GAS WELL TESTING

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Dehradun

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GAS WELL TESTING

A thesis submitted in partial fulfilment of the requirements for the Degree of

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(Gas Engineering)

By

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(ISO 9001:2000 Certified)

CERTIFICATE

This is to certify that the work contained in this thesis titled "GAS WELL TESTING" has been carried out by Abhishek Agrawal & Dharmendra Singh Rathore under my/our supervision and has not been submitted elsewhere for a degree.

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ABSTRACT

Gas well test analysis is a branch of reservoir engineering. Information derived from flow and pressure transient test about in situ reservoir conditions is important in many phases of petroleum engineering. Pressure are most valuable and useful data in reservoir engineering directly or indirectly. They enter into all phases of reservoir engineering calculations, therefore accurate determination of reservoir parameters is very important.

Two different types of test are used for gas wells. The first testing methods were only designed to define the well deliverability in order to predict the flow rate as a function of the wellhead pressure. The results were used in the design of the surface production equipment, setting taxes and also for regulating production. Back pressure test and isochronal or modified isochronal test are the usual deliverability testing methods. The theoretical rate at which the well would flow if the sand phase was at atmospheric pressure is called the "Absolute Open Flow Potential", AOFP. The analysis of the deliverability test does not yield a description of the well nor of the reservoir.

More recently, transient testing has become current practice for the gas wells. The analysis provides a description of the producing system, and therefore the well deliverability & finding of the reservoir parameters are also defined.

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LIST OF FIGURES

NOMENCLATURE

1. Bg= dry gas Formation Volume Factor (FVF), *RB/scf*
2. Bo oil FVF, RB/STB
3. $C1$ conversion constant, 0.00633 *ft3/ft*
4. ct total compressibility, $psi-1$
5. h reservoir thickness, *ft*
6. H Horner time
7. k absolute permeability, *md*
8. ks altered zone permeability, *md*
9. krg gas relative permeability
10. kro oil relative permeability
11. kh flow capacity
12. L molar liquid fraction
13. Kh= estimated flow capacity
14. $m(p)$ pseudopressure function
15. $mgas(p)$ real gas pseudopressure, $psi.lb-M/(cP.ft3)$
16. $D(p)$ real gas dimensionless pseudopressure
17. Rp producing gas-oil ratio, input parameter for the three-zone method, *MCF/stb*
18. $pdew$ original reservoir gas dew point pressure, *psi*
19. pi initial reservoir pressure, *psi*
20. p= pressure at the boundary between Region 1 and Region 2, *psi*
21. pr reservoir pressure, *psi*
22. pws well shut pressure, *psi*
23. pwf well flowing pressure, *psi*
24. qt total molar rate or wet gas rate $lb-M/days$
25. r radius, *ft*
26. R gas constant, 10.735 $psi.ft3/lb-M$.oR
27. $rdew$ radius at which the pressure equals the dew point pressure, *ft*
28. rs solution condensate-gas ratio, *stb/MCF*
29. $rskin$ extend of the altered permeability zone, *ft*
30. rw well radius, *ft*
31. Rs solution gas-oil ratio, *MCF/stb*
32. s skin
33. st total skin
34. sm mechanical skin
35. $s2p$ skin due to the two-phase region or condensate bank
36. s= estimated skin
37. $\Delta skin$ Difference between estimated skin and true skin: $\Delta skin = s\square - s$
38. So oil saturation
39. Soc critical oil saturation
40. $SoCVD$ oil saturation in lab CVD
41. Swi irreducible water saturation
42. T reservoir temperature, oR or oF
43. t time, *days* or *hours*

44. *tD* dimensionless time
45. *tp* producing time, *days* or *hours*
46. *v* molar volume, *ft3/lb −M*
47. *V* vapor molar fraction
48. *Z* Z factor
49. *zg* gas z factor
50. *zo* oil z factor

Abbreviations

51. *BHFP* bottom hole flowing pressure, *psi*
52. *CCE* constant composition expansion
53. *CVD* constant volume depletion
54. *GOR* gas-oil ratio, *MCF/stb*
55. *OGR* condensate-gas ratio, *stb/MCF*

Superscripts

56. *gas* refers to the real gas pseudopressure
57. *3Z* refers to the three-zone method
58. *SS* refers to the steady-state method

Subscripts

59. *D* dimensionless
60. *g* refers to the gas phase
61. *i* initial
62. *o* refers to the oil phase
63. *wf* well flowing
64. *ws* well shut-in
65. *wf, s* well flowing at the moment of shut-in

Symbols

66. Corey pore size distribution factor
67. *μg* gas viscosity, *cP*
68. *μo* oil viscosity, *cP*
69. *ρg* gas molar density, *lb − M/ft3*
70. *ρo* oil molar density, *lb − M/ft3*
71. *φ* porosity

CHAPTER 1

1.0 INTRODUCTION

Testing of wells plays an important role in the development of the reservoir. After drilling of well it is desirable to find out if it produces oil, gas or water and at what rate. The purpose of testing is to obtain certain information about the fluid properties and reservoir characteristics and to generate the relevant data to be used for reservoir engineering calculations. The information is obtained through visual observations, surface measurements, interpreting the well-test data. Following is the main information gathered:

Type of information and its application:-

1. Type of fluid : To know whether it is oil, gas or water. If it is oil and the flow is obtained at the surface, sample of oil can be collected and sent to laboratory to determine its properties. If it produces oil, reservoir declares as oil reservoir. If it is producing gas only, the reservoir is declared as gas reservoir. If it produces water, the well is declared dry and may not be of interest to us and can be abandoned.

2. Flow Rates : During the testing of well, the flow of oil, gas and water are measured. The observation is also made about the production of sand. The testing then can be planned according to the fluid content. Well capacity, deliverability of well etc can be determined.

3. Pressure Measurements : Generally most of reservoirs are having hydrostatic pressures. However some of the reservoirs can have super-hydrostatic or sub-hydrostatic pressures. This can be found during drilling of well. The static and flowing bottom hole pressures can be measured with the help of sub-surface bottom hole pressure manometers. The pressure at wellhead are also measured by the help of manometer installed at the wellhead.
4. Reservoir Characteristics : The following are the parameters covered under th1is:

a. Permeability of the formation

b. Radius of Drainage
c. Productivity Index
d. Flow Efficiency
e. Well-bore Damage
f. Loss of Pressure due to skin

The methodology for determining the above parameters has been dealt in the following chapters.

The data obtained is used for detailed reservoir engineering calculations viz.

- To determine the deliverability, capacity and injectivity of well.
- Prediction of oil, gas and water production.
- Prediction of pressure.
- Fixation of spacing between wells.
- Planning well completion policy.
- Planning of stimulation and work over jobs.
- Stimulation studies etc.

The theory of transient test is based on Diffusivity Equation. This is the basic equation in reservoir engineering. Therefore, the diffusivity equation has been derived and then equations of pressure build up and pressure drawdown have been derived, analyzed and discussed.

Diffusivity Equation

Basic assumption : A mathematical description of fluid flow in a porous medium can be obtained from physical principles viz,

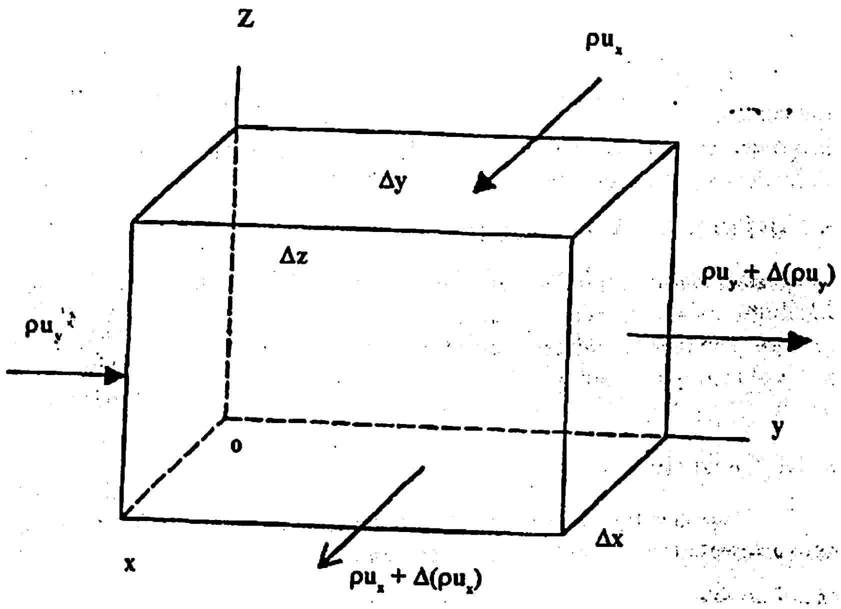
i. The law of conservation of mass,
ii. Darcy's equation and
iii. Equation of state

Conservation of Mass

This is simply a statement that some physical quantity is conserved i.e. neither created nor destroyed. In other words,

(Amount of mass in) - (Amount of mass out) + (Net amount of mass introduced) = (Increase in mass content of the region).

Let us consider a small element of dimensions Δx, Δy and Δz through which the fluid flows takes place as shown in figure. Let the velocity of fluid be u_x, u_y and u_z in x, y, z directions respectively and ρ be the specific density of the fluid. Assuming neither mass is generated nor destroyed in the element, the amount of net mass change in element in a time increment of Δt can be expressed



$$\left[-\frac{\Delta(\rho u_x)}{\Delta x} + \frac{\Delta(\rho u_y)}{\Delta y} + \frac{\Delta(\rho u_z)}{\Delta z} \right] = \frac{\left[(\varphi \rho)_{t+\Delta t} - (\rho \varphi)_t\right]}{\Delta t} \text{ ------ (1)}$$

(After dividing by Δx Δy Δz Δt)

Proceeding with limiting conditions when Δx, Δy, Δz and Δt approach zero.

$$\frac{\delta(\rho ux)}{\delta x} + \frac{\delta(\rho u_y)}{\delta y} + \frac{\delta(\rho u_z)}{\delta z} = -\frac{\delta(\varphi \rho)}{\delta t} \text{ --------- (2)}$$

This equation is called the equation of continuity in Cartesian co-ordinates. The corresponding equation of continuity in radial form is given as

$$\frac{\delta}{r\,\delta r}(r\,\rho u_r) = -\frac{\delta}{\delta t}(\varphi\,\rho) \text{ ------- } (3)$$

Darcy's Law

The velocities of flow in x, y and z directions according to Darcy's Law are given by

$$u_x = -\frac{k}{\mu}\frac{\delta p}{\delta x}$$

$$u_y = -\frac{k}{\mu}\frac{\delta p}{\delta y}$$

$$u_z = -\frac{k}{\mu}\left(\frac{\delta p}{\delta z} + \rho g\right) \quad \text{------}(4)$$

Putting values of above velocities in equation (2)

$$\frac{\delta}{\delta x}\left[\frac{k_x\,\rho}{\mu}\frac{\delta p}{\delta x}\right] + \frac{\delta}{\delta y}\left[\frac{k_y\,\rho}{\mu}\frac{\delta p}{\delta y}\right] + \frac{\delta}{\delta z}\left[\frac{k_z\,\rho}{\mu}\left(\frac{\delta p}{\delta z} + \rho g\right)\right] = \frac{\delta}{\delta t}(\varphi\rho) \quad \text{------}(5)$$

The above equation satisfies the law of conservation of mass and Darcy's law.

