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Determining Reservoir Model Based on Welltest Analysis for Production Forecasting

Harry Budiharjo Sulistyarso

Petroleum Engineering Department, Faculty of Mineral Technology, Universitas Pembangunan Nasional Veteran Yogyakarta, Daerah Istimewa Yogyakarta, Indonesia

Email address:
harry_hb@upnyk.ac.id

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Abstract: Welltest analysis is basically an analysis of fluid flow behavior in porous rocks, both in oil reservoirs and gas reservoirs that aim to obtain reservoir characteristics. Welltest analysis is not only limited to get reservoir characteristics and well productivity, but to determine the reservoir and boundary models that are close to the real situation. Until now, to determine the reservoir and boundary models are usually assisted by using a simulator, which is called modeling. However, to determine the reservoir and boundary models has its own challenges, because there are no specific methods or equations that can know for certain the model of a reservoir. Choosing the right type of model also requires some consideration, such as seismic data, geological data, log data, and information provided from other wells drilled into the same formation. From the determination of this model can be used as supporting information for a reservoir, which is then used to be a predictive model and renewal of its geological model, as well as allowing engineers to simulate production estimates. In this paper, we will present an analysis of determining the right reservoir model based on welltest analysis, which selected model is used to simulate production estimates. Case example is taken from an oil well named "HBR-05", which has been carried out a pressure build-up test on one productive layer that until now has not been produced or closed since the well testing was carried out. From the determination of the reservoir model based on welltest analysis, obtained heterogeneous anisotropic reservoir model and rectangular-no flow boundary model. The selected reservoir model is used to simulate the estimated production of the "HBR-05" well if it is produced from this layer. Production forecasting results for 48 months (4 years) the "HBR-05" well, the cumulative production is 107.8 Mbbl. In addition, the results of forecasting show that the reservoir pressure is already below the bubble point pressure in the 22nd month of forecasting.

Keywords: Pressure Derivatives, Matching, Modeling, Production Forecasting, Analysis

1. Introduction

The sophistication of technology and the rapid development of science, making well testing analysis also growing. Previously to analyze well testing using the Straight Line Method and Type Curve Matching which was limited to vertical well conditions and homogeneous reservoirs, so that no relieble was used for more complex reservoirs such as heterogeneous reservoirs, dual porosity, composites, multilayers, etc. Until finally found Modern Welltest analysis using computational techniques. In Modern Welltest, analysis and interpretation is done using Pressure Derivative so that it can be used for complex reservoirs [1]. Until now, to determine the right reservoir and boundary models are usually assisted by using simulators where this activity is called modeling. However, to determine the right reservoir and boundary model has its own challenges, because there are no specific methods or equations that can determine the exact model of a reservoir. At the time of modeling the analyst must be observant in the selection of models in the simulator because many reservoirs behave as homogeneous reservoirs, because in reality there is no single homogeneous reservoir. This happens because each model is not unique (several different types of models can match the same data set). Therefore, choosing the right type of model also requires consideration, such as seismic data, geological data, log data, and information provided from other wells drilled into the same formation. Welltest analysis was studied by many authors before, one of the author is Bahrami [2] who proposed a welltest analysis using geological models and studying reservoir behavior from pressure transient. Some previous authors only focus on studying reservoir behavior. From the determination of this model can be used as supporting information for a reservoir which is then used to be a predictive model and renewal of its geological model, and allows engineers to simulate production estimates. In this study, IHS Fekete Welltest software is used for modeling and production forecasting. The case study presented is the "HBR-05" well located in Jambi, Indonesia.

2. Literature Review

2.1. Reservoir Model

2.1.1. Heterogeneous Anisotropic

Reservoir heterogeneity is a variation of the physical properties of rocks and fluids from one location to another [3]. This heterogeneity is as a result of the processes of deposition, faults, folds, diagenesis in reservoir lithology and changes or types and properties of reservoir fluids [4]. Another reservoir characteristic associated with heterogeneity is permeability anisotropic. Anisotropic reservoir is a reservoir that has a variation of permeability in the direction of flow. Anisotropic is caused by the process of deposition (channel fill deposites) or by tectonic processes (parallel fracture orientation). Anisotropic can occur in heterogeneous reservoirs or also in homogeneous reservoirs. Most reservoir rocks have lower vertical permeability than their horizontal permeability, so there will be anisotropic in the reservoir. Reservoir heterogeneity can be caused by human activity and occurs near the drill hole, this is caused by the invasion of the drilling mud during the drilling process, hydraulic fracturing, acidification, or due to fluid injection. Anisotropic reservoir evolution is complex and can lead to an inadequate analysis [5]. So in terms of the reservoir heterogeneity level it is very important to know the heterogeneity system of the reservoir itself.

2.1.2. Dual Porosity

Reservoir rock is made of two porosity systems, the first is intergranular, which is the empty space between grains of rock, and the second is the empty space of fractures and vugs [6]. The first type of porosity is called primary porosity, while the second type is called secondary porosity. When referring to only vugs or fractures, it is called vugular porosity or fracture porosity. Secondary porosity is generally found in rocks that have low intergranular porosity, such as limestone, clay, shaly sand, and others. Secondary porosity is caused by rock breaking, folding and dissolution. In nature actually there is third porosity types (matrix, fractures, and vugs) are usually present in naturally fractured, vuggy carbonate reservoirs [7].

In the fractured reservoir, the total porosity (Øt) is the sum of the primary porosity and secondary porosity, where this total porosity will refer to fluid storage capacity.

$$Ø_t = Ø_1 + Ø_2 \tag{1}$$

Where:

Ø1=matrix pore volume / total bulk volume

Ø2=volume of fracture pore / total bulk volume

In laboratory measurements, for various rock types, it is known that fracture porosity is lower than the porosity of the matrix and the total bulk volume is the volume of the matrix plus the fracture volume.

