LA-UR- 96-2195

CONF-961003--3

Title: ADVANCED RESERVOIR MANAGEMENT FOR INDEPENDENT OIL & GAS PRODUCERS

RECEIVED
JUL 19 1996
OSTI

Author(s): A. G. Sgro, R. P. Kendall, J. M. Kindel, R. B. Webster, E. M. Whitney

Submitted to: Society of Petroleum Engineers
71st Annual Technical Conference and Exhibition
6-9 October 1996
Denver, Colorado

MASTER

Los Alamos
NATIONAL LABORATORY

Form No. 836 R5
ST 2629 10/91

SPE 36643

ADVANCED RESERVOIR MANAGEMENT FOR INDEPENDENT OIL AND GAS PRODUCERS

A.G. Sgro, R.P. Kendall, J.M. Kindel, R.B. Webster, E.M. Whitney
Los Alamos National Laboratory

~~ABSTRACT~~

INTRODUCTION

There are more than fifty-two hundred oil and gas producers operating in the United States today. Many of these companies have instituted improved oil recovery programs in some form, but very few have had access to state-of-the-art modeling technologies routinely used by major producers to manage these projects. Since independent operators are playing an increasingly important role in the production of hydrocarbons in the United States, it is important to promote state-of-the-art management practices, including the planning and monitoring of improved oil recovery projects, within this community. This is one of the goals of the Strategic Technologies Council, a special interest group of independent oil and gas producers.

Reservoir management technologies [1] have the potential to increase oil recovery while simultaneously reducing production costs. These technologies were pioneered by major producers and are routinely used by them. Independent producers confront two problems adopting this approach: the high cost of acquiring these technonogies and the high cost of using them even if they were available. Effective use of reservoir management tools requires, in general, the services of a professional (geoscientist or engineer) who is already familiar with the details of setting up, running, and interpreting computer models.

A previous paper [2] described a project which aims to make reservoir management tools available to the independent operator in a cost effective manner. The central feature of this approach exploits the potential of the World wide Web (WWW) to deliver software access at low cost. The proceedure of launching petrotechnical applications and retrieving results over the WWW, and the paradigm for the interaction between the independents, the petroleum service sector, and the government, were presented. It was emphasized that in contrast to the present situation, a non-expert Independent producer is able to make simple but meaningful changes to the simulation models, such as reconfiguring production or working over wells, in order to assess the effect of such stratigies on oil recovery rates.

This paper will illustrate this paradigm in action through an actual case study involving an independent operator. Local consultants, software vendors, expert users (specialized consultants), and independent operators are brought together by the WWW to persue low cost reservoir management. Meaningful geological modeling and reservoir simulation access is provided directly to independent operators who are not modeling experts. The particular case of interest is an evaluation of the performance of a waterflood that is presently underway. The objective is to maximize the oil recovery from the waterflood.

RESERVOIR MANAGEMENT PHASES

A typical reservoir management study is generally divided into phases: project planning, in which the details and needs of the particular project are specified and a time frame for completing the individual steps is decided; geological modeling, in which the reservoir geometry and the distribution of attributes important to recovery are modeled; reservoir simulation, in which forecasts of various management strategies are made; and economic analysis, in which the costs and income from the these strategies are combined to determine the most effective strategy.

SIMULATION OVER THE WORLD WIDE WEB

This paper will focus on various strategies considered during the reservoir simulation phase.

First, however, the geological modeling and history matching must be done. These tasks are rather complicated, and are done by a local consultant (for the data gathering and interpretation) and an expert user (for the rest). Ideally, these individuals would collaborate on all tasks. In terms of the capabilities presented in the previous paper [2], these professionals would work together to generate the geological and simulation models using their own computers or ones which can be accessed over the web.

The implementation of the well controls is quite different from the example of the previous paper [2]. In addition to the standard implementation in the input file, an HTML form for WWW viewing would be written that would allow the independent to change the relevant fields of the well description by pointing and clicking on the form. In this manner, once the history matching is completed, the independent can take over the execution of the reservoir management study. With very little training he can simulate various future scenarios resulting from the changes in the well parameters accessible to him and evaluate their economic consequences. Since the Independent himself is doing this rather than the consultant, the cost is simply the cost of access to the simulator. In this manner, the evaluation of alternative development strategies is more efficient than if a consultant were involved in setting up each change.

TASKS REQUIRING CONSULTANTS

GEOLOGICAL DESCRIPTION

For the purpose of this report the term geologic modeling will refer to the geologic description of the reservoir, specifically the spatial distribution properties like porosity and permeability, which determine the storage capacity and conductivity of the reservoir rock matrix. We also include the description of the lithological structure of the reservoir, including discontinuities such as pinch-outs and faults. In large scale projects the geological description of the reservoir has usually been captured in a geological modeling package. It is often possible to import the geological description from the geological modeling or mapping package into the reservoir simulator directly.

For this project the geological model took the form of contour maps for each reservoir zone, that is, each distinct lithological unit, which were digitized and gridded. An example of the resulting maps is shown in figure 1.

RESERVOIR DESCRIPTION

In addition to the geological description of the reservoir, the local consultant was able to provide the following:

- Fluid Contact Data

We have assumed that the reservoir was initially a gravity-capillary equilibrium. This data block defines the locations of the water-oil and gas-oil contacts, the appropriate capillary pressures at these contacts, the initial reservoir pressure, and the depth(datum) to which it applies. The initial fluid contacts lay outside the reservoir and the capillary reference pressures were unknown. The model was initialized to specified water saturation for each zone as follows: upper = 31%; middle = 28%; lower = 25%. The resulting simulation model was slightly out of equilibrium.

- Constant Fluid Property Data

This data block defines petrophysical properties which are considered to be constant over the reservoir. These properties include reservoir temperature, initial water formation volume factor, water compressibility and viscosity, and rock compressibiltity. Of the quantities, only the reservoir temperature was known.

- Fluid PVT Property Data:

This data block consists, essentially, of a characterization of the black-oil differential liberation test and viscoscity measurements made at different pressures. In this study, no PVT lab work had been performed on the reservoir fluids, so a PVT simulator was used to estimate the required properties.

