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CHERNE FIELD ARTIFICIAL LIFT SYSTEM

by

Glauco Barbosa de Andrade

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Golden, Colorado

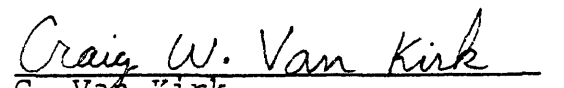
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ABSTRACT

An analysis for the best artificial lift system for the Cherne field, offshore Brazil is presented. Gas Lift, Electric Submersible Centrifugal Pumping and Hydraulic Pumping were evaluated using Orkiszewski correlations for multiphase flow.

The field is located 73 km from Rio de Janeiro coastline, the oil-in-place is estimated to be $59 \times 10^6 \text{m}^3$ and a total recovery factor of 35% is expected.

The utilization of two platforms for the development of the field was chosen. Twenty-eight oil producing and eleven water injection wells are to be drilled.

A discussion is presented and the selection of electric submersible centrifugal pumping as the artificial lift system is recommended.

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1. INTRODUCTION

The present paper studies the viability of oil exploitation in the Cherne's offshore field, in Brazil, plans the development of the wells in the area, applies the concepts of vertical, horizontal, and directional flow and determine the best artificial lift method for these offshore wells.

Using all the data and available knowledge of the area to date, the technical viability of the installation of one or two fixed production platforms was studied.

The oil in place is estimated at 56×10^6 cu. meters, or 352×10^6 STBO, for the Namorado sandstone located approximately 3,000 meters deep. The Carapebus sandstone, averaging 2,700 meters deep, has an estimated oil in place of 2.8×10^6 cu. meters, or 17.6×10^6 STBO. All this was obtained from a reservoir study recently completed by Luiz Carlos Cabral et al for PETROBRAS.

2. DESCRIPTION

The first drilled well in the area, 1-RJS-25, shown in Figure 1 produced from the Carapebus sandstone. The gas flow rate was $23 \times 10^6 \text{ m}^3/\text{d}$ (open flow test), the condensate ($150 \text{ m}^3/\text{d}$, 60° API) and oil ($481 \text{ m}^3/\text{d}$, 26° API). The total sandstone thickness was approximately 100 m, with 14 m hydrocarbon saturated. In this well, the Namorado sandstone was water bearing.

The second well drilled in the area was the 4-RJS-34 located 1400 m northeast from the pioneer as shown in Figures 1 and 2. The Namorado sandstone was discovered to be 76 m thick with 54 m net oil pay. The oil was 20° API with $35.5 \text{ m}^3/\text{m}^3$ gas oil ratio. The Carapebus sandstone had 7.5 m oil net pay, 26° API and $40 \text{ m}^3/\text{m}^3$ gas oil ratio.

In the 1-RJS-50, the Namorado sandstone, 85 m thick, was totally oil productive. This sandstone was perforated over an interval of 10 m and the oil flow rate was $470 \text{ m}^3/\text{d}$ with a productivity index of $13 \text{ m}^3/\text{d}/\text{kg}/\text{cm}^2$. This well has a much higher structural position than the 4-RJS-34.

The 3-RJS-59 was drilled intending to establish the south boundary of the field. A 16 m layer of oil was located. This small thickness of the Namorado sandstone appears to be close to the reservoir boundary.

The 1-RJS-17 (Figure 1) in the Carapebus sandstone layer was oil productive ($425 \text{ m}^3/\text{d}$, 26° API), having 8 m oil net pay within the 32 m thick section.

The 3-BG-2 produced $378 \text{ m}^3/\text{d}$ in a flow rate test from the Carapebus. The upper layer (20 m) was gas saturated, but the productivity was not estimated. The Namorado had 20 m of oil in a 30 m total thickness.

The ocean water depth increases from 100 m to 150 m south-southeast, from BG-2 to 1-RJS-25.

3. DISCUSSION AND ADDITIONAL TECHNICAL DATA

3.1 Geology-Geophysics

3.1.1 Namorado Reservoir

Structural Considerations: The top of Namorado sandstone on the seismic structural maps show a system of faults with a northwest-southeast principal direction, with layers dipping to the west, until a big fault with a north-south direction is reached.

The studied area presents the shape of an elongated, well defined, dome structure, north-south directed, having as a south boundary the area of the 1-RJS-24 and as a north boundary the BG-2.

Locally, there is a fault between 1-RJS-50 and 4-RJS-34, the latter being at the apex of the structure, and the former at the southeast flank, by the fault forming one of the boundaries of the accumulation.

The Bagre structure, at the Namorado sandstone level, takes shape like a block limited by faults to the east, west and south, the south-fault being the separation between the Bagre structure and the 1-RJS-50 structure.

One accumulation area is shown in Figures 2 and 3, which are the Namorado isopach map and the Namorado structural map, respectively.

3.1.2 Carapebus Reservoir

Structural Considerations: The structural map (Figure 4) depth, for the Carapebus sandstone shows an elongated dome appearance, having a north-south direction similar to the Namorado sandstone.

Isopach maps for the Carapebus Reservoir are shown in Figures 5, 6, 7 and 8.

3.2 Drilling and Production

3.2.1 Data Used (Namorado sandstone)

Petrophysics Data: The rock data were obtained from well logs in the field. The 1-RJS-50 was cored from 2897.3-2912.5 m, giving an average porosity of 24 percent and an average permeability of 660 md. Water saturation, porosity and permeability were also obtained by production tests and drill stem test. The petrophysics characteristics of the reservoirs discussed in this paper are shown in Table 1 and were determined after log and drill stem test interpretations.

Fluid Analysis: The P.V.T. data represent the variation of properties of the fluid as a function of the pressure variation at the reservoir temperature.

A fluid sample from the 1-RJS-50 used for the Namorado reservoir is shown in Table 2.

By analysis I concluded:

- 1) In terms of vertical flow, the oil does not have good properties because of the high viscosity and low API gravity.
- 2) The reservoir showed a high level of under-saturation. The initial pressure was 315 kg/cm^2 at 3080 m and the saturation pressure of only 132 kg/cm^2 .
- 3) The low gas solubility ($35.5 \text{ m}^3/\text{m}^3$ or 200 SCF/bbl) will result in a short flowing time.
- 4) The oil viscosity at the saturation pressure of 4.83 cp indicates that the flow in the formation will meet some difficulty. Water injection will not be too successful due to this viscosity and the water fingering that will occur.

Values of additional data will be shown in paragraph 3.2.7.

3.2.2. Maximum Range of the Directional Wells from the Platform

For directional wells 40° was adopted as the maximum angle from the vertical. This limits the horizontal radius of investigation of wells to 1900 m (to the top of the Namorado sandstone (-2,865 m)) from the platform.

Example of a Drilling Program: A typical drilling program for a vertical well in the area is the same as in Table 3.

The average penetration rate expected for one well in this area is 60 m/d. Total depths of 3600 m and 3400 m for the wells from platforms of CHERNE-1 (PCH-1) and CHERNE-2 (PCH-2), resulting in 70 and 65 days respectively to drill the wells. Tables 4 and 5 show the deviation angle from the vertical for each well, the total depth, the formation net pay expected, the expected productivity index, etc.

3.2.3. Oil in Place, Recoverable Oil and Oil Recovery Factor

An approximate evaluation of the volumes of oil in place, recoverable oil, and the oil recovery factor may be determined using Arps' equations (2) and (3) in the Namorado sandstone in CHERNE's area.

To calculate the oil in place (N), the volumetric equation (1) was used:

$$N = \frac{V_R \times \emptyset \times (1-S_w)}{B_o} \quad (1)$$

N - oil in place (m³ st)

V_R - volume of rock (m³)

∅ - porosity (fraction)

S_w - water saturation (fraction)

B_o - formation volume factor of oil (m³/m³)

with i subscript in the initial pressure and b subscript at the saturation pressure.

For the recovery factor (Fr), the Arps' expression was used for sandstone with and without water drive.

Primary Oil Recovery Factor Without Water Drive (FrP)

$$\begin{aligned} Frp = & (41.815) \times \frac{\phi(1-S_w)}{B_{ob}} \cdot .1611 \times \frac{K}{\mu_{ob}} \cdot .0979 \times \\ & \times (S_w) \cdot .3722 \times \left(\frac{P_b}{P_a}\right) \cdot .1741 \end{aligned} \quad (2)$$

Secondary Oil Recovery Factor with Water Drive (Frs)

$$\begin{aligned} Frs = & (54.898) \times \frac{\phi(1-S_w)}{B_{oi}} \cdot .0422 \times \left(\frac{\mu_{wi}}{\mu_{oi}}\right) \cdot .077 \times \\ & \times (S_w) \cdot .1903 \times \left(\frac{P_i}{P_a}\right) \cdot .2159 \end{aligned} \quad (3)$$

Frp - Primary oil recovery factor to sandstone without water drive below the saturation pressure (percentage).

Frs - Secondary oil recovery factor to sandstone from water drive reservoir in the reservoir initial pressure (percentage).

Rp - Primary recovery to sandstone without water drive below the saturation pressure (m³ st).

Rs - Secondary recovery to sandstone with water drive, from the reservoir initial pressure (m³ st).

K - Effective permeability (Darcies)

μ_o - oil viscosity (CP)

μ_w - water viscosity (CP)

P_i - Initial pressure (Kg/cm²)

P_b - saturation pressure (Kg/cm²)

P_a - abandonment pressure (kg/cm²)

V_r - bulk volume (m³)

A - reservoir area (Km²)

Using as a base the available data from Table 2, the oil in place was calculated using equation (1).

$N_i = 56.4 \times 10^6$ (m³ st) at reservoir initial pressure

$N_b = 55.3 \times 10^6$ (m³ st) at bubble point pressure

$F_{rp} = 15\%$ without water injection

$F_{rs} = 35\%$ with water injection

$R_p = N_b \times F_{rp}$

$R_P = 8.7 \times 10^6$ (m³ st)

Primary recovery calculated here was from the bubble point pressure.

$R_s = N_i \times F_{rs}$

$R_s = 19.7 \times 10^6$ (m³ st)

Secondary recovery calculated was from the initial pressure. It means, the recoverable oil from water drive reservoir was from the original pressure.

After All

$$N_i = 56.4 \times 10^6 \text{ m}^3 \text{ st}$$

$$N_b = 55.3 \times 10^6 \text{ m}^3 \text{ st}$$

3.2.4 Average Production and Number of Wells Estimated

The maximum average production expected per well at the initial phase of natural flow is $700 \text{ m}^3/\text{d}$, with the average productivity index of $\frac{15 \text{ m}^3/\text{d}}{\text{kg}/\text{cm}^2}$. The estimated average production per well during the productive life is $300 \text{ m}^3/\text{d}$. Assuming the volume of recoverable oil is $19.7 \times 10^6 \text{ m}^3$ with pressure maintenance by water injection, using 300 working days per year of oil production (loss of 18% of the year for mechanical reasons) and assuming that only 80 percent of the wells will be active, the time to drain the reservoir, T , is

$$T = \frac{19.7 \times 10^6}{300 \times 300 \times 0.80} = 276 \text{ years}$$

to drain the reservoir with one well. Using a productive life of 10 years, 28 wells will be necessary.

3.2.5 Field Development

From all the results obtained until now, we can say:

- 1) The expected volume of recoverable oil with water injection is $19.7 \times 10^6 \text{ m}^3 \text{ st}$.

- 2) The system needs water injection wells to keep the reservoir pressure as constant as possible for the oil recovery expected.
- 3) Artificial lift should be planned to be installed at the beginning of production.
- 4) The investigation limit radius for a well to reach the Namorado sandstone will be 1900 m and 40 degrees of deviation from the vertical.

Two hypothesis were considered to better drain the field, from the considerations shown above:

Hypothesis A: Draining the area from a fixed platform shown in Figures 9 and 10.

Hypothesis B: Draining the area from two fixed platforms, as shown in Figures 11 and 12.

With the geological-geophysical maps and with a well investigation radius of 1,900 m, the best pattern using one platform is shown in Figures 9 and 10. However, the reservoir will not be totally covered by drilled wells from one platform. The presence of the fault in the central area of the field makes necessary water injection wells to the north of 1-RJS-50. This would not be possible with just one platform. To cover the whole field, two platforms will be necessary. Figures 11 and 12 show the best configuration, making use of Hypothesis B. Using two platforms, besides

the total draining of Namorado sandstone, the BAGRE field (to the north) and the Carapebus sandstone of the area of RJS-34 (to the south) could be included in this system.

Therefore, the Hypothesis B is recommended for the best development of the field.

It is also recommended that the following additional steps be considered:

- 1) During the drilling phase, updating the geological model to determine if changes in the injection wells locations will be needed in order to guarantee an efficient water flood. If a well penetrates water instead of oil in some location, this well should be equipped as an injection well.
- 2) Injecting water at the beginning of the oil production and installing artificial lift in the oil wells.
- 3) In some wells, using dual completions, if possible, for better control of the Namorado and Carapebus reservoirs.
- 4) Complete one well in each platform to produce gas from the Carapebus, supplying the need for gas lift (make-up) and generating electricity to be used mainly in the artificial lift system.

- 5) Completion study is recommended for the oil wells in order to obtain a high initial productivity index.
- 6) Even though an indication of H₂S does not exist, the analysis of the oil of 1-RJS-50 revealed a high content of sulfur. This fact should be given special attention in order to diminish the possibility of corrosion.
- 7) Although the tests of 1-RJS-50 did not show sand production, care is recommended as the Namorado sandstone is soft, as indicated by its excellent permeability and porosity.
- 8) The vertical wells to be drilled in the platforms PCH-1 and PCH-2 should be cored and fluid samples obtained.

3.2.6 Specification of the Two Platforms

In order to design PCH-1 and PCH-2, some specifications are shown in Table 6.

It is expected that wells N-1, N-15, S-19, S-6, S-14, S-17, and S-13, even though they are initially oil producers, could be transferred into water injectors in the future. The well S-4 should be equipped to produce gas from the Carapebus sandstone, if necessary.

Water injection pressure estimated:

$$P_{inj} = P_f + \bar{P} + \frac{Q_w}{PI} - Gh \quad (4)$$

P_{inj} = Surface injection pressure

P_f = Pressure due to friction

\bar{P} = Reservoir pressure

Q_w = Rate of water

PI = Productivity index

G = Water gradient

L = Perforation depth

$$P_{inj} = 2.85 + 315 + \frac{1200}{15} - \frac{.45 \times 3100 \times 3.28}{14.22}$$

$$\underline{P_{inj} = 76 \text{ Kg/cm}^2}$$

4. OIL WELL PRODUCTION BEHAVIOR
BY FLOWING AND ARTIFICIAL LIFT

The variables that affect production rates can be classified into two groups: those which can be controlled and those over which there is little or no control. The first group includes flowline size and length, tubing size and length, surface restrictions and separator pressure. The other group includes the fluid properties, the reservoir static pressure, and the inflow ability or productivity index. In other words, there is fluid flow in porous media and there is fluid flow through the well bore and through surface flow line.

A graph plot of bottom-hole flowing pressure versus flow rate, Figure 13, the reservoir behavior will be shown by curve (1) after Vogel (if P_{wf} is below bubble point pressure) named Inflow Performance Relationship (IPR) or by straight line (2) Productivity Index (IP) if $P_{wf} > P_b$. The well behavior (mainly due to tubing) and surface behavior (well head pressure) are shown by curve (3) named Intake Pressure. All are shown schematically in Figure 13. The common point belonging to Intake Pressure and IPR (or IP) is the flow rate of the well and its bottom hole flowing

pressure. Changes in size of tubing, well head pressure, GOR, oil specific gravity, productivity index, etc. will change flow rate values and bottom-hole flowing pressure.

4.1 Multiphase Flow Correlations

The use of multiphase flow correlations is very important to understand flowing wells and in the design of artificial lift installations. All lift systems can be designed if proper multiphase flow correlations are used. The publication of gradient curves (working curves) has made this technology readily available for those who do not have a computer available for calculations.

In this paper, the author has used the FGERAL (Petrobras Computer Program written by Admar Machado) for the calculation of pressure losses in multiphase flow in pipes. So it was possible here to use pressure gradient curves obtained from the data of the area in the study, instead of using published gradient curve charts.

Two methods of vertical flow were tested; Orkiszewski and Hagedorn & Brown. The method of Orkiszewski was the best one when compared to the results of the production tests done in the area. This method was then chosen. The Eaton method was used for horizontal flow.

4.2 Goals of this Study

The need to equip, in the near future the wells of the Cherne field with an artificial lift system will be verified for the following conditions:

- . The system maximum flow rate with water cut = 0% and cut = 50%
- . The system flow rate with water cut = 0% and cut = 50% near P_{SLF} (Static Pressure Flowing Limit)
- . Estimating for each well the static pressure flowing limit (P_{SLF}) in order to preview the "latest date" to install an artificial lift system.
- . Verifying the convenience of the installation of an artificial lift system before the "latest date"; this means, to calculate the "earliest date" to install the system
- . The oil well behavior using gas lift, electric centrifugal or hydraulic pumping as an artificial lift method

4.3 Basic Premises

The basic premises of this study are:

- 1) The flow of the fluids will obey Orkiszewski's correlations for vertical multiphase flow and

Eaton's correlation for horizontal multiphase flow.

- 2) The main characteristics of the wells for the system are those shown on Tables 4 and 5. Most of this information was obtained from data files of the wells drilled in the area and the other ones were estimated.
- 3) The general data of the system are shown in Table 7.

5. MAXIMUM FLOW RATE OF THE SYSTEM
WITH WATER CUT OF 0% AND 50%

Some "times" in this paper will be given according to a scale of static pressures. The conversion into conventional scale of time almost always is possible by the reservoir studies. Such studies will be much more secure as more historical data of oil production are available in that area.

Figures 14 and 15 show the composition of the curves of Intake Pressure (generated by the FGERAL program) versus the Productivity Index (IP) straight line. The common point between the two curves gives the values of equilibrium flow rate and bottom hole flowing pressure. Figures 14 and 15 predict the behavior for the well S-5 (N), well S-5 (Namorado sandstone) using Table 8 data as input for the FGERAL program. Table 9 shows the output data which are plotted to generate Figures 14 and 15.

IP's (straight line) are used instead of Vogel IPR (curve) in the description of the flowing from the reservoir due to the bottom-hole flowing pressure being above the oil saturation pressure for the Namorado sandstone ($P_{bp} = 132$ Kg/cm²).

Vogel's curve (IPR) may and should be used for the Carapebus sandstone since it is a saturated reservoir.

In this paper (P_{SLF}) means the static pressure limit for the well to flow. Below that pressure, the well dies.

In the Cherne field, the high back-pressure in the vertical flow is mainly due to the high specific gravity of the oil and the low gas-oil-ratio of saturation. The wells calculated should stop flowing at relatively high reservoir pressures (255 Kg/cm^2 and 200 Kg/cm^2 for the Namorado and Carapebus respectively).

It is recommended that water injection into the Namorado sandstone be done to keep the reservoir pressure over 250 Kg/cm^2 and consequently, the wells flowing for more time.

The maximum and minimum estimated flow rate per each well at the reservoir initial pressure (P_i) and the static pressure limit flowing (P_{SLF}) to a water cut of 0% and 50% may be seen in Tables 10, 11 and 12 or in the Figure 15 for the well S-5 (N).

The production at P_i was calculated:

For water cut of 0%:

$$PCH-1 = 9,200 \text{ m}^3/\text{d}$$

$$PCH-2 = 5,710 \text{ m}^3/\text{d}$$

For water cut of 50%:

$$\text{PCH-1} = 4,250 \text{ m}^3/\text{d}$$

$$\text{PCH-2} = 3,300 \text{ m}^3/\text{d}$$

The production at P_{SLF} was calculated:

For water cut of 0%:

$$\text{PCH-1} = 4,100 \text{ m}^3/\text{d}$$

$$\text{PCH-2} = 3,700 \text{ m}^3/\text{d}$$

For water cut of 50%:

$$\text{PCH-1} = 2,380 \text{ m}^3/\text{d}$$

$$\text{PCH-2} = 2,880 \text{ m}^3/\text{d}$$

The wells will stop flowing at P_{SLF} .

If all the wells stop flowing at the same time, the fall of liquid production will be when the rate drops below $7,800 \text{ m}^3/\text{d}$ for a water cut of 0% and $6,260 \text{ m}^3/\text{d}$ for a water cut of 50%. At this time (the latest time) the installation of an artificial lift method would be necessary.

6. THE CONVENIENCE IN INSTALLING THE ARTIFICIAL
LIFT SYSTEM BEFORE THE LATEST DATE

From Figures 14 and 15 and Tables 10, 11 and 12, it follows that:

- 1) The production by natural flowing is high at the reservoir initial pressure, and averages 680 $\text{m}^3/\text{d}/\text{well}$ to the Namorado sandstone and 300 $\text{m}^3/\text{d}/\text{well}$ to Carapebus sandstone.
- 2) The wells lose the natural flowing condition when moments before they had produced 240 $\text{m}^3/\text{d}/\text{well}$ at the Namorado sandstone and 275 $\text{m}^3/\text{d}/\text{well}$ at the Carapebus sandstone.
- 3) The reservoir average pressure of natural flowing loss at the Namorado is 255 kg/cm^2 (being $P_i=315 \text{ Kg}/\text{cm}^2$) and 200 kg/cm^2 at the Carapebus (being $P_i=283 \text{ Kg}/\text{cm}^2$).
- 4) The use of gas lift (for example) at the static pressure flowing limit (P_{SLF}) increase the production to a level close to that at the original pressure of the reservoir (570 $\text{m}^3/\text{d}/\text{well}$ to the Namorado and 300 $\text{m}^3/\text{d}/\text{well}$ to the Carapebus).

Due to the thin Carapebus net oil pay, the production from this sandstone should be limited to the maximum of $300 \text{ m}^3/\text{d}/\text{well}$. This will avoid excessive velocity of fluid displacement in the formation, decreasing the possibility of sand production.

For the wells of the Namorado sandstone, it is necessary for a detailed study to fix the maximum production per well. Due to the water injection, the oil wells near by the injectors would have their production strictly controlled to avoid early production of water. I do not recommend production higher than $600 \text{ m}^3/\text{d}/\text{well}$ in this sandstone to avoid water and sand productions.

The artificial lift in the area should be started at a reservoir pressure between P_i and P_{SLF} .

The type of artificial lift (gas lift or hydraulic pumping) should be settled into the well at the beginning of productive life. If the option should be centrifugal pumping, the author recommends completing the wells as normally done for natural flowing. The artificial lift equipment will be run when an increase in oil is desired.

As previously stated, pressure maintenance by water injection at the Namorado sandstone should maintain the reservoir pressure at the level of $250 \text{ Kg}/\text{cm}^2$. This

pressure will be used to design the artificial lift system for the field.

7. OIL WELLS PRODUCTION
BEHAVIOR USING GAS LIFT

7.1 Intake Pressure vs IP

The curves of Intake Pressure shown on Figures 14 and 15 were generated from the pressure gradient data shown in Table 9.

For the well head pressure, $P_{wh} = 100$ psi, tubing string size, 3-1/2 in. O.D. (2.992 in. I.D.), water cut = 0% and 50%, various flow rate values (50, 100, 150, 200, 250, 300, 400, 500, 700 and 1000 (m^3/d)), and various values of gas liquid ratios (35.5, 50, 75, 100, 150 and 200 (m^3/m^3), etc.), pressure gradient curves using the program FGERAL were calculated.

The common point between Inflow Performance and Intake Pressure lines given a value of liquid flow rate and a value of bottom hole flowing pressure for each value of GLR. So, for the $GLR = 35.5 m^3/m^3$ (formation gas-oil-ratio), the equilibrium point indicates the flow rate and the flowing pressure to the well with $P_{wh} = 100$ psi and 3-1/2 in. O.D. tubing string.

With the same mechanical and flow conditions indicated above, an increase in GLR will result in decreasing the

fluid pressure gradient in the vertical flow lowering the bottom hole flowing pressure and increasing the flow rate. An increase of GLR from the GLR that gives the minimum gradient causes an increase in the bottom hole flowing pressure diminishing the production of liquid. Increasing GLR of the vertical flow stream until the minimum gradient is reached will increase the liquid production.

In horizontal flow, each and every increase in GLR corresponds to an increase of back pressure at the well head decreasing the well production.

The GLR indicated at Figures 14 and 15 can be treated like that being due to the gas formation and/or injected gas (gas lift) at the depth of the productive zone.

Evidently these values can, not always, be achieved due to the limitation of pressure and gas flow at the compressor discharge.

If the gas injection point is possible only at the shallower depth, evidently a smaller liquid production will be obtained.

In the case of CHERNE, a good value of gas for liquid production seems to be $GLR = 100 \text{ m}^3/\text{m}^3$ as shown in Figure 14 and Table 13 considering unlimited value for the gas lift injection pressure. Doubling gas injection value means increasing the oil production no more than 6 percent.

Keeping the gas lift volume constant for the well's productive life, a lower reservoir pressure will result in a smaller liquid flow rate, the GLR of injection will be bigger, increasing the flow rate before minimum gradient will be reached. It is good to keep in mind that excess of gas cause diminishing of liquid production.

7.2 Optimum Gas Injection Point

As the pressure of gas for gas lift is limited, the lowest point of gas injection for a determined reservoir pressure and productivity of the well, occurs generally in position, many times well above the production zone. This point can be found as shown on Figures 16, 17 and 18.

- 1) Draw a depth vs pressure graph as on Figure 16
- 2) Plot surface gas operating pressure (100 kg/cm^2) and construct the gas injection pressure gradient in the annulus.
- 3) From well head pressure (7 kg/cm^2), draw the gas lift flow gradient curve for each rate of production until it reaches the gas injection line. A natural flowing gradient from this point to the bottom is drawn at the same flow rate.
- 4) The common point to the three lines will indicate the depth which the gas lift mandril should be settled to produce this desired rate of oil.

- 5) Prepare a graph of Flow Rate vs Bottom-Hole Flowing pressure as Figure 17.
- 6) Reading the various bottom-holes flowing pressures from Figure 16 should be plotted on Figure 17 vs flow rate.
- 7) Plot the reservoir pressure and draw the IP as a straight line if P_{wf} is above bubble point.
- 8) The common point of these two lines predicts the gas lift flow rate.
- 9) Draw a depth vs flow rate graph on Figure 18.
- 10) From common point between gas injection line and flow rate line read the depth on Figure 16 and plot on Figure 18.
- 11) The gas lift flow rate from step (8) should be used on Figure 18 to determine the optimum gas injection point.

Another method to determine the optimum gas injection point is presented on Figure 19.

- 1) Draw a graph depth vs pressure.
- 2) Plot surface gas operating pressure (100 kg/cm^2) and construct the gas injection pressure gradient in the annulus.

- 3) From well head pressure (7 kg/cm^2) draw downward the gas lift flow gradient curve for each rate of production and $\text{GLR} = 100 \text{ m}^3/\text{m}^3$.
- 4) Determine the bottom hole flowing pressure for each production rate. A natural flowing gradient curve is drawn upward for each flow rate.
- 5) The common point between curves on step (3) and (4) represent the equilibrium point.
- 6) The curve generated by connecting the equilibrium points, when cut by gas injection line determines the depth of the optimum gas injection point.
- 7) The bottom hole flowing pressure can be determined, drawing downward from injection point a natural flowing gradient curve until the bottom of the well.

Obviously, the result from Figure 18 or 19 concerning gas injection point will be the same.

7.3 Predicting Gas Lift Flow Rate

Figure 20 obtained from Figure 17 allows us to determine the fluid production values for gas lift in any level of reservoir pressure for $\text{GLR} = 100 \text{ m}^3/\text{m}^3$.

From Figures 15 and 17 and Tables 11 and 14:

Natural Flowing at (P_i)

PCH-1 = 9,700 m³/d

PCH-2 = 5,700 m³/d

Gas Lift Flow Rate at (P_{SLF})

PCH-1 = 8,950 m³/d

PCH-2 = 6,300 m³/d

Still in Figure 17 can be observed the "static pressure limit of gas lift" P_{SLGL} to a GLR = 100 m³/m³. At this static pressure the well does not produce due to the insufficient level of fluid to reach the injection point (valve). A new design for the pocket mandril depth will be necessary. The lowering of the gas injection point makes possible the continuing of production by this method.

7.4 Gas-Lift Gas Consumption

The maximum Namorado sandstone oil production will be 8,360 m³/d for the 14 zones on PCH-1 and 4,210 m³/d for the 8 zones on PCH-2, using gas lift at P_{SLF} . This means average production volumes of 600 m³/d and 525 m³/d for wells on PCH-1 and PCH-2, respectively.

The author does not believe that further reservoir studies will set such high production levels especially for wells near the water injection line.

Taking a $300 \text{ m}^3/\text{d}$ limit for the Carapebus sandstone production per well, we have:

PCH-1	8,360 600	(Namorado) (Carapebus)
PCH-2	4,210 <u>2,100</u>	(Namorado) (Carapebus)
Total	15,270 m^3/d	

Considering the production with gas lift as a start, at P_{SLF} , the required amount of gas is shown in Tables 15 and 16, that is:

PCH-1

$$Q_{\text{gi}} = 8,360 (100-35.5) + 600 (100-40) = 575,000 \text{ m}^3/\text{d}$$

PCH-2

$$Q_{\text{gi}} = 4,210 (100-35.5) + 2100 (100-40) = 397,000 \text{ m}^3/\text{d}$$

7.5 Dimensioning Gas Lift Compressors

Calculations are done in Appendix A.1.

The total horsepower required for gas compression will be approximately:

$$\text{PCH-1} = 3,560 \text{ hp}$$

$$\text{PCH-2} = 2,460 \text{ hp}$$

7.6 Dimensioning the Gas Lift Column

The number and distribution of the gas lift side pocket mandrils on the tubing string are shown in Table 17 and Figure 21. The dimensioning was based on the previously

described "Optimum Gas Injection Point" and on the P_{SLF} in accordance with Table 14 and Figure 18.

The gas lift pressure may be assumed as:

$P_d = 116 \text{ Kg/cm}^2$ - compressor discharge pressure

$P_{ko} = 114 \text{ Kg/cm}^2$ - kick-off pressure

$P_a = 107 \text{ Kg/cm}^2$ - available pressure

$P_{so} = 100 \text{ Kg/cm}^2$ - surface operating pressure

Spacing Procedure:

- 1) Plot the gas gradient lines for KICK-OFF (114 Kg/cm^2), available (107 Kg/cm^2) and operating pressure (100 Kg/cm^2), as shown on Figure 21.
- 2) Draw the kill fluid gradient line of 0.4 psi/ft or $0.092 \text{ Kg/cm}^2/\text{m}$ from the flowing well head pressure $P_{wh} = 100 \text{ psi}$ or 7 Kg/cm^2 .
- 3) Extend the kill fluid gradient line until the available pressure line is 100 psi less than the kick-off casing pressure gradient line at depth. This locates the first gas lift mandril.
- 4) The depth of optimum gas injection point from Figure 18 or Table 14 is located over the surface operating pressure line (P_{so}).
- 5) The gradient curve between optimum gas injection point (L_{inj}) and flowing well head pressure (P_{wh})

can be plotted. A straight line is drawn here for safety's sake.

