	.0	.0	14.0	69.3	8209.4	.1328	.1328
264	1JAN2006	7670.0	.0	.0	13.6	74.3	8204.5	.1369	.1369
276	1JAN2007	8035.0	.0	.0	13.3	79.2	8199.2	.1407	.1407
288	1JAN2008	8400.0	.0	.0	13.0	84.0	8193.5	.1444	.1444
300	1JAN2009	8766.0	.0	.0	12.7	88.7	8187.3	.1478	.1478
312	1JAN2010	9131.0	.0	.0	12.5	93.3	8181.0	.1510	.1510
324	1JAN2011	9496.0	.0	.0	12.3	97.8	8175.0	.1540	.1540
336	1JAN2012	9861.0	.0	.0	12.1	102.3	8169.0	.1569	.1569
348	1JAN2013	10227.0	.0	.0	11.9	106.6	8162.9	.1596	.1596
360	1JAN2014	10592.0	.0	.0	11.7	110.9	8156.9	.1622	.1622
361	31JAN2014	10622.0	.0	.0	11.7	111.3	8156.4	.1624	.1624

TABLE 20

```
*********************************************************************************************************
(                   ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c  ))
( W o r k B e n c h )                                                                                  (  S o f t w a r e  -   ))
(                   )                      FIELD PERFORMANCE - Case 6                                  (  I n t e r c o m p     ))
*********************************************************************************************************
```

Project/Case: CASE 6 16 HECTARE SPACING WITH HORIZONTAL WELL TOTAL FIELD

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
13	31OCT1985	303.0	.0	.0	.0	.0	.0	.0	.0	.0000
15	31DEC1985	364.0	9.1	.6	.2	.0	18.6	.0	.0	.0025
28	31DEC1986	729.0	35.0	7.4	.7	.1	18.6	41.8	6.5	.5448
44	31DEC1987	1094.0	37.4	18.6	.8	.4	20.2	2.5	11.9	.0635
59	31DEC1988	1460.0	28.6	31.0	.6	.6	19.2	6.0	13.6	.1740
71	31DEC1989	1825.0	23.2	40.0	.4	.8	19.2	7.0	16.0	.2320
83	31DEC1990	2190.0	20.1	48.0	.4	.9	19.0	7.3	18.7	.2660
95	31DEC1991	2555.0	17.9	54.9	.3	1.1	19.1	7.3	21.3	.2903
107	31DEC1992	2921.0	18.3	61.8	.4	1.2	19.3	8.2	24.1	.3077
119	31DEC1993	3286.0	16.5	68.4	.3	1.3	19.3	21.8	29.3	.5697
120	31JAN1994	3317.0	16.3	68.9	.3	1.3	19.4	22.1	30.0	.5755
132	1JAN1995	3652.0	15.2	74.1	.3	1.4	19.4	7.8	35.8	.3402
144	1JAN1996	4017.0	14.5	79.5	.3	1.5	19.3	7.9	38.7	.3540
156	1JAN1997	4383.0	13.8	84.7	.3	1.6	19.3	8.0	41.6	.3656
168	1JAN1998	4748.0	13.2	89.6	.3	1.7	19.3	8.0	44.5	.3758
180	1JAN1999	5113.0	12.7	94.4	.2	1.8	19.3	7.9	47.4	.3844
192	1JAN2000	5478.0	12.2	98.9	.2	1.9	19.4	7.9	50.3	.3919
204	1JAN2001	5844.0	11.8	103.3	.2	2.0	19.6	7.8	53.1	.3991
216	1JAN2002	6209.0	11.4	107.5	.2	2.1	19.7	7.8	56.0	.4062
228	1JAN2003	6574.0	11.0	111.6	.2	2.2	19.8	7.7	58.8	.4126
240	1JAN2004	6939.0	10.7	115.6	.2	2.3	20.2	7.7	61.6	.4191
252	1JAN2005	7305.0	10.3	119.4	.2	2.3	20.6	7.6	64.5	.4254
264	1JAN2006	7670.0	10.0	123.1	.2	2.4	20.7	7.6	67.2	.4314
276	1JAN2007	8035.0	9.7	126.7	.2	2.5	20.3	7.5	70.0	.4362
288	1JAN2008	8400.0	9.5	130.2	.2	2.5	20.0	7.4	72.7	.4403
300	1JAN2009	8766.0	9.2	133.6	.2	2.6	20.0	7.4	75.4	.4444
312	1JAN2010	9131.0	9.0	136.9	.2	2.7	20.0	7.3	78.1	.4483
324	1JAN2011	9496.0	8.8	140.2	.2	2.7	20.2	7.3	80.8	.4520
336	1JAN2012	9861.0	8.6	143.3	.2	2.8	20.7	7.2	83.4	.4561
348	1JAN2013	10227.0	8.4	146.5	.2	2.9	21.1	7.2	86.0	.4602
360	1JAN2014	10592.0	8.2	149.5	.2	2.9	21.9	7.1	88.6	.4648
361	31JAN2014	10622.0	8.2	149.7	.2	3.0	21.9	7.1	88.9	.4651

TABLE 21

```
***************************************************************************************************
(                    )  W e l l   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c )
(  W o r k B e n c h )                                                                             (  S o f t w a r e -    )
(                    )                    WELL PERFORMANCE - Case 6                               (  I n t e r c o m p    )
***************************************************************************************************
```

Project/Case: **CASE 6 16 HECTARE SPACING WITH HORIZONTAL WELL**

Well Name: **H0528**

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
27	30NOV1986	698.0	.0	.0	.0	.0	.0	.0	.0	.0000
28	31DEC1986	729.0	16.4	.5	.3	.0	18.6	.1	.0	.0074
29	13JAN1987	742.5	13.3	.7	.2	.0	18.6	.1	.0	.0096
30	31JAN1987	760.0	12.3	.9	.2	.0	19.7	.1	.0	.0116
31	28FEB1987	788.0	11.4	1.2	.2	.0	21.5	.2	.0	.0145
32	31MAR1987	819.0	10.7	1.6	.3	.0	24.0	.2	.0	.0180
33	30APR1987	849.0	10.2	1.9	.3	.0	27.0	.2	.0	.0211
34	31MAY1987	880.0	9.8	2.2	.3	.0	28.4	.2	.0	.0245
35	21JUN1987	901.0	9.5	2.4	.3	.1	28.8	.3	.0	.0265
36	30JUN1987	910.0	9.4	2.4	.3	.1	29.2	.3	.0	.0273
37	31JUL1987	941.0	9.1	2.7	.3	.1	29.3	.3	.0	.0296
38	25AUG1987	965.8	8.9	3.0	.3	.1	28.8	.3	.1	.0312
39	31AUG1987	972.0	8.9	3.0	.3	.1	28.7	.3	.1	.0316
40	30SEP1987	1002.0	8.7	3.3	.2	.1	27.6	.3	.1	.0332
41	31OCT1987	1033.0	8.5	3.5	.2	.1	26.4	.3	.1	.0349
42	30NOV1987	1063.0	8.2	3.8	.2	.1	25.9	.3	.1	.0367
43	24DEC1987	1086.9	8.0	4.0	.2	.1	25.8	.3	.1	.0381
44	31DEC1987	1094.0	7.9	4.0	.2	.1	25.8	.3	.1	.0385
59	31DEC1988	1460.0	6.8	6.6	.1	.2	21.1	.4	.2	.0515
71	31DEC1989	1825.0	6.2	9.0	.1	.2	20.6	.4	.4	.0599
83	31DEC1990	2190.0	5.7	11.1	.1	.3	20.0	.4	.5	.0698
95	31DEC1991	2555.0	5.2	13.1	.1	.3	20.2	.4	.7	.0791
107	31DEC1992	2921.0	4.8	14.9	.1	.3	21.3	.4	.8	.0849
119	31DEC1993	3286.0	4.5	16.6	.1	.4	21.2	.4	1.0	.0886
132	1JAN1995	3652.0	4.3	18.2	.1	.4	21.1	.4	1.2	.0918
144	1JAN1996	4017.0	4.1	19.7	.1	.4	21.0	.4	1.3	.0940
156	1JAN1997	4383.0	3.9	21.2	.1	.5	20.9	.4	1.5	.0959

TABLE 21 Cont'd

WorkBench — Well Production And Injection Report — Scientific Software - Intercomp

WELL PERFORMANCE - Case 6

Project/Case: CASE 6 16 HECTARE SPACING WITH HORIZONTAL WELL

Well Name: H0528

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
168	1JAN1998	4748.0	3.7	22.6	.1	.5	21.0	.4	1.6	.0976
180	1JAN1999	5113.0	3.5	23.9	.1	.5	21.0	.4	1.8	.0984
192	1JAN2000	5478.0	3.4	25.2	.1	.5	21.5	.4	1.9	.0990
204	1JAN2001	5844.0	3.3	26.4	.1	.6	22.0	.4	2.0	.0999
216	1JAN2002	6209.0	3.1	27.5	.1	.6	22.4	.4	2.2	.1020
228	1JAN2003	6574.0	3.0	28.7	.1	.6	23.0	.4	2.3	.1050
240	1JAN2004	6939.0	2.9	29.8	.1	.7	23.8	.4	2.4	.1075
252	1JAN2005	7305.0	2.8	30.8	.1	.7	25.0	.3	2.5	.1099
264	1JAN2006	7670.0	2.7	31.8	.1	.7	25.0	.3	2.7	.1119
276	1JAN2007	8035.0	2.6	32.8	.1	.7	23.7	.3	2.8	.1131
288	1JAN2008	8400.0	2.6	33.7	.1	.7	22.7	.3	2.9	.1144
300	1JAN2009	8766.0	2.5	34.7	.1	.8	22.8	.3	3.0	.1156
312	1JAN2010	9131.0	2.5	35.6	.1	.8	23.0	.3	3.2	.1166
313	1FEB2010	9162.0	2.5	35.6	.1	.8	23.1	.3	3.2	.1166
324	1JAN2011	9496.0	2.4	36.5	.1	.8	23.5	.3	3.3	.1176
336	1JAN2012	9861.0	2.4	37.3	.1	.8	24.6	.3	3.4	.1187
348	1JAN2013	10227.0	2.3	38.2	.1	.9	26.0	.3	3.5	.1200
360	1JAN2014	10592.0	2.3	39.0	.1	.9	27.3	.3	3.6	.1213
361	31JAN2014	10622.0	2.3	39.1	.1	.9	27.4	.3	3.6	.1214

TABLE 22

(WorkBench) Field Production And Injection Report (Scientific Software - Intercomp)

FIELD PERFORMANCE - CASE 7

Project/Case: CASE 7 BASE CASE WITH INJ 13-21 (CASE 2) PLUS HORIZONTAL WELL PREDICTION FROM 1994 TOTAL FIELD

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
115	1FEB1994	3318.0	38.6	60.5	.7	1.1	18.6	34.1	32.8	.4686
127	1FEB1995	3683.0	23.3	69.5	.4	1.3	18.7	30.4	44.0	.5658
139	1FEB1996	4048.0	20.7	77.5	.4	1.4	18.7	17.7	51.8	.4600
151	1FEB1997	4414.0	18.6	84.7	.3	1.6	18.7	19.4	58.7	.5100
163	1FEB1998	4779.0	16.8	91.1	.3	1.7	18.7	20.8	66.0	.5531
175	1FEB1999	5144.0	15.3	97.0	.3	1.8	18.9	21.9	73.8	.5880
187	1FEB2000	5509.0	14.1	102.3	.3	1.9	19.0	22.7	82.0	.6169
199	1FEB2001	5875.0	13.1	107.2	.2	2.0	18.9	23.3	90.4	.6404
211	1FEB2002	6240.0	12.2	111.8	.2	2.1	18.9	23.8	99.0	.6604
223	1FEB2003	6605.0	11.5	116.2	.2	2.2	18.8	24.2	107.8	.6776
235	1FEB2004	6970.0	10.9	120.2	.2	2.3	18.8	24.5	116.7	.6923
247	1FEB2005	7336.0	10.3	124.1	.2	2.3	18.8	24.7	125.7	.7049
259	1FEB2006	7701.0	9.8	127.8	.2	2.4	18.6	22.6	134.1	.6974
271	1FEB2007	8066.0	9.4	131.3	.2	2.5	18.7	22.6	142.4	.7057
283	1FEB2008	8431.0	9.1	134.6	.2	2.5	18.8	22.6	150.6	.7137
295	1FEB2009	8797.0	8.7	137.9	.2	2.6	18.8	22.7	158.9	.7224
307	1FEB2010	9162.0	8.4	141.0	.2	2.6	18.8	22.7	167.2	.7310
319	1FEB2011	9527.0	8.0	144.0	.2	2.7	18.8	22.8	175.5	.7390
331	1FEB2012	9892.0	7.8	146.9	.1	2.8	18.8	22.9	183.8	.7467
343	1FEB2013	10258.0	7.5	149.6	.1	2.8	18.8	22.9	192.2	.7537
355	31JAN2014	10622.0	7.3	152.3	.1	2.9	19.1	23.0	200.6	.7599

TABLE 23

```
*****************************************************************************************************************)
(                 ) F i e l d   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c ))
( W o r k B e n c h )                                                                             (  S o f t w a r e -  ))
(                 )                    FIELD PERFORMANCE - CASE 7                                 (  I n t e r c o m p  ))
*****************************************************************************************************************)
```

Project/Case: CASE 7 BASE CASE WITH INJ 13-21 (CASE 2) PLUS HORIZONTAL WELL PREDICTION FROM 1994 TOTAL FIELD

Time Step Number	Date	Cumulative Time DAYS	Rate KSM3/D	Cumulative KKSM3	Gas Injection Rate STM3/D	Gas Injection Cumulative KSTM3	Water Injection Average Pressure KPA	Oil Recovery (CUM/OOV) FRACTION	Gas Recovery (CUM/OGV) FRACTION
115	1FEB1994	3318.0	.0	.0	20.0	2.4	7624.9	.1313	.1313
127	1FEB1995	3683.0	.0	.0	19.4	9.5	7172.8	.1509	.1512
139	1FEB1996	4048.0	.0	.0	19.2	16.5	7132.3	.1682	.1686
151	1FEB1997	4414.0	.0	.0	19.0	23.5	7071.7	.1837	.1842
163	1FEB1998	4779.0	.0	.0	18.9	30.4	6971.6	.1977	.1982
175	1FEB1999	5144.0	.0	.0	18.8	37.3	6867.9	.2104	.2110
187	1FEB2000	5509.0	.0	.0	18.7	44.2	6765.6	.2220	.2228
199	1FEB2001	5875.0	.0	.0	18.6	51.0	6665.9	.2327	.2337
211	1FEB2002	6240.0	.0	.0	18.6	57.8	6569.0	.2427	.2438
223	1FEB2003	6605.0	.0	.0	18.5	64.5	6474.1	.2521	.2532
235	1FEB2004	6970.0	.0	.0	18.5	71.3	6381.6	.2609	.2622
247	1FEB2005	7336.0	.0	.0	18.5	78.1	6291.0	.2693	.2706
259	1FEB2006	7701.0	.0	.0	17.7	84.7	6215.4	.2772	.2786
271	1FEB2007	8066.0	.0	.0	17.7	91.1	6136.0	.2849	.2862
283	1FEB2008	8431.0	.0	.0	17.7	97.6	6058.7	.2922	.2936
295	1FEB2009	8797.0	.0	.0	17.7	104.1	5983.5	.2992	.3007
307	1FEB2010	9162.0	.0	.0	17.7	110.5	5910.4	.3060	.3075
319	1FEB2011	9527.0	.0	.0	17.7	117.0	5838.9	.3125	.3141
331	1FEB2012	9892.0	.0	.0	17.7	123.5	5768.9	.3187	.3204
343	1FEB2013	10258.0	.0	.0	17.8	130.0	5700.2	.3248	.3265
355	31JAN2014	10622.0	.0	.0	17.8	136.5	5633.4	.3306	.3324

TABLE 24

```
**************************************************************************************************
(                  )  W e l l   P r o d u c t i o n   A n d   I n j e c t i o n   R e p o r t   (  S c i e n t i f i c )
(  W o r k B e n c h  )                                                                          (  S o f t w a r e  -  )
(                  )                     WELL PERFORMANCE - CASE 7                             (  I n t e r c o m p   )
**************************************************************************************************
```

Project/Case: CASE 7 BASE CASE WITH INJ 13-21 (CASE 2) PLUS HORIZONTAL WELL PREDICTION FROM 1994

Well Name: R0528 HORIZONTAL WELL 5-28 TO 6-28

			Oil		Gas			Water		
Time Step Number	Date	Cumulative Time DAYS	Production Rate STM3/D	Production Cumulative KSTM3	Production Rate KSM3/D	Production Cumulative KKSM3	Gas - Oil Ratio SM3/SM3	Production Rate STM3/D	Production Cumulative KSTM3	Water Cut FRACTION
115	1FEB1994	3318.0	20.8	.0	.4	.0	18.6	8.1	.0	.2793
127	1FEB1995	3683.0	5.8	2.6	.1	.1	19.0	7.4	2.6	.5613
139	1FEB1996	4048.0	4.9	4.5	.1	.1	18.9	7.9	5.4	.6178
151	1FEB1997	4414.0	4.4	6.2	.1	.1	18.9	8.1	8.3	.6465
163	1FEB1998	4779.0	4.1	7.8	.1	.1	18.9	8.1	11.3	.6620
175	1FEB1999	5144.0	3.9	9.2	.1	.2	19.5	8.0	14.2	.6723
187	1FEB2000	5509.0	3.7	10.6	.1	.2	19.9	7.9	17.1	.6811
199	1FEB2001	5875.0	3.6	11.9	.1	.2	19.7	7.9	20.0	.6876
211	1FEB2002	6240.0	3.4	13.2	.1	.3	19.4	7.8	22.9	.6931
223	1FEB2003	6605.0	3.3	14.5	.1	.3	19.3	7.7	25.7	.6986
235	1FEB2004	6970.0	3.2	15.6	.1	.3	19.2	7.6	28.5	.7035
247	1FEB2005	7336.0	3.1	16.8	.1	.3	19.2	7.5	31.2	.7074
259	1FEB2006	7701.0	3.1	17.9	.1	.3	18.6	7.3	33.9	.7027
271	1FEB2007	8066.0	3.0	19.0	.1	.4	19.0	7.0	36.5	.6997
283	1FEB2008	8431.0	2.9	20.1	.1	.4	19.3	6.8	39.1	.6978
295	1FEB2009	8797.0	2.9	21.2	.1	.4	19.2	6.6	41.5	.6984
307	1FEB2010	9162.0	2.8	22.2	.1	.4	19.1	6.5	43.9	.7018
319	1FEB2011	9527.0	2.7	23.2	.1	.4	19.1	6.4	46.2	.7071
331	1FEB2012	9892.0	2.5	24.1	.0	.5	19.1	6.4	48.6	.7137
343	1FEB2013	10258.0	2.4	25.0	.0	.5	19.2	6.3	50.9	.7210
355	31JAN2014	10622.0	2.4	25.9	.0	.5	20.0	6.3	53.2	.7278

FIGURES

FIGURES

FIGURE 1

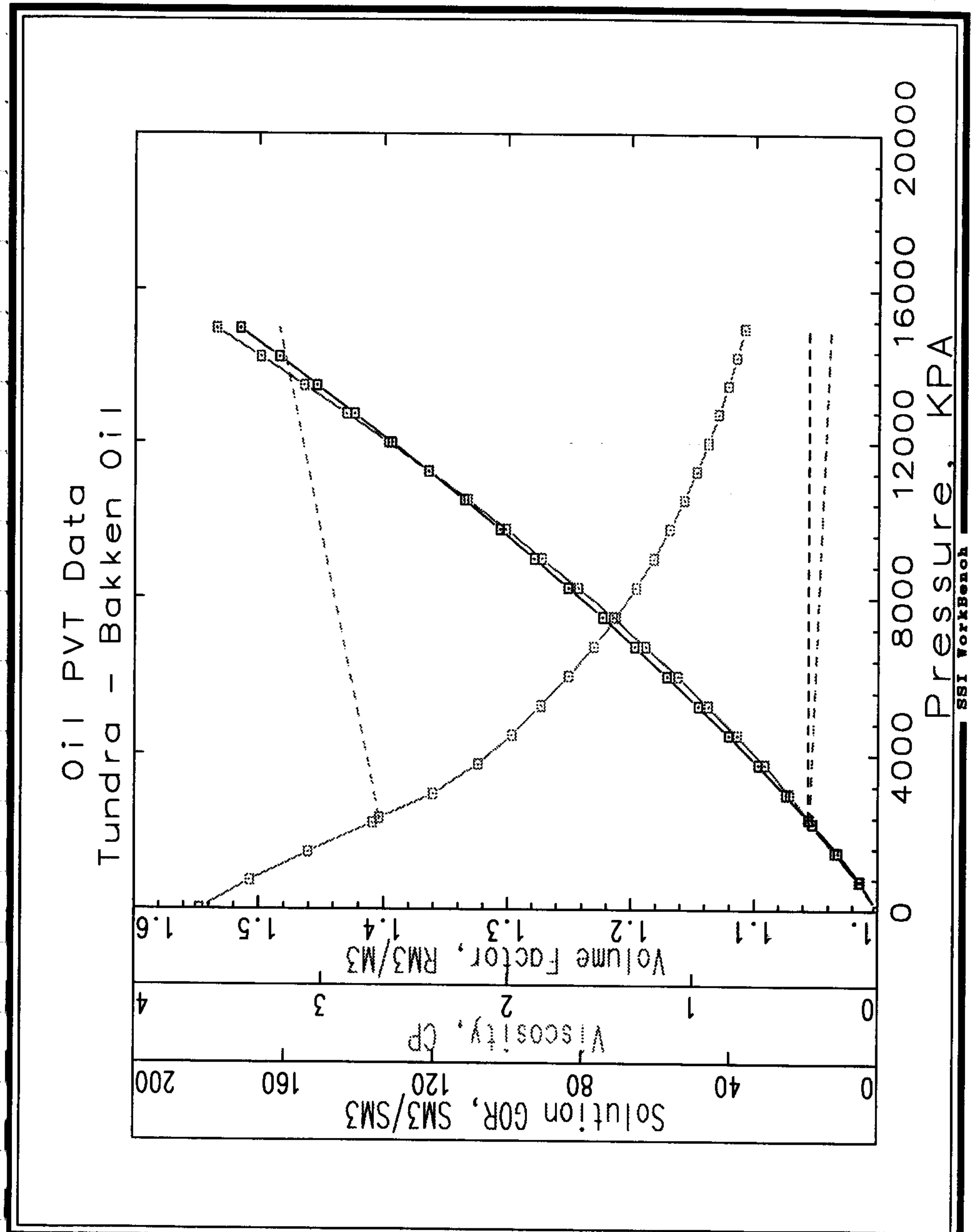
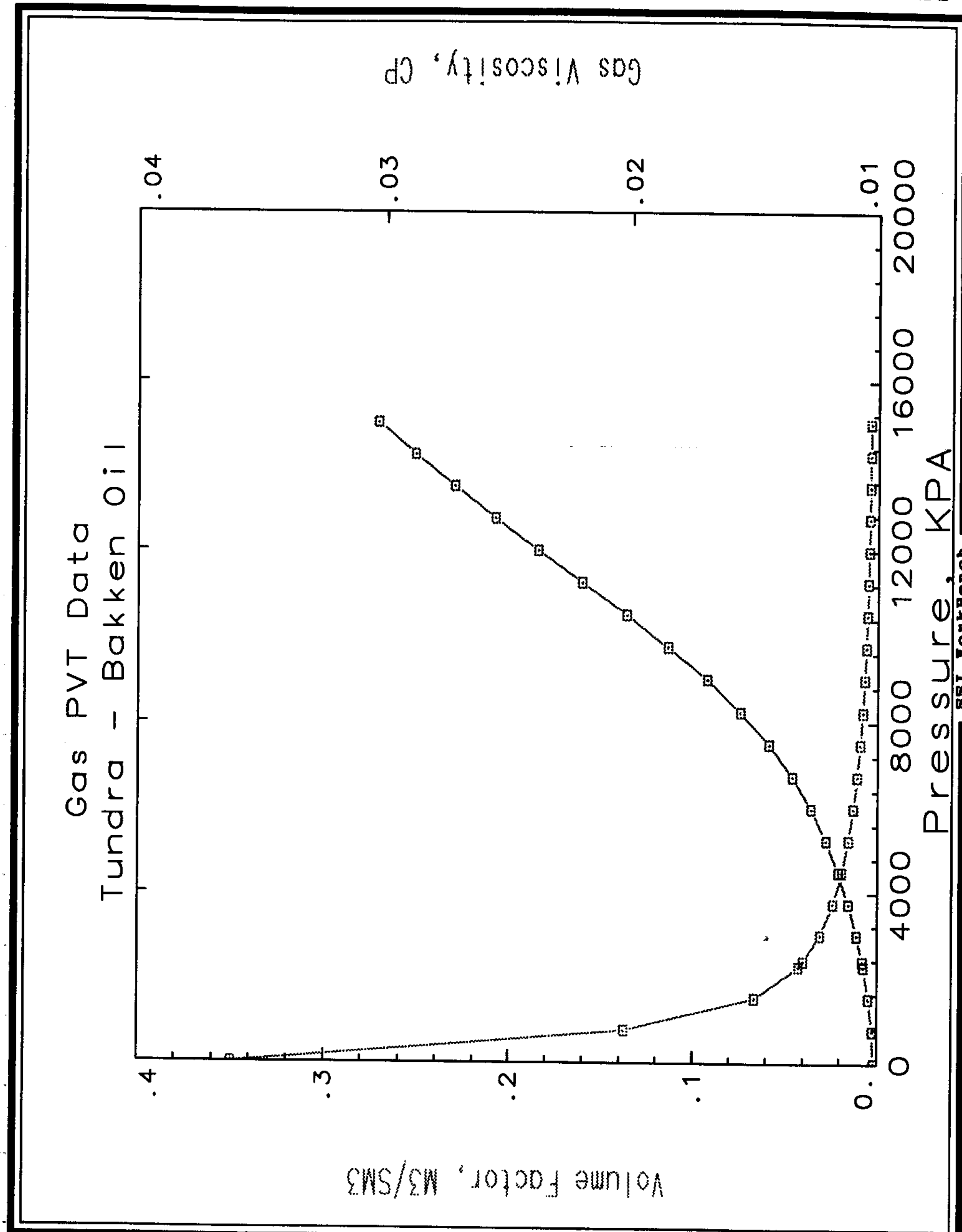

Oil PVT Data
Tundra - Bakken Oil
Pressure, KPA
0
4000
8000
12000
16000
20000
Volume Factor, RM3/M3
1.
1.1
1.2
1.3
1.4
1.5
1.6
Viscosity, CP
0
1
2
3
4
Solution GOR, SM3/SM3
0
40
80
120
160
200
SSI WorkBench

FIGURE 2



Gas PVT Data
Tundra - Bakken Oil
Pressure, KPA
Volume Factor, M3/SM3
Gas Viscosity, CP
0 4000 8000 12000 16000 20000
0. .1 .2 .3 .4
.01 .02 .03 .04
SSI WorkBench

FIGURE 3

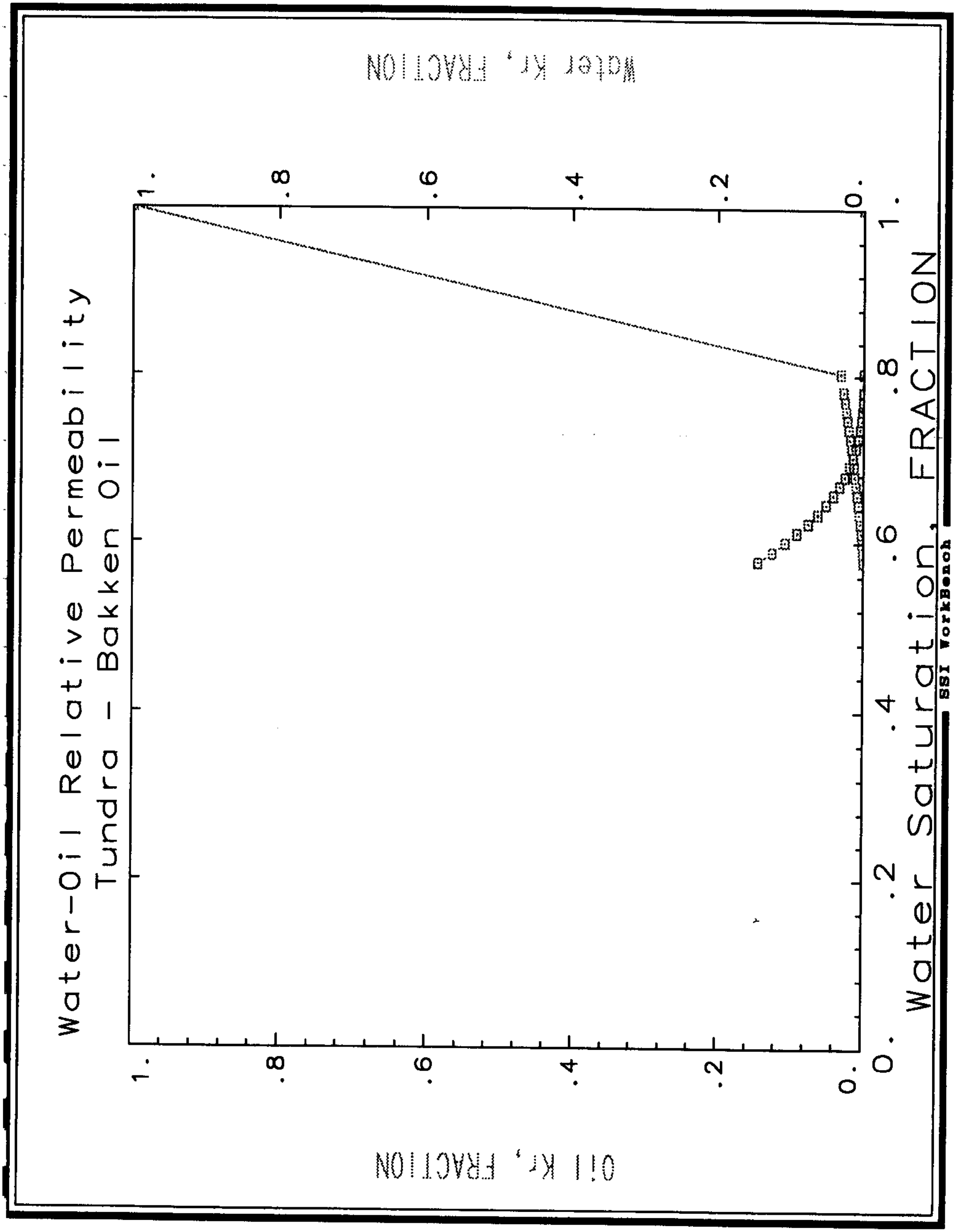
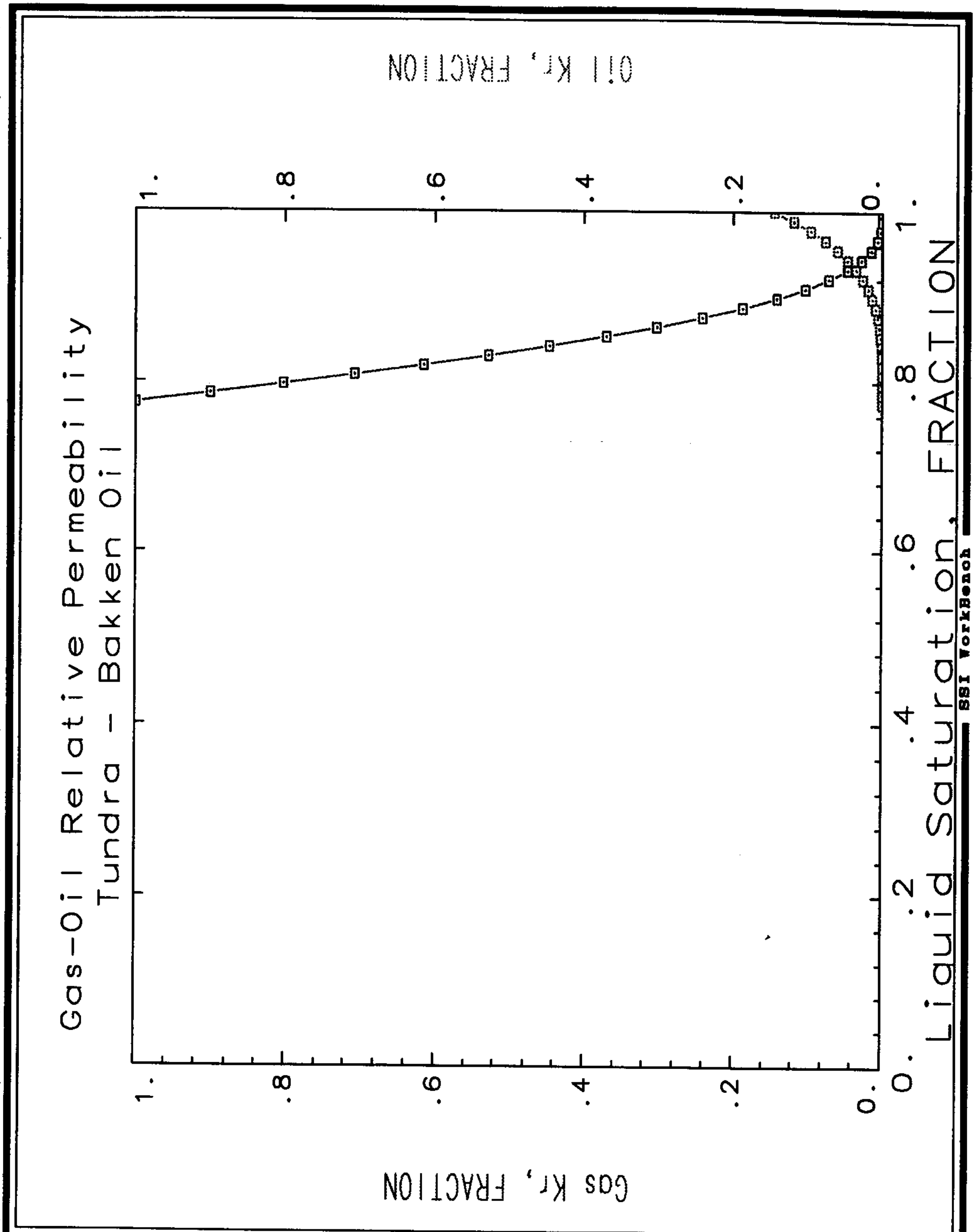
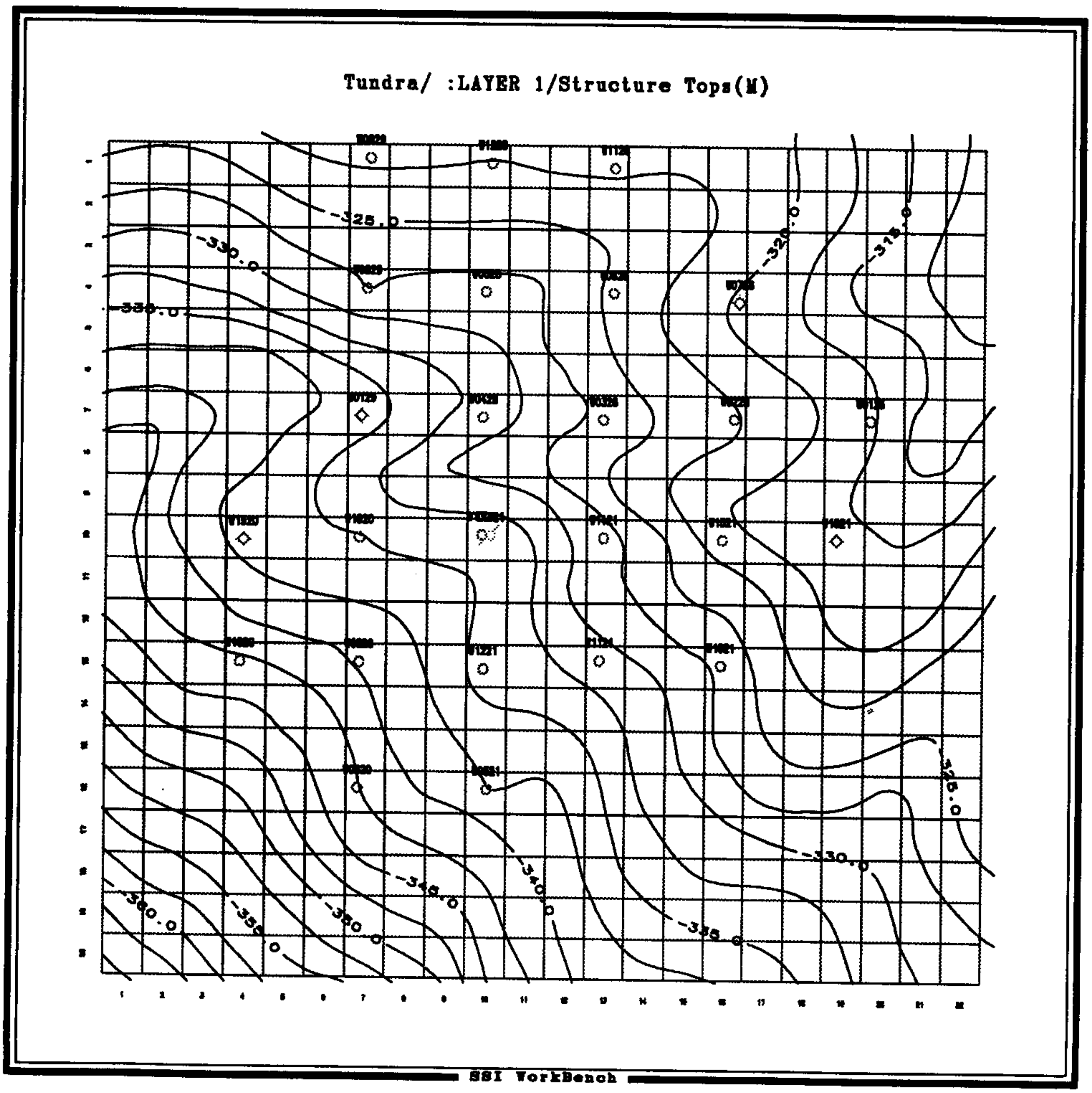

Water-Oil Relative Permeability
Tundra - Bakken Oil
Water Saturation, FRACTION
Oil Kr, FRACTION
Water Kr, FRACTION
0.
.2
.4
.6
.8
1.
SSI WorkBench

FIGURE 4



Gas-Oil Relative Permeability
Tundra - Bakken Oil
Liquid Saturation, FRACTION
Gas Kr, FRACTION
Oil Kr, FRACTION
0.
.2
.4
.6
.8
1.
SSI WorkBench

FIGURE 5



Tundra/ :LAYER 1/Structure Tops(M)
-325.0
-330.0
-335.0
-320.0
-315.0
-340.0
-345.0
-350.0
-360.0
SSI WorkBench

FIGURE 6

KOLA BAKKEN A POOL OIL FORMATION, MANITOBA
RESERVOIR SIMULATION STUDY

Porosity to Permeability Transform
Based on Middle Bakken Core Data

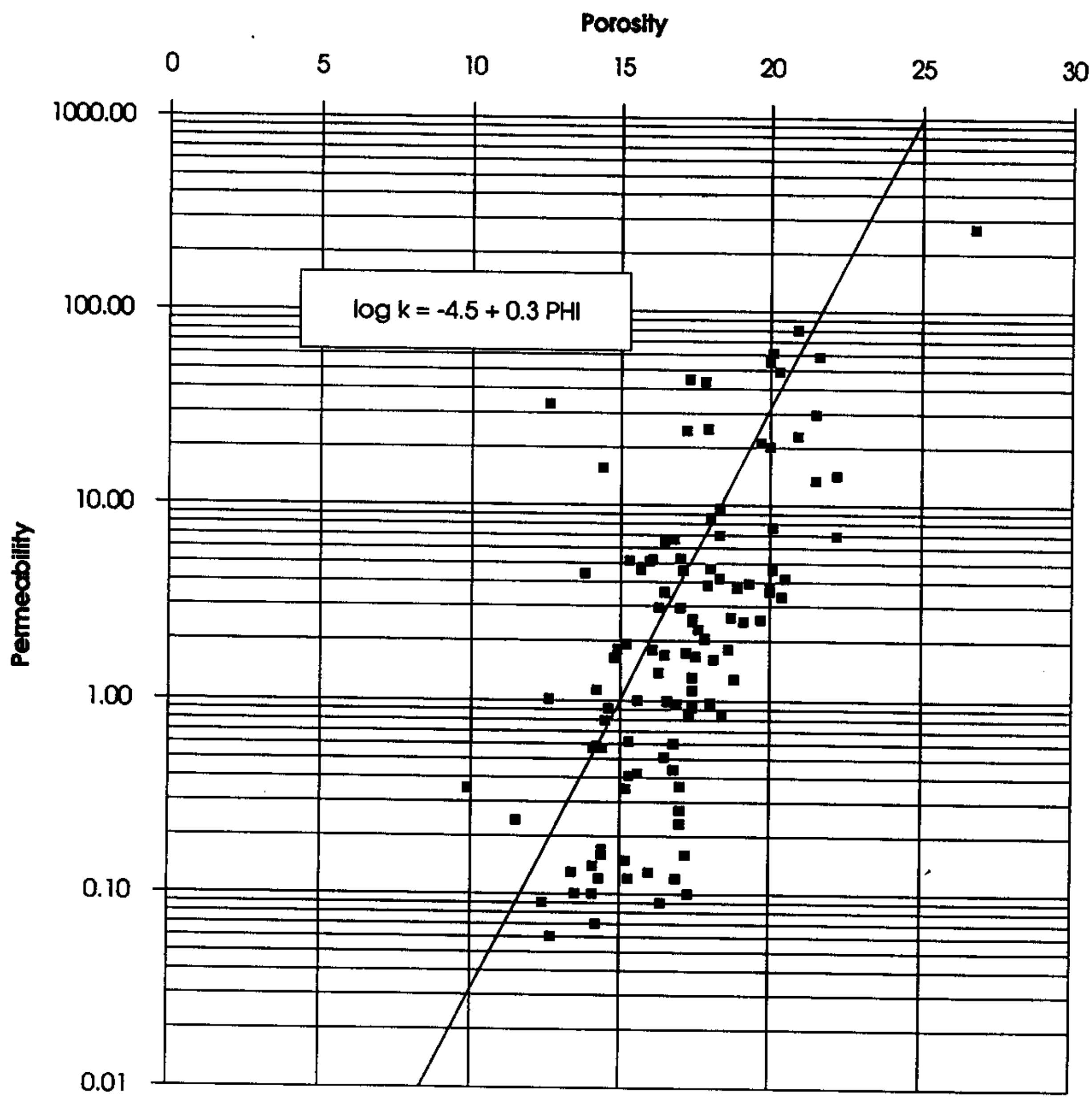


FIGURE 7

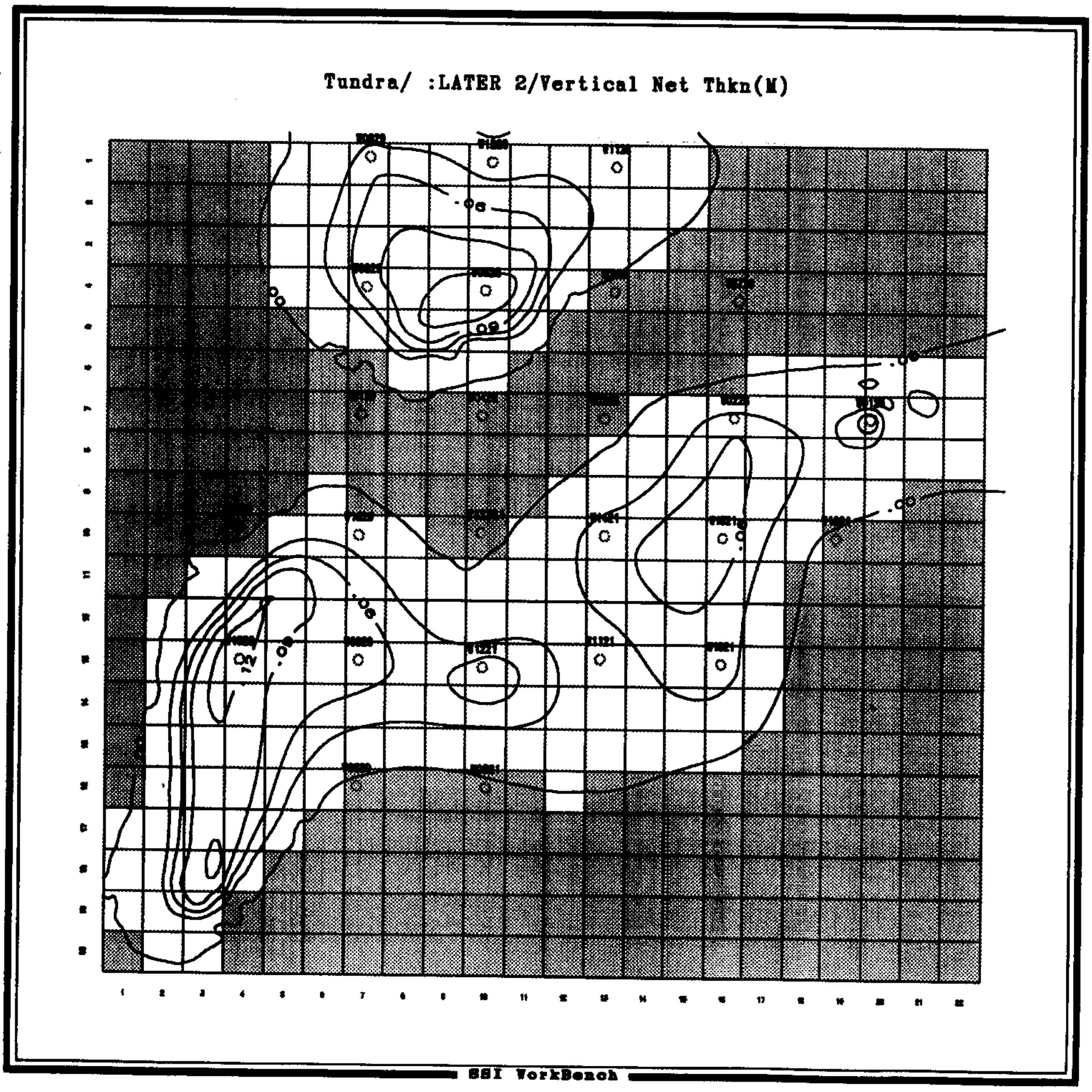
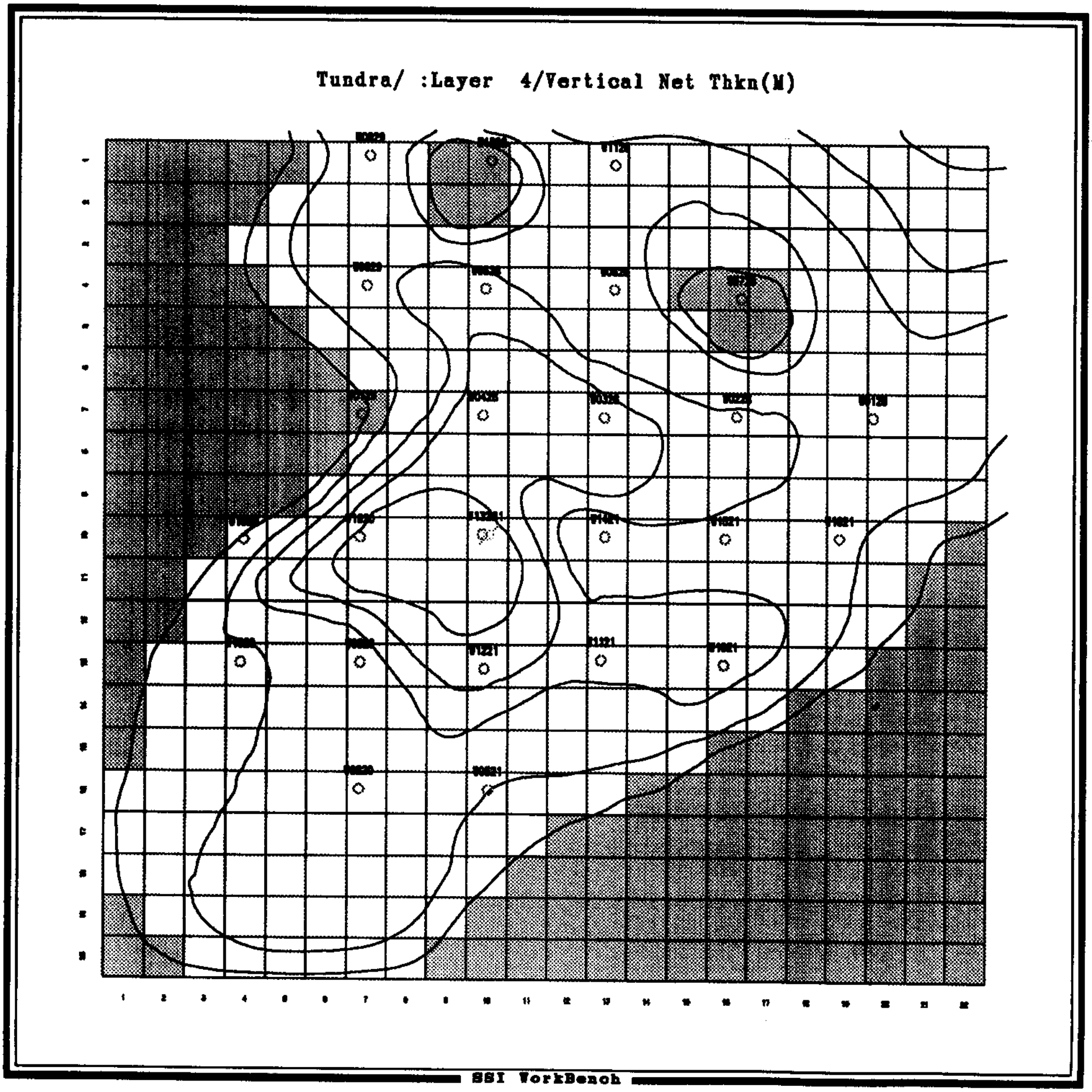
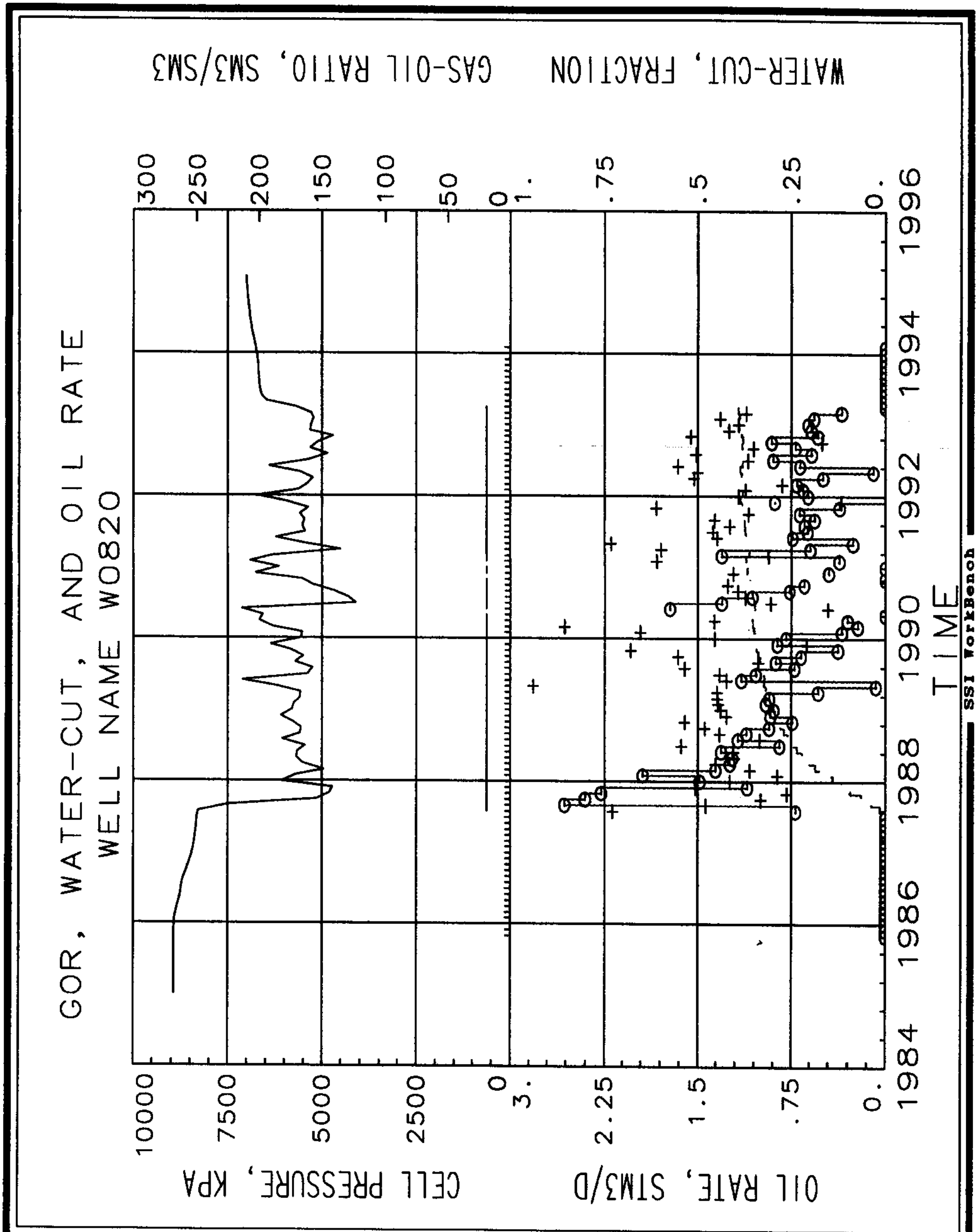
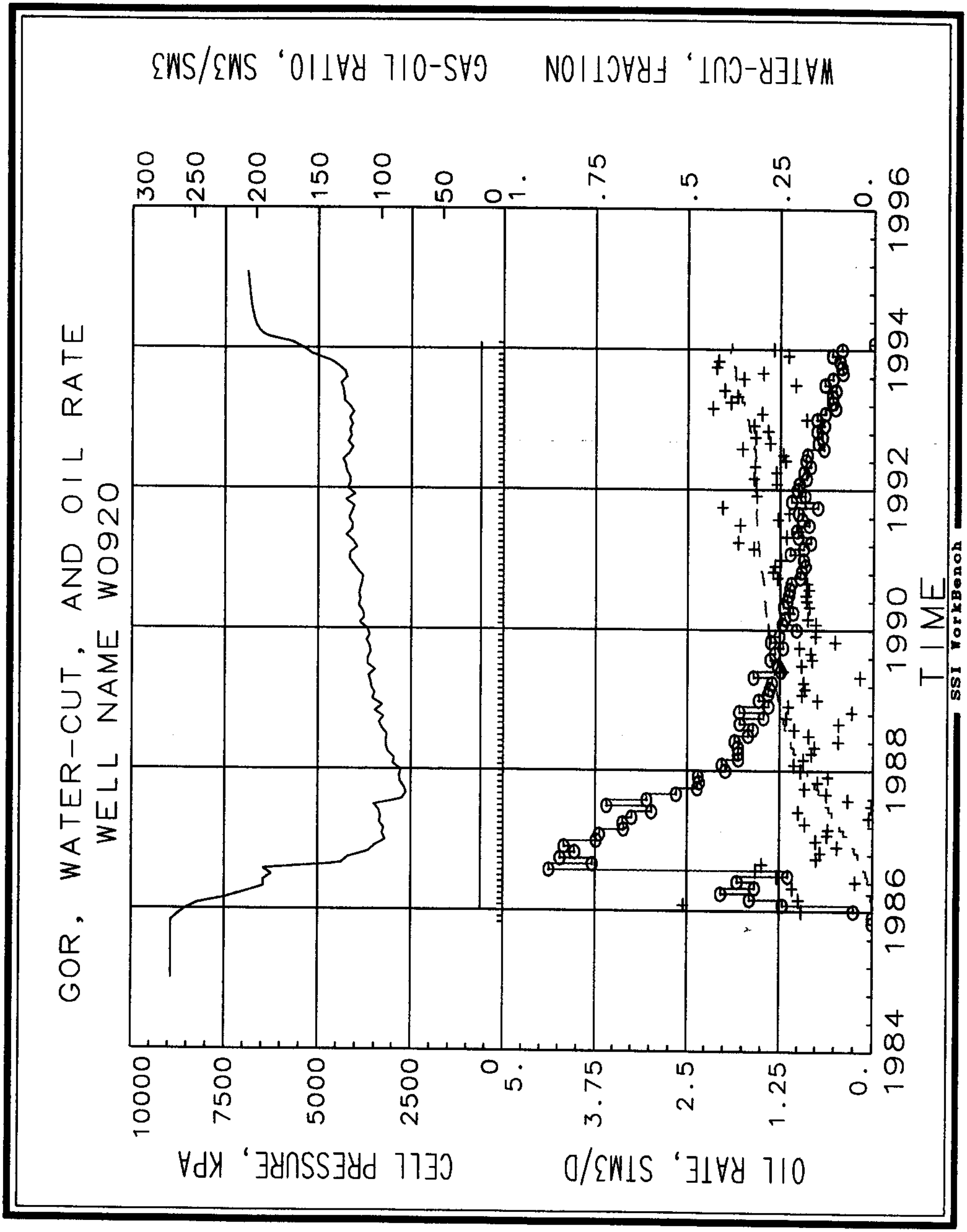


FIGURE 8

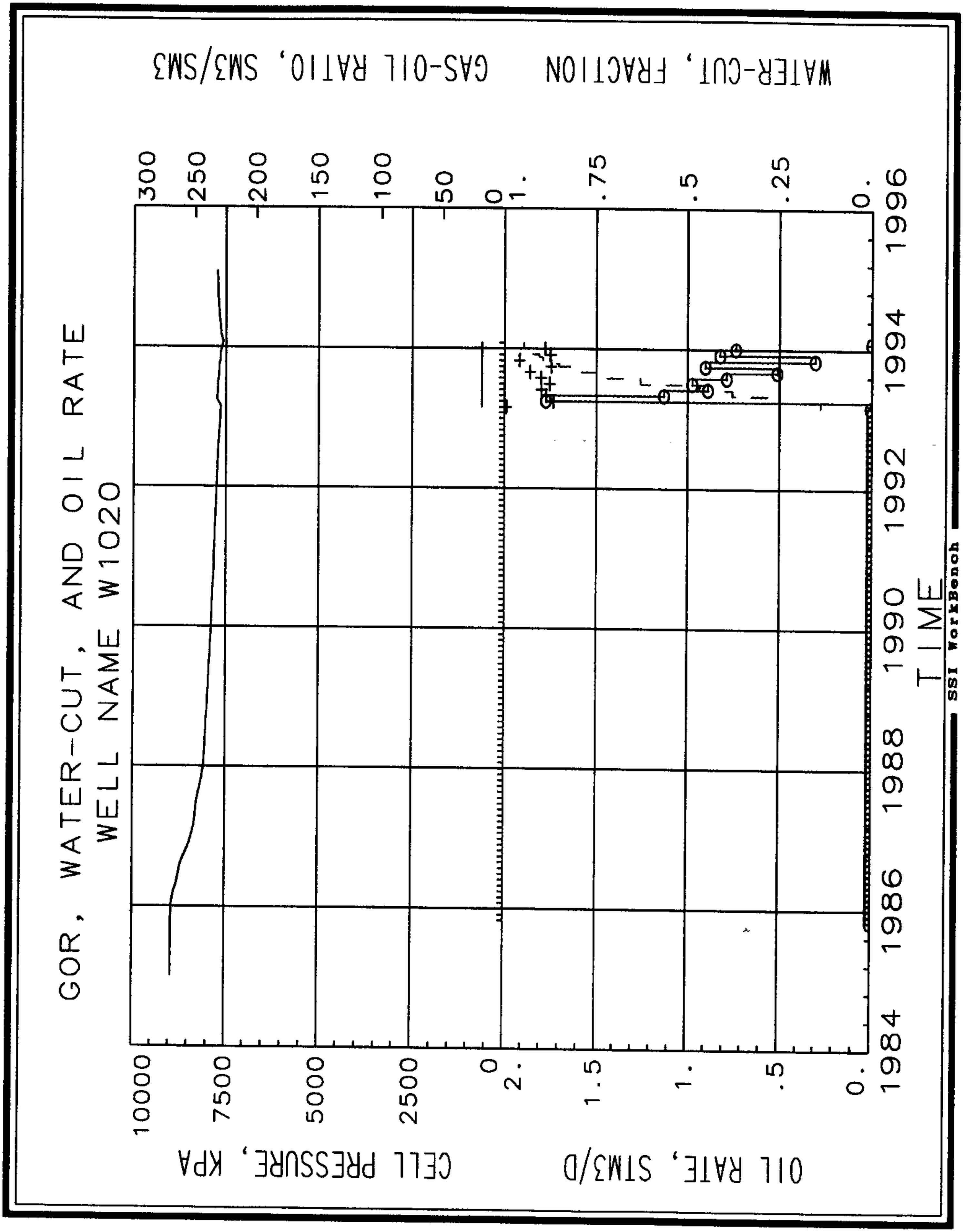


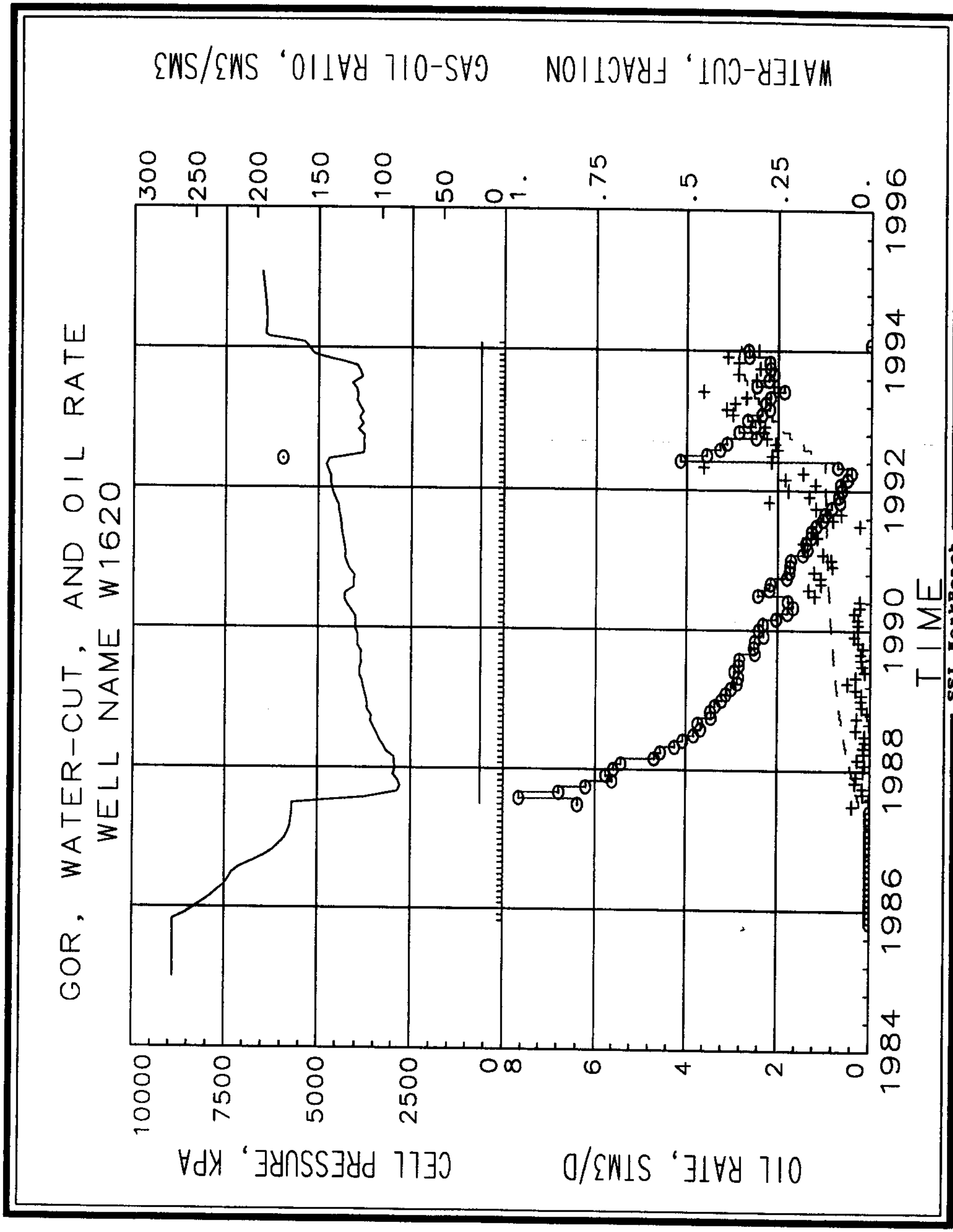

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0820
TIME
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
SSI WorkBench

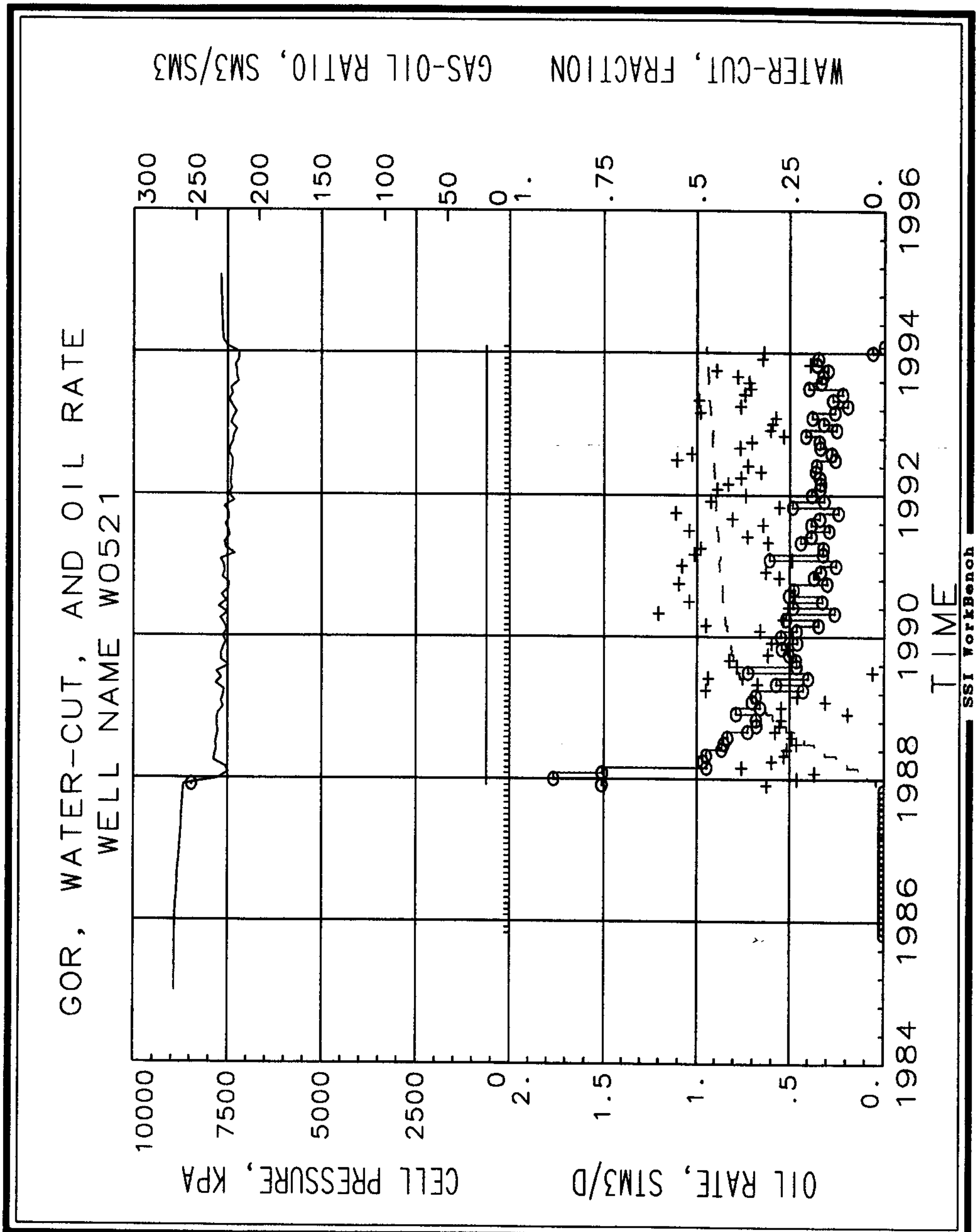
HISTORY MATCH FIGURE 10



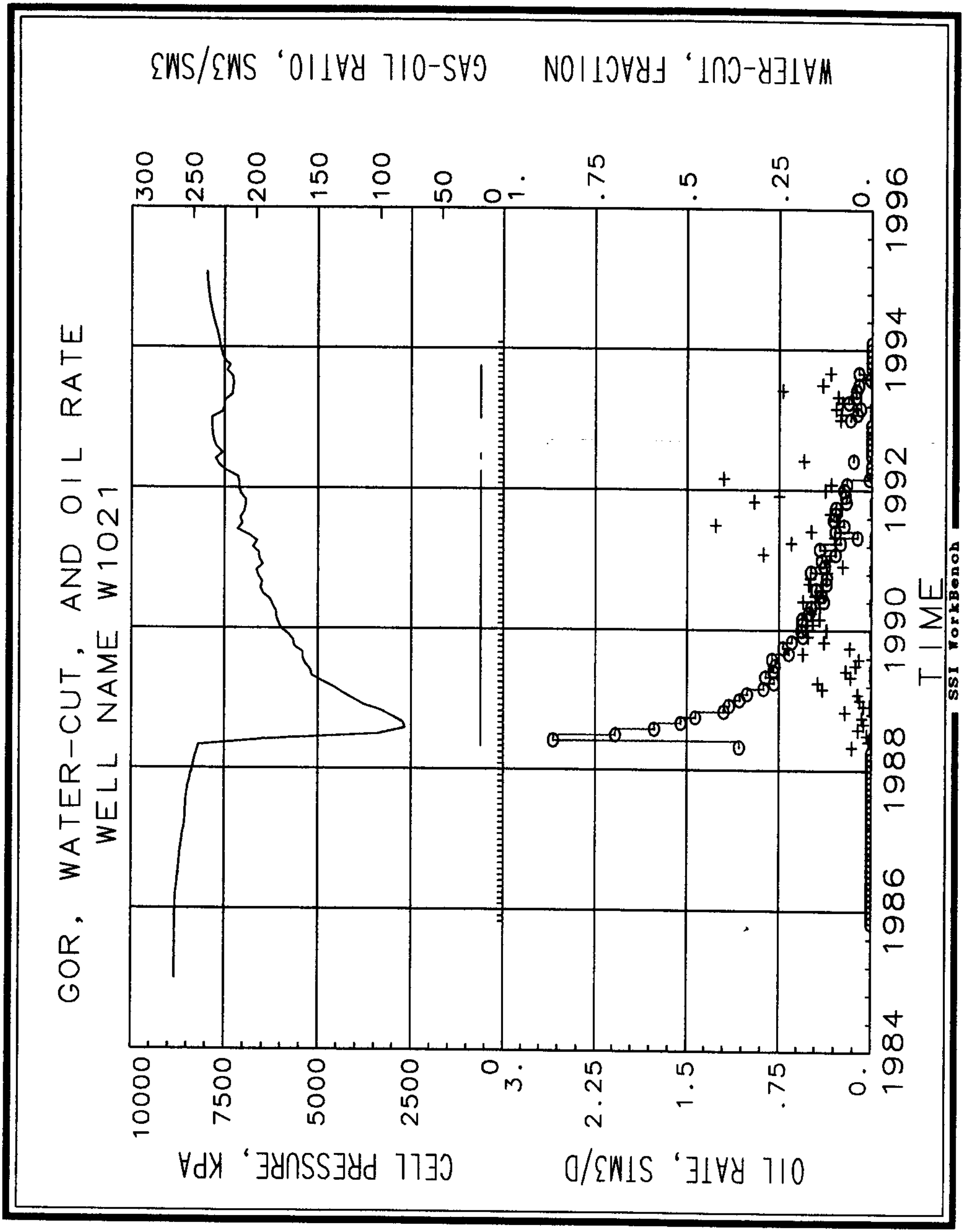
HISTORY MATCH FIGURE 11



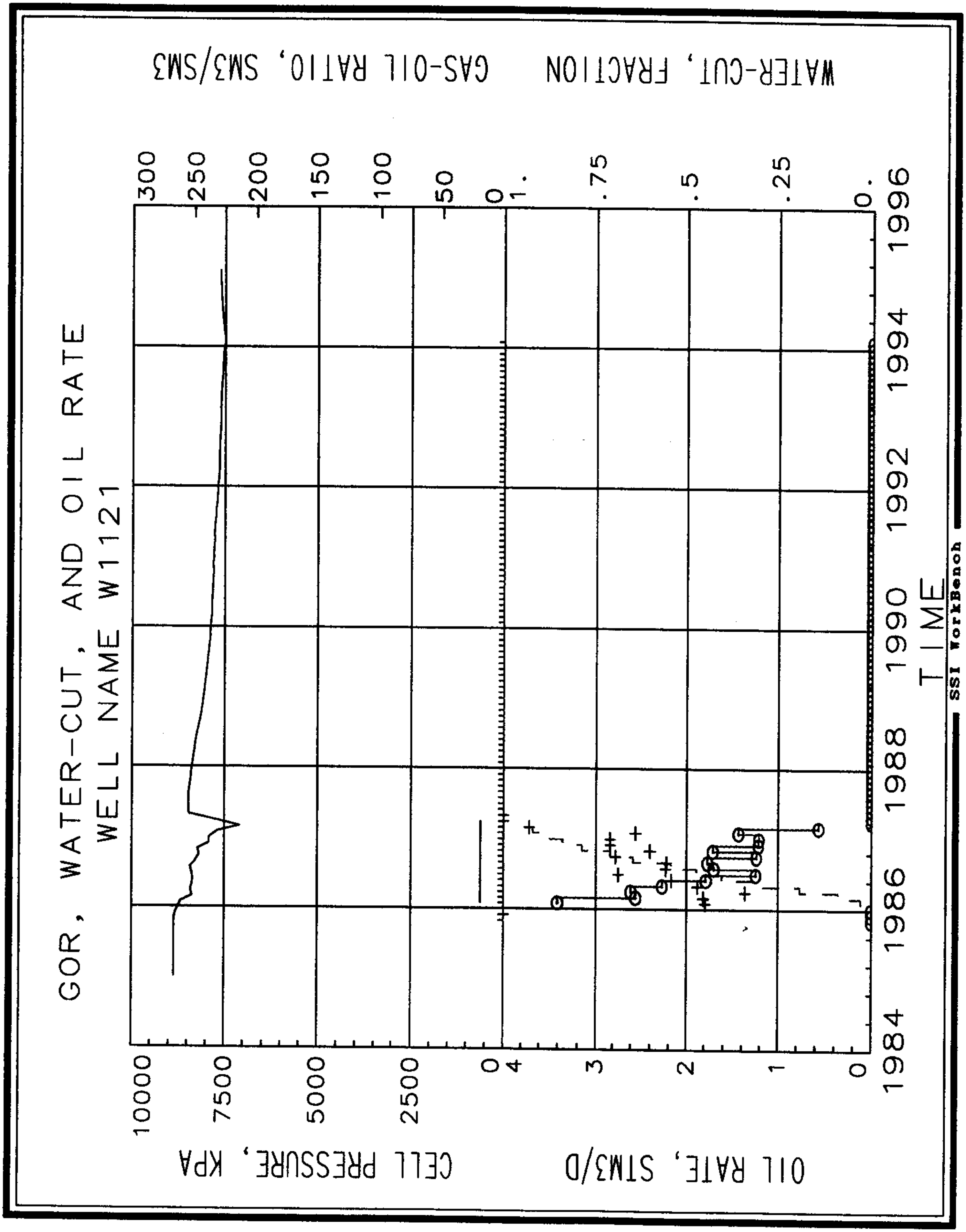

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1620
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1984
1986
1988
1990
1992
1994
1996
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W0521
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench
300 250 200 150 100 50 0
1. .75 .5 .25 0.
10000 7500 5000 2500 0
2. 1.5 1. .5 0.
1984 1986 1988 1990 1992 1994 1996

