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Cite as: AIP Conference Proceedings **2245**, 080001 (2020); https://doi.org/10.1063/5.0007067
Published Online: 08 July 2020

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Abstract. Layer A on the X field has been produced since September 2007 until December 2016. This layer consists of 9 wells with current status: 1 production well (natural flow), five shut-in wells, and three dry-hole wells. The original oil in place of this layer is 28.113 MMSTB. The production data shows that cumulative oil production of this layer is 1.066 MMSTB, which means that the current recovery factor is 3.79 %. This number is tiny, and since there is a lot of hydrocarbon area that has not been produced, an integrated reservoir simulation study is done to determine the optimum scenario for this layer development. The study begins with data collecting and processing; model validation through initialization, history matching, and PI matching; remaining reserve determination, and,; simulation of field development scenarios. There are 5 scenarios simulated and until January 2043; Base Case (production of 1 existing well) gives 2.53 MMSTB or 9 % RF; Scenario 1 (Base Case + 3 gas lift wells) gives 3.15 MMSTB or 11.21 % RF; Scenario 2 (Scenario 1 + 3 development wells) gives 6.49 MMSTB or 23.09 % RF; Scenario 3 (Scenario 1 + 6 development wells) gives 7.68 MMSTB or 27.32 % RF; and Scenario 4 (Scenario 1 + 9 development wells) gives 7.58 or 26.97 % RF. From the reservoir simulation result, the optimum development scenario for this layer is Scenario 3.

Keywords: Reservoir simulation, Field development, Optimum scenario.

INTRODUCTION

The X field is located on the west side of Tanjung Jabung Barat Regency, Jambi Province, on South Sumatra basin area. Lower Talang Akar Formation (LTAF) is the main reservoir in this field. The reservoir consists of two layers, A and B, where layer A is the main focus of this reservoir simulation study.

Layer A is put on production in September 2007 by one exploration well (X-3). There are six production wells in this layer (X-3, X-4, X-6, X-8, X-10, and X-15), and until December 2016, only one well that still produce oil (X-8). The other five wells are in shut-in condition. three of them is because of intermittent flow (X-4, X-10, and X-15), while X-3 is shut-in because the failure of fishing job and X-6 is now producing oil from Upper Talang Akar Formation (UTAF). Layer A has a water drive mechanism. The last production rate of this layer is 274 bbl/day with 1.066 of cumulative oil production. With total Original Oil in Place (OOIP) 28.113 MMSTB, the current recovery factor of this layer is 3.79%. This low number shows that the layer has a good prospect to be developed.

Since the number of current RF is small (big remaining reserve), and there is a lot of oil area that hasn't been produced, the reservoir simulation study is focused on development well scenario. The objective is to find the area with a high value of both hydrocarbon pore volume and flow rate capability, to find the optimum location and the optimum number of development wells in order to increase incremental oil production of layer A.

2nd International Conference on Earth Science, Mineral, and Energy
AIP Conf. Proc. 2245, 080001-1–080001-11; https://doi.org/10.1063/5.0007067
Published by AIP Publishing. 978-0-7354-2004-5/$30.00

LITERATURE REVIEW AND BASIC THEORY

Rock Region

A dynamic model of reservoir simulation needs rock region to divide or to separate an area with excellent properties from an area with poor properties. It is necessary to grouping production zone with similar production and pressure performance. This grouping helps to accelerate model validation and to give simulation results that not over or underestimation. Rock region can be determined based on the value of initial water saturation or based on permeability distribution we get from a static model.

Relative Permeability and Pc Normalization De-Normalization

One layer could have several core data. Then, normalization is done to determine a typical relative permeability curve as representative of the layer. The normalization of relative permeability continued with de-normalization will be plot for each rock region as data input to simulator.

Capillary pressure data processing is done by using the Leverett J-Function method, and it depends on reservoir rock characteristics such as porosity and absolute permeability to obtain the data that could represent the layer.

PVTi

To make the history matching process more manageable, PVT determination is done for oil formation volume factor (Bo), oil density, gas solution in oil (Rs) by using the PVTi menu on Eclipse simulator. By using hydrocarbon composition data, the simulation is run by modified the composition, especially the composition of C7+ component [1]. If the result is the same or able to approach result from a laboratory test, then the simulation is considered matched.

