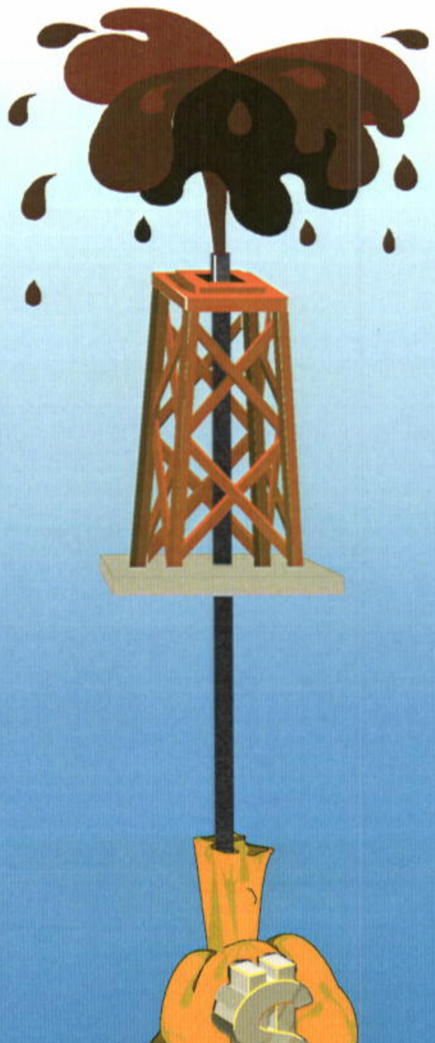
STATIC RESERVOIR PRESSURE EVALUATION

How to derive static pressure values without or with minimum shut - in

MARCH 1998



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1) INTRODUCTION

The knowledge of the average static pressure of the well inside its drainage area is a fundamental target in reservoir engineering. Particularly, its evolution with time is a key element in reservoir studies and management.

As a rule, in a producing reservoir, bottomhole static pressure in each well can be measured with the following methodologies:

⇒ **static profiles**
⇒ **production tests**

With the first method we obtain a direct measurement of the well pressure, while with the second one it is even possible to estimate the actual average pressure, if the testing times are sufficient to investigate the limits of the well drainage area. In both cases the knowledge of the static pressure clearly implies the shut-in of the well and, sometimes, of the whole field.
The negative economic impact due to lack of production is quite evident.

The aim of this Quaderno Tecnico is to present a theoretical approach to evaluate static pressure without shutting in the well, thus eliminating any " deferred production ".
Where such an approach is not applicable, practical tools, developed to minimize the well shut - in time, are presented.

The methodology proposed is valid for both oil and gas wells since ad hoc algorithms have been devised.

Through sensitivity cases, it has been possible to define the parameters which have a larger effect on the error made using the proposed theoretical approach. This enables us to understand if such an approach produces acceptable results or not.
The successful use of this methodology is a function of the reservoir characteristics and, accordingly, it must be verified on a case by case basis by the reservoir engineer in charge of reservoir management.

If the methodology proves to be not applicable, the conventional well shut-in will have to be made: theoretical auxiliary tools have been provided to quantify the minimum shut-in times to record a static pressure close to the average pressure of the drainage area (less than 5 psi).

2) CONCLUSIONS

The main conclusions of the study are as follows :

- ***<u>Static pressure evaluation without shut - in</u>***

The most commonly used methods for evaluating the static pressure in the presence of liquid or gaseous hydrocarbons, are:

for oil wells	⇒	**Jones & Glaze method**
for gas wells	⇒	**Bottom flow equation method**

The use of the proposed procedure provides, in addition to reliable static pressure estimates, also data on well deliverability by using bottomhole equation for gas wells or productivity index PI for oil wells.

The critical reservoir parameters for a correct application of the methodology are:

- Average static pressure
- Permeability - thickness product
- Density (oil wells)

while the not critical ones are :

- Well damage
- Drainage area
- Density (gas wells)

As a first approximation, the algorithm <u>can be considered reliable</u> (error < 2% with respect to reference static values) <u>when the following conditions take place contemporaneously</u>:

<u>For oil wells</u> :

- *Static well pressure (initial or affected by depletion) at least higher than 2500 psia*
- *Permeability - thickness product higher than 1500 mdft*
- *The density should be higher than 25° API .*

<u>For gas wells</u> :

- *Static well pressure (initial or affected by depletion) at least higher than 1500 psia*
- *Permeability - thickness product higher than 100 mdft*

Not honouring one of the above constraints and, even worse, the contemporaneous presence of two or more unfavourable situations can lead to the conclusion that the application of the theoretical algorithm generates very large errors (> 20 %) and thence <u>it is not recommendable.</u>
A software, named "FAST" , which can be used both for oil and gas wells, has been developed for a rapid solution of the theoretical algorithm. It can be requested to MOGI department.

- **Minimization of well shut - in time**

Where the above proposed procedure is not valid, the determination of static pressure requires the use of the standard well shut-in methodologies: static profiles or production tests.

In this case the present Quaderno Tecnico provides general guidelines to minimize the well shut-in time and obtain reliable reservoir information.

Particularly:

For oil wells:	an abacus was devised which allows the estimation of the minimum shut-in time to get a static pressure close to the average well pressure in its drainage area with a maximum difference of 5 psi.
For gas wells:	a methodology using the software " INT/2 " from SSI (Design option) has been introduced; it is able to reconstruct the minimum shut-in time which leads to a theoretical pressure with a maximum difference of 5 psi with respect to the real one.

3) DISCUSSION

3.1) THEORETICAL METHODOLOGY : Oil wells

Two different methodologies have been analysed to evaluate static pressure in oil wells in order to replace the conventional static profiles and/or production test:

⇒ **Fetkovich method**
⇒ **Jones & Glaze method**

For both of them the starting point is the direct knowledge of three different oil rates, reasonably stabilised and isochronous (Q_{o1}, Q_{o2}, Q_{o3}) and the corresponding flowing pressure values (P_{wf1}, P_{wf2}, P_{wf3}) obtained with bottomhole electronic gauges.

Since the durations of the single flowing periods are limited (about 8 - 10 hours), the flow regimes envisaged by the two methods must be considered as transitory.
The study did not take into consideration the calculation of static pressure in pseudo steady flow regime, since the monitoring times, with the use of bottomhole gauges in each flowing phase, are generally very long and, thence, not economical.

The next paragraphs present the theory at the basis of each method. Then, starting from an ideal oil well, their responses will be analysed to select the method to be used for the calculation of static pressure.

3.1.1) Fetkovich method

It is based on the following empirical correlation[1] :

$$Q_o = C \times \left(P_S^2 - P_{wf}^2\right)^n$$

It will be possible to implement a system with three unknowns: C coefficient, P_s static pressure and the n exponent respectively. When n = 0.5 conditions of pure turbulent flow will take place, while with n = 1.0 the flow will be of laminar type.

The solving system will be as follows:

$$\begin{cases} Q_{o1} = C \times \left(P_s^2 - P_{wf1}^2\right)^n \\ Q_{o2} = C \times \left(P_s^2 - P_{wf2}^2\right)^n \\ Q_{o3} = C \times \left(P_s^2 - P_{wf3}^2\right)^n \end{cases}$$

Since it is not possible to solve the system analytically the following trial and error procedure will be adopted.

