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Interpreting Well And Reservoir Model Based On The Well Testing Approach For Constructing Well Productivity

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ABSTRACT

Well testing is key to constructing the reservoir model, especially in the development of fields. Well test well-known as pressure transient analysis seeks the dynamic behavior of a reservoir in an inverse problem manner. The pressure transient analysis measures the change in pressure at the wellbore by altering the production rate that can provide a signature of reservoir properties typically in the build-up period. Availability of data is run into the first simulator Ecrin V4 thoroughly monitoring the change in pressure data to the production rate. Pressure and its derivative which is derived from the diffusivity equation are compared to reveal both models in a system of well production. Results show that the skin has negativity -3.43 to refer as no damage and 0.0125 bbl/d of wellbore coefficient at the vicinity wellbore. Further, dual porosity is identified as the reservoir model in which the derivative response showed the transitional dip at the middle time, and aside from that the infinite boundary act flattened at late time. To conclude, the initial pressure of 3915.35 psi in the matrix block flows into the fissure system with an average permeability of 100.8 md. An average pressure in the fissure system can be estimated using the transient flow equation which suits pressure drop depending on the radius and time. Once the reservoir pressure is estimated, 3900 psi. It is necessary to construct the well productivity. The second simulator Pipesim is used to design the inflow performance relationship and the tubing performance. The IPR was continued with Vogel to consider gas dissolved of 400 scf/stb and the tubing was assumed with an inside diameter of 2.735. Finally, the well production may be known as about 32% of AOF 18505.7 stb/d. This interpretation is simple and applicable to unlocking the well and reservoir model for constructing the well productivity-based computational model.

Keywords: *well test, pressure transient analysis, inverse problem, well and reservoir model, IPR, well productivity*

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1. Introduction

Well testing is a part of the key to constructing the entire reservoir model, especially in a development phase, which focuses on dynamic conditions in the underground. This is crucial to developing a well with reliable information on the boundary, reservoir potential (e.g., porosity and absolute permeability), and reservoir properties (e.g., reservoir type, average permeability, initial pressure, and damage in vicinity wellbore, etc.) that all would be only obtained from a proper interpretation during the pressure transient analysis (Alimohammadi et al., 2020).

Typically, to develop a well needs to define it to be commercial, the only proper way to measure the well to be profitable is to know its productivity, usually stated in value and called the productivity index, it is simple to define that the flow rate is proportional to the drawdown pressure in steady state with incompressible oil, this is gonna show the straight line in a constant slope. Since the oil contains a gas, several empirical equations for IPR have been done to predict the oil flow particularly Vogel IPR, unlike IPR's slope is decreasing as the drawdown pressure increases. However, when the data are limited to calculate with the empirical equation then it needs to do calculations based on the flow regime are known as transient, semi-steady, and steady-state flow within the reservoir. That flow regime is derived from the Darcy equation and some have dimension properties. To evaluate each value of properties such as permeability, skin, pressure (or *pi*) drainage radius, and the reservoir shape can be done with the well testing, further, to estimate the well productivity which can be revealed with the pressure and rate measurement (Jahanbani et al., 2009).

Therefore, this study of well X has been done with acquired the pressure and rate data, shown in Table 3. The pressure transient analysis was conducted to the vertical wellbore radius of 0.354 ft, a net thickness of 30 ft, and undersaturated oil accumulated in 25% of the porosity. Further, oil is known of 45^0 API gravity and 0.7 for the gas of 400scf/stb. In addition, pre-interpreting the pressure and rate data acquired during the test have to do quality matching within the QA/QC in the simulator of Ecrin V4 and then diagnose it with the best model. Selected the model that is almost similar to the pressure and its derivative log plot to achieve a suitable model for unlocking the reservoir model and its properties. Because selecting a proper model for each is a vital step in PTA (Alimohammadi et al., 2020). Once the pieces of information in the reservoir are revealed therefore those values can be used to plug into the transient flow equation to figure out the average pressure in case the wave has not reached the boundary and the pressure drop up to the time and the radius of the reservoir. However, when the

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reservoir pressure is attained then associating with the production rate test and pressure flowing are combined to perform the well productivity in a simple way of the dimensionless equation of Vogel empirical that considering the amount of gas solubility, as the consequence the IPR showed a curvature. Moreover, the well intake also can be achievable assuming the tubing ID 2.735 in. Finally, the production rate for well X in stb/d would be delivered. The crosssection between the IPR and TP is done with simulator Pipesim and they refer to the operating point of a certain production rate while the IPR point on the value of pressure 0 psi is to define the Absolute Open Flow (AOF).

