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The Selection of Optimal Gas Production Rate using Dynamic Reservoir Simulation in M-Alpha Field

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ABSTRACT

The Indonesian government has targeted a gas production rate of 12 BSCFD by 2030 to balance the energy demands and the carbon emission reduction. To achieve this goal, a comprehensive evaluation of a gas field will be carried out regarding the Recovery Factor, Stable Production Period (Plateau Time), Total Production Period, and Profits using a simulation program. Dynamic Reservoir Simulation is an integrated field development simulation that combines physics, mathematics, reservoir engineering, and computer programming to analyze and predict the well's performance under various operating conditions. There are stages in the simulation including Reservoir Model Creation, Initialization, History Matching, and Production Performance Forecasting. This research is a continuation of static reservoir modeling research that was done by LEMIGAS, which was started by reinitializing the model and ended by forecasting the production performance of the M-Alpha field using several gas production flowrate scenarios to find out the optimum gas production rate in ten years period. The simulation result showed that the best production flow rate for ten years is 3 MMSCFD. It gives 78,505% recovery factors, with a cumulative profit of $40,915,872 over a plateau period of 6.6 years.
Keywords: gas production rate, dynamic reservoir simulation, recovery factors, plateau time

I. INTRODUCTION

To strike the balance between energy needs and achieve carbon emission reduction targets, the clean energy transition from hydrocarbon to gas or other energy resources needs to be improved. Therefore, the Indonesian government has targeted natural gas production of 12 BSCFD by 2030 to maintain energy sustainability (Directorate General of Oil and Gas, 2022). To achieve this goal, an integrated field development plan is needed to optimize the gas rate production. M-Alpha field is a greenfield with a condensate gas type reservoir, located in the North Kalimantan Region as a part of the Bulungan Delta. A field development scenario will be carried out to increase production in the M-Alpha field. Therefore, an evaluation is needed regarding the appropriate injection rate, constant gas production time (plateau time), and calculation of the optimum profit.

There are many methods of field production forecasting and project planning by these results. One of the methods used to make field development planning is by Reservoir Simulation. It is a complement to field observations, experiments, laboratory tests, well tests, and an analytic model, and used by reservoir engineers to investigate the displacement of processes, to compare and contrast the characteristics of different production scenarios, or as a part of inverse modeling to calibrate reservoir parameters by integrating static and dynamic (production) data (Sankaran et al, 2020; Tan et al, 2022; Zargar & Thakur, 2022). Reservoir simulation combines physics, mathematics, reservoir engineering, and computer programming to develop a tool (in this case a model) to analyze and predict the performance or how fluid flows through reservoir rocks to the surface over time under a wide variety of operating conditions. These results are then used to optimize field development plans to analyze the operational and to decide the investment decisions (Ertekin et al., 2001; Lie, 2019).

The two most common types of reservoir models are Black Oil models and composition models (Ahmed, 2019). The Black Oil model assumes that the saturated phase properties of the two hydrocarbon phases (oil and gas) depend only on pressure. Composition models also assume two hydrocarbon phases, allowing the definition of many hydrocarbon components (Fanchi, 2006). According to (Chen, 2007), the gas component of the Black oil model is divided into two parts, one part is in the gas phase known as free gas, and the other part is in the oil phase known as solution gas. Free gas is characterized by the density ρ_g, but solution gas has its density (Chen, 2007). In this research, we try to characterize the M-Alpha field reservoir type and choose the optimum production scenario. This is a development of previous research that produced a Static Reservoir Model in the M-Alpha field and simulations at an early stage.

