# INTRODUCTION – GEOLOGY – MODEL CONSTRUCTION

Before the
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 9802 Exhibit No. 7
Submitted By: Marathon
Hearing Date:

## 1. Introduction

The Indian Basin Upper Penn Field is located approximately 20 miles west of Carlsbad in Southeastern New Mexico. The discovery well was J. C. Williamson's Standard Federal No. 1 located in Section 19, T21S, R23E, and completed in January 1962. The well missed the dolomite and was completed in the limestone. The second well in the field and first well to be completed in the Upper Penn dolomite was Ralph Lowe's Indian Basin Gas Commission No. 1 in Section 23, T21S, R23E. This well was completed in October 1962, as a dual Upper Penn-Morrow well.

During data gathering for the present simulation project, it was found that the total number of wells completed in the Upper Penn was 61. Some 80 to 90 other wells were drilled in the area which were completed in other formations or proved to be dry. By October 1, 1988, which represents the final date of history matching, the figures for field daily production rate and cumulative production were 91.0 MMSCF and 1.15 TSCF, respectively. These included condensate volumes as an equivalent volume of gas.

Gas produced from the field is sold to two pipeline companies, Southern Union and Natural Gas Pipeline, with Southern Union's take amounting to between 5% and 10% of total production. All gas sold to Natural Gas Pipeline is processed through the Marathon operated Indian Basin Gas Plant in which Marathon has a 20% interest. All of Marathon's reserves are dedicated to the Natural Gas Pipeline under a gas contract having a DCQ of 165 MMCFPD with a 25% swing.

## 2. Geology

This section focuses on the geological characteristics of the Upper Penn reservoir which affect fluid flow. A more detailed geological discussion may be found in the December 1972 Indian Basin Upper Penn Field report from which parts of the following discussion were obtained.

The Upper Penn section, occurring at a depth of about 7500 ft., consists of approximately 85% carbonates. Within the productive limits of the reservoir 80% to 90% of the carbonates are dolomite and the remainder are limestone which appear at the base or top of the section.

As may be noted from structure maps of the Upper Penn dolomite, the reservoir dips in an easterly direction and is bounded on the west by a fault, on the northern and southern extremes by a change of the carbonates from dolomite to limestone, and by a gas-water contact as the dolomite extends northward and eastward.

Zones of shales or shaly carbonate appear throughout the dolomite but probably make up no more than 15% of the total section. In some cases individual shale stringers appear to be correlatable over several miles. It seems likely that the effect of these impermeable zones has been to impede the vertical migration of fluids and cause their lateral movement in the reservoir. The possibility that correlation of these shale stringers would lead to zonation of the reservoir was investigated but no one appears to be continuous field-wide. Also, there is considerable uncertainty in correlating due to the 640 acre well spacing which results in large distances between wells.

Porosity in the dolomite is highly variable ranging from intercrystal pores to vugs and caverns. The extent and frequency of vugular porosity zones is very difficult to determine. However, it was noted in the 1972 report that a strong relationship existed between zones of vuggy porosity and zones of shale or shaly carbonate. Since it appears that some of the shale stringers can be traced for several miles, it is reasonable to expect some continuity of the vugular zones.

## 3. Model Description

All relevant figures have been included in Appendix A.

### I. Grid Details

The grid orientation has been influenced by the presence of the main fault on the west of the field, in the sense that the direction of the Y axis is parallel to that of the fault. The numbers of grid blocks in the X, Y and Z directions are 48, 59 and 8, respectively. Total number of nodes is 22,656 of which 16,648 are active. Figure 1 of Appendix A shows the grid superimposed on the field map. Grid dimensions are as follows:

1. For the squares of the center of the field DX=DY=1000 ft.

2. For the rectangles along the north, east and south sides of the grid either DX=1000 ft and DY=3000 ft. or DX=3000 ft. and DY=1000 ft.

3. For the two squares at the eastern corners of the grid DX=DY=3000 ft.

Values for DZ have been derived by subtracting the depths of the top structure map from those of the base structure map and then dividing the derived isopach thicknesses by 8. Selection of the aforementioned grid reflects an attempt to minimize computer running time and costs without compromising on accuracy.

## II. Geological Input

Porosity input has been generated by contouring the available thickness averaged porosity values and then digitizing the maps. NTG input has been generated similarly by dividing the difference between the gross isopach and total shale thickness by the gross isopach thickness and then contouring the values and digitizing the maps. Horizontal permeability values have been generated from the porosity input by means of the following correlation:

$$\log k = 0.10224344\ \phi - 0.212173$$

where $\phi$ is porosity expressed in percent units and k is permeability expressed in md. The aforementioned correlation has been derived from the conventional core analysis reports of wells North Indian Basin Well 1, North Indian Basin Well 2, North Indian Basin Well 3 and Indian Basin A Well 1. Vertical permeability being one of the history matching parameters has been assigned the same values as horizontal permeability.

It should be stressed in passing that description of the reservoir as a single porosity system is a gross simplification given that core inspection and core floods have demonstrated that the bulk of fluid movement occurs in the vugs and caverns. In other words the system appears to be similar to that of naturally fractured reservoirs with small or zero matrix porosity. The compromise has been dictated by the lack of detailed geological studies, well testing and open hole and production logging.

## III. Datum Pressure – Reservoir Temperature – Gas Water Contact (GWC)

The model has been initialized by assigning a pressure of 2930 psia to a subsea depth of 3640 ft. Average reservoir temperature is 146° F. The original gas water contact has been set at a depth of 3770 ft. ss.

## IV. Relative Permeability and Capillary Pressure Curves

Due to a complete lack of special core analysis data, saturation functions were derived at the E&PT laboratories. The gas and water relative permeabilities were measured during drainage flooding of matrix cores. The brine used contained 1% $NH_4Cl$, and the displacing gas was helium. Imbibition experiments involving brine and gas are virtually impossible. Measurements had to be adjusted so that the values of connate water saturation $S_{wc}$ and irreducible gas saturation $S_{gr}$ were 25.0% and 26.7%, respectively. This was carried out by normalizing and denormalizing saturations. The $S_{wc}$ value of 25% was adopted from R. J. Duenckel's 1976 report and the $S_{gr}$ value of 26.7% from the in-house core floods.

Capillary pressure curves were derived also by using 1% $NH_4Cl$ brine. The curve input in the model was chosen by:

- Calculating an average porosity figure for the field

- Calculating a permeability figure by means of the established correlation

- Using Leverett J functions to adjust the capillary pressure values of the sample which had a $k/\phi$ ratio closest to the average for the field to represent reservoir conditions.

We would like to reiterate that all aforementioned parameters apply to matrix cores and not to vugs and caverns. They were introduced to the model as initial guess parameters subject to changes during history matching and fortunately have performed well.

V. Rock and Fluid Properties

Rock compressibility was assigned the value of 17.17E-6, which was based on data quoted in the special core analysis of Indian Basin A Well 2. Testing was carried out by Core Laboratories.

Because condensate production was relatively low, it was decided to characterize the reservoir hydrocarbon as gas. Thus, the total well stream composition was used to calculate values for gas density, critical temperature and critical pressure, which in turn were used to generate values for gas formation volume factor and viscosity. Computations were based on the well stream composition of Indian Basin E Well 1.