2. Literature Review

2.1. Well test Approach

Well test known as Pressure Transient Analysis is a type of test for dynamic data (oil and gas flow). The transient test is the main source to reveal the dynamic behavior of a reservoir with appreciable volume in the formation (Clark et al., 1985). Fanchi & Christiansen (2017), PTA means pressure changing in the formation is to measure the change in pressure at the wellbore by altering the production rate which is modeled using a diffusivity equation that applies for a single phase of slightly compressible liquid, the equation expressed in an underivative manner:

$$\frac{\partial^2 p}{\partial r_D^2} + \frac{1}{r_D}\frac{\partial p}{\partial r_D} = \frac{\partial p}{\partial t_D} \tag{2.1}$$

Where p is fluid pressure, r_D is the dimensionless radius, and t_D is the dimensionless time. Additionally, r_e is the radial distance from the well and r_w is the well radius to define the dimensionless radius as

$$r_D = \frac{r_e}{r_w} \tag{2.2}$$

dimensionless time defined in terms of group parameters

$$t_D = 0.000264\frac{kt}{\emptyset(\mu c_r)_i\, r_w^2} \tag{2.3}$$

Where the group of $k/\emptyset\mu c_r$ is called the diffusivity coefficient. However, the dimensionless radius increases as radial distance increases and dimensionless time increases as time increases.

Therefore, the downhole pressure response to a constant surface rate during the pressure transient is a function of time. In addition, interpreting the pressure change at which production altered can provide a signature of reservoir properties which is usually analyzed by shut-in data rather than the data of well flowing because is often poor (Mireault et al., 2008). Then both data of rate and pressure are turned into a log-log plot and it will match with the models that have been developed for PTA (Houzé et al., 2011) while usually diagnosing with the mathematical model (Abbou-Sayed, 2001). Thus, the test is often done in several days as the production life of a well. To attain a stabilized condition for precisely investigating the whole reservoir (Mireault et al., 2008).

However, Alimohammadi et al. (2020) stated that the PTA approach is an inverse problem that has the model output (pressure) and the model input (change in well rate) but the reservoir behavior underlying the response to the inputted data is unknown, as shown in Figure 1. Besides that, using the PTA can uncover the reservoir characterizations and well productivity (Horne, 1997). Unfortunately, the PTA is mainly capable mostly in conventional reservoir (Torcuk et al., 2013).

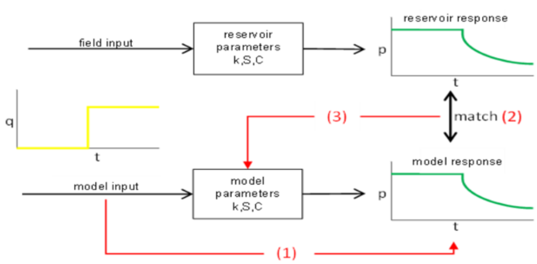

Figure 1. Well testing analysis as an inverse problem

As a result, the information within the reservoir may be unlocked by the fluids flow through different parts of a reservoir. This method has been used for many years to evaluate reservoir characteristics which could provide a description of the reservoir flowing behavior (Bourdet et al., 1989). Beside that, Jahanbani et al. (2009) determined the well productivity in a particular fractured reservoir using well testing, the result showed that it had attained the most accurately compared to other methods. Because it can measure the (1) reservoir properties; (2) reservoir size and shape (e.g. average permeability, fracture properties, distance to boundaries, etc.); (3) reservoir characterization (e.g. dual porosity, layered reservoir, composite, etc.); (4) completion efficiency (e.g. skin, fracture performance); (5) tubing performance (optimizing tubing design and artificial lift requirements) (Cobanoglu & Shukri, 2020). Finally, those parameters obtained can be simplified as an optimum integration of fluid flows from the subsurface onto the surface.