Equation Of State :

The fluid can be in form of either liquid or gas. We consider gas phase only

The equation for ideal gas is given by

$$pv = \frac{m\,RT}{M}$$

Where, v is the volume of gas occupied by gas of mass m whose molar weight is M, R is the gas law constant and T is the temperature of gas in 'o absolute.

The density of gas $= \rho = \frac{m}{v} = \frac{M p}{RT}$

Or

$$\frac{\delta \rho}{\delta t} = \frac{M}{RT} \frac{\delta p}{\delta t}$$

Then after putting values of ρ in equation (5), it reduces to, assuming $k_x = k_y = k_z = k$, φ as constant and ignoring terms of gravity and $\left[\frac{\delta p}{\delta x}\right]^2$ $\left[\frac{\delta p}{\delta y}\right]^2$ and $\left[\frac{\delta p}{\delta z}\right]^2$

$$\frac{\delta}{\delta x}\left(p \frac{\delta p}{\delta x}\right) + \frac{\delta}{\delta y}\left(p \frac{\delta p}{\delta y}\right) + \frac{\delta}{\delta z}\left(p \frac{\delta p}{\delta z}\right) = \frac{\varphi \mu}{k} \frac{\delta p}{\delta t}$$

$$\frac{\delta^2 p^2}{\delta x^2} + \frac{\delta^2 p^2}{\delta y^2} + \frac{\delta^2 p^2}{\delta z^2} = 2 \frac{\varphi \mu \delta p}{k \, \delta t} \text{ -------(6)}$$

This equation in radial coordinates is given by

$$\frac{1}{r}\frac{\delta}{\delta r}\left[r \frac{\delta p^2}{\delta r}\right] = \frac{\delta^2 p^2}{\delta r^2} + \frac{1}{r}\frac{\delta p}{\delta r} = 2 \frac{\varphi \mu}{k} \frac{\delta p}{\delta t} = \frac{\varphi \mu}{kp} \frac{\delta p^2}{\delta t} \text{ --------(7)}$$

This equation is non linear and can be solved by numerical methods.

CHAPTER 2

2.0 ROLE OF GAS WELL TEST

Gas well test analysis is a branch of reservoir engineering. Information derived from flow and pressure transient test about in situ reservoir conditions is important in many phases of petroleum engineering. Pressure is most valuable and useful data in reservoir engineering directly or indirectly. They enter into all phases of reservoir engineering calculations, therefore accurate determination of reservoir parameters is very important.

Two different types of test are used for gas wells. The first testing methods were only designed to define the well deliverability in order to predict the flow rate as a function of the wellhead pressure. The results were used in the design of the surface production equipment, setting taxes and also for regulating production. Back pressure test and isochronal or modified isochronal test are the usual deliverability testing methods. The theoretical rate at which the well would flow if the sand phase was at atmospheric pressure is called the "Absolute Open Flow Potential", AOFP. The analysis of the deliverability test does not yield a description of the well nor of the reservoir.

More recently, transient testing has become current practice for the gas wells. The analysis provides a description of the producing system, and therefore the well deliverability is also defined.

Further there are two main differences between gas well testing and liquid well testing. First, because

gas properties are highly pressure dependent, some of the assumptions implicit in liquid well testing theory are not applicable to gas flow. Second, high gas velocity usually occurs near the wellbore and an additional pressure drop is caused by visco-inertial effects. The additional pressure

drop is called the rate-dependent skin effect. And the other main difference is that gas can flow through the tight formations.

Objectives

a. Reservoir evaluation,

b. Reservoir management, and

c. Reservoir description.

Reservoir evaluation

To reach a decision as how best to produce a given reservoir (or even whether it is worthwhile to spend the money to produce it at all) we need to know its **deliverability, properties, and size.** Thus we will attempt to determine the reservoir conductivity (kh or permeability- thickness product), initial reservoir pressure and reservoir limits (or boundaries). At the same time we will sample the fluid so that their physical properties can be measured in laboratory. Also we will examine near well bore condition in order to evaluate whether the well productivity is governed by wellbore effects (such as skin and storage) or by the reservoir at large.

Reservoir pressure tells us how much potential energy the reservoir contains (or has left) and enables us to forecast how long the reservoir production can be sustained . Pressures in the vicinity of the wellbore are effected by drilling and production processes, and maybe quite different form the pressure and reservoir at large.Well test interpretation allows us to infer distant pressures from the local pressures that can actually be measured.

Analysis of reservoir limits enables us to determine how much reservoir fluid is present.(Be it oil , gas, water or any other) and to estimate whether the reservoir boundaries are closed or open.(With aquifer support or a free surface).

Reservoir Management

During the life of a reservoir , we wish to monitor performance and well condition.It is useful to monitor the changes in average reservoir pressure so that we can refine our forecast of future reservoir performance.By monitoring the condition of the wells it is possible to identify candidates for workover or stimulation. In special circumstances it may also be possible to track the movement of fluid fronts within the reservoir such as may be seen in water flooding or insitu combustion. Knowledge of the front location can allow us to evalutate the effectiveness of the displacement process and to forecast its subsequent performance.

Reservoir Description

Geological formations hosting oil , gas water and geothermal reservoirs are complex and may contain different rock types , stratigraphic inter faces , faults, barriers and fluid fronts. Some of theses features may influence the pressure transient behavior to a measureable extent, and most will effect the reservoir performance . To the extent that it is possible , the use of well test analysis for the purpose reservoir description will be an aid to the forecasting of the reservoir performance. In addition, characgerization of the reservoir can be useful in developing the production plan.

There are following tests that are done in gas well

1. Steady state tests
   a. Back Pressure Tests
   b. Two Term Formula
   c. Isochronal Tests(Conventional and modified)
2. Unsteady state tests
   a. BuildUp Tests
   b. Drawdown Tests

CHAPTER 3

3.0 BUILD UP TEST

Several methods have been presented for analysis of pressure build up data. These methods are :

1. Miller, Dyes and Hutchison method
2. Horner's method
3. Thomas method
4. Van Everdingen method
5. Hurst's method
6. Arps method
7. Glatfelter, Tracy and Wilsey method
8. Muskat method

The above methods provide a means of measuring:-

1. Degree of damage (Skin effect S).
2. Inherent flow capacity of the undamaged formation (kh) and
3. Static reservoir pressure.

There is a considerable similarity between methods proposed for analysis of pressure build up curves. The important difference is in the boundary conditions assumed. For successful analysis, some knowledge of reservoir conditions at the drainage radius is necessary. These methods of analysis can be divided into 2 broad classes. One class is applicable to new wells where only a small fraction of the oil in place has been produced. The second class is applicable to those wells where the effect of drainage boundary has been felt at the well.

In our project, only Horner's method has been discussed since it utilizes the best features of all the methods presented in the literature.

Conditions Assumed in Pressure Build Up Analysis

The recent methods proposed in the literature for PBU analysis are conveniently classified according to reservoir boundary conditions assumed.

The following 2 sets of condition are assumed in PBU analysis.

1. A small inner boundary (the well bore radius approaching zero) over which the steady state flow rate of compressible fluid is constant and a large but finite outer reservoir boundary exists. At the drainage radius either (a) the pressure remains constant after shut in or, (b) there is no influx of fluid across the boundary after shut in.
2. A small inner boundary over which the steady state rate of flow of compressible fluids is constant and an infinite outer boundary of the reservoir. The pressure is assumed to remain constant at the outer boundary. A small internal boundary may be finite or vanishingly small.

Several additional assumptions are required for mathematically rigorous derivations. Not all of the assumptions need to be fulfilled for practical application of the results. These assumptions are:-

1. Flow of compressible fluid,
2. an unsaturated, single fluid phase is flowing in the reservoir,
3. the properties of the reservoir fluid are constant under the reservoir conditions,
4. the well is shut in at the sand face, so that no fluid are produced in the well bore after shut in,
5. the sand comprising the reservoir is uniform in its properties,
6. the production rate is stabilized before shut in,
7. the reservoir shape is that of horizontal circular cylinder.

3.1 Theory of pressure build-up analysis

It is a general practice to develop the flow equations assuming the reservoir to be homogeneous, horizontal and of uniform thickness throughout. The fluid is considered to be in one phase only and is assumed to obey Darcy's law. Furthermore, it is assumed that the compressibility and absolute viscosity of the fluid remain constant and the flow to the well is radial.

The change in the production rate causes a change in the pressure at the bottom of the well as well as on the surrounding point in the reservoir. Hence, in case of sudden change in the production rate of the well from ‘q’ to ‘0’. The change of pressure at any time in the reservoir at a distance ‘r’ from the axis of the well can be obtained from the solution of the following equation:-

$$dp^2/dr^2 + 1/r(dp/dr) = 1/\eta\,(dp/dt)$$

where,

1. $\eta = k/\varphi\mu c$ = diffusivity constant
2. r = cms.
3. t = seconds
4. p = atm
5. k = Darcy’s
6. c = vol/vol/atm

The mathematical solution for one well in infinite reservoir is given by:-

$$P(r,t) = P_i - \frac{q\mu}{2\pi kh}\left[\frac{-1}{2} Ei(-\varphi\mu c r^2/4kt)\right] \text{ -------- } (1)$$

where,

$$-Ei(-x) = \int_x \frac{e^{-u}}{u}\,du$$

and u = volumetric rate of flow per unit cross sectional area.

