Journal of Petroleum Science and Engineering 34 (2002) 109–122

Journal of Petroleum Science & Engineering

www.elsevier.com/locate/jpetscieng

Detection of pressure buildup data dominated by wellbore phase redistribution effects

Fuad H. Qasem, Ibrahim S. Nashawi*, Muhammad I. Mir

Department of Petroleum Engineering, College of Engineering and Petroleum, Kuwait University, P.O. Box 5969, Safat 13060, Kuwait

Accepted 14 December 2001

Abstract

This paper presents a new diagnostic technique that detects the presence of any type of phase redistribution pressure response and determines the true beginning of the semilog straight line for conventional analysis techniques. The method can also be used to predict the end of any wellbore effects. This greatly enhances the conventional analyses and yields more accurate estimation of the reservoir parameters. The technique is based upon existing analytical solutions for radial flow in homogenous reservoirs. The proposed method is simple and straightforward. It does not require manual or automatic type curve matching and it does not use complicated nonlinear optimization or history matching as some other methods necessitate. The applicability and accuracy of the proposed method are demonstrated through the analysis of three simulated cases and two field examples. © 2002 Elsevier Science B.V. All rights reserved.

Keywords: Buildup test; Phase redistribution; Pressure hump; Type curve; Pressure derivative; Primary pressure derivative; Secondary logarithmic pressure derivative

1. Introduction

Pressure transient analysis is one of the major tools used to determine the formation characteristics around the wellbore. Today, state-of-the-art, highly sophisticated, electronic gauges are used for downhole pressure measurement. A significant amount of the pressure data that are recorded during a well test are dominated by wellbore and pressure gauge related effects and do not reflect the reservoir behavior. If not properly recognized, these effects can be easily misinterpreted as reservoir responses and included in the analyzed data. When this happens, the well test analysis yields improper identification of the reservoir model and wrong estimates of the formation parameters. To avoid such problems, the measured data must be critically examined and processed prior to the implementation of any pressure transient analysis technique.

The effects of the wellbore environment on the performance of the pressure gauges during well test and data measurement were discussed by several authors (Kerig and Watson, 1985; Veneruso et al., 1991; Kikani et al., 1997). They showed that part of the problems encountered during data analysis and some of the reasons for data misfit are attributed to malfunction of the presumably good pressure recording devices. This is simply because the accurate laboratory performance of any tool does not match the rough and unpredictable wellbore conditions. The effects of reservoir geometry and wellbore dynamics, including both mass-related and momentum effects on

* Corresponding author. Fax: +965-4849558.
E-mail address: nashawi@kuc01.kuniv.edu.kw (I.S. Nashawi).

PII: S0920-4105(02)00158-4

the well test analysis plots have been discussed by numerous authors (Shinohara and Ramey, 1979; Ershaghi and Woodbury, 1983; Reynolds and Thompson, 1986; Saldana and Ramey, 1986; Xiao and Reynolds, 1992; Mattar and Santo, 1992; Mattar, 1992, 1994, 1999; Fair, 1981, 1996; Gringarten et al., 2000). Ershaghi and Woodbury (1983) and Reynolds and Thompson (1986) confirmed, using field examples, that a good understanding of the flow regime and reservoir geometry allows for proper interpretation of the well test data and helps avoid many errors associated with force fitting a particular flow regime, or reservoir model, upon a set of pressure versus time data. The recorded data was considered as a combination of reservoir and wellbore responses by Shinohara and Ramey (1979); Saldana and Ramey (1986); Xiao and Reynolds (1992); Mattar and Santo (1992), Mattar (1992, 1994, 1999), Fair (1996) and Gringarten et al. (2000). To these authors, wellbore effects include wellbore storage, phase redistribution, geotidal, microseismic, recorder drift, and many other effects. Therefore, it is the duty of the well test analyst to scrutinize the measured data, identify the wellbore phenomena, and only analyze the reservoir response. This critical examination of the data, in addition to a good understanding of the flow regime and reservoir model, should ensure proper data analysis and accurate test results.

Wellbore effects have long been recognized since pressure transient testing was first established as a viable tool for evaluating well and reservoir performance. In an effort to quantify and evaluate these effects, the concept of wellbore storage was first introduced by van Everdingen and Hurst (1949) and van Everdingen (1953). Then, Stegemeier and Matthews (1958a,b) introduced the concept of wellbore phase redistribution. They showed that this phenomenon occurs in a shut-in well with gas and liquid flowing simultaneously in the tubing. In such wells, the gravity effects cause the liquid to fall to the bottom and the gas to rise to the top of the tubing. Because of the relative incompressibility of the liquid and the inability of the gas to expand in a closed system, the phase segregation yields a net increase in the wellbore pressure.

During a pressure buildup test, the increased pressure in the wellbore is relieved through the formation, and the equilibrium between the wellbore and the surrounding formation will be eventually attained. Sometime early during a buildup test, however, the pressure may rise above the formation pressure then decrease, causing an anomalous hump on the conventional pressure buildup analysis curves (Russell, 1966). Fig. 1 is a plot of actual field data displaying the classical pressure hump associated with phase redistribution. In less severe cases, the wellbore pressure may not increase sufficiently to reach a maximum buildup pressure.

General analyses methods of pressure buildup tests influenced by wellbore phase redistribution have been presented by Stegemeier and Matthews (1958a,b) and Pitzer et al. (1959a,b). In both of these investigations, the association of the pressure hump with phase redistribution were documented and indicated that the size of the hump could be correlated with the volume of the gas flowing in the tubing. Matthews and Russell (1967) considered the phase segregation effects as a significant unusual behavior to be noticed without proposing any interpretation technique. Earlougher (1977) also noted, based on the shape of the log–log plot of the pressure buildup data, that phase redistribution seems to be related to the wellbore storage problem. He suggested a multiple-rate analysis technique that minimizes the humping effects and provides reasonable test results.

