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Techno-Economic Analysis of Hydraulic Fracturing As A Solution for Developing Low-Resistivity and Low-Quality Zone on Offshore "RI" Field

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Abstract

Hydrocarbon production in Indonesia is continuously decreasing on a yearly basis, which is in contrast with its increasing level of consumption. Low-quality and low-resistivity reservoir zones are deemed to possess a lot of hydrocarbon potentials, however, little priority has been placed on their development due to their small level of production. The "RI" field that was utilized in this study is a mature offshore field with a reservoir which has a low-quality and low-resistivity zone. This area has been in use for more than thirty years, therefore its rate of oil production has declined. This study aims to review the techno-economic aspects of well stimulation in the form of hydraulic fracturing. And also, to determine the development method that is suitable for low-quality fields. The hydraulic fracturing process was modelled using Fracpro software as input parameters for the reservoir production simulations. The reservoir behavior was simulated using the CMG software to observe the amount of hydrocarbon liable for production in various development scenarios. Three cases were performed on the "RI" field, which was stimulated for ten years of operation. The first case was the instance with the natural flow, while the second implemented hydraulic fracturing at the beginning of production, and the third was the implementation of hydraulic fracturing, which started in the middle of the production period. Then, the three cases are evaluated utilizing a Gross Split scheme, to calculate the economics of the project both from the government and contractor's aspects. The simulation study concluded that fracturing at the beginning of the LRLC zone development is the most profitable. The novelty of this study is the comparison of scenarios for the implementation of hydraulic fracturing methods in fields with low-resistivity and low-quality zone whose economic value is evaluated by the Gross Split scheme.

INTRODUCTION

The utilization of energy has increased concurrently with the development of human civilization. And one of the most significant contributors to the energy sector is the oil and gas industry. **Figure 1** shows that over time, the energy needs in the Republic of Indonesia has constantly increased (ESDM, 2018), this is not corroborated by its production in the country, which experiences a downward trend almost every year. From the economic perspective, energy is a commodity that is very influential to the growth of a country. **Table 1** shows the contribution of the oil and gas industry to the Indonesia's national income. Based on the data from the Ministry of Energy and Mineral Resources, in 2018, as listed in **Table 2**, the Republic of Indonesia still has a vast oil reserve of about 7.5 billion barrels, that are yet to be produced. **Figure 2** shows that potential oil reserves are still higher than those that are proven. This is in contrast to gas, as shown in **Figure 3**, where proven gas reserves are higher when compared to that of the potential. Various methods are employed in the bid to stop this downward trend, one of which is to maximize oil production by well stimulation.

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Table 1. Oil and Gas Revenue Contribution to Indonesia's Economy

Year	State Revenue (Rp. T)	Oil and Gas Revenue (Rp. T)	% of Contribution
2004	403	85	21.09%
2005	494	104	21.05%
2006	636	158	24.84%
2007	706	125	17.71%
2008	979	212	21.65%
2009	847	126	14.88%
2010	992	153	15.42%
2011	1,205	193	16.02%
2012	1,338	205.8	15.38%
2013	1,438	203.6	12.56%
2014	1,538	216.9	14.11%
2015	1,508	78.2	4.46%
2016	1,555	44.1	2.84%
2017	1,666	81.8	4.91%
2018	1,942	143.3	7.38%
2019*	2,165	159.8	7.38%

Table 2. Indonesian Oil and Gas Reserves (ESDM, 2018)

Year	Oil Reserves (MMBBL)	Proven (MMBBL)	Potential (MMBBL)	Gas Reserves (TCF)	Proven (TCF)	Potential (TCF)
2007	8400	3990	4410	165.00	106.00	59.00
2008	8220	3750	4470	170.1	112.5	57.6
2009	8000	4300	3700	159.63	107.34	52.29
2010	7760	4230	3530	157.14	108.4	48.74
2011	7730	4040	3690	152.89	104.71	48.18
2012	7410	3740	3670	150.7	103.35	47.35
2013	7550	3690	3860	150.39	101.54	48.85
2014	7370	3620	3750	149.3	100.26	49.04
2015	7305	3603	3702	151.33	97.99	53.34
2016	7251	3307	3944	144.8	102	42.8
2017	7535	3171	4364	143.7	101.4	42.3
2018	7512	3154	4358	135.55	96.06	39.49

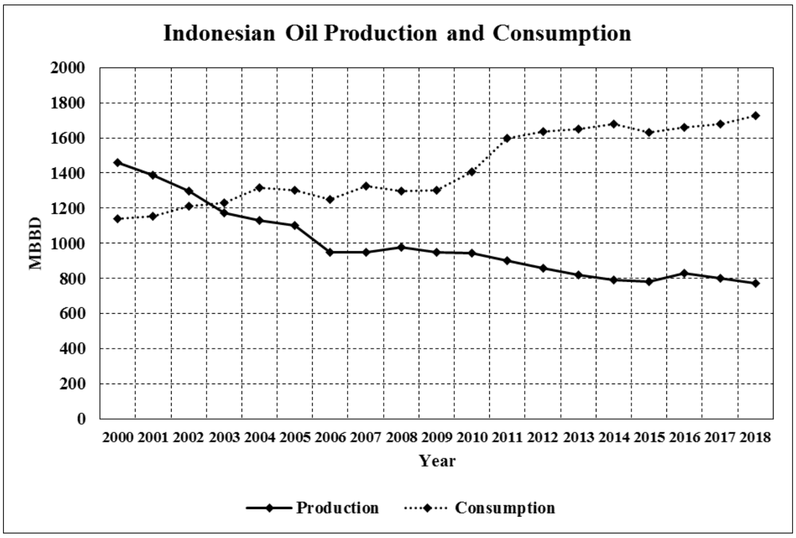

Figure 1. Indonesian Oil Production and Consumption, (ESDM, 2018)

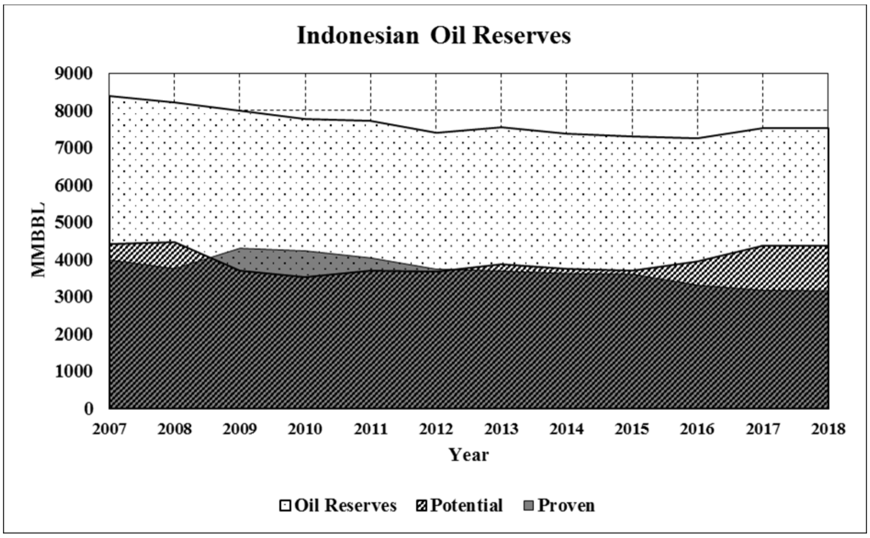

Figure 2. Indonesian Oil Reserves, (ESDM, 2018)

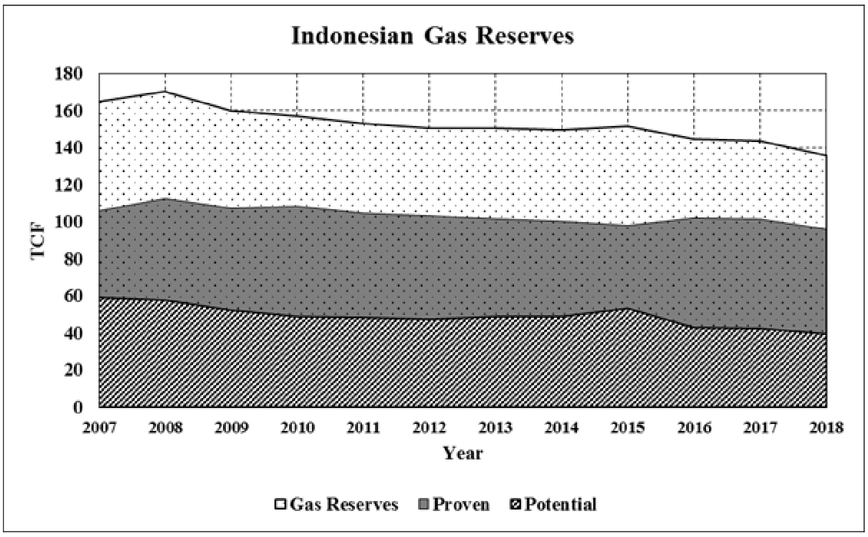

Figure 3. Indonesian Gas Reserves, (ESDM, 2018)

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Low-resistivity, also known as low-contrast zone, is a productive area in an oil and gas reservoir, which only contains formation water and has small reactivity with the surrounding area (Widarsono et al., 2006). Generally, in an oil layer the range of resistance is from 4 to 100 Ω.m, therefore, zones with values below 3 Ω.m, are described to be low-resistivity (Zhang et al., 1994). The low-resistivity zone is divided into 6 categories based on its formation, namely, fine sandstone of double pore structure, and those that are rich in mud, a low oil saturation, mineralized formation water, conductive minerals (like pyrite), and reservoirs with highly porous fine sandstone (Worthington, 2000).