For $x < 0.01$,

$$-Ei(-x) = -\ln(\gamma x) = \ln(1/x) - 0.5772$$

The symbol γ is Euler’s constant and is equal to 1.78

Thus, for $\frac{4kt}{\varphi\mu c r^2} > 100$

$$P(r,t) = P_i + q\mu \ln(\gamma\,\varphi\mu c\, r^2) \text{ ---------}(2)$$

$$4\pi kh \qquad 4kt$$

As such, the expression for pressure at the well bore (i.e. $r = r_w$) is:-

$$P_{wf} = P_i + \frac{q\mu}{4\pi kh} \ln\left(\frac{\gamma\, \varphi\mu c\, r_w^2}{4kt}\right)$$

so that the pressure drop is

$$P_i - P_{wf} = \frac{-q\mu}{4\pi kh} \ln\left(\frac{\gamma\, \varphi\mu c\, r_w^2}{4kt}\right) \text{ ---------(3)}$$

If, we now close the well for a time Δt, after producing for time t, the pressure drop at time Δt can be found by the principle of superposition and will be as follows:-

$(P_i - P_{ws})$ = (pressure drop caused by rate q for time $(t + \Delta t)$

+

pressure drop caused by rate change q for time Δt.) or,

$$(P_i - P_{ws}) = \frac{-q\mu}{4\pi kh} \ln\left(\frac{\gamma\, \varphi\mu c\, r_w^2}{4k(t+\Delta t)}\right) + \frac{q\mu}{4\pi kh} \ln\left(\frac{\gamma\, \varphi\mu c\, r_w^2}{4k\Delta t}\right) \text{ ------(4)}$$

Therefore,

$$P_{ws} = P_i - \frac{q\mu}{4\pi kh} \ln\frac{(t+\Delta t)}{(\Delta t)} \text{ --------(5)}$$

The above basic equation for PBU analysis was presented by Horner. After expressing this equation in practical oil field units of PSI, B/D, cp, md and ft, it becomes :-

$$P_{ws} = P_i - 162.6\, \frac{q\mu B}{kh} \log\frac{(t+\Delta t)}{\Delta t} \text{ --------(6)}$$

or

$$P_{ws} = P_i - m\log \frac{(t+\Delta t)}{\Delta t} \quad \text{---------(7)}$$

where $m = \dfrac{162.6\ q\mu B}{kh}$

This equation is similar to the equation of the straight line, Y = mx + c . Thus, if a graph of P_{ws} v/s $\log \frac{(t+\Delta t)}{\Delta t}$ is plotted, it should result in a straight line. The slope of this straight line is $m = \dfrac{162.6\ q\mu B}{kh}$

from which k, kh and kh/μ are determined. Extrapolation of the straight line section to an infinite shut in time (t+Δt/Δt) = 1 will give the initial or boundary pressure.

Horner's method

Horner's method of analysis results in the estimation of the effective permeability of the formation & the static reservoir pressure.

In this plot, the points are plotted on a semi log graph paper with P_{ws} v/s (t+Δt)/ Δt

It may be noted that the shut in pressure has been recorded after closing the well. Though the well has been shut in & no production is been obtained at the surface but, the fluid keeps on flowing in the formation till the pressure is stabilized i.e., the shut in pressure becomes equal to the reservoir pressure. During this period the fluid flow rate in the formation goes on reducing thus, unsteady state flow conditions have been achieved.

The plot should be a straight line as per theory but in actual practice it may be in a form of curve. The curve in general, has three parts :-

1. Initial stage – This get affected by well bore conditions.
2. Middle part of the curve gives the drainage effect and
3. last part gives effect of boundary.

Initial Stage It is called early time region. Most wells have altered permeability near the well bore. Until the pressure transient caused by shutting in the well for the build up test moves through this region of altered permeability, there is no reason to expect a straight line slope that is related to formation permeability. Continued movement of fluid into a well bore following the usual surface shut-in compresses the fluids in the well bore.

Middle Part: When the radius of investigation has moved beyond the influence of the altered zone near the tested well, and when after flow has ceased distorting the pressure build up test data, we usually observe the ideal straight line whose slope is related to formation permeability. This straight line ordinarily will continue until the radius of investigation reaches one or more boundaries, massive heterogeneities, or a fluid/fluid contact.

Last Part: This is the late time region. The radius of investigation eventually reach the drainage boundaries of a well. In this region pressure behavior is influenced by boundary configuration, interference from nearby wells, significant reservoir heterogeneities, and fluid/fluid contacts.

Effects of Afterflow: Afterflow causes several problems in build up analysis. These problems include (1) delay in the beginning of MTR making its recognition more difficult, (2) total lack of development of MTR in some cases, with relatively long periods of afterflow and relatively early onset of boundary effects; and (3) development of several false straight lines, any one of which could be mistaken for the MTR line. The characteristic influence of afterflow on a pressure build up test plot is a lazy S-shape at early time.

For our purpose middle part of the graph, which is a straight line is selected and the slope is found and from permeability and other parameters are calculated.

Determination of Permeability: Bulk formation permeability is calculated from the slope of the MTR line. Average permeability, k_j, also can be determined from information available in build up tests. The first problem is identification of the MTR. This region cannot begin until afterflow ceases distorting the data; indeed, cessation of afterflow effects usually determines the beginning of the MTR. If the altered zone is unusually deep, passage of the transient through the region of the drainage are influenced by the fracture will determine the beginning of the MTR.

Predicting the time at which the MTR ends is more difficult than predicting when it begins. Basically, the middle-time line ends when the radius of investigation begins to detect drainage boundaries of the tested well; at this time, the pressure build up curve begins to bend.

To simplify it a pressure derivative plot v/s elapsed time, t is plotted. From that select 2 points from the late time region and then by considering these points plot a straight line by joining these points in the Horner plot.

The permeability thus determined gives the true value of permeability of the reservoir. This value is used for all reservoir engineering calculations as the oil/gas is located in the drainage part of the reservoir. This value of permeability differs from that determine under steady state conditions because this is an average permeability (not the permeability of the drained part) that gets influenced by the well bore due to the presence of skin and cavity etc.

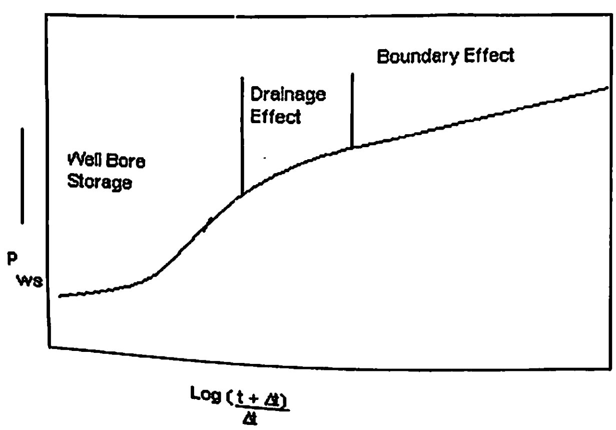


Figure 2:Horner's Plot

3.2 Pressure build-up in gas wells

Experience has shown that the pressuere build up method for oil wells could be extended to gas wells also. Tracy has presented a good discussion on the basis of such application. Such approximations is based upon the work of Aronofsky and Jenkins who obtained numerical solutions to the partial differential equations describing radial flow of ideal gas. On the basis of their result and method of approximation the build up equation can be expressed with considerable accuracy based on Horner's equation as

$$P^* - P_{wf} = \frac{q\mu B_o}{4\pi kh} \ln \frac{(t+\Delta t)}{\Delta t} \quad \text{---------(8)}$$

Now replacing simply B_o by B_g and q by q_g where q_g is the gas production rate in cm^3/sec and B_g is the formation volume factor for gas and is given by

$$B_g = \frac{Z T_r P_{sc}}{T_{sc} (P^* + P_{ws})/2}$$

Z = compressibility factor or gas deviation factor

T_r = Gas reservoir temperature, K

T_{sc} = Surface temperature, K

P_{sc} = Surface Pressure, atm

P^* = Initial pressure computed from Horner Plot, atm

Then the equation reduces to

$$P^{*2} - P_{ws}^2 = \frac{q_g \mu_g Z T_r P_{sc} 2}{T_{sc} 4\pi kh} \ln \frac{(t+\Delta t)}{\Delta t}$$

The above equation is an equation of straight line where Pws2 is plotted against log (t+Δt) the slope of which is

Δt

$m = 2.303\, q_g \; Z\, T_r\, P_{sc}$

$2\pi kh \qquad\qquad T_{sc}$

Then all the relevant parameters can be computed just as it has been done in case of oil well.

It has been found that for pressure above 2000psi, the product $\mu_g\, B_g$ is nearly constant and the plot of P_{ws} v/s log (t+Δt) gives the same result. Thus plot of P_{ws} vs

Δt

log(t + Δt) instead of $P_{ws}{}^2$ vs log(t + Δt) is preferred. Even at low pressure, very

$\Delta t \qquad\qquad\qquad\qquad \Delta t$

satisfactory results have been obtained for gas wells when P_{ws} vs log or log(t + Δt)/ Δt is plotted. Therefore the interpretation of pressure build up for gas wells can also be done in a similar manner as in case of oil wells.

3.3 Definition and formulas used to calculate reservoir parameters from pressure build up test

Permeability:- The permeability of rock is defined as its ability to permit the movement of oil, gas and water through it. The permeability of a porous medium may vary depending on the substance going through it and on the nature of its movement.

$K=162.6q\mu B$ md

mh

where,

m = slope obtained from graph

q = flow rate m3/day

μ = viscosity, cp

B = formation volume factor

h = thickness of formation, ft

Capacity :- It is the product of permeability and thickness of formation which gives us the flowing capacity of the formation. It is given by

$$kh = \frac{162.6\, q\mu B}{m} \quad \text{millidarcy-ft}$$

Hydro conductivity/Transmissibility: - It is a measure of the ability of the reservoir to transmit the fluid contained within it. It is a function of both reservoir rock and fluid properties. It is advisable to determine hydroconductivity instead of permeability in case values of h and μ are doubtful.

$$\frac{kh}{\mu} = \frac{162.6qB}{m} \quad \text{millidarcy-ft/cp}$$

Mobility: - The mobility of a certain fluid is the measure of the velocity of travel of fluid in a particular direction in the reservoir. In certain cases, the value of h is known but the value of viscosity is not known. In such cases, instead of finding permeability, or hydroconductivity, mobility is determined and used in calculations.

$$\frac{k}{\mu} = \frac{162.6qB}{mh} \quad \text{md/cp}$$

Skin effect: - Generally, permeability is higher in the area away from the well compared to the area surrounding the well (i.e. well bore permeability). This is because in most cases the permeability around the well decreases due to invasion of mud filtrate. The additional resistance to flow due to this damage is known as skin factor which is calculated from PBU curve. Skin effect is a measure of additional pressure drop necessary to overcome the flow resistance of the reduced permeability zone. A value of skin effect greater than 10 represents serious damage around the well bore. A value between 0 to 5 represents slight damage. Negative value represents improved permeability around the well bore.

$$S = 1.151\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k}{\varphi\mu c r_w^{2}}\right) + 3.23\right]$$

Effect of incompletely perforated interval: When the completed interval is less than total formation thickness, the pressure drop near the well is increased and the apparent skin factor becomes positive.

$$s = \frac{h_t}{h_p} s_d + s_p$$

where,

s_d = true skin factor

s_p = apparent skin factor

h_t = total interval heighr

h_p = perforated interval height

$$s_p = \left(\frac{h_t}{h_p} - 1\right)\left[\ln\left(\frac{h_t}{r_w}\sqrt{\frac{k_H}{k_V}}\right) - 2\right]$$

where,

k_H = horizontal permeability

k_V = vertical permeability

Pressure loss due to skin:-

$$\Delta P_{skin} = m \times 0.87 \times s \text{ psi}$$

Radius of skin:-

$$r_s = r_w \times e^{-s}$$

Permeability of skin:-

$$S = \left(\frac{k}{k_s} - 1\right) \ln(r_s/r_w)$$

Radius of investigation: - It is the measure of the investigation of the reservoir. Thus, one can know how far the reservoir is investigated from the well bore. It is calculated from the formula

$$r_i = \sqrt{\frac{0.00105kt}{\Phi\mu c}}$$

Productivity Index: - The potential of a well is determined by the product of J actual and pressure drawdown. The productivity of a well means the ability of well to produce oil. J actual is a measure of the ability of a well to yield oil at reservoir face. It gives the amount of fluid which can be produced from the well in a given time and drawdown. It is expressed as $m^3/day/kg/cm^2$

$$J\ actual = \frac{q}{P^* - P_{wf}}$$

Flow Efficiency: - In addition to skin effect formation damage can also be expressed in terms of flow efficiency. It is defined as the ratio of actual productivity index of a well to its productivity index if there were no skin(s = 0). Thus, flow efficiency

$$= \frac{J\ actual}{J\ ideal}$$

where,

$$J\ actual = \frac{q}{P^* - P_{wf}}$$

$$J_{ideal} = \frac{q}{P^{*} - P_{wf} - \Delta P_{skin}}$$

Damage Factor: - When we subtract flow efficiency from unity it gives damage factor.