- 6) From the gradient curve above the gas injection point at the first mandril depth, draw a line downward parallel to the kill fluid gradient line until the point 20 psi less than the available pressure at depth.

This locates the second gas lift mandril.

- 7) Continue this procedure until reaching a depth less than 90 meters from the optimum gas injection point.

7.7 Comments

The operating valve will be of the orifice type, Camco RDO or similar. The discharge valves will be of the type R-20 pressure operated valve with 20 psi drop in surface operating pressure between valves. The first valve will be set for 107 Kg/cm^2 .

A downstream pressure control valve of the Fisher type, or similar, should be placed on the gas lift line next to the well. The need here is to keep a constant gas pressure along the casing of each well and, in this way, to even out the flow inside the well, thus avoiding slugging.

The adjustment of the oil production to the maximum value or to a pre-fixed value should be made on the basis of production tests (measurements of liquid and gas) and pressure behavior tests, both on the casing (P_{whc}) and in the tubing (P_{wh}). To this end, a two stylus pressure gauge should be located near the well Christmas tree. Each production platform would require a wire line operation, especially in regard to the replacement of valves in mandrils and running bottom hole pressure recorders.

The wells S-9 and S-17 can be equipped as dual completions with 3-1/2" and 2-7/8" tubings, producing from the Namorado and Carapebus sandstones at the same time.

8. OIL WELLS PRODUCTION BEHAVIOR USING ELECTRIC SUBMERSIBLE CENTRIFUGAL PUMPING

8.1 The Method

The electric centrifugal pumping method requires some important and necessary conditions to operate successfully in oil wells, as follows:

- .Local electric power available
- .High and approximately constant rate of production as a function of time
- .Low gas-liquid ratio
- .working liquid level not too deep
- .negligible sand production

This method does not have problems in deviated wells. Special pumps are made to work in high bottom hole temperature and even to handle corrosive liquids.

8.2 Typical Submersible Pumping Unit

A typical electric submersible centrifugal pump, Figure 22, mainly consists of an electric motor, protector (seal section), gas separator, centrifugal pump, electric cable, junction box, switchboard and transformers.

In some areas such as offshore production platforms, engine generator sets are needed to supply electric power to the system.

8.2.1 Electric Motor

In developing electric submersible centrifugal pumping a major obstacle met by the experts was developing the submersible electric motor. This barrier was evidently due to the limited diameter of the well. The motors are induction type, two pole, three phase and run 3,500 rpm on 60 Hz or 2,915 rpm on 50 Hz (TRW-Reda catalog). For the same horsepower, the larger engine is less expensive. Increased casing size increases the motor horsepower available. For casing a 9-5/8" O.D., there are available motors over 1,000 hp.

The submersible motor is filled with refined mineral oil. This oil keeps the motor cool due to the transfer of heat to the produced fluid. The produced fluid velocity next to the motor assembly is about 1 ft/sec and never less than .5 ft/sec.

8.2.2 Protector (Seal Section)

The protector makes the physical connection between the electrical engine and submersible pump and prevents external (produced) fluids from entering the motor.

8.2.3 Gas Separator

The main function of this equipment is to reduce the amount of gas entering the pump. If free gas is pumped, the volumetric efficiency of the pump is decreased.

If the well has a high gas oil ratio, it is imperative to use a gas separator. Normally, part of the gas is vented through annular space to the surface while the other part and liquid phase enters the pump.

If the pump is pumping oil that is above bubble point, or if it is set below the perforations, the gas separator is not necessary. Evidently, if solid particles are being produced, the pump should be set above perforations.

8.2.4 Centrifugal Pump

Submersible centrifugal pumps are multi-staged centrifugal pumps. The number of stages determine the total head generated and the horsepower required. The size of the pump determines the volume of fluid to be produced.

The discharge rate and pressure of a submersible centrifugal pump depends on the speed (RPM), impeller size, number of stages, the dynamic head and the physical properties of the fluids being pumped. The total dynamic head (TDH) in feet reached by the fluid does not depend on the physical properties of the fluid. But the pressure at the

discharge pump will change in pumping different fluids at the same TDH.

8.2.5 Electric Cable

The motor is electrically connected to the surface by an electric cable. Insulated cables for submersible centrifugal pumps are available in either round or flat styles. Flat cable normally is used as a terminal cable by the motor connected to round cable by the tubing as shown in Figure 23. This increases the pump clearance on the cable side. Normally the cable type is selected principally on the bottom hole temperature and produced fluids and not based on size. The insulation resistance of the cables is very important and has to be determined frequently in running the submersible pump.

8.2.6 Junction Box

Junction box is a safety device located between the well head and the switchboard. The junction box main function is to prevent the gas that penetrates the cable from reaching the switchboard.

8.2.7 Switchboard

All the electric control devices are gathered in the switchboard box which is located between the junction box and the transformers. From this box it is possible to

start or stop the pump manually or use timers for intermittent pumping. A recording amperage meter is usually located on the outside of the switchboard. Overload and underload electric devices protect the electric motor against undesirable loads that could result in damage to the motor or pump.

To the energize panel, the switchboard door must be closed for safety reasons.

8.2.8 Transformer

Transformers are used to convert primary line voltage to motor voltage requirements. There are three different options to use transformers:

- 1) Three single-phase transformers, normally are used where higher voltage primaries are available.
- 2) Auto transformers are available to convert primary low voltage to secondary high voltage.
- 3) Three-phase transformers in a common range of primary and secondary voltages can be used.

8.3 Application of Submersible Pumps to the Cherne Field

The wells in Cherne field, mainly the ones of the Namorado sandstone, fulfill the necessary conditions for the utilization of electrical submersible centrifugal

pumping, mainly due to the low GOR, constant reservoir pressure and high working liquid level.

8.4 Rate of Design

In the section concerning gas lift, the P_{SLF} was assumed to be constant with time due to water injection for pressure maintenance in the Namorado reservoir. The estimated oil production per well, shown on Table 14 was the maximum obtainable production for the limited gas pressure (116 kg/cm² at the compression discharge) and limited GLR total of 100 m³/m³. The production being calculated in this way, was in a range of 550-650 m³/d/well for P_{SLF} of 250-260 Kg/cm².

In this section on centrifugal pumping as an artificial lift method, the P_{SLF} will also be considered constant with time. The liquid production will also be fixed like those obtained in the production by gas lift, at P_{SLF} .

The motor x pump setting depth is the unknown to be calculated. For the wells of the Carapebus sandstone, the production of 300 m³/d/well will be considered at P_{SLF} .

8.5 Production Gas-Liquid Ratio

The formation gas-liquid-ratio is 35.5 m³/m³ for the Namorado sandstone and 40 m³/m³ for the Carapebus sandstone. The Namorado sandstone oil saturation pressure is 132 kg/cm²

and the initial pressure is 315 Kg/cm². As the intention is to produce oil from this sandstone at constant producing bottom pressure of 250 Kg/cm², the bottom hole flowing pressure (P_{wf}) will be above the saturation pressure. In other words, the beginning of gas liberation will take place at a point in the tubing string and not in the formation.

8.6 Working Liquid Level

The working liquid level is the height reached by the liquid in the casing (if the annulus were open) at a determined rate of production. The static liquid level is the height reached by the liquid in the casing if the well is shut in at the surface.

The static liquid level is calculated transforming the reservoir static pressure into the equivalent height of liquid column. If the well is shut in, the depth of the static level will be:

$$D_{sll} = D_p - \left(\frac{P_s - P_{whc}}{G_s} \right) \quad (5)$$

D_{sll} = static liquid level depth

D_p = producing zone depth

P_s = reservoir pressure at D_p

P_{whc} = casing well head pressure

G_s = fluid static gradient (at bottom hole condition)

The working liquid level is calculated converting the bottom hole flowing pressure (P_{wf}) into height of liquid column.

$$D_{dll} = D_p - \left(\frac{P_{wf} - P_{whc}}{G_f} \right) \quad (6)$$

D_{dll} = dynamic or working liquid level depth

D_p = producing zone depth

P_{whc} = casing well head pressure

P_{wf} = bottom hole flowing pressure at D_p

G_f = fluid dynamic gradient (at bottom hole conditions). Here are considered the well mechanic conditions and the characteristics of the produced fluid.

The working liquid level of the wells equipped with centrifugal pumping was calculated from the obtained gradient curves in this paper, using vertical multiphase flow and Orkiszewski's correlation in the FGERAL program, considering the tubing diameter 3-1/2", the casing 9-5/8" and 35.5 m³/m³ formation GOR.

For each flow rate and determined casing well head pressure (P_{whc}), a working liquid level value was determined.

8.7 Pump Setting Depth

The ideal pump setting depth to obtain better pumping efficiency is that in which the pump intake pressure will have the smaller quantity of free gas.

In the Namorado sandstone, the best condition would be at a depth in which the suction pressure is equal to the oil saturation pressure, or 132 Kg/cm².

For the expected production rated between 550-650 m³/d and a suction pressure of 132 Kg/cm², the setting depth of the pump would have to be between 2000-2200 meters.

From Figure 24 or making calculations as for the following example:

well: S-5 (N)

$$Q = 650 \text{ m}^3/\text{d}$$

$$D_p = 2,970 \text{ m}$$

$$P_b = 132 \text{ Kg/cm}^2$$

$$P_s = 240 \text{ Kg/cm}^2$$

$$P_{wf} = 207.5 \text{ Kg/cm}^2$$

$$P_{wh} = P_{whc} = 7 \text{ Kg/cm}^2$$

$$G_f = .083 \text{ Kg/cm}^2/\text{m}$$

$$G_s = .093 \text{ Kg/cm}^2/\text{m}$$

$$\bar{B}_O = 1.13$$

Static Liquid Level Depth

$$D_{sll} = D_p - \frac{P_s - P_{whc}}{G_s} \times \bar{B}_o$$

$$D_{sll} = 2,970 - \frac{240-7}{0.093} \times 1.13 = 140 \text{ m}$$

Working Liquid Level Depth

$$D_{dll} = D_p - \frac{P_{wf} - P_{whc}}{G_f}$$

$$D_{dll} = 2,970 - \frac{207.5-7}{0.083} = 555 \text{ m}$$

Pump Depth

$$D_{PM} = D_{dll} + \frac{P_b - P_{whc}}{G_f} = 555 + \frac{132-7}{0.083} = 2,060 \text{ m}$$

In this example, the centrifugal pump can be set at 2,060 meters of depth and will pump only liquid, since all the gas will still be in solution in the oil at this bottom hole flowing pressure. Or the pump can be placed 170 meters below the expected working liquid level, in other words, at the depth of $170 + 555 = 725$ meters, and have to pump some gas. The 170 meters of liquid column above the pump assures continuous production without the risk of gas/liquid contact in the annular space, reaching the pump.

If there is any difficulty in gas ventilation at the down hole separator and the quantity of gas to be pumped is

large, the option of deepening the pump is useful and somewhat advantageous.

8.8 Gas Ventilation

If the pump is settled below the production zone, free gas will be vented into the annulus and the pumping will be mostly liquid, independent of the oil saturation pressure. That is what can be called a natural gas anchor or positional anchor. The inconvenience in adopting this solution is the risk of solids production. This may diminish the useful life of the pump.

If the pump is placed above the producing zone and in such a position that the pump intake pressure is less than the oil saturation pressure, the pump will have to handle all or part of the free gas at this intake pressure. If the option is to vent the gas, some free gas will be vented and the rest of the gas pumped. It is recommended that a back-pressure control valve be installed on the casing flow-line. If the casing is open to the atmosphere, a determined quantity of gas will be vented and the working liquid level in the annulus will be the highest (closer to the surface). Making the casing well head pressure higher by use of a back-pressure control valve will lower the working liquid level.

The gas/liquid contact into annulus space reaching the pump, the surface pressure in the casing will be maximum if the surface casing valve is closed.

8.9 Productivity and Working Liquid Level Determination

In 1975 the author made successful experiments in the determination of the working liquid level in wells with sucker rod pumping, using only one choke at the casing flow line and one gauge installed upstream of the choke. This was because the determination of the fluid level in those wells was not possible using the conventional sonolog method. Using sonolog, the results were surprisingly without any meaning at all. For example, the working liquid level was significantly higher than the static liquid level. The author believes that the sound's signal changed before it reached the working liquid level due to a thick layer of oil foam in the annulus of the wells.

To determine the pump intake pressure using centrifugal pumping, the casing of the well should be closed (using valve on the surface) until the gas liquid contact lowers to the pump level. At this point the pump shut-off by low electric current and the pressure shown on the casing gauge will be the maximum for the producing well at the determined production flow. The pressure at the pump inlet at this time will be the pressure at surface, plus the weight

of the gas column from the surface to the pump. If the reservoir static pressure is known, the productivity index or the Vogel's Inflow Performance curve could be calculated.

For high productivity wells the by-pass flow line between casing and tubing at surface is recommended. A check valve will avoid the flow in the tubing/casing direction. The casing valve would be totally open so that the tubing pressure will be slightly less than the casing pressure but just enough that it would have gas flow.

The old practice of opening the casing of a pumped well to the atmosphere should be avoided. Evidently, if the tubing well head pressure would be higher than the pump intake pressure, the by-pass tubing/casing, at the surface, will not be recommended. In this case, if possible, the well should operate with the casing closed, pumping all the gas.

8.10 Submersible Pump Design Procedure

Data from Table 18 was used to design submersible pump, as shown in the Appendix A-2. For the well S-5(N), was chosen:

REDA Pump G180, Series 540, 60 Hz, 85 stages, 32 HP

The pump is to be set at 700 m deep (see Figure 24).

One of the best ways to design submersible centrifugal pumps is to calculate number of stages and required

horsepower for each small pressure increment. Here, only one increment was used to express the pump behavior. Some error should be expected due to this fact.

Tables 19, 20 and 21 show calculation results in sequence used to select the submersible pumps for the wells.

9. OIL WELL PRODUCTION BEHAVIOR USING HYDRAULIC PUMPING

9.1 Consideration

The reservoir studies made in Cherne's field by Cabral et al to date, indicate a fast decline in oil production from Namorado sandstone if the reservoir pressure maintenance would not be started at the beginning of the productive life of the wells. This is mainly due to the undersaturated oil characteristics.

Then the oil exploitation will be most profitable if secondary recovery could be done to maintain the reservoir pressure at high level, close to 250 Kg/cm², keeping the flow rate per well high and approximately constant with time.

"Piston Type Hydraulic Pumping" shows advantages over other artificial lift methods for production rates less than 3,000 BPD or a deep well which has a low producing bottom hole pressure. As shown previously, the oil wells from Namorado sandstone produce 4,000 BPD/well with a high working liquid level, 500 m from the surface.

9.2 Power Fluid

It is better to install power fluid system on each oil production platform, instead of a central power fluid system. This idea is based on the reasons listed below:

- . To avoid whenever possible, laying underwater pipelines due to:
 - Investment cost
 - Maintenance cost
- . The inconvenience of a high pressure pipeline and increased pollution risk due to the leakage and repair cost.
- . Decreasing the possibility of failure of the complete system due to a failure of a central power fluid.
- . The possibility in dephasing the artificial lift installation on each production platform, by convenience or necessity.

9.3 Power Fluid Selection

The oil from Carapebus sandstone should be used as the power fluid if the oil from Namorado sandstone has worse quality. The author does not recommend water as a power fluid due to the high operation cost. Water must be fresh: no dissolved oxygen, chemicals added to lubricate submersible pump, closed power fluid system etc.

9.4 Power Fluid System

There are two basic types of power fluid systems:

- 1) The closed power fluid (CPF) system where the surface and subsurface power fluid stay in a

closed circuit and do not mix with the produced fluid.

- 2) The open power fluid (OPF) system where the power fluid mixes with the production down hole and returns to the surface commingled.

The open power fluid (OPF) would be chosen due to simplicity. In the subsurface only one down hole 4-1/2 inch O.D. tubing is needed to conduct power fluid to the engine with the 9-5/8 inch O.D. x 4-1/2 inch O.D. annulus used to conduct power fluid and oil to the surface. It would be better to use two strings of tubing instead of one tubing string and the tubing/casing annulus. Unfortunately, 4-1/2 inch O.D. x 3-1/2 inch O.D. tubing combination to pump high volume of fluid does not fit in the 9-5/8 inch O.D. casing.

9.5 Surface Facilities

A surface facility for an OPF system commonly used can be seen in Figure 26. A simplified oil production facility has been designed to be used on offshore platforms where space and load are important variables to be considered.

A "Cyclone Desander" would be placed upstream from the surface pump. This equipment is sized to remove suspended solids from liquid.

The oil after treatment in an Electrostatic Dehydrator would be dumped into a surge tank which has a 1 to 2 psi

working pressure. From the surge tank, the oil goes to the hydraulic pumping system through triplex pumps or goes to the sales line through centrifugal pumps.

Power fluid tank and stock tanks would be eliminated from offshore platforms whenever it is possible.

9.6 Subsurface Equipment

A free pump illustration can be seen on Figure 27. The pump fits inside of the power tubing and it is free to circulate to the bottom and back out again. The casing free tubing arrangement as shown on Figure 28 will be the configuration chosen. All gas must be handled by the pump.

9.7 Formation Gas

All free gas at intake pressure of the hydraulic pump would be pumped and no gas will be vented. A smaller pump could be used for the same rate of production if some gas was vented. With a pump intake pressure (P_{pin}) of 20 Kg/cm², 28 m³/m³ free gas-oil-ratio would be pumped. Due to this free gas, the pumping volumetric efficiency would be less than if only liquid were present.

9.8 Production Scheme

The oil well production scheme by artificial lift method using hydraulic pumping would be the same plan utilized in

gas lift or electric centrifugal pumping. The production ratio would be approximately constant for each well, as shown on Table 14, at P_{SLF} . The Carapebus reservoir pressure would drop freely until the abandonment pressure, since there would be no pressure maintenance of this reservoir.

9.9 Typical Wells Selection

Two typical wells have been selected to represent the wells on the platforms PCH-1 and PCH-2:

Well A - producing 550 m³/d (Namorado)

Well B - producing 300 m³/d (Carapebus).

9.10 Procedure for the Hydraulic Pumping Design

This procedure was used to select hydraulic pumps and determine the surface power fluid pressure needed.

Procedure:

- . Find the produced rate of fluids (oil, gas, and water) through pump (Q_{tp})
- . Select the pump to handle the required rate.
- . Determine the speed required to pump the fluid (SPM) and the power fluid rate required in two levels:

Q_{in} = Initial power fluid rate - new pump

D_{fo} = Final power fluid rate - old pump

- . Determine the returned rate of fluid (Q_{tr}).

- . Determine the power fluid friction loss (ΔP_{fi}).
- . Determine the returned fluid friction loss (P_{fr}).
- . Determine the pump discharge pressure (P_{pout}).
- . Effective pressure of column of power fluid.
- . Determine pump friction (P_f).
- . Determine the power fluid surface pressure (P_s).
- . Surface horsepower required (HP_s).

9.11 Summary of the Calculations

Appendix A.3 and A.4 show the Hydraulic Pump Design for wells producing from Namorado and Carapebus sandstones. Appendix A.5 shows the Surface Pump Design for the Cherne's field.

Tables 26 and 27 summarize the calculations related to the two typical wells (Namorado and Carapebus sandstone).

9.12 Hydraulic Pumping Operation

The following instructions to subsurface pumping operation come from the manufacturer and from conceptions used in designing the system previously discussed.

The hydraulic pump will be replaced or repaired when the first of these events listed below occurs:

- 1) The pump speed limit is reached; that means 77 SPM for KOBE Type A Pump or 53 SPM or KOBE Type E Pump.

- 2) The pump is no longer pumping the desired production, 473 m³/d and 300 m³/d in wells from Namorado and Carapebus sandstones, respectively.
- 3) The pump is using higher power fluid volume than that specified on the project (2,029 BPD and 2,812 BPD for KOBE Type A and KOBE Type E pumps, respectively).
- 4) The surface pressure in the power fluid line reaches a higher value than that specified by triplex pump manufacturer.

9.13 Subsurface Pump

The wells producing from Namorado sandstone will be equipped with "KOBE Type A Pump, Single Engine, Double Pump End" and the wells producing from Carapebus sandstone will be equipped with "KOBE Type E Pump, Single Engine, Single Pump End", as shown on Table 22.

Table 23 shows the utilized power fluid in PCH-1 and PCH-2 and the required horsepower for prime movers.

10. GENERAL DISCUSSION

1) The reservoirs (Namorado and Carapebus) would be approximately 70% covered by drilled wells from one platform. To cover the whole field, two platforms would be necessary.

2) The oil in place is estimated 56×10^6 (cu. meter) or 352×10^6 STBO for the Namorado sandstone and 2.8×10^6 (cu. meter) or 17.6×10^6 STBO for the Carapebus sandstone.

3) The recovery factor estimated is 15.% (primary oil recovery) or 35% (secondary oil recovery) from water drive in the Namorado sandstone.

4) The water injection for pressure maintenance of the reservoir energy is mainly useful for:

- a. Increasing the oil recovery factors
- b. Increasing the natural flowing period
- c. Stabilizing the reservoir pressure improving the use of some artificial lift systems.

5) The artificial lift equipment should be set into the well at the beginning of the field productive life if gas lift or hydraulic pumping or at the moment that an increase in oil production is desired if centrifugal pumping.

6) The pressure maintenance by water injection at the Namorado sandstone should maintain the reservoir pressure at the level of 250 Kg/cm^2 ,

7) The pressure from Namorado shows a high level of undersaturation. The initial pressure is 315 Kg/cm^2 and the bubble point pressure is 132 Kg/cm^2 .

8) The gravity of the oil (API 20) and low gas oil ratio ($35.5 \text{ m}^3/\text{m}^3$) will make difficult the production by natural flowing and will provoke a short flowing time.

9) Extending to a production of 10 years, at least 28 wells will be necessary to drain the area.

10) The investigation limit radius for a well to reach the Namorado sandstone will be 1900 meters and 40 degrees of deviation from the vertical.

11) The flow of fluids obey Orkiszewski's correlations to vertical multiphase flow.

12) The production by natural flowing is high at the reservoir initial pressure, and averages $680 \text{ m}^3/\text{d}/\text{well}$ to the Namorado sandstone and $300 \text{ m}^3/\text{d}/\text{well}$ to Carapebus sandstone.

13) The wells stop flowing naturally when the rate drops below $240 \text{ m}^3/\text{d}/\text{well}$ for the Namorado and $275 \text{ m}^3/\text{d}/\text{well}$ for the Carapebus sandstone.

14) The P_{SLF} is 255 Kg/cm^2 and 200 Kg/cm^2 for the Namorado and Carapebus, respectively.

15) The injection gas oil ratio in the gas lift method would be $64.5 \text{ m}^3/\text{m}^3$ for Namorado sandstone and $60 \text{ m}^3/\text{m}^3$ for Carapebus. The total GOR was taken $100 \text{ m}^3/\text{m}^3$.

16) The gas lift gas consumption was estimated at 575,000 m³/d for the wells on PCH-1 and 397,000 m³/d for the wells on PCH-2.

17) The gas lift pressure was assumed 1,650 psi.

18) The centrifugal pump setting depth is in such order that oil column of 170 meters has to stay above the pump.

19) The required nominal power for the submersible motors will be 2000 hp at PCH-1 and 2200 hp at PCH-2.

20) The hydraulic pump in the Namorado sandstone will be set at the depth which corresponds to 132 Kg/cm² bottom hole flowing pressure (bubble point pressure). This depth is approximately 2,150 meters.

21) The required nominal power for the triplex pump will be 2,640 hp at PCH-1 and 2,820 hp at PCH-2.

22) The wells from Namorado would produce no more than 550 m³/d due to limited capacity of the hydraulic pumps. Wells producing from Carapebus had to have the hydraulic pump set close to the production zone, decreasing the amount of gas to be pumped. In this case, two 3-1/2" tubing strings are to be used as shown in Figure 29.

The annulus 9-5/8" x 4-1/2" to be used as a production path if high level of flow rate would be required for the Namorado sandstone. In this case, some risk would occur concerning corrosion, erosion due to the solid in oil suspension and paraffin.

23) Gas lift and centrifugal pumping do not show flow rate limitations, since the working liquid level is high.

24) Gas lift and centrifugal pumping sizing was based on the reservoir pressure which would be approximately constant (250 Kg/cm²) in the Namorado sandstone if the water injection worked satisfactorily.

25) One well in each platform should be completed to produce gas from the Carapebus whenever necessary.

11. CONCLUSIONS AND RECOMMENDATIONS

- 1) Develop the area using two fixed platforms.
- 2) Start secondary recovery by water injection at the beginning of the field productive life. Maintain the reservoir pressure (Namorado) at the level of 250 Kg/cm².
- 3) Drill 22 wells (14 oil wells and 8 water injectors) from PCH-1 and 17 wells (14 oil wells and 3 water injectors) from PCH-2.
- 4) The author recommends using electric submersible centrifugal pumping in each platform as an artificial lift method, mainly due to:
 - . Surface equipment needs less space than the other two methods.
 - . Less horsepower is required per volume of produced fluid.
 - . Wells produce at high flow rate.
 - . Oil property adequate for pumping as gravity 20°API viscosity 5 cp and low GOR = 35.5 m³/m³. Using GL method, the viscosity increases due to decrease of temperature in the tubing.
 - . Low dynamic head.

12. LIST OF REFERENCES

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APPENDIX A

ANALYTICAL SOLUTIONS

1. Dimensioning Gas Lift Compressors

Gas for gas lift is required at 1650 psi discharge pressure from the compressor. Suction pressure is 90 psi. The gas flow rate required for gas lift is 575,000 m³/d for the wells on PCH-1 and 397,000 m³/d for the wells on PCH-2.

From Brown (Artificial Lift Method, Vol. 2b, pp. 336). we can calculate the brake horsepower:

$$1) \text{ Compressor ratio } r = \frac{1664.7 \text{ psia}}{104.7 \text{ psia}} = 15.90$$

This would be a two-stage compressor. The ratio per stage is $\sqrt{15.90} = 3.99$.

$$2) 104.7 \times 3.9 = 417.5 \text{ psia (suction to second stage)}$$

$$\frac{1,664.7 \text{ psia}}{417.5 \text{ psia}} = 3.99 \text{ (ratio of compression for second stage)}$$

$$3) \gamma_g = 0.7 \text{ at } 150^\circ\text{F (average temperature on the first stage), } K \text{ would be } 1.24$$

$$4) \text{ Discharge temperature for the first stage, for a compression ratio of } 3.99 \text{ and intake temperature } 80^\circ\text{F, would be } 250^\circ\text{F.}$$

$$5) \text{ Discharge temperature for the second stage (with } r = 3.99 \text{ and assuming interstage cooling at } 120^\circ\text{F) would be } 300^\circ\text{F.}$$

$$6) \text{ Compressibility factor at suction and discharge pressure and temperature for each stage:}$$

1st stage:

$$Z_s = 0.980$$

$$Z_d = 0.97$$

$$Z_{ave} = 0.975$$

2nd stage:

$$Z_s = 0.95$$

$$Z_d = 0.95$$

$$Z_{ave} = 0.95$$

- 7) At ratio $r = 3.99$ and $k = 1.24$; $bhp/MM_{scf} = 82.5$
(1st and 2nd stage).
- 8) Horsepower for compression:

$$BHP = bhp/MM_{scf} \left(\frac{P_L}{14.4}\right) \times \left(\frac{T_S}{T_L}\right) (Z_{avg}) (MM \text{ scf}) \quad (6)$$

1st stage:

$$BHP = 82.5 \times \left(\frac{14.7}{14.4}\right) \times \left(\frac{540}{520}\right) \times 0.975 \times 34.5$$

$$\underline{BHP = 2940}$$

2nd stage:

$$BHP = 82.5 \times \left(\frac{14.7}{14.4}\right) \times \left(\frac{580}{520}\right) \times 0.95 \times 34.5$$

$$\underline{BHP = 3080}$$

The total BHP will be:

$$BHP_t = 2,540 + 3,080$$

$$\underline{BHP_t = 6,020}$$

$$\underline{PCH-1} \quad BHP = 3,560$$

$$\underline{PCH-2} \quad GHP = 2,460$$

2. Submersible Pump Design Procedure (S-5(N))

This is an example of how I calculated the electric centrifugal pumps in Cherne field. Tables 19, 20 and 21 show calculation results in sequence used to select the submersible pump for the wells.

Using Brown's method (The technology of artificial lift methods, Volume 2b, page 74):

1) Volume of oil, gas and water associated with one STBO at 20 Kg/cm² (pump intake pressure) and 61 Kg/cm² (pump discharge).

a. Total flow rate at pump

$$V_{20} = V_o + V_g + V_w$$

$$V_o = 1 \times B_o = 1 \times 1.10 = 1.10$$

$$V_g = 23 \text{ m}^3/\text{m}^3 \times 5.615 = 129 \text{ ft}^3/\text{bbl} \text{ (at surface)}$$

$$B_g = \left(\frac{1}{5,615}\right) \left(\frac{14.7}{P}\right) \left(\frac{T}{520}\right) \left(\frac{Z}{1}\right) = 0.00504 \frac{TZ}{P}$$

$$T_c = 390 \quad P_r = \frac{299.1}{666} = 0.45$$

$$P_c = 666 \quad T_r = \frac{575}{390} = 1.47 \quad \underline{z = 0.95}$$

$$B_g = 0.00504 \frac{575 \times .95}{299.1} = 0.0092 \frac{\text{bbl}}{\text{scf}}$$

$$(\text{GOR})_I = 23 - 7 = 16 \text{ m}^3/\text{m}^3 = 90 \frac{\text{scf}}{\text{bbl}}$$

$$V_{20} = 1.1 + 90 \times 0.0092 = 1.93$$

$$(q_t)_I = 4,088 \times 1.93$$

$$(q_t)_I = \underline{7,882 \text{ bbl/d}}$$

b) Total flow rate at pump discharge $(q_t)_D$

$$B_o = 1.137$$

$$P_r = \frac{882.1}{666} = 1.32$$

$$T_r = \frac{575}{390} = 1.47 \quad z = 0.86$$

$$B_g = 0.00504 \frac{575 \times .86}{882.1} = 0.00283 \text{ bbl/scf}$$

$$(GOR)_D = 23 - 17 = 6 \text{ m}^3/\text{m}^3 = 34 \text{ scf/bbl}$$

$$V_{61} = 1.137 + 34 \times 0.00283 = 1.23$$

$$(q_t)_D = 4,088 \times 1.23$$

$$(q_t)_D = \underline{5,028 \text{ bbl/d}}$$

2) Total mass flow rate (lb mass/day).