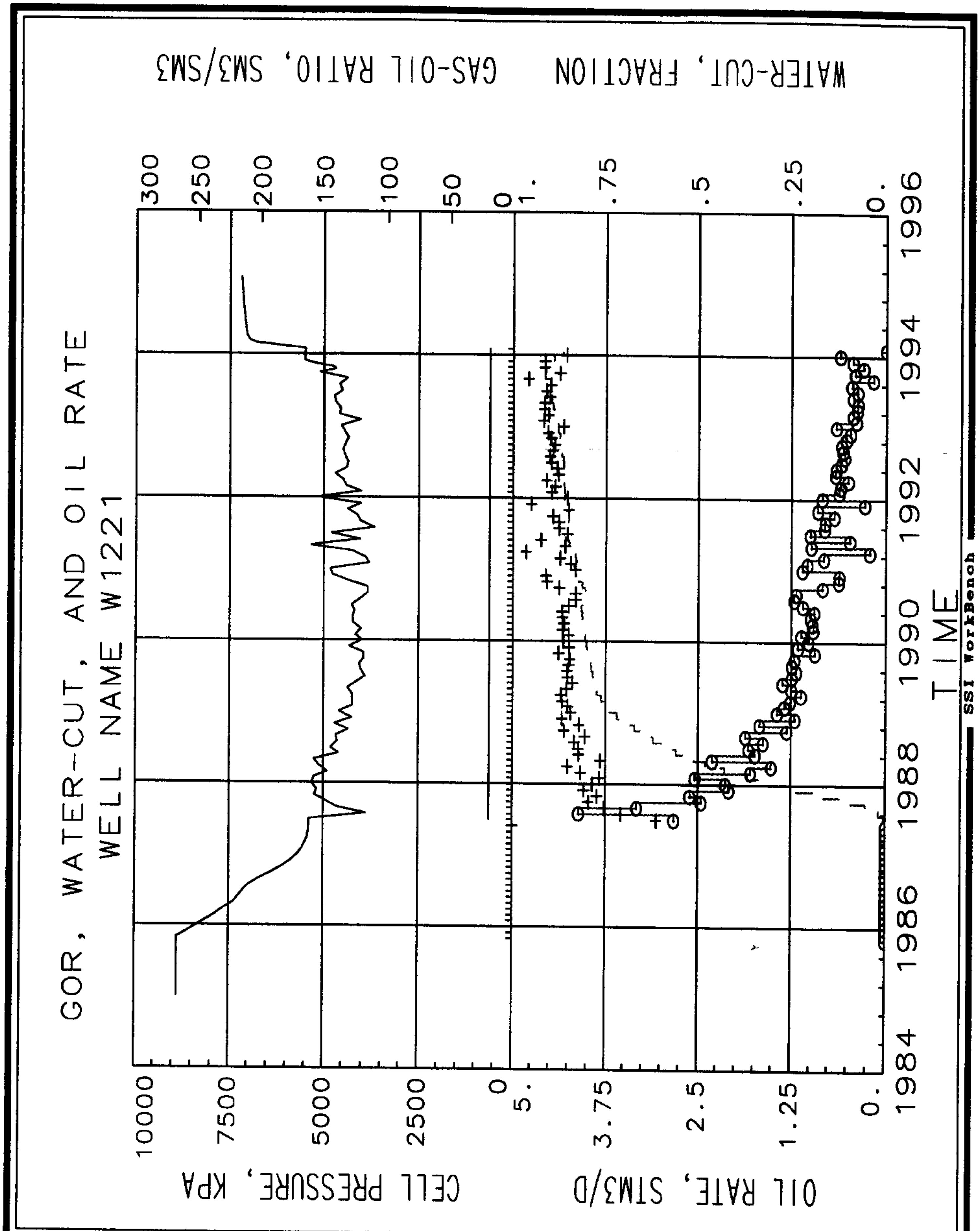
HISTORY MATCH FIGURE 14



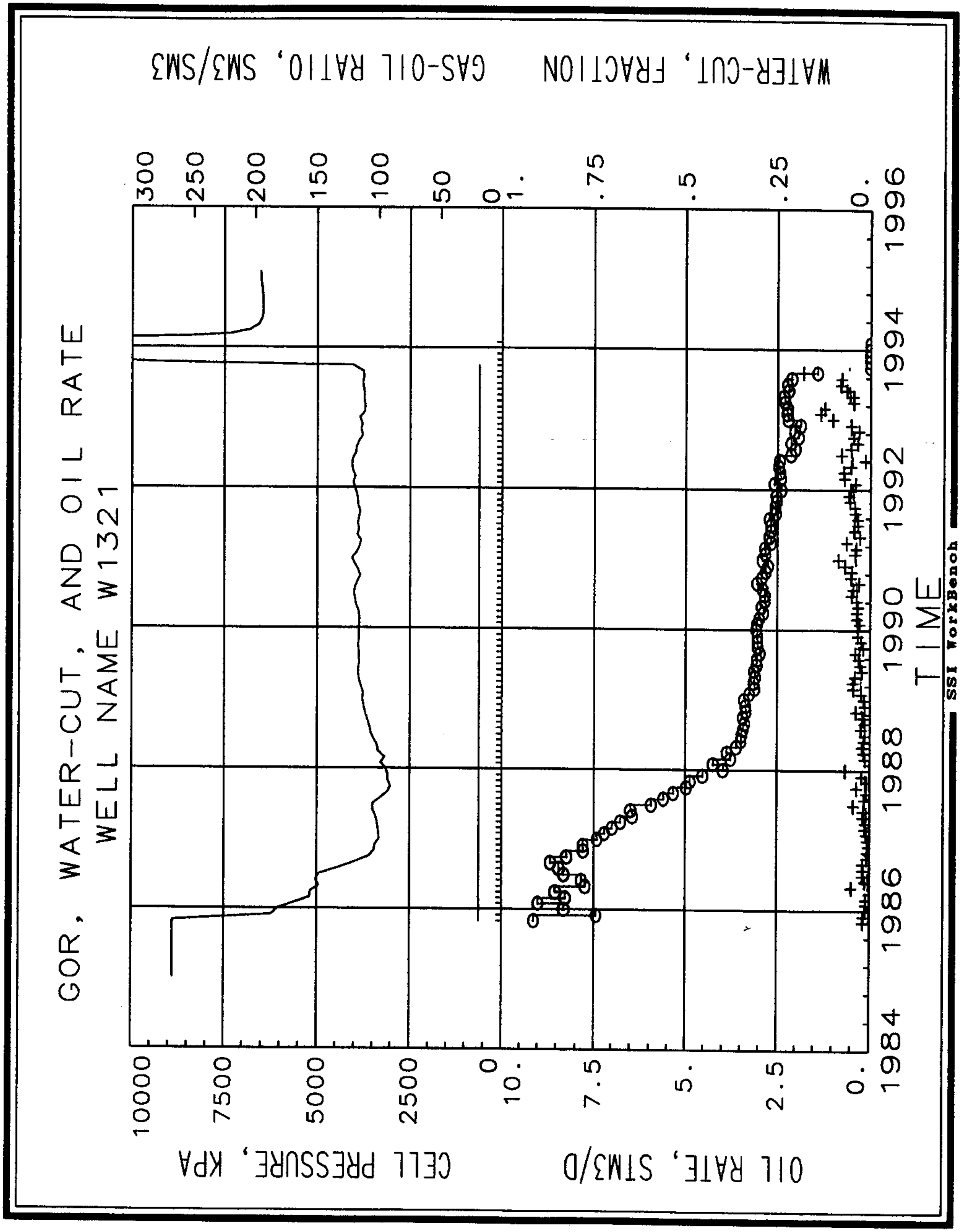
HISTORY MATCH FIGURE 15



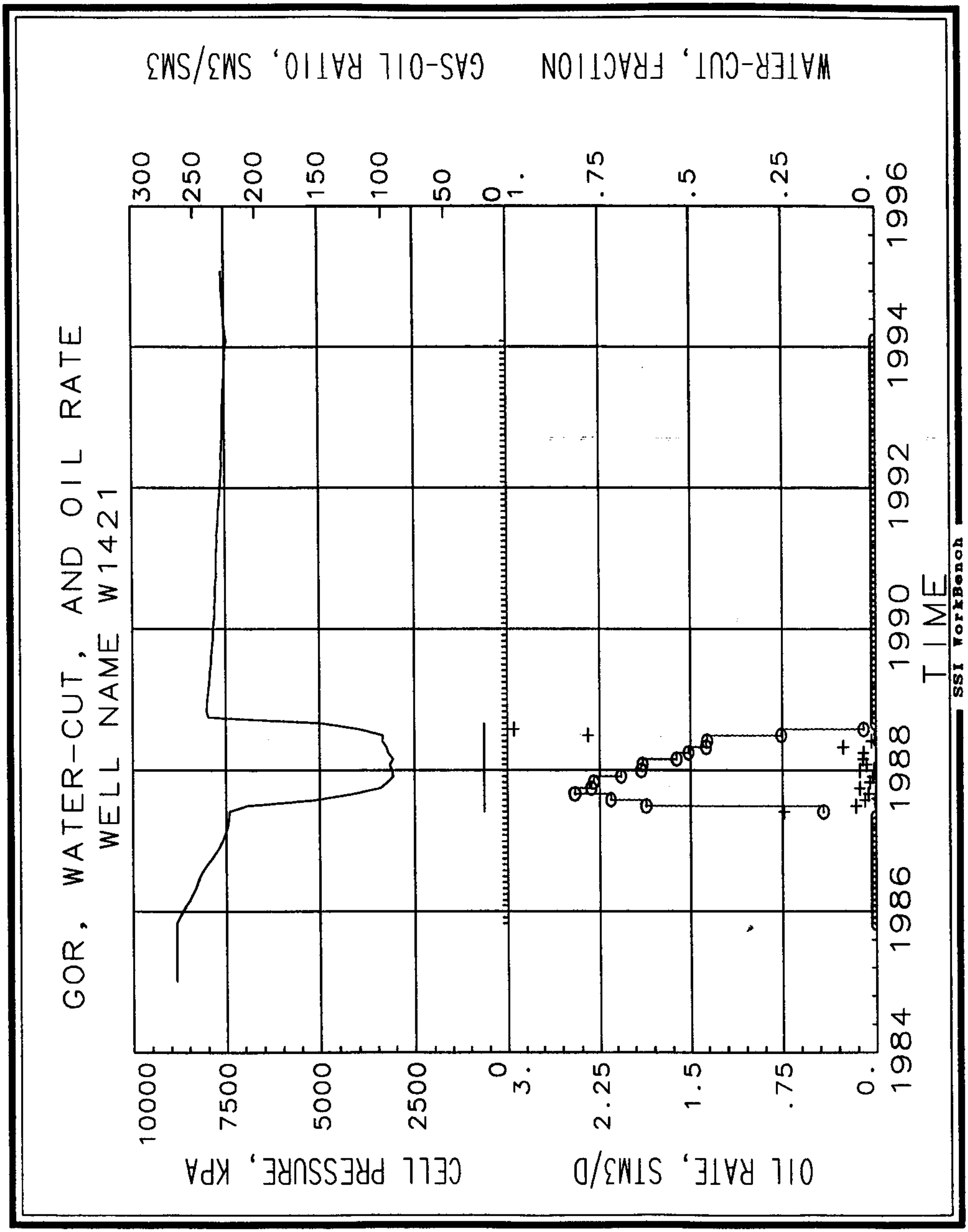
HISTORY MATCH FIGURE 16



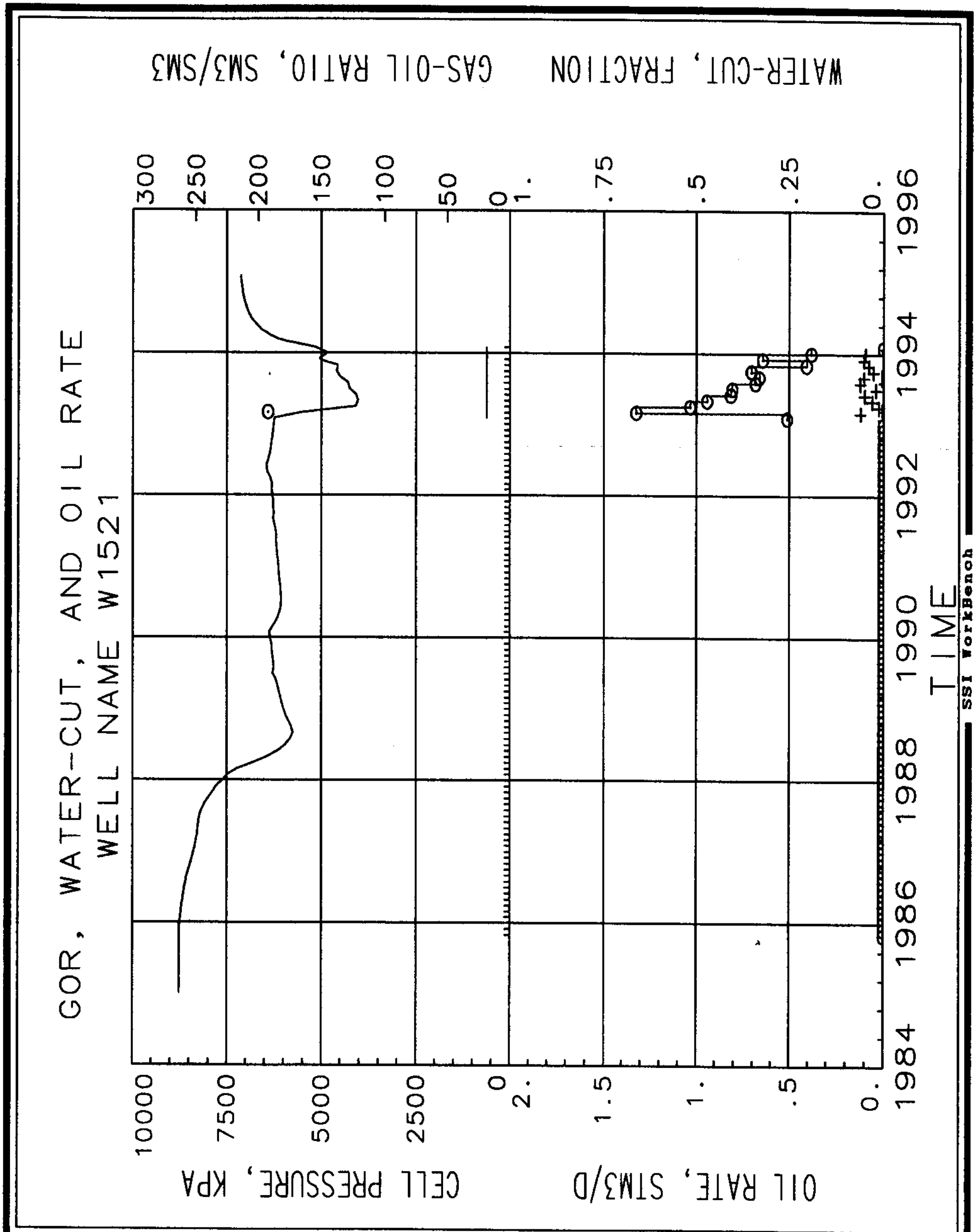
HISTORY MATCH FIGURE 17

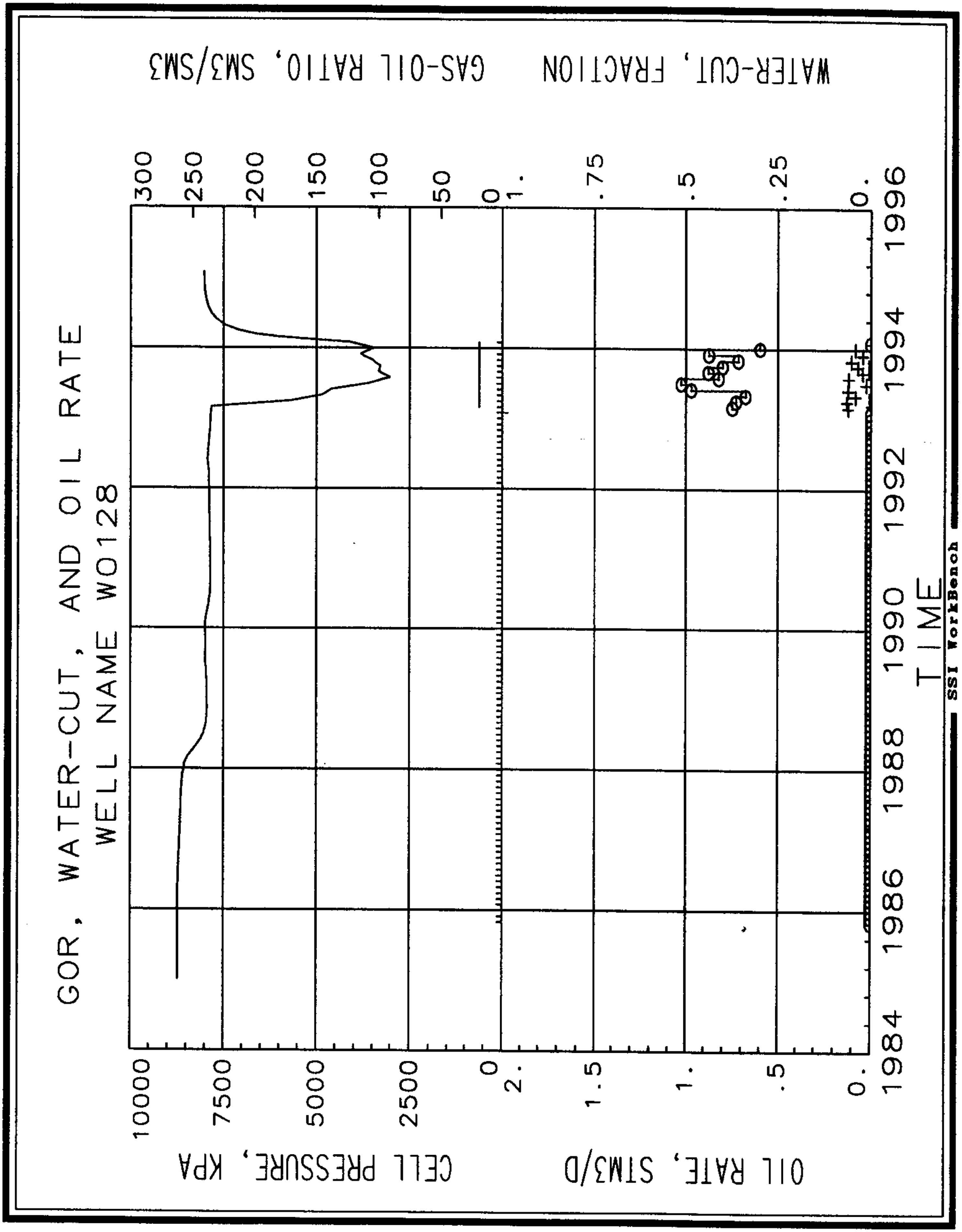


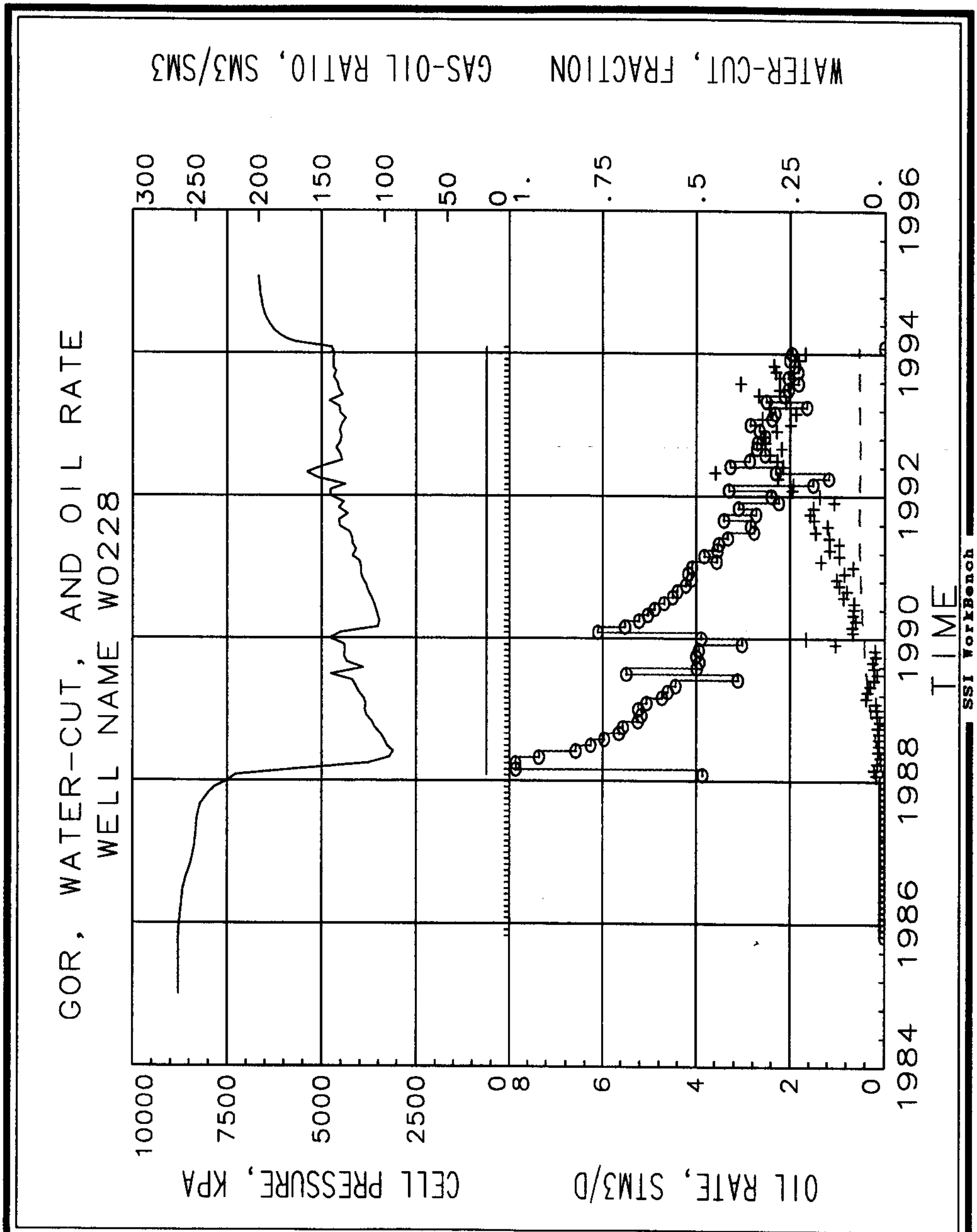
HISTORY MATCH FIGURE 18

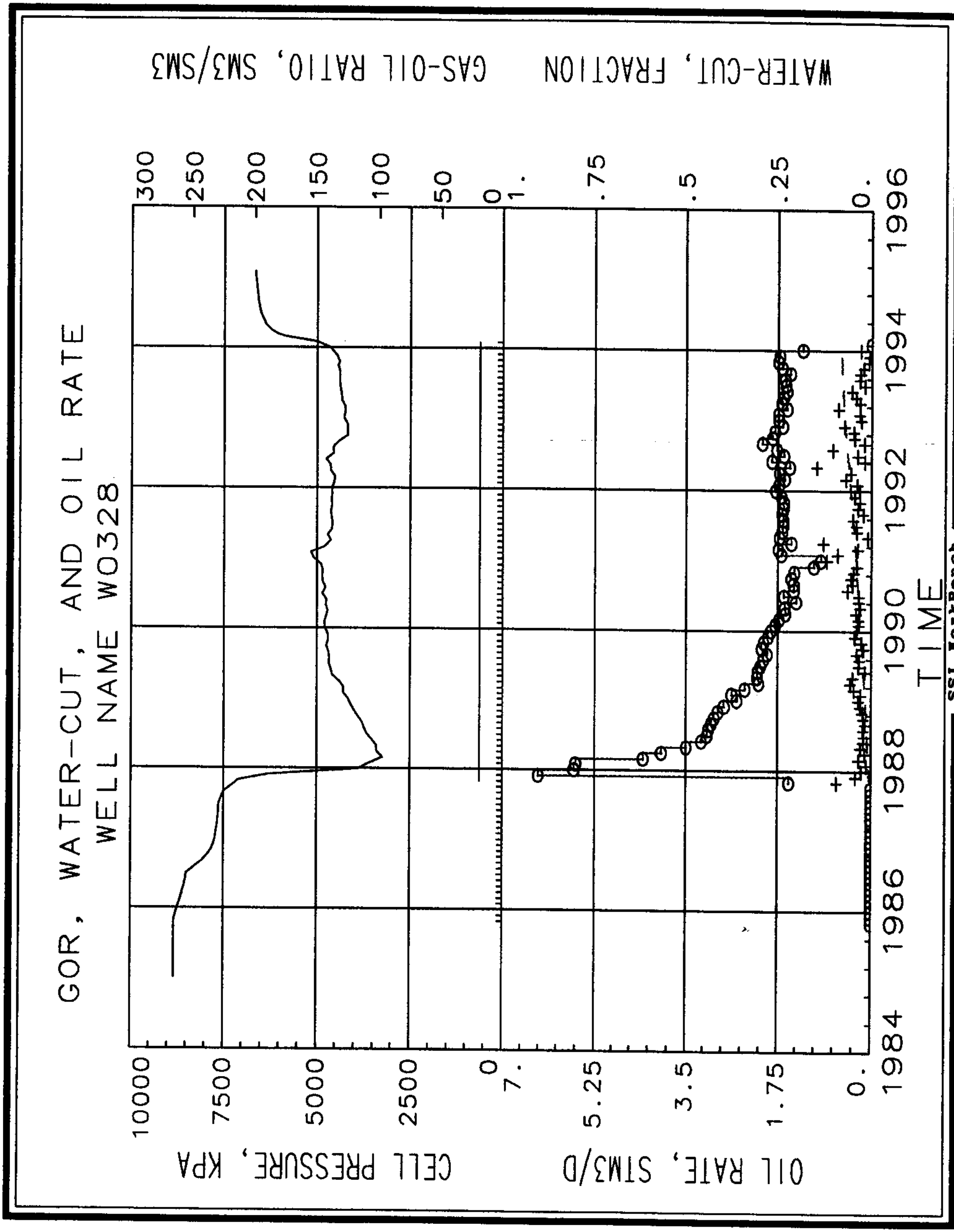


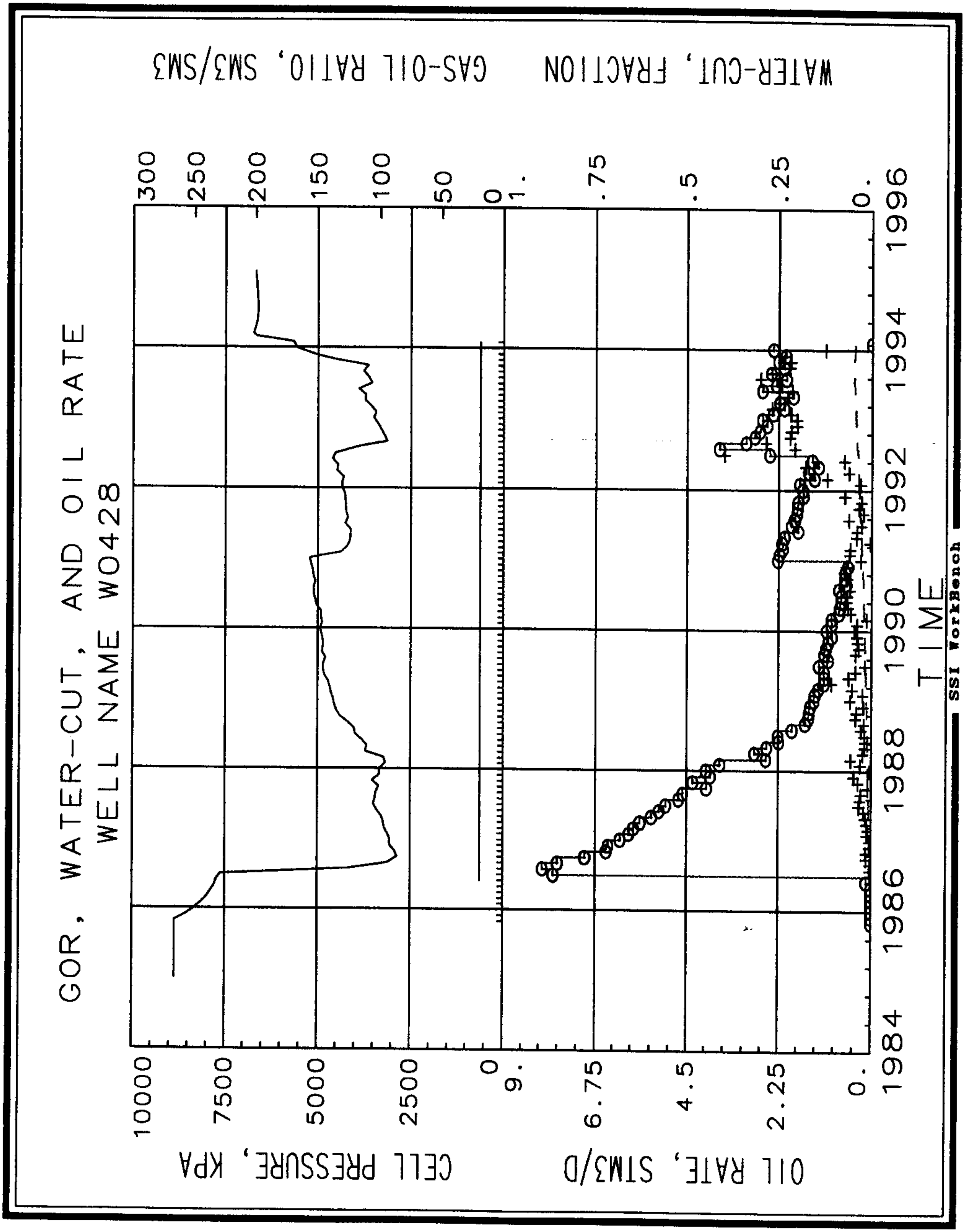
HISTORY MATCH FIGURE 19



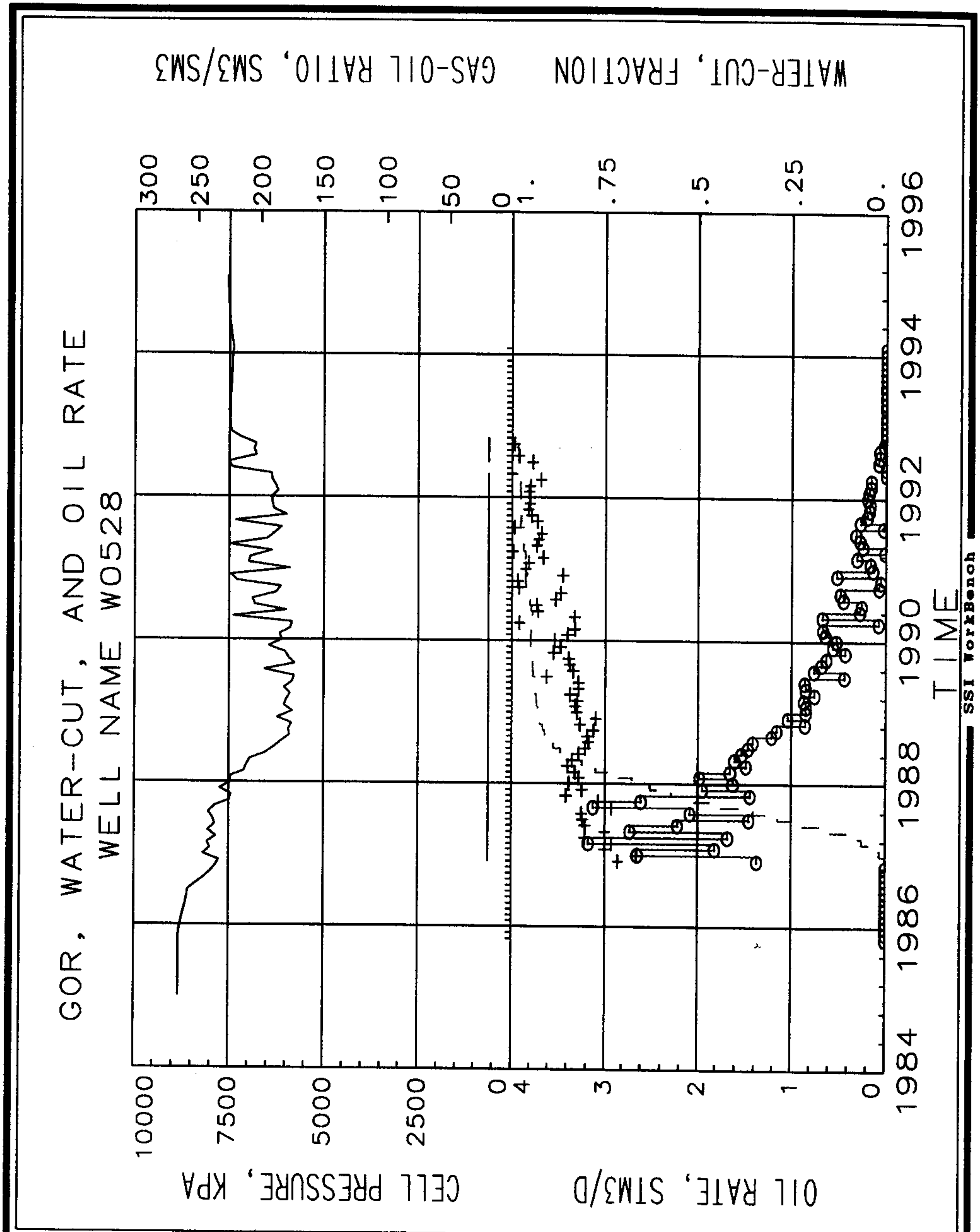

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0128
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench

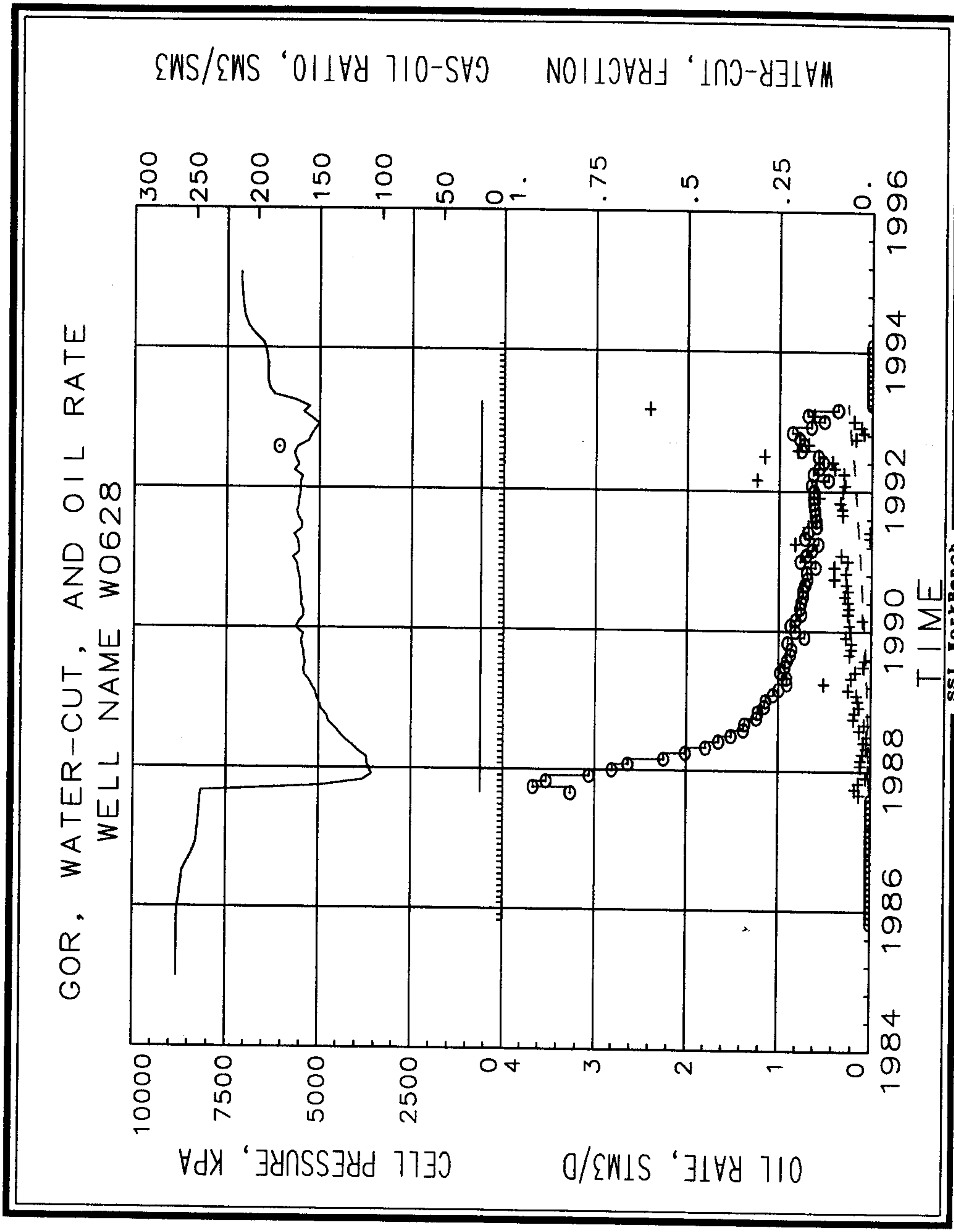

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0228
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W0328
CELL PRESSURE, KPA
10000
7500
5000
2500
0
OIL RATE, STM3/D
7.
5.25
3.5
1.75
0.
GAS-OIL RATIO, SM3/SM3
300
250
200
150
100
50
0
WATER-CUT, FRACTION
1.
.75
.5
.25
0.
1984
1986
1988
1990
1992
1994
1996
TIME
SSI WorkBench

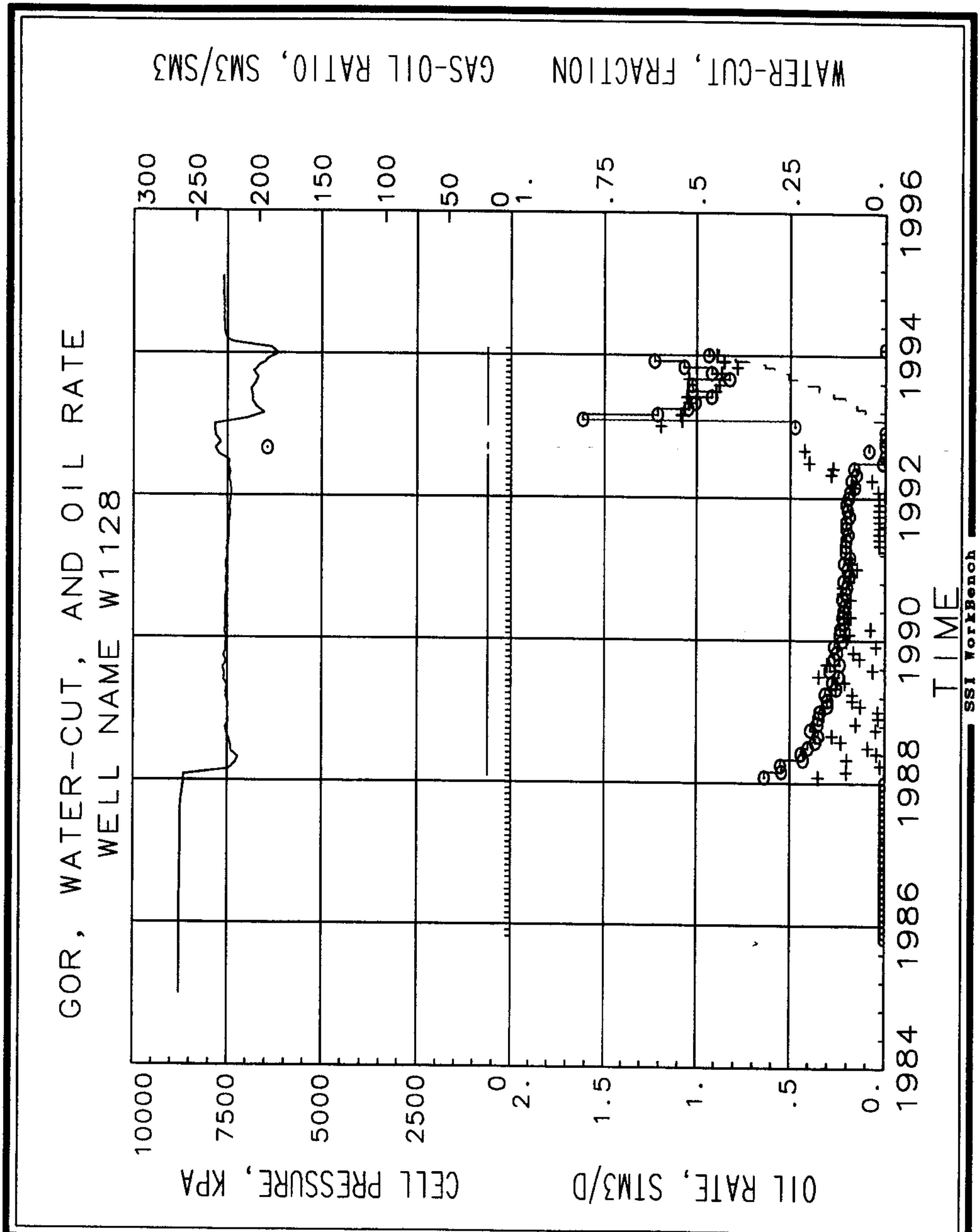

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0428
TIME
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
SSI WorkBench

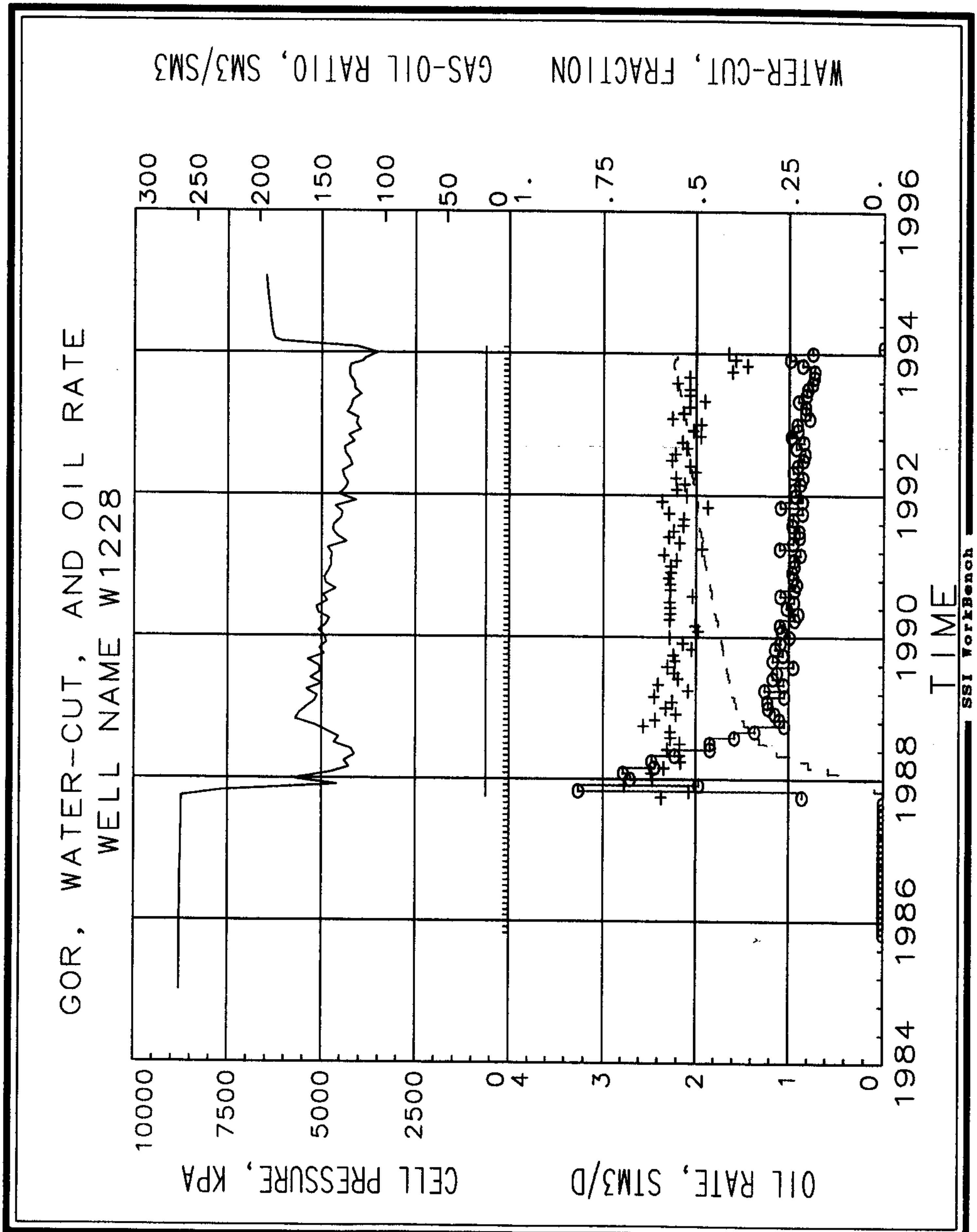
HISTORY MATCH FIGURE 24

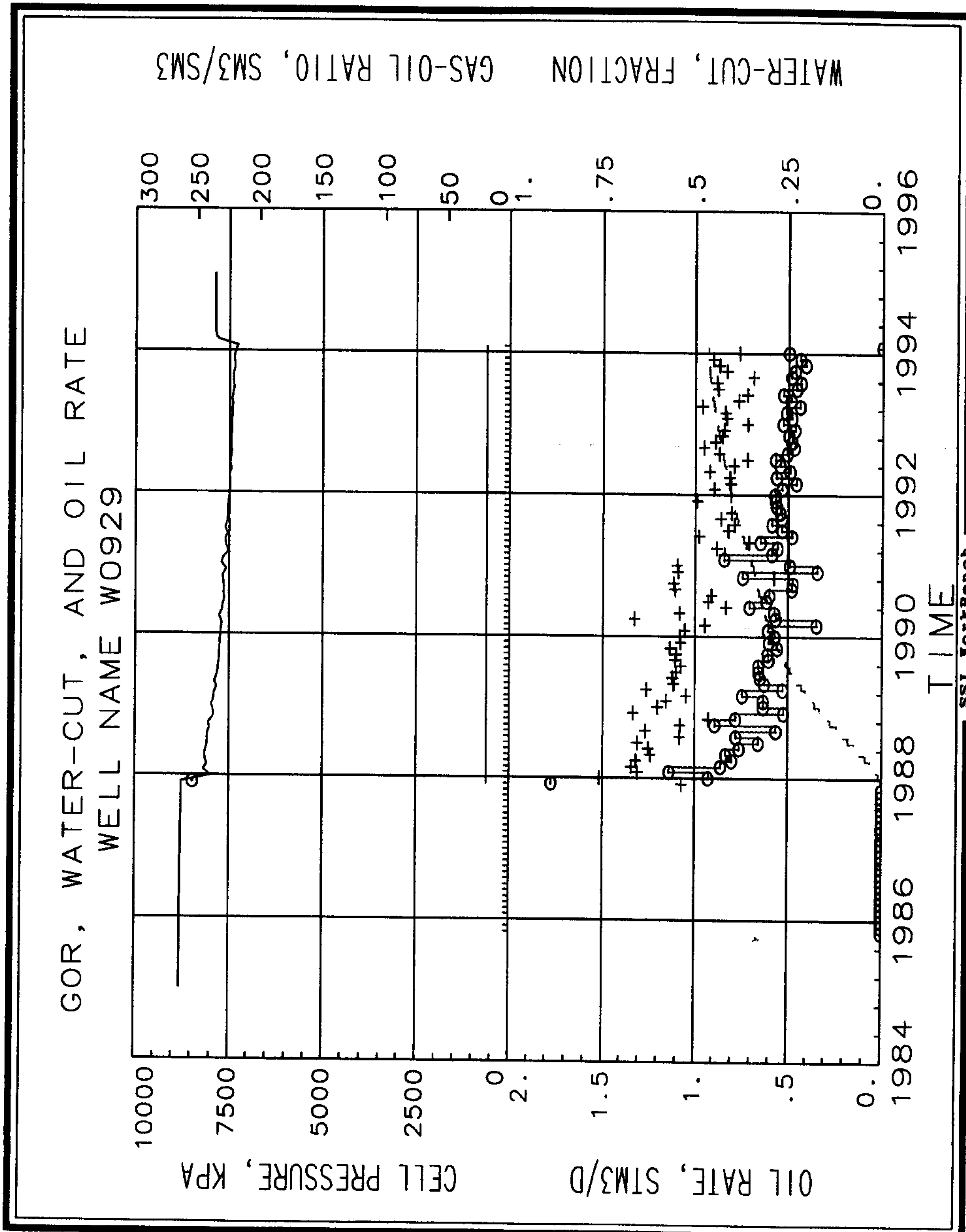


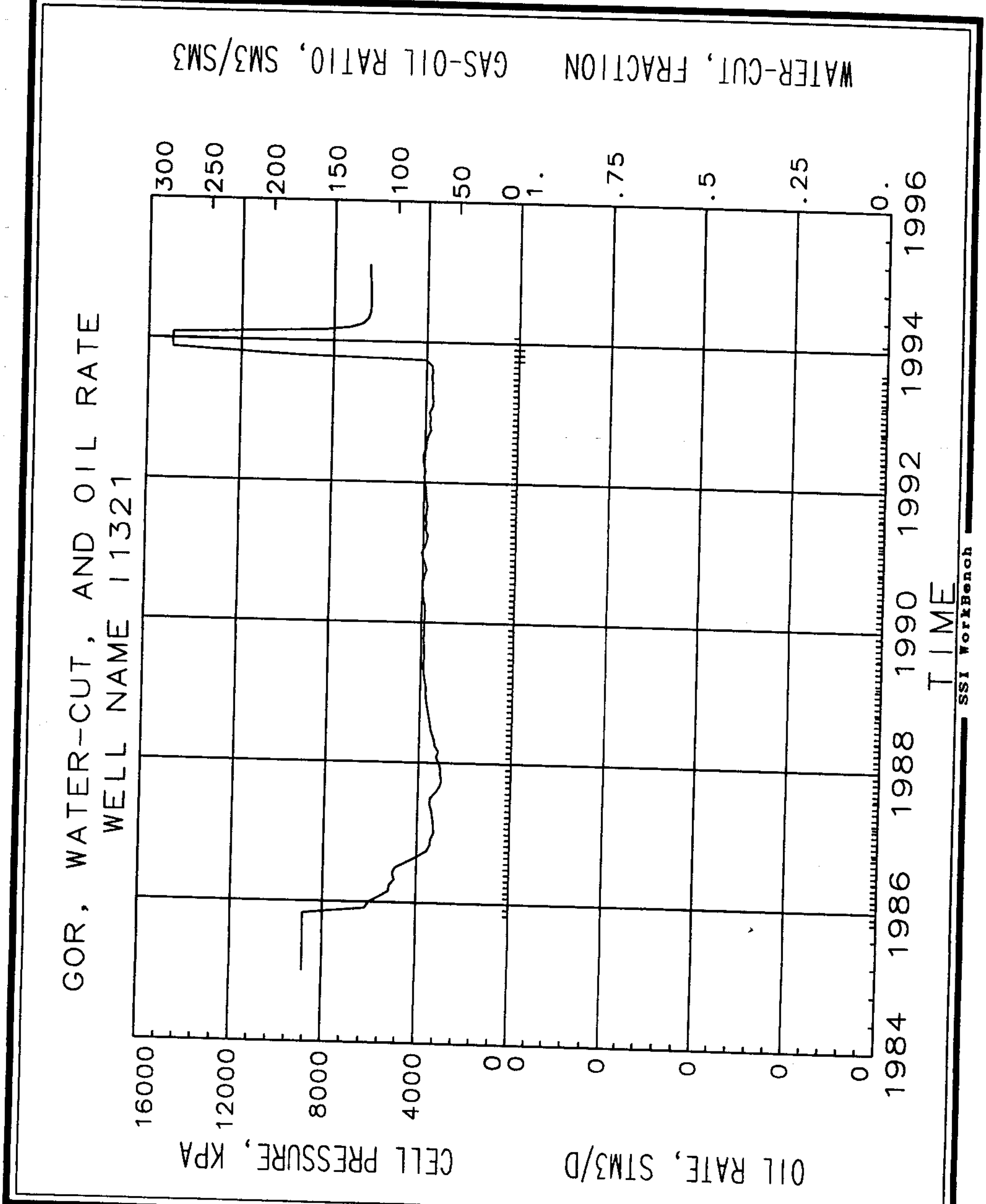

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0628
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
10000
7500
5000
2500
0
4
3
2
1
0
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
1984
1986
1988
1990
1992
1994
1996
TIME
SSI WorkBench

HISTORY MATCH FIGURE 26

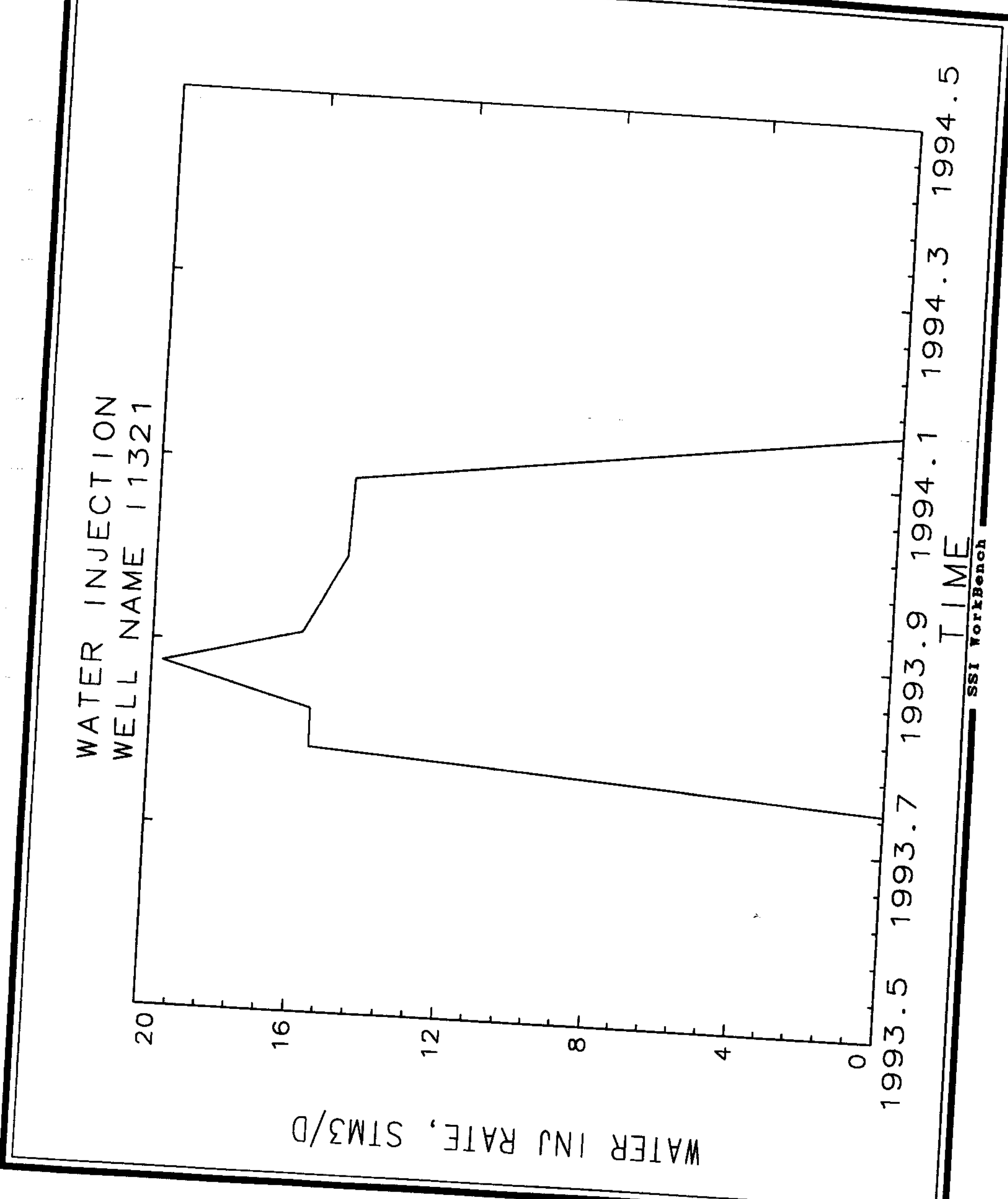



GOR, WATER-CUT, AND OIL RATE
WELL NAME W1228
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
4
3
2
1
0
1984
1986
1988
1990
1992
1994
1996

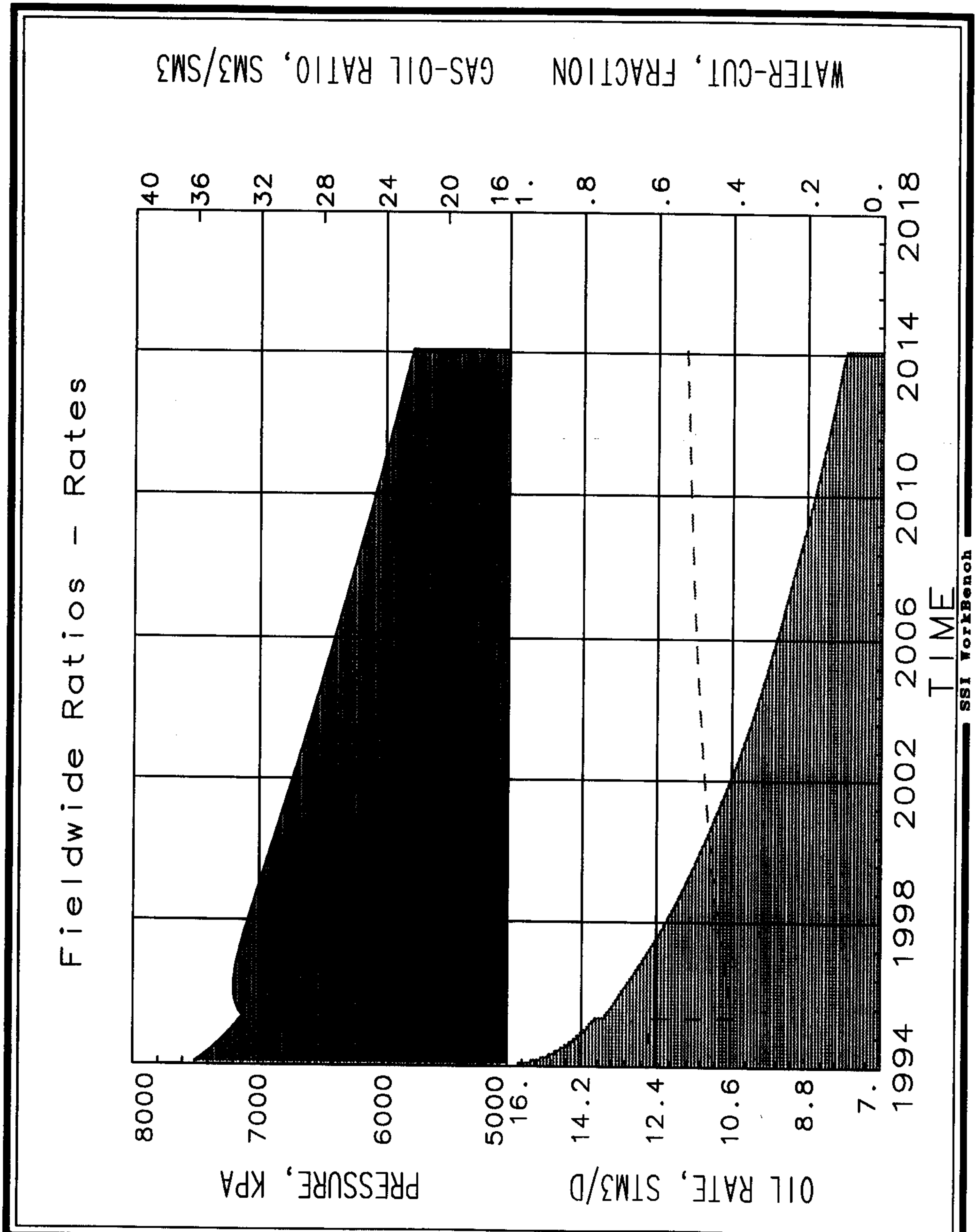

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0929
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench
1984
1986
1988
1990
1992
1994
1996


GOR, WATER-CUT, AND OIL RATE
WELL NAME I1321
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1984
1986
1988
1990
1992
1994
1996
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
16000
12000
8000
4000
0
SSI WorkBench

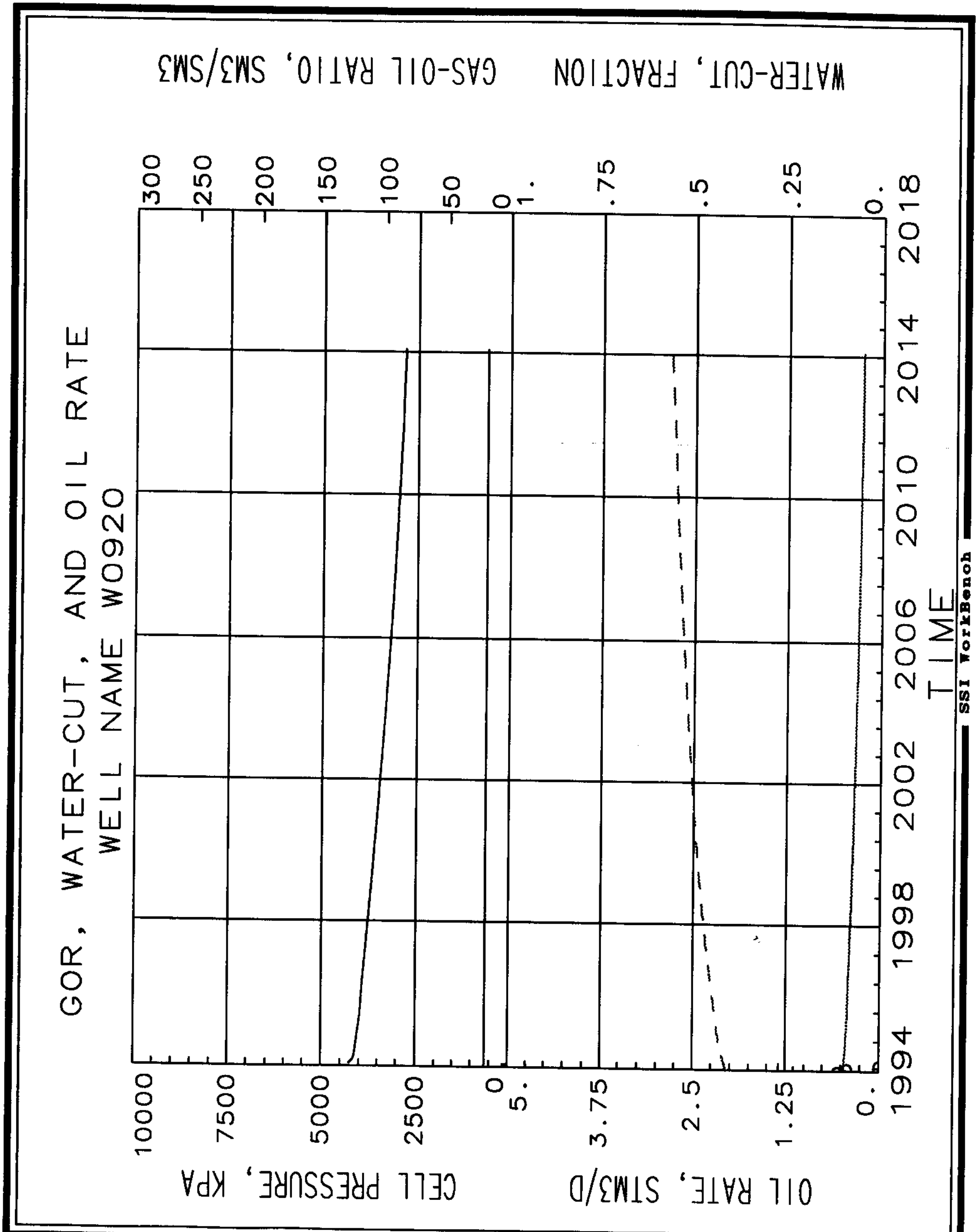
HISTORY MATCH   FIGURE 30



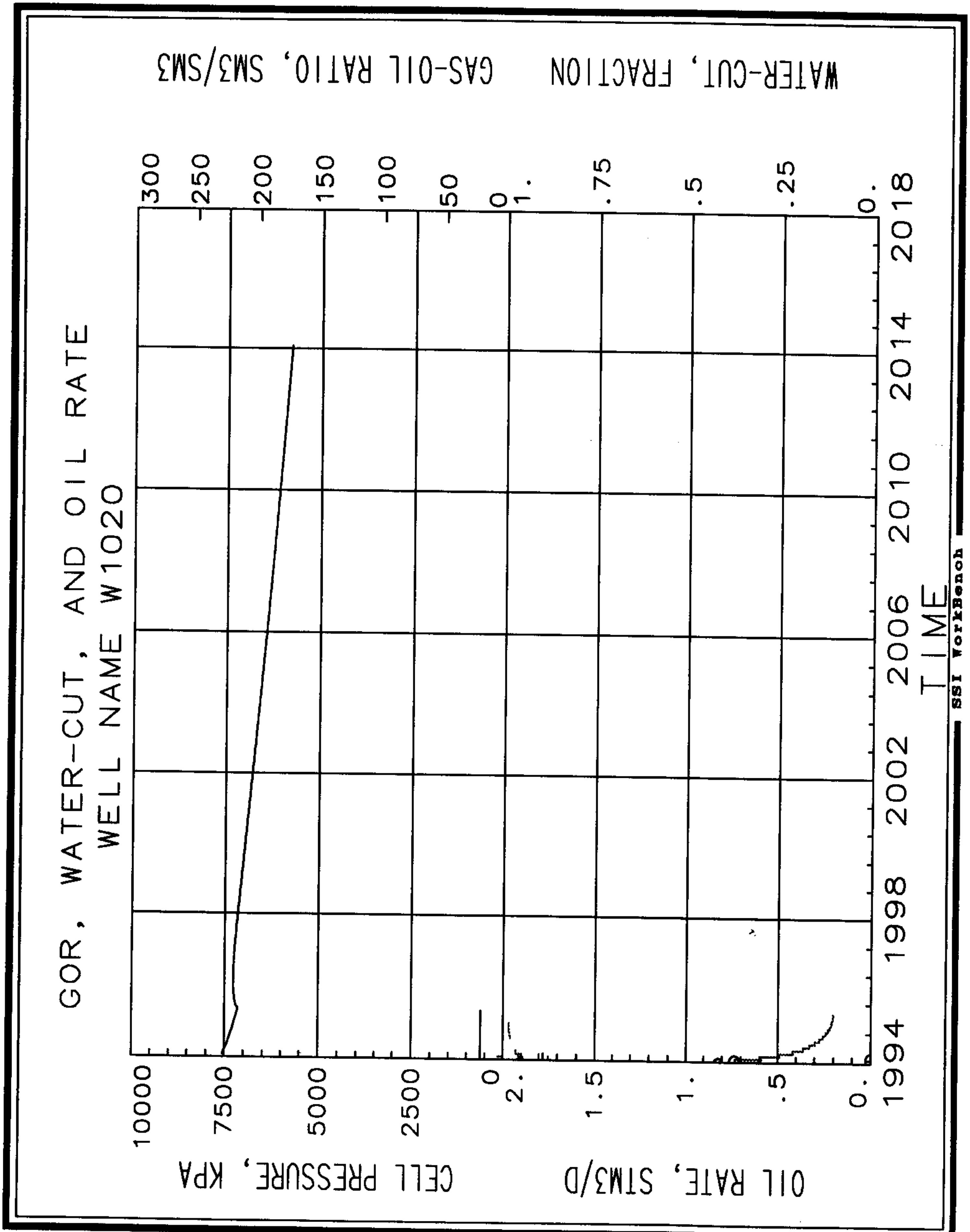
CASE 1 FIGURE 31

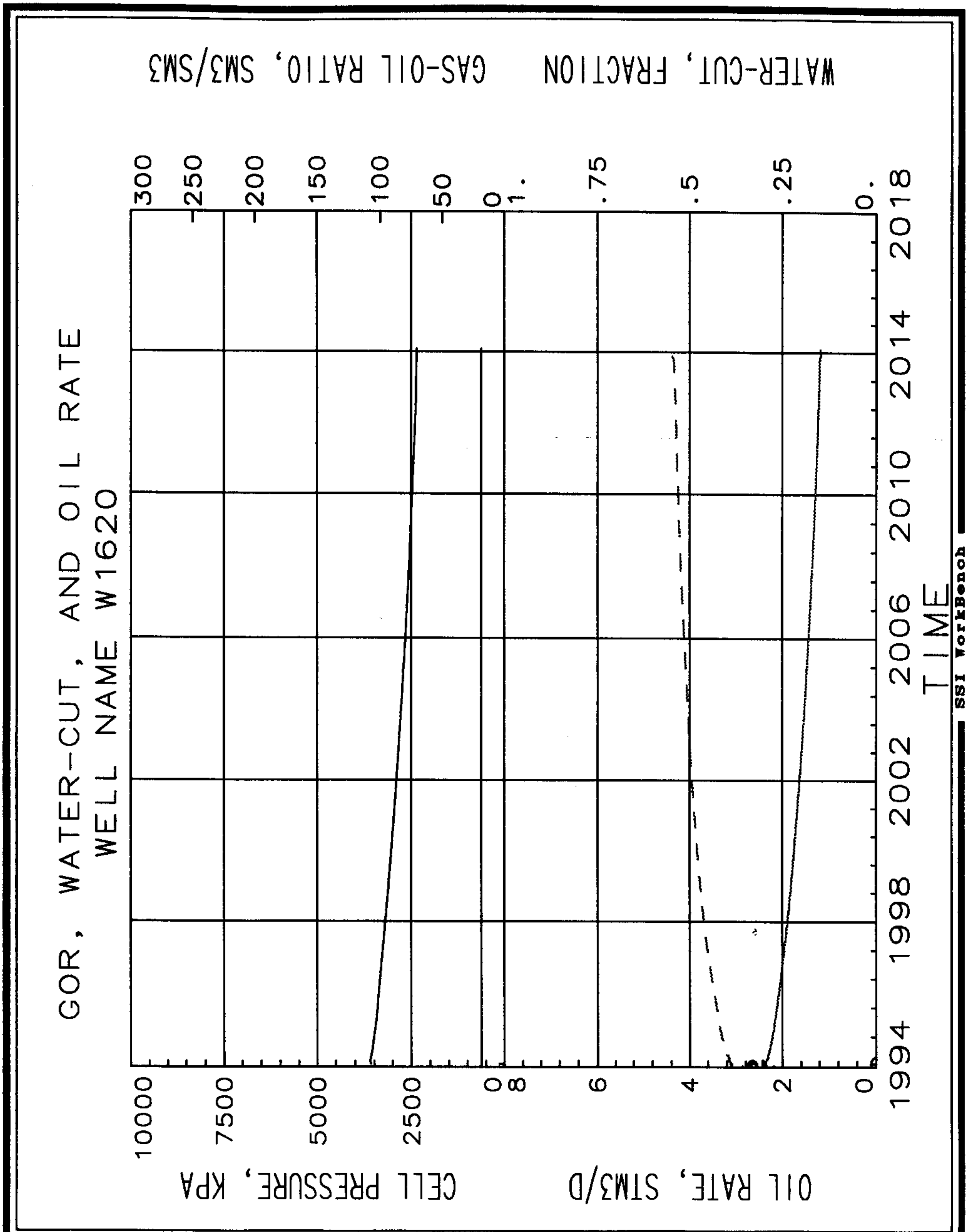


CASE 1 FIGURE 32

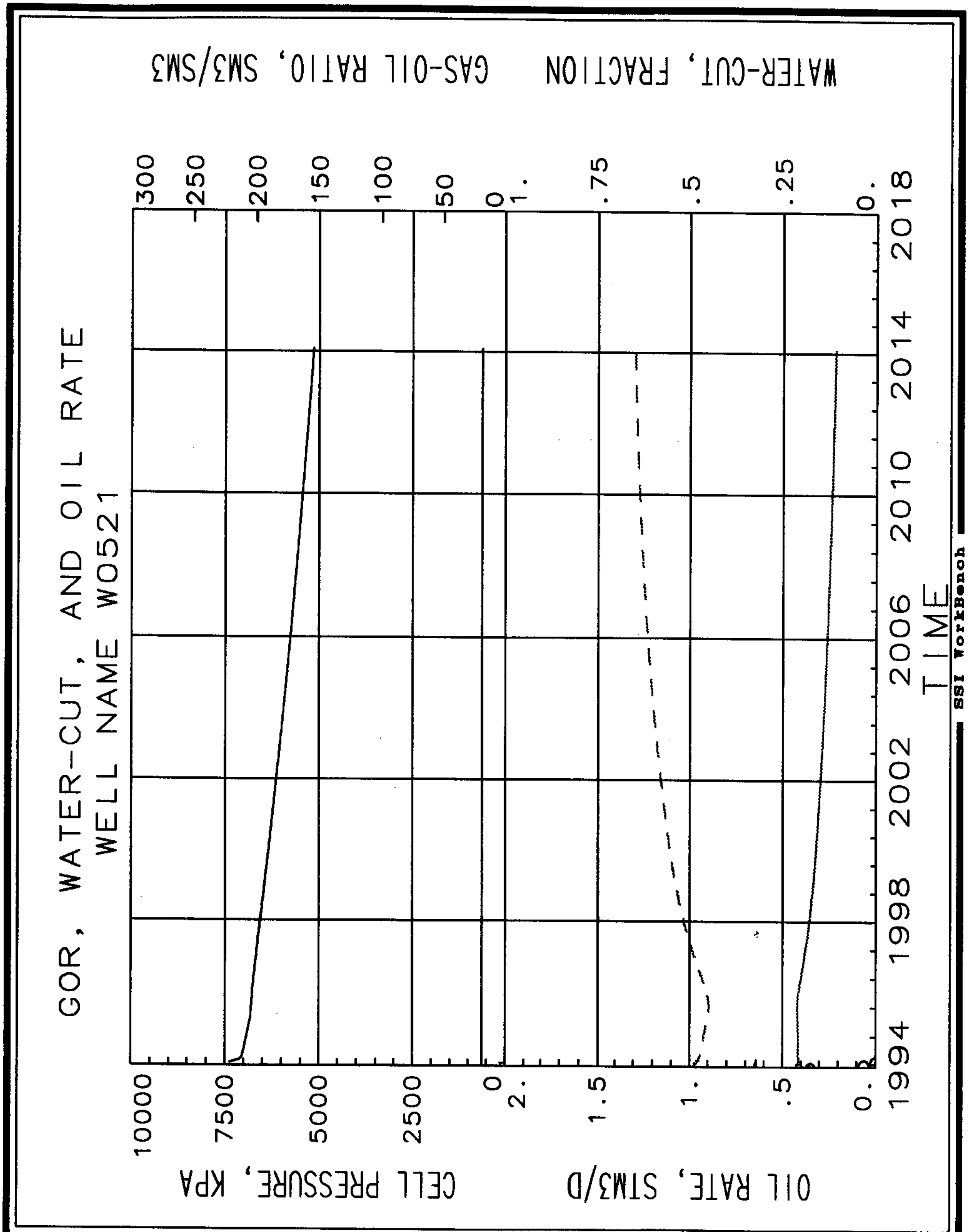


CASE 1 FIGURE 33

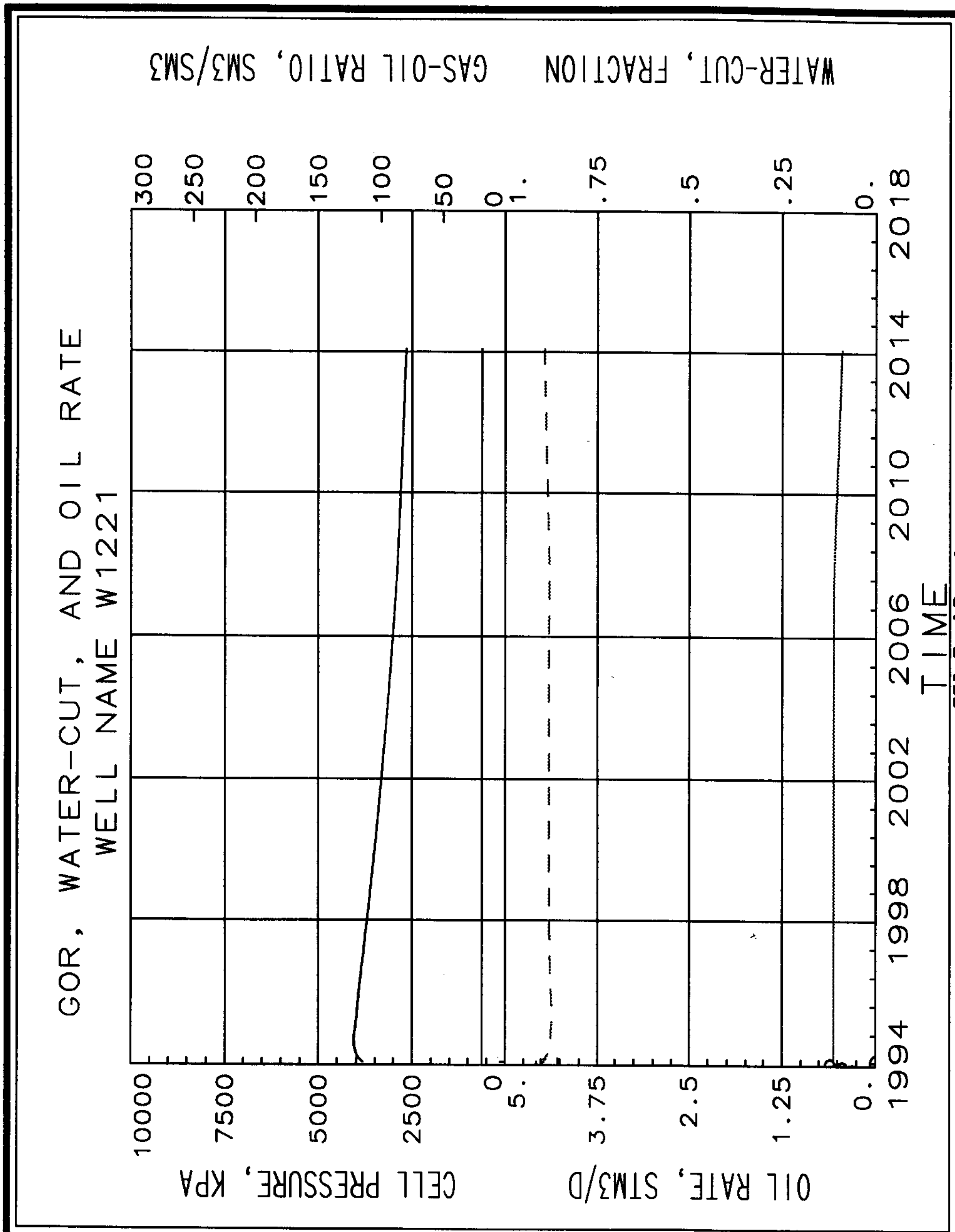



GOR, WATER-CUT, AND OIL RATE
WELL NAME W1620
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
0 50 100 150 200 250 300
0. .25 .5 .75 1.
10000 7500 5000 2500 0
0 2 4 6 8
1994 1998 2002 2006 2010 2014 2018
SSI WorkBench