The static pressure values Ps in function of the dynamic parameters found in the flowing phases are made explicit (i.e. : phases 1-2 and 1-3) :

$$P_{S(1-2)}^2 = \frac{P_{wf1}^2 \times \left(\dfrac{Q_{o2}}{Q_{o1}}\right)^{1/n} - P_{wf2}^2}{\left(\dfrac{Q_{o2}}{Q_{o1}}\right)^{1/n} - 1} \qquad P_{S(1-3)}^2 = \frac{P_{wf1}^2 \times \left(\dfrac{Q_{o3}}{Q_{o1}}\right)^{1/n} - P_{wf3}^2}{\left(\dfrac{Q_{o3}}{Q_{o1}}\right)^{1/n} - 1}$$

- Since only the static pressure value is physically acceptable, it will be necessary to evaluate by attempts the value of the n exponent which can satisfy the relationships :

$$P_s \cong P_{S(1-2)} \cong P_{S(1-3)}$$

When Ps and n are known, it is possible to estimate the C coefficient. For this reason, it is recommended to use the highest flowrate value Qo with the corresponding dynamic pressure.

3.1.2) Jones & Glaze method

In 1976 they published a study [2] considering the turbulence effect for which Darcy's law is not valid. The following equation is proposed for oil wells:

$$\Delta p = P_s - P_{wf} = A \times Q_O + B \times Q_o^2$$

where the contribution due to turbulence is implicit in the term BQ^2_0. In the case it is negligible the 1/A coefficient physically defines the well productivity index (P.I.).

Both A and B coefficients must be positive.

Being three different flowing phases available, it is possible to implement the following algebraic system of three equations with three unknowns:

$$\begin{cases} P_s - P_{wf1} = A \times Q_{o1} + B \times Q_{o1}^2 \\ P_s - P_{wf2} = A \times Q_{o2} + B \times Q_{o2}^2 \\ P_s - P_{wf3} = A \times Q_{o3} + B \times Q_{o3}^2 \end{cases}$$

The analytical resolution leads to the univocal evaluation of the three A, B unknowns and, particularly, of the well static pressure (P_s) value.

3.1.3) Comparison between the methodologies proposed

The behaviour of an ideal well producing from a homogeneous formation in a close system was simulated with an analytical model (INT/2) in order to be able to compare the two methodologies. The production mechanism is represented by simple oil expansion (22.5 °API) and its dissolved gas. Thus, no contribution related to the presence of an active aquifer (water drive = 0) was imposed. A reservoir static pressure of 3500 psia was assumed. In the theoretical simulation the well was considered not damaged and with a formation permeability thickness of 1640 md ft.
The summary of the main physical properties of the fluids flown and the PVT parameters used is given in Tab. 1.

The well was assigned a production profile whose length is sufficient to reach the limits of its drainage area, identified with a square geometry with a side of 10000 ft. The rate history used is the following:

Flow periods	Time , hours	Qo , STb/d	Qg , Mscf/d	Qw , b/d
1	8760	800	898.40	0
2	12	100	112.30	0
3	**12**	**400**	**449.20**	**0**
4	**12**	**600**	**673.80**	**0**
5	**12**	**800**	**898.40**	**0**

We want to point out the following:

- During the long flowing period (FP 1) the system reaches stationary flow conditions and, as a consequence, it is characterised by " depletion ". This period simulates the real behaviour of a well producing for a longtime.

- The next period is characterised by a strong reduction in the flow rate. This reduction can be justified from the operative point of view since it allows the run-in-hole of the electronic gauges for dynamic measurements. In fact the objective is to avoid the well shut-in. Obviously, the run-in-hole times can be optimised and reduced in function of the well depth, its deviation and the geometrical configuration of the production string. After locating the gauge as close as possible to the producing formation, it is recommended to keep the same reduced rate for at least 2 ÷ 3 hours before starting with three isochronous periods (FP : 3,4,5). This is to minimise possible distortions in the bottomhole readings which are caused by the strong thermic variations induced by the rapid run-in-hole operations.

- The isochronal flowing periods, in transitory regime, define the main periods on which the theoretical algorithm will be built in order to determine well static pressure. Considering the type of problem to be solved (3 unknowns) the flowing periods will never be less than three. At least 8 hours of flow are recommended for each flowing phase.
  The flow rate must be increasing with the constraint that the largest flow in the third flowing period (FP : 5) will not be higher than the usual flow rate.
  For safety reasons, it will be necessary to verify if the flowing conditions are compatible with the presence of tools with electric cable in the well in order to avoid dangerous "floating" phenomena of the same cable at high rates.

- The gas/oil ratio was considered constant and equal to 1123 Scf/STb during the isochronous flowing phase coinciding with the value recorded at the end of FP 1.

Then the theoretical well simulation, by using the Design option in INT/2, allowed the evaluation of the dynamic values of flowing pressure in correspondence of the three isochronal flowing periods (FP : 3,4,5). This was done for a high Kh range, keeping constant all the other parameters.

Particularly, we want to point out that:

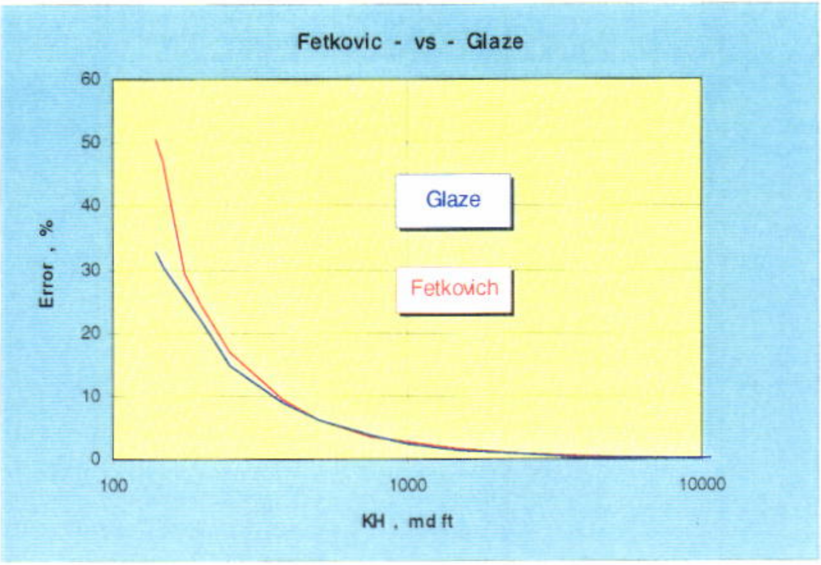
⇒ the Kh range considered is comprised between 450 and 8000 md ft. In the case examined no Kh value lower than 450 md ft was considered since the reconstruction of the bottomhole dynamic pressure, generated by INT/2, gave not acceptable P_{wf} values (they are negative).

⇒ In our example the reservoir is characterised by a saturation pressure of 1200 psia. For Kh values lower than 820 md ft, the dynamic pressures decrease below this value, activating a two phase flow in the reservoir. As a consequence, in both methods, the comparative analysis was carried out in a consistent way using single phase flow conditions for Kh > 820 mdft and two phase flow conditions (oil + gas) directly in the reservoir for Kh < 820 mdft.

The two algorithms proposed were solved obtaining the theoretical static pressure value P^* . This pressure was then compared with the average pressure of the drainage area P_{avg} obtained from simulation. Particularly, for each permeability-thickness Kh value considered, it was possible to calculate the percentage error defined as :

$$\varepsilon = \frac{P_{avg} - P^*}{P_{avg}}$$

The comparison between the two methodologies proposed is represented by the following plot:



The comparison leads to the conclusion that the Blount & Glaze method is more efficient than the one proposed by Fetkovich. In fact for Kh higher than 800 md ft the results are almost coinciding, while for Kh lower than 500 md ft the response of Blount & Glaze method is better.

