Reservoir and Wellbore Damage Estimation Using Pressure Transient Analysis (PTA).

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Abstract:- Reservoir formation damage is the impairment of the reservoir rock permeability which causes reduction in the productivity of a well. The quantification of wellbore formation damage using pressure transient analysis (PTA) is vital in the oil and gas industry as it helps to interpret key physical reservoir parameters to improve wellbore and reservoir management strategies for production optimization. In this paper, a single rate build-up test data generated from a vertical producing oil WELL X was analysed. Pressure transient was due to the pressure decline in the high permeability Niger Delta sandstone formation. Reduction in productivity index may have been caused by wellbore or formation damage as a result of pseudoskin due to completion (mechanical skin) or perforation, fines migration, inorganic scale deposition, or organic solids deposition in the near wellbore region. In order to resolve this problem and optimize production from this well, generated build-up pressure time data at a constant production rate was analysed to determine reservoir and wellbore parameters. The damage in the near wellbore zone is simulated using a numerical well test simulator (KAPPA-saphir); and the same build-up test data was analysed using the conventional method alongside with Microsoft Excel Sheet to estimate the reservoir and wellbore parameters like skin, average reservoir permeability, wellbore storage effect, and average reservoir pressure. The results obtained from the numerical well test simulator, and analytical solutions using Microsoft Excel Sheet were compared to ascertain the effectiveness of the numerical simulator in conducting pressure transient analysis on the measured data. Both analysis on the generated build-up test data showed close results for skin and permeability value, hence, the very high skin and permeability value obtained after analysis indicate damage due to mechanical or wellbore skin. This reveals that the vertical oil producing well of this field is a candidate well for workover operations.

***Keywords**:- Reservoir Formation Damage, Wellbore, Production, Skin, Permeability, Numerical Simulator, Build-Up Test, Pressure Transient Analysis, Workover Operation.*

I. INTRODUCTION

Formation damage assessment using pressure transient well testing is of great importance for evaluating and mitigating oil and gas bearing formations to optimize reservoir performance. Reservoir formation damage can be induced during several phases of oil and gas recovery such as drilling, completion, production and workover operations. These oil and gas recovery operations can lead to various processes of formation and wellbore damage mechanisms including mechanical, chemical, biological and thermal interactions of reservoir rock and fluid. In order to improve and enhance recovery from the hydrocarbon reservoir, there is need for formation damage assessment and reservoir characterization. The development of the pressure derivative technique has greatly improved the identification of reservoir rock and wellbore properties like permeability, porosity, skin factor etc. An adequate model of the reservoir can be diagnosed using pressure transient analysis to determine the pressure behaviour and even predict future production performance of the reservoir under test. Reservoir formation damage assessment can be improved by incorporating pressure transient test data with geoscience data. Pressure transient well testing can also be carried out using Wireline Formation Testers. In pressure transient analysis (PTA), we look at the different flow regimes that we encounter during a well test period and the pressure response will reflect all of the flow regimes that pressure transient has encountered during the test period.

The Effect of Near-Wellbore Permeability and Porosity on Wells Productivity

Permeability and porosity are petrophysical properties which may vary as a result of formation damage caused by rock, fluid and particle interactions [3]. Wettability is a vital property of oil bearing formations and when altered, can affect fluid distribution and the relative permeability in reservoirs.

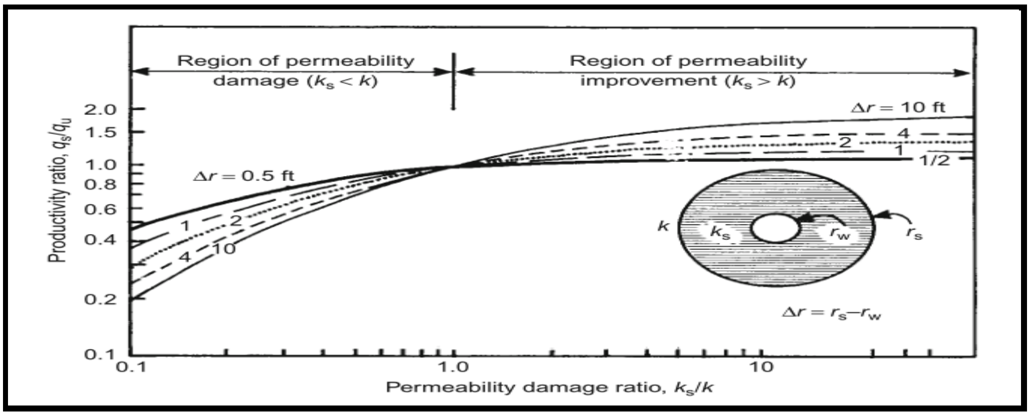

Fig 1: The effect of permeability damage on wells productivity ratio (Source:Tiab & Donaldson,2004).

Kalfayan [5] noted that "to assess formation damage, it is imperative to understand the skin term in the equation derived from Darcy's law, which defines well production rate vis-a-vis understanding its effect on production rate." A simple form of Darcy's law which represent well production rate for a steady state liquid flowing in a radial reservoir is denoted as follows:

$$q = \frac{7.082kh(P_e - P_{wf})}{\beta\mu \ln(\frac{r_e}{r_w}) + S} \qquad (1)$$

where
q = Production rate, in barrels per day (b/d).
k = Permeability, in millidarcies (mD).
h = Formation height, in ft
p_e = Reservoir pressure, in pounds per square inch (psi).
P_{wf} = Flowing wellbore pressure, in psi.
B = Formation volume factor i.e. reservoir volume/production volume (RB/STB).
μ = Formation fluid viscosity, in centipoise (cp)
r_e = Reservoir radius, in ft.
r_w= The wellbore radius, in ft
s = The skin factor.

From equation (1) above, the production rate (q) is directly proportional to the reservoir permeability (k) and is inversely proportional to the skin factor(s). For accurate workover operation and stimulation design, the reservoir and wellbore property which is permeability and skin is of great importance. In general, higher values of skin factor ranging from +1 to +10 and above can be obtained in wells [10]. Partial penetrations or limited perforations can result to higher total skin value ranging from 20-30 [11].

Formation Damage Mechanisms Affecting Reservoir Permeability

Bennion [2] stated that there are four primary mechanisms of formation damage. These are:
- Mechanical formation damage mechanism.
- Chemical formation damage mechanism.
- Biological formation damage mechanism.
- Thermal formation damage mechanism.

Kalfayan [5] noted that there are various possible damage mechanisms initiated during production depending on the type of well and the characteristics of the formation. These are:
- Fines migration within oil and gas bearing formations.
- Inorganic scale deposition.
- Organic solids deposition (e.g. paraffin and asphaltene).

