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Completion Design for The Development of a Multi-Layer and Multi Fluid Reservoir Systemin Offshore Well AA-01, North-West Java

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Abstract

Completion systems are important components of hydrocarbon field development. As the link between the reservoir and surface facilities, completions need to be designed to maximize hydrocarbon recovery and withstand consistently changing conditions for years, within the safety requirements. However, designing completion for a well comprising a multi-layer and multi-fluid reservoir is quite challenging. The completion design must use the right materials and be able to safely produce single, as well as commingle products, and add any artificial lifts, depending on the method with the most optimum value. This paper, therefore, discusses the model development of completion design for an offshore well AA-01, one of the offshore wells with multi-layer and multi-fluid reservoir systems in Indonesia. Well AA-01 penetrates two productive layers, the upper layer AA-U1, and the lower layer AA-L2. The upper layer is a gas reservoir with initial gas in place of 1440 MMSCF, while the lower layer is an oil reservoir with initial oil in place of 6.1 MMSTB. In addition, the model design used available field data, for instance, PVT and DST, from well X. The base well completion was also used to model the completion design in software. Meanwhile, commercial software was utilized to estimate the well hydrocarbon recovery. Subsequently, several designs were tested, and the design with maximum production as well as hydrocarbon recovery was selected. The completion design selected comprises 9⅝ inch 47 ppf L-80 production casing, as well as 7⅝ inch 29.7 ppf L-80 liner, and produced commingle with oil and gas recovery of about 50.16% and 92.3%, respectively, in 5 years production.

INTRODUCTION

Well development is a challenging task laden with high risks. Once a well has been drilled, the well must then be designated a producer, an injector, or be plugged and abandoned. Subsequently, completion works are carried out in cases where the well development is decided to be continued. Completions transform a drilled well into a producer or an injector. Currently, there are various types of well completion models, each with respective applicable conditions and limitations. However, only the most suitable well completion model is selected and developed to fully utilize the reservoir's potential. With the continuous developments in technology, completions have evolved to incorporate downhole sensors, leading to the creation of intelligent or smart wells. These sensors are able to measure rate, pressure, and gas-to-oil ratio, and are, therefore, useful for attaining optimum production. Certain wells have production flowing from multiple reservoir levels and types of fluid phase. These wells require more complex completions to ensure production.

A vast amount of technical information on multiphase flow in pipes is available in the literature (J.P. Brill & Arirachakaran, 1992; James P Brill, 1987; Petalas & Aziz, 2000). However, many of these sources are related to other industries. Multi-fluid flow in the petroleum industry has many distinct features creating complications unique to this industry. Furthermore, multi-fluid or multiphase flow is possible throughout the entire production system involved in conveying fluids from oil and gas reservoirs to processing facilities at the surface. The production system in this context includes the reservoir, the well completion, tubulars

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connecting the reservoir to the surface, as well as all surface facilities on land, seabed, or offshore platform, and any pipelines carrying the fluid produced to other processing facilities.

This paper, therefore, discusses the model development of completion design using commercial software. The model used data from an offshore well in Indonesia with a multi-layer and multi-fluid reservoir system. Furthermore, the reservoir in question comprises two layers with different types of fluid and characteristics. The upper layer is a gas reservoir, while the lower counterpart is an oil reservoir. Field data obtained from the well, including PVT, DST, and base model well completion, are used to develop the optimum completion design. The PVT data, for instance, pressure, temperature, gas to oil ratio, and saturation, are used to define the reservoir's characterization and are integrated with the base completions to estimate the well productivity index (PI) as well as the inflow performance relationship (IPR). Meanwhile, the DST data are used to determine the constructed IPR's validity. Subsequently, the base model is integrated into the software to predict the production. This is followed by combining several producing methods (single or commingle), casing sensitivities, and tubing sizes, are used to achieve the most optimum hydrocarbon recovery from the prediction results. Ultimately, the method with the best result is selected as the well completion design.

Basic Theory

Completion System

In addition to being a link between the reservoir and the surface facility, completion is applied as a combination of reservoir geology, reservoir engineering, and petroleum production engineering. The reservoir geology and reservoir engineering involve lithology, and the reservoir characteristics as well as flow characteristics, and these are theoretically, the basis for determining the completion design. Meanwhile, production engineering involves designating the well for production or injection and determining the production method, whether single separate zone production, commingle production, or added artificial lift (Bonapace & Perazzo, 2016; Rytlewski, 2008).

Casing and Tubing

In well drilling, besides fulfilling the geologist's objectives of the well, there is a need to determine the well size and configuration, to maintain the wellbore stability and the well productivity. Figure 1 shows the most common casing size and hole size configurations, while Figure 2 shows the common conventional well configuration. Casing and tubing are essential in well completion. Wells drilled for oil and gas production or injection must be cased with materials of sufficient strength and functionality. A casing is series of steel pipes joined to create a continuous hollow tube running into a drilled well, to stabilize the wellbore. Furthermore, there are five types of casing, and these are conductor, surface, intermediate, production, and liner casings. Meanwhile, tubing is a smaller or slimmer casing used to transport fluids produced to the surface or transport injected fluid to formation. The tubing selection, design, and installation are critical to ensure efficient fluid flow and permit artificial lift installation.

Most countries follow the American Petroleum Institute (API) standards for casing and tubing design. Both designs must meet strict requirements for compression, tension, collapse, and burst resistance, and have the capacity to withstand hydraulic fracturing pressure, production pressures, as well as corrosive conditions. The API SPEC 5CT are the standards for casing and tubing design (Figure 1).