Water formation volume factor and viscosity figures were calculated from existing correlations for a chloride content of 40,000 ppm.

VI. Well Input – Production Rates

For each well, subsea completion depths were calculated by subtracting the KB elevation from the measured depths of the top and bottom of the perforations. In each well block, perforations were assigned a kh figure which was equal to the product of permeability times the actual length of the perforations within the block.

Condensate production rates were converted to equivalent gas rates by using the formula.

$$GE = 133{,}000\ \gamma_o/M_o\ \text{SCF/STB}$$

where: GE was the gas equivalent of 1 stb of oil in scf, $\gamma_o$ was the specific gravity of oil (water = 1.00) and $M_o$ was the molecular weight of oil. The resulting figures were then added to the respective gas rates. For wells for which production data were not available prior to January 1970, but only cumulative production through January 1970, it was assumed that production from completion date to January 31, 1970, was at constant rate and daily rates were calculated accordingly.

—— FIELD BOUNDARY

- - - - - PARTIAL BOUNDARY TO FLOW

MARATHON OIL COMPANY
E&PT

INDIAN BASIN

UPPER PENN RESERVOIR

5

OCTOBER 1, 1988

RATES

| | | |
|---|---|---|
| NIBU1 | 1927 | MSCF/D |
| NIBU4 | 2677 | |
| NIBU5 | 178 | |
| WIBU1 | 914 | |

CUMULATIVES

| | | |
|---|---|---|
| NIBU1 | 24106 | MMSCF |
| NIBU4 | 27584 | |
| NIBU5 | 23021 | |
| WIBU1 | 30328 | |

MIGRATION 1888750 MSCF

DECEMBER 31, 2050

| | ORTHODOX LOCATION | | | UNORTHODOX LOCATION | | |
|---|---|---|---|---|---|---|
| RATES | | | | | | |
| NIBU1 | SI | MSCF/D | | SI | MSCF/D | |
| NIBU4 | 537 | | | 482 | | |
| NIBU5 | 165 | | | 256 | | |
| WIBU1 | 114 | | | 110 | | |
| CUMULATIVES | | | | | | |
| NIBU1 | 49540 | MMSCF | | 48027 | | |
| NIBU4 | 61842 | | 125.502 | 59571 | | 128.816 |
| NIBU5 | 14120 | | | 21218 | | |
| WIBU1 | 41902 | | | 41740 | | [illegible] |
| MIGRATION | 9300492 | MSCF | | 8029839 | | |

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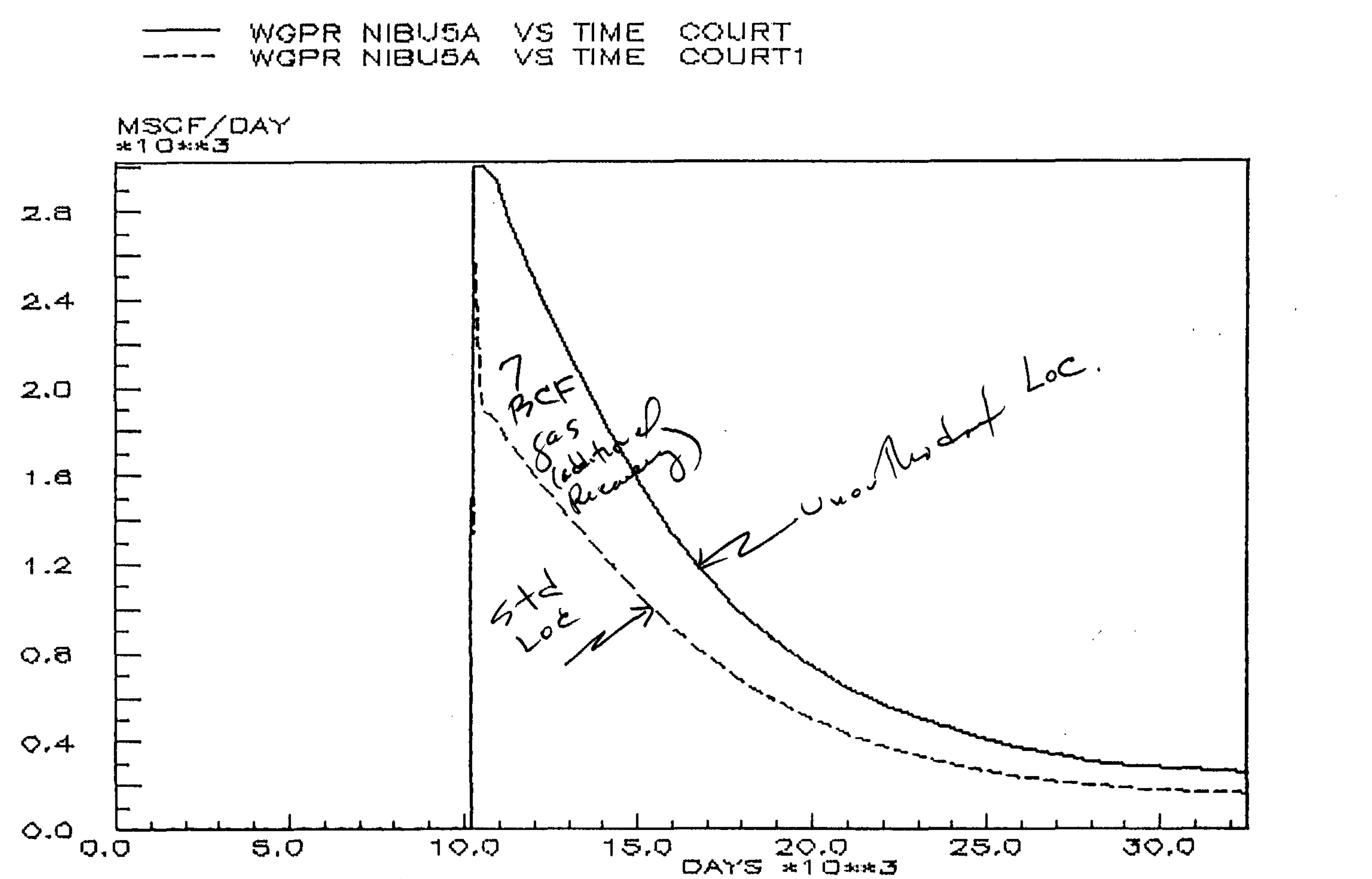