Storage Capacity is the ratio of the volume of hydrocarbons stored in the pores of rock to the total volume of hydrocarbons. It is usually worth between 0.01 and 0.1 [5].

$$\omega = \frac{(\varphi V c_t)_f}{(\varphi V c_t)_{f+m}} = \frac{(\varphi V c_t)_f}{(\varphi V c_t)_f + (\varphi V c_t)_m} \tag{2}$$

Where:

ω=omega (storage capacity)

Ø=matrix pore volume / total bulk volume

V=ratio of total bulk volume to total system volume

Ct=rock compressibility

f=fracture

m=matrix

Pressure transient analysis in porous media is commonly studied by assuming constant reservoir permeability over an entire range of formation pressure [8].

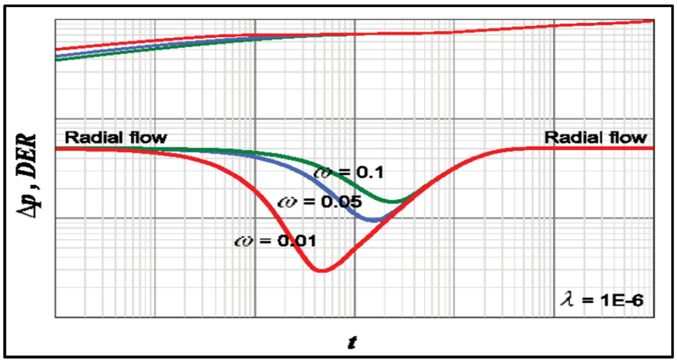

Figure 1. *Omega effect on the reservoir fractures naturally [5].*

2.1.3. Dual Permeability

Interporosity flow coefficient is a ratio of rock matrix permeability and fracture [9]. This coefficient depends on the geometry and size of the matrix.

$$\lambda = \alpha r^2{}_w \frac{k_m}{k_f} \tag{3}$$

$$\alpha = \frac{4j(j+2)}{L^2} \tag{4}$$

Where:
Lambda=interflow porosity
Alpha=characteristic parameters of system geometry
L=characteristic dimensions of matrix blocks
Km=matrix permeability
Kf=fracture permeability

Dual-porosity and dual-permeability system definitions are usually associated with naturally-fractured and layered systems, respectively [10].

At dual porosity, only porosity 1 is connected to the wellbore, and porosity 2 acts as a source (matrix). While on dual permeability, both porosity are connected to the well, for example, a well that has two commingle reservoir layers is produced, crossflow can occur.

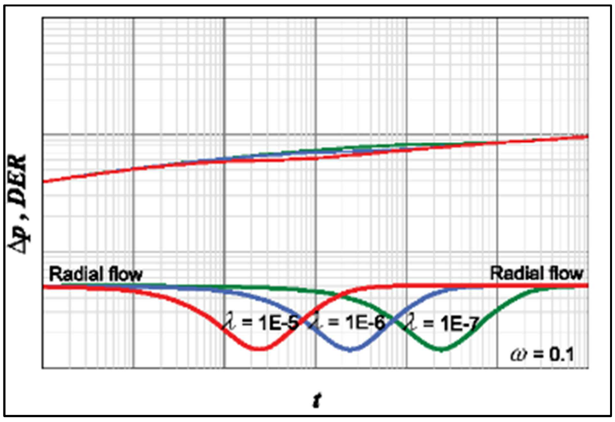

Figure 2. Lambda effect on the reservoir fractures naturally [10].

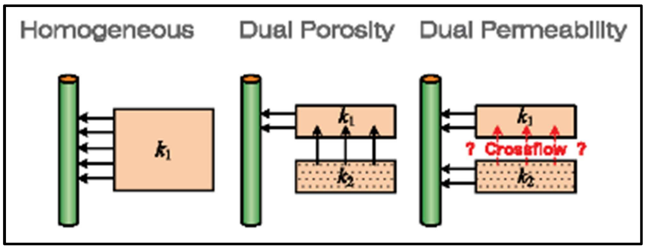

Figure 3. The difference between Homogeneous, Dual Permeability, and Dual Porosity [10].

2.1.4. Composite

One of the most commonly used reservoir models is the radial-composite reservoir model. The composite reservoir, consisting of a circular zone surrounding the well in which rock and/or fluid properties are different from properties in the unaltered reservoir outside of the altered circular zone, represents a wide variety of reservoir configurations of practical interest [11]. Another composite model also used is a linear-composite model. In both radial and linear-composite models, reservoir is divided into two regions, Region 1 with mobility k1 / μ1 and storativity φ1ct1, and Region 2 with mobility k2 / μ2 and storativity φ2ct2. Mobility and storativity can be combined to provide diffusivity of two parts each (k / ctφμ) 1 and (k / ctφμ) 2. The dimensionless solution for composite reservoir models can be explained by dimensionless ratio mobility variables:

$$M = \frac{(k\mu)_2}{(k\mu)_1} \tag{5}$$

and storativity ratio:

$$S = \frac{(\varphi c_t)_2}{(\varphi c_t)_1} \tag{6}$$

or with the M mobility ratio and diffusivity ratio:

$$D = \frac{M}{S} \text{ atau } S = \frac{(k/\varphi\mu c_t)_2}{(k/\varphi\mu c_t)_1} \tag{7}$$

Mathematically, ratio of mobility and storativity can vary independently. As a result, this ratio is often used as an installation parameter to model according to the observed pressure response, without ensuring that the value is realistic. In fact, the ratio of mobility and storativity is not independent. Instead, they are connected by two factors:

(1) Viscosity and compressibility are largely controlled by fluid systems.

(2) Correlated porosity and permeability, at least to some extent for most reservoir rock types.

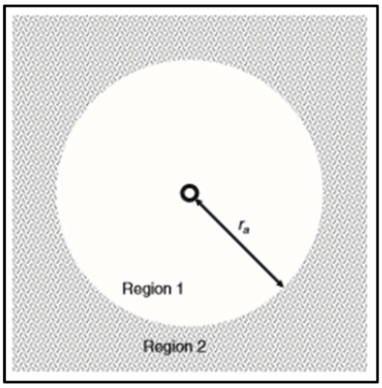

Figure 4. Infinite Radial Composite Reservoir [11].

