CHANGING WELLBORE STORAGE IN GAS WELL TESTING

by
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ABSTRACT

Extended wellbore storage can be mistakenly interpreted as a reservoir response in gas well testing with surface shut in. This interpretation usually results in false value for permeability, skin and reservoir size and shape.

This paper investigates changing wellbore storage in pressure transient testing with surface shut-in in gas well. This study was prompted by the observation, that in gas wells, many of the buildup tests obtained with surface shut-in exhibited complex reservoir model behavior with relatively low skin.

The results presented in this paper are based on well test simulation and field data from North Sumatera. This work demonstrates the effect changing wellbore storage on the pressure derivative curve. Knowledge of the expected pressure derivative shape, and duration, will improve the design of buildup tests that will allow enough time for the actual reservoir response to be observed. This will result in a reliable reservoir model and correct estimation of permeability and skin factor.

Key word : Changing wellbore storage, gas well testing

I. INTRODUCTION

In most cases, well test analysis is the interpretation of the pressure response of the reservoir to a given change in the rate from zero to a constant value for a drawdown test (Figure 1), or from a constant value to zero for buildup test (Figure 2). However, for many well tests, the only means of controlling the flow rate is at the wellhead valve or flow line. Hence although the well produces at a constant rate at the wellhead, the flow transient within the wellbore itself

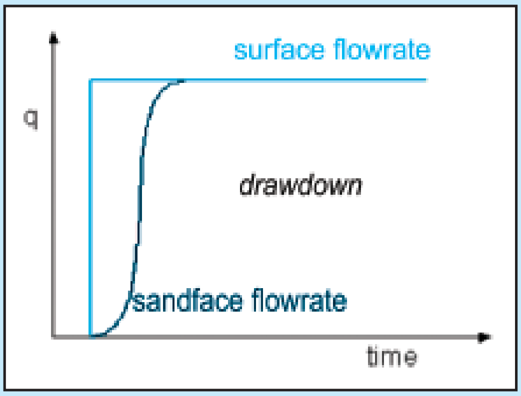

Figure 1
Downhole Flowrate (Drawdown test)

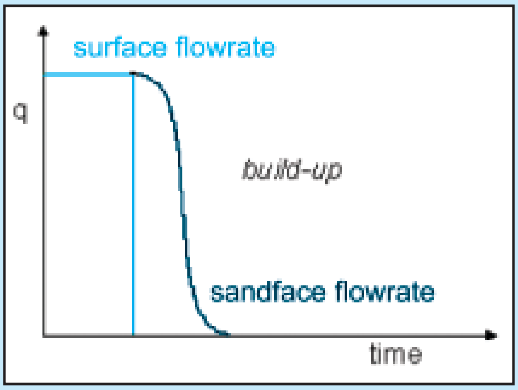

Figure 2
Downhole Flowrate (Buildup test)

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may indicate that the flow rate from the reservoir into the wellbore (the "sand face" flow rate, q_{sf}) is constant at all. This effect is due to wellbore storage.

Wellbore storage effect can be caused in several ways, but there are two common means. One is storage by fluid expansion, the other is storage by changing liquid level. Consider the case of a drawdown test. When the well is first open to flow, the pressure in the wellbore drops. This drop causes an expansion of the wellbore fluid, and thus the first production is not the fluid from the reservoir but is the fluid that was stored in the wellbore volume. As the fluid expands, the wellbore is progressively emptied, until the wellbore system can give up no more fluid, and it is the wellbore itself which provides most of the flow during this period. This is wellbore storage due to fluid expansion.