II. METHODS

2.1. Equipment and Materials

The data used in this study was previous data from previous research and laboratory tests carried out by BBPMGB "LEMIGAS". The data include Fluid Composition Analysis, Routine Core Analysis, Rapid Formation Test (RFT), Well

Test, and Reserves Analysis. Well X-1 is a producing well in the M-Alpha field which is used as an object in this research with fluid composition as shown in **Table 1.**

Table 1. M-Alpha field Reservoir Fluid Composition

Component	ZI	Weight fraction	MW	SG (Gram/cc)
CO2	2.97	5.6745	44.01	0.777008
N2	0.1	0.12161	28.013	0.803999
C1	79.9	55.648	16.043	0.425002
C2	5.94	7.7542	30.07	0.548008
C3	5.39	10.318	44.097	0.581999
IC4	1.27	3.2046	58.124	0.556994
NC4	1.37	3.457	58.124	0.579003
IC5	0.59	1.848	72.151	0.619995
NC5	0.33	1.0336	72.151	0.626002
C6	0.42	1.5316	84	0.684998
C7+	1.72	9.4084	126	0.763

The data was analyzed using software such as ®ECLIPSE PVTi, ®PROSPER, Microsoft Excel, and ®PETREL RE. Software Eclipse PVTi was used to obtain a phase diagram model of M-Alpha field reservoir fluids. Meanwhile, an Inflow Performance Relationship (IPR) graph was obtained using PROSPER, and PETREL was used to perform dynamic reservoir modeling and production forecasting in several different production scenarios. To analyze the data, a computer with high specifications is needed. To perform this study, we were using a laptop unit with specifications of AMD Ryzen 7 4800H processor (~2.9 GHz), Memory Capacity RAM 16 GB, SSD Storage Capacity 500 GB, VGA NVIDIA Geoforce GTX 1650Ti, and *Display Monitor* 1920 x 1080 px.

2.2. Research Methodology

Using several gas production flow rate scenarios, an optimum gas production flow rate was determined. The parameters used to determine the optimum conditions include the Recovery Factor, Stable Production Period (Plateau Time), Total Production Period, and economic elements. The stages of research carried out include Data Analysis, Property Modelling, Initialization, History Matching, and Forecasting. Data analysis was done to obtain the data needed to start a dynamic reservoir simulation. These data were Phase Diagrams and PVT data models. In this case, the PVT data models were based on Constant Composition Expansion and Constant Volume Depletion test results using the PVTi program in Eclipse software. The test was done by applying Peng-Robinson 3-parameter equation of state and Lohrenz-Bray-Clark viscosity correlation, Permeability Distribution Equation (using power regression analysis), IPR and VLP (using PROSPER software with Multirate C and n IPR equations), Datum Depth (Fluid contact, in this case GWC) and Pressure Distribution Equation (using linear regression analysis). The Inflow Performance Relationship (IPR) graph was obtained from equation (1), as follows:

$$Q_g = C(p_r^2 - p_{wf}^2)^n \tag{1}$$

For natural gas production, the estimated maximum production of each well was determined by test data and does not exceed 30% AOF of the IPR curve (PTK 037, 2017; PTK 037, 2021).

The next stage was Property Modelling, where the properties of the reservoir will be put into a static reservoir model before doing the actual simulation. In this case, the reservoir model has been made by BBPMGB "LEMIGAS". Several types of data represent the actual condition of the reservoir such as Geometric Data (grid cell size, volume, elevation, slope, etc.), structural and stratigraphic data, Petrophysical Data, Reservoir Fluid (PVT) Data, Well and Production History, etc. Data can be derived from log or laboratory data that is input as a scale-up from log data.

The Initialization process was carried out to equalize the reserve volume (hydrocarbon in place) from the results of volumetric calculations and simulation results. The volumetric method can be used when the available data is incomplete (Ardiansyah et al, 2021). It is useful for determining the value of the initial hydrocarbon in place, ultimate recovery, and recovery factor. Due to limited laboratory test data to complete the required data, several equations have been provided on PETREL according to the type of formation, in this case, *consolidated sandstone* was selected as the formation type. The equations include Corey correlation to find the value of relative permeability to fluid saturation, and Newman correlation to find the compaction value of rocks.

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Then History Matching was conducted to see the difference and to match data between the observed data (pressure and production) and the simulation results. This was done to ensure that the input data was correct and adequate to start the simulation. The smaller the difference between the simulation results and the actual data, the more accurate the model's ability to simulate reservoirs. Thus, the more reliable the simulation result. The acceptable difference for in-place volume is < 5% (Pamungkas, 2011). The last stage was the Forecasting process which was carried out with specific parameters according to the goals of the simulation or field development scenario that had been planned.

