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DISTORTED PRESSURE-BUILDUP TESTS BY PHASE REDISTRIBUTION – CHANGING WELLBORE STORAGE EFFECTS

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ABSTRACT: Reliable data about in-situ reservoir measurements is significant in many phases of petroleum reservoir engineering. The reservoir engineer must have sufficient data and information about the reservoir to effectively analyze reservoir performance and forecast future production under various means of operation. The production engineer must know the condition of production and injection wells to choose the best possible performance from the reservoir. Much of that information can be obtained from pressure transient tests. Analysis of pressure transient data is normally done by analytical solution and modern simulation programs. Several programs are available for performing well testing analysis. In this paper, Saphir software is used along with the normal analytical models to develop and analysis the pressure build up data in a different way in order to detect and investigate the effect of wellbore phase redistribution in the test. This work is mainly performed to investigate and detect the wellbore phase redistribution (WPR) and explain the different phases and types qualitatively and quantitatively using 6 pressure transient tests, one of them is Egyptian case. The average reservoir permeability of the tested well is ranging from 9.91 md to 497 md, and the reservoir pressure covers a range from 237 psi to about 5000 psia. It presents analysis of pressure buildup, fall of tests, and DST taken from the oil field. In addition, it describes the effect of the wellbore two phase segregation of the pressure derivative curves while performing pressure buildup tests. Moreover, this work may leads to a method for eliminating or reducing wellbore phase redistribution in pressure transient tests especially in high GOR reservoir and tight oil reservoirs. It helps to better understanding the variable wellbore storage and phase redistribution mechanisms involved in the pressure buildup tests and improved physical understanding of the phase segregation process and it influences pressure buildup data. Such level of understanding is critical to our success of developing new models or approaches in order to handle field tests both from design and interpretation point of views.

Keywords: Wellbore Storage (WBS), Phase Redistribution, WPR, PTA, Pressure Transient.

1. INTRODUCTION: Pressure transient tests, such as pressure buildup, drawdown, injectivity, falloff, step rate test, interference, and pulse test are very significant for both production engineering and reservoir engineering. Therefore, it is important to analysis all of these test correctly to get the best estimate of most of the reservoir permeability such as reservoir permeability, skin factor and average reservoir pressure in the drainage areas.

It is well know that [1, 2], the pressure transient testing includes creating and measuring pressure variations with time in certain well and subsequently, calculating rock, fluid, and well properties. Among these properties, reservoir effective oil permeability (K_{eo}), average reservoir pressure (P_R), total skin factor (S), reservoir heterogeneity, fault detecting, fault distance, porosity, and it could be also used to calculate the reserve (pore volume of the reservoir). All this information can be used to help analyze, improve and predict reservoir performance.

Defining average reservoir pressure, P_R, is very significant in describing and characterizing an oil and gas reservoirs. It is essential in calculating original oil in place (OOIP) or water influx from material balance equation (MBE), knowing the pressure distribution for the recognition of fluid movement and in predicting future reservoir performance in primary, secondary, and tertiary recovery projects.

2. PHASE REDISTRIBUTION:

2.1. PHASE REDISTRIBUTION OVERVIEW: In pressure build up tests, after shutting in the well from the surface, the fluids (gas and/or liquid) in the tubing segregate and separate. These phases will be redistributed based on the gravity, the gas moves up while the liquid phase going down to the bottom of the tubing. This phenomenon, called phase redistribution in which the different phases redistributes in the vertical tubing while and immediately after standing condition. The effects of phase redistribution during a buildup test cause the wellbore- pressure response to depart from its anticipated manners, thus confusing the analysis of the test data.

The wellbore phase redistribution phenomenon described and presented mathematically by so many investigators [(1), (2), (3)]. Phase redistribution is one form of a more general phenomenon of *changing well bore storage*. Other examples include increasing well bore storage resulting from changing gas compressibility in a gas well with a large drawdown before shut-in, and a step increase or decrease in well bore storage.

2.2. DESCRIPTION OF PHASE REDISTRIBUTION: The wellbore phase redistribution (WPR) phenomenon could happen through closing a well with multiphase flow of gas and liquid while performing pressure buildup test. Gravity forces cause the free-gas phase to rise through the liquid column and the liquid phase to move down. The gas bubbles near the bottom of the tubing are at a pressure comparable with formation pressure. As the bubbles growth to the surface after shut-in, they cannot expand if the well bore is in poor communication with the pay zone. Thus, a high-pressure gas column develops at the top of the tubing and a column of liquid develops below that gas. Under these conditions, the total pressure at the sandface is equal the pressure formed due to gas column plus that created by the liquid column below that gas (1).

The far odd example for this case, is that the bottornhole pressure (BHP) for the moment go above formation pressure and oil in the wellbore moves again into the formation until balance is got and BHP drops to formation pressure. Such behavior causes crating a hump in the BHP response during a buildup. At early times during the test, the pressure increase will be abnormally large, confounding and complicating the determination of reservoir permeability, skin effect, and wellbore storage term [(2), (3), (4)].

In 1958, Stegemeier and Matthews (2) mentioned that the gas hump occurs while performing a pressure build up in an oil reservoir having permeability ranges from 10 to 100 md or a gas reservoir having permeability varies from 0.1 to 1 md and high positive skin factor. Moreover, they stated that the wells without packers tend to have smaller hump than that with packers. As a results, they plotted a relationship between the sizes of the produced pressure humps in about 75% of their tests (a field south Texas) versus their reservoir productivity index (PI). It is found that that hump size is very high in a low PI reservoir and decreases as the PI increases.

In some cases, the hump does not appear in case of low permeability formations. The reason for that may attributed to higher reservoir pressure than that of fluid column in the tubing. While in case of high permeability reservoirs, the fluid can return to the formation fast to avoid a major increase in BHP resulting from growing gas bubbles up.

2.3. PHASE-REDISTRIBUTION MODELS: In 1981, Fair (3) developed a mathematical model for describing the phase red-distribution while performing pressure buildup test. He modified the WBS equation by adding term describing the pressure change caused by phase redistribution ($dP_{\phi D} \ dt_D$). Therefore, he derived a new term call pseudowellbore storage coefficient (C_{eD}) by the following equation:

$$C_{eD} = C_D \ \ 1 - \frac{dP_{\phi D}}{dt_D} / \frac{dP_{wD}}{dt_D} \qquad \text{--1}$$

Where $P_{\phi D}$ is the dimensionless phase-redistribution pressure, it is calculated by the exponential function given by:

$$P_{\phi D} = \ C_{\phi D} \ \ 1 - e^{-t_D/\alpha_D} \quad \text{--2}$$

Where $C_{\phi D}$ is the maximum dimensionless phase-redistribution pressure change defined by

$$C_{\phi D} = \ \frac{khC_\phi}{141.2qB\mu} \text{--3}$$

The term α_D is the dimensionless time at which 63.2% of this maximum pressure change occurs and is defined by:

$$\alpha_D = \frac{0.0002637k\alpha}{\phi\mu C_t r_w^2} \text{--4}$$

It is noted that Fair's model is stable with his limited laboratory data only, therefore, it may not model all field conditions accurately.