The second common kind of wellbore storage is due to changing liquid level. This is easily envisaged in the case of a completion consisting of a tubing string without a packer. When the well is open to flow during a drawdown test, the reduction in pressure causes the liquid level in the annulus to fall. The liquid extracted from the annulus joins that from the reservoir and makes up a proportion of the total flow from the well. The falling liquid level is generally supplying much more fluid than simply from expansion of the fluid alone, thus wellbore storage effects are usually much more prominent in this type of completion

II. CHANGING WELLBORE STORAGE

To minimize cost and operational risk, many well test are performed with a surface shut-in with a bottom-hole pressure measurement, rather than bottom-hole shut-in and pressure measurement. However, a surface shut-in includes many factors that can effect the bottom-hole pressure value. The combined effect of these factors is usually referred to as the wellbore storage effect and period. A surface shut-in allow fluid flow from the tested formation into the wellbore for a long period of time, depending on the permeability and thickness of the formation, and the wellbore volume. Moreover, the multiphase composition of wellbore fluid results in an upward movement of the gas phase relative to the liquid phase. This changes in fluid pressure and temperature, may also result in liquid drop out or evaporation (phase changes). This factors will results in significant changes in the wellbore fluid compressibility, density and composition.

Changing wellbore storage during well testing has been reported in the technical literature. This class of problems includes wellbore phase redistribution (Fair, 1981) and increasing or decreasing storage in connection with injection well testing (Earlougher, *et al.*, 1973). Decreasing storage, usually caused by decreasing wellbore fluid compressibility, frequently is encountered during pressure-buildup testing. Low-permeability gas wells that build up over a large pressure range often show this effect. Although simultaneous measurement of downhole rate and pressure can reduce the severity of changing storage, it does not eliminate the problem when wellbore volume is appreciable below the production logging tool.

Changing storage makes application of analysis techniques based on a constant-storage assumption, such as type-curve matching, difficult. Use of these techniques usually results in a systematic mismatch of the model to the measured data at early times. When a well test is run long enough to develop infinite-acting radial flow in the reservoir, the most serious side effect of the early-time mismatch will be a visual impact on the observer and reduced confidence in the interpretation. Furthermore, numerous situations arise where well-test data are considered un interpretable because of the combined effects of changing wellbore storage and in sufficient transient data (test stopped too soon, equipment failures, etc.)

Lee (1987) presented procedures to design well tests including after-flow conditions. He used Agarwal, *et al.* (1970) type curve empirical fit which predict the end of wellbore storage duration. In terms of equivalent shut-in times, Δt_e, the duration of after-flow is given by the following equation :

$$\Delta t_e = \frac{(200{,}000 + 12{,}000 s_a)C}{k_e h / \mu} \qquad (1)$$

Hegemen, *et al*. (1993) presented a model for analyzing increasing or decreasing wellbore storage. Their model is based on modification and extension of Fair (1992) approach. Fair (1992) modified Van Everdingen, *et al.* (1949) equation by adding a term to account for the pressure change by phase redistribution :

$$\frac{q_{sf}}{q} = 1 - C_D \left(\frac{dp_{wD}}{dt_D} - \frac{dp_{\phi D}}{dt_D} \right) \qquad (2)$$

The changing storage pressure function has the following properties :

$$\lim_{t\to 0} p_{\phi D} = 0 \tag{3}$$

$$\lim_{t\to\infty} p_{\phi D} = C_{\phi D} \tag{4}$$

and $$\lim_{t\to\infty}(dp_{\phi D} / dt_D) = 0 \tag{5}$$

Fair used an exponential form for the changing storage pressure function,

$$p_{\phi D} = C_{\phi D}(1 - e^{-t_D/\alpha D}) \tag{6}$$

Hegeman, *et al.* (1993) showed that, in some cases, field data exhibited a sharper (than exponential) changing storage pressure function was required. They concluded that the following equation is representative of the field data :

$$p_{\phi D} = C_{\phi D} erf(t_D / \alpha_D) \tag{7}$$

Hasan and Kabir (1992) argued that Fair (1992) and Hegeman, *et al.* (1993) methods do not lend themselves to be used in forward mode to predict reservoir and/or well conditions that would give rise to changing wellbore storage situation. Such prediction are very useful in obtaining a successful well test design with a surface shut-in.