FIG.1 WELL NIBU5A GAS PRODUCTION RATE, YEARS 1962 TO 2050

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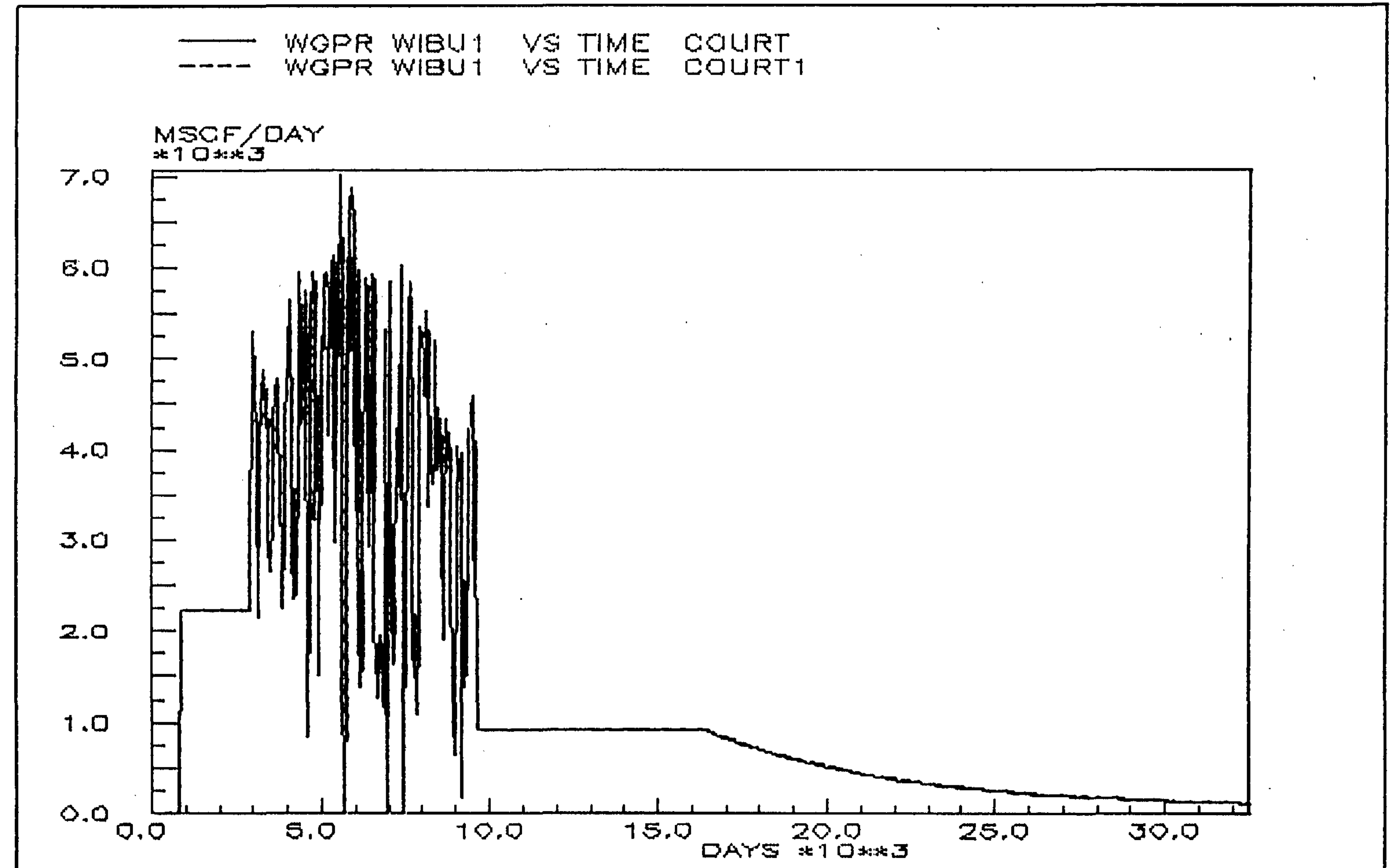