Lee et al. (2003) (1) suggested a new form of the apparent wellbore-storage coefficient, $C\alpha v$, as

$$\frac{1}{C_{aD}} = \frac{1}{C_D} + \frac{C_{\phi D}}{\alpha_D} \text{---5}$$

They stated at early times, if phase-redistribution effects are negligible ($C_{\phi D} = 0$), the pressure behavior represents true wellbore storage ($C_{aD} = C_D$). If phase redistribution affects the pressure response ($C_{\phi D} > 0$), the apparent wellbore-storage coefficient is less than the true wellbore-storage coefficient ($C_{aD} < C_D$). This effect appears as a deviation of the early-time data from the theoretical unit slope line. The dimensional apparent wellbore-storage coefficient, C_a, is found with any point (Δt_e, Δp) on the unit-slope line or its extrapolation,

$$C_a = \frac{qB}{24} \frac{\Delta t_e}{\Delta p}_{USL} \text{--6}$$

And the dimensionless apparent wellbore-storage coefficient, C_{aD}, is calculated by

$$C_{aD} = \frac{0.0372qB}{\phi h C_t r_w^2} \frac{\Delta t_e}{\Delta p}_{USL} \text{--7}$$

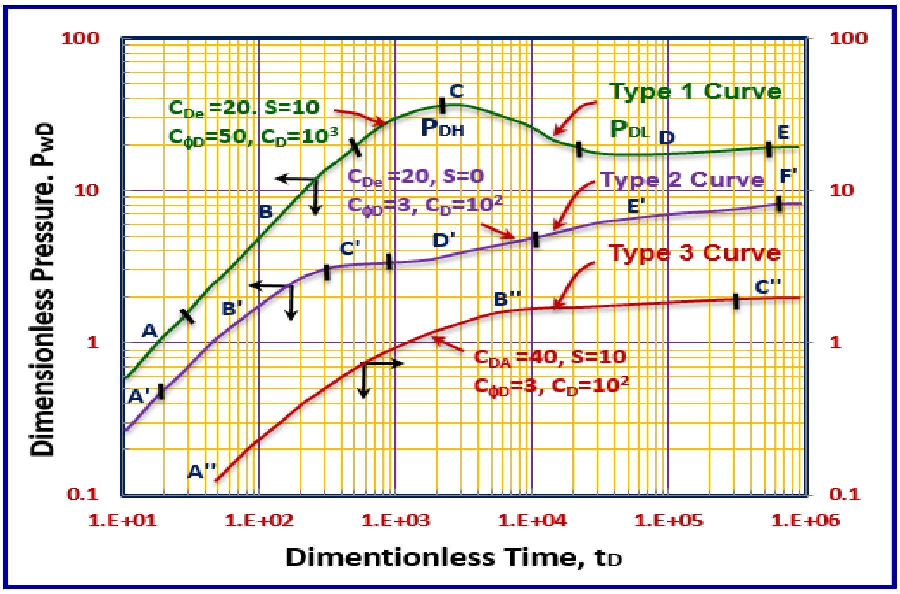

Fig. I: Types of pressure responses resulting from phase redistribution (5).

Thompson et al. (1986) (5) categorized the effect of phase redistribution in a buildup test into three Types (I, II, and III) as shown in Figure I. Type I, denotes the utmost degree of phase redistribution as wellbore pressure rises above formation pressure and pushes crude oil from the wellbore back into the formation. The Type 2 curve represents a smaller degree of phase redistribution than the Type 1 curve. While, Type 3 curve displays the smallest effects of phase redistribution on the pressure response. The curve has a shape similar to those of the well bore storage and skin solutions with no phase-redistribution effects as mentioned by Agarwal et al. (1970) (6). Thompson et al. (5) described each of these three curve Types region by region, starting from region A in the left side of each curve to region F in the right hand side of the curve.

In 1993, Hasan-Kabir (7) presented a primitive mechanistic model for understanding the main causes for phase redistribution. A simple physical model, consisting of a liquid column and a small pocket of segregated gas at the top, is assumed to mimic a wellbore. The physical model cannot receive any fluid from the reservoir upon shut-in; however, backflow from the wellbore into the reservoir is allowed to release excess pressure, created by a rising bubble. A mathematical model is established for the idealized well by studying the rise velocity of a single bubble in the liquid column. Interestingly enough, a simplified analytical solution leads to an exponential form to describe the excess pressure behavior, caused by a single-bubble rise, as hypothesized by Fair (3).

Baghdarvazehi et al. (8) (1993) presented an analytical solutions and type curves for the constant rate radial flow of fluid in both conventional and naturally fractured reservoirs including the effect of wellbore phase redistribution. They developed an automated procedure for non-linear least square minimization using the analytical solution and their derivatives with respect to the unknown parameters to analyze the pressure build up data affected by phase redistribution. Field examples and analysis are also presented.

Hageman et al. (9) (1993) introduced two additional dimensionless wellbore constants, apparent storage (C_{aD}) and the pressure parameter ($C_{\phi D}$). Hegeman et al. (9) revealed that the negative $C_{\phi D}$ values in the Fair model can be used for buildup data that has an unusual pressure reduction. Therefore, for these wells, they said that using an error function to model the anomalous pressure may permit for better modeling of field data with increasing or decreasing storage. Thus, Hegeman et al. (9) suggested that:

$P_{\phi D} = C_{\phi D} erf\ t_D\ \ \alpha_D$ --8

However, it has been found in practice that the models of Fair and Hegeman et al. are not substantially different. The following plots illustrate the effects of the three dimensionless storage parameters on the dimensionless type curves.

As stated before, Fair's model (with $C_D > C_{aD}$ and $C_{\phi D} > 0$) makes an exponential increase in wellbore storage. Figure II-a shows sample type curves for increasing storage. In the course of this study, we found that setting $C_D < C_{aD}$ and $C_{\phi D} < 0$ created an exponential decrease in wellbore storage. Figure II-b shows a set of curves for decreasing well bore storage.

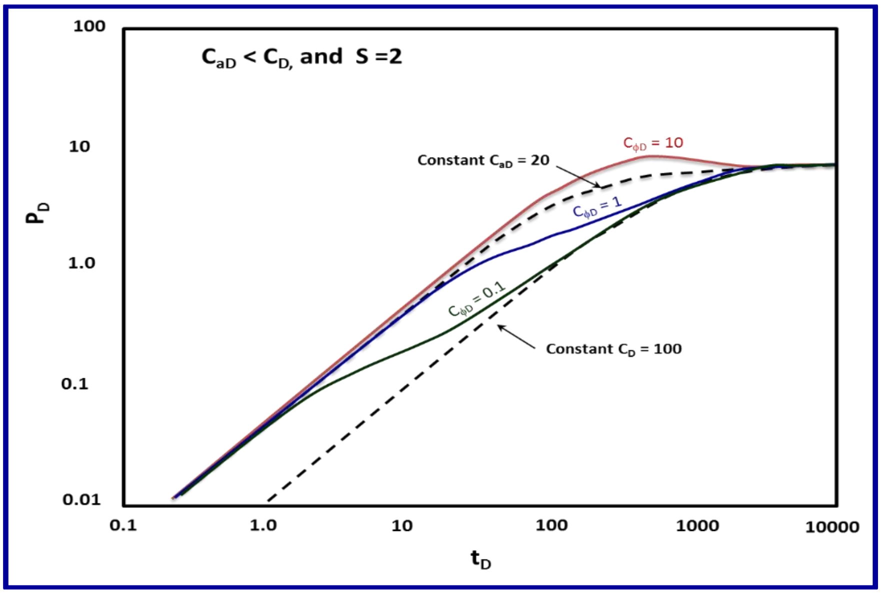

Fig. II-a. Storage increase [Initial C_{aD} = 20 and final C_D = 100]