Primasari [8] stated that with "poorly sorted sand grains, fines migrate and deposit at the gravel-pack matrix, causing permeability reduction and hence, decreasing well productivity. Matrix stimulation has proven to remove the fines blocking the pore throat."

II. WELLBORE DAMAGE DUE TO SKIN

After drilling a well and casing it, to provide communication between the reservoir and wellbore there is need to perforate through the walls of the cemented casing to penetrate into the reservoir formation [10]. During this process, a perforation tunnel is created as shown in **Figure 2**. Poor connection between the well and the reservoir as a result of plugged perforation, mud invasion or partial penetration will lead to a high pressure drop around the wellbore.

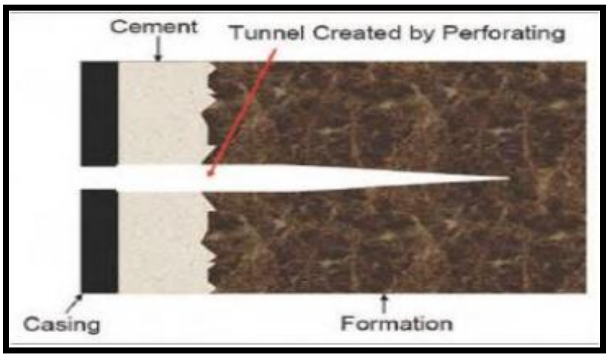

Fig 2: The perforation process (Source: Halliburton 2012, cited in, Elmouzemill, 2017).

The productivity of the well can be decreased if the perforating part of the well completion operation is not done correctly. If the displacement of debris plugs the perforation tunnels and rock matrix, this may result to individual productive zones and the well may even be abandoned [10].

III. BOTTOM HOLE PRESSURE (BHP) TESTS

There is need to obtain vital information down-hole for reservoir management. The common types of bottom-hole pressure tests include:

- Drawdown tests (see Figure 3)
- Build-up tests
- Injectivity tests
- Fall off test
- Interference/pulse tests

Onyekonwu [7] stated that bottom-hole pressure tests are conducted to obtain data that can be used to determine well parameters like skin, productivity index, wellbore storage constant, fluid distribution in wellbore, flowing pressures in wellbore, and static gradients. It can also be used to determine reservoir parameters like average pressure in the drainage area, permeability, distance to boundaries, vertical/horizontal permeability, and Gas/oil contacts.

A build-up test measures change in sandface pressure with time while the well is shut-in. The well must have been allowed to flow for a period of time. According to Ahmed and Meehan [1], the use of pressure buildup data has given the reservoir engineer useful tool for determining reservoir behaviour; and pressure buildup analysis explains the buildup in wellbore pressure with respect to time after the well is shut-in [1]. Furthermore, pressure build-up analysis is carried out to determine the following:

- Effective permeability of the reservoir formation.
- The degree of damaged permeability around the wellbore.
- Existing faults and to some extent the identification of the distance to the fault.
- Interference between producing wells.
- Reservoir limits.

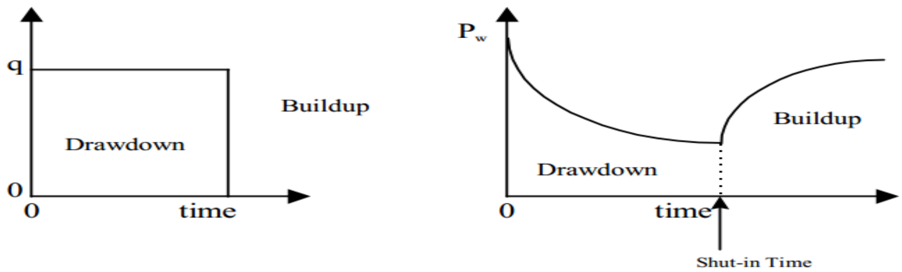

Figure 3: Rate and Pressure Profiles During Drawdown and Build-up (Source: Onyekonwu, 1997)

Identifying the Flow Phases

It is fundamental to identify the various flow regimes during the build-up test conducted in a production well in order to obtain vital information for reservoir characterization. Pressure transient analysis will assist to identify the early transient region which is the early time response that is dominated by wellbore storage effect(C) and skin(S) as shown in Figure 4. Pressure changes occur during this phase as a result of hydrocarbons stored in the wellbore or produced hydrocarbons from the wellbore [7]. At the middle time region, the reservoir acts as if there are no flow boundaries i.e. infinite-acting during pressure response. This region is captured by a straight line on the semilog plot, and the slope(m) is estimated to calculate average reservoir permeability. Through the interpretation of the late time transient data, characterisation and indication of geologic heterogeneity in oil and gas reservoirs is made possible. There will be a no-flow boundary where geologic heterogeneities occur such as faults and pinchouts.

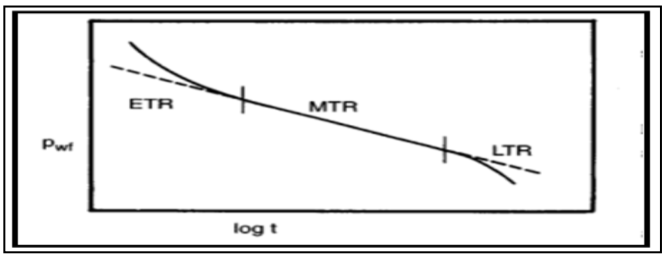

Fig 4: Early-Middle-Late time flow regions(Source: Lyon & Plisga,2005)

The Statement of Problem/Objectives

The Niger Delta Basin is a province characterized by a principal system known as the Tertiary Niger Delta (Akata-Agbada) Petroleum System. Well productivity in this system usually diminishes over time, either as a result of damage due to wellbore skin (perforation or mechanical skin), or formation damage from fines migration within the reservoir formation. There was a sudden sharp decline in productivity in one of the producing wells in Niger Delta province which may have been caused by partial penetration or perforation problems, particle invasion and fines migration into the near wellbore zone. Company engineers sought to diagnose these problems to find a practical, faster and economic solution to analyse the reservoir rock and wellbore properties and subsequently, actions that needs to be taken to optimize production if damaged wellbore or formations are encountered. The measured transient data is history-matched to type curves or formation model while actual production is compared with predicted production to assess the need for workover operation or effective stimulation treatments of the candidate well. Interpretation of the pressure derivative plots obtained during the analysis was carried out in order to investigating the limitations and general characteristics of the different flow regimes (i.e. early and late transient times).

IV. METHODOLOGY

A generated build-up test data in combination with PVT and reservoir data is analysed to estimate the wellbore and reservoir parameters of a producing well in the Niger Delta region. Accurate estimation of the well and reservoir characteristics were carried out through the use of a numerical simulator (Kappa Saphir) and the conventional method (analytical solutions) in comparison with Microsoft Excel sheet. The excel sheet was used to plot the build-up pressure and time data. The different flow regimes that occurred in the vertical oil well during the build-up test were identified and the reservoir and wellbore parameters were obtained.

