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A Deliverability Method for Estimating Stabilized Gas Well Performance during Transient Flow in Unconventional Reservoir

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Abstract

This study discusses the determination of the stabilized flow coefficient, C, in the Rawlins and Schellhardt equation. It is applicable in the reservoir with low porosity and permeability model, usually found in unconventional reservoirs. In determining the flow coefficient, a deliverability test method proposed by Hashem and Kazemi was used during the transient flow period of a gas well. Besides, in determining the deliverability exponent, n, used in the least squared analysis equation derived by Johnston and Lee in the determination of C stabilized so that from each value of n, there will be supporting data for determining stabilized flow coefficient. Finally, the application and previous method will determine the flow coefficient value based on reservoir model time stabilization. Later it compares with the John Lee equation and IPR constructs from the model and John Lee.

INTRODUCTION

Rawlins & Schellhardt (1986) developed a gas deliverability equation based on pressure squared and flow coefficients. Recent discoveries of unconventional reservoirs have changed history in oil and gas production activities (Holditch, 2006). Unconventional reservoirs such as tight-gas sands, gas and oil shales, coalbed methane, heavy oil and tar sands, and gas-hydrate deposits need special treatment in processing and producing the resources (Acquah-Andoh et al., 2019; Bakshi et al., 2017; Guo et al., 2016; Hidayat, 2016; Moridis et al., 2009; Suranto, 2016). Applying the Rawlins and Schellhardt equation for an unconventional reservoir will take a long time to stabilize due to the very small permeability and porosity values (Johnston et al., 1991). In this study, one of the case models in the unconventional reservoir will be discussed, namely Tight Gas Reservoir. In determining the stabilized flow coefficient, the deliverability test method will assist by well test data in the tight gas reservoir model while it is in the transient period (Al-Attar & Al-Zuhair, 2008; Al-Hussainy & Ramey, 1966; Chase & Anthony, 1988; Zhao et al., 2019). A tight Gas Reservoir is a type of reservoir that has porosity below 10% and has an average permeability below 0.6 mD, according to the German Society for Petroleum and Coal Science and Technology (DGMK). The existing model will be computed using CMG (Computer Modeling Group) IMEX Software to create its reservoir model from various reservoir properties. From that model, Isochronal data can be made. Isochronal data itself is a well test data conducted when opening the well until a period of time and shut-in until the bottom hole pressure returns to the reservoir pressure and carried out several times.

The deliverability test uses data while still in a transient flow. It used to predict the flow coefficient's value when it has entered a stabilized flow or pseudo-steady-state using time stabilization. Later it will be computed using Saphir software to determine it.

Rawlins & Schellhardt (1986) stated that when the pressure squared data is plotted in a log-log scale with a gas rate, it will produce a straight line equation which can be represented in the following equation :

$$Qg=C\,(Pres^2-Pwf^2\,)^n \quad (1)$$

Existing methods and applications are one way to get a stable C without the need for data flow stabilized by using data well tests and predicting the performance of a gas well in the tight gas reservoir model.

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BASIC THEORY AND DEVELOPMENT

Deliverability testing is a test conducted on a gas well that aims to measure the production gas's performance in certain reservoir conditions that are usually associated with bottom hole pressure (BHP) in the well. Also, deliverability tests help measure Absolute Open Flow (AOF) in a gas well where AOF is the maximum rate that can flow against the ideal atmospheric pressure in the sandface. Usually, AOF conditions cannot be achieved. However, AOF can determine gas production performance that is allowable to determine the amount of production in a gas well. The Deliverability Test on a gas well can also determine several reservoir properties such as skin, permeability, and wellbore storage. In this study, using the deliverability method requires data pressure to measure time stabilization and flow coefficient. The simulator aims to obtain pressure and time stabilization data from the desired reservoir model while finding the flow coefficient value related to the deliverability exponent. To get the stabilized C from Rawlins and Schellhardt, Eq. 1 will be arranged to get the form.

$$Pi^2 - Pwf^2 = \frac{1}{C^{\frac{1}{n}}}\, q^{\frac{1}{n}} \tag{2}$$

In transient flow, it is also known that compressible flow can be applied in gas well so that the following equation is formed

$$Pi^2 - Pwf^2 = 1422\frac{\mu zT}{K_g h} q\ [\ln\left(\frac{k_g\, t}{1688\phi\mu C_t r_w^2}\right)^{\frac{1}{2}} + s + D|q|] \tag{3}$$

Where :

$$\mathrm{D} = 1.8295 \times 10^{-13}\, \frac{\beta\rho}{2\pi h}\frac{k_g}{\mu}\frac{B_g}{r_w} \tag{4}$$

Besides that, Eq. 3 can be rewritten as

$$Pi^2 - Pwf^2 = a(t)q + bq^2 \tag{5}$$

$$\frac{Pi^2 - Pwf^2}{q} = a(t) + bq \tag{6}$$

Where :

$$a(t) = 1422\frac{\mu zT}{K_g h}\ [\ln\left(\frac{K_g t}{1688\phi\mu C_t r_w^2}\right)^{\frac{1}{2}} + s] \tag{7}$$

with a slope which, if extrapolated with time stabilization it will get a stabilized value of a. By substituting Eq. 2 and Eq. 3, a new equation form can be obtained :

$$\frac{1}{C^{1/n}}\, q^{1/n} = 1422\frac{\mu zT}{k_g h} q\ [\ln\left(\frac{k_g t}{1688\phi\mu c_t r_w^2}\right)^{1/2} + S + D|q| \tag{8}$$

If a(t) is plotted with log t, it will obtain a straight line equation with slope and intercept b. If Q = 1 Mscf / D and t = 1 hour input in that slope it will get the equation :

$$\frac{1}{C^{1/n}} = 1637\frac{\mu zT}{k_g h}\ [\log\left(\frac{k_g}{1688\mu\phi c_t r_w^2}\right) + \log t + \ 0.869\ s] + b \tag{9}$$

Where :

$$b = m[\log\left(\frac{k_g}{1688\mu\phi c_t r_w^2}\right) + \log t + 0.869\ S] \tag{10}$$

From the above equation, it can be seen that if the plot of $\frac{1}{C^{1/n}}$ vs log t gives a straight line, then stabilized C can be obtained by inputting stabilization time into the straight linear equation.