When using a composite model, it is the responsibility of the analyst to ensure that the mobility and storativity ratios make sense and are consistent with other reservoir data. If the boundary separating the two regions representing fluid contact in a homogeneous reservoir is stated to have uniform permeability and porosity, the ratio of mobility and storativity is determined uniquely by the fluid properties of two fluids, fluid saturation in each region, and permeability relative to the fluid phase in each region.

2.2. Boundary Model

2.2.1. Closed Circular Boundary

The simplest closed reservoir model is a well centered in a circular (circular) closed drainage area. The first flow regime that appears is IARF, before boundary affects the pressure response. When the boundary begins to affect the pressure response, the derivative deviates upward, approaching the unit-slope line characteristic of the pseudosteady state flow after a short transition period that lasts about ¼ log cycle. Geologically, there is a slight impulse for the well centered in a closed circular reservoir [12]. However, a well located near the center of the drainage area that is quite symmetrical will show a pressure response that is very similar to a circular reservoir reservoir model. For example, the pressure response for a well in the middle of a square is almost indistinguishable from a cicular reservoir that has the same drainage area, differs 3% from the pressure derivative response and is less than 0.3% in the pressure response.

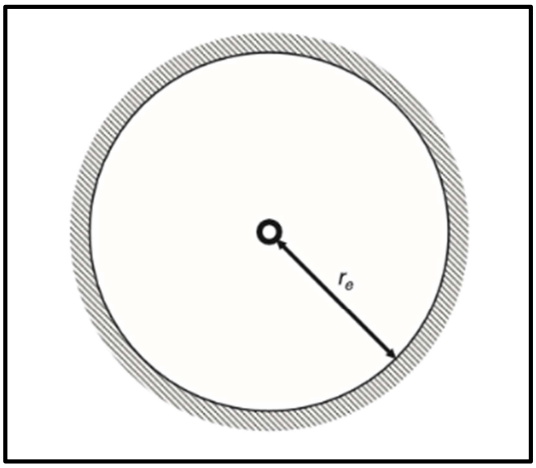

Figure 5. *Closed Circular Boundary [12].*

2.2.2. Circular Constant Pressure Boundary

Effect of an aquifer can be modeled with a constant pressure boundary model. This model assumes that the pressure at the boundary of the reservoir consistently remains at the initial reservoir pressure during the drawdown and build up phases of the well test [13]. One application commonly used in this boundary model is in injection well testing or production in waterflood patterns, such as five spots, regular or 7 spot inversions, or regular or 9 spot inversions. For isolated production wells, it is difficult to imagine a geologically suitable scenario that would provide the pressure response this model might predict. Initially, the pressure response showed that the IARF lasted until the time given by:

$$tb_{IARF} = \frac{745\varphi\mu c_t r_e^2}{k} \tag{8}$$

After the boundary effect has appeared, the pressure derivative will decrease exponentially with time, written in the equation:

$$\mathrm{P}wf = Pi - \frac{141.6qB\mu}{kh}\ln\frac{r_e}{r_w} \tag{9}$$

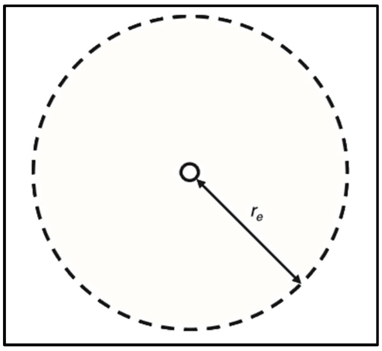

Figure 6. *The well in the middle of Circular Constant Pressure Boundary Reservoir [13].*

2.2.3. Rectanguler

One of the most commonly used reservoir boundary models is a well in a rectangular reservoir. Because of its flexibility in matching many different pressure responses, this model is often used even when there is no external information to justify its use. Geologically, the most direct rectangular reservoir model applies to wells in fault blocks which are limited by sealing faults [14, 15]. The rectangular reservoir model also finds applications in fluvial channels, point bars, and offshore bar deposits where the end of the reservoir affects the test response. Finally, rectangular reservoir models are often used to analyze tests on development wells which are drilled in a regular pattern. In the latter application, the model will be justified if all wells are produced and synchronized with the test well.

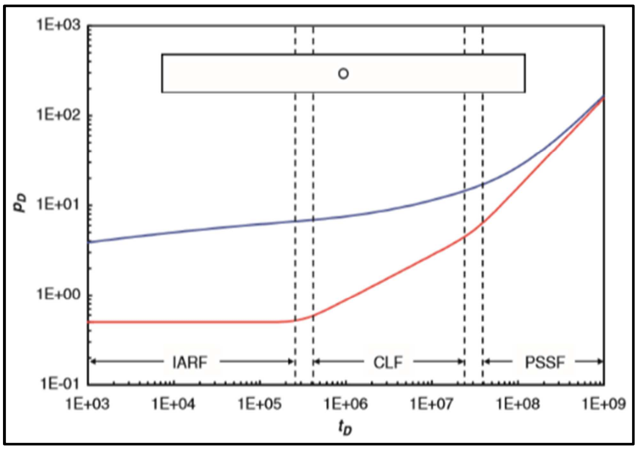

Figure 7. *Pressure Response for Wells in the Middle of the Rectangular Reservoir [14].*

3. Work Procedures

In this study, the authors used IHS Fekete Welltest software to simulate the pressure response for modeling. Before doing the modeling, it starts with a diagnostic analysis on the pressure derivative curve to provide some information about the well or reservoir conditions needed in the modeling. In the IHS Fekete Welltest software there are several models available such as vertical, fully penetrating anisotropic, slanted, composite, multilayer cylindrical, multilayer rectanguler, and fracture with boundaries. The available models are analyzed, then only one model is chosen that is considered the most representative of the pressure response and from consideration of supporting data such as geological data and data logging. The selected model was matched with two conditions of the alignment model, namely homogeneous / heterogeneous anisotropic and dual porosity. Analysis of parameters resulting from matching, it can be estimated which model is close to the actual reservoir and boundary model. The selected model, before being used for production forecasting is validated first by comparing the IPR model's with the IPR test. After validation, an analysis of production performance is performed using Pipesim software to obtain input parameters for production forecasting, such as the optimum production rate. Next, the production forecasting simulation is carried out for 50 months. From production forecasting, information is obtained that is the estimated production rate, cumulative production, and the profile of the reservoir pressure drop due to production.