Because of the low reaction value, this zone often experience misinterpretation, and It is usually regarded as water-bearing, since it is not easily distinguished from reservoir zones through electricity. In 2000, Worthington stated that the causes of the low-resistivity zones are, sandstone/shale lamination, formation water with low salinity, metallic minerals, very fine grains, internal, and pseudo microporosity. This zone is a phenomenon that occurs in many regions of the world, such as the Gulf of Mexico, Louisiana, USA, basins from the North Sea, West Africa, China and Indonesia (Wibowo et al., 2019). It stores approximately 30% of the world's hydrocarbon reserves (Sayed et al., 2017). The development of log interpretation methods and technologies is needed to detect the low-resistivity zone. In addition, this zone holds a large potential for hydrocarbons, however, the amount of production by primary oil recovery is small. This leads to the necessity for an appropriate production scenario, that maximizes hydrocarbon exploitation. The objective of this study is to determine a solution for the development of low-resistivity and low-quality zones, and to examine the best exploration scenario of hydraulic fracturing for these areas on the offshore "RI" field. However, the study had several limitations, namely isotropic permeability, all non-productive zones were assumed to be sealing shale, using only one production well and no gas sales.

The block where the "RI" field that was utilized in this study is located, consists of 112 structures, 8 formations, and around 50 reservoirs. The field is situated near the capital city of the Republic of Indonesia and has been operating since 1986. It is categorized as a mature field with approximately 30 million barrels of oil as OOIP value and an OGIP value of about 10 billion cubic feet of gas, with an average water depth of 49 ft. However, because of its low-resistivity value, i.e., low reservoir quality, it is not prioritized for development. In this study, the hydraulic fracture design was implemented on the "RI" field and various production scenarios with the implementation of stimulation were created based on available data. The techno-economic analysis was also examined to show the economics of the project on this field. It is expected that the development scenario based on the techno-economic analysis from this study, produce a maximum amount of oil production and NPV value.

METHODOLOGY

This study was completed in several steps. **Figure 4** shows a flowchart that illustrates the methodology of this study as a whole, which consists of the following,

- **Literature Study.** The literature review was obtained from various sources, that were complemented theories and applications of low-resistivity zones, hydraulic fracturing, and techno-economic analysis.
- **Data Preparation.** At this stage, data were collected on construction, initialization, and simulation. Additional data were also obtained to support the primary information and model construction.
- **Fracture Simulation.** Fracture simulation was carried out based on the data that were collected at the previous session. The fracture was simulated using Fracpro software, and the results were utilized as input parameters in the reservoir model construction.
- **Model Construction and Initialization.** At this step, the reservoir model was built according to the field and supporting data. The software that was used to build the reservior model was CMG. Then it was programmed and adapted to the characteristics of the "RI" field.
- **Reservoir Simulation.** Based on the results of the model construction, reservoir simulation using CMG software was carried out with three scenarios. The first case, was when the reservoir was explored through natural flow. The second case, was when hydraulic fracturing was performed at the beginning of the production period (2020). And the third case was the production scenario where the hydraulic fracturing started in the middle of the production (2025).
- **Development Scenario and Economic Analysis**. The results of the reservoir simulation were analyzed. And the economic variables were reviewed to determine the best among the three scenarios. Furthermore, conclusions were drawn from this study based on the results and analysis.

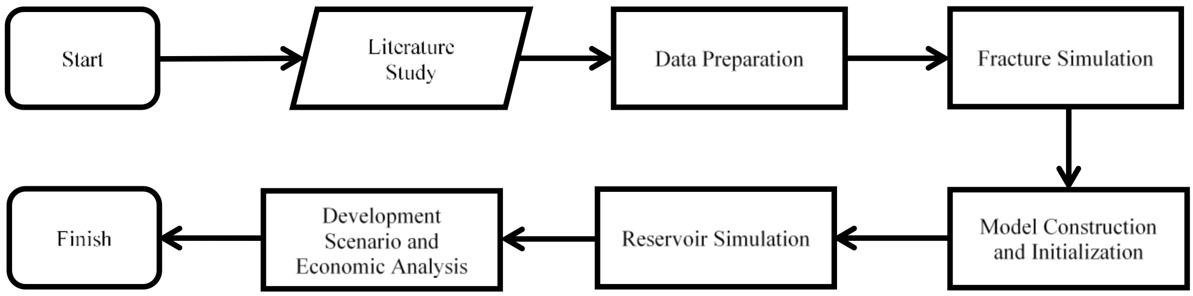

Figure 4. Methodology Flowchart of The Study

Model Description

The "RI" utilized in this study is a field located on an offshore block on the north coast of Java, as shown in **Figure 5**. And because it has been operating for a long time, the field has been experiencing a downward trend in oil production. As shown in **Figure 6**, a typical reservoir log in the "RI" field showed that it is a zone with low resistivity, at a range of 1.8 Ω.m to 2.5 Ω.m. Although it has a low resistivity value, the analogue well data in the "RI" field showed that the water cut is 0%, i.e., there is production without the presence of water. Therefore, it was concluded as an oil zone.

The formation in the field "RI" consists of 5 layers with rock lithology in the form of shale and sandstone. Where the productive zone that has sandstone lithology, is located at layer 2 (depth 5030 ft to 5068.1 ft) and 4 (depth 5185.5 ft to 5191 ft) as shown in **Table 3,** and the first layer to be produced was that of the 2nd. In addition to the low resistivity value, the productive zone in the "RI" field also has a fair permeability value at 3.3 md (Sajjad et al., 2018). Therefore, a directional well was built to conduct production at an inclination angle of 61.66°, as observed in **Figure 7**. Perforation was also carried out in the first productive zone, at 5035 ft depth.

Table 3. "RI" Field Lithology Parameter

Layer #	Top of Zone (ft)	Thickness (ft)	Lithology
1	0.0	5030	Shale
2	5030.0	38.1	Sandstone
3	5068.1	117.4	Shale
4	5185.5	5.5	Sandstone
5	5191.0	665.18	Shale

Because of the declining production rate, stimulation was carried out in the form of hydraulic fracturing to increase oil production. This was performed using Fracpro simulation software, according to the data obtained from the "RI" field. The hydraulic fracturing utilized two types of fluids, HG35G2K and KCl - 7% (for flush), and type 20/40 BauxLite proppant. As noted in **Table 4** and **Figure 8**, hydraulic fracturing was performed in 13 stages. As the proppant was injected, the fracture grew, as shown in **Figure 9**, until the final rupture (**Figure 10)**. Therefore, a fracture with the half-length value of 290.7 ft, 486.6 ft height, 0.212 in average fracture width and 2.116 dimensionless conductivity was obtained, according to the results in **Table 5**. Although from the simulation results, it appeared that the fracture was not only created in the productive layer by perforation, it also went through layer 4.

Reservoir modelling was based on the available field and supporting data. In this model, it was assumed that the reservoir temperature was constant at 235°F, and the initial reservoir pressure was 2448 psi. In addition, the assumption used was the laying of WOC at a depth of 5860 ft, far below the productive zone. **Table 6** shows the layer properties used in reservoir simulations. Due to the lack of field data, the permeability used in reservoir simulation was isotropic, where k_V=k_H. Reservoir modelling used CMG simulation software with cartesian model and 101 × 101 grid sizes, as shown in **Figure 11** and **Figure 12**. The production well was placed at the centre of the grid, with constraints in the form of a maximum surface oil rate of 200 BBD and a minimum bottom hole pressure of 1500 psi.