2.2. Well and Reservoir model

The well and reservoir parameters to construct a model must be accurate information because determining the life of the well and predicting the profit of a field recoverable in the future. Hence, a precise model is usually gained from an interpretation of a dynamic test (Alimohammadi et al., 2020). In the process of pressure transient analysis, providing an input impulse of rate and measuring the pressure response is governed by parameters of the well and reservoir such as permeability, skin effect, storage

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coefficient, boundaries, fracture properties, dual porosity, etc. Those parameters are inferred as the real values if the pressure response matches with a mathematical model response that has developed (Horne, 1997).

a) Skin effect

Skin S is an altered zone by particles of mud in the near wellbore during the drilling and completion process that has to reduce the capacity of well flow (Fanchi & Christiansen, 2017). Often called formation damage. If there is a presence of a skin effect then defined in a positive number, conversely in negative terms, the well is being stimulated while being an original permeability when the value is showing near zero. Thus, a dimensionless pressure drop is given by the following expression:

$$S = \left(\frac{k}{k_d} - 1\right) ln\left(\frac{r_d}{r_w}\right) \qquad (2.4)$$

In the log curve, skin does not change the early time unit slope (pure wellbore storage) but affects the amplitude of the hump (Houzé et al., 2011).

b) Wellbore Storage effect

It is wellbore fluids that are unproportional to the surface volume when the well starts to produce or shut in by creating a time lag between the sandface and the surface. Commonly wellbore storage is affected in ways of fluid expansion and changing liquid level (Horne, 1997). Additionally, the wellbore storage does not play any role in the whole process except it masks the infinite radial flow on a time which can affect the interpretations (Houzé et al., 2011). The amount of fluids is proportional to the value of C.

c) Well derivability

Assuming the reservoir is producible precisely when it has the value of thickness (h) and permeability (k) accurately. In addition, the h *is* often obtained from logging analysis whereas k is better achieved in pressure response testing. If the k has the greater value then is faster to react and deviate of log curve from pure well bore storage (Houzé et al., 2011).

d) Reservoir and Boundary model

Revealing both models is usually using the diagnostic mathematical model to compare what is already known from other sources. The derivative response signatures the flow regime in a reservoir with a different slope of the log curve. Further, infinity-acting radial flow does not show a deviated curve and considers the value to be zero and if a quartel slope it defines the flow regime at middle time as dual porosity that consists of original and fracture porosity. Meanwhile, at the late time, the pseudo-steady-state flow which is known as no flow in the boundary has a slope of 1 (Houzé et al., 2011). In addition, if constantly infinite radial flow to a late time means the well yet reached the boundary of the reservoir which can be expressed in the following equations for oil well production:

$$q = \frac{kh(p_i - p_{wf})}{162.6B\mu}\left(\log t + \log\frac{k}{\emptyset\mu c_t r_w^2} - 3.23\right)^{-1} \qquad (2.5)$$

2.3. Well Productivity

In well productivity of oil commonly assumed that oil flows into the well is directly proportional to the drawdown which is derived from Darcy's law for the steady-state flow of a single and incompressible fluid and is stated in a straight line (Vogel, 1987). However, Evinger & Muskat (1942) showed the curvature in the theoretical calculations because of the presence of liquid and gas flowing simultaneously in a reservoir. Whereas the well rate is not proportional to the given bottom-hole pressure owing to the value of a curvature having a varied slope for variations drawdown. Thus, further research of Vogel in 1987 shown on the empirical equation for two-phase solution gas in a reservoir undersaturated oil is expressed as follows:

$$\frac{q_o}{(q_0)max} = 1 - 0.2\,\frac{p_{wf}}{p_r} - 0.8\left(\frac{p_{wf}}{p_r}\right)^2 \qquad (2.6)$$

A new term of inflow performance relationship (IPR) was developed by Gilbert (1954) for further well analysis including the production rate curve plotted against the intake pressure (tubing). Moreover, the well-known term for intake pressure is the vertical lift performance which refers to the lifting in a vertical flow where dependent on the pressure required, interval depth, gas-oil-ratio, and tubing size for a well liquid in a given rate.