FIG.1 WELL WIBU1 GAS PRODUCTION RATE. YEARS 1962 TO 2050

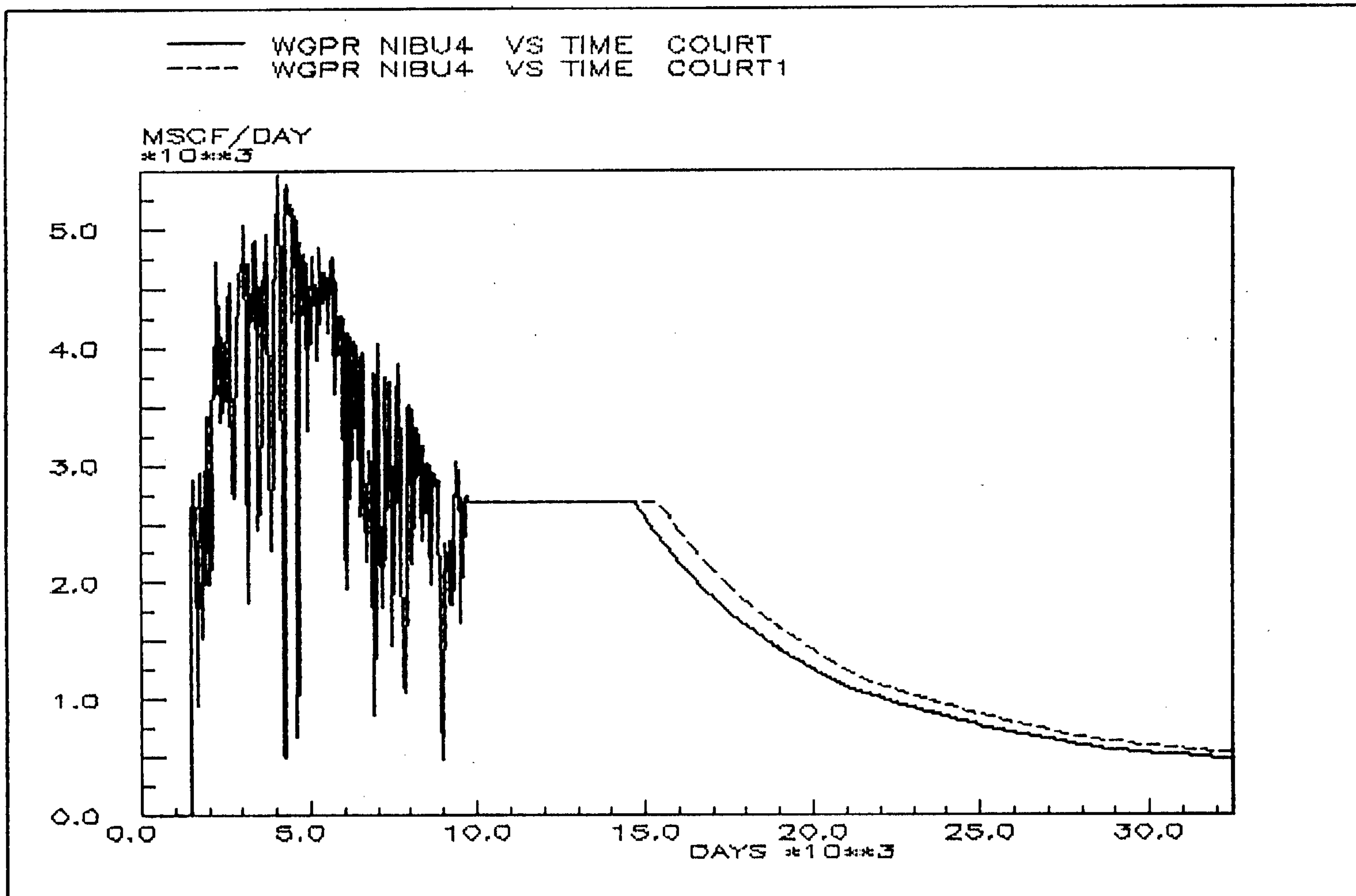



FIG.1 WELL NIBU4 GAS PRODUCTION RATE. YEARS 1962 TO 2050