The mass/STB will be:

$$\text{Mass (oil)} = \gamma_o \times 350 = 0.934 \times 350 = 326.9 \text{ lbs/STB}$$

$$\begin{aligned} \text{Mass (gas)} &= \gamma_g (GOR) (0.0764) = 0.7025 \times 129 \times 0.0764 \\ &= 6.93 \text{ lbs/STB} \end{aligned}$$

$$\text{Mass (oil, gas, water)/STB} = 326.9 + 6.93 = 333.8 \text{ lbs/STB}$$

$$W_t = 333.8 \text{ lbs/STB} \times 4,088 \text{ STB/day}$$

$$W_t = 1,364,500 \text{ lb mass/day}$$

3) Pressure gradient (psi/ft)

$$(\rho_{\text{mix}})_{20} = \frac{\text{mass}}{\text{vol.}} = \frac{333.8}{1.93 \times 5.615} = 30.80 \text{ lbm/ft}^3$$

$$(\rho_{\text{mix}})_{61} = \frac{333.8}{1.23 \times 5.615} = 48.33 \text{ lbm/ft}^3$$

$$(\text{GRAD})_I = \frac{30.80}{144} = 0.214 \text{ psi/ft}$$

$$(\text{GRAD})_D = \frac{48.33}{144} = 0.336 \text{ psi/ft}$$

$$4) \quad \overline{\text{GRAD}} = \frac{0.336 + 0.214}{2} = 0.275 \text{ psi/ft}$$

5) Average volume flow rate

$$\bar{q}_t = \frac{V_{20} + V_{61}}{2} = \frac{7,882 + 5,028}{2} = 6,455 \text{ bbl/day}$$

6) Select pump for $\bar{q}_t = 6,455 \text{ bbl/day}$

From Figure 25 will be chosen (Source: TRW-REDA):

REDA pump

G 180

Series 540

60 Hz

7) Convert to psi/stage

Head = 25 ft/stage

$$\overline{\text{GRAD}} = 0.275 \text{ psi/ft}$$

$$\text{Pressure/stage} = 25 \times 0.275 = 6.88 \text{ psi/stage}$$

8) Number of stages per increment of pressure:

$$\text{No. stages} = \frac{(PM)_D - (PM)_I}{\text{pressure/stage}} = \frac{(61-20) 14.22}{6.88}$$

$$\text{No. stages} = \underline{85}$$

9) Required horsepower

$$\text{HP} = \text{No. stages} \times \text{HP/stage} \times \overline{\text{SG}}$$

$$HP = 85 \times 1.85 \times \frac{0.275}{0.433}$$

$$HP = \underline{100}$$

The horsepower if pumping water (SG = 1.0) will be

$$HP = 85 \times 1.85$$

$$\underline{HP = 160}$$

3. Hydraulic Pumping Design (Well N-8(N))

1) Type of Installation: Casing free tubing arrangement OPF system will be the chosen installation (Figure 28).

Pumping high volume of fluid using 4-1/2" as a power fluid tubing into a 9-5/8" casing will force 9-5/8" x 4-1/2" annulus to be used as a path for power fluid and production to reach the surface.

3) Determine bottom hole flowing pressure (P_{wf}), pump intake pressure (P_{pin}) and depth of the pump (D_p).

Using vertical multiphase flow (Orkizewski) for the well flowing 550 m³/d through casing we can determine the pseudo liquid level (680 m), the depth of the pump ($D_p = 850$ m), the pump intake pressure ($P_{pin} = 20$ Kg/cm²) and bottom hole flowing pressure ($P_{wf} = 205$ Kg/cm²).

3) Determine the produced rate of fluids (oil, gas and water) through pump (Q_{tp}) or the actual pump displacement to produce fluids at $P_{pin} = 20$ Kg/cm², $R_s = 6.5$ m³/m³
 $(GOR)_f = \text{Free Gas} = 29$ m³/m³ = 163 SCF/bbl.

Downhole Volume

$$Q_o = (\text{STBOPD}) \times (B_o) = 550 \times 1.1 = 605 \text{ m}^3/\text{d}$$

$$Q_g = (\text{STBOPD}) \times (\text{GOR}-R_g)/(B_g) = 550 \times (35.5-6.5)/17.5 \\ = 911 \text{ m}^3/\text{d}$$

$$Q_w = 0$$

$$Q_{tP} = 1,516 \text{ m}^3/\text{d} = 9,535 \text{ BPD}$$

There is no hydraulic pump available in the market to handle such a high rate of oil.

In this second trial the pump is settled to a depth (2,150 m) at 132 Kg/cm² pump intake pressure (P_{pin}) which is a bubble point pressure. Here no free gas goes into the pump.

$$Q_{tP} = (\text{STBOPD}) \times (B_o) = 550 \times 1.177 = 647 \text{ (m}^3/\text{d)}$$

$$Q_{tP} = 4,072 \text{ BPD}$$

4) Select the pump to handle the required displacement.

As a rule of thumb (Source: Kobe catalog):

$$\left(\frac{P}{E}\right)_{\max} = \frac{10,000}{\text{net lift (ft)}} = \frac{10,000}{600 \times 3.28} = 5$$

Pump/engine efficiency is shown on Table 25.

Normally the pumping speed increases from the minimum SPM (new pump) to the maximum SPM (old pump) to compensate for lower pump efficiency.

The biggest hydraulic pump available in the market is shown on Table 22:

KOBE Type A Pump, Single Engine, Double Pump End

5) Determine the speed (SPM) required to pump the fluid and the power fluid rate.

Q_{tp} - Total rate of oil to be produced

Q_{in} - Initial power fluid rate - new pump

Q_{fo} - Final power fluid rate - old pump

NEW PUMP/ENGINE

PUMP $Q_{tp} = Q_{pm} \times \text{SPM} \times E_{ff}$
 $4,072 = 65 \times \text{SPM} \times 0.9$
 $\text{SPM} = 69.6 < 77 \text{ (SPM)}_{\max}$

Q_{pm} - from Table 22

E_{ff} - from Table 25

ENGINE $Q_{in} = Q_{en} \times \text{SPM} \times E_{ff}$
 $Q_{in} = 32.94 \times 69.6 \times 0.95$
 $Q_{in} = 2,178 \text{ BPD} = 346 \text{ m}^3/\text{d}$

OLD PUMP/ENGINE

PUMP $Q_{tp} = Q_{po} \times \text{SPM} \times E_{ff}$
 $4,072 = 65 \times \text{SPM} \times 0.7$
 $\text{SPM} = 89.5 > 77 \text{ (SPM)}_{\max}$

This old pump cannot displace the required rate of 4,072 BPD. The maximum flow rate for the old pump would be:

$$Q_{tp} = Q_{po} \times (SPM)_{max} \times E_{ff}$$

$$Q_{tp} = 65 \times 77 \times 0.7$$

$$Q_{tp} = 3,503 \text{ BPD} = 557 \text{ m}^3/\text{d} \text{ at bottom hole conditions,}$$

or

$$Q_{tp} = \frac{3,503}{1.177} = 2,976 \text{ STBOPD} = 473 \text{ m}^3/\text{D} \text{ at surface}$$

conditions

$$\underline{\text{ENGINE}} \quad Q_{fo} = Q_{en} \times (SPM)_{max} \times E_{ff}$$

$$Q_{fo} = 32.94 \times 77 \times 0.8$$

$$Q_{fo} = 2,029 \text{ BPD} = 323 \text{ m}^3/\text{d}$$

- 6) Determine the returned rate of fluid through annulus (Q_{tr}).

$$Q_{tr} = \text{production} + \text{power fluid}$$

$$Q_{tr} = Q_{tp} + Q_i$$

$$\underline{\text{NEW PUMP}} \quad Q_{tr} = 4,072 + 2,178$$

$$Q_{tr} = 6,250 \text{ BPD}$$

$$\underline{\text{OLD PUMP}} \quad Q_{tr} = 3,503 + 2,029$$

$$Q_{tr} = 5,532 \text{ BPD}$$

- 7) Determine the power fluid friction loss (ΔP_{fi})

$$T_{avg} = \frac{82 + 178}{2} = 130^\circ\text{F}$$

From Table 26 (Refinery Analysis of Crude Oil Sample Made by Flopetrol):

75°F - 72 cst

155°F - 10.4 cst

115°F - 22 cst

200°F - 5.4 cst

Plotting kinematic viscosity and temperature in a semi-log paper (Figure 30) and extrapolating for $T_{avg} = 130^{\circ}\text{F}$ the viscosity will be:

$$\mu_o = 16 \text{ cst or } \mu_o = 80 \text{ SSU}$$

From Figure 31, for

$\phi_t = 4\text{-}1/2$ " tubing

$\mu_o = 80 \text{ SSU}$ and $Q_{in} = 2,178 \text{ BPD}$ power fluid rate

Friction loss = 3.0 psi/1000'

$$\Delta P_{fi} = 3.0 \times \frac{2,448 \times 3.28}{1000} \times 0.934$$

$$\Delta P_{fi} = 22.5 \text{ psi (power fluid friction loss)}$$

$$D_p = 2,150\text{m (vertical)} = 2,448 \text{ m (directional)}$$

$$\gamma_o = 0.934$$

8) Determine the returned fluid friction loss (ΔP_{fr}) coming up 9-5/8" x 4-1/2" annulus, $Q_{tr} = 6,250 \text{ BPD}$.

$T_{avg} = 150^{\circ}\text{F}$ and neglecting gas from Figure 30,

$$\mu_o = 11 \text{ cst}$$

$$\mu_o = 60 \text{ SSU}$$

From Figure 32 at $Q_{tr} = 6,250 \text{ BPD}$

$$\mu_o = 60 \text{ SSU, friction loss} = 1.0 \frac{\text{psi}}{1000'}$$

$$\Delta P_{fr} = 1.0 \times \frac{2,448 \times 3.28}{1000} \times 0.934$$

$$\Delta P_{fr} = 7.5 \text{ psi (returned fluid friction loss)}$$

9) Determine the pump discharge pressure (P_{pout})

$$P_{ef} = P_{cwh} + P_{fr} + P_{head}$$

P_{ef} = pressure to lift fluid

D_{ll} = 600 m working liquid level

$$P_{head} \text{ (neglecting gas)} = 600 \times 3.28 \times 0.934 \times 0.433 = 796 \text{ psi}$$

$$P_{ef} = 100 + 7.5 + 796$$

$$P_{ef} = 903.5 \text{ psi}$$

$$P_{ef} = 63.5 \text{ Kg/cm}^2$$

Then,

$$P_{pout} = P_{ef} + P_{pin}$$

P_{pin} = pump intake pressure

$$P_{pout} = 63.5 + 132$$

$$P_{pout} = 195.5 \text{ Kg/cm}^2 = 2,780 \text{ psi.}$$

By including the gas and calculating the pressure pump discharge from the Orkiszewski correlations using FGERAL, it is necessary to find a pipe diameter equivalent to the annulus 9-5/8" x 4-1/2". I used Figure 32 here to calculate friction loss.

10) Effective pressure of power fluid column = $0.934 \times 0.433 \times 2,150 \times 3.28 - 22.5 = 2,830 \text{ psi} = 199 \text{ Kg/cm}^2$.

11) Determine pump friction (ΔP_f).

$$\text{Percent of rated speed} = \frac{\text{SPM cal.}}{\text{SPM max.}} = \frac{69.6}{77} \times 100 = 90\%$$

From Figure 33 using KOBE A, SE, DP (KOBE Type A, Single Engine, Double Pump End) % SPM = 90% and $\mu_o = 7$ cst (Figure 30) at bottom hole temperature (180°F at 2150 m).

$$\Delta P = 650 \text{ psi (this value is off scale)}$$

Then, pump friction will be

$$\Delta P_f = \Delta P \times \gamma_o = 650 \times 0.934 = 607 \text{ psi}$$

12) Determine the power fluid surface pressure (P_s)

$$P_{ein} = P_s + hG_o - \Delta P_{fi}$$

$$P_{ein} = P_s + 2,150 \times 3.28 (0.432 \times 0.934) - 22.5$$

$$P_{ein} = P_s + 2,830$$

$$P_{eout} = P_{pout} = 2,780 \text{ psi}$$

$$P_{pin} = 132 \text{ Kg/cm}^2 = 1,877 \text{ psi}$$

$$(P_{ein} - P_{eout}) - (P_{pout} - P_{pin}) \frac{P}{E} - \Delta P_f = 0$$

$$\Delta P_f = 607 \text{ psi (pump friction)}$$

$$\frac{P}{E} = 2$$

$$(P_s + 2,830 - 2,780) - (2,780 - 1,877) \times 2 - 607 = 0$$

$$\underline{P_s = 2,363 \text{ psi}}$$

13) Determine hydraulic hp and prime mover hp

$$(\text{HP})_{\text{hyd}} = (1.7 \times 10^{-5}) P_s \times Q$$

$$(\text{HP})_{\text{hyd}} = (1.7 \times 10^{-5}) 2,363 \times 2,178 = 88 \text{ hp}$$

$$(\text{HP})_{\text{prime mover}} = \frac{(\text{HP})_{\text{hyd}}}{0.9} = 97 \text{ hp}$$

4. Hydraulic Pumping Design (Well N-16(c))

Using data from Table 27, the hydraulic pump can be calculated as follows:

1) Type of installation: Parallel free tubing arrangements OPF system will be the installation chosen as shown on Figure 29.

Both tubing strings will be 3-1/2"; 2.992 in I.D.

The gas will be vented through annulus 9-5/8" x 3-1/2" x 3-1/2".

2) Determine bottom hole flowing pressure (P_{wf}), pump intake pressure (P_{pin}) and depth of the pump (D_p).

The flow rate will be fixed at 300 m³/d and the static pressure will decrease freely since no reservoir pressure maintenance will be done in Carapebus sandstone. For this reason, a hydraulic pump should be set close to the production zone to give the widest range of pumping rates. The reservoir pressure can drop to the abandonment pressure and no workover will be used to continue pumping the well.

Assuming the reservoir pressure at 175 Kg/cm², we can calculate the hydraulic pump as follows:

Using vertical multiphase flow (Orkiszewski) correlations for the well flowing 300 m³/d through a 3-1/2" tubing string, 175 Kg/cm² reservoir pressure, 15 m³/d/Kg/cm² productivity index, we can determine the working liquid

level ($D_{11} = 800\text{m}$), the depth of the pump ($D_p = 2,670\text{ m}$), the pump intake pressure and the bottom hole flowing pressure, $P_{pin} = P_{wf} = 155\text{ Kg/cm}^2$.

I used here to determine the working liquid level, the dynamic gradient 0.343 psi/ft from Figure 24 "Submersible Pump Setting" N-16(C).

3) Determine the produced rate of fluids (oil, gas, and water through pump (Q_{tp}) or the actual pump displacement to produce fluids.

The hydraulic pump should displace at least

$$\frac{Q_{tp}}{0.7} = \frac{356}{0.7} = \frac{2,240}{0.7} = 3,200\text{ BPD}$$

4) Select the pump

From Table 22: KOBE Type E Pump, Single Engine,
Single Pump End

Determine the speed (SPM) required to pump the fluid and the power fluid rate.

NEW PUMP/ENGINE

$$\text{PUMP} \quad Q_{tp} = Q_{pm} \times \text{SPM} \times E_{ff}$$

$$2,240 = 75.76 \times \text{SPM} \times 0.90$$

$$\text{SPM} = 32.8 < 53 (\text{SPM})_{\text{max}}$$

$$\begin{aligned} \text{ENGINE} \quad Q_{in} &= Q_{en} \times \text{SPM} \times E_{ff} \\ Q_{in} &= 66.32 \times 32.8 \times 0.95 \\ Q_{in} &= 2,066 \text{ BPD} = 328 \text{ m}^3/\text{d} \end{aligned}$$

$$\text{at } P_{pin} = P_{wf} = 155 \text{ Kg/cm}^2$$

$$R_s = 20 \text{ m}^3/\text{m}^3 \text{ (gas in solution) assumed}$$

$$(\text{GOR})_F = 20 \text{ m}^3/\text{m}^3 \text{ (free gas)}$$

$$(\text{GOR})_P = 10 \text{ m}^3/\text{m}^3 \text{ (pumped free gas) estimated}$$

$$(\text{GOR})_V = 10 \text{ m}^3/\text{m}^3 \text{ (vented gas) estimated}$$

$$B_o = 1.12 \text{ by Standing's correlation}$$

DOWNHOLE VOLUME

$$Q_o = (\text{STBOPD}) \times B_o = 300 \times 1.12 = 336 \text{ m}^3/\text{d}$$

$$\begin{aligned} Q_g &= \frac{P_{sc} T_{wf}}{T_{sc} P_{wf}} z_{wf} \times (\text{GOR})_P \times Q_o = \frac{14.7 \times 610}{520 \times 2204} \\ &\quad \times 0.87 \times 10 \times 300 = 20 \text{ m}^3/\text{d} \end{aligned}$$

$$Q_{tp} = 336 + 20 = 356 \text{ m}^3/\text{d} = 2,240 \text{ BPD}$$

5) Select the pump to handle the required displacement.

As a rule of thumb (Kobe catalog):

$$\left(\frac{P}{E}\right)_{\max} = \frac{10,000}{\text{Net Lift (ft)}} = \frac{10,000}{710 \times 3.28} = 4.3$$

$$D_{11} = 800 \text{ m at } P_{cwh} = 100 \text{ psi}$$

or

$$D_{11} = 710 \text{ m at } P_{cwh} = 1 \text{ atm}$$

Normally the pumping speed increases from the minimum SPM (new pump) to the maximum SPM (old pump) to compensate lower pump efficiency.

OLD PUMP/ENGINE

$$\begin{aligned}
 \text{PUMP} \quad Q_{tp} &= Q_{PO} \times \text{SPM} \times E_{ff} \\
 2,240 &= 75.76 \times \text{SPM} \times 0.7 \\
 \text{SPM} &= 42.2 < 53 \text{ (SPM)}_{\max} \\
 2,240 &= 75.76 \times 53 \times E_{ff} \\
 E_{ff} &= 56\%
 \end{aligned}$$

This old pump can displace the required rate of 2,240 BPD. This pump can be used until it reaches 56 percent pumping efficiency.

After that, the pump needs repair or the oil production will drop below 300 STBOPD.

$$\begin{aligned}
 \text{ENGINE} \quad Q_{fo} &= Q_{eo} \times (\text{SPM})_{\max} \times E_{ff} \\
 Q_{fo} &= 66.32 \times 53 \times 0.8 \\
 Q_{fo} &= 2,812 \text{ BPD} = 447 \text{ m}^3/\text{d}
 \end{aligned}$$

- 6) Determine the returned rate of fluid through 3 1/2".

$$Q_{tr} = \text{Production} + \text{Power Fluid}$$

$$\text{OLD PUMP } Q_{tr} = Q_{tp} + Q_{fo}$$

$$Q_{tr} = 2,240 + 2,812$$

$$Q_{tr} = 5,052 \text{ BPD} = 803 \text{ m}^3/\text{d}$$

- 7) Determine the power fluid friction loss (ΔP_{fi})

$$T_{avg} = 146^{\circ}\text{F}$$

From Figure 30, $\mu_o = 17$ cst or $\mu_o = 85$ SSU. From Figure 34 for $\phi_t = 3 \frac{1}{2}$ " tubing, $\mu_o = 85$ SSU and $Q_{fo} = 2,812$ BPD, the pressure drop = 13 psi/1,000 ft.

$$\Delta P_{fi} = 13 \times \frac{2730 \times 3.28}{1,000} \times 0.898$$

$$\Delta P_{fi} = 105 \text{ psi (power fluid friction loss)}$$

- 8) Determine the returned fluid friction loss (ΔP_{fr}) coming up through 3 1/2" EU tubing.

$$Q_{tr} = 803 \text{ m}^3/\text{d} = 5,052 \text{ BPD}$$

$$T_{avg} = 146^{\circ}\text{F}$$

Neglecting gas

$$\mu_o = 85 \text{ SSU from Figure 30}$$

pressure drop in 3 1/2" tubing = 40 psi/1,000 ft from Figure 34.

$$\Delta P_{fr} = 40 \times \frac{2,730 \times 3.28}{1,000} \times 0.898$$

$$\Delta P_{fr} = 322 \text{ psi (returned fluid friction loss)}$$

9) Determine the pump discharge pressure (P_{pout})

$$P_{ef} = P_{cwh} + \Delta P_{fr} + P_{head}$$

$$P_{ef} = \text{Pressure to lift fluid}$$

$$D_{11} = 710 \text{ m working liquid level}$$

$$P_{head} \text{ (neglecting gas)} = 710 \times 3.28 \times 0.898 \times 0.433 = 906 \text{ psi}$$

$$P_{ef} = 100 + 322 + 906$$

$$P_{ef} = 1,328 \text{ psi} = 93.4 \text{ Kg/cm}^2$$

$$P_{pout} = P_{ef} + P_{pin}$$

$$P_{pin} = P_{wf} = 155 \text{ Kg/cm}^2$$

$$P_{pout} = 93.4 + 155$$

$$P_{pout} = \underline{248.4} \text{ Kg/cm}^2 = 3,532 \text{ psi}$$

10) Effective pressure of power fluid column = $0.898 \times 0.433 \times 2,670 \times 3.28 - 105 = 3,300 \text{ psi} = 232 \text{ Kg/cm}^2$.

11) Determine pump friction (ΔP_f).

$$\text{Percent of rated speed} = \frac{\text{SPM cal}}{\text{SPM max}} = \frac{53}{53} = 100\%$$

I have calculated the system to work until the pump efficiency drops to 56 percent. At that time the pump will reach the maximum stroke per minute (SPM) specified.

From Figure 33 using KOBE E, SINGLE ENGINE, SINGLE PUMP END, SPM = 100% and $\mu_o = 7.5 \text{ cst}$ from Figure 30 at bottom hole temperature = 210°F .

$$\Delta P = 1,400 \text{ psi (this value is off scale)}$$

$$\Delta P_f = 1,400 \times 0.898 = 1,257 \text{ psi} = 88.4 \text{ Kg/cm}^2$$

- 12) Determine the power fluid surface pressure (P_s)

$$P_{ein} = P_s + hG_o - \Delta P_{fi}$$

$$P_{ein} = P_s + 2,670 \times 3.28 \times 0.898 \times 0.433 - 105$$

$$P_{ein} = P_s + 3,300$$

$$P_{eout} = P_{pout} = 3,532 \text{ psi}$$

$$P_{pin} = 155 \text{ Kg/cm}^2 = 2,204 \text{ psi}$$

$$(P_{pin} - P_{eout}) - (P_{pout} - P_{pin}) \frac{P}{E} - \Delta P_f = 0$$

$$\Delta P_f = 1,257 \text{ psi (pump friction)}$$

$$\frac{P}{E} = 1.142$$

$$(P_s + 3,300 - 3,532) - (3,532 - 2,204) \times 1.142 - 1,257 = 0$$

$$\underline{P_s = 3,005 \text{ psi}}$$

- 12) Determine hydraulic hp and prime mover hp

$$(HP)_{hyd} = (1.7 \times 10^{-5}) \times P_s \times Q_{FO}$$

$$(HP)_{hyd} = 1.7 \times 10^{-5} \times 3,005 \times 2,812 = 144 \text{ hp}$$

$$(HP)_{\text{prime mover}} = \frac{(HP)_{hyd}}{0.9} = \frac{144}{0.9} = 160 \text{ hp}$$

5. Surface Pumps Design

The surface pumps size did not consider every well from one platform spending the maximum in power fluid all at once. Naturally there will be old and new pumps in operation at the same time.

The power fluid rate to surface pumps calculation was taken as the totality of average power fluid needed in each well.

$$Q_s = \Sigma \frac{Q_{\max} + Q_{\min}}{2}$$

The Table 23 shows the prime mover horsepower required (1,707 HP and 1,783 HP) to the wells in PCH-1 and PCH-2, respectively.

The biggest KOBE triplex pump in the market is shown on Table 28.

The triplex pump below should be used to pump wells producing from Carapebus sandstone.

(Source: KOBE catalog)

Serie - 4 inches

180 HP input

5000 psi cylinder block

plunger diameter - 1 3/4 inches

maximum pressure (psi) 4,000

displacement/100 RPM - 535 BPD

displacement/400 RPM - 2,140 BPD

displacement/450 RPM - 2,408 BPD

Working in 400 RPM and 3,000 psi at surface, the number of triplex needed to produce oil from Carapebus sandstone will be:

$$\text{PCH-1} = \frac{4,875 \text{ BPD}}{2,140 \text{ BPD}} = 2.3 = 3 \text{ pumps}$$

$$\text{PCH-2} = \frac{14,625 \text{ BPD}}{2,140 \text{ BPD}} = 6.8 = 7 \text{ pumps}$$

The triplex pump below should be used to pump wells producing from Namorado sandstone:

(Source: KOBE catalog)

Series - 4 inches

180 HP input

5,000 psi cylinder block

plunger diameter - 2 inches

maximum pressure - 3,060 psi

displacement/100 RPM - 700 BPD

displacement/400 RPM - 2,800 BPD

displacement/450 RPM - 3,150 BPD

Working at 400 RPM and 3,000 psi at surface, the number of triplex pumps needed to produce oil from Namorado sandstone will be:

$$\text{PCH-1} = \frac{25,248}{2,800} = 9 \text{ pumps}$$

$$\text{PCH-2} = \frac{16,832}{2,800} = 6 \text{ pumps}$$

TOTAL TRIPLEX PUMPS

PCH-1

3 pumps (plunger 1 3/4")

9 pumps (plunger 2")

3 spare parts pumps (plunger 2")

15 Total PCH-1

PCH-2

7 pumps (plunger 1 3/4")

6 pumps (plunger 2")

3 spare parts pumps (plunger 1 3/4")

16 Total PCH-2

The total installed horsepower will be:

PCH-1

$$12 \times 180 \text{ hp} = 2,160 \text{ hp}$$

$$3 \times 180 \text{ hp (spare parts)} = \underline{480} \text{ hp}$$

$$2,640 \text{ hp}$$

PCH-2

$$13 \times 180 \text{ hp} = 2,340 \text{ hp}$$

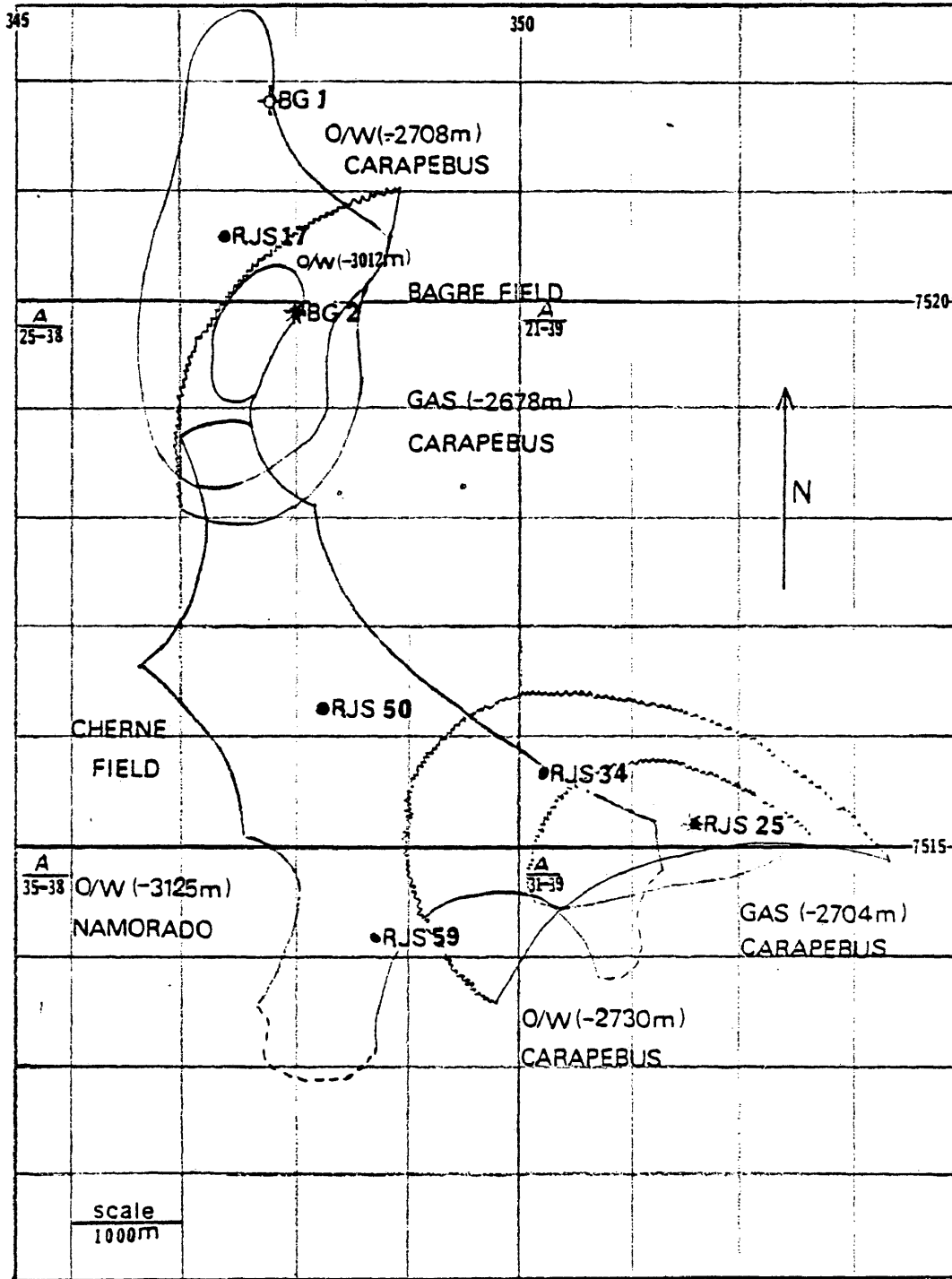
$$3 \times 180 \text{ hp (spare parts)} = \underline{480} \text{ hp}$$

$$2,820 \text{ hp}$$

Table 29 shows the fluid and rock properties for Namorado. Tables 30 and 31 show general data and required horsepower, respectively.