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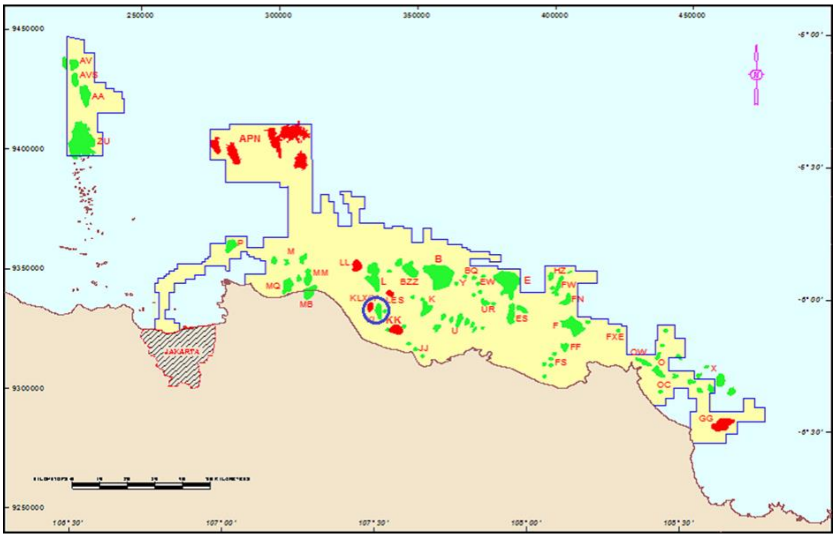

Figure 5. "RI" Field Boundary Map (Sajjad et al., 2018)

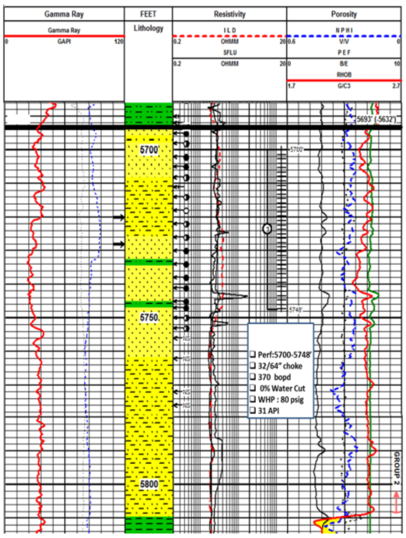

Figure 6. Typical Well Log at "RI" Field (Sajjad et al., 2018)

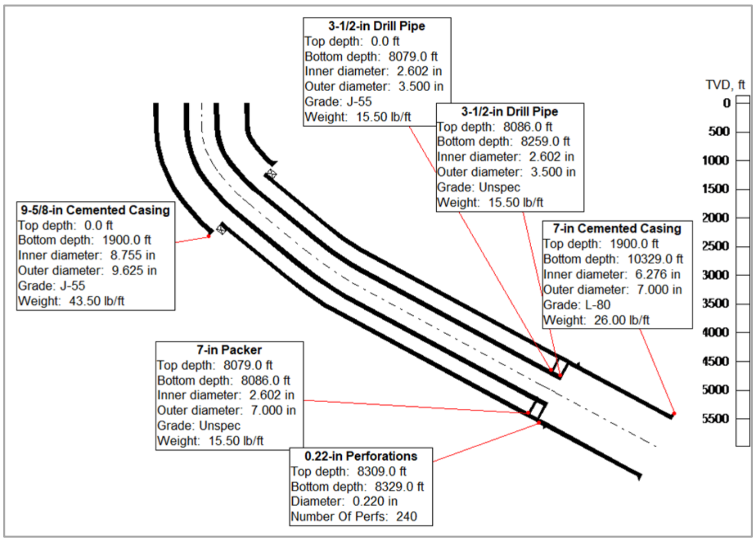

Figure 7. Well "NK" Completion Diagram

Table 4. Hydraulic Fracturing Design Treatment Schedule

No.	Stage Description	Fluid Type	Pump Rate (bpm)	Proppant Concentration (ppg)	Clean Volume (gal)	Proppant Type
	Wellbore Fluid	HG35G2K			2362	
1	PAD	HG35G2K	15	0	10,000	
2	SLF	HG35G2K	15	2	2,800	20/40 BauxLite
3	SLF	HG35G2K	15	4	4,000	20/40 BauxLite
4	SLF	HG35G2K	15	6	2,000	20/40 BauxLite
5	SLF	HG35G2K	15	8	2,000	20/40 BauxLite
6	SLF	HG35G2K	15	10	1560	20/40 BauxLite
7	SLF	HG35G2K	15	12	1600	20/40 BauxLite
8	SLF	HG35G2K	15	14	1600	20/40 BauxLite
9	SLF	HG35G2K	15	16	1600	20/40 BauxLite
10	SLF	HG35G2K	15	18	1800	20/40 BauxLite
11	SLF	HG35G2K	15	20	2,000	20/40 BauxLite
12	Flush	KCl - 7%	15	0	4,062	
13	Shut In	SHUT IN	0	0	0	

Table 5. Fracture Simulation Result Summary

Fracture Geometry Summary		
Fracture Half-Length	290.7	ft
Propped Half-Length	137.1	ft
Total Fracture Height	486.6	ft
Total Propped Height	229.5	ft
Avg. Fracture Width	0.212	in
Dimensionless Conductivity	2.116	

Table 6. "RI" Field Reservoir Layer Properties

Layer #	Top of Zone (ft)	Thickness (ft)	Porosity	Permeability I (md)	Permeability J (md)	Permeability K (md)
1	0.0	5030	0.00001	0.00001	0.00001	0.00001
2	5030.0	38.1	0.2	3.3	3.3	3.3
3	5068.1	117.4	0.001	0.00001	0.00001	0.00001
4	5185.5	5.5	0.2	3.3	3.3	3.3
5	5191.0	665.18	0.00001	0.00001	0.00001	0.00001

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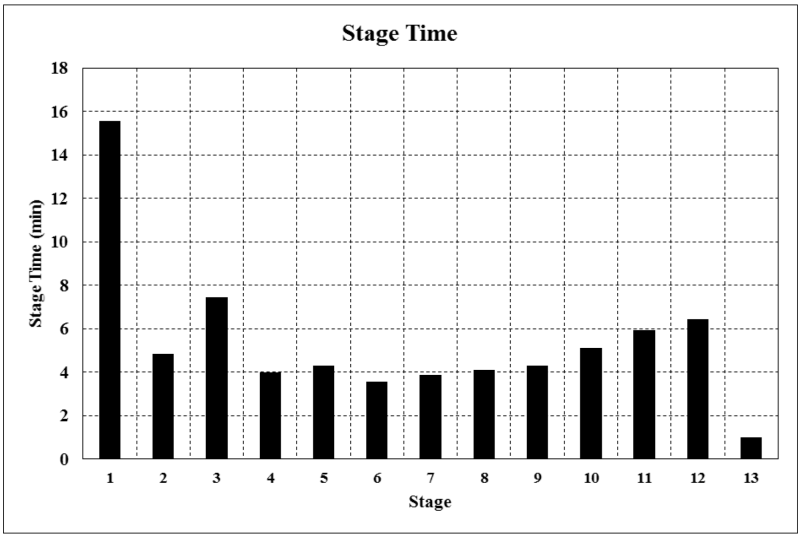