Even though the negative impact of phase redistribution on pressure transient analysis has long been recognized, it was not given serious consideration until Fair (1981) presented the first mathematical model incorporating the phase segregation effects. Fair's model, known as the increasing wellbore storage model, could be solved analytically in the Laplace

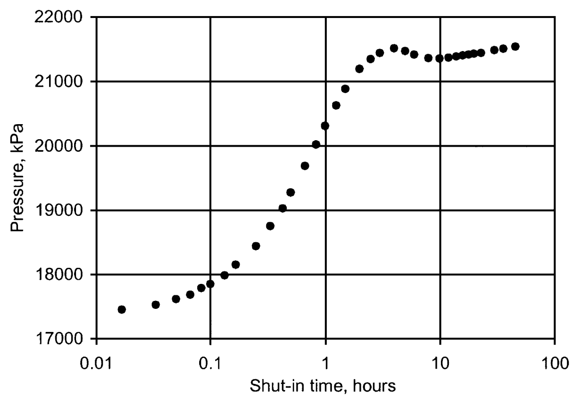

Fig. 1. MDH pressure buildup plot: field example no. 1.

domain to obtain a dimensionless pressure solution. This is actually a single-phase model in which phase redistribution is assumed to cause an additional pressure change. Fair used his dimensionless solution to construct type curves that are suitable to analyze pressure buildup data influenced by wellbore phase segregation. Hegeman et al. (1991) reported that in some cases, Fair's model does not yield a good fit of the field data. This is especially true when the pressure buildup test shows a decreasing wellbore storage coefficient. Consequently, Hegeman et al. suggested another model that suits this situation. They also presented type curves that are applicable to their case. Although Fair and Hegeman et al.'s type curves successfully treated pressure buildup data dominated by phase redistribution effects, it is well known that type curve matching results may not be unique and should be used as a last resort for a diagnostic tool to determine the reservoir model that fits the well test data (Agarwal et al., 1970a,b; McKinley, 1971a,b; Earlougher et al., 1973). Both Fair and Hegeman et al. did not present a physical explanation of the process that takes place in the wellbore and causes the wellbore storage coefficient to either increase or decrease.

Numerical simulators for multiphase flow in the wellbore were also developed by Winterfeld (1989), Almehaideb et al. (1989) and Hasan and Kabir (1992); however, to the best of our knowledge, these simulators do not generate results that confirm the equations given by Fair (1981) and Hegeman et al. (1991) or verify why some field buildup data match the increasing wellbore storage model of Fair whereas other well test data follow the decreasing wellbore storage model of Hegeman et al. This puzzling data behavior was finally clarified by Xiao et al. (1995), who used a simple mechanistic numerical wellbore model that offered a physical explanation for both Fair and Hegeman et al.'s models.

Thompson et al. (1986) further investigated Fair's (1981) work. They classified the pressure response obtained during phase redistribution into three distinct types and delineated the conditions under which each type exists. They also provided rules for determining the beginning of the semilog straight line for each type. Moreover, they presented the general procedure for pressure data analysis when sandface flow rates are available. The use of simultaneously measured transient sandface flow rate and pressure data to minimize the wellbore storage and phase redistribution effects were proposed by Meunier et al. (1985) and others (Kuchuk and Ayestaran, 1985; Thompson and Reynolds, 1986; Thompson et al., 1986; Nashawi, 1994). These methods, collectively known as either convolution or deconvolution techniques, have been proven effective in yielding accurate test results. The well test analyst, however, should be well aware of the negative effects of inaccurate sandface rate measurements on the test results. Rushing and Lee (1989) presented an automatic type curve matching method that matches measured field data with the pressure simulated by Fair's phase redistribution model. He showed with field examples that his technique is especially useful when the conventional semilog analysis methods cannot be applied. Olarewaju and Lee (1989a) employed pressure derivative type curves to detect the presence of phase segregation distortion when the hump is not apparent from the conventional pressure plot. They stated that when phase redistribution effects exist in the wellbore, the pressure derivative type curve exhibits a V-shaped curvature. This same feature is also a characteristic of some reservoir heterogeneity such as crossflow in layered reservoirs and dual-porosity systems. The main difference between the graphical behavior of the phase segregation effects and the other heterogeneous systems is that the V-shaped depression for phase segregation is associated with the bell-shaped wellbore storage. Moreover, the depth of the V-shaped curvature depends on the time span of the phase redistribution data (Olarewaju and Lee, 1989b; Olarewaju, 1990). It is also interesting to note that the phase segregation effects distorts the bell-shaped wellbore storage derivative curve, making it narrower than that resulted from any kind of reservoir system without phase redistribution. If the inter-porosity transfer coefficient λ is very large, such that the transition flow regime of the dual-porosity system occurs very early, the suggested method for differentiating between the two different behaviors may not be very useful (Olarewaju and Lee, 1989b). Olarewaju (1990) set simple guidelines to analyze pressure buildup data dominated by wellbore storage and phase segregation effects. His method utilizes both the conventional pressure plots and the pressure derivative type curves. The technique is only applicable when the buildup test is performed long enough until the wellbore storage and phase redistribution effects cease distorting the buildup data and the pressure derivative curve displays the 1/2-slope feature indicating infinite-acting radial flow [$p'_D(t_D/C_D) = 0.5$] as discussed by Bourdet et al. (1983). Mattar and Zaoral (1992) proposed the use of Primary Pressure Derivative (PPD) to differentiate between the wellbore dominated phenomena and the reservoir fluid flow responses. They confirmed that when the PPD plot displays an increasing trend, that particular portion of the data is affected by wellbore effects. In actual field cases where the changes in slopes are subtler, they recommended the use of a magnified scale to detect these changes. Baghdarvazehi et al. (1993) presented analytical solutions for the constant rate radial flow in both conventional and naturally fractured reservoirs influenced by wellbore phase redistribution effects. They used nonlinear regression analysis for reservoir parameter estimation. Thompson (1986) and Olarewaju et al. (1988, 1990) illustrated that phase redistribution is not always associated with the pressure hump on the analysis plot. The absence of the hump may lead the well test analyst to serious misinterpretation.