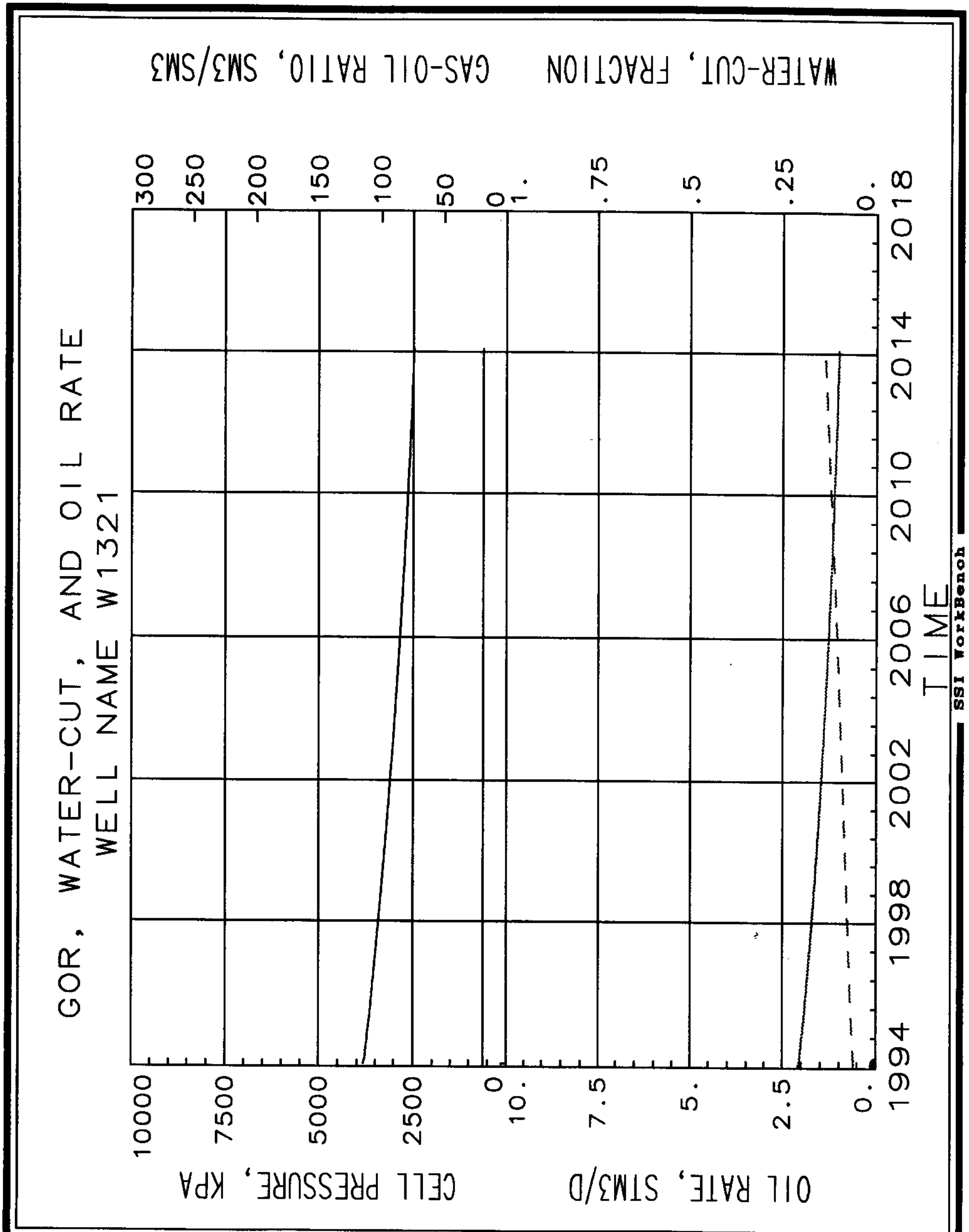
CASE 1 FIGURE 35



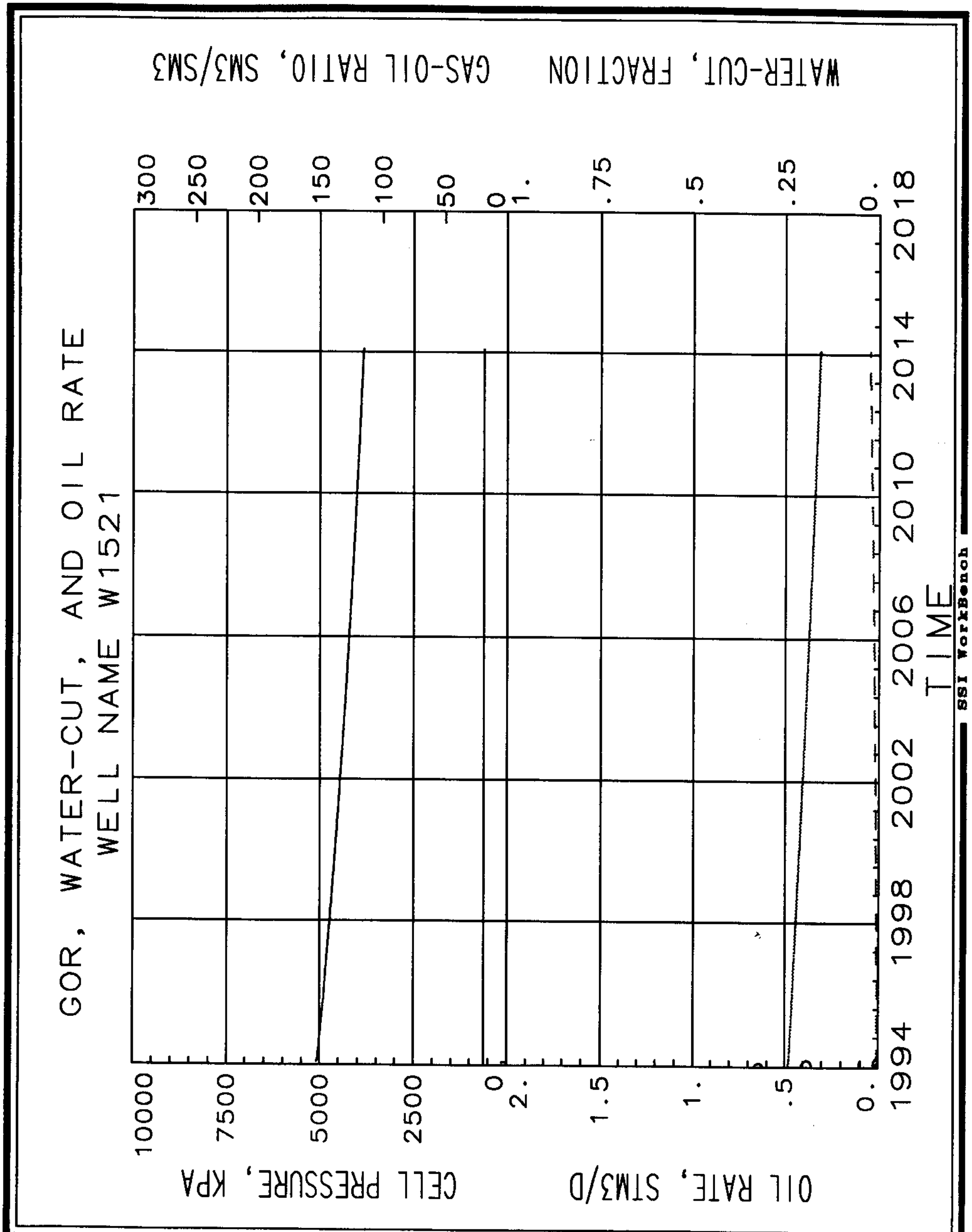
CASE 1 FIGURE 36

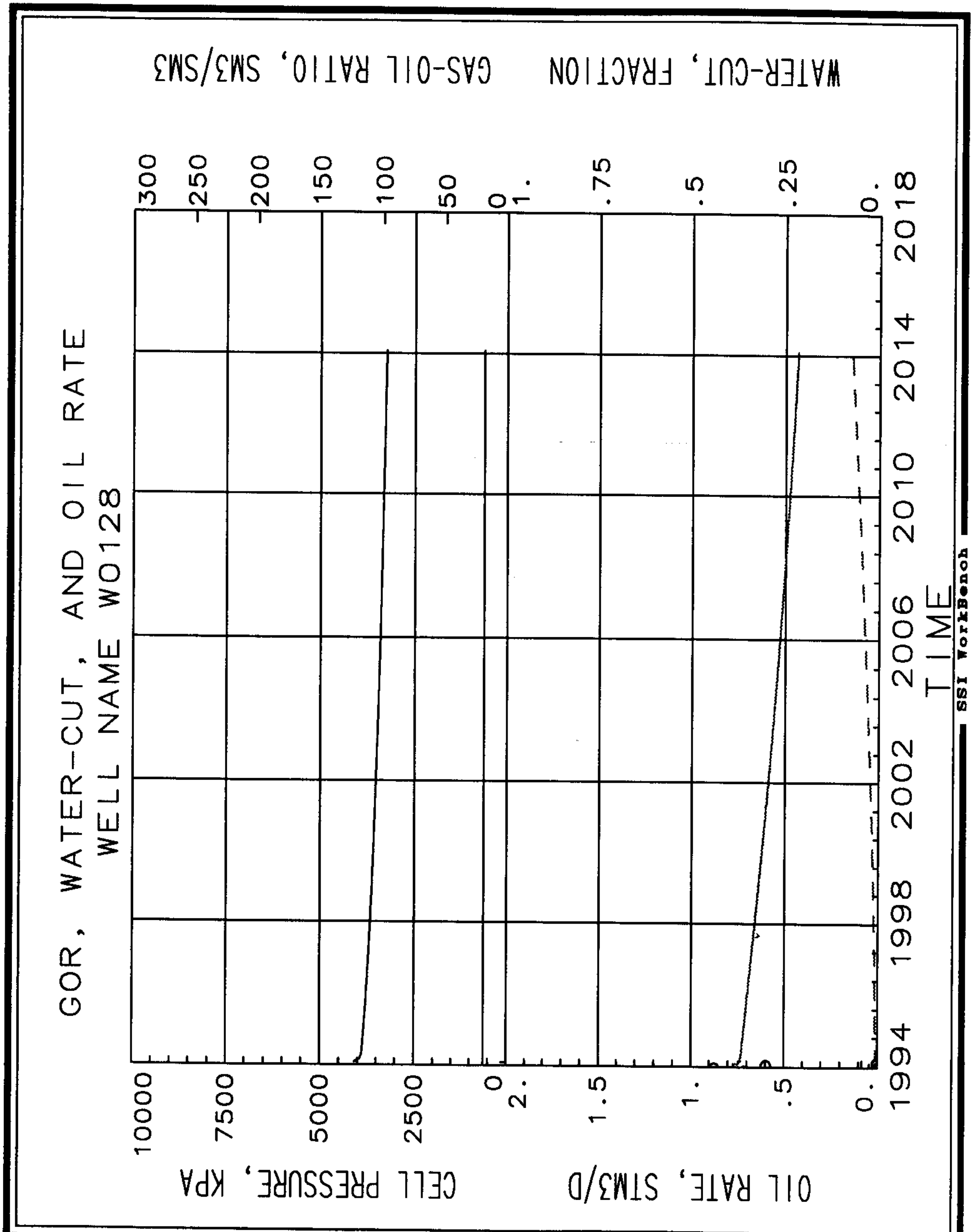


CASE 1 FIGURE 37

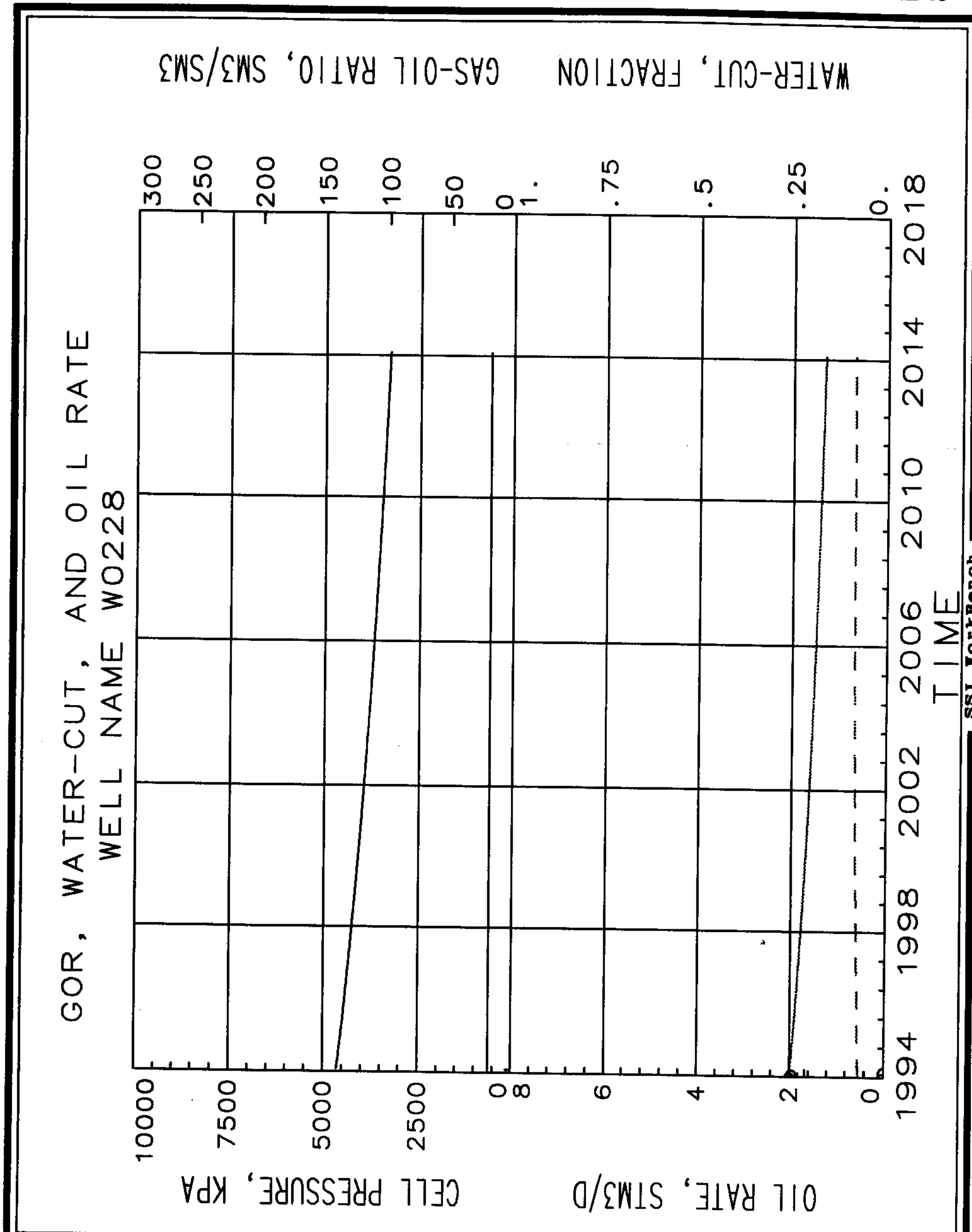


CASE 1 FIGURE 38

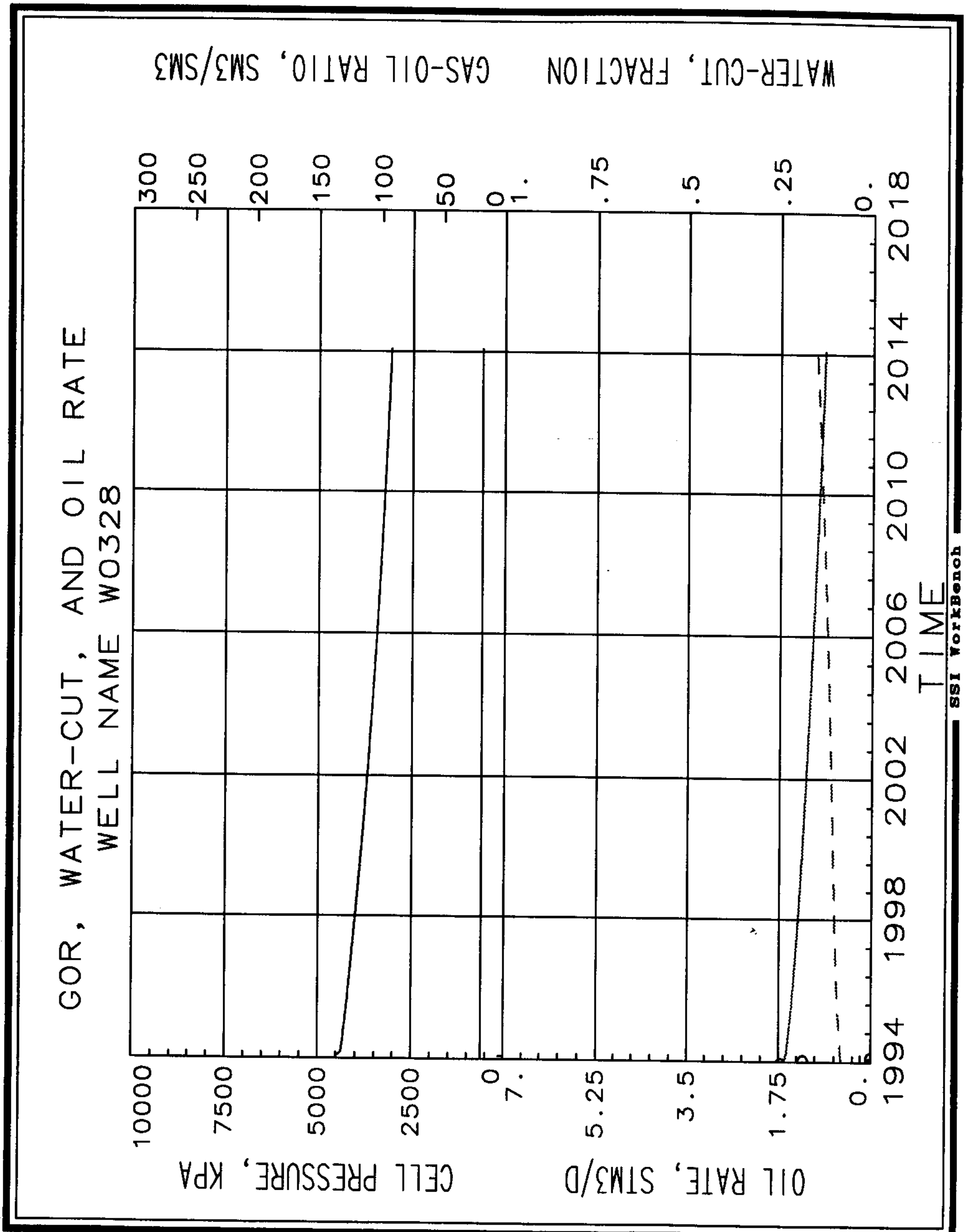



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0128
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench

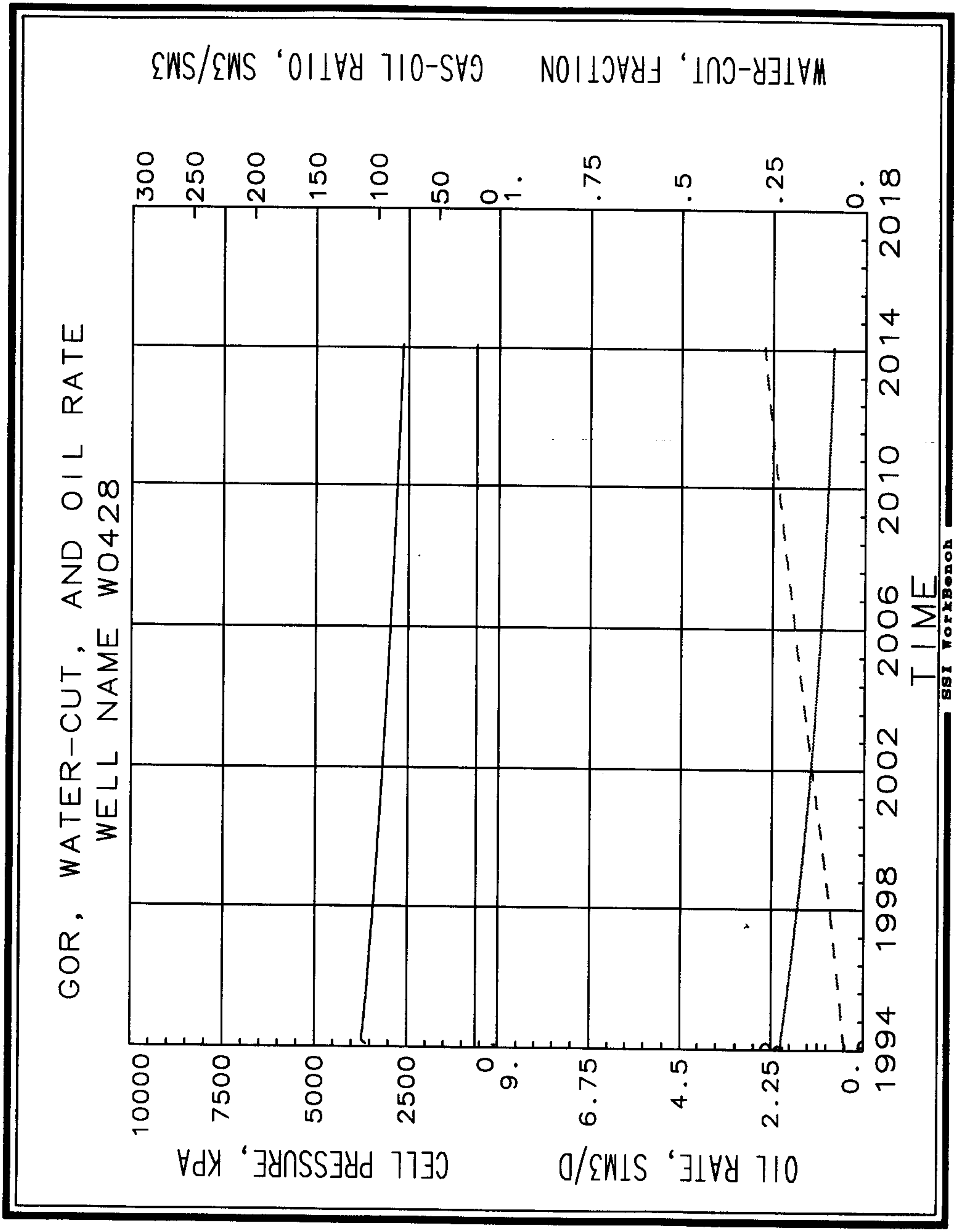
CASE 1 FIGURE 40



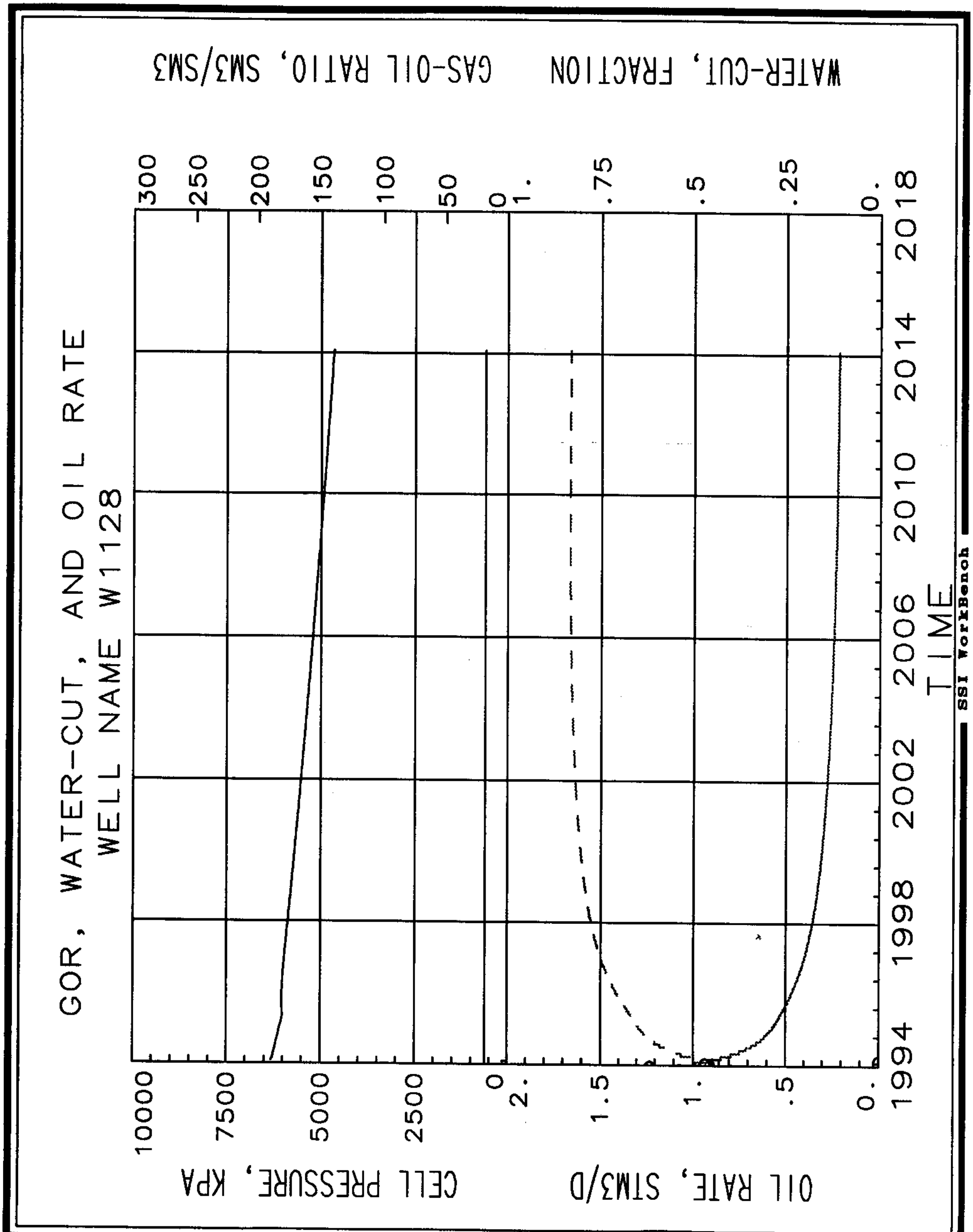
CASE 1 FIGURE 41



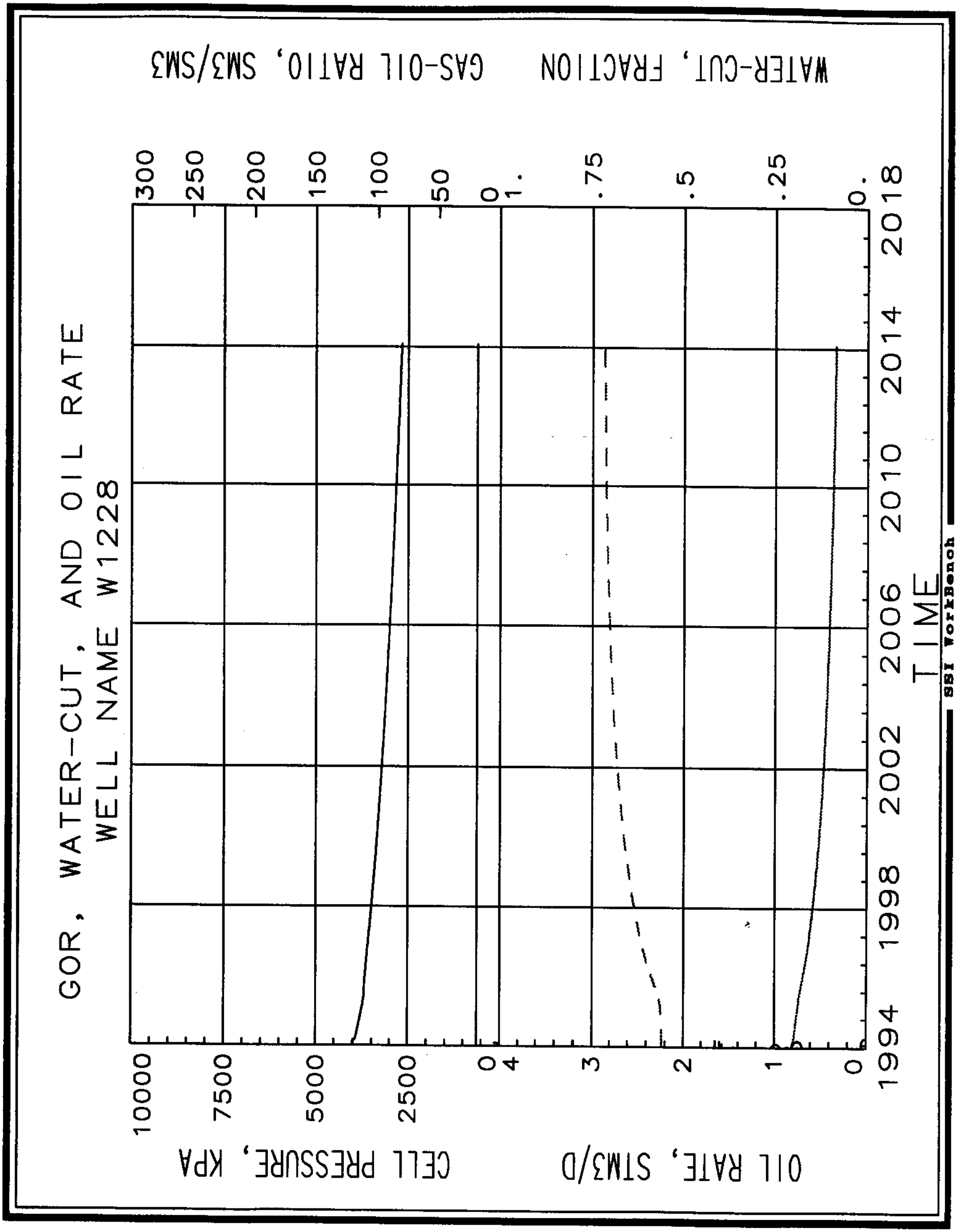
CASE 1 FIGURE 42



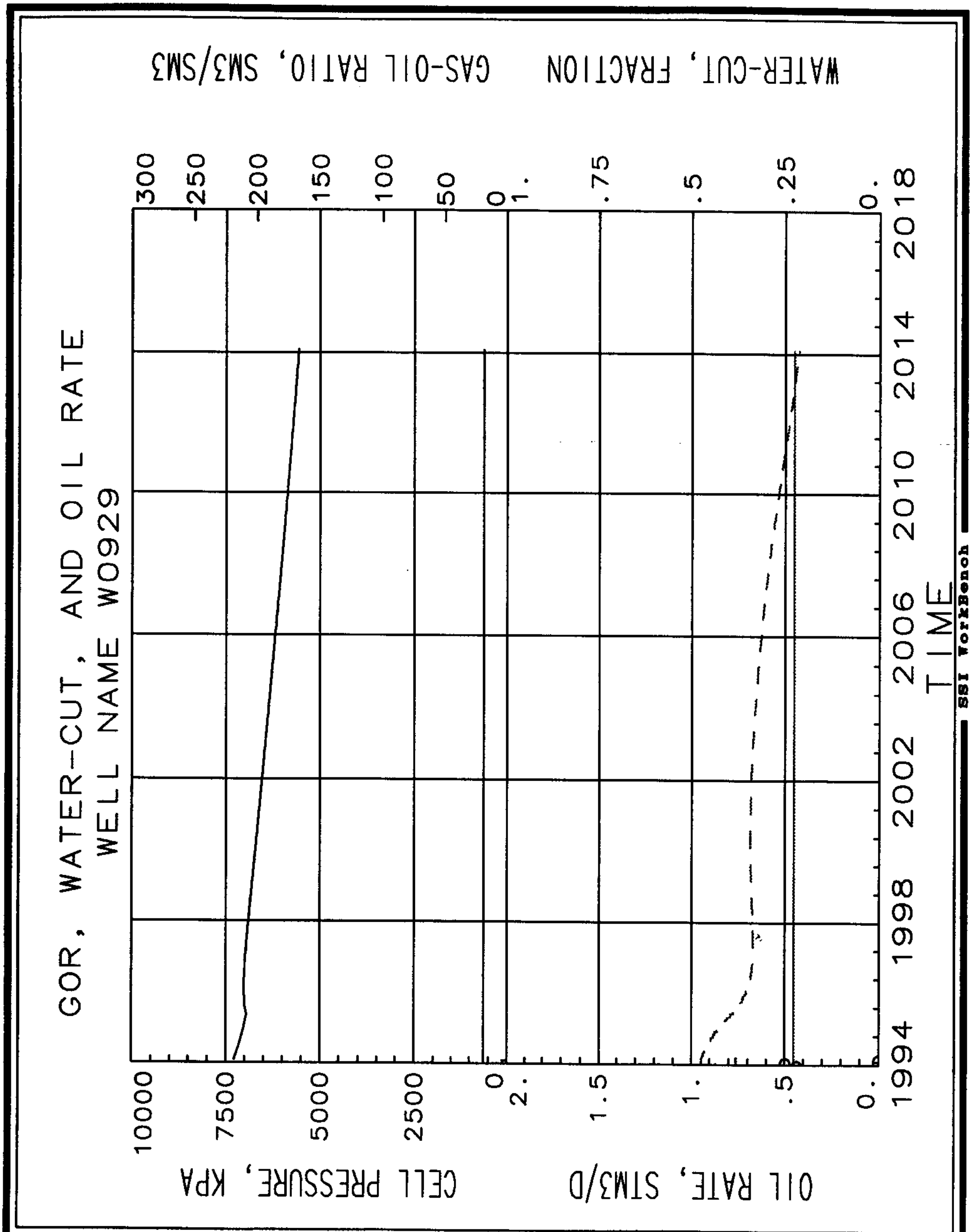
CASE 1 FIGURE 43



CASE 1 FIGURE 44



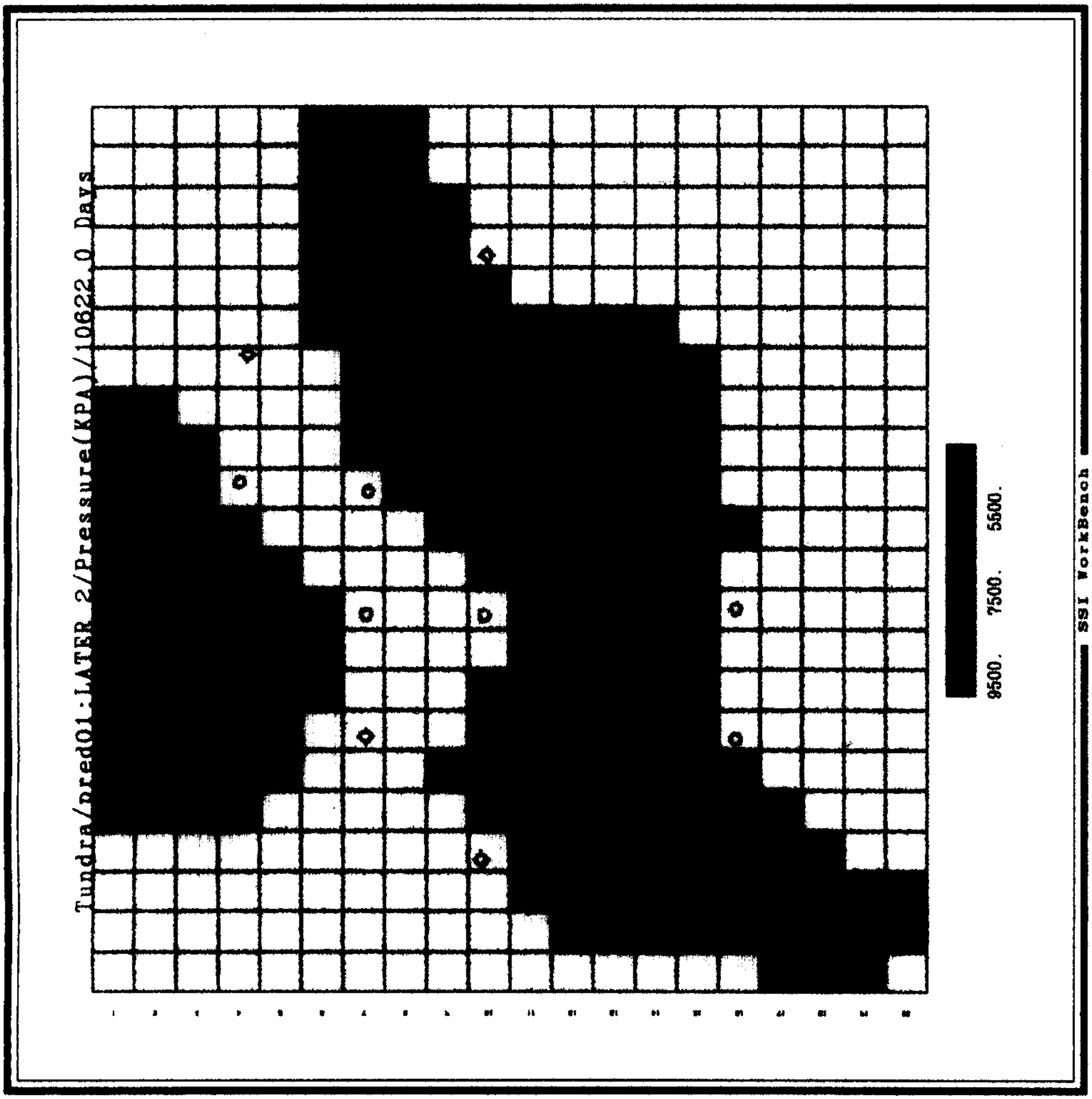
CASE 1   FIGURE 45



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 1 FIGURE 46

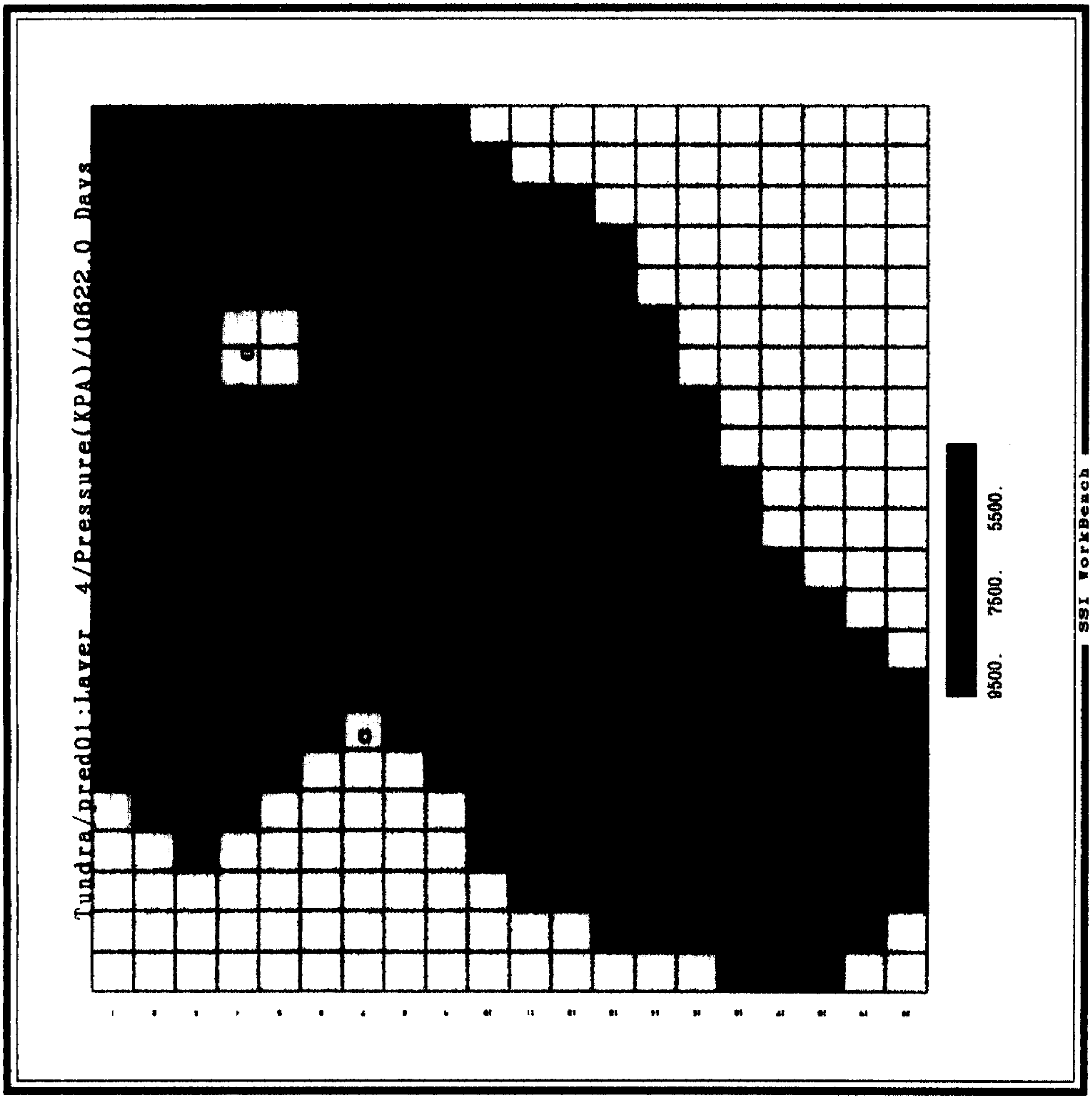
Prediction Case 1 - Pressure Distribution Map Layer 2



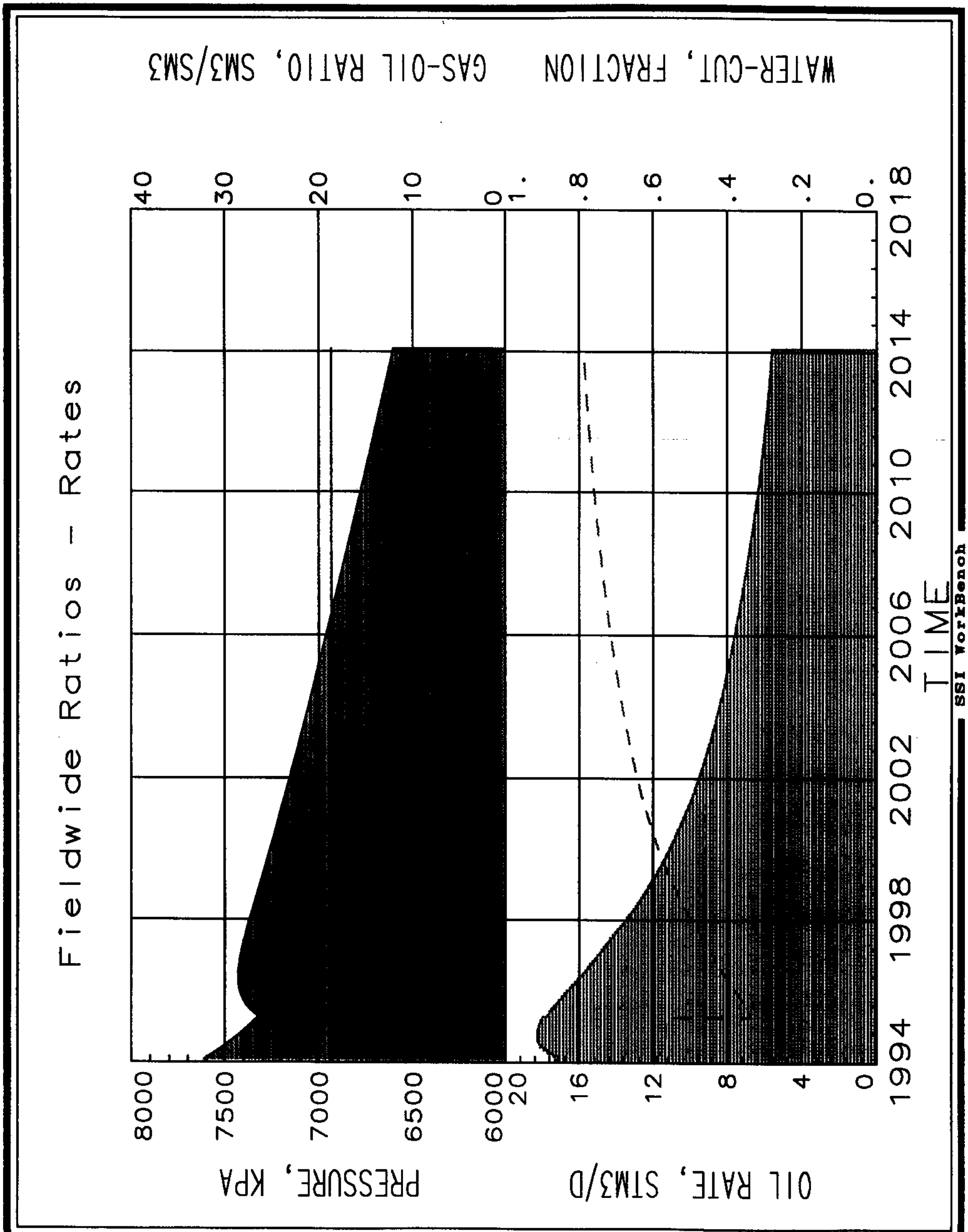
Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 1 FIGURE 47

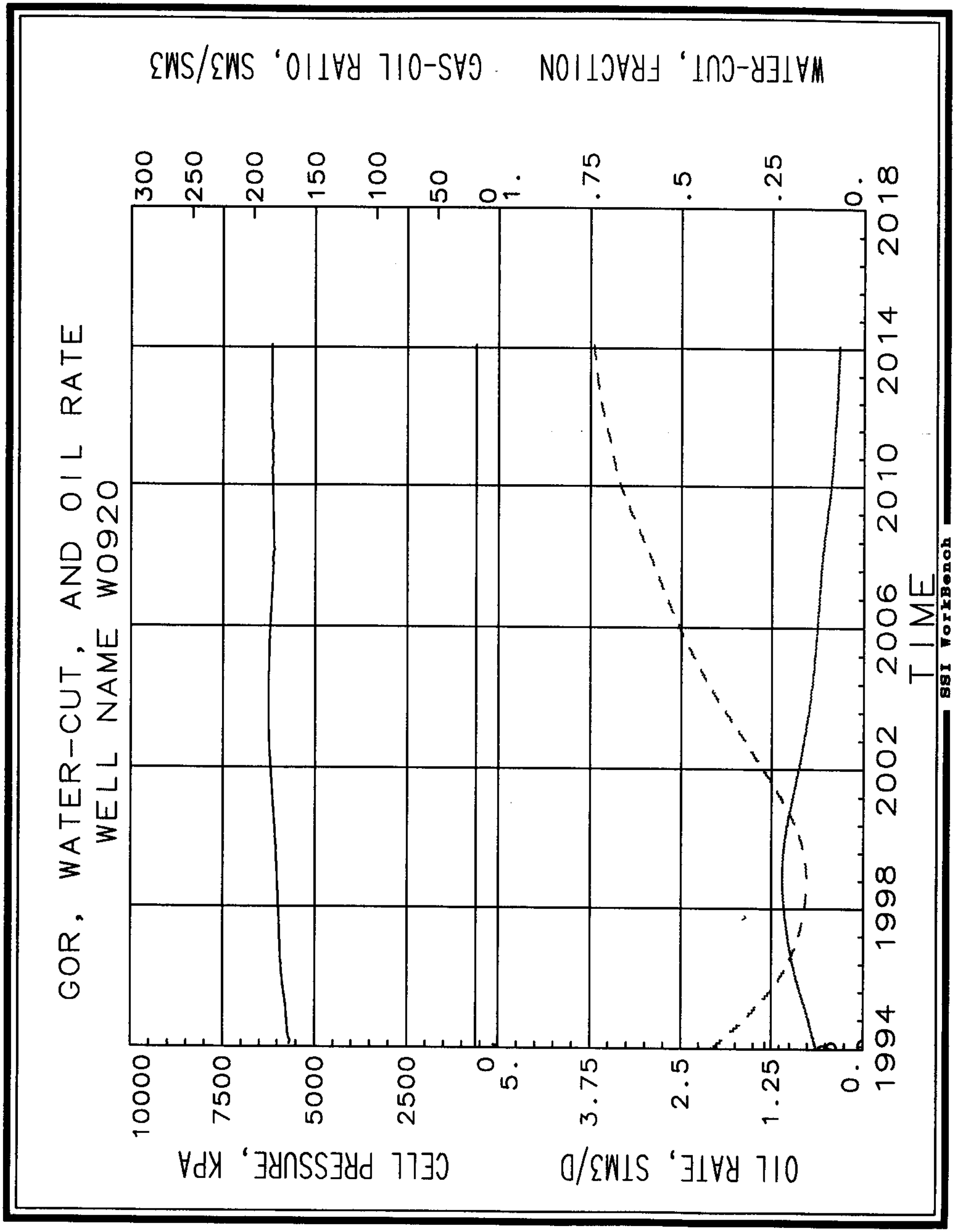
Prediction Case 1 - Pressure Distribution Map Layer 4



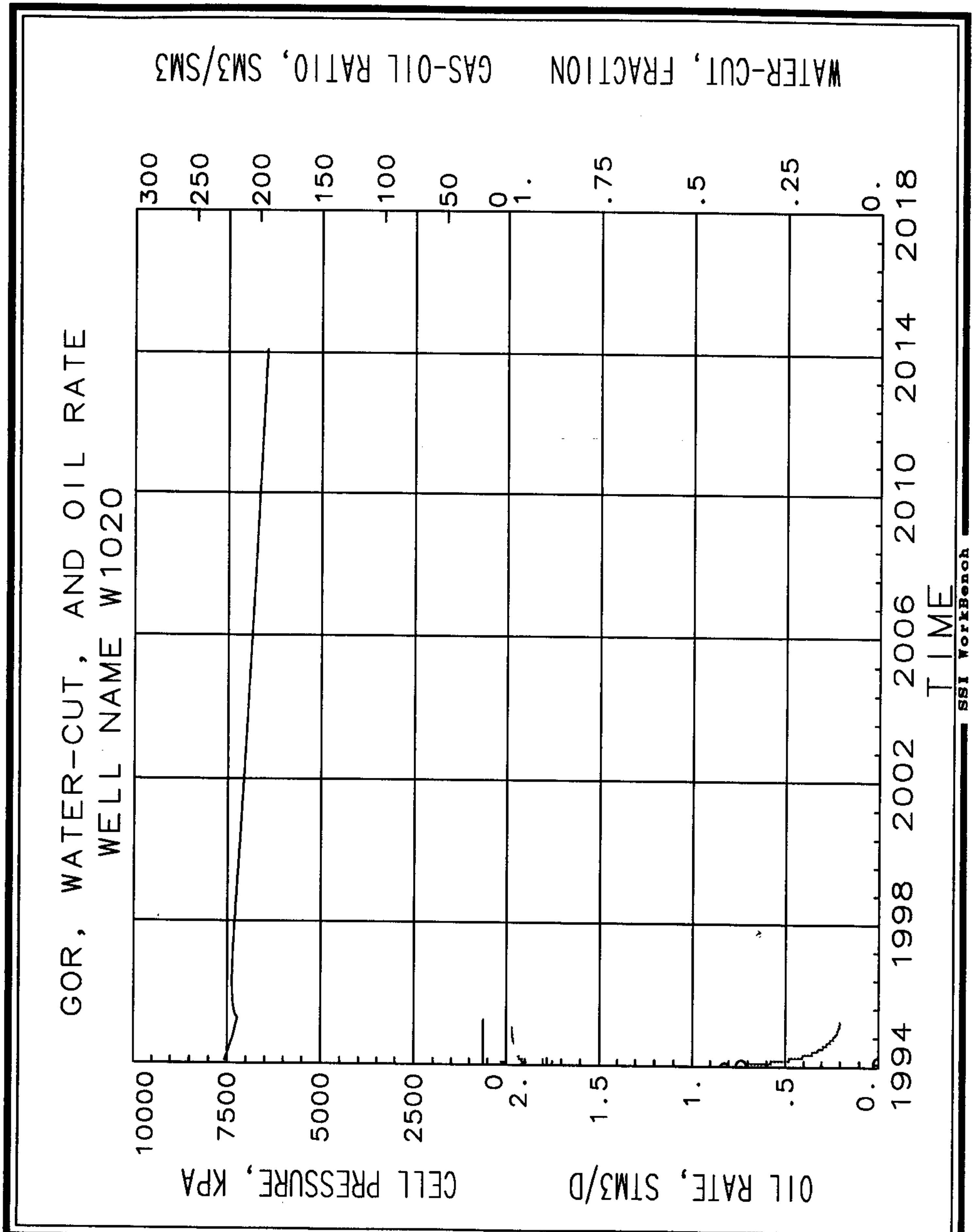
CASE 2 FIGURE 48

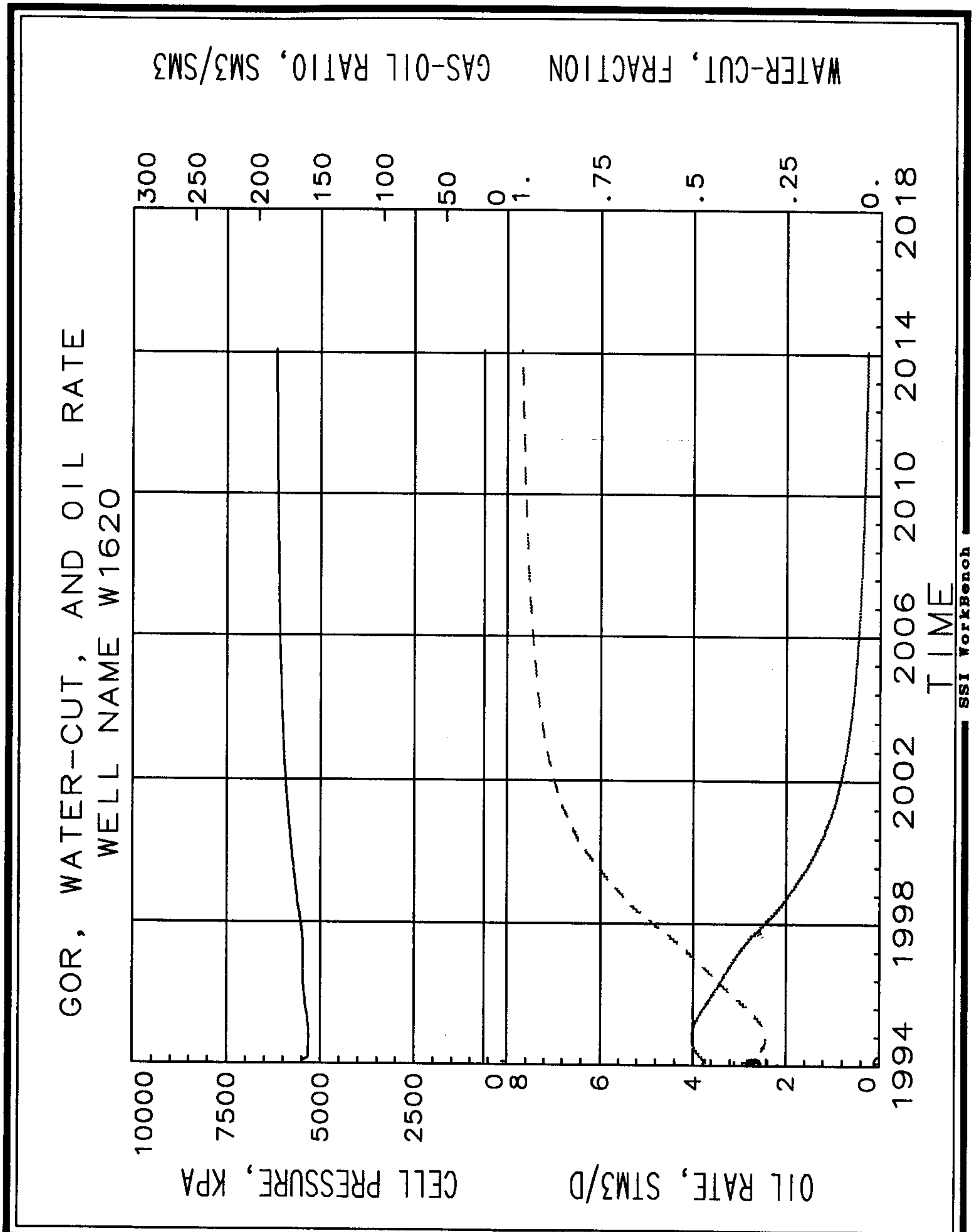


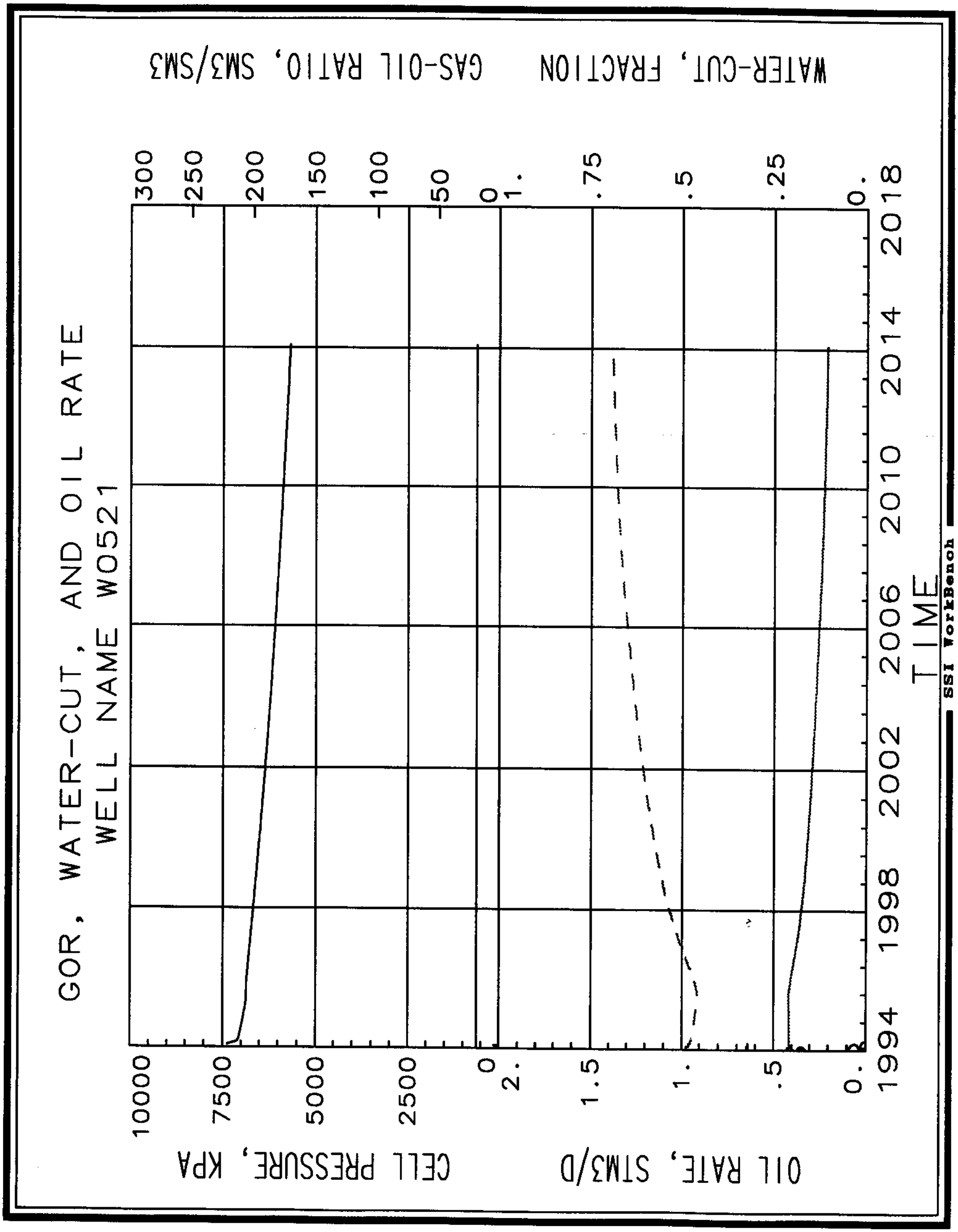
CASE 2 FIGURE 49

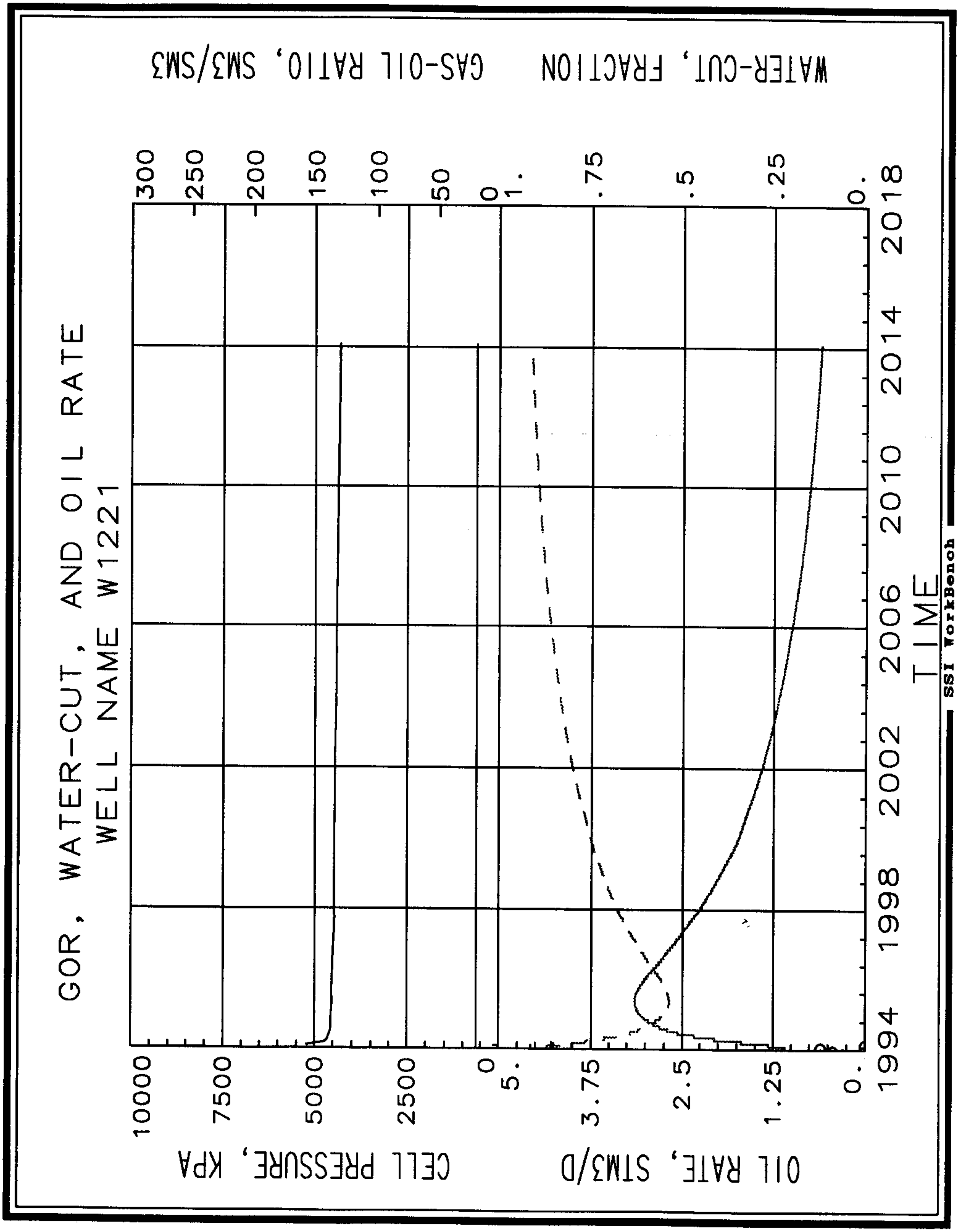


CASE 2 FIGURE 50

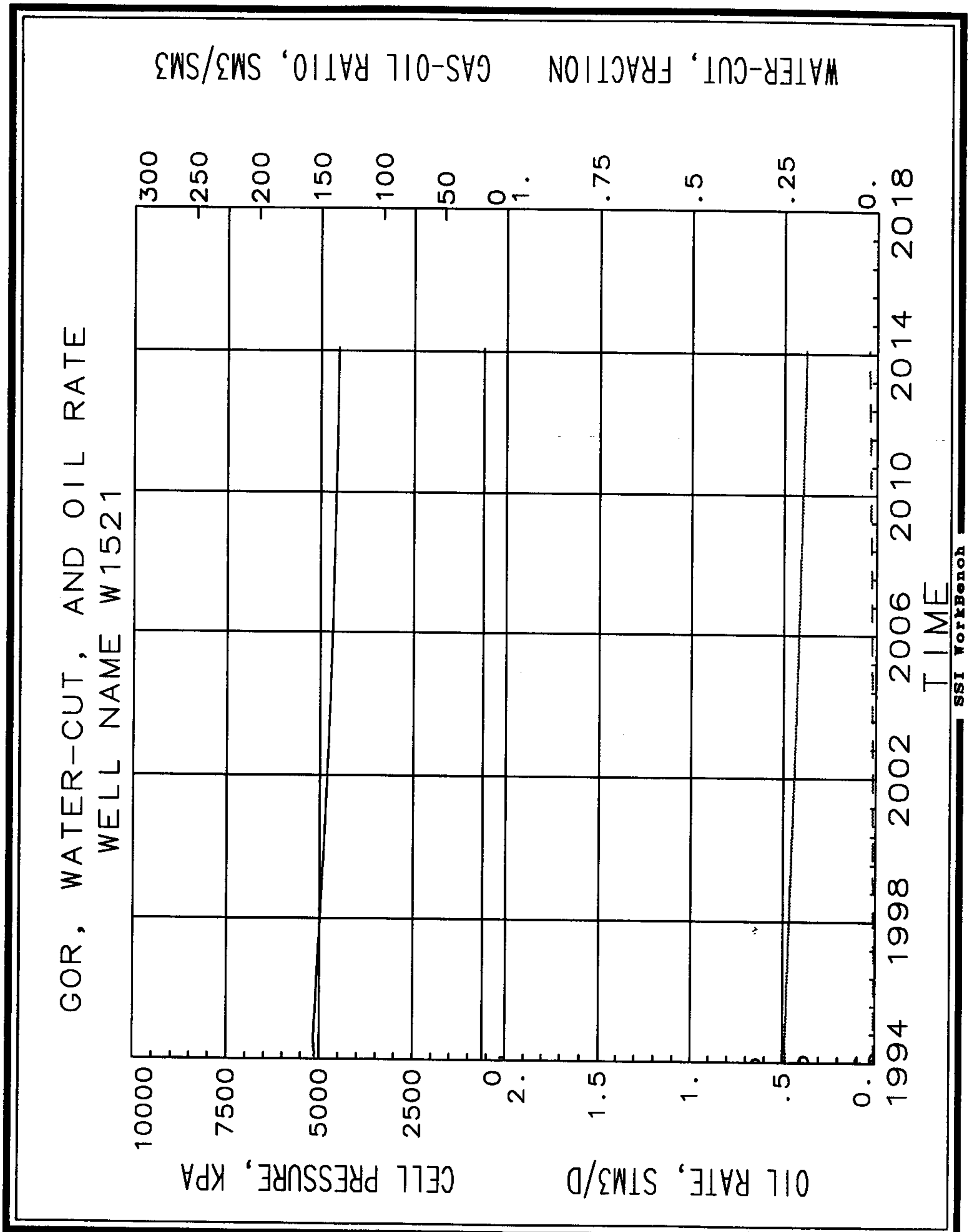


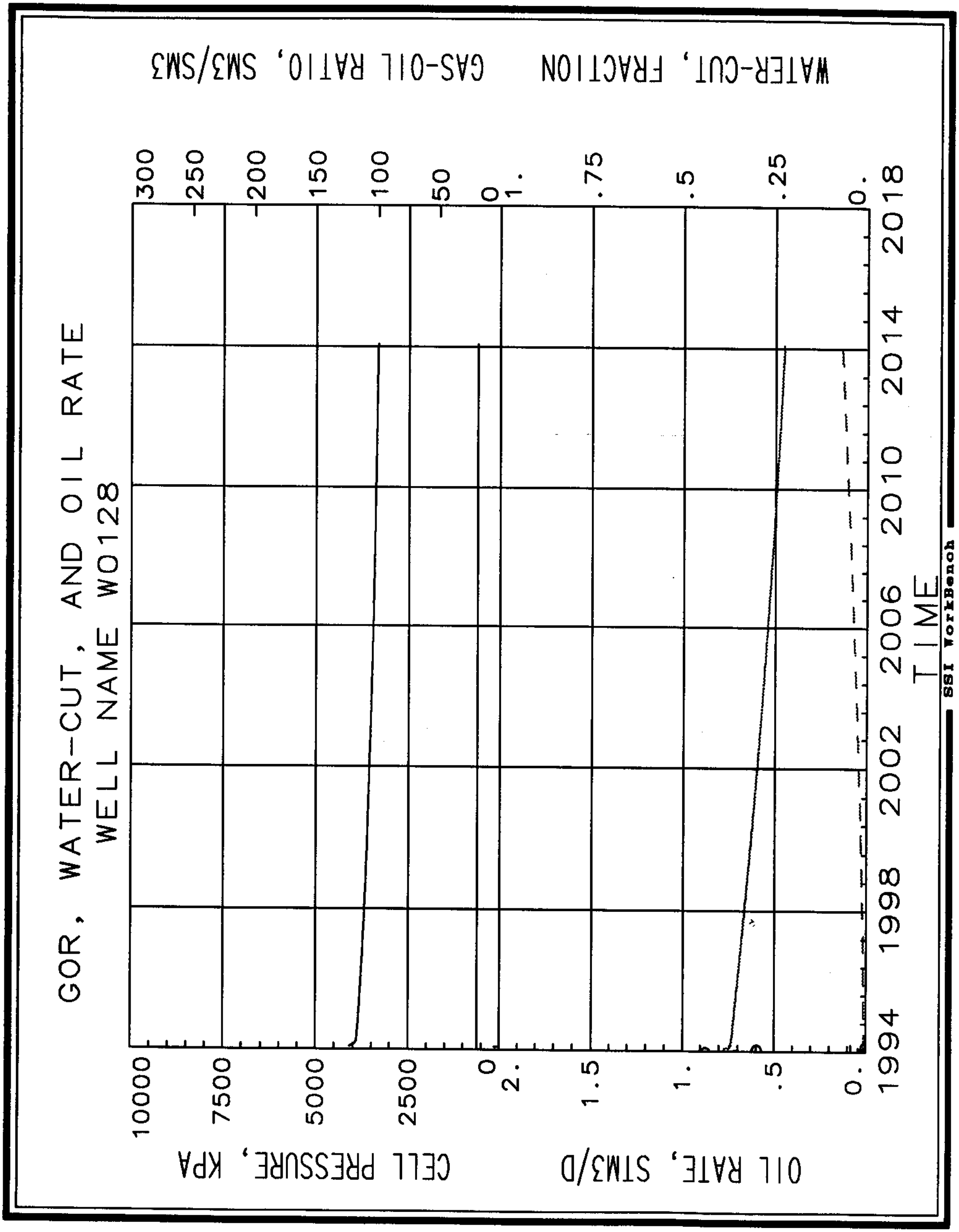

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1620
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300 250 200 150 100 50 0
1. .75 .5 .25 0.
10000 7500 5000 2500 0
8 6 4 2 0
CELL PRESSURE, KPA
OIL RATE, STM3/D
1994 1998 2002 2006 2010 2014 2018
TIME
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W0521
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
1994
1998
2002
2006
2010
2014
2018
SSI WorkBench

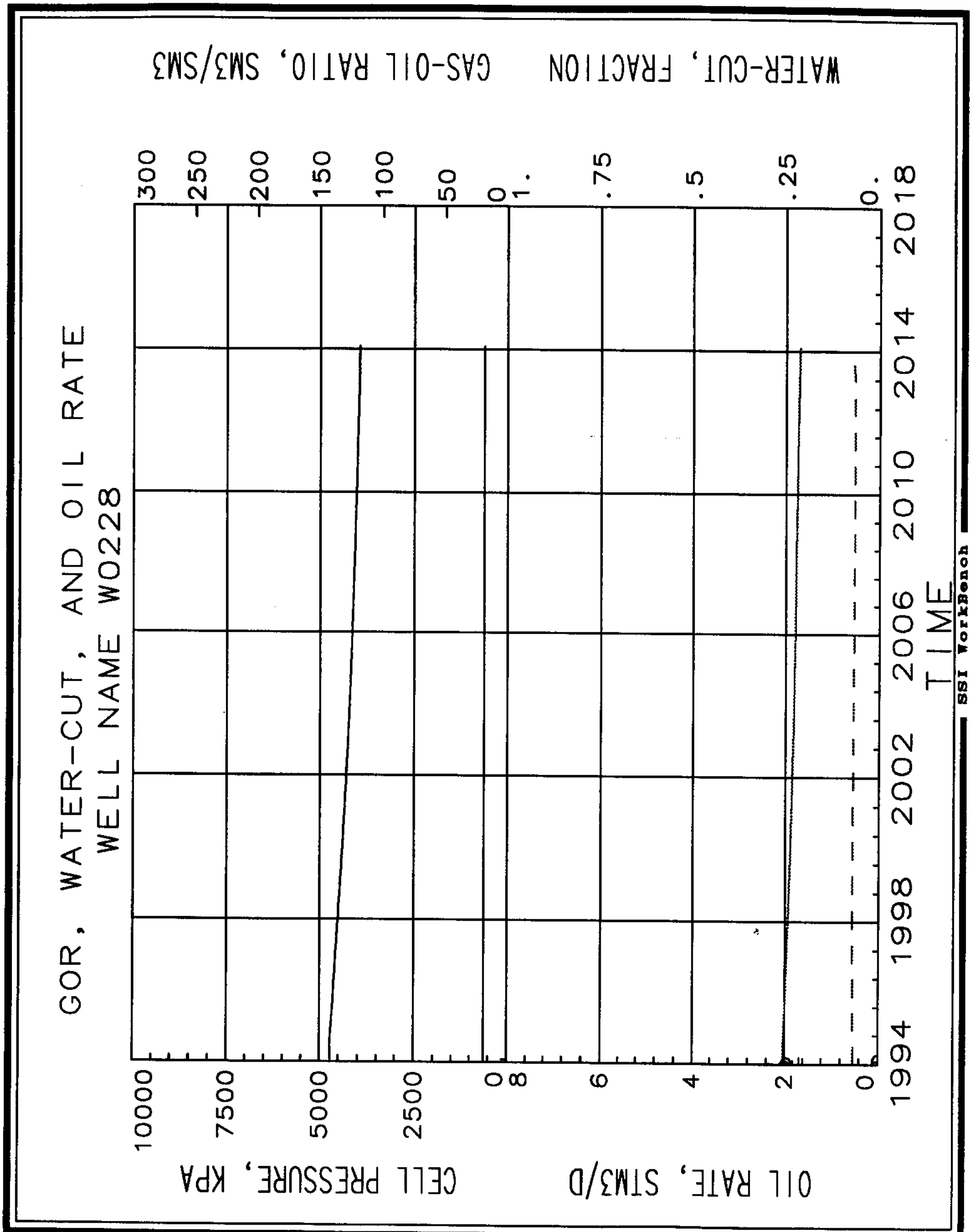

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1221
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
CELL PRESSURE, KPA
OIL RATE, STM3/D
10000
7500
5000
2500
0
5.
3.75
2.5
1.25
0.
1994
1998
2002
2006
2010
2014
2018
TIME
SSI WorkBench

CASE 2 FIGURE 54

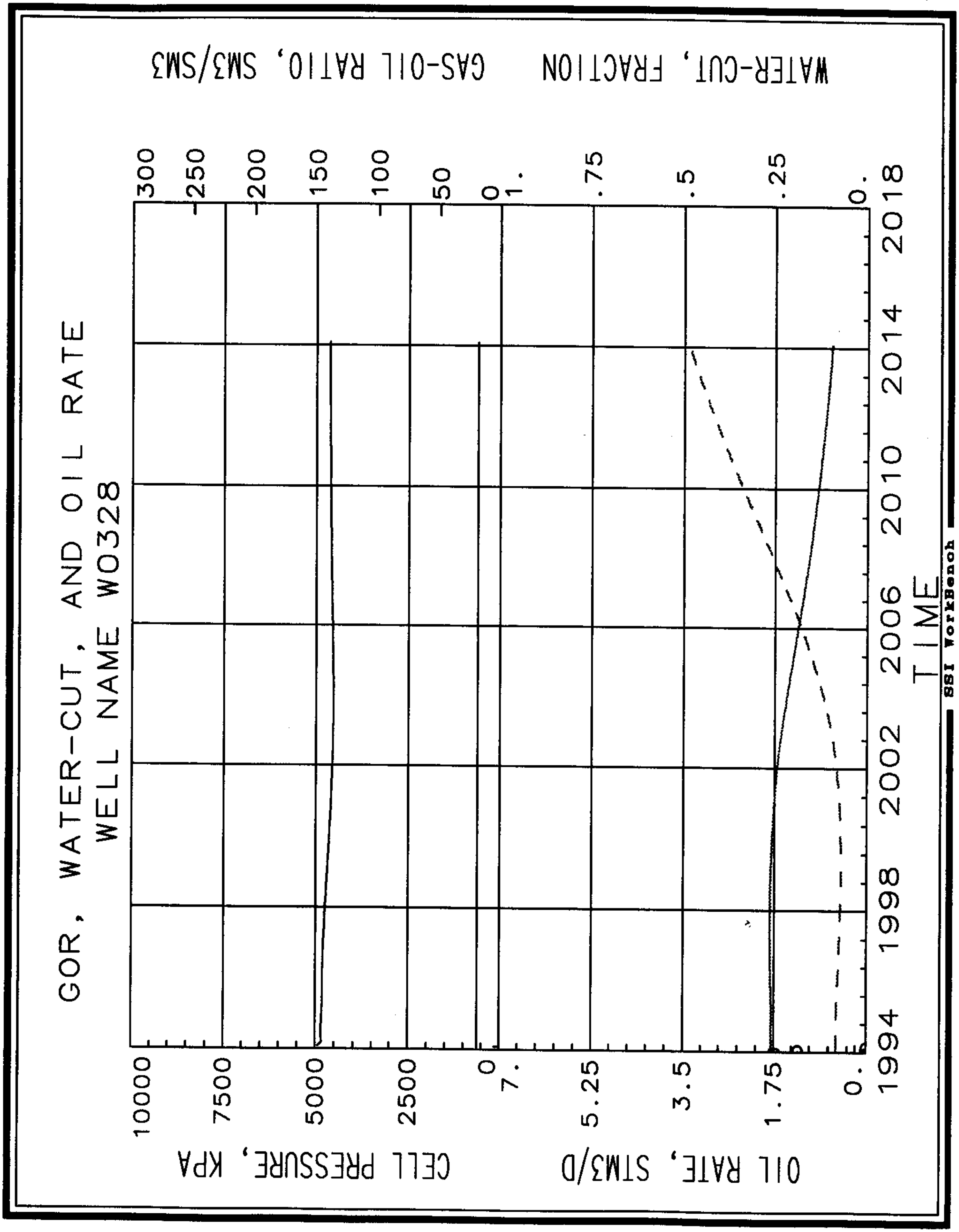


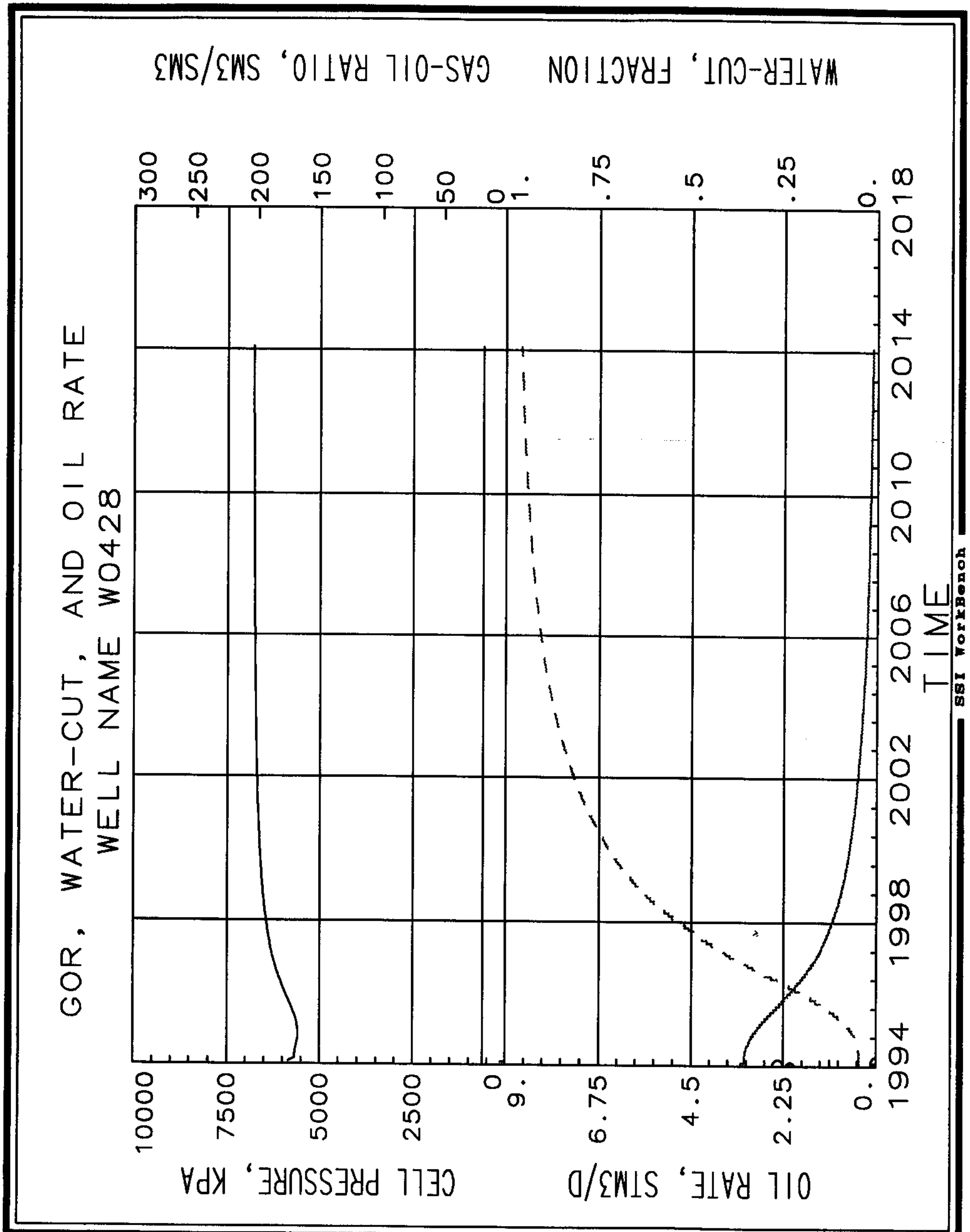

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0128
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1994
1998
2002
2006
2010
2014
2018
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
SSI WorkBench