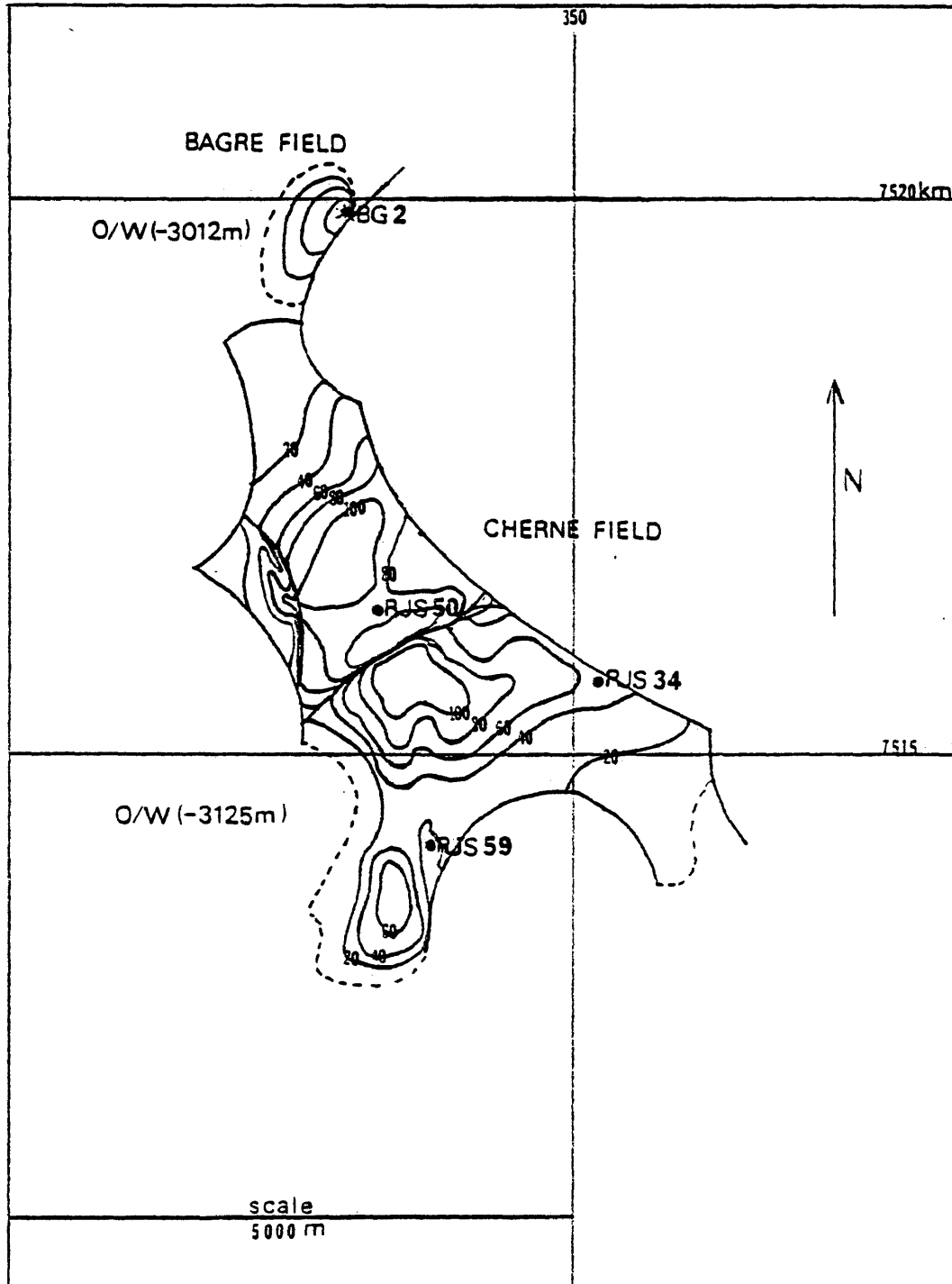
Appendix B

Figure 1
Hydrocarbon Zones (Namorado and Carapebus)



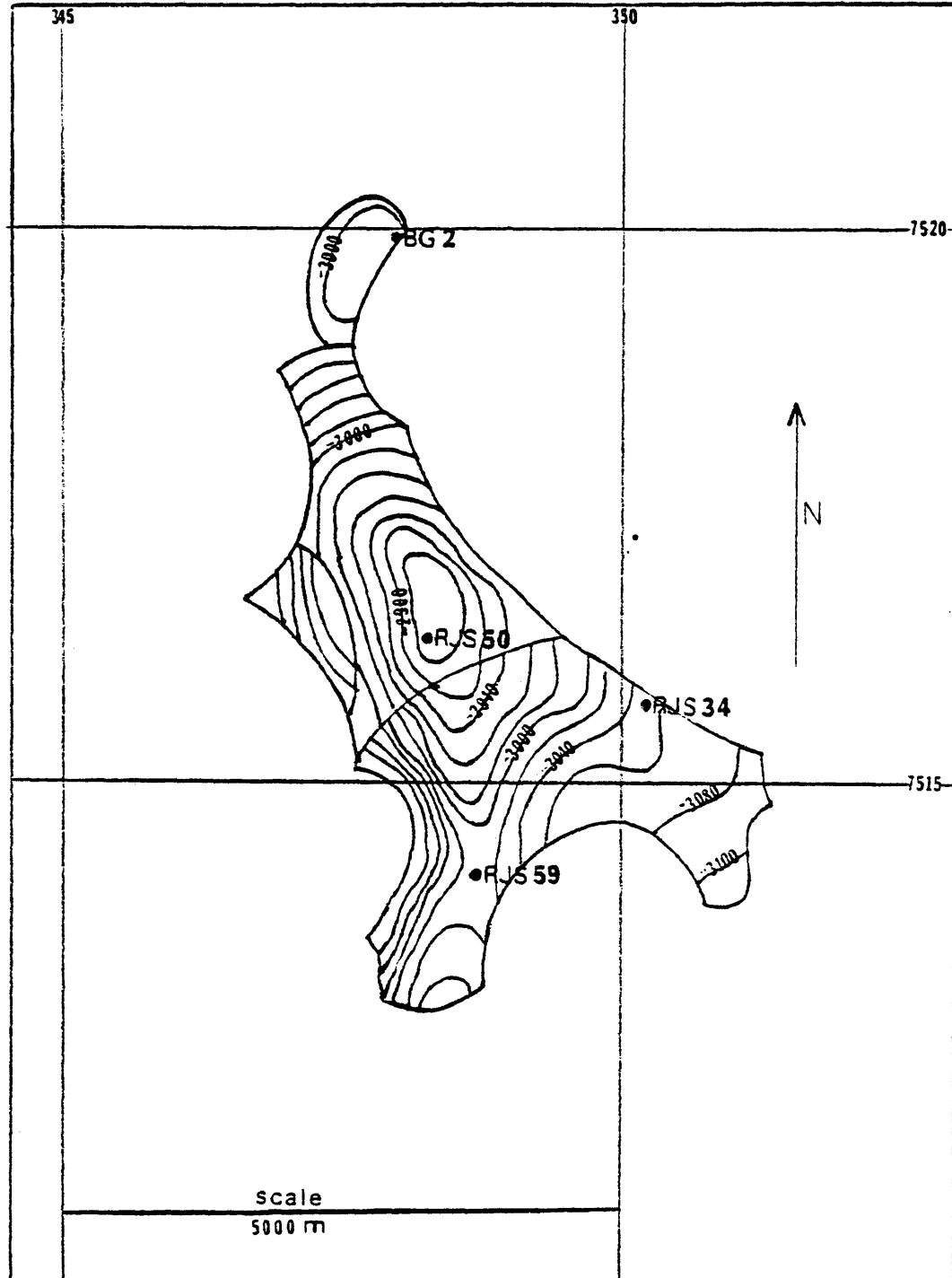
Source: PETROBRAS

Figure 2
Namorado Isopach Map



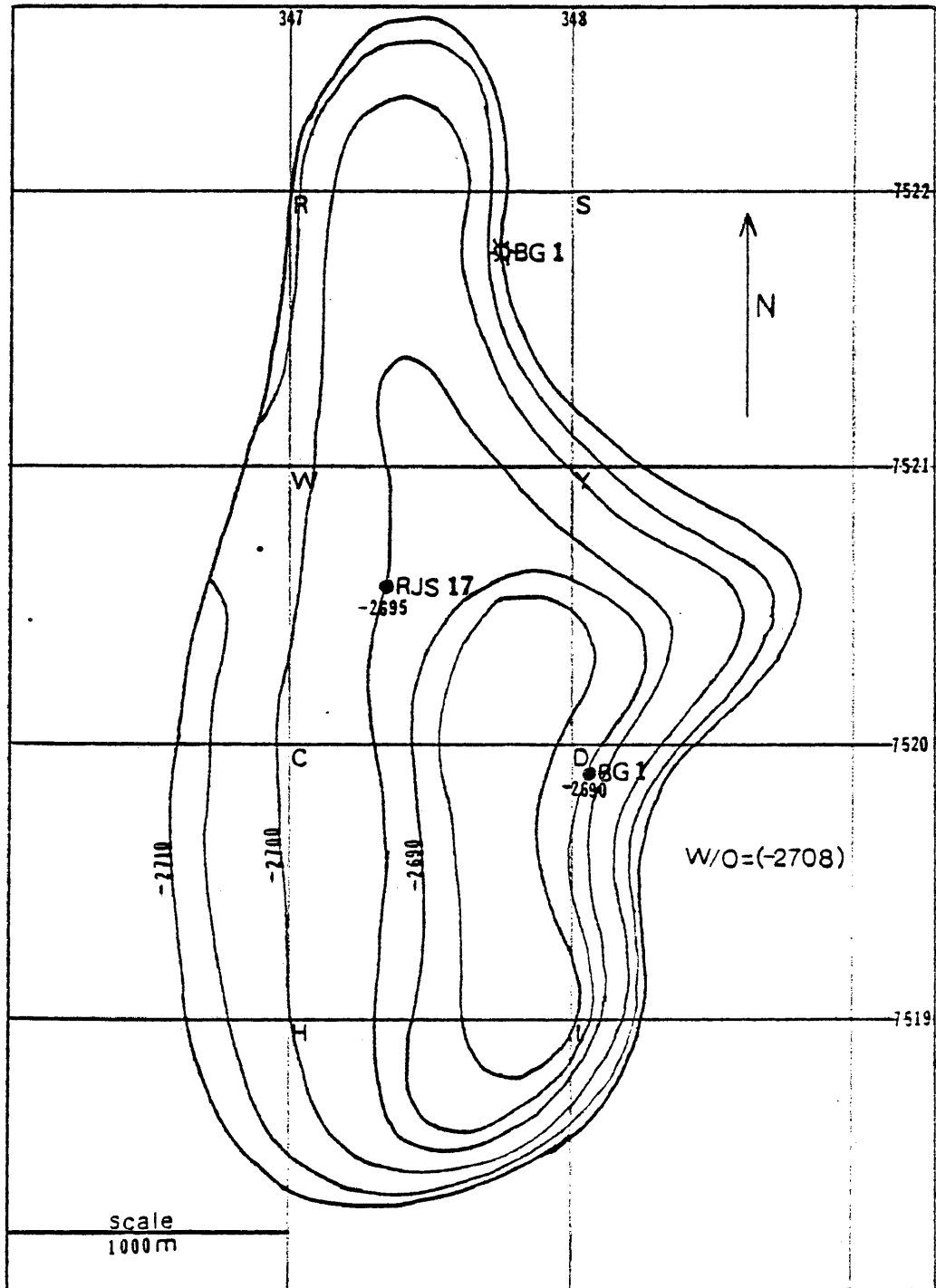
Source: PETROBRAS

Figure 3
Namorado Structural Map



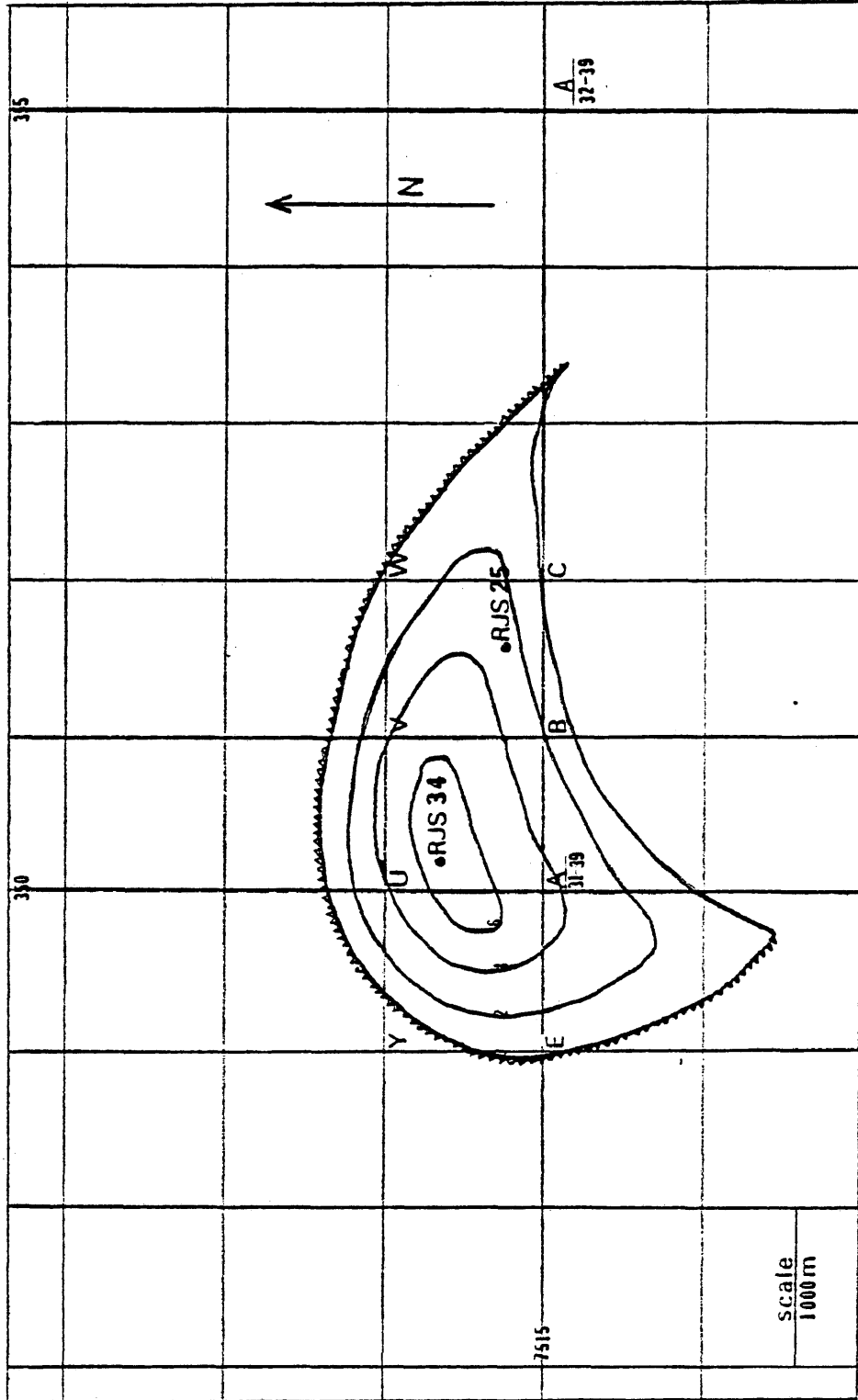
Source: PETROBRAS

Figure 4
Carapebus Structural Map (RJS-17 Area)



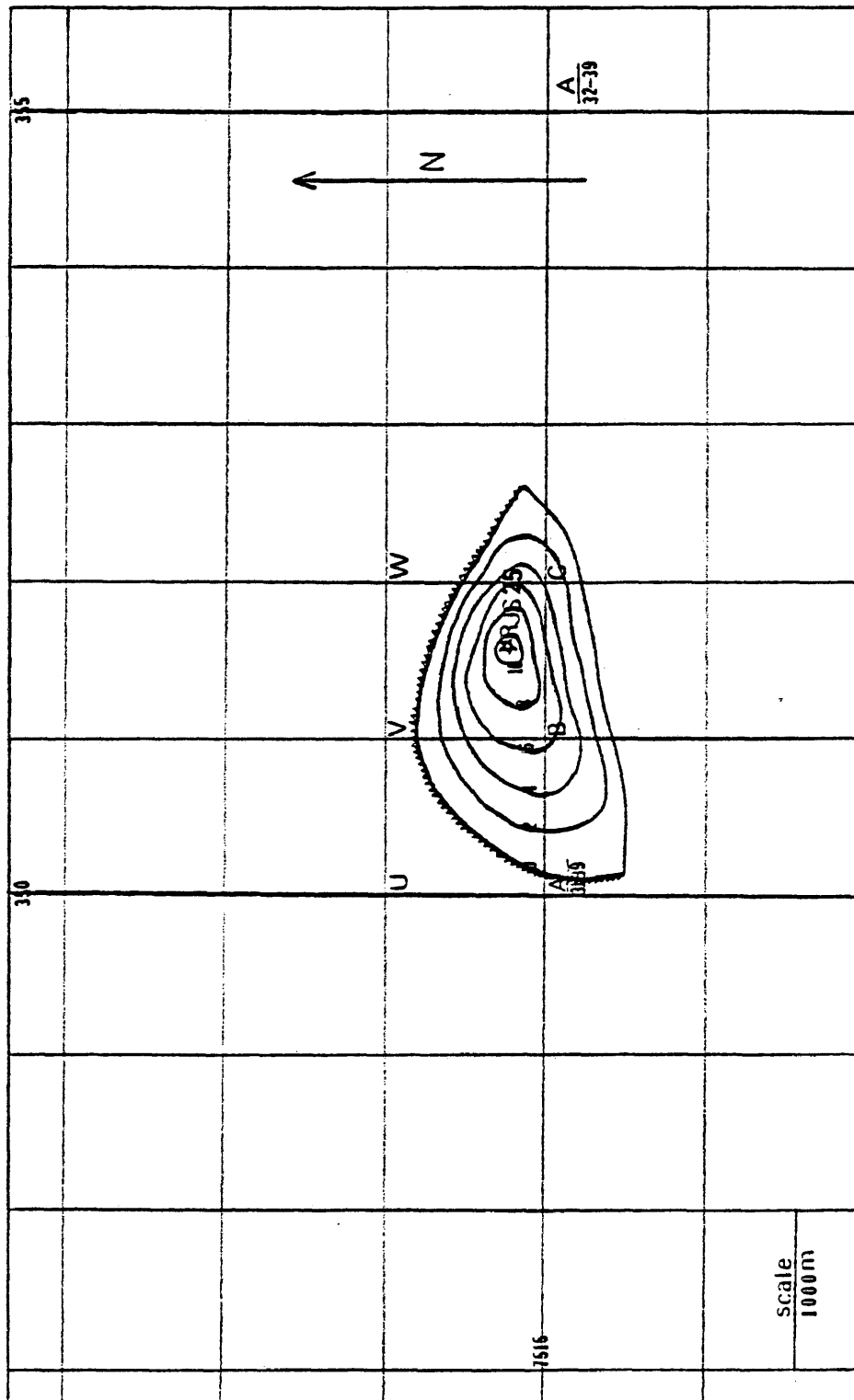
Source: PETROBRAS

Figure 5
Carapebus Isopach Map (RJS-34 Area)



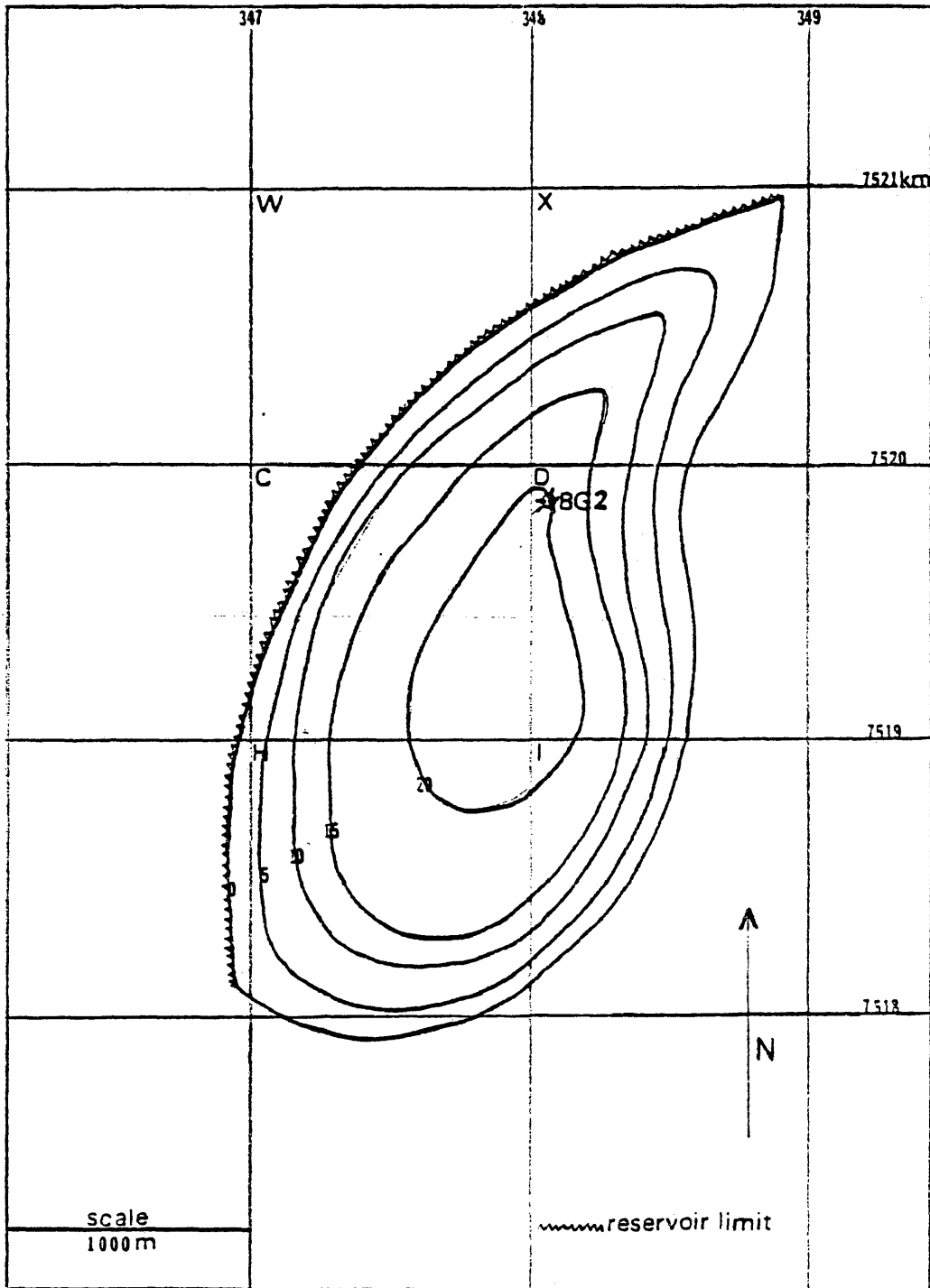
Source: PETROBRAS

Figure 6
Carapebus Isopach Gas Map (RJS-25 Area)



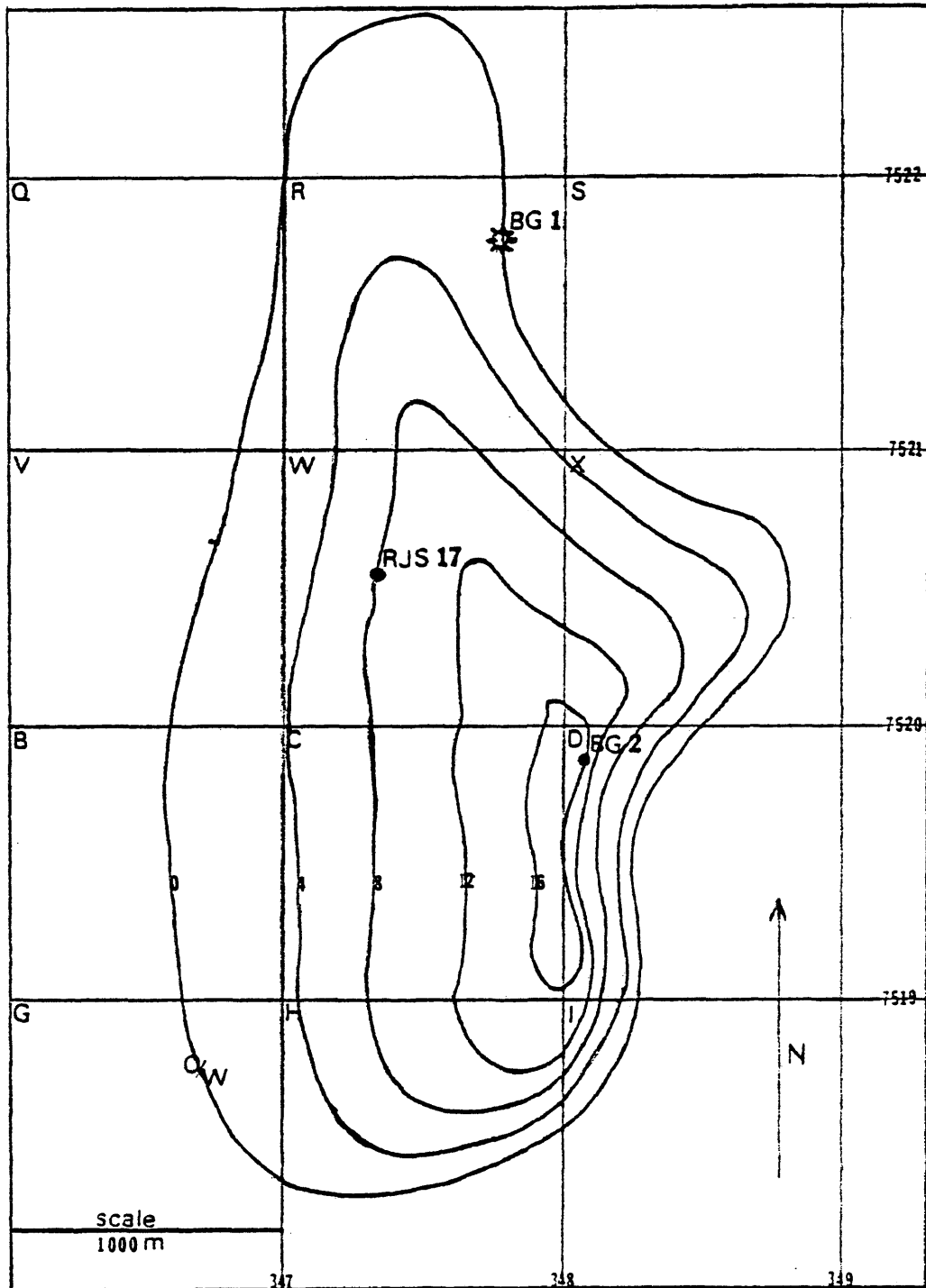
Source: PETROBRAS

Figure 7
Carapebus Isopach Gas Map (BG-2 Area)



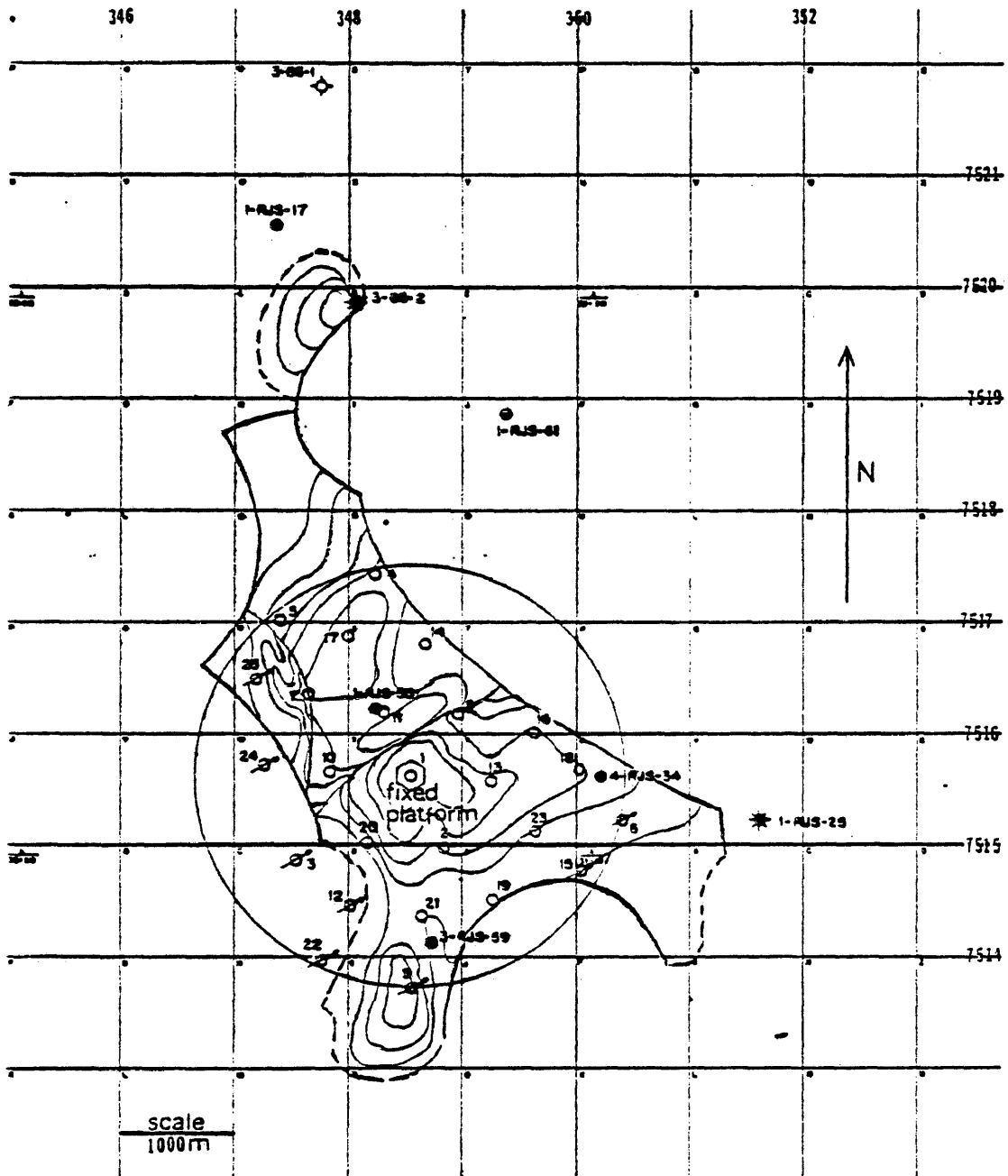
Source: PETROBRAS

Figure 8
Carapebus Isopach Map (RJS-17 Area)