- Rock Property Data:

This data block contains the special core analysis data, specifically relative permeability and capillary pressure measurements. Unfortunately, no such data has been collected for this reservoir. However, some data was available from another nearby reservoir. It served as the starting point for the model validation step, but was modified to better match the late history water production. There is strong evidence that each zone should have its own rock curves, but only a single set of curves was used in this study.

PERFORM MODEL VALIDATION (HISTORY MATCHING)

In the model validation step the simulation model is required to "predict" known reservoir performance. The petrophysical parameters upon which the reservoir description is based are modified until a reasonable match is obtained.

Using actual oil production rates by well, it became clear that the net water volumes represented in the model were probably incorrect. There were three years of primary production before water injection started. Without additional energy in the form of aquifer support, the model shuts in because of insufficient reservoir pressure within the first two years of primary production. Both bottom water drive and flank water drive were investigated as remedies. Bottom water drive was selected because low water influx volumes were required to prevent premature shut in of the unit.

Figure 1 exhibits the average reservoir pressure and cumulative oil production during history. Unfortunately, there were no historical measurements available to compare this behavior. Average reservoir pressure (hc-weighted) declines to a low of less than 200 psia during primary production. After water injection is initiated, reservoir pressure is restored to initial levels by 1988. No gas production rates were available to compare with model results, but water production is in qualatative agreement with field measurements. Water-oil relative permeabilities were available to obtain this match.

The overall match to the water production during late historical time is:

Year	Field Measurement	Simulator Prediction
1991	487 BWD	288 BWD
1992	561 BWD	475 BWD
1993	605 BWD	614 BWD

The most sensitive history matching parameter happens to be the most uncertain one: water-oil relative permeabilities. A reduction in Krw of only a few percent at low saturations can reduce the production rate by 50%.

RESERVOIR MANAGEMENT ENABLED BY THE WWW

Once the history matching is complete the Independent can simulate various manangement scenarios using the WWW forms to, as an example, modify well parameters. The basemap in figure 2 illustrates the locations of pre-existing wells in our project. The cases described below were set up by the Independent to evaluate the incremental oil recovery from reconfiguring the existing waterflood. No new well were to be drilled- existing producers were to be converted into water injectors. The primary goal of these cases was to determine if moving the water injection up structure in existing wells would be cost-effective.

Base Case (Case 0) and six short term forecasts were run with the reservoir simulation model. The base case can be run by changing nothing and only clicking on the submit button, while six short term forcasts could be run by changing values in the web forms before submitting. A brief description of the cases follows:

Case 0: The basecase, which forecasts the result of the continuation of the current operation strategy: injectors inject at the maximum of a 1500 psia wellhead pressure or a fbhp of 80% of the reserve fracture pressure; producers pumped off (fbhp= 25 psia).

Case 1: Convert RFF#7 and TRFF#1 to water injectors at the beginning of 1994. Inject against wellhead pressure constraints of 1500 psia; produce against fbhp constraint of 25 psia. No water cut constraint. Maximum warer injection rate is 300 BWD.

Case 2: Convert FF#7 and SDW#6 to injectors at the beginning of 1994.Constraints as in Case 1.No water cut constraint.

Case 3: Convert RFF#2, TRFF#1, FF#7 and SDW#6 to water injectors at the beginning of 1994. Constraints as in previous two cases.

Case 4: Convert RFF#7, TRFF#1, FF#7 and SDW#6 to water injectors at the beginning of 1994. Injection rates computed to maintain average reservoir pressure by voidage replacement. All producers are to be reperfered whenever water cut exceeds 0.90. The most offending perf is shut in. If only one zone is flowing, the well is shut in.

Case 5: Convert FF#7, SDW#3, RFF#7 and TRFF#1 to water injectors at the beginning of 1994. Injection rates computed to replace voidage to maintain average reservoir pressure. All wells are to be reperfered at the beginning of the forecast in order to reduce water cut. Nowater cut constraint on production.

Case 6: Rematch the simulation model (well PI's) to bring producers onto pumping status at the beginning of the forcast. Convert RFF#2, TRFF#1, FF#7 and SDW#6 to water injectors at the beginning of 1994.Producers were converted to a total liquid (oil + water) constraint of 900 STB/D and water cut limit of 0.995. Water injection rates were calculated to replace voidage as follows:

RFF#7	TRFF#1	FF#7	SDW#6	SSDW#1	FF#5	GOLD#1
.1	.1	.3	.3	.1	.05	.05

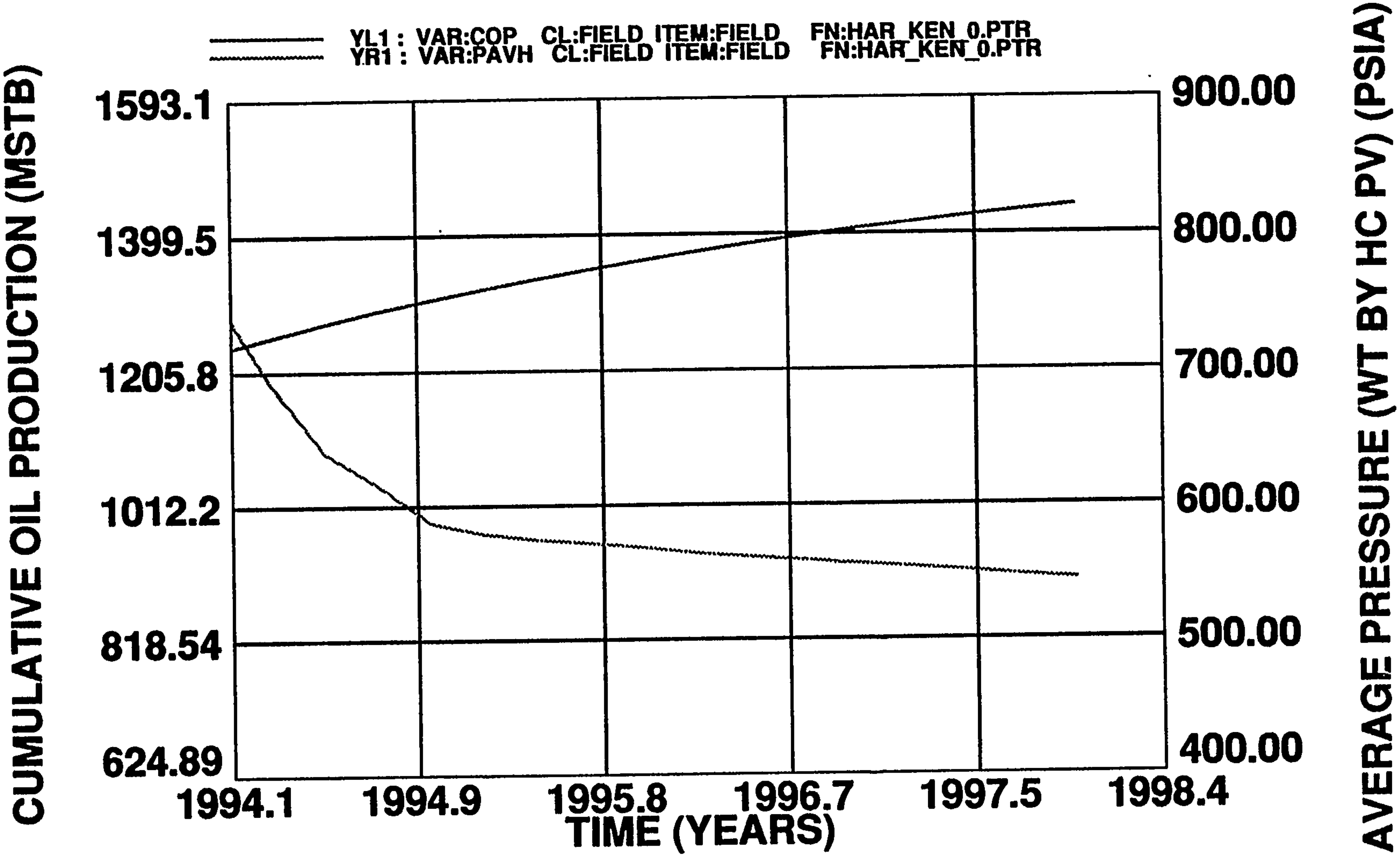
All other injectors were shut-in.

Figure 3 shows the cumulative oil production and the average pressure during the forcast period as predicted by the base case simulation (Case 0). Figures 4 to 8 compares these two variables for Cases 1 to 6 with case 0. Evidentally, cases 3 and 6 provide the greatest increase in oil production, and case 6 does it with less water production (figure 9) while maintaining a higher reservoir pressure.

CONCLUSIONS

The proceedures defined in the WWW paradigm described in a previous paper were applied to a real reservoir study to demonstrate the empowerment of the independent to do reservoir management studies inexpensively.