Each field has its characteristics which may affect the decision-making of optimum field development plan. A good data analysis will provide accuracy and predictability in production forecasting of the project outcome to committing the financial risk associated with the project and ensuring the correct production action (Tan et al., 2022). In the oil and gas industry, data analytics plays an important role in reducing the risk inherent in the development of subsurface resources by reducing operational cost, improving efficiency, and increasing the production and reservoir recovery together with good quality field data (log, fluid, core, etc.) to ensure the low uncertainty (Sankaran et al., 2020). This research was conducted by forecasting the production of the M-Alpha field for the next ten years starting from 24th May 2022. The evaluation includes the economic element of the final profit obtained over the past ten years where operating costs are negligible.

III. RESULTS AND DISCUSSION

3.1. Production Performance

Generally, if the reservoir temperature (T) is above the critical temperature (T_c) of the hydrocarbon system, then the reservoir is classified as a natural gas reservoir. According to the phase diagram, natural gas can be classified into four categories, namely Retrograde Gas Condensate Reservoir, Near Critical Gas Condensate Reservoir, Wet Gas Reservoir, and Dry Gas Reservoir (Ahmed, 2019). Using ECLIPSE PVTi, a phase diagram model of the M-Alpha field reservoir was obtained, as can be seen in **Figure 1** and **Table 2.**

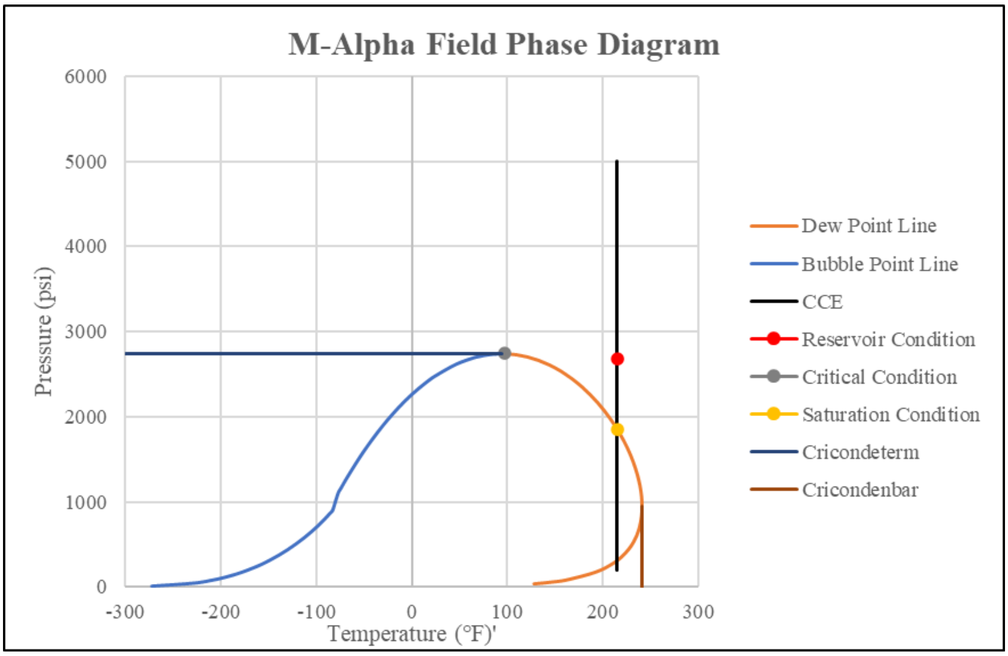

Figure 1. Phase Diagram of Reservoir X

Table 2. Fluid Properties of Phase Diagram and PVT Modeling Using Eclipse PVTi

Condition	Pressure	Temperature
	psi	ºF
Critical Point	2751.56	97.67
Reservoir	2676.47	214.8
Saturation	1847	214.8