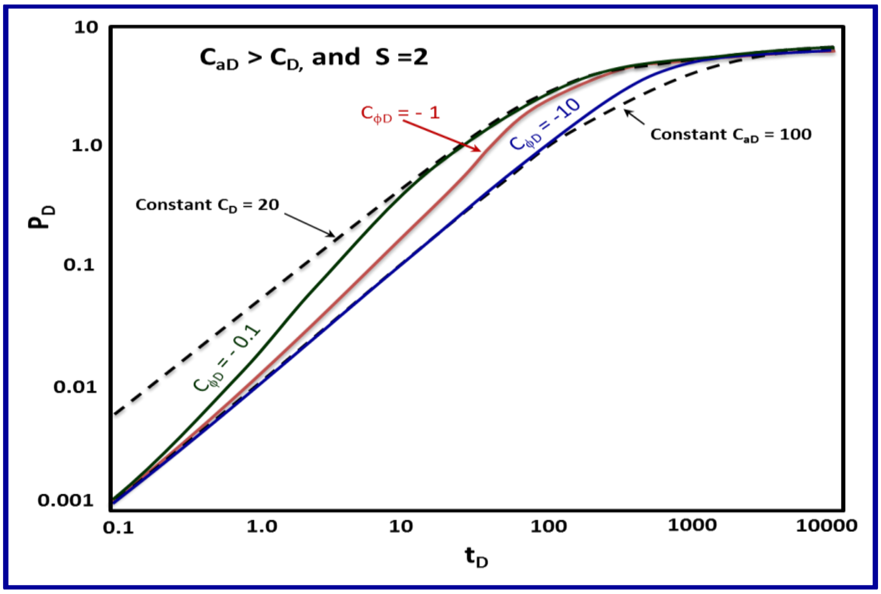

Fig. II-b. Storage decrease [Initial C_{aD} = 100 and final C_D = 20]

Fig. II: The effects of the three dimensionless storage parameters on the dimensionless type curves after Hegeman et al. (9)

In 1996, Xiao et al. (10) developed of a simple mechanistic model to simulate the wellbore phase redistribution (WPR) and predict the effects that the transient two-phase flow of oil and gas have on pressure buildup data. Their results from that model provided an improved physical understanding of the phase segregation process and how it influences buildup pressure data. They revealed that buildup tests in wells with multiphase flow in the wellbore prior to shut-in can show either an ***increase*** or a ***decrease*** in the wellbore storage coefficient. This conclusion had been confirmed again by Thompson et al.(5).

In 2001, Qasem et al. (11) mentioned that even the best available diagnostic techniques fail to detect the phase redistribution effects when they are not obvious from the analysis plots and the data do not match the pressure derivative type curves over the complete time range. Therefore, they presented a new method for the detection of wellbore phase redistribution effects during pressure transient analysis.

In 2002, Qasem et al. (12) presented another diagnostic technique that discovers the occurrence of any type of phase redistribution pressure response and defines the true starting of the semi-log straight line for conventional analysis techniques. Their approach can also be used to expect the end of any wellbore effects. This enhances the conventional analyses and yields more precise calculation of the reservoir parameters.

In 2005. Ali et al. (13) investigated experimentally the effects of phase redistribution and phase re-injection on pressure build up data. Their experiments were carried out in the LOTUS (LongTUbeSystem) facility at Imperial College. LOTUS is a vertical two-phase air-water system that was originally built at the Harwell Laboratory of the UKAEA in the early 1960's. It was relocated to the pilot plant area of the Chemical Engineering Department of Imperial College in 1992. They concluded that WPR occur normally in two-phase flow tests before the end of wellbore storage, and WPR was shown to take place. Rising gas causes an increase in bottomhole pressure.

Phase redistribution is one of the most important in gas wells with high liquid production (condensate or water) and volatile oil wells. The longer the wellbore phenomena, the higher the probability to distort reservoir pressure behavior (infinite acting flow regime, linear flow, etc.) (14).

In 2016, Adrian et al. (14) mentioned that if the test data is affected by phase redistribution, the conventional pressure transient analysis would be hard to perform, increasing the probability to obtain erroneous values of permeability and skin factor. Nevertheless, in the last years, the use of primary and secondary pressure derivative as a diagnostic plots (Semilog and Log-Log plots), demonstrated to be very useful in low permeability gas wells and weak phase redistribution gas wells.

3. RESULTS AND DISCUSSIONS:

3.1. PHASE REDISTRIBUTION VARIATIONS: To show the effect of variation of wellbore storage due to phase redistribution, I classified this change into three categories: (1) constant WBS, (2) decreasing WBS due phase redistribution, and (3) increasing WBS due to phase redistribution. With the help of well testing Saphir (15) software and some of the given field data examples in Saphir Manual and examples, the pressure derivatives are plotted and presented in this work.

Wellbore storage is usually expected to be constant during any pressure transient test and, practically, this assumption may be reasonable. However, there are several cases where wellbore storage is changing. This variable wellbore storage may be caused by a changing wellbore fluid compressibility, by phase redistribution, or by a change in the type of storage from a changing liquid level to a liquid filled wellbore. Changing wellbore storage is monitored for using a modified form of the dimensionless wellbore storage definition offered by Fair (3), Hegeman et al. (9), and Thompson et al. (5), which contains extra constraints such as apparent dimensionless storage (C_{aD}) and a storage pressure parameter ($C_{\phi D}$).

CASE I: CONSTANT WBS EFFECT: A well and pressure build up test data that has been performed in a well having the properties listed in Table I. This well is an oil well, vertical well in a homogeneous reservoir most probably damaged while drilling operation.

The analytical solution and the pressure derivative solution is presented in Figures III and IV respectively. It is shown that the pressure trend is very normal as stated theoretically for any constant wellbore storage effect which means the effect of phase segregation and phase distribution is very minimal or one can say it is zero effect. As shown, an excellent match of all data was obtained. The early field data do not deviate from the simulated curve, which again suggests not only true storage behavior but also minimum early phase redistribution effect. The output results in this case revealed that the wellbore storage (C) is equal 0.1 bbl/psi, and reservoir permeability 9.91 md. The main results of this field example is shown in Table II.

Well Data			
Test Type	Buildup	Well radius, ft	0.3
Net Thickness, ft	100	FVF, RB/STB	1.3
Flow rate, sbpd	1000	μ_o, cp	5
Porosity, %	10	C_t, psi^{-1}	3×10^{-6}
Test sequence: 100 hrs flow followed by 100 shut-in			

Pressure Data					
Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia
0	3069	0.285281	3873	14.02137	4830
0.002	3078	0.32009	3933	15.02137	4836
0.004	3084	0.359147	3996	16.02137	4839
0.006	3093	0.40297	4059	17.02137	4845
0.008	3102	0.45214	4122	18.02137	4848
0.01	3111	0.507309	4185	19.02137	4851
0.012	3117	0.56921	4242	20.02137	4854
0.014	3126	0.638664	4302	21.02137	4857
0.016	3135	0.716593	4356	22.02137	4860
0.018	3141	0.80403	4407	24.02137	4863
0.020196	3150	0.902137	4455	25.02137	4869
0.022661	3159	1.012214	4494	28.02137	4872
0.025426	3171	1.135723	4533	29.02137	4875
0.028528	3180	1.274302	4566	30.02137	4878
0.032009	3195	1.429791	4596	32.02137	4881
0.035915	3210	1.604252	4617	34.02137	4884
0.040297	3225	1.80000	4641	35.02137	4887
0.045214	3243	2.019633	4659	38.02137	4890
0.050731	3264	2.266066	4674	41.02137	4893
0.056921	3285	2.542568	4692	43.02137	4896
0.063866	3309	2.852808	4704	45.02137	4899
0.071659	3336	3.200903	4716	46.02137	4902
0.080403	3366	3.591472	4725	52.02137	4905
0.090214	3396	4.029698	4737	54.02137	4908
0.101221	3429	4.521396	4746	55.02137	4911
0.113572	3465	5.073089	4755	63.02137	4914
0.12743	3507	5.6921	4764	67.02137	4917
0.142979	3552	8.040305	4791	73.02137	4920
0.160425	3597	9.02137	4800	77.02137	4923
0.18	3648	10.02137	4806	78.02137	4926
0.201963	3699	11.02137	4815	89.02137	4929
0.226607	3753	12.02137	4821	99.02137	4932
0.254257	3813	13.02137	4824	100	4935

Table I: Well and test data for Case I.