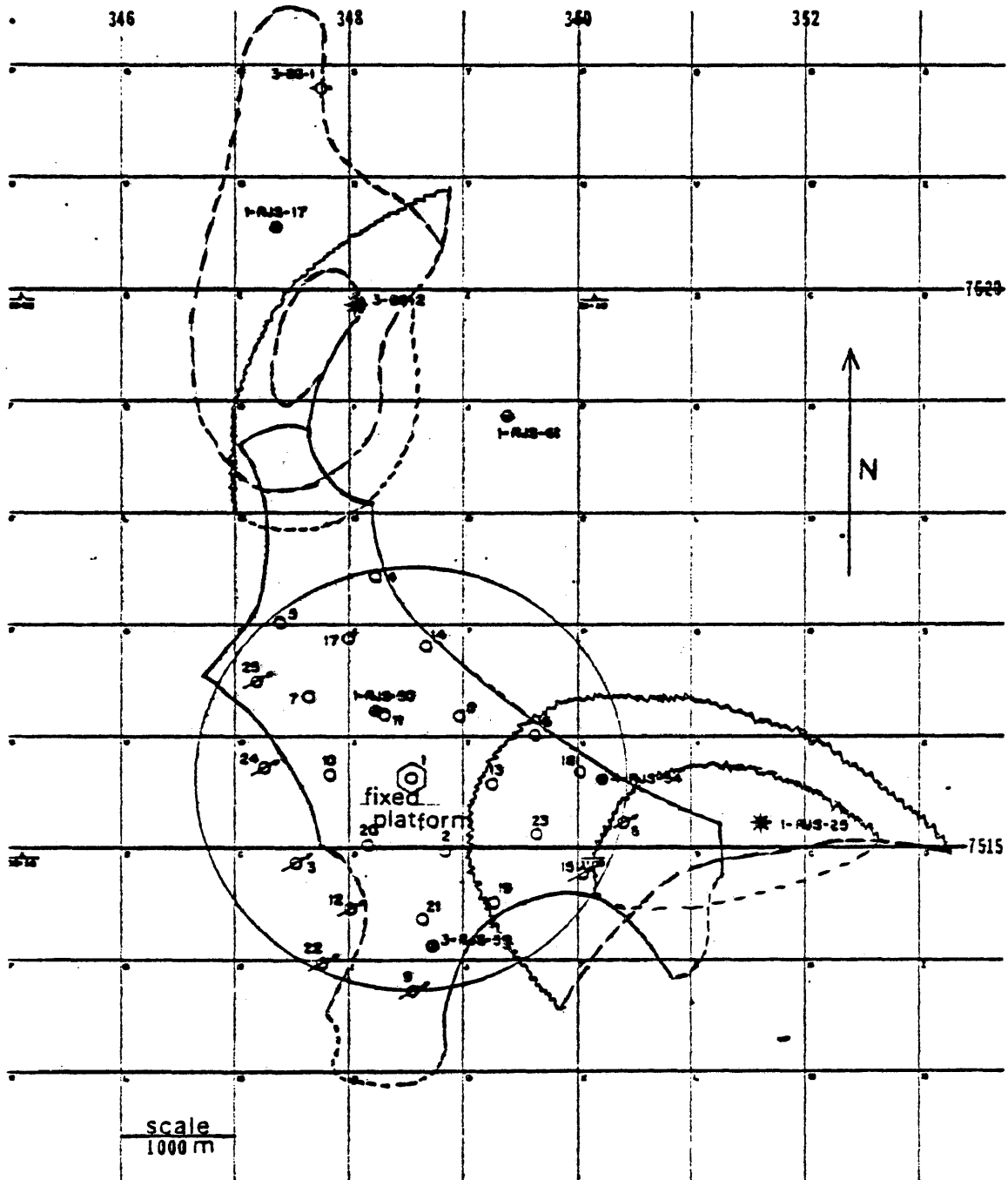
Source: PETROBRAS

Figure 9
One Platform - Namorado Sandstone



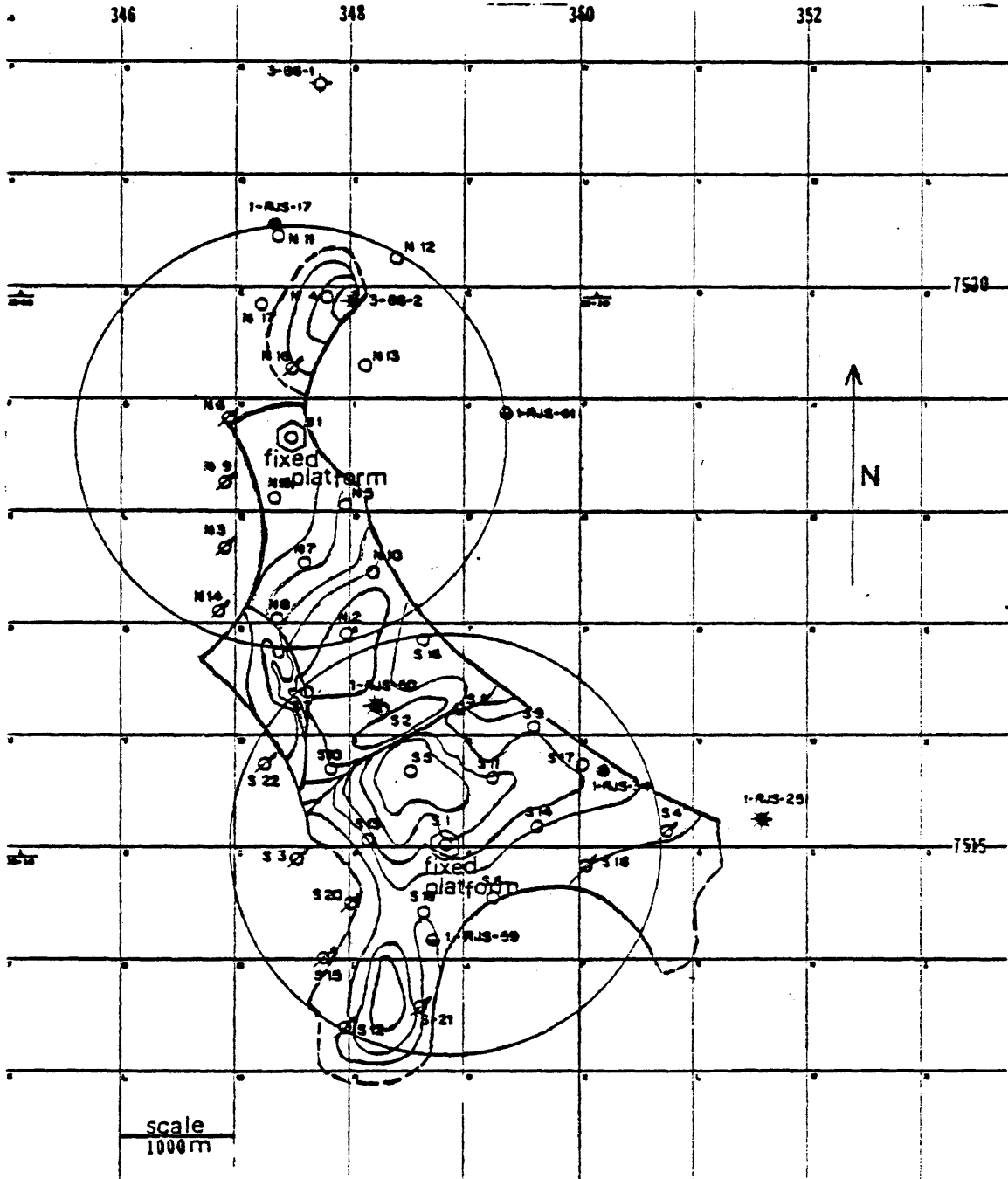
Source: PETROBRAS

Figure 10
One Platform - Namorado and Carapebus Sandstone



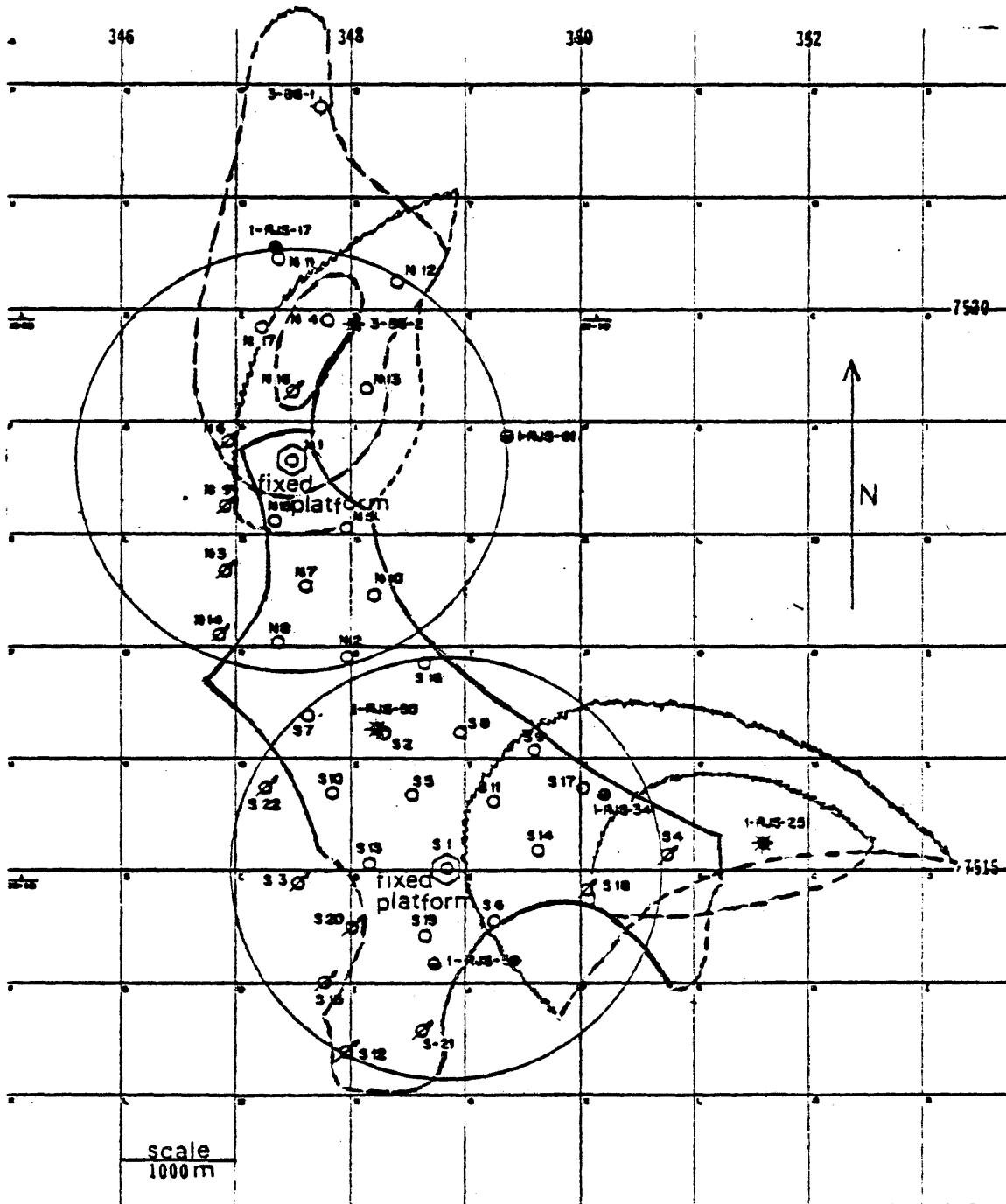
Source: PETROBRAS

Figure 11
Two Platforms - Namorado Sandstone



Source: PETROBRAS

Figure 12
Two Platforms - Namorado and Carpebus Sandstone



Source: PETROBRAS

Figure 13
Production Behavior

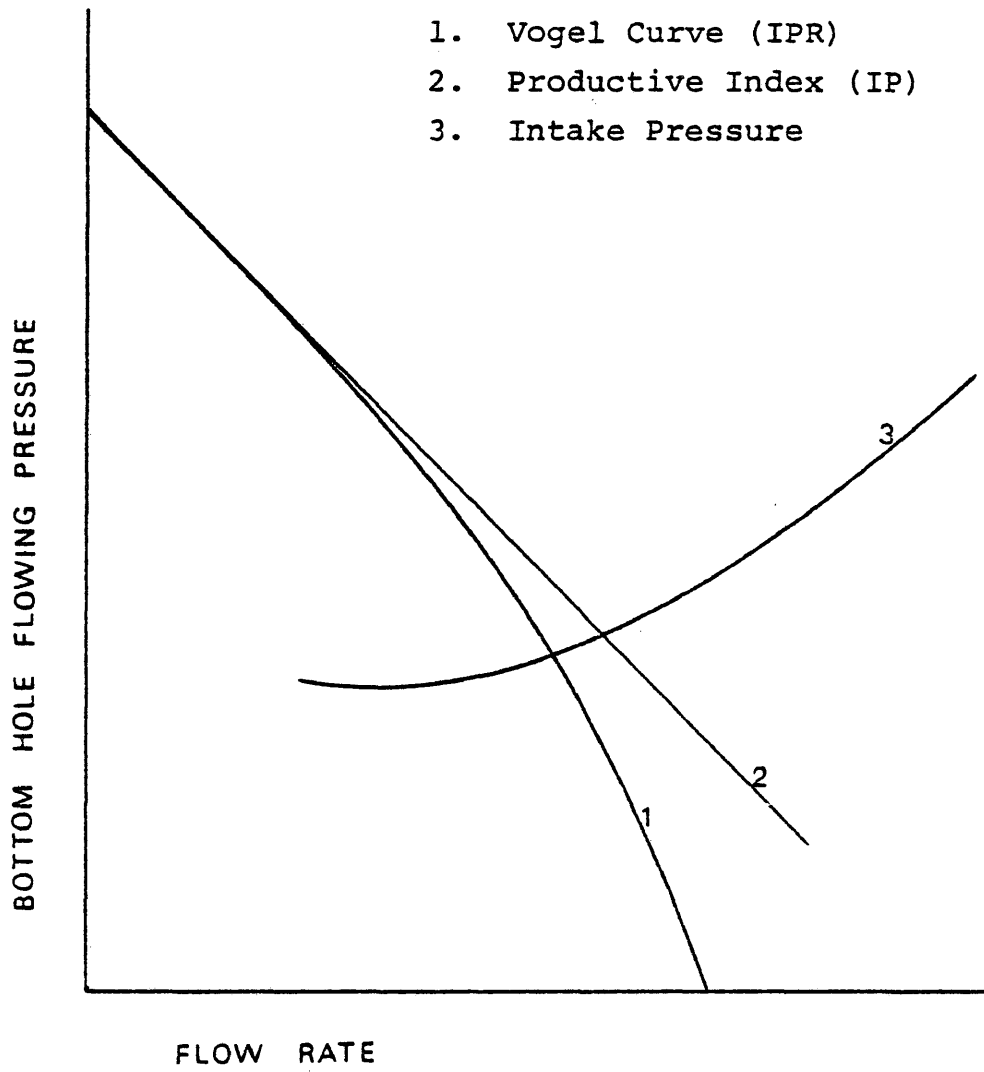


Figure 14

INTAKE PRESSURE VS. IP
S-5 (N) ORKISZEWSKI

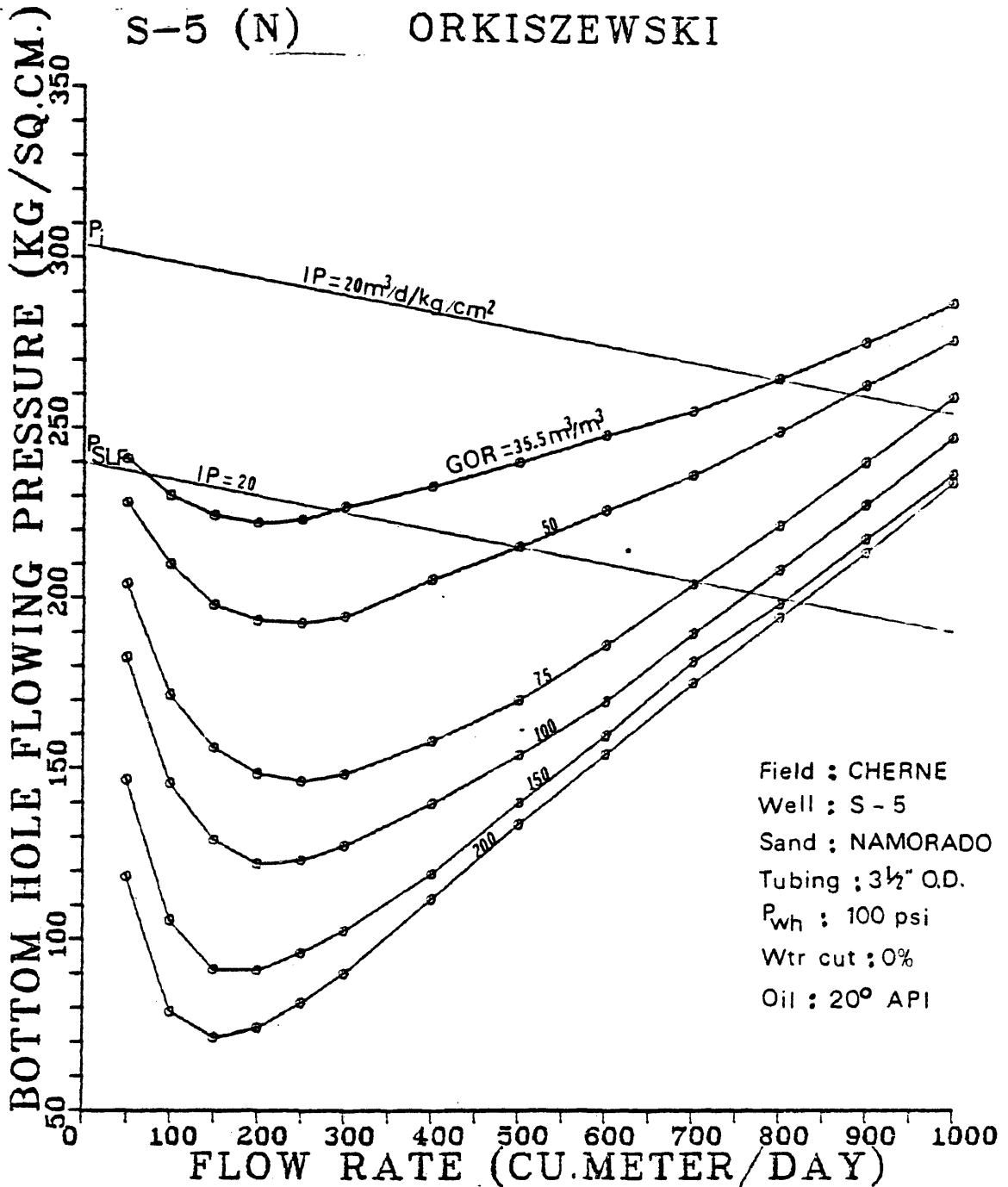


Figure 15

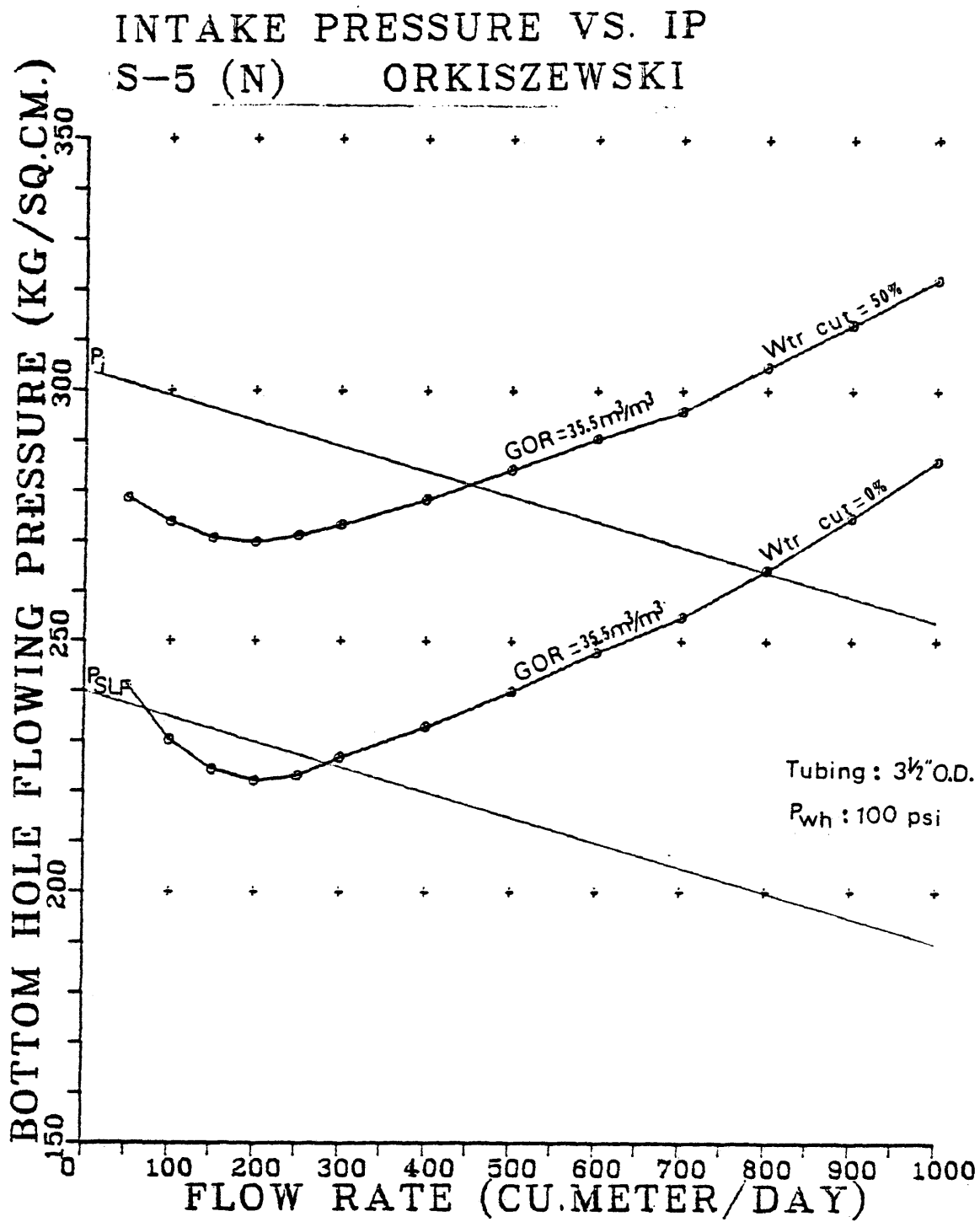
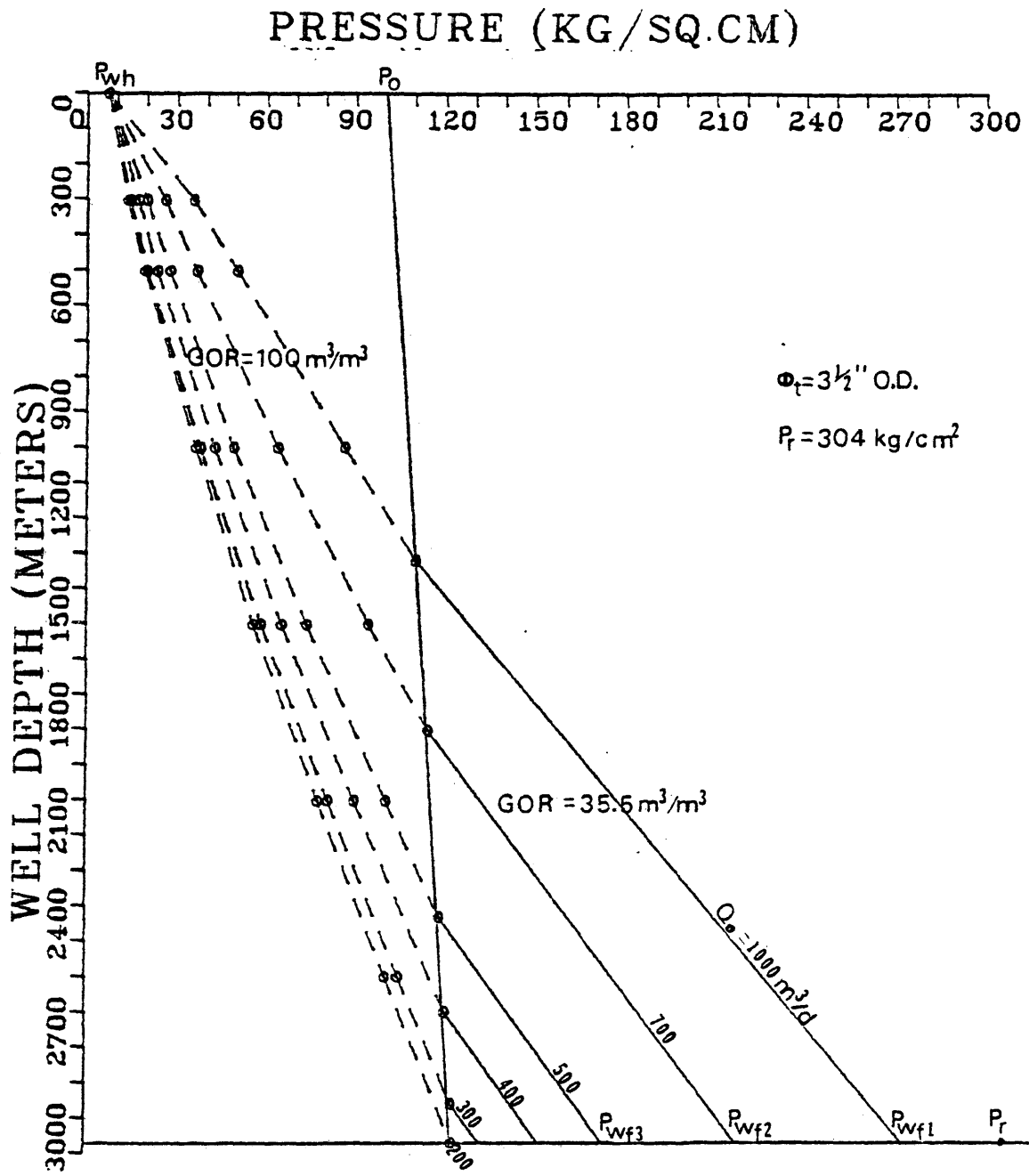


Figure 16



$\phi_t = 3\frac{1}{2}$ " O.D.

$P_r = 304 \text{ kg/cm}^2$

GOR = $100 \text{ m}^3/\text{m}^3$

GOR = $35.6 \text{ m}^3/\text{m}^3$

$Q_e = 1000 \text{ m}^3/\text{d}$

100

500

1000

P_{wf3}

P_{wf2}

P_{wf1}

P_r

R_{wh}

P_b

0

300

600

900

1200

1500

1800

2100

2400

2700

3000

30

60

90

120

150

180

210

240

270

300

Figure 17

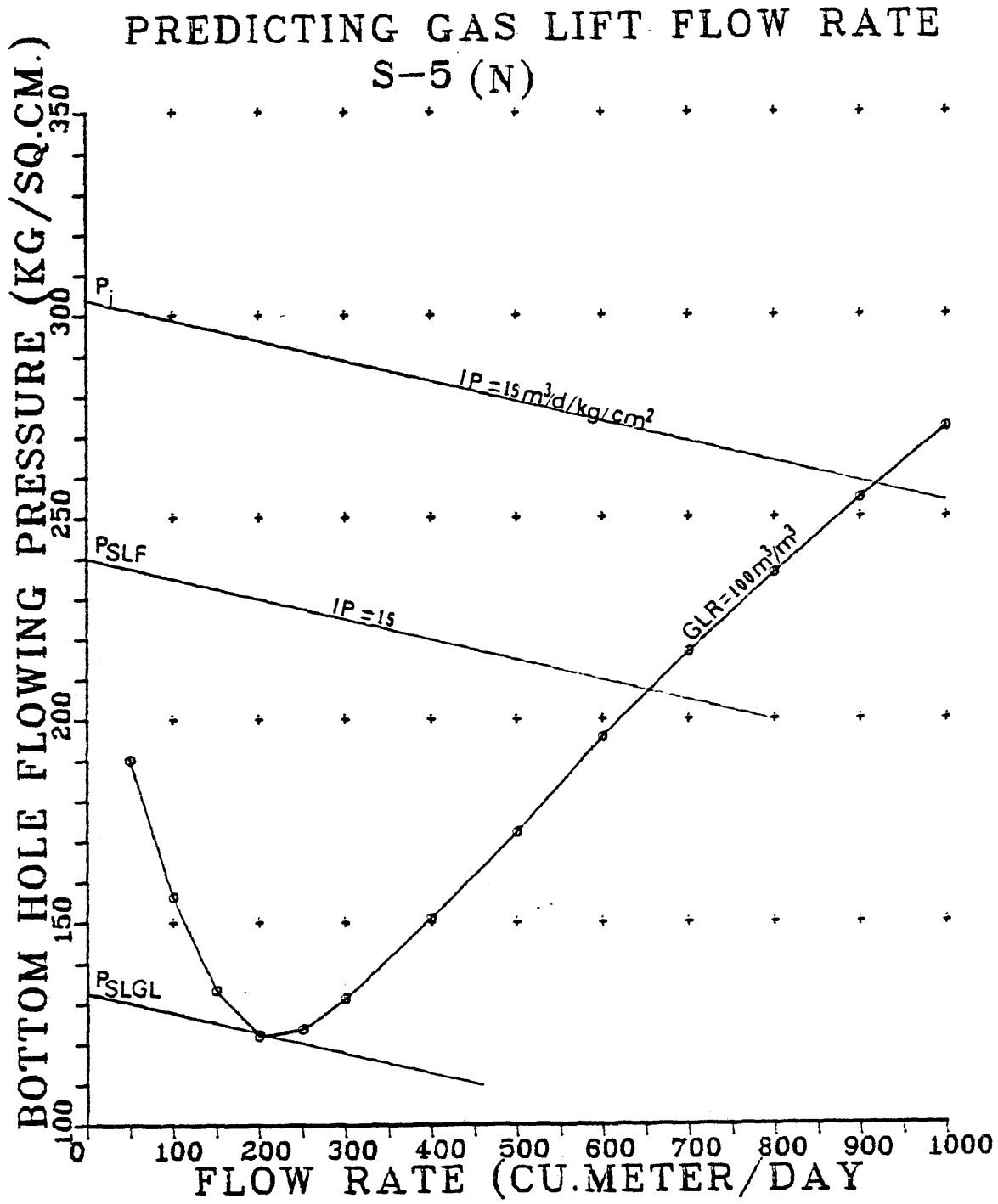
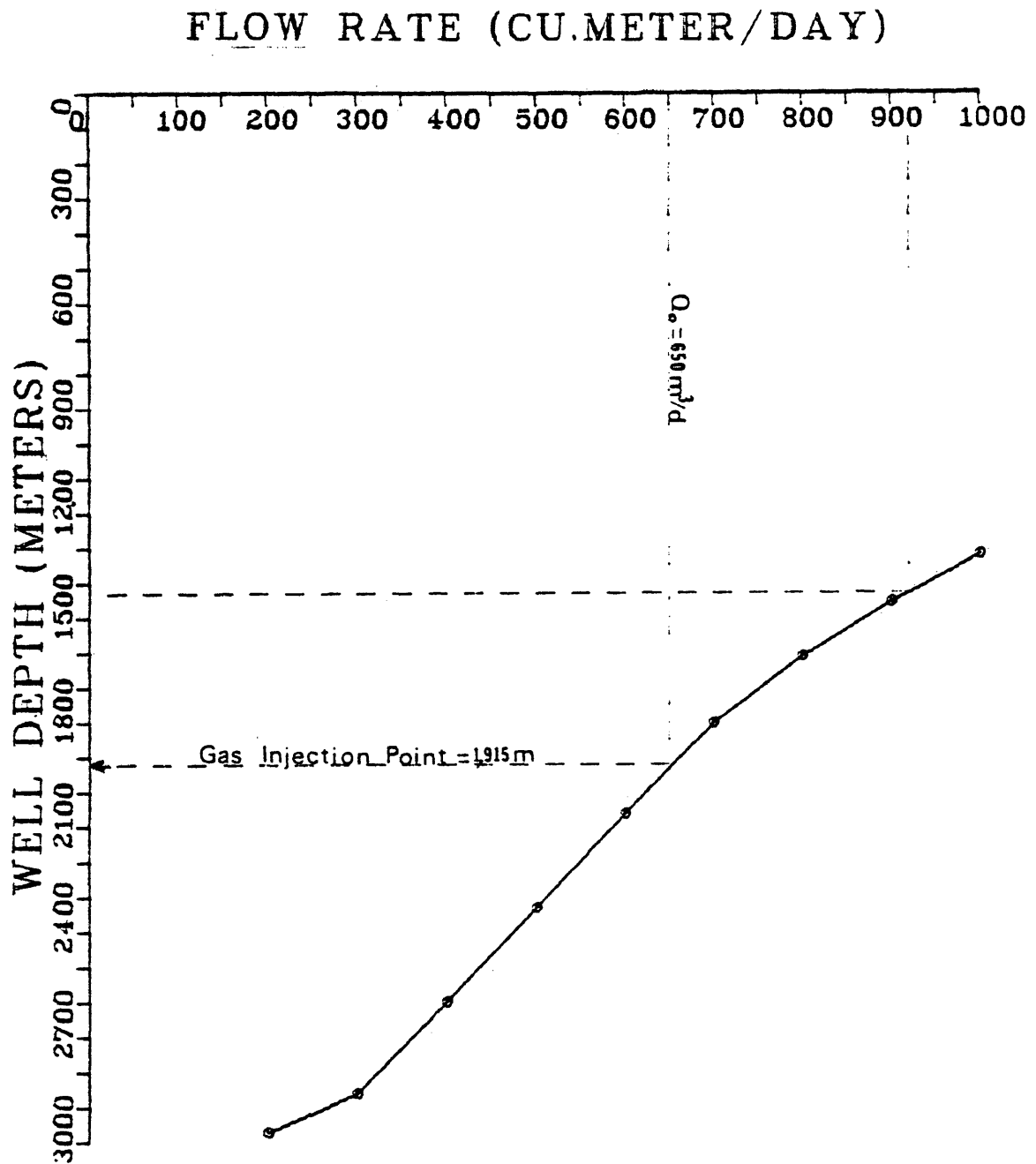