Remaining Reserve

Reserve is defined as the volume of hydrocarbon that can be produced from total OOIP in a reservoir. Reserve can state as 2P Risked, which is 90% of P1 (proven) plus 50% P2 (probable). The remaining reserve can find from 2P Risked minus cumulative oil production.

Dynamic Model Validation

Initialization: According to BPMigas – SKK Migas Indonesia, initialization is done to synchronize oil-in-place and initial pressure of the dynamic model with oil-in-place from volumetric calculation or from the geostatic in-place calculation and initial pressure from well-testing analysis [2]. Standard of in-place synchronization from SKK Migas Indonesia is: the synchronization result is less than 5%. Initialization of oil-in-place can be done by modifying capillary pressure curve and rock region, while initialization of initial pressure can be done by modifying datum depth.

History Matching: While initialization is done to validate oil-in-place and initial pressure, history matching is done as a regression analysis of production history data. The objective is to synchronize the production performance of the dynamic model with the production history of a layer. For a reservoir with the water drive mechanism, the input for history matching is liquid rate with constraints:

- Liquid cumulative production of model vs actual liquid cumulative production < 1%
- Np of model vs. actual Np < 5%
- Wp of model vs. actual Wp <10%
- Gp of model vs. actual Gp < 20%

Parameters that are allowed to modify in history matching are aquifer model, reservoir transmissibility, relative permeability curve, rock region, permeability, porosity, NTG, PVT, PI, BHP, skin, and fluid contact.

PI Matching: Especially for oil field, productivity index (PI) matching has to be done by synchronizing the oil production trend of a model to actual, 3 to 6 months of last production history. It has to be done in order to get the result of prediction that is not over or underestimation.

PI Matching is done on key-well and production well that still open until the last date. The validation parameters are oil and water rate production. Parameters that are allowed to modify in PI matching are well parameters such as PI, injectivity, skin, vertical lift performance (VLP), etc.

Prediction Constrains

Before field performance prediction through scenarios is made, firstly we must set the constraint for prediction. By referring to SKK Migas Indonesia, the constraint for the oil field are:

- Input rate, for example, liquid rate,
- VLP and minimum Tubing Head Pressure (THP) for natural flow well,
- Minimum Bottom Hole Pressure (BHP) for artificial lift well,
- Economic limit of well and layer (minimum oil rate and maximum water cut), and
- Maximum BHP for injection well (BHP < initial reservoir pressure).

Field Development through Development Wells

Optimum Location of Development Wells

Hydrocarbon Pore Volume (HCPV) Distribution: Map of HCPV distribution is used to find the area of oil that hasn't been produced by existing wells. This map is a combination of iso-porosity map, iso-saturation map, and net pay map. A development well must be put on the area with high HCPV.

Flow Rate Capability Distribution: The area with high HCPV does not guaranty that the hydrocarbon will flow smoothly from the reservoir to the production well. That is why flow rate capability distribution map, as the combination of iso-permeability map and iso-pressure map, is needed. Since permeability shows a reservoir capability to pass the fluids and pressure shows a reservoir capability to flow the fluids, a development well must be put on the area with high flow rate capability.

Drainage Radius of Existing Wells: The location of development wells determination also must consider the drainage area of existing wells. It is curcial to have a bubble map of existing wells as a guide to preventing interference or connection between development wells to existing wells. The interference can disturb the production performance of each well.

Optimum Number of Development Wells

There is a limit on the number of development wells. The more wells we open, the more oil we can produce, until the optimum point, where when we add more wells, the production will decrease. This phenome happens because of the more wells open, the faster reservoir pressure will drop, and will affect the production performance of a layer. The optimum number of development wells can be obtained by plotting the number of well versus oil cumulative production. The optimum point is the point where the addition of well does not give a significant incremental of oil production.

METHODOLOGY

This reservoir simulation study begins with data preparation and processing. The data include SCAL, PVT, well trajectory, production history, and 3D geology static model. All the data is used to build a dynamic model. This model needs a validation process through initialization, history matching, and PI matching, before the prediction is done. The remaining reserve calculation is made to determine the volume of oil in a dynamic model that can be simulated. After that, development scenarios are predicted with the simulator to find the best scenario of this layer development. **FIGURE 1** shows the methodology used in this study.