III. GAS COOLING EFFECTS ON PRESSURE TRANSIENT TESTING

The wellbore storage models which are available today are developed for either use isothermal wellbore fluid properties such as compressibility and density, are unable to fully predict the length and behavior of the wellbore storage period with a surface shut in. As it is known, both gas compressibility and density may change significantly with changes in temperature during the shut-in periods. Formation natural gas usually flows into the wellbore at a temperature close to the produced interval temperature. Then, this gas flows upward inside the wellbore (or tubing) to the surface passing through zones of relatively lower temperatures until it reaches the lowest temperature at sea bottom or surface. During production time, the produced gas does not have enough contact time with the surrounding to cool down (depending on production rate) and will be produced at the surface at higher temperatures. However, during surface shut-in period, this same gas will go through a cooling period associated with continuous change in compressibility and density. These changes become even more dramatic in the case of phase changes from gas to liquid.

During surface shut-in period, the rate of change in gas temperature with time depends on many factor including the temperature deference from the surrounding wellbore materials and formation (T), and the heat conductivity of the same surroundings. For each depth, this rate of change in temperature with time will change as T decrease in a way similar to the transient behavior of reservoir pressure in a falloff in an injection well. However, ΔT decreases with depth as wellbore fluid temperature approaches formation temperature at total depth. This will result in a series of different temperature transient for each point in space along the production tubing in a shut-in well. This, in turn, may result in an extended wellbore storage periods associated with changes in fluid compressibility and density.

IV. FIELD EXAMPLE

The field example is a drillstem test (DST) from North Sumatera. The DST valve was open for 6.63 hours, during which the zone produced gas at 2090 Mscf/D from a mid perforations true vertical depth of 9847 ft. Formation thickness is 165 ft, temperature 345 ^{o}F, porosity 13.0 %, reservoir pressure 6700 psia, and wellbore radius of 0.25 ft. The flow was followed by a 12.73-hour buildup. Figure 3 shows test period analysis. Figure 4 and 5 shows log-log and Horner plots for the buildup. Table 1 list well/reservoir and test data. The data were matched with a constant-wellbore-storage model with homogeneous reservoir behavior. The early-time buildup data show evidence of decreasing wellbore storage, with the log-log plot exceeding unit-slope in some places and the derivative curve exceeding pseudo pressure, m(p). The match with the constant-storage model is so poor that it would be difficult to place high degree of confidence in the results.

The data set was re-matched with the decreasing (changing)-wellbore-storage model by use of the error-function storage transition (Equation 7). Figure 6 and Figure 7 shows this match. With the addition of decreasing storage, the entire buildup could be matched, improving overall confidence in the inter-

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Table 1
Well and test data for field example

Well Data			
Test type	Buildup	Porosity, %	7
Depth, ft	9847	Hole size, in	2,94
Net thickness, ft	20	Temperature, ^oF	345
Flow rate, Mscf/D	2090	Test sequence	6.63-hour flow followed by 12.73-hour shut-in
Gas specific gravity	0,868		
Gas impurities, % H_2S	0,1		

Pressure Data

Shut-In Time (hours)	Pressure (psi)	Shut-In Time (hours)	Pressure (psi)	Shut-In Time (hours)	Pressure (psi)	Shut-In Time (hours)	Pressure (psi)
0,0000	1185,8	1,4833	5652,7	4,0667	5915,3	8,0667	6108,7
0,0028	1191,7	1,5667	5675,7	4,1500	5920,2	8,2333	6114,2
0,0056	1236,9	1,6500	5696,5	4,2333	5925,2	8,4000	6120,4
0,0083	1323,7	1,7333	5716,0	4,3167	5930,3	8,5667	6126,1
0,0167	1636,2	1,8167	5734,1	4,4000	5935,1	8,7333	6131,4
0,0250	1932,7	1,9000	5750,9	4,4833	5939,9	8,9000	6136,5
0,0333	2207,8	1,9833	5766,9	4,5667	5945,2	9,0667	6141,4
0,0417	2459,6	2,0667	5782,0	4,6500	5950,1	9,2333	6146,2
0,0500	2682,1	2,1500	5796,1	4,7333	5955,3	9,4000	6151,5
0,0583	2889,4	2,2333	5809,1	4,8167	5960,1	9,5667	6156,2
0,0667	3077,0	2,3167	5821,1	4,9000	5965,1	9,7333	6161,4
0,0833	3400,5	2,4000	5830,9	4,9833	5969,7	9,9000	6165,6
0,1000	3666,0	2,4833	5838,6	5,0667	5974,5	10,0667	6169,9
0,1167	3884,2	2,5667	5843,5	5,1500	5979,0	10,2333	6174,1
0,1333	4062,0	2,6500	5846,9	5,2333	5983,6	10,4000	6178,4
0,1500	4207,6	2,7333	5849,5	5,4000	5993,4	10,5667	6182,8
0,2333	4650,9	2,8167	5852,4	5,5667	6002,8	10,7333	6187,5
0,3167	4871,1	2,9000	5855,8	5,7333	6010,9	10,9000	6192,3
0,4000	5008,5	2,9833	5859,4	5,9000	6019,2	11,0667	6196,3