Figure 18



OPTIMUM GAS INJECTION POINT
S-5 (N)

Figure 19

GAS INJECTION POINT VS. PWF
S-5 (N)

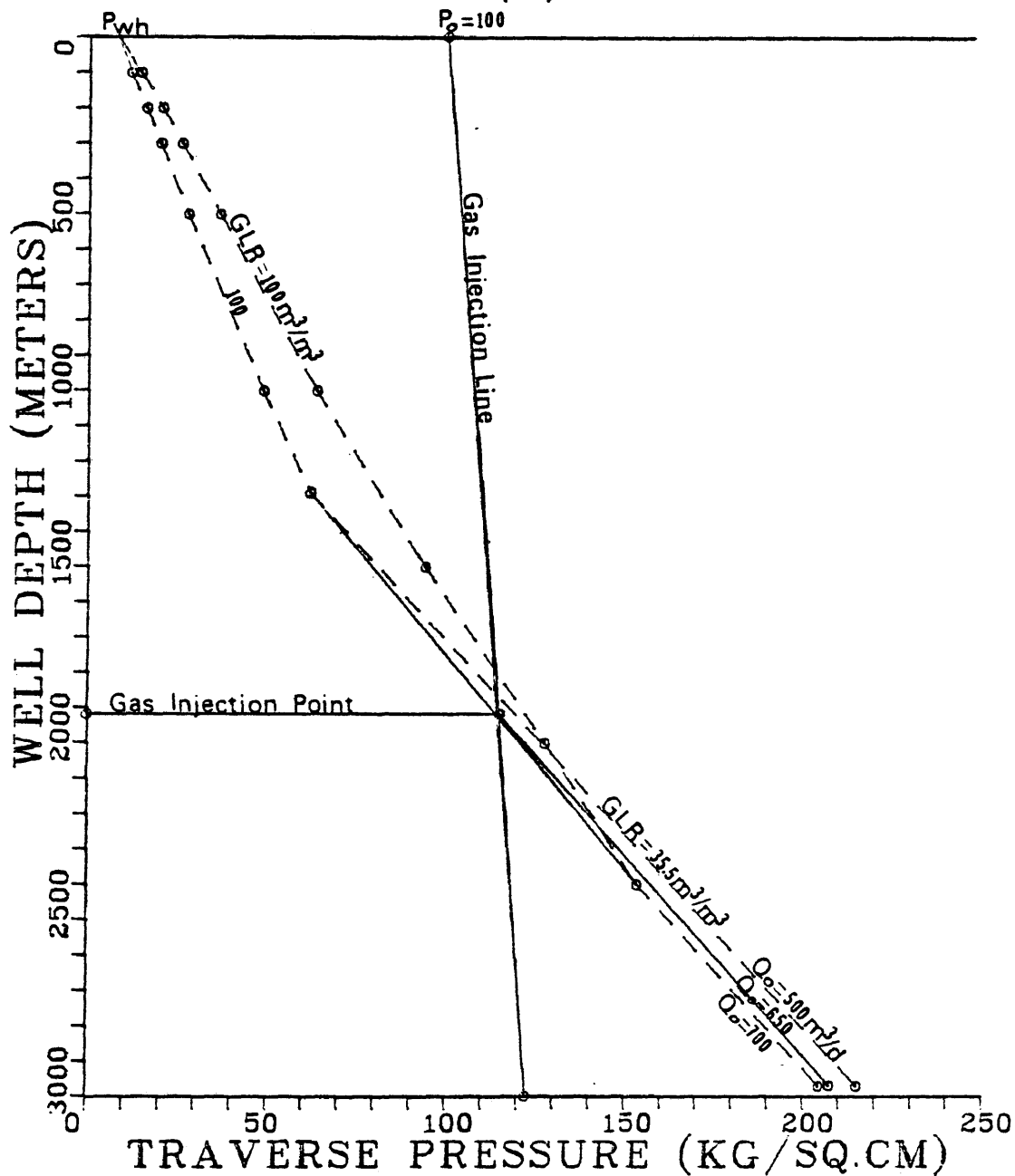


Figure 20

STATIC PRESSURE VS. FLOW RATE S-5 (N)

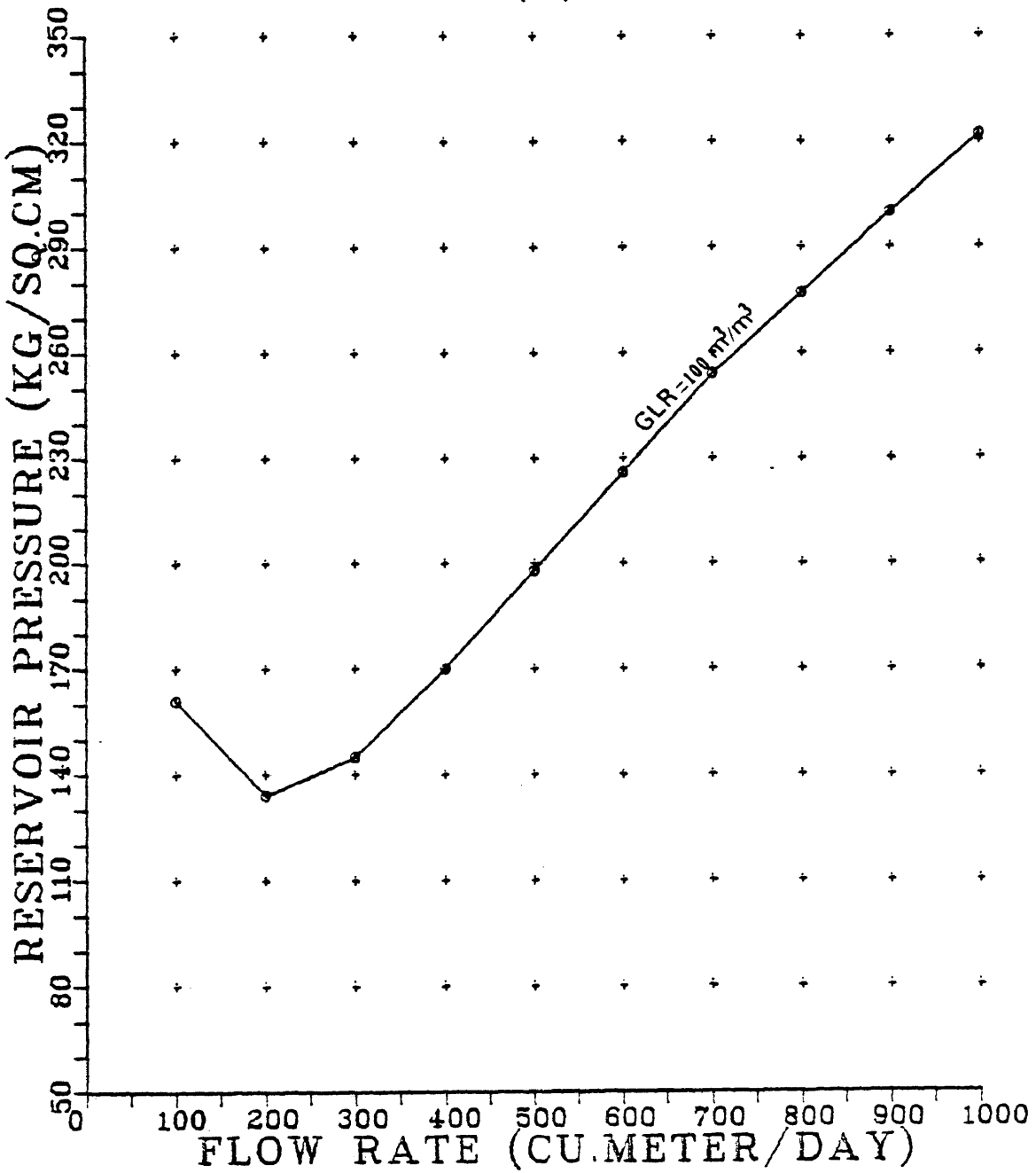


Figure 21

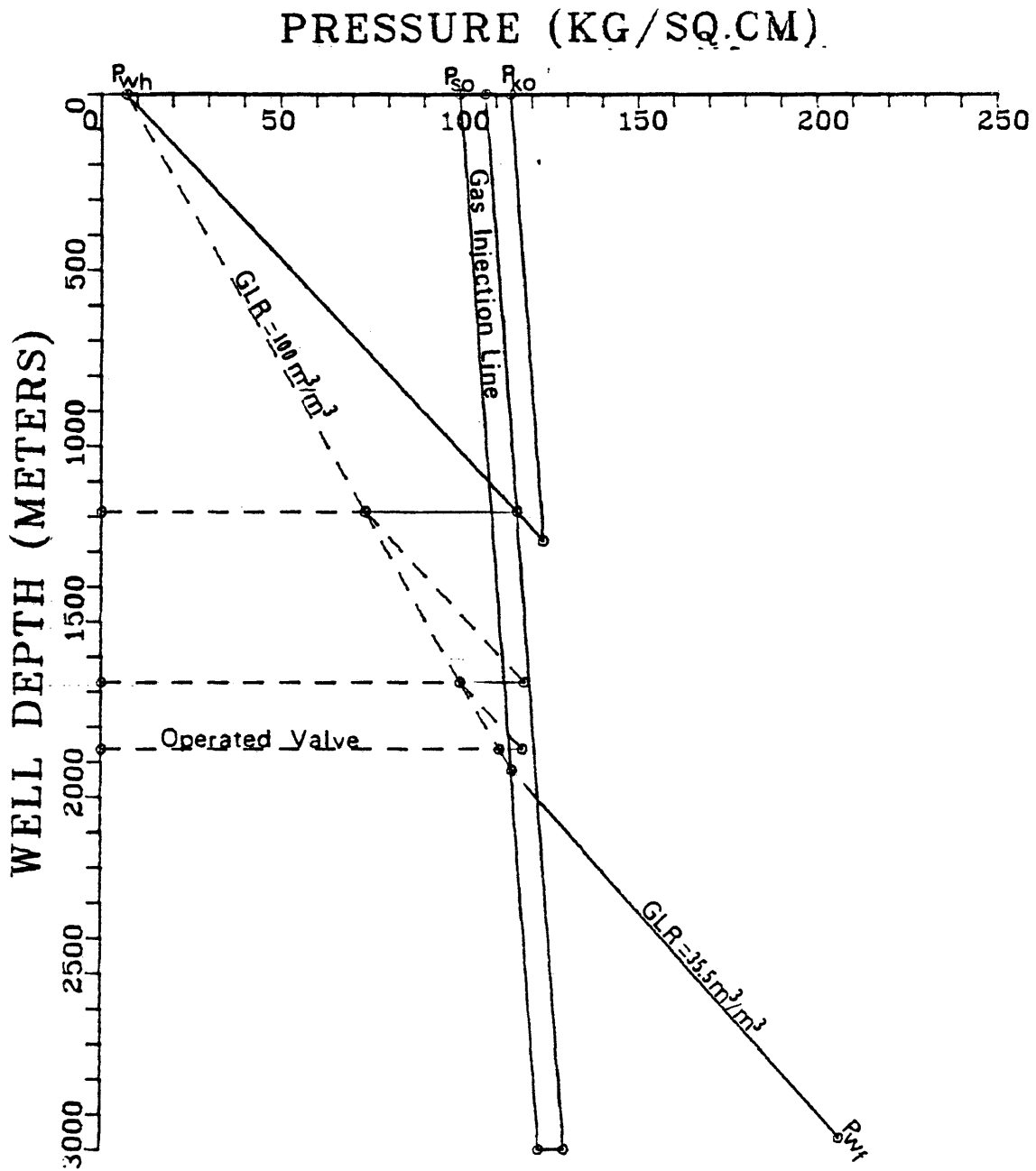
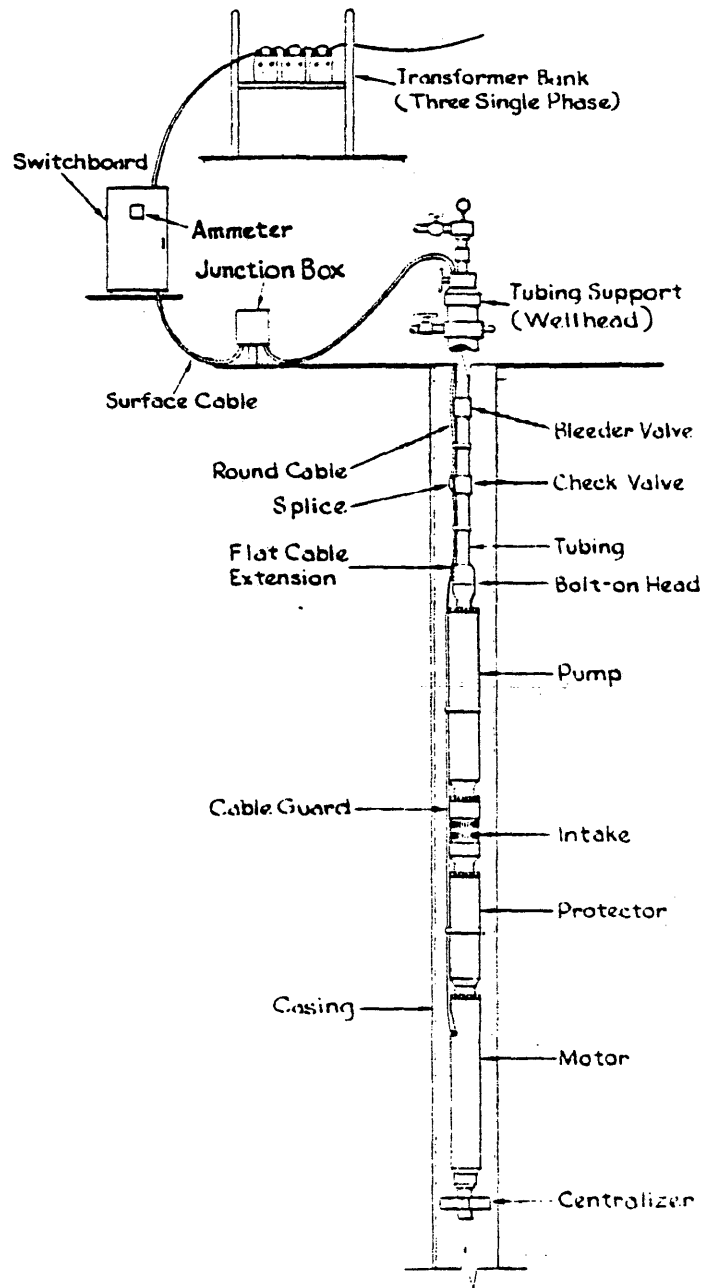
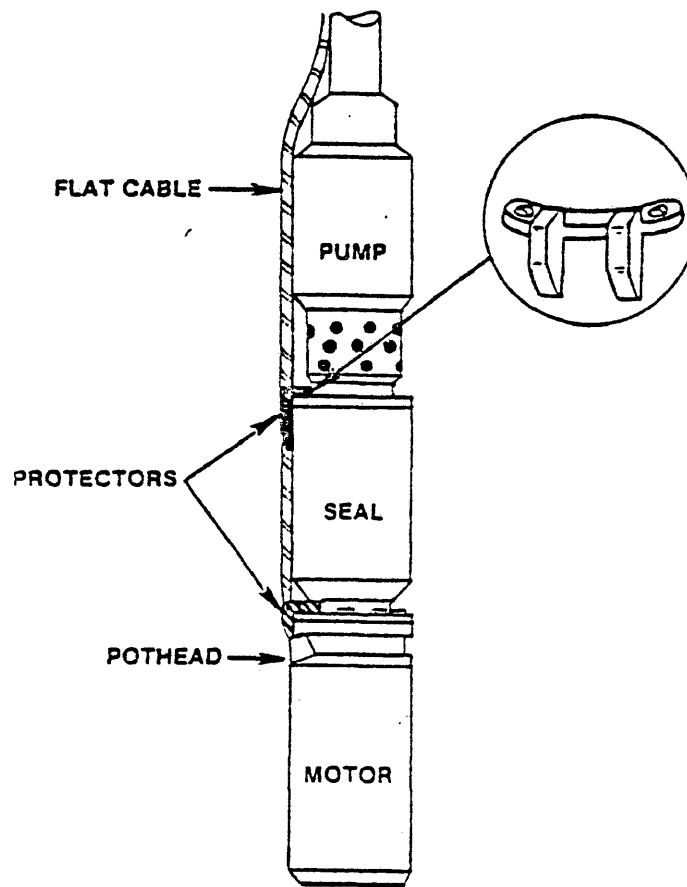


Figure 22
Electric Submersible Centrifugal Pump Unit



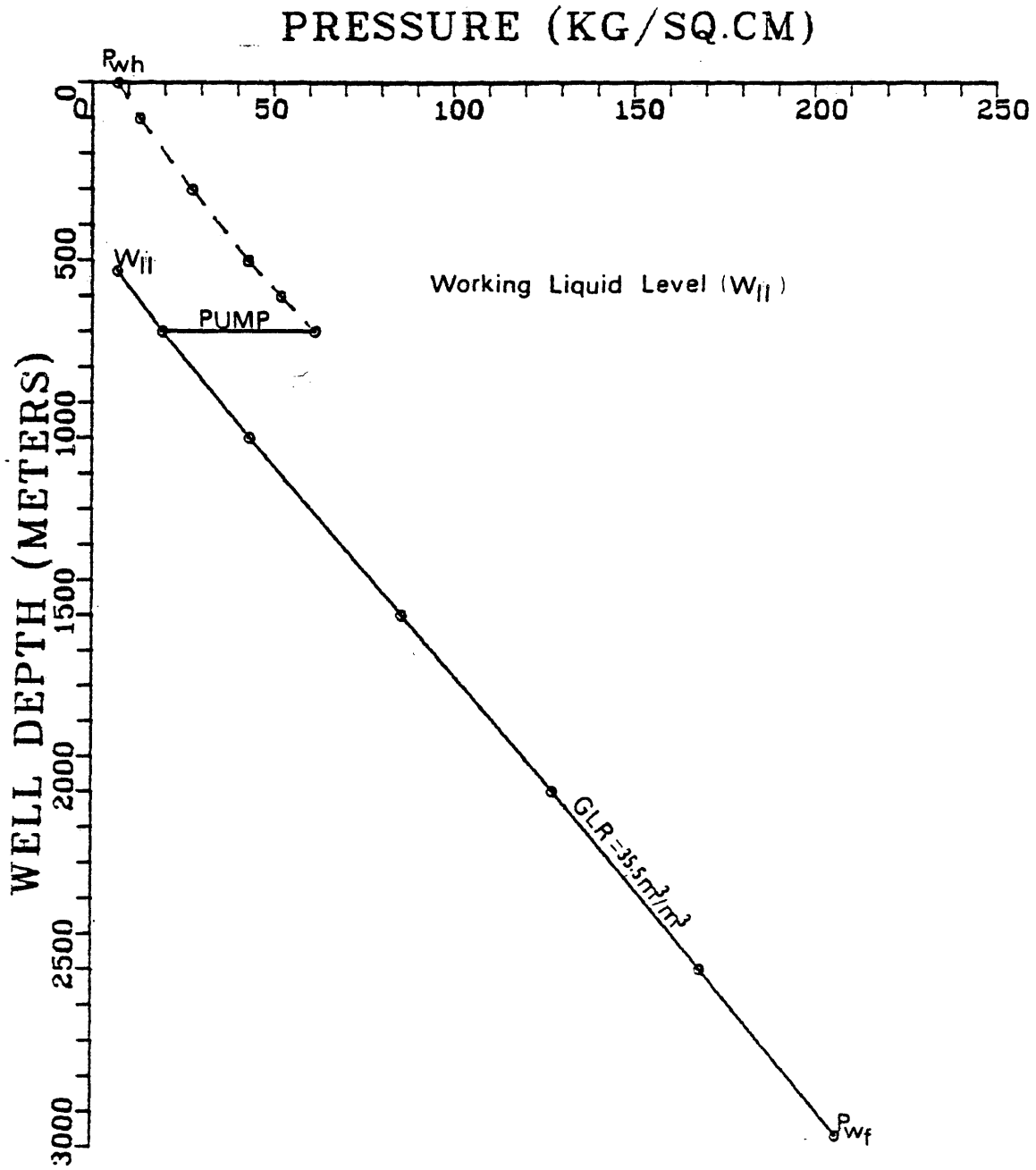
Source: TRW-REDA PUMP

Figure 23
Flat Cable Protector



Source: BRYON JACKSON - CENTRILIFT

Figure 24



SUBMERSIBLE PUMP DEPTH
S-5 (N)

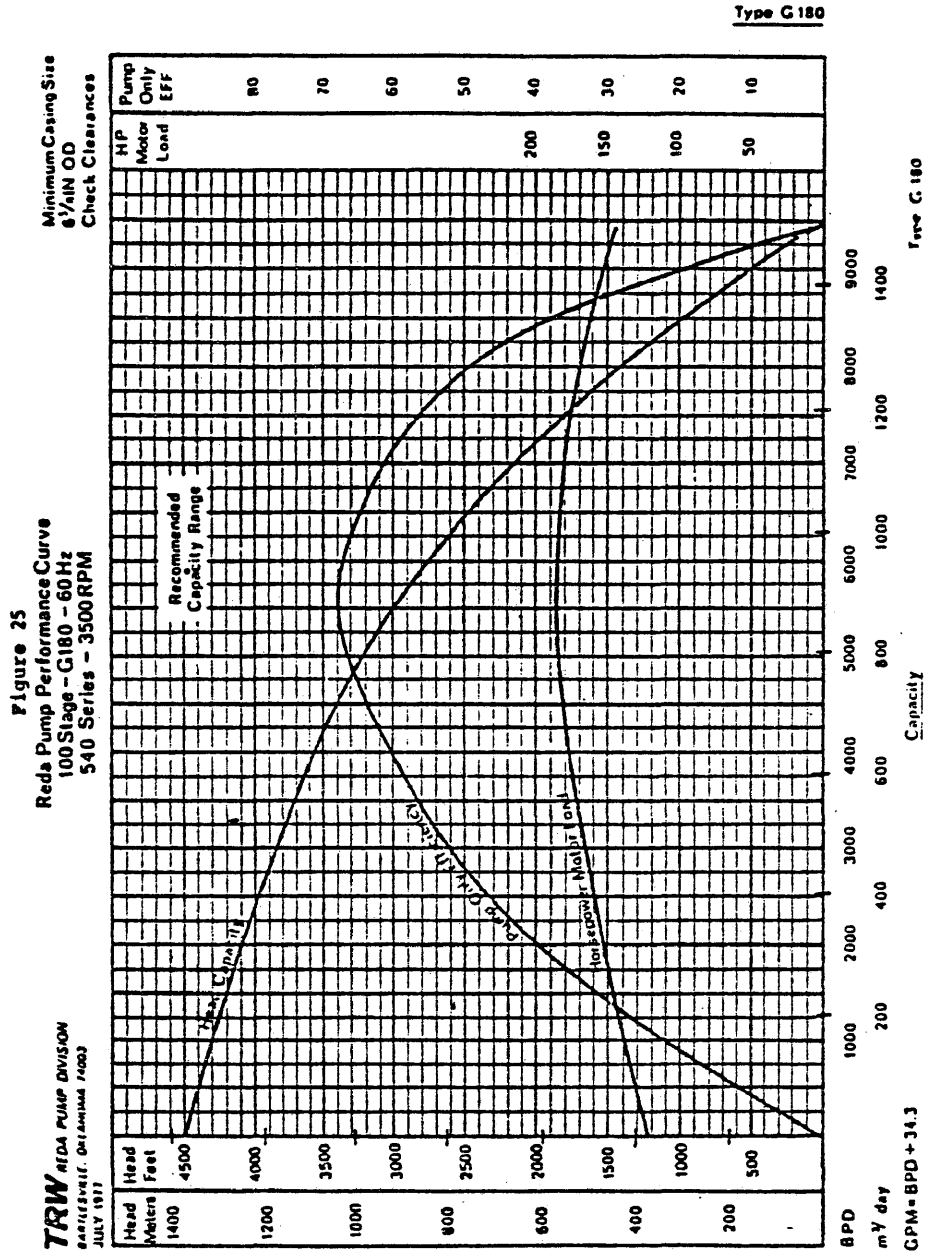
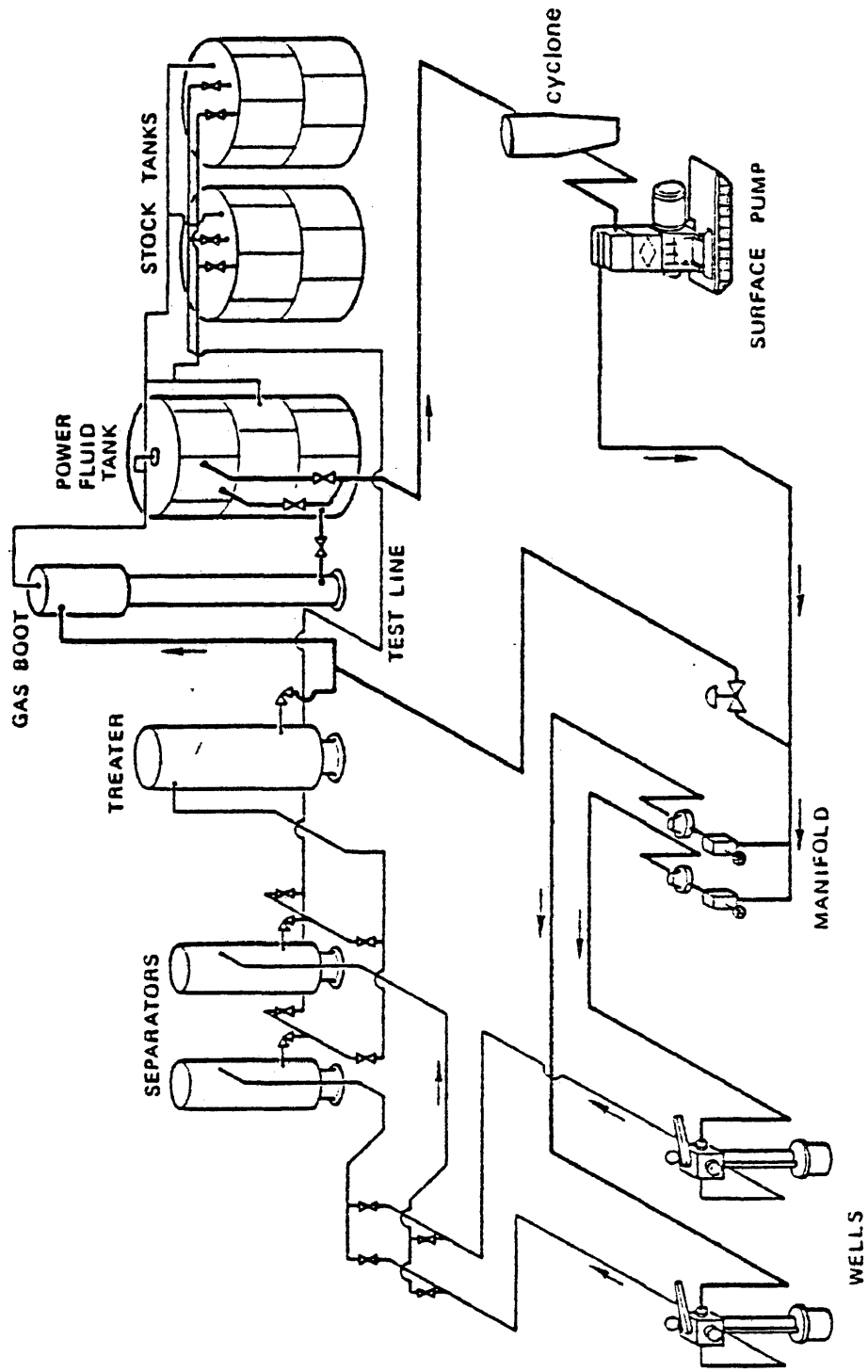