Formation Damage Assessment Through Numerical and Analytical Solutions

As stated by Civan [3], “development of a numerical solution scheme for the highly nonlinear phenomenological model and its modification and verification by means of experimental testing of a variety of cores from geological porous media are the challenges for formation damage research.” The numerical calculation schemes are developed for computer programming. Reservoir simulators use mathematical expressions, in partial differential equation forms, to model flow characteristics of oil, water and gas within reservoirs [4]. Civan [3] noted that “formation damage models can be generated from algebraic equations, ordinary and partial differential equations or the combination of both equations.”

Loading flow-rate data during the pressure transient analysis using KAPPA-Saphir

Step 1: The flow-rate data is loaded from spreadsheet in the define data source shown in figure 5 below.
Step 2: The flow-rate in STB/D is displayed in field B in the define data source.
Step 3: Free is selected for the lines format.
Step 4: Steps-duration is selected to define the time format.

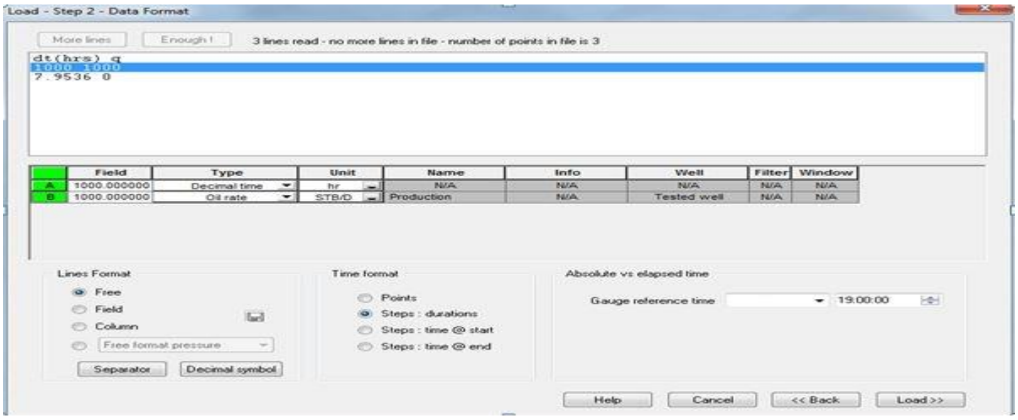

Fig 5: Loading flow rate data

Loading Pressure data during pressure transient analysis using KAPPA -Saphir

Step 1: The pressure data is loaded from spreadsheet in the define data source.
Step 2: The decimal time (t + dt) in hours is specified in the first column (field A) in the define data source.
Step 3: The pressure Pws in psia is specified in the second column (field B) in the define data source.
Step 4: The field is selected in the lines format and point is selected to define the time format.

Calculations and Results

The reservoir rock, fluid and wellbore data for Well X is highlighted in Tables 1 below while interpretation models is shoown in Table 2:

Table 1: Reservoir rock, fluid and wellbore Parameter used for pressure transient analysis.

The Reservoir Rock Parameters for Well X	
Reservoir thickness (h)	50ft
Reservoir porosity(φ)	0.25
The PVT Parameters for Well X	
Oil viscosity (μ)	0.6cp
Total Compressibility of fluid (C_t)	2E-5 ps-1
Oil Formation Volume Factor(B_o)	1.125rb/STB
The Wellbore Parameter	
Wellbore radius	0.5ft

Table 1: The interpretation models and chosen interpretation models for pressure transient analysis

Interpretation models	**Chosen Interpretation models**
Model option	Standard model
Well	Vertical
Reservoir	Homogeneous
Boundary	Infinite
Fluid phase	Oil
Fluid flow rate	Single flow rate
Wellbore storage and skin	Constant

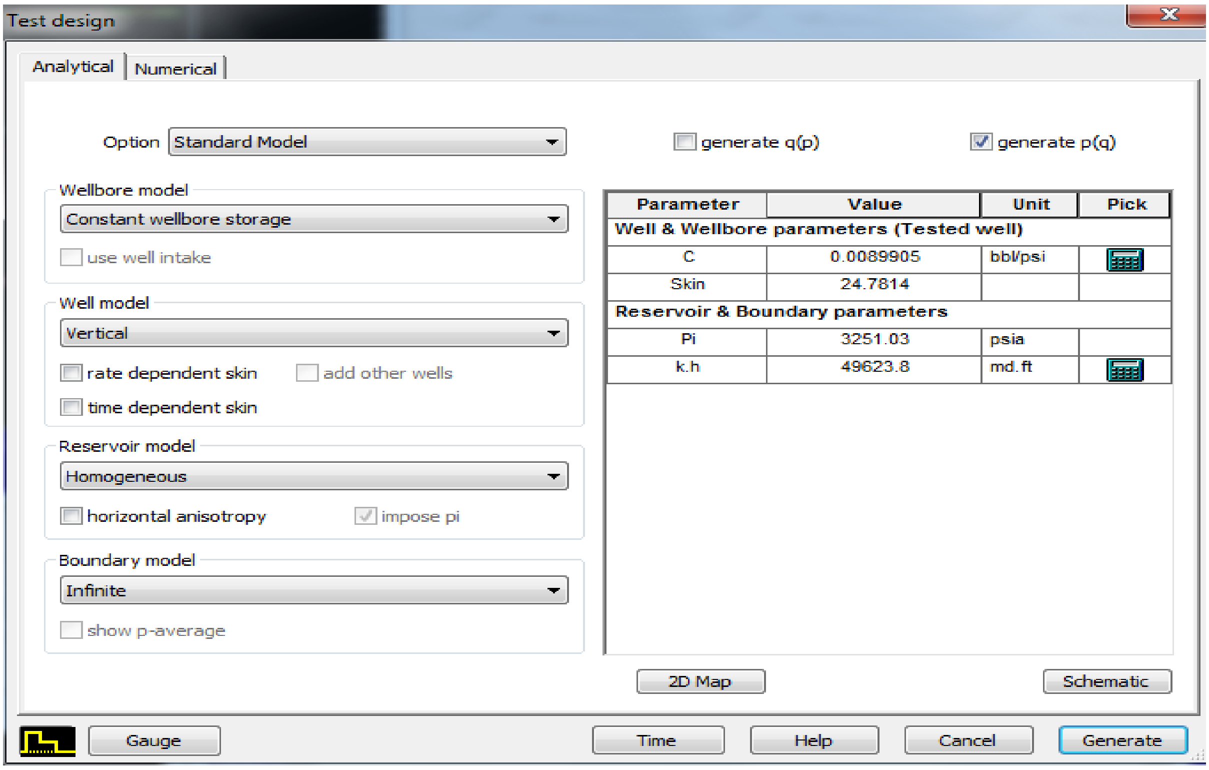

Fig 6: Chosen interpretation models for pressure transient analysis

The selected interpretation models used during the pressure transient analysis best fits the measured test data from Well X. The well model selected is a vertical well model because the well test data was generated from a vertical well and this gives a good interpretation at the early transient times(ETR). The flow regime at the intermediate times(MTR) is identified by selecting a reservoir model that best fits the measured data. In this case, the reservoir is assumed to be a homogeneous infinite-acting (boundary) reservoir with an oil phase.