4. Case Study

There is a well testing activity that is a pressure build up test conducted on a well in the "X" field in Jambi, Indonesia, namely the "HBR-05" well. The "HBR-05" well is a production well that has three productive layers, namely layers A, B, and C. From the three productive layers, the "HBR-05" well is only produced from layer A only, while layers B and C are closed. The "HBR-05" well was first produced in 2006 with an initial rate is 1007 BOPD and WC is 0.1%. This well was produced until 2016 before finally being closed with a final rate is 56 BOPD, WC is 0.6%, and a cumulative oil production is 966 MSTB. The current status of the "HBR-05" well is that the well is closed because at layer A it has allegedly reached an abandonment rate. It is known that this well has two productive layers still isolated that have the potential to be produced so that the "HBR-05" well can operate again. One of the isolated layers and considered prospects to be produced is layer C. Based on the production test data, layer C has an initial rate is 267 BOPD, 1 BWPD, 0.4% WTR, and 77 MSCFD. To get an estimate of production, an analysis of reservoir and boundary characteristics is needed. One of the characteristics related to get an estimate of the production of a layer is to determine a reliable reservoir and boundary model. The following are reservoir data needed for analysis, in full, can be seen in (Table 1).

Table 1. *Reservoir Data.*

Parameter	Unit	Value
Porosity, Ø	%	17.3
Total Compressibility, C_t	Psi^{-1}	1.63×10^{-4}
Net Pay Sand, h	Ft	11
Reservoir Temperature, T_{res}	°F	253
Initial Pressure, P_i	Psia	2640.4
Bubble Pressure, P_b	Psia	1680
Oil Viscosity, μ_o	Cp	0.92
Relative Oil Volume, B_o	RB/STB	1.49

5. Result and Discussion

In the Pressure Build-up test (figure 8), the "HBR-05" well is produced first with a stable rate for 12 hours, then the well is shut in for 30 hours. During testing, time and pressure changes are recorded. The test data was then analyzed with IHS Fekete Welltest software.

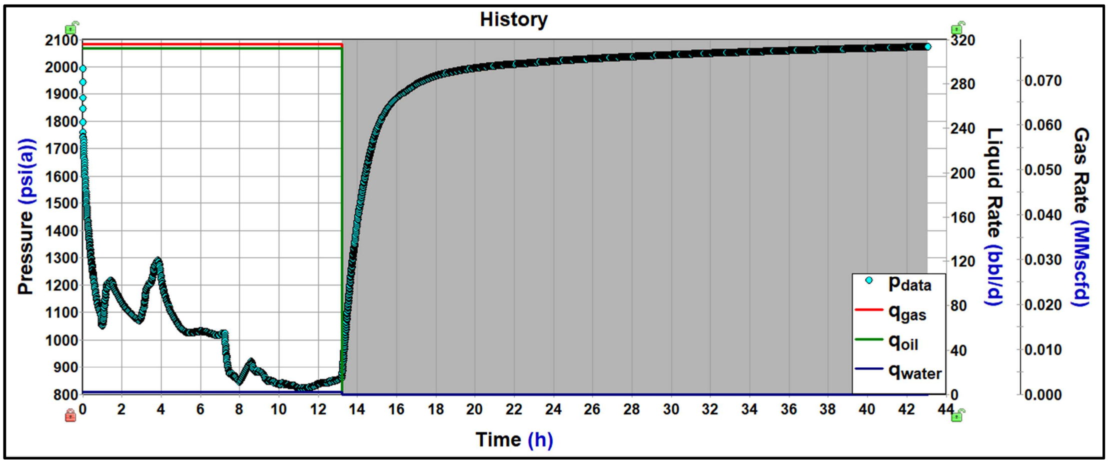

Figure 8. *PBU Test Plots.*

5.1. Diagnostic Analysis

Diagnostic analysis of pressure derivative curves aims to provide some information about the condition of the well and reservoir needed at the time of modeling. In the diagnostic analysis the pressure derivative curve is divided into three time phases that show the flow behavior that occurs namely early time, middle time, and late time. During the early time phase, flow regimes that occur are afterflow, linear fracture, bilinear, and spherical. For the middle time phase which in this phase is the phase that contains information about the condition of the reservoir. Flow regimes that occur in this middle time phase are radial. Whereas for the late time phase which is the phase that contains information about boundary conditions, where in this phase the flow regimes that occur are linear channels and the pseudosteady state. The following are parameters that are generated from diagnostic analysis, based on the observed flow regimes, in full, can be seen in (Table 2).

Table 2. *Results of diagnostic analysis on "HBR-05" well.*

Flow Regimes	Parameter	Value
Afterflow	Wellbore Storage Coefficient (C)	0.02 bbl/psi
	Dim. Wellbore Storage Constant (C_D)	7709.9
Linear Fracture	Fracture Half-Length (X_f)	21.12 ft
	Skin Equivalent to X_f (s_{xf})	-3.56
Bilinear	Fracture Flow Capacity	112.49 md.ft
Spherical	Spherical Permeability (k_s)	1.49 md
	Spherical Radius (r_s)	1.53 ft
Radial	Effective Permeability (k)	33.37 md
	Flow Efficiency (FE)	0.95
	Extrapolated Pressure (P*)	2101 psia
	Radius of Investigation (r_i)	417.32 ft
	Pressure Drop Due to Total Skin (dPs)	87.3 psia
	Total Skin (s')	0.53
Linear Channel	Channel Width (w)	424.67 ft