Divine Unit Base Case



HAR-KEN OIL CO.
DIVINE UNIT FORECAST
HEBBARDSVILLE FIELD
BASE CASE: FIGURE 1

FIG 1

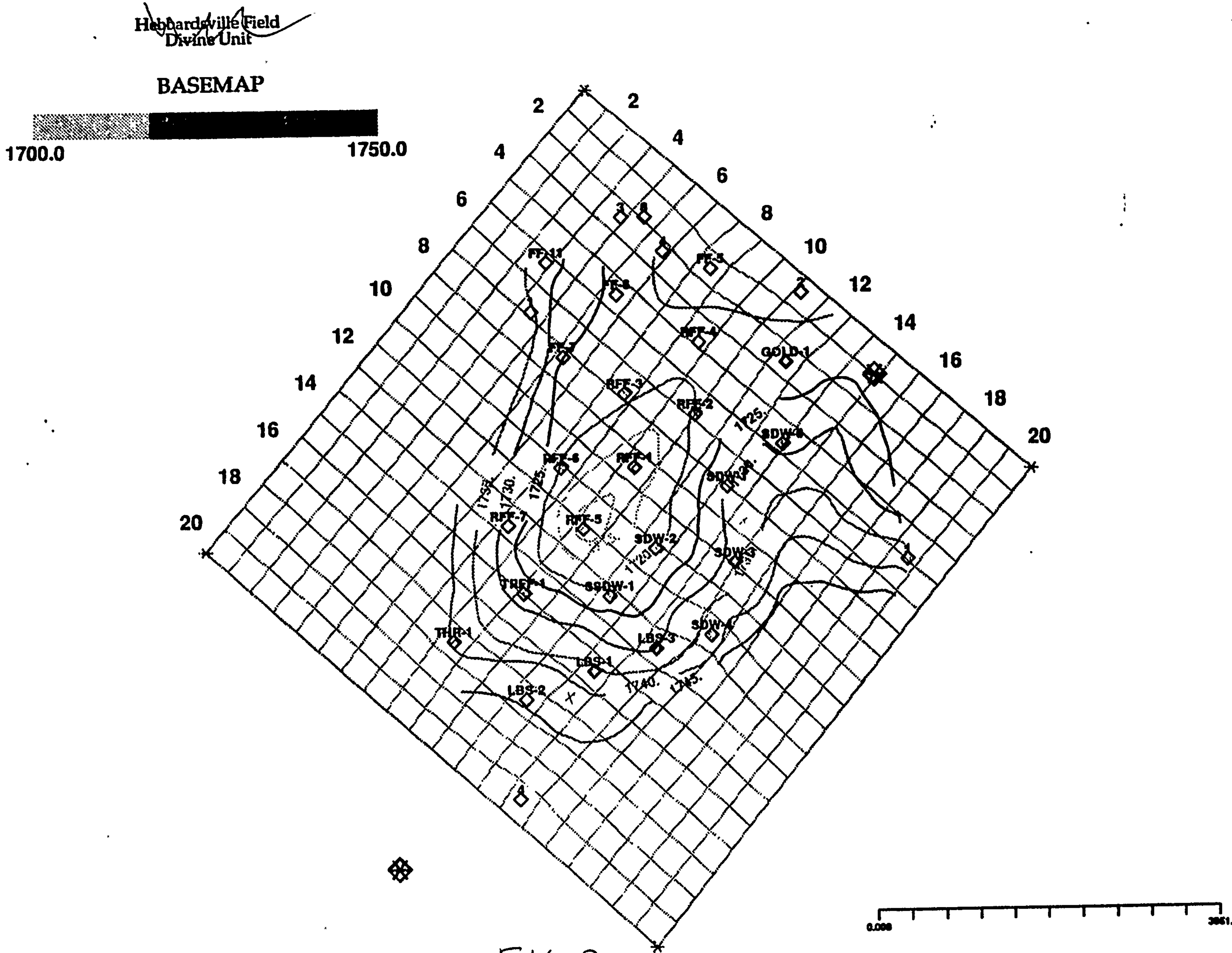
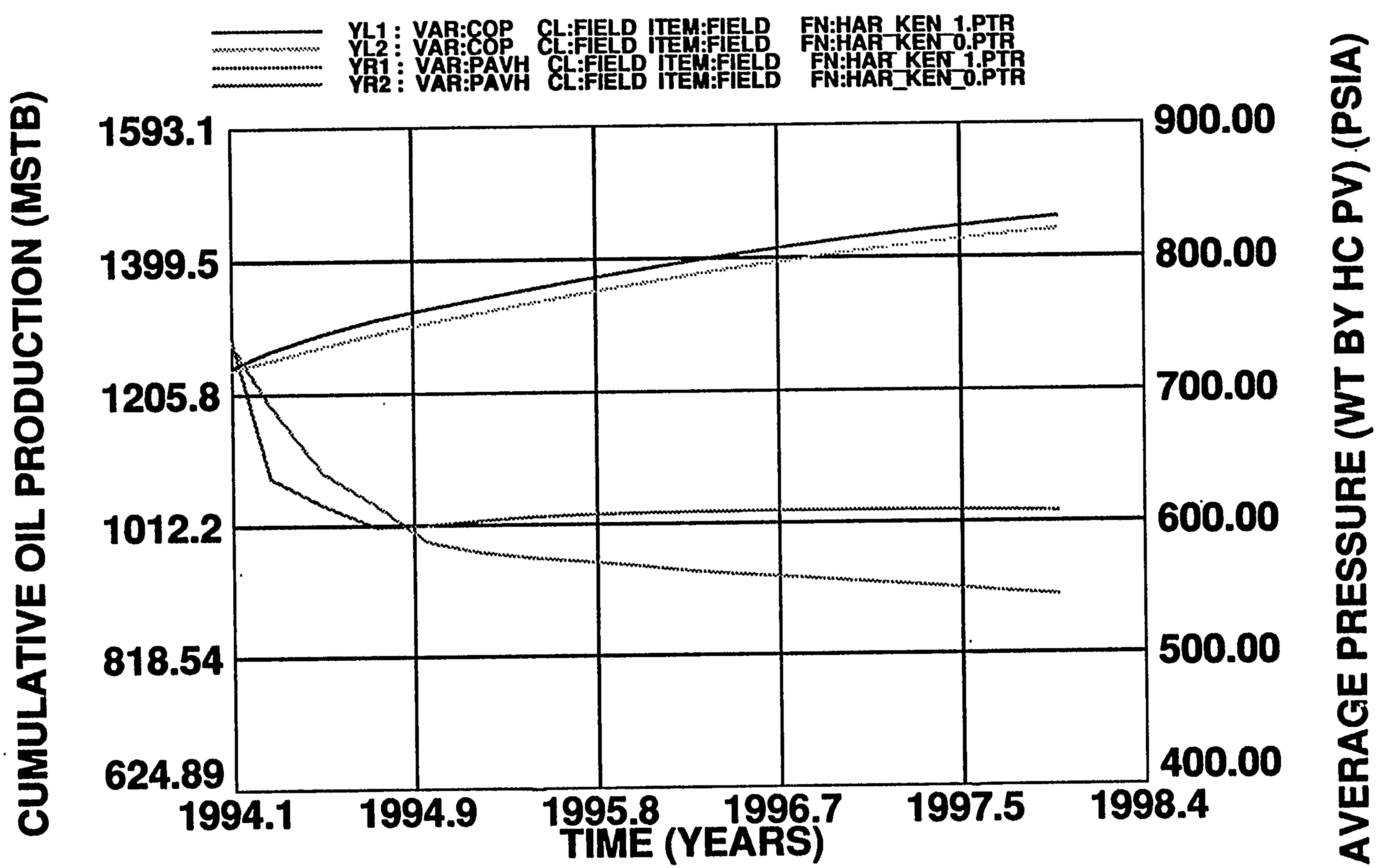

Hebbardsville Field
Divine Unit
BASEMAP
1700.0
1750.0
FF-11
FF-8
FF-5
FF-7
RFF-4
GOLD-1
RFF-3
RFF-2
SDW-6
RFF-6
RFF-1
RFF-7
RFF-5
SDW-2
SDW-3
TRFF-1
SSDW-1
SDW-4
THR-1
LBS-3
LBS-1
LBS-2
1725.
1730.
1735.
1720.
1740.
1745.
0.000
3661.