3. Research Methodology

3.1 Data Collection

This study is carried out by quantitative data where categorized into basic well-reservoir data and recorded test data that were inferred as inputted data to unlock the reservoir characterization for constructing well deliverability. However, the basic data were used for analysis as follows:

a) Well-reservoir data are included as a type of test in standard on a given well radius (0,354ft), pay zone (30 ft), porosity (25%) with 45^0 API of oil and gas gravity is 0.7 as well as a reference time of testing. In addition, for oil properties are 1.25 of oil volume factor in rb/stb, 0.43 centipoise, total compressibility 1.47e-5, reservoir temperature 250 ^{0}F and pressure recorded was 3914 psi and gas-oil-ratio about 400 scf/stb.
b) Rate and pressure recorded data during the test are the main inputs for further analysis. The recorded pressure and rate data are shown in Table 3. a and 3. B

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3.1 Data Processing and Analysis

Firstly, input the necessary well-reservoir data into a simulator Ecrin v4 then continued with recorded data of rate and pressure test into a quality matching in QA/QC for quality control on pressure data. Once the history match of rates to pressure is matched, analysis is continually extracted into the derivative pressure (dP) for advanced interpretations, later the log derivative will be diagnosed with the mathematical model to reveal the reservoir and boundary characterization. If there is no matching between the field model and the calculating model, both have to be improved to attain a piece of better information in an underground reservoir. After the model can defined, the value properties of the reservoir and well value are known. They are associated with the rate and pressure flowing, the reservoir pressure could be determined for further analysis of well productivity

Secondly, the reservoir pressure and rate test data are run into a well design simulator, Pipesim for constructing the inflow performance relationship of the well and its maximum production rate, known as absolute open flow (AOF). The inflow-IPR plotted against outflow-VLP is done then a production rate for the well would be carried out. Finally, the reservoir model and well rate can be applied to a field, particularly in a well.

3.1 Diagram Workflow

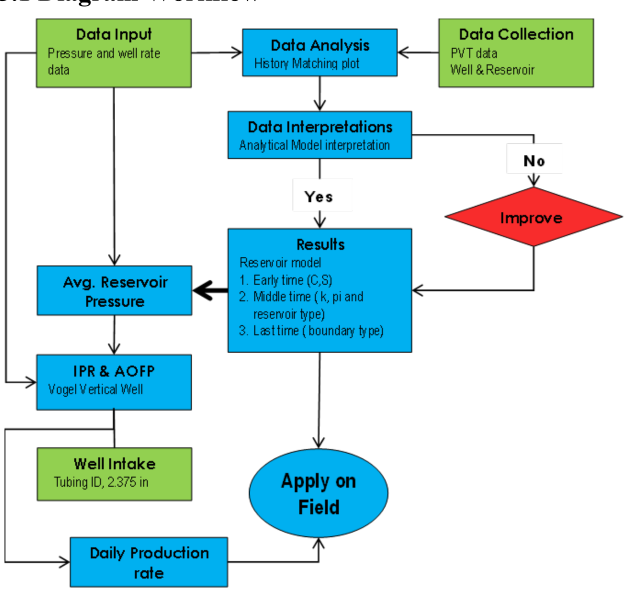

Figure 2. Research diagram workflow

4. Result and Discussion

Interpretations by well test method aim to build a reservoir model and boundary and continue to integrate the achievable production rate at given bottom hole pressure using Vogel equations.

4.1 Mathcing the pressure and production rate data

Once the well-reservoir data are already inputted the simulator Ecrin v4 then followed by acquired pressure and rate data for further analysis. The pressure data is plotted in QA/QC for quality control to remove unnecessary or error points of input that can affect the analysis of log plots. Thus, the pressure could match with the production rate to attain a good result of parameter values. In matching, only the pressure is to change precisely to the rate when both data are not synchronized to the time. Because the pressure response is a sign of reservoir properties values which is dependent on a single reservoir unit.