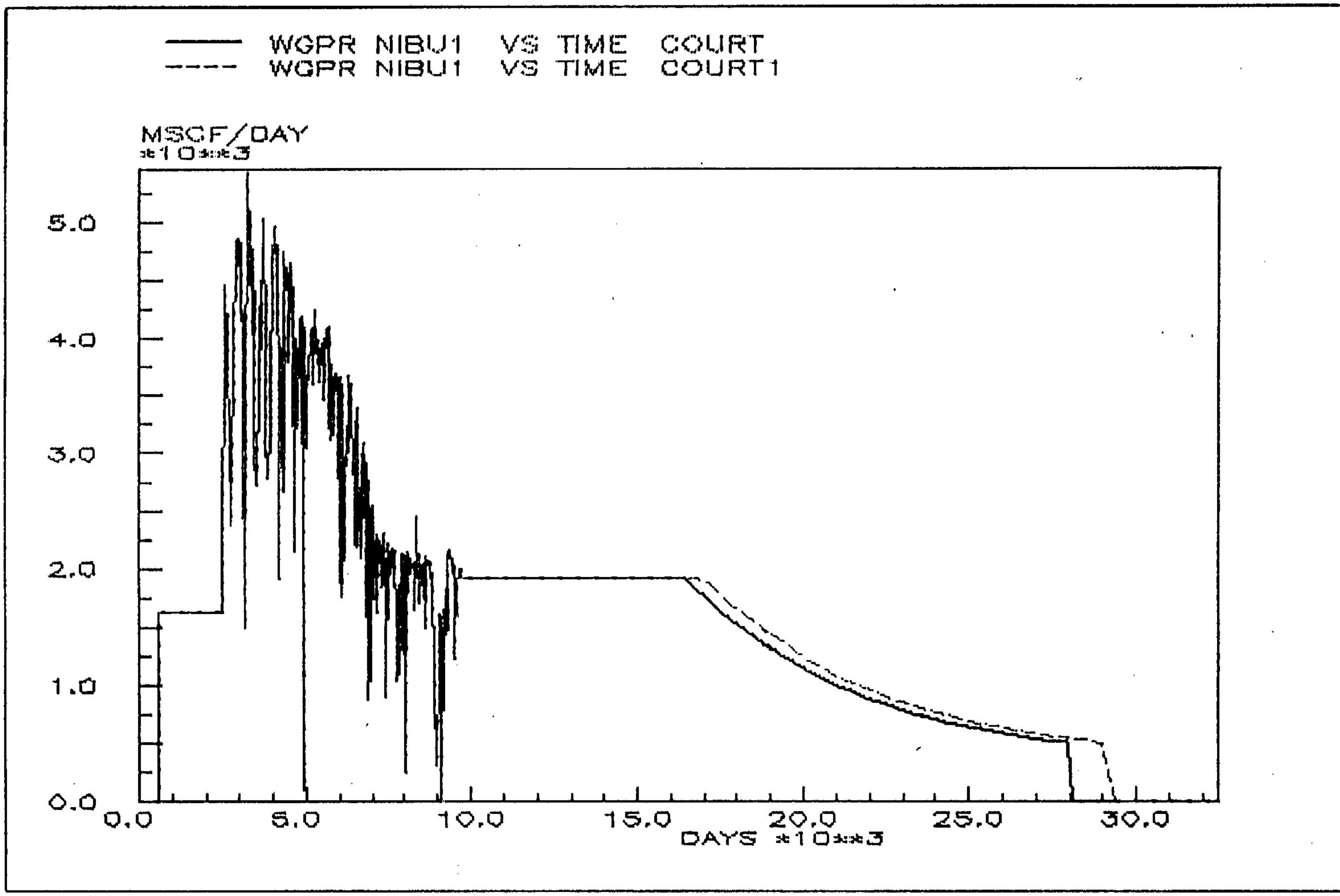
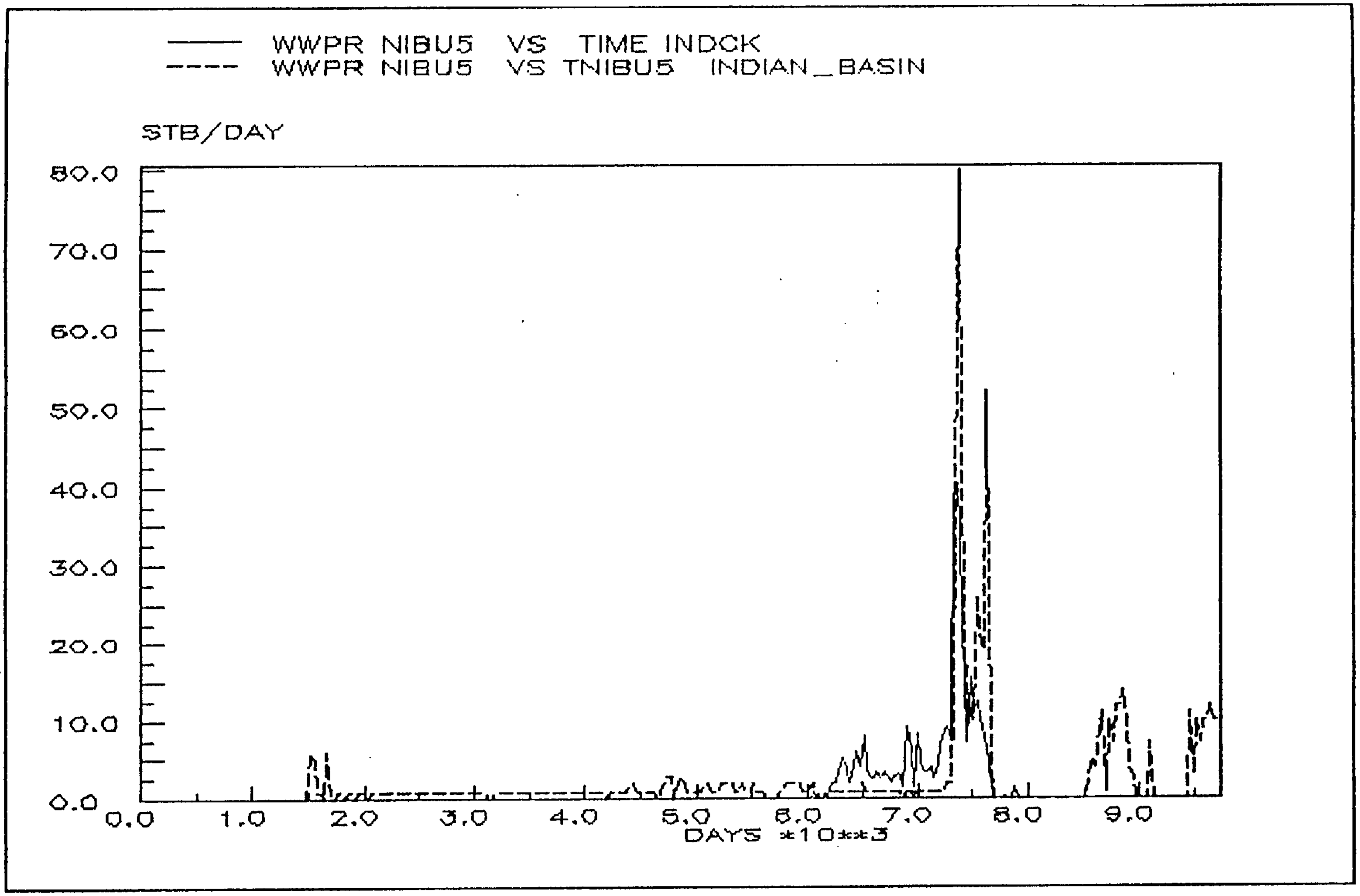
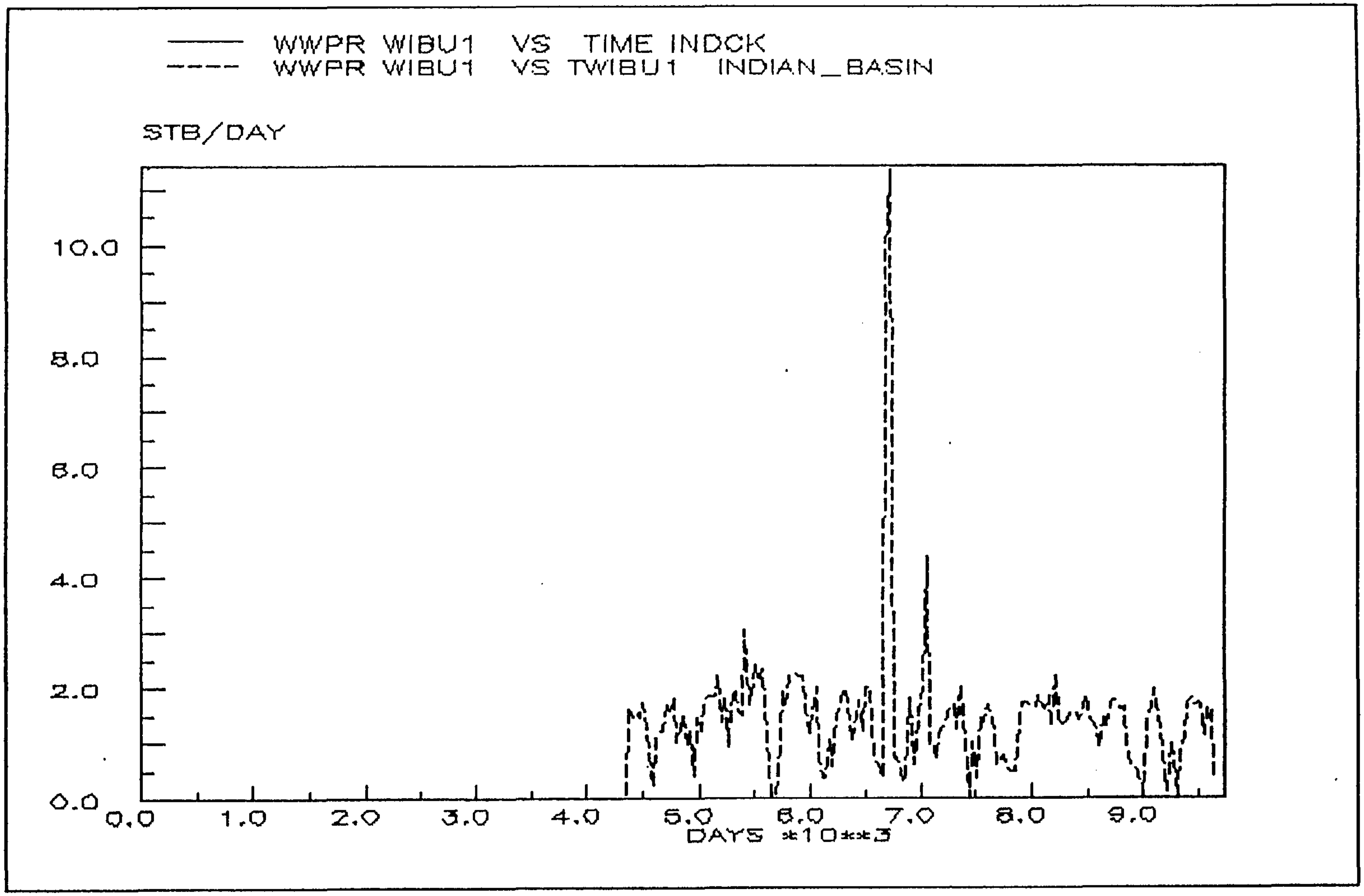



