GAS TRANSMISSIBILITY FORECAST AND THE SUSTAINABLE DEVELOPMENT OF NIGERIA'S DWINDLING ECONOMY

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Abstract

The United Nations Commission on Environment and Development has defined sustainable development as one which allows nations to meet their present needs without compromising the ability of future generations of the citizenry to meet their own needs. This concept of sustainable development is properly illustrated by a system which operates in an equilibrium state or in a steady state and hence undergoes changes at a monetary inflationary rate which is carefully and promptly regulated by the governmental agencies i.e. Central Bank of Nigeria (CBN) the financial institutions etc. Sustainable development of Nigeria's economy is directly hinged on the prudent and efficient management of its natural resources the greater percentage (approximately 80%) being natural hydrocarbon reserves. Natural gas as it comes from the well head is properly processed, liquefied in liquefied Natural gas (LNG) Cascade of Heat Exchangers for in country domestic application and for export for the boasting of the external monetary reserves. The paper highlights computational algorithms for the transmissibility forecast of gas delivery from a case study well Excravos field south west Nigeria. The simulation algorithm is translated into a software (MATLAB) which is implemented on a digital desktop computing device.

Keywords: *Pseudo-Pressure, Deliverability, Transmissibility, Isochronal Test, Nonlinearity, Stabilization Time.*

1.0 INTRODUCTION

Transmissibility refers to the testing of a gas well to measure its production capabilities under specific conditions of reservoir and bottom hole flowing pressure (BHFP). A common productivity indicator obtained from these measurements is the absolute open flow potential (AOF). The AOF is the maximum rate at which a well could flow against a theoretical atmospheric back pressure at the sand face. Another important parameter obtainable is the generation of reservoir inflow performance equations (IPE) or gas pressure curve. The IPE curve show the relations between surface production rate and BHFP for a specified reservoir pressure (original reservoir pressure in place). The IPE curve could be used to evaluate gas-well current transmissibility potential under a variety of surface conditions i.e. production against back pressure. In addition the IPE could be used to forecast the future production at any stage in the reservoir's life (Al Hussainy et al, 1966).

Several methods had been devised for making transmissibility forecasts for gas wells. Flow-after-flow tests are conducted by producing the well as a series of stabilized production flow rate and measuring the stabilized bottom hole pressure (BHP). Each flow rate is stabilized in succession without an intermediate shut-in period. A single point test is conducted by flowing the well at a single rate until the BHFP is stabilized. The other methods include the isochronal and modified isochronal tests. An isochronal tests consists of a series of single point tests usually conducted by alternately producing at a stabilized (or slowly declining) sand face rate and then shutting in and allowing the well to build to the average reservoir pressure before the next flow period. The modified isochronal test is conducted similarly except flow periods are of equal duration and the shut in periods are of equal duration (but not same as the flow periods).

2.0 DEVELOPMENT OF THE GAS TRANSMISSIBILITY MODEL

The equation describing the flow of a real gas through a radial, homogenous, isotropic, porous medium is given by (Lee et al., 1996).

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{p}{\mu_g z}\frac{\delta p}{\delta r}\right)\frac{1}{0.0002637} = \frac{\phi C_t p}{k_g z}\frac{\partial p}{\partial t} \qquad (1)$$

This is non-linear partial differential equation hence to linearize it, we assume $\frac{p}{\mu_g z}$ to be constant with respect to pressure hence we can write (1) as

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right) = \frac{\phi_{\mu_g c_t}}{0.0002637}\frac{\partial p}{k_g \partial t} (2)$$

$$Introducing \quad p\frac{\partial p}{\partial r} = \frac{1}{2}\frac{\partial p^2}{\partial r} \qquad (3)$$

$$and \;\; p\frac{\partial p}{\partial t} = \frac{1}{2}\frac{\partial p^2}{\partial t} \qquad (4)$$

Substituting (3) and (4) into equation (1) we have

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{r}{\mu_g}\frac{\partial p^2}{\partial r}\right) = \frac{\phi C_t}{0.0002637kg}\frac{\partial p^2}{z\partial t} \qquad (5)$$

