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Practical Considerations in the Analysis of Gas-Condensate Well Tests

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ABSTRACT

Several pressure buildup tests are analyzed with a view to evaluate the potential of the ideas given in the literature. A broad range of tests is examined to demonstrate the characteristics of responses in wells producing below the dew point. Methods to obtain quantitative information that is consistent for different tests are outlined.

INTRODUCTION

Because of the extraordinary success of the diffusivity equation in enabling us to analyze pressure measurements and the conveniences derived therefrom, the analysis of pressure responses subject to the influences of multiphase flow is, at best, provided only a perfunctory treatment in the literature. Single-phase flow is the paradigm in this area of reservoir engineering. The reluctance in shifting from this paradigm may be partially attributed to the perception that relative-permeability measurements are not reliable enough for us to analyze the rapid changes in pressure that occur over a very short period of time. The other principal reason is that a simple method needs to be devised to relate relative permeability to pressure, although studies have suggested procedures to address this issue.[1,2]

This paper provides information for those interested in using multiphase-flow concepts for analyzing pressure-buildup tests in wells producing gas-condensate reservoirs. This class of tests was chosen for a number of reasons besides the fact that our principal interest is to apply the ideas in the literature[1,2] to field tests. We believe that only in this way can the true merit of theoretical ideas be evaluated, and more importantly, can advances be made. Furthermore, the gas-condensate system provides us with an opportunity to combine both single-phase and two-phase flow concepts.

Although the emphasis is on the analysis of field tests, we have conducted a number of simulations using a compositional model to evaluate plausible reasons for explanations we provide. Thus, our evaluations of these field tests have been verified by considering synthetic pressure-responses. In the following, we examine 5 tests to demonstrate important features of buildup responses in gas-condensate reservoirs. Four of these tests are in "depletion" systems and the fifth one discusses buildup tests in a pressure-maintenance project.

BACKGROUND

The depletion tests we consider presume that the results of a constant-composition-expansion (CCE) test on a representative sample are available. An equation of state, tuned to this sample, provides information on molar density and viscosity. In addition, we assume that the appropriate relative-permeability measurements are available. Using this information, we proceed to analyze buildup tests using the concepts suggested by Jones, Vo, and Raghavan.[3] Their basic ideas are summarized in the next section. The buildup tests for the pressure-maintenance system are evaluated using the single-phase analogue because information on the in-situ composition (pressure-maintenance project) is unavailable to us. These tests are analyzed by the composite-reservoir formulation.[4-6] Figs. 1 and 2 present the pertinent CCE and relative-permeability information used in Examples 1-4. As shown in Fig. 1, we consider a wide range of mixtures with the maximum liquid dropout in the range of 0.07 to 0.35. Mixtures 1, 2, and 3 are for depletion experiments, and Mix 4 applies to the test for the well in the pressure-maintenance project. The relative-permeability curves for oil and gas (k_{ro} and k_{rg}) shown in Fig. 2 were obtained from core tests and are also used in reservoir-simulation studies. The water saturation for Sets 1, 2, and 3 is, respectively, 0.115, 0.400, and 0.400. Water is assumed to be immobile. Note that relative-permeability to oil is negligibly small until the liquid saturation becomes quite large. Again, a broad range of relative-permeability curves is considered in this work. Table 1 presents additional reservoir properties that are needed to analyze the buildup tests. Our primary focus in all of the following is to obtain a consistent interpretation of multiple buildup tests after the wellbore pressure has fallen below the dew-point pressure.

THEORETICAL CONSIDERATIONS

As noted in the Introduction, we use single-phase and two-phase analogues to analyze pressure measurements. Our focus will be the interpretation of buildup measurements. The single-phase analogue given by

$$m(p) = \int_{p_{wf,s}}^{p_{ws}} \frac{\rho_g}{\mu_g} dp, \qquad (1)$$

is essentially identical to the analogue commonly used for dry-gas systems. Here, ρ is the molar density, μ is the viscosity, $p_{wf,s}$ is the pressure at the time of shut in, p_{ws} is the shut-in pressure, and the subscript g refers to the gas phase. This analogue takes advantage of the unique character of the condensate system, namely that, under normal circumstances, the condensate is immobile over substantial portions of the reservoir. Thus, if the variation in the relative permeability for the gas phase is negligibly small over the region where liquid is immobile, then this analogue should be useful whenever this region of the reservoir begins to influence the well response. (In all of the following, we assume that water is immobile.)

The two-phase analogue used here is given by

$$m(p) = \int_{p_{wf,s}}^{p_{ws}} \left(\rho_o \frac{k_{ro}}{\mu_o} + \rho_g \frac{k_{rg}}{\mu_g} \right) dp. \qquad (2)$$

Here, k_{rm} is the relative permeability to phase m, and the subscript o refers to the oil phase. The key problem in using Eq. 2 is that we need to express k_{ro} and k_{rg} as a function of pressure. In this work, we use the recommendation of Jones and Raghavan[1] to relate k_{rm} with pressure:

$$\frac{k_{ro}}{k_{rg}} = \frac{\rho_g \mu_o L}{\rho_o \mu_g V}. \qquad (3)$$

Here, L and V are the mole fractions of liquid and vapor, respectively, that are in equilibrium. As recommended by Jones and Raghavan, we use the values of L and V obtained via the constant-composition-expansion (CCE) experiment. In terms of physical considerations, this method of computing the two-phase analogue is best suited for those conditions wherein a

two-phase bank with a reasonably small transition zone develops around the wellbore. This observation implies that the two-phase analogue works best when the pressure differences $p_i - p_{dew}$ (or $\bar{p} - p_{dew}$) and $p_{dew} - p_{wf}$ are large (here, p_{dew} is the dew-point pressure). It should be borne in mind that, above the dew-point pressure, the change in the value of the two analogues (with pressure) is identical.

Skin factors may also be estimated by each of the above analogues. The appropriate expression is:

$$s = 1.151 \left[\frac{m(p, \Delta t)}{m} - \log \frac{\eta_i \Delta t}{r_w^2} + 3.2275 \right], \quad (4)$$

where m is the slope of the semilog straight line.

Under normal circumstances, the estimate of the skin factor via the single-phase analogue reflects the effects of the mechanical skin-factor and that of two-phase-flow. Consequently, this analogue provides an upper bound for the mechanical skin-factor. The two-phase analogue, on the other hand, will provide, as demonstrated by Jones et al.,[3] a lower bound for the mechanical skin-factor. This happens because Eq. 3 predicts values of k_{ro} that are much too high and values of k_{rg} that are much too low and that the high values of k_{ro} usually do not compensate for the low values of k_{rg}. Usually, the estimate of the skin factor by this method is within two units of the mechanical skin-factor.[2]

The magnitude of the skin factor that can be attributed to two-phase flow may be obtained by the relation

$$s_{2p} = \frac{1.151}{m} \int_{p_{wf,s}}^{p_{dew}} \left[\frac{\rho_g}{\mu_g} - \left(\rho_o \frac{k_{ro}}{\mu_o} + \rho_g \frac{k_{rg}}{\mu_g} \right) \right] dp. \quad (5)$$

If the results of a CCE experiment are used, then Eq. 5 will provide an upper bound for s_{2p}.