Time stabilization can be defined as the time used by the investigation radius to reach the reservoir boundary of a well. Spivey & Lee (2013) reported that time stabilization is the estimated time to achieve stabilized flow. The time stabilized equation is described in the form below.

$$Ts = 948\ \frac{\phi\mu C_t re^2}{k_g} \tag{11}$$

The coefficient 948 is a constant resulting from a derivation in the existing method. The other variables are the reservoir properties that determine whenever the gas well stabilization time can be achieved.

When plot log $P_i^2 - Pwf^2$ vs log q, it will get a straight line equation at each period in isochronal data. The curve will get the values of C and n where if C is changed in the form $\frac{1}{C^{\frac{1}{n}}}$ and plotted with log t, it will get an equation

$$\frac{1}{C^{\frac{1}{n}}} = m\ log\ t + Constant \tag{12}$$

The value of deliverability exponent (n), then followed by the Johnston and Lee equation analyzed through least-squared regression, the equation n for each line :

$$n = \frac{N\sum_{J=1}^{N}(\log Q_g \log \Delta P_p)_j - \sum_{J=1}^{N}\log Q_{g\,j}\sum_{J=1}^{N}(\log \Delta P_p)_j}{\sum_{J=1}^{N}(\log \Delta P_p)^2{}_j - \left[\sum_{J=1}^{N}(\log \Delta P_p)_j\right]^2} \tag{13}$$

So that when in determining the stabilized C, the average deliverability exponent will be used, then the equation n will be :

$$n = \frac{\sum_{i=1}^{M} n_i}{M} \tag{14}$$

M is the number of isochronal tests in a well. Eq. 13 will be substituted to Eq. 11, which helps support data in determining the value of stabilized C in the deliverability test this time.

METHODOLOGY

The methodology used here is the Computer Modeling Group (CMG) IMEX and Saphir. CMG IMEX will produce well test / isochronal data to determine stabilized flow coefficients. In contrast, Saphir will be used to determine when stabilization time can be achieved by looking at the performance of pressure changes in the pressure derivative graph. Finally, the model deliverability results will be seen, which will get a stabilized flow coefficient value. Figure 1 shows the work steps summarized in the form of a flowchart in this study. From the Figure 1, here are some explanations of the methodology in this study.

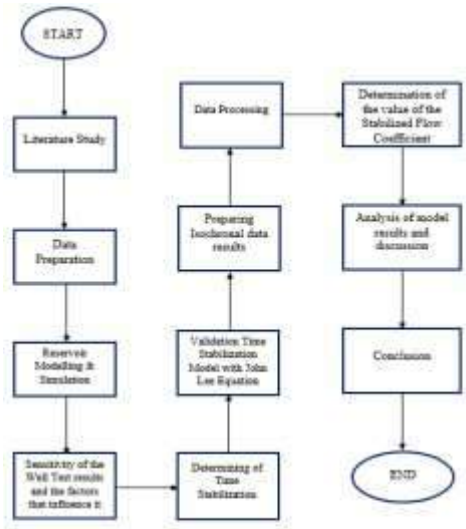

Figure 1 Research Work Steps

Reservoir Modeling Evaluation

In evaluating reservoir modelling, one of the methods above is used, which is CMG IMEX. We use a 10% value of porosity which is the maximum considering on tight gas reservoir. We associate Dashtgard et al. (2008) results for the permeability, which shows the relationship between porosity and permeability of several types of existing reservoirs. Dashtgard et al. (2008), in their study, inject the CO_2 into certain formations and reservoirs to get a relationship between permeability and porosity, shown in Figure 2. From Figure 2, we decided to use K /ϕ = 3, where we decided to take that comparison to facilitate the results obtained.

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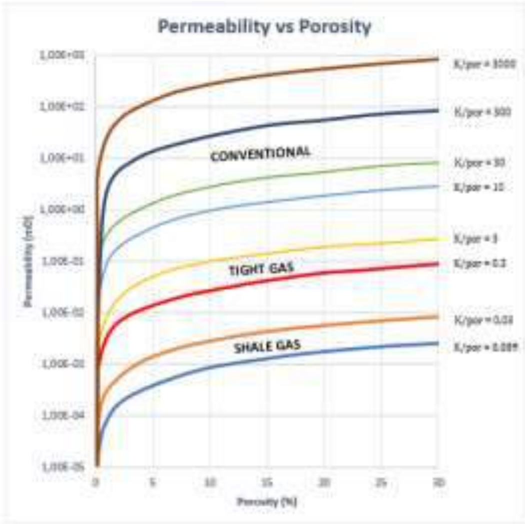

Figure 2. Permeability vs porosity showing flow units for conventional, tight gas and shale gas reservoirs based on process (or delivery) speed (K/φ) (Dashtgard et al., 2008)

Furthermore, we use CMG Builder for reservoir geometry and data, where we assume a radial shape with a thickness of 150 ft, a drainage radius of 3280 ft and a reservoir pressure of 3000 psia with a temperature of 110 °F. Figure 3 shows the reservoir's shape. After that, put the gas well in the middle of the reservoir. To form a production curve, then input a rate of 1 MMSCFD in the well, then run IMEX, which calculates numerically on the data inputted in the Builder. After that, a well test curve will appear by plotted the bottom hole pressure vs time which is seen in Figure 4.