The various categories of phase redistribution as presented by Thompson et al. (1986) are discussed in this study. The cases where the diagnostic methods proposed by Olarewaju et al. (1988, 1990) and Mattar et al. (1992) fail to detect the presence of phase redistribution are also illustrated. More importantly, an innovative technique that clearly recognizes the various levels of wellbore phase segregation effects when other methods fail to do so is presented. Finally, a simple method to determine the beginning of the semilog straight line without resorting to type curve matching techniques is proposed. The success of the proposed method is illustrated by analysis of several simulated and field cases. The relative merits of the technique are quite evident when it is compared with Mattar and Zaoral (1992), Olarewaju (1990), and other well established methods.

2. Classification of phase redistribution effects

Fair's (1981) phase redistribution drawdown solution is a unique function of four parameters: (1) the dimensionless wellbore storage coefficient, C_D, (2) the dimensionless maximum phase redistribution pressure change, $C_{\phi D}$, (3) the dimensionless apparent wellbore storage coefficient, C_{Da}, and (4) the skin factor, s. C_D, $C_{\phi D}$, and C_{Da} are defined as:

$$C_D = \frac{0.894C}{\phi c_t h r_w^2} \tag{1}$$

$$C_{\phi D} = \frac{khC_\phi}{141.2qB\mu} \tag{2}$$

$$\frac{1}{C_{Da}} = \frac{1}{C_D} + \frac{C_{\phi D}}{\tau_D} \tag{3}$$

where C_ϕ is the maximum pressure change resulting from phase redistribution effects. The dimensionless time τ_D is defined by:

$$\tau_D = \frac{0.0002637k\tau}{\phi\mu c_t r_w^2} \tag{4}$$

where τ is the time at which 63% of the maximum pressure change resulting from phase redistribution occurs.

Thompson et al. (1986) used Fair's (1981) model to study the various variables affecting the buildup pressure response under the influence of phase segregation. Having conducted extensive computer investigations, they classified the phase redistribution effects into three distinct types according to certain specific criteria. Three simulated cases are presented in the following sections to illustrate the impact of the various types on the conventional pressure buildup curves.

2.1. Type 1 phase redistribution effects

Type 1 has the most adverse impact on the buildup test. It is characterized by the presence of a relatively large pressure hump. For this type to exist, the following three conditions must be simultaneously satisfied (Thompson et al., 1986):

$$s \leq \frac{C_{\phi D}}{3} \tag{5}$$

$$C_{\phi D} \geq 10 \tag{6}$$

and

$$C_{Da} \leq \frac{C_D}{5} \tag{7}$$

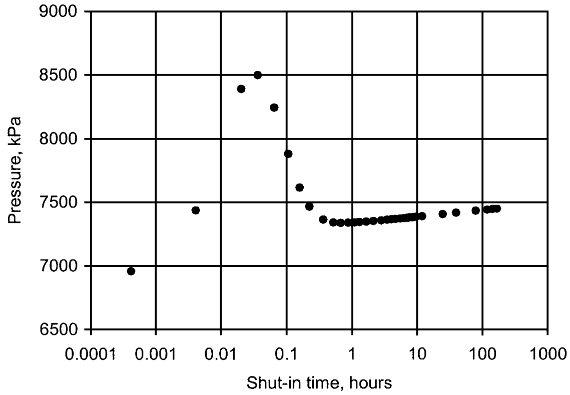

Fig. 2. MDH plot: simulated case no. 1—pressure response type 1.

Thompson et al. (1986) stated that if any of the three conditions above are violated even slightly, a small pressure hump may still appear; however, if any one of the three conditions does not hold, phase redistribution effects will be of either type 2 or 3.

Fig. 2 displays the effects of this type on the conventional Miller–Dyes–Hutchinson (MDH) plot. The pressure hump caused by phase redistribution is quite pronounced. Most of the methods presented in the literature are able to recognize the pressure response caused by this type.

Fig. 3 is a conventional pressure derivative plot. Olarewaju and Lee (1989a) stated that phase redistribution effects should be reflected on the pressure derivative curve as a downward V-shaped depression. This statement is quite justified in this case as shown in the figure. The same can be said about the method

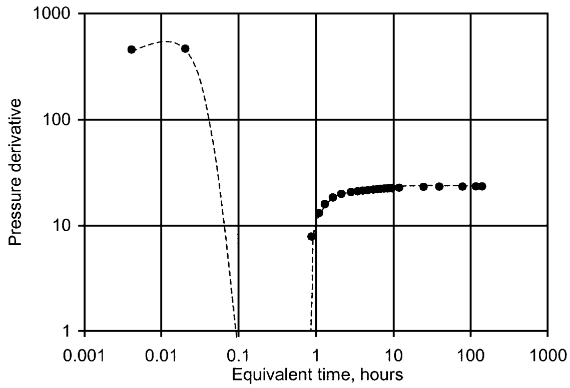

Fig. 3. Pressure derivative plot: simulated case no. 1—pressure response type 1.

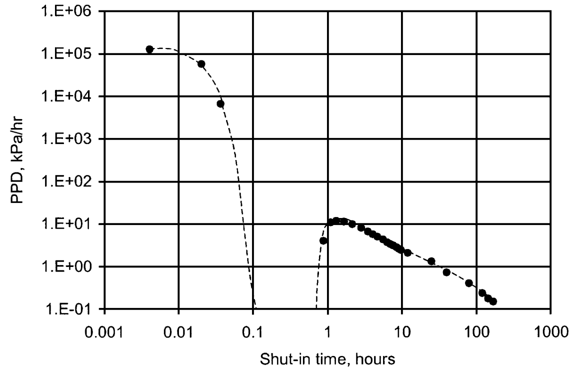

Fig. 4. PPD plot: simulated case no. 1—pressure response type 1.

proposed by Mattar and Zaoral (1992) who mentioned that the PPD plot should divert from a decreasing to an increasing trend for the entire duration of the phase segregation effects, then it should return to the normal decreasing behavior. This statement is also proven to be correct in Fig. 4.