The tests to be discussed below represent a severe test of the ideas proposed above for a number of reasons. Most important is the fact that we examine multirate tests that consist of flowing and shut-in periods; that is, the wellbore pressure traverses the phase envelope a number of times. Under such circumstances, the phase-behavior effects around the wellbore can become rather complex. Also, the increasing rate-sequence used in some of the tests examined here complicates the use of Eq. 3, because this rate schedule delays (in some cases precludes) the development of a bank of the kind under which Eq. 3 works best; thus, care is needed in interpreting estimates of the skin factor by the two-phase analogue. Computer simulations suggest that for tests with an increasing rate sequence, the two-phase analogue will yield skin factors that decrease with rate. The single-phase analogue, on the other hand, always yields increasing values of skin factor.

In the following, for convenience, we express pseudopressures in terms of conventional units $(psia^2/cp)$. Often, we will compare derivative responses not only in terms of the two analogues given above, but also in terms of pressure. For ease of comparison, derivatives in terms of pressure are multiplied by $2 \, p_i/\mu_i Z_i$. Also, we shall use time transformations whenever needed. For the depletion tests examined here, numerical experiments indicated that time transformations are not important (see also Ref. 3).

Figure 3 is a log-log plot of a simulated pressure-buildup response in terms of its derivative (expressed in terms of Horner[7] time) using three analogues. The well had been produced at a constant rate for 100 days at a total rate of 10 MMSCF/d. This is the only synthetic response that is used in this paper and is intended to provide a starting point for this discussion. As noted by Raghavan,[1] the pressure-buildup curve is a reflection of the pressure distribution at the instant the well is shut in. Curve A, the derivative curve in terms of pressure (Cf. dp/dlnt) reflects the variation in fluid properties and in the saturation (relative permeability) with distance from the well. Curve B is a replot of the same information in terms of the single-phase analogue and may be said to be an attempt to incorporate the variation in fluid properties with distance. The large value of the

pressure-derivative curve for small values of Δt (small distances from the wellbore) reflects the low-permeability region where liquid is present. The vertical displacement between Curve A and Curve B for $10 < \Delta t < 140$ is proportional to $p_{ws}/[\mu_g(p_{ws})Z_g(p_{ws})]$. In the single-phase reference frame, it is possible to analyze Curve B in terms of the composite-reservoir formulation.[4-6] This point will be demonstrated in Example No. 5. Curve C is the pressure response in terms of the two-phase analogue, that incorporates both the effects of fluid properties and relative permeability with distance. The values of k_{ro} and k_{rg} were related to pressure by using Eq. 3 and the relative permeability curves are shown in Fig. 2. For this particular simulation, the line is essentially flat because Eq. 3 reproduces the saturation profile at the instant of shut in almost exactly. Thus, in this particular case, the semilog straight line exists even for $p_{ws} < p_{dew}$. The arrow on the time axis denotes the time at which $p_{ws} = p_{dew}$ and this nomenclature is used in all of the following. We have verified this observation by comparing the profile that results by using Eq. 3 with the profile prevailing at $\Delta t = 0$. Curves B and C appear to merge beyond $\Delta t = 3$ hours, because $k_{ro} = 0$ and $k_{rg} = 0.95$ when p_{ws} becomes greater than p_{dew}, and, under these circumstances, the integrands of Eqs. 1 and 2 are identical. (Curve A appears to merge with the other two curves because variations in fluid properties become negligibly small.) If the derivative curve were similar to that of Curve C, then it is possible to compute kh from any time range, and the skin factor so computed would reflect the mechanical skin-factor, provided that $m(p_{ws})$ can be estimated correctly. As already mentioned, the skin factor estimated by the two-phase analogue, in general, will be a lower bound for the mechanical skin-factor: For the specific case considered here, the skin factor obtained by using the two-phase analogue is equal to - 0.73 (true value = 0). The single-phase analogue, on the other hand, would reflect the total (mechanical plus two-phase-flow) skin-factor if the response curve beyond $p_{ws} \approx p_{dew}$ were used in the analysis. The estimate of skin factor for this analogue in this particular case is 18.62. An upper bound for the estimate of the

skin factor caused by two-phase-flow may be obtained by taking the difference between the two estimates and should equal that predicted by Eq. 5.

The added value of incorporating relative-permeability effects should be abundantly clear from Fig. 3. For example, in the case under consideration, if the test were to be terminated at 5 hours either by design or by untoward circumstances, then the advantages of using the two-phase analogue become abundantly clear. Rather than discarding measurements under the category "unanalyzable" or to arrive at tentative conclusions concerning estimates of permeability and skin factor, we are now in a position to make forthright statements concerning the variables we desire to estimate. This discussion completes the major points we wish to make concerning pressure tests wherein the wellbore pressure falls below the dew point. This preamble will permit us to understand the field tests to be discussed in the following pages, particularly when measurements cannot be interpreted unambiguously.

We emphasize that the profile of the two-phase analogue shown in Fig. 3 appears to be typical of many of the field examples that we have examined. In some cases, however, it is possible that predictions of gas saturation by Eq. 3 will be low. When this happens, the derivative response for the two-phase analogue will be different and this issue will be discussed in Example No. 3.

RESULTS

We begin with the depletion-system cases, where we present a detailed explanation of the behaviors to be expected. Example 1 is similar to that of the simulated example. We then proceed to the consideration of two multi-point tests. The second of these represents a case wherein an attempt had been made to stimulate the well and the attempt had not met initial expectations. Example 4 examines a post-fracture buildup test and results are compared with pre-fracture results. The final example, Example 5, explores the use of the composite-

reservoir[4-6] formulation to analyze tests in gas-condensate systems. Pressure measurements during the flowing periods were not analyzable; hence, they are not discussed.

Field Example No. 1. The results of this buildup test in terms of the three analogues are shown in Fig. 4. Set 1 and Mix 1 properties are used in the analysis. The well was produced at a rate of 24.74 MMSCF/day prior to shut in, and the flowing pressure at shut in was 3,488 psia. This value is well below the dew-point pressure of 5,965 psia. The characteristics of all three curves are similar to those in Fig. 3. Wellbore-storage effects appear to be insignificant after about 1/2 hour. In computing the two-phase analogue, Eq. 3 was used to relate relative-permeability values to pressure. Note that the two-phase analogue is essentially flat for times greater than 1 hour. The other two analogues clearly demonstrate that the effective-permeability-thickness product increases with distance. Above the dew-point pressure, the single- and two-phase analogues merge (note $k_{rg} \simeq 0.95$ for $S_w = S_{wi}$). The single-phase and two-phase analogues yield kh = 735.5 md.ft; s = 5.27 (single-phase), and s = -5.0 (two-phase). From these estimates and our earlier observations, we conclude that the mechanical skin-factor is in the range -5.0 to +5.27. From our experience in analyzing synthetic buildup tests, we expect the mechanical skin-factor to be around -3.