Figure 8. Fracture Pumping Stages

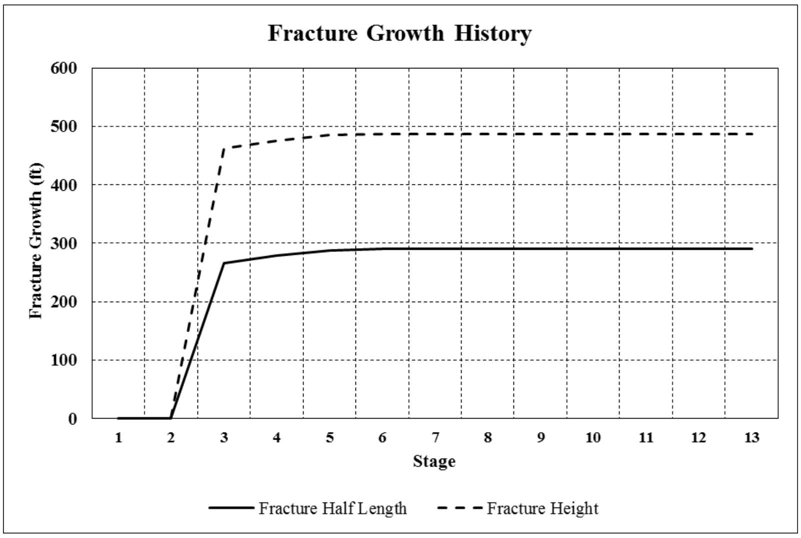

Figure 9. Fracture Growth History

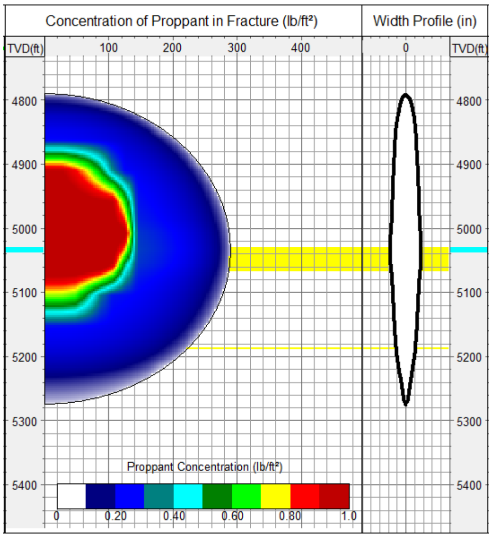

Figure 10. Fracture Profile

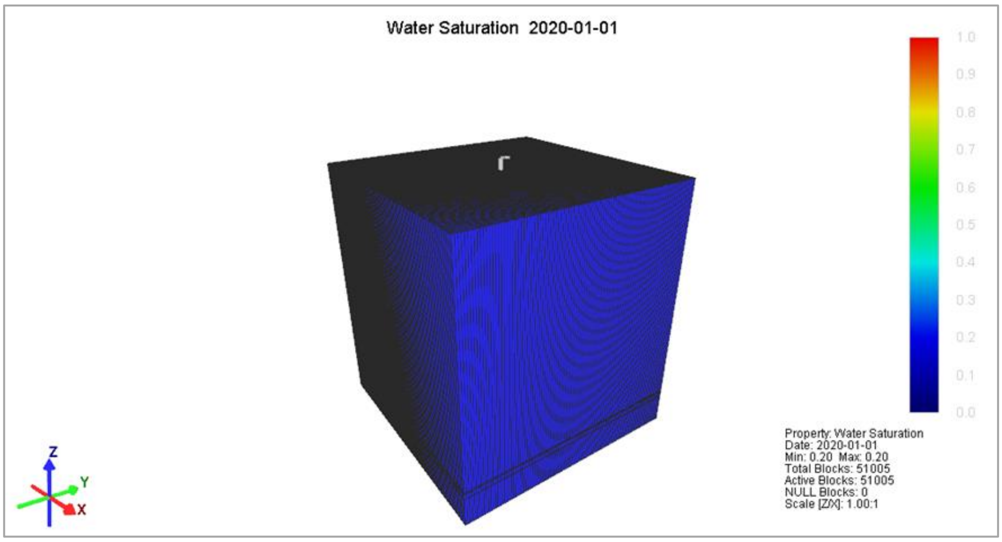

Figure 11. Three Dimensional Reservoir Model

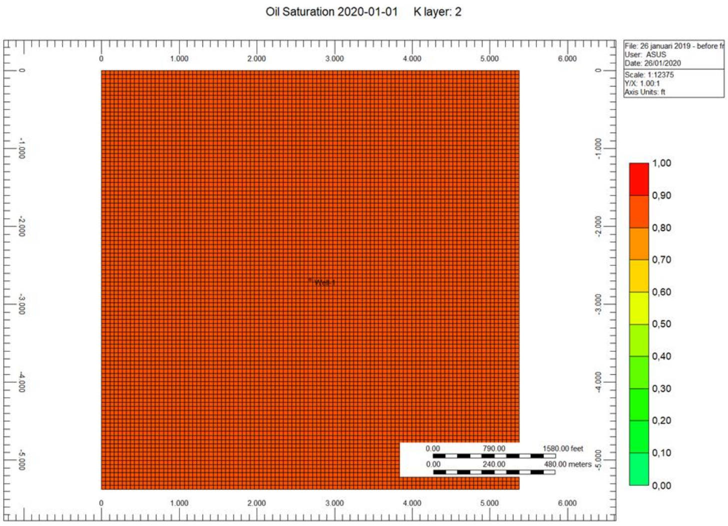

Figure 12. Two Dimensional Reservoir Model

From the reservoir characteristics, the permeability value of the productive zone was 3.3 md, and Sajjad et al. (2018) classified this value as fair permeability, one level below high. The Gross Split Scheme, which was set in Regulation of The Ministry of Energy and Mineral Resources Number 8 of 2017, stated that all costs are borne by the contractors, therefore they have the freedom to manage costs without having to consult with the government. This led to the following deliberation, first, because of the low permeability value of the productive zone, stimulation was needed to increase the reservoir's conductivity. Second, contractors efficiently allocate the cost of hydraulic fracturing without having to go through a complicated bureaucratic process with the government. Another consideration was the timing of hydraulic fracturing. Reservoir pressure continued to decrease along with production, therefore determining the right time for hydraulic fracturing is important to maximize oil production. The "RI" field development consists of three scenarios based on the implementation of hydraulic fracturing. Production simulations were carried out in a span of 10 years (3654 days). The three field development scenarios are,

- **Case 1.** In this case, oil production was carried out in the natural flow. This occurred from 1 January 2020 to 1 January 2030.
- **Case 2**. In this case, hydraulic fracturing was carried out from the beginning of the production period, on 1 January 2020 till 1 January 2030.
- **Case 3**. In this case, hydraulic fracturing was carried out in the middle of the production period, on 1 January 2025. In the first five years, the well was naturally explored, and the next five years, the well produced oil after hydraulic fracturing.

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The parameters that were reviewed from these three scenarios were cumulative oil production and NPV. Where NPV was calculated by the Gross Split scheme in accordance to the Regulation of the Ministry of Energy and Mineral Resources of the Republic of Indonesia Number 8 of 2017.

RESULTS AND DISCUSSION

In Case 1, the reservoir was produced naturally without hydraulic fracturing for 3654 days, from 1 January 2020 to 1 January 2030. **Figure 13** shows the condition of the reservoir grid with the oil saturation function in the initial condition. After being explored for 10 years, there was a decrease in oil saturation, approximately 23% reduction was observed in the area near the wellbore, as shown in **Figure 14**. Based on reservoir simulation results, it was discovered that the "NK" production well in the "RI" field cumulatively produced 106.81 thousand barrels of oil and 35.34 million cubic feet of gas, as listed in **Table 7**. And aside oil and gas, water was produced by 1.38 barrels, which is only 0.00129% of liquid production. The average oil production in Case 1 was 10.68 thousand barrels per year or 29.23 barrels per day. While the average gas production was 3.53 million cubic feet per year or 9.67 thousand cubic feet per day.

Table 7. Oil and Gas Production per Year – Case 1

Year	Oil Production (MBBL)	Gas Production (MMSCF)
2021	12.56	4.17
2022	11.38	3.79
2023	11.05	3.65
2024	10.82	3.55
2025	10.66	3.48
2026	10.43	3.43
2027	10.21	3.41
2028	10.05	3.35
2029	9.92	3.29
2030	9.74	3.22
Total	106.81	35.34