FIG 2

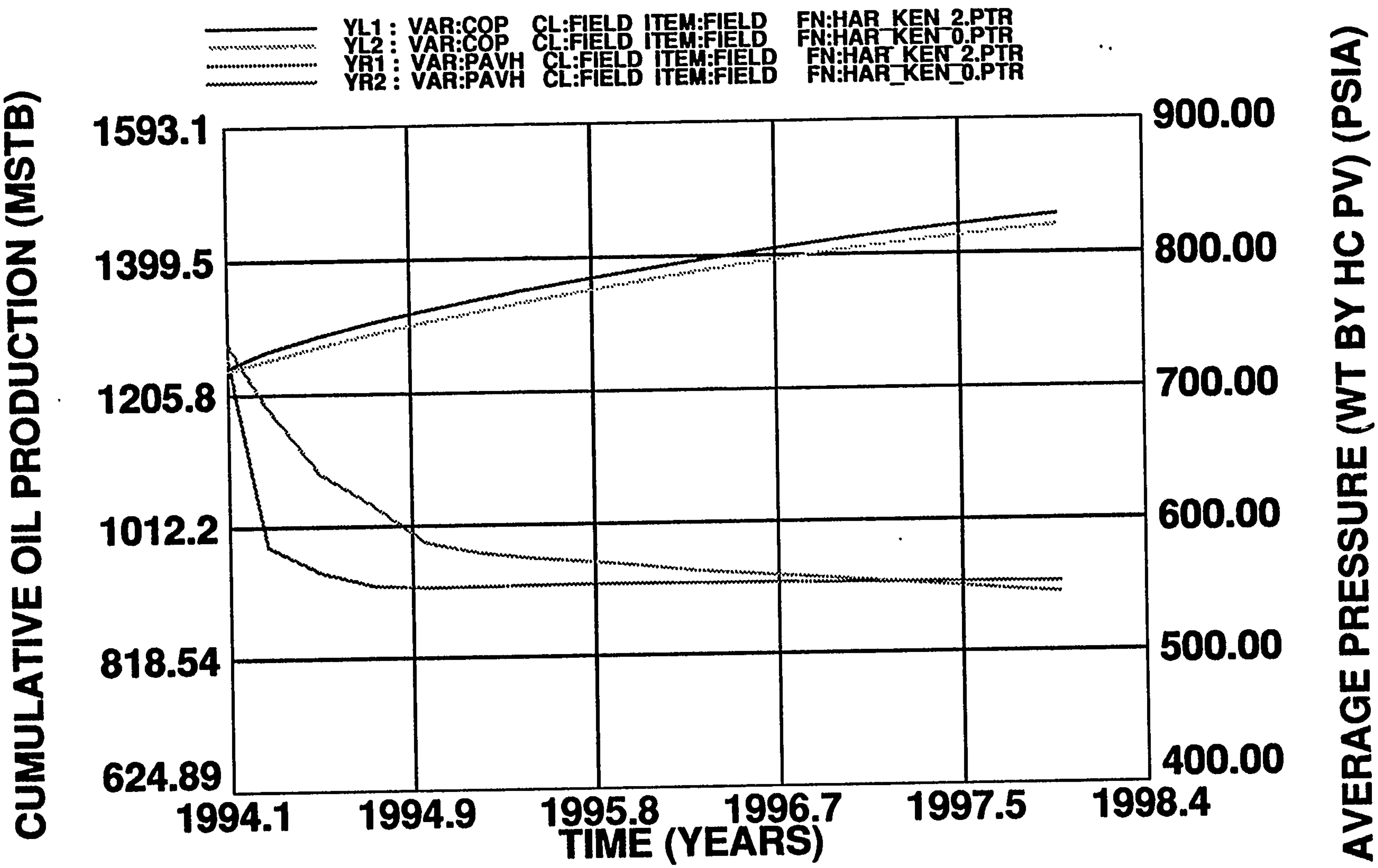
Case 1 vs. Case 0



~~HAR-KEN OIL CO.~~
~~DIVINE UNIT FORECAST~~
~~HEBBARDSVILLE FIELD~~
~~CASE 1: FIGURE 1~~

FIG 3

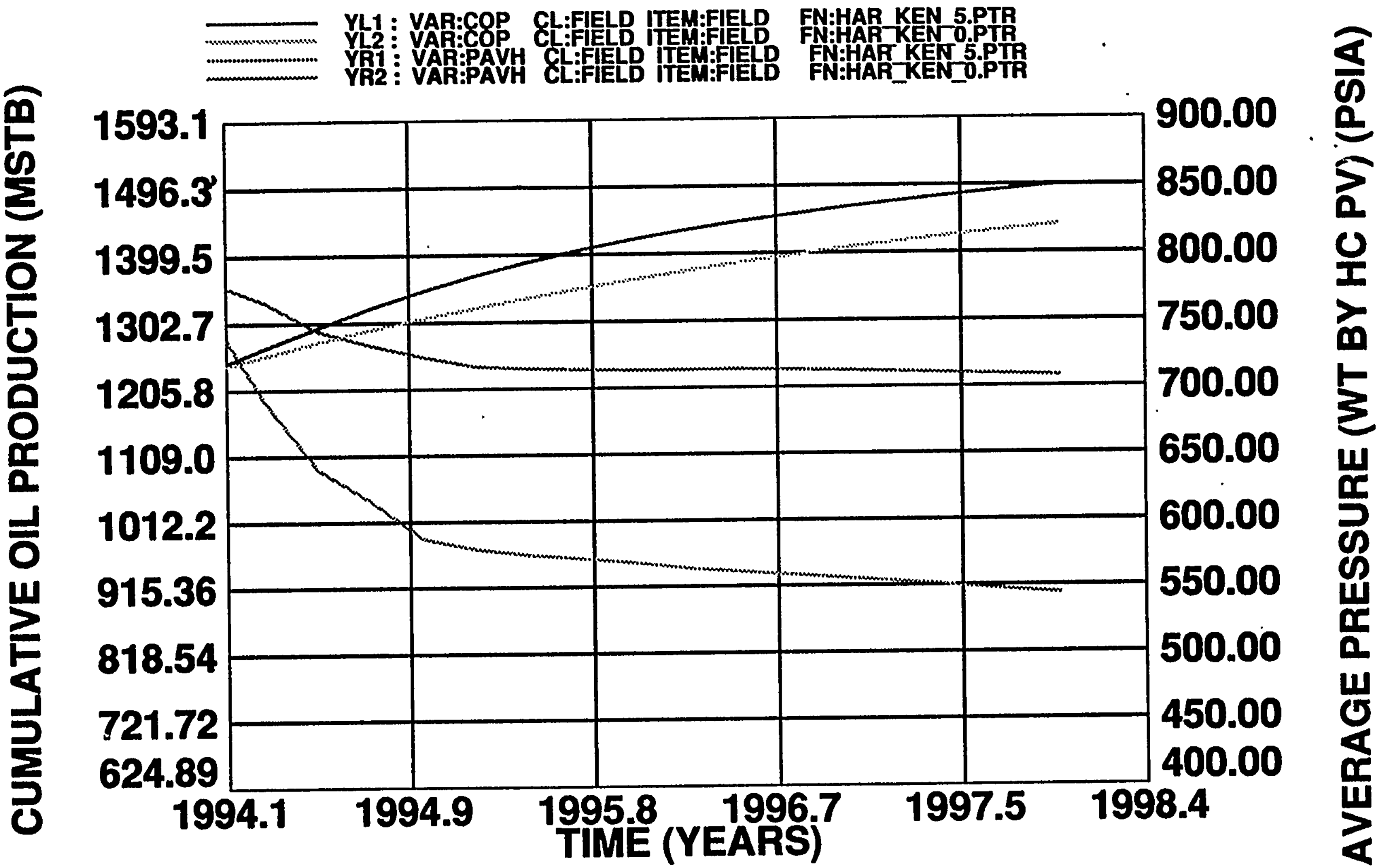
Case 2 vs. Case 0



~~HAR-KEN OIL CO.~~
~~DIVINE UNIT~~ FORECAST