We noted earlier that our ability to use the two-phase analogue depended on its ability to reproduce the saturation profile at $\Delta t = 0$. Also, we have noted that values of the integrand of Eq. 2 will be low, because Eq. 3 may predict larger values for S_o. Fig. 5 is a plot of the variation in mobility with pressure. The bottom line reflects the variation in total mobility, λ_t (obtained from Eq. 3)with pressure, and the top line is the variation in single-phase mobility of gas, λ_g, with pressure. The circles represent mobility values calculated by the method given in Ref. 1. These values are obtained by using the following expression:

$$\lambda_t = \frac{q_t}{kh\, d_{pws}/d\ln t_{sup}}, \qquad (6)$$

and are representative of the in-situ mobility-profile. Here, we have used a kh value of 735.5 md-ft. The reason for obtaining a line that is essentially flat for the two-phase analogue becomes abundantly clear. We see that the agreement between the circles and the line is excellent. Because Eq. 3 appears to predict the in-situ mobility-profile rather well, the derivative of the two-phase analogue is essentially flat once wellbore-storage effects become negligibly small. We have used this comparison in more than one case to ensure that the proper straight line is chosen on the derivative plot for $p_{ws} < p_{dew}$. Incidently, this example is an excellent verification of Raghavan's thesis - the saturation profile at $\Delta t = 0$ governs the buildup response. (It is unfortunate that it is not possible to obtain a reasonable estimate of λ_t in the immediate vicinity of the wellbore for it would have been possible to get a better estimate of the mechanical skin-factor.)

The profiles shown in Fig. 5 represent the best agreements we have been able to obtain between values predicted by Eqs. 3 and 6. In many cases, the profile predicted by Eq. 3 will fall below that predicted by Eq. 6 (because Eq. 3 predicts low values of S_g), and this phenomenon can cause some distortions (this behavior is exacerbated by the nature of the log-log scale) that must be handled with some care. This point is further discussed in Example No. 4.

Field Example No. 2. This example consists of a sequence of four drawdown and four buildup tests as shown in Fig. 6. The initial pressure was 5,378 psia and the dew-point pressure at the initial composition is 4,986 psia; that is, the wellbore pressure fell below the dew-point pressure prior to each buildup period. The test sequence, an increasing rate-sequence, consisted of (total) production rates of 0.9360, 1.493, 1.960, and 2.547 MMSCF/d. Figure 7 presents the derivative response for the 4th buildup period in terms of the single- and two-phase analogues. Mix 2 and Set 2 curves were used in the analysis. Early-time responses are governed by wellbore-storage effects and the conventional, semilog straight-line becomes evident after $\Delta t > 5$ hours. As expected, responses for both

analogues merge when p_{ws} becomes greater than p_{dew}. At earlier times, the two-phase analogue falls below the single-phase analogue because the integrand of Eq. 2 is smaller than that of Eq. 1. Buildup responses for all 4 buildup periods for each analogue are shown in Figures 8 and 9, respectively. For each analogue, the buildup responses merge when shut-in times are long enough. The permeability-thickness product, kh, for this test is 67.12 md-ft. This estimate of kh is also in agreement with an earlier test. Either analogue yields the same result. Because all curves in Figures 8 and 9 merge (and also extrapolate to essentially the initial-reservoir pressure), we may conclude that depletion has been negligibly small.

Estimates of the skin factors for each of the analogues are noted on the appropriate figure. For the single-phase analogue, as expected, the total skin factor increases because of the increasing rate-schedule. This increase *may not* be attributed to non-Darcy flow. Use of the two-phase analogue results in a decreasing skin factor with an increase in rate because this rate schedule precludes the formation of a stabilized bank of fluid.

As mentioned earlier, Eq. 3 works best when the differences between $p_i - p_{dew}$ and $p_{dew} - p_{wf}$ are large. Numerical simulations confirm our observation that for the increasing rate-sequences shown here, the two-phase analogue will yield skin-factor estimates similar to that shown in Fig. 9. We have also examined synthetic buildup responses for decreasing sequences of rates and found that the estimates of skin factor obtained via this analogue would be a better representation of the mechanical skin-factor. This happens because the decreasing rate-sequence permits the development of a bank wherein both gas and oil are mobile (and the transition zone between this bank and the single-phase zone is small). The above observation is illustrated in Table 2, where we consider the results of two synthetic tests. As in Example 2 (also Example 3), each case consists of 4 flowing periods with each flowing period followed by a buildup period. Case A uses properties of Example 1, a high-permeability reservoir. For the

normal sequence tests, we see that skin-factor estimates *increase* with rate (single-phase analogue) and *decrease* with rate (two-phase analogue). These results are consistent with the results of the tests in Example 2. For the reverse-sequence tests, however, the analysis of the buildup tests indicates that skin-factor estimates *decrease* with rate (single-phase analogue) and *increase* with rate (two-phase analogue). Similar results are obtained in Case B; the properties used in this simulation are the same as those of Example 3.

Returning to Example 2, based on many simulations, we are led to the conclusion that the first buildup test will provide the best estimate of the mechanical skin-factor. Thus, we conclude that the mechanical skin-factor is in the range $8.17 < s < 9.47$.

Field Example No. 3. Again, we consider a multiple-rate test that consists of 4 drawdown and 4 buildup periods. The pressure at the start of the test is 5,243 psia and the dewpoint pressure is 4,992 psia. As shown in Fig. 10, in this case also, the test sequence is an increasing rate-sequence with production rates of 1.423, 1.939, 2.366, and 2.863 MMSCF/d. Figure 11 is the 'Horner plot' for all 4 buildup periods. From the slopes of the straight lines, we obtain kh to be 56.18 md-ft. The estimates of the skin factor from the single- and two-phase analogues are noted in Fig. 11. Again, skin-factor estimates (line 3) obtained by the single-phase analogue *increase* with rate, and the estimates (line 4) obtained by the two-phase analogue *decrease* with rate. The reasons for these results have been explained previously. From the table in Fig. 11, and our previous discussion, we conclude that the mechanical skin-factor is approximately -0.6. Thus far, our analysis has been straightforward.

We now point out an important characteristic of the two-phase analogue. Fig. 12 is a plot of the derivative responses for Buildup No. 4. Early-time responses are controlled by the wellbore-storage phenomenon. If we examine the two-phase analogue, we see that this curve, rather than stabilizing immediately after the hump,

shows an upward trend beginning at around 1 hour. The upward trend is a reflection of the fact that Eq. 3 underpredicts the value λ_t with pressure. One may not construe the upward trend to represent reservoir behavior, for example, a sealing fault. In this context, we should note that no such trend is seen on the trace of the single-phase analogue. If we compute λ_t from Eq. 6 in the pressure range $4000 < p < 5000$, we find that Eq. 3 predicts values of λ_t that are lower than that predicted by Eq. 6.