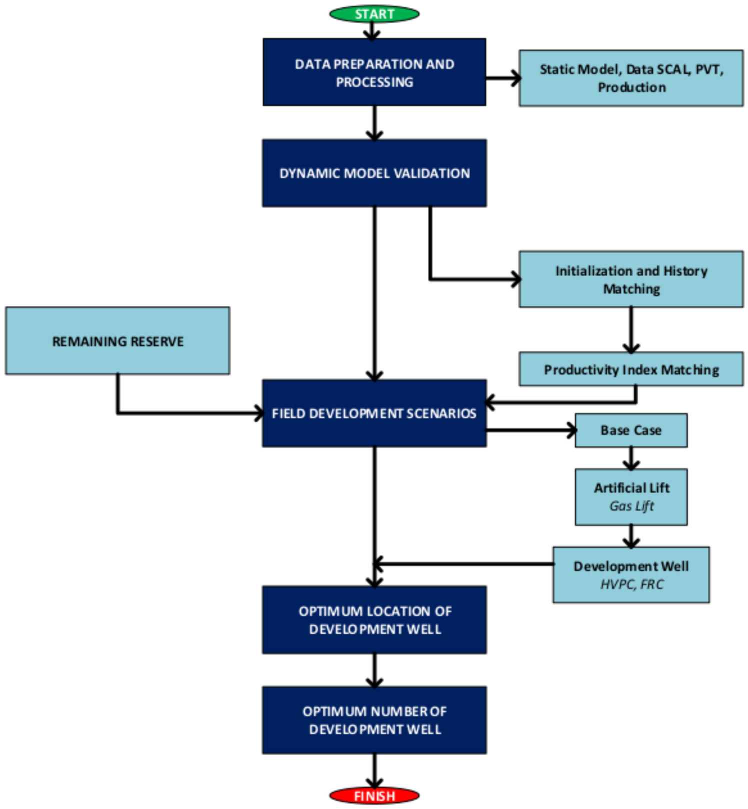


FIGURE 1. Reservoir Simulation Study Workflow

CASE STUDY

Data Preparation and Processing

Initial Condition

First data to prepare is the initial condition of layer A. It includes the initial pressure and temperature, formation volume factor, gas solution, bubble point pressure, initial oil in place, reserve, and drive mechanism of the layer, as shown in **TABLE-1**.

TABLE 1. Initial Condition of Layer A on X Field

Initial Condition	Layer A
$P_{i,}$ psia	2,196
T_i, ^{0}F	235
B_{gi}, bbl/SCF	0.01115
B_{oi}, bbl/STB	1.445
R_{si}, SCF/STB	511
P_b, psia	1,775
OOIP, MMSTB	28.11
2P Risked.MMSTB	11.66
Drive Mechanism	Water Drive

Rock Region

Rock region determination of layer a is done using permeability value of the layer from the static model. With this method, there are five regions as shown in **FIGURE 2.**

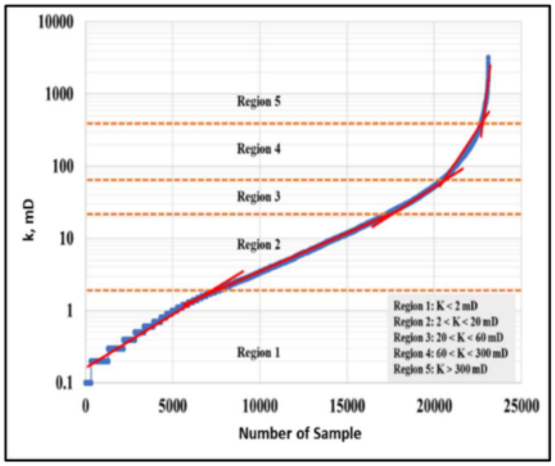
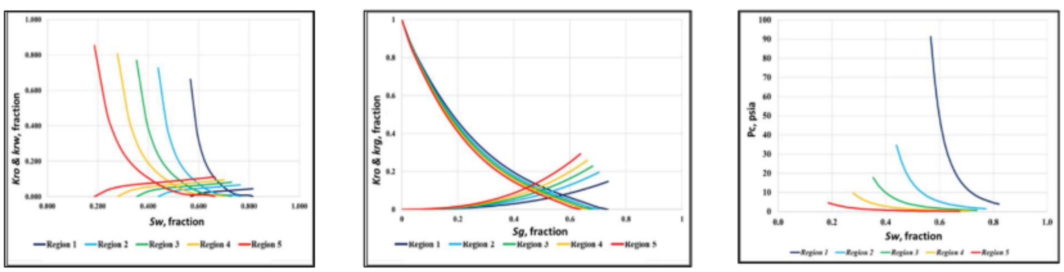