Inflow Performance Relationship (IPR)

Inflow Performance Relationship is defined as the relationship between flow rate and flowing bottom hole pressure. An IPR curve provides information including the well and reservoir deliverability and is combined with tubing relationship performance, to obtain optimum well performance.

- **Oil well deliverability**: An oil well's performance is estimated by the productivity index. Muskat (1941) proposed the constant productivity index concept is only appropriate for single-phase flow conditions oil wells with pressure above the reservoir bubble point pressure. The straight-line productivity index curve between flow rate and pressure does not apply to multiphase flow. Numerous empirical formulas have been proposed to predict oil well performance under two-phase flow conditions. However, Vogel (1968) is the most popular and commonly used formula. The formula was the first to present an easy method for predicting oil well performance. This empirical inflow performance relationship (IPR) is based on computer simulation. The curve is generated using Vogel's equation for reservoir pressure below the bubble point pressure (Equation 1) and at bubble point pressure (Equation 2), as shown below.

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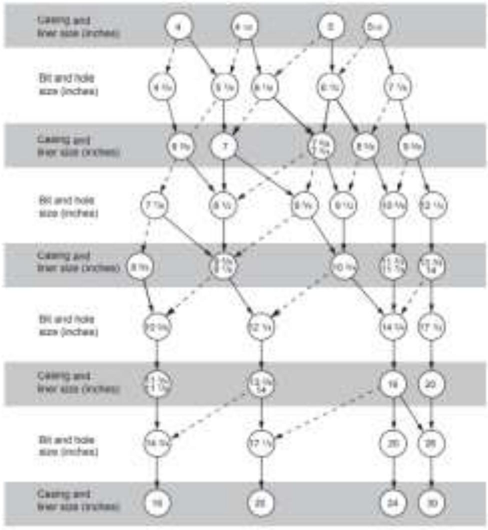

Figure 1. Casing String Size (Heriot Watt, 2005)

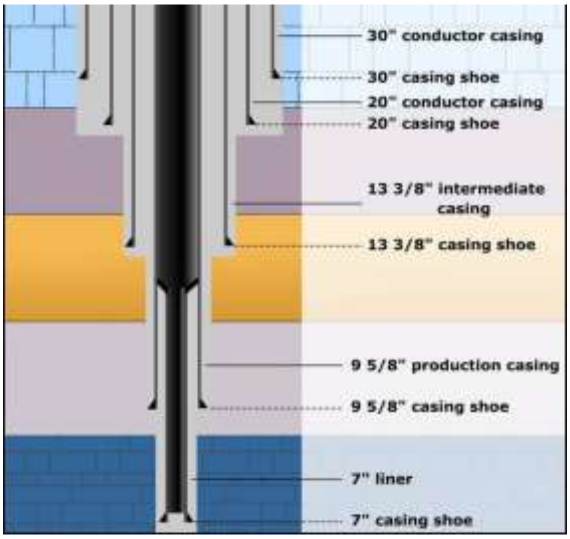

Figure 2. Conventional Well Configuration (drillingcourse.com, 2015)

$$\frac{qo}{qo,max} = 1 - 0.2\left(\frac{Pwf}{\bar{P}r}\right) - 0.8\left(\frac{Pwf}{\bar{P}r}\right)^2 \quad (1)$$

$$\frac{qo}{qo,max} = 1.8\left(\frac{Pr}{Pb} - \frac{Pwf}{Pb}\right) \quad (2)$$

Another empirical formula used is the isochronal test proposed by fetkovich in 1973. The deliverability equation is based on the empirical gas-well deliverability equation proposed by Rawlins & Schellhardt (1935), as shown below.

$$qo = C(\bar{P}r^2 - Pwf^2)^n \quad (3)$$

$$\frac{qo}{qo,max} = [1 - \left(\frac{Pwf}{\bar{P}r}\right)^2]^2 \quad (4)$$

Where, C represents the flow coefficient and n denotes the deliverability exponent, the inverse slope of the log-log plot of pressure-squared difference against flow rate. C and n are used to obtain the multiple rates.

Table 1. PI SPEC 5CT – Specification for Casing and Tubing (drillingformulas.com)

No	O.D. (inch)	Nominal Weight T & c lbs/ft	Grade	Collapse Pressure (psi)	Internal yield Pressure Minimum yield (psi)			
					PE	STC	LTC	BTC
1	7	38	HCN-80	12700	10800		9240	8460
2	7	38	C-90	12820	12150		10390	9520
3	7	38	H2S-90	12820	12150		10390	9520
4	7	38	S-95	13440	12830		10970	10050
5	7	38	T-95	13440	12830		10970	10050
6	7	38	H2S-95		12830		10970	10050
7	7	38	C-95	13440	12830		10970	10050
8	7	38	P-110	15140	14850		12700	11640
9	7	38	Q-125	16750	16880		14430	13220
10	7	38	LS-140	18280	18900		16170	14810
11	7	38	V-150	19240	20250		17320	15870
12	7	41	C-90	13900	13280		10390	9520
13	7	41	H2S-90	13900	13280		10390	9520
14	7	41	T-95	14670	14010		10970	10050
15	7	41	H2S-95	14670	14010		10970	10050
16	7	41	P-110	16990	16230		12700	11640
17	7	41	Q-125	19300	18440		14430	13220
18	7	41	V-150	22820	22130		17320	15870
19	7	42.7	C-90	14640	14060			
20	7	42.7	T-95	15450	14840			
21	7	46.4	C-90	15930	15460			
22	7	46.4	T-95	16820	16320			
23	7	50.1	C-90	17220	16880			
24	7	50.1	T-95	18810	17810			
25	7	53.6	C-90	18460	18270			
26	7	53.6	T-95	19480	19290			
27	7	57.1	C-90	19690	19690			
28	7	57.1	T-95	20780	20780			
29	7 5/8	24	H-40	2030	2750	2750		
30	7 5/8	26.4	J-55	2890	4140	4140	4140	4140
31	7 5/8	26.4	K-55	2890	4140	4140	4140	4140
32	7 5/8	26.4	LS-65	3100	4890	4890	4890	4890
33	7 6/8	26.4	L-80	3400	6020		6020	6020
34	7 5/8	26.4	HCL-80	4850	6020		6020	6020
35	7 5/8	26.4	N-80	3400	6020		6020	6020