DF = 1-FE

Absolute Open Flow Potential(AOFP) :- The total quantity of gas produced/day when the flowing Bottom hole pressure is reduced to 1kg/cm2 is called the open flow potential of the well. The allowable gas production is generally taken as one-fourth of the AOFP of the well. This can be achieved by producing well without bean but the production rate would be so high that the formation may get damaged and chances of loosing well are high. This can be calculated by 2 methods:

1. Back Pressure Test (American Method)

2. Two terms Formula (Russian Method)

In our calculations we are using Back Pressure Test method and the AOFP is calculated using the following formula

$$Q = C\,(P_e^2 - P_w^2)^n$$

where,

C = Performance coefficient

n = the reciprocal of mathematical slope of the straight line when log Q vs P2-Pw2 is plotted.

3.4 Uses of pressure build-up study

1. Build up curve is used to calculate various reservoir parameters like k, kh, kh/μ, s, flow efficiency etc from the build up study, the average permeability of the reservoir is obtained.
2. If the build up curve has two straight line portions and the second straight line has a slope approximation twice the slope of the first, then a fault/barrier is inferred.
3. Certain interpretations like boundary effects, interference, phase separation in tubing, stratified layer or lateral increase in mobility can be done from the build up curve.
4. Reservoir pressure (p*) is determined from the build up curve. P for infinite reservoir can also be calculated from P*.
5. Presence of damage near the well bore is ascertained. A positive value of 's' indicates the presence of damage near the well bore. A negative value of 's' indicates increased permeability within this region. From this, the well can be recommended for stimulation purposes.
6. The productivity ratio which is a measure of damage around a well is evaluated from the build up curve. The productivity ratio can be used to know the damage or the improvement of permeability around the well bore since,

   q <1 indicates damage to the formation

   q_o

   q > 1 indicates improvement of 'k' around the well bore.

   q_o

7. From the pressure build up analysis, it is possible to determine oil/gas in place within drainage radius.

Discussions

Pressure build up and pressure drawdown methods are theoretically same and are mirror reflections of each other. Pressure build up is preferred because in draw down no stabilized flow rate is achieved due to which result interpretation is not good. In build up we get stabilized rate and interpretation done is good.

The value of reservoir pressure P* will be less if the stabilized flow rate is les than the last production rate (when the well is closed). Similarly, if the stabilized rate is greater than the last flow rate, the value of P* obtained will be greater.

If the well is not stabilized before the buildup then the curve may give rise to two slopes showing as if a fault or barrier is present at some distance from the well.

Certain wells exhibit "humping" peculiarity. In such cases bottom hole pressure builds up to a maximum and then decreases. This behavior is due to segregation of oil and gas in the tubing and casing subsequent to shut in at surface. The rise of gas bubbles increase the bottom hole pressure. This may increase to the extent that liquid in the well will be forced back into the formation, thus decreasing the bottom hole pressure. In case, the straight line portion is not developed, it is recommended to run a draw down test.

In a well partially penetrating the productive thickness or partially blocked perforations having high vertical permeability, the build up curve will show the characteristics as the formation is damaged. However, this effect is due to the flow convergence of the fluid when it is entering the well.

Apart from finding the reservoir parameters from the pressure build up curve, static reservoir pressure in infinite and bounded reservoirs can be founded by the extrapolation of the straight line portion of the curve. The reliability of the curve can be checked using dimensionless time limits and by the criteria that the static pressure obtained by extrapolation of the curve in individual wells are not very different than average reservoir pressure.

The production rates for oil, gas and water during the two week interval immediately preceding the pressure build up test should be recorded. These rates should be reported exactly as they have been observed so that any variations can be considered in the subsequent computations. The pressure effect can then be reliably obtained.

CHAPTER 4

4.0 ISOCHRONAL TEST

This test is developed by-"CULLENDER". This test is mainly developed for the tight reservoir. Or the reservoir having very low permeability from which it is possible to produce gas but the time of achieving steady production is very long.

Procedure

Step 1st: Find out the static bottom hole pressure.

Step 2nd : Flow the well through the stipulated bean for a specific time & note the flow rate & BH flowing pressure.

Step 3rd: shut in the well till steady state is achieved & again flow the well for a specific period of time.

Step 4th: Repeat the operation at least three times.

Step 5th: Change the bean and do the operations as indicated above from 2nd to 4th but keeping the time period same for each observation in sequence.

Step 6th: after taking all the data do the interpretation.

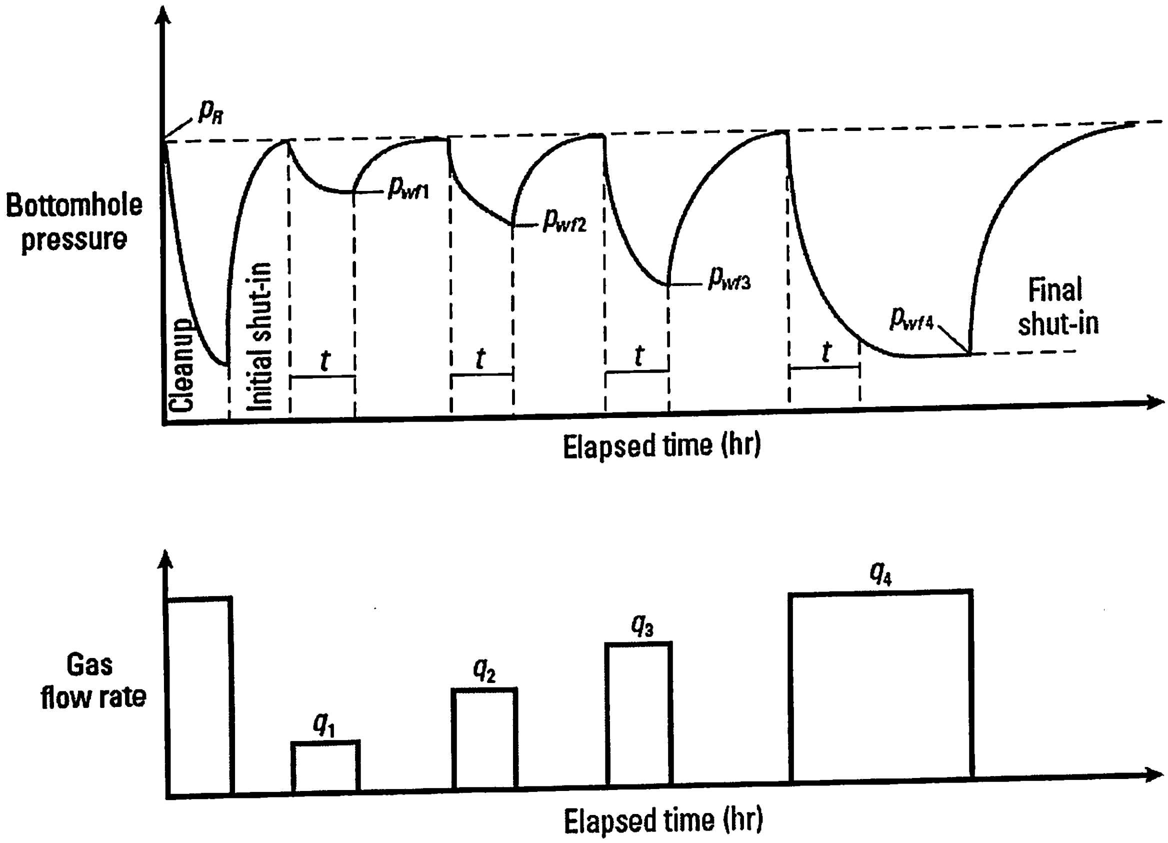
Interpretation

Graphical method:-

Draw the plot b/w (Ps^2 -Pf^2) v/s Q on Log-Log paper for each hour (1st hr, 2nd hr, 3rd hr.). It may be seen that all lines comes parallel to each other. The distance b/w lines of 1st hr & 2nd hr is more than the distance b/w lines of 2nd & 3rd hr. it shows that if well is flowed for longer period steady state flow can be achieved.

- OPF is calculated by reading the extrapolated lines of 3rd hr against ($Ps^2 - 1$).
- Deliverability of the well will be the 25% of the OPF.

Figure 3 : Graph of isochronal test



CHAPTER 5

5.0 MODIFIED ISOCHRONAL TEST

But as isochronal test take long time & it proves impractical. So we need a modified isochronal test. The modified isochronal test is the shortest version of isochronal test. In tight reservoir in practice it is not possible to achieve shut in pressure equal to the original pressure. The only difference b/w the isochronal & modified is that in modified isochronal test we have a constant time for both flowing & shut in pressure.

Procedure

The procedure of modified isochronal test is the same as isochronal test.

Interpretation

Interpretation of modified isochronal test is also same as isochronal test.