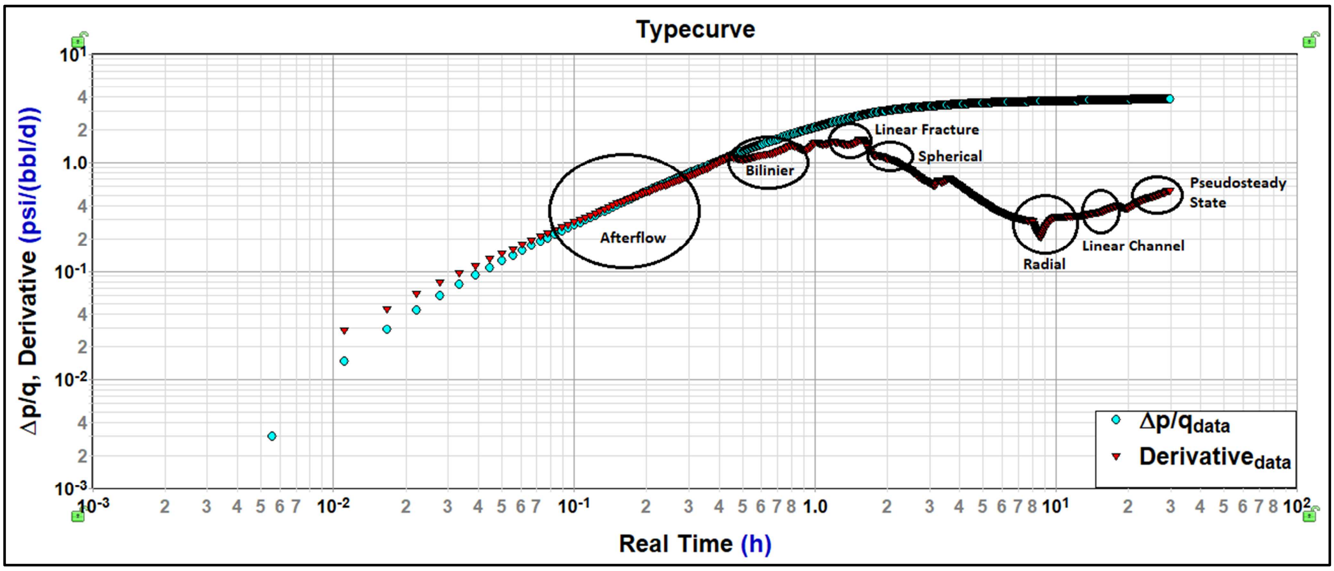

Figure 9. *Pressure Derrivative Curve.*

5.2. Modeling

Based on work procedures on the IHS Fekete Welltest software, one model was chosen that was considered to represent the pressure response and was supported by several supporting data (geological data and log data), the model is Slanted model. This model will go through the process of matching or aligning the pressure derivative data curve with the pressure derivative curve of the IHS Fekete Welltest software model by changing existing parameters.

A set of models is composed of wellbore models, reservoir models, and boundary models. The selected wellbore model is changing wellbore storage. From Pressure Derrivative Curve (Figure 9) it can be seen that the pressure curve and the pressure derivative curve do not coincide at both ends so that constant wellbore storage cannot be selected as a wellbore model. This shows that there is changing wellbore storage. Changing wellbore storage can occur due to gas production which can disrupt wellbore storage readings due to differences in compressibility between oil and gas. When the well is closed, the response of the pressure curve and pressure derivative curve does not follow the behavior of the slope wellbore storage unit.

In the Slanted model, the default reservoir model is heterogeneous. The pressure derivative curve (Figure 9) shows a valley in the middle time phase that indicates heterogeneity in the reservoir or a characteristic of the dual porosity reservoir. Therefore to get the best alignment tried with two conditions. The two conditions used in the model are the first heterogeneous, then the second is dual porosity. Whereas the boundary condition based on diagnostic analysis shows that the pressure response has reached the boundary. This is indicated by an increase in the end of the pressure derivative curve (Figure 9) forming slope 1 which indicates the pseudo steady state flow. Pseudo steady state flow is a characteristic of a closed system (no flow) reservoir.