FIGURE 2. Rock Region of Layer A

Relative Permeability and Pc Normalization De-Normalization

Normalization de-normalization of SCAL data is done using equations stated on literature review and basic theory. From the process, we get the relative permeability curve of the water-oil system for each region, the relative permeability curve of the gas-oil system for each region, and the capillary pressure curve for each region as shown in **FIGURE 3.**



(a) (b) (c)

FIGURE 3. (a) Relative Permeability Curve of Each Region for Water-Oil System (b) Relative Permeability Curve of Each Region for Gas-Oil System (c) Capillary Pressure Curve of Each Region for Water-Oil System

PVTi Modeling

PVT modeling and matching are done using the PVTi menu on Eclipse simulator. The simulation result is synchronized to laboratory data. **FIGURE 4** shows that the PVT model is already matched and ready for dynamic model.

All the data above, include well trajectory and production history, are used as data input to build the dynamic model.

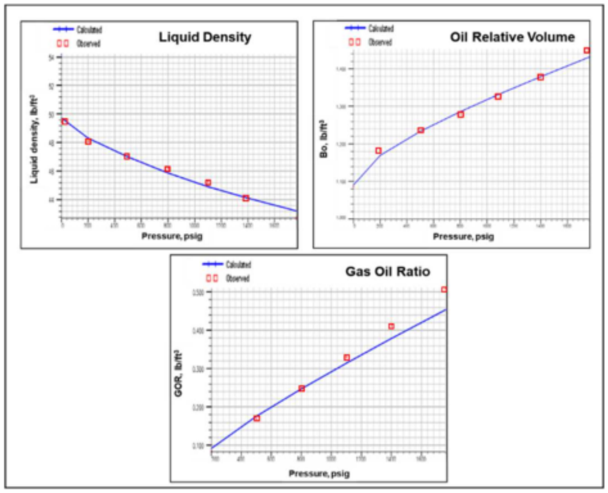


FIGURE 4. PVTi Matching Result of Layer A

Model Validation

Initialization

At initialization, a modification is done on capillary pressure data. On first initialization, the difference of initial oil in-place is 7.89 %. Therefore, a change in the capillary curve envelope of each region is done so that the difference becomes 0.57%. Since the pressure already matched, there is no need to modify datum depth. The summary of initialization is shown in **TABLE 2.**

TABLE 2. Summary of Initialization

Parameter	Data	Dynamic Model			
		First		Final	
		Result	**Diff.**	**Result**	**Diff.**
In-Place, MMSTB	28.11	26.17	-6.89%	27.95	-0.57%
Pressure, psia	2,196	2,166	-1.35%	-	-

History Matching and PI Matching

At the first history matching, pressure and liquid production of simulation result already show a good result. Yet, there is a vast difference in water and gas production of the model with the production history (oil production is matched). To match water and production data, modification is done to relative permeability curve and value of the gas solution (Rs). The result of history matching is shown in **TABLE 3.**

Since until December 2016 only one well that still on (X-8), PI matching is only done to the well.

TABLE 3. Summary of History Matching

Parameters of History Matching	Data	Dynamic Model			
		Initial HM		Final HM	
		Model	Diff.	Model	Diff.
Liquid, MSTB	1,130	1,128	-0.17%	1,126	-0.29%
Oil MSTB	1,066	1,080	1.32%	1,062	-0.42%
Water Mbbl	63	47	-25.17%	65	1.92%
Gas, MMSCF	940	661	-29.62%	828	-11.87%

Remaining Reserve Determination

Since the reserve in layer A is 11.66 MMSTB, and the cumulative oil production of the dynamic model obtained from history matching is 1.062, then the remaining reserve of layer A is:

RR = 11.66 MMSTB – 1.062 MMSTB

RR = 10.60 MMSTB

Field Development Scenarios

There are five scenarios created for the development of this layer. Base case as the production performance prediction of 1 existing production well; Scenario 1 as the base case + 3 gas lift wells; Scenario 2 as Scenario 1 + 3 development wells; Scenario 3 as Scenario 1 + 6 development wells; and Scenario 4 as Scenario 1 + 9 development wells. **TABLE 4** shows a summary of development scenarios.