Table 2: History listings of the Build-up test

HISTORY LISTINGS	
Name of Company	NIGER DELTA UNIVERSITY
Name of Field	FIELD X
Name of Well	Well X (Tested well)
Name of Test	Build-up test
Start Date of Build-up test	01/01/2021
End Date of Build-up test	02/01/2021
ToD @ Start date of Build-up test	19:00:00
Liquid Rate(STB/D) @ Start time of flow	1000
Duration of Flow(hr) @ Start time	1000
Liquid Rate @Shut-in time	0
Duration of Build-up @ time of Shut-in(hrs)	7.9536
Number of gauges used during build-up test	Single gauge

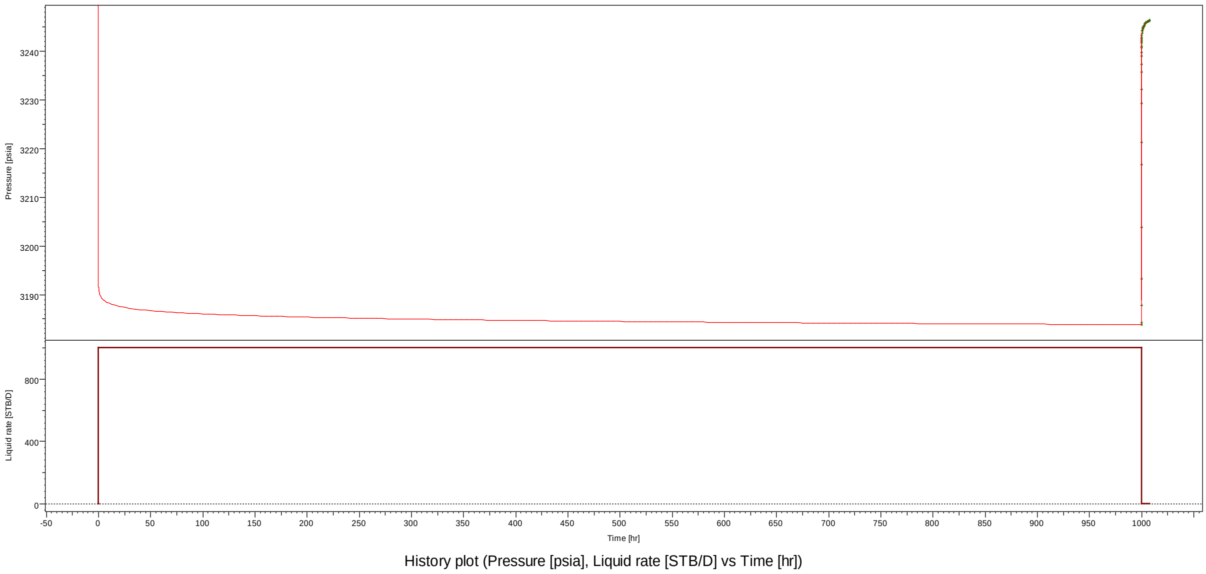

Fig 7: The History Plot (Pressure in psia, Liquid rate in STB/D vs Time in hr)

From the history plot in Figure 7, it is observed that pressure declined from 3250 psia to 3188 psia as the well is produced at a constant flowrate of 1000 stb/d for 1,000 hrs. Inaccurate rate measurement will affect the derivative plot, selection of interpretation models and calculated well and reservoir parameters. It is observed that the pressure curve mirrors the flowrate to validate absence of anomalies during flow test and as a result the derivative of the Buildup test should share the same stabilization level on the derivative plot.

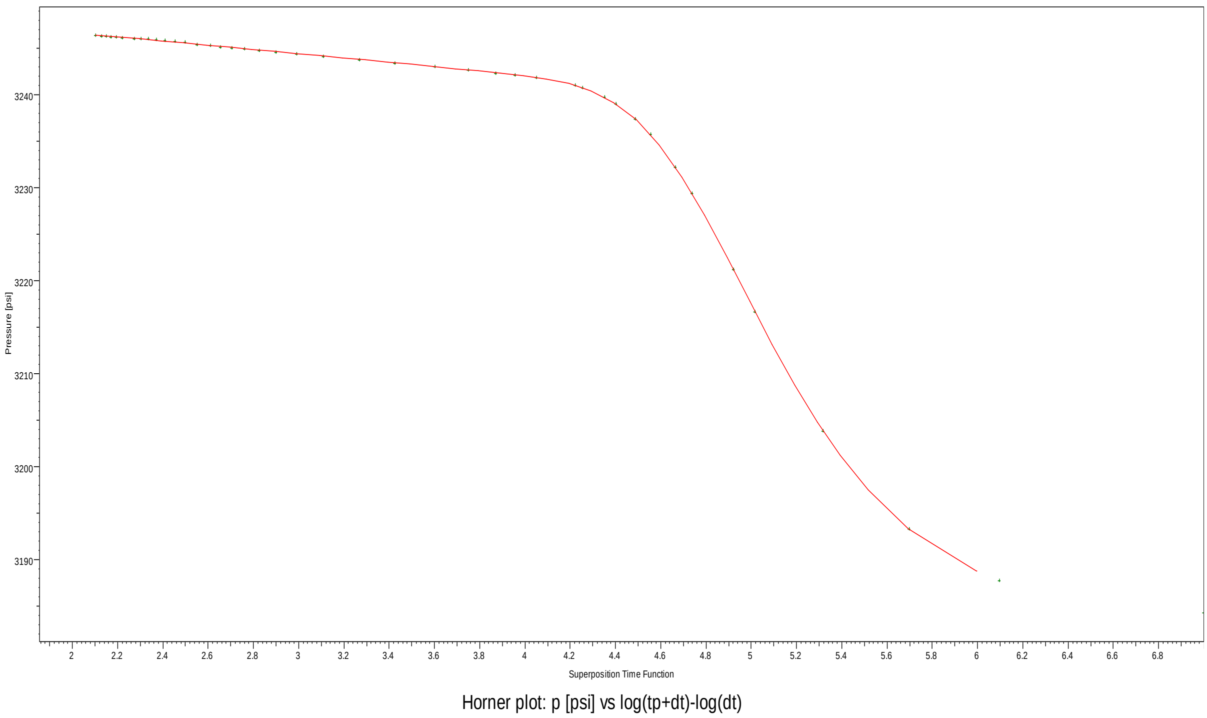

Fig 8: The Horner plot[Semilog plot of bottom-hole pressure vs log (tp + Δt)/Δt]

From the semilog Horner plot shown above, the constraint points which represents the measured data obtained from Well X properly match the derivative type curve and shows a good model for well test interpretation of the reservoir and wellbore characteristics as well as identifying the different flow regimes such as the early transient region(ETR), middle transient region that shows the intermediate times(MTR) and the late transient region(LTR) of the tested well.