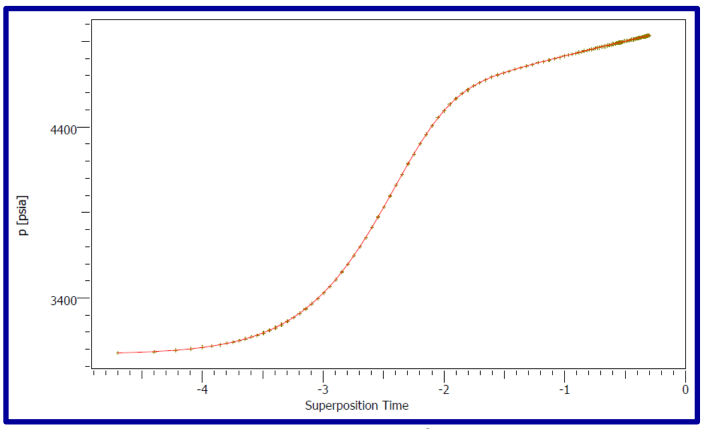

Fig. III: Semilog plot for Case I.

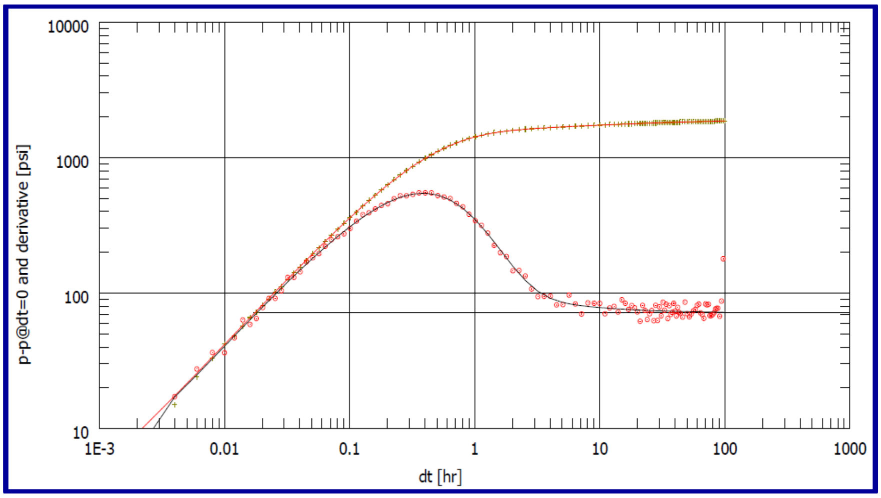

Fig. IV: Pressure derivative curve for Case I.

Well	Vertical	P_{Match}	0.007 psi^{-1}
Reservoir	Homogeneous	C	0.01 bbl/psi
Boundary	Infinite	Total Skin	5
P_i	5000 psia	k.h. total	991 md-ft
Main Model Parameters		K, average	9.91 md
T_{Match}	29 hr-1	ΔP_s	712.371 psi

Table II: Results of constant WBS field example Case I

The purpose of analyzing wellbore storage effect is to determine the wellbore storage constant (C), and to determine when wellbore storage duration and subsequently its end and reservoir main data point starts. Thus, the wellbore storage constant (C) is a measure of the storage capacity associated with the wellbore volume (V_w).

The wellbore storage (C) is normally as a results of wellbore fluid compressibility / expansibility and change fluid level in the wellbore. For oil well testing, it should be noted that the oil expansion is generally unimportant due to the small compressibility of liquids. For gas wells, the primary storage effect is due to gas expansion (16). To determine the time duration of the wellbore storage factor, it is appropriate to define the wellbore storage factor in a dimensionless form (C_D). Several investigators have indicated that the wellbore pressure is directly proportional to the time during the wellbore storage-dominated period of the test ($P_D = t_D/C_D$). By taking the logarithm of both sides gives us a relationship that indicated by a unit slop straight line. Therefore, in the previous case a unit slope straight line achieved as shown in Figure III and IV, indicating a constant wellbore storage effect.

CASE II: DECREASING WBS EFFECT AS A RESULT OF PHASE REDISTRIBUTION: In this case, the data recorded for the pressure build up test (Table III) is analyzed and the pressure derivative is shown in Figure V.

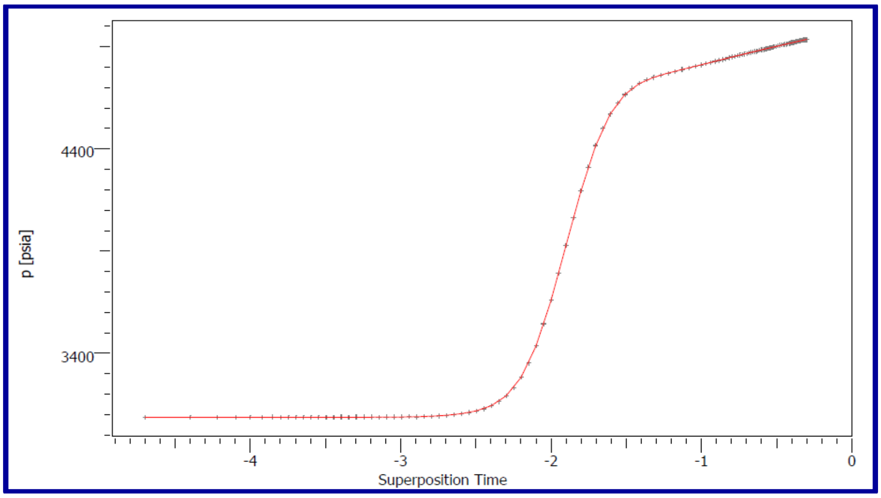

Fig. V: Semilog plot for decreasing WBS field example Case II.

The semilog plot as shown in Figure V is having different shape than that of constant shape of Figure III of case I. if they overlapped over each other, the semilog plot of case II will be above that of case I.

In this case, it is found that the pressure derivative curve is moved above the pressure drop curve and its shape is normal as shown in Figure VI. The results of this case is tabulated in Table IV. This type of WPR is the most adverse impact on the pressure test data as shown in Figure VI. It has a relatively large pressure hump. It looks like the first Type of Thompson et al. work (5).