Graph 1

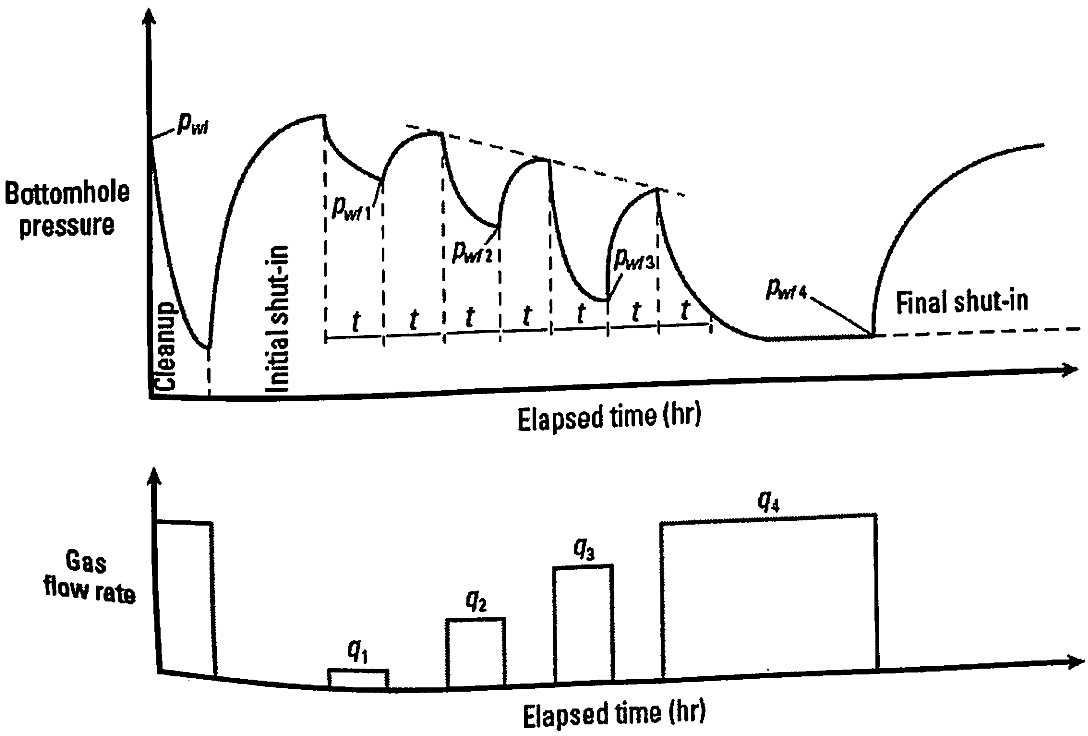


Figure 4 : Modified Isochronal test – flow rate and pressure diagram

Graph 2

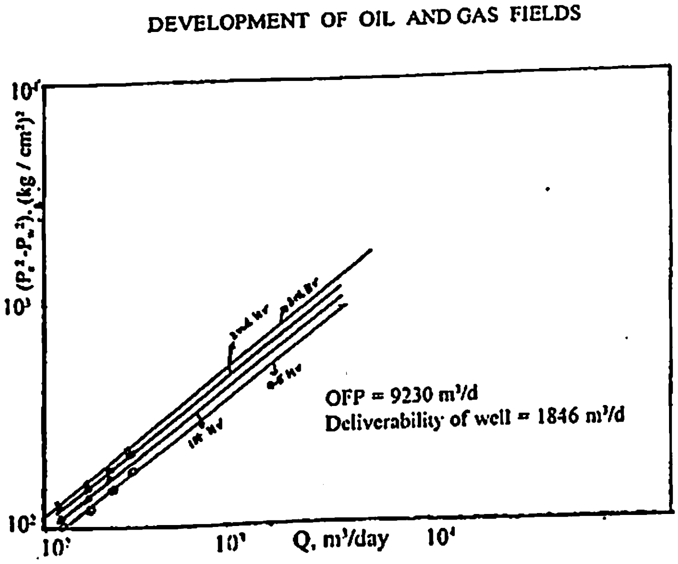


Fig 5.9 : Isochronal Test

nal test is that the shut in period is equal to the flow period (Fig. :

Figure 5 : Modified Isochronal test – flow rate and pressure diagram

CHAPTER 6

6.0 FLOW AFTER FLOW TEST

Flow after flow test is nothing but it is the American & Russian method.

American method:

To determine the value of open flow potential " Rawlins & Schellhardt's given a equation that is mostly used in the oil industry.

The main gas flow rate Equation is- $Q = C\,(Ps^2 - Pf^2)^n$

Where n= Exponent

C= constant

Taking log on both side

$$\text{Log } Q = \log C + n \text{ Log } (Ps^2 - Pf^2)$$

The value of n can be calculated in two ways.

1. The equation 2 is an equation of straight line when $\log(Ps^2 - Pf^2)$ v/s log Q are plotted on Cartesian co-ordinate axes. OR $(Ps^2 - Pf^2)$ v/s Q are plotted on the log –log graph paper. Hence the inverse of slope of this straight line gives the value of n(exponent). And 'C' can be calculated a the intercept of the line on Y-axis.
2. The second way is to directly put the vales of Different-2 pressure & flow rate in the given formulae

$$n = \quad \log (Q_2) - \log (Q_1)$$

$$\log(Ps^2 - Pf_2^{\,2}) - \log(Ps^2 - Pf_1^{\,2})$$

And 'C' can be determine by the formulae- $C = Q/(Ps^2 - Pf^2)^n$

Now by putting the values of n & C we can determine the value of OPF.

NOTE:- The value of n lies b/w 0.5 to 1.0 which should not be more than 1.0 for a particular well.

Russian Method:- (two Term formula)

Russian method is also known as "Two Term Formula". The formula is given as :

$(Pe^2 - Pw^2) = AQ + BQ^2$ This is the quadratic equation.-------(1)

OR $\dfrac{(Pe^2 - Pw^2)}{Q} = A + BQ$ Equation like $Y = mx+c$----------(2)

Then the solution of this equation will be given as-

$$Q_{OPF} = \frac{-A + (A^2 + 4B(Pe^2 - 1))^{1/2}}{2B} \text{ ------------------------(3)}$$

1^{st} **case :-** When the line passes through ORIGIN.

- Now plot a graph b/w $(Pe^2 - Pw^2)/Q$ v/s Q . this should give a straight.
- The value of B can be determined directly as the slope of the line.
- The value of A can be determined as the intercept on Y-axis.
- Now putting this value of A & B in the solution equation no-(3).& calculate the Open Flow Potential.

2^{nd} case:-

When the line does not passes through the ORIGIN & makes (+)ve intercept. this situation may occur due to presence of liquid column in the well bore.

- Now plot the graph b/w (Pe^2 -Pw^2 + C')/Q v/s Q . It will give straight line.
- The value of B can be determined directly as the slope of the line.
- The value of A can be determined as the intercept on Y-axis.
- Now putting this value of A & B in the solution equation no-(3).& calculate the Open Flow Potential.
- **3^{rd} case:-**

When the line does not passes through the ORIGIN & makes (-)ve intercept. This situation may occur due to presence of liquid column in the well bore.

- Now plot the graph b/w (Pe^2 -Pw^2 - C')/Q v/s Q . It will give straight line.
- The value of B can be determined directly as the slope of the line.
- The value of A can be determined as the intercept on Y-axis.
- Now putting this value of A & B in the solution equation no-(3).& calculate the Open Flow Potential.

CHAPTER 7

7.0 WELL BORE & SKIN EFFECT IN GAS WELLS

Near the well bore, the flow of gas is generally turbulence or non darcy in the gas well. Turbulence is because of eddy current formation. But turbulence is not the only cause of non-darcy flow conditions. Formation of mist & evaporation of connate water also cause of non darcy flow condition which occur at the vicinity of the well bore. so this effect also added in skin effect.

Hence in gas well skin S is replaced by- S'

$$S' = S + DQ$$

Where D = non darcy flow coefficient which is a function of flow rate.

Q = flow rate.

'D' can be determined by two drawdown or build up tests.

For different -2 flow rate different-2 skin factor will be there.

Hence $S_1' = S + DQ_1$

$S_2' = S + DQ_2$

Diagram showing skin effect:

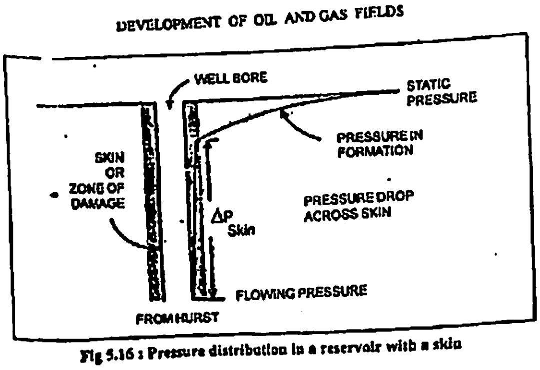


Figure 6 : Pressure distribution in a reservoir with a skin

Skin factor

1. A positive skin factor increases the time to reach radial flow.
2. • A negative skin reduces the time toreach radial flow.
3. • Large well bore storage coefficient increases time to reach radial flow.

Caused by well going on a vacuum, formation bugs, presence of fracture or large well bore tubular dimensions.

CHAPTER 8

8.0 TYPES OF FLOW REGIMES

8.1 Radial flow

The most important flow regime for well test interpretation is radial flow, which is recognized as an extended constant or flat trend in the derivative. Radial flow geometry is described as flow streamlines converging to a circular cylinder (Fig. 18). In fully completed wells, the cylinder may represent the portion of the well bore intersecting the entire formation (Fig. 18b). In partially penetrated formations or partially completed wells, the radial flow may be restricted in early time to only the section of the formation thickness where flow is directly into the well bore

(Fig.18a). When a well is stimulated (Fig. 18c) or horizontally completed (Fig. 18e), the effective radius for the radial flow may be enlarged. Horizontal wells may also exhibit early time radial flow in the vertical plane normal to the well (Fig. 18d). If the well is located near a barrier to flow, such as a fault, the pressure transient response may exhibit radial flow to the well, followed by radial flow to the well plus its image across the boundary (Fig. 18f).

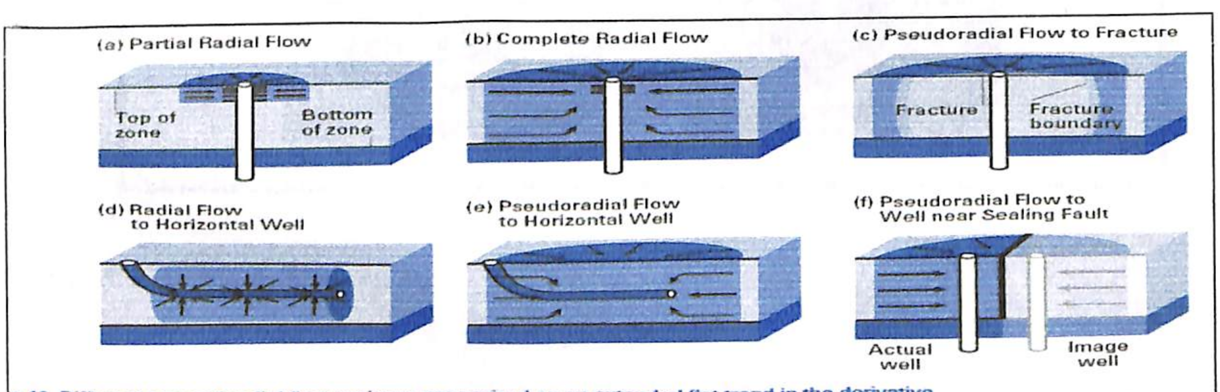


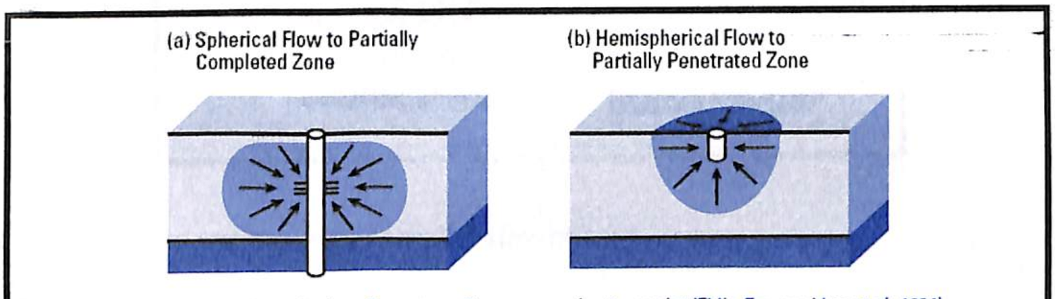
Figure 7 : Different types of radial flow regimes

8.2 Spherical flow

Spherical flow occurs when the flow streamlines converge to a point (Fig. 20). This flow regime occurs in partially completed wells (Fig. 20a) and partially penetrated formations (Fig. 20b). For the case of partial completion or partial penetration near the upper or lower bed boundary, the nearest impermeable bed imposes a hemispherical flow regime. Both spherical and hemispherical flow are seen on the derivative as a negative half-slope trend. Once the spherical permeability is determined from this pattern, it can be used with the horizontal

Permeability *kh* quantified from a radial flow regime occurring in another portion of the data to determine the vertical permeability *kv*.