2.2. Type 2 phase redistribution effects

This type of phase redistribution effects exists if either of the following two sets of conditions holds. The first condition is given by (Thompson et al., 1986):

$$C_{\phi \mathrm{D}} \leq s \leq 5C_{\phi \mathrm{D}} \tag{8}$$

and

$$C_{\mathrm{Da}} \leq \frac{C_{\mathrm{D}}}{5} \tag{9}$$

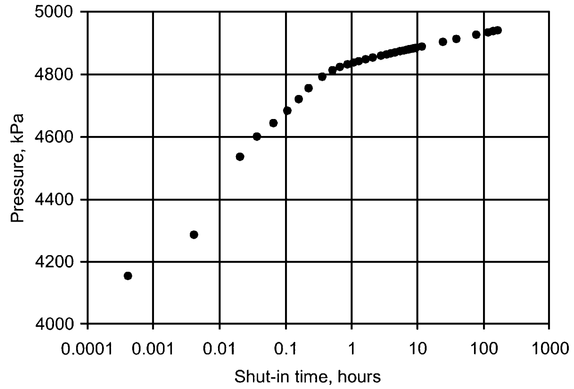

Fig. 5. MDH plot: simulated case no. 2—pressure response type 2.

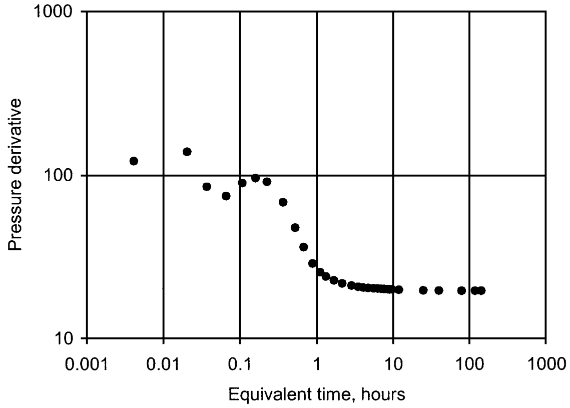

Fig. 6. Pressure derivative plot: simulated case no. 2—pressure response type 2.

whereas the second condition is given by (Thompson et al., 1986):

$$C_{\phi D} \leq 5 \tag{10}$$

$$C_D \geq 10^4 \tag{11}$$

and

$$C_{Da} \leq \frac{C_D}{5} \tag{12}$$

Fig. 5 illustrates the MDH plot of data dominated by type 2 phase redistribution effects. This figure does not show any sign of pressure hump indicating phase segregation behavior. Therefore, the presence of the hump on the pressure curve is not a sufficient condition for the confirmation of the existence of phase redistribution effects. This type of pressure response requires further data processing before making the final judgment whether phase redistribution effects exist or not.

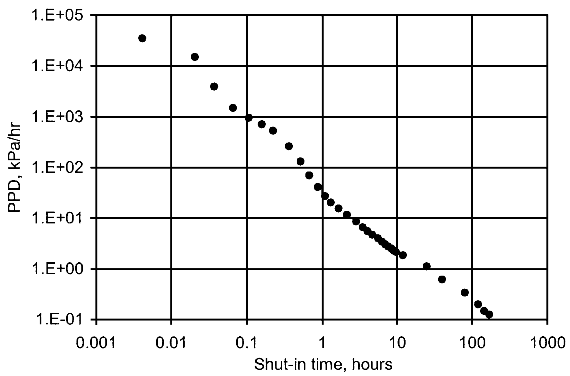

Fig. 7. PPD plot: simulated case no. 2—pressure response type 2.

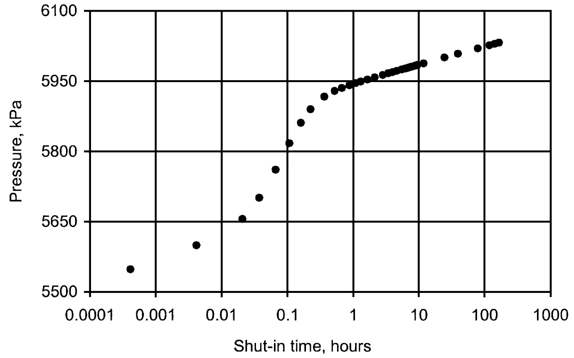

Fig. 8. MDH plot: simulated case no. 3—pressure response type 3.

Fig. 6 is a pressure derivative plot of the data. The downward V-shaped curvature displayed in the figure proves the presence of either phase redistribution effects, or dual-porosity system, as suggested by Olarewaju et al. (1989). However, the V-shaped depression is not as clear as the one illustrated in Fig. 3 for type 1 phase segregation effects.

Fig. 7 is the PPD plot of Mattar and Zaoral (1992). Although the curve displays few deflections, all the PPD values are continuously decreasing, indicating that phase redistribution does not affect the data. Hence, this method does not detect the pressure buildup data influenced by type 2 phase segregation effects.

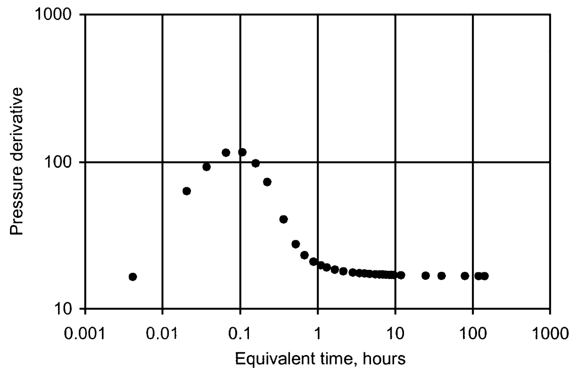

Fig. 9. Pressure derivative plot: simulated case no. 3—pressure response type 3.

2.3. Type 3 phase redistribution effects

This type is the least severe. The hump is often invisible on the pressure plot. Whenever the conditions of type 1 given by Eqs. (5)–(7), or those of type 2 given by either Eqs. (8) and (9) or Eqs. (10)–(12), are not satisfied, phase redistribution effects can be classified as type 3 (Thompson et al., 1986).

Fig. 8 illustrates the MDH plot for type 3 data. Again, as it was the case with type 2 effects, no sign of phase redistribution is shown in the figure. Fig. 9 is the conventional pressure derivative graph. This figure displays a smooth bell-shaped curvature indicating wellbore storage distortion immediately followed by a horizontal line implying radial flow behavior. No sign of downward V-shaped curvature is observed meaning the absence of any phase redistribution effects. Therefore, Olarewaju and Lee (1989a) pressure derivative technique fails to detect type 3 phase segregation effects.