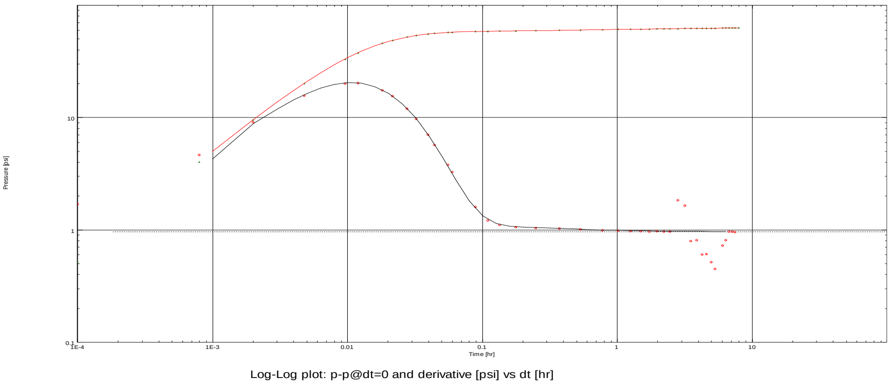

Fig 9: Log-Log plot of differential pressure(dp) and pressure derivative(dp') vs.dt(hr)

From the Log-Log plot (derivative plot) shown above, the delta-pressure (differential pressure) versus delta-time (dt) is plotted by the upper curve and the lower curve is used to plot the pressure derivative (dp') versus the delta time(dt). The lower curve is called the first derivative of the Horner plot; and represents the slope of the Horner semilog straight line that is used to estimate the reservoir and wellbore parameters such as skin(S) and reservoir permeability(k).

The vertical separation between the two plots is a negative of the skin i.e. a larger separation will mean a larger skin and vice versa.

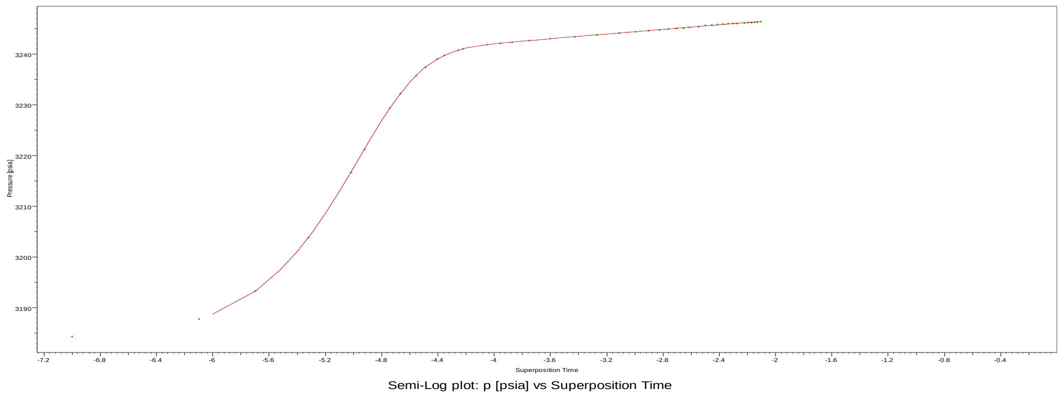

Fig 10**:** The Semilog plot of pressure[psia] vs Superposition Time

Pressure Transient Test Summary and Results from KAPPA-Saphir

The test summary and pressure transient results are listed as follows in the table below:

Table 4: Pressure transient test Summary and Results from KAPPA-Saphir

Model Parameters	**Values**	**Units**
TMatch	2710	[hr]-1
PMatch	0.521	[psia]-1
C	0.00899	bbl/psi
Total Skin	24.8 --	
k.h, total	49623.8	md.ft
Pi	3251.03	Psia
Well & Wellbore parameters (Tested well)		
C	0.00899	bbl/psi
Skin(S)	24.8 --	
Reservoir & Boundary parameters		
Initial Reservoir Pressure(Pi)	3251.03	Psia
Permeability thickness Product(k.h)	49623.8	md.ft
Permeability(k)	992md	Md
Derived and Secondary Parameters		
Radius of Investigation, R_{inv}	1490	Ft
Test. Vol.	15.4773	MMB
Delta P (Total Skin)	47.5982	Psi
Delta P Ratio (Total Skin)	0.7602	Fraction

Analytical Solutions for Estimating Reservoir and Wellbore Parameters

The Microsoft excel sheet is used to plot the measured pressure build-up test data versus the time obtained during the pressure transient test, and the reservoir and wellbore parameters were estimated.

Calculating the Wellbore Storage Constant

A plot of ΔP= (P_{ws}-P_{wf}) versus log Δt on a log-log graph gives the wellbore storage constant during the early transient region (ETR) of the build-up period. This can be done by selecting a match point that is strongly affected by wellbore storage effect on the early time line of unit slope as shown in **Figure 11**, tracing the corresponding Δt*and ΔP and calculating the wellbore storage constant(C) using the equation shown below:

$$C_s = \frac{q_s B}{24\Delta P} t \qquad (2)$$

Where,

C_s =Wellbore storage constant in bbl/psi.

q_s = The flow rate in STB/D

B = Oil formation volume factor B/STB

ΔP = Shut-in wellbore pressure - Flowing wellbore pressure (P_{ws} - P_{wf}) in P_{si}

t = Matching time that corresponds to the match point selected on the unit slope in hr.