The importance of *kv* in predicting gas or water coning or horizontal well performance emphasizes the practical need for quantifying this parameter. A DST can be conducted when only a small portion of the formation has been drilled (or perforated) to potentially yield values for both *kv* and *kh*, which could be used to optimize the completion engineering or provide a rationale to drill a horizontal well.



Spherical flow regime, which results from flow streamlines converging to a point (Ehlig-Economides *et al.* 1994).

Figure 8 : Spherical flow regime

8.3 Linear flow

The geometry of linear flow streamlines consists of strictly parallel flow vectors. Linear flow is exhibited in the derivative as a positive half-slope trend. Figure 23 shows why this flow regime develops in vertically fractured and horizontal wells. It also is found in wells producing from an elongated reservoir. Because the streamlines converge to a plane, the parameters associated with the linear flow regime are the permeability of the formation in the direction of the streamlines and the flow area normal to the streamlines. The *kh* value of the formation determined from another flow regime can be used to calculate the width of the flow area. This

provides the fracture half-length of a vertically fractured well, the effective production length of a horizontal well or the width of an elongated reservoir.

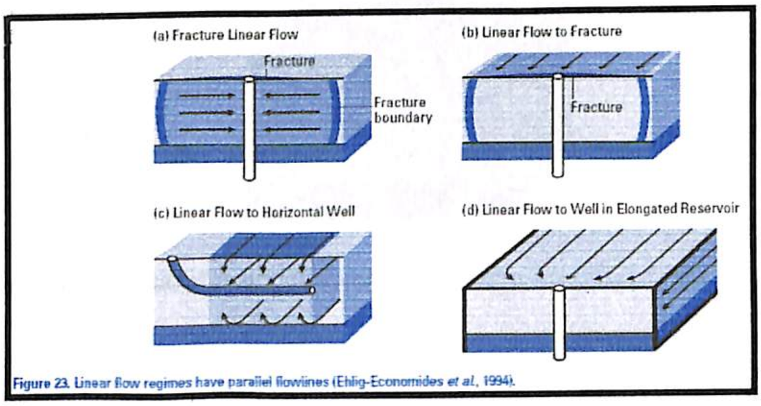
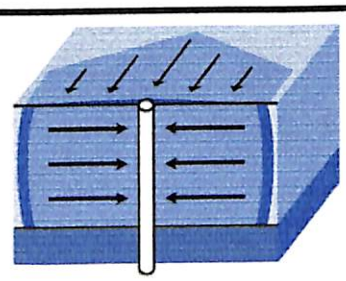


Figure 9 : Linear flow regimes have parallel flowlines

8.4 Bilinear flow

Hydraulically fractured wells may exhibit bilinear flow instead of, or in addition to, linear flow. The bilinear flow regime occurs because a pressure drop in the fracture itself results in parallel streamlines in the fracture at the same time as the streamlines in the formation become parallel as they converge to the fracture (Fig. 25). The term bilinear refers to the simultaneous occurrence of two linear flow patterns in normal directions. The derivative trend for this flow regime has a positive quarter-slope. When the fracture half-length and formation permeability are known independently, the fracture conductivity *kfw* can be determined from the bilinear flow regime.

Figure 10 : Bilinear flow regimes commonly exhibited by hydraulically fractured wells



Bilinear flow regime commonly exhibited by hydraulically fractured wells (Ehlig-Economides *et al.* 1994)

CHAPTER 9

9.0 INTERPRATATION OF LOGS

9.1 Importance of Semi – log plots

- • A semilog plot is used to evaluate the radial flow portion of the **welltest.**
- • Reservoir **transmissibility** and **skin factor** are obtained from the slope of the **semi log straight line** during **radial flow .**
- •Superposition is used for ratevariations

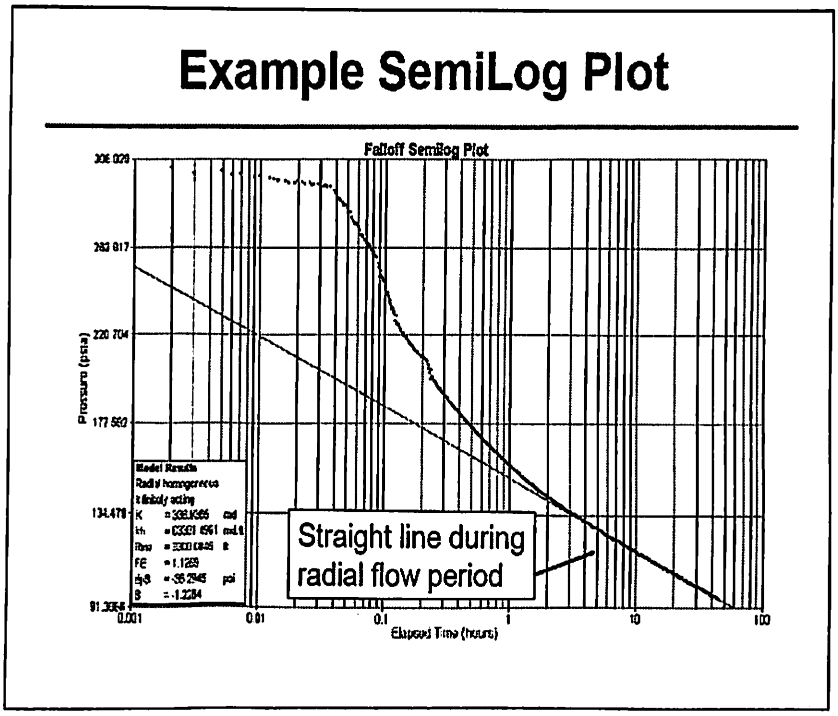


Figure 11 : Example SemiLog Plot

9.2 Importance of Log Log Plots

These are:

1. Log-log Plot Pressure Functions
2. Log-log Plot Time Functions
3. Log-log Plot Derivative Function.

The log-log plot contains two curves:

Pressure curve Plot

Plot of measured pressures from start of the test on the Y-axis versus

The appropriate time on the X-axis.

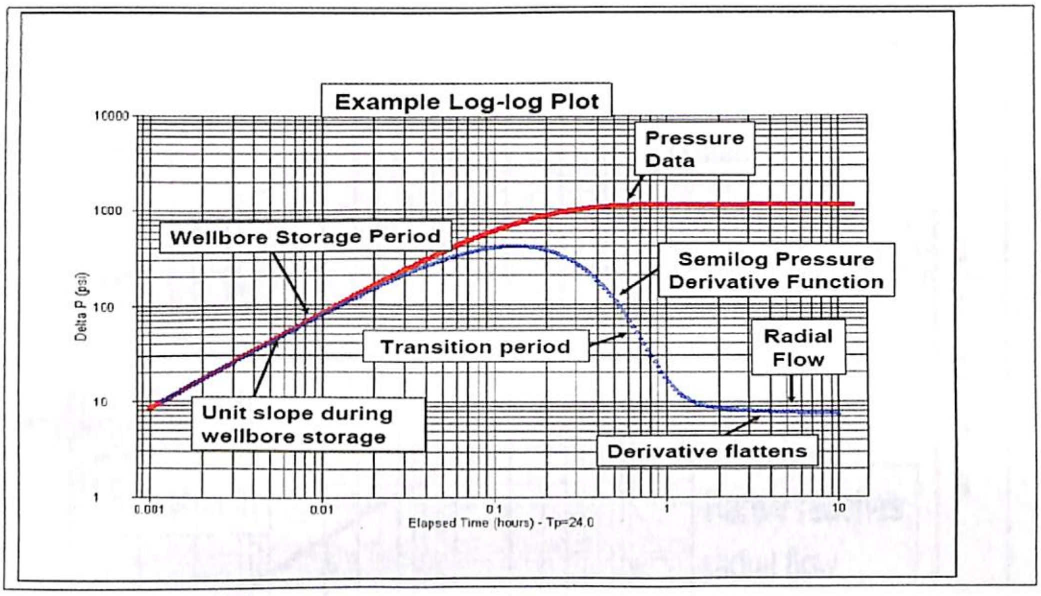
Derivative curve Plot :

Plot of the slope of the semilog pressure function on the Y-axis versus the appropriate time function on the X-axis.

Importance

- The first plot used to identify flow regimes is the log-log plot.
- The log-log plot is a master diagnostic plot that contains two curves, a pressure curve and a derivative curve
- The log-log plot identifies the various stages and flow regimes present in a falloff test
- Individual flow regimes have characteristic slopes and a sequential order on the log-log plot with the critical flow regime being radial flow.
- The radial flow portion of the log-log plot is identified and then the corresponding time frame on the semilog plot is used for the calculations.
- Flow regimes are characterized by specific slopes and trends for P and P', as well as specific separation between the two curves
- The radial flow portion is the critical flow regime because it is the portion of the test that the calculations are based.