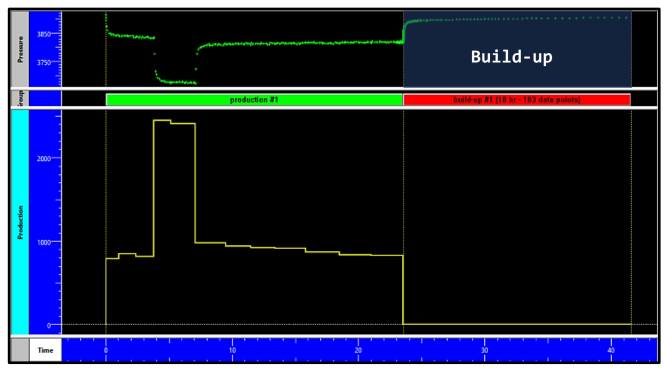

Figure 3. Quality matching of pressure and production rate in 42 hours of drawdown and build up period

Figure 3 shows the good matching of pressure and rate data in production and shut-in time which is a total of 42 hours. The pressure dropped from 3913.15 psi along the drawdown period to 3672.5 psi and achieved the maximum rate of 2450 bbl/d during the particular test. In addition, 18 hours are taken for the build-up period, therefore, to achieve the stabilized condition and further analysis using the period of no flow because it could investigate the whole reservoir precisely (Mireault et al., 2008). The genuine information of reservoir parameters can predict the profit of a field in the future.

4.2 Extracting Derivative Pressure (dP)

Furthermore, extracting the derivative pressure when have attained a good matching of pressure response to the production rate. A derivative pressure corresponds to the change of rate in quantity due to the pressure being altered. dp is a diagnostic tool for making type curve analysis more reliable. A derivative analysis deals with model diagnosis and evaluation of parameters which increases the confidence of results (Clark et al., 1985). In addition, this type of curve is often called a log-log plot which is a plot of pressure derivative in pressure and differential time (dt) axes. The

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mathematical log-log curve is used to reveal the information on fluid behavior in the reservoir unit.

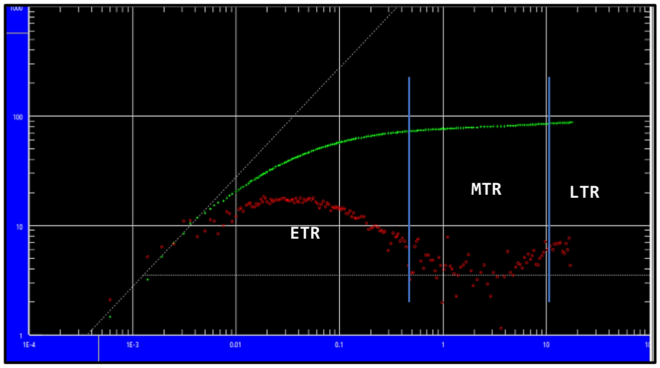

Figure 4. Extracting the derrivative pressure in log-log plot

The log-log plot in Figure 4 is extracted from the field model in the build-up period which is 18 hours in duration and a differential pressure of 96 psi. However, the pressure at the differential time to zero is indicated at 3816.5 psi. This log-log plot expresses the reservoir parameters in different slopes of the log curve. However, the value of a slope is obtained from a rise (vertical axis) divided by the run (horizontal axis). In addition, the curve is read smoothly in 0.05 of the pressure data (green line) and pressure derivative (red line) to read clearly.

Houzé et al. (2011) introduced the Bourdet et al. (1983) of various slopes to read the information on the log-log plot along the wellbore until the boundary condition, shown in Table 1. The log-log plots reveal the model of identification into three categories of time. In the early time of the log, a plot is performed to obtain the wellbore coefficient, skin, and fracture, further homogenous or heterogenous are in the middle time. However, for boundary model is late.