CASE 2 FIGURE 56

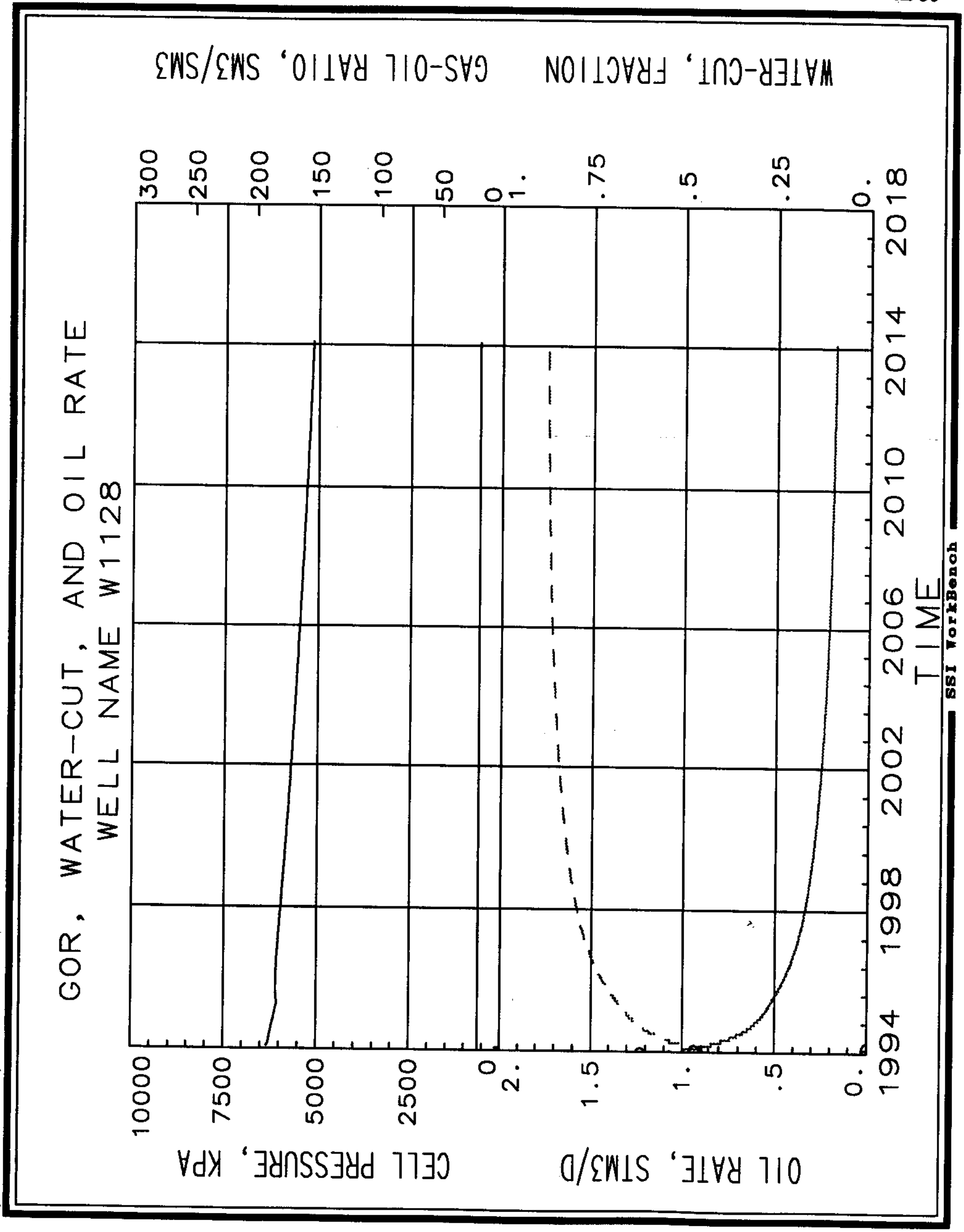


CASE 2 FIGURE 57

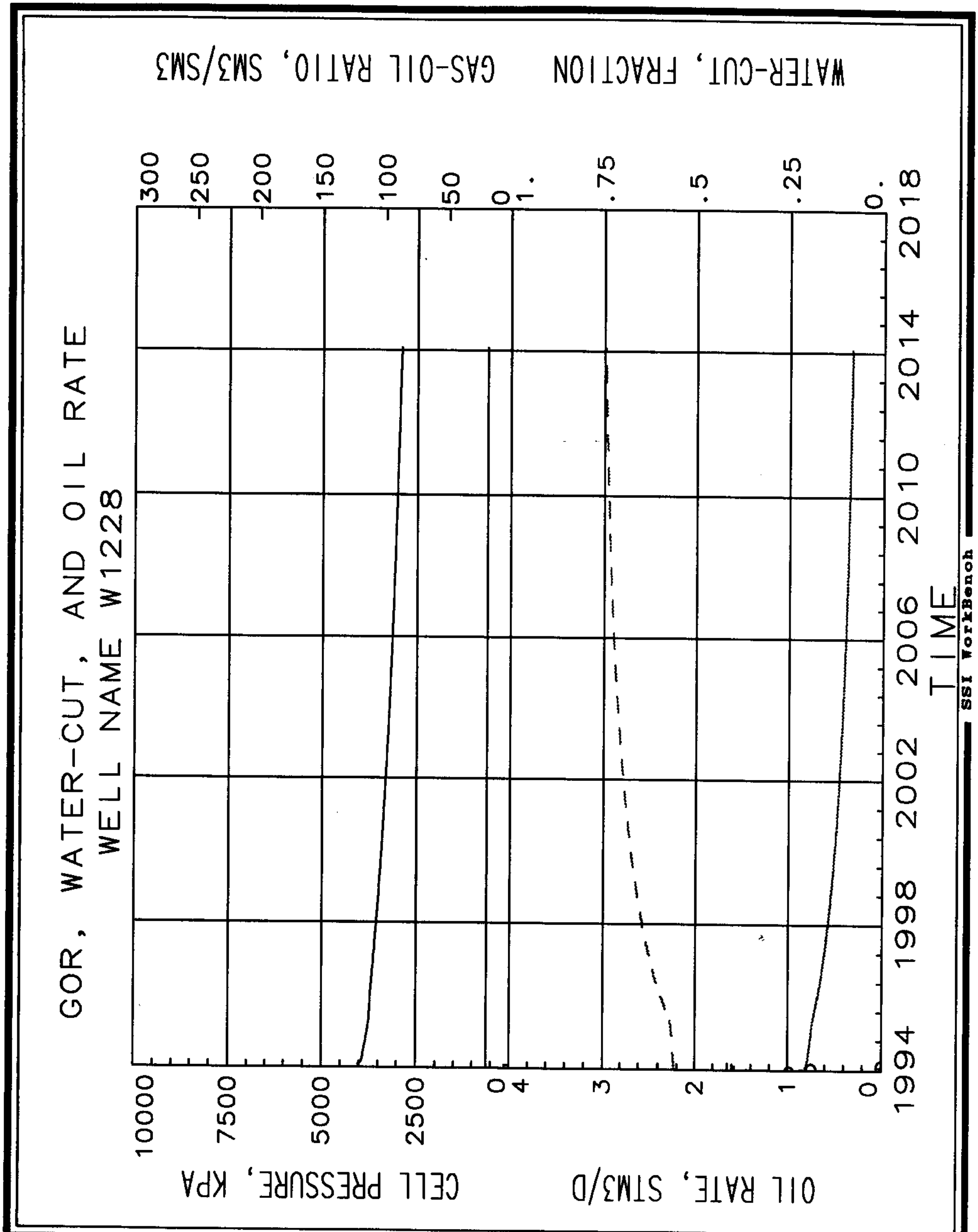


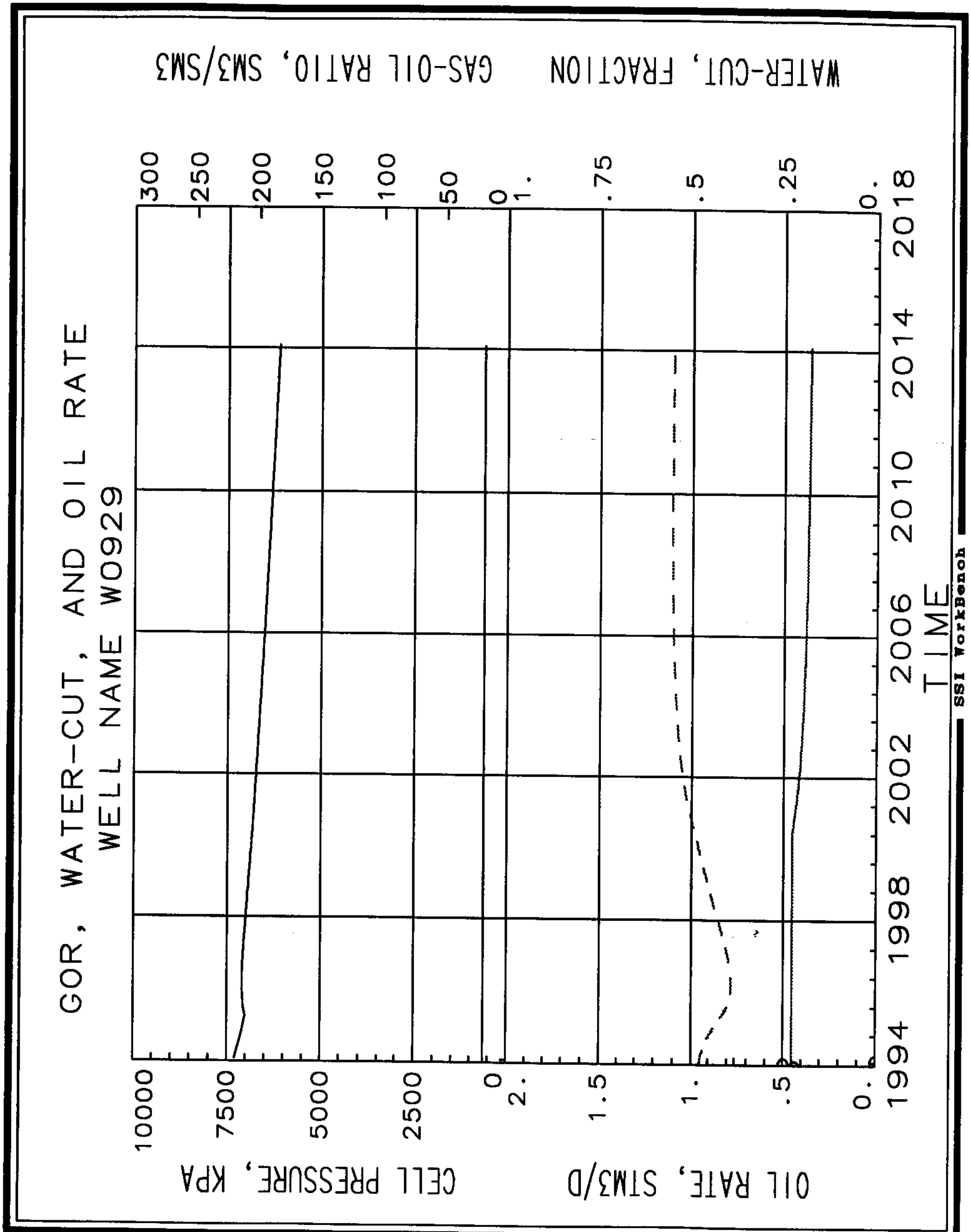

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0428
WATER-CUT, FRACTION
GAS-OIL RATIO, SM3/SM3
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
9.
6.75
4.5
2.25
0.
1994
1998
2002
2006
2010
2014
2018
SSI WorkBench

CASE 2 FIGURE 59

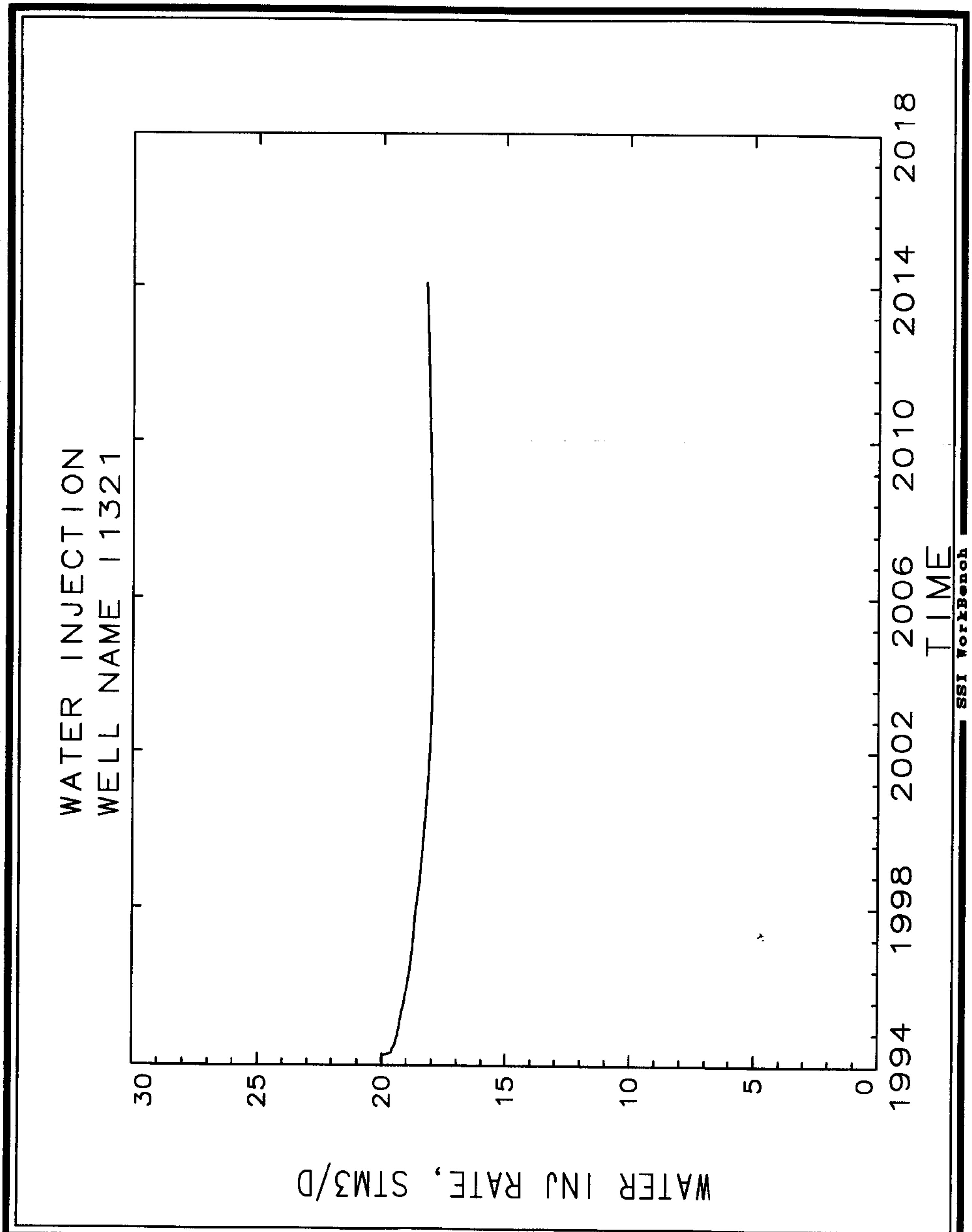


CASE 2 FIGURE 60




GOR, WATER-CUT, AND OIL RATE
WELL NAME W0929
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
1994
1998
2002
2006
2010
2014
2018
SSI WorkBench

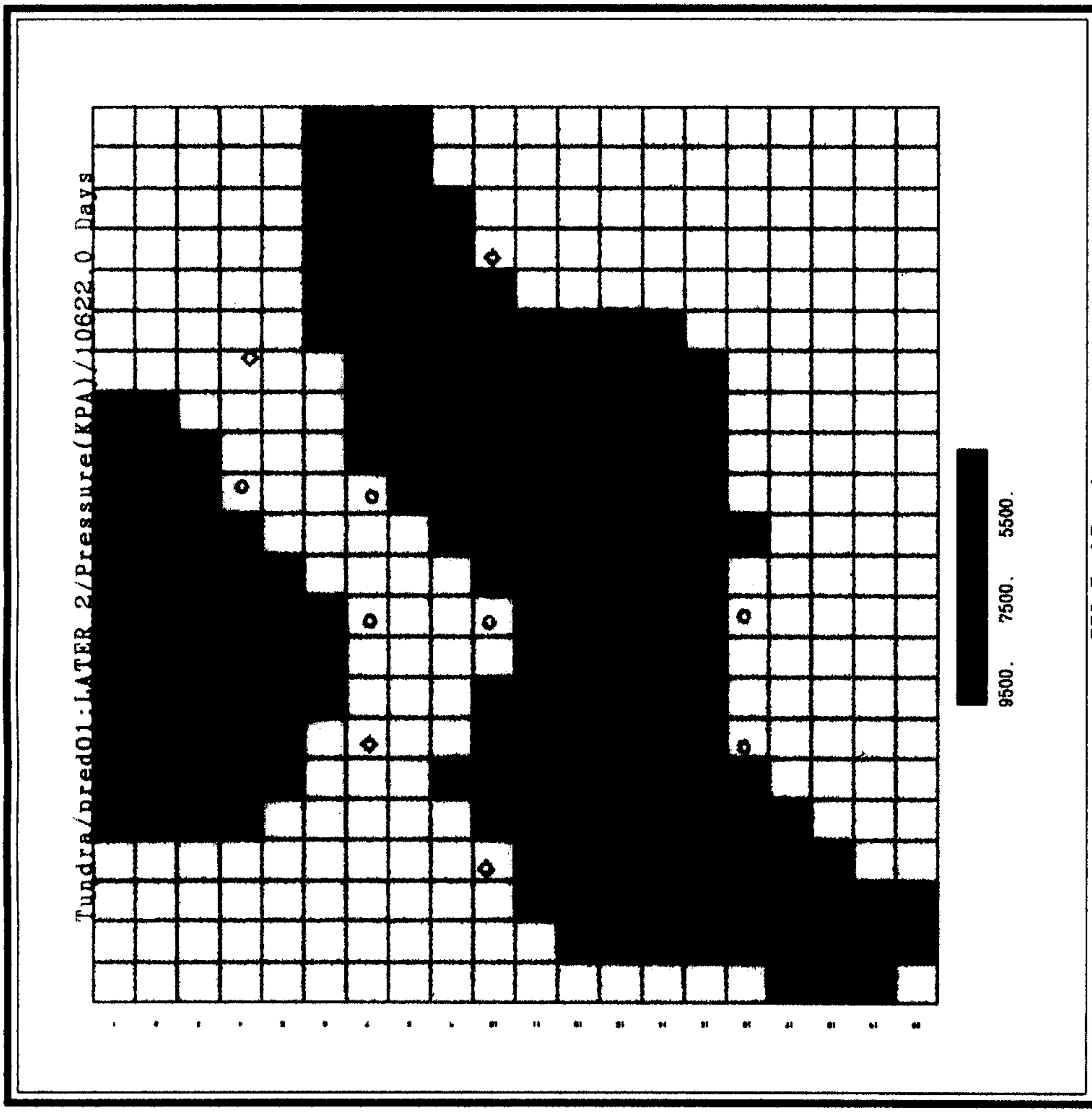
CASE 2 FIGURE 62



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 2 FIGURE 63

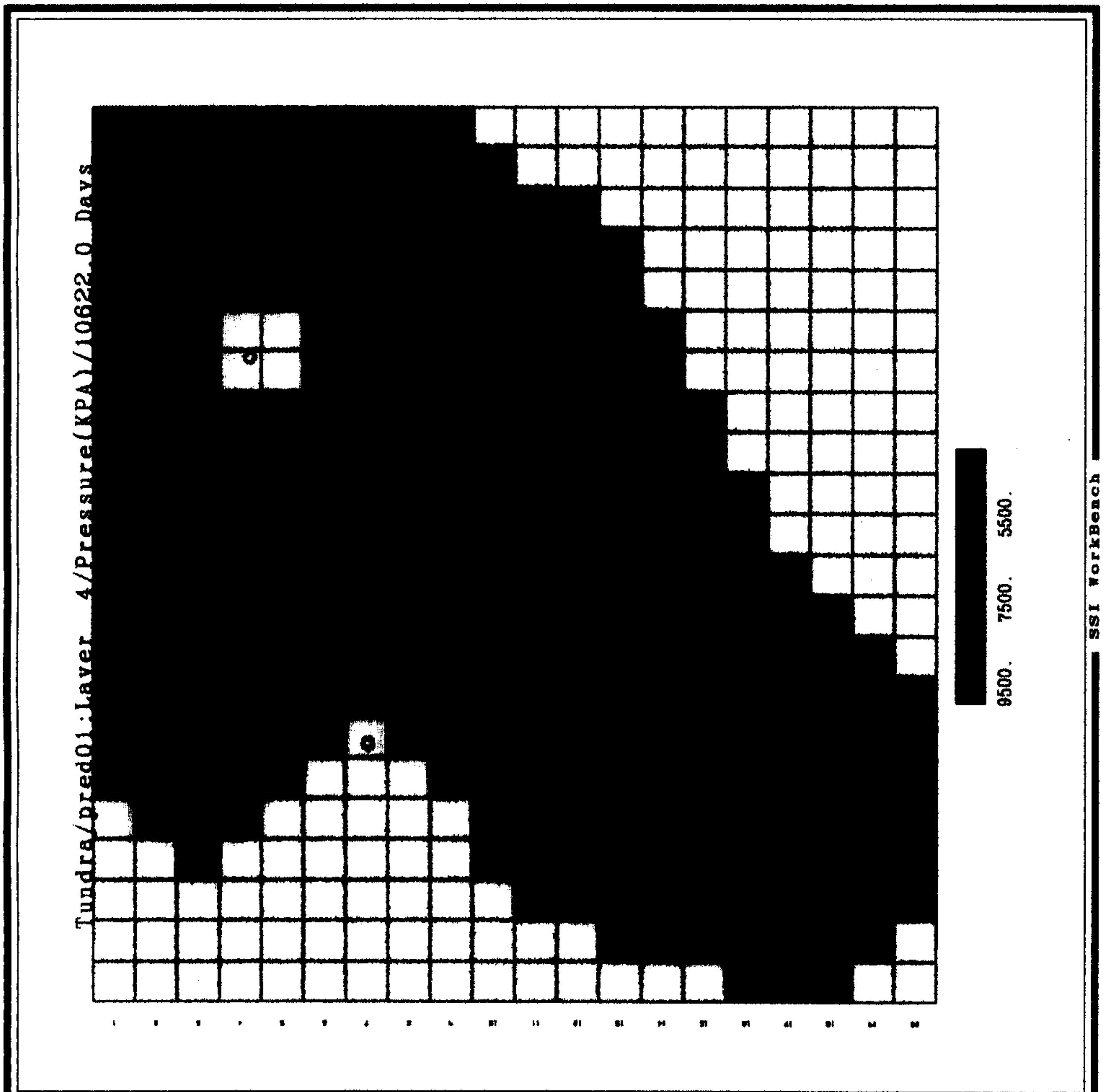
Prediction Case 2 - Pressure Distribution Map Layer 2



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 2 FIGURE 64

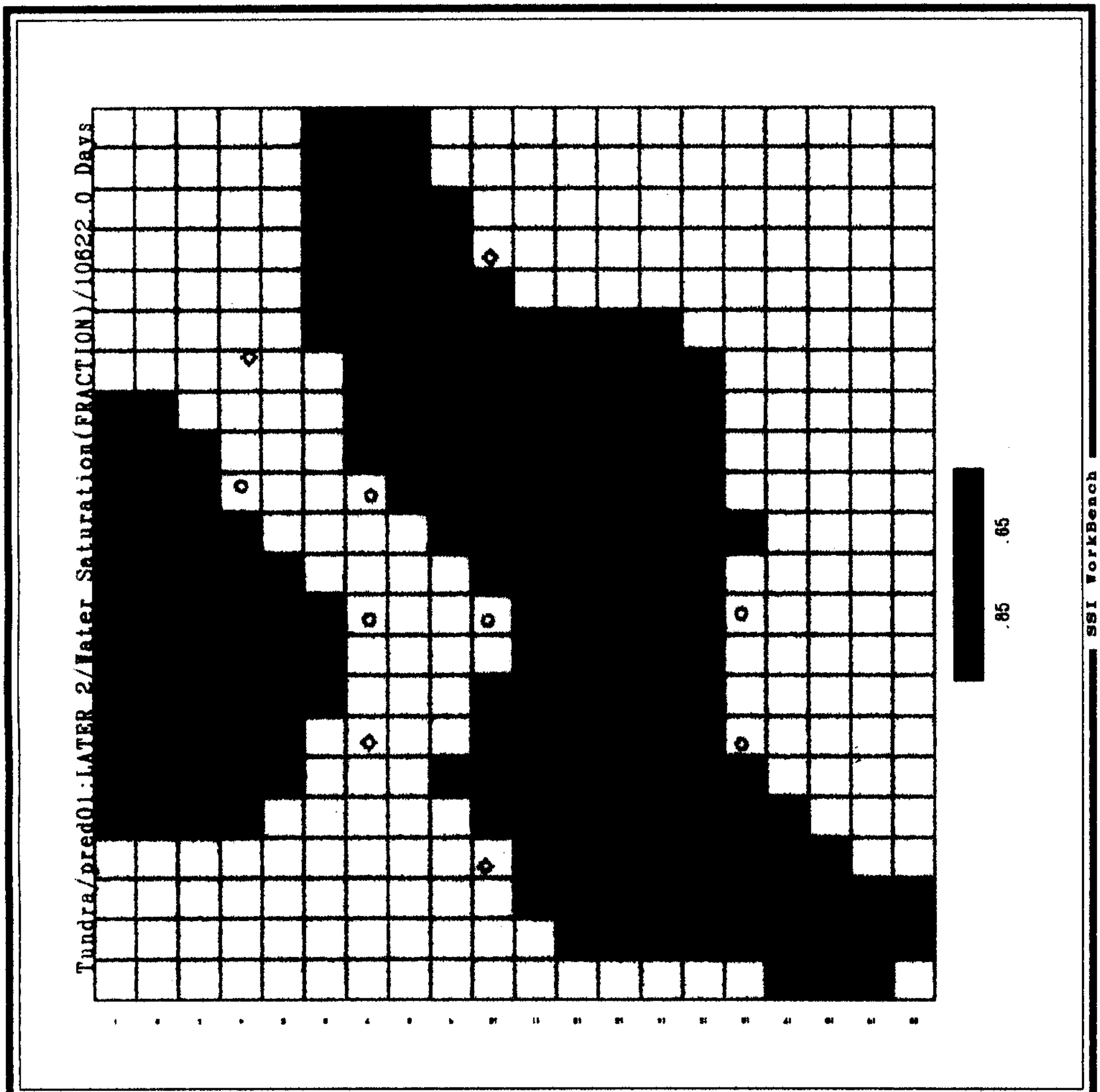
Prediction Case 2 - Pressure Distribution Map Layer 4



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 2 FIGURE 65

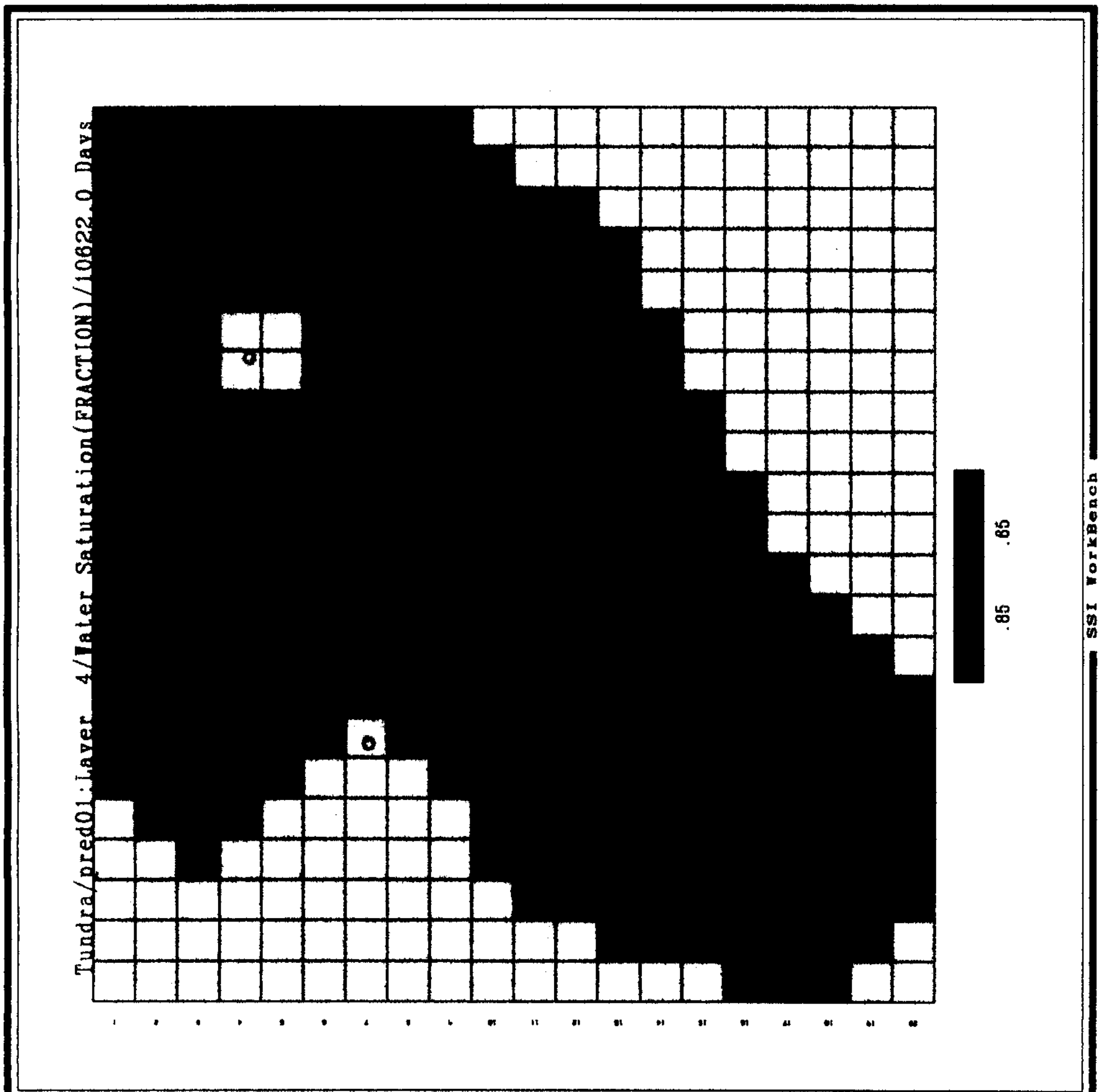
Prediction Case 2 - Water Saturation Distribution Map Layer 2



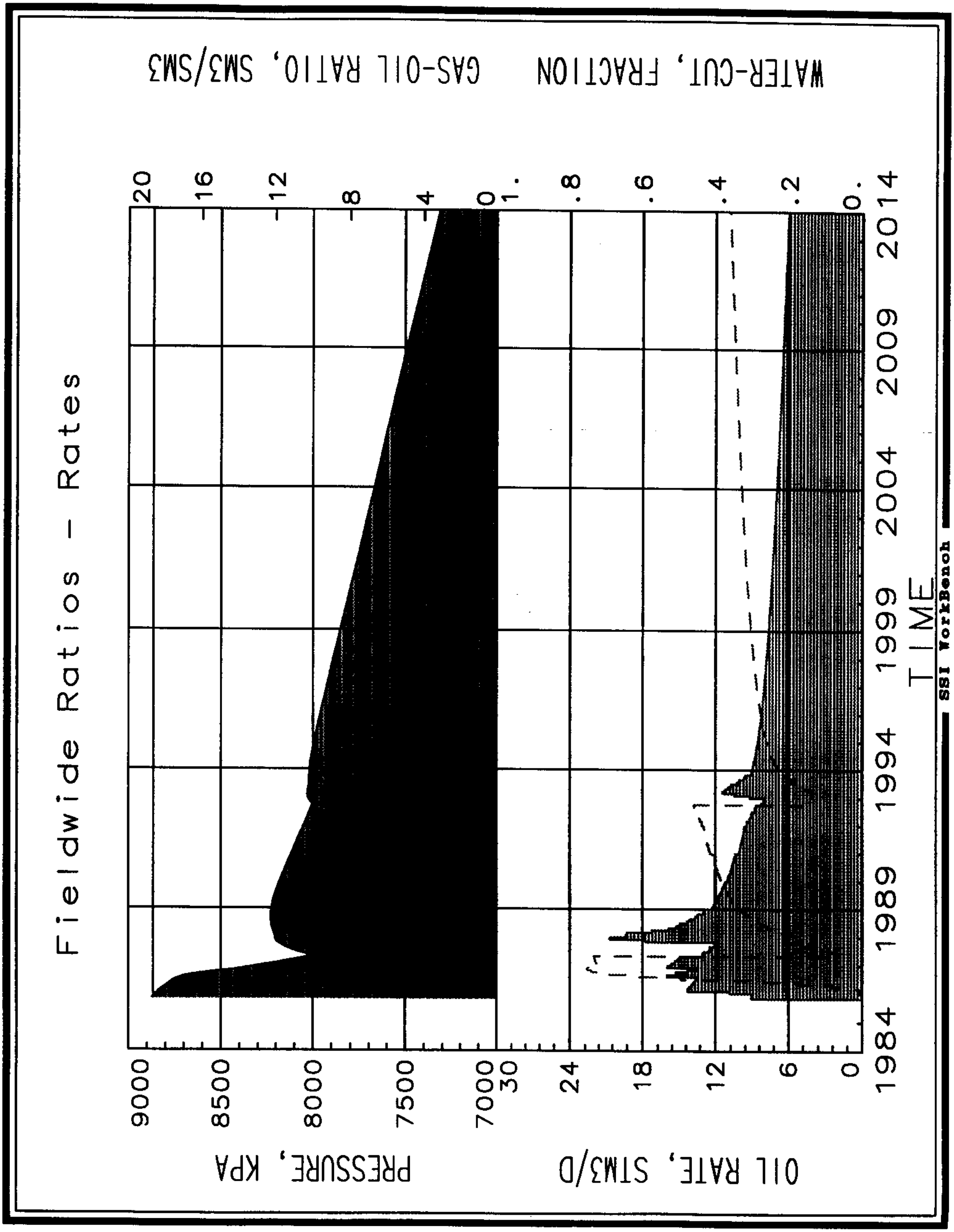
Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

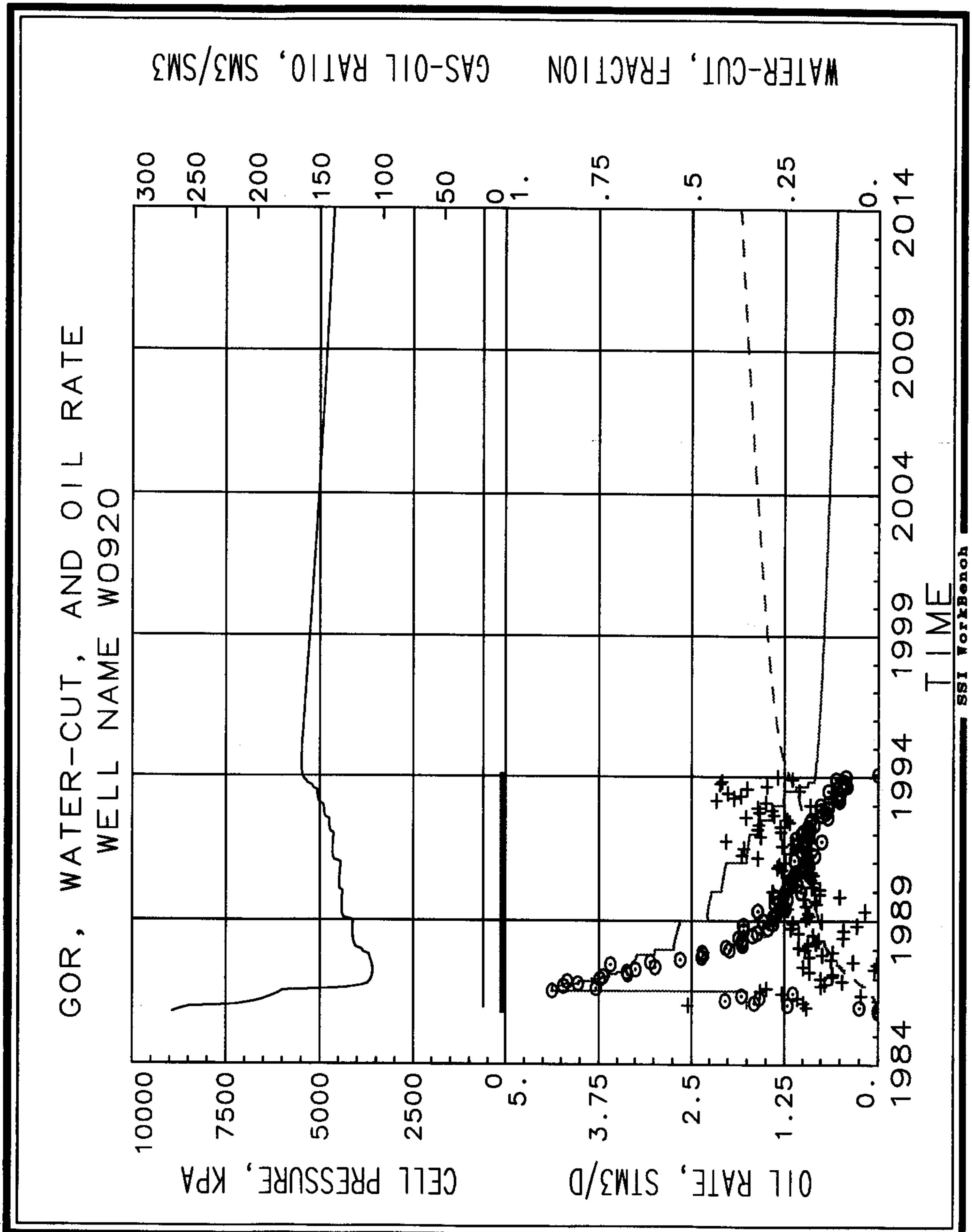
CASE 2 FIGURE 66

Prediction Case 2 - Water Saturation Distribution Map Layer 4

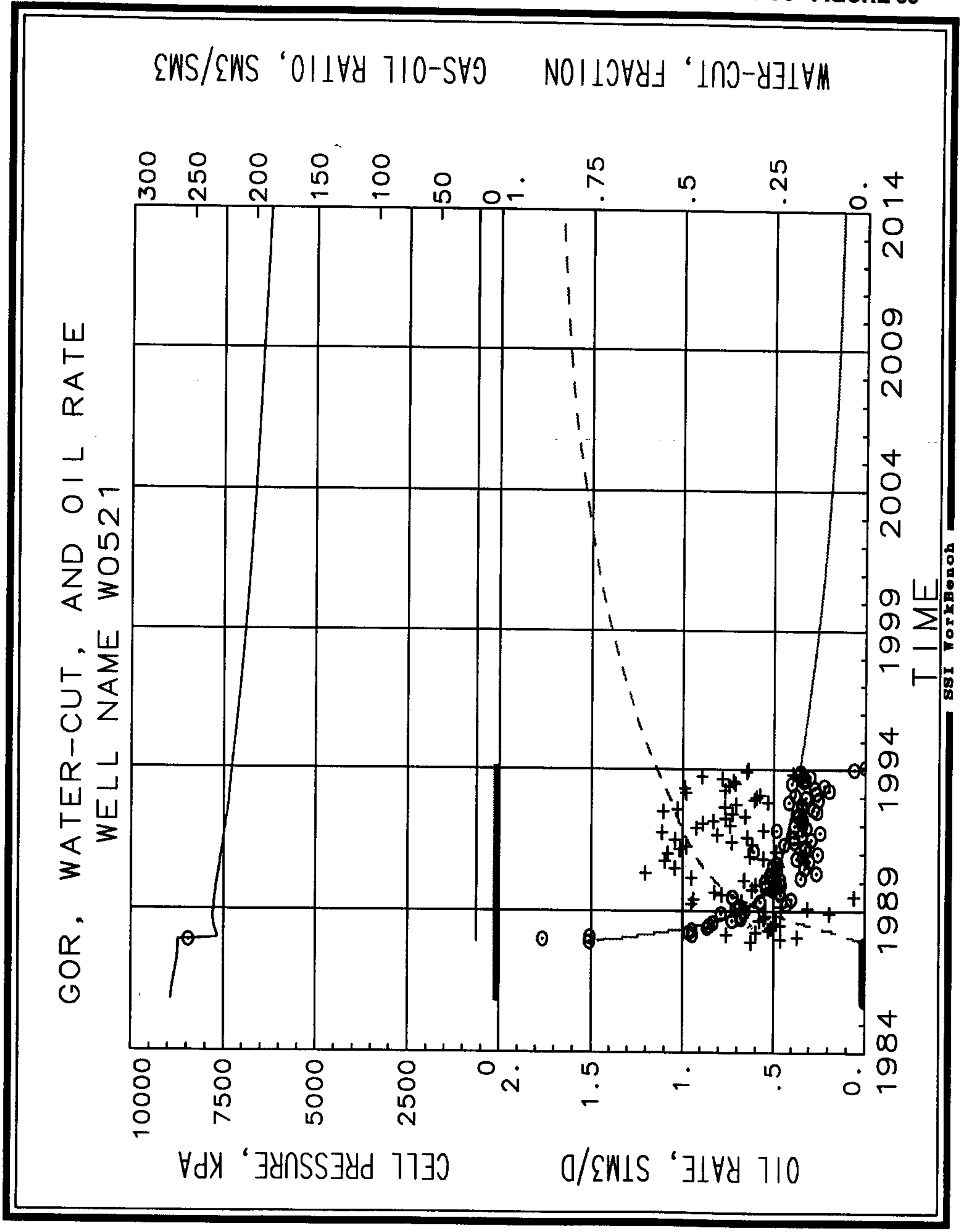


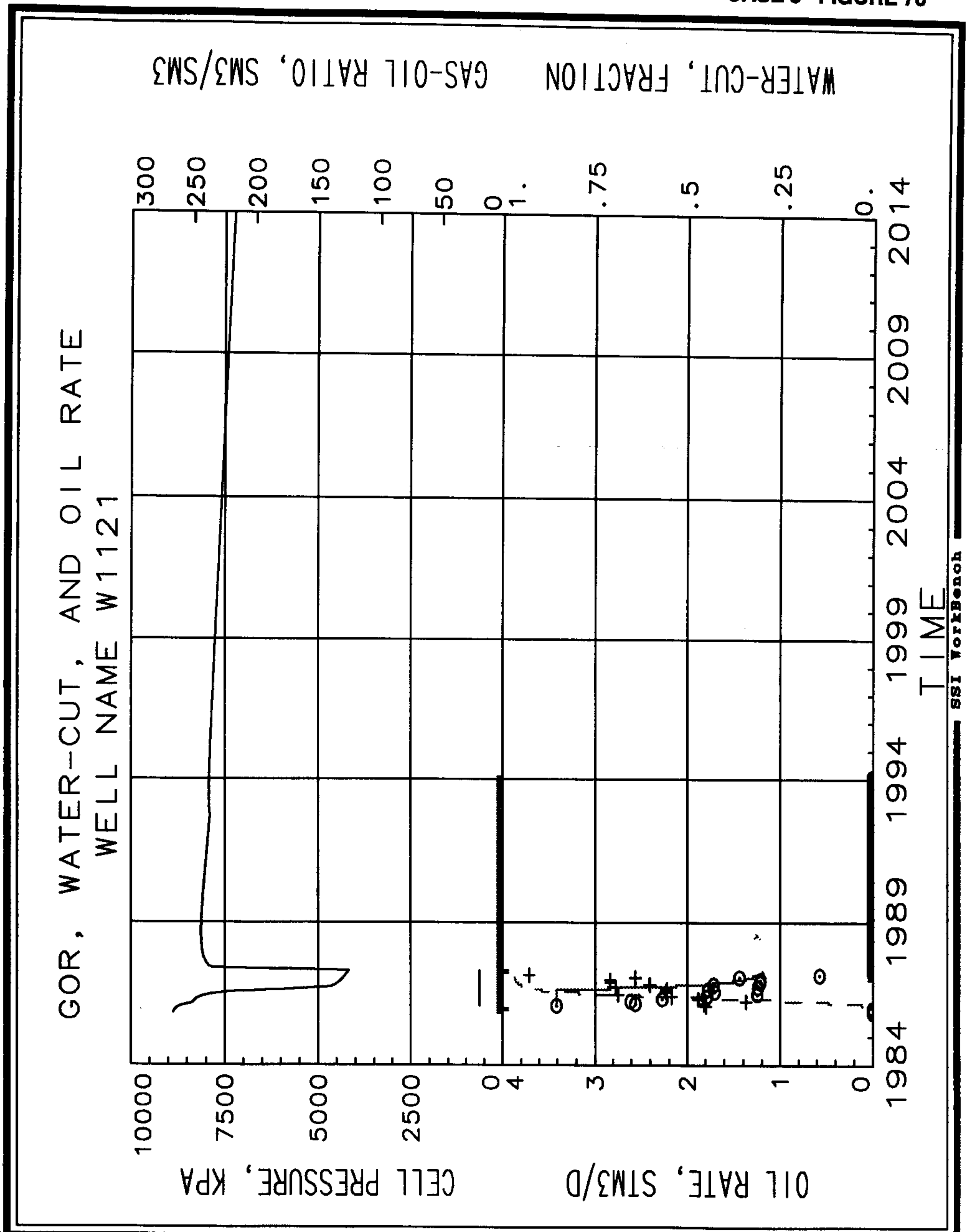
CASE 3 FIGURE 67

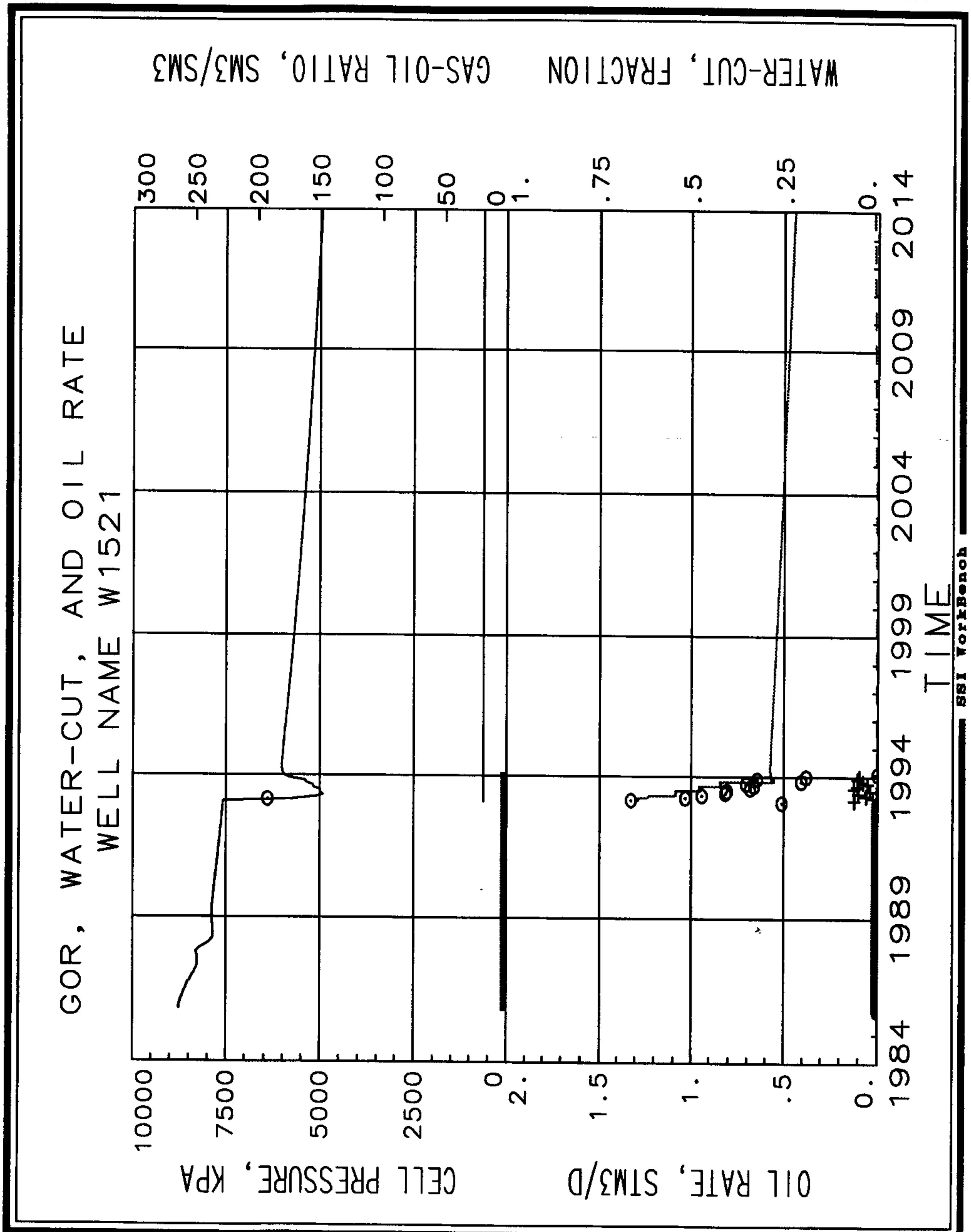



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0920
TIME
1984
1989
1994
1999
2004
2009
2014
CELL PRESSURE, KPA
10000
7500
5000
2500
0
OIL RATE, STM3/D
5.
3.75
2.5
1.25
0.
GAS-OIL RATIO, SM3/SM3
300
250
200
150
100
50
0
WATER-CUT, FRACTION
1.
.75
.5
.25
0.
SSI WorkBench

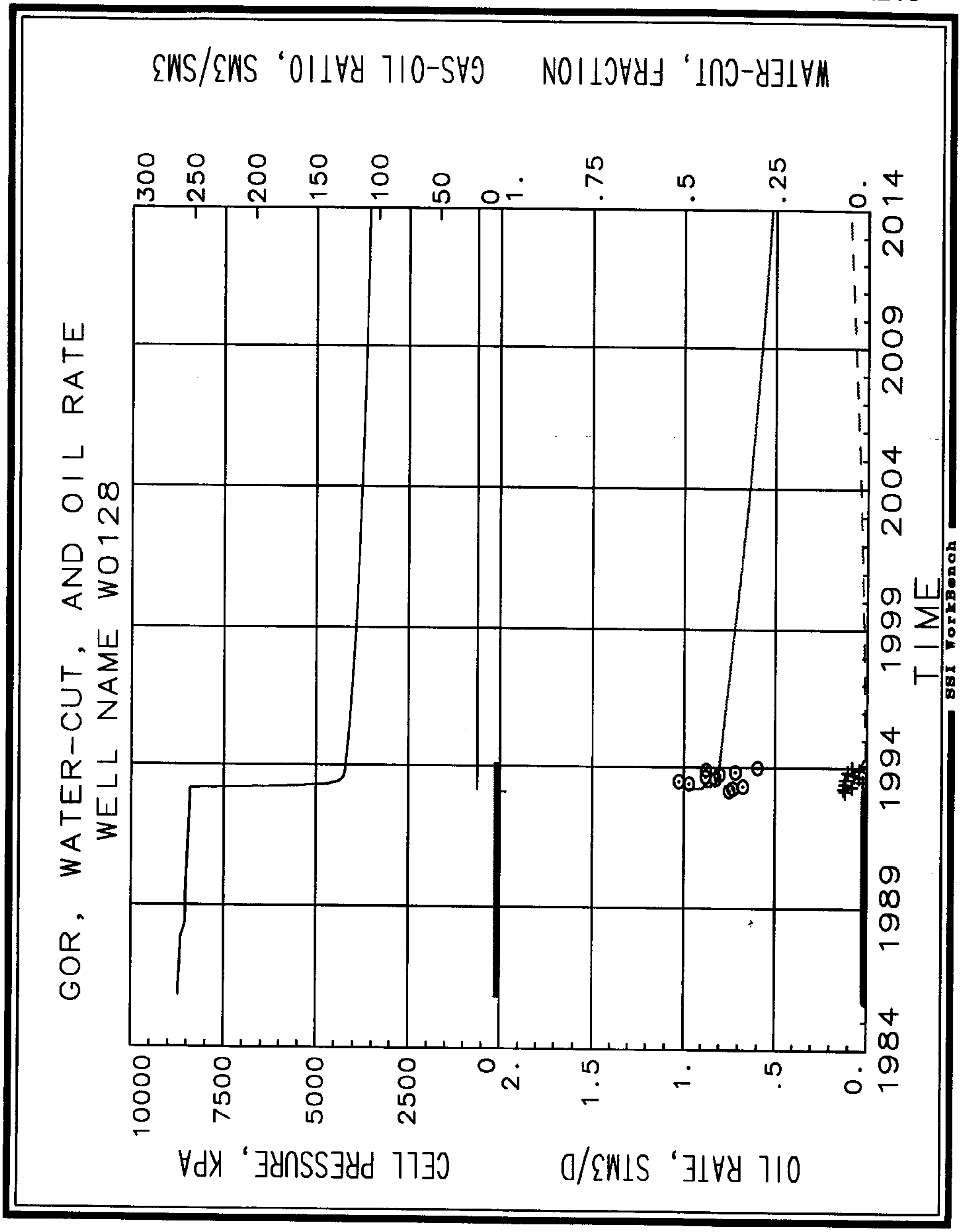
CASE 3 FIGURE 69

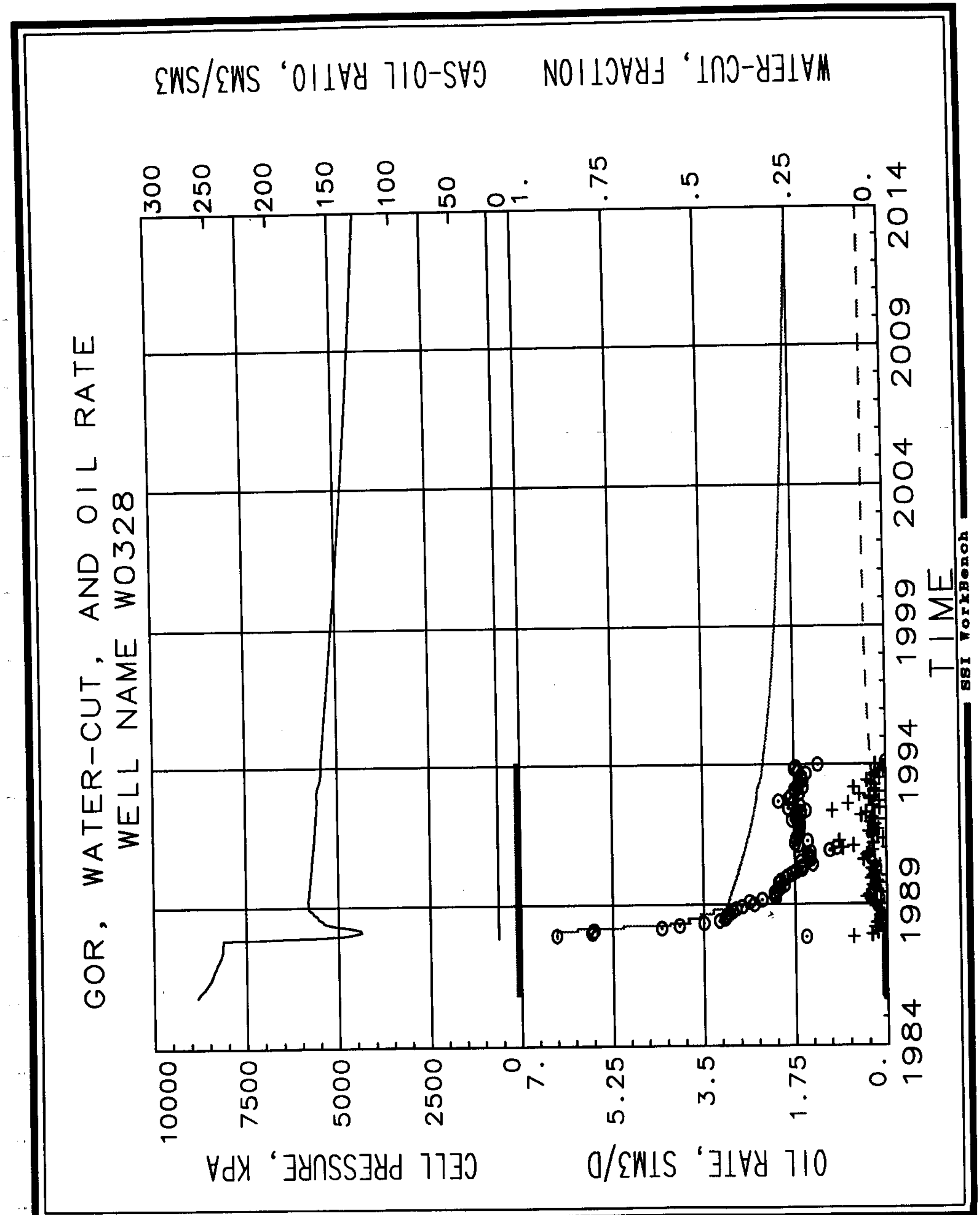



GOR, WATER-CUT, AND OIL RATE
WELL NAME W1121
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
4
3
2
1
0
CELL PRESSURE, KPA
OIL RATE, STM3/D
1984
1989
1994
1999
2004
2009
2014
TIME
SSI WorkBench

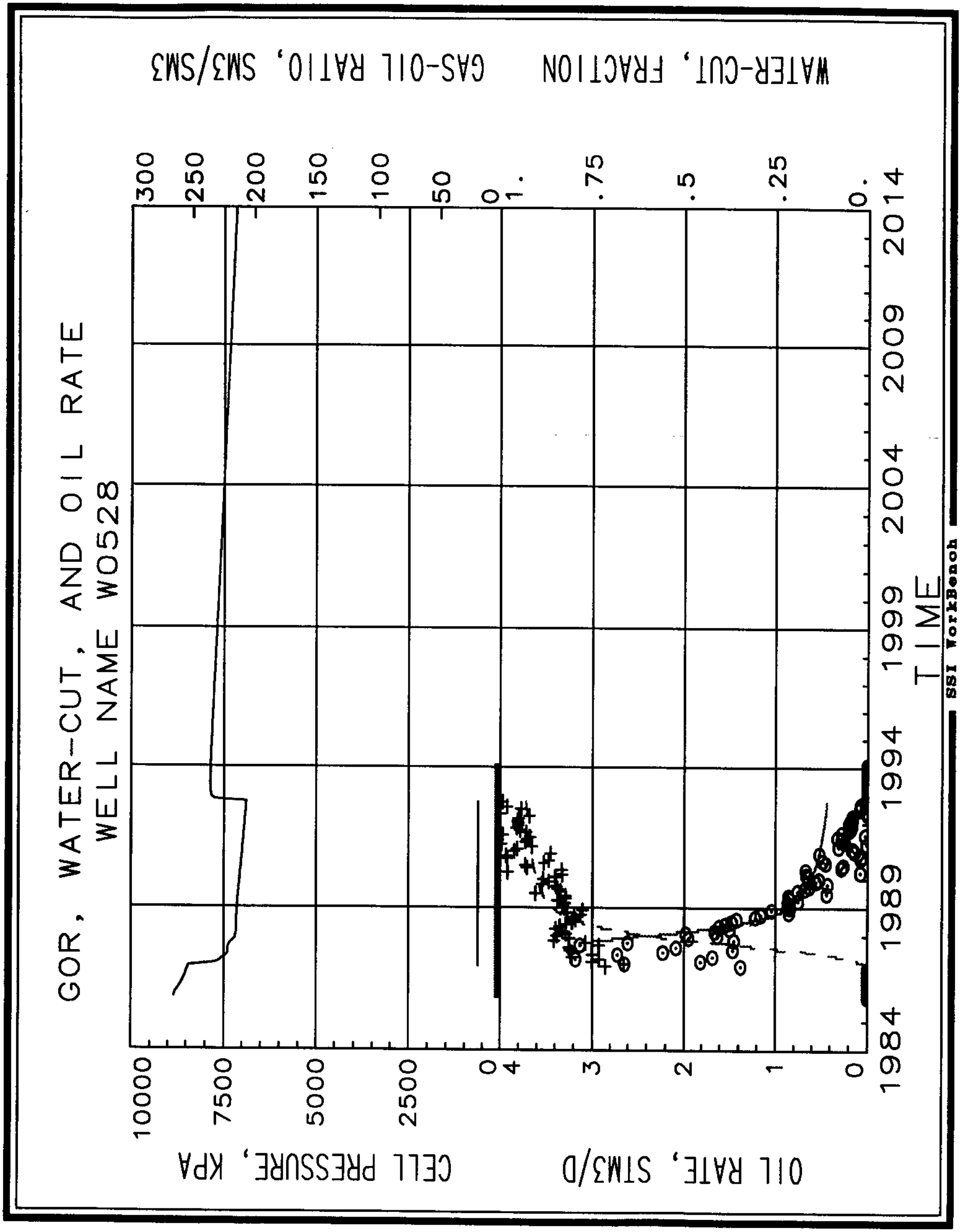

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1521
TIME
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
1984 1989 1994 1999 2004 2009 2014
10000 7500 5000 2500 0
2. 1.5 1. .5 0.
300 250 200 150 100 50 0
1. .75 .5 .25 0.
SSI WorkBench

CASE 3 FIGURE 73

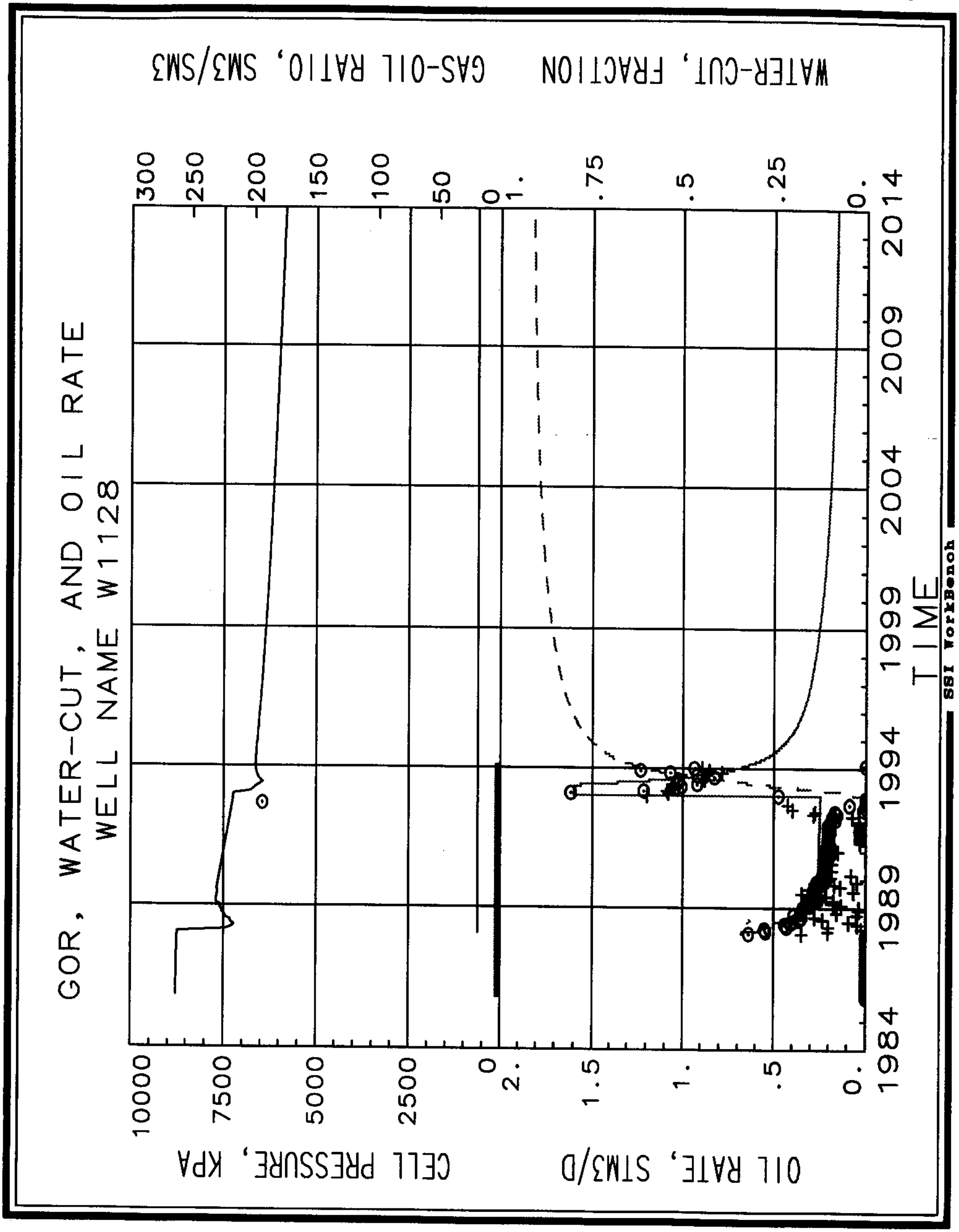



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0328
TIME
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
SSI WorkBench

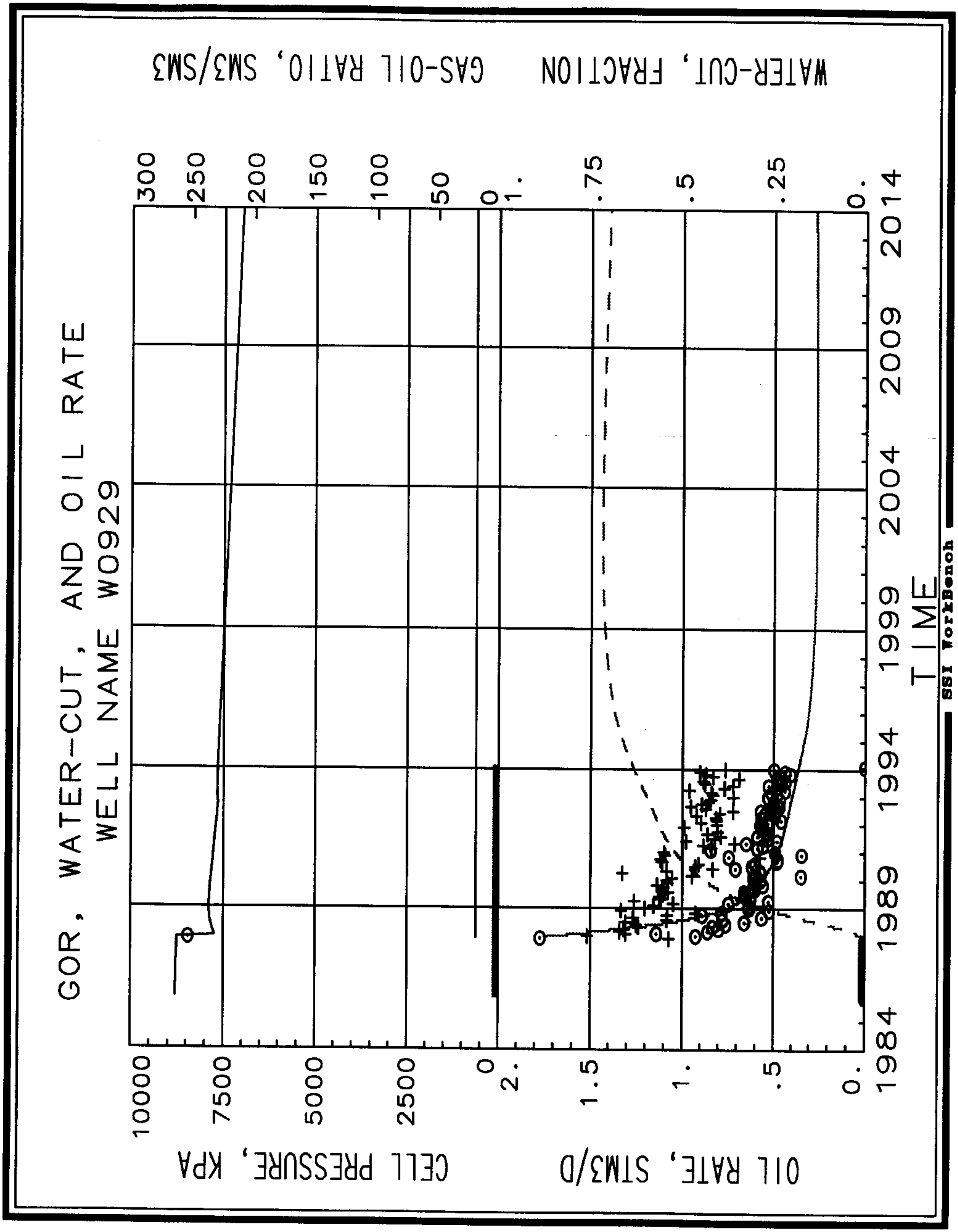
CASE 3 FIGURE 75



CASE 3 FIGURE 76



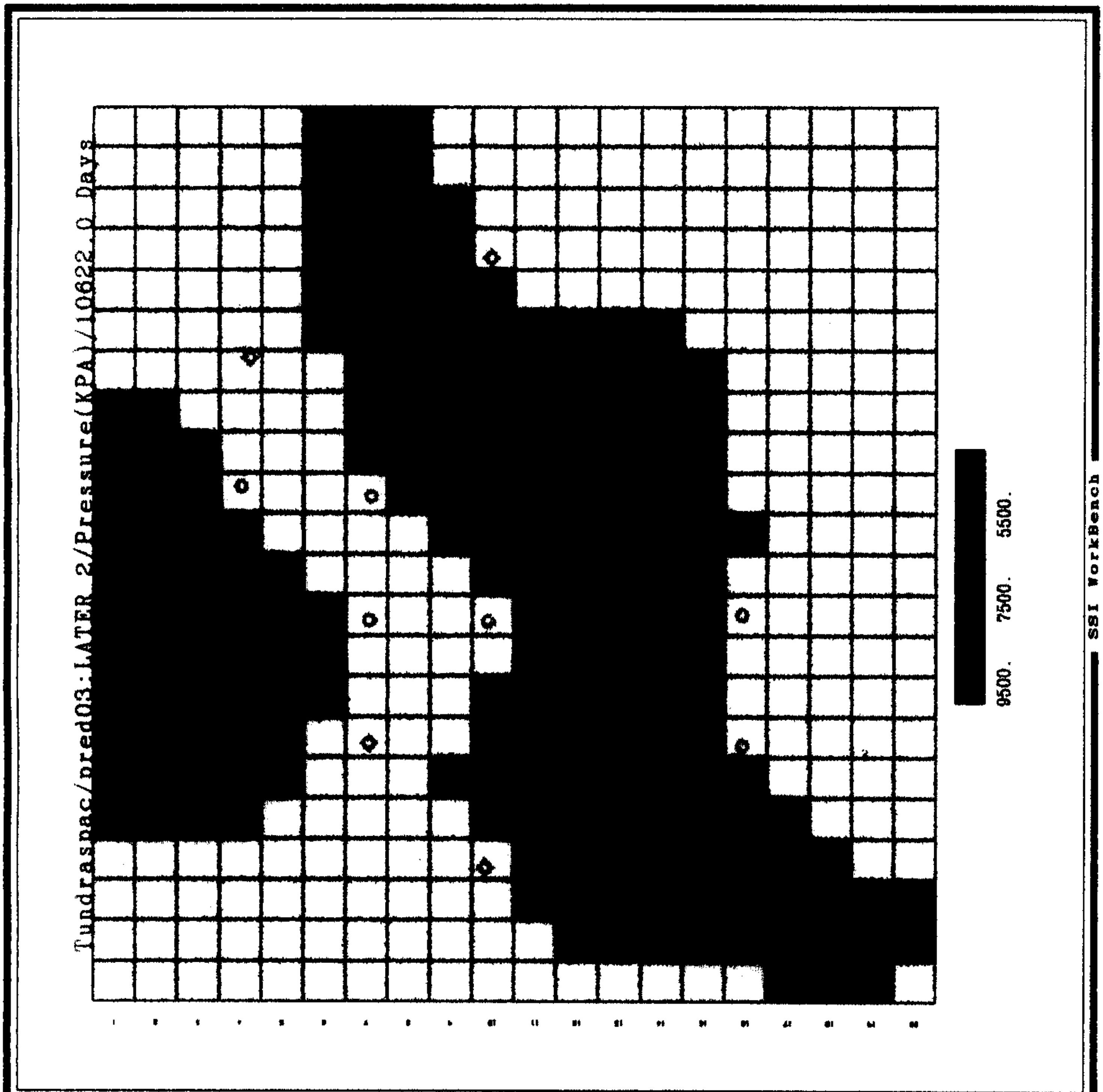
CASE 3 FIGURE 77



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 3 FIGURE 78

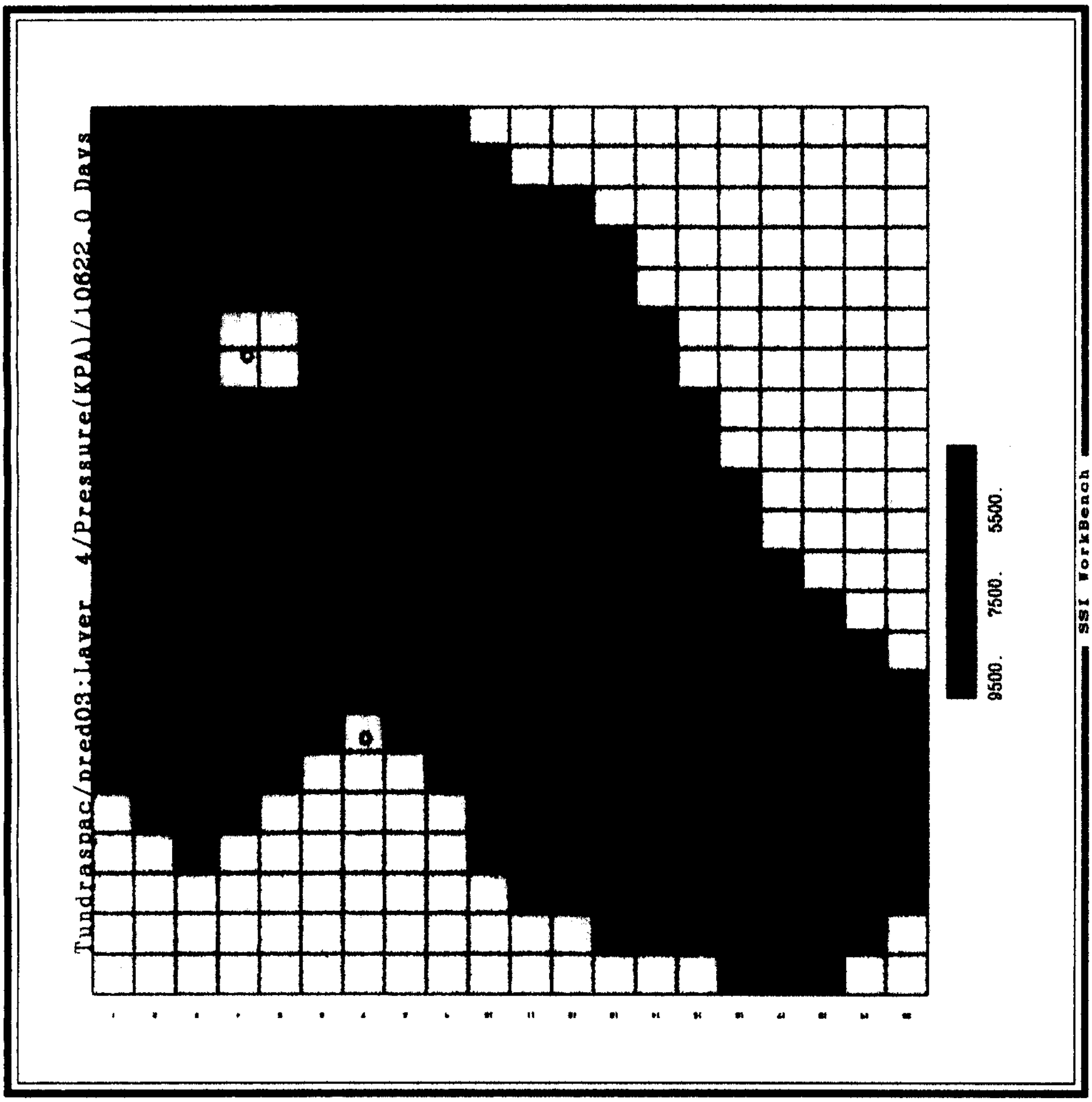
Prediction Case 3 - Pressure Distribution Map Layer 2