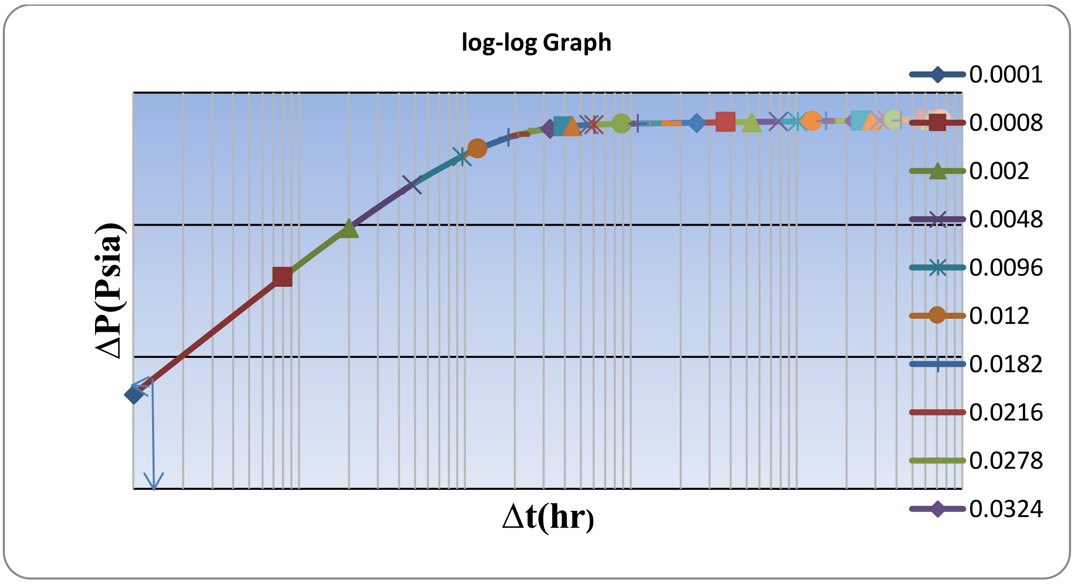

Fig 11**:** Excel sheet Showing the Log-Log Plot for the Buidup test analysis

Hence,

Δt* = 0.00015hr

ΔP = 0.7psia

q= 1000stb = flow rate before shut-in.

By substituting the above parameters into equation (2) above, strong wellbore storage coefficient(C) is obtained:

$$Cs = \frac{1000 \ x \ 1.125}{24 \ x0.7} \text{x } (0.00015) = 0.010045\text{bbl/psi}$$

To determine wellbore storage effect i.e where wellbore storage effect dies completely, the 50Δt* (1.5 cycle) gentle slope rule is used as shown below:

C = 50Δt* = 50 x 0.00015 = 0.0075bbl/psi

Estimating the Slope(m), Average permeability(k), Permeability thickness product, Skin Factor(s) and the Average reservoir pressure(P*)

The Horner method (conventional method) is applied for estimating the slope (m), the average reservoir permeability (K), the total skin factor(S) and the average reservoir pressure(P*) of the infinite-acting homogeneous reservoir.

By plotting the bottom-hole shut-in pressure (P_{ws}) versus $\log\frac{t_p+\Delta t}{\Delta t}$ in a semilog paper as shown in Figure 11, the aforementioned parameters for Well X are estimated.

The Horner's plot, shows the scale of time ratio $[\frac{t_p+\Delta t}{\Delta t}]$ which increases from right to left and is obtained by adding the time of production(t_p =1000hrs) to the shut-in time(Δt) and dividing $(t_p + \Delta t)$ by the shut-in time(Δt). This is done over the entire shut-in time period and the figure below is obtained.

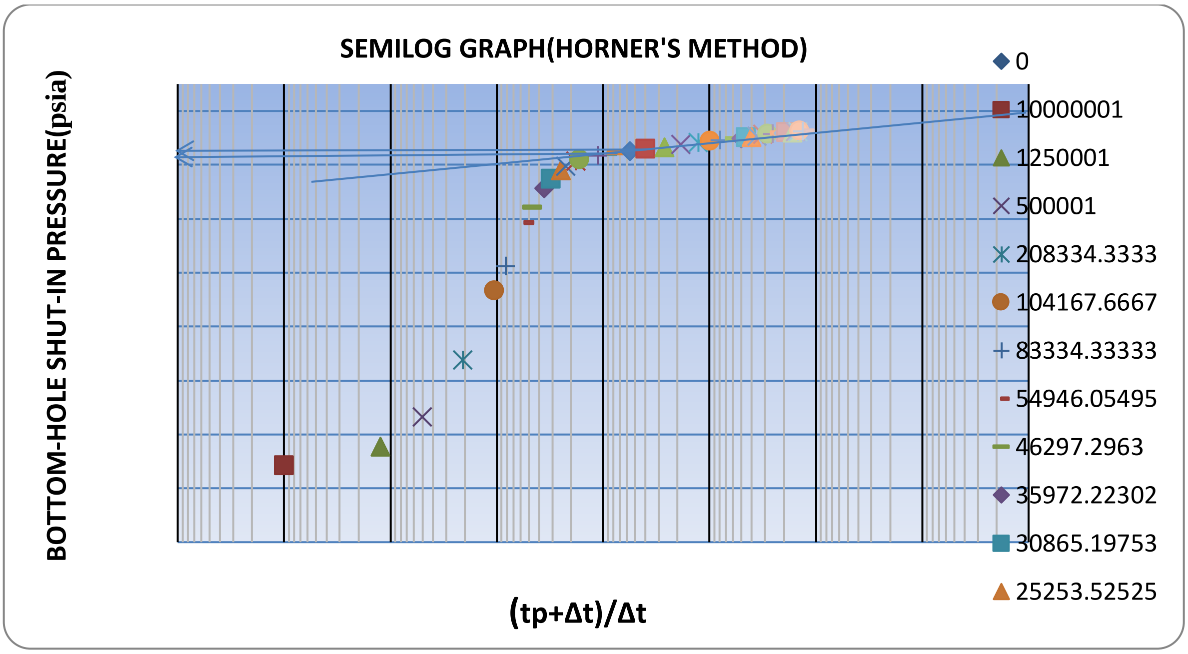

Fig 12: Excel Sheet Showing the Semilog Plot for the Build-up test analysis.

Analytical method (Microsoft excel sheet) for estimating the slope(m)

The slope(m) of the Horner semilog straight line in the Excel sheet shown in Figure 12, can be estimated by taking two points on the straight line that is in the middle transient region (where the pressure response indicates an infinite-acting reservoir), tracing the corresponding bottom-hole shut-in pressures and finding the difference between the two pressures.