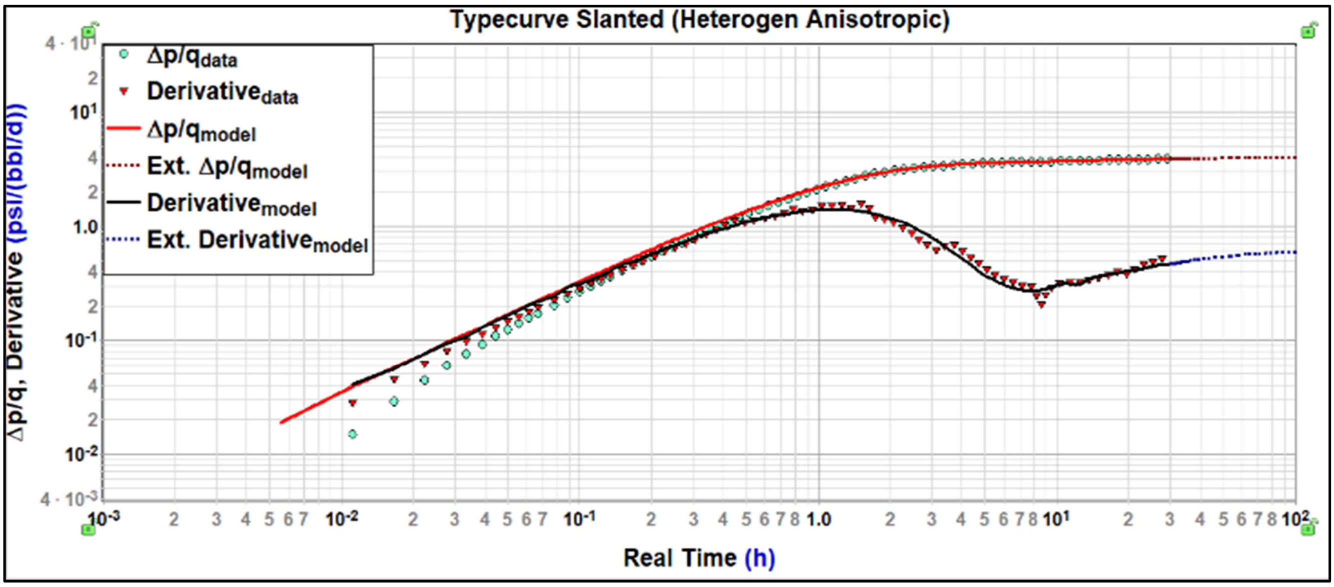

Figure 10. *Slanted (Heterogeneous Anisotropic) Model.*

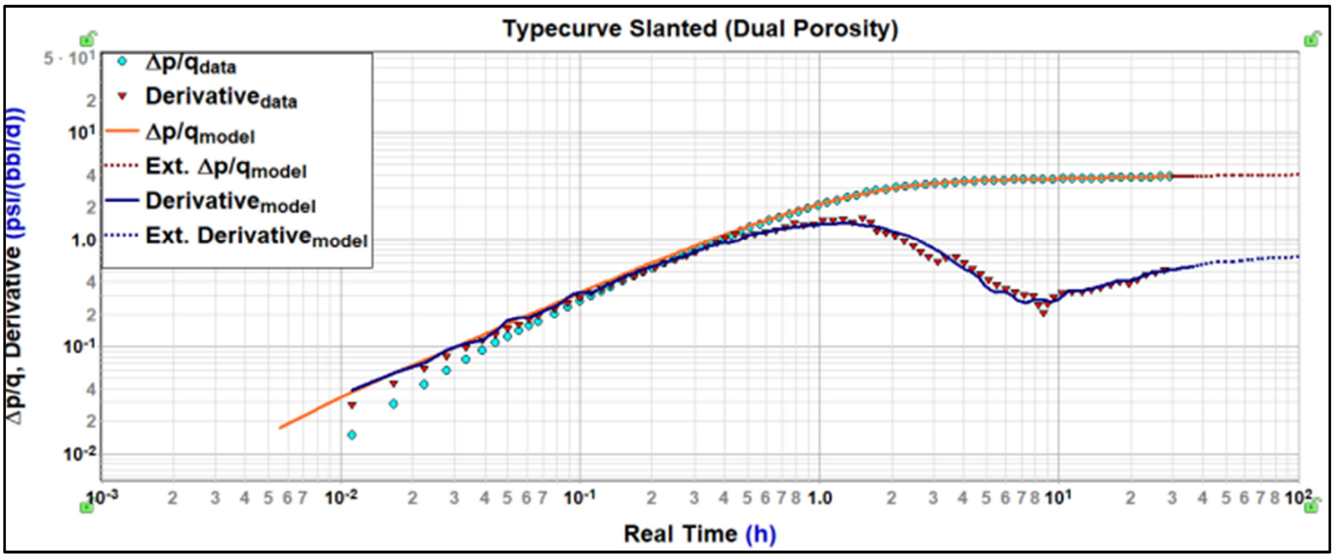

Figure 11. *Slanted (Dual Porosity) Model.*

The Slanted model simulates the pressure response in a tilted well (the wellbore enters the reservoir at an angle) in a heterogeneous anisotropic rectangular reservoir (differences in permeability in x, y, and z directions) or dual porosity characteristics. Based on the well diagram data, the "HBR-05" well is a directional well, which slants when entering the productive layer. This is reinforced by the discovery of spherical flow regimes in the wellbore, where flow regimes are commonly found in these conditions. Assuming the rectangular reservoir model is strengthened from the discovery of flow regimes linear channel in the late time phase. Linear channel flow only occurs in narrow and long reservoirs.

Meanwhile, for the two conditions of alignment carried out, namely heterogeneous model (figure 10) or dual porosity model (figure 11), both are matching. From the analysis using a heterogeneous model the kx value is 47.66 md, ky is 45.81 md, and the kz value is 45.50 md. Generally the value of kx> ky> kz indicates the presence of anisotropic in the reservoir, so for heterogeneous anisotropic reservoir models it is acceptable. While the analysis on the dual porosity reservoir model obtained omega values is 0.1 and lambda is 4.79e-06. Omega values indicate the predominance of the existence of fluids, whether more fluid is stored in rock matrices or in fractures. If the omega value is 1, then the fluid is completely stored in the fracture and if the omega value is 0 (zero), then the fluid is completely stored in the rock matrix. While the lambda value is the time of the end of the transition between the fracture and the matrix, where the smaller the lambda value, the longer the reservoir reaches the total system flow condition between the fracture and the matrix.

By considering the omega and lambda values that are considered too small for a dual porosity reservoir, the heterogeneous anisotropic model was chosen for the Slanted model. Based on the previous analysis, choosing the Slanted model (heterogeneous anisotropic) was also strengthened by parameters resulting from matching that matched the well, reservoir and boundary conditions. So the "HBR-05" well has a heterogeneous anisotropic reservoir model and rectangular-no flow boundary model. The sketch of the Slanted model (heterogeneous anisotropic) can be seen in (Figure 12).

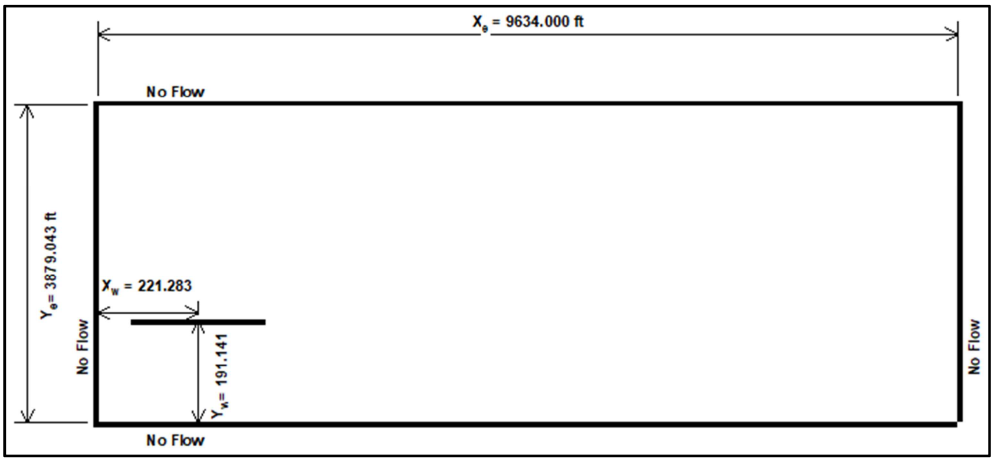

Figure 12. *Sketch of the Slanted Model (Heterogeneous Anisotropic).*

Table 3. *Well data "HBR-05".*

Parameter	Value	Unit
ID Tubing	2.441	Inch
Tubing Length	5819	ft
Perforations (MD)	5844	ft
Bean Size	0.625	inch
W_{cut}	0.37	%
GOR	288	SCF/STB
WHP	150	psia
T_R	253	°F
Pe	2166	psia
Q_{test}	268	BFPD
Pwf_{test}	860.4	psia

The Slanted (Heterogeneous Anisotropic) model is then used for production forecasting. To ascertain whether or not the Slanted model is reliable for forecasting production, validation is performed by comparing the IPR model's curve with the IPR test curve. Using the Standing method, an IPR (Inflow Performance Relationship) curve is made with the data listed in (Table 3).