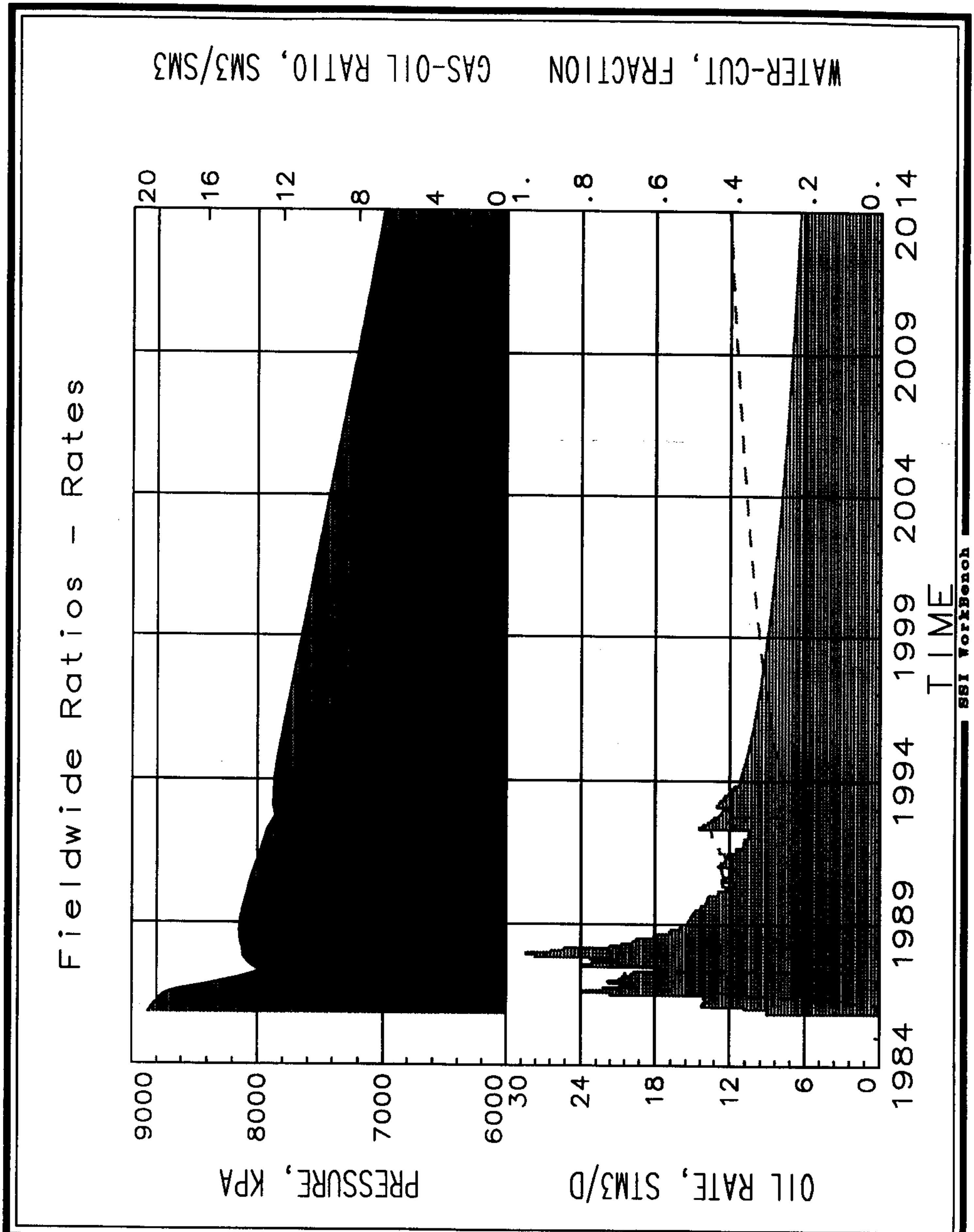


Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

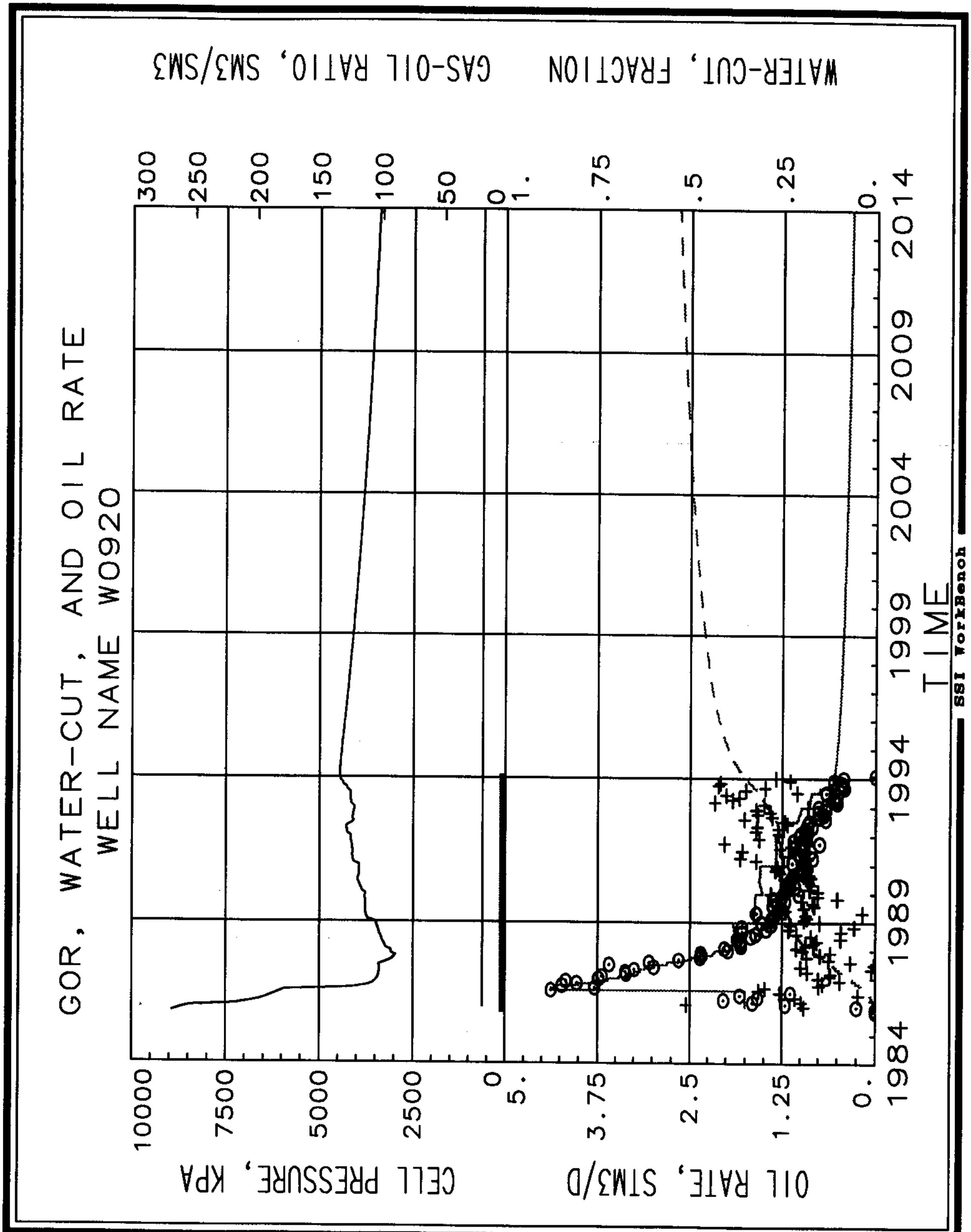
CASE 3 FIGURE 79

Prediction Case 3 - Pressure Distribution Map Layer 4

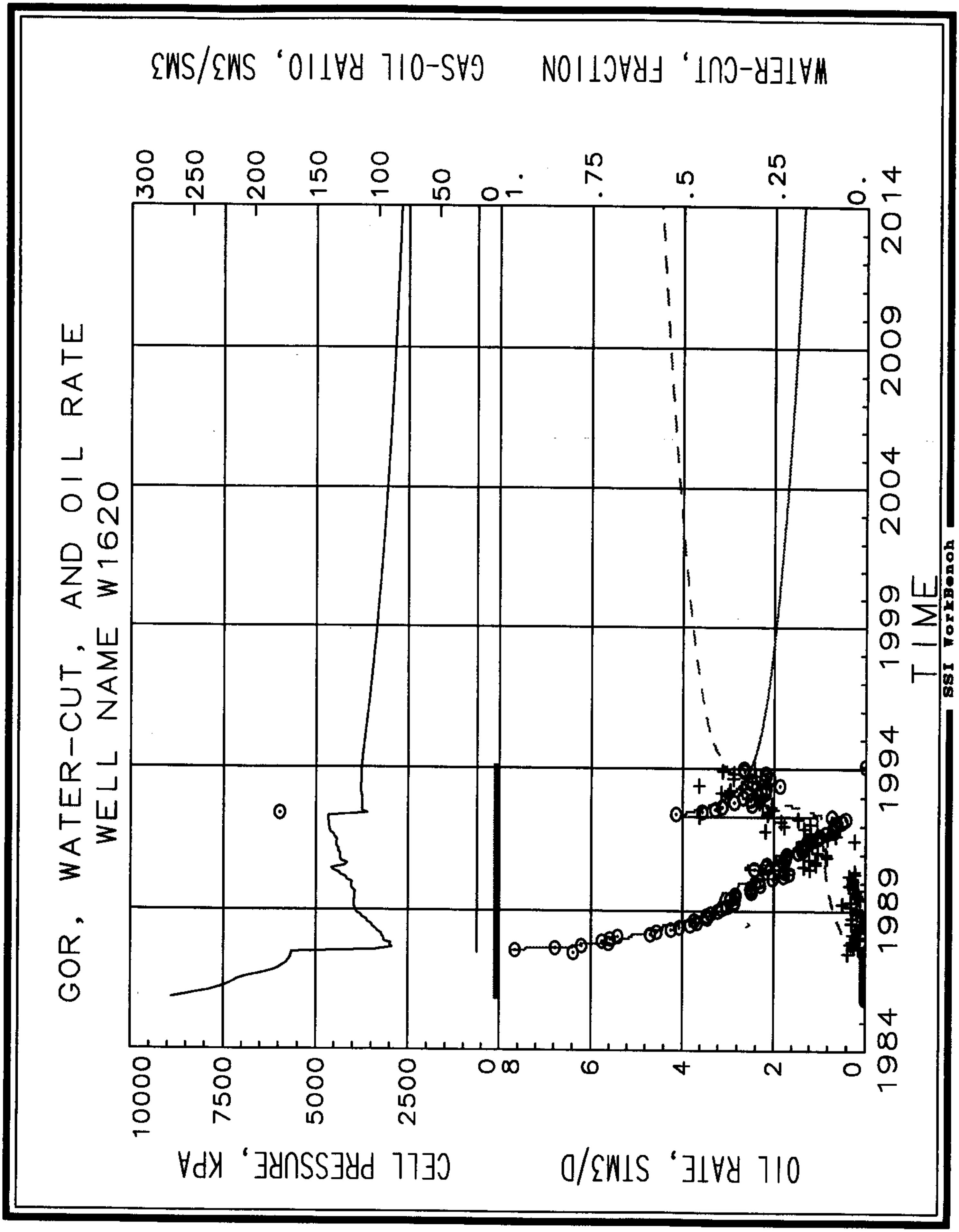



Fieldwide Ratios - Rates
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench
9000
8000
7000
6000
30
24
18
12
6
0
20
16
12
8
4
0
1.
.8
.6
.4
.2
0.
1984
1989
1994
1999
2004
2009
2014

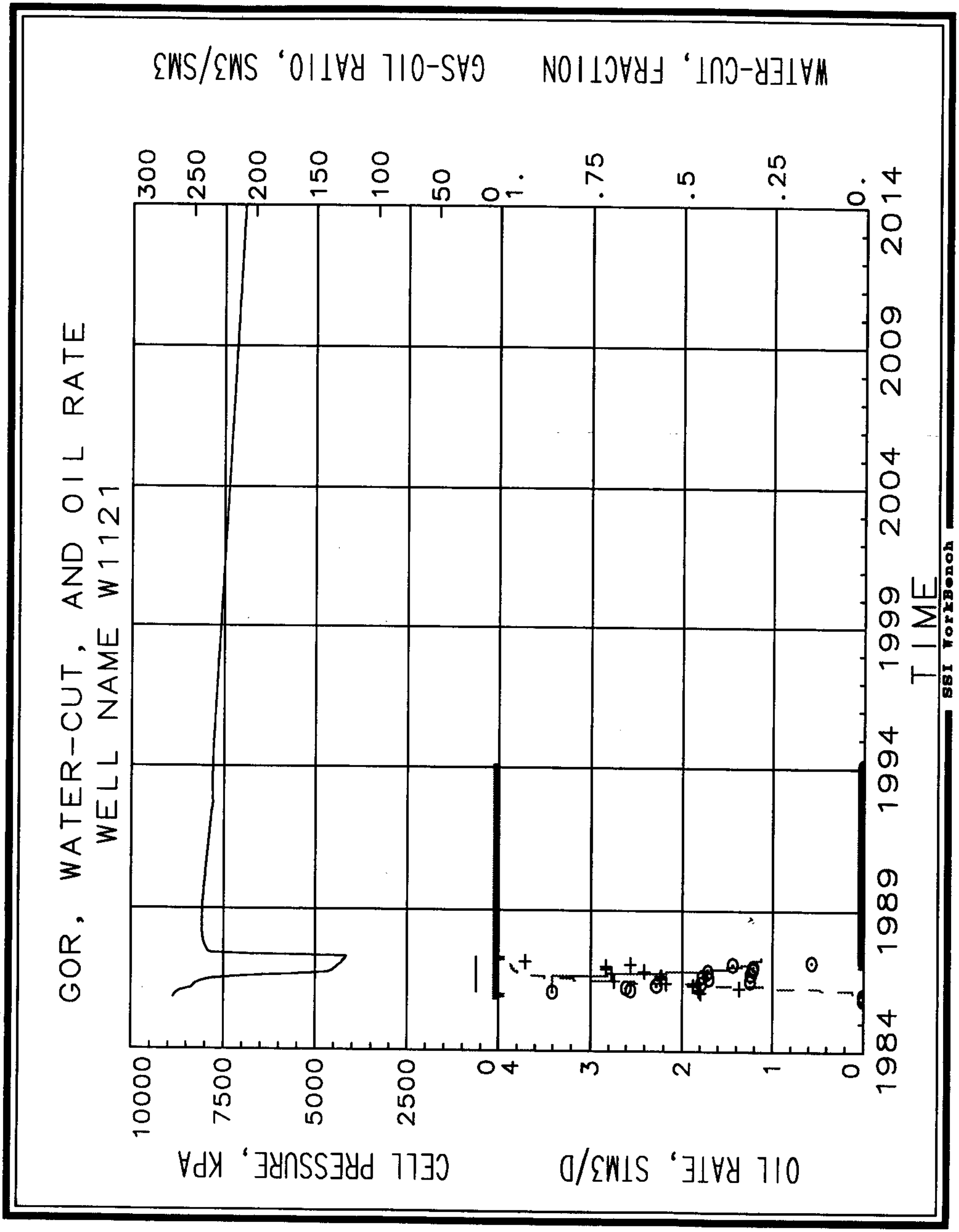
CASE 4 FIGURE 81



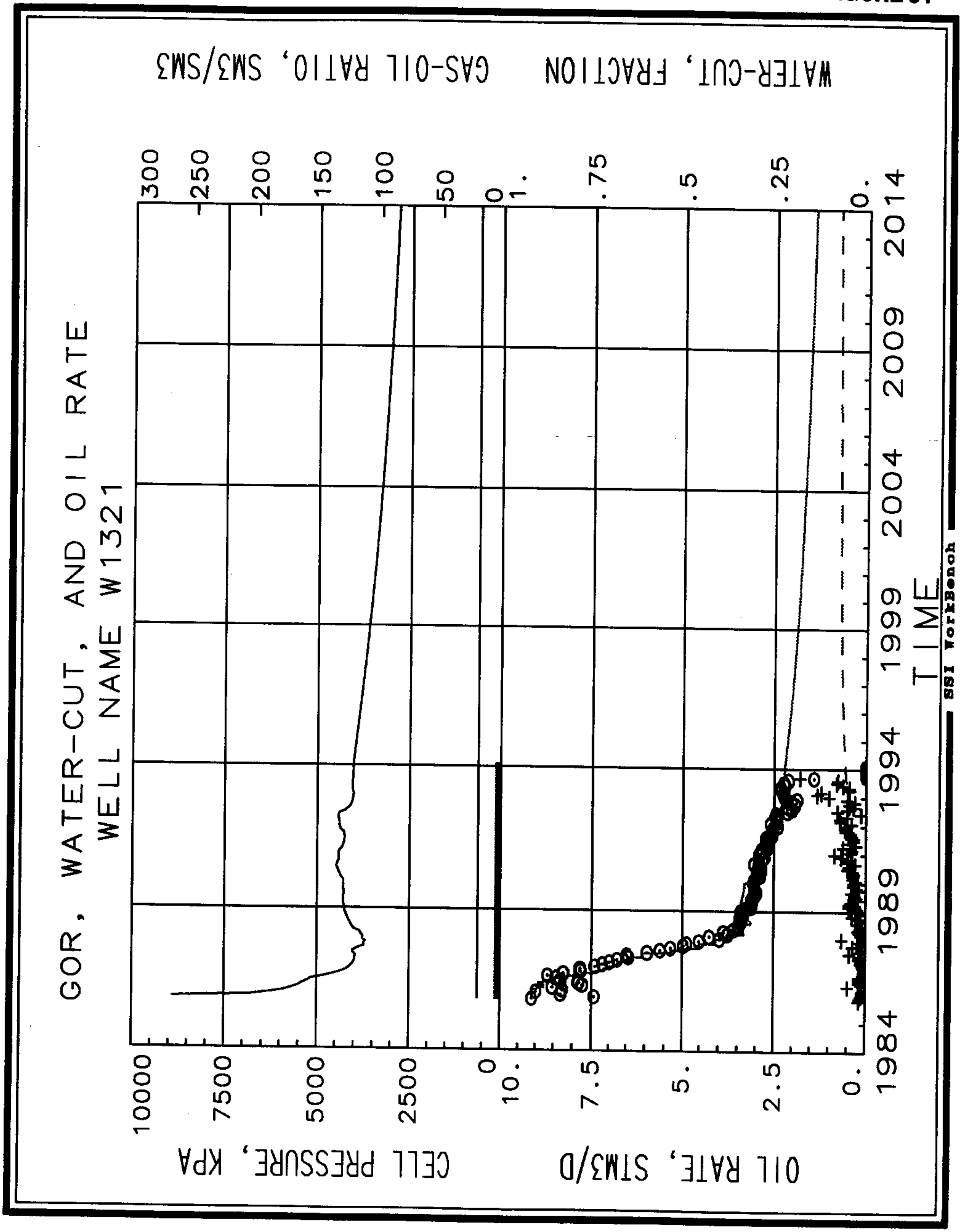
CASE 4 FIGURE 82

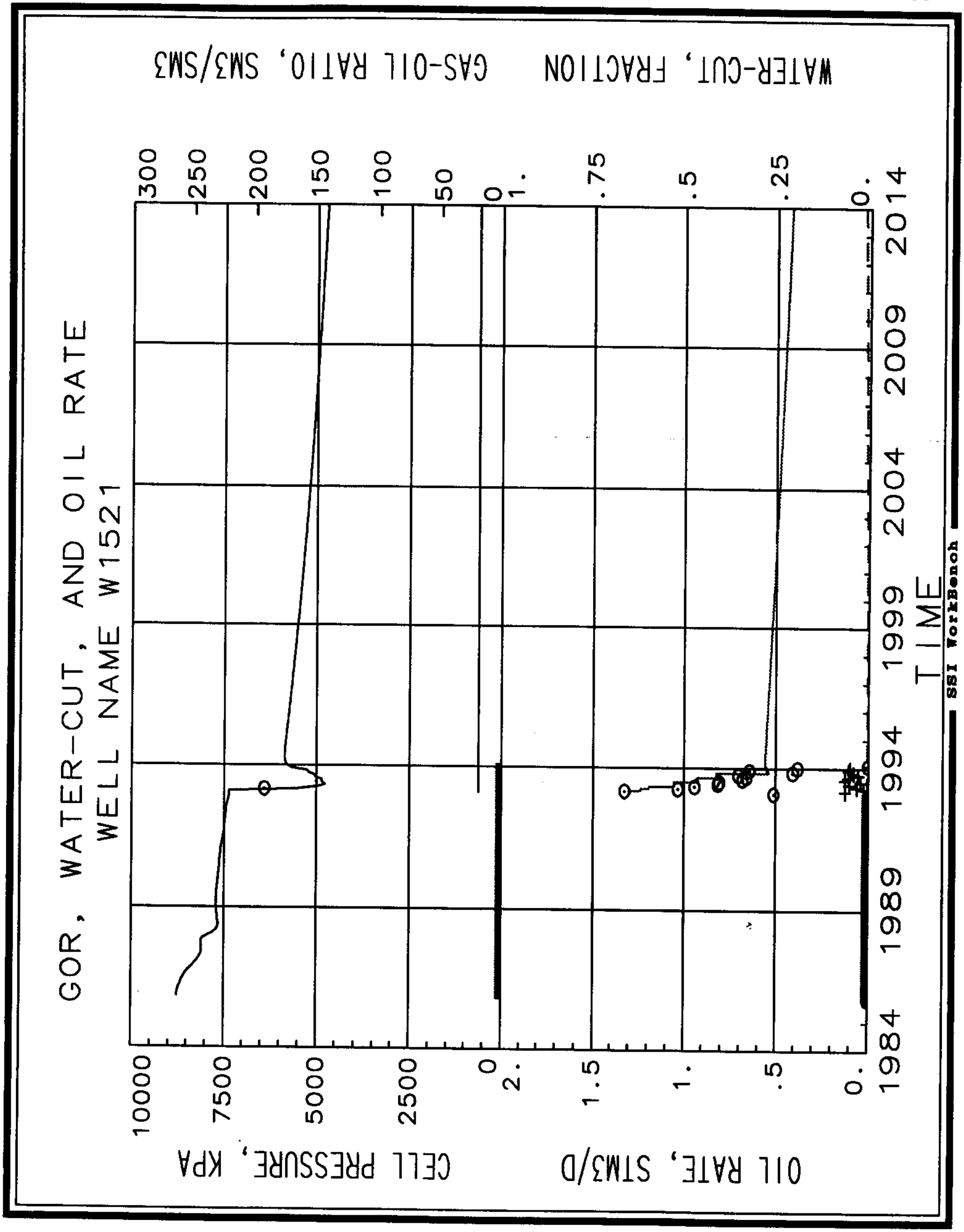


CASE 4 FIGURE 83

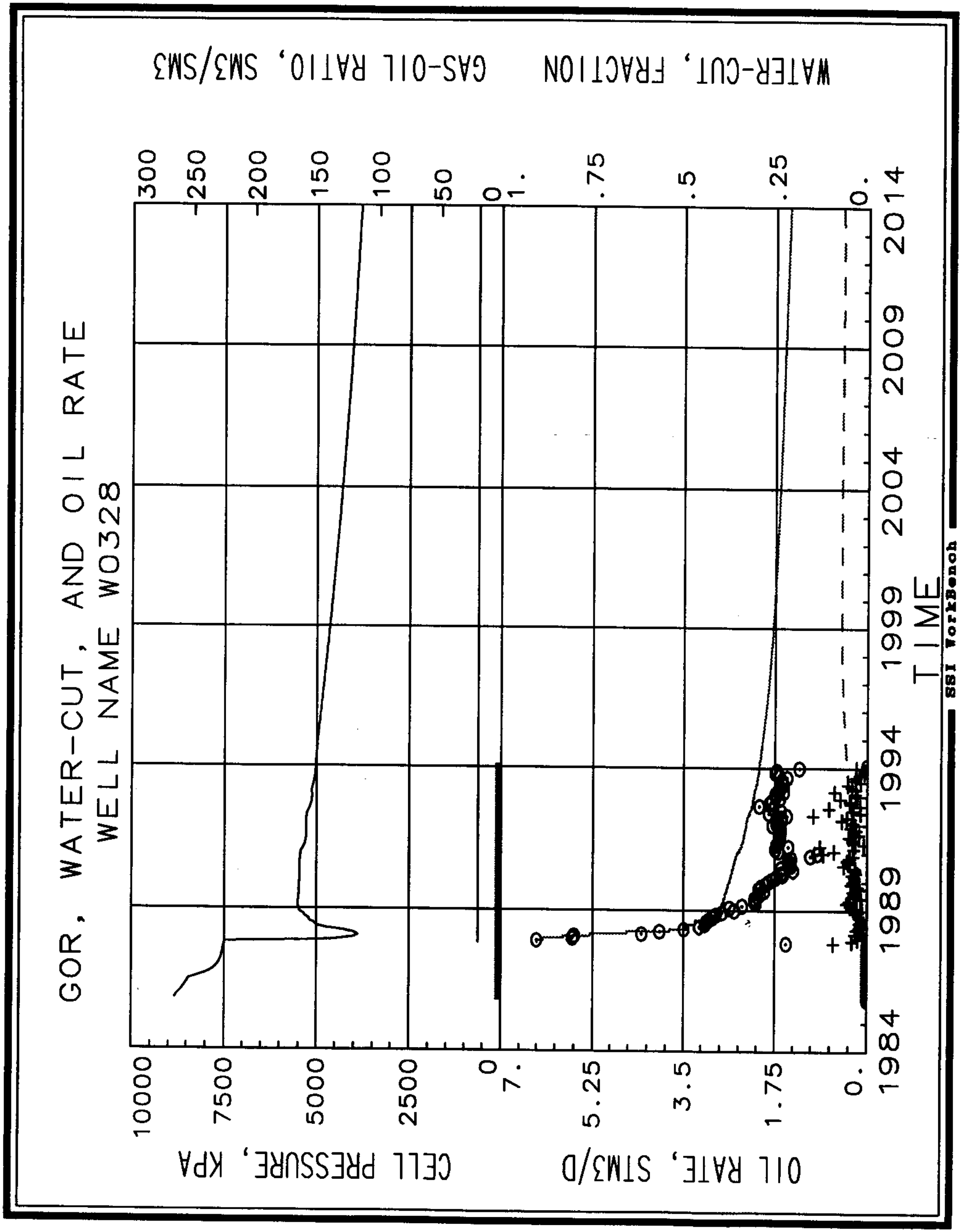


CASE 4 FIGURE 84

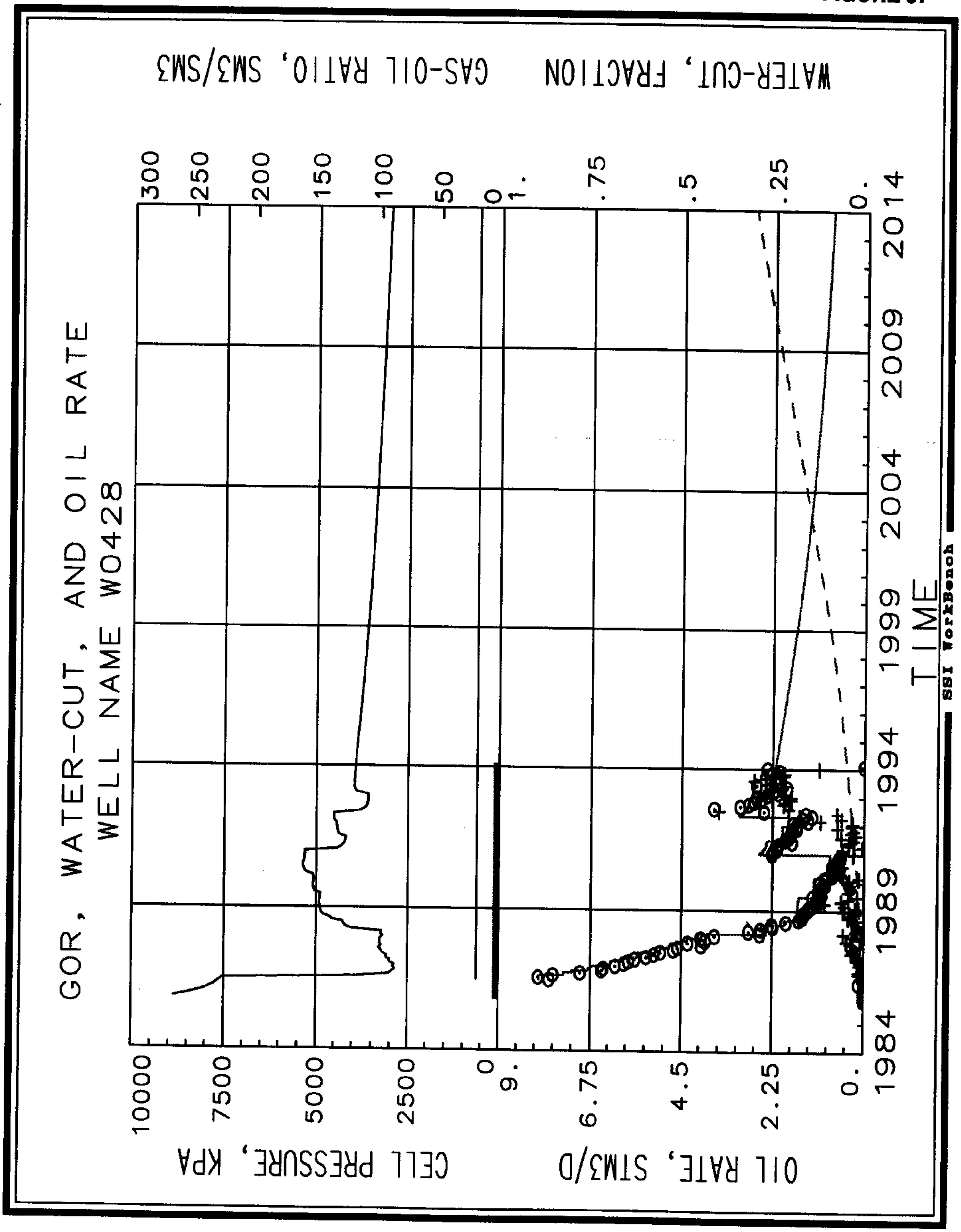



GOR, WATER-CUT, AND OIL RATE
WELL NAME W1521
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

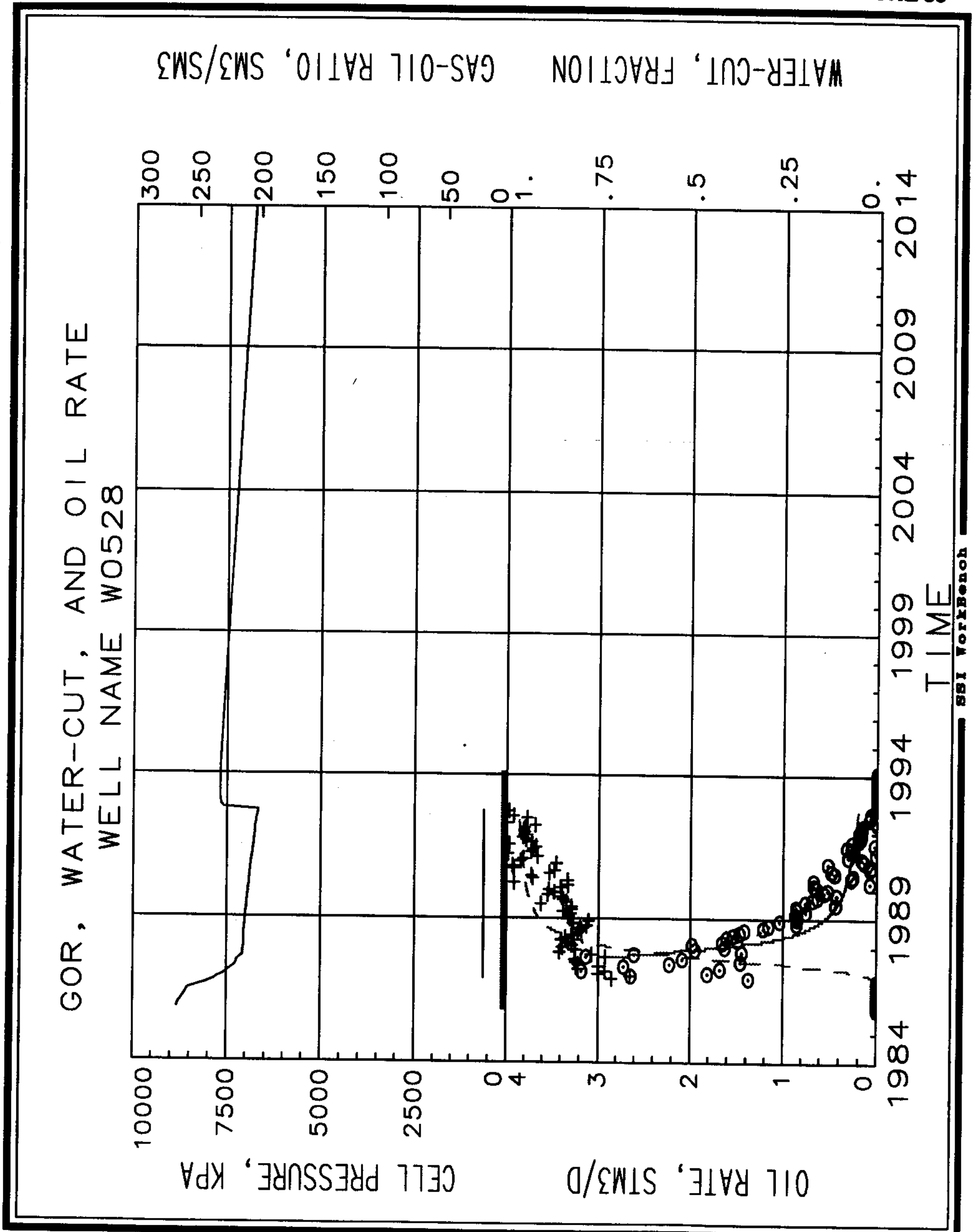
CASE 4 FIGURE 86



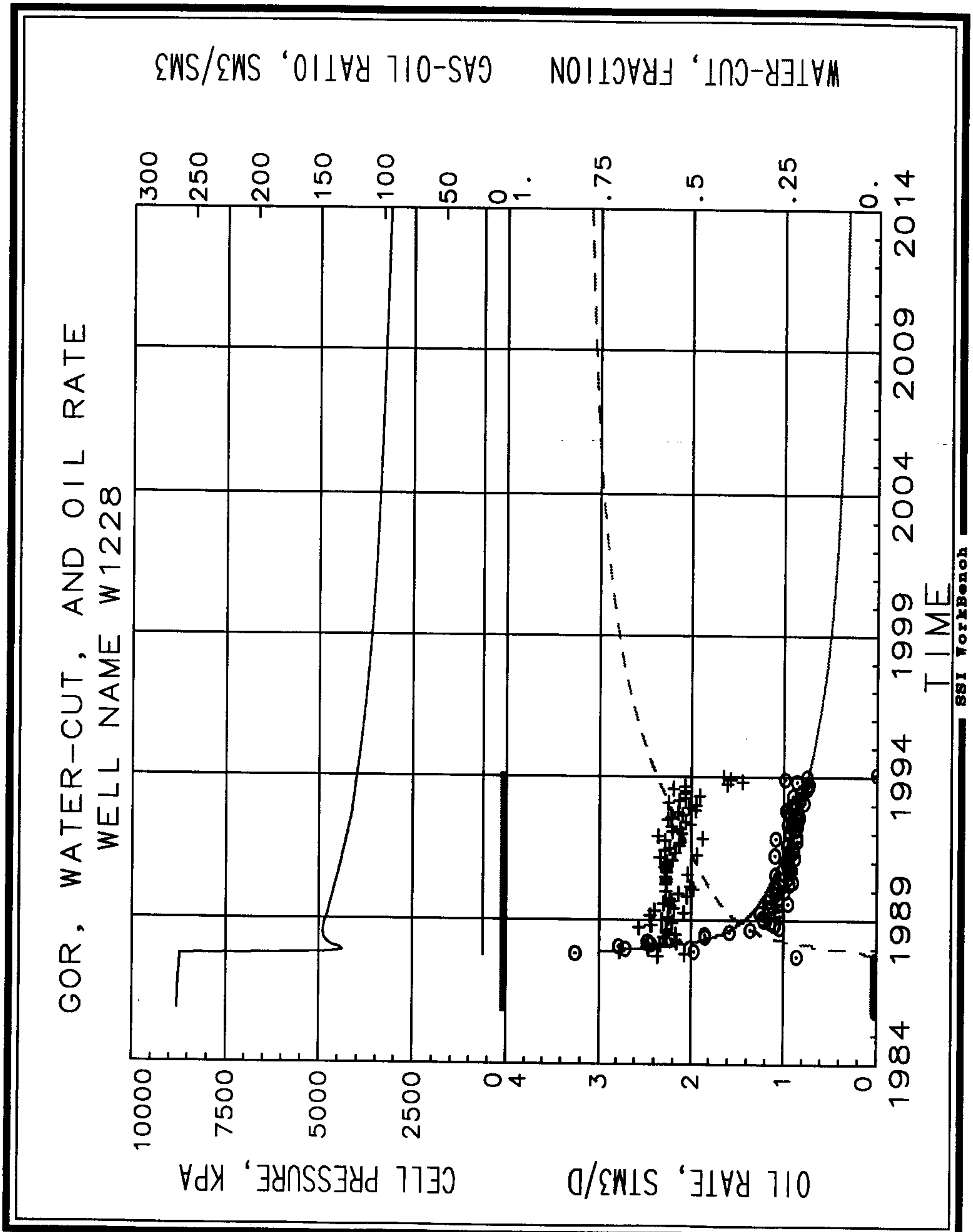
CASE 4 FIGURE 87

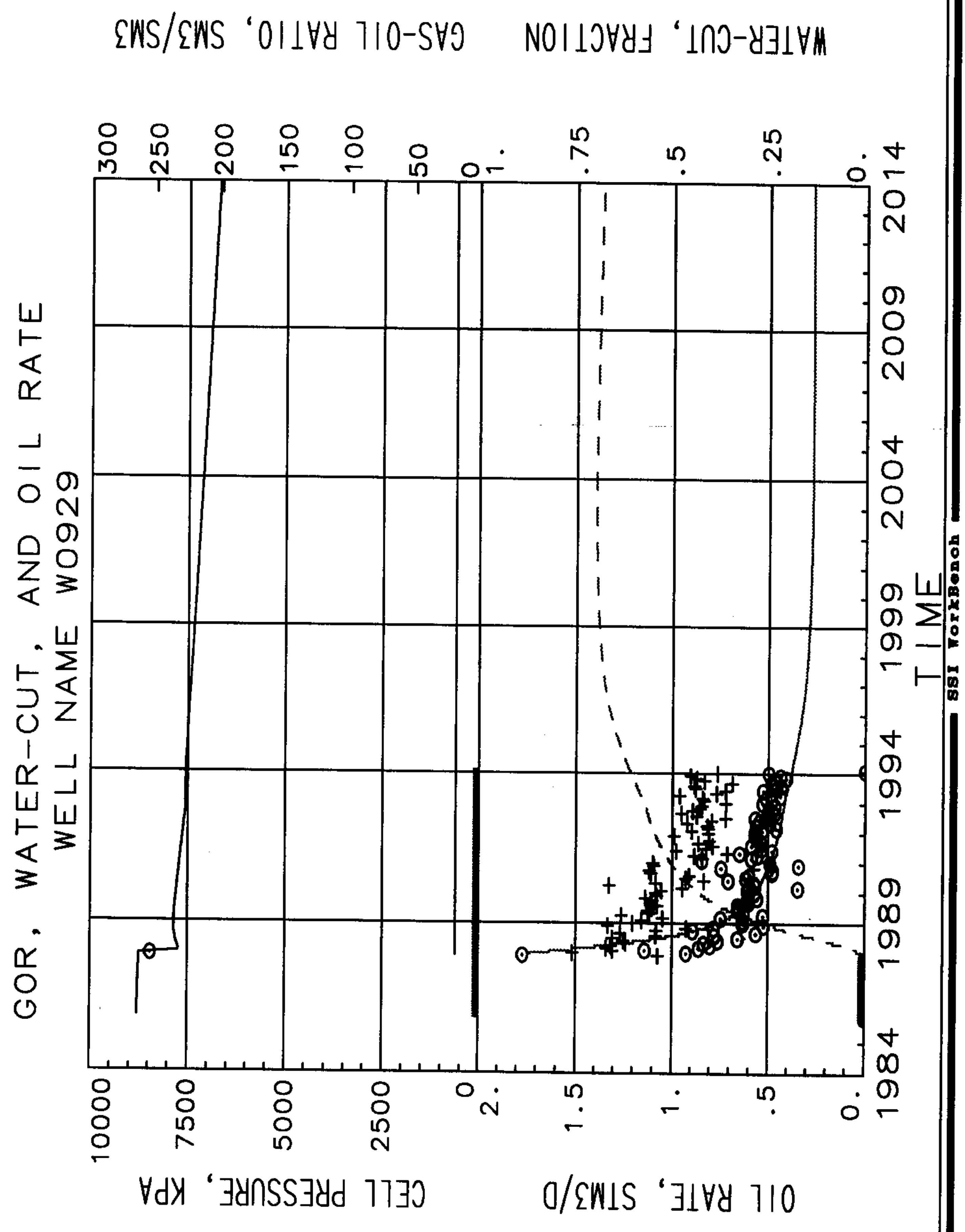


CASE 4 FIGURE 88



CASE 4 FIGURE 89

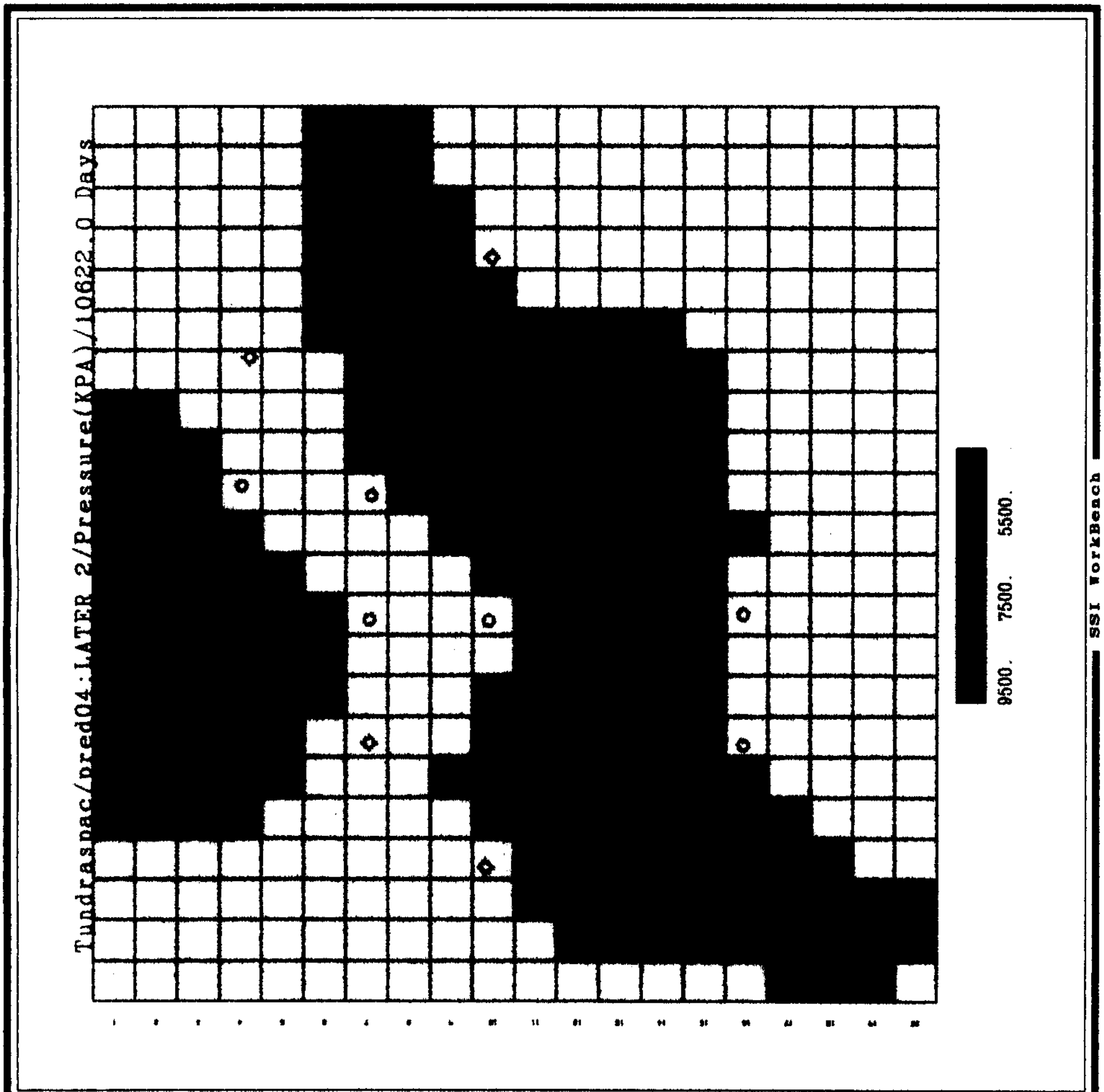



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0929
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 4 FIGURE 91

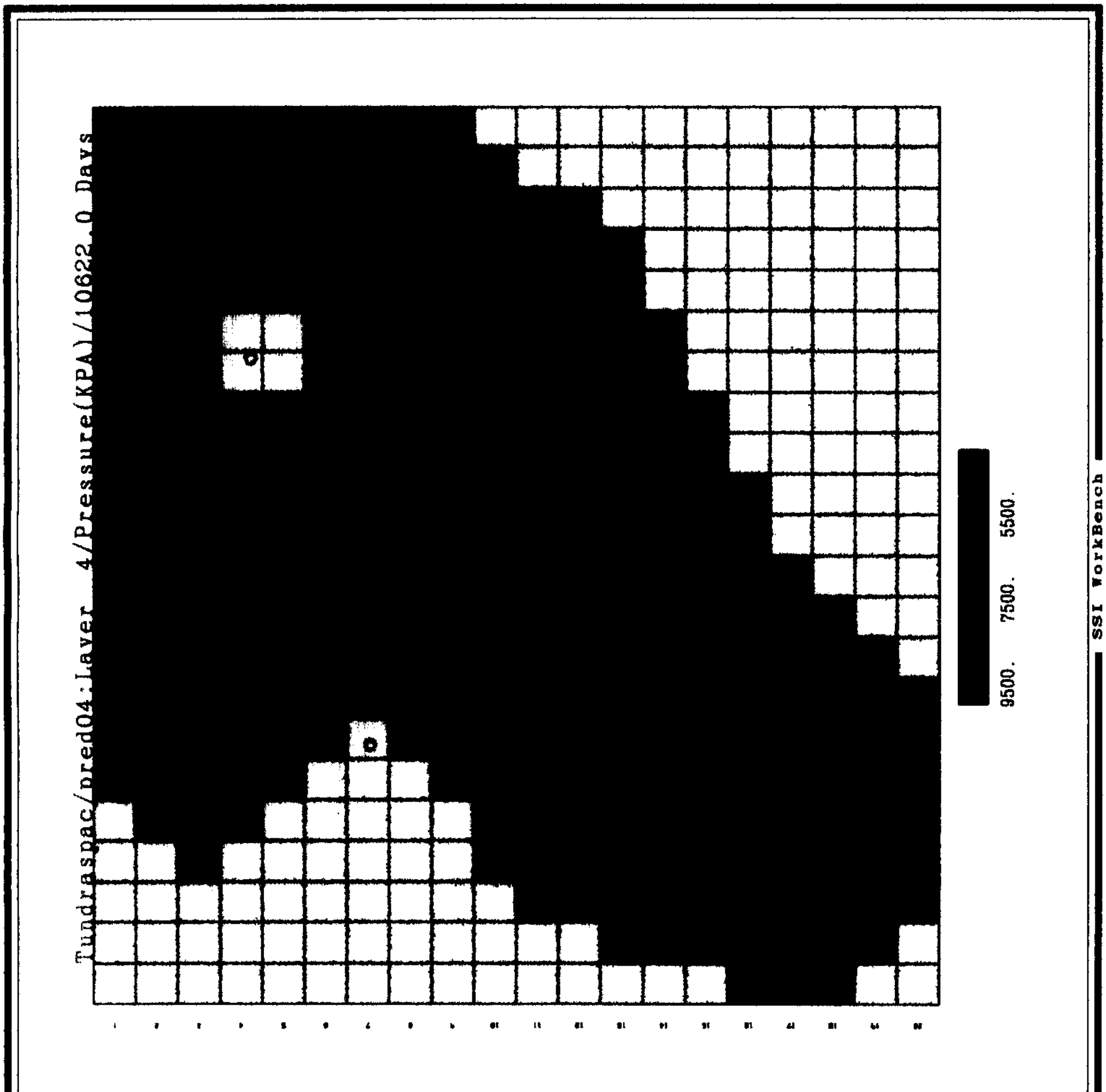
Prediction Case 4 - Pressure Distribution Map Layer 2

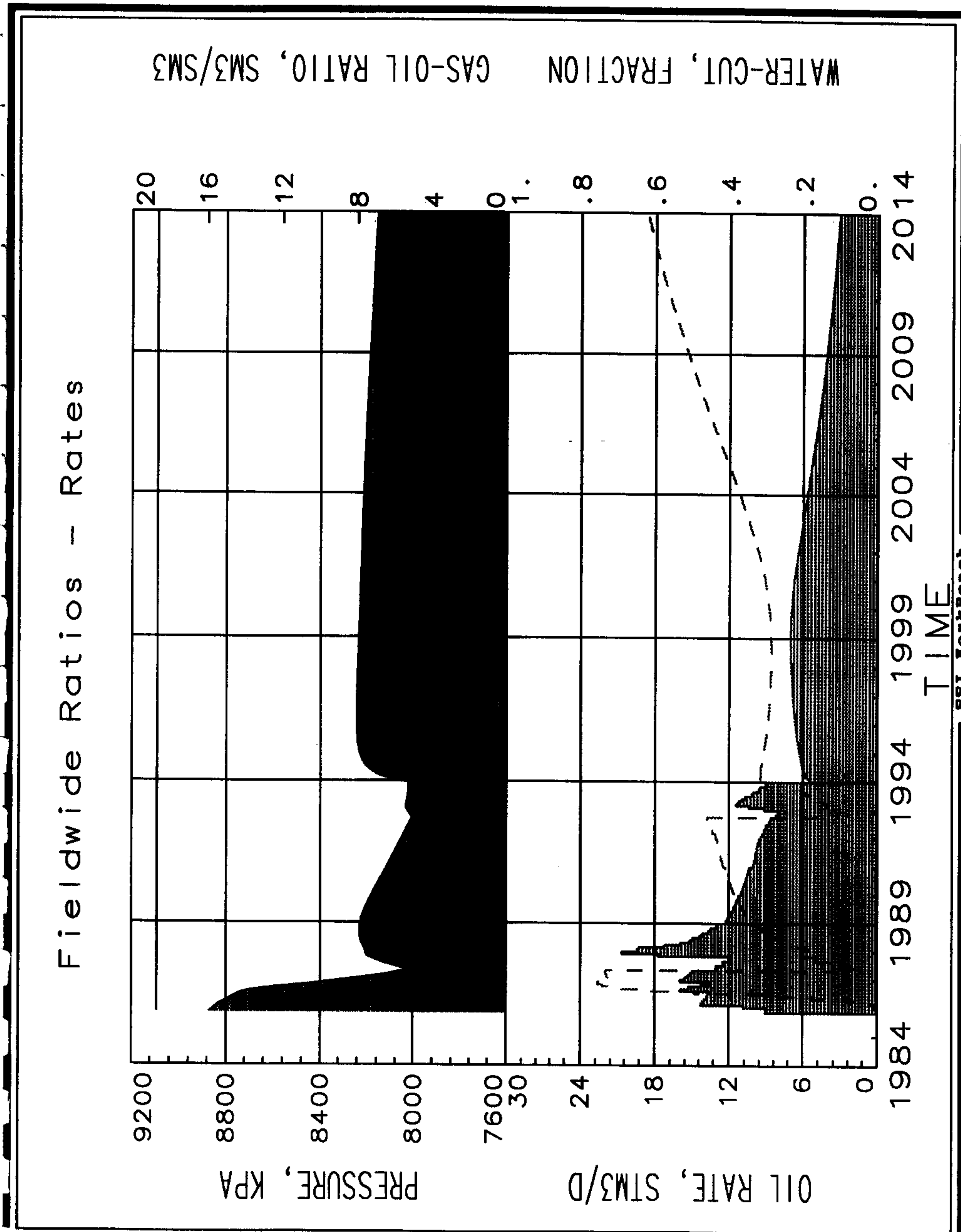


Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

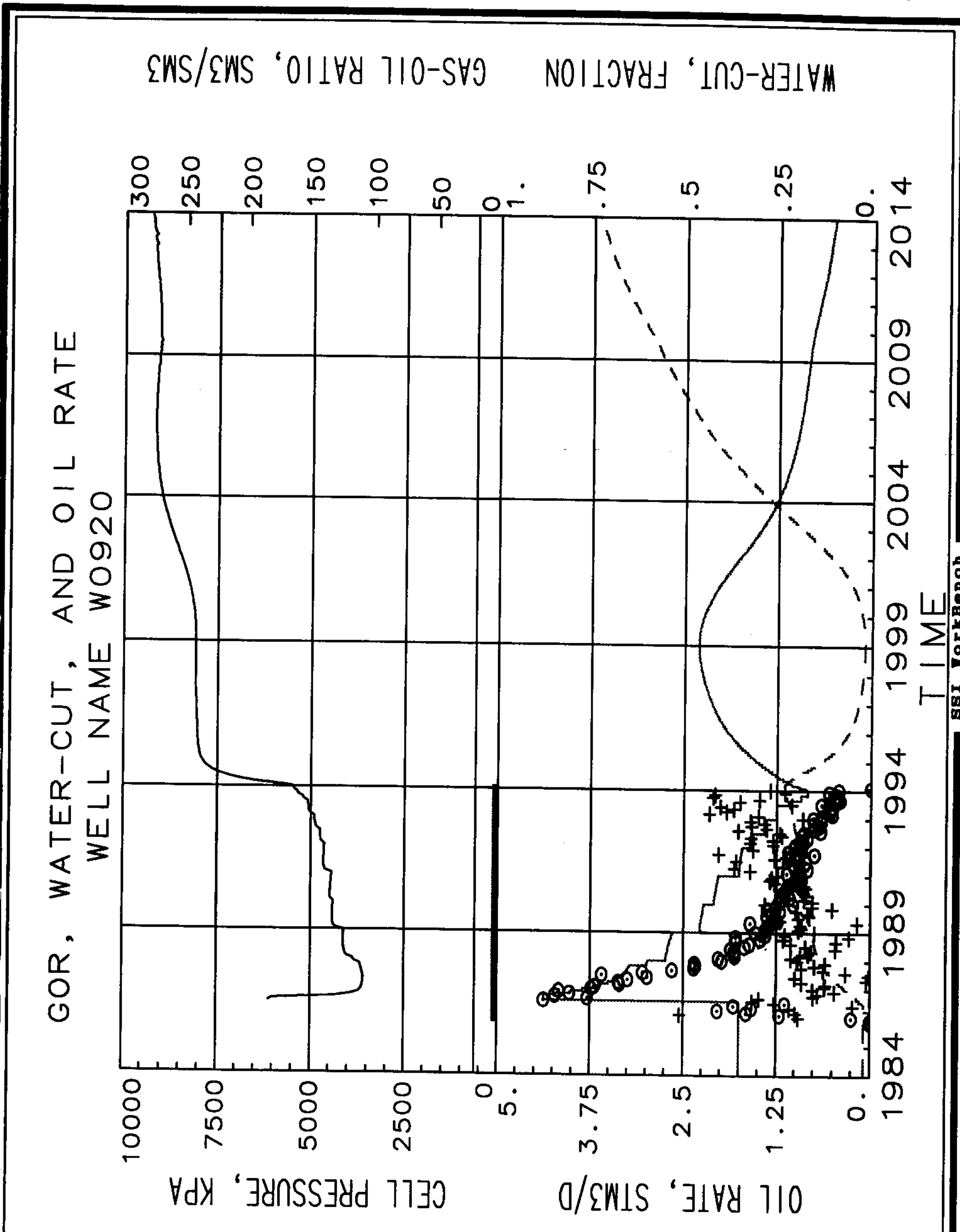
CASE 4 FIGURE 92

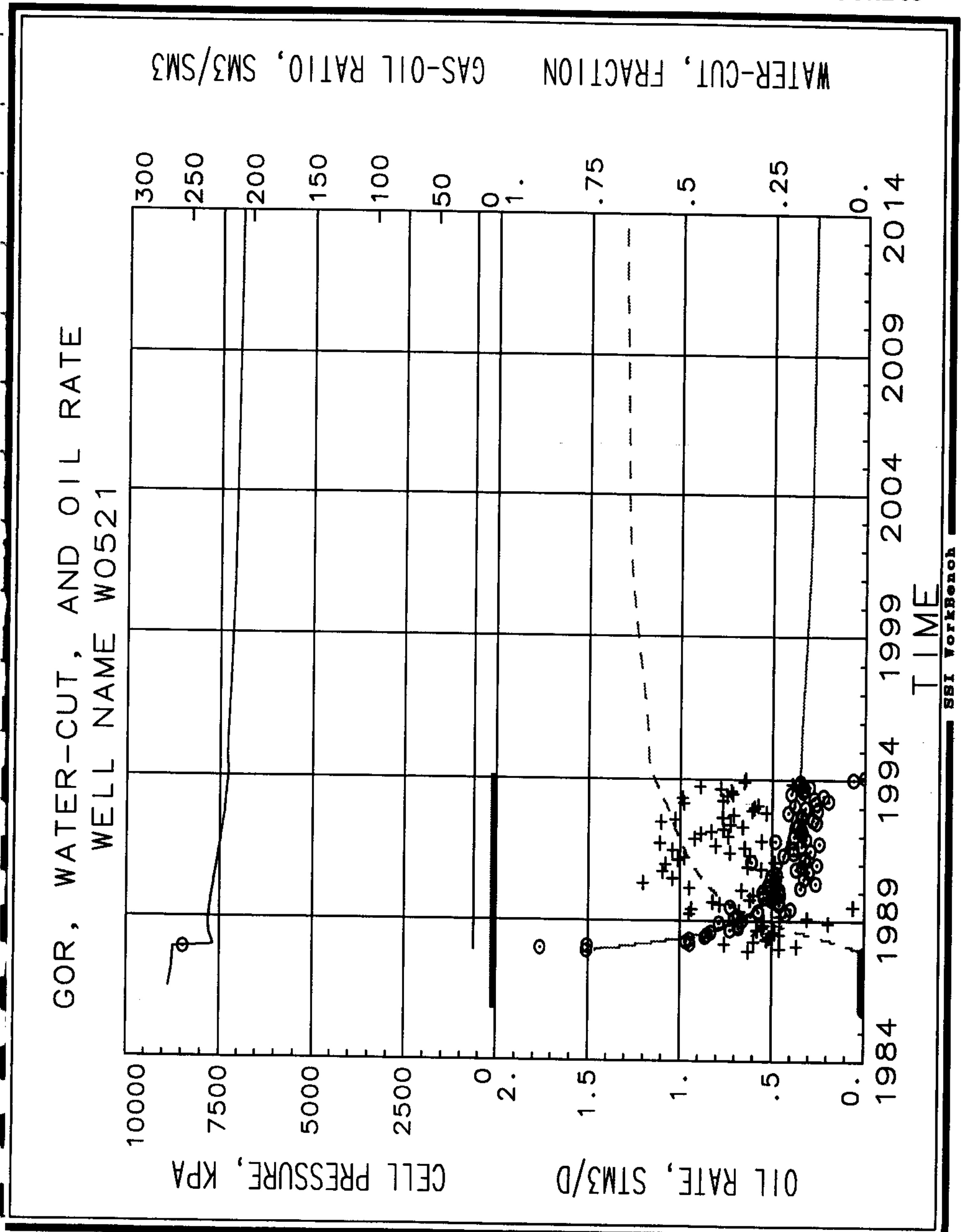
Prediction Case 4 - Pressure Distribution Map Layer 4

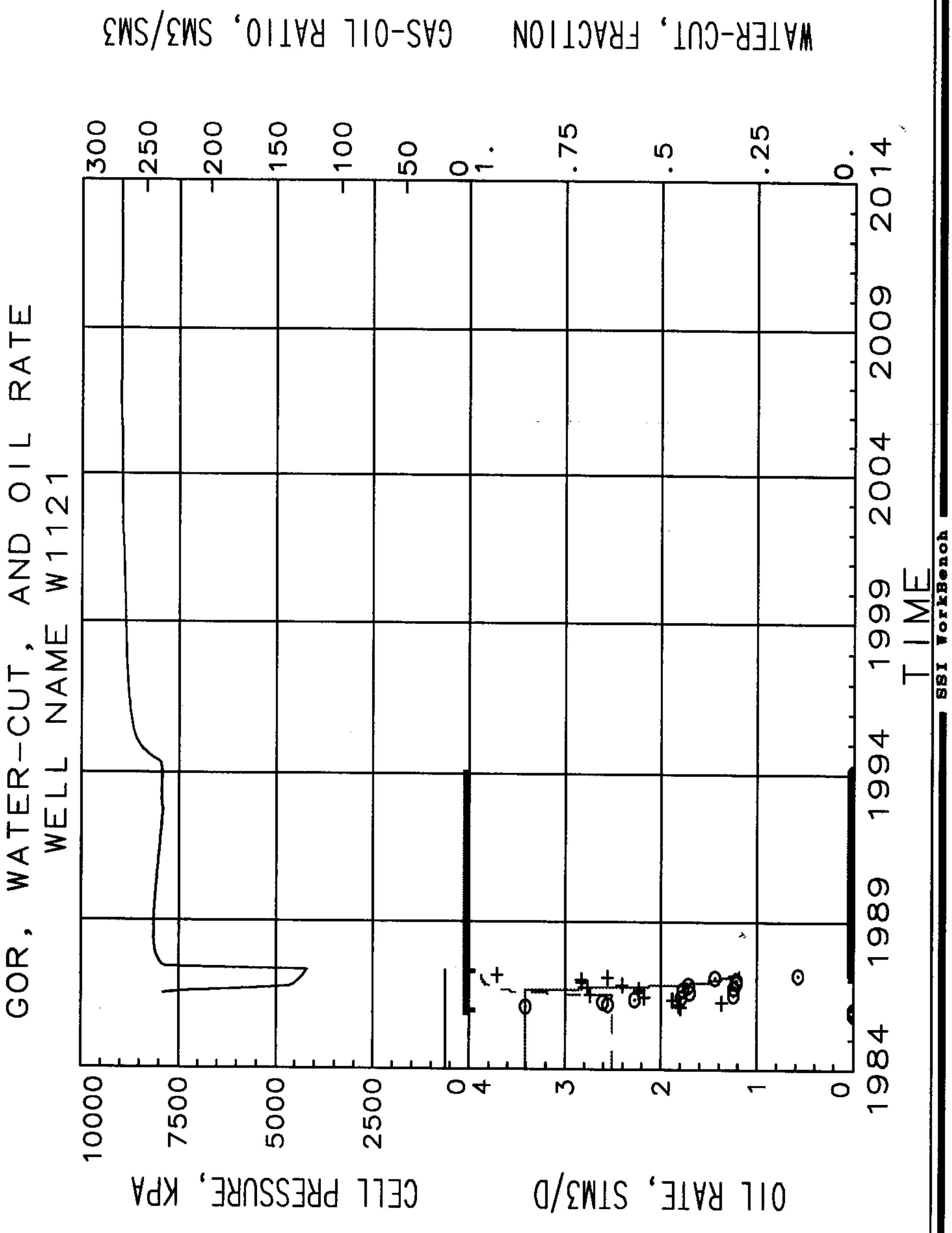




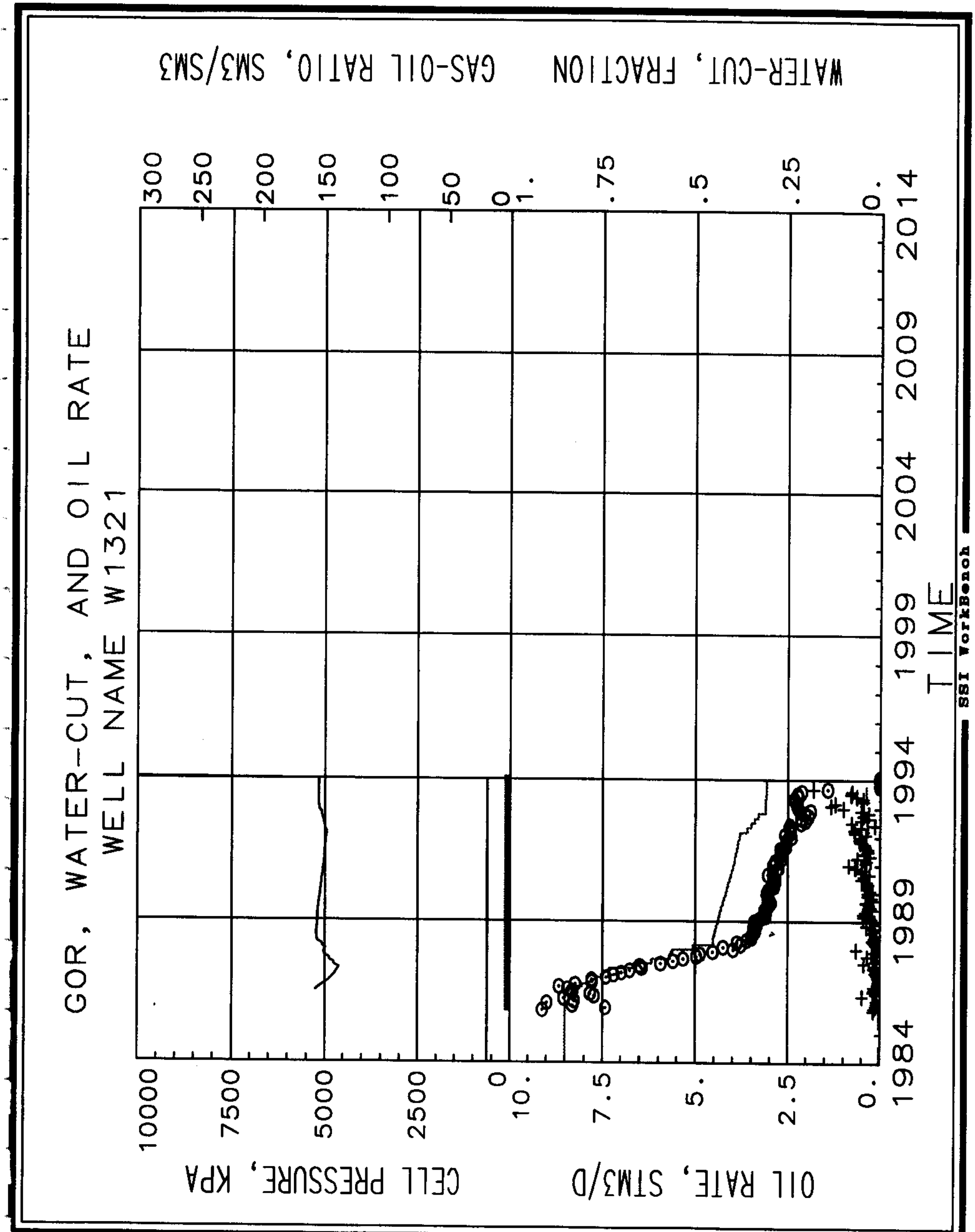
Fieldwide Ratios - Rates
PRESSURE, KPA
9200
8800
8400
8000
7600
OIL RATE, STM3/D
30
24
18
12
6
0
GAS-OIL RATIO, SM3/SM3
20
16
12
8
4
0
WATER-CUT, FRACTION
1.
.8
.6
.4
.2
0.
1984
1989
1994
1999
2004
2009
2014
TIME
SSI WorkBench

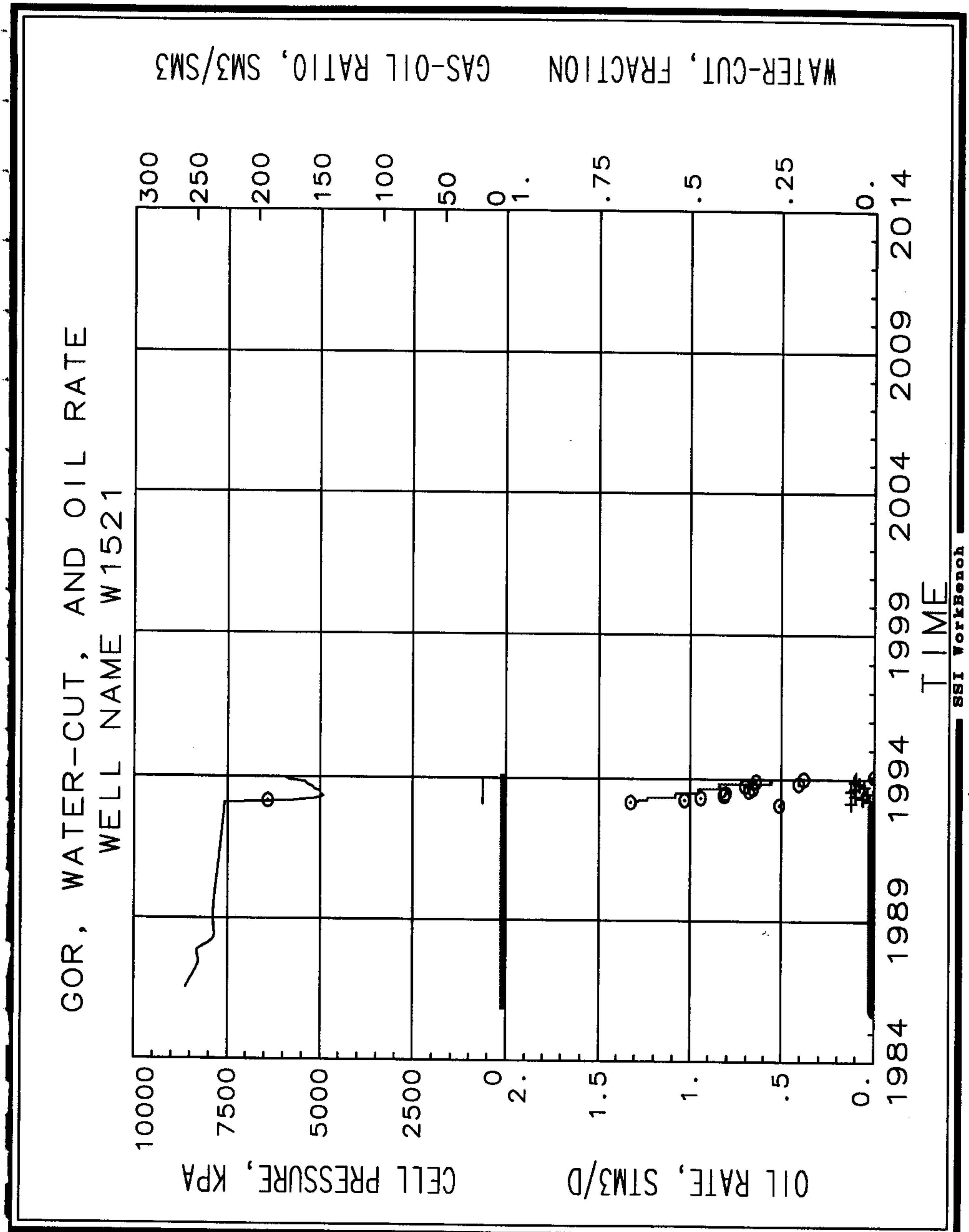

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0920
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1984
1989
1994
1999
2004
2009
2014
10000
7500
5000
2500
0
5.
3.75
2.5
1.25
0.
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
SSI WorkBench

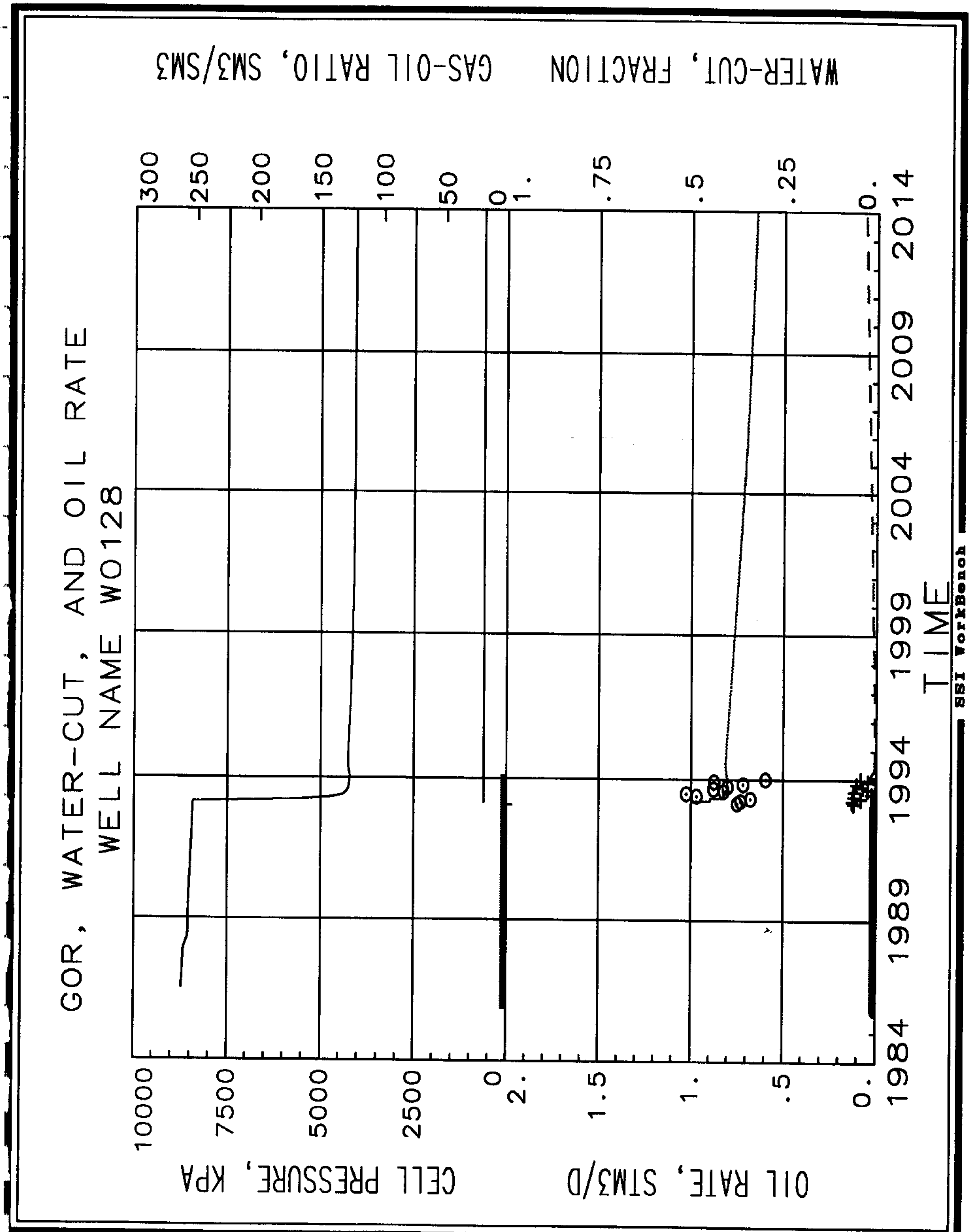

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0521
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
CELL PRESSURE, KPA
OIL RATE, STM3/D
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
1984
1989
1994
1999
2004
2009
2014
TIME
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W1121
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300 250 200 150 100 50 0
1. .75 .5 .25 0.
CELL PRESSURE, KPA
10000 7500 5000 2500 0
OIL RATE, STM3/D
4 3 2 1 0
1984 1989 1994 1999 2004 2009 2014
TIME
SSI WorkBench

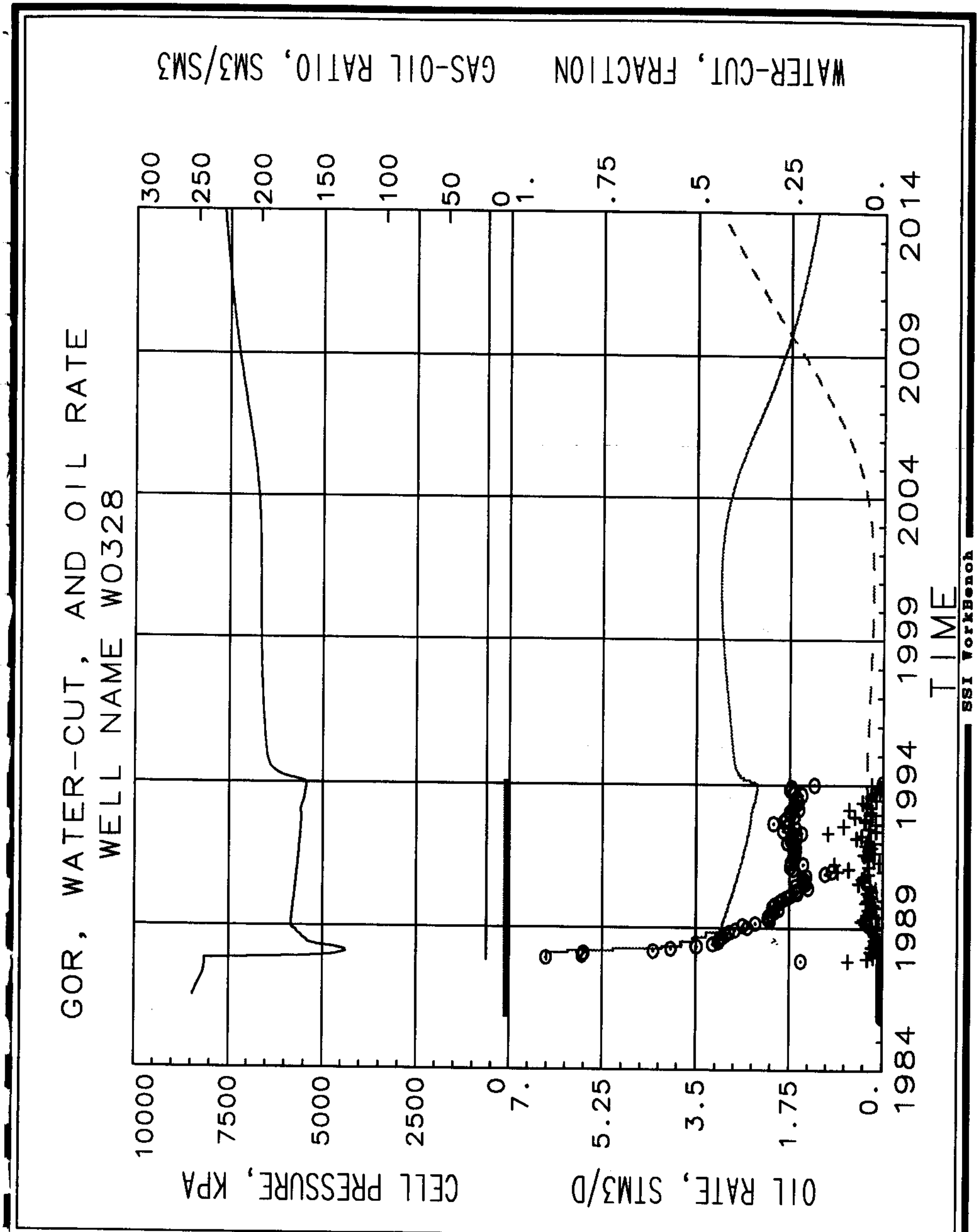
CASE 5 FIGURE 97



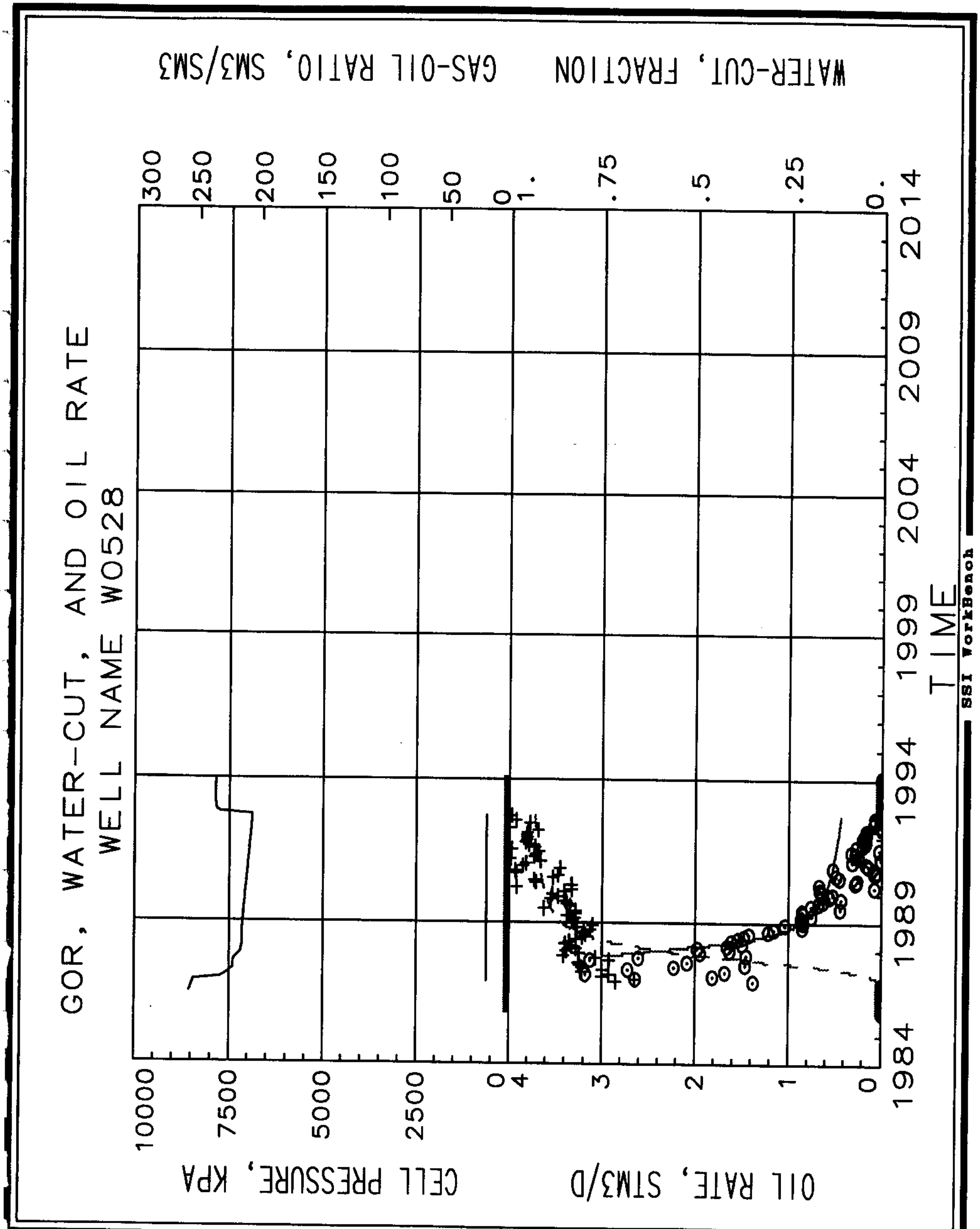

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1521
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W0128
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1984
1989
1994
1999
2004
2009
2014
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
SSI WorkBench