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In **Figure 1,** the blue dot on the top of the bubble point line represents the critical condition, the green dot represents the saturation condition, and the orange dot represents the reservoir conditions. PVT data was also obtained through Constant Composition Expansion (CCE) and Constant Volume Depletion (CVD) test modeling. GOR and condensate density values were obtained from well test data respectively 32633 SCF and 62.5°API. Based on these results, it can be said that the M-Alpha field is a condensate gas reservoir. This is convenient with the (Ahmed, 2019) theory which states that condensate gas reservoirs are characterized by the temperature of the reservoir lying between the critical temperature and cricondeterm, GOR from 8000 to 70000 scf/stb, and condensate density > 50°API. Meanwhile, from PVT data, it is known that the Gas Formation Volume Factor (Bg) at reservoir conditions is 0.006050 cuft/SCF.

The relationship between porosity and permeability data was obtained from Core Analysis and Well Test with Power Regression Analysis. **Figure 2** depicts the distribution of the effective porosity in the reservoir. The distribution of effective porosity appears to be in line with the formation types that have been modeled previously, where the purple color depicts shale formations with very small porosity and the other colors depict sandstone formations with varying porosity, with the largest porosity value being 21.86%. Color variations indicate the level of porosity, where the closer to red, the greater the porosity, and the closer to purple, the smaller the porosity. An equation is obtained which describes the distribution of permeability values in the reservoir, as follows:

$k\ (md) = 2.18.10^6 \times \Phi^{6.2258}$..........(2)

From equation (2), the permeability value can be determined, which was 160.285 md.

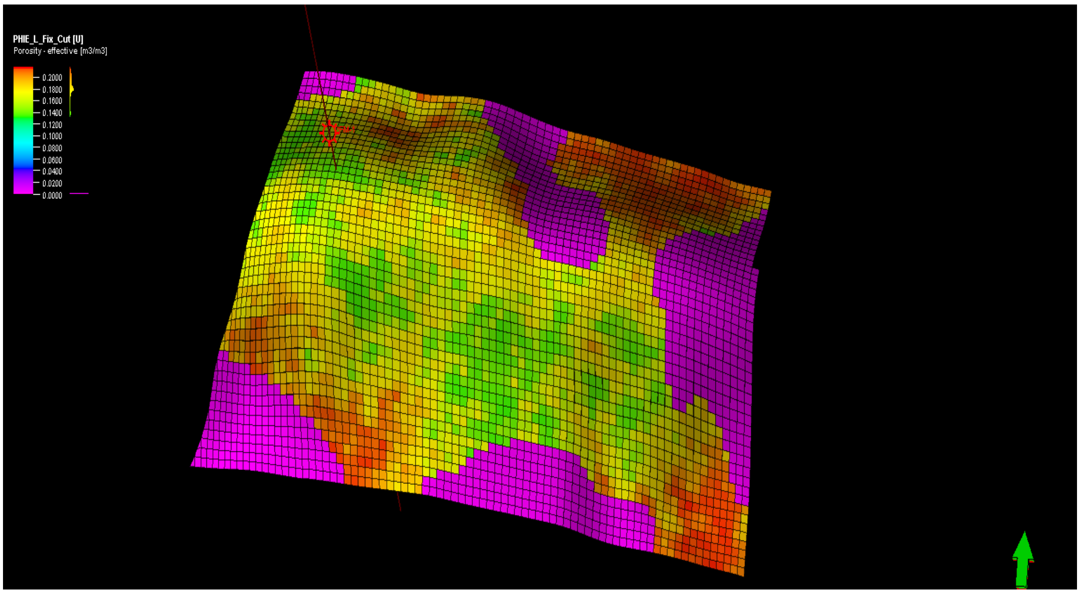

Figure 2. The distribution of the effective porosity in the reservoir

Using PROSPER software, an *Inflow Performance Relationship* (IPR) graph was obtained from the production of Well X-1. The well-testing method used was *the Drill Stem Test* (DST) with a tubing size of 2,992 inches. It was carried out in several stages with different flow rates, so it produced several *Vertical Lift Performances* (VLP) with different *Tubing Head Pressure* (THP) as shown in **Figure 3**. The green line is the IPR and the red lines are the VLPs. The blue dots represent the intersection point between IPR and VLP with a combination of gas rate and bottom hole pressure. The maximum gas rate, which is also called AOF, is shown in **Figure 2** at 68,227 MMSCFD. Using the assumption that the optimum production limit is ≤ 30% AOF, then the optimum production limit for well X-1 is less than 20,468 MMSCFD. This is by intersection point 6. In addition, we get a C value of 0.12195 MMSCFD/psi^2 and an n value of 0.83796.