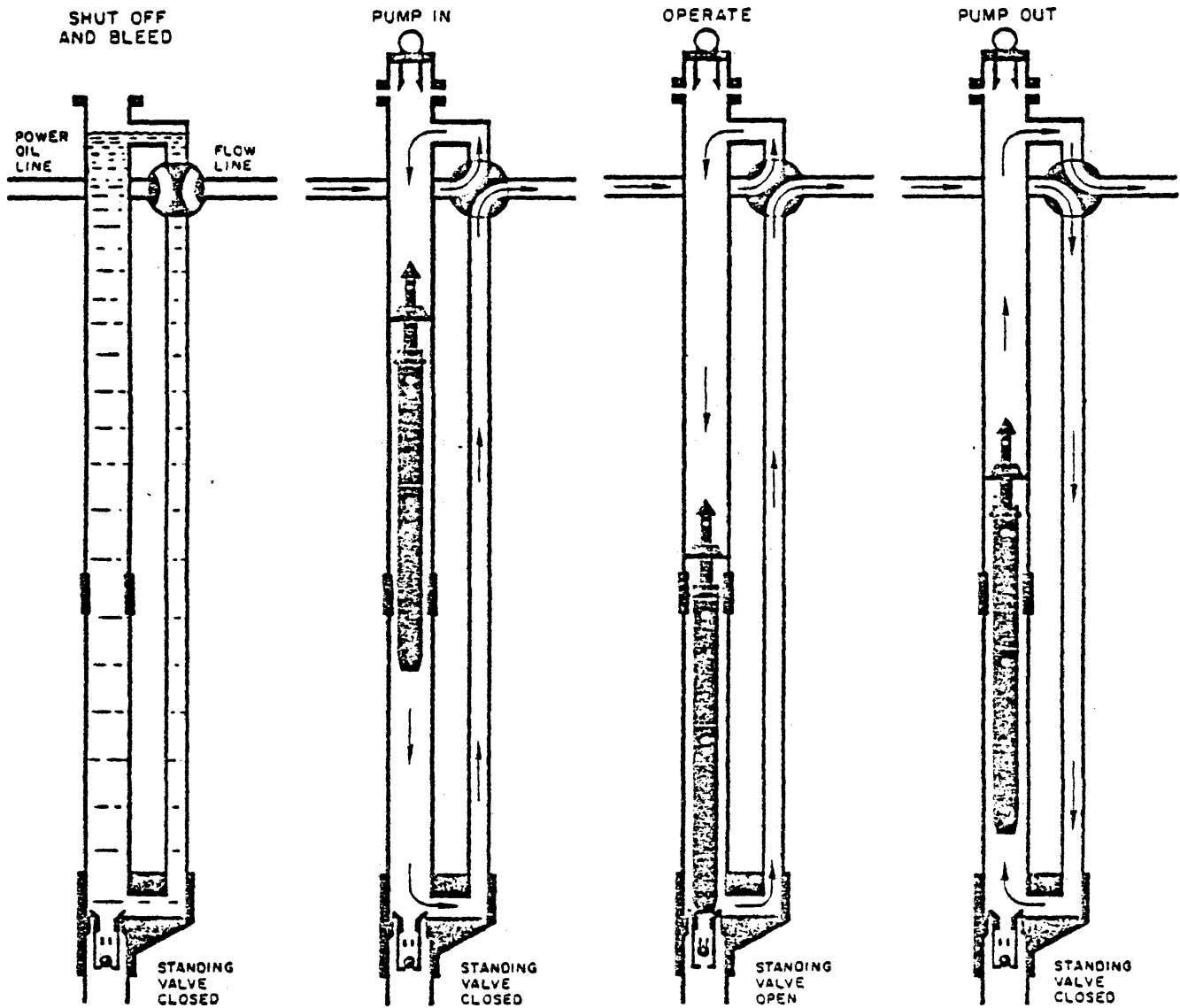
Figure 26
Hydraulic Pumping - Surface Facilities



Source: (BROWN, Artificial Lift Method, 2B)

Figure 27

Hydraulic Pumping—Piston Type



Source: KOBE catalog

Figure 28
Casing Free Tubing
Arrangement

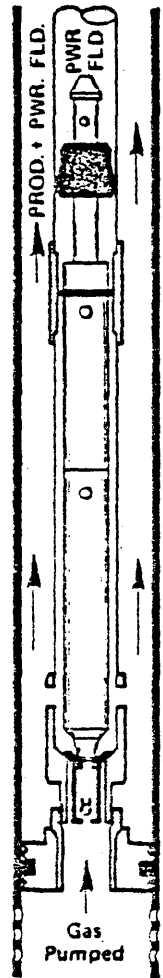
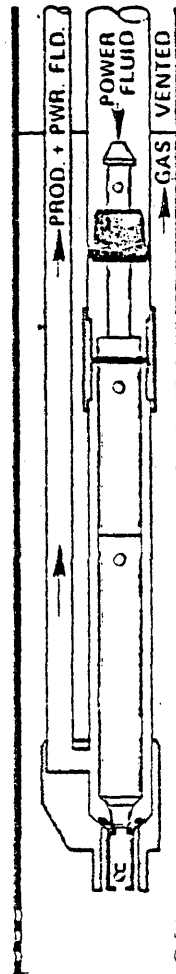


Figure 29
Parallel Free Tubing
Arrangement



Source: (Brown, Artificial Lift Method, Vol. 26)

Figure 30
Kinematic Viscosity vs Temperature

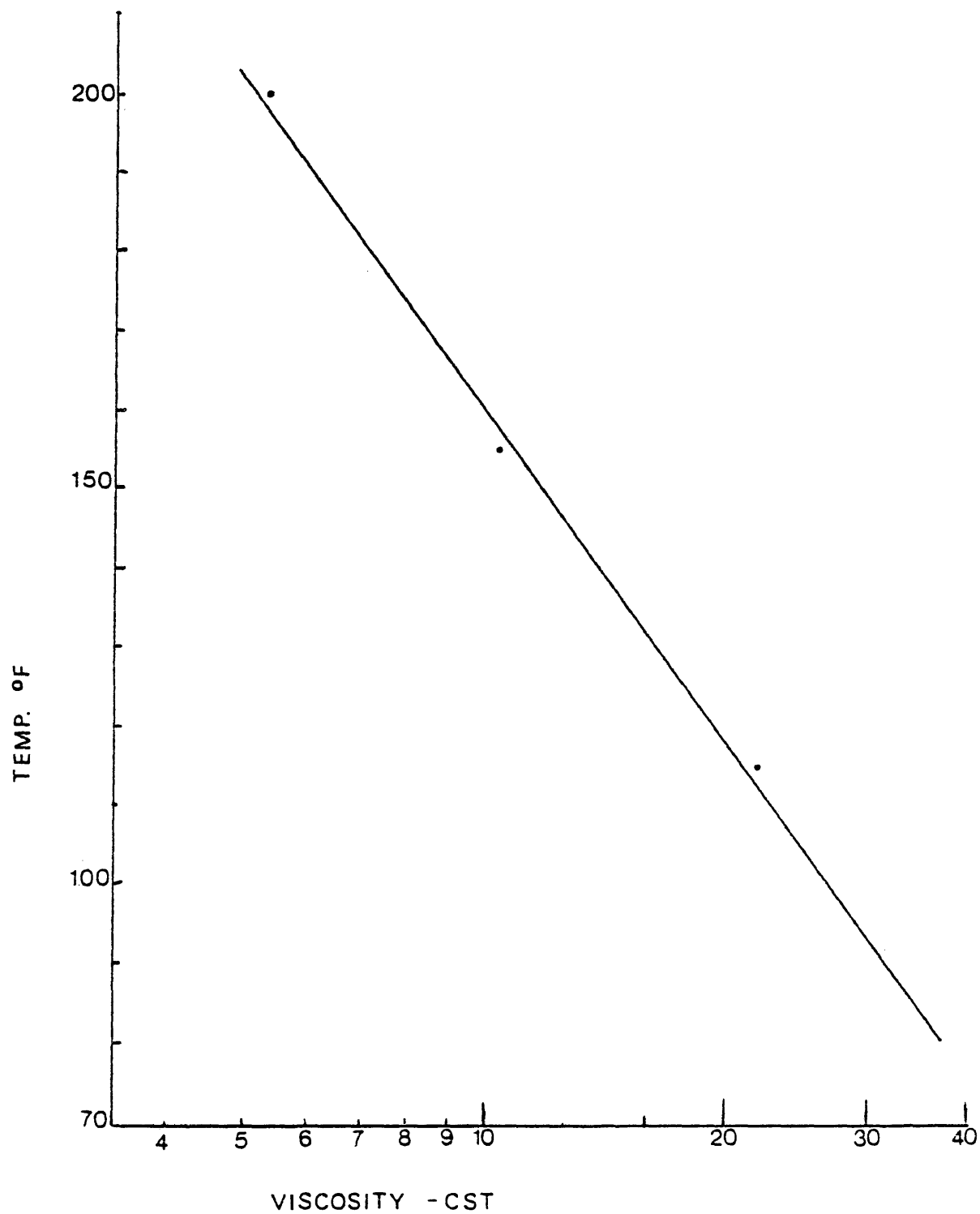
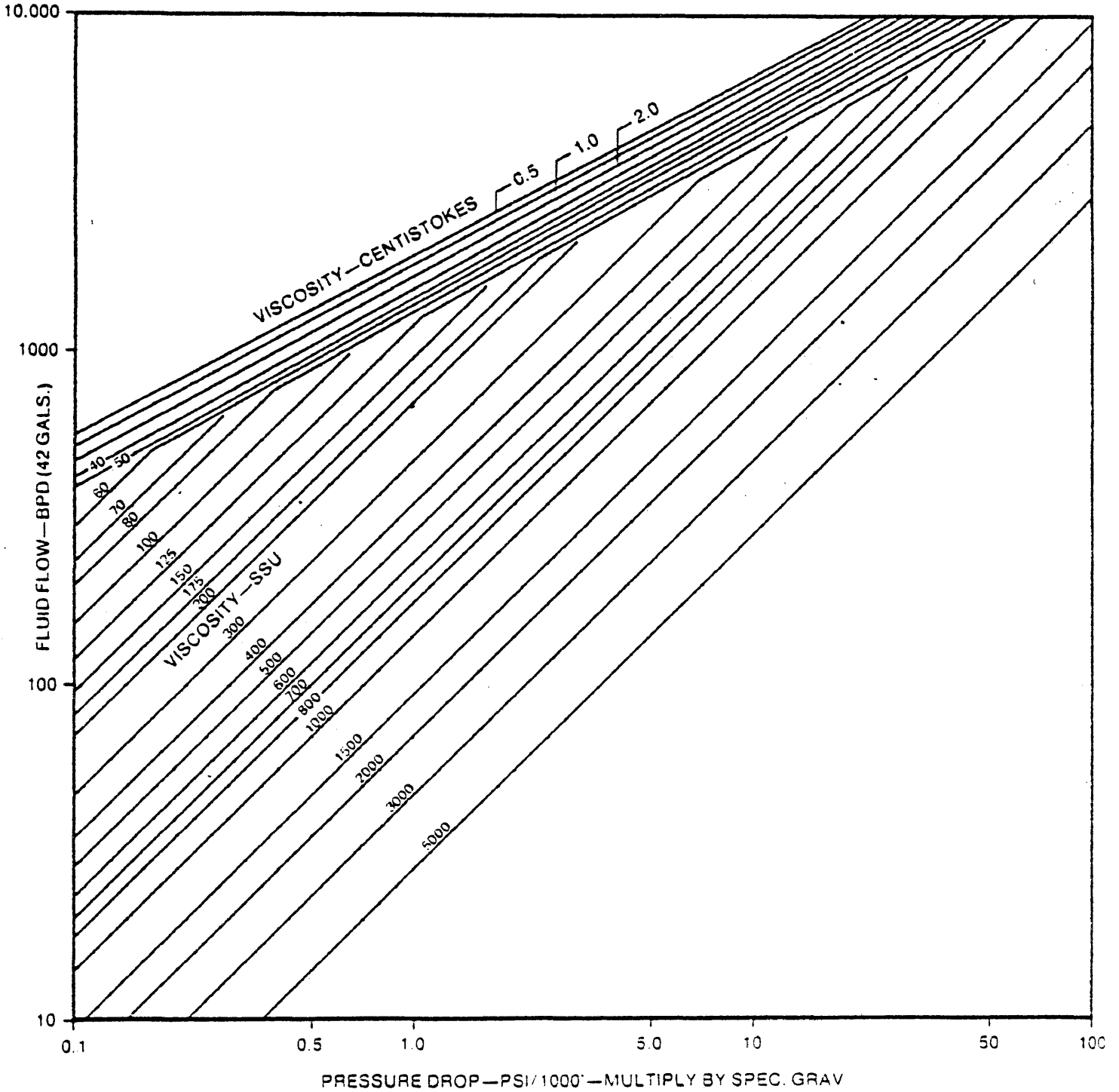
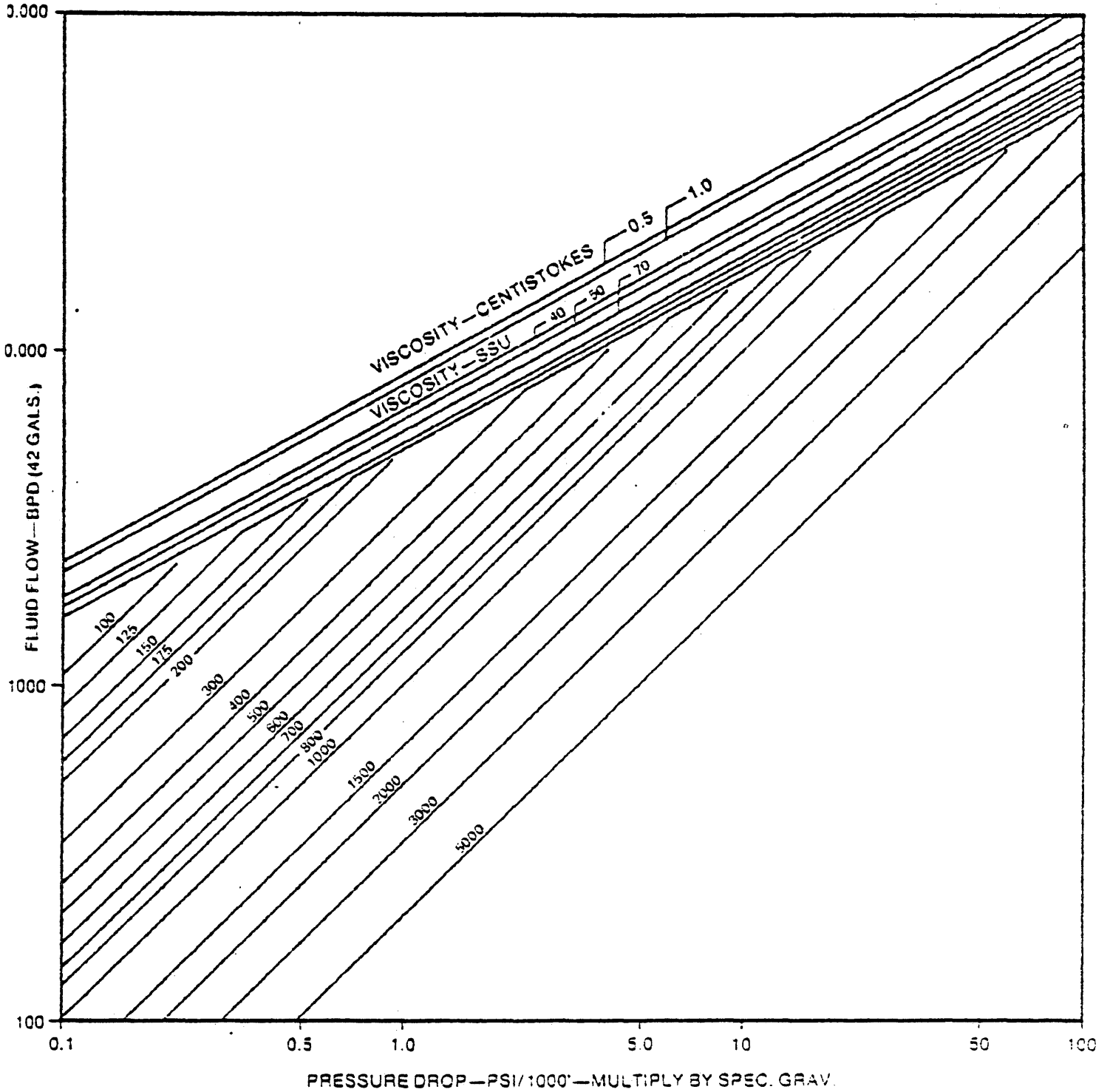


Figure 31
PRESSURE DROP IN TUBING
4-1/2" EU API TUBING



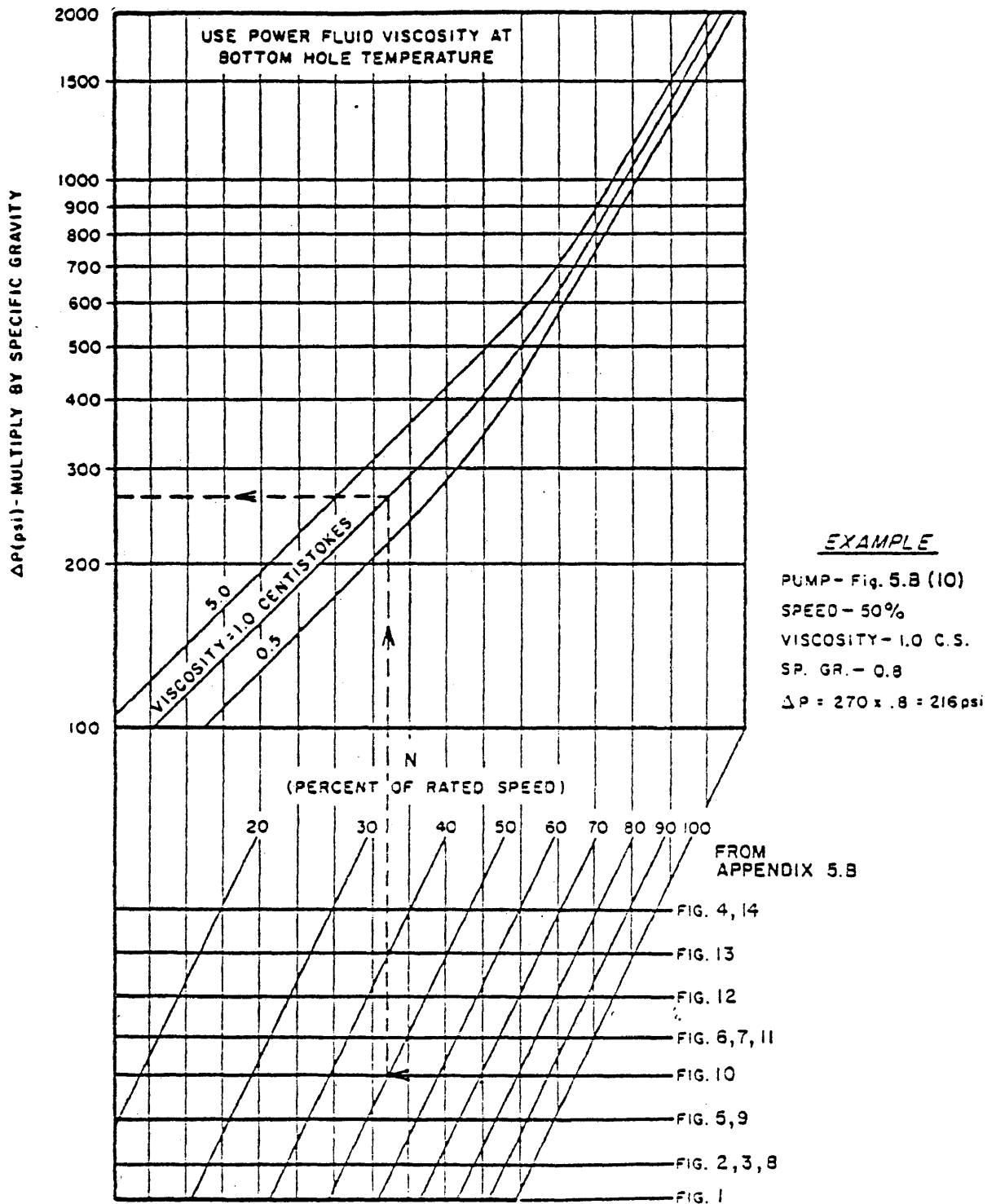
Source: (Brown, Artificial Lift Method, Vol. 26, Appendix C)

Figure 32
PRESSURE DROP IN TUBING
FLOW BETWEEN 9-5/8", 43-1/2# CSG. & 4-1/2" O.D. EU TUBING



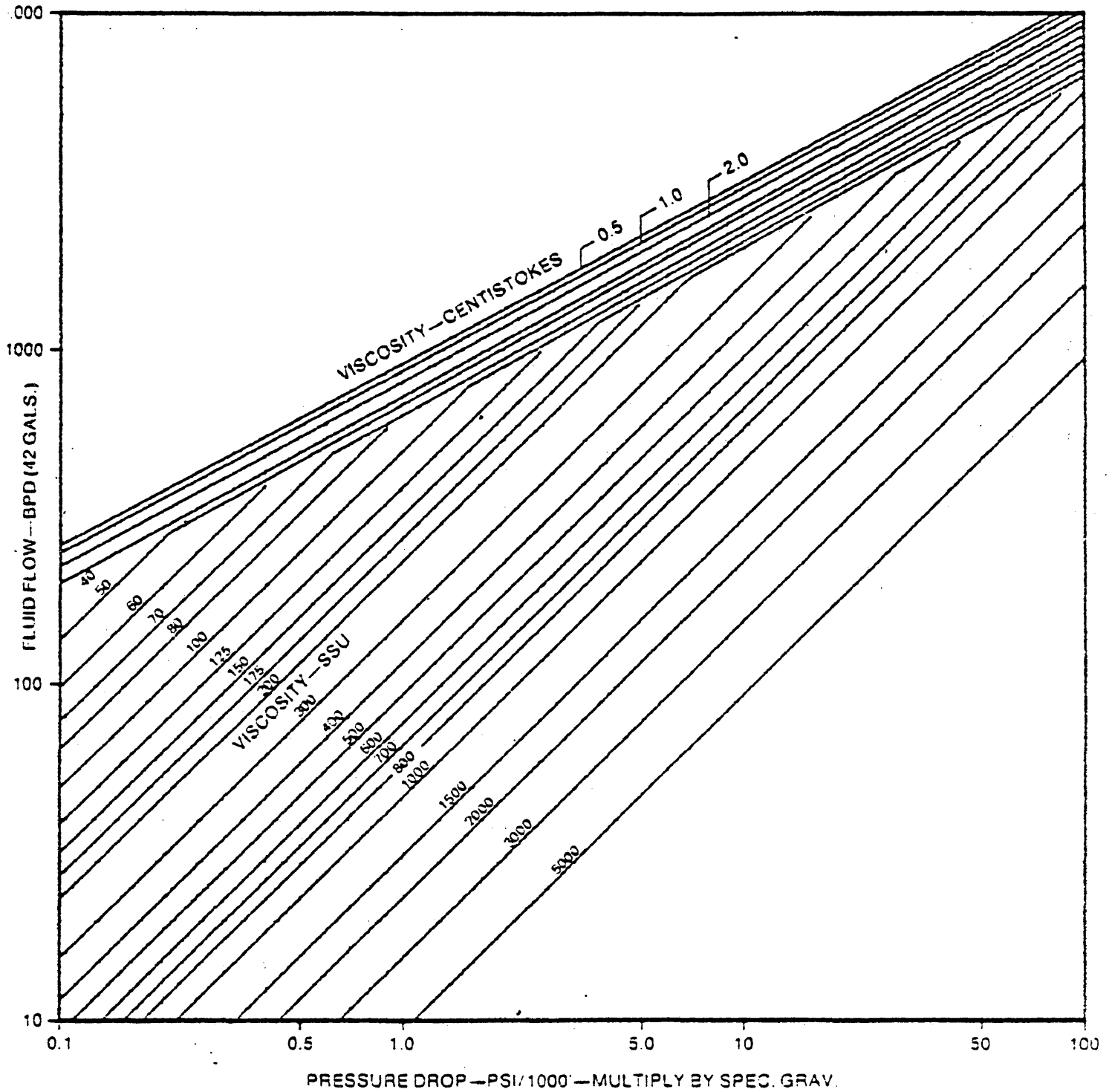
Source: (Brown, Artificial Lift Method, Vol. 26, Appendix C)

Figure 33
 PRESSURE INCREASE DUE TO MECHANICAL AND
 HYDRAULIC FRICTION IN PUMP AND BOTTOM HOLE ASSEMBLY
 vs
 PERCENT OF RATED SPEED



Source: (Brown, Artificial Lift Method, Vol. 26)

Figure 34
PRESSURE DROP IN TUBING
3-1/2" EU API TUBING



Source: (Brown, Artificial Lift Method, Vol. 26, Appendix C)

APPENDIX C

TABLE 1

PETROPHYSICS DATA

Well No.	Formation	Top (m)	Base (m)	Interval Thickness (m)	Thickness w/oil (m)	Thickness w/water (m)	Average Porosity (%)	Water Saturation (%)	O/W Contact (m)	P _i Initial Pressure (KG/cm ²)	Depth of P _i (m)	K Permeability (md)	Productive Index (m ³ /d/KG/cm ²)	GOR (m ³ /m ³)	API OIL	BHT (°F)
RJS-34	Carapebus	-2,720	-2,738	16	7.5	8.5	24	34	-2,729	283	2,720	164	13	95	26	211
	Namorado	-3,055	-3,168	85	54	31	28	14	-3,125	315	3,080	2,050	41	35.5	19	228
RJS-50	-															
	Namorado	-2,847	-2,998	85	85		22-30	10-28		300	2,920	1,063	13	35.5	20	220
RJS-59	-															
	Namorado	-3,015	-3,032	10	10	-	22	25	-			?	?	35.5	17	
RG-2	Carapebus	-2,690	-2,753	44.5	15.5	29	22	30	-2,710	280	2,690	?	?	?	23	210
	-	-2,911	3,024	30.5	19.5	11	22	16	-3,012	306	2,980	140	2	35.5	24	222
RJS-17	Carapebus	-2,695	-2,727	32	8	24	21	33	-2,708	281	2,700	1,990	74	40	26	210
RG-1	Carapebus	-2,695														
	-															
RJS-25	Carapebus (Gas)	-2,692	-2,704	11	11		28	20						150,000	61	
	Carapebus (O11)	-2,725	-2,817	90	?	85	27	35	-2,730	284	2,730	3,019	20	64	26	211

Table 2

Well: 1-RJS-50

Fluid Property; PVT Analysis

(Source: PETROBRAS)

Pr (Kg/cm ²)	BO (bbl/bbl)	BG (bbl/bbl)	^{RS} (m ³ /m ³)	μ_o (CP)	μ_g (CP)
132	1.176	159.399	35.500	4.83	0.0155
120	1.170	140.000	32.409	5.03	0.0155
110	1.165	123.700	29.829	5.25	0.0153
100	1.159	107.700	27.299	5.50	0.0151
90	1.154	91.500	24.709	5.79	0.0147
80	1.148	75.799	22.140	6.11	0.0138
70	1.142	60.700	19.620	6.45	0.0136
60	1.136	47.500	17.000	6.80	0.0134
50	1.128	37.000	14.400	7.17	0.0132
40	1.120	28.799	11.820	7.57	0.0131
35	1.115	25.799	10.540	7.78	0.0130
30	1.110	22.899	9.280	8.02	0.0129
25	1.106	20.000	8.020	8.26	0.0128
20	1.100	17.500	6.720	8.52	0.0127
15	1.095	15.000	5.480	8.84	0.0126
10	1.089	12.500	4.200	9.20	0.0125
5	1.081	10.200	2.910	9.60	0.0125
3	1.077	8.900	2.300	9.84	

TABLE 3

DRILLING PROGRAM

<u>Depth</u>	<u>Bit</u>	<u>Casing</u>
220 m	36"	30"
400 m	26"	20"
1800 m	17-1/2"	13-1/2"
3100 m	12-1/4"	9-5/8"

(Source: Petrobras)

TABLE 4
PCH-1 GENERAL DATA

Well No.	Namorado Top (m)	Carapebus Top (m)	Distance from Vertical (m)	Degree from Vertical (°)	PI (m ³ /g/Kg/cm ²)	Final Length (m)	Net Pay (m)	Vertical Depth (m)	Incl. Depth (m)	P _i (Kg/cm ²)
S-1	-2,990	--	Vertical	0	20	3,200	80	3,030	3,030	310
S-2	-2,847	--	1,300	28	13	3,400	85	2,920	3,250	299
*S-3	-3,180	--	1,300	28	--	3,700	(wtr)	3,200	3,500	--
*S-4	-3,070	--	1,900	36	5	3,900	20(wtr)	3,110	3,730	318
	--	-2,695	--	36	--	3,900	3(gas)	2,715	3,240	282
S-5	-2,930	--	700	16	20	3,200	105	2,970	3,070	304
S-6	-3,055	-2,680	650	14	10	3,400	30	3,095	3,180	316
S-7	-2,960	--	1,800	36	20	3,780	105	3,000	3,580	307
S-8	-2,880	--	1,200	26	20	3,400	80	2,920	3,200	299
S-9	-3,000	--	1,200	25	20	3,500	55	3,040	3,310	311
	--	-2,690	--	25	5	3,500	2	2,710	2,945	282
S-10	-2,970	--	1,200	26	20	3,450	80	3,010	3,280	308
S-11	-3,000	-2,670	700	15	20	3,300	80	3,040	3,130	311
*S-12	-3,040	--	1,900	36	5	3,900	20(wtr)	3,080	3,700	315
S-13	-3,040	--	700	15	20	3,400	40	3,080	3,170	315
S-14	-3,060	-2,690	800	17	20	3,400	40	3,100	3,220	317
*S-15	-3,160	--	1,500	29	--	3,700	(wtr)	3,180	3,570	--
S-16	-2,900	--	1,800	36	20	3,700	60	2,940	3,530	301
S-17	-3,055	--	1,400	28	41	3,780	54	3,080	3,440	315
	--	-2,710	--	28	13	3,780	6	2,730	3,040	284
*S-18	-3,070	-2,710	1,200	25	5	3,600	20(wtr)	3,110	3,370	318
S-19	-3,015	--	650	14	3	3,300	10	3,055	3,140	312
*S-20	-3,160	--	1,000	20	--	3,500	(wtr)	3,180	3,360	--
*S-21	-2,995	--	1,500	31	5	3,600	50(wtr)	3,045	3,450	310
*S-22	-3,180	--	1,700	32	--	3,900	(wtr)	3,200	3,690	--

TABLE 5

PCH-2 GENERAL DATA

Well No.	Namorado Top (m)	Carapebus Top (m)	Distance from Vertical (m)	Degree from Vertical (a)	PI (m ³ /d/Kg/cm ²)	Final Length (m)	Net Pay (m)	Vertical Depth (m)	Incl. Depth (m)	Pi (Kg/cm ²)
N-1	-3,060	-2,650	Vertical	0	3	-3,250	5	3,080	3,080	315
N-2	-2,885	--	1,800	37	20	-3,700	105	2,915	3,510	298
N-3*	--	--	--	--	--	--	WTR	--	--	--
N-4	-2,995	--	1,300	27	7*	-3,500	15	3,035	3,350	310
N-5	-2,970	-2,645	--	27	30	-3,500	14	2,670	2,940	278
N-6	-3,060	-2,675	800	18	10	-3,350	45	3,010	3,135	308
N-7	--	--	600	13	--	-3,400	WTR	3,100	3,170	--
N-8	-2,930	-2,700	--	13	5	-3,400	3	2,720	2,780	283
N-9*	-2,980	--	1,100	24	10	-3,400	35	2,970	3,205	304
N-10	--	-2,665	1,600	32	10	-3,680	45	3,020	3,485	309
N-11	-2,920	--	700	--	--	-3,000	WTR	--	--	--
N-12	--	-2,695	1,400	30	15	-3,500	75	2,960	3,330	303
N-13	--	-2,660	1,800	39	74*	-3,550	9	2,720	3,360	283
N-14*	--	-2,650	1,850	40	15	-3,550	8	2,680	3,360	279
N-15	-3,020	--	900	23	15	-3,050	12	2,670	2,850	278
N-16	-3,000	--	1,700	--	--	--	WTR	--	--	--
N-17	--	-2,665	600	13	7	-3,300	10	3,040	3,110	311
	--	-2,645	600	13	7	-3,300	10	3,040	3,110	311 (WTR)
	--	-2,695	--	13	15	-3,300	10	2,670	2,730	278
	--	--	1,200	28	15	-3,200	8	2,720	3,025	283

Kickoff Point: 500 m

* Water Injectors

TABLE 6

TECHNICAL SPECIFICATION OF THE TWO PLATFORMS

(PCH-1 and PCH-2)

	<u>PCH-2</u>	<u>PCH-1</u>
Expected number of wells	17	22
Number of guides for wells	21	25
Number of producer wells with single completion	10	12
Number of water injection wells with single completion	3	7
Number of producer and injector wells with dual completion	4	3
Number of oil production zones	15	16
Number of gas production zones	1	1
Number of water injection zones	5	8
Average initial flowing production estimated per well per zone	380 m ³ /d	600 m ³ /d
Maximum average gas lift production per well/zone	490 m ³ /d	730 m ³ /d
Maximum flowing production estimated	5,700 m ³ /d	9,700 m ³ /d
Maximum gas lift production estimated	7,380 m ³ /d	11,800 m ³ /d
Total water injection expected	6,000 m ³ /d	8,000 m ³ /d
Water injection expected per well	1,200 m ³ /d	1,000 m ³ /d
Water injection for design	8,000 m ³ /d	10,000 m ³ /d
Maximum fluid production	8,000 m ³ /d	12,000 m ³ /d
Maximum water production per well	400 m ³ /d	400 m ³ /d
Water cut limit	90%	90%
Initial gas production per well/zone not counting gas lift	13,500 m ³ /d	21,500 m ³ /d
Maximum gas production per well/zone	17,500 m ³ /d	26,200 m ³ /d
Gas for gas lift per well/zone	24,500 m ³ /d	39,000 m ³ /d
Maximum gas consumption for GL per well/zone	32,000 m ³ /d	47,000 m ³ /d
Maximum total gas produced (including gas of GL)	.74x10 ⁶ m ³ /d	1.8x10 ⁶ m ³ /d
Minimum well head pressure	7 Kg/cm ²	7 Kg/cm ²
Maximum well head pressure	80 Kg/cm ²	80 Kg/cm ²
Initial water injection surface pressure	76 Kg/cm ²	76 Kg/cm ²
Initial reservoir static pressure	315 Kg/cm ²	315 Kg/cm ²
Reservoir temperature	109°C	109°C
Platform lasting time	20 years	20 years

TABLE 7PCH-1 AND PCH-2 GENERAL DATA

Bottom hole temperature = 228°F at 3080 m

Surface flowing temperature = 82°F

Tubing size = 3-1/2 inch O.D. (2.992 inch I.D.)