Well Data			
Test Type	Buildup	Well radius, ft	0.3
Net Thickness, ft	100	FVF, RB/STB	1.35
Flow rate, sbpd	890	μ_o, cp	6.5
Porosity, %	10	C_t, psi^{-1}	3×10^{-6}
Test sequence: 100 hrs flow followed by 100 shut-in			

Pressure Data

Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia
0	3086	5.073089	4750	37.02137	4890
0.035915	3086	5.692100	4760	38.02137	4892
0.101221	3088	6.386641	4770	39.02137	4892
0.113572	3090	7.165929	4778	40.02137	4894
0.160425	3092	8.040305	4788	41.02137	4896
0.18	3094	9.021370	4796	42.02137	4896
0.201963	3096	10.02137	4804	43.02137	4898
0.226607	3100	11.02137	4810	46.02137	4900
0.254257	3104	12.02137	4818	47.02137	4902
0.285281	3110	13.02137	4822	49.02137	4904
0.32009	3118	14.02137	4828	50.02137	4906
0.359147	3128	15.02137	4832	52.02137	4908
0.40297	3144	16.02137	4836	55.02137	4910
0.45214	3164	17.02137	4840	56.02137	4912
0.507309	3192	18.02137	4846	60.02137	4914
0.56921	3232	19.02137	4850	64.02137	4916
0.638664	3284	20.02137	4852	65.02137	4918
0.716593	3352	21.02137	4856	68.02137	4920
0.80403	3438	22.02137	4858	69.02137	4922
0.902137	3544	23.02137	4860	70.02137	4920
1.012214	3662	24.02137	4864	73.02137	4922
1.135723	3792	25.02137	4866	74.02137	4924
1.274302	3928	26.02137	4870	77.02137	4926
1.429791	4064	27.02137	4872	78.02137	4926
1.604252	4194	28.02137	4874	79.02137	4928
1.8	4310	29.02137	4876	80.02137	4926
2.019633	4416	30.02137	4876	81.02137	4928
2.266066	4500	31.02137	4878	85.02137	4930
2.542568	4570	32.02137	4882	90.02137	4932
2.852808	4624	33.02137	4884	92.02137	4932
3.591472	4696	34.02137	4884	93.02137	4934
4.029698	4720	35.02137	4886	94.02137	4932
4.521396	4738	36.02137	4888	100	4934

Table III: Well and test data for Case II

Well	Vertical	P_{Match}	0.007 psi^{-1}
Reservoir	Homogeneous	C	0.01 bbl/psi
Boundary	Infinite	Total Skin	5
P_i	4985 psia	k.h. total	1000 md-ft
Main Model Parameters		K, average	10 md
T_{Match}	29 hr^{-1}	ΔP_s	706 psi

Table IV: Results of Case II

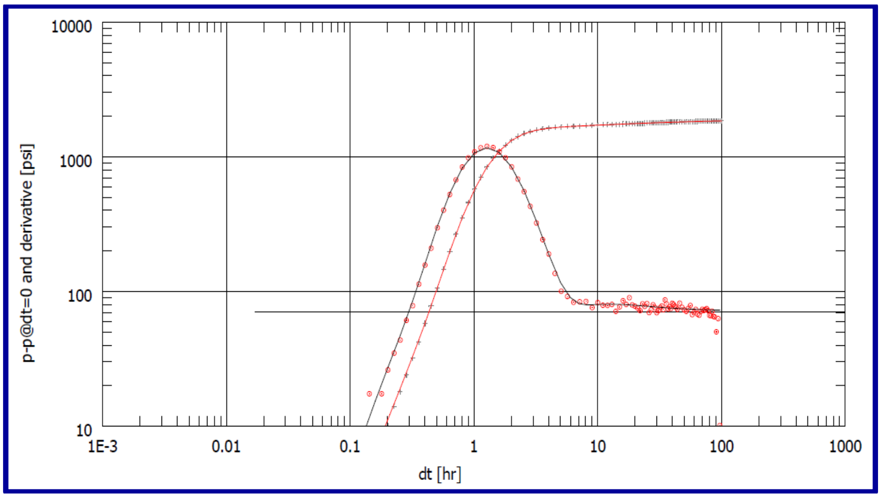

Fig. VI: Pressure Derivative for Case II

CASE III DECREASING WBS WITH ONE FAULT EXAMPLE: This example is a pressure buildup test in an area having a fault, the test performed has the data tabulated in Table V. The pressure data plotted in Figure VII. The pressure derivative is depicted in Figure VIII.

As shown in this case, the pressure derivative curve (red line) is laying above the pressure change curve such as the previous case indicating decreasing WBS as a result of phase redistribution. In this case also is found that it have a fault. The results of this case is tabulated in Table VI.

Well Data			
Test Type	Buildup	Well radius, ft	0.255
Net Thickness, ft	150	FVF, RB/STB	1.36
Flow rate, sbpd	2114	μ_o, cp	0.38
Porosity, %	20	C_t, psi^{-1}	7.23×10^{-5}
Test sequence: 20 hrs flow followed by 51.5 shut-in			

Pressure Data

Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia
0.00	2081.38	2.00	2109.72	12.00	2153.6
0.10	2083.38	2.10	2110.65	13.00	2155.72
0.20	2085.24	2.20	2111.56	14.00	2157.75
0.30	2087.12	2.30	2112.44	14.50	2158.85
0.40	2088.85	2.40	2113.27	15.00	2159.66
0.50	2090.6	2.50	2114.1	15.50	2160.63
0.60	2092.23	2.60	2114.9	16.00	2161.49
0.70	2093.75	2.70	2115.69	16.50	2162.83
0.80	2095.23	3.00	2118.02	17.00	2163
0.90	2096.71	3.15	2119.12	17.09	2163.4
1.00	2098.08	3.30	2120.13	17.44	2164
1.10	2099.46	3.50	2121.3	18.31	2165.43
1.20	2100.73	4.00	2123.85	18.70	2166.07
1.30	2101.96	5.30	2131.76	19.40	2167.16
1.40	2103.2	6.00	2135.06	21.50	2170.36
1.50	2104.4	7.00	2139.03	24.19	2174.17
1.60	2105.59	8.00	2142.57	27.48	2178.42
1.70	2106.64	9.00	2146.44	30.55	2182
1.80	2107.72	10.00	2149.13	34.93	2186.57
1.90	2108.73	11.00	2151.3	38.87	2190.27