Table 1. Bourdet Derivative (1983) of various slopes for flow regime

Model	Regime	Δp slope	Δp' slope	DDA chapter
Wellbore storage	Storage	1	1	Wellbore
Fracture	Linear	0.5	0.5	Well
Fracture	Bilinear	0.25	0.25	Well
Limited entry	Spherical	-	-0.5	Well
Homogeneous	IARF	-	0	Reservoir
Channels	Linear	0.5 (late)	0.5	Boundary
closed	Pss	1 (late)	1	Boundary

Based on Table 1 of Bourdet derivative slope for flow regime in the underground, the extracted field model in Figure 4 can be read which tends to give information on storage coefficient, skin, permeability, and the heterogeneous and infinite boundary of a reservoir in three different times. In brief, the wellbore is indicated by the first line which goes up straightly with slope 1, because it creates the time lag between constant flow on the surface when there is yet no flow in the sandface. This is increased constantly until the flow from the bottom hole reaches the surface making the first deviated line in derrivative line. When the first curvature of a hump in derivate pressure is dipped enough in early time then it tends to have a great number of permeability units. However, skin can be obtained in positive terms when the red and green lines are long distances from each other. Conversely, the two lines are close to each other is indicated as the well has been stimulated. In the middle time, no indication of homogenous flow which is often has zero slope known as a radial flow regime in the reservoir. Nevertheless, the flow regime in the reservoir is dual porosity owing to the pressure derivative not stabilized horizontally but instead forming a transitional dip sometimes called a derivative valley (Houzé et al., 2011). In addition, the late time is shown the continuous to the flat line which does not indicate the slope of any boundary or constant pressure from an external pressure which is termed water influx. That means the well has not reached the boundary yet and the pressure drop at the system is dependent on the radius and time of the maximum propagation wave in the flow regime tested.

4.3 Diagnostic Model

After the field model has been extracted. It is time to determine the values of those parameters which affect pressure response. A developed model where provided to reveal the values of each affecting unit from a reservoir, including the unit in the vicinity well. Thus, selecting a properly developed model for diagnosis is an essential phase in pressure transient analysis (Alimohammadi et al., 2020). Based on the model in Figure 4 is knowable by looking at various slopes from early time to last behavior. Therefore, an approaching mathematical model proposed for validating this particular input model is used such as constant wellbore storage and vertical well for the well model and the reservoir model approaches by dual porosity and infinite model defined in the boundary.

Initially, showing both models are not slightly matched. Then being assisted by a computational approach which is done for an improvement of matching. Randomly is carried out in many wavelengths of variable that state in lambda and omega measures the leverage of option positions. In particular, the case showed omega in 0.088 and the lambda 8.5e-7 that acquired a good matching of models.

4.4 Final Model Parameters Values

After attaining a satisfactory matching of both models shown in Figure 5, it likely gains proper information on reservoir parameters such as skin, wellbore storage, absolute permeability, initial pressure, and especially reservoir behavior in terms of fluid flow. Those values are shown

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below in Table 2. Nevertheless, the well is vertical not even indicating various fractures surrounding the well. Moreover, the reservoir does not reach any boundary which is shown at a late time but merely flattened inclined which is an infinite radial flow that the pressure drop dependent on the radius and time.

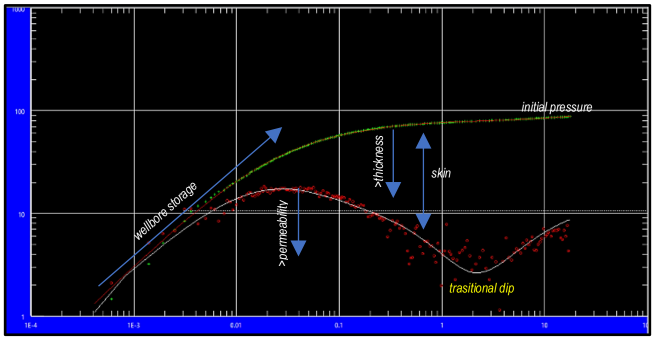

Figure 5. showing a good mathing between a field input model and mathematical model (white line)