~~HEBBARDSVILLE~~ FIELD
~~CASE 2: FIGURE 1~~

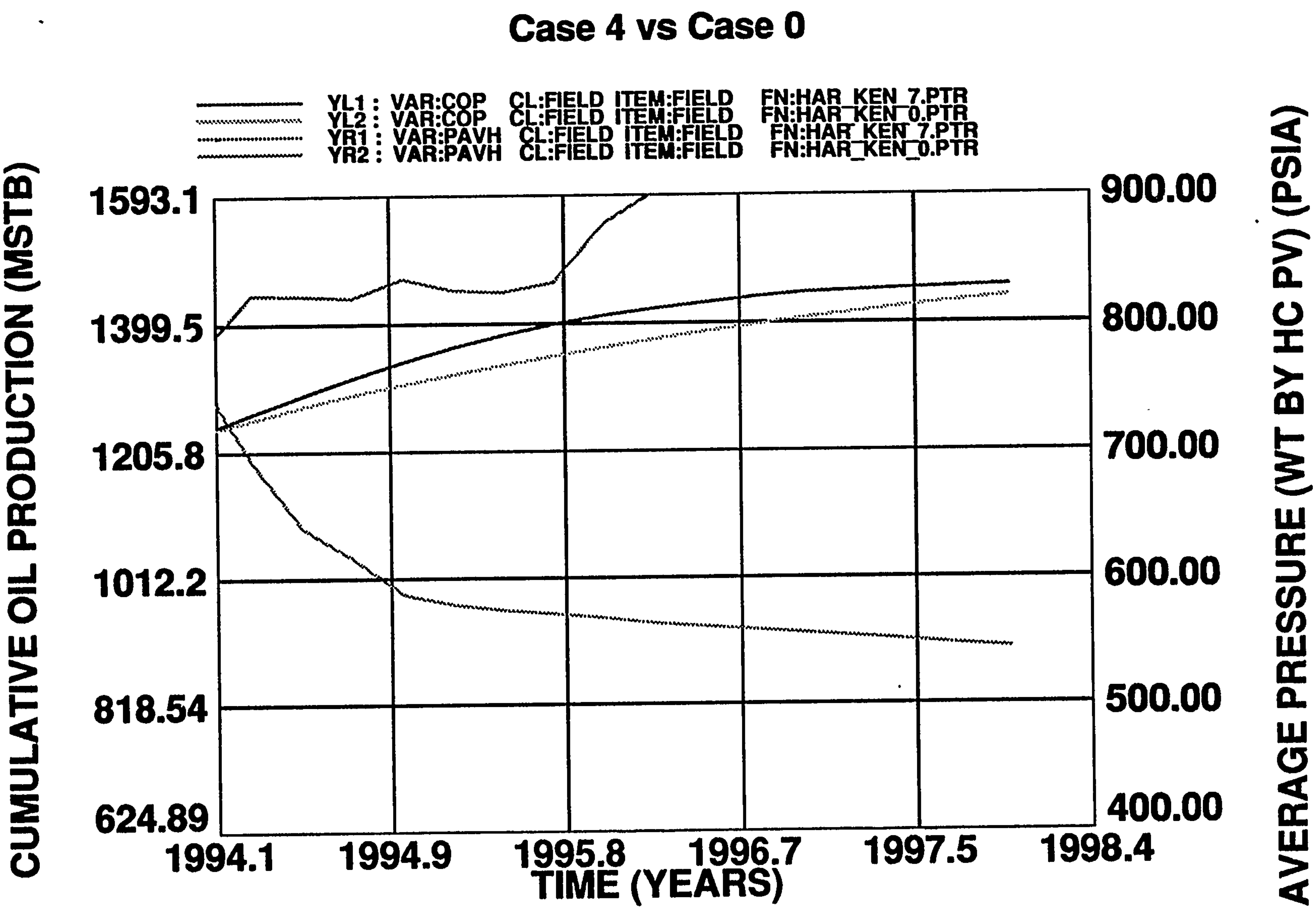
FIG 4

Case 3 vs. Case 0



~~HAR-KEN OIL CO.~~
~~DIVINE UNIT FORECAST~~
~~HEBBARDSVILLE FIELD~~
~~CASE 3: FIGURE 1~~

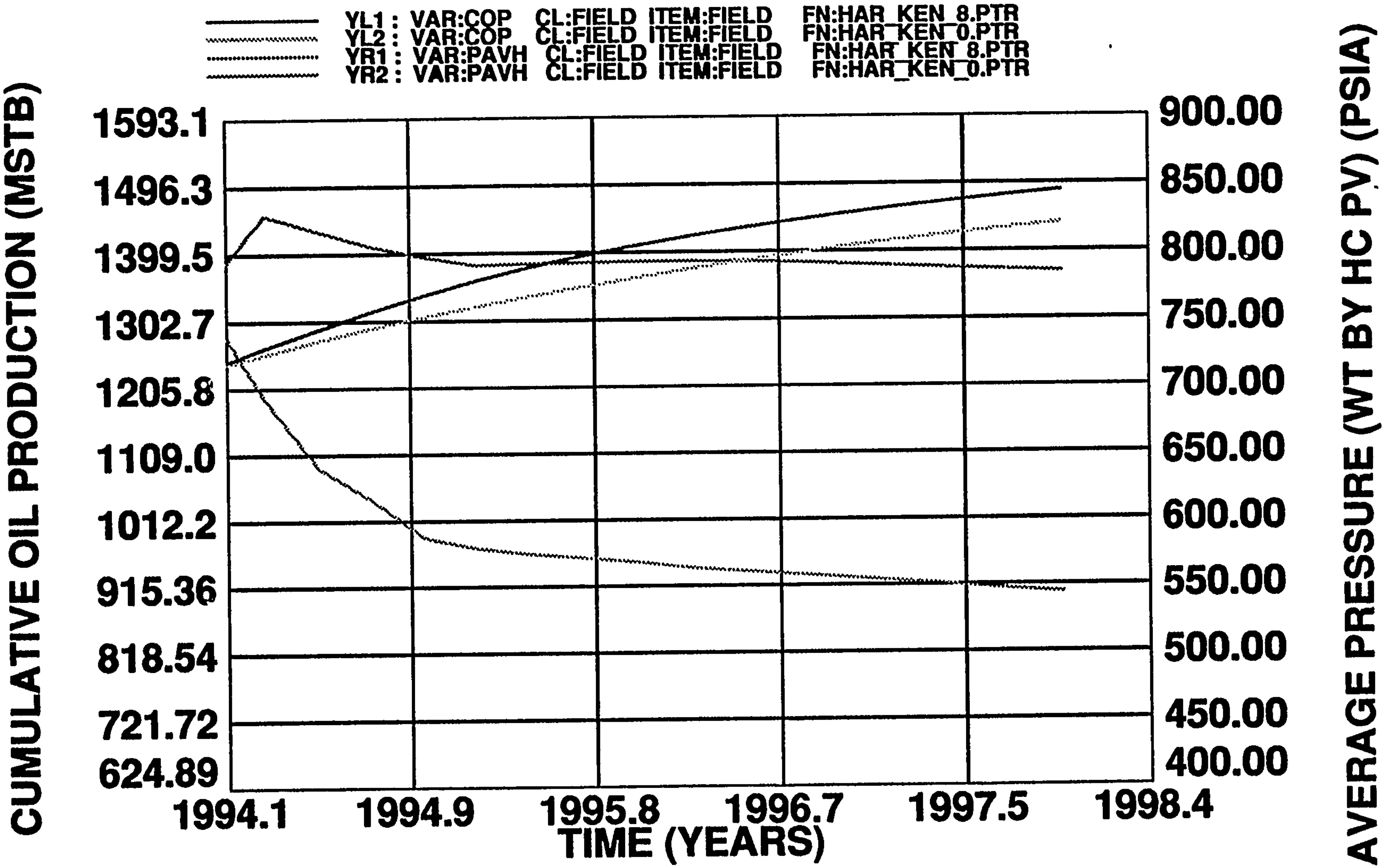
FIG 5



~~HAR-KEN OIL CO.~~