Field Example No. 4. We examine a buildup test following a fracture treatment. One of the objectives in presenting this example is to demonstrate the advantages of using the two-phase analogue. Curve A in Fig. 13 is the derivative response in terms of pressure. Curves B & C are the derivative responses in terms of the single- and two-phase analogues, respectively. Mix 3 and Set 3 information is used in the analysis. At the time the test was terminated, the shut-in pressure was less than p_{dew} (4,992 psia). Thus, we do not expect the single-phase analogue to provide information regarding formation permeability and skin factor. The two-phase analogue, however, appears to flatten out after 90 hours (Cf. Fig. 3). A Horner plot of this response is shown in Fig. 14. Calculations using the slope of the straight line shown in Fig. 14 yield kh = 38.18 md-ft and s = -4.56. This estimate of kh is in agreement with that of the pre-fracture buildup test (kh = 38.5 md-ft). We also computed λ_t from the pressure-derivative curve in the time range $\Delta t > 100$ hours (Eq. 6) and obtained excellent agreement with the λ_t values used to calculate the two-phase analogue in this pressure range (Fig. 15 shows the agreement in this pressure range).

For reasons already noted, the mechanical skin-factor would be greater than -4.56. This result suggests that the frac-job was indeed successful, although it is not possible to get a definite estimate of the mechanical skin-factor. (Estimates of skin factor from the pre-fracture test were s = 20.21 and s = 3.26 from the single- and two-phase analogues, respectively.)

Field Example No. 5. The well considered here is a downdip producer in a rich-gas-condensate reservoir (> 200 BBL/MMscfD initial yield; see Mix 4 of Fig. 1). The productive horizon has an average permeability in the 1-5 md range. The reservoir was on full-pressure maintenance until recently. In 1994, a blowdown pilot in the area of this well was initiated. Because breakthrough of the injected gas was observed early in the life of the pressure-maintenance project and areal and vertical sweep have remained open questions, it is very difficult to determine the effective composition of the in-situ fluids and the effective dewpoint pressures associated with this well at the time of these tests. Nevertheless some useful conclusions can be reached.

Figure 16 is a log-log diagnostic plot of two pressure-buildup tests from this well. Both responses are plotted in terms of the rate-normalized change in single-phase-analogue and the log-time derivative of this function versus single-phase-gas pseudotime. Gas properties used in the calculation of pseudopressure and pseudotime[8] are determined from recombined samples obtained immediately prior to each test. The circles and triangles represent these functions for a buildup test performed in late 1990 prior to the blowdown pilot. The squares and asterisks represent similar information for a buildup test performed in early 1995 after the beginning of the blowdown pilot.

Because the composite-reservoir model assumes a sharp interface, in using this model for the problem under consideration, one must devise a methodology to handle the saturation gradient in the reservoir. Obviously, many approaches may be taken. Thus, in the following, we first outline the basis used to discern the appropriateness of the model. Second, we outline the philosophy to obtain a value for the "radius of the zone of reduced permeability" and then demonstrate how our concept is applied.

This plot has four main features indicating damage caused by condensate accumulation. First, the derivative shapes after the early-time, storage-dominated periods strongly suggest a near-well region of lower

permeability followed by a transition zone which appears to be trending toward defining an outer region of greater permeability. Second, the near-well permeability-level indicated by the intermediate-time derivative shapes remains approximately constant between the 1990 and 1995 tests. Third, the time at which the derivative begins to decrease away from the near-well value increases between the 1990 and 1995 test indicating an increased radius for the near-well region of lower permeability. Finally, the level of the rate-normalized change in pseudopressure increases between the two tests implying an increase in skin factor after the beginning of the blowdown pilot. Indeed, semilog straight lines fitted through the ends of these tests yield consistent values of reservoir permeability ($k = 1.177$ md) and skin factors of 37.8 and 52.6, respectively.

To quantify these qualitative observations, both of these tests have been history matched using composite-system models.[4-6] Figures 17 and 18 show the matches of the 1990 and 1995 buildup tests, respectively. Note that in these two figures rate normalization has not been used. These matches have been made by fixing the outer-zone permeability at 1.177 md and adjusting the inner-zone permeability and radius to obtain a match. The best value for the radius of the inner zone was determined by ensuring that the model predicted derivative *entered* the transition period at the same time as the derivative of the measured responses. Deviations between predicted and measured derivatives after this time were not considered and are due mainly to the difference between the composite-system model and the actual mobility distribution in the reservoir. The match of the 1990 test includes phase-redistribution effects which allow the model responses to follow closely the derivative response up to the beginning of the transitional period. The 1995 response does not warrant the use of this extra complication.

As the match results on these two figures show, the qualitative conclusions reached above are confirmed quantitatively. The radius of the inner zone increases from 45 ft in 1990 to 57.5 ft in 1995 while the

permeability of the inner zone has only changed slightly if at all. The zone has grown in size after the beginning of the blowdown period probably because of local depletion.

CONCLUDING REMARKS

We began this work primarily because there is a dearth of information pertaining to the analysis of pressure-buildup tests under multiphase-flow conditions. We believed it would be worthwhile to document different behaviors that may be expected and outline procedures to understand these behaviors. The objectives have been met by evaluating the shapes of pressure-buildup traces for a wide variety of conditions and showing that it is possible to arrive at a consistent interpretation of buildup responses under multiphase-flow conditions. This is the first, serious study that attempts to combine relative-permeability measurements with pressure measurements. The advantages and disadvantages of using various analogues are explored thoroughly. The conclusions we detail and the plausible explanations we provide for various tests have been verified by considering synthetic responses to mimic the pertinent test under consideration. Because of the rather broad and general nature of this study, we will not document specific conclusions except to note the following: (i) it is possible to relate relative-permeability values to pressure and use the resulting analogue to evaluate pressure-buildup tests in a quantitative manner, and (ii) the saturation profile at shut in governs the shape of the pressure buildup trace and the success of the two-phase analogue is dependent on our ability to estimate this profile. This paper outlines a practical method to compute the profile.