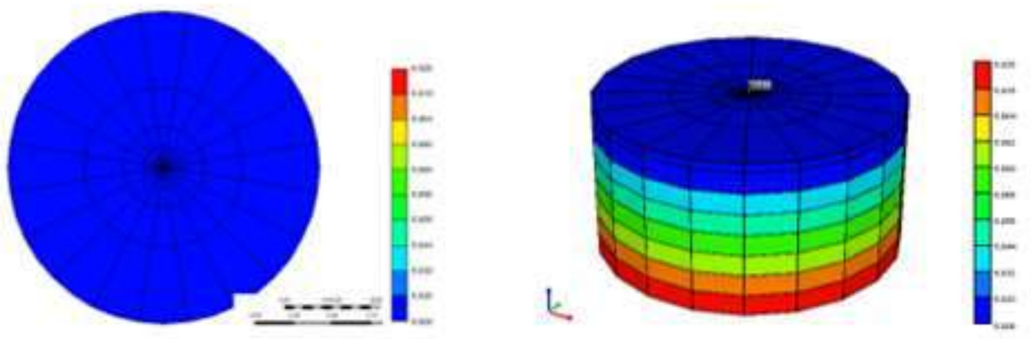

Figure 3. The Shape of Reservoir Model

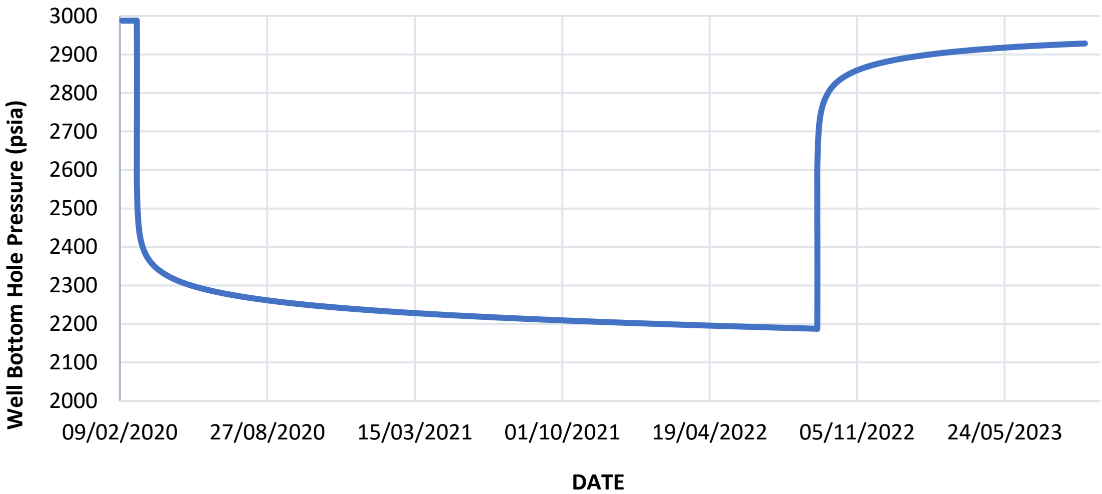

Figure 4. Well Test Base Model

Factors Affecting Well Test Data

Before determining the time stabilization, one must know what factors determine the well test data. Time stabilization is determined from the well test curve results. In dividing it into several factors, we divide it into six factors: Drainage Radius, Gas Gravity, Number of Grid Radius in the reservoir, Rate Production, Porosity and Relative Permeability. If sensitivity is performed of the data from low, mid and high, it will show what factors affect the data well test. Figure 5, 6, 7, 8, 9, and 10 shows that the results of the well test can change due to these factors. These factors can affect the results of the well test due :

- **Drainage Radius** can affect well test results because the range of well determines changes in reservoir pressure. The wider drainage area makes the pressure drop in the bottom hole pressure more tremendous.
- **Gas Gravity** can also affect bottom hole pressure because the higher the gas Gravity value, the higher the gas's density. More pressure is needed to produce the existing gas.
- **The number of radius grids** affects the results because it is likely that the numbers get more overlapped in the calculation and cause a more significant pressure drop in the results. However, the value of the number grid in reservoir modelling has limits that ultimately bring the pressure drop does not change significantly. In this case, the well test curve with a radial grid of 100 and 1000 shows no significant pressure drop changes.
- **Rate Production** certainly affects bottom hole pressure because bottom hole pressure is the connecting variable between reservoir pressure and flow rate. The greater the desired rate, the smaller the bottom hole pressure required.
- **Porosity** can also certainly affect the well test results. The flow of gas produced in reservoirs with good porosity certainly does not require a bottom hole pressure low enough to produce the flow.
- **Relative Permeability** data can affect the results. If the value of "Krg" gets higher, it is easier to obtain a gas flow so that the pressure drop is not too significant to get the desired target rate.

In addition to the factors above, certain factors can influence the results in the well test. However, here we only discuss six factors. This factor shows that changes in the existing data can undoubtedly affect the results. If the change in data from High to Mid or Mid to Low increases, the results' difference will be more significant. Suppose changes in the well test results occur. In that case, it will affect the results of time stabilization, showing a relationship between the initial data and time stabilization.

Determination of Time Stabilization

In determining the time stabilization, well test data generated from the reservoir model will be inputted into Saphir. Saphir will determine when the transient flow can reach a pseudo stabilized flow. In Saphir Software, when a flow has reached a stabilized flow when there is a significant pressure change. Figure 11 is an example of a pressure derivative plot when log delta P is plotted against log time. It can be seen that the Pseudo Steady State (PSS) flow occurs when in the area of the late time region with flow outside the boundary is a no-flow boundary. The reservoir acts as a tank, and the pressure will decrease at the same and cause a constant rate. When inputting data in Saphir and plotted the pressure derivative in the drawdown section, it will see a change at the end of the curve (Figure 12). These changes indicate an increase in the curve on day 571 so that on that day, PSS flow occurs, which means the flow has reached the boundary. A change in pressure derivatives in the late time region happened due to the reservoir model has entered the no-flow boundary stage. This boundary makes the flow no longer allow the flow through it.

The results obtained from Saphir will be validated from the John Lee equation on Eq. 10. By inputting reservoir model data into the John Lee equation, it will be seen in Table. 1. The results obtained in Saphir are from bottom hole pressure data generated in the model's reservoir property and set the rate value in the well test curve. The analysis in the Drawdown section was chosen for several reasons :

1. A gas well shut-in for sufficient time can establish a stabilized pressure distribution.
2. Wells produce at a constant rate.
3. The drawdown test provides information about the reservoir boundaries. The reservoir boundary test requires continued pressure drawdown until a pseudo-steady flow (PSS) is reached.