FIG.1 WELL NIBU1 GAS PRODUCTION RATE, YEARS 1962 TO 2050



WELL NIBU5 WATER RATE. MODEL RESULTS AND FIELD DATA

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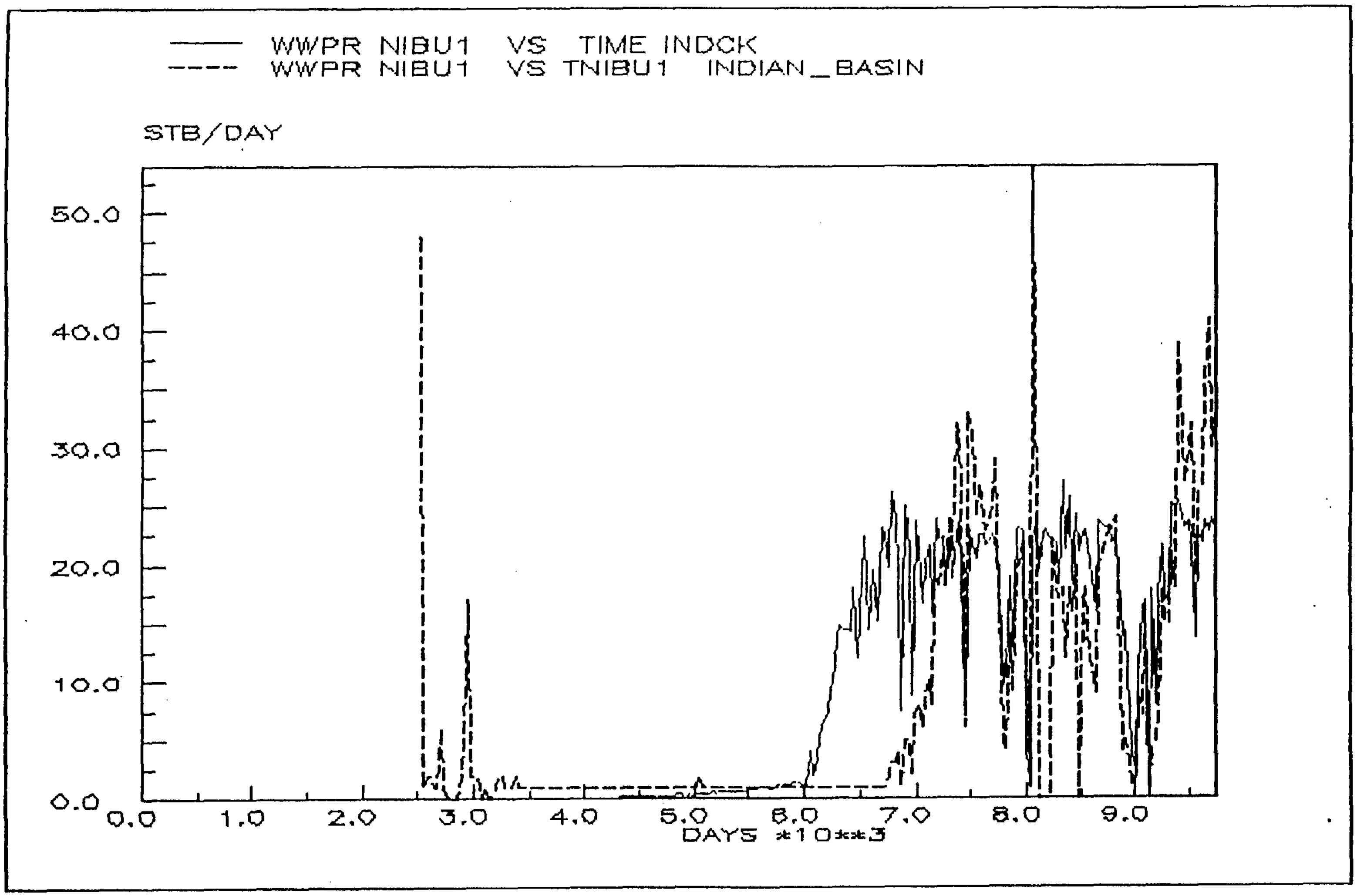
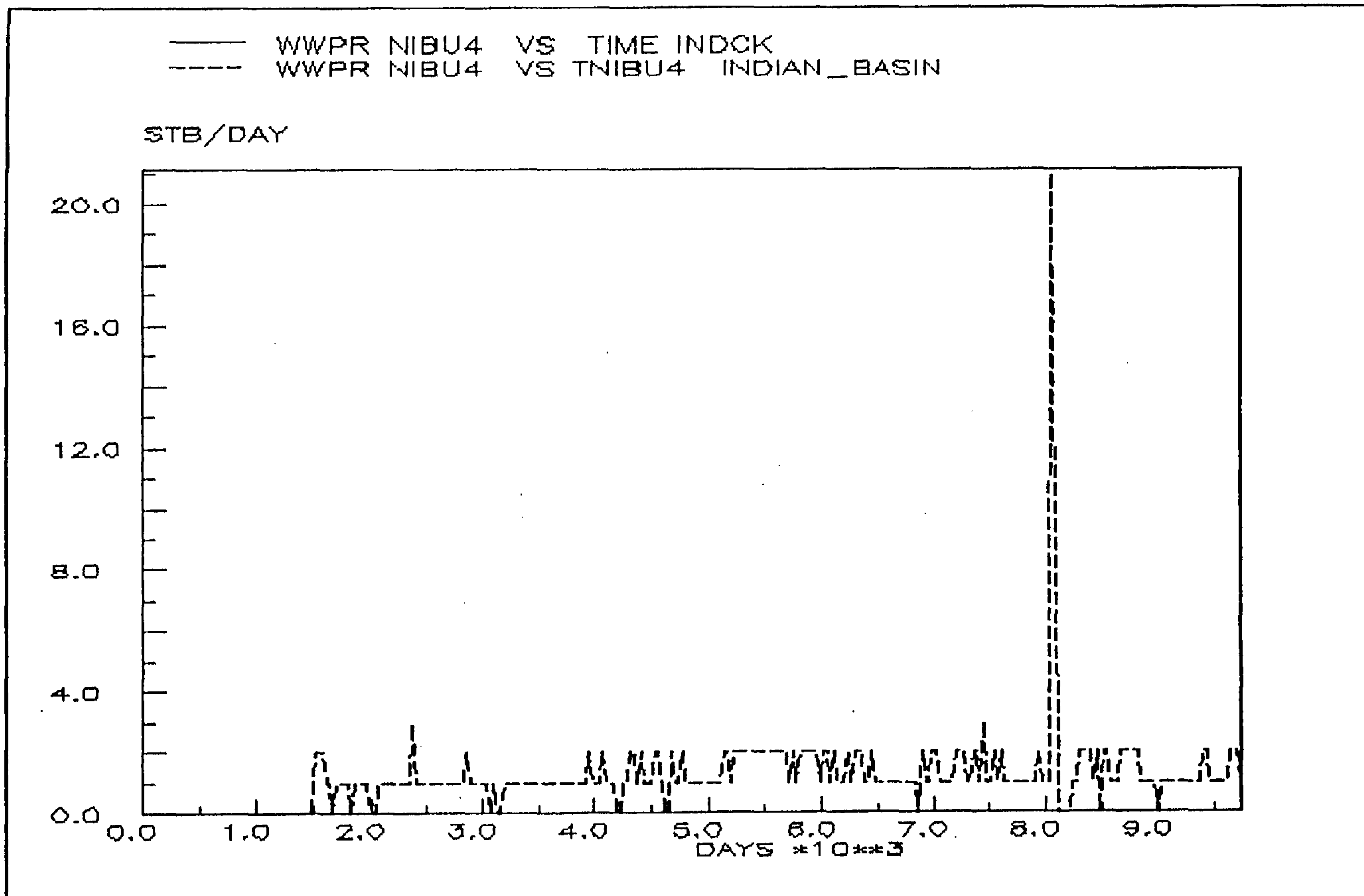