Table V: Well and test data for Case III

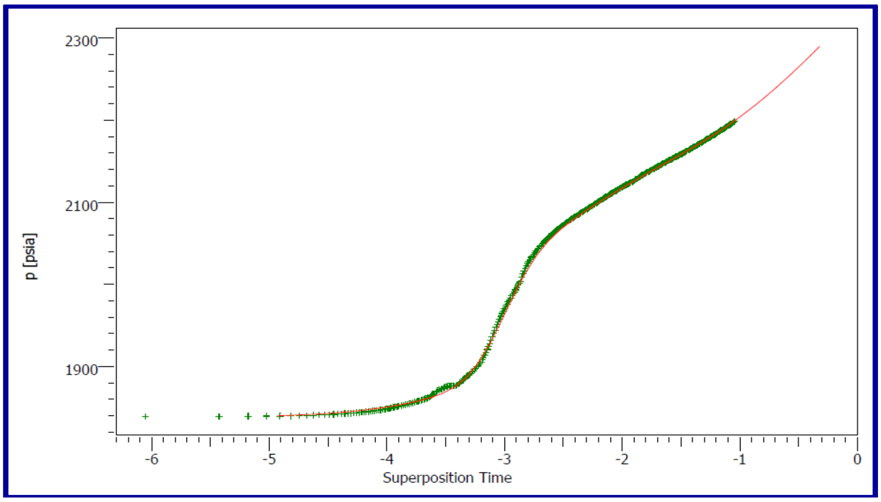

Fig. VII: Semilog plot for decreasing WBS field example Case III

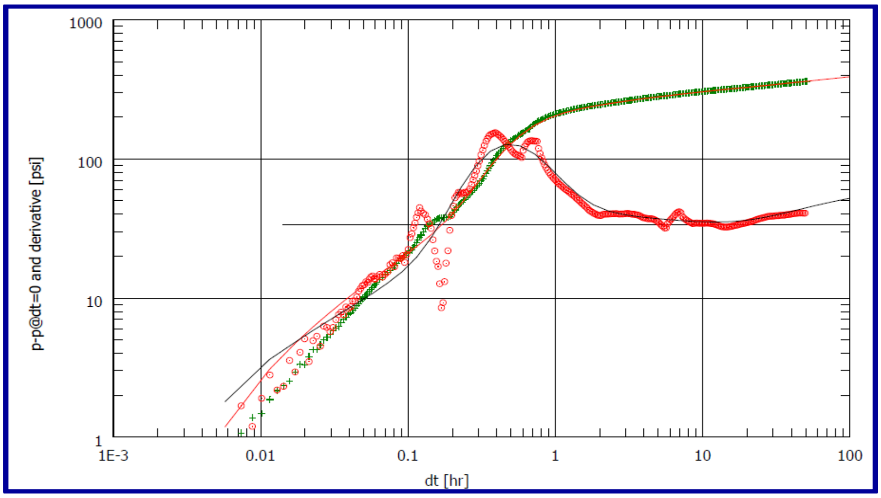

Fig. VIII: Pressure Derivative for decreasing WBS field example Case III

Well	Vertical	P_{Match}	0.0148 psi^{-1}
Reservoir	Homogeneous	C	0.05 bbl/psi
Boundary	One fault	Total Skin	-1.66
P_i	2338 psia	k.h. total	2120 md-ft
Main Model Parameters		K, average	14.1 md
T_{Match}	35.6 hr^{-1}	ΔP_s	-112.528 psi
L	195 ft		

Table VI: Results of Case III

CASE IV: INCREASING WBS EFFECT AS A RESULT OF PHASE REDISTRIBUTION: In this case, when liquid and gas flow vertically after the well is shut-in at surface, the heavier liquid will travel toward the bottom of the well while the lighter phase will upswing to the top of the well. This process leads to a slight decrease in the pressure increment value versus time after the main wellbore storage effect as shown in Figure IX. As a result of compressibility effects, this wellbore phase redistribution (WPR) causes a net increase of wellbore pressure. In all of the build-up tests, the increased pressure is dissipated through the formation until there is equilibrium between reservoir pressure and wellbore pressure values very quickly, especially in a high permeable reservoirs. However, in low permeability reservoirs, it may take some time for this overpressure to be dissipated and this causes the anomalous pressure hump at early times.

The data and well data are tabulated in Table VII, and these data is plotted in Figure IX. The shape of pressure versus time is different than those of the previous cases indicating that case is entirely different than those of the previous cases.

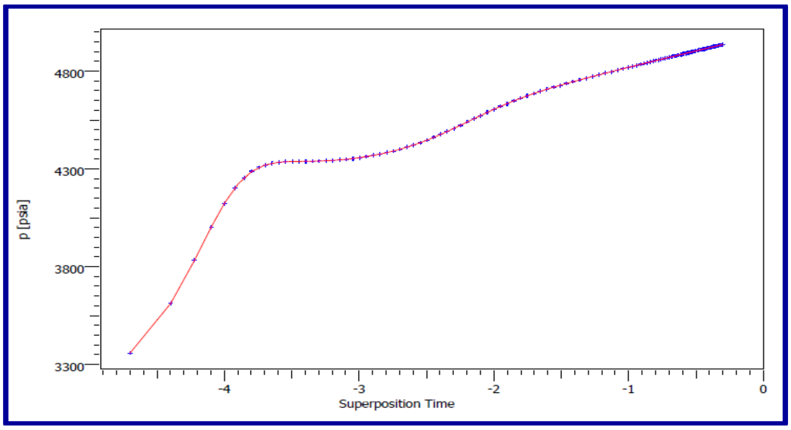

Fig. IX: Semilog plot for increasing WBS field example Case IV

Well Data			
Test Type	Buildup	Well radius, ft	0.3
Net Thickness, ft	100	FVF, RB/STB	1.17
Flow rate, sbpd	990	μ_o, cp	1
Porosity, %	10	C_t, psi^{-1}	3×10^{-6}
Test sequence: 100 hrs flow followed by 100 shut-in			

Pressure Data

Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia
0	3086	0.56921	4522	24.02137	4867
0.002	3358	0.638664	4540	25.02137	4869
0.004	3612	0.716593	4557	30.02137	4881
0.006	3832	0.80403	4571	31.02137	4881
0.008	4002	0.902137	4589	32.02137	4884
0.01	4123	1.012214	4604	34.02137	4888
0.016	4288	1.135723	4620	35.02137	4890
0.018	4308	1.274302	4633	38.02137	4893
0.020196	4320	1.429791	4648	39.02137	4894
0.022661	4329	1.604252	4661	40.02137	4896
0.025426	4333	2.266066	4696	43.02137	4900
0.035915	4338	2.542568	4707	44.02137	4901
0.040297	4337	2.852808	4718	48.02137	4905
0.045214	4339	3.200903	4726	51.02137	4907
0.050731	4340	3.591472	4737	52.02137	4909
0.056921	4341	4.029698	4746	56.02137	4912
0.063866	4342	4.521396	4755	57.02137	4913
0.071659	4346	5.073089	4762	59.02137	4915
0.080403	4348	5.6921	4771	60.02137	4914
0.090214	4352	8.040305	4796	65.02137	4919
0.101221	4357	9.02137	4805	67.02137	4921
0.113572	4363	10.02137	4812	74.02137	4925
0.12743	4369	11.02137	4818	77.02137	4927
0.142979	4376	12.02137	4823	78.02137	4926
0.160425	4383	13.02137	4829	79.02137	4927
0.18	4390	14.02137	4835	86.02137	4929
0.254257	4422	15.02137	4839	87.02137	4930
0.285281	4433	16.02137	4843	95.02137	4934
0.32009	4446	17.02137	4846	96.02137	4933
0.359147	4461	18.02137	4850	97.02137	4934
0.40297	4476	19.02137	4854	98.02137	4935
0.45214	4491	20.02137	4857	99.02137	4934
0.507309	4506	23.02137	4864	100	4936

Table VII: Well and test data for Case IV

Figure X depicts the typical hump of this case in the pressure derivative line. The phase segregation may delay or completely suppress the development of this line, so semi log analysis methods often cannot be used in it analysis. The downward v-shaped depression in the pressure derivative curve immediately following the wellbore storage distortion as a results of phase redistribution. After such hump the pressure derivative of is normally laying in a horizontal line. By using this range of the data, one can get most of the reservoir parameter such as all parameters listed in Table VIII.

Well	Vertical	P_{Match}	0.007 psi^{-1}
Reservoir	Homogeneous	C	0.01 bbl/psi
Boundary	Infinite	Total Skin	5
P_i	4985 psia	k.h. total	1000 md-ft
Main Model Parameters		K, average	10 md
T_{Match}	29.5 hr^{-1}	ΔP_s	706 psi
Ci/Cf	0.03	R_{inv}, ft	1670

Table VIII: Results of Case IV

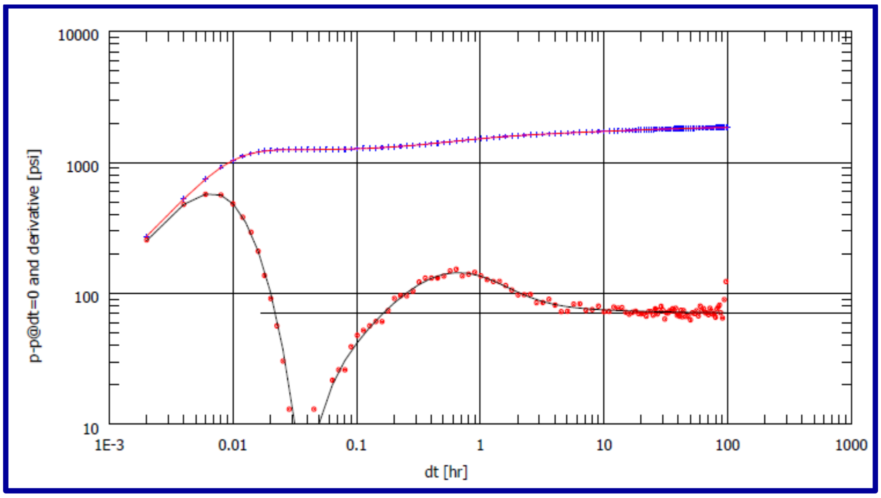

Fig. X: Pressure Derivative for increasing WBS field example Case IV

CASE V: ANOTHER FIELD EXAMPLE:

INJECTION WELL TESTING: FALL OFF TEST: A pressure falloff test is usually performed in an injection well during water flooding operation. The Falloff testing is analogous to pressure buildup testing in a production well. After the injectivity test that lasted for a total injection time of t_p at a constant injection rate of q_{inj}, the well is then shut in. The pressure data taken immediately before and during the shut in period is analyzed. The well and fall of test data are presented in Table IX and Figure XI.