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Figure 5. Well Test at High Drainage Rad, Mid Drainage Rad, Low Drainage Rad

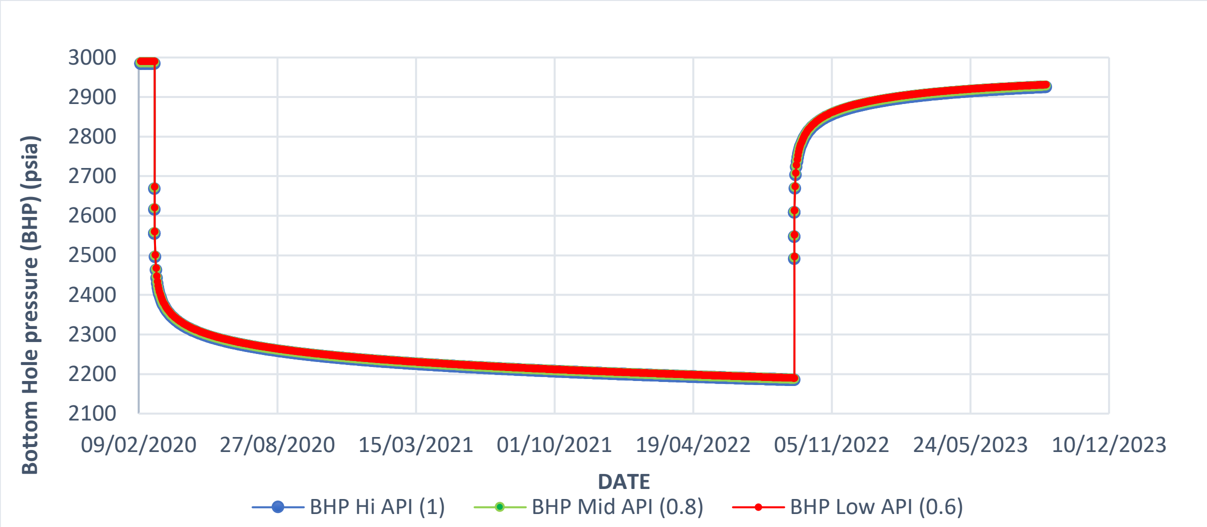

Figure 6. Well Test at Hi API, Mid API, Low API

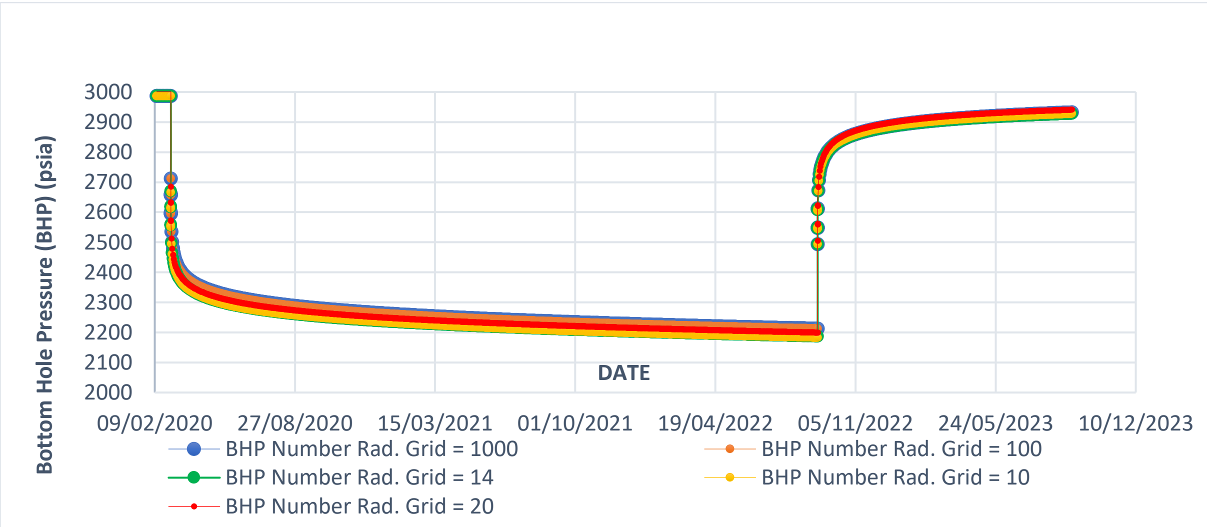

Figure 7. Well Test at Number Rad. Grids

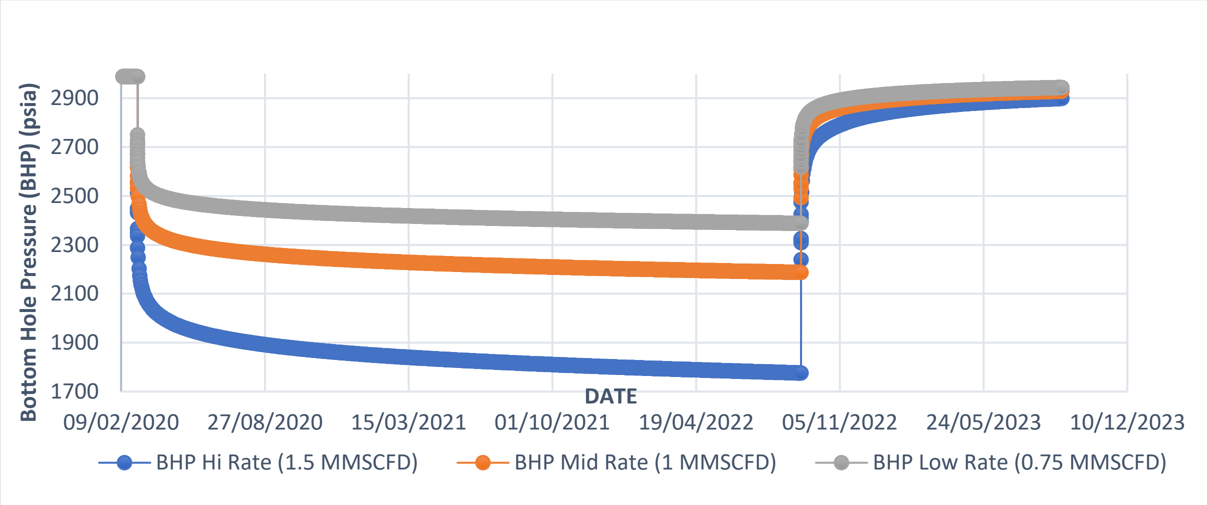

Figure 8. Well Test at Number of Rates

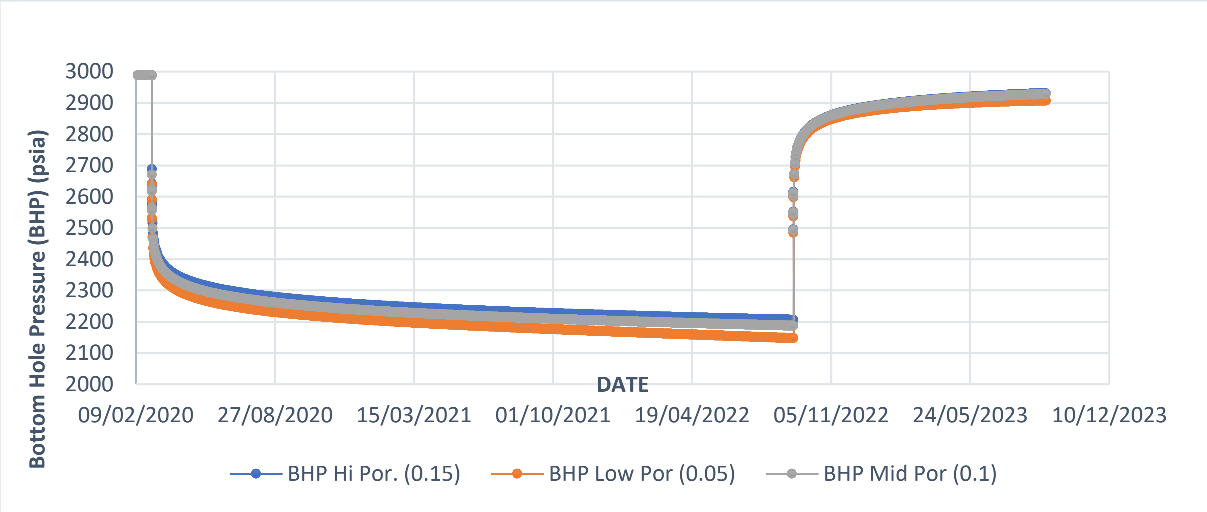