Fig. 10 shows the PPD plot; again, as was the case with type 2 effects, the method proposed by Mattar and Zaoral (1992) does not exhibit any increase in the PPD values that confirms the presence of phase redistribution. Therefore, this method also fails to recognize type 3 phase segregation effects.

Hence, it is useful to provide an eminent technique that sets a clear foundation for the detection of all types of phase redistribution especially the minute effects that could not be recognized with other methods. The proposed method is intended to do just that.

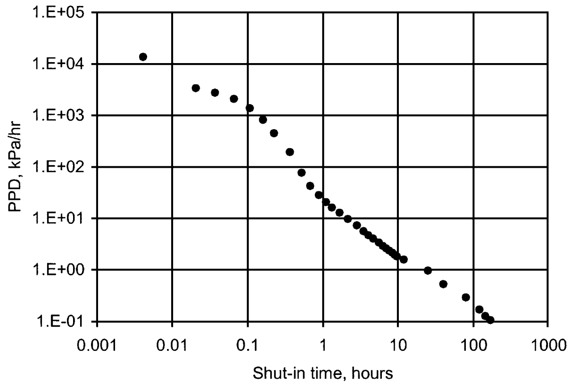

Fig. 10. PPD plot: simulated case no. 3—pressure response type 3.

3. Mathematical development

The new technique can be derived from either Horner or MDH pressure buildup equations. Horner's equation will be used in this section, whereas the MDH equation will be discussed in Appendix A.

Horner's pressure buildup equation is given as (Horner, 1951):

$$p_{\mathrm{ws}} = p_{\mathrm{i}} - \frac{162.6qB\mu}{kh}\log\left(\frac{t_{\mathrm{p}}+\Delta t}{\Delta t}\right) \tag{13}$$

The PPD proposed by Mattar and Zaoral (1992) is obtained by simple differentiation of Eq. (13) with respect to shut-in time Δt as follows:

$$\mathrm{PPD} = \frac{\mathrm{d}p_{\mathrm{ws}}}{\mathrm{d}\Delta t} = \frac{\mathrm{constant}}{\Delta t(t_{\mathrm{p}}+\Delta t)} \tag{14}$$

where the constant in Eq. (14) is defined by:

$$\mathrm{constant} = \frac{162.6qB\mu}{kh}\left(\frac{t_{\mathrm{p}}}{2.303}\right) \tag{15}$$

It is obvious from Eq. (14) that PPD defines a continuously decreasing function. Mattar and Zaoral (1992) stated that if the wellbore dynamics affect the pressure buildup data, the PPD plot should exhibit an increasing trend during the wellbore effects then it reverts back to the normal decreasing trend at the end of these effects. This behavior was clearly illustrated in Fig. 4; however, it was also shown that if the buildup data are influenced by phase redistribution pressure response of either type 2 or 3, the PPD plots do not exhibit any sign of increasing trend (Figs. 7 and 10), which contradicts Mattar and Zaoral's observations.

Taking the logarithm base 10 of both sides of Eq. (14) yields:

$$\log(\mathrm{PPD}) = \log(\mathrm{constant}) - \log[\Delta t(t_{\mathrm{p}}+\Delta t)] \tag{16}$$

Eq. (16) can be written as:

$$\log(\mathrm{PPD}) = \log(\mathrm{constant}) - \log(\Delta t) - \log(t_{\mathrm{p}}+\Delta t) \tag{17}$$

Differentiating Eq. (17) with respect to $\log(\Delta t)$ yields:

$$\frac{\mathrm{dlog(PPD)}}{\mathrm{dlog}(\Delta t)} = -1 - \frac{\Delta t}{t_{\mathrm{p}}+\Delta t} \tag{18}$$

If $t_p \gg \Delta t$, the second term on the right-hand side of Eq. (18) can be neglected. Thus, Eq. (18) can be written in absolute value as:

$$\left|\frac{\mathrm{dlog(PPD)}}{\mathrm{dlog}(\Delta t)}\right| \cong 1 \tag{19}$$

Let:

$$\mathrm{SLPD} = \left|\frac{\mathrm{dlog(PPD)}}{\mathrm{dlog}(\Delta t)}\right| \cong 1 \tag{20}$$

SLPD will be called Secondary Logarithmic Pressure Derivative.

Eq. (20) implies that the data points that lie on a horizontal line at SLPD = 1 on the SLPD versus Δt curve, should lie on the semilog straight line on the conventional pressure buildup plot. These data points are free of any wellbore effects. In other words, the beginning of the SLPD horizontal straight line indicates the start of the true semilog straight line. It is important to mention that the buildup test has to achieve radial flow conditions for the proposed technique to be applicable. Even though the unit slope line of the PPD plot of Mattar and Zaoral (1992) can also be used to predict the beginning of the radial flow regime, the SLPD technique offers an extra advantage over the PPD method in the sense that it detects the presence of all types of phase redistribution effects whereas the PPD plot fails to detect types 2 and 3 effects as it has been illustrated in simulated cases 2 and 3 (Figs. 7 and 10).

4. Applications

Three simulated cases and two field examples are employed to illustrate the applicability of the proposed methods.

4.1. Simulated cases

These are the same simulated cases that were previously used to illustrate the effects of various types of phase redistribution on the MDH plots (Figs. 2, 5 and 8) and to test the reliability of Olarewaju et al. (1989) (Figs. 3, 6 and 9) and Mattar and Zaoral (1992) (Figs. 4, 7 and 10) methods.

A visual inspection of Fig. 2 may tempt the well test analyst to draw the semilog straight line starting at 1 h; however, this case is not as simple as it may seem. Lee et al. (in press) could not find a good match of this data with any of the Bourdet (1983) type curves. The objective of this paper is not only to detect the presence of phase redistribution but also to determine the end of these effects and to specify the beginning of the semilog straight line, t_{sl}, on the conventional pressure plots. Fig. 11 illustrates the SLPD curve for this case. This figure implies that the phase segregation effects die out as the SLPD values approach 1. At the same time, the semilog straight line starts once the SLPD values stabilize at 1. For this case, t_{sl} corresponds to 13 h into the buildup test. Obviously, there is a big difference between 1 h obtained from visual inspection of the MDH plot (Fig. 2) and 13 h obtained from the SLPD plot (Fig. 11).