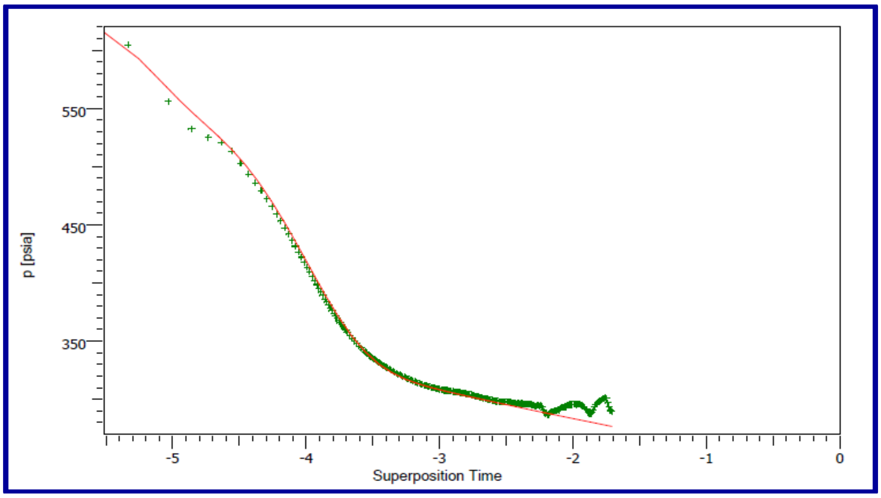

Fig. XI: Semilog plot for increasing WBS field example Case V

After analyzing the fall of test as shown in Figure XII, it is shown that the pressure derivative curve is having the hump that indicating changing wellbore storage immediately after the wellbore storage period. This is means that the normal fitting and type curve matching will not be suitable for analyzing such test. The results of this test is tabulated in Table X.

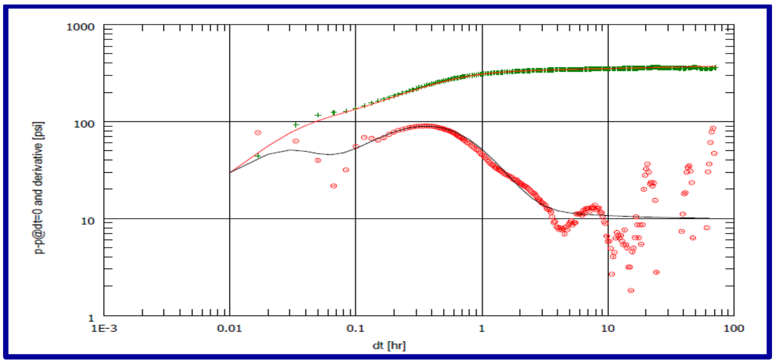

Fig. XII: Pressure Derivative for increasing WBS field example Case V

Well Data			
Test Type	Fall off Test	Well radius, ft	0.25
Net Thickness, ft	243	FVF, RB/STB	1.00
Injection rate, sbpd	-22000	μ_o, cp	0.76
Porosity, %	13	C_t, psi^{-1}	6×10^{-6}
Test sequence: 3600 hrs injection followed by 71 shut-in			

Pressure Data					
Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia
0.00	649	21.78	291	52.80	292
0.03	604	21.97	290	53.22	293
0.23	459	22.50	289	53.72	294
0.73	359	22.72	288	54.42	295
1.23	333	22.97	287	55.12	296
1.73	322	23.37	286	56.22	297
2.23	316	23.97	287	56.23	297
2.73	312	24.27	288	58.13	298
3.23	310	26.35	289	59.65	299
3.73	308	26.37	290	59.67	300
4.23	307	27.37	290	66.35	299
4.73	306	27.38	291	66.67	298
5.23	306	28.45	290	66.68	298
5.73	305	29.77	292	66.70	297
6.23	304	31.25	293	67.08	297
6.73	303	31.38	294	67.52	296
7.73	301	34.28	295	67.97	295
8.23	300	42.22	295	68.60	294
8.73	299	43.35	294	68.62	293
9.23	299	44.55	293	68.63	293
9.73	298	45.28	292	69.35	292
10.23	298	46.50	291	69.37	291
10.73	298	46.52	290	69.38	291
11.23	298	47.60	289	70.62	291
11.58	298	48.32	288	70.63	290
12.05	297	48.33	287	71.62	289
14.98	296	48.35	287	71.63	289
18.50	295	51.03	289	71.72	289
19.73	295	51.48	290	71.73	289
20.47	294	52.35	291	71.75	294
21.35	293	52.37	291	71.77	301
21.50	292	52.38	292	71.78	304

Table IX: Well and test data for case V WBS field example

Well	Vertical	P_{Match}	0.05 psi^{-1}
Reservoir	Homogeneous	C	1.01 bbl/psi
Boundary	Infinite	Total Skin	8.6
P_i	237.374 psia	k.h. total	121000 md-ft
Main Model Parameters		K, average	497 md
T_{Match}	47 hr^{-1}	ΔP_s	171 psi
C_i/C_f	0.302	R_{inv}, ft	7220

Table X: Results of Case V

CASE VI: EGYPTIAN FIELD EXAMPLE: A pressure build up section of a DST test has been performed in an Egyptian oil field, the reservoir rock and fluid properties is presented in Table XI. The pressure data recorded and plotted as shown in Figure XIII. It is Pressure versus time for the buildup data section of the test performed in an Egyptian oil company.