Figure 12 : Example of log log plot



1. Pressure curve -red
2. Derivative curve -blue
3. Well bore storage period: Pressure and derivative curves overlay on a unit slope
4. Radial flow: Derivative flattens
5. Notice the pressure curve flattens prior to radial flow so the pressure curve is not a good indicator of radial flow

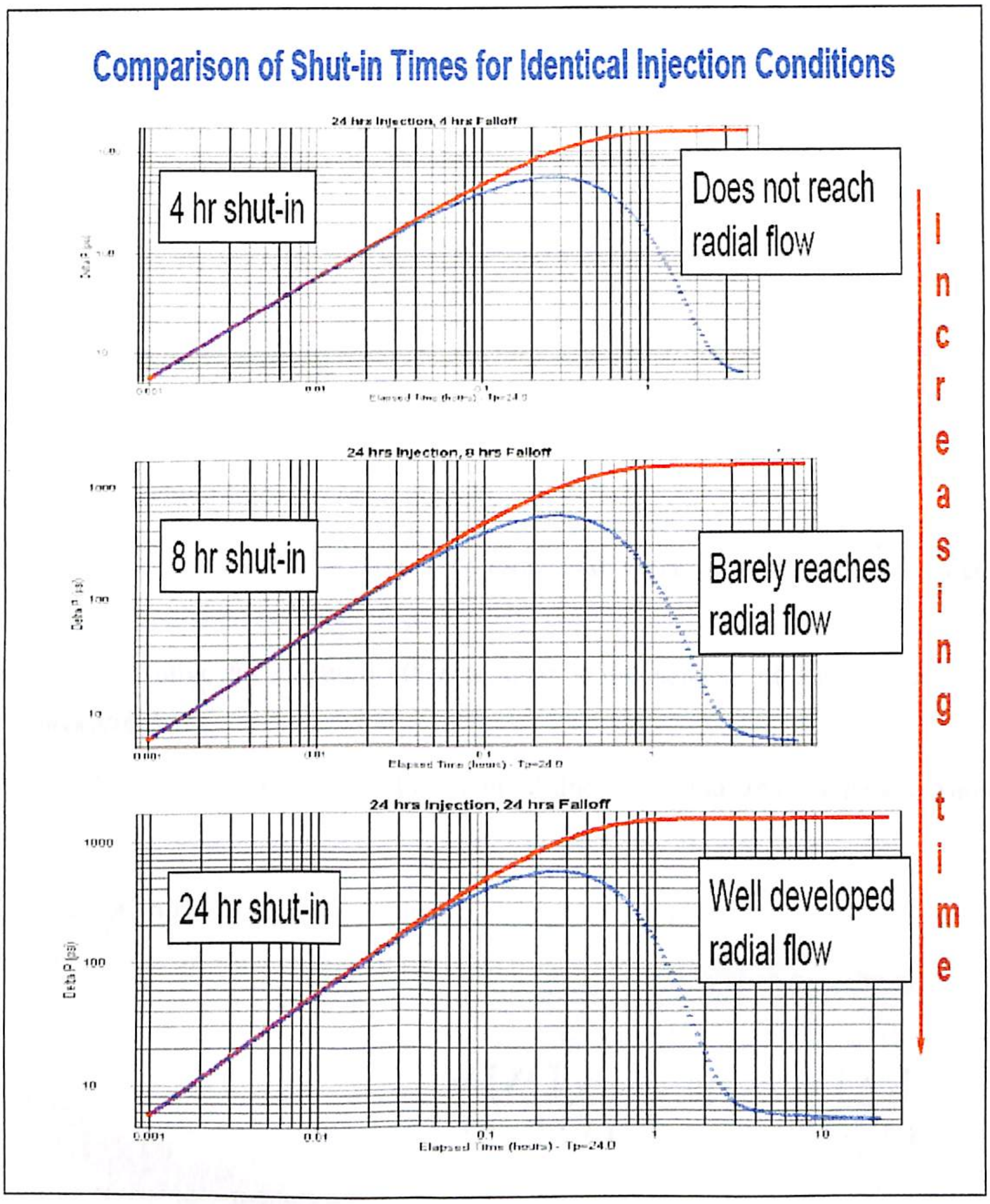


Figure 13 : Comparison of shut – in times for identical injection conditions

9.3 Importance of derivative plots

The derivative function is graphed on the log-log plot.

1. The main use of the derivative is to **magnify** small changes in pressure trends (slope) of the semilog plot to help identify:
    - Flow regimes
    - Boundary effects
    - Layering
    - Natural fractures (dual porosity)
2. Derivatives amplify reservoir signatures and noise so the use of a good pressure recording device is critical
3. The derivative for a specific flow regimes is independent of the skin factor, while the pressure is not
4. Use of derivative curves have been around since 1983 and are not a new technology

Note: The derivative function is nothing but simply the slope of the semilog plot which is the change in pressure over the change of log delta t

$$P' \quad \frac{d[P]}{d[\ln(\Delta t)]} \quad \Delta t \cdot \frac{d[P]}{d[\Delta t]}$$

- The derivative combines a semilog plot with a log-log plot
- The derivative is the running slope of the MDH, Horner, or superposition semilog plots of pressure vs. log delta t.
- The derivative functions can be calculated based on the plots:

CHAPTER 10

10.0 CASE HISTORIES

Well Data : Rajamundry KVDF (Kesvadasupalem)

Formation sandstone

Total Depth Drilled : 1776m

Study on Sand -46

Depth of pressure measurement : 840m

Recorded highest shut in bottom hole pressures : 88.8 Kg/cm2

Formation bottom hole temperature : 141.06 degree Farenhiet (60.6 degree centrigrade)

Reservoir and Fluid Parameter Data

1. Layer Parameter Data

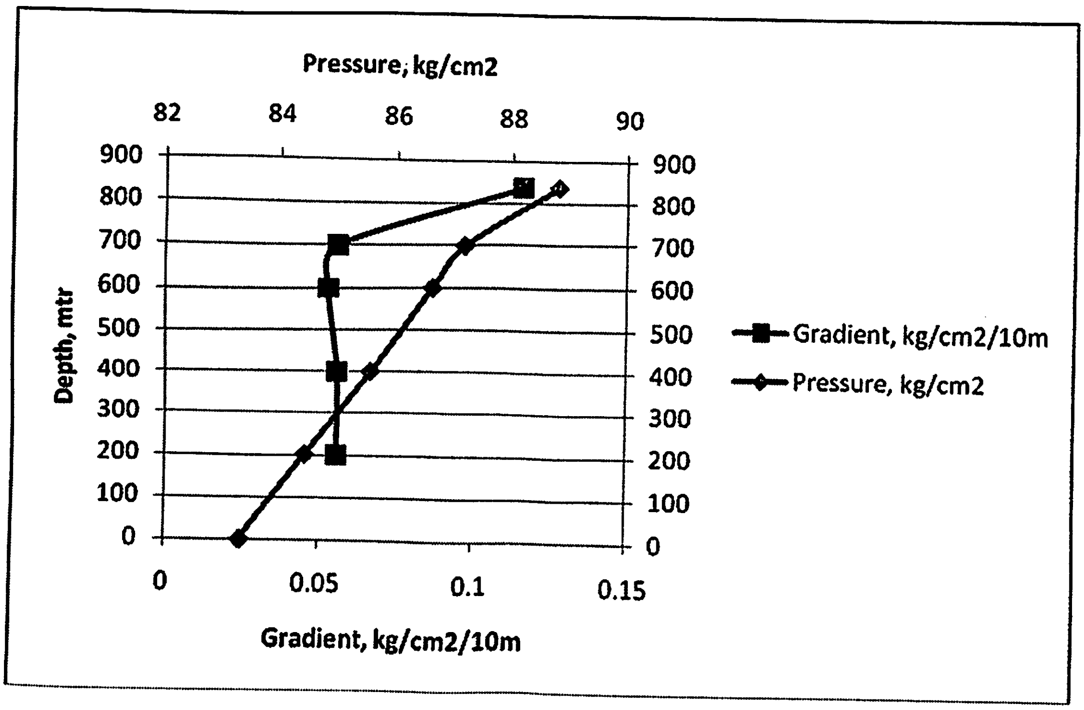
1	Well radius(ft)	0.354
2	Formation Thickness(ft)	36.08
3	Formation Porosity (%)	0.095
4	Formation compressibility (psi-1)	4.9669 e-6
5	Total system compressibility (psi-1)	8.6831 e-4
6	Layer pressure (kg/cm2)	88.8
7	Layer tempreture (°F)	141

2. **Fluid Parameter:**

1	Gas gravity (Air=1.000)	0.6
2	Gas viscosity (cp)	0.0138573
3	Gas formation volume factor(v/v)	0.0119529
4	Water viscosity (cp)	0.444862
5	Water formation volume factor (RB/STB)	1.01508
6	Gas deviation factor Z	0.889363
7	Gas compressibility (psi-1)	8.6334 e-4

10.1 Study of static bottom hole pressure gradient survey

Serial No.	Measured Depth	Pressure (Kg/cm2)	Gradient (Kg/cm2/10m)	Remarks
1	0	83.32		
2	200	84.44	0.056	Average static gas
3	400	85.57	0.056	gradient is
4	600	86.62	0.053	0.06 Kg/cm2/10m
5	700	87.18	0.056	
6	840	88.8	0.116	



Graph

(Range of gradients for different reservoir fluids in static condition:

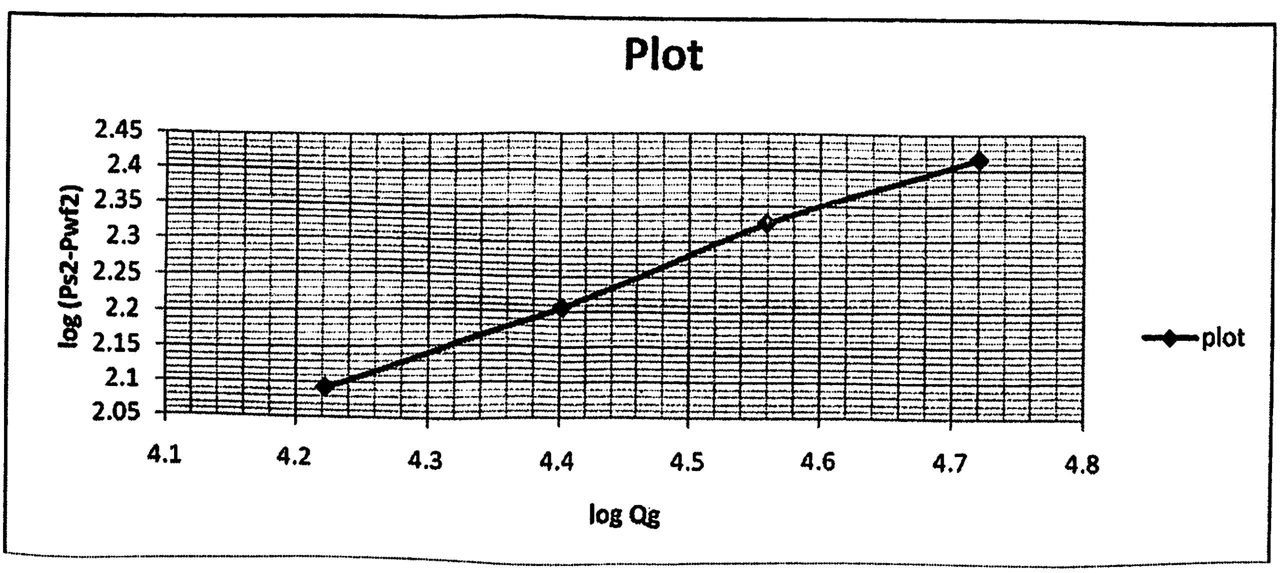
- Gas - 0.01-0.05 Kg/cm^2/10m
- Condensate - 0.20-0.30 Kg/cm^2/10m
- Oil - 0.50-0.80 Kg/cm^2/10m
- Emulsion - 0.80-0.90 Kg/cm^2/10m
- Water - 1.00 Kg/cm^2/10m)

10.2 Estimation of open flow potential/ Multi Bean Study:

Date	Duration (hrs)	Bean size (mm)	THP (Kg/cm2)	BHP(Kg/cm2)	Qg(m3/day)	Qo(m3/day)	Qw(m3/day)
18.12.06	4	4	82.54	88.1	16680	-	-
18.12.06	4	5	81.91	87.89	25224	-	-
18.12.06	4	6	81.28	87.6	36180	-	-
18.12.06	7	7	80.85	87.32	52416	-	-
19.12.06	7	BuildUP	83.32	88.8	-	-	-
19.12.06		SPGS	83.32	88.8	-	-	-