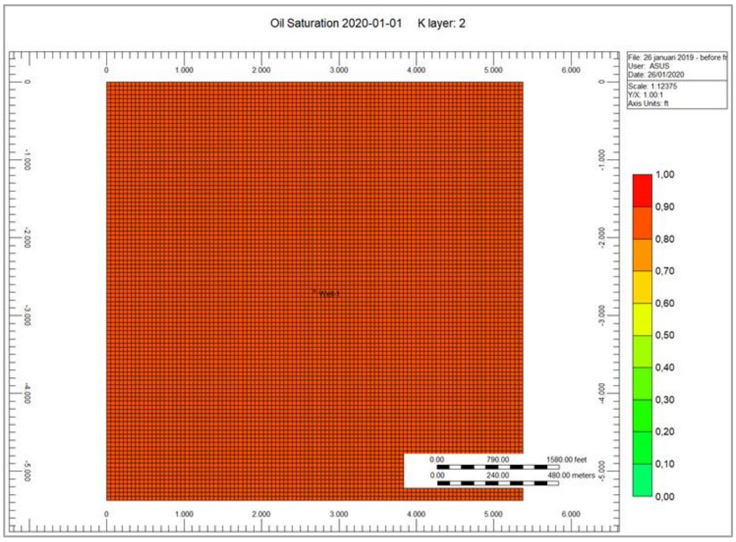

Figure 13. Grid Initial Condition – Case 1

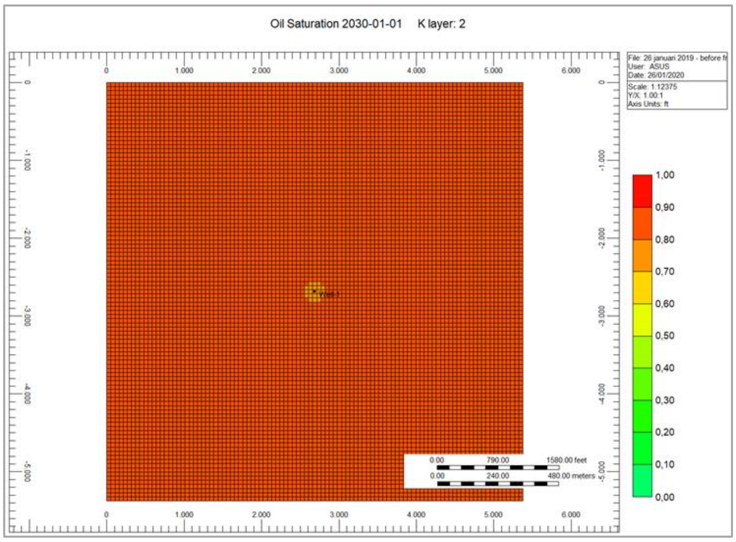

Figure 14. Grid Final Condition – Case 1

In Case 2, the hydraulic fracturing was carried out on 1 January, 2020, and the reservoir was explored for 3654 days, from 1 January 2020 to 1 January 2030. **Figure 15** shows the condition of the reservoir grid with the oil saturation function before hydraulic fracture was carried out. After 10 years of production, a decrease in oil saturation was recorded in the area near the wellbore, as shown in **Figure 16**. Based on reservoir simulation results, it was discovered that the "NK" production well in the "RI" field produced 330.61 thousand barrels of oil and 116.60 million cubic feet of gas, as listed in **Table 8,** also 12.79 barrels of water was yielded, which is only 0.00387% of liquid production. The average oil production in Case 2 was 33.06 thousand barrels per year or 90.48 barrels per day. While the average gas production was 11.66 million cubic feet per year or 31.91 thousand cubic feet per day.

Table 8. Oil and Gas Production per Year – Case 2

Year	Oil Production (MBBL)	Gas Production (MMSCF)
2021	51.90	19.79
2022	38.36	13.52
2023	35.12	12.05
2024	33.13	11.31
2025	31.69	10.81
2026	30.27	10.41
2027	29.07	10.08
2028	27.98	9.79
2029	27.05	9.56
2030	26.05	9.29
Total	330.61	116.60

In Case 3, the reservoir was produced by natural flow from 1 January 2020 to 1 January 2025. Then, a hydraulic fracture was carried out on 1 January 2025 and the reservoir was explored post-stimulation until 1 January 2030. **Figure 17** shows the condition of the reservoir grid with the oil saturation function in the initial conditions. After being manufactured for 5 years, a hydraulic fracture was installed in it, as shown in **Figure 18**. **Figure 19** shows that after hydraulic fracturing, there was a decrease in oil saturation in the area near the wellbore after the well was produced for the next 5 years. The results showed that the "NK" production well in the "RI" field produced 232.76 thousand barrels of oil and 82.57 million cubic feet of gas, as listed in **Table 9,** and 7.57 barrels of water which is only 0.003254% of liquid production. The average oil production in Case 3 was 23.28 thousand barrels per year or 63.70 barrels per day. While the average gas production in Case 3 was 8.26 million cubic feet per year or 22.60 thousand cubic feet per day.

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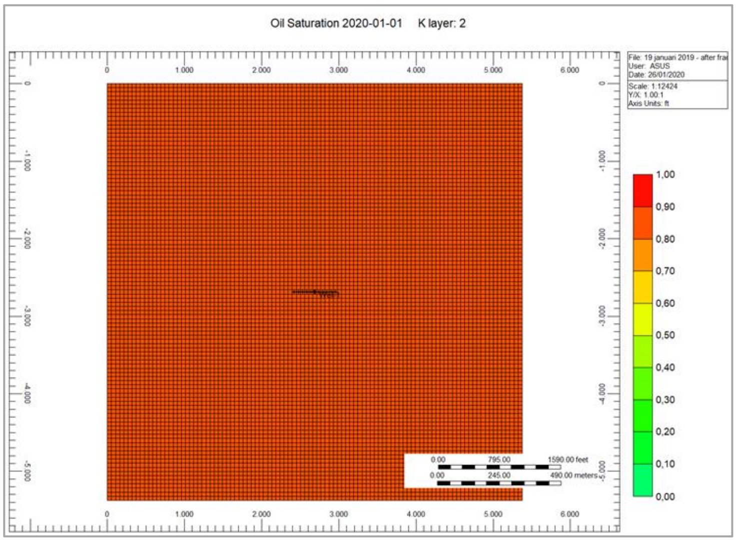

Figure 15. Grid Initial Condition – Case 2

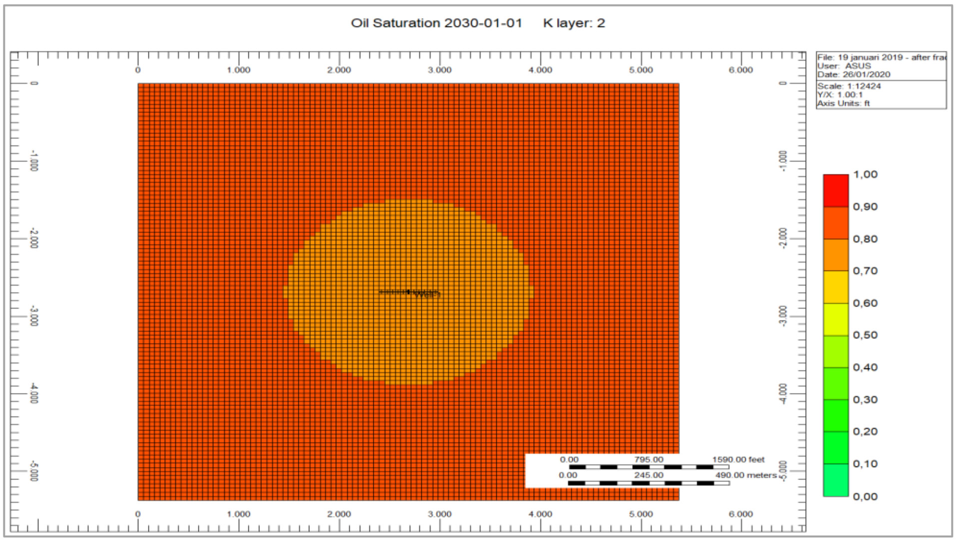

Figure 16. Grid Final Condition – Case 2

Table 9. Oil and Gas Production per Year – Case 3

Year	Oil Production (MBBL)	Gas Production (MMSCF)
2021	12.56	4.17
2022	11.38	3.79
2023	11.05	3.65
2024	10.82	3.55
2025	10.66	3.48
2026	46.43	18.81
2027	35.66	12.67
2028	32.98	11.40
2029	31.34	10.76
2030	29.88	10.29
Total	232.76	82.57