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36	7 5/8	26.4	C-90	3610	6780		6780	6780
37	7 5/8	26.4	H2S-90	4850	6780		6780	6780
38	7 5/8	26.4	S-95	4850	7150		7150	7150
39	7 5/8	26.4	T-95	3710	7150		7150	7050
40	7 5/8	26.4	H2S-95	4850	7150		7150	7050

No	Joint Strenght 1000 lbs			Body Yield 1000 lbs	Wall (inch)	I.D. (inch)	Drift Diameter (inch)	Displacement (bbl/ft)	Capacity (bbl/ft)
	STC	LTC	BTC						
1		831	876	877	0.54	5.92	5.795	0.01356	0.03405
2		883	876	986	0.54	5.92	5.795	0.01356	0.03405
3		883	876	986	0.54	5.92	5.795	0.01356	0.03405
4		944	964	1041	0.54	5.92	5.795	0.01356	0.03405
5		931	920	1041	0.54	5.92	5.795	0.01356	0.03405
6		931	920	1041	0.54	5.92	5.795	0.01356	0.03405
7		931	920	1041	0.54	5.92	5.795	0.01356	0.03405
8		1067	1096	1205	0.54	5.92	5.795	0.01356	0.03405
9		1207	1183	1370	0.54	5.92	5.795	0.01356	0.03405
10		1341	1315	1534	0.54	5.92	5.795	0.01356	0.03405
11		1430	1402	1644	0.54	5.92	5.795	0.01356	0.03405
12		903	876	1069	0.59	5.82	5.695	0.01470	0.03290
13		903	876	1069	0.59	5.82	5.695	0.01470	0.03290
14		952	920	1129	0.59	5.82	5.695	0.01470	0.03290
15		950	920	1129	0.59	5.82	5.695	0.01470	0.03290
16		1111	1096	1307	0.59	5.82	5.695	0.01470	0.03290
17		1244	1183	1485	0.59	5.82	5.695	0.01470	0.03290
18		1488	1402	1782	0.59	5.82	5.695	0.01470	0.03290
19				1127	0.625	5.75	5.625	0.01548	0.03212
20				1189	0.625	5.75	5.625	0.01548	0.03212
21				1226	0.687	5.626	5.5	0.01685	0.03075
22				1294	0.687	5.626	5.5	0.01685	0.03075
23				1325	0.75	5.5	5.375	0.01821	0.02939
24				1399	0.75	5.5	5.375	0.01821	0.02939
25				1421	0.812	5.376	5.251	0.01952	0.02808
26				1500	0.812	5.376	5.251	0.01952	0.02808
27				1515	0.875	5.25	5.125	0.02083	0.02678
28				1600	0.875	5.25	5.125	0.02083	0.02678
29	212			276	0.3	7.025	6.9	0.00854	0.04794
30	315	346	483	414	0.328	6.969	6.844	0.00930	0.04718
31	342	377	581	414	0.328	6.969	6.844	0.00930	0.04718
32	368	403	554	489	0.328	6.969	6.844	0.00930	0.04718
33		482	635	602	0.328	6.969	6.844	0.00930	0.04718
34		533	691	602	0.328	6.969	6.844	0.00930	0.04718
35		490	659	602	0.328	6.969	6.844	0.00930	0.04718
36		532	681	677	0.328	6.969	6.844	0.00930	0.04718

37	553	691	677	0.328	6.969	6.844	0.00930	0.04718
38	568	740	714	0.328	6.969	6.844	0.00930	0.04718
39	560	716	714	0.328	6.969	6.844	0.00930	0.04718
40	560	716	714	0.328	6.969	6.844	0.00930	0.04718

- **Gas well deliverability:** Deliverability testing is performed to determine the productivity of a gas well. Gas well deliverability tests are used to predict the flow rate of a gas well during reservoir depletion. An empirical relationship was proposed by Rawlins & Schellhardt (1935) and is frequently used today. The empirical backpressure method of testing gas wells is based on the analysis of results obtained from testing over 500 wells. The difference between the squares of the average reservoir pressure and flowing bottom hole pressures were plotted against the flow rates on logarithmic coordinates to obtain a straight-line graph. This led Rawlins & Schellhardt (1935) to propose the backpressure equation (Equations 3 and 4).

Nodal Analysis

In the production system, reservoir performance and piping system performance are inseparable and interdependent. Fluid transported from the reservoir to the surface through the tubular or flowline requires pressure difference to move. The amount of fluid transported into a well from the reservoir relies more on the pressure drop in the piping system, and the piping system's pressure depends on the amount of fluid flowing through it. Therefore, the entire production system must be analyzed as a unit. Nodal analysis is a tool used to attain optimum well design in terms of perforations, tubing size, and underbalance design. This analysis is applied in both oil and gas wells, as well as many other well systems, and is able to simulate impacts in the variations of tubing size, choke size, surface pressure, and inflow on the well's performance. The nodal analysis aims to combine the various components of the production system for an individual well, to estimate production rates and optimize the production system's components (Awal & Heinze, 2009).