WELL NIBU1 WATER RATE. MODEL RESULTS AND FIELD DATA

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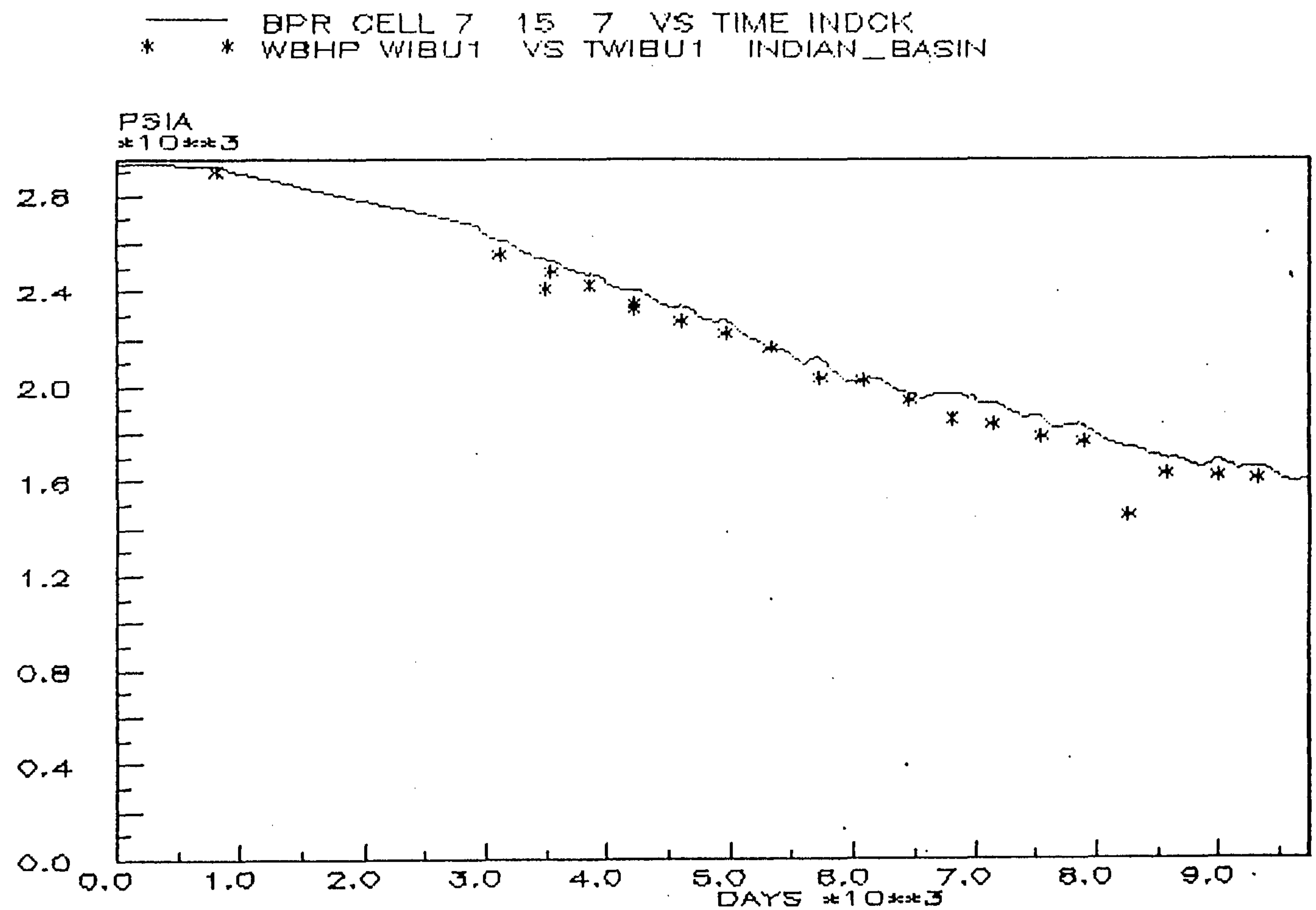
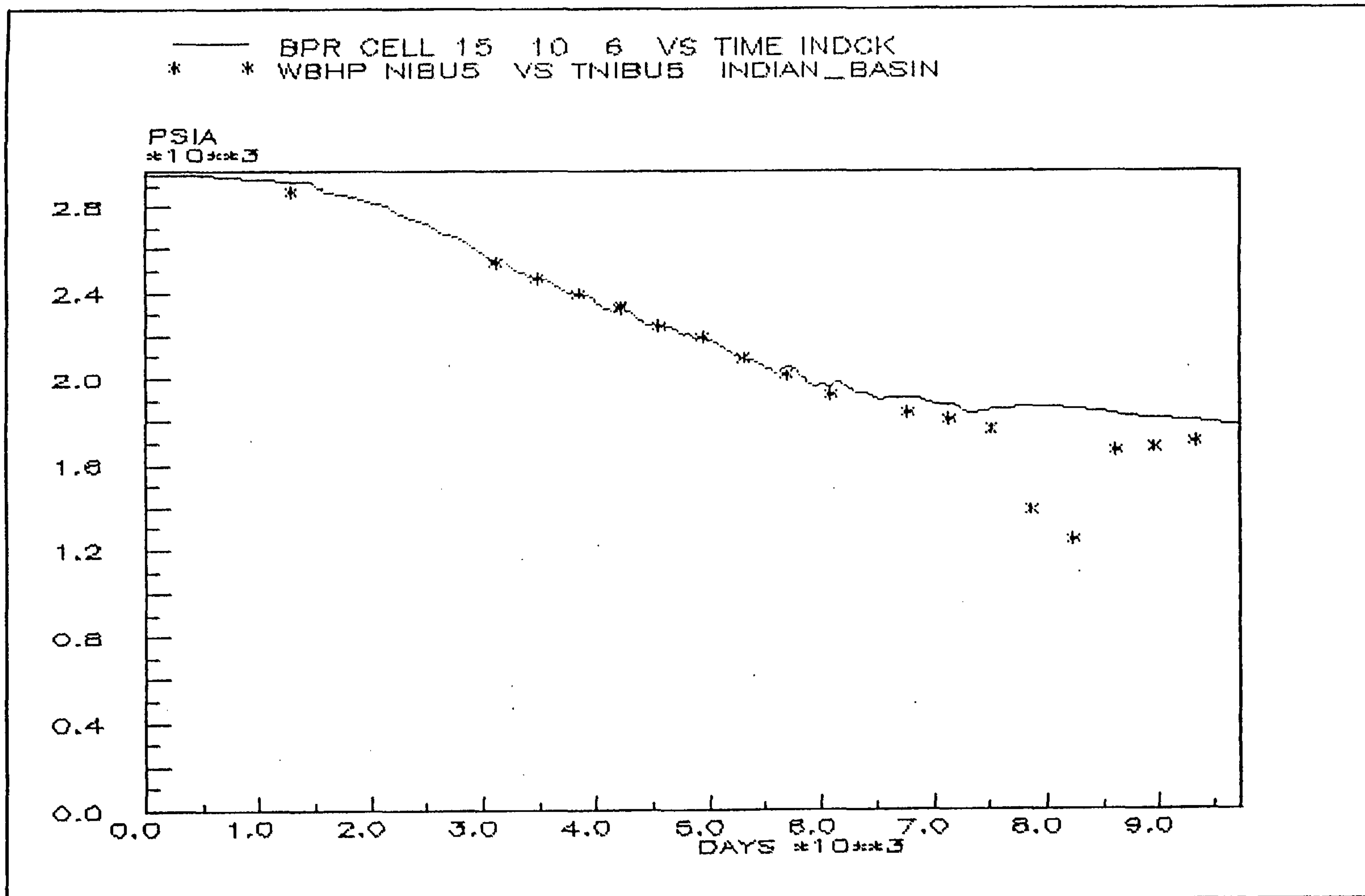