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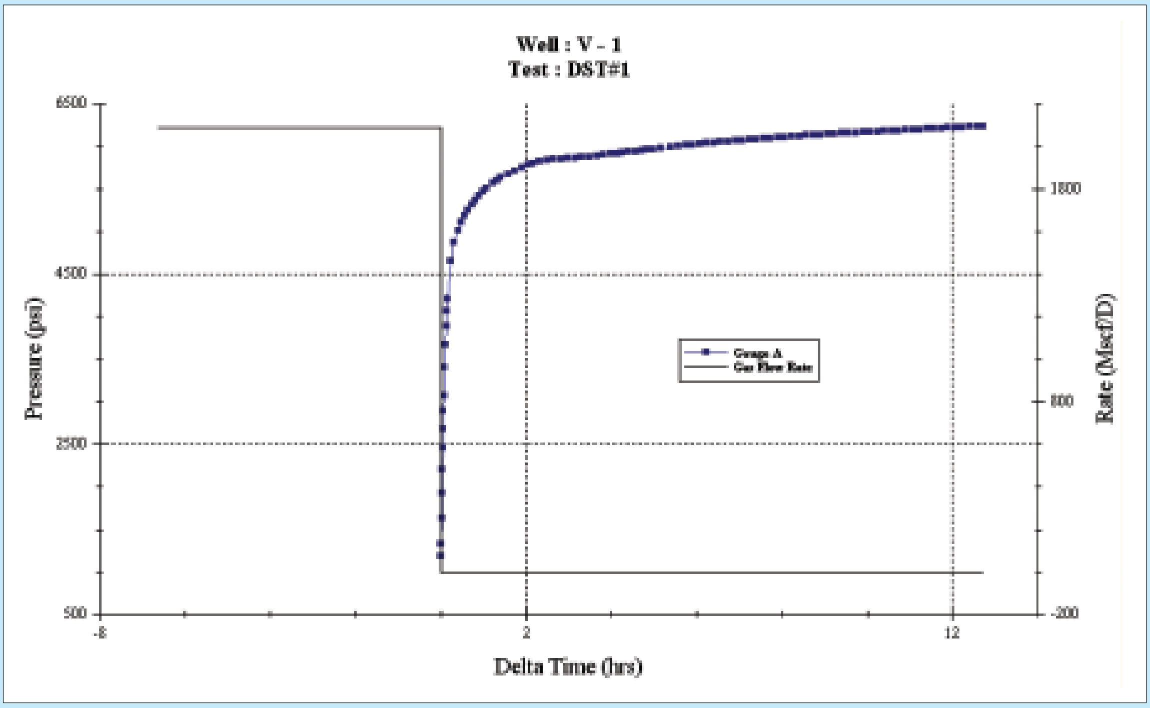