TABLE 4. Development Scenarios Summary of Layer A

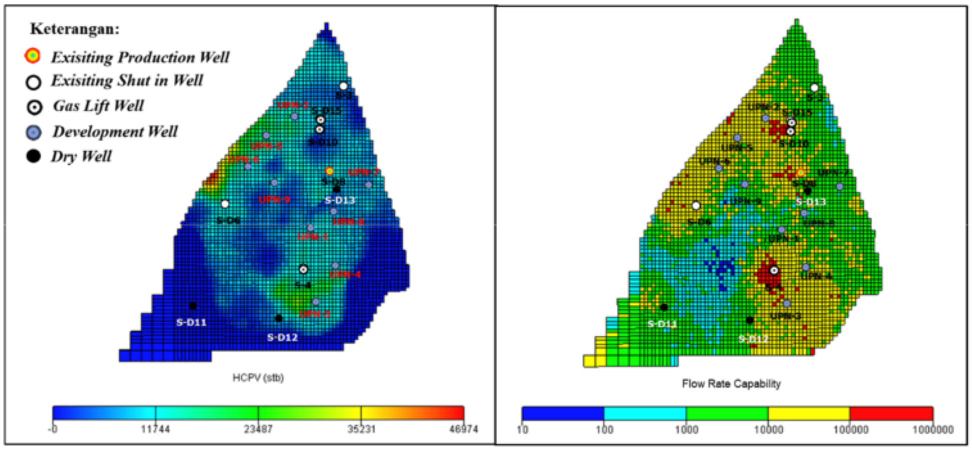
Case	Objectives
Base Case	Production of Existing Wells
Scenario 1	Base Case + 3 Gas Lift Wells (X-4, X-10, and X-15)
Scenario 2	Scenario2 + 3 Development Wells (UPN-1, UPN-2, and UPN-3)
Scenario 3	Scenario 2 + 6 Development Wells (UPN-1, UPN-2, UPN-3, UPN-4, UPN-5, and UPN-6)
Scenario 4	Scenario 2 + 9 Development Wells (UPN-1, UPN-2, UPN-3, UPN-4, UPN-5, UPN-6, UPN-7, UPN-8 and UPN-9)

Base Case (1 Existing Well)

With the production of X-8 well, layer A can produce until June 2076 with 3.06 MMSTB of cumulative oil production. Since X-8 well still produces on natural flow method, the constrain used in this layer is minimum THP and VLP.

Scenario 1 (BC + 3 Gas Lift Wells)

In this scenario, the prediction is made with one existing well (X-8) and three gas lift wells (X-4, S-10, and X-15). The constraint used for gas lift well is minimum BHP and VLP for gas lift. With this scenario, layer A can produce until July 2043 with 3.16 MMSTB of cumulative oil production; 0.1 MMSTB of incremental oil to the base case.



(a) (b)

FIGURE 5. Proposed Location of Development Wells for Layer A (a) Overlay HCPV Map (b) Overlay Flow Rate Capability Map

Scenario 2 (Scenario 1 + 3 Development Wells)

In this scenario, the prediction is made with the combination of Scenario 1 and three development wells (UPN-1, UPN-2, and UPN-3). The constraint used for development well is minimum THP and VLP. With this scenario, layer A can produce until April 2077 with 8.04 MMSTB of cumulative oil production; 4.98 MMSTB of incremental oil to the base case.

Scenario 3 (Scenario 1 + 6 Development Wells)

In this scenario, the prediction is made with the combination of Scenario 1 and six development wells (UPN-1, UPN-2, UPN-3, UPN-4, UPN-5, and UPN-6). The constraint used for development well is minimum THP and VLP. With this scenario, layer A can produce until November 2060 with 8.01 MMSTB of cumulative oil production; 4.95 MMSTB of incremental oil to the base case.