With a skin effect is 0.448, the maximum flow rate is 346.9 BFPD. Whereas from the IPR Model, maximum flow rate is 339.4 BFPD. IPR curve validation can be seen in (Figure 13), it can be concluded that the Slanted (heterogeneous anisotropic) model relieble for the production forecasting of "HBR-05" wells.

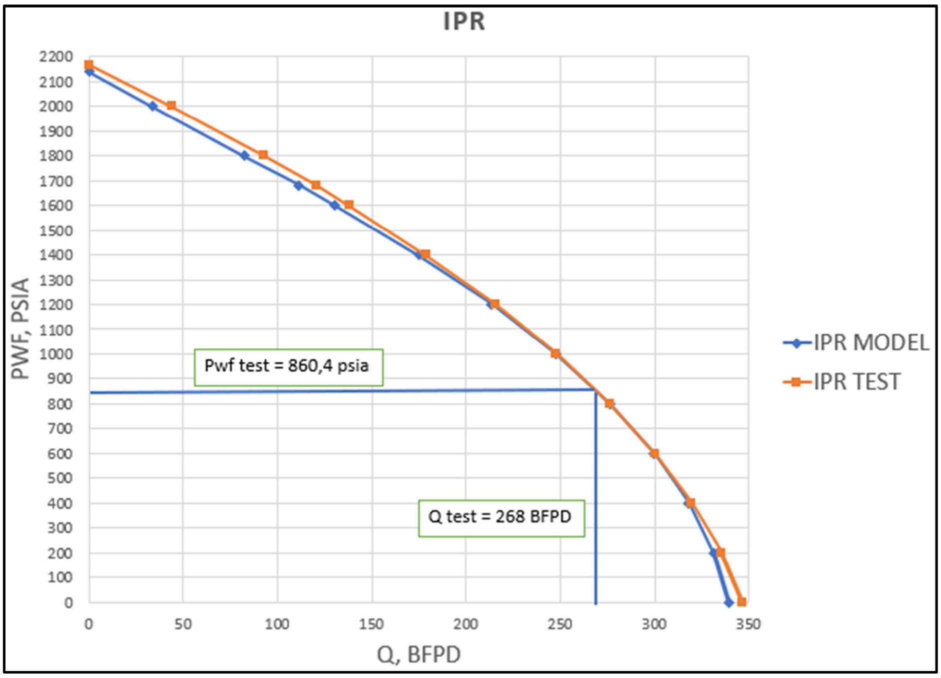

Figure 13. *IPR Curve Validation.*

Analysis of production performance using Pipesim software with the data listed in (Table 3), an analysis is carried out to determine the optimum production rate of the well. The sensitivity is done by cutting the IPR curve with various kinds of TIP (Tubing Intake Performance) so that an appropriate tubing size is obtained to drain oil at its optimum rate. Sensitivity was carried out on five tubing sizes, namely 1.995", 2.441", 2.992", 3.548", and 3.958". The sensitivity results (Figure 14), showed that the optimum "HBR-05" well flow rate when produced with a tubing of 2.441" size, with a flow rate is 279 BFPD.