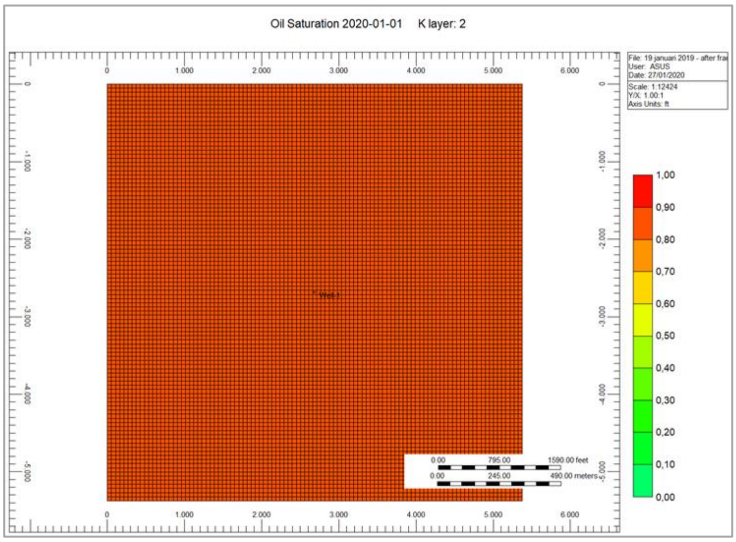

Figure 17. Grid Initial Condition – Case 3

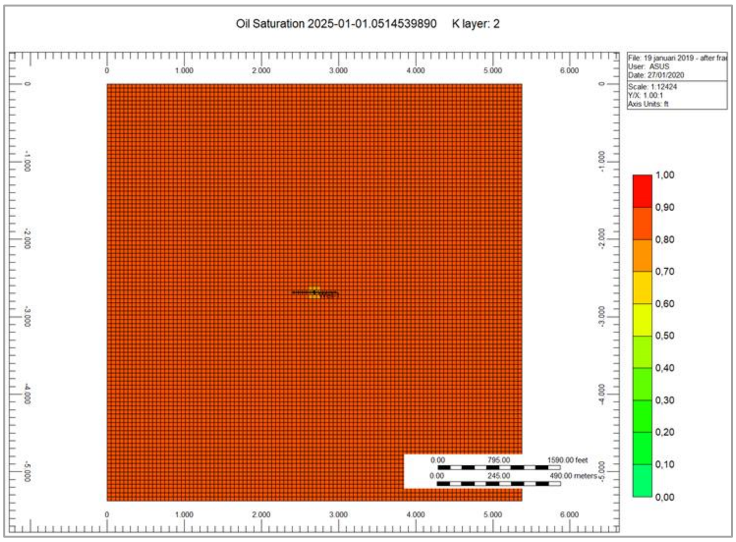

Figure 18. Grid Fracturing Condition – Case 3

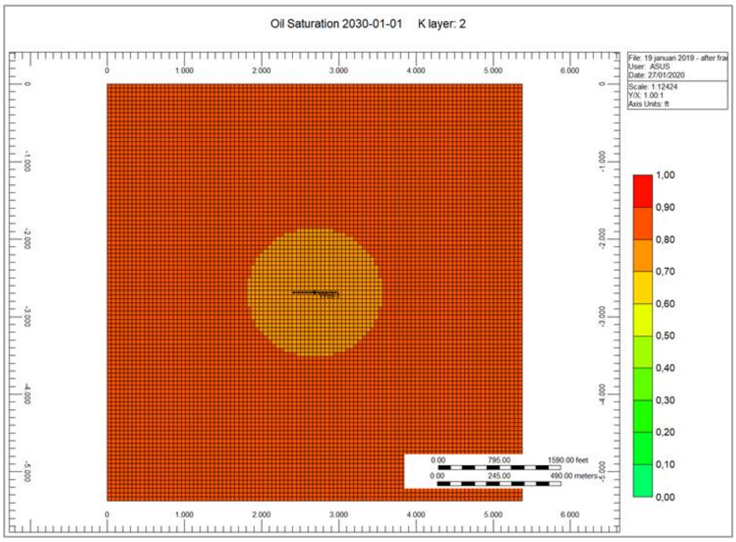

Figure 19. Grid Final Condition – Case 3

The production rates for each development scenario from oil, gas and water are listed in **Figure 20, Figure 21,** and **Figure 22,** respectively. While the cumulative production for each development scenario for oil,

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gas, and water are listed in **Figure 23**, **Figure 24**, and **Figure 25**, respectively. From the six graphs, especially in Case 3, it was observed that hydraulic fracturing increased the rate and cumulative production during the span of the production operation. When compared to Case 1, it was evident that the hydraulic fracturing stimulation at the beginning of the production period, as carried out in Case 2, increased oil production by about 3.1 times and gas by 3.3 times. Meanwhile, hydraulic fracturing in the middle of the production period, as observed in Case 3, increased oil production by about 2.2 times and gas by about 2.3 times fold. **Table 10** shows that the development scenario where the implementation of hydraulic fracturing was at the beginning of the production period (Case 2) had the highest significant oil and gas production. Moreover, the reservoir pressure along with oil production continued to decrease, which is significant in the determination of hydraulic fracturing time to in order to produce the highest oil. As observed in Case 2 where the hydraulic fracturing was carried out when the reservoir pressure was still high and had not decreased. The implementation of hydraulic fracturing in the Republic of Indonesia is usually carried out after the reservoir has decreased in production, due to the fact that the contractor does not yet have sufficient data to submit the hydraulic fracturing stimulation. With the Gross Split scheme in accordance to the Regulation of the Ministry of Energy and Mineral Resources of the Republic of Indonesia Number 8 of 2017, all operations are the responsibility of the contractor, therefore the implementation of hydraulic fracturing at the beginning of the production period is possible.

Table 10. Reservoir Simulation Result Summary

Development Scenario	**Cumulative Oil Production (MBBL)**	**Cumulative Oil Production Percentage Change***	**Cumulative Gas Production (MMSCF)**	**Cumulative Gas Production Percentage Change***
1	106.81	0	35.34	0
2	330.61	+209.53%	116.60	+229.96%
3	232.76	+117.91%	82.57	+133.64%