The analysis of the *Rapid Formation Test* (RFT) on Well X using linear regression analysis showed that the contact between the aqueous and gas phases occurred at a depth of 6500 ft or 1981.1 meters. The pressure gradient was 0.1456 psi/ft for gas and 0.453 psi/ft for water, respectively. The regression equation describes the pressure distribution that applies in field reservoir X, as follows.

$P, psi = 0.453(d, ft) - 226.86$..........(3)

for water-bearing formation, and

$P, psi = 0.1456(d, ft) - 1770.8$..........(4)

for gas-bearing formation.

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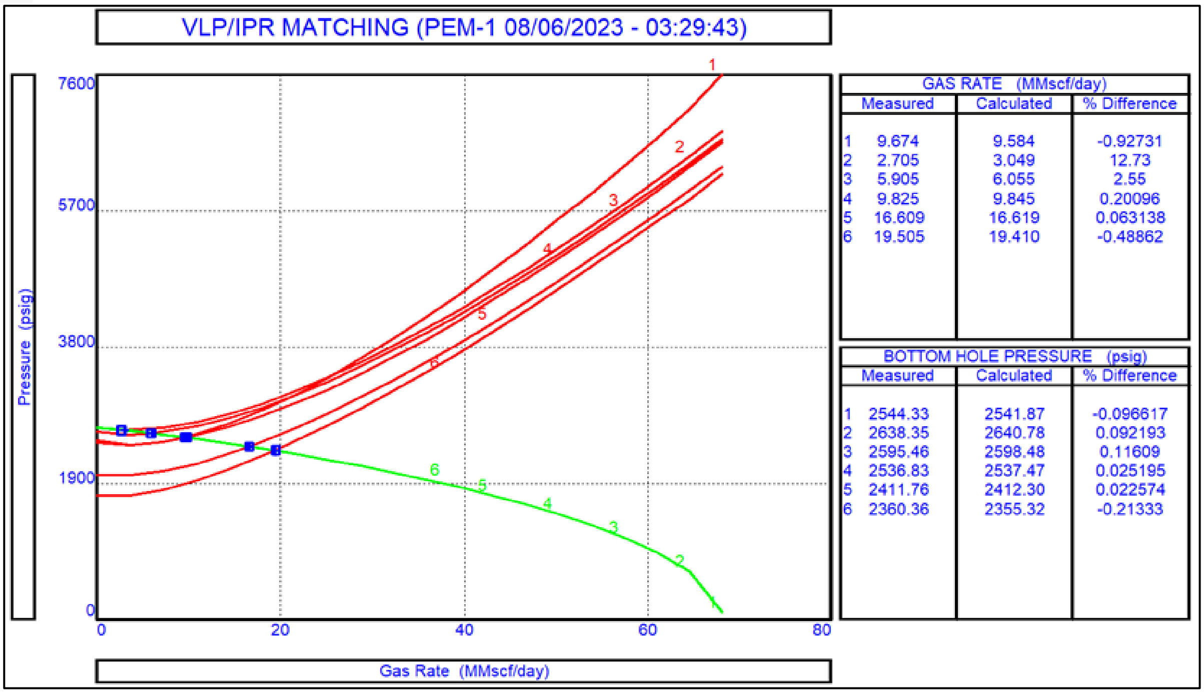

Figure 3. The IPR and VLP matching

3.2. Initialization and History Matching

The initialization process is carried out on the well reservoir model, with the previous configuration. The Initial Gas in Place (IGIP) for the M-Alpha field reservoir using volumetric calculation showed a result of 9610 MMSCF but the simulation result was 20277.24 MMSCF. The difference between IGIP from volumetric and simulation was 71.38%. This significant difference resulted because the area used for simulation are whole reserves area or 3P area (Proven (P1) + Probable (P2) + Possible (P3)). Meanwhile, the area used for volumetric IGIP calculation is 2P area (Proven (P1) + Probable (P2)). After adjusting the area for simulation, the second attempt of initialization resulted in IGIP 9539.666 MMSCF, minimizing the difference significantly up to 0.73 %. As the difference is < 5% (difference tolerance), the initialization process was considered successful.