NOMENCLATURE

c_t = total compressibility, psi^{-1}
h = formation thickness, ft
k = permeability, md
k_r = relative permeability
L = moles of liquid

m = slope of the semilog straight-line, also local slope

m(p) = pseudopressure, $psia^2/cp$

p = pressure, psia

p_{dew} = dew-point pressure, psia

$p_{wf,s}$ = wellbore pressure at shut-in, psia

p_{ws} = shut-in pressure, psia

q_t = total molar rate, lb mol/D

r = radius, ft

r_w = wellbore radius, ft

s = estimate skin factor from Horner analysis

s_{2p} = two-phase skin factor

S = saturation

t = time, hours or days

$\tilde{t}$ = pseudotime, hours, days

Δt = shut-in time, hours or days

T = temperature, °R

V = moles of vapor

Z = deviation factor

η = diffusivity, ft^2/hr

λ = mobility, psia/cp

μ = fluid viscosity, cp

ρ = molar density, $lbm\ mol/ft^3$

ϕ = porosity

Subscripts

g = gas

i = initial

m = oil or gas

o = oil phase

s = skin

w = water

Superscripts

$-$ = derivative

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Table 1
Formation Properties

Example	1*	2	3	4	5
Condensate Yield, bbl/MMs	180	115	185	165	200
Thickness, h, ft	205	34	19	41	629
Porosity, ϕ	0.123	0.082	0.104	0.104	0.110
Initial Pressure, p_i, psia	6,700	5,378	5,243	5,686	5,700
Dew-point pressure, p_{dew}, psia	5,965	4,986	4,992	4,992	5,310
Temperature, °F	240	170	173	173	215

* Simulated Example uses properties of Example 1.

Table 2
Skin Factor Estimates

A: Set 1, Mix 1; Mechanical Skin-Factor, s = 0

Normal Sequence

Buildup	1	2	3	4
Gas Rate, MMscf/D	6	9	12	15
Skin, single-phase analogue	-0.06	1.47	4.18	7.09
Skin, two-phase analogue	-0.54	-1.27	-1.66	-1.88

Reverse Sequence

Gas Rate, MMscf/D	15	12	9	6
Skin, single-phase analogue	5.61	5.20	3.73	2.08
Skin, two-phase analogue	-1.95	-1.31	-0.86	0.20

B: Set 3, Mix 3; Mechanical Skin-Factor s = 0

Normal Sequence

Buildup	1	2	3	4
Gas Rate, MMscf/D	1.5	2	2.5	3
Skin, single-phase analogue	3.21	4.66	5.9	6.88
Skin, two-phase analogue	-0.53	-0.81	-1.03	-1.23

Reverse Sequence

Gas Rate, MMscf/D	3	2.5	2	1.5
Skin, single-phase analogue	6.08	6.49	6.30	5.72
Skin, two-phase analogue	-1.23	-0.89	-0.52	-0.02
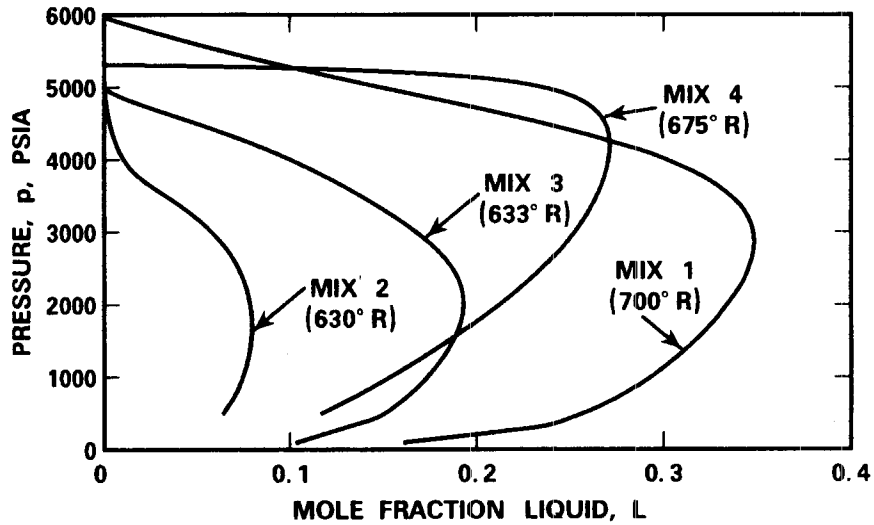
Figure 1: Constant-Composition-Expansion Results.
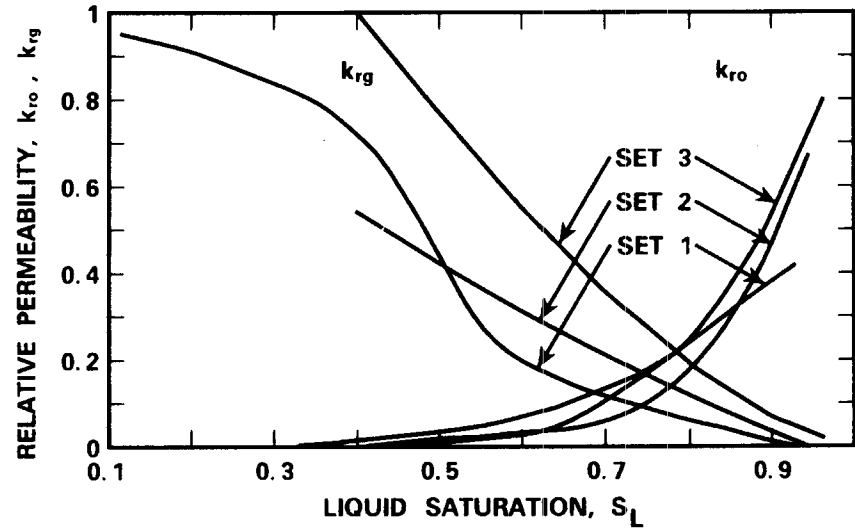
Figure 2: Relative Permeability.