The MDH plots of simulated cases 2 and 3 are shown in Figs. 5 and 8, respectively. Although the two figures do not display any sign of phase segregation effects, the SLPD plots of these cases, displayed in Figs. 12 and 13, respectively, clearly specify the portion of the data affected by wellbore dynamics. The SLPD curves indicate that the semilog straight line starts at 5.64 and 6.97 h for cases 2 and 3, respectively. It is worthy to note that neither Olarewaju et al. (1989) nor Mattar and Zaoral (1992) methods were able to detect type 3 effects. However, Fig. 13 of the proposed technique does not leave any doubt about either the presence or the end of these

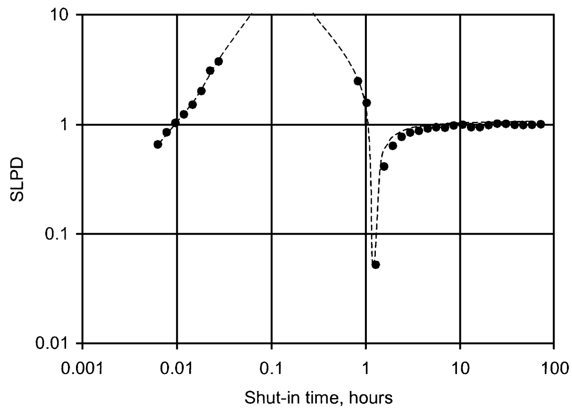

Fig. 11. SLPD plot: simulated case no. 1—pressure response type 1.

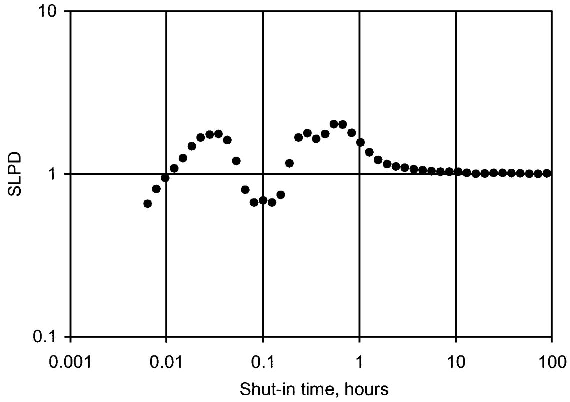

Fig. 12. SLPD plot: simulated case no. 2—pressure response type 2.

Table 1
Results of the simulated cases

Case study	Pressure response type	Input parameters		Results		
		k (md)	s	t_{sl} (h)	k (md)	s
Simulated case no. 1	1	50	3.3	13	50.05	3.31
Simulated case no. 2	2	60	12	5.64	59.30	12.04
Simulated case no. 3	3	70	7	6.97	69.32	6.86

effects. A comparison of the results of all simulated cases is presented in Table 1. MDH analysis and t_{sl} values obtained from the SLPD plots were used to determine the reservoir parameters. As can be noticed from Table 1, the calculated values of the formation permeability and skin factor of all cases fall within 1.16% and 2%, respectively, from the parameters used in the simulator.

4.2. Field example 1

This case is Rushing and Lee (1989) field example No. 2. This is an oil well located in south Louisiana. The well was producing at a low production rate of 13.5 Sm^3/D (85 STB/D) before it was shut in at the surface for 46 h to conduct a pressure buildup test. A detailed description of the reservoir, well and fluid properties as well as the recorded test data can be found in the Rushing and Lee paper. The pressure versus time data were displayed in Fig. 1 (MDH plot) to illustrate the influence of phase redistribution on the conventional buildup curves. The pressure hump implies that the buildup data were, for some time, dominated by phase segregation effects. The pressure drop plot shown in Fig. 14 is similar to the one developed by Agarwal et al. (1970a,b) for wellbore storage and skin solution except for an almost invisible hump at about 2 h of equivalent time. The pressure derivative type curve, also shown in Fig. 14, displays the V-shaped curvature characteristic of either phase redistribution effects or dual porosity system as suggested by Olarewaju et al. (1989).

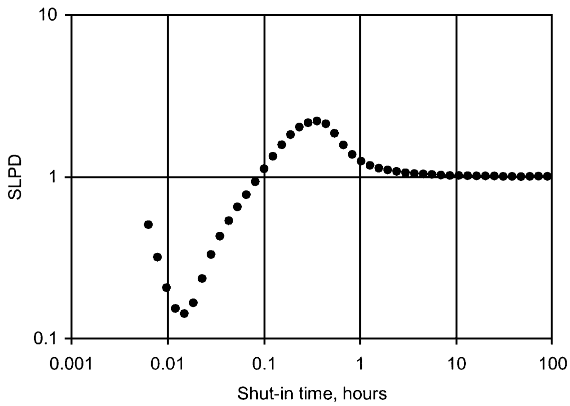

Fig. 13. SLPD plot: simulated case no. 3—pressure response type 3.

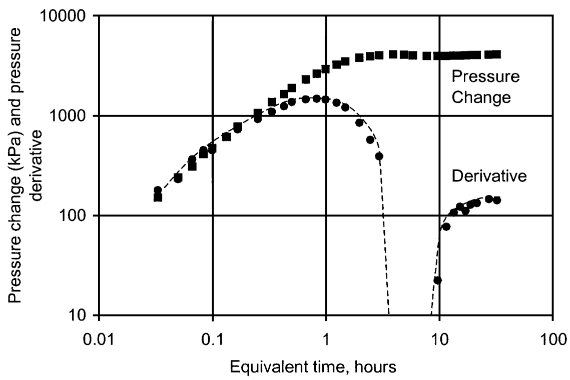

Fig. 14. Pressure drop and pressure derivative graphs: field example no. 1.