Table 2. Reservoir parameters values and models

Name	Value	Unit
skin	-3.43	
C	0.0125	bbl/psi
k, average	100.8	md
h	30	ft
k.h	3024	md.ft
Pi	3915.35	psia
Well model		
vertical		
Reservoir model		
Dual porosity		
Boundary model		
Infinite reservoir		

Interestingly this test simply revealed the reservoir model that is dual porosity as fluids flowing behave within a geological formation. A dual porosity assumes that the reservoir is not homogeneous which made up of rock matrix blocks with high storativity and low permeability (Houzé et al., 2011). Typically the pressure effects come from primary porosity which has a low transmissivity inside the matrix and the high transmissivity that holds in the fissure system as secondary porosity (Horne, 1997).

Furthermore, a basic concept of dual porosity is the matrix blocks that cannot flow directly to the well but instead, the storage oils within blocks could enter through the fissure system to be produced and there is no pressure change inside the matrix blocks which is considered as the initial pressure that may support effectively for the flowing pressure when oil start producing to the fissure system, illustrated in Figure 6. Therefore, energy support tends to stabilize the pressure and simultaneously create a transitional dip in the derivative which is induced by a discontinuity of pressure drop across the surface of blocks, and the rate of dip is measured by the differential pressure drop in the fissure system to the matrix blocks (Houzé et al., 2011). However, when the fissure system can be yielded, a pressure differential is established between the blocks and fissures. An establishment of the pressure is often referred to as a diffusion state.

In double porosity model is described by two variables in terms of the homogenous parameters model. Storativity ratio ω, is defined as the fraction of fluid stored in the fissure system. However, Interporosity flow λ is the coefficient to describe the ability of the matrix blocks to flow into the fissure system. Both equations below are used to find the value for variables respectively:

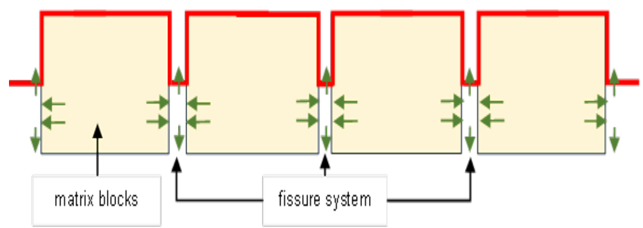

Figure 6. An illustrations of dual porosity model in the reservoir. Oil within blocks flows (green) to the fissure system. The pressure behavior (red) across the blocks and pressure drop insignificant on the fissure system

$$\omega = \frac{(V\varphi c_t)_f}{(V\varphi c_t)_m + (V\varphi c_t)_f} \tag{2.7}$$

$$\lambda = a r_w^2 \frac{k_m}{k_f} \tag{2.8}$$

However, in this study, we do not seek the values of storativity and inter-porosity for oil flowing in the reservoir but merely identify the model in the particular reservoir and the reservoir pressure for designing the inflow performance in this particular test.

4.5 Average Reservoir Pressure In The System

The units such μ, r_w, h that are already known are combined by parameters acquired from the previous validating data such k, s then populate to the unsteady-state solution of the diffusivity equation to determine the average reservoir pressure in the system. An estimated drainage area is 100 acres which stated in A, followed by a production test naturally which proposed 830 stb/d in 3816.5 flowing pressure for calculating. However, γ is the exponential of Euler's constant and is equal to 1.781, C_A is expressed in the Dietz shape factor and for this particular case, the well is assumed to produce from the center of a circle and defined

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as 31.62 for the shape factor (Dake, 1978). Calculated is shown below:

$$p - pwf = \frac{q\mu}{2\pi kh}\left(\frac{1}{2} ln \frac{4A}{\gamma C_A r_w^2} + s\right) \quad (2.9)$$

$$p = 3900\, psia$$

4.6 Well Production

In well production system simply categorized two variables most important which are inflow performance is the ability to produce the fluids from the reservoir to the bottom hole and outflow performance is defined as fluid flows from the well onto the surface (Guo et al., 2017). Reservoir pressure plays a tremendous role in designing the inflow performance relationship. In particular, IPR is designed by simulator Pipesim which uses the Vogel equations for solution oil in a reservoir along with the necessary parameters associated with a vertical well. However, depth is assumed by the reservoir pressure approach and the gradient pressure is normal which is mostly agreeable with 0.5 psi/ft. likewise, casing size, tubing OD, packer setting depth and datum point are negligible.

$$depth = \frac{3900}{0.5} \quad (2.8)$$

Results shown calculated in Figure 7, that the well inflow has the curvature on the line that across to the value of maximum production of oil which is about 18505.7 stb/d.