METHODOLOGY

Figure 3 shows the methodology or workflow of this project.

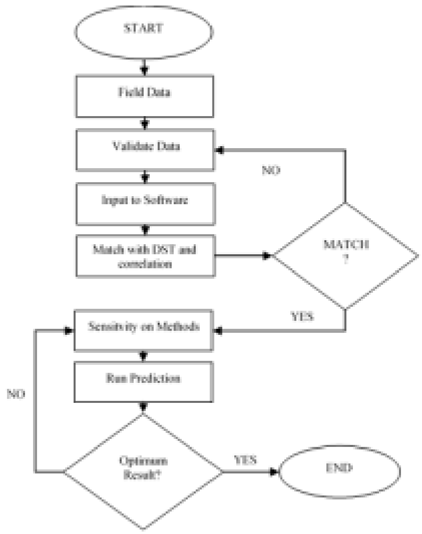

Figure 3. Workflow Chart

Data Validation

Analysis of a multi-layer and multi-fluid reservoir well is quite difficult and tricky, due to well complexity. In some cases, the fluid remains in the wellbore before well testing, leading to data inaccuracy for instance, in the fluid rate, flowing wellhead pressure, or gas-to-oil ratio. In this project, the field data was validated by inputting it into the first commercial software. This was carried out to ensure the field data represents the actual reservoir. In the software, the input data is then validated using various available correlations. The software is used to validate several data, from the reservoir data to well completion.

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After testing all the correlations, the data is corrected in cases where the data did not match the actual well data obtained DST. From the field data, invalid data was discovered on DST for the oil reservoir. Based on Figure 4, the gas-oil ratio (GOR) is a bit off. Subsequently, the data were corrected using simple linear regression and the corrected result was obtained (Figure 5). The GOR required correction because the incorrect data affected the calculation of flowing bottom-hole pressure (Pwf), and consequently, the IPR calculation. In this study, the Pwf calculation was based on Cullender & Smith (1956) method for the gas reservoir, as well as the Poettman & Carpenter (1952) method for the oil reservoir. Data validation was necessary to ensure the data obtained are the exact data produced from the actual reservoir to the well, thus, minimalizing error in advanced simulation. The project then proceeded after data validation had been performed.

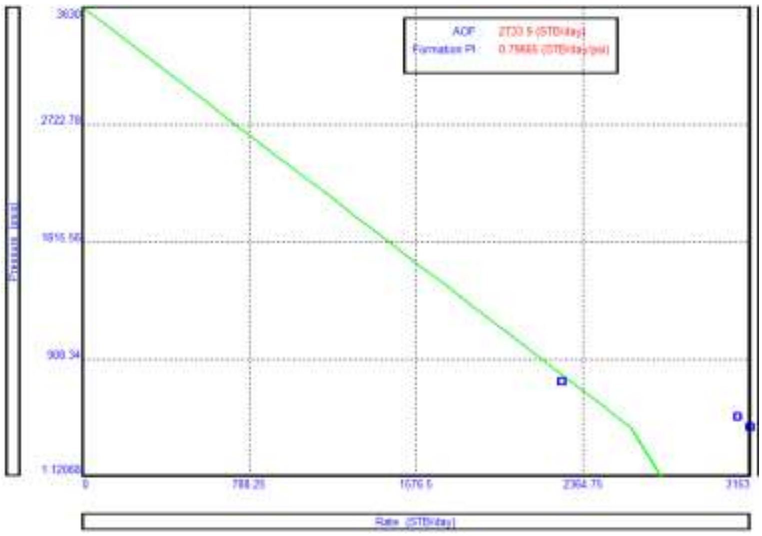

Figure 4. Vogel IPR before data validation

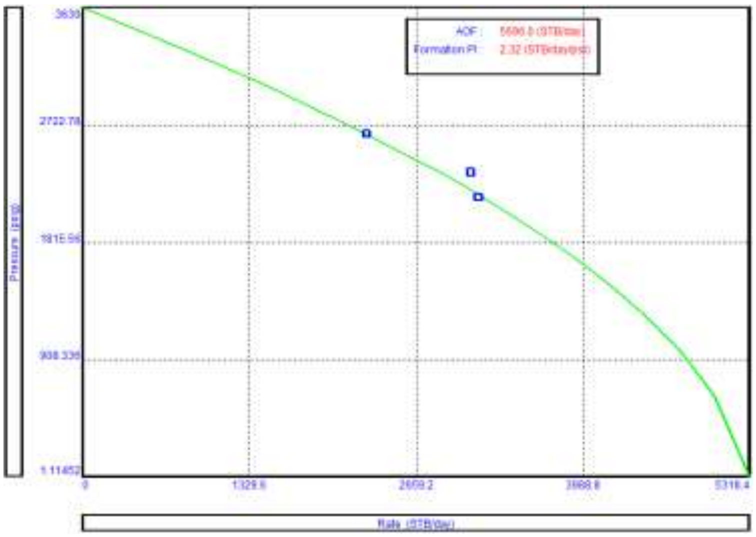

Figure 5. Vogel IPR after data validation

Production Data Matching

After all the data were validated, the model was matched with the available correlations for constructing the IPR curve, based on the data availability and reservoir characterization. The IPR for the oil reservoir with the best match correlation was found to be the Vogel method (Figure 5), while the gas reservoir counterpart was the multi-rate C and n method (Figure 6).