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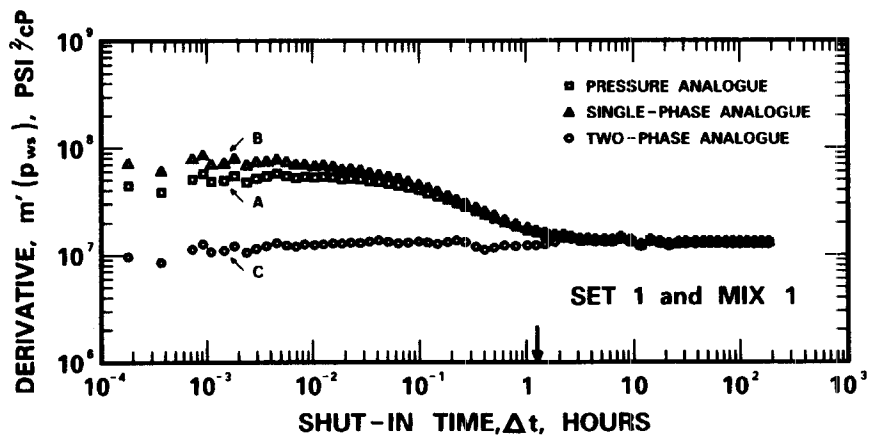
Figure 3: Derivative Responses, Simulated Case.
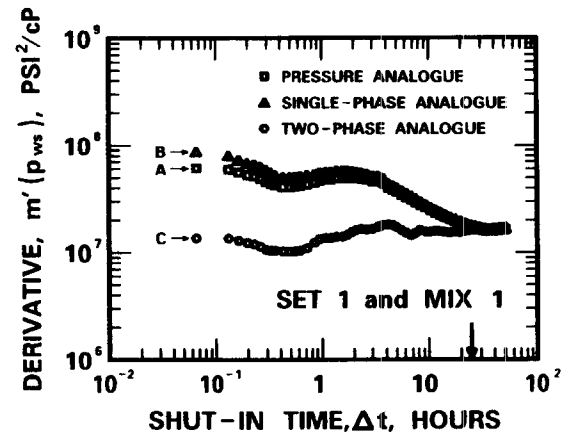
Figure 4: Derivative Response; Example 1.
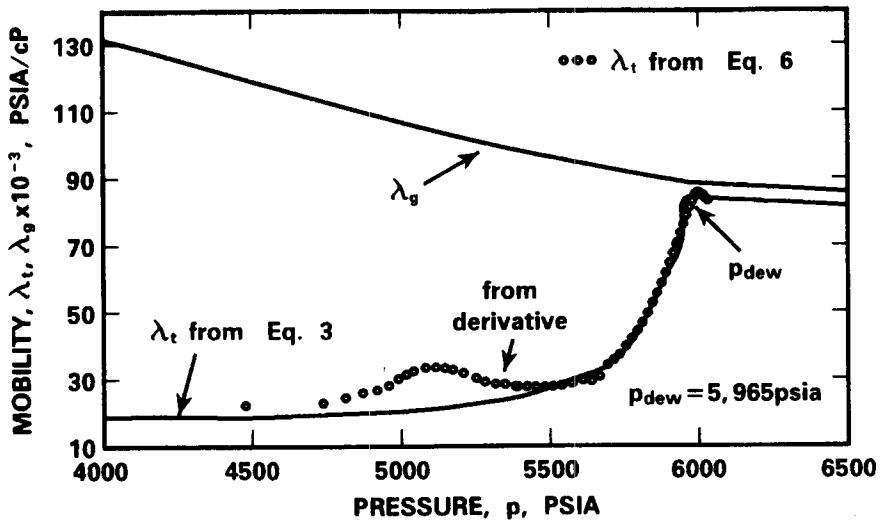
Figure 5: Mobility – Pressure Relation: Example 1.
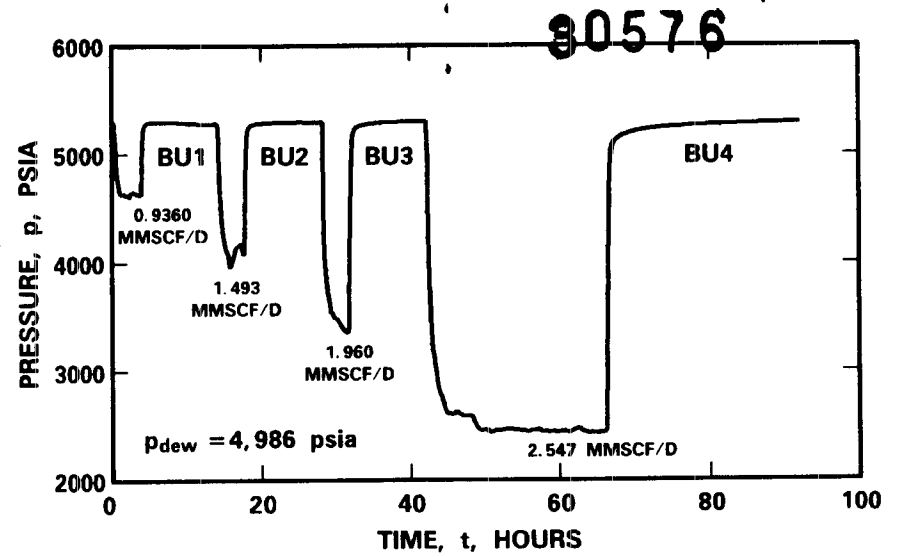
Figure 6: Pressure History: Example 2.

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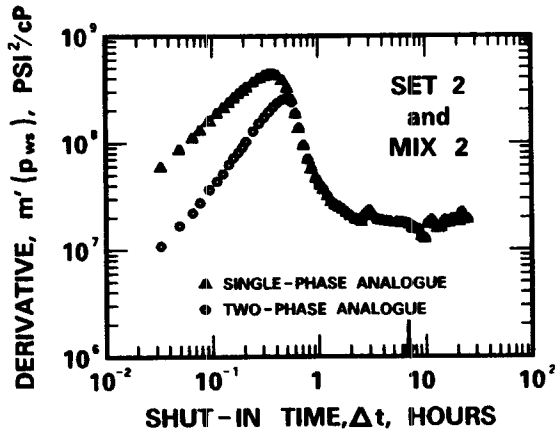
Figure 7: Derivative Response of BU4; Example 2.
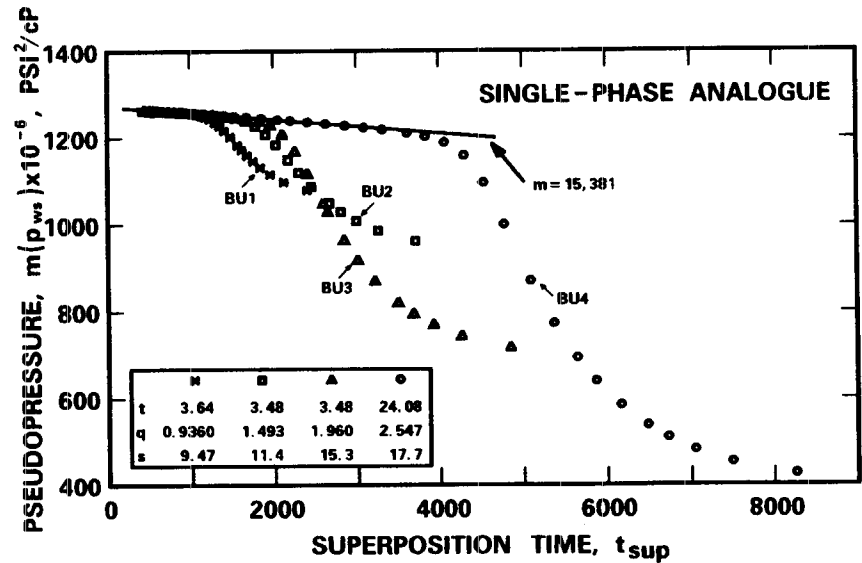
Figure 8: Superposition Plot of Single-Phase Analogue. Example 2.