If $u_g z$ *is constant then* (5) *can be written as*

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p^2}{\partial r}\right) = \frac{\phi \mu_g C_t}{0.0002637kg}\frac{\partial p^2}{\partial t} \qquad (6)$$

Utilizing the real gas pseudo-pressure transformation by (Al-Hussainy et al, 1966)

$$P_p = 2\int_{P_p}^{p}\frac{p}{\mu_g z}dp \qquad (7)$$

We can re-write equation (1) as

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P_p}{\partial r}\right) = \frac{\phi \mu_g(P) C_t(P)}{0.0002637kg}\frac{\partial P_p}{\partial t} \qquad (8)$$

2.1 Nonlinear Pseudo Pressure Transformations

Equation (8) is not completely linear because μ_g (P) depends on both Pressure and Pseudo Pressure and an acceptable approximation is to assume that $\bar{\mu}_g(_t$ is constant and can be conveniently evaluated at some $\bar{P}$. Familiar solutions such as the Ei-function solution are reasonably accurate for gas wells when the Pseudo Pressure Linearizing transformations are utilized. The early time or transient solution to equation (8) for constant rate production from a well in a radial reservoir with closed outer boundaries is

$$P_p(P_s) - P_p(P_{wf}) = \frac{1.422 \times 10^6 q^T}{k_g h}\left[1.151 log\left(\frac{k_g t}{1.688\phi\bar{\mu}_g C_t r_w^2}\right) + s + D_q\right]$$

where $P_s =$ the stabilized shut-in BHP (9)

For late time or pseudo steady state solution to equation (8) we have (Houperut, 1959).

$$P_p(\bar{P}) - P_p(P_{wf}) = \frac{1.422 \times 10^6 q^T}{k_g h}\left[1.151 log\left(\frac{10.06A}{C_A r_w^2}\right) + s + D_q\right] \qquad (10)$$

(Houpeurt, 1959) wrote equation (10) as a quadratic i.e.

$$\Delta P_p = P_p(P_s) - P_p(P_{wf}) = a_t \mathrm{q} + \mathrm{b}q^2 \qquad (11)$$

$$where\ a_t = \frac{1.422 \times 10^6 q^T}{k_g h}\left[1.151 log\left(\frac{k_g t}{1.688\phi\bar{\mu}_g C_t r_w^2}\right) + s\right] \qquad (12)$$

or for pseudo steady state flow as

$$\Delta P_p = P_p(\bar{P}) - P_p(P_{wf}) = a\mathrm{q} + \mathrm{b}q^2 \qquad (13)$$

$$where\ a = \frac{1.422 \times 10^6 q^T}{k_g h}\left[1.151 log\left(\frac{10.06A}{C_A r_w^2}\right) - \frac{3}{4} + s\right] \qquad (14)$$

The q^2 term represent the inercial and turbulent flow effects which result from

high gas flow velocities near the wellbore

$$b = \frac{1.422 \times 10^6 TD}{k_g h} \qquad (15)$$

The non-darcy flow coefficient D is defined in terms of turbulence factor β which is correlated with the reservoir rock properties i.e. permeabilities and porosities.

$$D = \frac{2.715 \times 10^{-12} \beta k_g M P_{sc}}{h\mu_g(P_{wf}) rw\, T_{sc}} \qquad (16)$$

2.2 Empirical Correlations for Estimating Transmissibility of Gas

(Rawlins and Schellhardt, 1935) developed empirical mathematical correlations for predicting gas transmissibility in MMSCF/D as

$$q = C\left(P^2 - P_{wf}^2\right)^n \qquad (17)$$

In terms of Pseudo pressure equation (17) is

$$q = C\left[P_p(\bar{P}) - P_p(P_{wf})\right]^n \qquad (18)$$

C = stabilized performance coefficient and n is the inverse slope of the line on a log-log plot of the change in pressure squared or pseudo pressure versus gas flow rate depending on the flow conditions theoretical value for n lies between 0.5 for turbulent non Darcy flow behavior to 1.0 for flow behavior described by Darcy's equation.