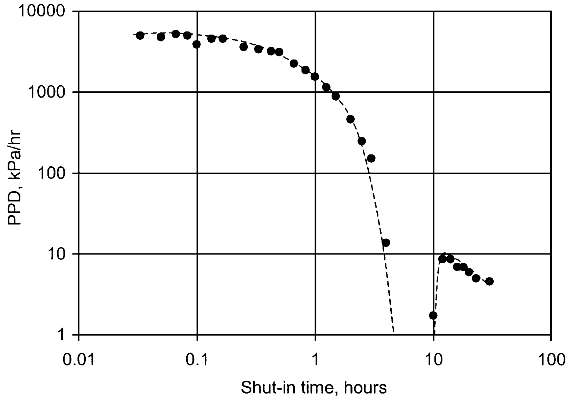

Fig. 15. PPD plot: field example no. 1.

Therefore, another diagnostic tool has to be applied to confirm the presence of phase redistribution. Fig. 15 is the PPD plot for this example. The figure clearly shows increasing values of the PPD at about 10 h of buildup, assuring that the data is affected by wellbore effects. However, it does not clearly indicate the exact time when these effects diminish. Hence, the SLPD plot is very important in this regard. The SLPD graph is illustrated in Fig. 16. Note the similarity between this figure and the pressure response type 3 shown in Fig. 13. After 12 h of buildup, the SLPD values approach 1. This time was used as the beginning of the semilog straight line for the MDH analysis. Rushing and Lee (1989) used two kinds of type curve matching techniques to analyze this example. First, they applied the manual type curve matching suggested by Fair

Table 2
Comparison of results: field example 1

Analysis method	k (md)	s
Manual type curve matching 1	12.3	0
Manual type curve matching 2	49.4	20
Manual type curve matching 3	83.7	40
Automatic history matching	24.7	5.6
SLPD method	27.8	7.1

(1981) then they employed their own technique called automatic history matching. A comparison of the results obtained from the MDH analysis using 12 h as the start of the semilog straight line with the results obtained by Rushing and Lee is presented in Table 2. The discrepancy of the manual type curve matching results reported in the table reveals the nonunique problems associated with manual multi-parameter type curve analyses especially when not all the required parameters are known. The comparison shows that the results obtained using the simple SLPD technique are in good agreement with those determined by the complicated automatic history matching of Rushing and Lee.

4.3. Field example 2

This field example was reported by Baghdarvazehi et al. (1993) as field example No. 1. A 6 h pressure buildup test was conducted on an oil well producing from high-permeability sandstone formation. The res-

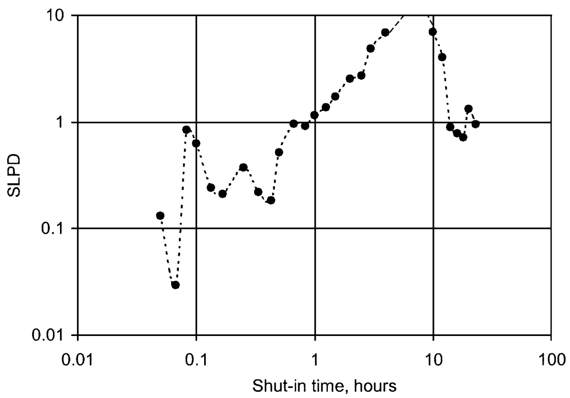

Fig. 16. SLPD plot: field example no. 1.

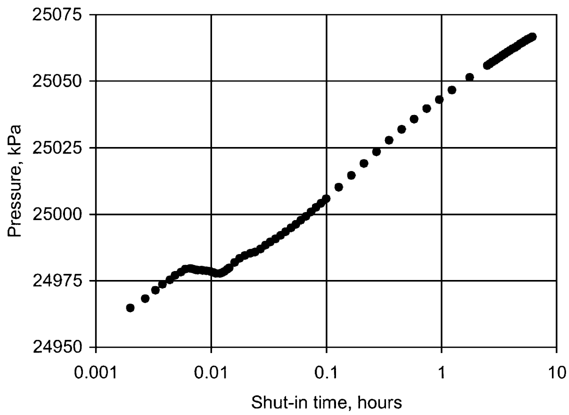

Fig. 17. MDH plot: field example no. 2.

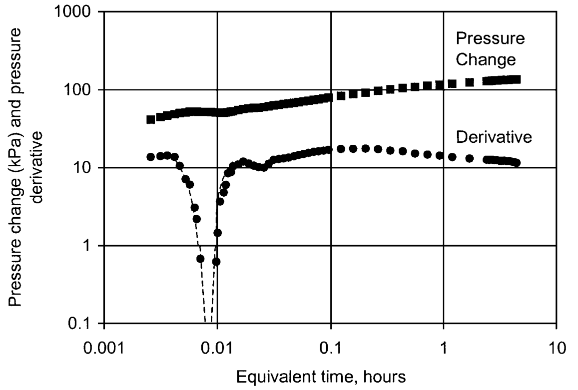

Fig. 18. Pressure drop and pressure derivative graphs: field example no. 2.

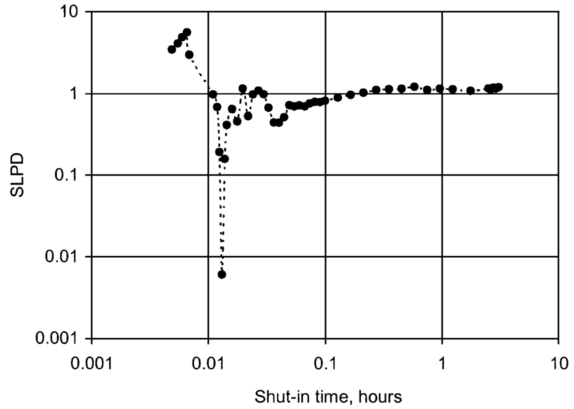

Fig. 20. SLPD plot: field example no. 2.