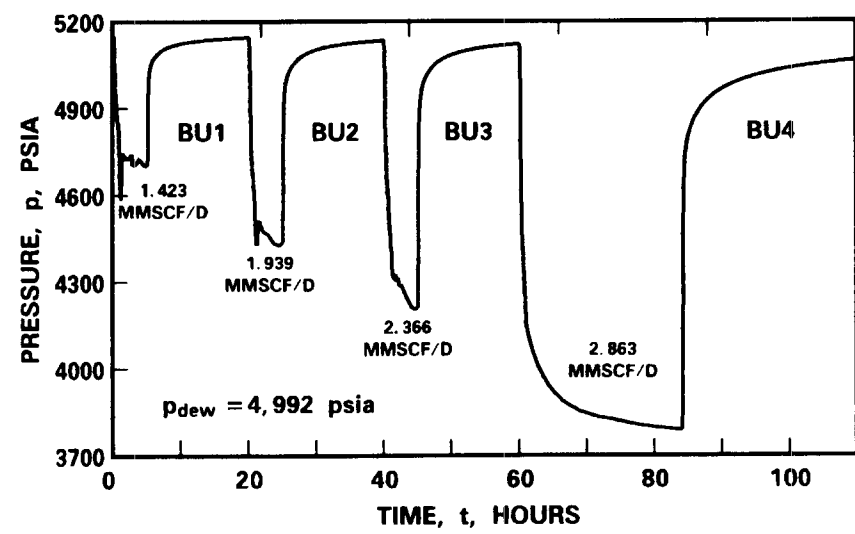/PQR/RR070695.DGN KRC
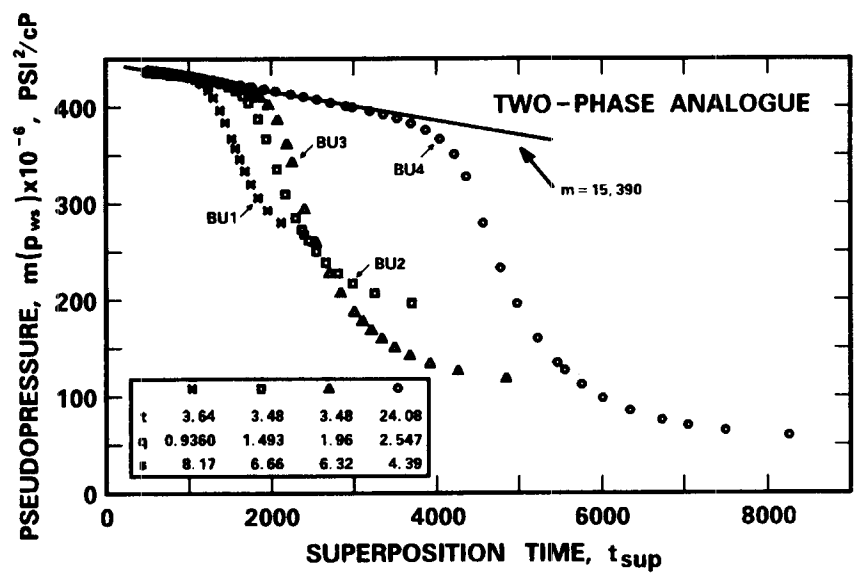
Figure 9: Superposition Plot of Two-Phase Analogue. Example 2.

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Figure 10: Pressure History: Example 3.
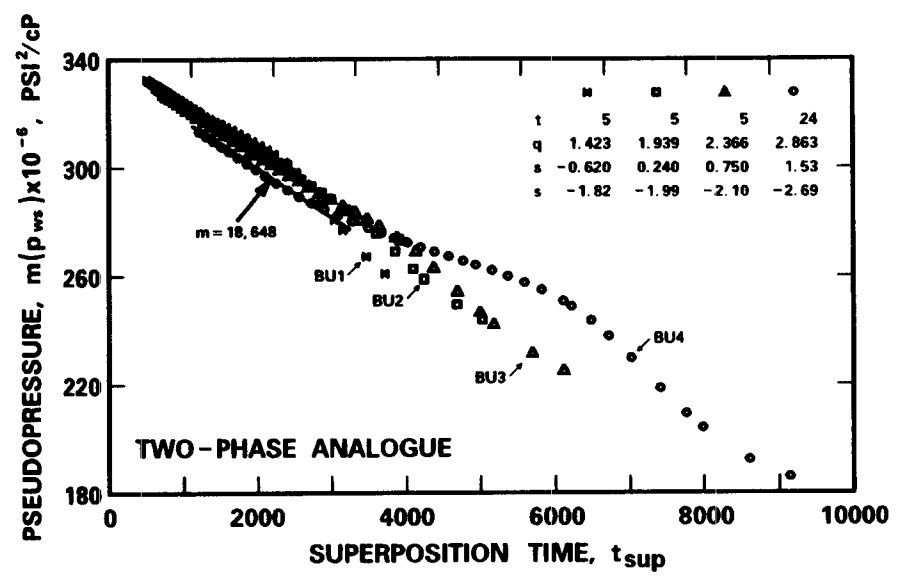
Figure 11: Superposition Plot of Two-Phase Analogue, Example 3.
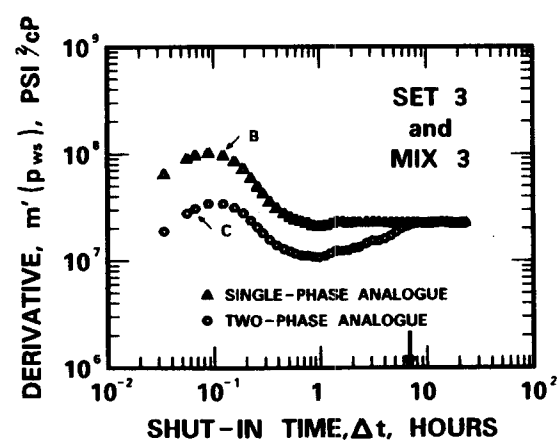
Figure 12: Derivative Response; Example 3.