~~DIVINE UNIT FORECAST~~
~~HEBBARDSVILLE FIELD~~
~~CASE 4: FIGURE 1~~

FIG 6

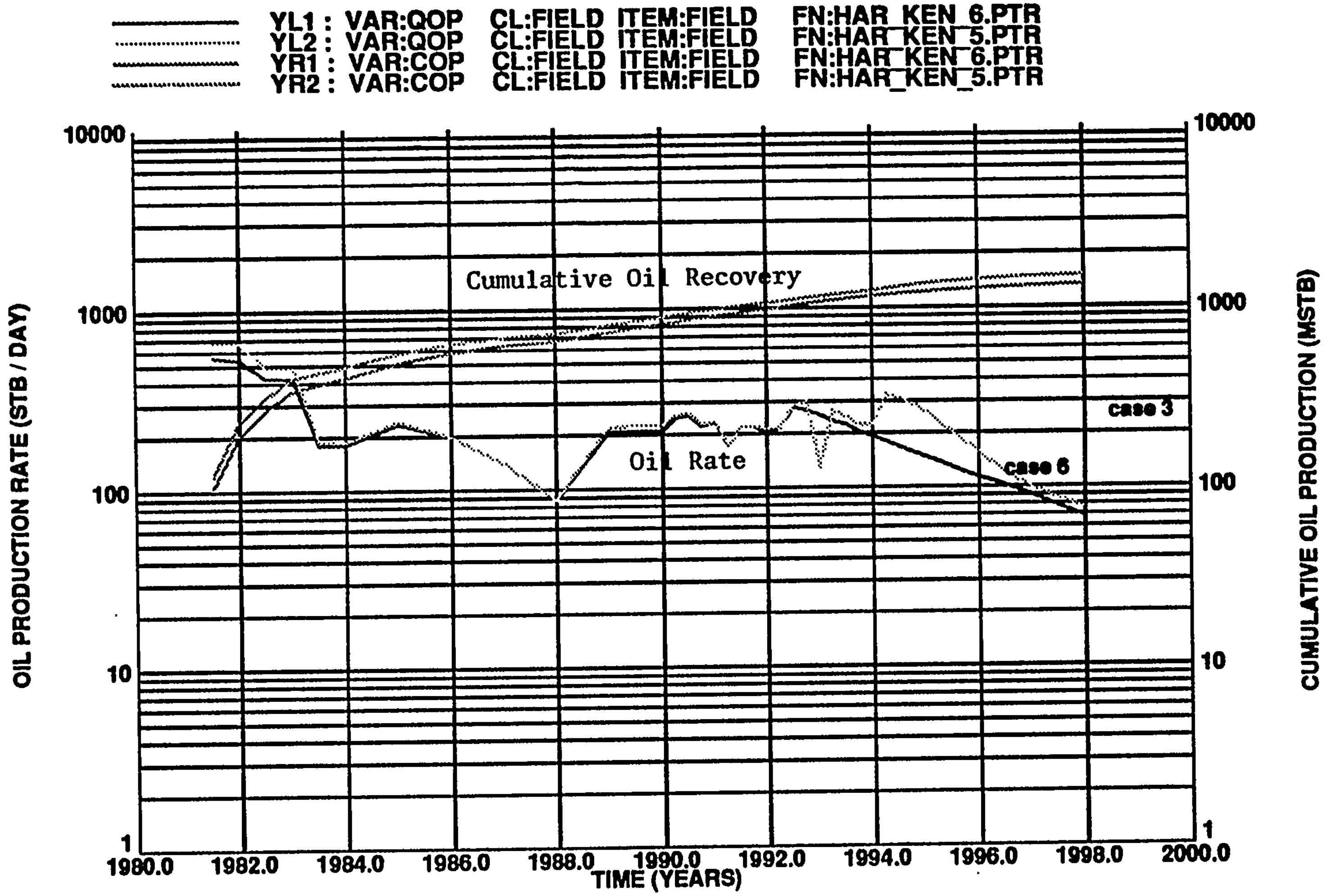
Case 5 vs. Case 0



~~HAR-KEN OIL CO.~~
~~DIVINE UNIT FORECAST~~
~~HEBBARDSVILLE FIELD~~
~~CASE 5: FIGURE 1~~

FIG 7

Har_ken Case 6

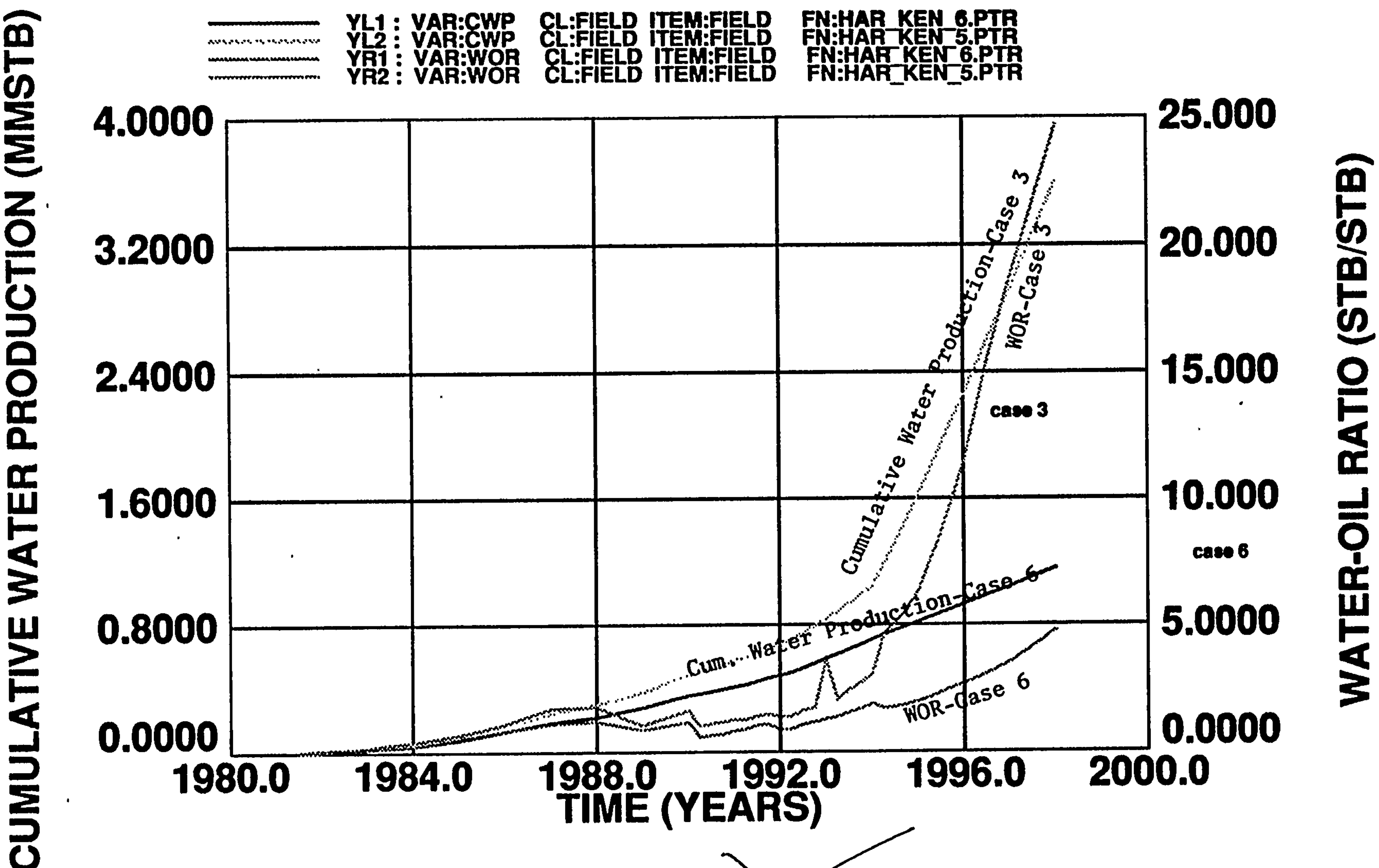


HAR-KEN OIL CO.
DIVINE UNIT FORECAST
HEBBARDSVILLE FIELD
CASE 6: FIGURE 2

FIG 8

?? one comparing case 6 + case [illegible] on lin-lin?

Case 6 vs. Case 3



~~HAR-KEN OIL CO.~~
~~DIVINE UNIT FORECAST~~
~~HEBBARDSVILLE FIELD~~
~~CASE 6: FIGURE 5~~

Fig 9