Figure 3
Test period analysis

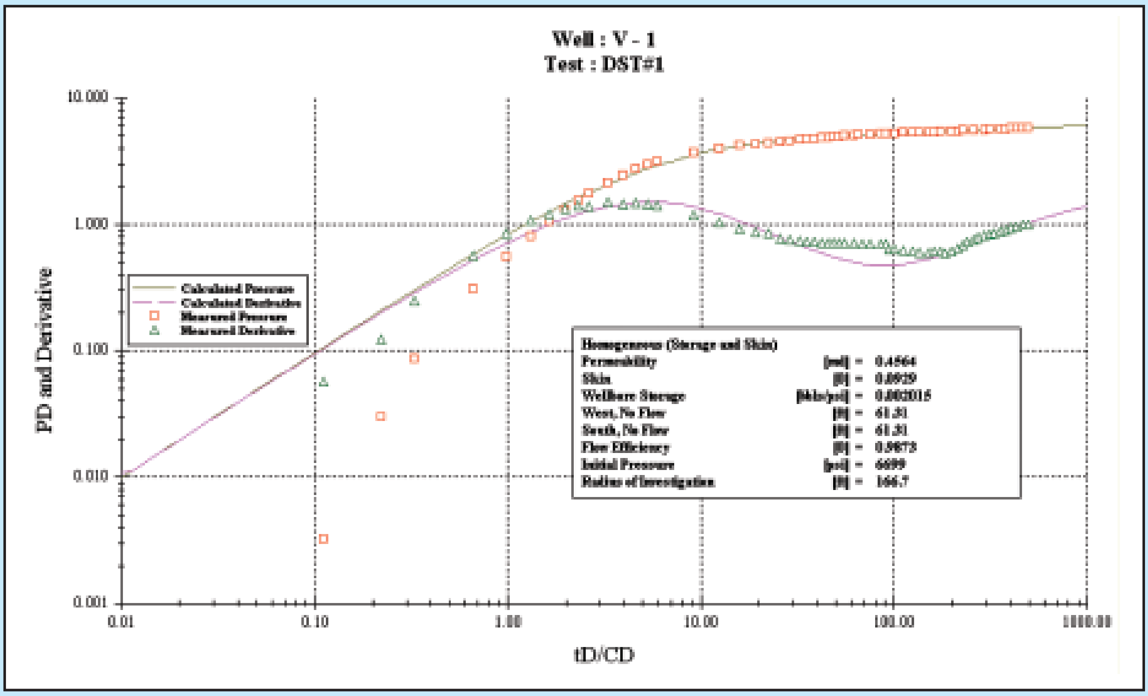

Figure 4
Automatic type curve match (Constant Wellbore Storage)