*Percentage Change Relative to Case 1

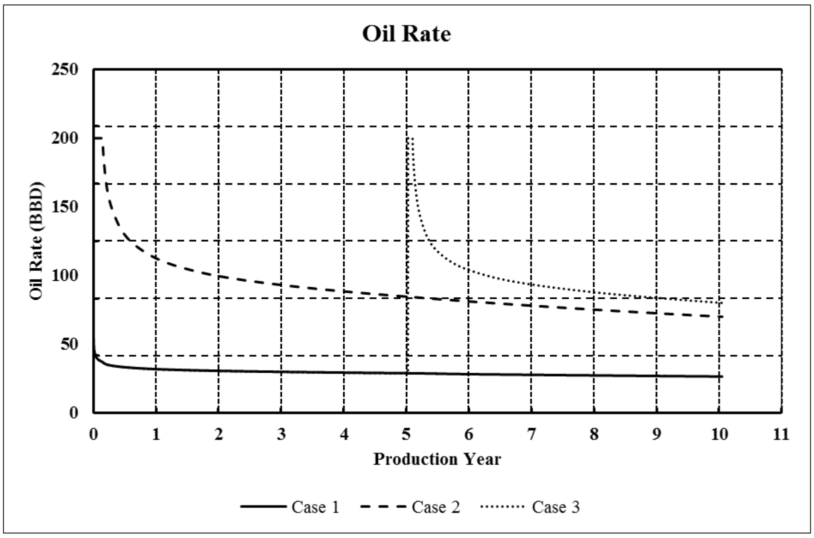

Figure 20. Oil Production Rate

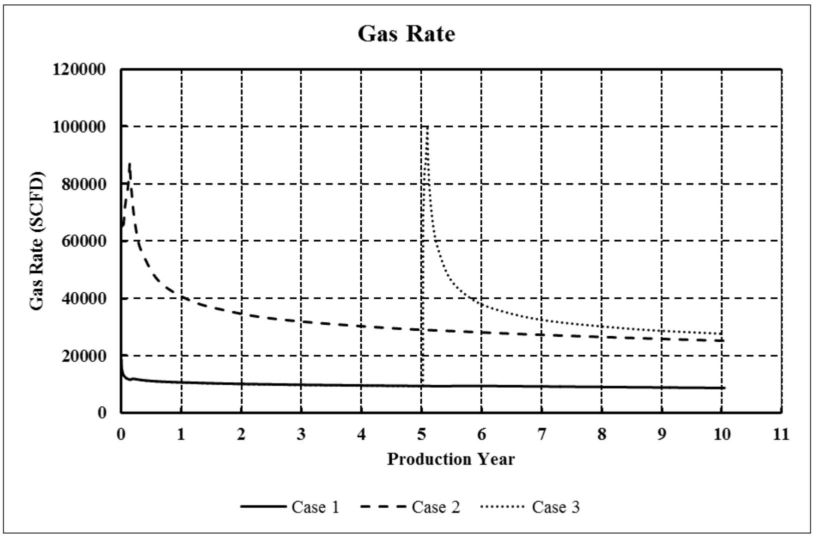

Figure 21. Gas Production Rate

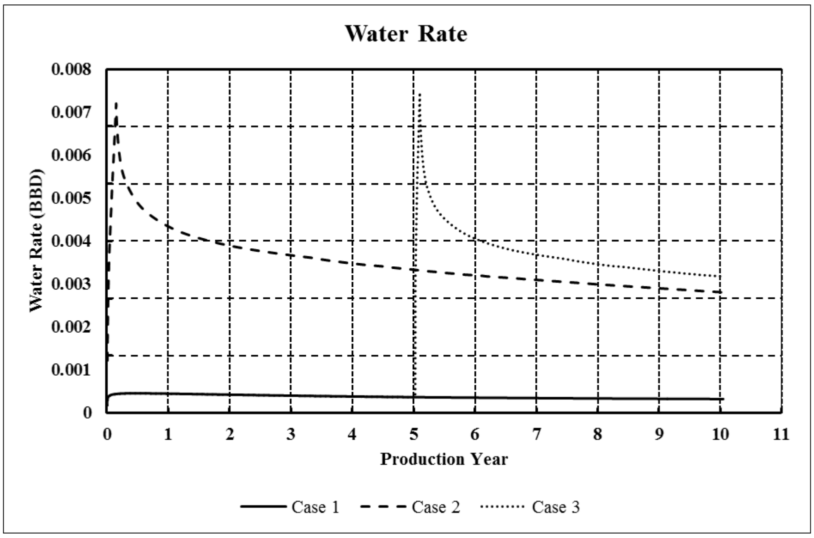

Figure 22. Water Production Rate

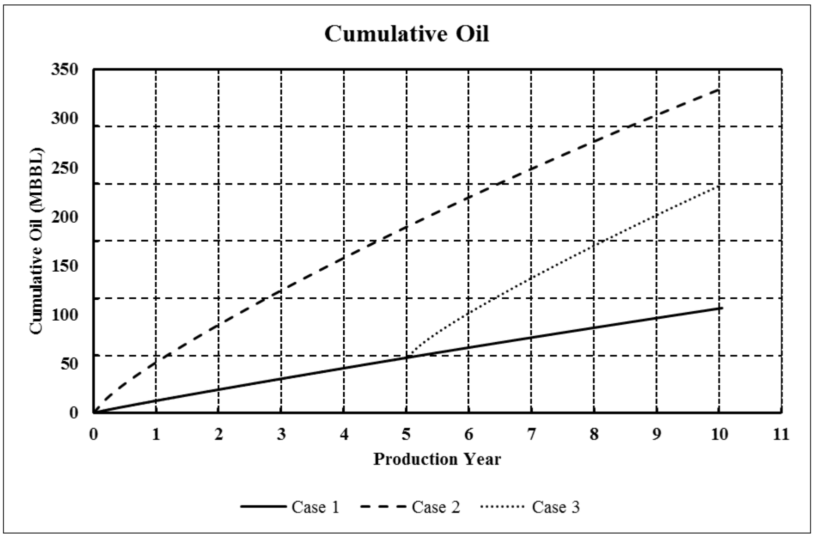

Figure 23. Cumulative Oil Production

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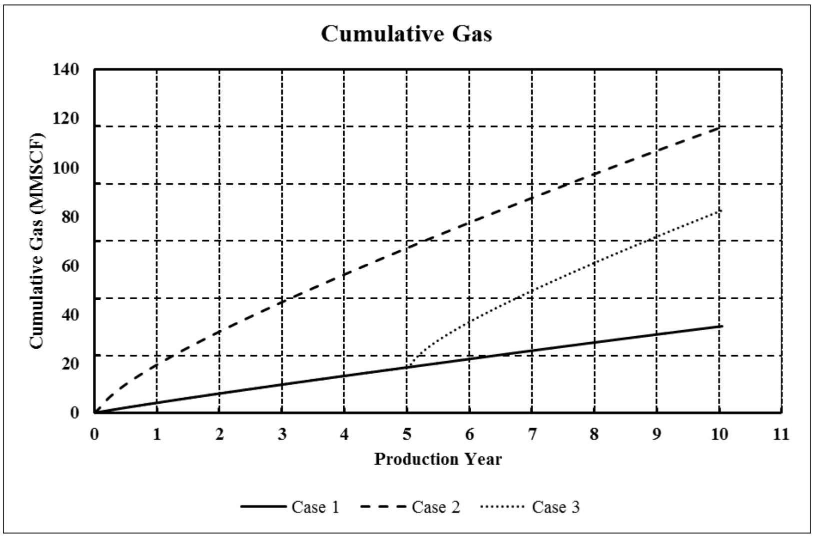

Figure 24. Cumulative Gas Production

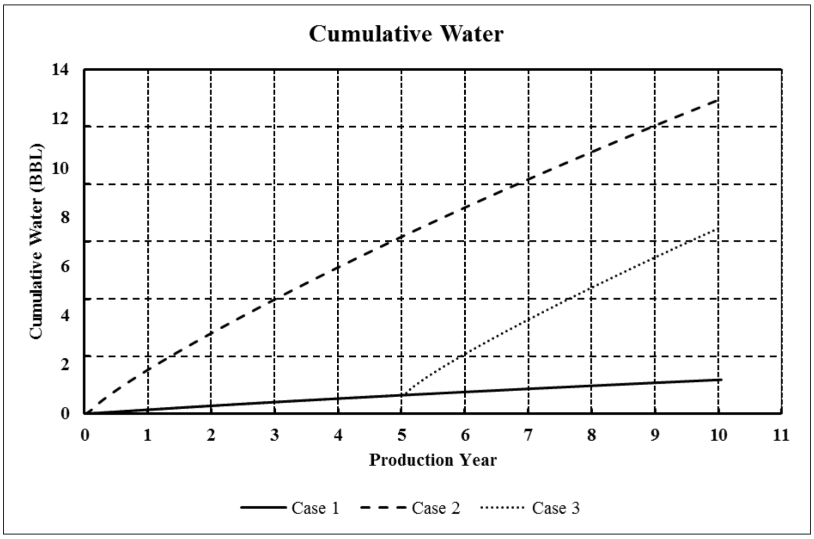

Figure 25. Cumulative Water Production

Also, based on the Regulation of the Ministry of Energy and Mineral Resources of the Republic of Indonesia Number 8 of 2017, the distribution of oil production results is regulated under the Gross Split scheme. And the components that affect contractor's share split correction in the scheme, include field status, location, reservoir depth, supporting infrastructure availability, reservoir type, CO2, and H2S content, oil density, local content, production stage, oil price, gas price, and cumulative oil and gas production. **Table 11** shows the contractor split correction which applies to this study, including the entire development scenario. With the contractor split correction, the Gross Split scheme applicable to this study is listed in **Figure 26**. In addition, there are also other economic parameters that affect the results of the calculations, as listed in **Table 12**, most notably OPEX, assumed oil price, DMO and tax. In the final condition, the government's take is 43.47%, while that of the contractor is 33.04%, and the remaining 23.60% is borne on the cost of production.

In Case 1, natural production flow with the amount generated is as listed in **Table 10**, which results in government's NPV being 1.67 MMUSD, and that of contractor being 1.16 MMUSD. Cash flow for the government and the contractors in this development scenario is listed in **Table 13**. In Case 2, a hydraulic fracture was installed at the beginning of the production period, and the amount generated is listed in **Table 11**, resulting in 5.26 MMUSD as government's NPV, and 3.62 MMUSD as that of the contractor. Cash flow for the government and contractors in this development scenario is listed in **Table 14**. In Case 3, the hydraulic fracture was carried out in the middle of the production period, and the total amount generated is as listed in **Table 12**, resulting in government's NPV of 3.13 MMUSD, and that of contractor as 2.16 MMUSD. Cash flow for the government and contractors in this development scenario is listed in **Table 15**.

Table 11. Contractor Share Split Correction of The Study (*Minister of Energy and Mining Resources Regulation Number 8 of 2017*, 2017)

Parameter	**Characteristic**	**Contractor Share Split Correction (%)**	**Additional Information**
1. Variable Component			
Field Status	POD II	3.00%	
Field Location (*h=depth of the sea in meter)	Offshore (0<h≤20)	8.00%	
Reservoir Depth (m)	1534	0.00%	
Supporting Infrastructure Availability	Well Developed	0.00%	
Reservoir Type	Sandstone	0.00%	
CO_2 Content (%)	0%	0.00%	
H_2S Content (ppm)	0	0.00%	
Oil Density (API)	56	0.00%	
Local Content	60%	3.00%	SKK Migas, 2019.
Production Stage	Secondary	6.00%	
2. Progressive Component			
Oil Price (US$/ BBL)	62.37	5.66%	ICP, December 2019.
Gas Price (US$/MMBTU)	0*	17.50%	*In this study, gas is not for sale.
Oil and Gas Cumulative Production (MMBOE)	0.106	10.00%	

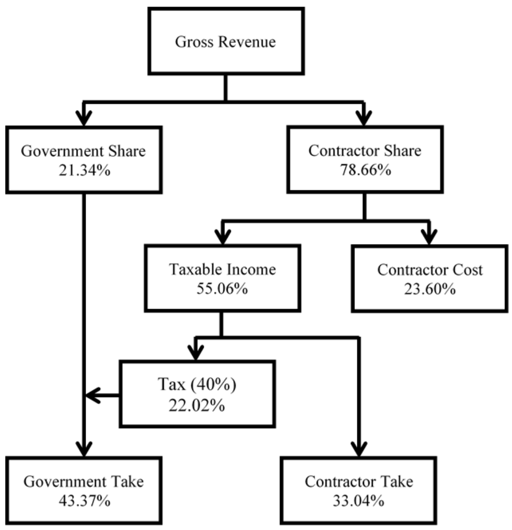

Figure 26. Gross Split Scheme of "RI" Field Case

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Table 12. Other Economic Parameter of the Study