Thence, Blount & Glaze method was selected to evaluate the static pressure for oil wells.

3.2) THEORETICAL METHOD : Gas wells

The well established methodology based on the concept of bottom hole equation was proposed for the evaluation of static pressure in gas wells, instead of the conventional campaigns of static profiles or production tests:

$$\Delta p^2 = P^2{}_S - P^2{}_{wf} = A \times Q_G + B \times Q_G^2$$

where the contribution due to turbulence is implicit in the term BQ^2_g. To make the parameters used physically acceptable, both the coefficients A and B of the flow equation must be positive.

However, as for the oil wells, the starting point is the direct knowledge of the three different gas isochronal rates (Q_{g1} , Q_{g2} , Q_{g3}) and of the corresponding bottomhole flowing pressure values (P_{wf1} , P_{wf2} , P_{wf3}).

Due to the short length of the flowing phases, the system is characterised by a transitory flow regime.

Being three different flowing phases available, it is possible to implement the following algebraic system of three equations with three unknowns:

$$\begin{cases} P^2{}_s - P^2{}_{wf1} = A \times Q_{g1} + B \times Q_{g1}^2 \\ P^2{}_s - P^2{}_{wf2} = A \times Q_{g2} + B \times Q_{g2}^2 \\ P^2{}_s - P^2{}_{wf3} = A \times Q_{g3} + B \times Q_{g3}^2 \end{cases}$$

The analytical resolution leads to the univocal evaluation of the three unknowns A, B and, particularly, to the well static pressure value (P_s).

4) RESOLUTIVE APPROACH

After defining the most suitable theoretical methodologies for the evaluation of static pressure both in case of oil and gas wells, an attempt was made at quantifying the error with respect to three different static pressure values taken as reference. Particularly, for the reservoir model considered, the following ideal parameters were reconstructed with INT/2 :

P_{avg} : It defines the average static pressure of the well inside its drainage area as a consequence of the long production period. Since the reservoir has reached its limits, it is characterised by depletion with respect to its initial **P_i** value The energy loss is quantified as $P_i - P_{avg}$.

P_{24} : It defines the static well pressure measured after a shut-in of 24 hours. It represents the value obtained by both a hypothetical build - up and a static profile carried out after 24 hours. The shut-in time follows immediately the flow - after flow isochronal phase.

P_{36} : It defines the static well pressure measured after a shut-in of 36 hours. It represents the value obtained by both a hypothetical build - up and a static profile carried out after 36 hours. The shut-in time follows immediately the flow - after flow isochronal phase.

The choice of the shut-in times of 24 and 36 hours is a function of the minimum shut-in times which are generally applied when recording the static profiles.

Since the methodology is aimed at evaluating the calculated static pressure P^* as an alternative to the real pressures recorded after shut-ins of 24 and 36 hours, the following percentage errors were defined with respect to the values obtained with INT/2 and taken as reference:

$$\varepsilon_{24} \equiv \frac{P_{24} - P^*}{P_{24}} \qquad\qquad \varepsilon_{36} \equiv \frac{P_{36} - P^*}{P_{36}}$$

It was also decided to evaluate the error between the static pressure P^* and the average well pressure in its drainage area P_{avg} :

$$\varepsilon \equiv \frac{P_{avg} - P^*}{P_{avg}}$$

Practically only in some cases it is possible to evaluate P_{avg} since the duration of the production tests does not generally allow a complete investigation of the limits of the well drainage area. As a consequence, the interpretation of a test carried out in a well flowing since longtime and potentially subject to depletion, leads to a static pressure value which can have a physical meaning even very different with respect to the actual P_{avg}.

In this sense, the comparison between the theoretical value calculated P^* and the pressure values actually measured during the static profiles P_{24} and P_{36} is considered more representative.

5) SENSITIVITY - CASES

Thence the analysis of the error was carried out for the parameters assumed as more critical. Particularly, at the same conditions, error curves were built to consider the impact of each of the parameters considered.

Five sensitivity - cases were studied to this purpose:

1. Error - vs - Average reservoir pressure , P_{avg}
2. Error - vs - Permeability - thickness product, Kh
3. Error - vs - Skin , S
4. Error - vs - °API gravity
5. Error - vs - Drainage area , A_d

We preferred to take into account the Kh and not the permeability since there are sometimes uncertainties in the evaluation of the real net pay of the producing formation (i.e. fractured reservoirs).

Different types of sensitivities were carried out for the oil and gas base cases presented here below.

6) BASE CASE : Oil well

The study was carried out starting from the same hypothesis defined in paragraph § 2.3. Particularly, the main input data were the following:

- P_i = 3500 psia (initial static pressure)
- kh = 500 md ft
- Skin = 0
- A_d = 10^8 sqft (drainage area with square geometry)

The summary of the petrophysical and PVT parameters of the fluids produced as well as the production history imposed at the well are presented in Tab. 1 and 2.

Then the impact that each parameter considered as critical has on the evaluation of the error between the theoretical pressure P^* and the values P_{24}, P_{36} and P_{avg} was evaluated. These values were directly obtained in the different simulations carried out with INT/2 ; particularly the measurements P_{24} and P_{36} replace the real field measurements.

The following five sensitivity cases were then analysed:

a) Error - vs - Average reservoir pressure P_{avg}
b) Error - vs - Permeability thickness product, Kh
c) Error - vs - Skin , S
d) Error - vs - ° API gravity
e) Error - vs - Drainage area , A_d

The trends of the percentage errors were reconstructed for each critical parameter :

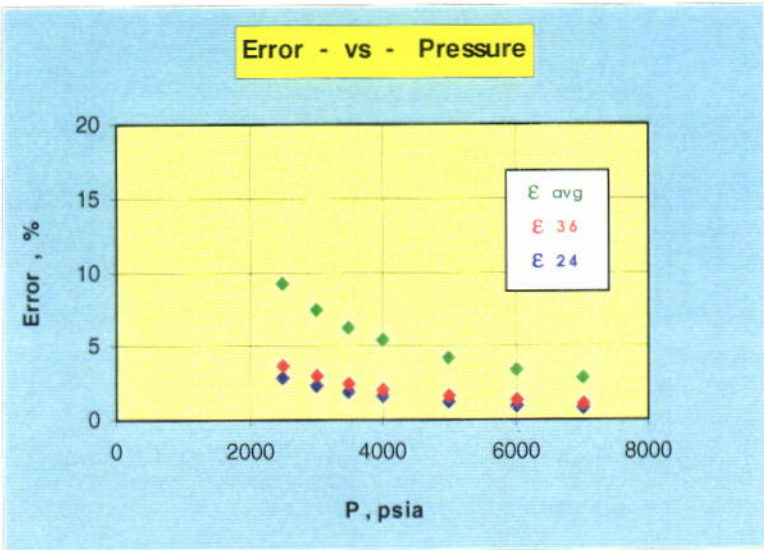
$$\varepsilon_{24},\ \varepsilon_{36},\ \varepsilon$$

In each sensitivity, all the other data were considered constant.