After initialization, an alignment process was carried out on Well X-1, sequentially this alignment was carried out on Bottom Hole Pressure, Tubing Head Pressure, Gas Production, and Condensate Production. The result of the history-matching process can be seen in **Figure 4**. There is a discrepancy in the condensate production data, due to several factors, including limited data (SCAL and PVT data) and very low liquid saturation. After matching various VLP data with different THPs, the observed data and simulation result match with VLP data of 1966.99 psi THP, and a flow rate of 9,825 MMSCFD. This flow rate will be used as the maximum flowrate parameter in the dynamic simulation.

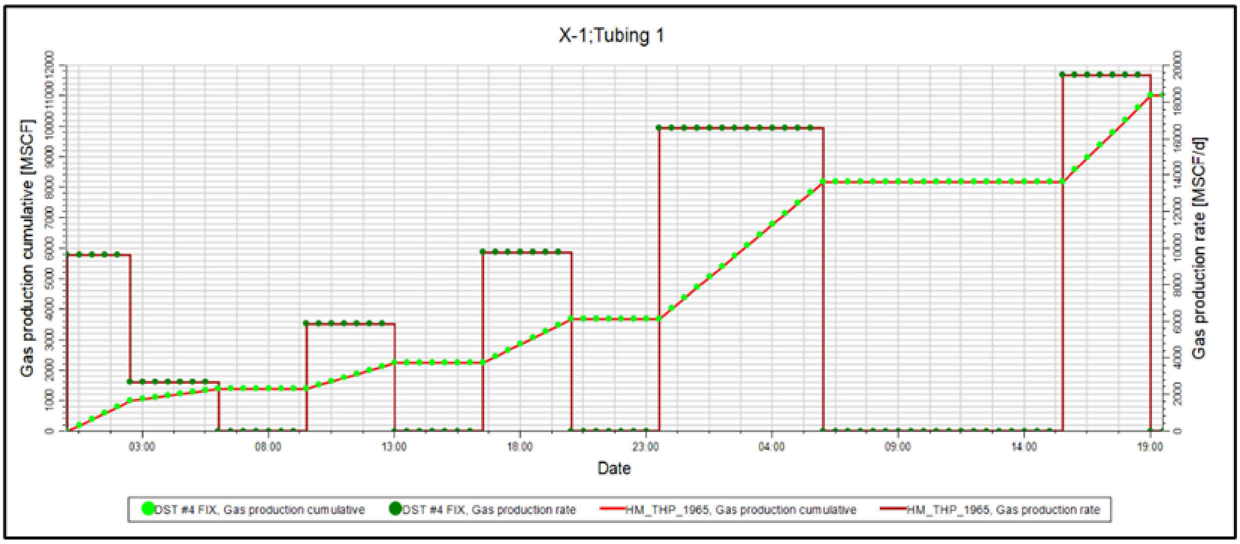

Figure 4. The result of the Initialization and History Matching process

3.3. Production Forecasting

In this stage, sensitivity analysis was used in gas production flowrate. The initial gas flow rate was maintained at 9,825 MMSCFD and a plateau period of around 1.69 years started from the initial simulation. Then proceed with sensitivity for the production flowrate to find out the most profitable production scenario in the 6 years, with a maximum THP of 100 psi and a minimum gas flowrate of 1000 MSCFD. In this scenario, the profits obtained during the production period were also calculated. The calculation was based on presidential decree No. 121, 2020, which states that the highest natural gas price in the domestic market (Indonesia) is USD 6/MMBTU (The Amendments to Presidential Regulation Number 40 of 2016 concerning Determination of Natural Gas Prices, 2020). The plot of gas production rate versus time was presented in **Figure 5** and the results of the sensitivity analysis, plateau time, and profits were presented in **Table 3**.