Let the bottom-hole pressures selected be P_{ws1} and P_{ws2}.
Where,
Pw_{s1} = The point corresponding to the upper bottom-hole pressure at the middle time region where the pressure response is infinite-acting.
P_{ws2} = The point corresponding to the lower bottom-hole pressure at the middle time region where the pressure response is infinite-acting.
From Error! Reference source not found.**2**
Pw_{s1}= 3242.953
P_{ws2}= 3241.103
The slope (m) = Pw_{s1} - P_{ws2} = 3242.953 - 3241.103 = **1.85psi/cycle**

Analytical solution for estimating the average reservoir permeability(k)

The average reservoir permeability can be estimated using equation (3) as shown below:

$$k = \frac{162.6q\beta\mu}{mh} \quad (3)$$

Where,
q = 1000STB/D = Production rate
β = 1.125rb/STB = Oil formation volume factor
µ = 0.6cp = Oil viscosity
k = Average reservoir permeability =**?**
h = 50ft = Net formation thickness
m = Horner semilog straight line slope = 1.85psi/cycle

From equation (3) above,

$$k = \frac{162.6q\beta\mu}{mh}$$

$$k = \frac{162.6\ x\ 1000\ x\ 1.125\ x\ 0.6}{1.85\ x\ 50}$$

k = **1186.54md**

Analytical solution for estimating the permeability thickness product (kh)

$$kh = \frac{162.6q\beta\mu}{m} \quad (4)$$

$$= \frac{162.6\ x\ 1000\ x\ 1.125\ x\ 0.6}{1.85}$$

kh= 59,327.03md. ft

Note: The permeability thickness product also represents the reservoir formation capacity.

Analytical solution for estimating the skin factor(S)

$$S = 1.151\left\{\frac{P_{1hr} - P_{wf}(t_p)}{m_1} - \log\frac{k}{\emptyset\mu C_t {r_w}^2} + 3.232\right\} \quad (5)$$

Where,
P_{1hr} = Pressure at 1hr from the Horner semilog straight line portion of the curve = 3244.104

Note: Pressure at 1hr corresponds to Pws when {tp + dt}/{dt}= {1000 + 1}/ {1} =1001]

$P_{wf}(t_p)$ = Pressure corresponding to the time of shut-in (P_{wf}@ $\Delta t = 0$)

$$S = 1.151\left\{\frac{3244.104 - 3183.78}{1.85} - \log\frac{1186.54}{0.25\ x\ 0.6\ x 2x10^{-5} x 0.5^2} + 3.232\right\}$$

S = 1.151 x {32.6076 - 9.1219+ 3.232}

= 1.151 x {20.2537} = **23.31**

Analytical solution for estimating the additional pressure drop around the damaged zone

The additional pressure drop around the altered zone decreases the production rate and is expressed as:

$$\Delta P_{skin} = 0.87|m|s \qquad (6)$$

= 0.87 x 1.85 x 23.31

= **37.52**

Analytical solution for estimating the average reservoir pressure

Due to the fact that the reservoir is finite, continuous production will lead to a decline in pressure throughout the reservoir. At this point, the semilog straight line will not extrapolate to the initial reservoir pressure (P_i) but rather to the false pressure (P*). As illustrated by Mathews and Russell (1967), the false pressure has no physical meaning but is equivalent to the initial reservoir pressure (P_i) only if the field in question is a newly developed field. The false pressure (P*) is estimated using the expression:

$$P_{ws} = P^* - m\left[\log\frac{t_p + \Delta t}{\Delta t}\right] \qquad (7)$$

$$P^* = P_{ws} + m\left[\log\frac{t_p + \Delta t}{\Delta t}\right]$$

Where,

P_{ws} = Shut-in well pressure when time scale ratio$\left[\frac{t_p + \Delta t}{\Delta t}\right]$ =1hr = 3244.104psia

m = Slope of the Horner semilog straight line = 1.85

t_p = The flowing time before shut-in, hours = 1000hrs

Δt = Shut-in time, hours = 1hr

By substituting into equation (7) above, the false pressure is obtained:

P^* = 3244.104 + 1.85 [log (1000 + 1)/(1)]

= 3244.104 + 5.551 = **3249.65psia**

NOTE: The false pressure (P^*) can be estimated by extrapolating the Horner semilog straight line to $\left[\frac{t_p + \Delta t}{\Delta t}\right]$ =1hr = **3250psi**

Table 3**:** Results Summary Obtained from Numerical Simulation and Analytical Solutions

RESERVOIR AND WELLBORE PARAMETERS	NUMERICAL SIMULATION USING KAPPA-SAPHIR	ANALYTICAL SOLUTION USING MICROSOFT EXCEL SHEET
Permeability(K)	992md	1186.54md
Permeability thickness product(kh)	49623.8md.ft	59327.03 md.ft
Skin factor(s)	24.8	23.31
Wellbore storage constant(C)	0.00899bbl/psi	0.010045bbl/psi

V. DISCUSSION

From the results obtained, it is clearly seen that the oil well is not stimulated rather it is damaged as a result of wellbore skin. The vertical well in this case study is a candidate well for workover operations due to a high positive skin factor obtained. The Kappa Saphir gives a higher estimation of skin value (S = +24.8) as compared to the skin value (S= +23.31) obtained when using analytical solutions with Microsoft excel sheet. The cause of high skin well damage in this Niger Delta production well may be due to plugged or limited perforations. We know that the Niger Delta formation has permeability greater than 1000mD; so the high average reservoir permeability values (1186.54md and 992md) still obtained after analytical and Numerical analysis is as a result of the test being conducted in a highly permeable formation like the Niger Delta Basin in Nigeria. Both analysis used for reservoir property estimation showed close results. The transient state phase observed in Figure 10 has a short duration due to the high permeable Niger Delta Formation. The welltest was run long enough to reach infinite-acting radial flow phase which made it possible for the Horner semilog straight line to be obtained during the pressure transient analysis. Pressure loss in the production tubing as a result of the pressure gauge being located at a shallow position can lead to a very large positive skin even when the well may not be damaged.

From the Log-Log plot of differential pressure (dp) and pressure derivative (dp') vs. dt(hr) as shown in Figure 9, a clearly defined "wellbore storage hump" is observed due to gas phase segregation arising as the vertical oil well is shut-in. This causes dissolved gas to move out of the solution to the top of the wellbore. From the analytical solutions carried out, it is observed that inaccurate placement of the Horner semilog straight line would definitely lead to improper estimation of the slope (m) which will negatively influence the estimation of reservoir and wellbore parameters like permeability (K) and skin (S).

VI. CONCLUSION AND RECOMMENDATION

From the Log-Log plot (derivative plot) of differential pressure(dp) and pressure derivative(dp') versus dt(hr), Horner semilog plot of the bottom-hole pressure versus (tp + dt)/dt and the semilog plot of pressure(psia) versus the superposition time, you will notice that the model chosen in Kappa Saphir properly match the measured data from WELL X.

The results achieved using Kappa Saphir corresponds with the results achieved using the Microsoft excel sheet. The Kappa Saphir package, enhances the speed with which the dynamic model can be created and also allows for proper investigation of other factors that may influence tests although so many computation and interpretation of graphs are involved which sometimes may lead to inconsistent results.