Subsequently, the vertical lift performance relationship (VLP) or tubing performance relationship (TPR) was determined. The field data, including the measured depth, true vertical depth, well schematic, as well as casing and tubing sizes, were inputted into the first software, to determine the VLP. Based on the correlation sensitivity and the VLP results, the best match for the gas reservoir was found to be Beggs and

Brill (Figure 7), while the oil reservoir counterpart was found to be Petroleum Expert (Figure 8) for oil reservoir. Figures 9 and 10 show the VLP/IPR curve constructed using the selected correlations.

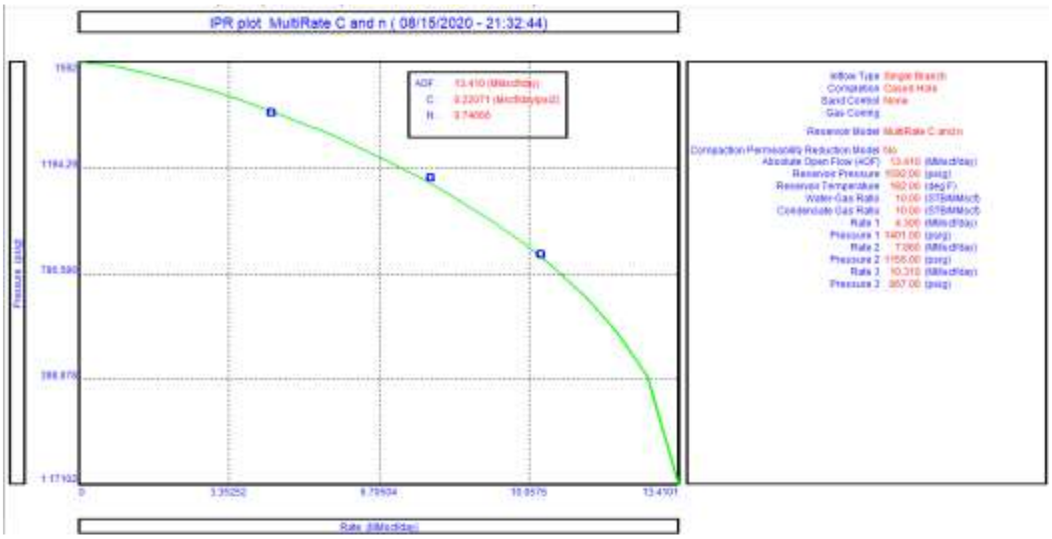

Figure 6. IPR model for Gas Zone in well X-1

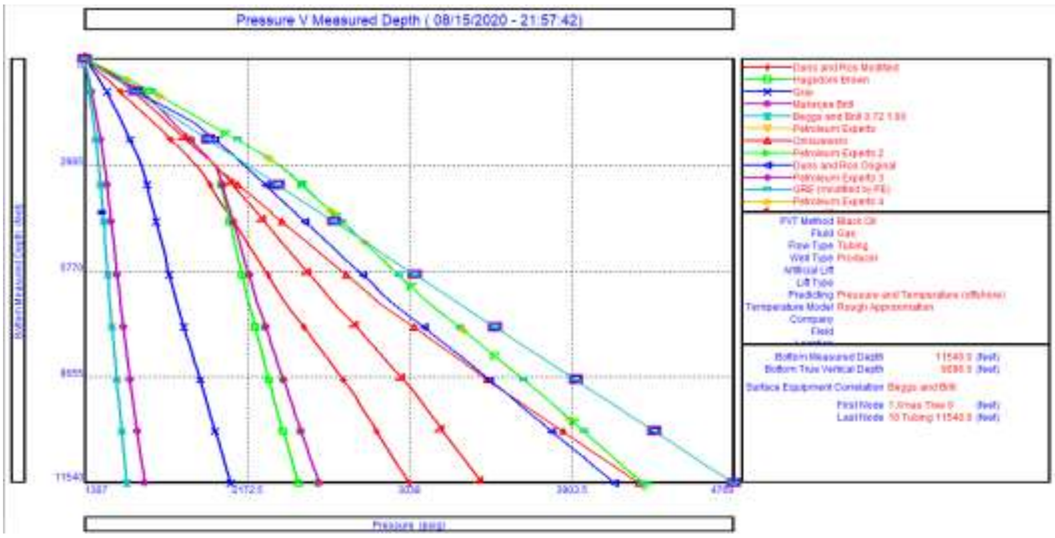

Figure 7. Tubing Performance Correlation Comparison for Gas Reservoir Zone

Run Prediction

The results from the first software were integrated into a second commercial software, to carry out the production prediction. Figure 11 shows the model used to run the production prediction, for 5 years with time step per week. The sensitivity of the production method (Table 2), as well as the casing and tubing sizes (Table 3), were determined, based on the most common casing size and hole size configurations (Figure 1), as well as API SPEC 5CT.

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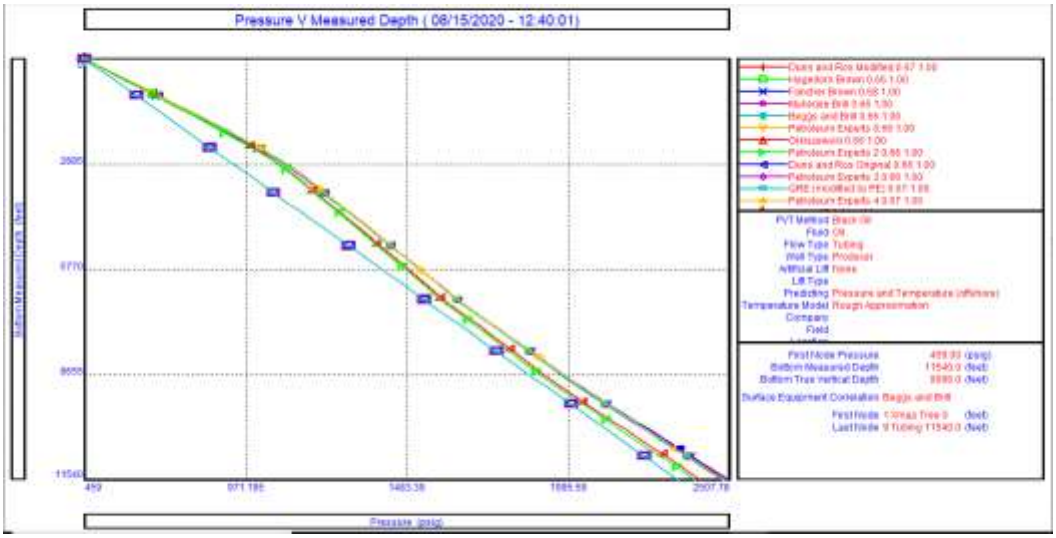