Parameter	Value	Unit	Additional Information
OPEX Gas	0.78	USD/MSCF	
OPEX Oil	19.71	USD/BBL	
Gas Price	0*	USD/MMBTU	*In this study, gas is not for sale.
Tax	40	%	
Discount Rate	10	%	
Oil Price	62.37	USD/BBL	
Price Escalation	0	% /year	
Heating Value	1000	BTU/SCF	ICP, December 2019.
DMO Vol	25	%	Government Regulation Number 53 of 2017 (Article 17 Paragraph 2).
DMO Fee	100	%	
Fracturing Cost	0.22	MMUSD	

Table 13. Government and Contractor Cash Flow – Case 1

Year	Government CF (MMUSD)	Contractor CF (MMUSD)
2021	0.31	0.22
2022	0.28	0.20
2023	0.27	0.19
2024	0.27	0.19
2025	0.27	0.19
2026	0.26	0.18
2027	0.25	0.18
2028	0.25	0.17
2029	0.25	0.17
2030	0.24	0.17

Table 14. Government and Contractor Cash Flow – Case 2

Year	Government CF (MMUSD)	Contractor CF (MMUSD)
2021	1.21	0.77
2022	0.96	0.67
2023	0.88	0.61
2024	0.83	0.58
2025	0.79	0.55
2026	0.76	0.53
2027	0.73	0.51
2028	0.70	0.49
2029	0.67	0.47
2030	0.65	0.45

Table 15. Government and Contractor Cash Flow – Case 3

Year	Government CF (MMUSD)	Contractor CF (MMUSD)
2021	0.31	0.22
2022	0.28	0.20
2023	0.27	0.19
2024	0.27	0.19
2025	0.27	0.19
2026	1.07	0.67
2027	0.89	0.62
2028	0.82	0.57
2029	0.78	0.54
2030	0.74	0.52

As noted in **Figure 27** and **Figure 28**, the government cash flow is always higher than that of the contractor, this was also observed in Case 3, where cash flow increased after the hydraulic fracture was performed. When compared to the NPV in Case 1, that of Case 2 was 3.15 times higher for the government and 3.12 times higher for the contractor. While Case 3 produced a government NPV that was 1.87 times more than that of Case 1 and 1.84 times higher in the contractor's. **Figure 29** shows that the NPV sequence from the largest is Case 2, Case 3, then Case 1. From the economic analysis, it is clear that the scenario development with the hydraulic fracturing stimulation at the beginning of the production period (Case 2), had the most massive NPV value from both the government and contractor's side as listed in **Table 16**.

Table 16. Economic Evaluation Result Summary

Development Scenario	NPV Government (MMUSD)	NPV Government Percentage Change*	NPV Contractor (MMUSD)	NPV Contractor Percentage Change*
1	1.67	0	1.16	0
2	5.26	+214.97%	3.62	+212.07%

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3	3.13	+87.43%	2.14	+84.48%

*Percentage Change Relative to Case 1

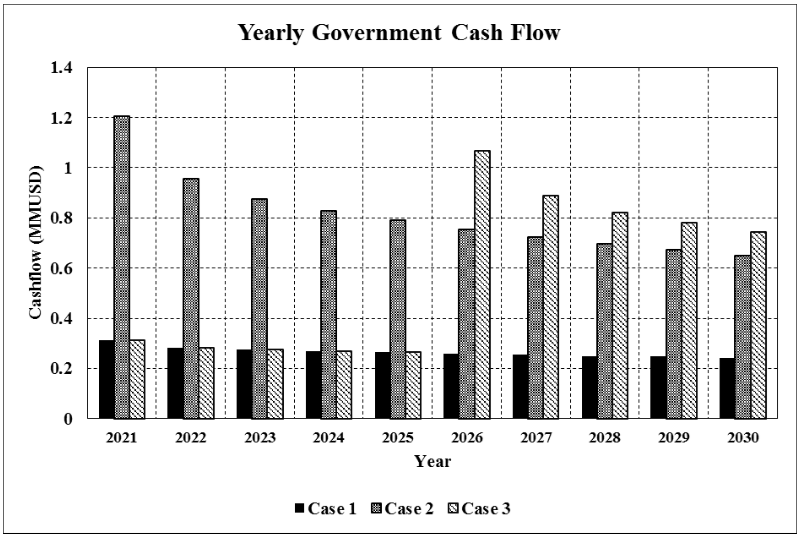

Figure 27. Government Cash Flow

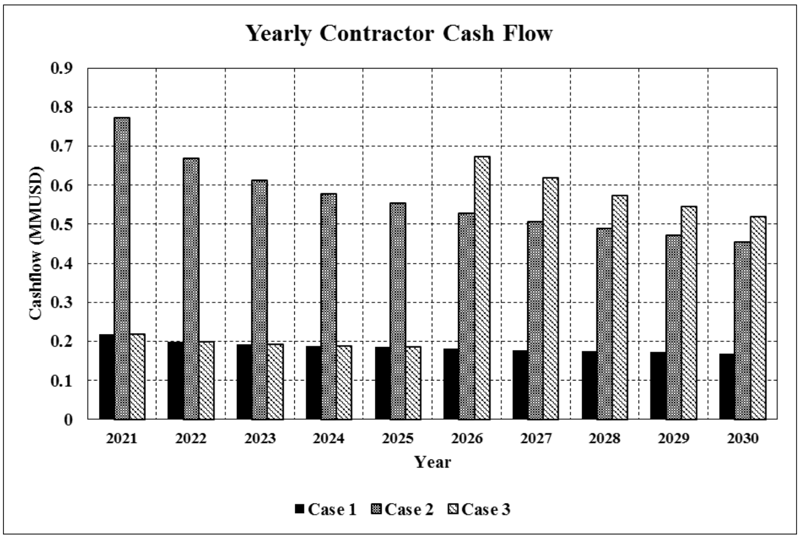

Figure 28. Contractor Cash Flow

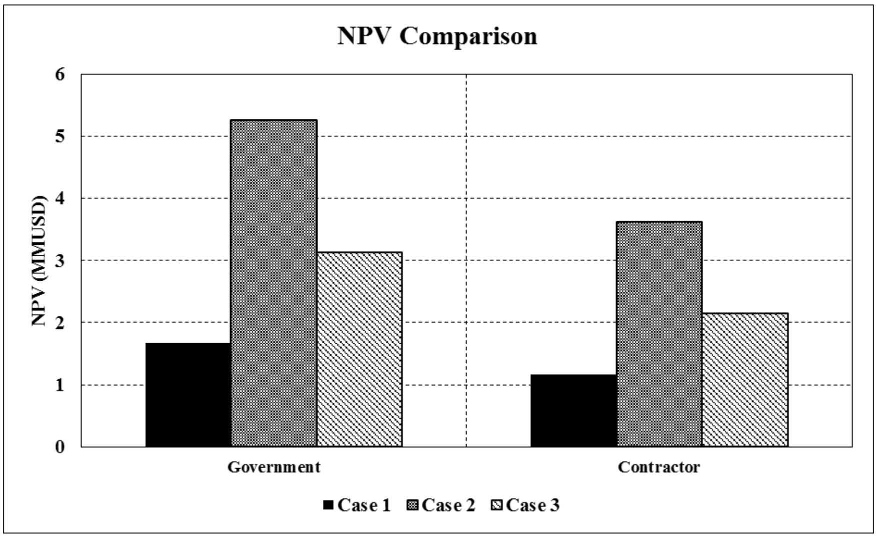

Figure 29. NPV Comparison

CONCLUSIONS

- Based on the results, reservoirs in mature fields are characterized with low-resistivity and low-quality zones. Therefore, the appropriate field development solution is to stimulate the wells using hydraulic fractures at the beginning of the production and also at intervals till the end in order to produce the maximum amount of oil.
- Based on the results of the reservoir simulation, the Case 2 development scenario, where hydraulic fracturing was performed at the beginning yielded the most significant amount of production, at 330.61 thousand barrels of oil and 116.60 million cubic feet of gas. Also, the results of the economic evaluation, showed that Case 2 development scenario produced the most massive NPV value, both from the government's aspect (5.26 MMUSD), and that of the contractor (3.62 MMUSD).

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