Moreover, we want to point out that in each simulation, when pressure is below the bubble point (in our case equal to 1200 psia), the proper multiphase reservoir flow options were used.

a) Error - vs - Average static pressure P_{avg}

The simulations produced led to the following plot :



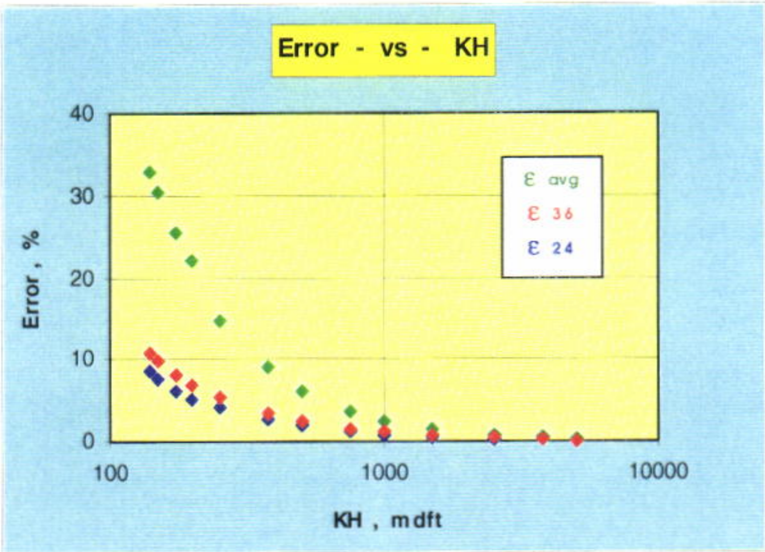
The three cases examined clearly show that the percentage error tends to amplify as the reservoir initial static pressure decreases. The phenomenon is furtherly emphasised if the error between the calculated pressure P^* and P_{avg} is considered.

The actual average static pressure of the reservoir during the test is a critical parameter since the percentage error tends to increase when referred to low static pressures and to reduce when referred to high static pressures.
This is true when the well is at the end of its production life and thence, except for a strong aquifer contribution, it can be characterised by a remarkable depletion with respect to the original pressure.

The above plot clearly shows that the error is < 2% when the reservoir pressure is higher than 2500 psia, while it becomes remarkable for reservoir pressure lower than 2500 psia.

b) Error - vs - Kh

The impact of the variation in the permeability - thickness product on the percentage error is pointed out as follows:

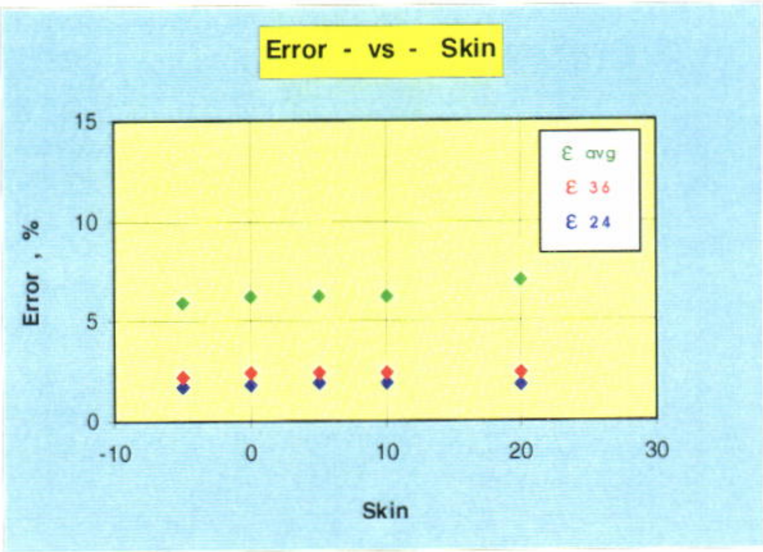


The formation Kh represents one of the most critical parameters in the theoretical evaluation of the static pressure P^*. It is clear that the higher the Kh the lower are the times required for pressure stabilisation. In fact for very high Kh (> 10000 md ft), the pressure measured by a static profile can be considered equivalent to P_{avg}.

The plot shows that the error increases according to an almost exponential law as formation Kh decreases: in our case the error is not very high (< 2%) for Kh values higher than 1500 md ft, while it becomes remarkable with very low Kh (less than 500 md ft).

c) **Error - vs - Skin**

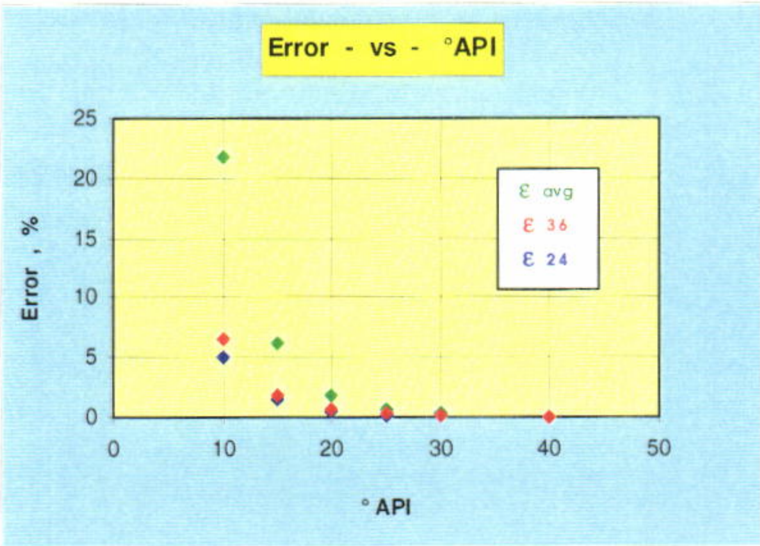
The type of damage in the well and its influence on the percentage error was considered in the following plot:



As a first approximation we can say that the presence of damage does not have any influence on the error calculation. For this reason, it can be considered as a non critical parameter.

d) Error - vs - ° API gravity

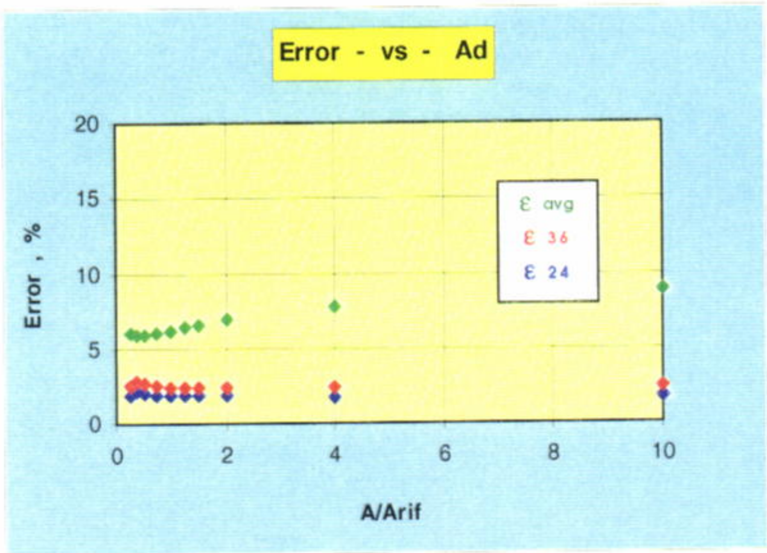
A sensitivity case was carried out to consider the influence of the oil density produced in ° API degrees. An oil well with a formation Kh of 16400 md ft was considered to this purpose. The assumption was decided out of simplicity since in the range of °API considered, the system behaves as a single phase. In this case also, it is evident that, other conditions being the same, the increase in the oil density involves an error increase. In fact heavy oils are characterised by high viscosity values also at the reservoir conditions that involve a penalization of transmissibility inside the formation with a consequent increase in the stabilisation times.
The results are shown in the following plot :



It can be noted that the error increases remarkably with the reduction of the ° API degrees of the oil produced, while the error is low (< 2 %) for oil density higher than 25° API.

e) **Error - vs - Drainage area**

The influence of the variation of the dimensions of the well drainage area was considered.