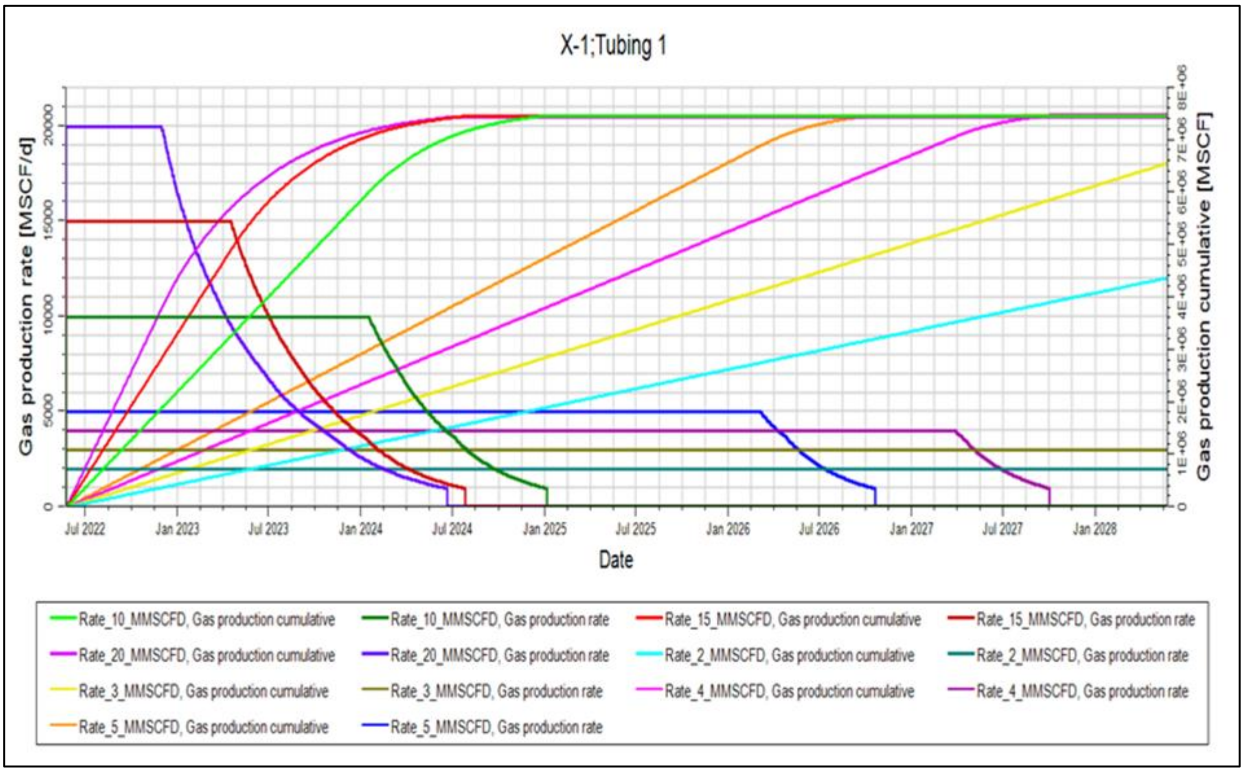

Figure 5. The Simulation Results of Flow Rate and Cumulative Gas Production from 2022 – 2028

Table 3. Forecasting and Economic Analysis of M-Alpha Field with Variation of Gas Production Rate Scenarios

Flowrate Scenario		RF	Plateau	Plateau	Production	Prod. Time	Profit/day	Cumulative Profit
No	**MMSCFD**	**%**	**End**	**Year**	**End**	**Year**	**$**	**$**
1	20	78.054	01/12/2022	0.5	23/06/2024	2.1	124,440	23,768,040
2	15	78.300	17/04/2023	0.9	27/07/2024	2.2	93,330	30,612,240
3	10	78.419	18/01/2024	1.7	06/01/2025	2.6	62,220	37,580,880
4	5	78.488	07/03/2026	3.8	21/10/2026	4.4	31,110	43,025,130
5	4	78.496	30/03/2027	4.9	05/10/2027	5.4	24,888	44,076,648
6	3	78.505	Ongoing	6.6	Ongoing	7.0	18,666	40,915,872
7	2	78.524	Ongoing	10.0	Ongoing	10.0	12,444	27,277,248