Well Data			
Test Type	DST	Well radius, in	6.125
Net Thickness, ft	136	FVF, RB/STB	1.17
Flow rate, sbpd	350	μ_o, cp	9.50
Porosity, %	17	C_t, psi^{-1}	9.6×10^{-6}
Test sequence: 5.26 hrs injection followed by 35.5 shut-in			

Pressure Data					
Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia	Δt, hrs	P_{ws}, psia
0.00	550.737	4.64	606.316	15.14	608.114
0.01	551.361	4.65	606.287	15.15	608.114
0.02	550.94	5.66	607.215	15.16	608.143
0.03	551.143	5.67	607.012	15.17	608.114
0.03	550.94	7.78	607.374	15.18	608.114
0.04	550.911	7.79	607.345	15.18	608.114
0.07	551.564	7.80	607.142	17.54	608.636
0.08	556.727	7.81	607.345	17.55	608.636
0.08	564.661	7.82	607.142	21.66	609.303
0.09	572.362	7.83	607.345	21.67	609.332
0.10	579.6	7.83	607.519	21.68	609.535
0.11	584.865	7.84	607.345	21.68	609.535
0.12	588.708	7.85	607.316	21.69	609.506
0.13	590.942	7.86	607.519	21.70	609.303
0.13	592.508	7.87	607.548	21.71	609.506
0.14	593.277	7.88	607.519	21.72	609.332
0.23	595.713	7.88	607.316	21.73	609.535
0.23	596.105	10.01	607.142	21.73	609.535
0.24	596.903	10.02	607.287	21.74	609.535
0.25	597.425	10.03	607.287	21.75	609.535
0.30	601.109	10.03	607.084	23.11	609.68
0.31	601.79	10.04	607.258	23.12	609.477
0.32	602.284	10.05	607.229	23.13	609.709
0.33	602.559	10.06	607.403	23.13	609.68
0.33	603.009	10.07	607.403	24.66	610.072
0.34	603.531	10.08	607.171	24.67	610.043
0.35	604.024	10.08	607.374	24.68	610.043
0.38	605.489	10.09	607.374	24.77	609.84
0.38	605.764	10.10	607.345	27.96	610.406
1.68	605.88	13.47	608.027	27.97	610.406
1.69	606.113	13.48	607.824	33.82	611.145
3.09	606.33	15.13	608.085	33.83	611.145
3.10	606.533	15.13	608.332	33.83	611.145

Table XI. Rock and fluid properties of the Egyptian Field example Case VI

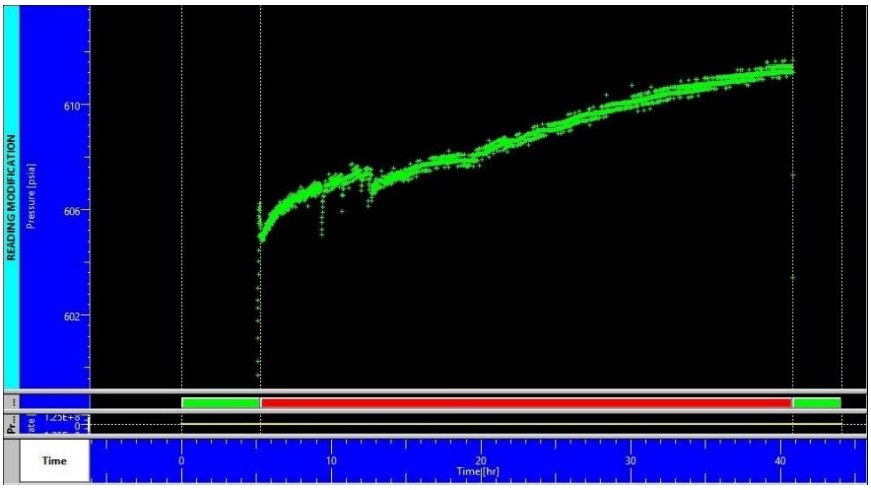

Fig. XIII : Pressure vs. time for the egyptian example Case VI

The pressure derivative analysis for that test is presented in Figure XIV. It shows the anomaly in the normal diagram of the normal pressure buildup test.

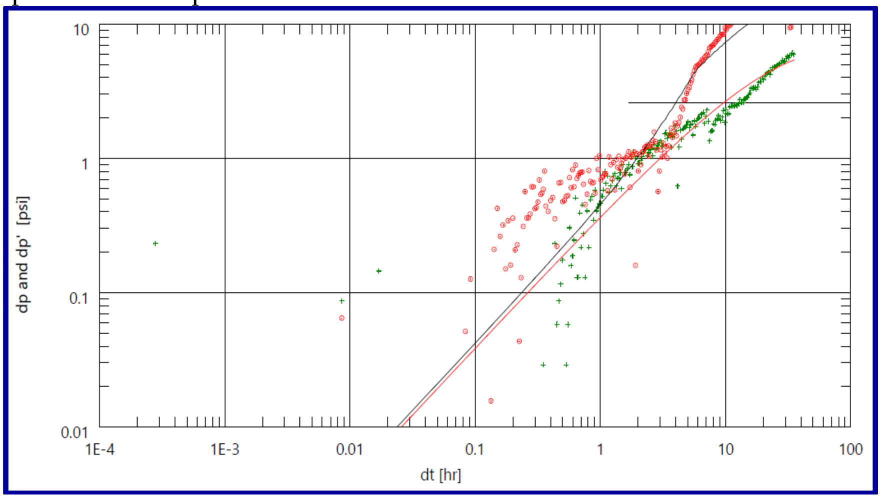

Fig. XIV : Pressure derivative analysis for Egyptian example Case VI

As shown in Figure XIV, the pressure buildup section of the DST and their pressure derivative curve is shown an anomaly especially at the period of wellbore storage. In this case the entire WBS region in affected by the wellbore phase redistribution phenomenon. It looks like the wellbore storage decreasing by the time in which the curve is above the pressure change line.

4. CONCLUSIONS: Based on this study, the following conclusions are resulted:

1. Wellbore Phase Redistribution (WPR) can influence the recorded bottom hole pressure leading to anomalies, irregularities while pressure build up test analysis called pressure humps.
2. Wellbore phase redistribution is normally take place during a pressure buildup test in wellbore having very compressible fluids such as single phase gas and high gas/liquid ratio multiphase fluid mixture during the wellbore storage period.
3. Wellbore Phase redistribution (WPR) is one of the main non-reservoir effects that influences the pressure buildup tests.
4. The variation of wellbore storage coefficient can either increase or decrease during the pressure transient tests as a results of simultaneous flow of oil and gas in the wellbore.
5. Analysis of six field example has been performed in order to show the different types of wellbore phase redistribution phase while pressure transient tests. The reservoir rock permeability for these cases ranges from 9.91 md to 497 md and average reservoir pressure ranges from 237 to about 5000 psia.
6. Pressure derivative hump of phase redistribution may rise above the normal pressure change curve as in Case II, and III.
7. After investigating the cases under this study, the effect of wellbore phase redistribution (WPR) does not be able to be detected by Horner approximation.

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NOMENCLATURE:

Symbol	Definition	Equation
C	wellbore storage coefficient, bbl/psi	
Ca	apparent storage coefficient, bbl/psi	
C_{aD}	apparent dimensionless storage coefficient	$C_{aD} = \frac{5.612\, C_a}{2\pi\phi C_t h r_w^2}$
C_{eD}	effective dimensionless storage coefficient	
C_t	compressibility, psi^{-1}	
C_D	dimensionless well bore storage coefficient	$C_D = \frac{5.612\, C}{2\pi\phi C_t h r_w^2}$
C_ϕ	Phase redistribution pressure parameter, psi	
$C_{\phi D}$	dimensionless phase redistribution pressure parameter	$C_{\phi D} = \frac{khC_\phi}{141.2\, qB\mu}$
h	thickness, ft	
K	permeability, md	
P_w	wellbore pressure, psi	
P_{whf}	flowing wellhead pressure, psi	
P_{wD}	dimensionless wellbore pressure	
P_D	dimensionless pressure	
P_ϕ	phase redistribution pressure, psi	
$P_{\phi D}$	dimensionless phase redistribution pressure	$P_{\phi D} = \frac{khP_\phi}{141.2\, qB\mu}$
Q	flow rate, bpd	
r_w	wellbore radius, ft	
t_D	dimensionless time	$t_D = \frac{0.000264kt}{\phi\mu C_t r_w^2}$
α	phase redistribution time parameter, hours	
α_D	dimensionless phase redistribution time parameter	$\alpha_D = \frac{0.000264k\alpha}{\phi\mu C_t r_w^2}$
μ	fluid viscosity, cp	
ϕ	porosity,	

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