Figure 9. Well Test at Number of Porosities

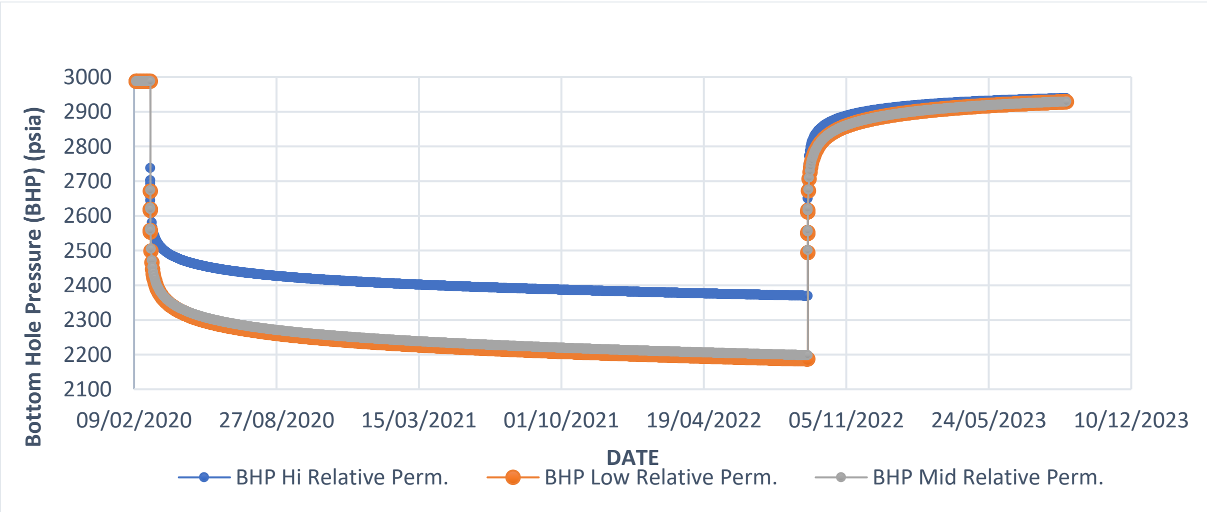

Figure 10. Well Test at Number of Relative Permeabilities

Table 1. Comparison Time Stabilization Model with John Lee Equation

Parameter	Time Stabilization (day)
Pressure Derivative	571
John Lee Equation	594

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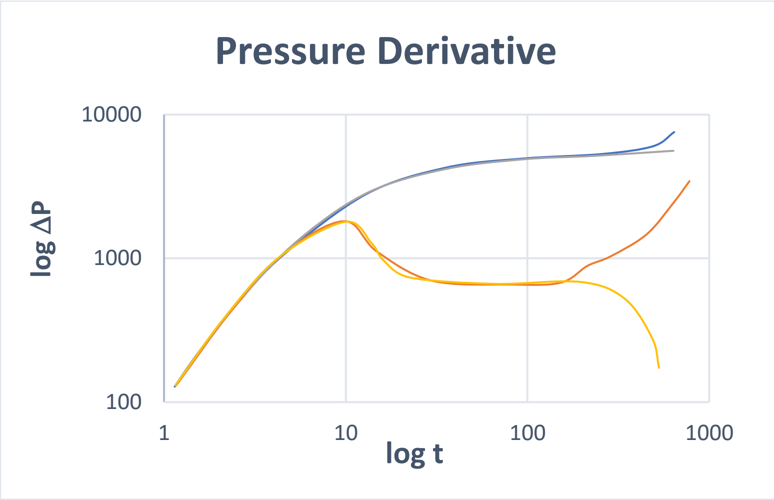