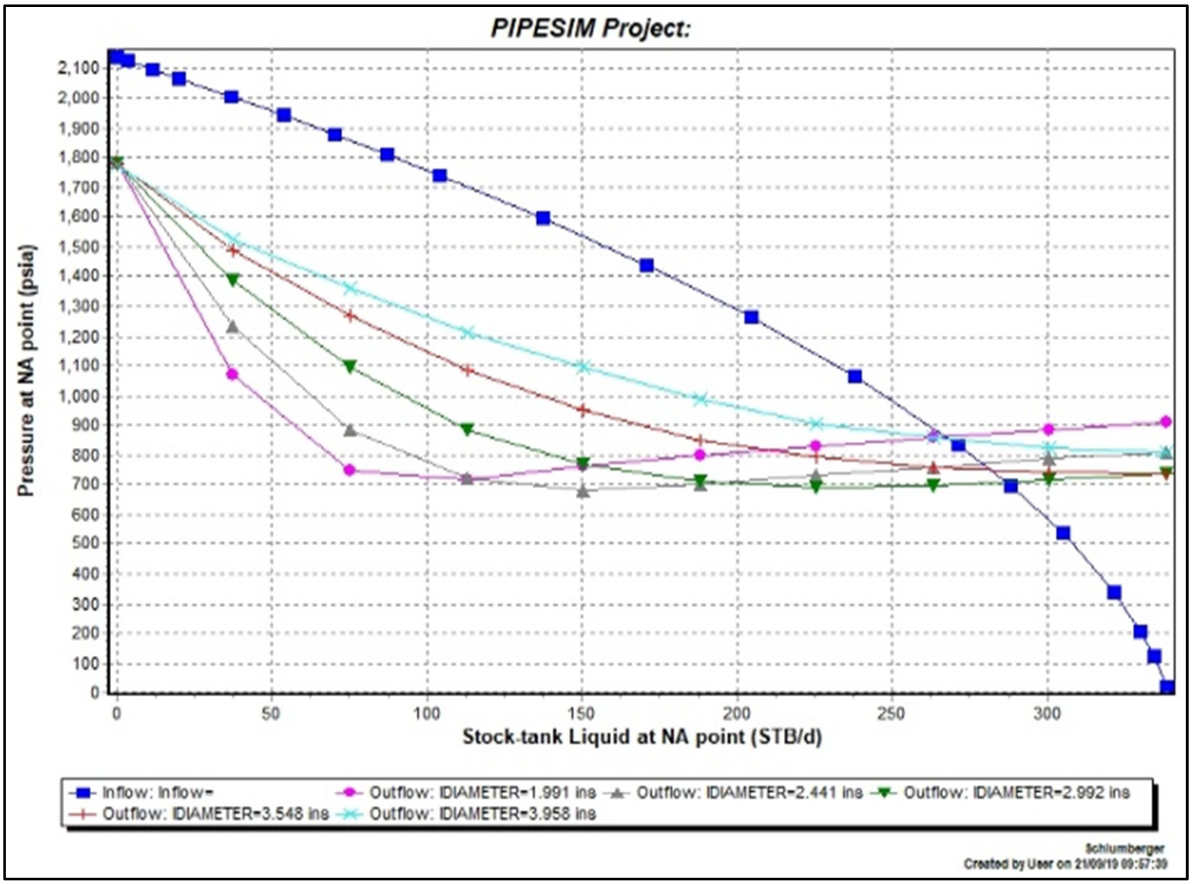

Figure 14. Results of IPR Sensitivity and Intake Tubing in "HBR-05"Well.

The Slanted (Heterogeneous Anisotropic) model contains the parameters that form the basis for simulating the estimated production of the "HBR-05" well. These parameters can be seen in (Table 4). In addition to the parameters of the model, there are also input data used to run production forecasting. Input data is obtained from available supporting data and from production performance analysis. Input data for production forecasting in the IHS Fekete Welltest software are listed in (Table 5).

Table 4. Slanted Model Parameters (Heterogeneous Anisotropic).

Reservoir Parameters	Calculation Results	Unit
Model Reservoir	Heterogen *Anisotrophic*	
Model *Boundary*	*Rectangular-no flow*	
OIP_{MODEL}	6.76	MMstb
P*	2138.7	psia
k_x	47.66	md
k_y	45.81	md
k_z	45.50	md
s_d	0.45	
X_e	9634	ft
Y_e	3552.87	ft
X_w	221.28	ft
Y_w	191.14	ft
Z_w	10.84	ft

Table 5. *Input Data for Production Forecasting.*

Parameter	Value	Unit
Mid of Perforations	5844	ft (MD)
ID Tubing	2.441	inch
ID Casing	6.1	inch
Tubing Depth	5819	ft (MD)
Casing Depth	6598	ft (MD)
Time	50	bulan
Pwf starting	1400	psia

After being run, the results of production forecasting can be seen in (Figure 15) and (Figure 16). (Figure 15) is an estimate of the production profile of the "HBR-05" well for 50 months (from 2019 to 2023). Whereas (Figure 16) is the profile of the reservoir pressure drop due to production.

In natural flow production forecasting, the initial Pwf value used is 2/3 of Pr, which is 1400 psia so that the reservoir pressure does not drop significantly due to production. For production forecasting is carried out for 50 months (starting from 2019 until 2023) with 2 scenarios of Pwf price changes. The scenario of lowering the price of Pwf is done in the 6th and 14th months with a decrease of 200 psia so that the minimum production rate is in the range of 40 BFPD in 2023 or the last year of forecasting. Production forecast results in the "HBR-05" well if produced for 48 months or in 2023 obtained a cumulative production of 107.8 Mbbl. Forecasting results also show that in the 22nd month (2020) reservoir pressure is already below the bubble point pressure.

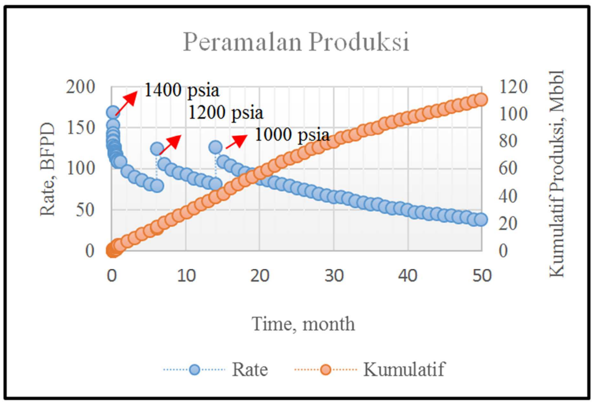

Figure 15. *"HBR-05" Well Production Profile Estimation Curve.*

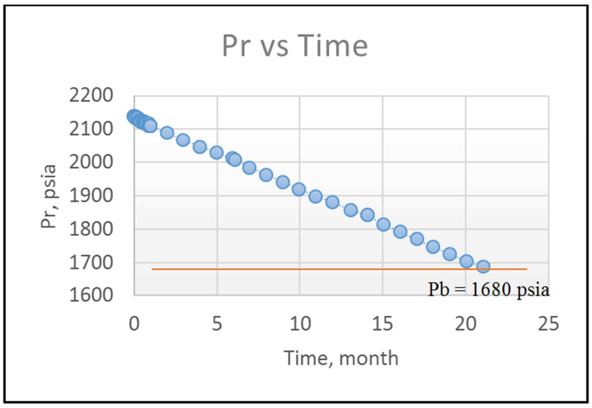

Figure 16. *Profile of the reservoir pressure drop due to production.*

Keep in mind that forecasting is forecast when the well has not been stimulated. As production goes on, the value of the skin will be even greater. By doing stimulation such as hydraulic fracturing will reduce the value of the skin and increase production gains.

6. Conclusion

1. Slanted model with heterogeneous anisotropic reservoir model and rectangular-no flow boundary model was chosen as a model of the "HBR-05" well for production forecasting, because it most represented the pressure response and was supported by supporting data.
2. From the analysis of production performance with nodal analysis it is known that the production of "HBR-05" optimum wells with tubing of 2.441" size, the flow rate is 279 BFPD.
3. The "HBR-05" well, if produced for 48 months (in 2023), the cumulative production is 107.8 Mbbl.
4. Forecasting results show that in the 22nd month or in 2020 the reservoir pressure is already below the bubble point pressure.
5. From the results, it can conclude that by determining the reservoir model of the pressure transient behavior we can forecast production and decide the steps to be taken for further well planning.

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