ervoir, fluid and test data are documented by Baghdarvazehi et al. (1993). Fig. 17 illustrates the MDH analysis plot of the recorded data. The small pressure hump displayed in the figure indicates that the well test data were under the influence of phase redistribution effects. The pressure drop curve shown in Fig. 18 reveals a minor deflection trend at early testing time whereas the pressure derivative plot displays the familiar V-shaped curvature. As with field example No. 1, the pressure derivative graph does not give a conclusive evidence of whether the V-shaped behavior is due to phase segregation effects or to dual-porosity system. The PPD plot (Fig. 19) is used to confirm which one of the two effects actually influences the well test data. Fig. 19 shows that the PPD values decrease to about − 398 kPa/h then sharply increase to about 954 kPa/h, indicating that the buildup data is clearly dominated by wellbore phase redistribution effects. The SLPD plot (Fig. 20) also confirms this conclusion. Having assured the presence of phase segregation, the final step is to determine the end of these effects and the beginning of radial flow behavior. Fig. 20 is used for this purpose. The SLPD values approach 1 at about 0.09 h of buildup. This time can be considered as the actual starting time of the semilog straight line for conventional analysis. The results of this field example are reported in Table 3. It can be seen that the proposed method is able to deliver competitive results without resorting to inconvenient nonlinear optimization or history matching procedures that may yield inaccurate parameter estimation.

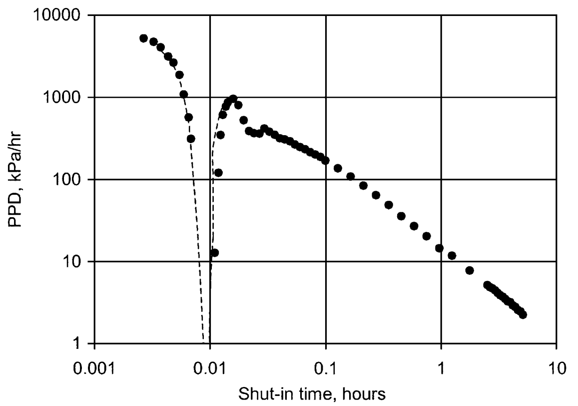

Fig. 19. PPD plot: field example no. 2.

Table 3
Comparison of results: field example 2

Analysis method	k (md)	s
Nonlinear optimization	2458.7	− 4.5
SLPD method	2703.0	− 4.9

5. Conclusions

Several important conclusions summarize this study:

(1) A method is presented to predict the wellbore phase redistribution effects. Neither manual nor automatic type curve matching is required. Furthermore, the technique does not use complicated nonlinear optimization or history matching as some other methods require.

(2) The proposed SLPD technique is able to detect the presence of any type of phase redistribution pressure response especially the minor effects of types 2 and 3 while other methods fail to do so.

(3) The SLPD method can also predict the end of any wellbore effects and the actual beginning of the semilog straight line. This greatly enhances the conventional analyses and results in more accurate estimation of the reservoir parameters.

(4) The applicability and accuracy of the proposed method were demonstrated through the analysis of three simulated cases and two field examples.

Nomenclature

B	formation volume factor (m^3/Sm^3)
c_t	total system compressibility (kPa^{-1})
C	wellbore storage coefficient (m^3/kPa)
C_D	dimensionless wellbore storage coefficient
C_{Da}	dimensionless apparent wellbore storage coefficient
C_ϕ	maximum pressure change resulting from phase redistribution effects (kPa)
$C_{\phi D}$	dimensionless maximum pressure change caused by phase redistribution effects
h	net pay zone thickness (m)
k	formation permeability (md)
MDH	Miller–Dyes–Hutchinson
p_i	initial reservoir pressure (kPa)
p_{wf}	wellbore flowing pressure (kPa)
p_{ws}	shut-in pressure (kPa)
PPD	Primary Pressure Derivative (kPa/h)
PPD1	Primary Pressure Derivative of MDH equation (kPa/h)
q	flow rate (Sm^3/D)
r_w	wellbore radius (cm)
s	skin factor
SLPD	Secondary Logarithmic Pressure Derivative
t_p	Horner production time (h)
t_{sl}	beginning of the semilog straight line (h)
Δt	shut-in time (h)

Greek symbols

λ	inter-porosity transfer coefficient
μ	viscosity (mPa s)
τ	time at which 63% of the maximum pressure change resulting from phase redistribution occurs (h)
τ_D	dimensionless time defined by Eq. (4)
ϕ	formation porosity, fraction

Subscripts

D	dimensionless
Da	dimensionless apparent
i	initial
t	total
p	production
sl	semilog straight line
w	well
wf	well flowing
ws	well shut in/

Acknowledgements

The authors express their appreciation to Kuwait University Research Administration for financially supporting this work through a university research grant (EP 05/00).

Appendix A

The Miller–Dyes–Hutchinson (MDH) equation for pressure buildup test can be written as (Miller et al., 1950):

$$p_{ws} = p_i - \frac{162.6qB\mu}{kh}[\log(t_p) - \log(\Delta t)] \qquad (A-1)$$

differentiating Eq. (A-1) with respect to Δt yields:

$$\frac{dp_{ws}}{d\Delta t} = \frac{162.6qB\mu}{kh}\left(\frac{1}{2.303\Delta t}\right) \qquad (A-2)$$

let:

$$\mathrm{PPD1} = \frac{162.6qB\mu}{kh}\left(\frac{1}{2.303\Delta t}\right) \qquad (A-3)$$

taking the logarithm base 10 of both sides of Eq. (A-3) yields:

$$\log(\mathrm{PPD1}) = \log\left(\frac{162.6qB\mu}{kh}\right) - \log(2.303) - \log(\Delta t) \qquad (\mathrm{A}-4)$$

differentiating Eq. (A-4) with respect to log(Δt) yields:

$$\frac{\mathrm{dlog}(\mathrm{PPD1})}{\mathrm{dlog}(\Delta t)} = -1 \qquad (\mathrm{A}-5)$$

let:

$$\mathrm{SLPD} = \left|\frac{\mathrm{dlog}(\mathrm{PPD1})}{\mathrm{dlog}(\Delta t)}\right| = 1 \qquad (\mathrm{A}-6)$$

Eq. (A-6) is similar to Eq. (20) in the main text.

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