Figure 11. Example of Pressure Derivative Plot

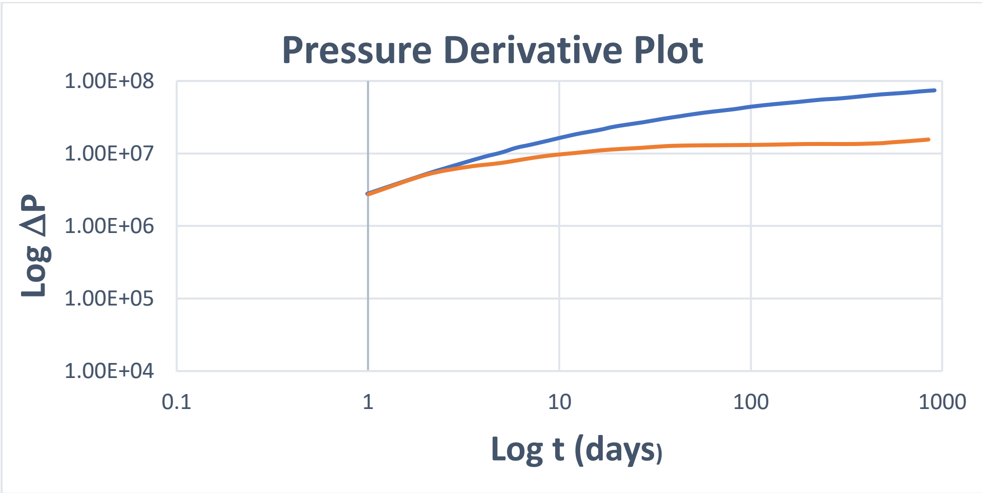

Figure 12. Change of log ΔP on Pressure Derivative plot

Flow Coefficient Stabilized Value

In determining the stabilized C value, isochronal data is needed, which will be used as initial input data in finding these values. Isochronal data is obtained from the reservoir model results in well test by performing some flow rate sensitivity in the gas well. Figure 13 shows that by determining some time duration on the well test curve, bottom hole pressure data can be obtained at that time duration. Table 2 shows the results of the isochronal data conclusions obtained from the results of the well test so that the isochronal data will be used as input data in determining the stabilized flow coefficient.

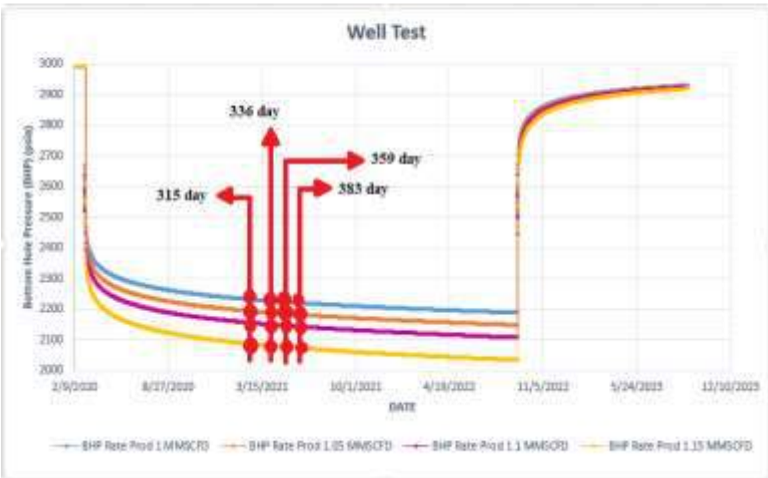

Figure 13. Isochronal Data from Well Test Results

Table 2. Isochronal Data from Well Test Model.

Pres (psia)	Duration (day)	Rate (MMscf/D)	Pwf (psia)
3000	315	1	2238.96
	336	1	2235.94
	359	1	2232.87
	383	1	2229.88
3000	315	1.05	2201.28
	336	1.05	2198.14
	359	1.05	2194.93
	383	1.05	2191.8
3000	315	1.1	2163.64
	336	1.1	2160.35
	359	1.1	2156.96
	383	1.1	2153.64
3000	315	1.15	2095.48
	336	1.15	2091.86
	359	1.15	2088.16
	383	1.15	2084.55

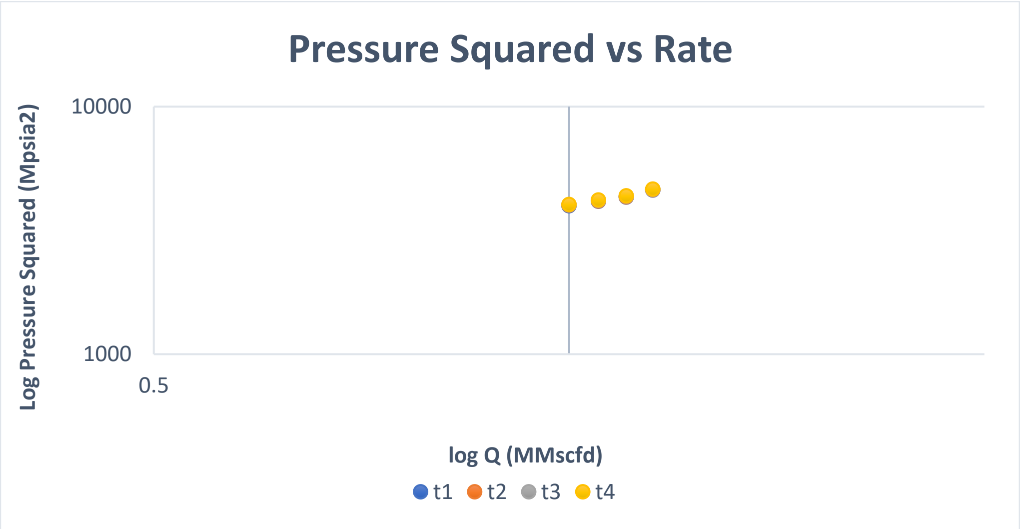

Figure 14. Deliverability Plot

Table 3. Deliverability Exponent value of each isochronal data

Time	Exponent	Deliverability
t1 = 315	n1	0.965321738
t2 = 336	n2	0.965911716
t3 = 359	n3	0.966423267
t4 = 383	n4	0.96689139
	n	0.966137028