3.0 ESTIMATION OF STABILIZATION TIME ON FLOW DATA

The stabilization time for a flowing gas well such as the case study well under consideration is defined as the time when the flowing pressure is no longer changing or is no longer changing significantly with time. Physically stabilized flow is interpreted to be the time when the pressure transients is affected by a No flow boundary either a natural reservoir boundary or an artificial boundary created by active wells surrounding the test well. The radius of investigation r, which is the point in the formation beyond which the pressure drawn down is negligible, is given by

$$r_i = \sqrt{\frac{k_g t_s}{948\phi\bar{\mu}_g\bar{C}_t}} \qquad (19)$$

Stabilized flow conditions occur when r_i equals or exceeds the distance to the no-flow boundary of the well $r_i \geq r_e$ consequently using this in equation (19) we have the empirical correlation for predicting the stabilization time for a well at the centre of a circular drainage area as

$$t_s = \frac{948\phi\bar{\mu}_g\bar{C}_t r_e^2}{k_g} \qquad (20)$$

As long as $r_i \leq r_e$ then stabilization has not been attained and the pressure behavior is still transient

3.1 Case Study Analysis and Data Validation

Table 1.0 show the stabilization times in gas transmissibility testing computed for a case study well in the Escravos Swamp fields producing gas with a specific gravity of 0.6 from a formation of 210°F and at an average pressure of 3,500psia ($\bar{\mu}_g = 0.2\ C_p\ and\ \bar{C}_t = 2.468\ \times 10^{-4}\ psia^{-1}$ and a porosity of 10% as shown in Fig 1.0

The deliverability exponent was determined from a plot of equation (17) on a log-log chart and the computed n is approximately 0.67 indicating turbulent flow of gas within the entire drainage area. If a value of n = 1.0 is obtained it shows completely laminar flow in the drainage region. The stabilized performance coefficient C was obtained to be C = 8.12 $\times 10^{-4}$ hence the transmissibility of gas at $\bar{\rho}$ = 407.6psia is computed to be q = 49.7MMSCF/D. Table 2 is the flow after flow test data set.

4.0 DISCUSSION OF RESULT AND CONCLUSION

From the result of the computations using the MATLAB software table 1.0 for case study well it was observed that wells completed in low permeability reservoirs requires very long stabilization time, several days if not years to reach stabilization flow compared to those completed in high permeability formations. The computed deliverability exponent also show the well is operating within the turbulent flow (transient) region Table 2.0 was plotted for log (q) vs log $(P^2 - P_{wf}^2)$ and this enabled the computing of the deliverability exponent as n = 0.67 and hence the gas transmissibility was determined as q = 49.7MMSCF/D.

Table 1: Computing Stabilization time for Case Study Well

K(md)	A(Acres)	$t_s(hours)$
0.01	40	25.953 (3yrs)
0.01	640	415.242(47yrs)
0.1	40	2,595(108yrs)
0.1	640	41.524(4.7yrs)
1.0	40	259.5(10/8yrs)
1.0	640	4,152.4(173yrs)
10.0	40	25.95(1.1days)
10	640	415.2(17.3days)
100.0	40	2-59(0.11days)
100.0	640	41.52(1.73days)
1000.0	40	0.259(0.011days)
1000.0	640	4.15(0/173days)

Table 2: Flowing Well Test Data

q(MMSCF/D)	$T_{tf}(^0F)$	P_{tf}(Psia)	P_{wf}(psia)	$P_p(P_{wf})$ (psia$^2/cp$
0	75	375.2	407.60	1.6173×10^7
4.288	70	371.2	403.13	1.5817×10^7
9.265	73	361.3	393.03	1.5032×10^7
15.552	77	343.8	375.79	1.3736×10^7
20.177	77	327.1	359.87	1.2591×10^7