/PQR/RR070695.DGN KRC
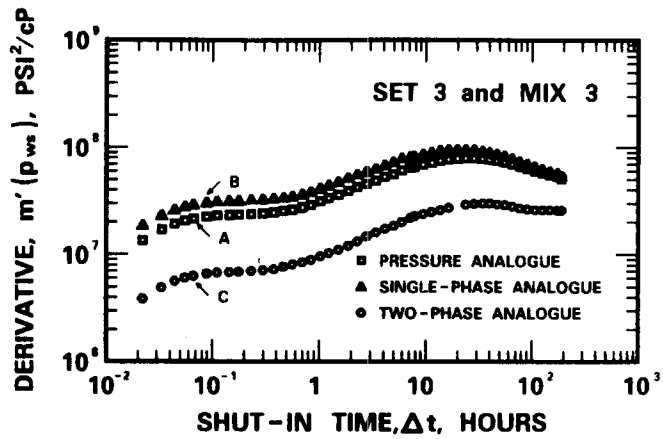
Figure 13: Derivative Response; Example 4.
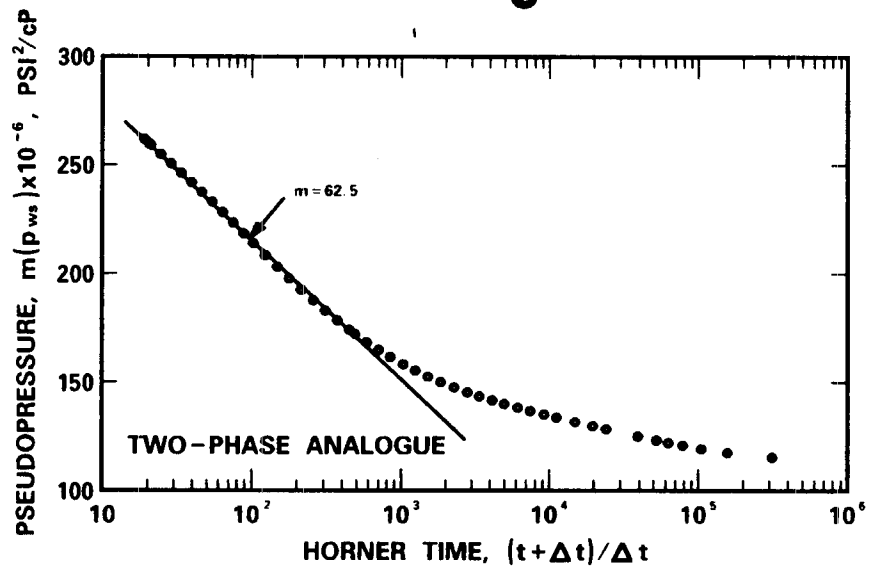
Figure 14: Horner Plot of Example 4.
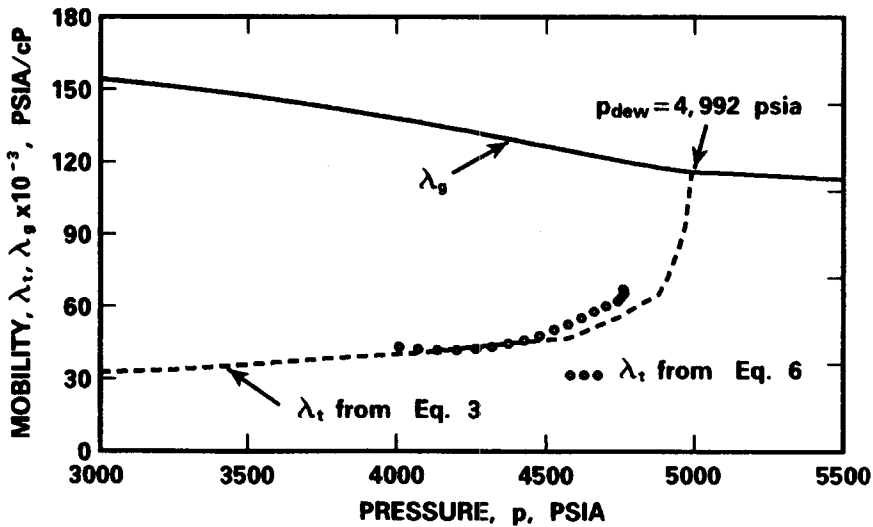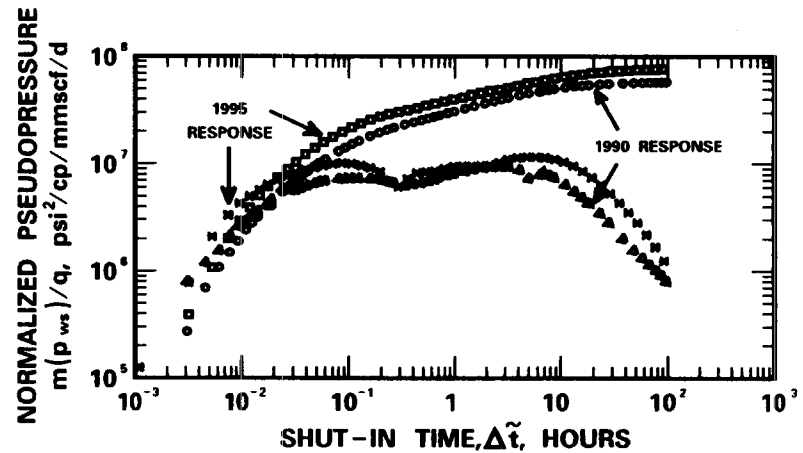
Figure 15: Mobility – Pressure Relation: Example 4.

Figure 16: Rate–Normalized Diagnostic Plot
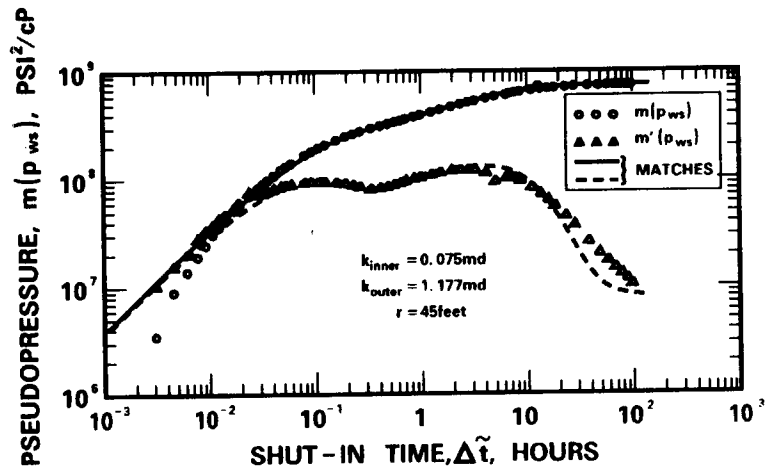
Comparing 1990 and 1995 Buildup Tests.

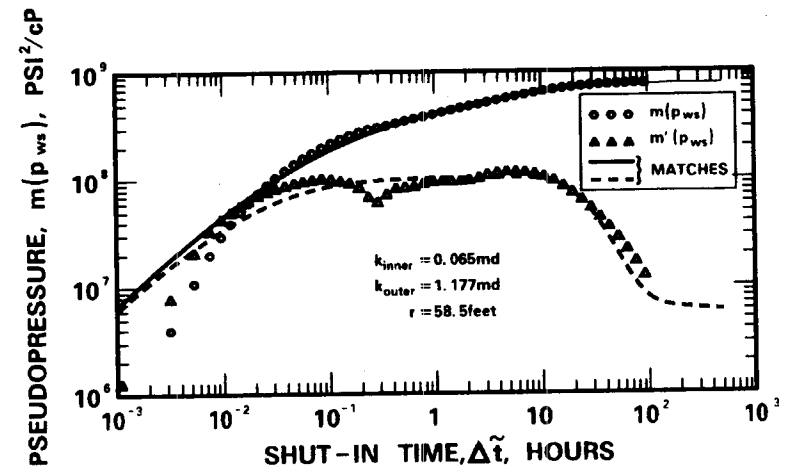**Figure 17:** Composite - System Match of 1990 Test.

Figure 18: Composite - System Match of 1995 Test.

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