As the result above, the observed parameter (Recovery Factor (RF), Plateau time, Production Lifetime, and Profit), seems to have increased as the wells started to produce. There was an exception on Scenario 6 and 7 because the production was forecasted to still be ongoing after a year. The parameter enhancement from one scenario to another was varied. The RF and Profit kept declining as the gas rate decreased. As an illustration in **Figure 5**, from scenarios 1 to 2 the increase of RF was 0.315% and the profit was 28.8%. In the end, the enhancement from scenarios 5 to 6 was 0.011% for RF and 2.06% for profit. This change was very minuscule compared to the enhancement at the beginning. However, in the case of a period of plateau and production time, the enhancement becomes more varied. The increase from certain scenarios was more substantial than others. For example, the plateau year from scenario 2 increased by 0.4 years or about 71.73% from scenario 1. A drastic change occurred in scenario 4 when the plateau year increased more than two-fold from the previous scenario (scenario 3) and gained extra after 2.1 years. Then, the enhancement became smaller but a sudden increase occurred again in scenario 7 when the plateau year was increased by 3.4 years or about 51.58% from scenario 6. Fulfilling the ten years and prediction was still ongoing.

According to simulation using scenario 7, where the plateau and production time have not yet reached the end time, the M-Alpha field potentially can be operated over ten years. From this point of view, it can be inferred that Scenario 7 was more advantageous than other scenarios. Moreover, it gave the best recovery factor which was 78.524%. However, if the total gross profit obtained from gas sales was also taken into account, the enhancement was not too significant (around 1.05%) compared to scenario 6. If the payback period for developing the M-Alpha field and the profits were considered, then scenario 6 was more profitable because the payback period is faster than scenario 7. Taking other factors into account, scenario 6 appears to be the best option for gas production in the M Alpha field. It gave 78.505 % of RF, and even though the RF value is smaller than scenario 7, the difference was small so gas recovery can be said to remain high.

Using several software and calculations, an analysis to determine the best production scenario has been carried out. With a phase diagram model, the M-Alpha field reservoir type was determined and although the porosity value does not exceed 21.86%, the reservoir has a permeability value of 160.285 md which indicates that the reservoir has a good ability to flow fluid. By IPR and VLP matching, then the optimum production limit for well X-1 was determined not more than 20,468 MMSCFD with a maximum flowrate of 9,825 MMSCFD. This value becomes the basic calculation for subsequent production forecasting. Using sensitivity analysis, and considering the economic analysis of the M-Alpha field, the best production flowrate was determined at 3 mmscfd for a maximum of 7 years of production period. Regardless of this potential, gas production rate determination is always following consumer requests that have been approved in the prior business contract between the company and the government.

IV. CONCLUSION

A reservoir simulation analysis was done to select the optimum gas production rate for well X in the M-Alpha field which is located in North Kalimantan. Based on the PVT analysis, the M-Alpha field is a condensate gas reservoir with the GOR 32633 SCF and a density of 62.5°API. The IGIP obtained was 9539,666 MMSCF indicating that this field has very promising productivity. Using sensitivity analysis, the best production scenario was obtained with a gas flowrate of 3 mmscfd. It gives the best recovery factor which is 78.505% with a cumulative profit of $40,915,872 over a plateau period of 6.6 years. The effect of altering the gas production rate is minuscule towards the recovery factor value of the M-Alpha field. Indicated by less than a 1% increase in recovery factor. The decreasing of the gas flowrate gives a more effective lifetime of the field which gives more profit for the benefit. According to the analysis and calculations that have been carried out, it can be concluded that the M-Alpha field has optimum productivity for a maximum of 7 years with a flowrate of 3 mmscfd.

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