A deliverability plot can be obtained from isochronal data by plotted log pressured squared vs log Q as shown in Figure 14. Furthermore, the results of isochronal data can be determined by the value of the deliverability exponent on any existing data using Eq. 12. Table 3 shows the deliverability exponent results, where usually the range in the value is between 0.5 - 1.0. The value of the range depends on the

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flow characteristics that exist. If the value of n approaches 0.5, then the flow is turbulent, whereas if it is close to 1.0, the flow is more likely to be laminar. To prove the results of true exponent deliverability can be likened to the Power equation of Rawlins and Schellhardt, we can see in Figure 15 that the value of n in each plot's power equation is the same with a result the deliverability exponent derived in Eq. 12. Then, the average result of deliverability exponent data in Eq. 13 is used to determine the stabilized flow coefficient from which isochronal data will be inputted into Eq. 2 and then from each of the existing $\frac{1}{C^{1/n}}$ results will be averaged based on the number of flow rate sensitivity in the previous. The results can be seen in Table 4. In the end, when plotted $\frac{1}{C^{1/n}}$ results with log t based on time duration in isochronal data, a graph is obtained in Figure 16. When a linear trendline is made on the line, we can get the equation's results to determine the stabilized C value.

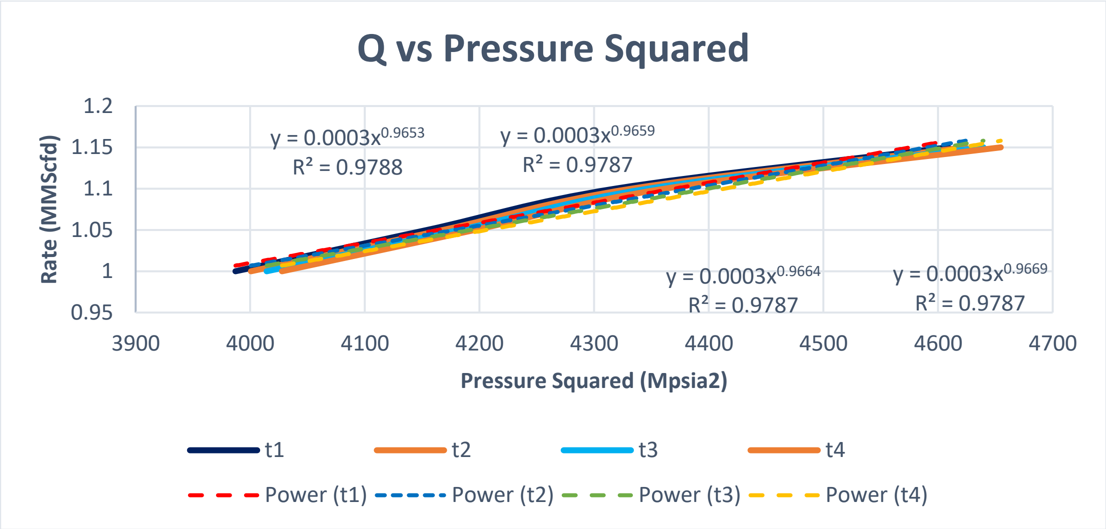

Figure 15. Rate vs Pressure Squared with Trendline Power

Figure 16. Graph $\frac{1}{C^{1/n}}$ $vs \log t$

Table 4. Data plot $\frac{1}{C^{\frac{1}{n}}}$ vs log time

Time (day)	$\frac{1}{C^{1/n}}$ (Mpsia^2/M Mscfd)
315	3961.444451
336	3974.506369
359	3987.954929
383	4001.06126

RESULT AND DISCUSSION

When the log graph $\frac{1}{C^{1/n}}$ vs log t is made in Figure 16; the following linear equation is obtained :

$$\frac{1}{C^{1/n}} = 0.5823 \log t + 3778.4 \qquad (15)$$

Suppose a time stabilization value is inputted from the above equation. In that case, a value is obtained, which C = 0.000322435 MMscfd / Mpsia^{2}, so that the result is a stabilized C value. Comparing the results of the time stabilization of Saphir with John Lee's results, it only has an error of about 3.8%. The differences that occur may be due to the calculation of reservoir properties in the John Lee equation while Saphir is looking more at the changing conditions of the bottom hole pressure. The error value is still relatively small, under 5%, and when the time stabilization value of the John Lee equation is inputted into the results of the linear equation, the value obtained is not too far from the Saphir results, which can be seen in Table 5. When an Inflow Performance Relationship (IPR) chart is made on the two C values, the result difference between the two AOF is only 0.322% (Figure 17). The results of the AOF model with validation are not too large, so that it can be stated that the method used can be applied in determining the Stabilized flow coefficient value. In Figure 18, there is a comparison of IPR plots when using C-stabilized values with IPR when using C at transient's period. The results can cause over predictions that can be seen from the current AOF values, with the largest error of 8.41%. The transient state here is tested at 2 hours, 4 hours, 6 hours, and 8 hours. The results show that when using IPR modelled with the value of flow coefficient in the transient period, it will make the production of a gas well will be different.

The working system to get the results above is based on the flowchart listed in the section above. It can be seen for the reservoir modelling section, done by using CMG builder software. The results are already in Figure 3. After that, do sensitivity into well test results base case with six factors that have been explained. The well test results can affect the time stabilization data carried out on the derivative pressure plot analysis results in Figure 12. The next step is to calculate and analyze according to the results of the previously developed equations.