Figure 8. Tubing Performance Correlation Comparison for Oil Reservoir Zone

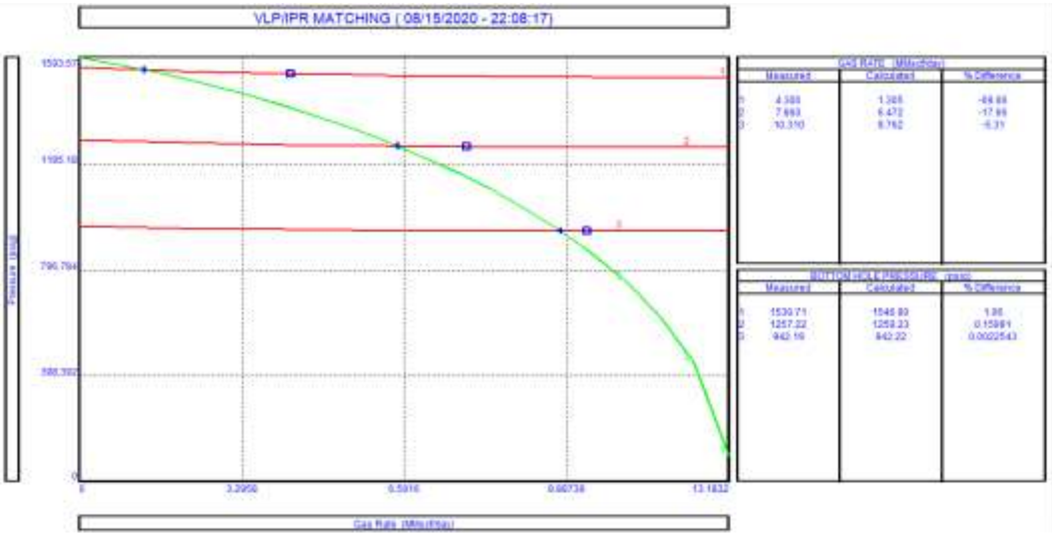

Figure 9. VLP/IPR plot using *Beggs and Brill* correlation

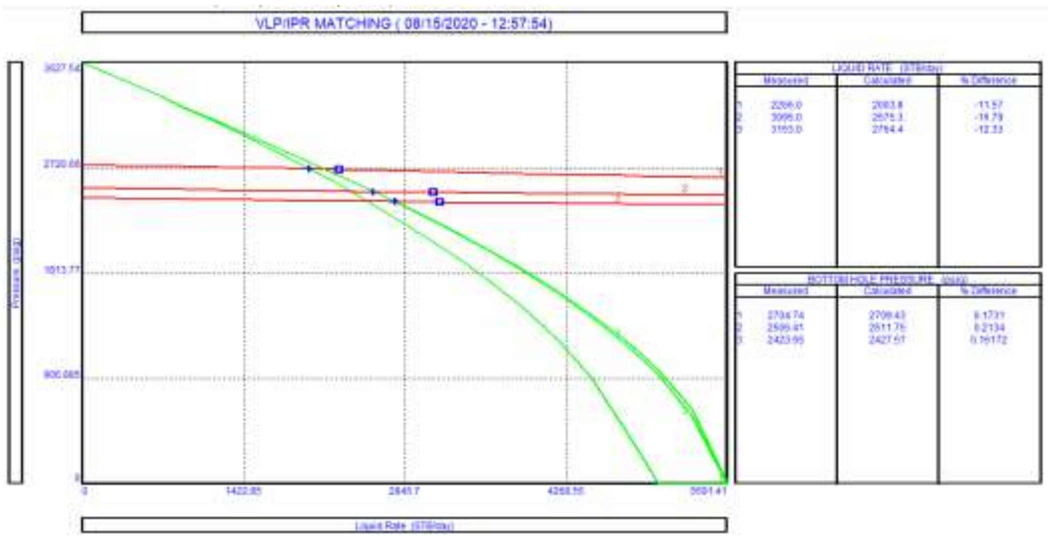

Figure 10. VLP/IPR plot using *Petroleum Expert* correlation

Case Study

An offshore well in Indonesia was used as the case study in this project. The well is deviated and comprises two main layers with different types of fluid. The Upper layer AA-U1 is a gas reservoir, while the lower layer AA-L2 is an oil reservoir. Furthermore, the well is drilled to 9,096 ft TVD (11,540 ft MD), using a jack-up rig comprising a 30-inch conductor casing, 18 ⅝ inch, 87 ppf, K-55 surface casing, 13⅜ inch, 61 ppf, K-55 intermediate casing, 9⅝ inch, 47 ppf, L-80 production casing, and a 7 inch, 26 ppf, L-80 liner (Figure 12). The assumptions used in this project are outlined below.