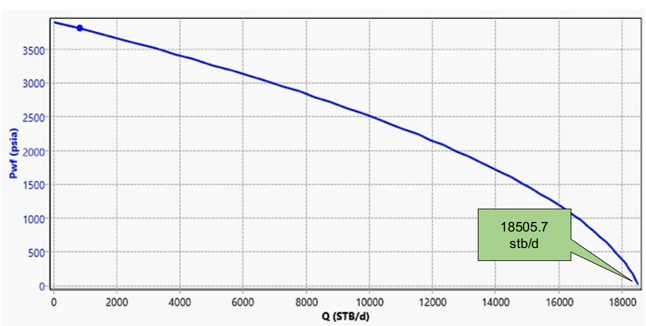

Figure 7. Absolute open flow potential in the well X

Once the well capability is known, the rate on the surface could be found out with a tubing inside diameter of 2.375 in. as the outflow ability and the outlet pressure in the wellhead is assumed to be 250 psi.

Figure 8, shows the intersection line between the inflow and outflow performance of well X referred to as an operating point. Operating production in the particular well is 5992 stb/d in 3131 psi of flowing pressure. The withdrawal of around 32% of the well provided and well X could be said as a productivity well in terms produced technically by the standard of 30-70% of given production in natural (Brown, 1977).

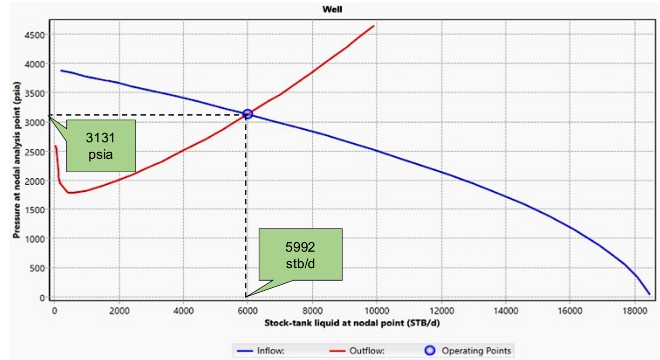

Figure 8. Production rate which is achievable using tubin inside diameter 2,375 inch

5. Conclusion and Recommendation

5.1 Conclusion

Pressure Transient Analysis test revealed the value of skin -3.43 and 0.0125 bbl/d of wellbore coefficient in the vicinity of the wellbore. The reservoir model known as dual-porosity that fluids flowing through the matrix blocks and fissure system in geological formations with an average permeability of 100.8 md and the initial pressure within the blocks which is 3915.35 psi and the late time the well has not yet reached the boundary due to the flattened line inclined in derivative response which is as infinite boundary model that the pressure drop dependent on the radius and time. Additionally, the reservoir pressure 3900 psi, is determined by an unsteady-steady state solution of diffusivity equation along with the drainage area of 100 acre and production test of 830 stb/d in 3816.5 psi.

Inflow performance relationship is created using simulator Pipesim and carried out the results in Vogel equations as 18505.7 stb/d of maximum production daily and the well rate that can be taken is 32% of 5992 stb/d in a certain pressure 3131 psi by the tubing ID 2.735 in. with known GOR 400 scf/stb in well X that considered as the productivity well.

5.2 Recommendation

Well test approach applied for this study uses using inverse problem technique in a standard test of a single oil that is revealed by the pressure transient analysis. Therefore, suggestions for further research include putting considerations on the forward problem technique that acquires the reservoir characterization by log and core analysis to define the well productivity even if it is time-consuming and more complex.

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