In this sensitivity the different drainage areas considered were normalised to the one of the base case taken as reference. The A reference drainage area was assumed equal to 10^8 sqft and corresponds to a square geometry with a side of 10000 ft. In this configuration the well is located in the centre.
Particularly, case $A/A_r = 10$ corresponds to the behaviour of a homogeneous and infinite reservoir.

The previous plot clearly points out that the error calculation is not affected by the dimensions of the well drainage area. This is more evident when the error is calculated with respect to the minimum shut-in times (24 and 36 hours) in transitory flow.

Thence, this parameter was considered not critical.

6) BASE CASE : Gas well

The same procedure was also applied to gas wells. Particularly, the main input data were assumed as follows:

- P_i = 3000 psia (initial static pressure)
- kh = 330 md ft
- Skin = 0
- A_d = 10^8 sqft (drainage area with square geometry)
- S.G. = 0.56 (air = 1.0)

In our case we have a dry gas mineralisation. A production history whose length is sufficient to reach the limits of the well drainage area was imposed. It is shown in the table below:

Flow periods	Time , hours	Qo , STb/d	Qg , Mscf/d	Qw , b/d
1	8760	0	3000	0
2	12	0	500	0
3	**12**	**0**	**2000**	**0**
4	**12**	**0**	**3000**	**0**
5	**12**	**0**	**4000**	**0**

The summary of the PVT and petrophysical parameters of the gas produced are presented in Tab. 2.

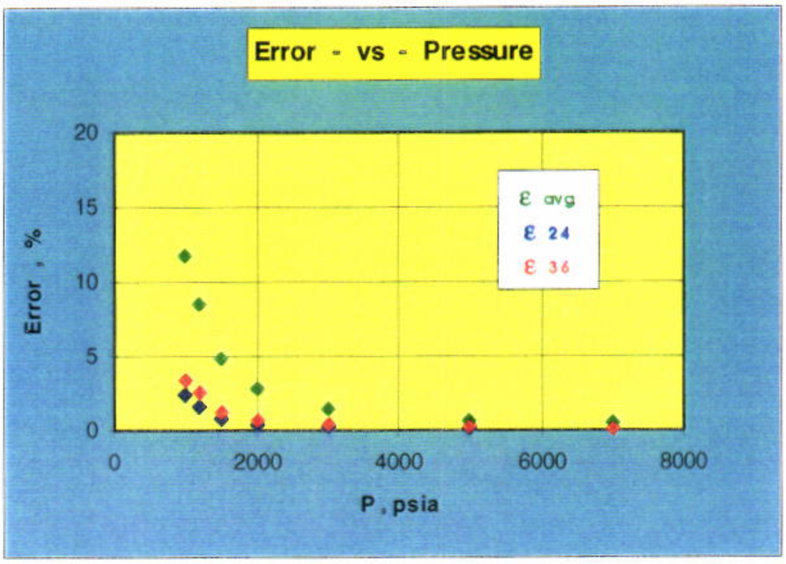
The resolutive approach was built starting from the three contemporaneous flowing periods defined by periods 3, 4 and 5. As for the oil case, it was possible to evaluate the influence of each single parameter on the evaluation of the percentage error between the theoretical calculated P^* pressure and the P_{24} , P_{36} e P_{avg} values derived from the simulations with INT/2.

The following four sensitivity - cases were analysed:

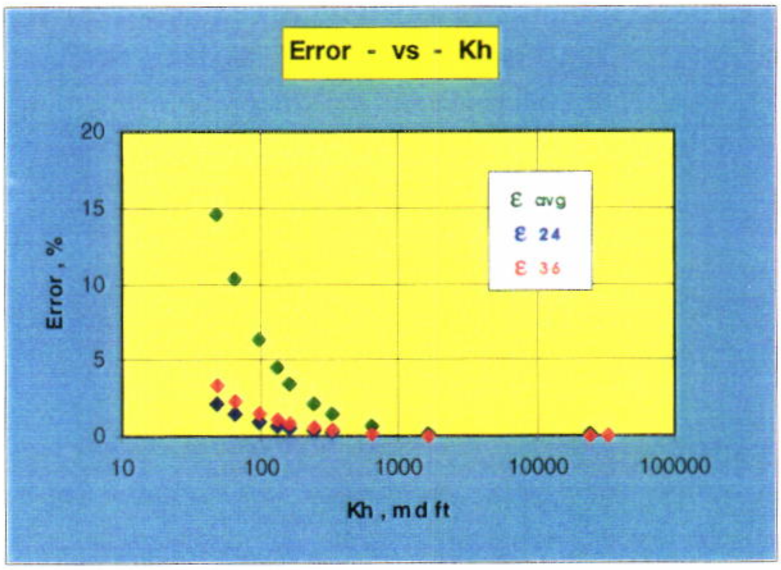
- **a)** Error - vs - Average reservoir pressure , P_{avg}
- **b)** Error - vs - Permeability thickness product , Kh
- **c)** Error - vs - Skin , S
- **d)** Error - vs - Drainage area A_d

The results of the analysis are presented in the following plots :

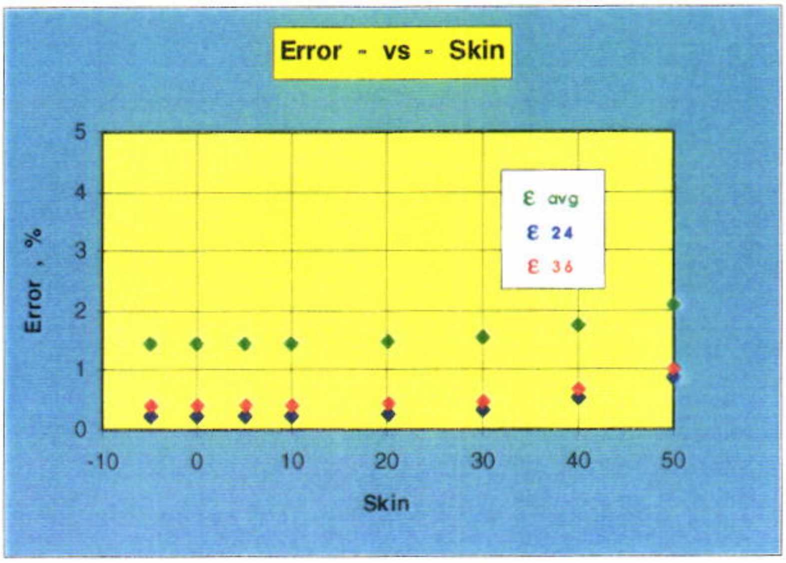
a) **Error - vs - Average reservoir pressure, P_{avg}**



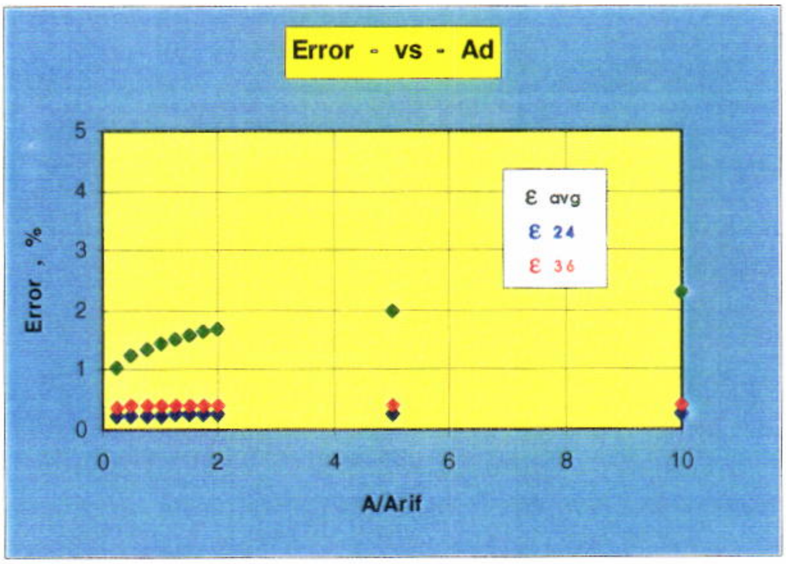
b) **Error - vs - Kh**



c) Error - vs - Skin



d) Error - vs - Drainage area



Without taking into account the magnitude of error made, it is possible to point out analogies with the oil case:

- the parameters which present problems for the evaluation of the error are:

  ◊ **Average reservoir pressure**
  ◊ **Formation permeability - thickness**

- the parameters which do not present problems are:

  ◊ **Well damage**
  ◊ **Drainage area**

The corresponding sensitivity cases showed that they have a minimum impact, if not negligible, on the error determination.
The density variation of the fluid produced, expressed as specific gravity, was not considered in the gas well analysis. Physically the error will tend to increase as S.G. increases. However, we think that as concerns gaseous mixtures, the impact will be reduced.

8) HISTORY - CASES

The response of the theoretical algorithm was verified with real history - cases. In particular five history - cases are here below presented : three of them are relevant to tests carried out on oil wells and two are relevant to dry gas wells.

a) 1° history - case (oil well)

Main well data :

- Exploration well (offshore) : LIMANDE 2 Dir (May 97' - Gabon)
- Oil density : 25° API
- GOR : 210 scf/bbl
- Final measured pressure , P_{24} : 2400 psia (last 24 hours build - up)
- Actual reservoir pressure , P_i : 2483 psia
- Formation Kh : 3540 md ft
- Skin factor , S : - 2

Rate history :

Flow periods	Time , hrs	Qo , STb/d	Pwf , psia
1	8	415	2196.1
2	8	786	1991.4
3	8	1183	1799.5

The calculated static pressure with the algorithm is equal to :

$$\boxed{P^* = 2430 \text{ psia}}$$

and the corresponding errors with respect to the real values are as follows :

◊ error with respect to the reservoir pressure P_i : $\boxed{\varepsilon_i = 2.1\ \%}$

◊ error with respect to the measured pressure P_{24} : $\boxed{\varepsilon_{24} = 1.3\ \%}$

b) 2° history - case (oil well)

Main well data :

- Exploration well (offshore) : ABO 2 (August 96' - Nigeria)
- Oil density : 35.8 ° API
- GOR : 715 scf/bbl
- Final measured pressure , P_{38} : 3361 psia (last 38 hours build-up)
- Actual reservoir pressure , P_i : 3366 psia
- Formation Kh : 97500 md ft
- Skin factor , S : 3.5

Rate history :

Flow periods	Time , hrs	Qo , STb/d	Pwf , psia
1	5.5	1812	3345.8
2	5.5	3642	3324.7
3	5.5	4787	3307.4

The calculated static pressure with the algorithm is equal to :

P* = 3358 psia

and the corresponding errors with respect to the real values are as follows :

◊ error with respect to the reservoir pressure P_i : $\varepsilon_i = 0.2\ \%$

◊ error with respect to the reservoir pressure P_{38} : $\varepsilon_{38} = 0.08\ \%$

c) 2° history - case (oil well)

Main well data :

- Appraisal well (onshore) : VOLTURINO 1 (February 98' - Italy)
- Oil density : 31 ° API
- GOR : 1100 scf/bbl
- Final measured pressure , P_{48} : 4564 psia (last 48 hours build - up)
- Actual reservoir pressure , P_i : 4690 psia
- Formation Kh : 415 md ft
- Skin factor , S : -4.8

Rate history :

Flow periods	Time , hrs	Qo , STb/d	Pwf , psia
1	8	1220	4170.9
2	8	1466	4004.4
3	8	2030	3745.6

The calculated static pressure with the algorithm is equal to :

P* = 5467 psia

and the corresponding errors with respect to the real values are as follows :

◊ error with respect to the reservoir pressure P_i : ε_i = **16.6 %**

◊ error with respect to the measured pressure P_{48} : ε_{48} = **19.8 %**

In this case the algorithm leads to very large errors and thence it cannot be applied. In fact the formation Kh of the reservoir is almost 4 times lower than the one envisaged for oil wells.

d) 2° history - case (gas well)

Main well data :

- Producing well (onshore) : CORREGGIO 35 (May 92' - Italy)
- Specific Gravity S.G. : 0.56 (air = 1.0)
- Final measured pressure , P_{24} : 1023 psia (last 24 hours build - up)
- Actual reservoir pressure , P_i : 1025 psia
- Formation Kh : 5410 md ft
- Skin factor , S : 39.1

Rate history :

Flow periods	Time , hrs	Qg , Mscf/d	Pwf , psia
1	12	834	975.0
2	12	2019	936.2
3	12	2732	912.0

The calculated static pressure with the algorithm is equal to :

P* = 1001 psia

and the corresponding errors with respect to the real values are as follows :

◊ error with respect to the reservoir pressure P_i : $\boldsymbol{\varepsilon_i = 2.3\ \%}$

◊ error with respect to the measured pressure P_{24} : $\boldsymbol{\varepsilon_{24} = 2.1\ \%}$

In this case the algorithm leads to small errors even if the reservoir pressures, of the order of 1000 psia, are much lower than the envisaged limit of 1500 psia. This can be ascribed to the high formation Kh of the reservoir.

e) 2° history - case (gas well)

Main well data :

- Producing well (offshore) : LUNA 12 Dir (August 97' - Italy)
- Specific Gravity S.G. : 0.56 (air = 1.0)
- Final measured pressure , $P_{3.5}$: 1117.1 psia (last 3.5 hours build - up)
- Actual reservoir pressure , P_i : 1117.5 psia
- Formation Kh : 66500 md ft
- Skin factor , S : -0.5

Rate history :

Flow periods	Time , hrs	Qg , Mscf/d	Pwf , psia
1	2.5	10240	1085.8
2	2.5	6886	1101.7
3	2.5	3602	1111.8

The calculated static pressure with the algorithm is equal to :

P* = 1116.8 psia

and the corresponding errors with respect to the real values are as follows :

◊ error with respect to the reservoir pressure P_i : $\boldsymbol{\varepsilon_i = 0.06\ \%}$

◊ error with respect to the measured pressure $P_{3.5}$: $\boldsymbol{\varepsilon_{3.5} = 0.03\ \%}$

The very high formation Kh minimises the error made ($\varepsilon < 1\%$) even if the reservoir pressures are much lower than the limit of 1500 psia envisaged for gas wells.

9) EVALUATION OF SHUT-IN TIME : Oil wells

The methodology presented in chapter 3.11 enables us to determine the bottomhole static pressure without the well shut-in. For oil wells it is reliable when:

- *the reservoir pressure is higher than 2500 psi*
- *formation Kh is higher than 1500 md ft*
- *oil density is higher than 25° API*

When even one of these hypotheses has not been honoured, the average pressure evaluated starting from bottomhole dynamic data could be affected by a large error. In these cases the well shut-in will be necessary.

The time needed to restore the well pressure to the average pressure in its drainage area is different from well to well and has a remarkable impact as concerns the lack of production; as a consequence, the shut-in duration must be carefully evaluated.