- The aquifer's boundary,
- Constants Bo, WC, CGR, WGR, and GOR, in prediction.
- No sand problems and water coning.

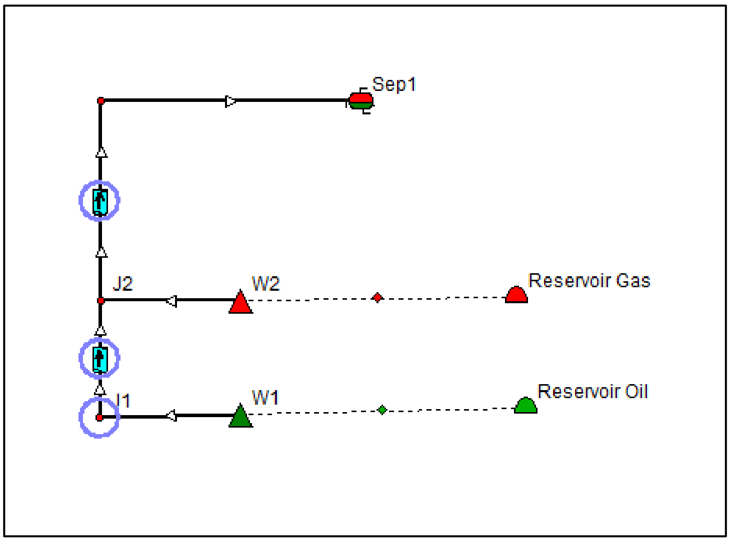

Figure 11. Well Design Model for Running Prediction

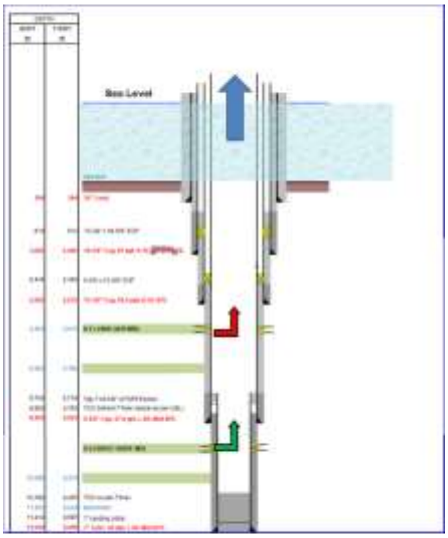

Figure 12. Existing Well X Completion

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Table 2. Production Method for Running Prediction

Production Method	Description
Single	Gas Only
	Oil Only
Commingle	Gas and Oil

Table 3. Casing and Tubing Specification for Running Prediction

Production Casing (inch)	Tubing or Liner (inch)	Nominal Weight (ppf)	Collapse Pressure (psi)
9⅝	6 ⅝	24	5760
		28	8170
	7	23	3830
		26	5410
	7⅝	29.7	4790
		33.7	6560
	7¾	46.1	11340

Upper Layer

Layer AA-U1 is a gas reservoir with initial gas in place of 1440 MMSCF and a reservoir pressure of 1594 psia. The layer is produced at 4184'-4215' MD through the 9⅝ inch production casing. Tables 4 and 5 show the reservoir's other properties and the DST data, respectively.

Table 4. Gas Fluid Properties

Parameters	Unit	Value
Condensate *API Gravity*	API	55
SG Gas	sp. Gravity	0.688
WGR	STB/MMSCF	10
CGR	STB/MMSCF	10
Temperature	^{0}F	182
Initial Pressure	psi	1594
Porosity	fraction	0.25
S_{wc}	fraction	0.35
Water Compressibility	1/psi	3E-06

Table 5. Upper layer DST data

DST	Choke Size	Oil (BOPD)	Gas (MMSCFD)	Water (BWPD)	FWHP (psi)	FWHT (°F)	Chloride (ppm)
AA-U1	32/64	1	4.30	1	1307	113	58000
	48/64	70	7.86	33	1081	128	44000
	64/64	156	10.31	74	811	135	40000

Lower Layer

Layer AA-L2 is an oil reservoir with initial oil in place of 6.1 MMSTB and a reservoir pressure of 3630 psia. The layer is produced at 10,655'-10,691' MD through the 7-inch liner. Tables 6 and 7 show the reservoir's other properties and the DST data, respectively.

Table 6. Oil Fluid Properties

Parameter	Unit	Value
Oil *API Gravity*	API	29
SG Gas	sp. Gravity	1.18
GOR	scf/STB	537
WCT	Persen	10
Temperature	^{0}F	283
Initial Pressure	psi	3630
Porosity	fraction	0.12
S_{wc}	fraction	0.3
Water Compressibility	1/psi	3E-06

Table 7. Lower layer DST data

DST	Choke Size	Oil (BOPD)	Gas (MMSCFD)	Water (BWPD)	FWHP (psi)	GOR
AA-L2	32/64	2266	1.21	0	730	534
	48/64	3095	1.67	0	459	539.9
	64/64	3153	1.19	0	380	377.4

RESULT AND DISCUSSION

In comparison with the existing well completion, the new model did not change excessively, but provided a slightly better hydrocarbon recovery, compared to the base model (Figure 13). The completion selected is the 9⅝ inch 47 ppf L-80 production casing and 7⅝ inch 29.7 ppf L-80 liner, with oil and gas recovery of 50.16% and 92.3%, respectively. Meanwhile, the production method selected was commingled production, with some constraints for the upper layer. The upper layer reservoir was predicted to produce at full potential for only 2 years. The production casing was not changed because the layer is going to produce for 2 years, thus changing the casing is not economical. In addition, the tested liners were the 6⅝ inch, 7-inch, 7⅝ inch, and 7¾, with the specification based on the reservoir profile pressure, compared to the collapse pressure provided in API SPEC 5CT, and the selected liner was the 7⅝ inch 29.7 ppf L-80 liner.