WELL WIBU1 RES. PRESSURE. MODEL RESULTS AND FIELD DATA. Sec 17

Western Indian Basin Unit #1

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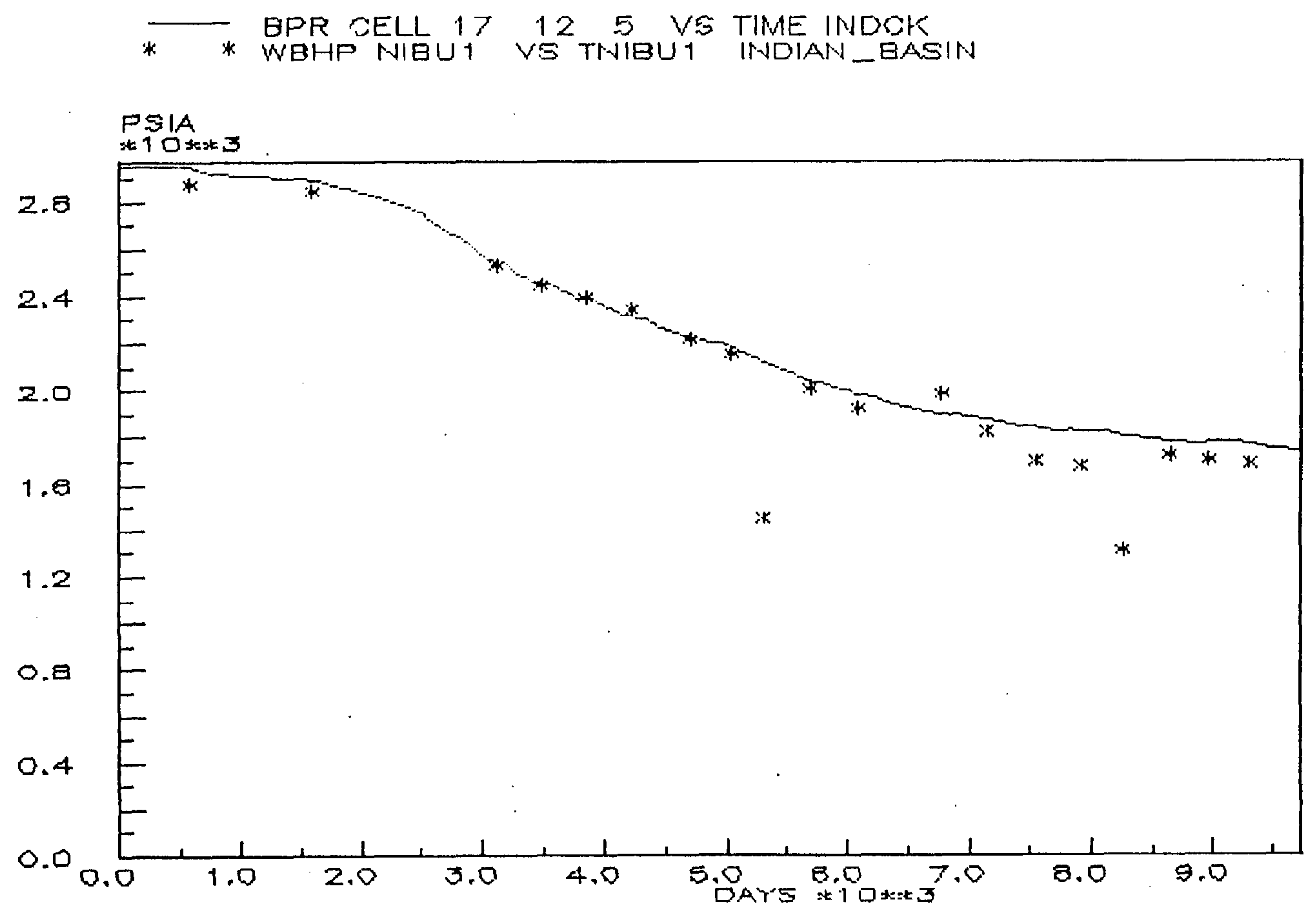


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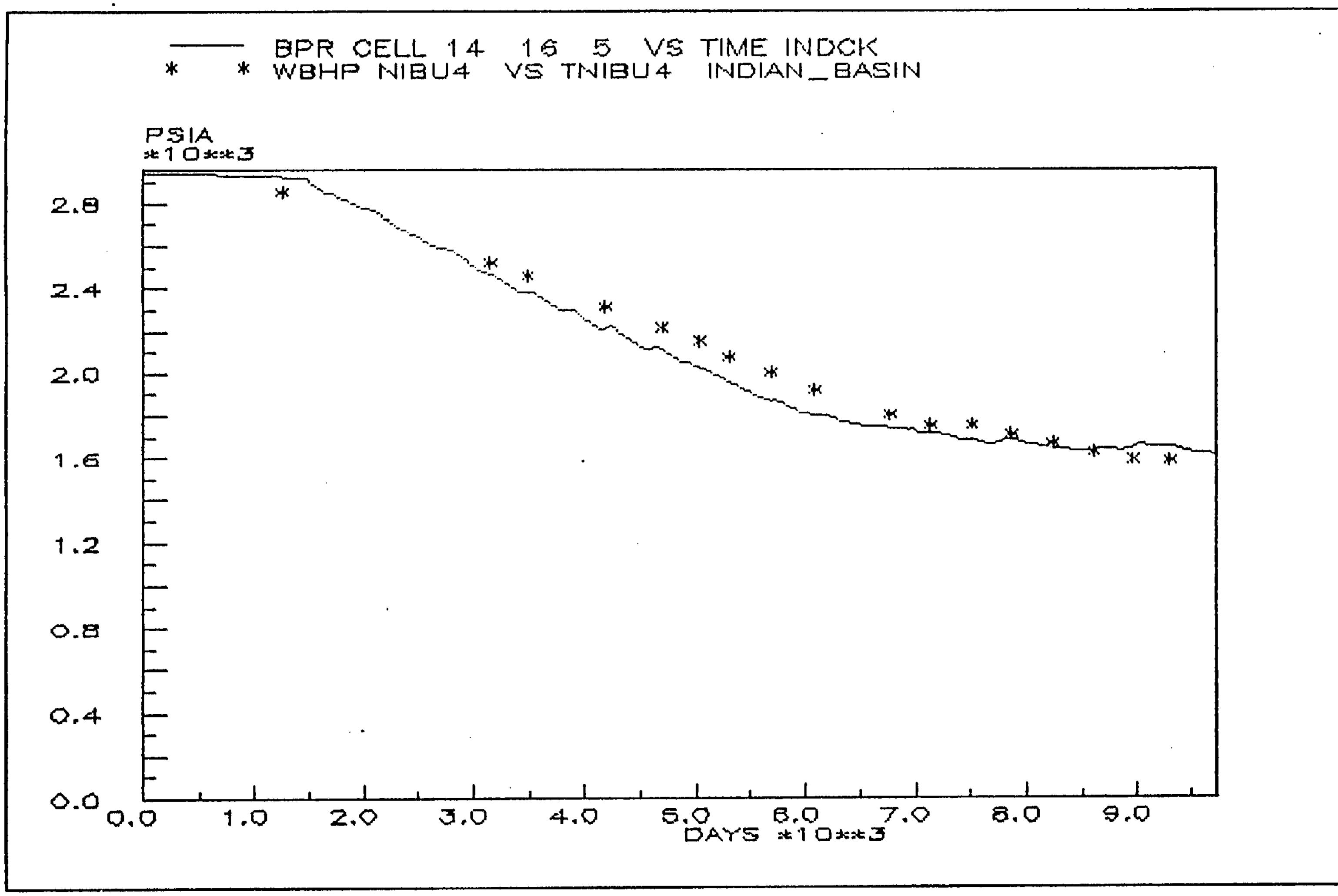


WELL NIBU4 RES. PRESSURE. MODEL RESULTS AND FIELD DATA.