In the case of fluids with low compressibility an abacus was devised; it enables us to estimate the minimum shut-in time to determine the average pressure with a conventional assumed difference of 5 psi.

The hypotheses adopted are as follows:

1. reservoir with homogeneous behaviour
2. flow preceding the build-up at steady state conditions
3. build-up at transitory conditions

The following petrophysical, PVT and geometrical parameters should be known to use this abacus:

- permeability and porosity
- viscosity and volume factor
- drainage area and Dietz shape factor (Ann. n.1)
- well flow rate

The Kh and then the average formation permeability k are known when an already interpreted test is available, while the drainage area and the shape factor can be obtained by a map of the structural top or by a numerical reservoir model, if available.

The abacus is applied as follows:

- the following parameters are determined (Oil field Units):

C_A	:	Dietz shape factor (adimensional)
A	:	drainage area (ft^2)
k	:	permeability (mD)
Φ	:	porosity (fraction)
μ_o	:	viscosity (cP)
C_t	:	total compressibility (1/psi)
h	:	net pay (ft)
Q_o	:	flow rate (STB/d)

- the following values are then calculated : $\alpha = (C_A * k) / (A \cdot \Phi \cdot \mu o \cdot C_t)$

$$\beta = (Q_o * B_o * \mu o) / (kh)$$

- after defining α, we must select the corresponding β straight line. On the ordinate it is possible to obtain the shut-in time.

Two abacuses were devised to ease the reading: one in semilogarithmic shape (All. 2) and one in bilogarithmic shape (Ann. 3).

At least in the initial phase, in order to calibrate the theoretical response of the abacus, we recommend to compare the real measured pressure with the theoretical pressure given by the INT/2, according to the same procedure described for gas wells (§ 10). This comparison must be referred to the same testing time duration

Thus, it is possible to control the reliability of the input data introduced in the abacus, particularly those concerning the drainage area and its geometry and take into account the adjustments for the execution of the future profiles.

10) EVALUATION OF THE SHUT-IN TIME : Gas wells

As concerns the fluids with high compressibility, in contrast with the oil case, it was not possible to create an abacus that enables us to obtain the shut-in time necessary to evaluate the average pressure in function of the petrophysical, PVT and flow rate parameters.

This is because the gas is studied with the M(P) function and it was not possible to consider the viscosity variation and the Z factor in function of pressure.

In those cases where the theoretical approach cannot be applied, since the following conditions are not honoured:

- *reservoir pressure higher than 1500 psi*
- *formation Kh higher than 100 md ft*

we recommend to determine first the well shut-in time by means of the procedure shown below.

The following data must be available:

1. petrophysical parameters (porosity and permeability), known from a previous test interpreted
2. PVT parameters through the gas composition (or the gas gravity), temperature and reservoir pressure
3. estimation of geometry in the drained area
4. gas flow rate

These data are introduced in INT/2 activating the Design option.

The reconstruction of the production history must be made starting from when the last significant shut-in has been carried out. A very long shut-in must be imposed to the well (at least 100 hours) and the time necessary to restore the well pressure close to the theoretical average pressure (5 psi difference) should be estimated. As a first approximation, this represents the ideal shut-in time length.

It must be noted that, as a general rule, the average pressure will not coincide with the initial pressure due to the depletion effects.

11) BIBLIOGRAPHY

1. Fetkovich, M.J. : " The isochronal testing of oil wells " : Paper 4529, 48th Annual Fall Meeting of SPE, Las Vegas - 1973.

2. Jones L.G., Glaze O.H. : " Use of short term multiple rate flow test to predict performance of wells having turbulence ". SPE 6133, 51th Annual Fall Meeting of SPE, New Orleans - 1976.

TABLES

PVT and PETROPHYSICAL PARAMETERS

BASE CASE: Oil mineralisation (Pi = 3500 psia - T = 212°F)

Parameter	unit	SINGLE PHASE	TWO PHASE
porosity	%	10	10
Net pay	m	50	50
Gas saturation	%	0	15
Oil saturation	%	50	35
Water saturation	%	50	50
Total compressibility	$psia^{-1}$	1.5 e-05	1.4 e-05

Parameter	unit	OIL	GAS	WATER
Viscosity	cp	1	0.0294	0.3
Volume factor	m^3/m^3	1.5	0.0044	1.03
Compressibility	$psia^{-1}$	1.34e-05	1.87e-04	3.68e-6
Density	-	22.5 °API	0.9 (air = 1)	

BASE CASE : GAS mineralisation (Pi = 3000 psia - T = 135°F)

Parameter	unit	GAS	Water
Porosity	%	20	20
Net pay	m	10	10
Fluid saturation	%	50	50
Compressibility	$psia^{-1}$	3.0 e-04	3.72e-06
Viscosity	cp	0.0187	0.3
Volume factor	m^3/m^3	0.0049	1.03

TAB. 1

PRODUCTION HISTORY USED

BASE CASE : OIL mineralisation (22.5 ° API)

Flow periods	Time , hours	Qo , STb/d	Qg , Mscf/d	Qw , b/d
1	8760	800	898.40	0
2	12	100	112.30	0
3	12	400	449.20	0
4	12	600	673.80	0
5	12	800	898.40	0

- The gas/oil ration was considered constant during the phase with isochrone flowing of 12 hours equal to 1123 Scf/STb.

BASE CASE : GAS mineralisation (S.G. = 0.56)

Flow periods	Time , hours	Qo , STb/d	Qg , Mscf/d	Qw , b/d
1	8760	0	3000	0
2	12	0	500	0
3	12	0	2000	0
4	12	0	3000	0
5	12	0	4000	0