Nomenclature and Units

a = Stabilized deliverability coefficient (psia^2-C_t)/(MMSCFD)
a_t = transient deliverability coefficient (psia^2-C_t)/(MMSCFD)
A = drainage area of well ft^2
b = deliverability coefficient (psia^2-C_t)/(MMSCFD)
C_f = formation compressibility, psia^{-1}
$\bar{C}_g$ = gas compressibility at average pressure, psia^{-1}

C_t = total system compressibility psia^{-1}
C = Stabilized performance coefficient MMSCFD/(psiaP$)^n$
C_A = shape factor
D = Non Darcy flow constant, D/MMSCF
h = net formation thickness, ft
Pp = gas pseudo pressure, psia^{-2}/C_p
Pp(P_{wf}) = flow sandface pseudo pressure psia^{-2}/C_p
Pp(P_{ws}) = static sandface pseudo pressure psia^{-2}/C_p
P_s = stabilized shut-in BHP before deliverability test
q = total well stream gas flowrate, MMSCF/D
P_{wf} = BHFP, psia
P_{tf} = flowing well head pressure, psia
n = inverse slope of deliverability curve
r = radial distance from well bore centre, ft
r_e = external drainage radius, ft
r_i = radius of investigation, ft
r_w = well bore radius
k_g = reservoir effective permeability to gas, md
P_{ws} = shut-in BHP, psia
S = skin factor, dimensionless
t = elapsed time, hours
t_D = dimensionless time
S_g = gas saturation, %
S_o = oil saturation, %
S_w = water saturation, %
rd = effective (transient) drainage radius, ft
ΔP_p = difference of static and flowing sandface pseudo pressure, psia^2/C_p
β = turbulence factor
μ_g = gas viscosity, C_p
ϕ = porosity of reservoir, rock, fraction
T = temperature, ^oR
T_f = temperature, ^oF
t_s = well stabilization time, hours
$\bar{P}$ = average reservoir pressure, psia
$\bar{\mu}_g$ = gas viscosity at average reservoir pressure and temp, C_p
Z = gas-law deviation factor, dimensionless
M = molar gas rate, Mol/sec.

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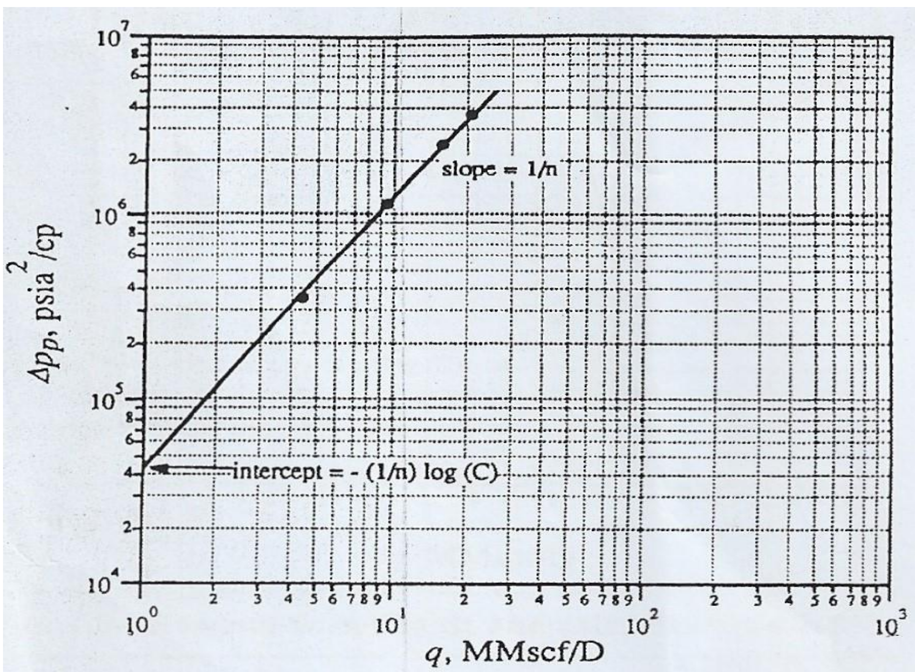

Figure.1: Plot of Gas Transmissibility