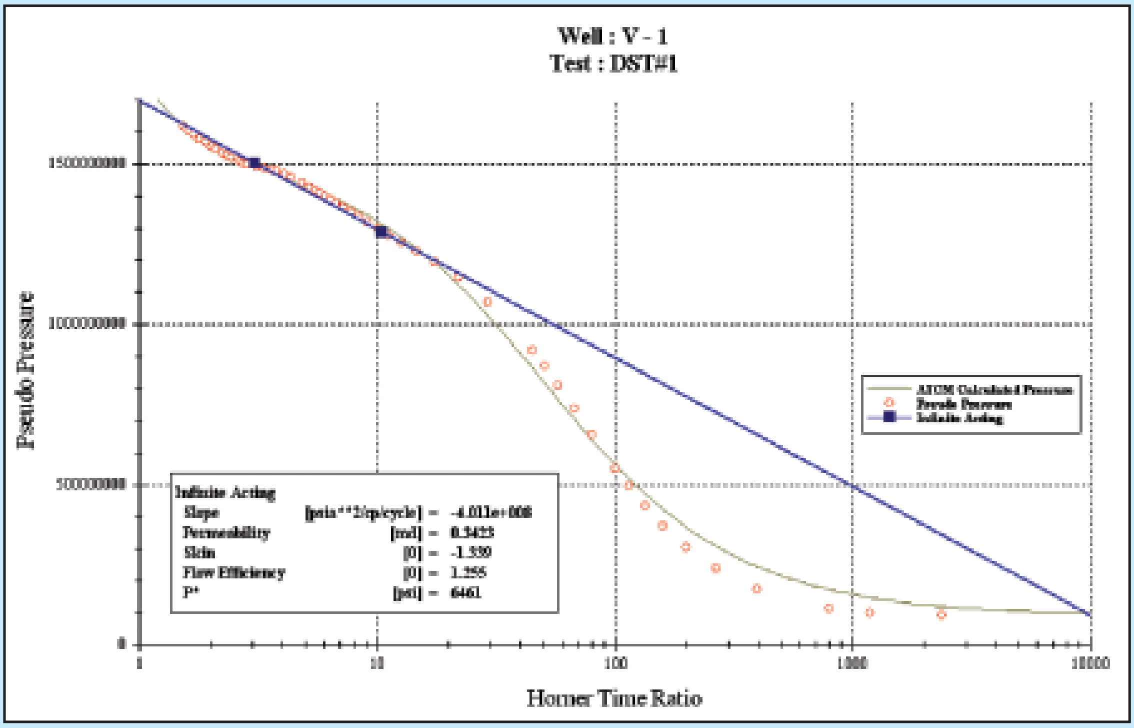

Figure 5
Horner plot (Constant Wellbore Storage)

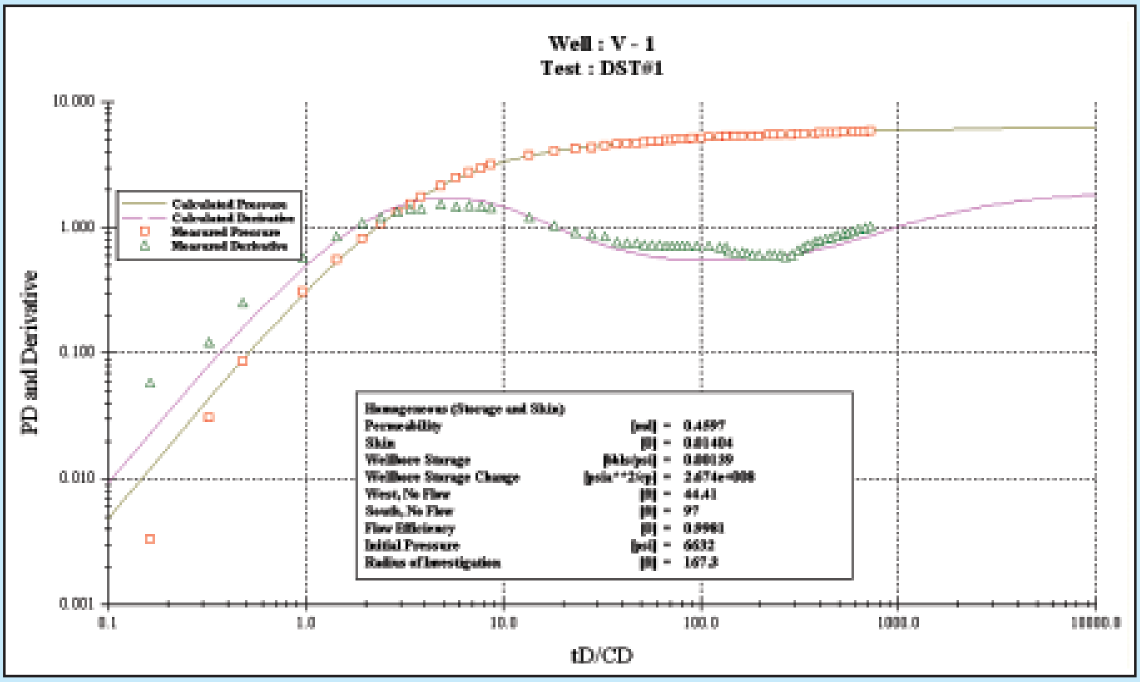

Figure 6
Automatic type curve match (Changing Wellbore Storage)