Scenario 4 (Scenario 1 + 9 Development Wells)

In this scenario, the prediction is made with the combination of Scenario 1 and nine development wells (UPN-1, UPN-2, UPN-3, UPN-4, UPN-5, UPN-6, UPN-7, UPN-8, and UPN-9). The constraint used for development well is minimum THP and VLP. With this scenario, layer A can produce until June 2061 with 7.75 MMSTB of cumulative oil production; 4.69 MMSTB of incremental oil to the base case.

RESULT

The prediction is made until the economy limit of each scenario. The result on both economic limit and end of the contract extension is shown in **FIGURE 6** to determine the best scenario. **FIGURE 7** shown that after 6 development wells, the addition of well does not give a significant incremental oil production. By considering that the contract extension will end in January 2043, the summary of the simulation result is shown in **TABLE 5**.

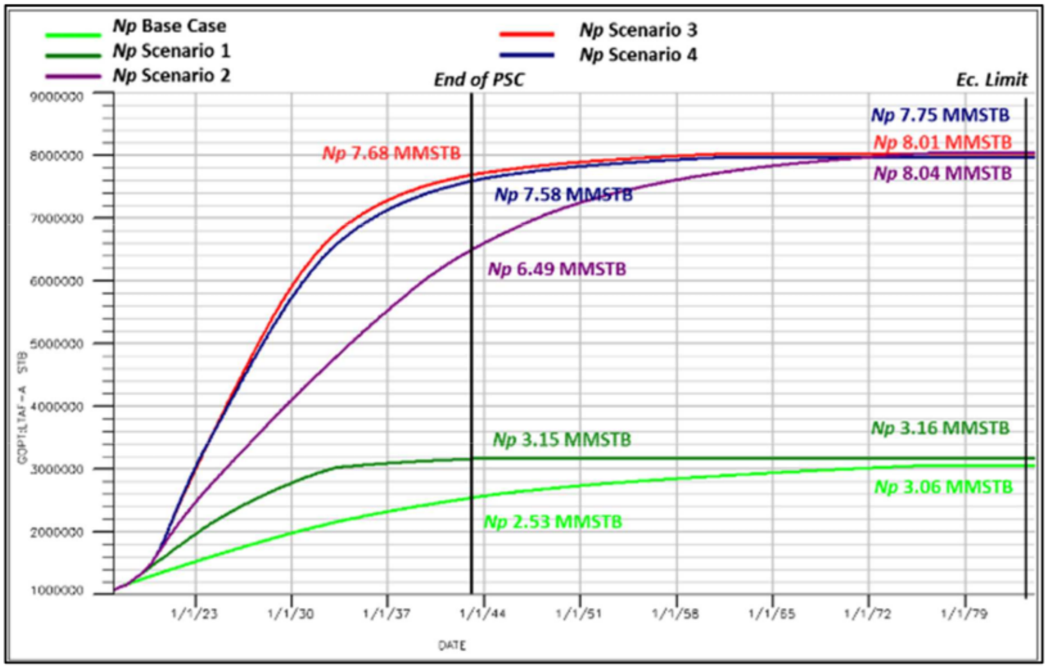


FIGURE 6. Layer A Reservoir Simulation Result

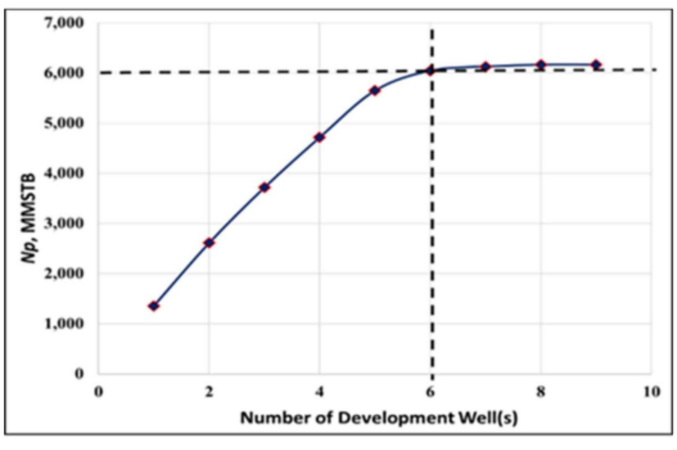
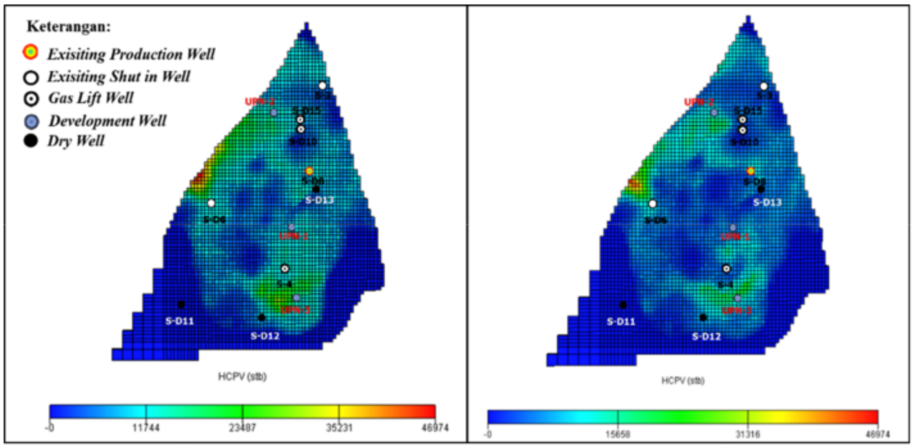


FIGURE 7. Optimum Number of Development Well



(a) (b)

FIGURE 8. Well Location Overlay HCPV Map Scenario 3

(a) December 2016 (b) Economic Limit – November 2060

TABLE 5. Summary of Reservoir Simulation Result

Case	OOIP, MMSTB	Reserve, MMSTB	Current			Forecast to End of Contract			Incremental to BC	
			Np, MMSTB	Remaining Reserve, MMSTB	RF	*Np*, MMSTB	Remaining Reserve, MMSTB	RF	*Np*, MMSTB	Δ RF
Base Case	28.11	11.66	1.062	10.60	3.78%	2.53	9.13	9.00%	-	-
Scenario 1						3.15	8.51	11.21%	0.09	0.34%
Scenario 2						6.49	5.17	23.09%	3.43	12.22%
Scenario 3						7.68	3.98	27.32%	4.62	16.45%
Scenario 4						7.58	4.08	26.97%	4.52	16.10%

DISCUSSION

Starting with data preparation and processing, the rock region determination based on the permeability distribution of static model shows that layer A has 5 regions. The production history data, well trajectory, and PVT data from PVTi are put into the simulator to build dynamic reservoir model.