Calculations:

Date	Bean size (mm)	BHP(Kg/cm2)	Ps2-Pwf2	Qg(m3/day)	log (Ps2-Pwf2)	log Qg
18.12.06	4	88.1	123.83	16680	2.092825873	4.222196046
18.12.06	5	87.89	160.7879	25224	2.206253363	4.401813958
18.12.06	6	87.6	211.68	36180	2.325679827	4.558468563
18.12.06	7	87.32	260.6576	52416	2.416070392	4.719463876
19.12.06	BuildUP	88.8	0			
19.12.06	SPGS	88.8	0			



Graph

10.3 Build up

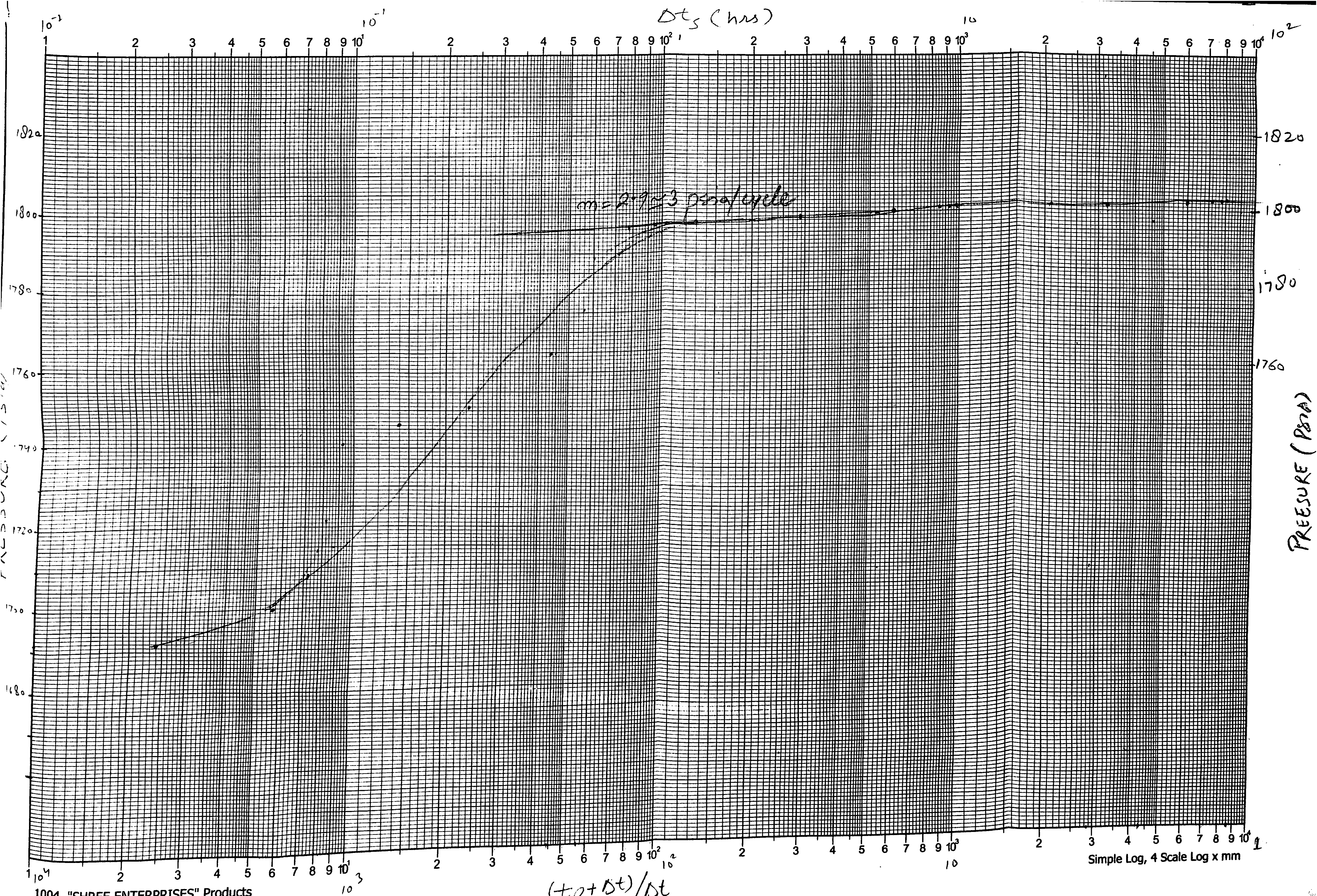
Producing time before shut-in, t_p = 24hrs

Δt	(tp + Δt)/Δt	Pressure
(hrs)		(psia)
		1688.3
0.002778	8640.3089	1692.3
0.005556	4320.6544	1700.3
0.008334	2880.7696	1708.5
0.011112	2160.8272	1715.7
0.013889	1728.9862	1722.5
0.016667	1440.9712	1729
0.019445	1235.2504	1735.1
0.022223	1080.9622	1741
0.025	961	1746.5
0.027778	864.99309	1751.7
0.030556	786.44312	1756.6
0.033334	720.9856	1761.1
0.036112	665.59903	1765.3
0.038889	618.14109	1769.3
0.041667	576.99539	1773
0.044445	540.99325	1776.3
0.047223	509.22692	1779.3

0.05	481	1782.1
0.052778	455.73493	1784.5
0.055556	432.99654	1786.8
0.058334	412.42387	1788.8
0.061112	393.72156	1790.5
0.063889	376.65152	1792
0.066667	360.9982	1793.2
0.069445	346.59724	1794.2
0.072223	333.30411	1795.1
0.075	321	1795.8
0.077778	309.57055	1796.4
0.080556	298.92939	1796.7
0.083334	288.9977	1797
0.086112	279.7068	1797.2
0.088889	270.99966	1797.3
0.091667	262.81723	1797.5
0.094445	255.11615	1797.6
0.097223	247.85517	1797.6
0.1	241	1797.8
0.102778	234.51301	1797.8
0.105556	228.36746	1797.8
0.108334	222.5371	1797.8
0.111112	216.99827	1797.8
0.113889	211.7315	1797.9

0.116667	206.7137	1797.9
0.119445	201.9293	1797.9
0.122223	197.36239	1798
0.125	193	1798
0.15	161	1797.9
0.175	138.14286	1798
0.2	121	1797.9
0.225	107.66667	1797.9
0.25	97	1798
0.275	88.272727	1798.1
0.3	81	1798.1
0.325	74.846154	1798.4
0.35	69.571429	1798.6
0.375	65	1798.7
0.4	61	1799.1
0.425	57.470588	1799.8
0.45	54.333333	1800
0.475	51.526316	1800.3
0.5	49	1800.6
0.525	46.714286	1802.7
0.730556	33.851691	1802.4
1.005556	24.867393	1802.6
1.280556	19.741859	1802.6
1.555556	16.428567	1802.6

2.013889	12.917241	1802.6
2.288889	11.485436	1802.8
2.563889	10.36078	1802.8
3.022223	8.9411744	1802.7
3.480556	7.89545	1802.9
4.030556	6.9545135	1803
4.580556	6.2395386	1803
5.038889	5.7629547	1803
5.497223	5.3658407	1803
5.955556	5.0298504	1803.1
6.505556	4.6891543	1803.1
7.055556	4.4015746	1803.1
7.513889	4.194085	1803.3
8.063889	3.9762314	1803.2
8.522223	3.8161666	1803.3
9.072223	3.6454376	1803.3
9.530556	3.5182161	1803.3
10.08056	3.3808201	1803.3
10.53889	3.2772797	1803.4
11.08889	3.1643284	1803.4
11.54722	3.0784223	1803.4
12.09722	2.9839269	1803.4
12.55556		



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Calculations:

1. Slope, m = 3.00 (from horner's plot)

2. Extrapolated pressure P *= 1805 psi

3. P^{1hr} = 1801 psi

4. Capacity, kh = 2627.5md-ft

5. Permeability $K = 162.6\frac{q\mu B}{mh}$ md-ft/cp

=160.21 md

6. Hydroconductivity, kh/μ = 1.70 x 10^5 md-ft/cp

7. mobility, k/μ = 10402.5 md/cp

8. Skin factor, $S = 1.151\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k}{\varphi\mu c r_w^2}\right) + 3.23\right]$

= +32

9 ΔP skin = m*.87*s

= 83.52 psia

10 Diffusivity constant, $\eta = \dfrac{0.006328*k}{\varphi\mu c}$

$= 6.19*10^5$

11. Radius of investigation, $r_i = {}^3\sqrt{\eta t_i}$

$= 187.9$ ft

12. J actual $= \dfrac{q}{P^*-P_{wf}}$

$= 3093.4$

13. J ideal $= \dfrac{q}{P^*-P_{wf}-(\Delta P)skin}$

$= 10880.04$

14. Flow Efficiency $= \dfrac{J\ actual}{J\ ideal}$

$= 28.4\%$

15. Damage Factor = 1-FE

$= 71.6\%$

CHAPTER 11

11.0 CONCLUSION

There are many applications of well testing, but they are grouped into four fundamental classes.

Formation pressure measurement
This class of application uses the direct static formation pressure measurement. It includes static pressure measurement and depletion determination determination of the inflow performance and productivity index (PI) of the reservoir and, in gas wells, the absolute open flow (AOF) potential of the reservoir determination of reservoir fluid density from gradients determination of reservoir fluid contacts identification of reservoir vertical permeability barriers identification of vertical flow through layered sequences in developed reservoirs numerical reservoir simulation applications.

Permeability and skin
The pressure and associated measurements (e.g., downhole flow) are interpreted to yield reservoir dynamic parameters relevant to fluid flow, such as formation permeability, and any occurrence of skin (e.g., formation damage) that would impair the flow. The measurements will help determine reservoir permeability well deliverability a damaged or stimulated well condition vertical rock permeability the efficiency of stimulation treatments.

Formation fluid characterization
The essence of formation testing is flowing the well, which presents the unique opportunity to recover samples of the reservoir fluid. It enables collecting representative reservoir sample characterizing the fluid composition, its phase behavior and its pressure-volume-temperature (PVT) properties.

Reservoir characterization
The pressure response during a well test provides the characteristic signature of reservoir fluid flow events that will be interpreted in terms of boundaries, heterogeneities and reservoir volume. It enables determining the total reservoir pore volume connected to the tested well determining the average reservoir pressure determining reservoir boundary conditions such as impermeable barriers and constant pressure conditions characterizing reservoir heterogeneities such as layered systems and natural fractures quantifying vertical and horizontal reservoir communications.
Hence 1. Well testing is used to study and produce the reservoir models.
2. The results of well testing depends on the experience of the engineers and the accuracy of the instruments used.
3. Since reservoir is very complex system , we cannot predict everthing with 100% accuracy

CHAPTER 12

12.0 REFERENCES

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