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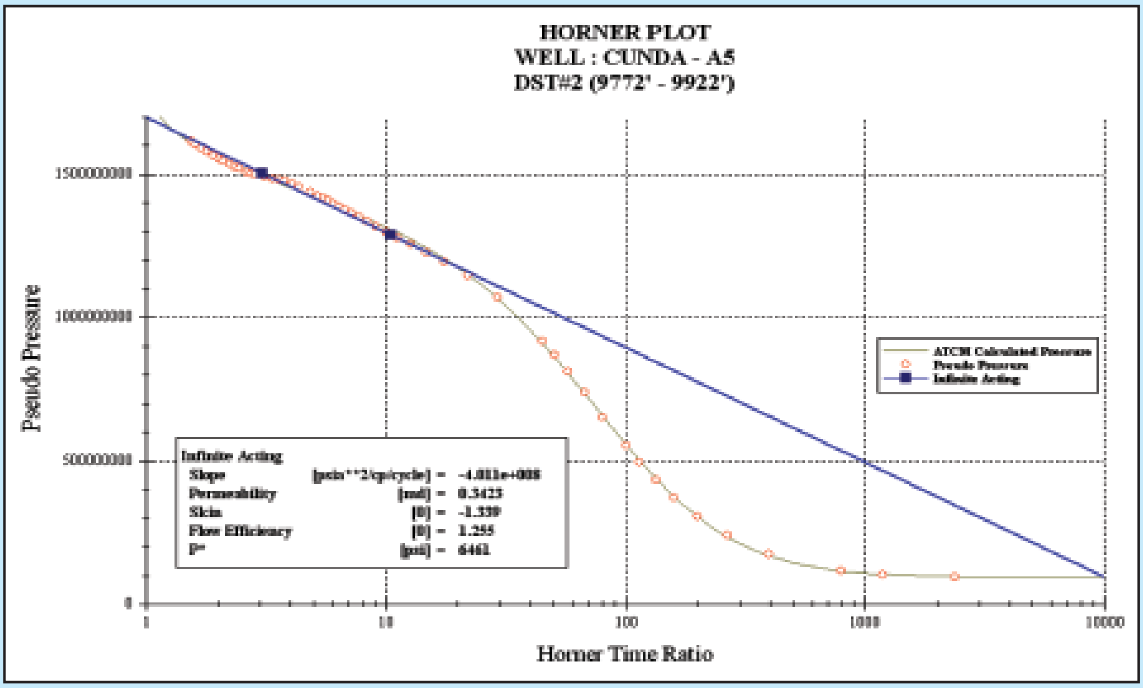

Figure 7
Horner plot (Changing Wellbore Storage)