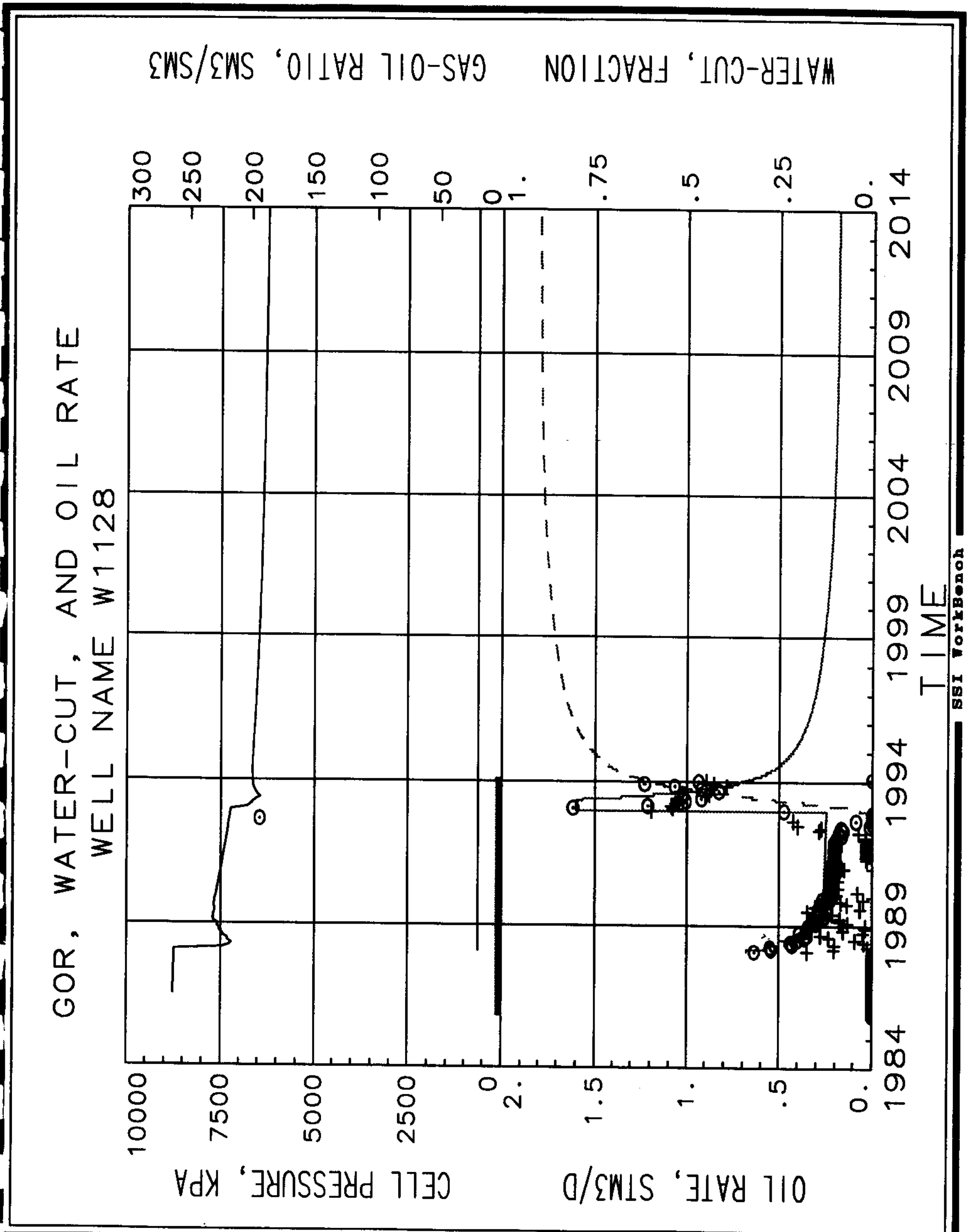
CASE 5 FIGURE 100

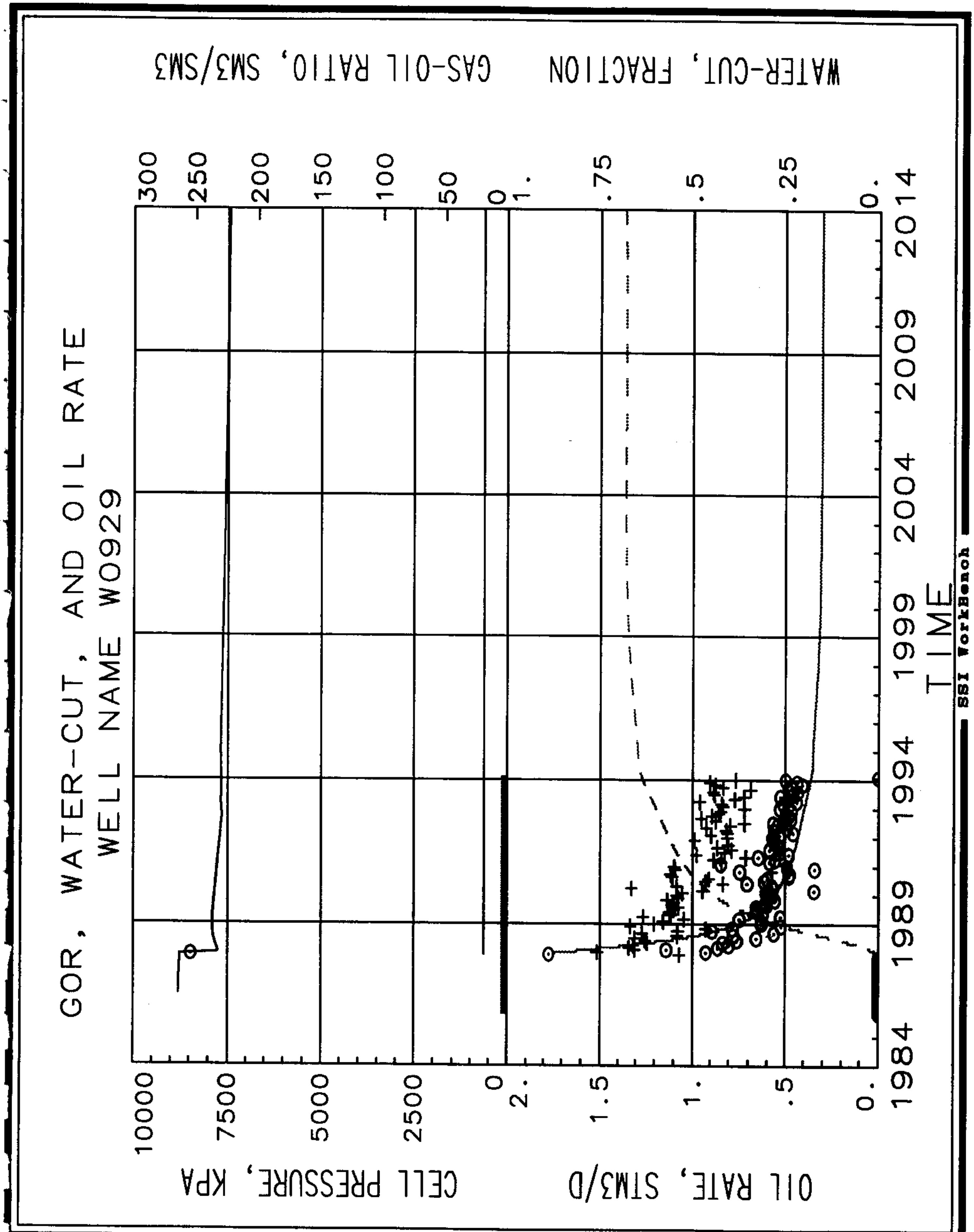


CASE 5 FIGURE 101

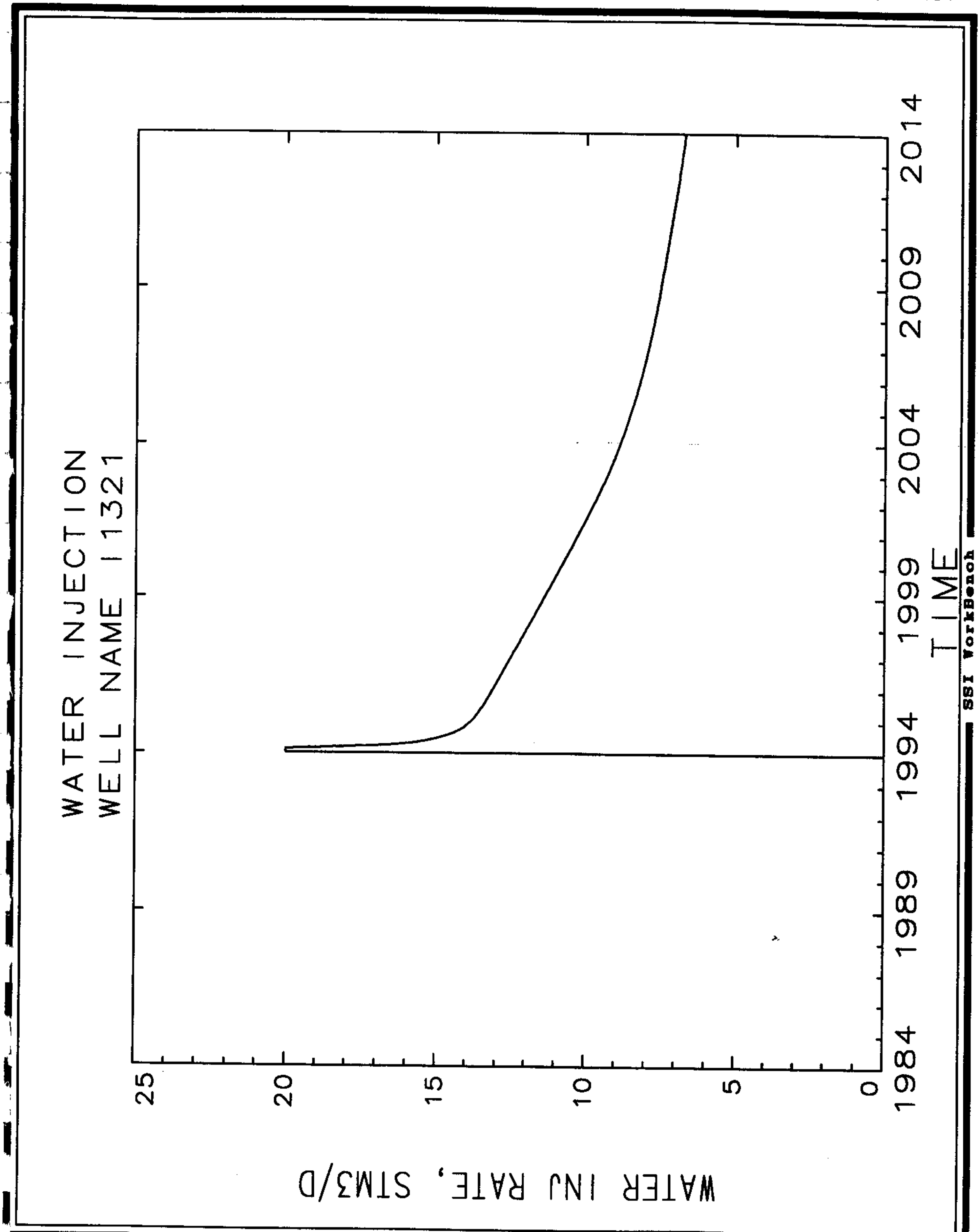


CASE 5 FIGURE 102

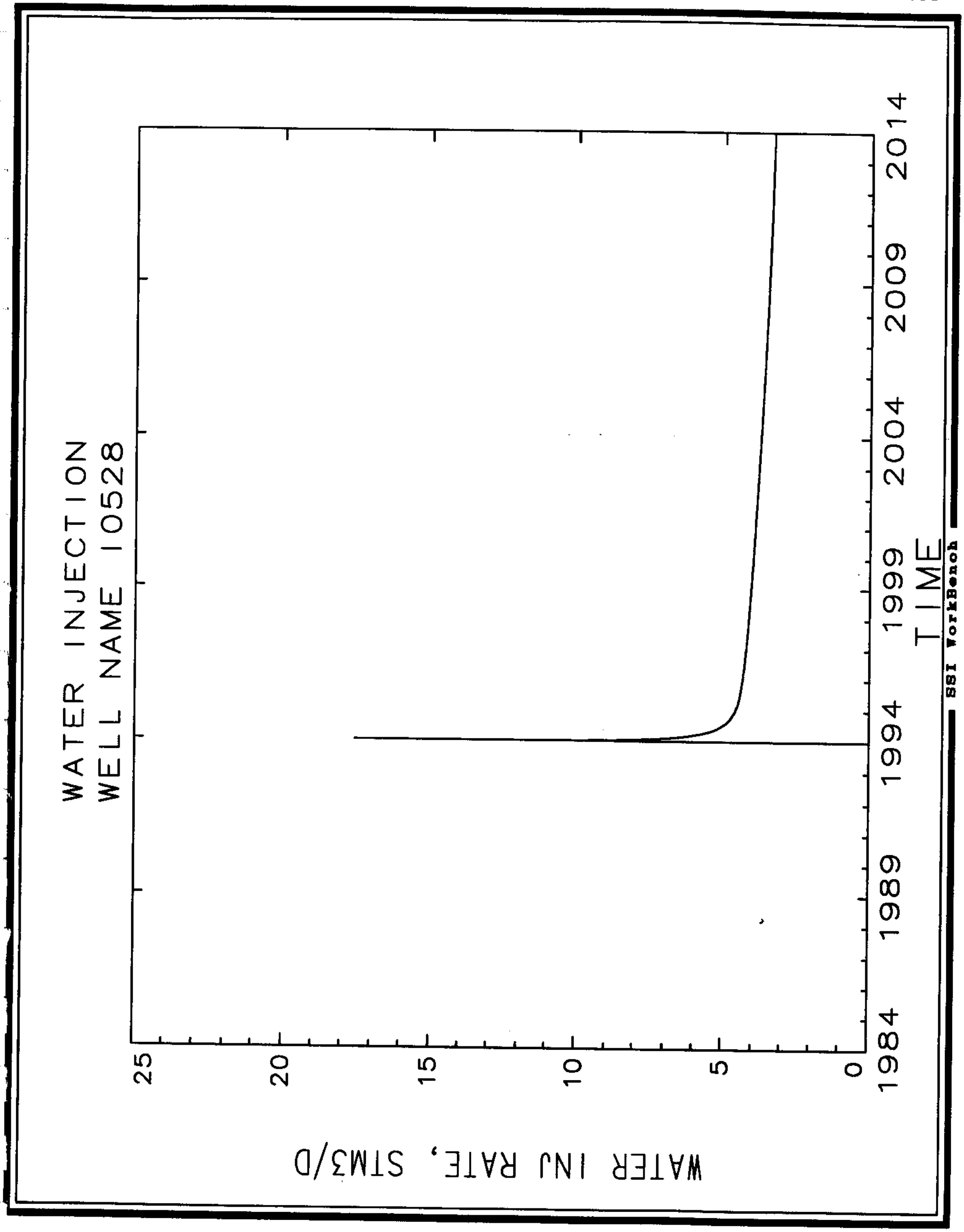


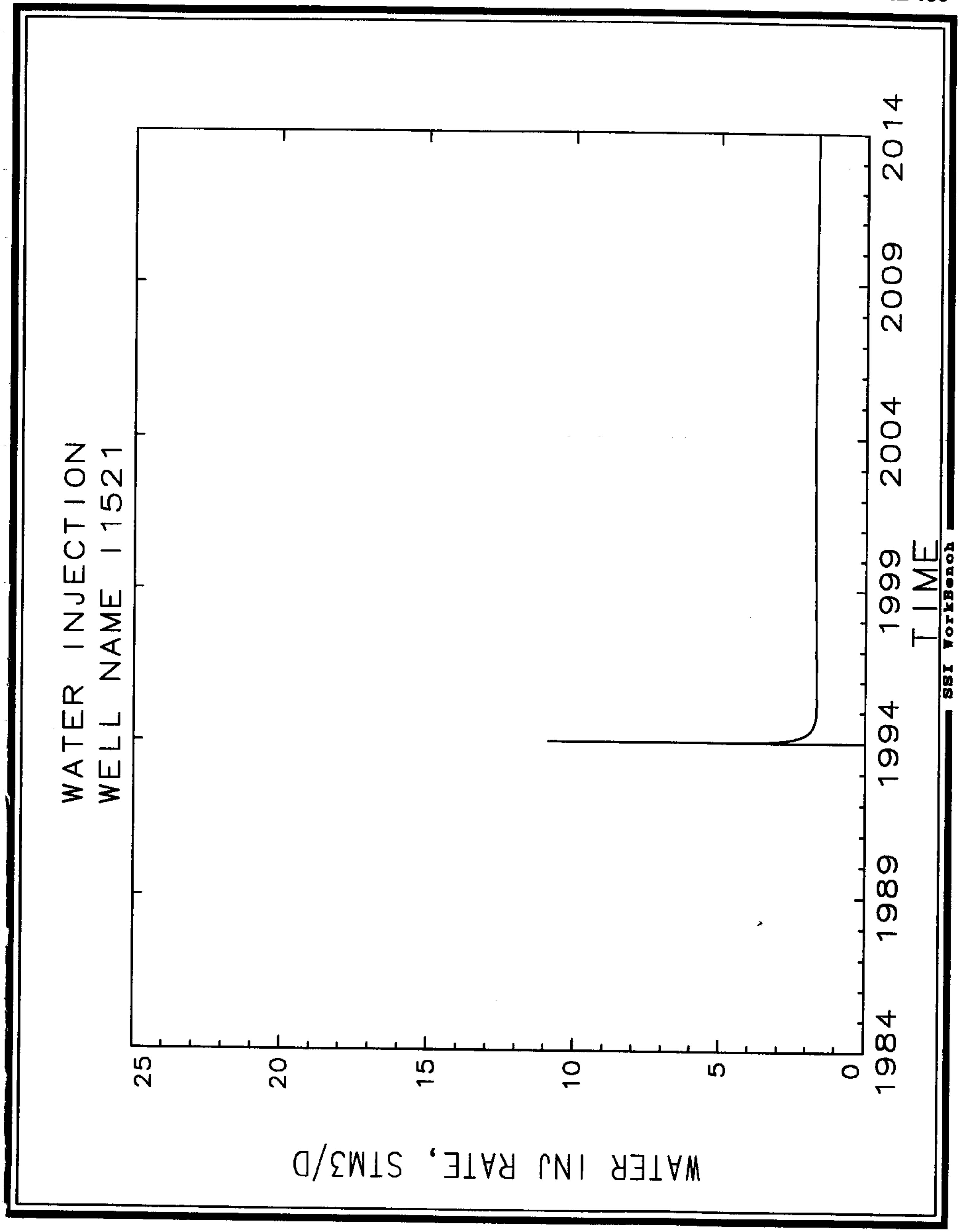

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0929
TIME
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

CASE 5 FIGURE 104



CASE 5 FIGURE 105

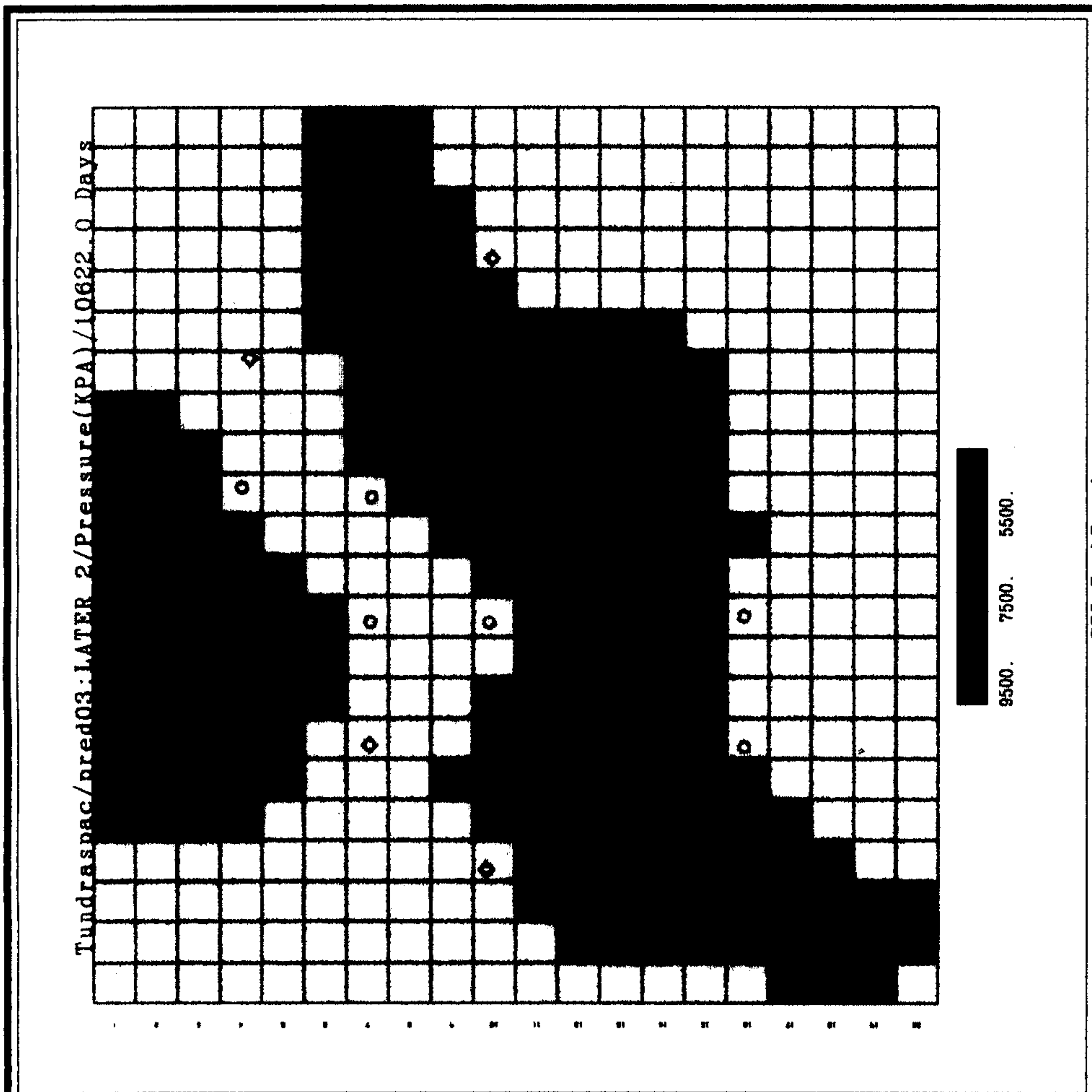



WATER INJECTION
WELL NAME I1521
WATER INJ RATE, STM3/D
0
5
10
15
20
25
TIME
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 5 FIGURE 107

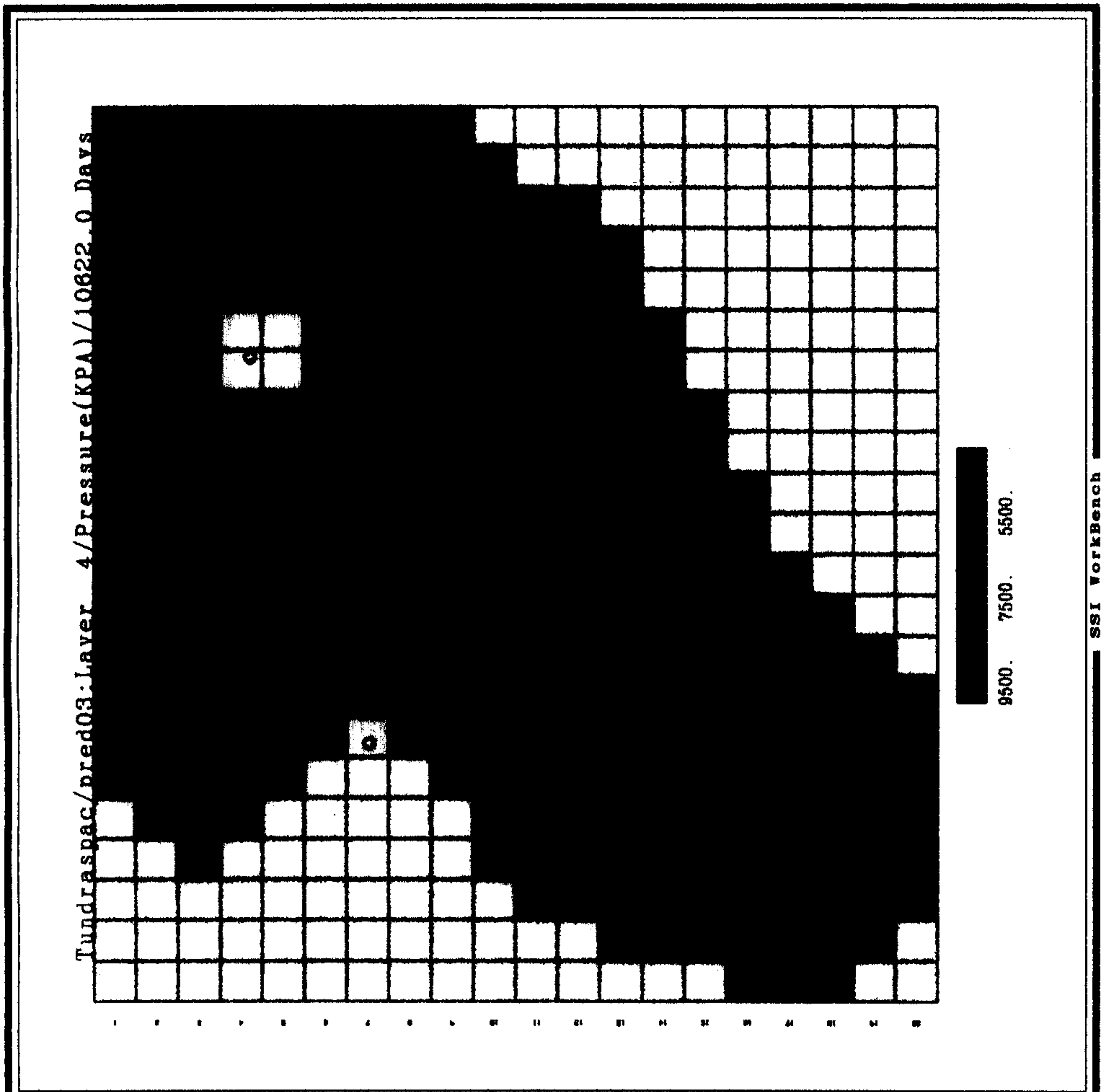
Prediction Case 5 - Pressure Distribution Map Layer 2



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 5   FIGURE 108

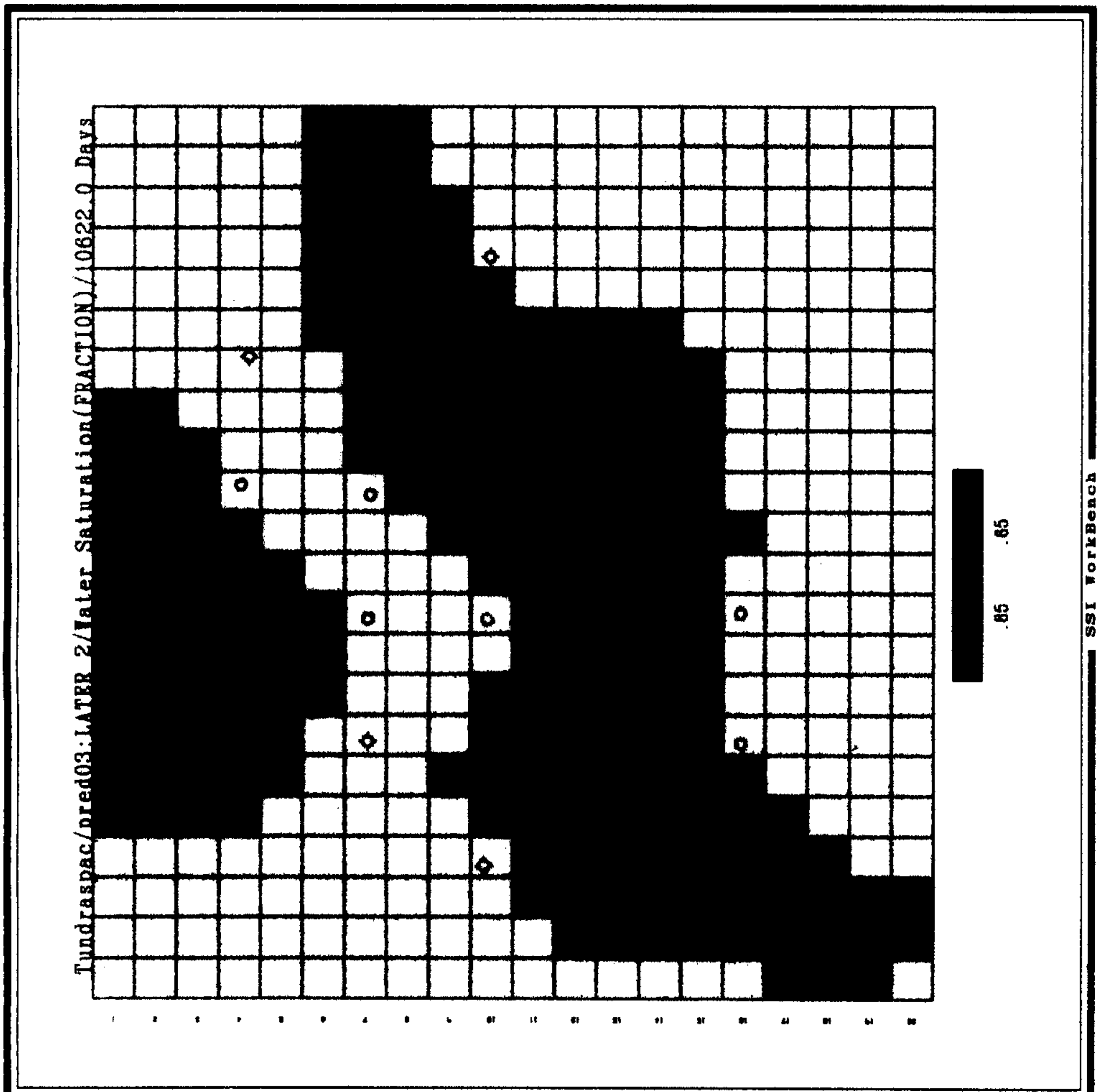
Prediction Case 5 - Pressure Distribution Map Layer 4



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 5 FIGURE 109

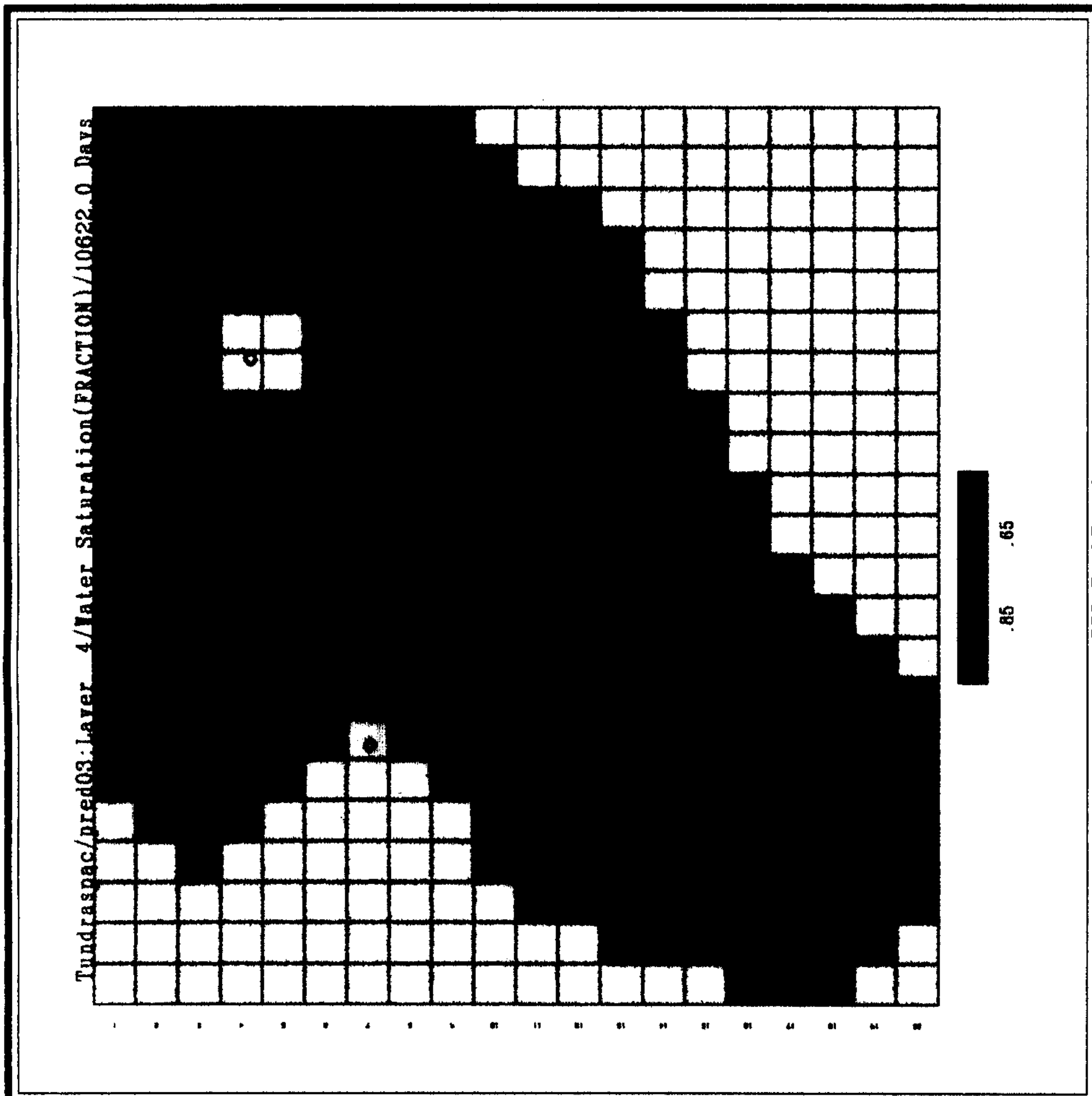
Prediction Case 5 - Water Saturation Distribution Map Layer 2

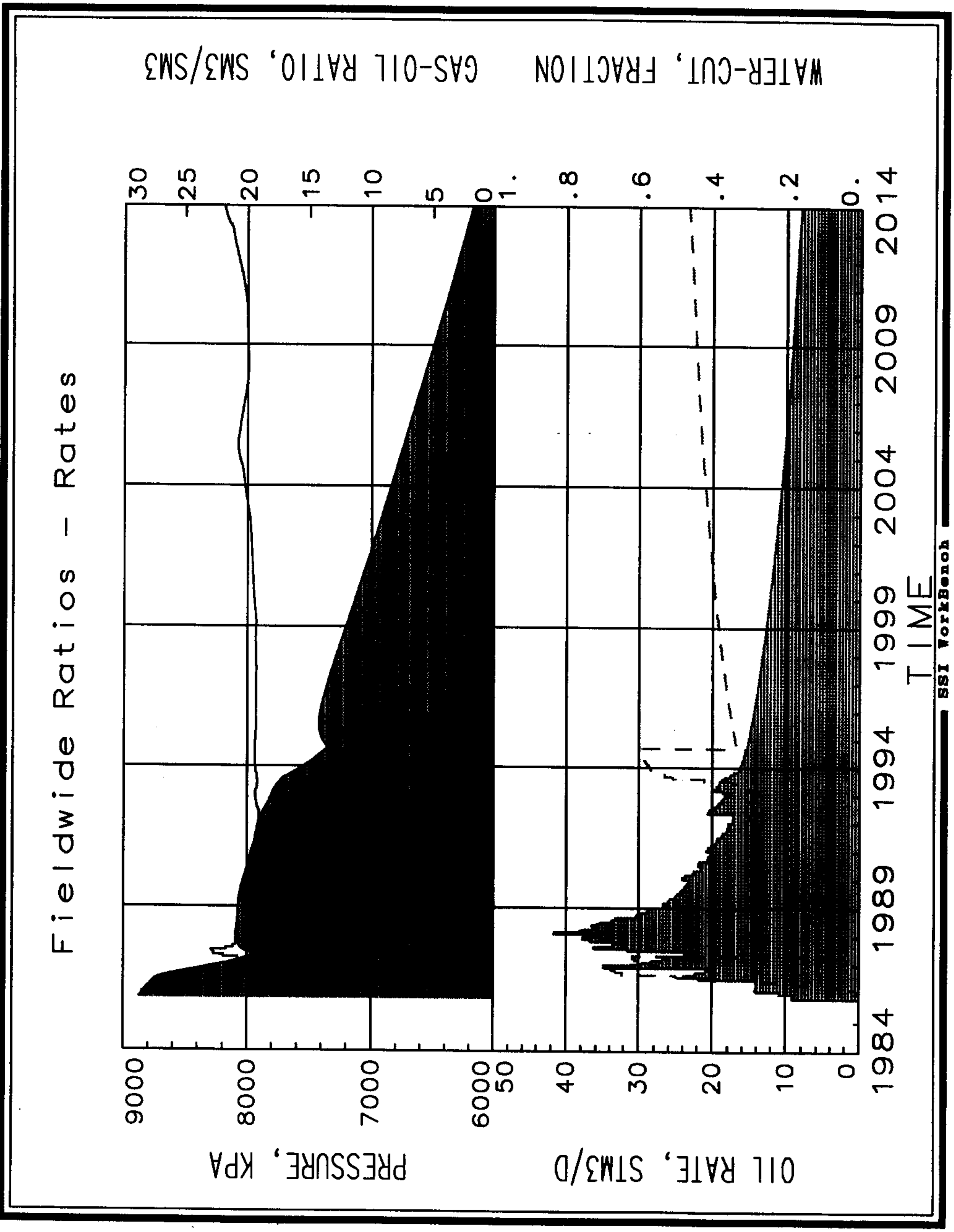


Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

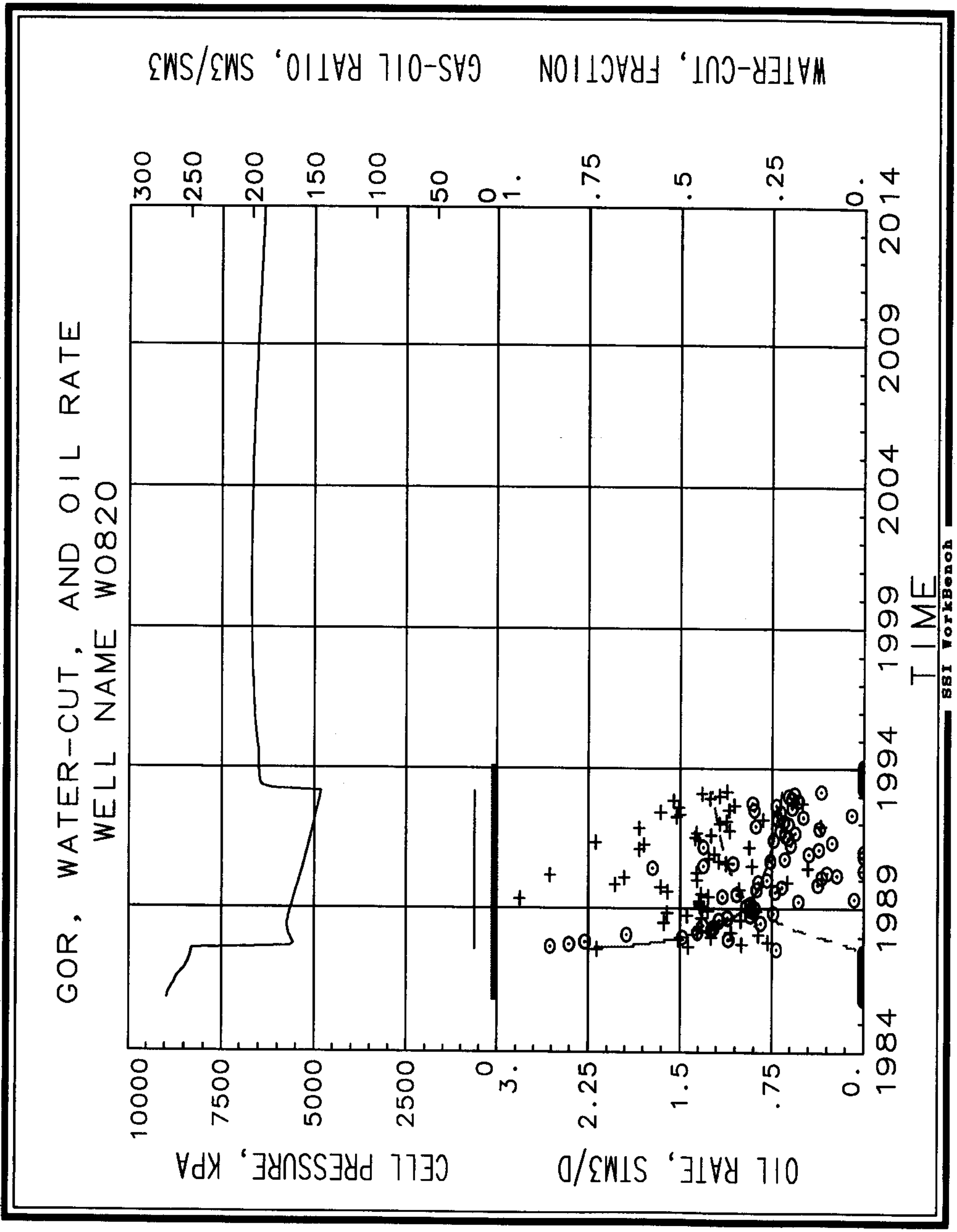
CASE 5 FIGURE 110

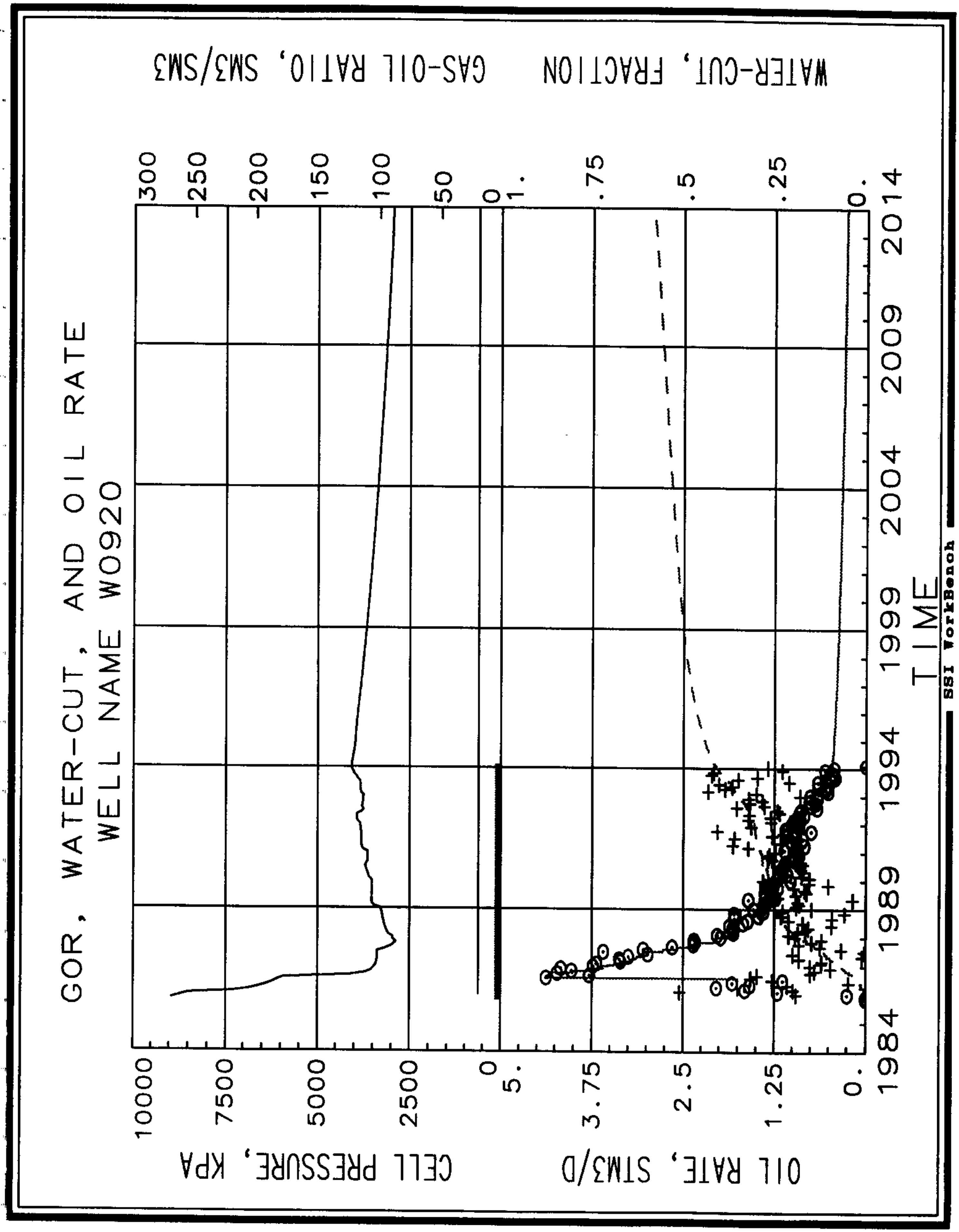
Prediction Case 5 - Water Saturation Distribution Map Layer 4

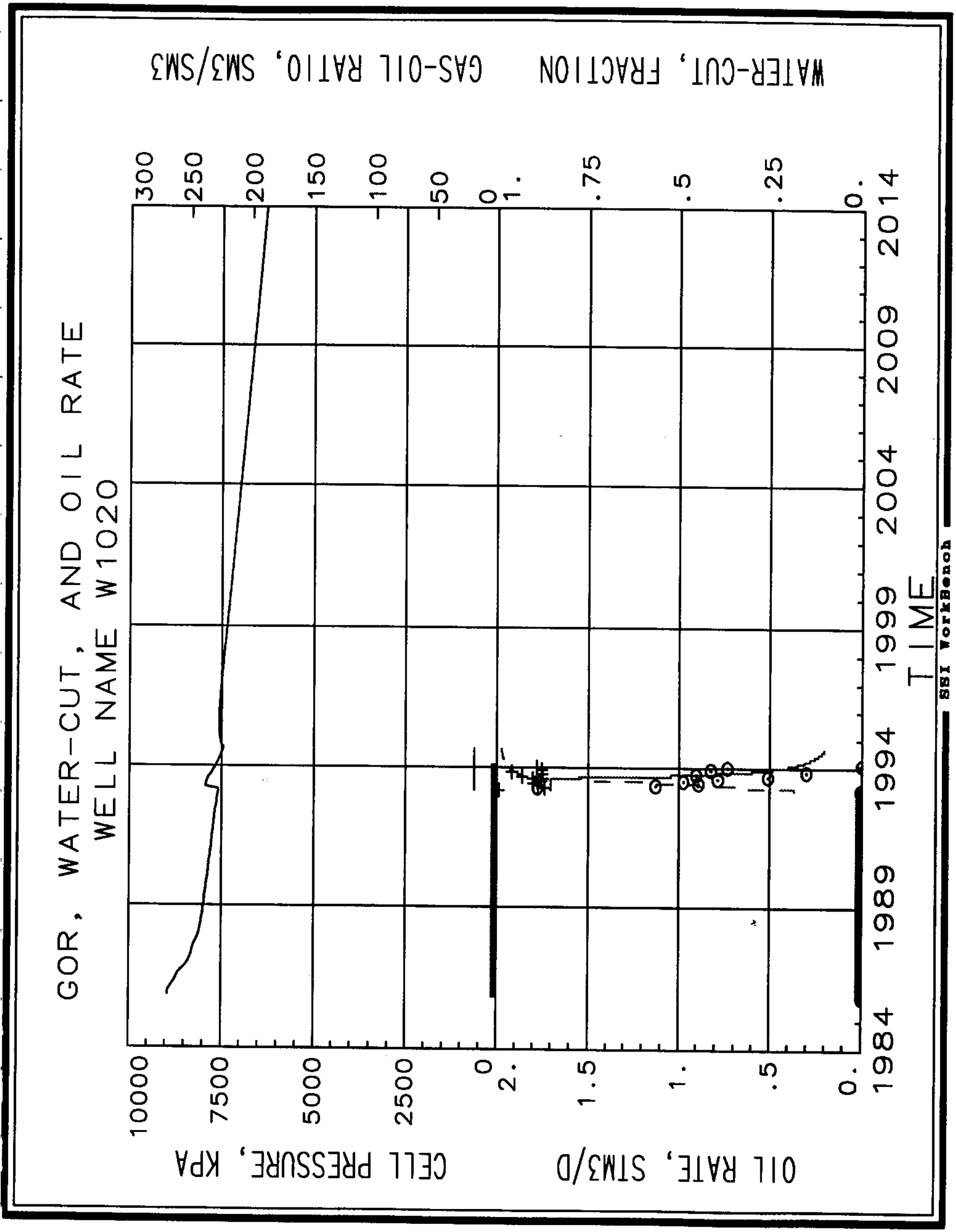


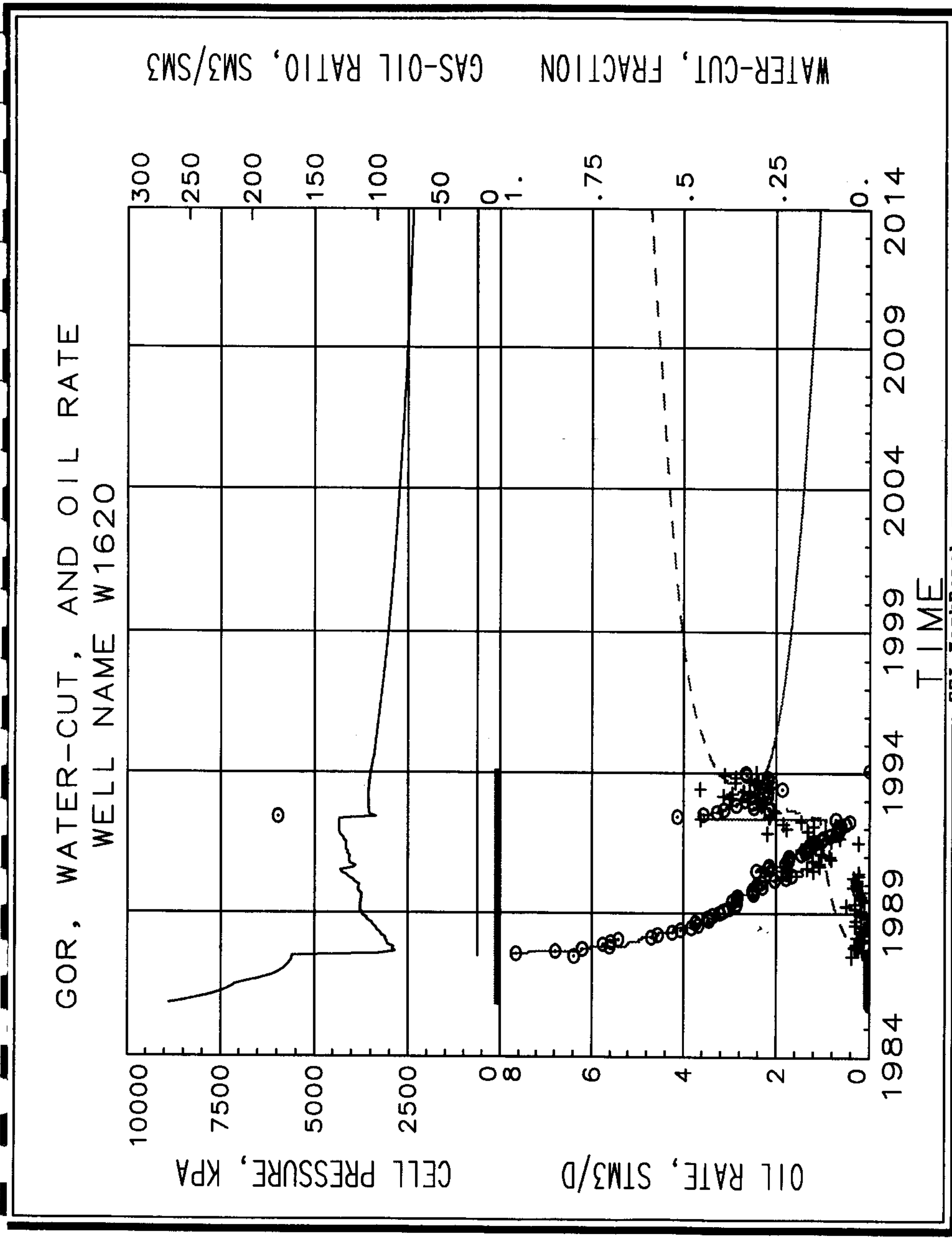

Fieldwide Ratios - Rates
PRESSURE, KPA
GAS-OIL RATIO, SM3/SM3
OIL RATE, STM3/D
WATER-CUT, FRACTION
TIME
9000
8000
7000
6000
30
25
20
15
10
5
0
50
40
30
20
10
0
1.
.8
.6
.4
.2
0.
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

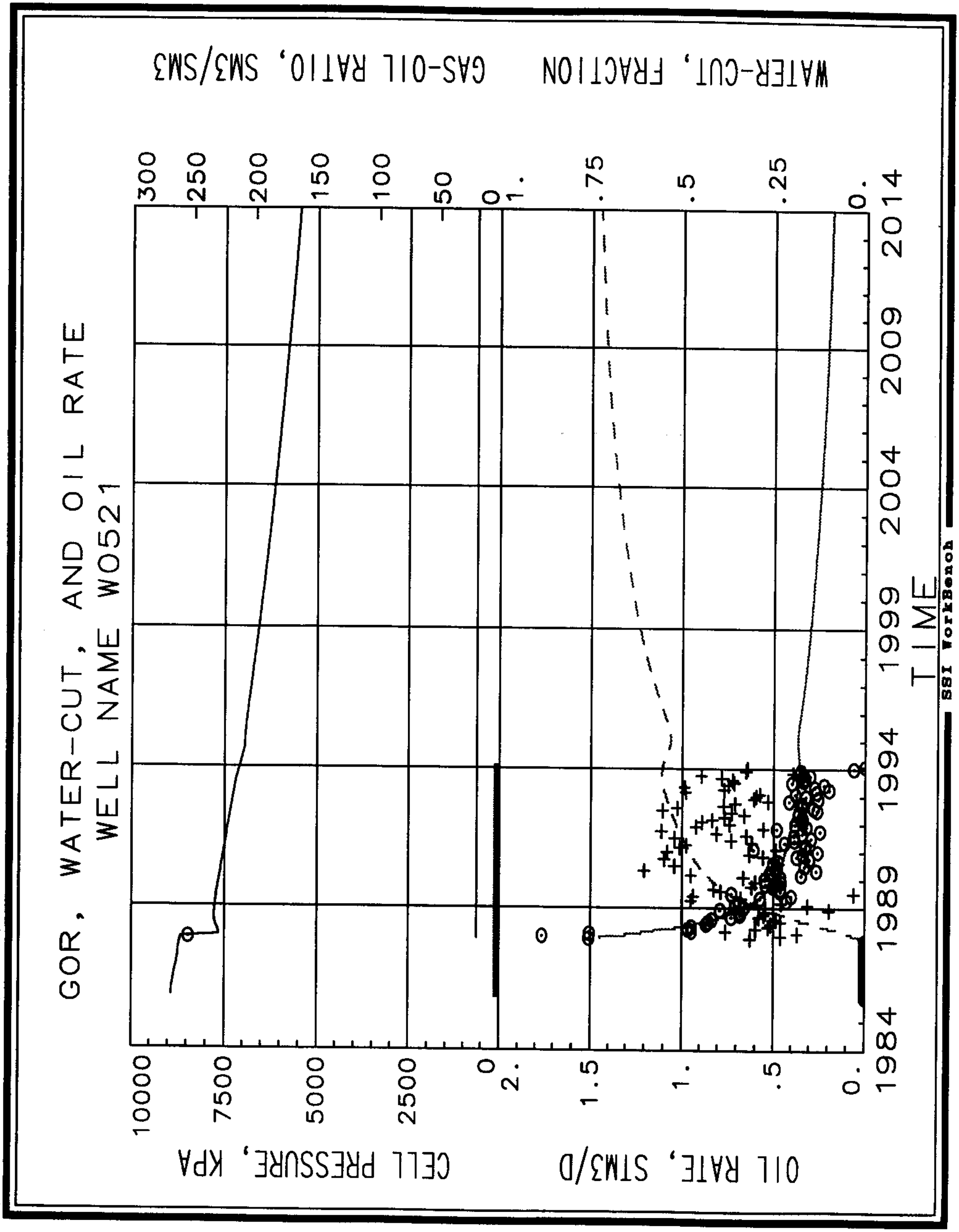
CASE 6 FIGURE 112

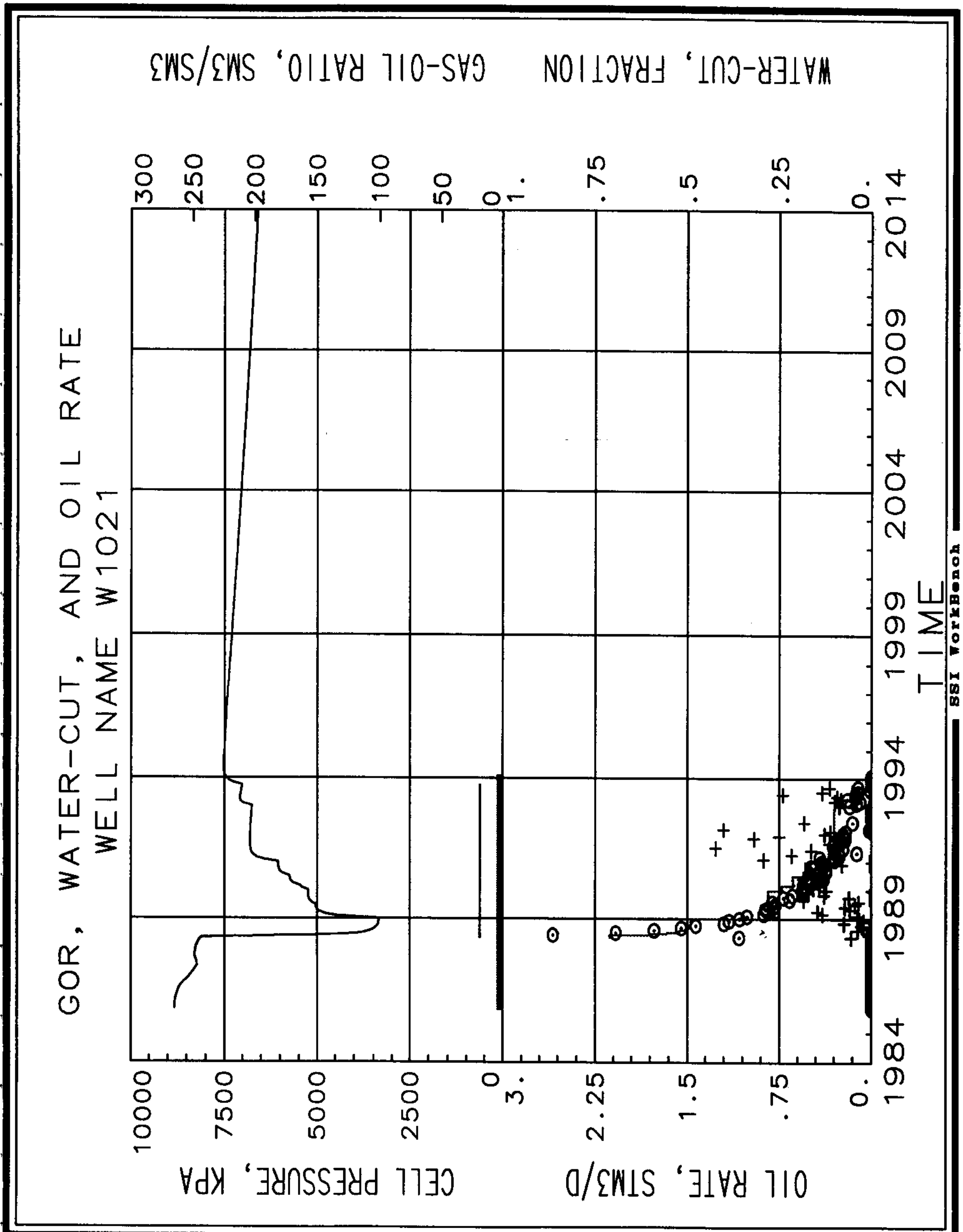



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0920
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300 250 200 150 100 50 0
1. .75 .5 .25 0.
10000 7500 5000 2500 0
5. 3.75 2.5 1.25 0.
1984 1989 1994 1999 2004 2009 2014
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W1020
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
1984
1989
1994
1999
2004
2009
2014
TIME
SSI WorkBench

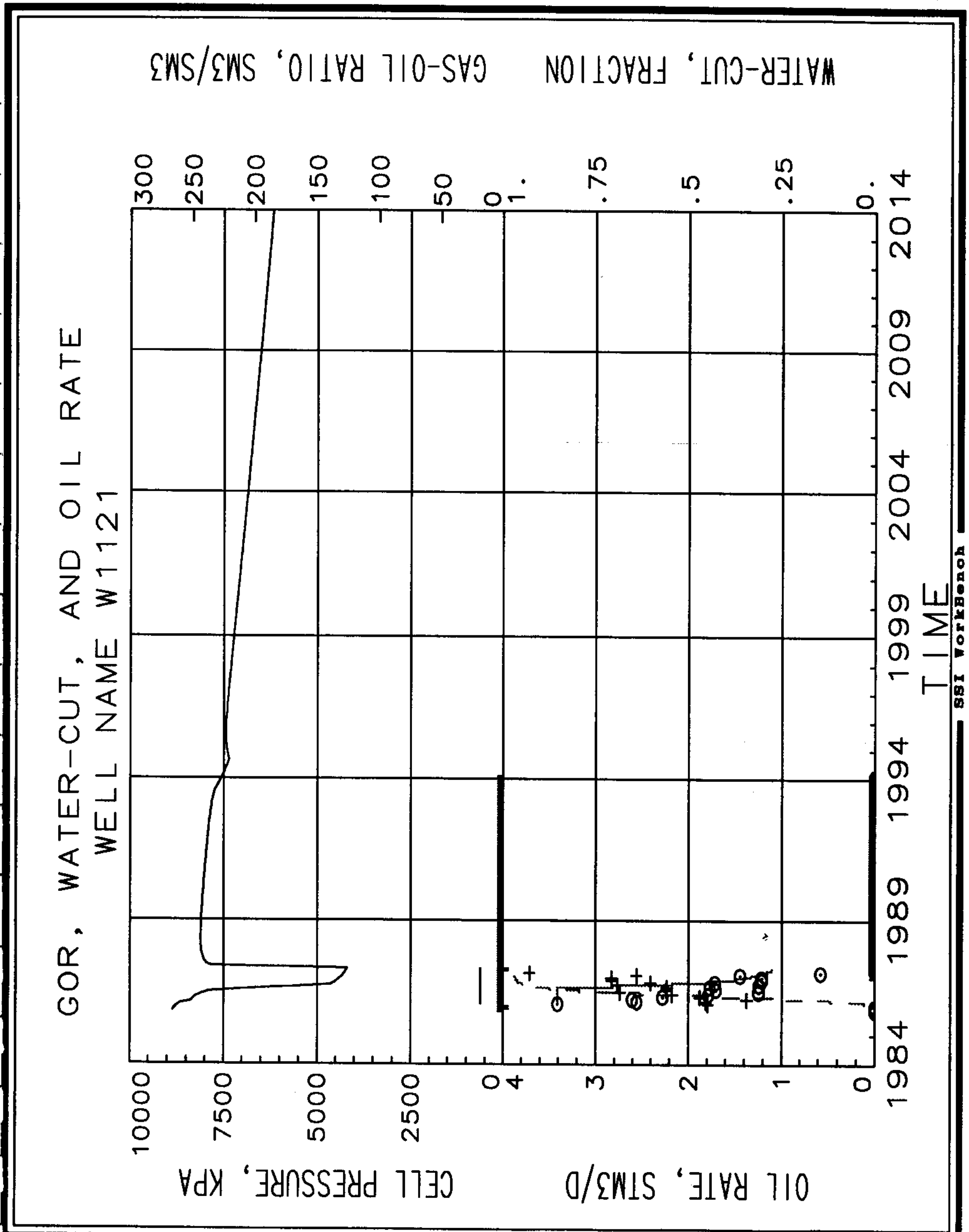

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1620
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
TIME
SSI WorkBench

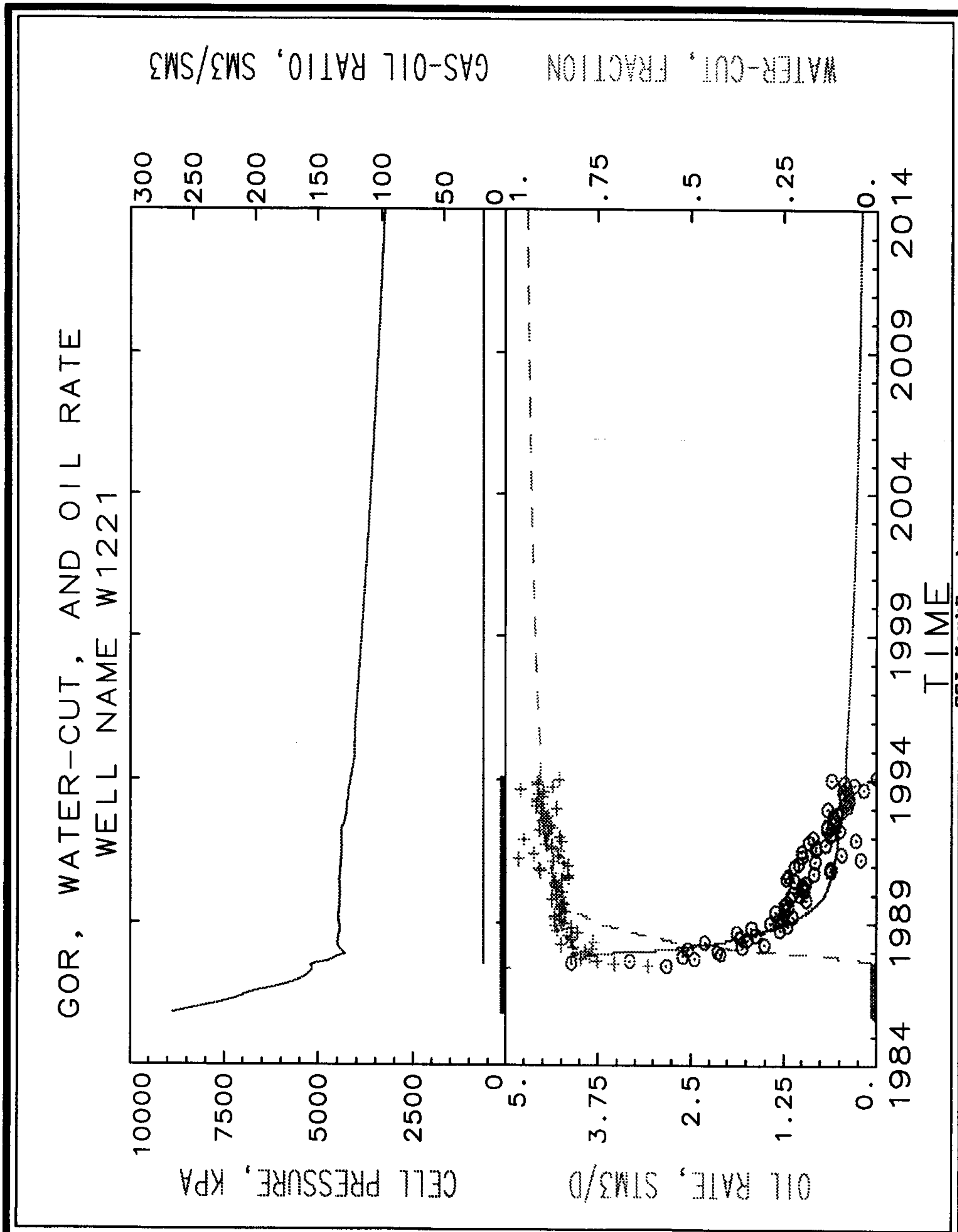

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0521
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
TIME
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

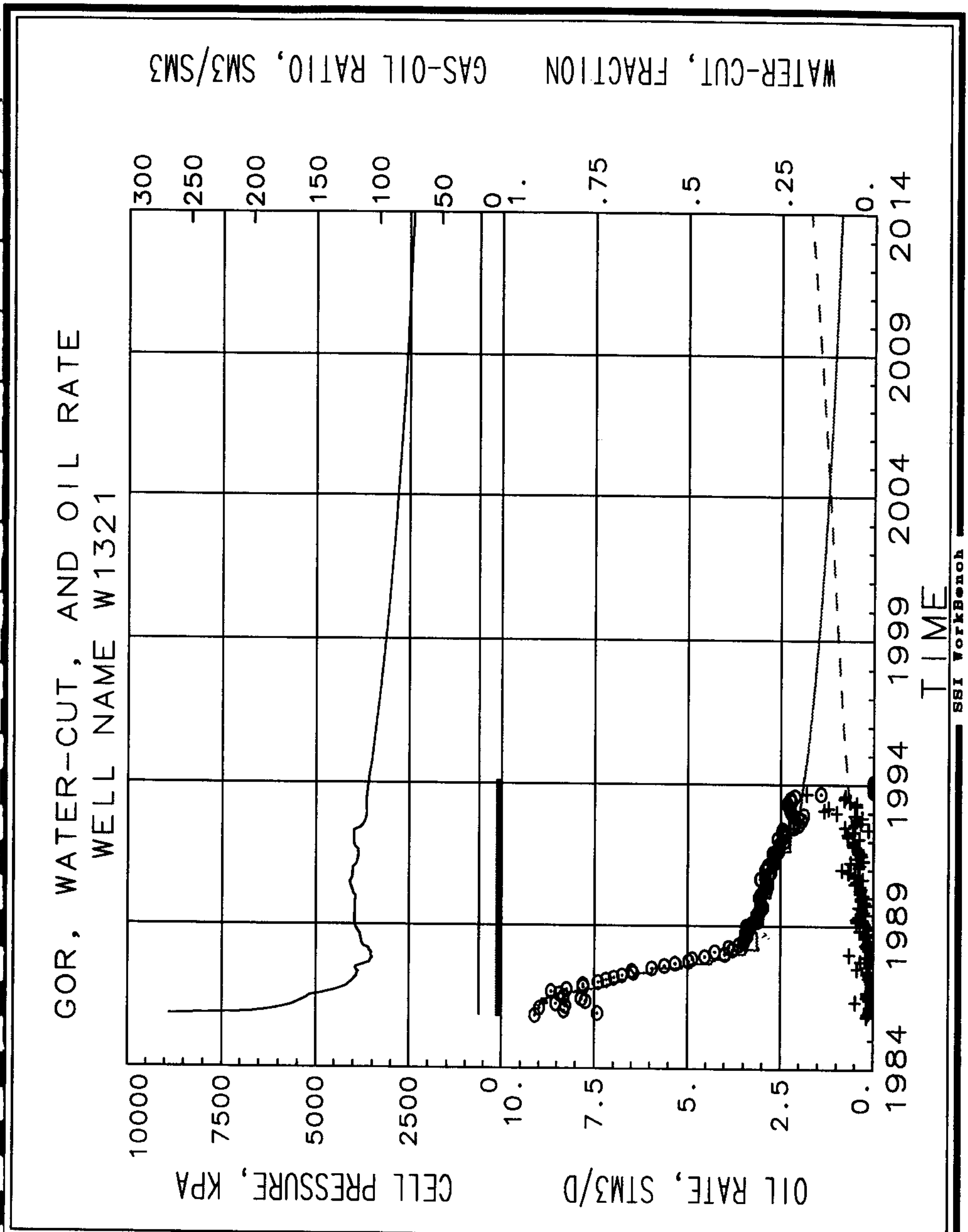


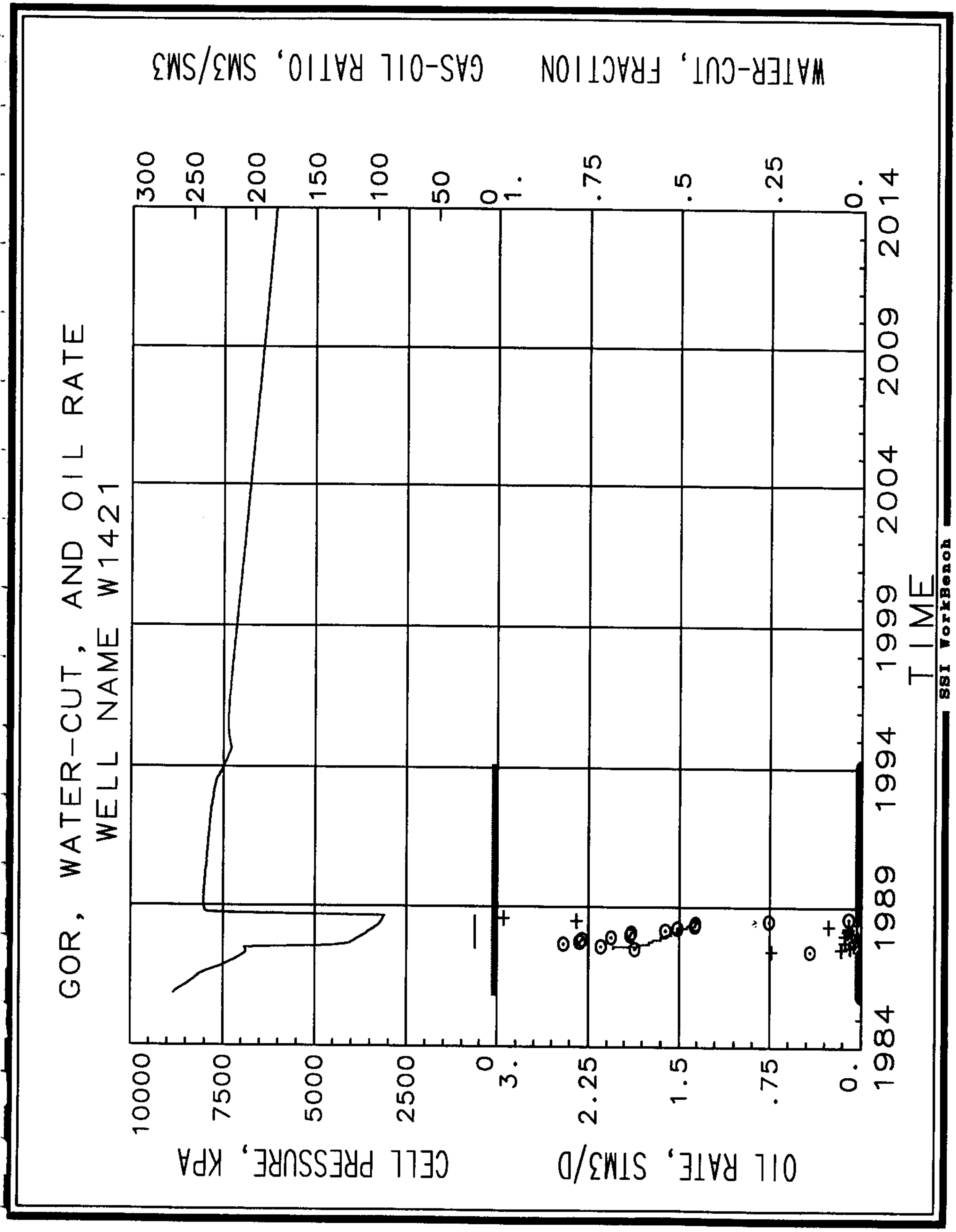
GOR, WATER-CUT, AND OIL RATE
WELL NAME W1021
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
TIME
1984
1989
1994
1999
2004
2009
2014
10000
7500
5000
2500
0
3.
2.25
1.5
.75
0.
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
SSI WorkBench

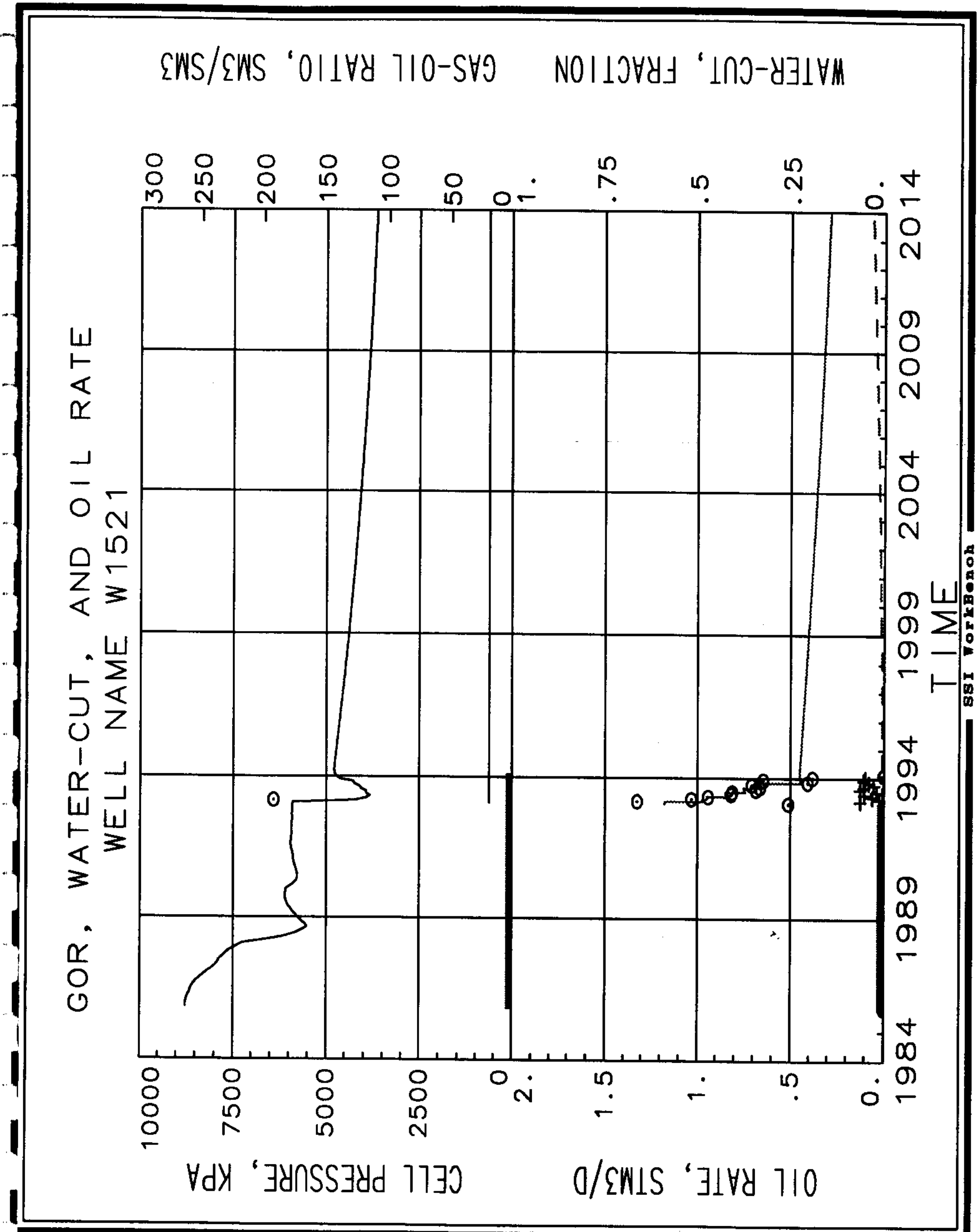
CASE 6 FIGURE 118

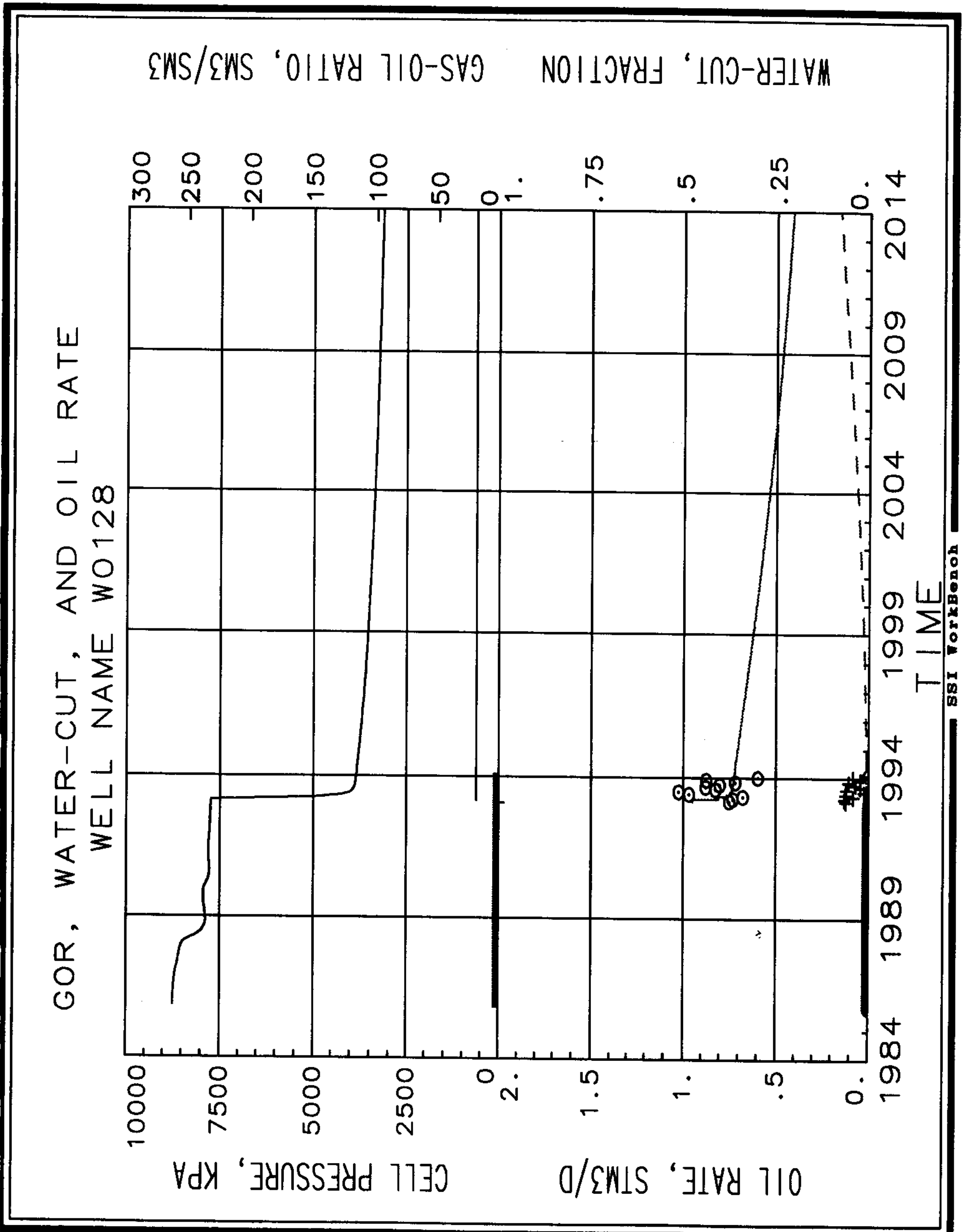



GOR, WATER-CUT, AND OIL RATE
WELL NAME W1221
CELL PRESSURE, KPA
GAS-OIL RATIO, SM3/SM3
OIL RATE, STM3/D
WATER-CUT, FRACTION
TIME
SSI WorkBench