Table 5. Results Comparison of model flow coefficient values with the results of validation

Parameter	C "Stabilized" Value (MMscfd/Mpsia^2)
Model	0.000322435
John Lee	0.000321395

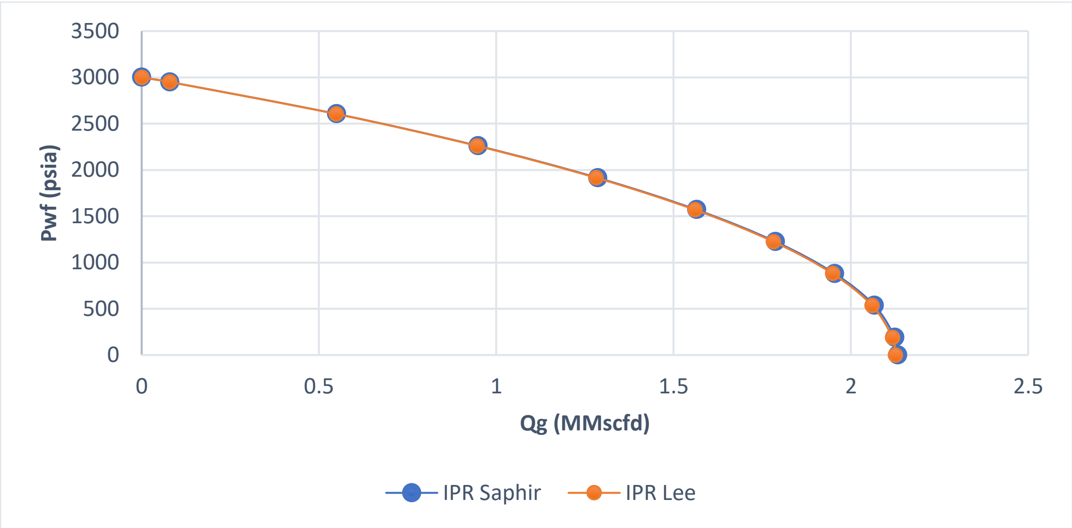

Figure 17. Comparison IPR Model with Validation

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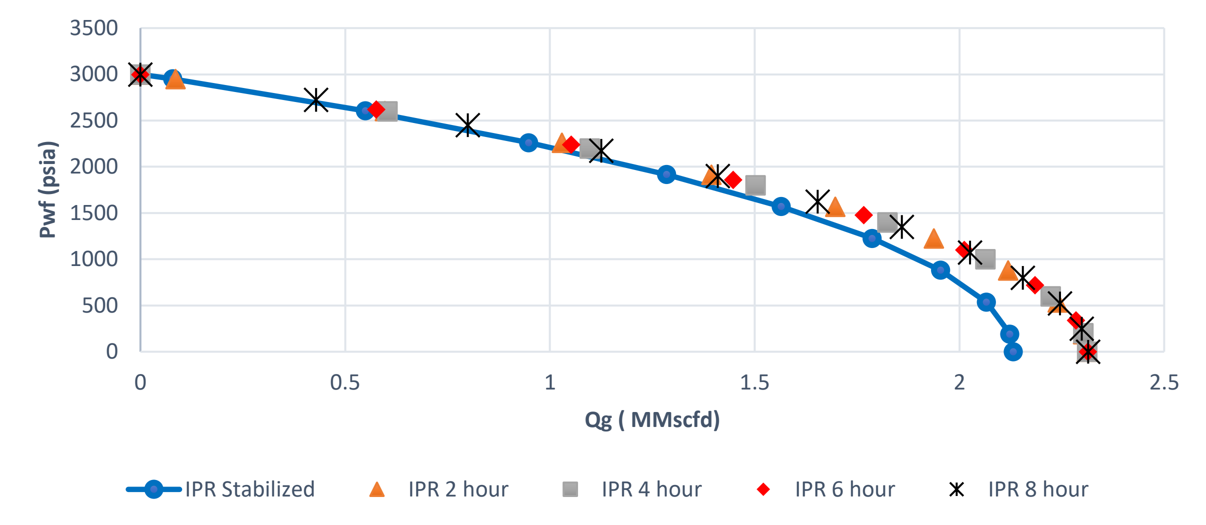

Figure 18. Comparison Model IPR Flow Coefficient Stabilized with IPR Flow Coefficient when in Transient Period

In determining the time stabilization value in the tight gas reservoir model, it takes quite a long time, not only in a matter of hours but even for days. Because of the flow situation with the reservoir condition, many technologies are developed to increase the permeability and porosity value. Figure 13 shows that there is a significant pressure change on day 571. The John Lee equation model can also be obtained in days and can even be calculated in years. Also, the development of the Hashem and Kazemi equations can be applied to the tight gas reservoir model (Hashem & Kazemi, 1996). From a prediction in the transient period, a stabilized C value can be determined for the future. The derived exponent equation can help complete the determination of the flow coefficient.

CONCLUSION

From the results of the calculations, it can be seen that using the deliverability test can show the value of flow stabilized coefficient based on the data of bottom hole pressure and constant rate in the time stabilization period. With the proposed method, it can be seen that the difference between the model and validation results is not too different, with a difference in AOF of only 0.322%. Finally, it shows that the difference when predicting gas well performance from the transient period to the stabilized period shows quite a difference, around 8.41%. The error will be more significant if predicted from the earlier state of the transient period.

NOMENCLATURE

a = coefficient in Pseudosteady state equation ($Mpsia^2/MMscfd$).

b = coefficient in Pseudosteady state equation ($Mpsia^2/MMscfd$).

Bg = Formation Volume Factor gas (Rcf/scf).

C = Flow coefficient ($MMscfd/Mpsia^2$).

Ct = Total Compressibility (psi^{-1}).

D = Non Darcy Coefficient (1/Mscfd).

h = Thickness (ft).

K_g = Gas Permeability (mD).

m = Slope of the straight line ($Mpsia^2/MMscfd/cycle$).

n = Deliverability exponent of Rawlins and Schellhardt and reciprocal slope of the line on a log log deliverability plot.

P_i = Initial reservoir pressure (psia).

P_p = Gas Pseudopressure ($psia^2/cP$).

P_{wf} = Bottom hole pressure (psia).

Q_g = Gas flow rate (MMscfd).

R_e = Radius exterior reservoir (ft).

R_w = Wellbore radius (ft).

S = Skin Factor.

t = time (day).

Ts = time stabilization (hr).

T = Temperature (^oR).

z = Gas Deviation Factor

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