After the dynamic model is ready, the first thing to do is dynamic model validation. The final result of initialization shows that both original oil in-place and initial pressure of dynamic model already gives the difference less than 5 % of the original oil in-place and initial pressure of actual data. Meanwhile, the final result of history matching shows that liquid production already less than 1 % of the difference (0.29 %); oil production already less than 5 % (0.42 %); water production already less than 10 % (1.92 %); and gas production already less than 20 % (11.87 %). Since the PI matching already matched, then the dynamic model is already valid for prediction.

There are 5 scenarios simulated until the economic limit of each scenario. The detail of the scenarios is shown in **TABLE-4**. Until then end of contract extension at January 2043; Base Case (production of 1 existing well) gives 2.53 MMSTB or 9 % RF; Scenario 1 (Base Case + 3 gas lift wells) gives 3.15 MMSTB or 11.21 % RF; Scenario 2 (Scenario 1 + 3 development wells) gives 6.49 MMSTB or 23.09 % RF; Scenario 3 (Scenario 1 + 6 development wells) gives 7.68 MMSTB or 27.32 % RF; and Scenario 4 (Scenario 1 + 9 development wells) gives 7.58 or 26.97 % RF. From the reservoir simulation result, the optimum development scenario for this layer is Scenario 3.

CONCLUSIONS

1. Based on permeability distribution, there are 5fiverock regions on layer A.
2. Dynamic model validation is good because already fulfill the standard from SKK Migas Indonesia.
3. The remaining reserve of the dynamic model of layer A is 10.60 MMSTB.
4. The optimum development scenario is Scenario 3 with six development well.
5. With Scenario 3, until the end of the contract extension, the cumulative oil production is 7.68 MMSTB or 27.32% of recovery factor.

ACKNOWLEDGEMENT

Thanks to PSME UPN "Veteran" Yogyakarta for all support.

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