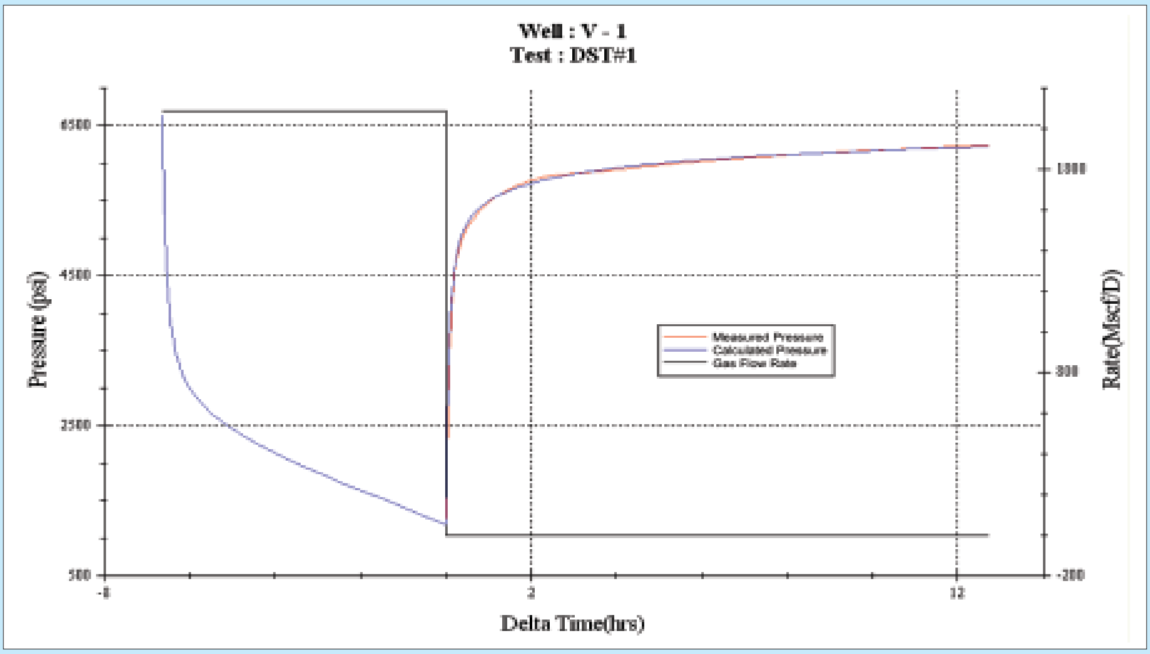

Figure 8
Simulation (Changing Wellbore Storage)

pretation. Analysis with pressure derivative method then gives indicates that the reservoir is homogeneous, which is defined by the two intersecting no flow boundaries with a 44.41 ft (west) and 97.0 ft (south) of distant from well. Further calculation gives an effective oil permeability of 0.4597 md, a skin damage of 0.01404, the flow efficiency of 0.9981, initial pressure of 6632.0 psi, and radius of investigation of 167.3 ft.

The decreasing-storage match resulted in a corresponding significantly lower value for skin damaged (s = 0.01404 vs s = 0.00929 for the constant-storage match). Figure 8 shows simulation match (measured pressure vs calculated pressure).

V. CONCLUSIONS

1. Field data affected by changing wellbore storage can be interpreted; a higher degree of confidence can be placed on the interpretation compared with constant-wellbore storage analysis.
2. Using a constant-wellbore storage model to analyze buildup data exhibiting decreasing storage may lead to significant overestimation of skin damage.

VI. NOMENCLATURE

B = formation volume factor, res bbl/STB
c_t = total compressibility, psi^{-1}
C = wellbore-storage coefficient, bbl/psi
C_a = apparent (early time) wellbore storage coefficient, bbl/psi
C_{aD} = $0.8937C_a/(\phi c_t h r^2_w)$
C_D = $0.8937\ C/(\phi c_t h r_w^{\ 2})$
C_ϕ = changing storage pressure parameter, psi
$C_{\phi D}$ = $khC_\phi/(141.2\ qB\mu)$
D = non-Darcy flow factor, Mscf^{-1}
h = formation thickness, ft
k = formation permeability, md
k_g = formation permeability to gas, md
$m(p)$ = gas pseudopressure, psi^2/cp
p = pressure, psi
p_D = $kh(p_i - p)/(141.2\ qB\mu)$
p_i = initial pressure, psi
p_w = wellbore pressure, psi
p_{wD} = $kh(p_i - p_w)/(141.2\ qB\mu)$
p_ϕ = changing storage pressure, psi
$p_{\phi D}$ = $khp_\phi/(141.2\ qB\mu)$
Δp = pressure change, psi
q = flow rate, STB/D
q_{sf} = sandface flow rate, STB/D
r_w = wellbore radius, ft
s = skin faktor
s_a = $s + Dq_g$, apparent skin factor, dimensionless
T = temperature, ^{o}F
t = time, hours
t_D = $0.0002637\ kt(\phi\mu c_t\ r_w^{\ 2})$
t_p = producing time, hours
α = changing-storage time parameter, hours
α_D = $0.0002637k\alpha/(\phi\mu c_t r_w^{\ 2})$
Δt = time elapsed since shut-in, hours
Δt_e = $\Delta t/(1+\Delta t/t_p)$, equivalent shut-in time for a test, hours
μ = viscosity, cp
ϕ = porosity

Subscripts

D = dimensionless
i = initial
sf = sandface
w = wellbore

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