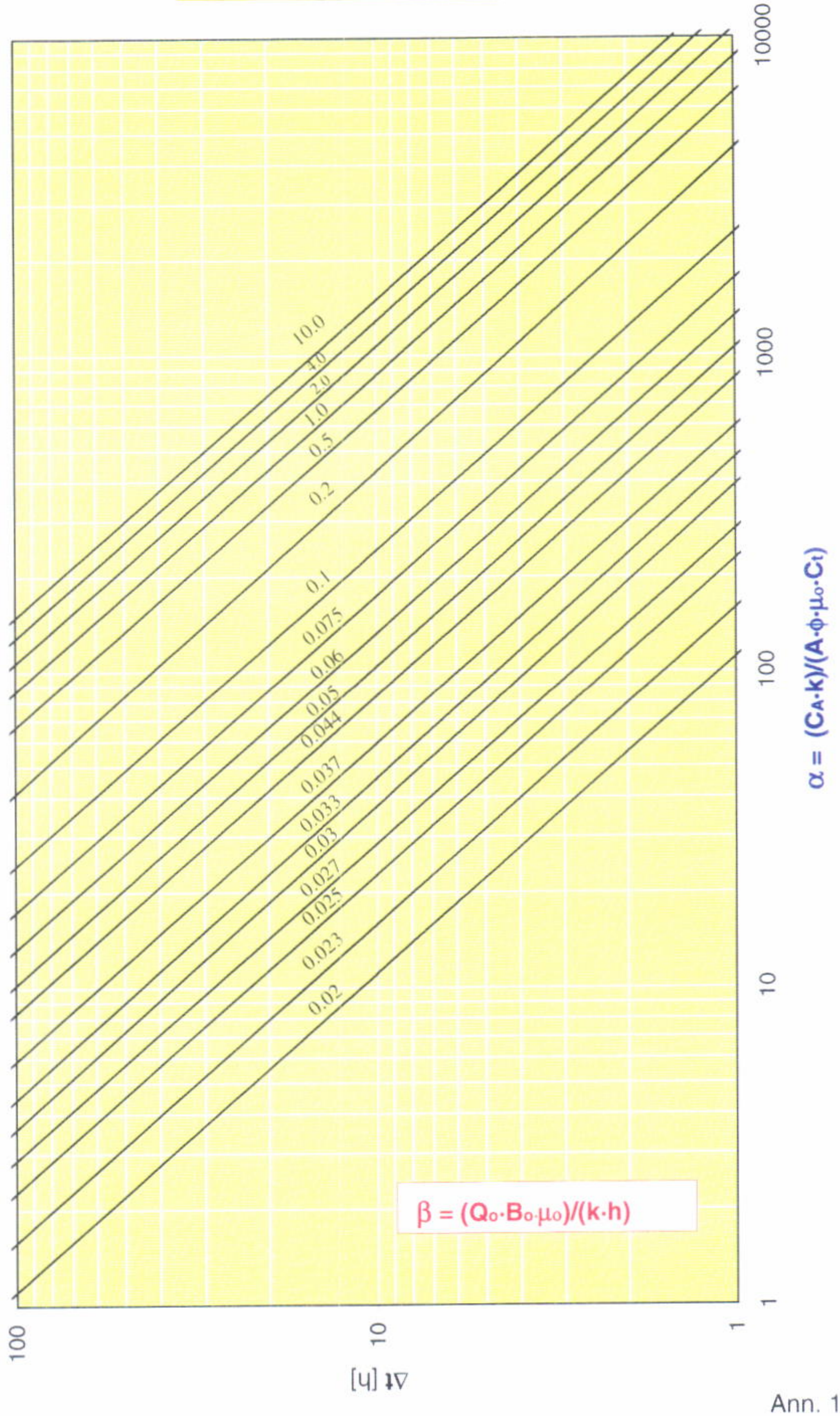
Notes : In both cases the theoretical algorithm was built on the three isochrone flow rates relevant to the periods 3 , 4 and 5.
The static pressures P_{24} and P_{36} were evaluated with INT/2 imposing, at the end of the flowing phase, shut in times of 24 and 36 hours. These values simulate the real parameters which can be obtained with the static profiles.

TAB. 2

ANNEXES

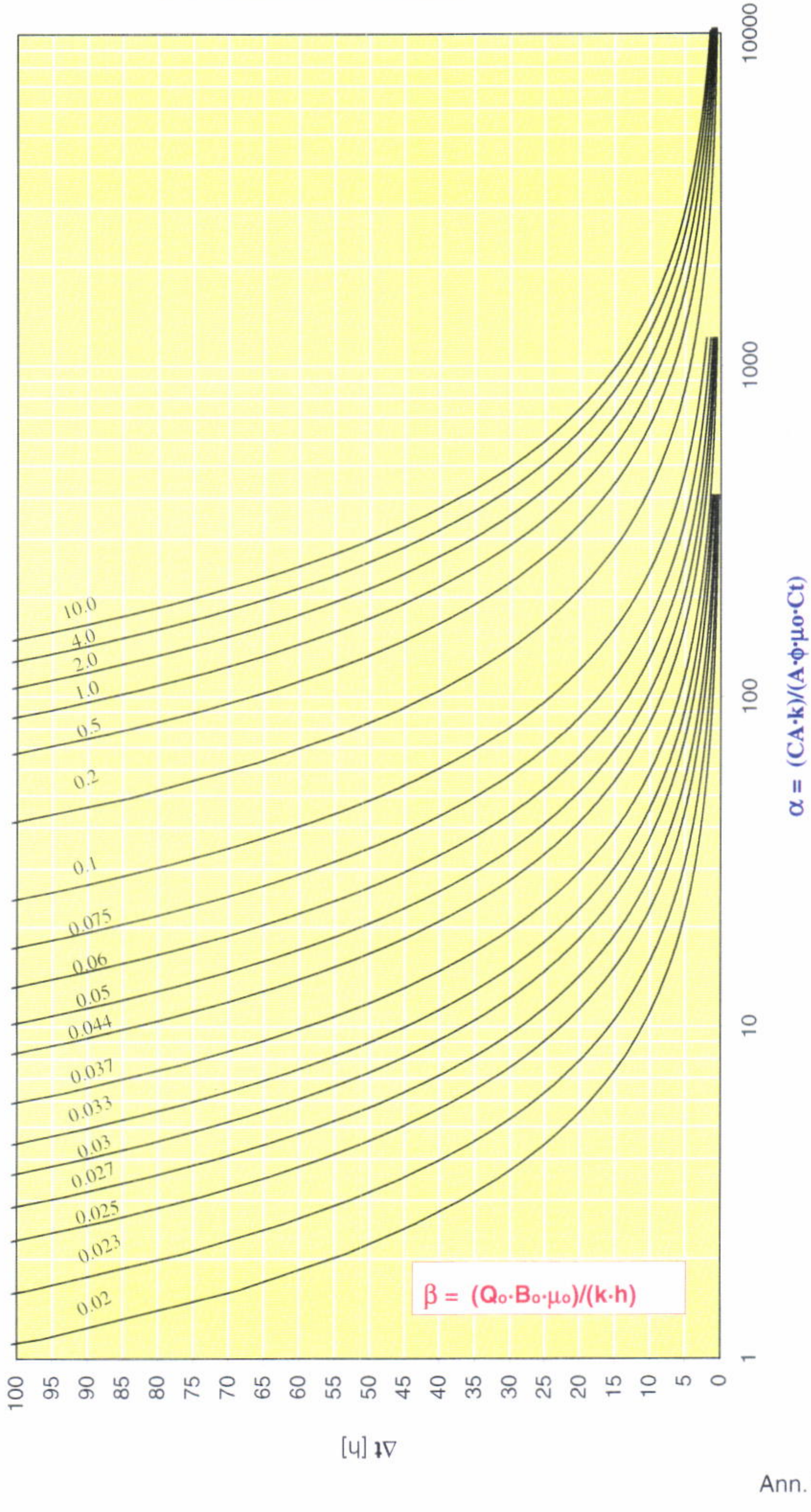
Ann. 1	Semilog abacus (Oil)
Ann. 2	Log-Log abacus (Oil)
Ann. 3	Shape factors C_A

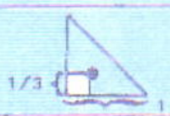
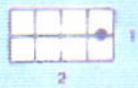
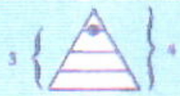
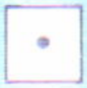
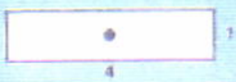
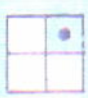
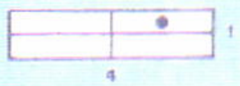
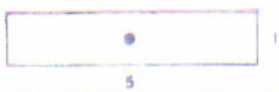
Shut in time (Oil Well)



Ann. 1

Shut in time (Oil Well)



	C_A	$\ln C_A$		C_A	$\ln C_A$
	31,62	3,4538		10,8374	2,3830
	31,6	3,4532		4,5141	1,5072
	27,6	3,3178		2,0769	0,7309
	27,1	3,2995		3,1573	1,1497
	21,9	3,0865		0,5813	-0,5425
	0,098	-2,3227		0,1109	-2,1991
	30,8828	3,4302		5,3790	1,6825
	12,9851	2,5638		2,6896	0,9894
	4,5132	1,5070		0,2318	-1,4619
	3,3351	1,2045		0,1155	-2,1585
	21,8369	3,0836		2,3606	0,8589