Due to the high skin wellbore damage affecting well's productivity, reservoir teams have sought for various recommendations to prevent the abandonment of oil and gas wells. From this study, the following recommendations are suggested and should be taken into proper consideration by Welltest engineers, reservoir, production and well completion engineers, and academicians:

- It is important to note that moving gauges during well test before shut-in or during build-up, will render the bottom-hole pressure test useless. Ensure that your pressure gauge is well calibrated to avoid errors during well test data interpretation. Leaks during bottom-hole pressure build-up tests will lead to continuous flow, and this will make the sandface rate not to be equal to zero ($q_{sf} \neq 0$) [7].
- Further calculations can be carried out to estimate the individual pseudoskin contributing to the total skin. This may include: damaged zone skin (S_d), and partial penetration skin (S_{pp}). It should be noted that the total skin effect is composed of a number of factors that cannot be removed by conventional matrix treatments.
- Noise during pressure readings by gauge may cause overestimation and underestimation of reservoir and wellbore parameters, and the derivative plots may have features which may be misinterpreted as boundary effect.
- The conventional method (Horner's method) in cooperation with excel sheet provides a fast and easy means of plotting the measured data to obtain the slope (m) for estimating reservoir permeability and skin factor.
- Due to the difficulties in estimating the slope (m) of the Horner semilog straight line from the graph plotted using excel sheet, large graphs at least of 11″ x 8″ should be created for easy reading of the slope (m) used for estimating average reservoir permeability (K). Nevertheless, this procedure has uncertainties which may affect the estimated results.
- The use of Kappa Saphir (PTA) for the quantification of formation damage is faster, interactive, robust and more reliable when working with a huge number of gauge data (normally more than 5000). Some other good packages such as Fekete Welltest, PIE and Pansystem should be used for pressure transient analysis.
- Optimizing well completion operation will help to avoid mechanical skin damage. The higher the wellbore damage, the higher the skin value. A large positive skin in a high permeable reservoir reveals an opportunity to optimize production rate by well treatments such as creating new perforations, well acidizing or hydraulic fracturing to reduce skin factor.
- Laboratory tests should also be conducted on the cores for proper and economical means of formation damage assessment. This is to ensure that the petrophysical properties of the Niger Delta sandstone formation is optimized using matrix acidization treatments to reduce the effect of skin due to damage thereby optimising well's productivity.
- To avoid further damage of the formation, matrix acid treatments should be pumped at pressures that are lower than the fracturing pressure to ensure that damages plugging the pore spaces of the rock matrix are removed and flow through the pore spaces are intact. Kalfayan [5] recommended that pressure transient well test should be conducted even after stimulation operation (pp. 23).
- The data collected during well testing should be validated by checking the accuracy of devices used for recording, checking the start and end of flow periods, and checking the consistency in well flow rates.

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APPENDIX A

GENERATED BUILD-UP TEST DATA [SOURCE: Onyekonwu, 1997]

Shut-in Time, hr	Pressure, psi	Shut-in Time, hr	Pressure, psi
0.00000	3183.763	1.01760	3244.368
0.00010	3184.281	1.25760	3244.574
0.00080	3187.768	1.49760	3244.743
0.00200	3193.224	1.73760	3244.887
0.00480	3203.799	1.97760	3245.011
0.00960	3216.630	2.21760	3245.122
0.01200	3221.209	2.45760	3245.220
0.01820	3229.340	2.81760	3245.352
0.02160	3232.170	3.17760	3245.467
0.02780	3235.686	3.53760	3245.569
0.03240	3237.330	3.89760	3245.662
0.03960	3238.996	4.25760	3245.746
0.04440	3239.712	4.61760	3245.824
0.05570	3240.730	4.97760	3245.895
0.06000	3240.973	5.33760	3245.962
0.08880	3241.795	5.69760	3246.024
0.11040	3242.080	6.05760	3246.082
0.13440	3242.302	6.41760	3246.137
0.17760	3242.598	6.77760	3246.189
0.24960	3242.953	7.13760	3246.238
0.37440	3243.372	7.49760	3246.285
0.53760	3243.738	7.95360	3246.341
0.77760	3244.104		

APPENDIX B

BUILDUP TEST DATA FROM WELL X IN NIGER DELTA PROVINCE

t_p = production time = 1000

Pws (psi)	ΔP(Pws-Pwf)	Shut-in Time Δt (hr)	(tp + Δt)/ Δt	Q
3183.763		0.0000	0	1000
3184.281	0.518	0.0001	10000001	1000
3187.768	4.005	0.0008	1250001	1000
3193.224	9.461	0.002	500001	1000
3203.799	20.036	0.0048	208334	1000
3216.63	32.867	0.0096	104167.7	1000
3221.209	37.446	0.012	83334.33	1000
3229.34	45.577	0.0182	54946.05	1000
3232.17	48.407	0.0216	46297.3	1000
3235.686	51.923	0.0278	35972.22	1000
3237.33	53.567	0.0324	30865.2	1000
3238.996	55.233	0.0396	25253.53	1000
3239.712	55.949	0.0444	22523.52	1000
3240.73	56.967	0.0557	17954.32	1000

3240.973	57.21	0.06	16667.67	1000
3241.795	58.032	0.0888	11262.26	1000
3242.08	58.317	0.1104	9058.971	1000
3242.302	58.539	0.1344	7441.476	1000
3242.598	58.835	0.1776	5631.631	1000
3242.953	59.19	0.2496	4007.41	1000
3243.372	59.609	0.3744	2671.94	1000
3243.738	59.975	0.5376	1861.119	1000
3244.104	60.341	0.7776	1287.008	1000
3244.368	60.605	1.0176	983.7044	1000
3244.574	60.811	1.2576	796.1654	1000
3244.743	60.98	1.4976	668.735	1000
3244.887	61.124	1.7376	576.5064	1000
3245.011	61.248	1.9776	506.6634	1000
3245.122	61.359	2.2176	451.938	1000
3245.22	61.457	2.4576	407.901	1000
3245.352	61.589	2.8176	355.912	1000
3245.662	61.899	3.1776	315.7029	1000
3245.746	61.983	3.5376	283.6775	1000
3245.824	62.061	3.8976	257.5681	1000
3245.895	62.132	4.2576	235.8741	1000
3245.962	62.199	4.6176	217.5627	1000
3245.962	62.199	4.9776	201.9	1000
3246.024	62.261	5.3376	188.3501	1000
3246.082	62.319	6.0576	166.0819	1000
3246.137	62.374	6.4176	156.8215	1000
3246.189	62.426	6.7776	148.5449	1000
3246.234	62.471	7.1376	141.1031	1000
3246.285	62.522	7.4976	134.376	1000
3246.341	62.578	7.9536	126.7292	1000