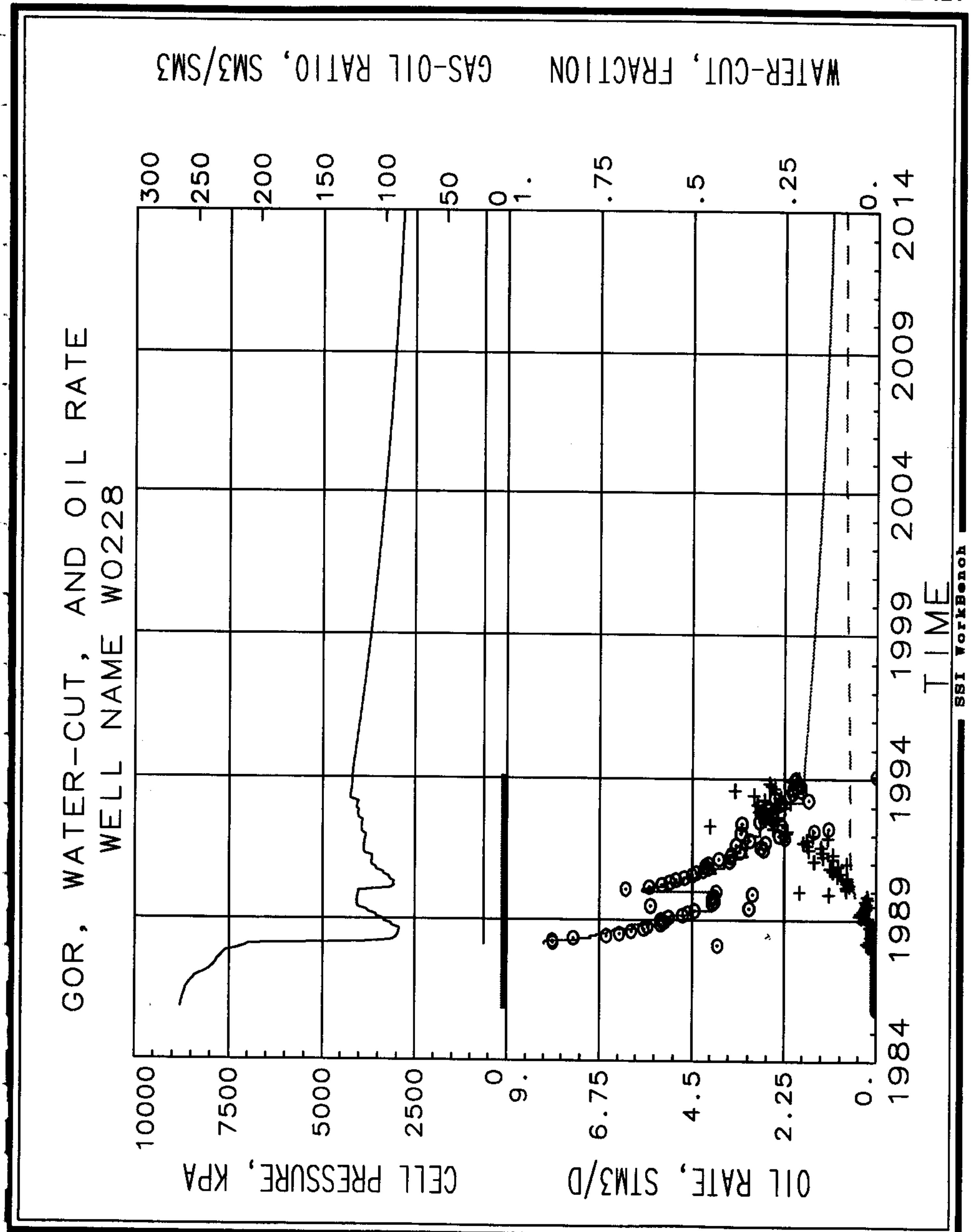

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1321
CELL PRESSURE, KPA
10000
7500
5000
2500
0
OIL RATE, STM3/D
10.
7.5
5.
2.5
0.
GAS-OIL RATIO, SM3/SM3
300
250
200
150
100
50
0
WATER-CUT, FRACTION
1.
.75
.5
.25
0.
1984
1989
1994
1999
2004
2009
2014
TIME
SSI WorkBench

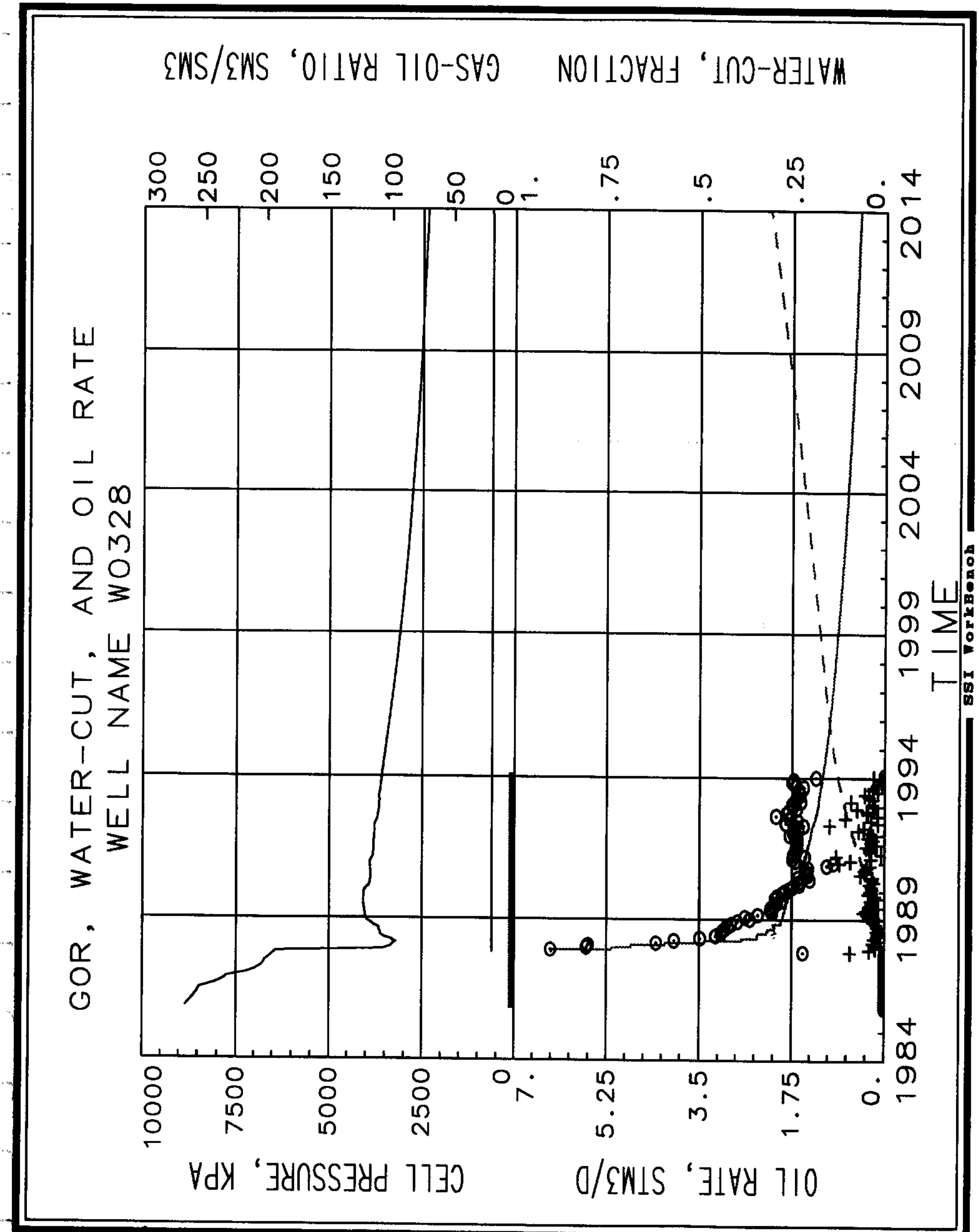

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1421
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
300 250 200 150 100 50 0
1. .75 .5 .25 0.
10000 7500 5000 2500 0
3. 2.25 1.5 .75 0.
1984 1989 1994 1999 2004 2009 2014
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W1521
CELL PRESSURE, KPA
10000 7500 5000 2500 0
OIL RATE, STM3/D
2. 1.5 1. .5 0.
GAS-OIL RATIO, SM3/SM3
300 250 200 150 100 50 0
WATER-CUT, FRACTION
1. .75 .5 .25 0.
1984 1989 1994 1999 2004 2009 2014
TIME
SSI WorkBench

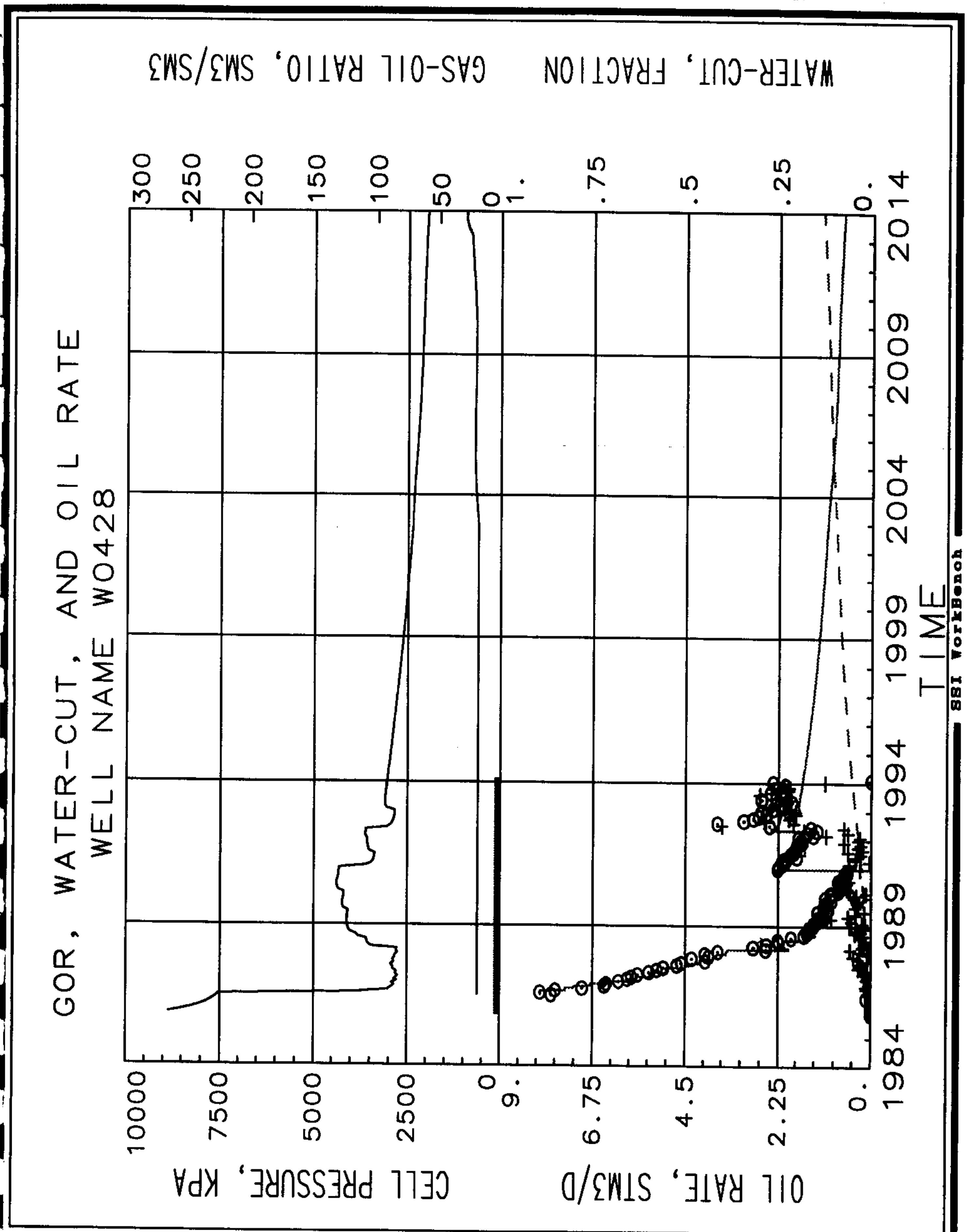

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0128
CELL PRESSURE, KPA
OIL RATE, STM3/D
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
TIME
10000
7500
5000
2500
0
2.
1.5
1.
.5
0.
300
250
200
150
100
50
0
1.
.75
.5
.25
0.
1984
1989
1994
1999
2004
2009
2014
SSI WorkBench

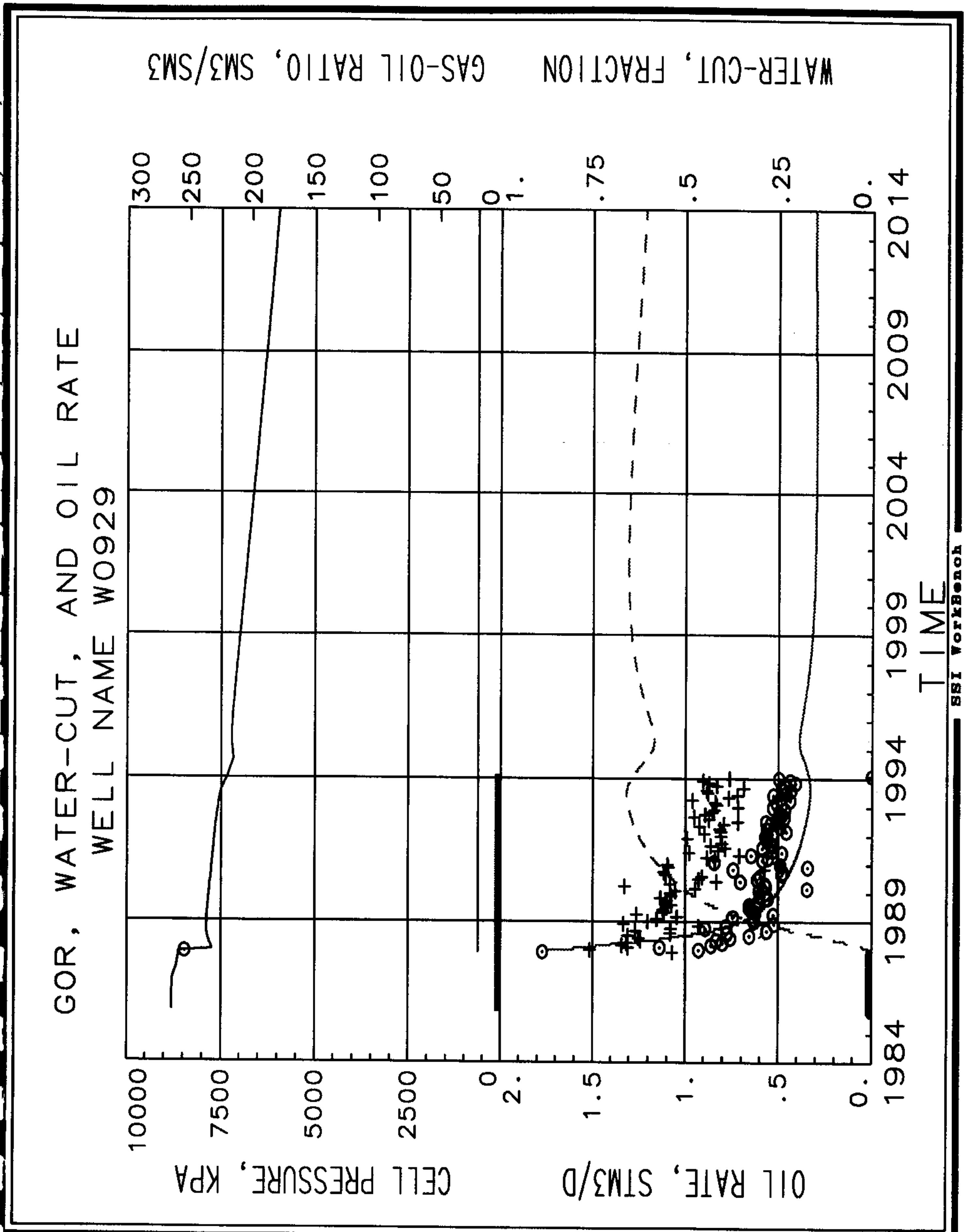
CASE 6 FIGURE 124

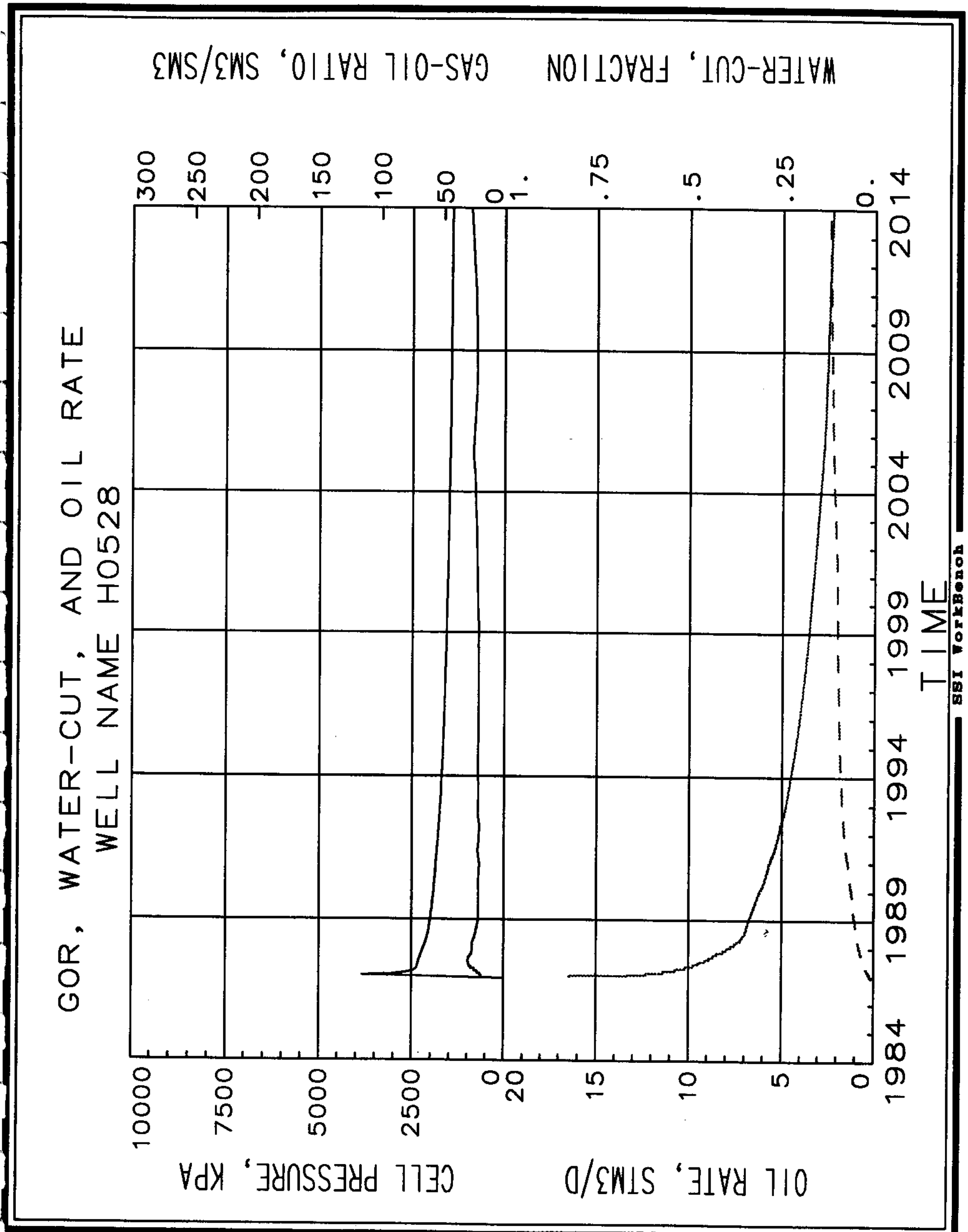



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0328
CELL PRESSURE, KPA
10000
7500
5000
2500
0
OIL RATE, STM3/D
7.
5.25
3.5
1.75
0.
GAS-OIL RATIO, SM3/SM3
300
250
200
150
100
50
0
WATER-CUT, FRACTION
1.
.75
.5
.25
0.
1984
1989
1994
1999
2004
2009
2014
TIME
SSI WorkBench

CASE 6 FIGURE 126



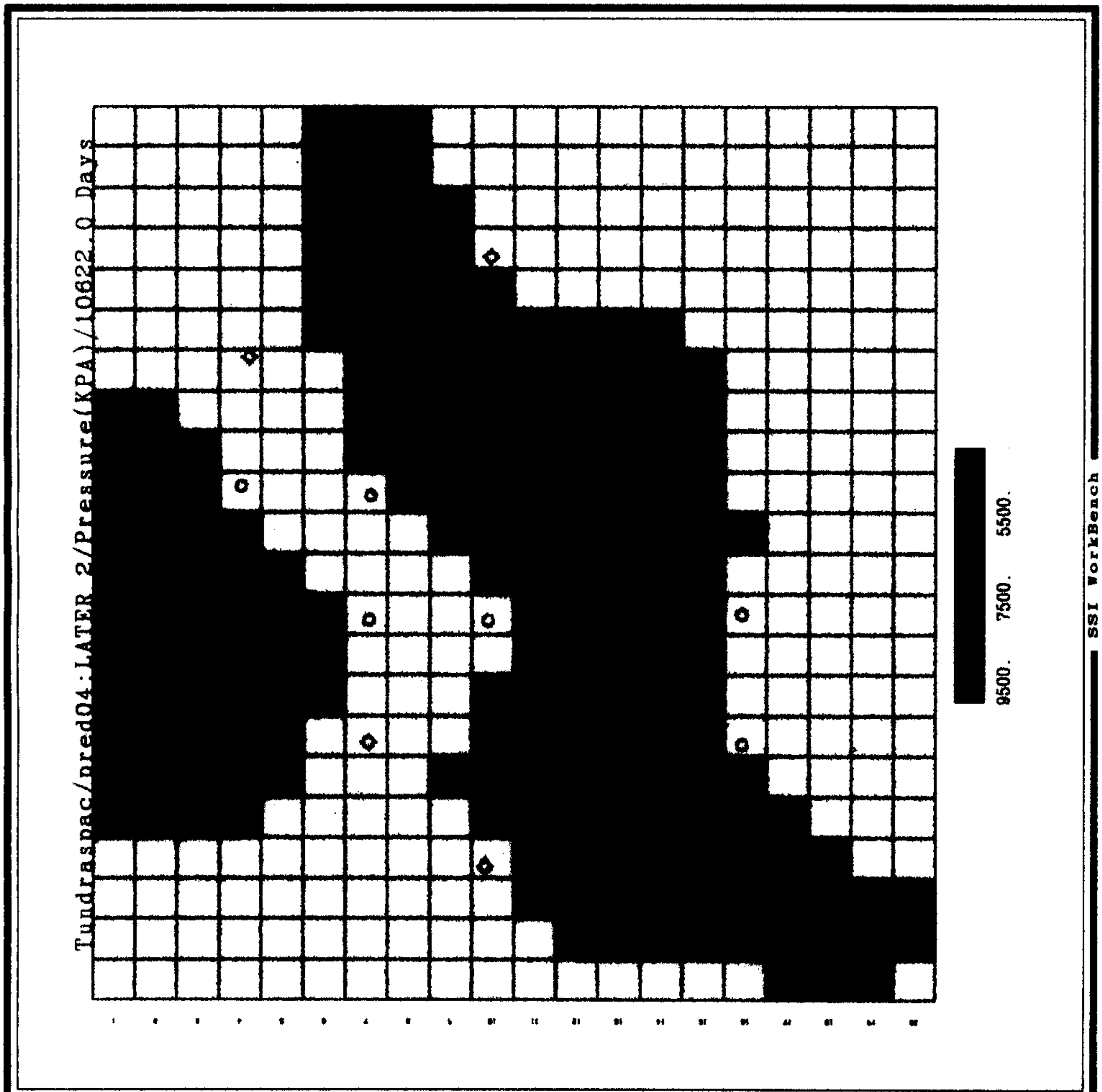

GOR , WATER-CUT, AND OIL RATE
WELL NAME W0929
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300 250 200 150 100 50 0
1. .75 .5 .25 0.
CELL PRESSURE, KPA
OIL RATE, STM3/D
10000 7500 5000 2500 0
2. 1.5 1. .5 0.
1984 1989 1994 1999 2004 2009 2014
TIME
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME H0528
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
SSI WorkBench
0 50 100 150 200 250 300
0. .25 .5 .75 1.
10000 7500 5000 2500 0
20 15 10 5 0
1984 1989 1994 1999 2004 2009 2014

Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 6 FIGURE 129

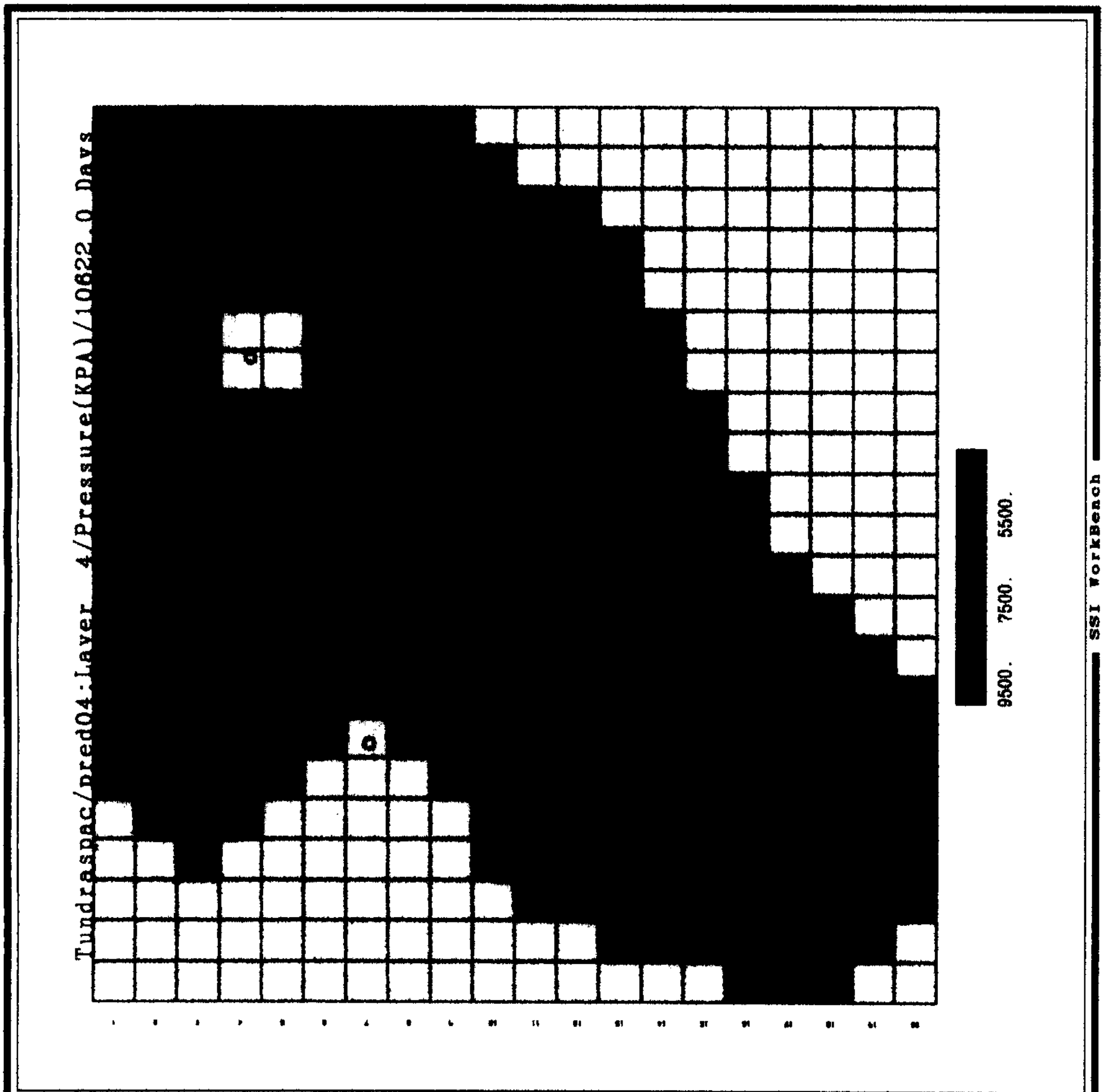
Prediction Case 6 - Pressure Distribution Map Layer 2



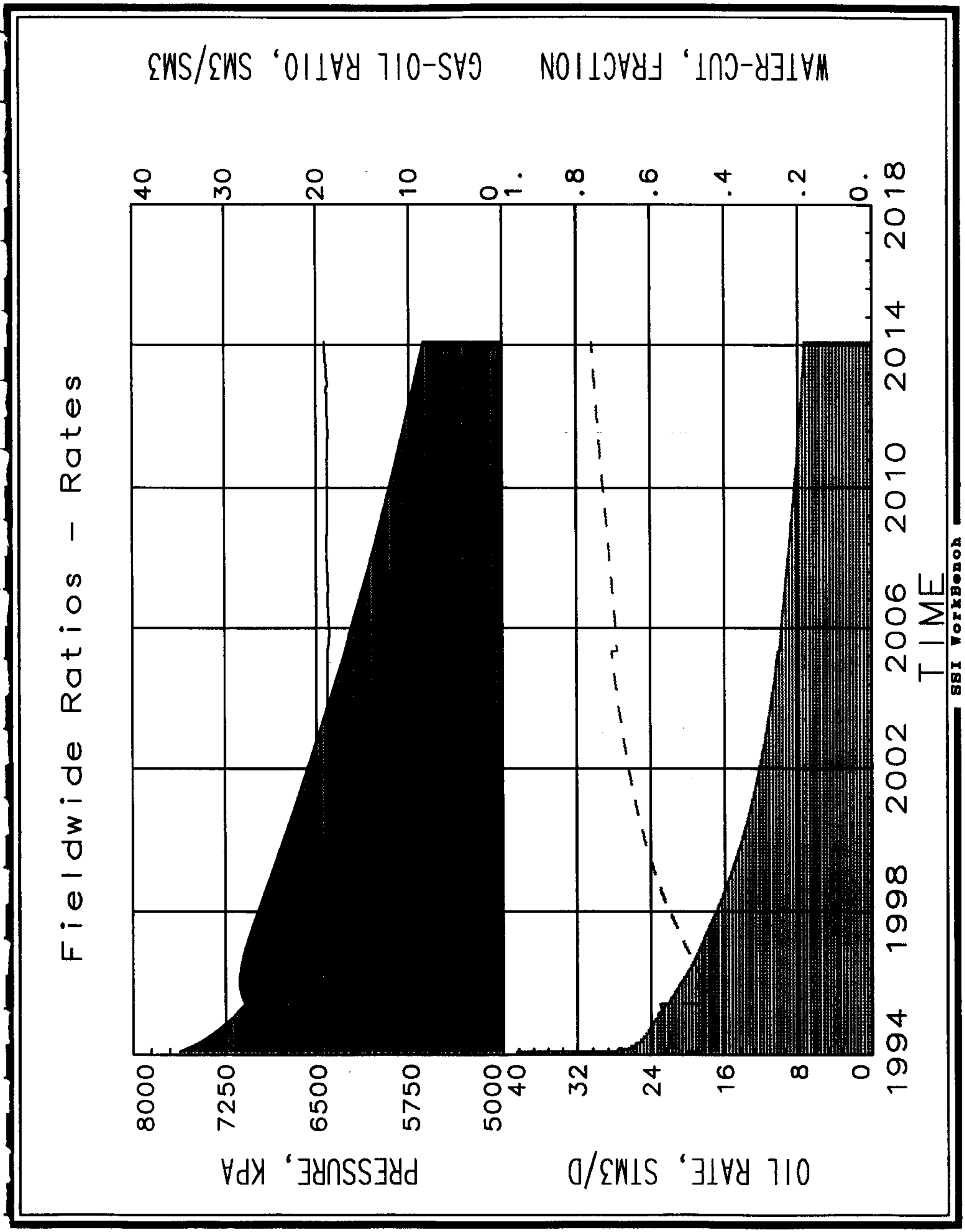
Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

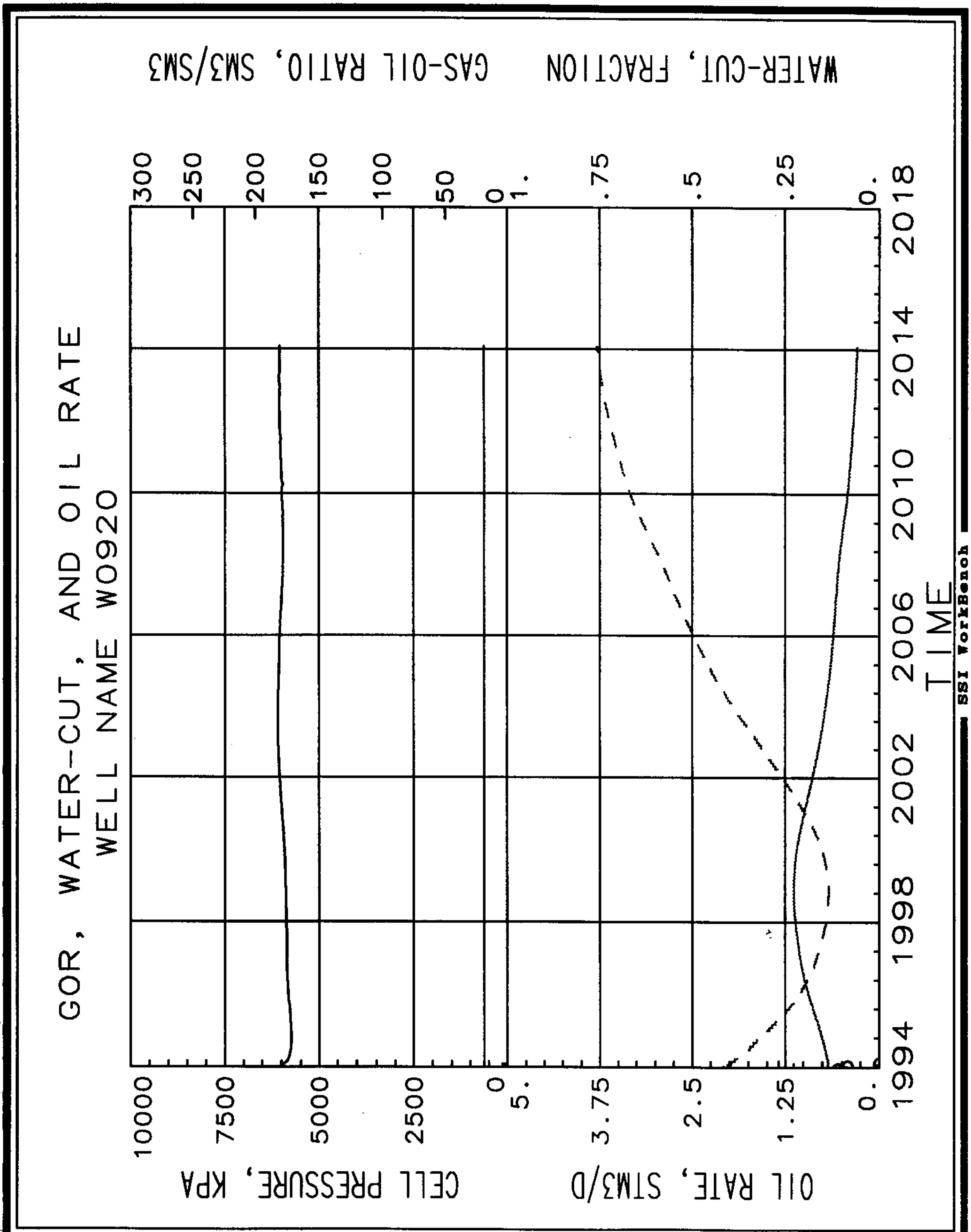
CASE 6 FIGURE 130

Prediction Case 6 - Pressure Distribution Map Layer 4

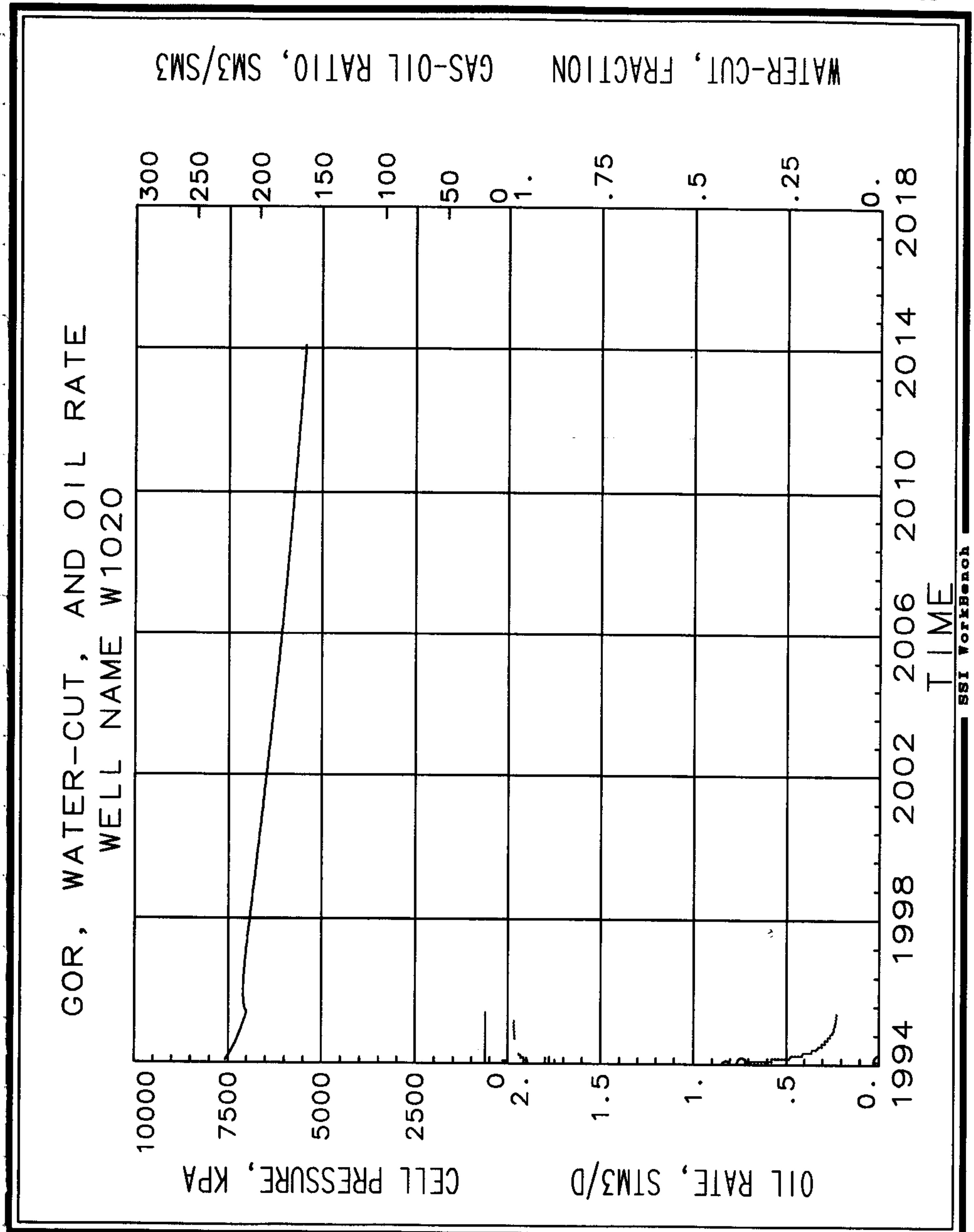


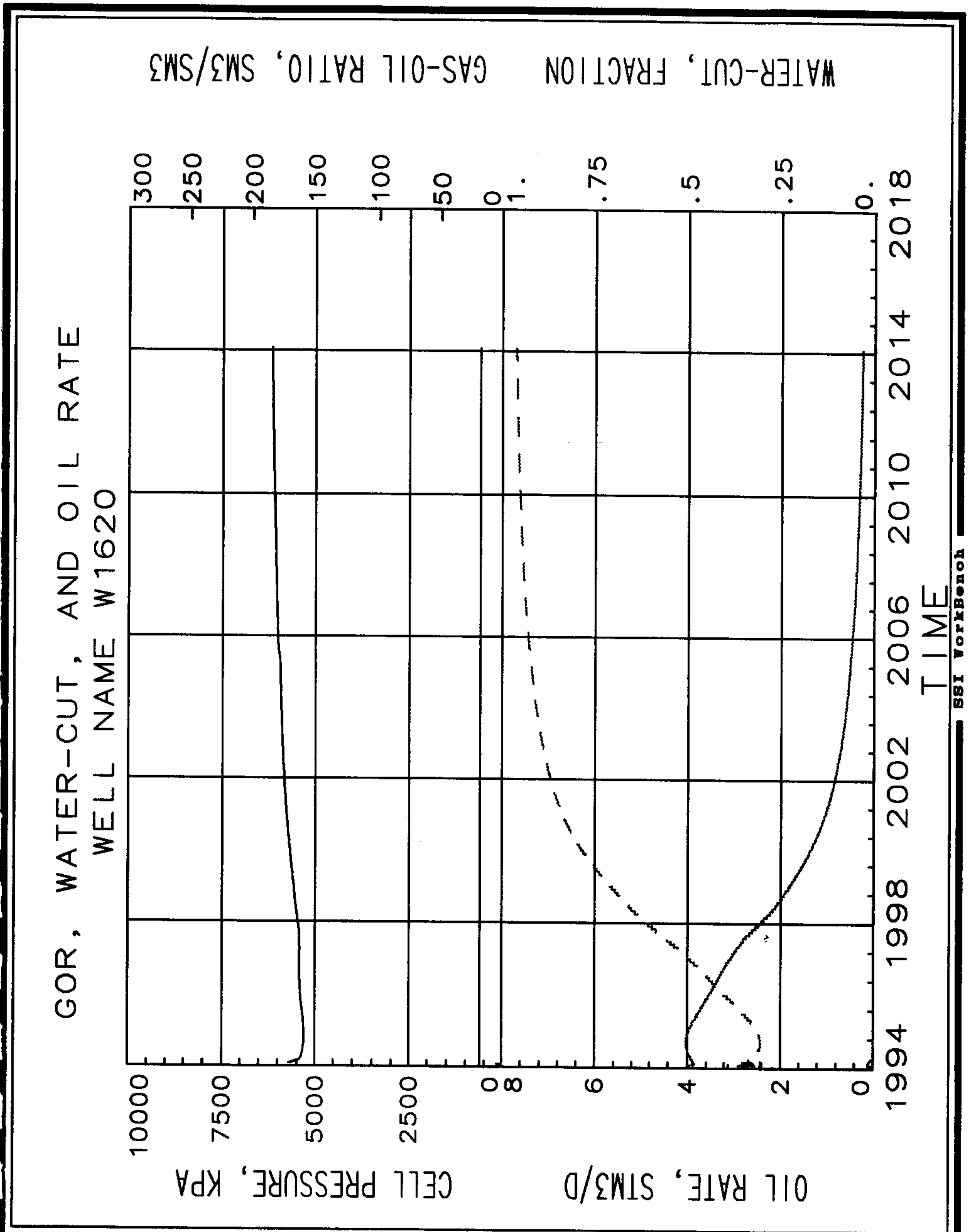
CASE 7 FIGURE 131



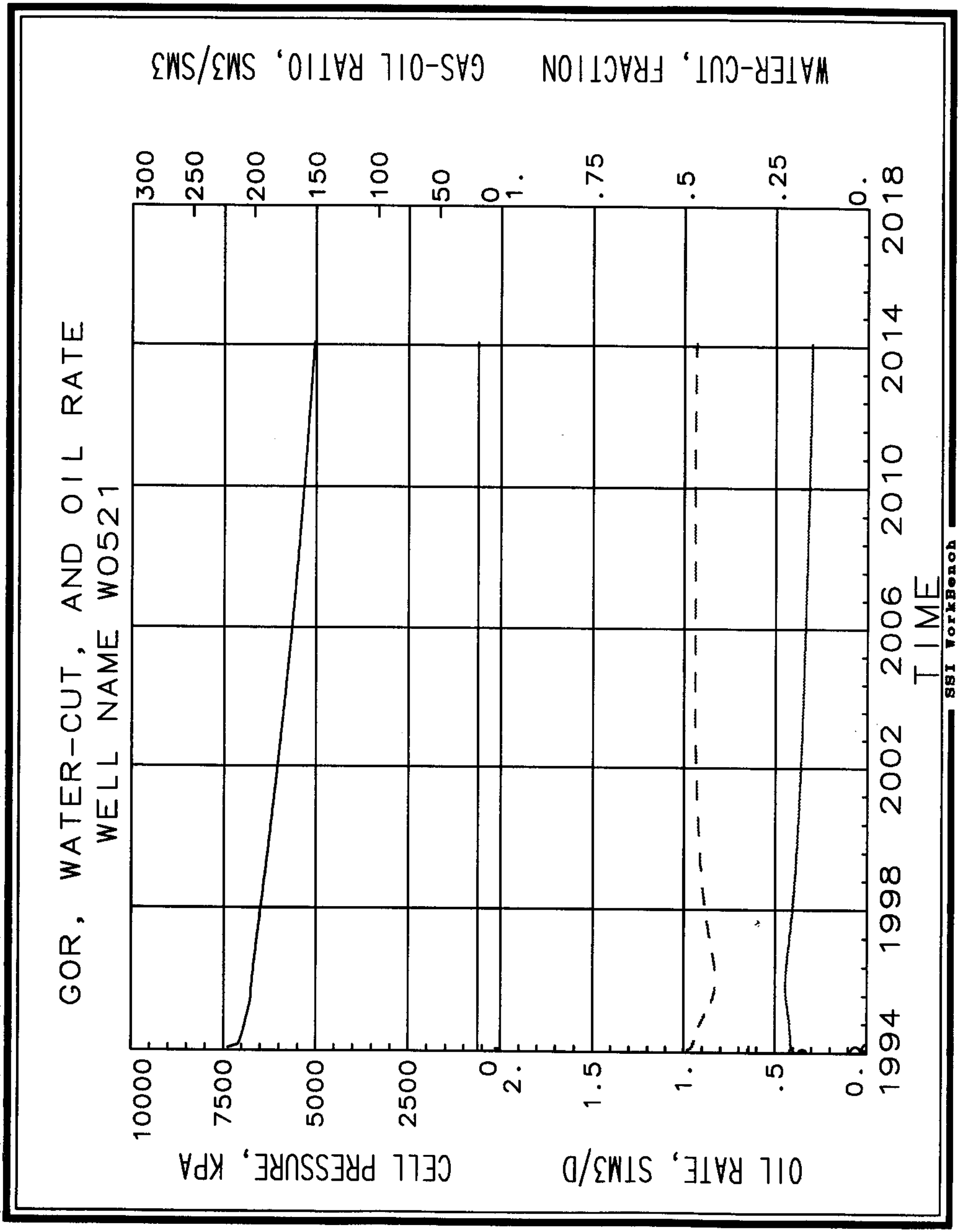

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0920
TIME
1994
1998
2002
2006
2010
2014
2018
CELL PRESSURE, KPA
10000
7500
5000
2500
0
OIL RATE, STM3/D
5.
3.75
2.5
1.25
0.
GAS-OIL RATIO, SM3/SM3
300
250
200
150
100
50
0
WATER-CUT, FRACTION
1.
.75
.5
.25
0.
SSI WorkBench

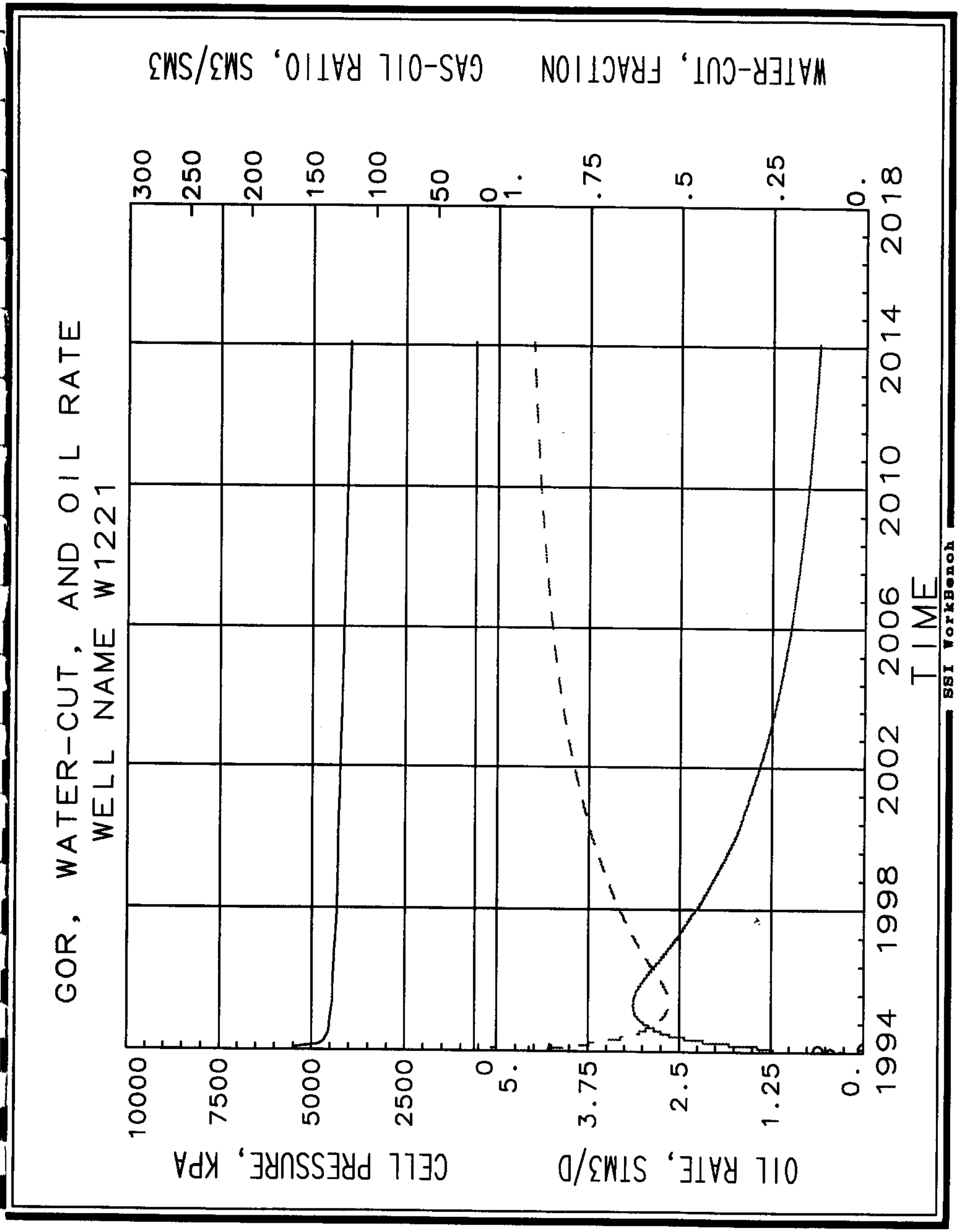
CASE 7 FIGURE 133

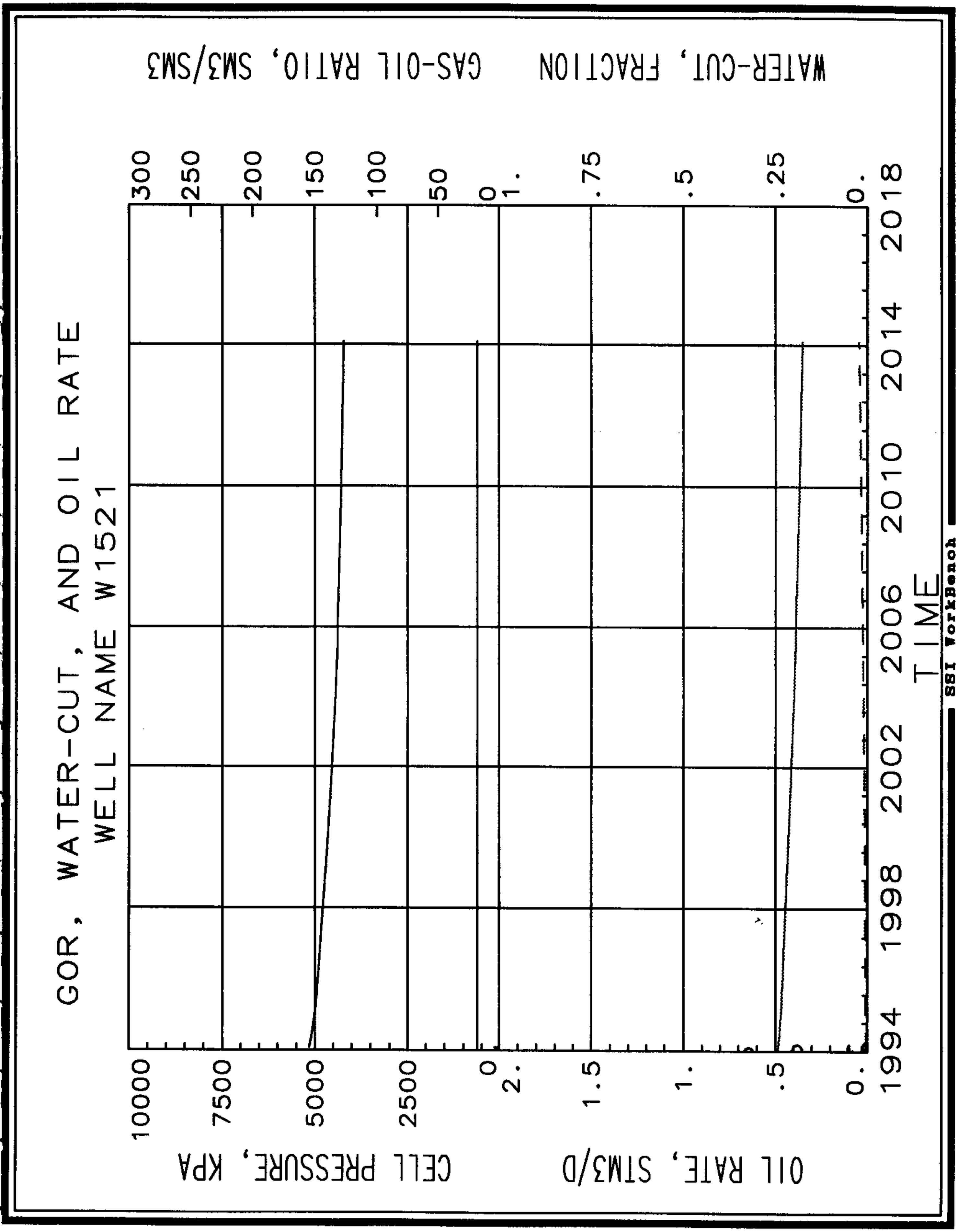


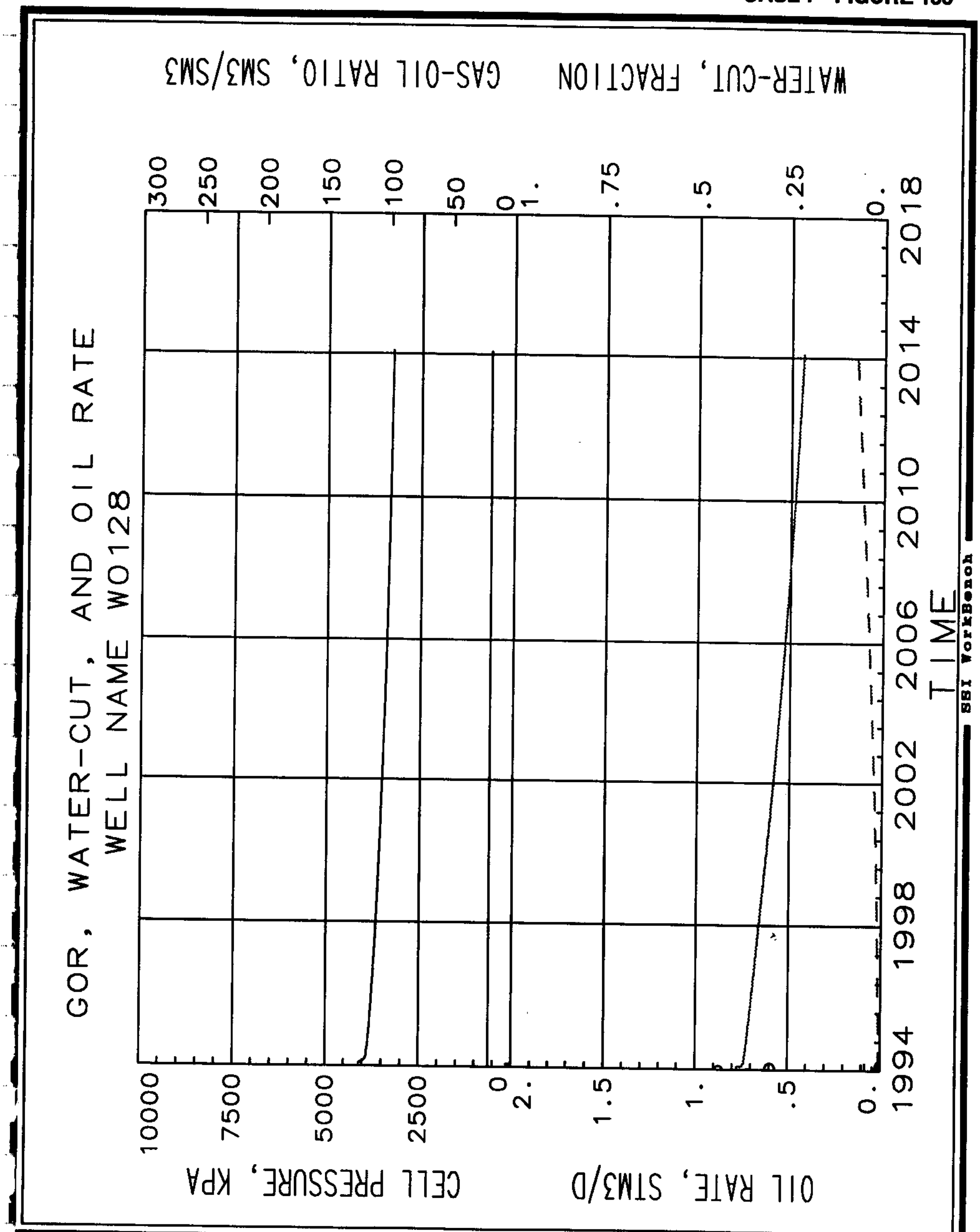

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1620
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
300 250 200 150 100 50 0
1. .75 .5 .25 0.
CELL PRESSURE, KPA
10000 7500 5000 2500 0
OIL RATE, STM3/D
8 6 4 2 0
1994 1998 2002 2006 2010 2014 2018
TIME
SSI WorkBench

CASE 7 FIGURE 135

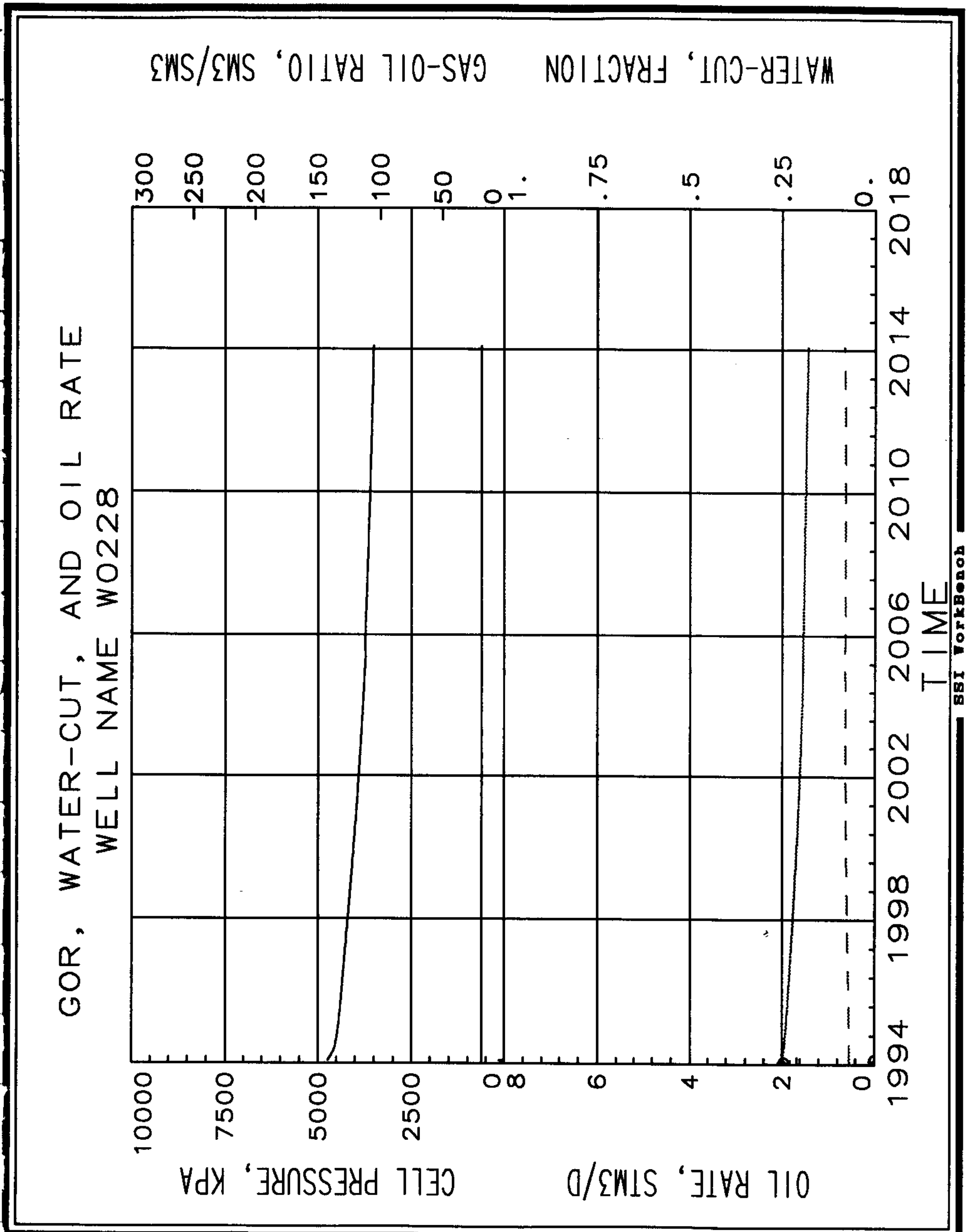


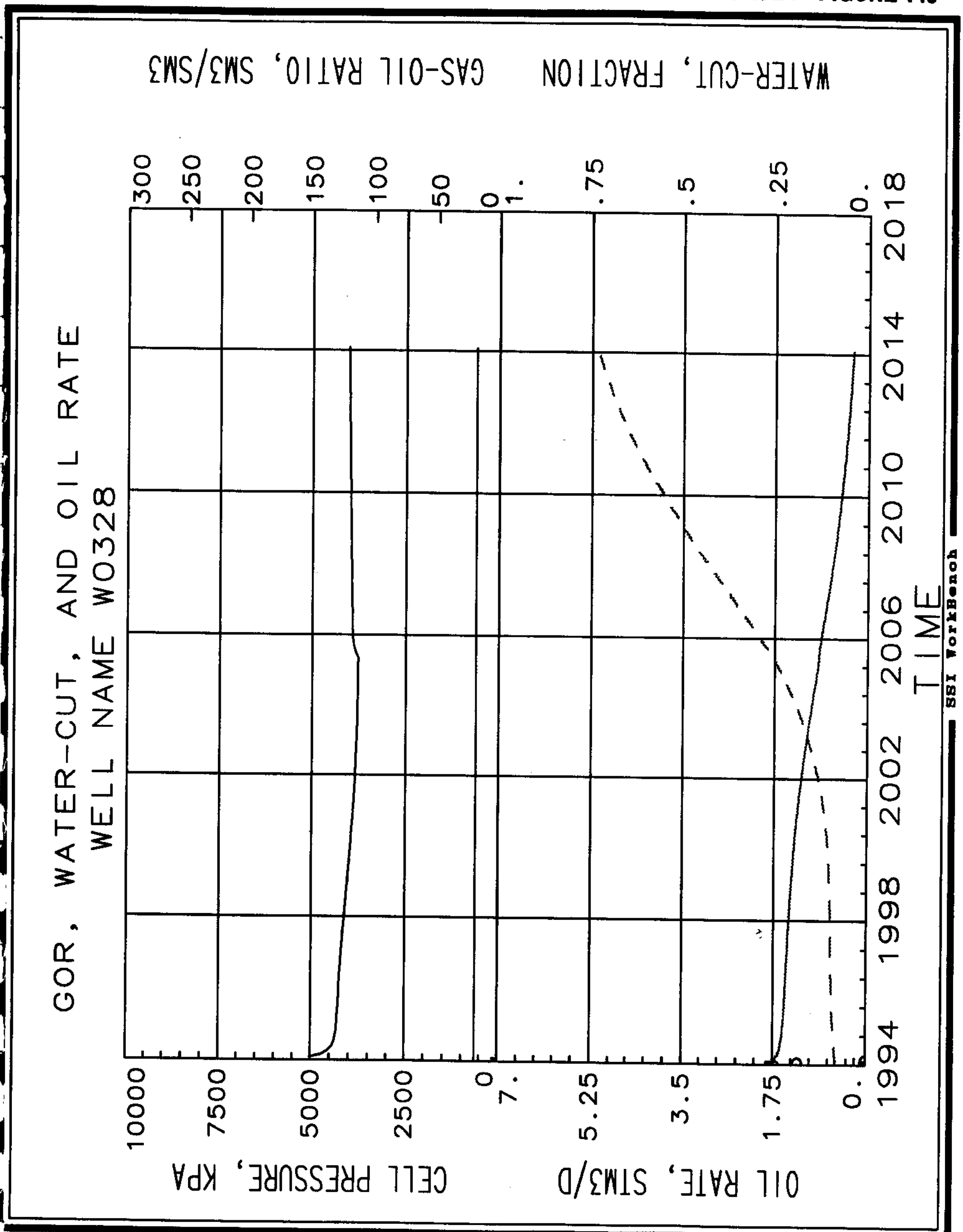

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1221
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1994 1998 2002 2006 2010 2014 2018
0 50 100 150 200 250 300
0. .25 .5 .75 1.
10000 7500 5000 2500 0
0. 1.25 2.5 3.75 5.
SSI WorkBench

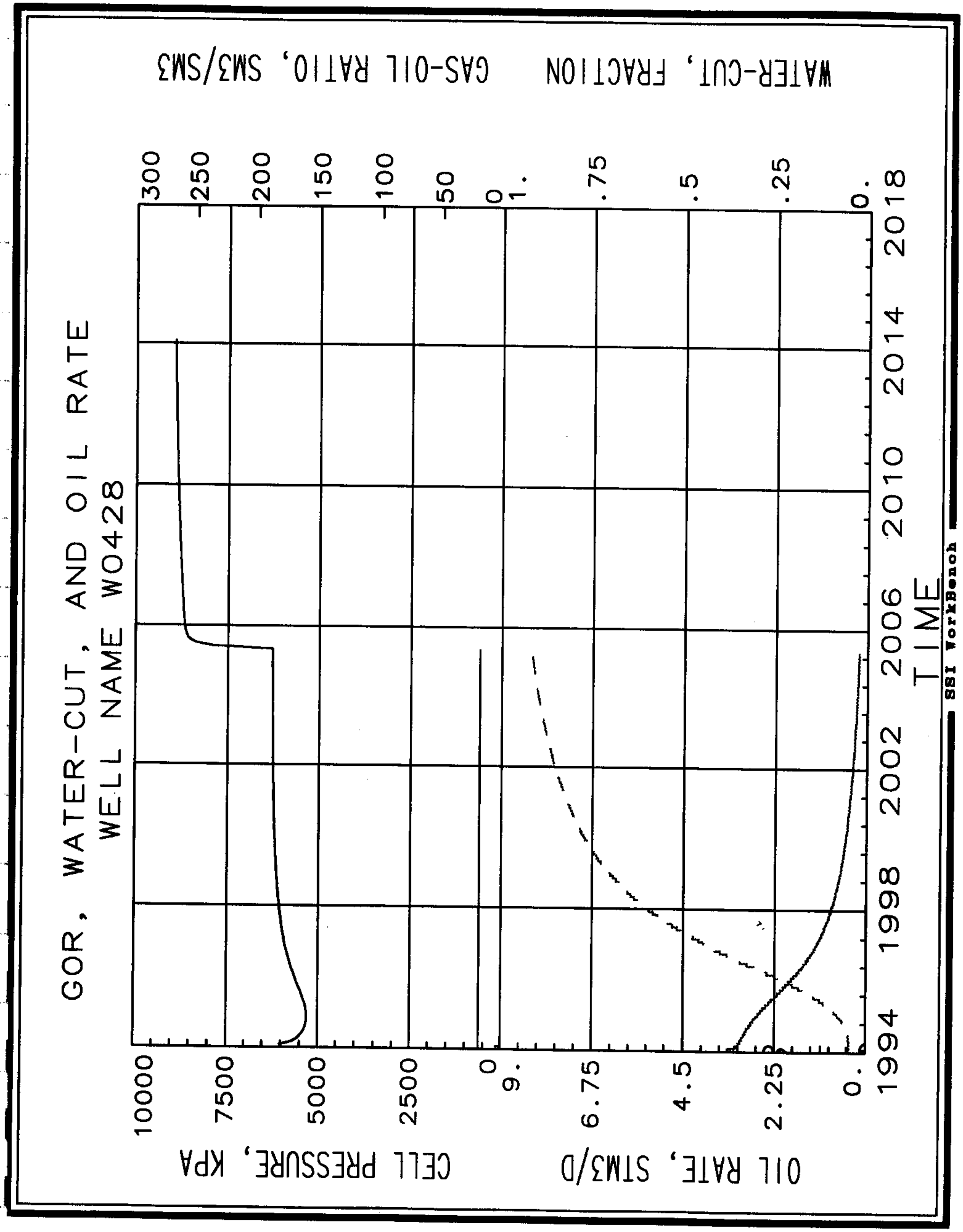

GOR, WATER-CUT, AND OIL RATE
WELL NAME W1521
CELL PRESSURE, KPA
10000 7500 5000 2500 0
OIL RATE, STM3/D
2. 1.5 1. .5 0.
GAS-OIL RATIO, SM3/SM3
300 250 200 150 100 50 0
WATER-CUT, FRACTION
1. .75 .5 .25 0.
TIME
1994 1998 2002 2006 2010 2014 2018
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME W0128
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1994
1998
2002
2006
2010
2014
2018
SSI WorkBench

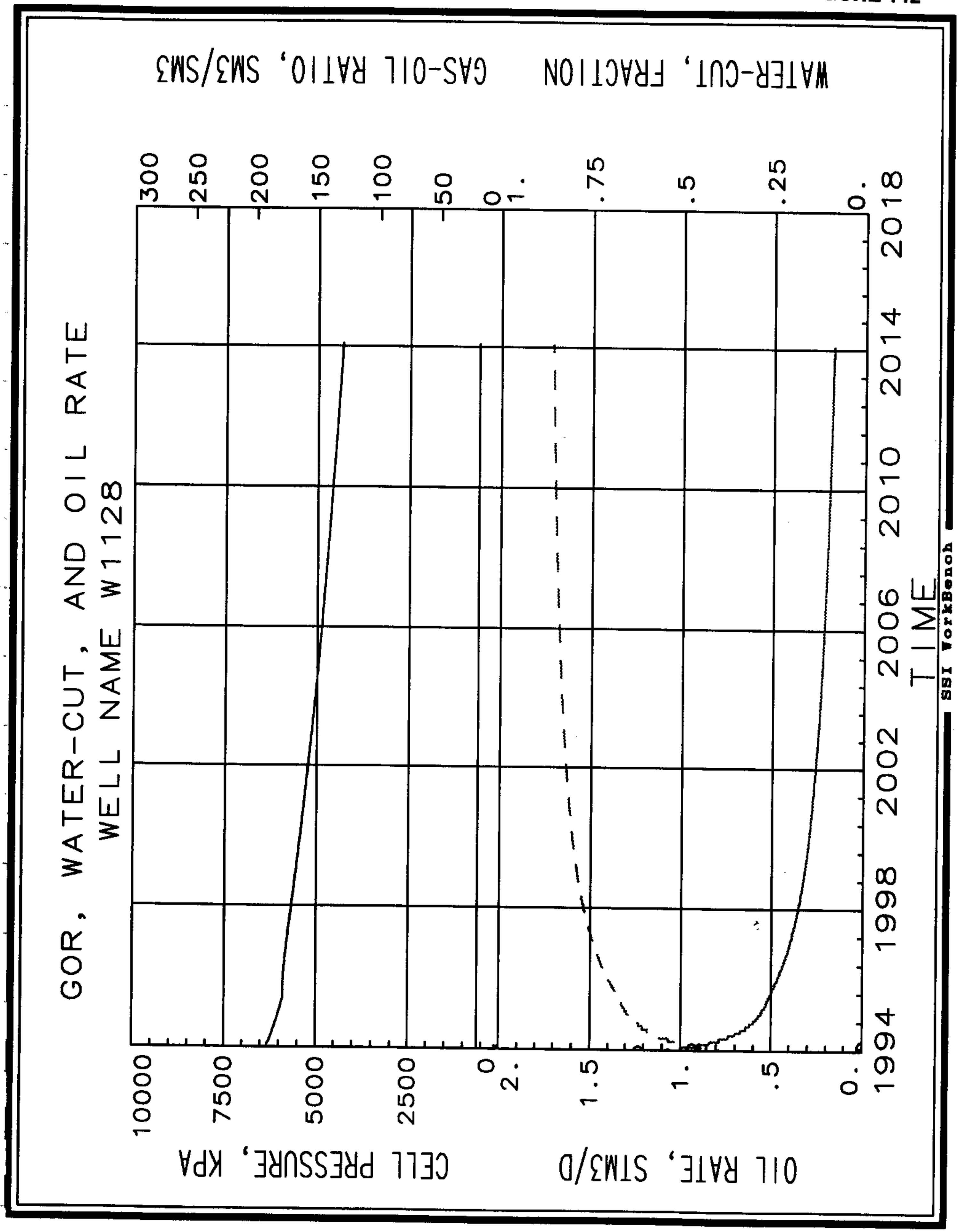
CASE 7 FIGURE 139

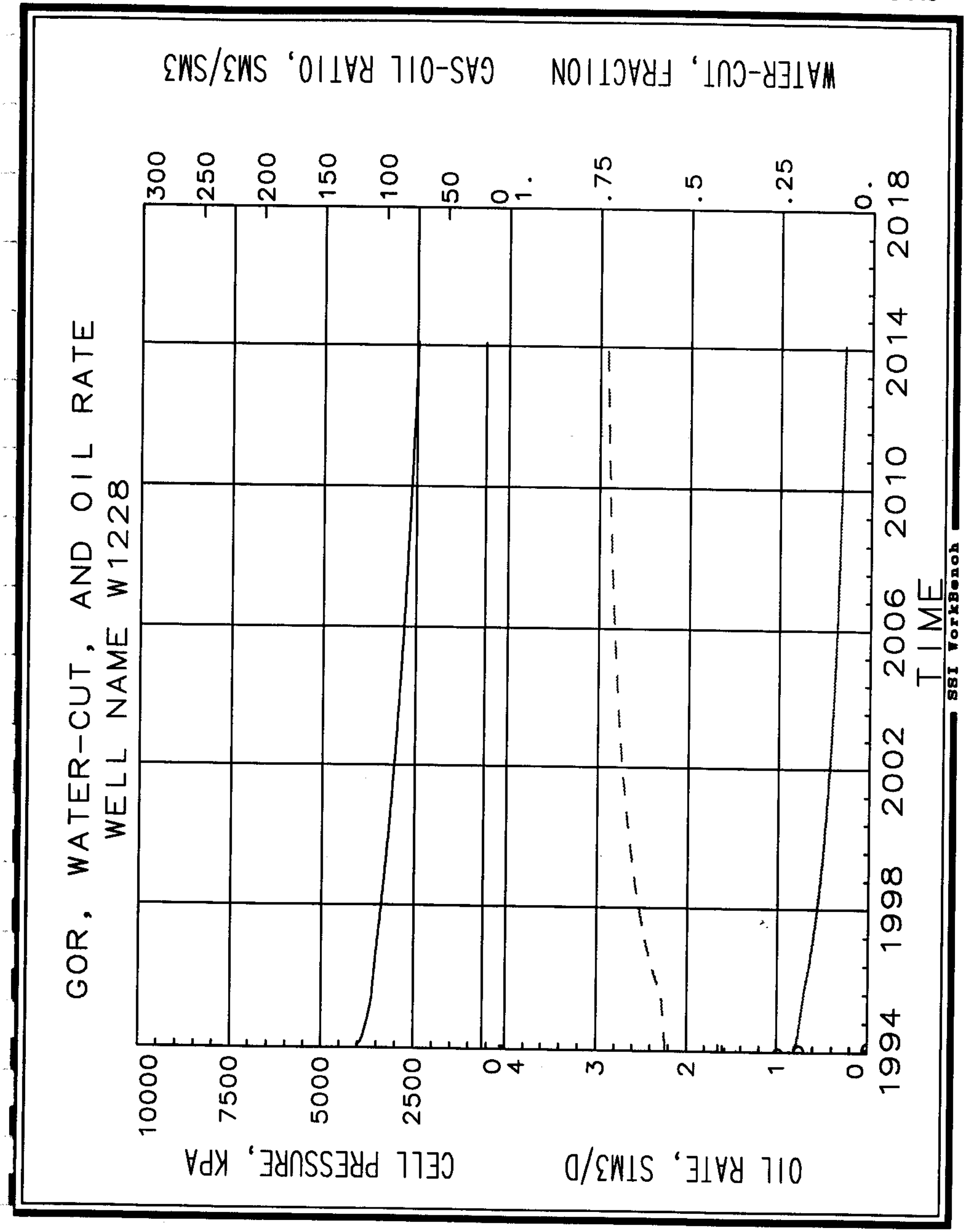



GOR, WATER-CUT, AND OIL RATE
WELL NAME W0328
WATER-CUT, FRACTION
GAS-OIL RATIO, SM3/SM3
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1994 1998 2002 2006 2010 2014 2018
300 250 200 150 100 50 0
1. .75 .5 .25 0.
10000 7500 5000 2500 0
7. 5.25 3.5 1.75 0.
SSI WorkBench