The oil rate decreased from 2795.2 STB/day on the first day to 1594.6 STB/day after 5 years prediction, while the gas rate decreases from 13.854 MMSCF/day to 0.856 MMSCF/day (Figure 14). The high decreasing rate occurred because the well was producing at full capacity. In addition, the reservoir is assumed to be volumetric, due to inadequate driving mechanism data. Also, the aquifer reservoir is another constrain on the production result.

This project method is recommendable and possibly reliable for model completions. However, this model development method requires improvement to be fully applicable, because numerous assumptions were used in this study. Furthermore, the software's inability to consider all applied limitations and constraints led to the use of a less efficient method, and consequently, the obstruction of results with more potential. This project did discover any problems, however, considering the flow type's dynamic characteristics, certain problems, including slug flow and cross-flow, are bound to occur as the reservoir becomes depleted. Therefore, to minimalize the problems in the future, dual string completion ought to be used. However, this model is more expensive, compared to this study's model. Also, artificial lifts ought to be added in the future, to improve hydrocarbon recovery.

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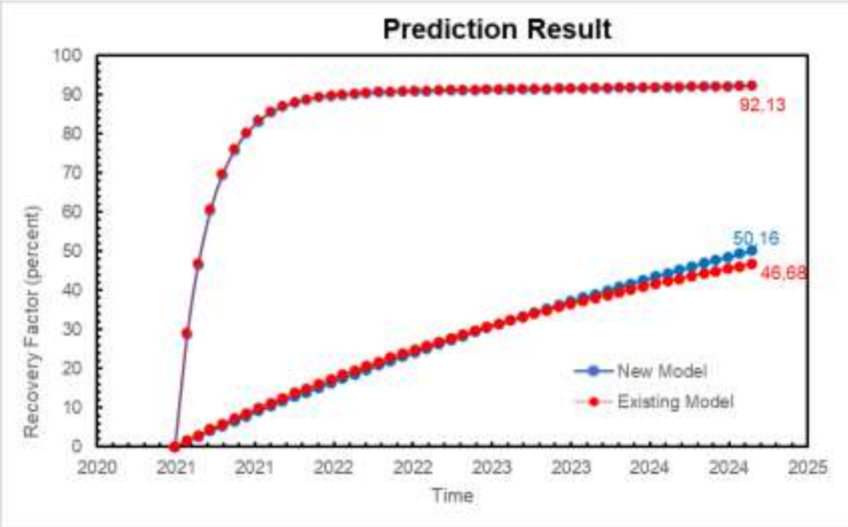

Figure 13. New model vs Existed model Recovery Factor Comparison

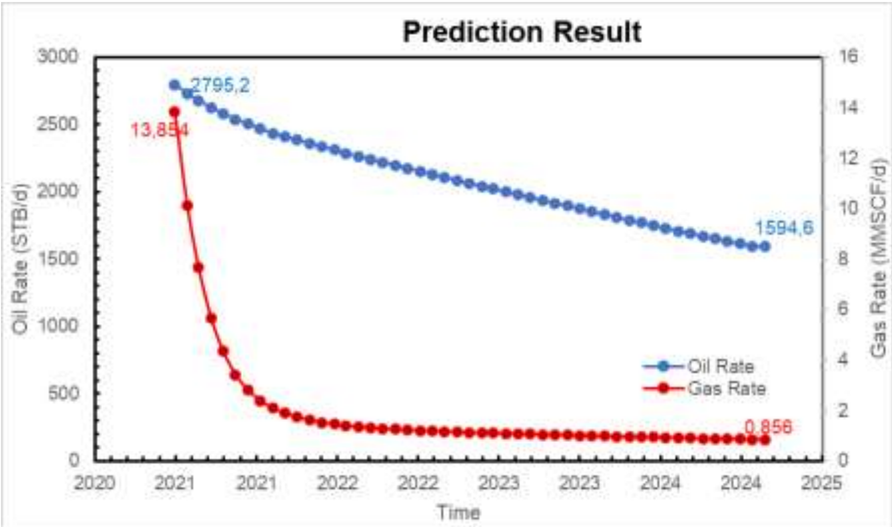

Figure 14. Oil and Gas Rate Comparison

CONCLUSION

The proposed design is completion with 9⅝ inch 47 ppf L-80 production casing, and 7⅝ inch 29.7 ppf L-80 liner. In addition, the existing well X completion produces good results, however, the new model's result is slightly better, due to the use of a bigger liner, with oil and gas recovery of 50.16% and 92.3%, respectively. This is probably because a smaller size leads to a higher flow rate, but quickly reduces the reservoir pressure, in cases where the rate is not controlled properly.

Nomenclature

DST	= Drill Stem Test
ppf	= pound per foot
qo	= Oil Rate (STB/d)
qo, max	= Maximum Oil Rate (STB/d)
P_{wf}	= Flowing bottom-hole pressure (psia)
P_r	= Reservoir pressure (psia)
P_b	= Bubble point pressure (psia)
C	= Flow coefficient (MMscfd/(psi^2)^n)
n	= Deliverability exponent (varies between 0.5-1.0)
MD	= Measured Depth (ft)
TVD	= True Vertical Depth (ft)
Bo	= Oil formation volume factor (RB/STB)
WC	= Water Cut (percent)

CGR = Condensate Gas Ratio (bbl/scf)
WGR = Water Gas Ratio (bbl/scf)
GOR = Gas Oil Ratio (scf/bbl)

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