Casing size = 9-5/8 inch O.D.

P_{wh} - Well head pressure = 100 psi

P_{cg} - Pressure in the gas lift line = 1600 psi

γ_g - Gas specific gravity = 0.7025

Water cut = 0% at the beginning of productive life of
the wells

Formation GOR = 35.5 m³/m³ and 40 m³/m³ in Namorado and
Carapebus respectively

Oil gravity = 20° API (Namorado) and 26° API (Carapebus)

γ_w - Formation water specific gravity = 1.07

Formation water salinity = 110,000 ppm

TABLE 8FGERAL INPUT DATA, WELL S-5 (N)

Flow rate = 50; 100; 150; 200; 250; 300; 400; 500; 700;
1000 m³/d

Well head pressure = 100 psi

Diameter of the tubing = 3-1/2 in. O.D. = 2.992 in I.D.

Vertical depth = 2,970 m

Directional depth = 3,070 m

Kick-off point = 500 m

Oil specific gravity = .934

Water specific gravity = 1.07

Gas specific gravity (air = 1) = .7025

Surface temperature = 82°F

Bottom hole temperature = 228°F

* Gas oil ratio = 35.5; 50; 75; 100; 150; 200 m³/m³

* Water cut = 0%

** Gas oil ratio = 35.5 m³/m³

** Water cut = 0%; 50%

* To generate Figure 14

** To generate Figure 15

TABLE 9

FGERAL OUTPUT DATA, WELL S-5(N)

Flow Rate (m ³ /d)	Bottom Hole Flowing Pressure (Kg/cm ²)										
	Gas Oil Ratio (m ³ /m ³)										Water Cut %
	35.5	50	75	100	150	200	0	50			
50	241.3	228.4	204.6	182.9	147.0	118.6	241.3	278.7			
100	230.4	210.3	171.9	145.9	105.8	79.1	230.4	274.0			
150	224.5	198.3	156.3	129.2	91.3	71.5	224.5	270.7			
200	222.3	193.7	148.7	122.3	91.2	74.4	222.3	270.0			
250	223.3	192.9	146.5	123.3	96.2	81.8	223.3	271.3			
300	227.0	192.8	148.6	127.6	102.7	90.2	227.0	273.5			
400	233.1	205.8	158.3	139.9	119.3	111.9	233.1	278.5			
500	240.2	215.5	170.4	154.3	140.3	134.0	240.2	284.5			
700	255.1	236.3	204.3	189.9	181.7	175.0	255.1	296.2			
1000	286.3	275.6	258.9	247.1	236.4	233.9	286.3	322.4			

Table 10

Natural Flowing Rate (m³/d) at P_{SLF}
water cut = 0%

Well No.	Q _o (m ³ /d) Namorado	Q _o (m ³ /d) Carapebus	P _{WF} (Kg/cm ²)	P _{SLF} (Kg/cm ²)	Well No.	Q _o (m ³ /d) Namorado	Q _o (m ³ /d) Carapebus	P _{WF} (Kg/cm ²)	P _{SLF} (Kg/cm ²)
S-1	300	-	-	-	N-1	130	-	-	-
S-2	275	-	229	250	N-2	225	-	-	-
S-5	270	-	226	240	N-4	200	-	-	-
S-6	230	-	-	-	N-4	-	310	-	-
S-7	225	-	242	265	N-5	230	-	-	-
S-8	270	-	-	-	N-6	-	200	-	-
S-9	270	-	235	250	N-7	230	-	-	-
S-9	-	200	-	-	N-8	210	-	227	250
S-10	270	-	-	-	N-10	250	-	239	260
S-11	290	-	-	-	N-11	-	350	-	-
S-13	290	-	-	-	N-12	-	310	195	200
S-14	290	-	240	255	N-13	-	330	-	-
S-16	225	-	-	-	N-15	220	-	178	200
S-17	305	-	248	255	N-16	-	310	228	260
S-17	-	280	93	115	N-17	-	310	174	195
S-19	110	-	-	-					
Sub-Total	3,620	480			Sub-Total	1,695	2,000		
Total	4,100				Total	3,695			

Table #1
Maximum Natural Flowing Rate (m³/d)

Well No.	Q _o (m ³ /d)		P _{wf} (Kg/cm ²)	P _i (Kg/cm ²)	Well No.	Q _o (m ³ /d)		P _{wf} (Kg/cm ²)	P _i (Kg/cm ²)
	Namorado	Carapebus				Namorado	Carapebus		
S-1	740	-	273	310	N-1	250	-	232	315
S-2	570	-	255	299	N-2	430	-	276	298
S-5	790	-	269	304	N-4	340	-	261	310
S-6	600	-	256	316	N-4	-	950	246	278
S-7	430	-	264	307	N-5	560	-	252	308
S-8	720	-	263	299	N-6	-	450	193	283
S-9	720	-	275	311	N-7	530	-	251	304
S-9	-	450	192	282	N-8	470	-	262	309
S-10	720	-	272	308	N-10	550	-	266	303
S-11	790	-	271	311	N-11	-	920	270	283
S-13	790	-	275	315	N-12	-	680	234	279
S-14	790	-	276	317	N-13	-	820	224	278
S-16	430	-	279	301	N-15	480	-	247	311
S-17	790	-	295	315	N-16	-	850	220	278
S-17	-	990	207	284	N-17	-	780	231	283
S-19	220	-	239	312					
Sub-total	9,100	600			Sub-total	3,610	2,100		
Total		9,700			Total		5,710		

Table 12

Flow Rate (m³/d) at P_f and P_{SIF}
 Water Cut = 50% (Namorado) and Cut = 0% (Carapebus)

Well No.	Q _L (m ³ /d)	P _f (Kg/cm ²)	Q _L (m ³ /d)	P _{SIF} (Kg/cm ²)	Well No.	Q _L (m ³ /d)	P _f (Kg/cm ²)	Q _L (m ³ /d)	P _{SIF} (Kg/cm ²)
S-1	320	310	130	295	N-1	160	315	100	305
S-2	220	299	100	290	N-2	50	298	50	298
S-5	440	304	180	280	N-4	160	310	100	305
S-6	230	316	150	300	N-4*	300	278	300	200
S-7	50	307	50	307	N-5	230	308	150	295
S-8	320	299	130	290	N-6*	300	283	200	200
S-9	320	311	130	295	N-7	230	304	150	295
S-9*	300	282	200	200	N-8	100	309	100	309
S-10	320	308	130	295	N-10	220	303	100	295
S-11	440	311	200	295	N-11*	300	283	300	200
S-13	440	315	200	295	N-12*	300	279	300	200
S-14	440	317	210	295	N-13*	300	278	300	200
S-16	50	301	50	301	N-15	250	311	130	295
S-17	310	315	190	305	N-16*	300	278	300	195
S-17*	300	284	280	115	N-17*	300	283	300	205
S-19	50	312	50	312					
Total	4,250	-	2,380	-	Total	3,300		2,880	

*Q = 300 m³/d maximum flow rate assumed to Carapebus sand due small net pay.

Table 13
Maximum Gas Lift Flow Rate at P_{SLF} Assuming Unlimited Gas Operating Pressure

Well No.	PCH-1			PCH-2		
	Flow Rate (m ³ /d)			Flow Rate (m ³ /d)		
	GLR = 35.5 (m ³ /m ³)	GLR = 100 (m ³ /m ³)	GLR = 150 (m ³ /m ³)	GLR = 35.5 (m ³ /m ³)	GLR = 100 (m ³ /m ³)	GLR = 150 (m ³ /m ³)
S-1	300	770	805	130	370	390
S-2	275	745	770	225	690	720
S-5	270	770	805	200	590	620
S-6	230	680	715	300	300	300
S-7	225	700	735	230	690	720
S-8	270	780	820	200	300	300
S-9	270	780	820	230	665	695
S-9*	200	300	300	210	690	720
S-10	270	780	820	250	720	750
S-11	290	750	780	300	300	300
S-13	290	750	780	300	300	300
S-14	290	790	825	300	300	300
S-16	225	700	735	220	600	630
S-17	305	880	925	300	300	300
S-17*	280	300	300	300	300	300
S-19	110	370	390	300	300	300
Total	4,100	10,845	11,325	3,695	7,115	7,345
			11,595			7,495

*Q_o = 300 (m³/d) assumed due to the oil small net pay in Carapebus Sandstone.

Table 14

Gas Lift Flow Rate (m^3/d) at P_{SIF} and (GOR)_T = 100 m^3/m^3

Well No.	Q _o (m^3/d)		Well No.	P _{SIF} (Kg/cm ²)	L _{ing} (Meter)	P _{SIF} (Kg/cm ²)	Q _o (m^3/d)		L _{ing} (Meter)	P _{SIF} (Kg/cm ²)
	Namorado	Carapebus					Namorado	Carapebus		
S-1	650	-	N-1	-	1,910	-	370	-	2,600	-
S-2	615	-	N-2	250	2,010	250	560	-	2,130	-
S-5	650	-	N-4	240	1,920	240	490	-	2,300	-
S-6	550	-	N-4	-	2,150	-	-	600	2,260	-
S-7	560	-	N-5	265	2,130	265	560	-	2,130	-
S-8	635	-	N-6	-	1,950	-	-	400	2,700	250
S-9	635	-	N-7	250	1,960	250	565	-	2,130	260
S-9	-	400	N-8	-	2,700	-	560	-	2,150	-
S-10	635	-	N-10	-	1,950	-	600	-	2,030	-
S-11	620	-	N-11	-	1,980	-	-	580	2,340	-
S-13	620	-	N-12	-	1,980	-	-	500	2,670	-
S-14	650	-	N-13	255	1,900	255	-	640	2,180	200
S-16	560	-	N-15	-	2,130	-	505	-	2,280	260
S-17	680	-	N-16	255	1,840	255	-	620	2,250	195
S-17	-	550	N-17	-	2,450	-	-	550	2,150	-
S-19	300	-		-	2,820	-	-	-	-	-
Sub-Total	8,360	600	Sub-Total	4,210			2,100			
Total	8,960		Total				6,310			(PCH-2)

(PCH-1)

Table 15

PCH-1

Gas-Lift Gas Consumption

Well No.	P_{SLF_2} (Kg/cm ²)	Q_o (m ³ /d)	GOR_F (m ³ /m ³)	GLR_T (m ³ /m ³)	Q_{GINJ} (m ³ /d)
S-1	-	650	35.5	100	41,925
S-2	250	615	35.5	100	39,670
S-5	240	650	35.5	100	41,925
S-6	-	550	35.5	100	35,475
S-7	265	560	35.5	100	36,120
S-8	-	635	35.5	100	40,960
S-9	250	635	35.5	100	40,960
S-9	-	300*	40	100	18,000
S-10	-	635	35.5	100	40,960
S-11	-	620	35.5	100	39,990
S-13	-	620	35.5	100	39,990
S-14	255	650	35.5	100	41,925
S-16	-	560	35.5	100	36,120
S-17	255	680	35.5	100	43,860
S-17	115	300*	95	200	31,500
S-19	-	300	35.5	100	19,350
Total	-	8,960	-	-	575,730

$Q_o = 300$ (m³/d) assumed due to the small net oil pay in Carapebus sandstone.

Table 16

PCH-2

Gas-Lift Gas Consumption

<u>Well No.</u>	<u>P_{SLF} (Kg/cm²)</u>	<u>Q_o (m³/d)</u>	<u>GOR_F (m³/m³)</u>	<u>GLR_T (m³/m³)</u>	<u>Q_{GINJ} (m³/d)</u>
N-1	-	370	35.5	100	23,865
N-2	-	560	35.5	100	36,120
N-4	-	490	35.5	100	31,605
N-4	-	300*	40	100	18,000
N-5	-	560	35.5	100	36,120
N-6	-	300*	40	100	18,000
N-7	250	565	35.5	100	36,445
N-8	260	560	35.5	100	36,120
N-10	-	600	35.5	100	38,700
N-11	-	300*	40	100	18,000
N-12	-	300*	40	100	18,000
N-13	200	300*	40	100	18,000
N-15	260	505	35.5	100	32,575
N-16	195	300*	40	100	18,000
N-17	-	300*	40	100	18,000
Total	-	6,310	-	-	397,550

* $Q_o = 300$ (m³/d) assumed due to the small net oil pay in Carapebus sandstone.

TABLE 17
GAS LIFT MANDRILLS' DEPTH (METERS)

Well No.	PCH-1						PCH-2						
	Mandril 1	Mandril 2	Mandril 3	Mandril 4	Mandril 5	Mandril 6	Well	Mandril 1	Mandril 2	Mandril 3	Mandril 4	Mandril 5	Mandril 6
S-1	1185	1670	1860	1950	--	--	N-1	1185	1850	2200	2420	2510	2610
S-2	1185	1720	1910	2000	--	--	N-2	1185	1740	1985	2095	2185	--
S-5	1185	1670	1860	1950	--	--	N-4	1185	1800	2090	2220	2310	--
S-6	1185	1730	1970	2070	2160	--	N-4	1185	1760	2050	2180	2270	--
S-7	1185	1740	1985	2095	2185	--	N-5	1185	1740	1985	2095	2185	--
S-8	1185	1680	1885	1975	--	--	N-6	1185	1860	2250	2470	2580	2670
S-9	1185	1680	1885	1975	--	--	N-7	1185	1730	1980	2090	2170	--
S-9	1185	1860	2250	2470	2580	2670	N-8	1185	1740	1990	2100	2190	--
S-10	1185	1680	1885	1975	--	--	N-10	1185	1730	1920	2020	--	--
S-11	1185	1720	1910	2000	--	--	N-11	1185	1800	2075	2200	2290	2380
S-13	1185	1720	1910	2000	--	--	N-12	1185	1840	2230	2440	2550	2640
S-14	1185	1665	1850	1940	--	--	N-13	1185	1750	2005	2120	2210	--
S-16	1185	1740	1985	2095	2185	--	N-15	1185	1755	2025	2135	2225	--
S-17	1185	1640	1815	1905	--	--	N-16	1185	1765	2060	2180	2270	--
S-17	1185	1810	2150	2310	2400	--	N-17	1185	1750	2000	2110	2200	--
S-19	1185	1880	2300	2540	2700	2790							

Table 18Centrifugal Pump Design Data

S-5 (N)

Depth	=	2,970 m
ϕ_T	=	3 1/2" OD = 2.992" I.D.
ϕ_C	=	9 5/8" O.D.
P_R	=	240 Kg/cm ²
P_{wf}	=	207.5 Kg/cm ²
P_{wh}	=	7 Kg/cm ²
γ_g	=	.7025
q_L	=	650 m ³ /d
q_O	=	650 m ³ /d
γ_w	=	1.07
γ_o	=	.934
T_s	=	82°F
T_{PM}	=	115°F
T_D	=	228°F
GOR_T	=	35.5 m ³ /m ³
GOR_{pm}	=	23 m ³ /m ³
$(PM)_I$	=	20 Kg/cm ² (pump intake pressure)
$(PM)_D$	=	61 Kg/cm ² (pump discharge pressure)

TABLE 19

PUMP INTAKE CONDITION

Well	$\frac{Q_o}{(STBOD)}$	$\frac{(B_o)_I}{(z)_I}$	(PM) I psia	(T) I OR	$\frac{(B_g)_I}{bb1/scf}$	$\frac{(GOR_{free})_I}{scf/bbl}$	$\frac{(Q_t)_I}{bb1/d}$	$\frac{(GOR_{PM})}{scf/bbl}$	$\frac{(Wt)_I}{1000}$ (lbs/d)	(SG) I	$\frac{(GRAD)_I}{psi/ft}$
N-15 (N)	3,176	1.100	299.1	590	.0094	90	6,180	129	1,060	.490	.212
S-14 (N)	4,088	1.100	299.1	565	.0090	90	7,808	129	1,364	.499	.216
S-5 (N)	4,088	1.100	299.1	575	.0092	90	7,882	129	1,364	.495	.214
N-7 (N)	3,554	1.100	299.1	585	.0094	90	6,916	129	1,186	.490	.212
S-9 (N)	3,994	1.100	299.1	572	.0092	90	7,700	129	1,333	.495	.214
S-2 (N)	3,868	1.100	299.1	578	.0093	90	7,492	129	1,291	.492	.213
S-17 (N)	4,277	1.100	299.1	563	.0090	90	8,169	129	1,428	.499	.216
S-21 (N)	2,596	1.103	341.8	597	.0084	87	4,761	129	866	.520	.225
N-8 (N)	3,522	1.100	299.1	582	.0093	90	6,822	129	1,176	.493	.213
S-7 (N)	3,522	1.100	299.1	578	.0093	90	6,822	129	1,176	.493	.213
N-16 (C)	3,900	1.100	299.1	588	.0094	90	7,589	152	1,307	.492	.213
N-13 (C)	4,025	1.100	299.1	588	.0094	90	7,833	152	1,349	.492	.213

$$\rho_g = \frac{28.97 \times Y_g \times P}{Z \times R \times T} = \frac{28.97 \times 7.025 \times 14.7}{1 \times 10.73 \times 520} = .0536 \text{ lbs/ft}^3 \text{ at S.C.}$$

$$SG = \frac{W_L}{q_L \times 350} \quad W_L = 350 \text{ lbs/bbl (fresh water)}$$

$$B_g = .00504 \frac{T_z}{P}$$

$$q_L = q_o (B_o + GOR_{free} \times B_g)$$

$$W_L = q_o [.0536 \times GOR_{PM} + .934 \times 350]$$

$$GRAD = \frac{W_L}{q_L \times 5.615 \times 144}$$

TABLE 20
PUMP DISCHARGE CONDITION

Well	Q_o (STBOD)	$(B_o)_D$	$(z)_D$	(PM) _D psia	$(T)_{OR}$ _D	$(B_g)_D$ bbl/scf	$(GOR_{free})_D$ scf/bbl	$(Q_t)_D$ bbl/d	$(GOR_{PM})_D$ scf/bbl	$(Wt)_D$ 1000 lbs/d	$(S.G.)_D$	$(GRAD)_D$ psi/ft
N-15(N)	3,176	1.147	.85	1,108.2	590	.00228	11	3,723	129	1,060	.813	.352
S-14(N)	4,088	1.126	.89	674.5	565	.00376	52	5,402	129	1,364	.721	.312
S-5(N)	4,088	1.137	.86	882.1	575	.00283	34	5,028	129	1,364	.775	.336
N-7(N)	3,554	1.141	.86	964.6	585	.00263	24	4,279	129	1,186	.792	.343
S-9(N)	3,994	1.127	.89	705.8	572	.00364	51	5,242	129	1,333	.727	.315
S-2(N)	3,868	1.133	.88	808.2	578	.00317	39	4,861	129	1,291	.759	.328
S-17(N)	4,277	1.114	.92	489.7	563	.00533	73	6,429	129	1,428	.635	.275
S-21(N)	2,956	1.155	.83	1,318.7	597	.00189	0	3,414	129	866	.725	.314
N-8(N)	3,522	1.138	.88	910.6	582	.00283	30	4,308	129	1,176	.780	.338
S-7(N)	3,522	1.134	.88	829.5	578	.00309	38	4,408	129	1,176	.762	.330
N-16(C)	3,900	1.140	.91	953.2	588	.00283	48	4,976	152	1,307	.750	.325
N-13(C)	4,025	1.140	.91	963.2	588	.00280	48	5,129	152	1,349	.751	.325

TABLE 21
SUBMERSIBLE PUMP SELECTION

	Q_o m ³ /d	\bar{q}_t bbl/d	SG	GRAD psi/ft	REDA Pump Type	SERIE	Hz	Stages	HP Required (Production)	HP Required (Kick-Off)	Depth (m)
N-15(N)	505	4,952	.651	.282	G150	540	60	91	105	160	1,000
S-14(N)	650	6,605	.610	.264	G220	540	60	45	65	110	620
S-5(N)	650	6,455	.635	.275	G180	540	60	85	100	160	700
N-7(N)	565	5,598	.641	.278	G150	540	60	85	95	150	870
S-9(N)	635	6,471	.611	.265	G180	540	60	62	70	115	650
S-2(N)	615	6,177	.626	.271	G180	540	80	75	90	140	750
S-17(N)	680	7,299	.567	.246	G220	540	60	28	40	70	440
S-21(N)	470	4,088	.623	.270	G110	540	60	110	105	165	1,170
N-8(N)	560	5,565	.637	.276	G150	540	60	80	90	140	850
S-7(N)	560	5,615	.628	.272	G150	540	60	70	75	125	780
N-16(C)	620	6,283	.621	.269	G180	540	60	94	110	175	980
N-13(C)	640	6,481	.622	.269	G180	540	60	99	115	185	980

$$\text{Stages} = \frac{(PM)_D - (PM)_I}{GRAD \times \text{head/stage}}$$

Horsepower (actual fluid) = hp/stage x stages x SG

Horsepower (water) = hp/stage x stages

Table 22

KOBE Type A Pump - Single Engine
 Double Pump End (Source: KOBE Catalog)
 KOBE Type E Pump - Single Engine
 Single Pump End (Source: KOBE Catalog)

Pump Type	Pump Size	P/E Ratio	Displacement		Maximum Rated Speed (SPM)
			At Rated Speed (BPD)	BPD/SPM Engine Pump	
A	$4 \times 2 \frac{3}{8} - 2 \frac{3}{8} \times 2 \frac{3}{8}$	2	5,005	32.94 65	77
E	$3 \times 2 \frac{1}{8}$	1.142	4,015	66.32 75.76	53

Table 23

Power Fluid and Required Horsepower

Platform	Wells equipped with KOBÉ Type A	Wells equipped with KOBÉ Type E	Nemorados' Power Fluid (STBOPD)			Carapebus' Power Fluid (STBOPD)			Prime Mover (hp)
			Maximum	Minimum	Average	Maximum	Minimum	Average	
PCH-1	12	2	26,116	24,380	25,248	5,623	4,126	4,895	1,707
PCH-2	8	6	17,410	16,253	16,832	16,869	12,378	14,625	1,783

$$\text{Prime Mover (PCH-1)} = \frac{(1.7 \times 10^{-5}) P_S \times Q}{.9} = \frac{(1.7 \times 10^{-5}) 3,000 \times (25,248 + 4,875)}{.9} = 1,707 \text{ hp}$$

$$\text{Prime Mover (PCH-2)} = \frac{(1.7 \times 10^{-5}) 3,000 \times (16,832 + 14,625)}{.9} = 1,783 \text{ hp}$$

Table 24Hydraulic Pumping Design Data

N-8 (N)

Well: N-8 (Namorado)

$D_t = 3,020 \text{ m (vertical)}$
 $\phi_t = 4 \frac{1}{2} \text{ in O.D. tubing}$
 $\phi_c = 9 \frac{5}{8} \text{ in. O.D. casing}$
 $\gamma_o = 0.934 \text{ (20°API)}$
 $\gamma_g = 0.7025$
 $\text{GOR} = 35.5 \text{ m}^3/\text{m}^3 = 200 \text{ SCF/B}$
 $P_{res} = 260 \text{ Kg/cm}^2 = 3697 \text{ psi}$
 $P_{wh} = 7 \text{ Kg/cm}^2 = 100 \text{ psi}$
 $\text{IP} = 10 \text{ m}^3/\text{d}/\text{Kg/cm}^2$
 $Q = 550 \text{ m}^3/\text{d} = 3460 \text{ STBOPD}$
 $T_b = 220^\circ\text{F}$
 $T_s = 82^\circ\text{F}$
 $T_{avg} = 151^\circ\text{F}$

Table 25

Pump/Engine Efficiency
 (Source: KOBE Catalog)

<u>Condition</u>	<u>Pump</u>	<u>Engine</u>
New	90%	95%
Old	70%	80%

Table 26

Well: 1-RJS-50

Routine Refinery Analysis of Crude Oil Sample

(Source: PETROBRAS)

CRUDE OIL CHARACTERISTICS

- Molecular weight -----	: 339.5
- Specific gravity -----	: 0.938 60/60°F
- Kinematic viscosity at 35°F -----	: 550 cst
75°F -----	: 72 cst
115°F -----	: 22 cst
155°F -----	: 10.4 cst
200°F -----	: 5.4 cst
- Pour Point -----	: <-21°C
- Mean average boiling point -----	: 780°F
- B.S.W. -----	: 0.04 weight percent
- Sulphur content -----	: 2.4 weight percent
- Salt content at ClNa -----	: 0.2 weight percent
- Reid vapor pressure -----	: 0.512 kg/cm ²
- Heat content gross -----	: 10115 mth/kg
- Heat content net -----	: 9544 mth/kg

PONA by mass spectrometry

Paraffin -----	: 47.8 weight percent
Olefin -----	: 0 weight percent
Naphtenic -----	: 40.4 weight percent
Aromatic -----	: 11.8 weight percent

Table 27Hydraulic Pumping Design Data

N-16 (C)

Well: N-16 (Carapebus)

 $D_t = 2,670 \text{ m (vertical)}$ $\phi_{\text{tpf}} = 3 \frac{1}{2} \text{ (2.992 in ID) power fluid tubing}$ $\phi_{\text{tr}} = 3 \frac{1}{2} \text{ (2.992 in ID) prod. + pwr. fld. tubing}$ $\phi_c = 9 \frac{5}{8} \text{ " casing}$ $\gamma_o = 0.898 \text{ (26°API)}$ $\gamma_g = 0.7025$ $\text{GOR} = 40 \text{ m}^3/\text{m}^3 = 225 \text{ scf/bbl}$ $P_i = 278 \text{ Kg/cm}^2$ $P_{\text{res}} = 175 \text{ Kg/cm}^2$ $P_{\text{wh}} = 7 \text{ Kg/cm}^2 = 100 \text{ psi}$ $\text{PI} = 15 \text{ m}^3/3/\text{Kg/cm}^2$ $Q = 300 \text{ m}^3/\text{d} = 1887 \text{ STBOPD}$ $T_B = 210^\circ\text{F}$ $T_s = 82^\circ\text{F}$ $T_{\text{avg}} = 146^\circ\text{F}$

Table 28

KOBÉ Triplex Pumps

Size 4 - 180 HP Input-5000 psi (Cylinder Block)

(Source: KOBÉ catalogue)

Plunger Diameter (Inches)	Maximum Pressure (psi)	DISPL. / 100 RPM		DISPL. / 450 RPM	
		GPM	B/D	GPM	(rated speed) B/D
1 1/2	5,000	11.5	393	51.8	1,768
1 5/8	4,630	13.5	464	60.8	2,079
1 3/4*	4,000	15.6	535	70.2	2,408
1 7/8	3,480	17.9	615	80.6	2,768
2*	3,060	20.4	700	91.8	3,150
2 1/8	2,720	23.0	790	104.0	3,555
2 1/4	2,420	25.8	885	116.0	3,983
2 3/8	2,170	28.8	986	130.0	4,437

TABLE 29

AVERAGE FLUID AND ROCK PROPERTIES

(Namorado Sandstone)

A = 10.3 Km ²	ϕ = 26%	B _{oi} = 1.153
V _r = 309 x 10 ⁶ m ³	S _w = 19%	B _{ob} = 1.177
K = .25 darcies	μ_{oi} = 6.5 cp	μ_{ob} = 4.83 cp
μ_w = 1.02 cp	P _i = 315 Kg/cm ²	P _b = 132 Kg/cm ²
P _a = 40 Kg/cm ² (assumed)		

TABLE 30

GENERAL DATA AND FLOW RATE (HYDRAULIC PUMPING)

Well	Casing	φ pf	φ rf	Pump Depth (m)		Production (m ³ /d)		Power Fluid (m ³ /d)	
				Vertical	Directional	New Pump	Old Pump	New Pump	Old Pump
Namorado Sandstone	9-5/8" 43.5 lb/ft	4-1/2" OD	9-5/8" x 4-1/2"	2,150	2,448	550	473	346	323
Carapebus	9-5/8" 43.5 lb/ft	3-1/2" OD	3-1/2" OD	2,670	2,730	300	300	328	447

φ pf = Power fluid tubing (inches)

φ rf = Path of returned fluid (inches)

TABLE 31

PRESSURE AND HORSEPOWER REQUIRED PER WELL

<u>Well</u>	<u>Surface Pressure (P_s)</u> psi	<u>Engine Intake Pressure (P_{ein})</u> psi	<u>Pump Discharge Pressure (P_{pout})</u> psi	<u>Pump Intake Pressure (P_{pin})</u> psi	<u>Friction Loss (psi)</u>		<u>Pump Friction (ΔP_f)</u> psi	<u>Horsepower (HP)</u>	
					<u>Power Fluid (ΔP_{fi})</u>	<u>Returned Fluid (ΔP_{fr})</u>		<u>Hydraulic</u>	<u>Prime Mover</u>
Namorado Sandstone	2,363	5,193	2,780	1,877	22.5	7.5	607	88	97
Carapebus Sandstone	3,005	6,305	3,532	2,204	105	322	1,257	144	160