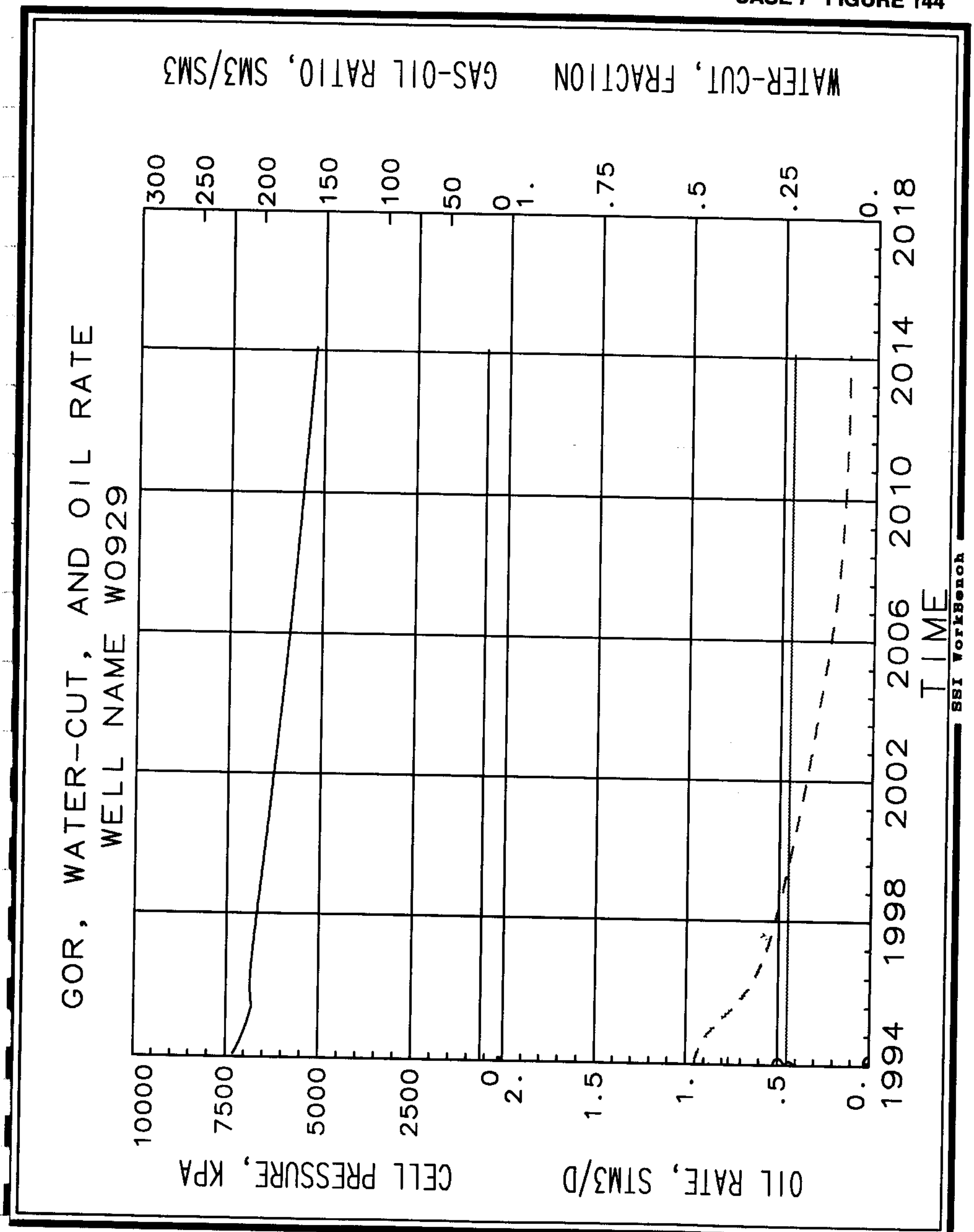

GOR, WATER-CUT, AND OIL RATE
WELL NAME W0428
GAS-OIL RATIO, SM3/SM3
WATER-CUT, FRACTION
CELL PRESSURE, KPA
OIL RATE, STM3/D
TIME
1994
1998
2002
2006
2010
2014
2018
SSI WorkBench

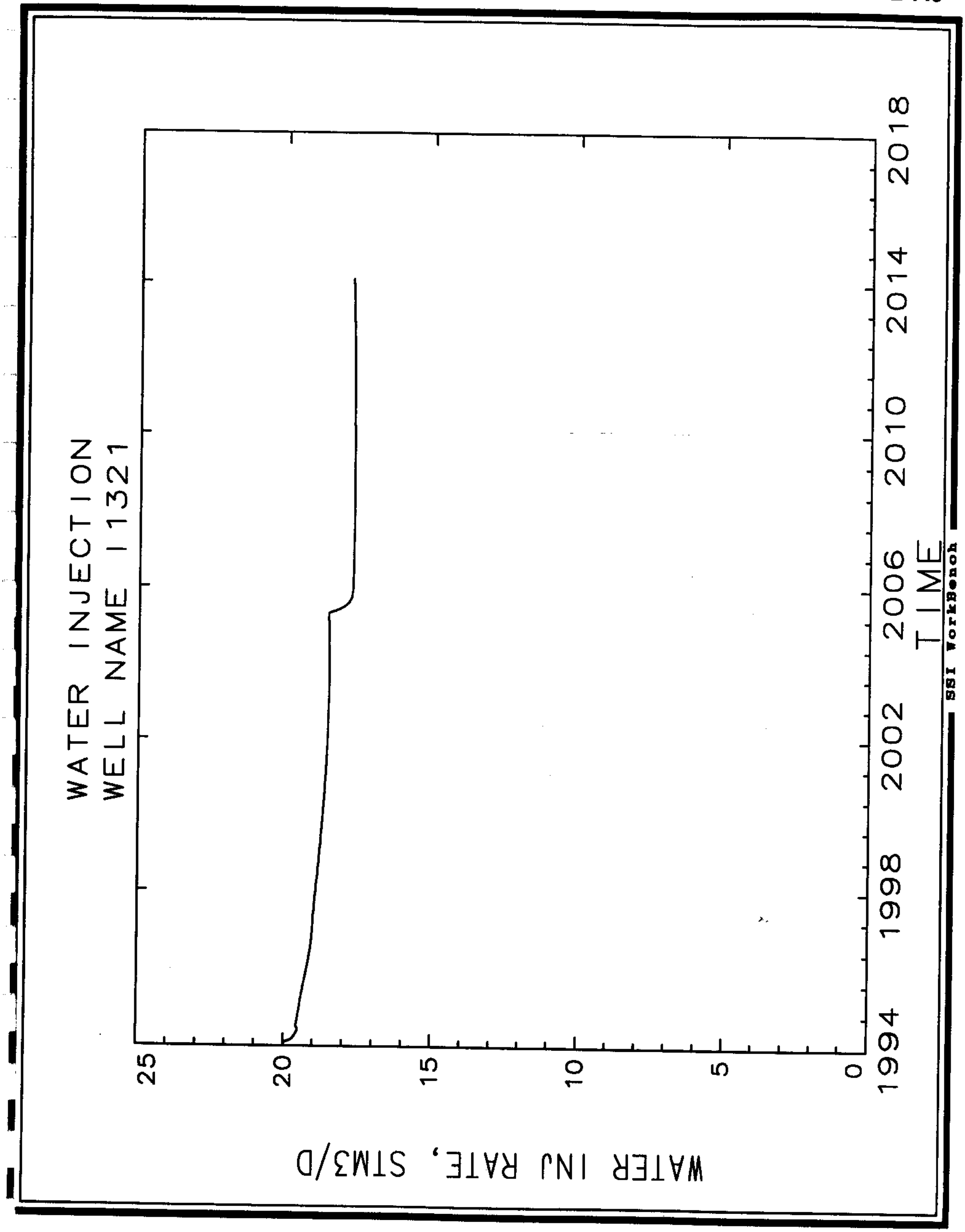
CASE 7 FIGURE 142

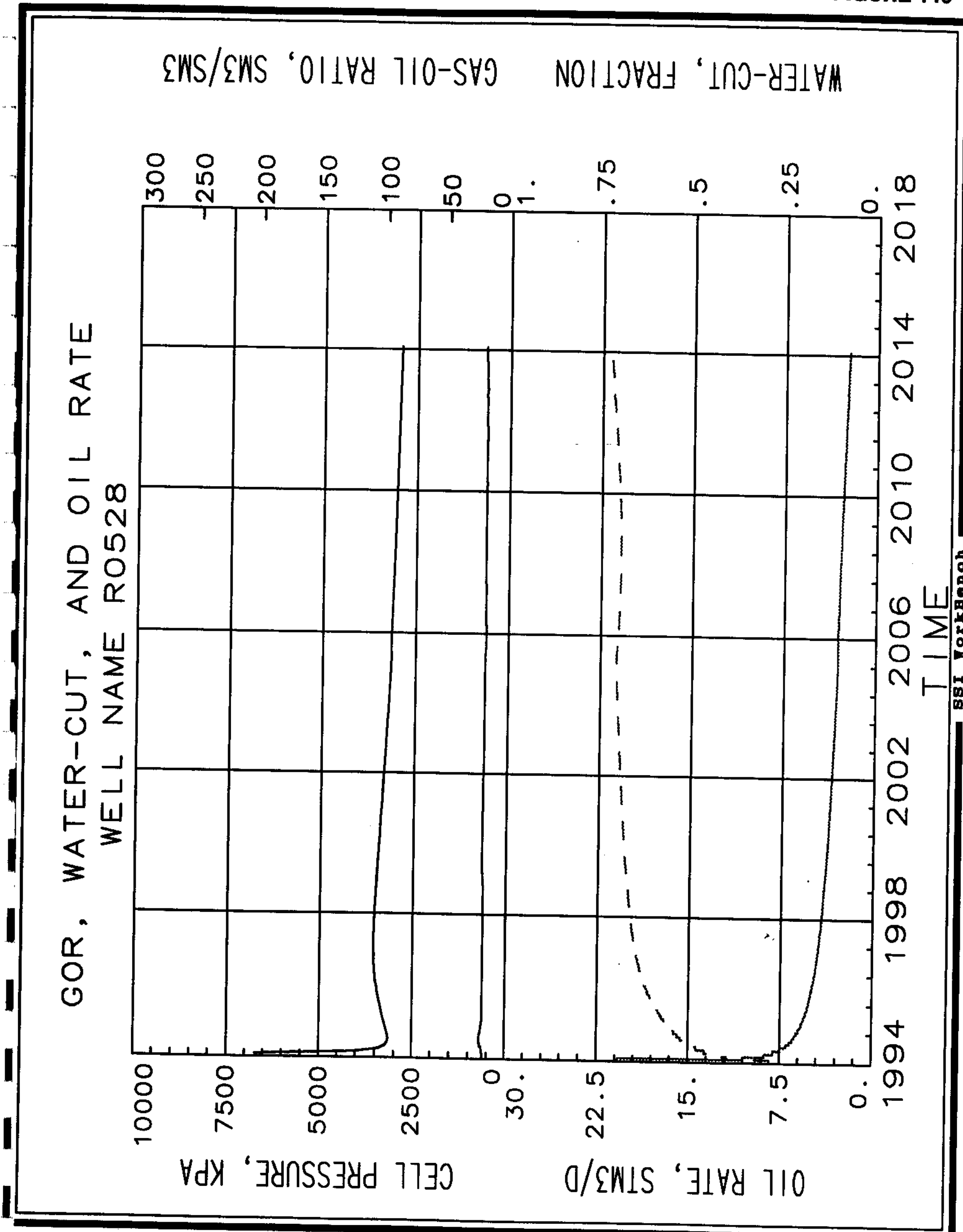



GOR, WATER-CUT, AND OIL RATE
WELL NAME W1228
TIME
1994 1998 2002 2006 2010 2014 2018
CELL PRESSURE, KPA
10000 7500 5000 2500 0
OIL RATE, STM3/D
4 3 2 1 0
GAS-OIL RATIO, SM3/SM3
300 250 200 150 100 50 0
WATER-CUT, FRACTION
1. .75 .5 .25 0.
SSI WorkBench

CASE 7 FIGURE 144



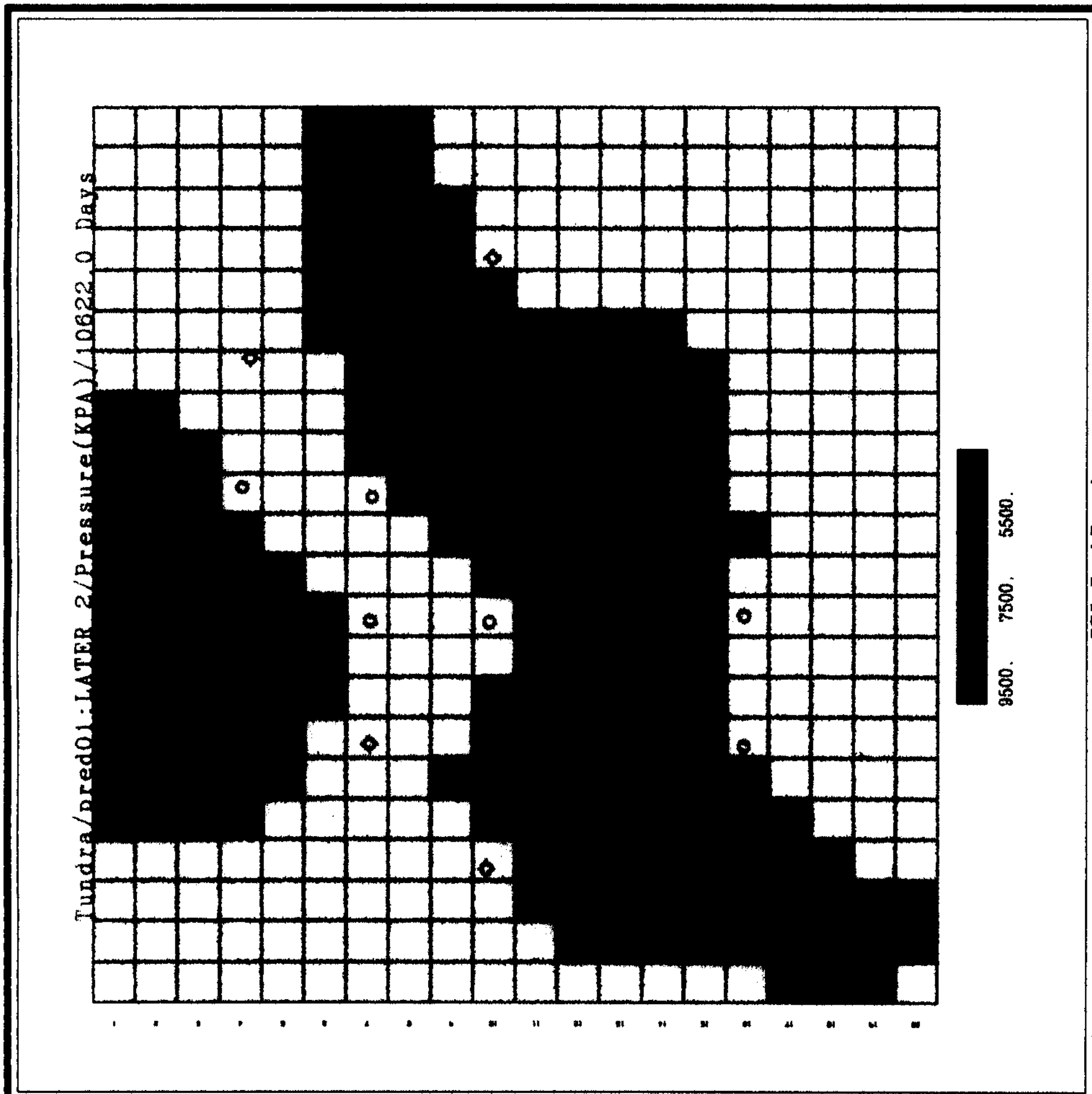

WATER INJECTION
WELL NAME I1321
WATER INJ RATE, STM3/D
TIME
0
5
10
15
20
25
1994
1998
2002
2006
2010
2014
2018
SSI WorkBench


GOR, WATER-CUT, AND OIL RATE
WELL NAME R0528
TIME
1994 1998 2002 2006 2010 2014 2018
CELL PRESSURE, KPA
10000 7500 5000 2500 0
OIL RATE, STM3/D
30. 22.5 15. 7.5 0.
GAS-OIL RATIO, SM3/SM3
300 250 200 150 100 50 0
WATER-CUT, FRACTION
1. .75 .5 .25 0.
SSI WorkBench

Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 7 FIGURE 147

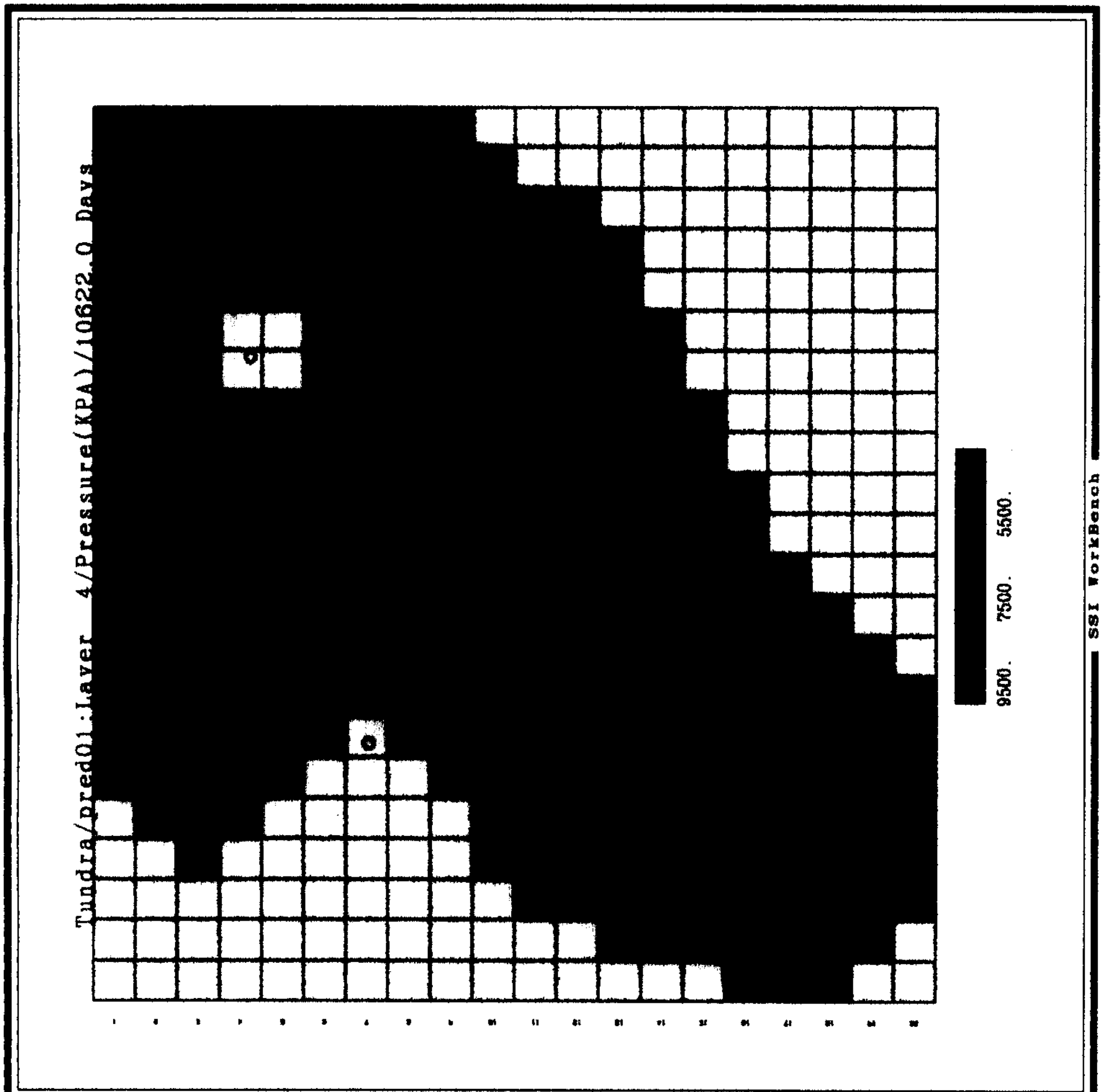
Prediction Case 7 - Pressure Distribution Map Layer 2



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 7 FIGURE 148

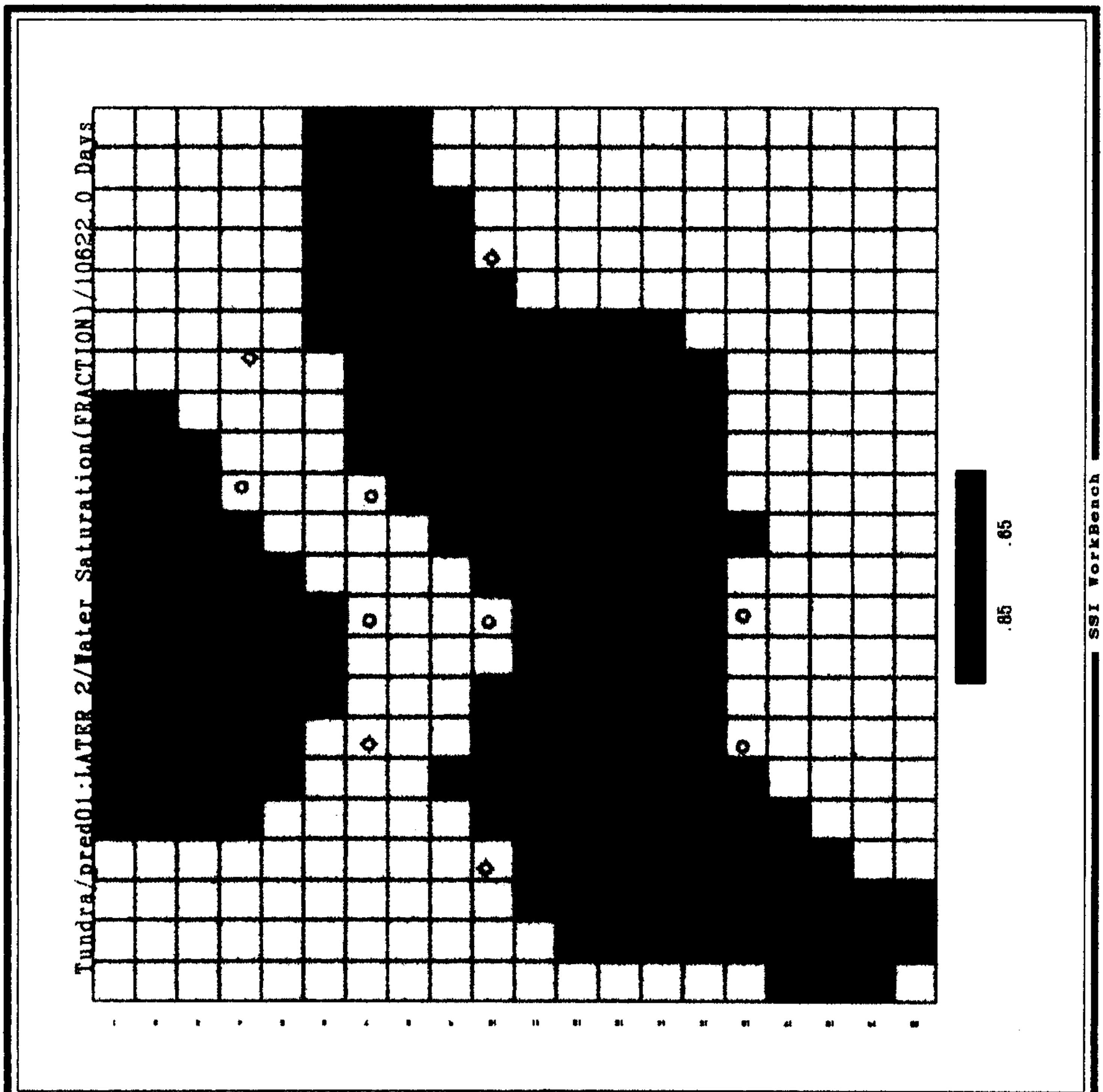
Prediction Case 7 - Pressure Distribution Map Layer 4



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 7 FIGURE 149

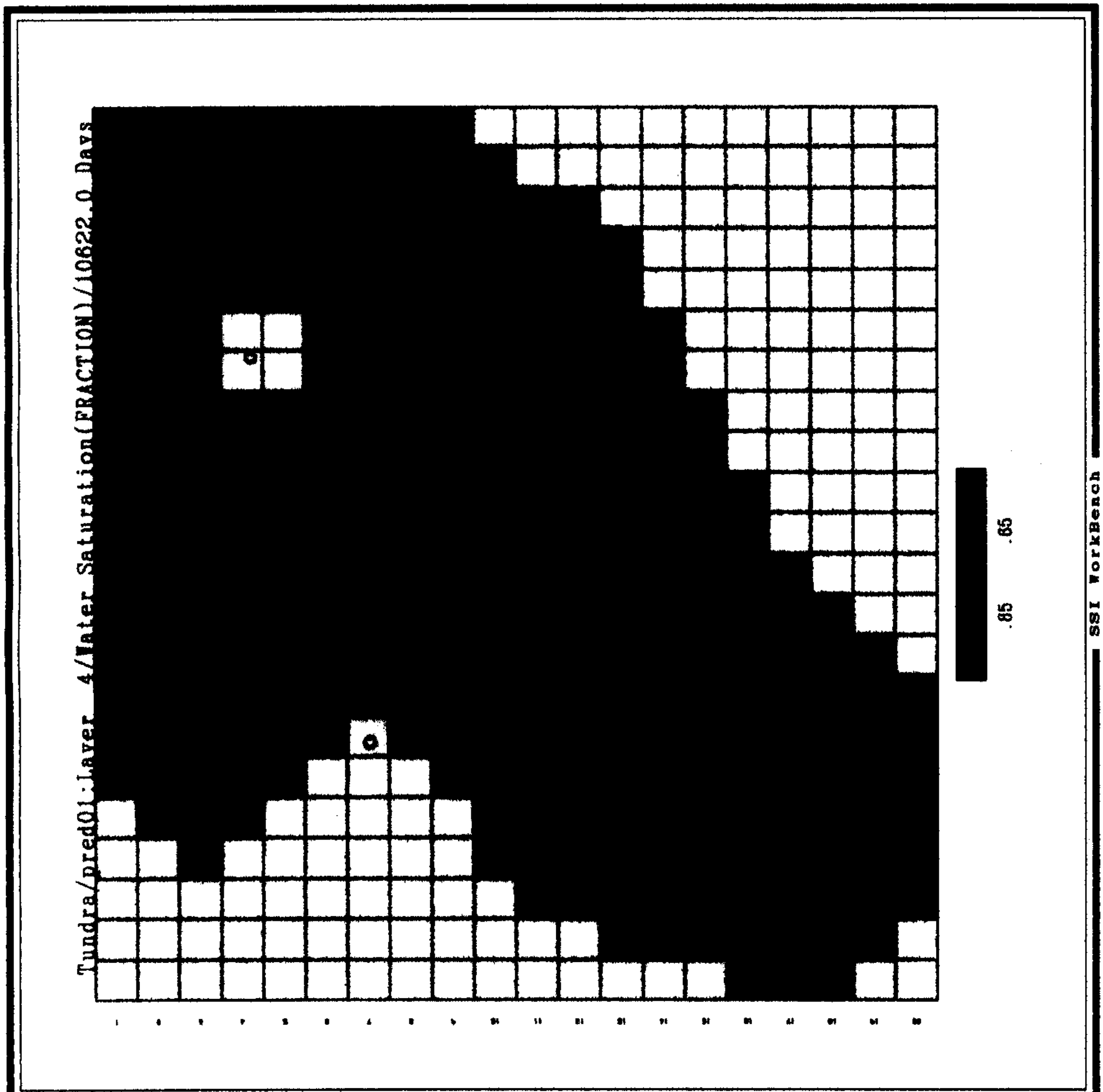
Prediction Case 7 - Water Saturation Distribution Map Layer 2



Kola Bakken 'A' Pool Oil Formation, Manitoba
Reservoir Simulation Study

CASE 7 FIGURE 150

Prediction Case 7 - Water Saturation Distribution Map Layer 4



APPENDICES

APPENDICES

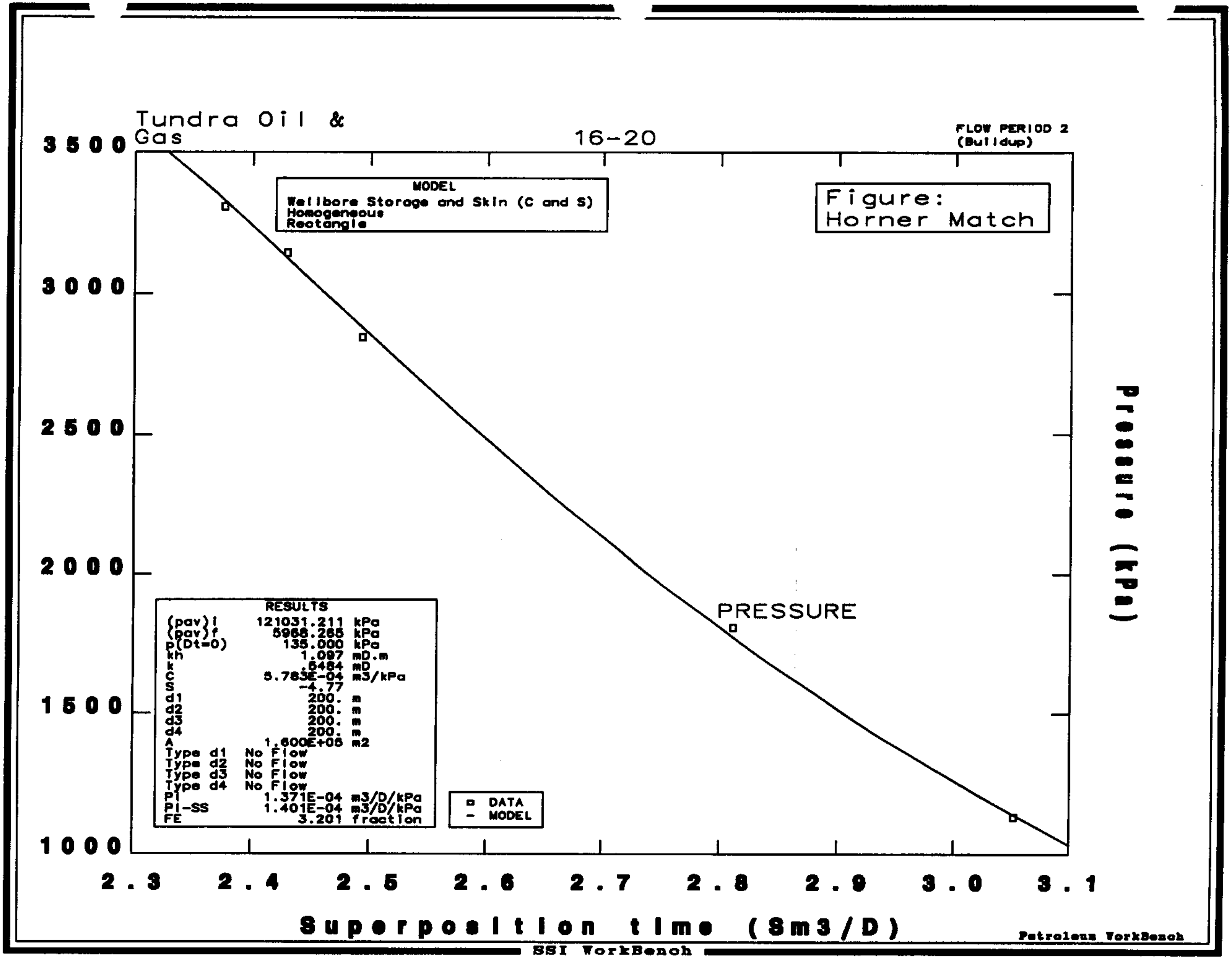
Well Tests

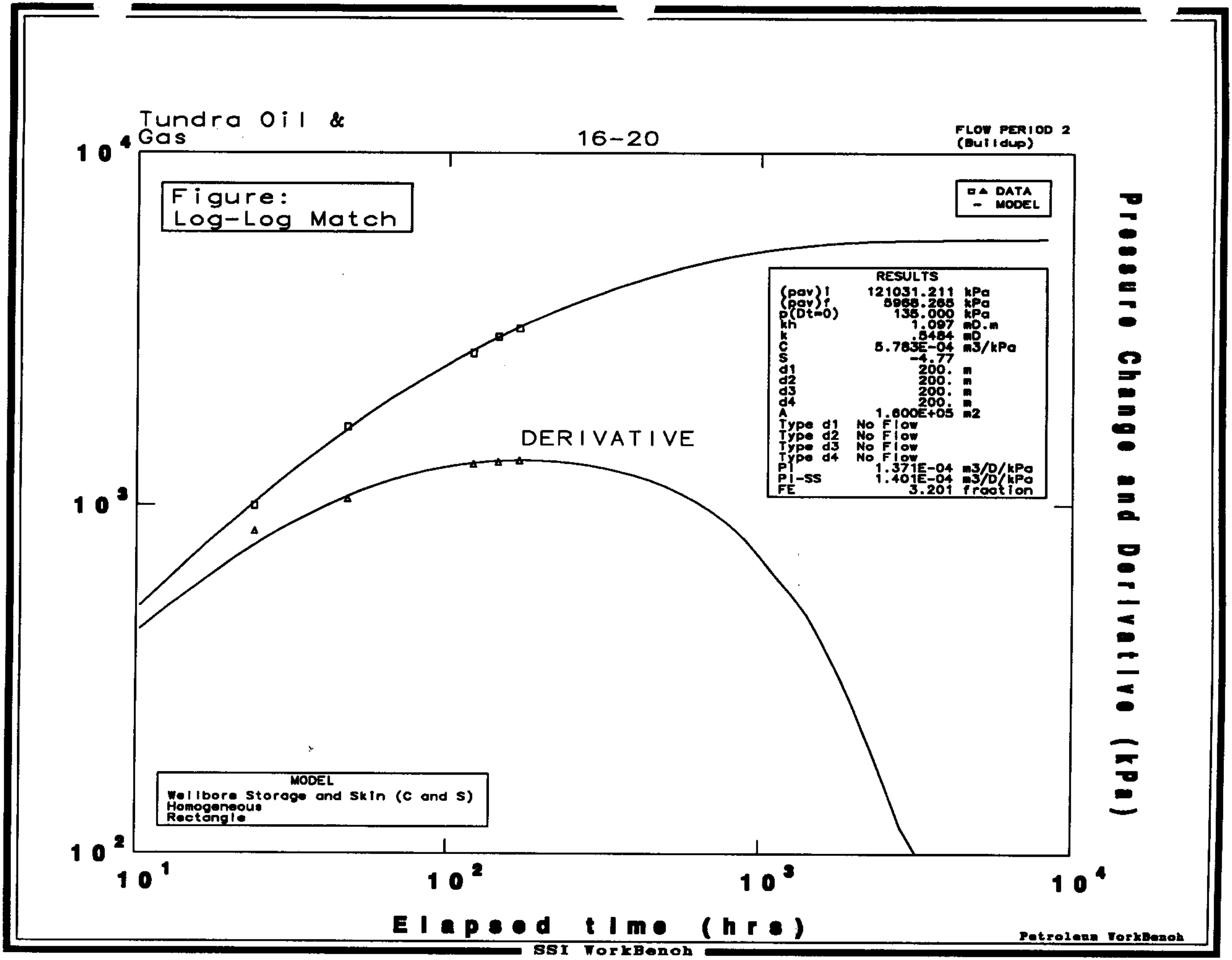
16-20-10-29 WIM

06-28-10-29 W1M

04-28-10-29 W1M

11-28-10-29 W1M


Tundra Oil & Gas
16-20
FLOW PERIOD 2 (Buildup)
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
Figure: Horner Match
RESULTS
(pav)i 121031.211 kPa
(pav)f 5968.265 kPa
p(Dt=0) 135.000 kPa
kh 1.097 mD.m
k .5484 mD
C 5.783E-04 m3/kPa
S -4.77
d1 200. m
d2 200. m
d3 200. m
d4 200. m
A 1.600E+05 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 1.371E-04 m3/D/kPa
PI-SS 1.401E-04 m3/D/kPa
FE 3.201 fraction
DATA
MODEL
PRESSURE
3500
3000
2500
2000
1500
1000
2.3
2.4
2.5
2.6
2.7
2.8
2.9
3.0
3.1
Superposition time (Sm3/D)
Pressure (kPa)
Petroleum WorkBench
SSI WorkBench



Tundra Oil & Gas
16-20
FLOW PERIOD 2 (Buildup)
Figure: Log-Log Match
DATA
MODEL
RESULTS
(pav)i 121031.211 kPa
(pav)f 5968.265 kPa
p(Dt=0) 135.000 kPa
kh 1.097 mD.m
k .5484 mD
C 5.783E-04 m3/kPa
S -4.77
d1 200. m
d2 200. m
d3 200. m
d4 200. m
A 1.600E+05 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 1.371E-04 m3/D/kPa
PI-SS 1.401E-04 m3/D/kPa
FE 3.201 fraction
DERIVATIVE
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
Pressure Change and Derivative (kPa)
Elapsed time (hrs)
SSI WorkBench
Petroleum WorkBench

Scientific Software-Intercomp	WorkBench

WELL TEST ANALYSIS REPORT

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

Perforations:	From	To
1	m	m

ANALYSIS SUMMARY

Scientific Software-Intercomp	WorkBench

Results Summary

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

Near wellbore effects: Wellbore Storage and Skin (C and S)
Reservoir behaviour: Homogeneous
Boundary effects: Rectangle

Flow Period:	2	UNITS
(pav)i	121031.211	kPa
(pav)f	5968.265	kPa
p(Dt=0)	135.000	kPa
kh	1.097	mD.m
k	.5484	mD
C	5.783E-04	m3/kPa
S	-4.77	
d1	200.	m
d2	200.	m
d3	200.	m
d4	200.	m
A	1.600E+05	m2
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Type d4	No Flow	
PI	1.371E-04	m3/D/kPa
PI_SS	1.401E-04	m3/D/kPa
FE	3.201	fraction

Scientific Software-Intercomp	WorkBench

Well & Reservoir Parameters

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

WELL AND RESERVOIR DATA (Oil)

Multiphase flow at wellbore: NO
Multiphase in reservoir : NO

Matrix Porosity	.137	fraction
Reservoir Thickness	2.00	m
Wellbore Radius	.107	m
Distance To Producing Well (*)	.00	m
Oil Formation Volume Factor	1.160	Rm3/m3
Oil Viscosity	1.67	cp
Total Compressibility	1.202E-06	1/kPa

(*) = For Interference Tests Only

Scientific Software-Intercomp	WorkBench

Rates

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

RATES

Flow Period	Start hrs	End hrs	Duration hrs	Oil Sm3/D	Gas 1E3Sm3/D	Water Sm3/D
1	.0000	156810.00	156810.00	.80	.00	.00
2	156810.00	156978.00	168.0000	.00	.00	.00

Scientific Software-Intercomp	WorkBench

Pressure History

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

	TIME hrs	PRESSURE kPa		TIME hrs	PRESSURE kPa
1	156810.00	135.000	4	156930.00	2844.000
2	156834.00	1131.000	5	156954.00	3143.000
3	156858.00	1806.000	6	156978.00	3307.000

Scientific Software-Intercomp	WorkBench

Analysis Parameters

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

ANALYSIS PARAMETERS, FLOW PERIOD: 2

Pressure match, PM	3.792E-04	1/kPa
Time match, TM	2.535E-02	1/hr
Curve Match, Log CDe2S	.249	
Dimensionless drainage area, (A)D	572.	
Rectangle aspect ratio, xe/ye	1.00	
Well position, xw/xe	0.000E+00	
Well position, yw/ye	0.000E+00	

Scientific Software-Intercomp	WorkBench

Analysis Results

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

ANALYSIS RESULTS, FLOW PERIOD: 2

Initial average reservoir pressure, (pav)i	121031.211	kPa
Final average reservoir pressure, (pav)f	5968.265	kPa
P (Delta t = 0), p(Dt=0)	135.000	kPa
Permeability-thickness, kh	1.10	mD.m
Permeability, k	.548	mD
Wellbore storage coefficient, C	5.783E-04	m3/kPa
Wellbore skin factor, S	-4.77	
Distance to first boundary, d1	200.	m
Distance to second boundary, d2	200.	m
Distance to third boundary, d3	200.	m
Distance to fourth boundary, d4	200.	m
Drainage area, A	1.600E+05	m2
Type of first boundary, Type d1	No Flow	
Type of second boundary, Type d2	No Flow	
Type of third boundary, Type d3	No Flow	
Type of fourth boundary, Type d4	No Flow	
Measured Productivity Index, PI	1.371E-04	m3/D/kPa
Steady State Productivity Index, PI_SS	1.401E-04	m3/D/kPa
Flow Efficiency, FE	3.20	fraction

Scientific Software-Intercomp	WorkBench

Pressure Data by Flow Period

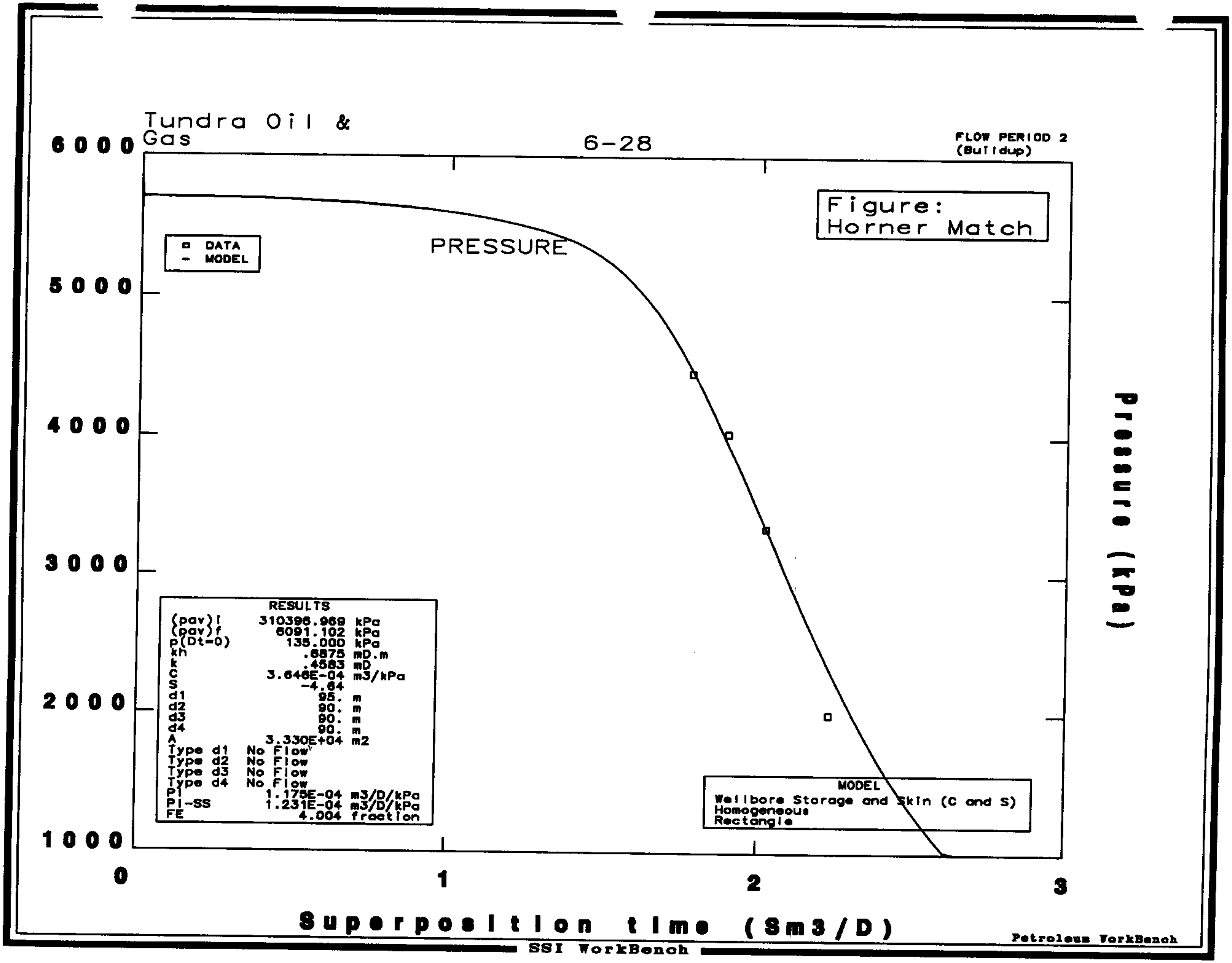
Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

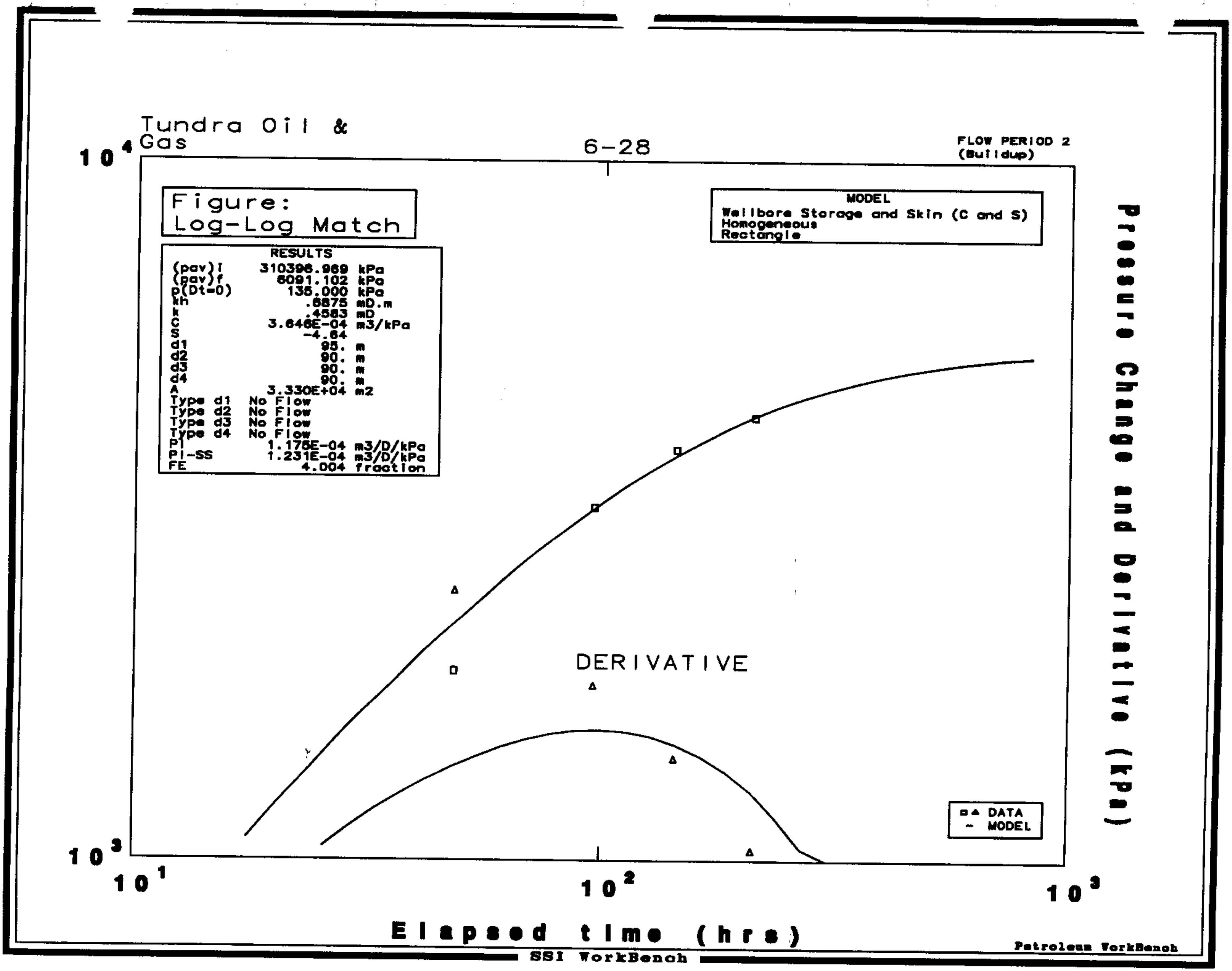
Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

PRESSURE DATA, FLOW PERIOD: 2

	T hrs	DELTA T hrs	SUP. T Sm3/D	PRESSURE kPa	DELTA P kPa	DERIVATIVE kPa
1	156834.00	24.0000	3.05	1131.000	996.000	839.034
2	156858.00	48.0000	2.81	1806.000	1671.000	1042.678
3	156930.00	120.0000	2.49	2844.000	2709.000	1311.805
4	156954.00	144.0000	2.43	3143.000	3008.000	1328.991
5	156978.00	168.0000	2.38	3307.000	3172.000	1343.520



Tundra Oil & Gas
6-28
FLOW PERIOD 2
(Buildup)
Figure:
Horner Match
DATA
MODEL
PRESSURE
RESULTS
(pav)i 310396.969 kPa
(pav)f 6091.102 kPa
p(Dt=0) 135.000 kPa
kh .6875 mD.m
k .4583 mD
C 3.646E-04 m3/kPa
S -4.64
d1 95. m
d2 90. m
d3 90. m
d4 90. m
A 3.330E+04 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 1.175E-04 m3/D/kPa
PI-SS 1.231E-04 m3/D/kPa
FE 4.004 fraction
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
6000
5000
4000
3000
2000
1000
0
1
2
3
Superposition time (Sm3/D)
Pressure (kPa)
SSI WorkBench
Petroleum WorkBench


Tundra Oil & Gas
6-28
FLOW PERIOD 2
(Buildup)
Figure:
Log-Log Match
RESULTS
(pav)i 310396.969 kPa
(pav)f 6091.102 kPa
p(Dt=0) 135.000 kPa
kh .6875 mD.m
k .4583 mD
C 3.646E-04 m3/kPa
S -4.64
d1 95. m
d2 90. m
d3 90. m
d4 90. m
A 3.330E+04 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 1.175E-04 m3/D/kPa
PI-SS 1.231E-04 m3/D/kPa
FE 4.004 fraction
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
DERIVATIVE
DATA
MODEL
Pressure Change and Derivative (kPa)
Elapsed time (hrs)
SSI WorkBench
Petroleum WorkBench

```
+----------------------------------------------------------------------+
| Scientific Software-Intercomp                             WorkBench  |
+----------------------------------------------------------------------+
|                                                                      |
|                     WELL TEST ANALYSIS REPORT                        |
|                                                                      |
+----------------------------------------------------------------------+
```

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

Perforations:	From	To
1	m	m

ANALYSIS SUMMARY

Scientific Software-Intercomp	WorkBench

Results Summary

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

Flow Period:	2	UNITS
(pav)i	310396.969	kPa
(pav)f	6091.102	kPa
p(Dt=0)	135.000	kPa
kh	.6875	mD.m
k	.4583	mD
C	3.646E-04	m3/kPa
S	-4.64	
d1	95.	m
d2	90.	m
d3	90.	m
d4	90.	m
A	3.330E+04	m2
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Type d4	No Flow	
PI	1.175E-04	m3/D/kPa
PI_SS	1.231E-04	m3/D/kPa
FE	4.004	fraction

Scientific Software-Intercomp	WorkBench

Well & Reservoir Parameters

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

WELL AND RESERVOIR DATA (Oil)

Multiphase flow at wellbore: NO
Multiphase in reservoir : NO

Matrix Porosity	.137	fraction
Reservoir Thickness	1.50	m
Wellbore Radius	.107	m
Distance To Producing Well (*)	.00	m
Oil Formation Volume Factor	1.160	Rm3/m3
Oil Viscosity	1.67	cp
Total Compressibility	1.202E-06	1/kPa

(*) = For Interference Tests Only

Scientific Software-Intercomp	WorkBench

Rates

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

RATES

Flow Period	Start hrs	End hrs	Duration hrs	Oil Sm3/D	Gas 1E3Sm3/D	Water Sm3/D
1	.0000	73982.0000	73982.0000	.70	.00	.00
2	73982.0000	74194.0000	212.0000	.00	.00	.00

Scientific Software-Intercomp	WorkBench

Pressure History

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

	TIME hrs	PRESSURE kPa		TIME hrs	PRESSURE kPa
1	73982.0000	135.000	4	74126.0000	4025.000
2	74030.0000	1999.000	5	74194.0000	4457.000
3	74078.0000	3340.000			

Scientific Software-Intercomp	WorkBench

Analysis Parameters

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects: Wellbore Storage and Skin (C and S)
Reservoir behaviour: Homogeneous
Boundary effects: Rectangle

ANALYSIS PARAMETERS, FLOW PERIOD: 2

Pressure match, PM	2.716E-04	1/kPa
Time match, TM	2.521E-02	1/hr
Curve Match, Log CDe2S	.284	
Dimensionless drainage area, (A)D	142.	
Rectangle aspect ratio, xe/ye	1.03	
Well position, xw/xe	-2.703E-02	
Well position, yw/ye	0.000E+00	

```
+-------------------------------------------------------------------------------+
| Scientific Software-Intercomp                                       WorkBench |
+-------------------------------------------------------------------------------+
|                                                                               |
|                            Analysis Results                                   |
|                                                                               |
+-------------------------------------------------------------------------------+
```

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

ANALYSIS RESULTS, FLOW PERIOD: 2

Initial average reservoir pressure, (pav)i	310396.969	kPa
Final average reservoir pressure, (pav)f	6091.102	kPa
P (Delta t = 0), p(Dt=0)	135.000	kPa
Permeability-thickness, kh	.687	mD.m
Permeability, k	.458	mD
Wellbore storage coefficient, C	3.646E-04	m3/kPa
Wellbore skin factor, S	-4.64	
Distance to first boundary, d1	95.	m
Distance to second boundary, d2	90.	m
Distance to third boundary, d3	90.	m
Distance to fourth boundary, d4	90.	m
Drainage area, A	3.330E+04	m2
Type of first boundary, Type d1	No Flow	
Type of second boundary, Type d2	No Flow	
Type of third boundary, Type d3	No Flow	
Type of fourth boundary, Type d4	No Flow	
Measured Productivity Index, PI	1.175E-04	m3/D/kPa
Steady State Productivity Index, PI_SS	1.231E-04	m3/D/kPa
Flow Efficiency, FE	4.00	fraction

Scientific Software-Intercomp	WorkBench

Pressure Data by Flow Period

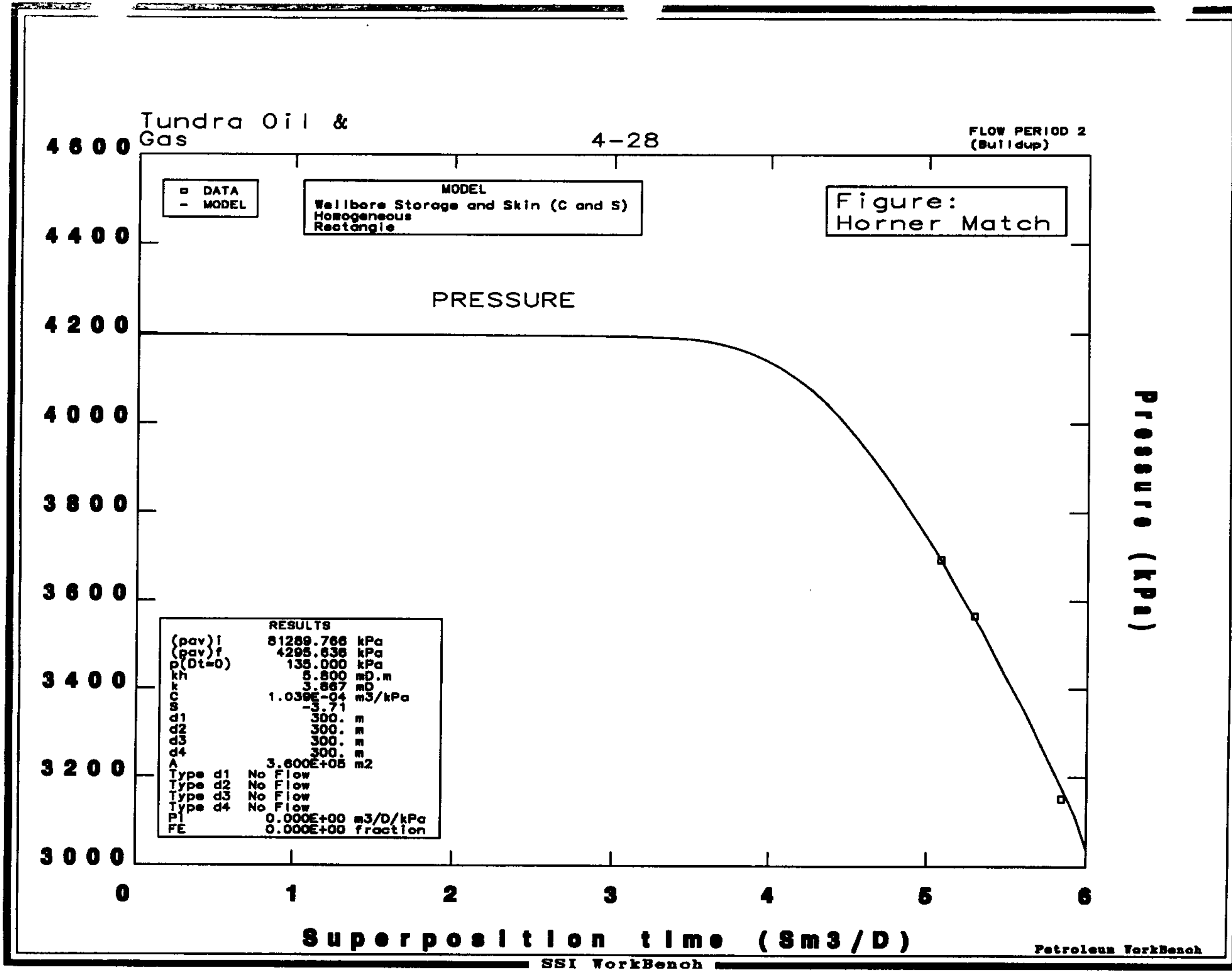
Company: Tundra Oil & Gas

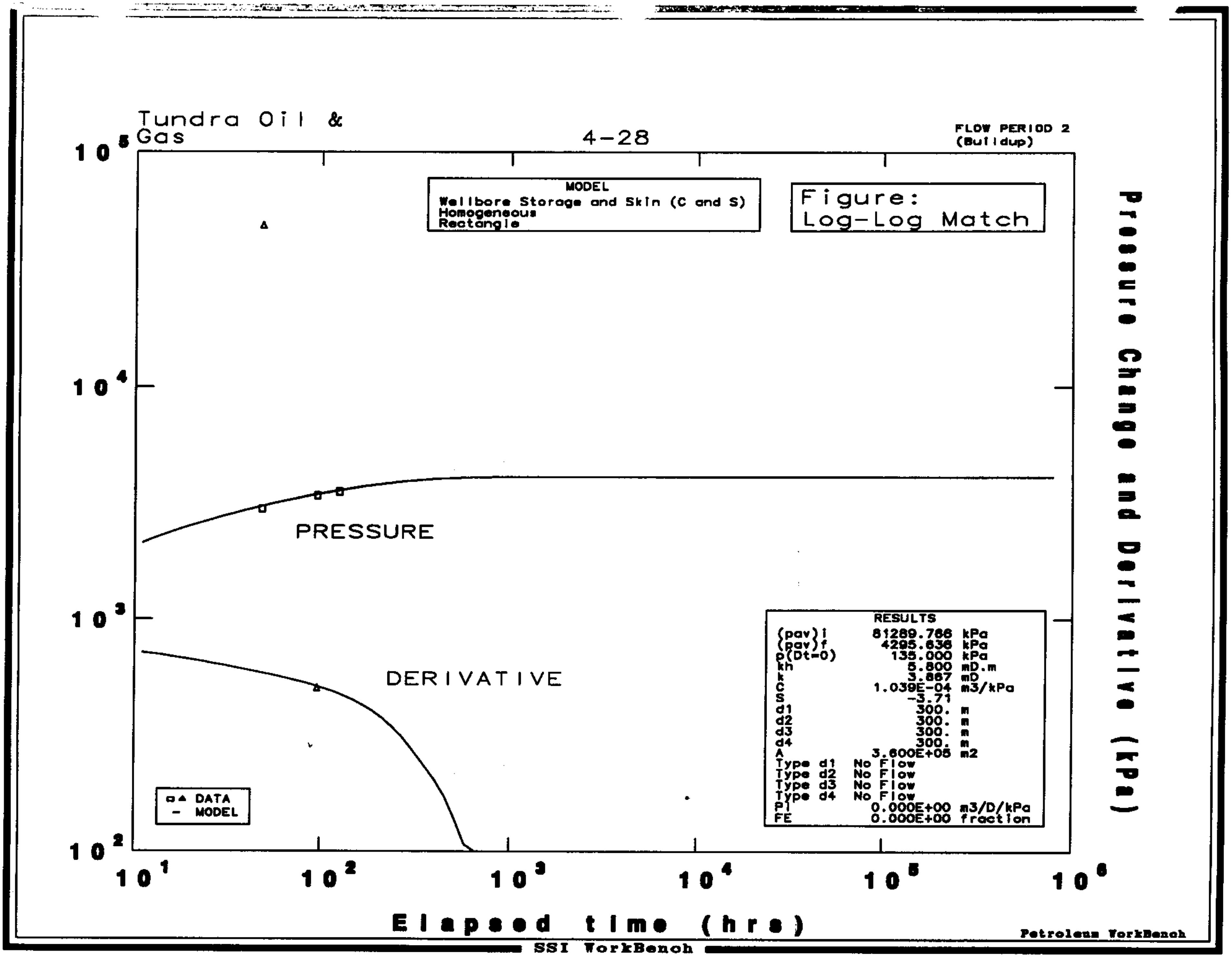
Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

PRESSURE DATA, FLOW PERIOD: 2

	T hrs	DELTA T hrs	SUP. T Sm3/D	PRESSURE kPa	DELTA P kPa	DERIVATIVE kPa
1	74030.0000	48.0000	2.23	1999.000	1864.000	2437.904
2	74078.0000	96.0000	2.02	3340.000	3205.000	1782.262
3	74126.0000	144.0000	1.90	4025.000	3890.000	1398.990
4	74194.0000	212.0000	1.78	4457.000	4322.000	1033.671


Tundra Oil & Gas
4-28
FLOW PERIOD 2 (Buildup)
□ DATA
- MODEL
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
Figure: Horner Match
PRESSURE
RESULTS
(pav)i 81289.766 kPa
(pav)f 4295.636 kPa
p(Dt=0) 135.000 kPa
kh 5.800 mD.m
k 3.867 mD
C 1.039E-04 m3/kPa
S -3.71
d1 300. m
d2 300. m
d3 300. m
d4 300. m
A 3.600E+05 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 0.000E+00 m3/D/kPa
FE 0.000E+00 fraction
4600
4400
4200
4000
3800
3600
3400
3200
3000
0
1
2
3
4
5
6
Superposition time (Sm3/D)
Pressure (kPa)
Petroleum WorkBench
SSI WorkBench



Tundra Oil & Gas
4-28
FLOW PERIOD 2 (Buildup)
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
Figure: Log-Log Match
PRESSURE
DERIVATIVE
RESULTS
(pav)i 81289.766 kPa
(pav)f 4295.636 kPa
p(Dt=0) 135.000 kPa
kh 5.800 mD.m
k 3.867 mD
C 1.039E-04 m3/kPa
S -3.71
d1 300. m
d2 300. m
d3 300. m
d4 300. m
A 3.600E+05 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 0.000E+00 m3/D/kPa
FE 0.000E+00 fraction
DATA
MODEL
Pressure Change and Derivative (kPa)
Elapsed time (hrs)
SSI WorkBench
Petroleum WorkBench

```
+----------------------------------------------------------------------------+
|  Scientific Software-Intercomp                                  WorkBench  |
+----------------------------------------------------------------------------+
|                                                                            |
|                        WELL TEST ANALYSIS REPORT                           |
|                                                                            |
+----------------------------------------------------------------------------+
```

Company:	Tundra Oil & Gas		
Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

Perforations:	From	To
1	m	m

ANALYSIS SUMMARY

Scientific Software-Intercomp	WorkBench

Results Summary

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

Near wellbore effects: Wellbore Storage and Skin (C and S)
Reservoir behaviour: Homogeneous
Boundary effects: Rectangle

Flow Period:	2	UNITS
(pav)i	81289.766	kPa
(pav)f	4295.636	kPa
p(Dt=0)	135.000	kPa
kh	5.800	mD.m
k	3.867	mD
C	1.039E-04	m3/kPa
S	-3.71	
d1	300.	m
d2	300.	m
d3	300.	m
d4	300.	m
A	3.600E+05	m2
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Type d4	No Flow	
PI	0.000E+00	m3/D/kPa
FE	0.000E+00	fraction

Scientific Software-Intercomp	WorkBench

Well & Reservoir Parameters

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

WELL AND RESERVOIR DATA (Oil)

Multiphase flow at wellbore: NO
Multiphase in reservoir : NO

Matrix Porosity	.137	fraction
Reservoir Thickness	1.50	m
Wellbore Radius	.107	m
Distance To Producing Well (*)	.00	m
Oil Formation Volume Factor	1.160	Rm3/m3
Oil Viscosity	1.67	cp
Total Compressibility	1.202E-06	1/kPa

(*) = For Interference Tests Only

Scientific Software-Intercomp	WorkBench

Rates

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

RATES

Flow Period	Start hrs	End hrs	Duration hrs	Oil Sm3/D	Gas 1E3Sm3/D	Water Sm3/D
1	.0000	77832.0000	77832.0000	1.82	.00	.00
2	77832.0000	77958.0000	126.0000	.00	.00	.00

Scientific Software-Intercomp	WorkBench

Pressure History

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 16-20

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

	TIME hrs	PRESSURE kPa		TIME hrs	PRESSURE kPa
1	77832.0000	135.000	3	77928.0000	3564.000
2	77880.0000	3151.000	4	77958.0000	3691.000

Scientific Software-Intercomp	WorkBench

Analysis Results

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

ANALYSIS RESULTS, FLOW PERIOD: 2

Initial average reservoir pressure, (pav)i	81289.766	kPa
Final average reservoir pressure, (pav)f	4295.636	kPa
P (Delta t = 0), p(Dt=0)	135.000	kPa
Permeability-thickness, kh	5.80	mD.m
Permeability, k	3.87	mD
Wellbore storage coefficient, C	1.039E-04	m3/kPa
Wellbore skin factor, S	-3.71	
Distance to first boundary, d1	300.	m
Distance to second boundary, d2	300.	m
Distance to third boundary, d3	300.	m
Distance to fourth boundary, d4	300.	m
Drainage area, A	3.600E+05	m2
Type of first boundary, Type d1	No Flow	
Type of second boundary, Type d2	No Flow	
Type of third boundary, Type d3	No Flow	
Type of fourth boundary, Type d4	No Flow	
Measured Productivity Index, PI	0.000E+00	m3/D/kPa
Flow Efficiency, FE	0.000E+00	fraction

Scientific Software-Intercomp	WorkBench

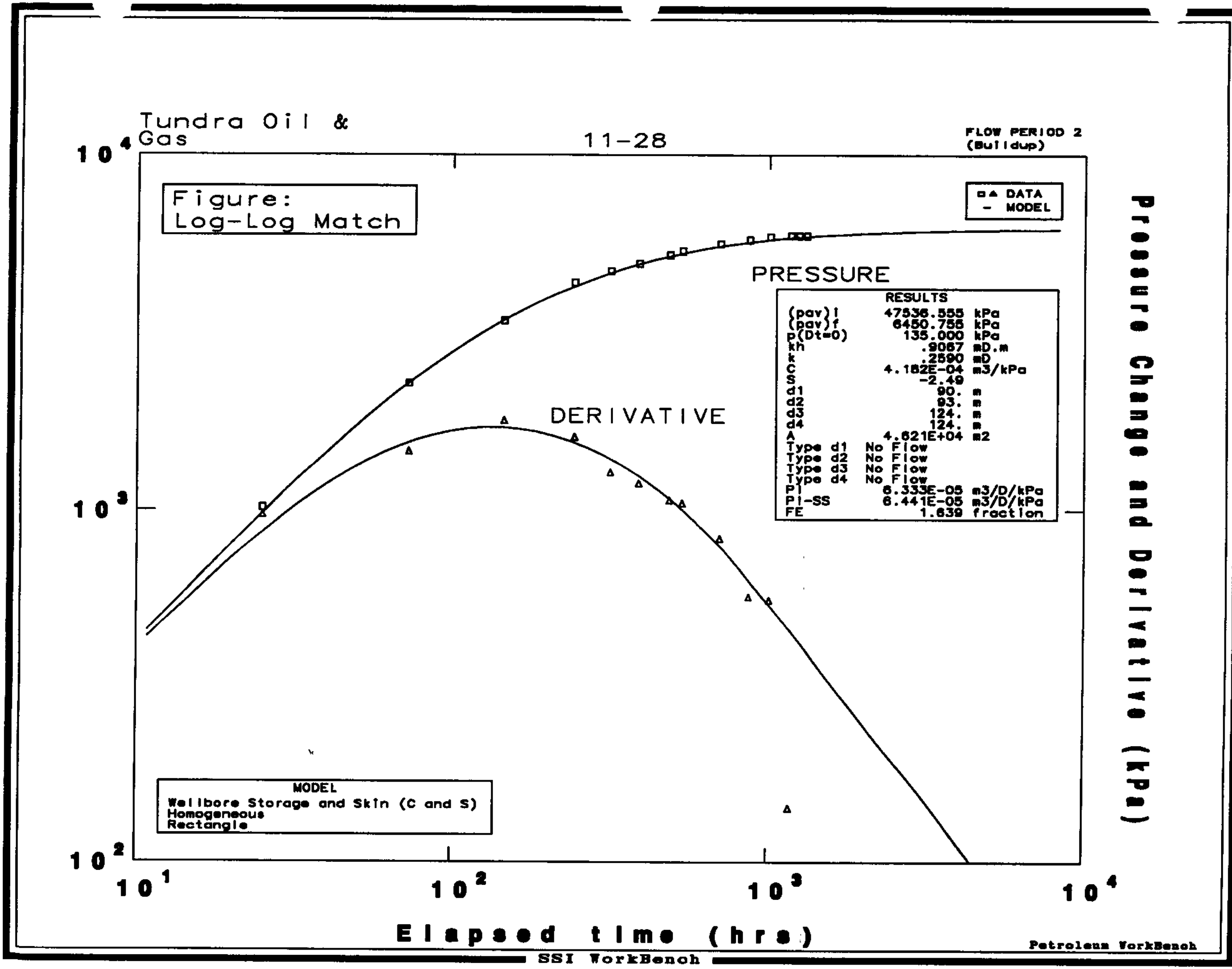
Pressure Data by Flow Period

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	16-20	Gauge:	
		Depth:	m

PRESSURE DATA, FLOW PERIOD: 2

	T hrs	DELTA T hrs	SUP. T Sm3/D	PRESSURE kPa	DELTA P kPa	DERIVATIVE kPa
1	77880.0000	48.0000	5.84	3151.000	3016.000	48587.277
2	77928.0000	96.0000	5.30	3564.000	3429.000	503.931
3	77958.0000	126.0000	5.08	3691.000	3556.000	



Tundra Oil &
Gas
11-28
FLOW PERIOD 2
(Buildup)
Figure:
Log-Log Match
DATA
MODEL
PRESSURE
DERIVATIVE
RESULTS
(pav)i 47536.555 kPa
(pav)f 6450.755 kPa
p(Dt=0) 135.000 kPa
kh .9067 mD.m
k .2590 mD
C 4.182E-04 m3/kPa
S -2.49
d1 90. m
d2 93. m
d3 124. m
d4 124. m
A 4.621E+04 m2
Type d1 No Flow
Type d2 No Flow
Type d3 No Flow
Type d4 No Flow
PI 6.333E-05 m3/D/kPa
PI-SS 6.441E-05 m3/D/kPa
FE 1.639 fraction
MODEL
Wellbore Storage and Skin (C and S)
Homogeneous
Rectangle
10^4
10^3
10^2
10^1
10^2
10^3
10^4
Elapsed time (hrs)
Pressure Change and Derivative (kPa)
SSI WorkBench
Petroleum WorkBench

Scientific Software-Intercomp	WorkBench

WELL TEST ANALYSIS REPORT

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	11-28	Gauge:	
		Depth:	m

Perforations:	From	To
1	m	m

ANALYSIS SUMMARY

Scientific Software-Intercomp	WorkBench

Results Summary

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	11-28	Gauge:	
		Depth:	m

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

Flow Period:	2	UNITS
(pav)i	47536.555	kPa
(pav)f	6450.755	kPa
p(Dt=0)	135.000	kPa
kh	.9067	mD.m
k	.2590	mD
C	4.182E-04	m3/kPa
S	-2.49	
d1	90.	m
d2	93.	m
d3	124.	m
d4	124.	m
A	4.621E+04	m2
Type d1	No Flow	
Type d2	No Flow	
Type d3	No Flow	
Type d4	No Flow	
PI	6.333E-05	m3/D/kPa
PI_SS	6.441E-05	m3/D/kPa
FE	1.639	fraction

Scientific Software-Intercomp	WorkBench

Well & Reservoir Parameters

Company:	Tundra Oil & Gas		
Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	11-28	Gauge:	
		Depth:	m

WELL AND RESERVOIR DATA (Oil)

Multiphase flow at wellbore: NO
Multiphase in reservoir : NO

Matrix Porosity	.137	fraction
Reservoir Thickness	3.50	m
Wellbore Radius	.107	m
Distance To Producing Well (*)	.00	m
Oil Formation Volume Factor	1.160	Rm3/m3
Oil Viscosity	1.67	cp
Total Compressibility	1.202E-06	1/kPa

(*) = For Interference Tests Only

Scientific Software-Intercomp	WorkBench

Rates

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 11-28

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

RATES

Flow Period	Start hrs	End hrs	Duration hrs	Oil Sm3/D	Gas 1E3Sm3/D	Water Sm3/D
1	.0000	56600.0000	56600.0000	.40	.00	.00
2	56600.0000	57920.0000	1320.0000	.00	.00	.00

Scientific Software-Intercomp	WorkBench

Pressure History

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 11-28

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

	TIME hrs	PRESSURE kPa		TIME hrs	PRESSURE kPa
1	56600.0000	135.000	9	57128.0000	5500.000
2	56624.0000	1153.000	10	57296.0000	5765.000
3	56672.0000	2421.000	11	57464.0000	5904.000
4	56744.0000	3558.000	12	57608.0000	6020.000
5	56840.0000	4519.000	13	57776.0000	6070.000
6	56912.0000	4859.000	14	57848.0000	6070.000
7	56984.0000	5088.000	15	57920.0000	6070.000
8	57080.0000	5372.000			

Scientific Software-Intercomp	WorkBench

Analysis Parameters

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 11-28

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

ANALYSIS PARAMETERS, FLOW PERIOD: 2

Pressure match, PM	6.269E-04	1/kPa
Time match, TM	2.898E-02	1/hr
Curve Match, Log CDe2S	1.84	
Dimensionless drainage area, (A)D	400.	
Rectangle aspect ratio, xe/ye	.984	
Well position, xw/xe	.159	
Well position, yw/ye	.141	

Scientific Software-Intercomp	WorkBench

Analysis Results

Company: Tundra Oil & Gas

Field:		Date:	23-Mar-94
Formation:		Test No:	
Zone:		Test Date:	
Well:	11-28	Gauge:	
		Depth:	m

ANALYSIS MODEL, FLOW PERIOD: 2

Near wellbore effects:	Wellbore Storage and Skin (C and S)
Reservoir behaviour:	Homogeneous
Boundary effects:	Rectangle

ANALYSIS RESULTS, FLOW PERIOD: 2

Initial average reservoir pressure, (pav)i	47536.555	kPa
Final average reservoir pressure, (pav)f	6450.755	kPa
P (Delta t = 0), p(Dt=0)	135.000	kPa
Permeability-thickness, kh	.907	mD.m
Permeability, k	.259	mD
Wellbore storage coefficient, C	4.182E-04	m3/kPa
Wellbore skin factor, S	-2.49	
Distance to first boundary, d1	90.	m
Distance to second boundary, d2	93.	m
Distance to third boundary, d3	124.	m
Distance to fourth boundary, d4	124.	m
Drainage area, A	4.621E+04	m2
Type of first boundary, Type d1	No Flow	
Type of second boundary, Type d2	No Flow	
Type of third boundary, Type d3	No Flow	
Type of fourth boundary, Type d4	No Flow	
Measured Productivity Index, PI	6.333E-05	m3/D/kPa
Steady State Productivity Index, PI_SS	6.441E-05	m3/D/kPa
Flow Efficiency, FE	1.64	fraction

Scientific Software-Intercomp	WorkBench

Pressure Data by Flow Period

Company: Tundra Oil & Gas

Field:
Formation:
Zone:
Well: 11-28

Date: 23-Mar-94
Test No:
Test Date:
Gauge:
Depth: m

PRESSURE DATA, FLOW PERIOD: 2

	T hrs	DELTA T hrs	SUP. T Sm3/D	PRESSURE kPa	DELTA P kPa	DERIVATIVE kPa
1	56624.0000	25.0000	1.34	1153.000	1018.000	970.359
2	56672.0000	73.0000	1.16	2421.000	2286.000	1474.283
3	56744.0000	145.0000	1.04	3558.000	3423.000	1796.668
4	56840.0000	241.0000	.95	4519.000	4384.000	1619.457
5	56912.0000	313.0000	.90	4859.000	4724.000	1281.459
6	56984.0000	385.0000	.87	5088.000	4953.000	1190.284
7	57080.0000	481.0000	.83	5372.000	5237.000	1065.760
8	57128.0000	529.0000	.81	5500.000	5365.000	1043.917
9	57296.0000	697.0000	.77	5765.000	5630.000	829.301
10	57464.0000	865.0000	.73	5904.000	5769.000	566.779
11	57608.0000	1009.0000	.70	6020.000	5885.000	555.629
12	57776.0000	1177.0000	.68	6070.000	5935.000	141.540
13	57848.0000	1249.0000	.67	6070.000	5935.000	
14	57920.0000	1321.0000	.66	6070.000	5935.000	