JRSSEM 2025, Vol. 05, No. 05
E-ISSN: 2807 - 6311, P-ISSN: 2807 - 6494

JRSSEM
JOURNAL RESEARCH OF SOCIAL SCIENCE, ECONOMICS, AND MANAGEMENT

Initial Gas Reserve Estimation for Wells W-1, W-1A, and W-2 Based on Well Log Data in the Wailawi Field, East Kalimantan

Julieta Da Silva Dos Reis
Institut Teknologi Nasional Yogyakarta, Indonesia
Email: dasilvajulieta58@gmail.com

Abstract. The Wailawi Field, located in East Kalimantan, is a mature oil and gas field that still holds potential hydrocarbon reserves despite experiencing a decline in production. This study aims to evaluate the remaining hydrocarbon reserves in Wells W-1, W-1A, and W-2 based on well log data to assess the potential for field redevelopment. The methods used include qualitative and quantitative petrophysical analyses using gamma ray, resistivity, neutron, and density logs, which are then integrated with volumetric calculations to determine the Original Gas in Place (OGIP), Recoverable Reserves (R_{total}), and Remaining Reserves (RR). The petrophysical analysis results show that Well W-1 has an average porosity of 0.16 and a water saturation of 0.77; Well W-1A has a porosity of 0.16 and water saturation of 0.61; and Well W-2 has a porosity of 0.18 and water saturation of 0.64. High porosity and low water saturation values indicate good reservoir quality for hydrocarbon accumulation. Based on volumetric calculations, the OGIP values obtained are 92.06 BSCF for Well W-1, 15.55 BSCF for Well W-1A, and 58.55 BSCF for Well W-2. With a recovery factor of 85%, the total recoverable reserves (R_{total}) reach 78.25 BSCF, with cumulative production (N_p) of 23.21 BSCF, resulting in remaining gas reserves (RR) of 55.04 BSCF. These results indicate that the Wailawi Field still possesses economically viable hydrocarbon reserves that can be developed through workover operations, infill drilling, and optimization of productive zones.

Keywords: Well log, petrophysics, volumetric, remaining reserves, Wailawi Field.

INTRODUCTION

The increasing global energy demand encourages the importance of optimizing the hydrocarbon resources that have been discovered, especially in old fields that still hold potential residual reserves. The Wailawi Field, located in North Penajam Paser, East Kalimantan, is one of the oil and gas fields that has entered the production maturity phase, but still holds the potential for residual hydrocarbons that have not been fully utilized. In this context, a re-evaluation of the remaining reserves becomes crucial to determine the feasibility of redevelopment (redevelopment) through strategies such as infill drilling and identification zone bypassed pay (Raimi et al., 2022).

One of the most commonly used approaches to assess the residual potential of hydrocarbons is the data-driven volumetric calculation method Well Log. Data Well Log provides very important information regarding the characteristics of reservoir rocks below the surface, such as porosity, water saturation, shale volume, and productive zone thickness. Through the proper interpretation of the data, it can be calculated that the volume of the reservoir rock (bulk volume), pore volume, to the estimation of the initial and residual hydrocarbon content (remaining reserves) (Worden et al., 2018).

Several studies have been conducted in the Kutai Basin and surrounding areas, providing a geological and methodological foundation for this research. Cloke et al. (1999) analyzed the structural controls on the evolution of the Kutai Basin, highlighting the complex tectonic history that influences reservoir distribution and compartmentalization, which is relevant for understanding the Wailawi Field's structural framework. Bachtiar (2018) investigated the Tertiary paleogeography of the Kutai Basin, identifying unexplored hydrocarbon plays and depositional environments that help contextualize the reservoir units in the Wailawi Field, such as the Middle and Lower Block sequences.

While these previous studies establish robust methods for reserve estimation, there is a lack of detailed, field-specific studies integrating comprehensive petrophysical analysis with production data to re-evaluate the remaining gas potential in mature fields of the East Kalimantan region, particularly the Wailawi Field. Many evaluations rely heavily on seismic data or generalized basin models. This research aims to fill that gap by conducting a detailed, well-centric analysis using readily available well log and production data from three specific wells (W-1, W-1A, W-2) to provide a precise, data-driven update on the remaining gas reserves. The novelty lies in the specific application and integration of these established volumetric and petrophysical methods to the under-studied Wailawi Field, generating updated reserve figures that can directly inform localized redevelopment strategies.

In the Wailawi Field, well log data from several exploration and development wells is available and can be used to conduct petrophysical assessments and volumetric estimates. By utilizing geological modeling software such as Petrel or petrophysics software such as Interactive Petrophysics, the process of integrating and interpreting log data can be carried out quantitatively, resulting in more representative reserve estimates. This evaluation will be compared with actual production data to find out how much residual hydrocarbon potential is still possible to produce.

Through this study, it is hoped that a comprehensive picture can be obtained of the current condition of the reservoir, as well as opportunities to increase production from old fields with a data-based engineering approach and quantitative analysis. This research can also be an important reference for companies or policy makers in making technical and economic decisions related to the further development of the Wailawi Field.

The formulation of the problem in this study includes three main questions, namely: (a) What is the value of the petrophysical parameters in terms of quality and quantity used to identify productive zones based on well log data? (b) How much of the initial hydrocarbon reserves (Initial Hydrocarbons in Place) can be calculated using the volumetric method? (c) How much of the remaining hydrocarbons (Remaining Reserves) are still in the reservoir and can be produced based on the results of volumetric calculations and cumulative production data? This study aims to analyze the petrophysical parameters of reservoirs from well log data in wells in the Wailawi Field, calculate the amount of initial hydrocarbon reserves using volumetric methods based on well log data and PVP data, and determine residual hydrocarbons by comparing initial reserves to cumulative production to evaluate the potential for further development. The benefits of this research include providing a technical basis for re-evaluating the potential of old fields, providing initial information for redevelopment considerations, and encouraging efficiency in productive zone identification and infill drilling planning.

RESEARCH METHOD

This study employed a quantitative descriptive and applied research design. The research was descriptive as it systematically described the characteristics of the reservoir (porosity, water saturation, thickness) and quantified the gas reserves in the Wailawi Field based on existing well log and production data. It was applied in nature, as the primary goal was to solve a practical problem—accurately estimating remaining reserves to inform field redevelopment decisions. The approach was data-driven and analytical, relying on the interpretation of measured subsurface data rather than experimental manipulation.

This study used two main types of data, namely primary and secondary data, both of which served as the basis for interpreting well logs, petrophysical analysis, and volumetric calculations of remaining hydrocarbons in the Wailawi Field. The primary data consisted of well log data from Wells W-1, W-1A, and W-2 in the Wailawi Field, East Kalimantan, which included gamma ray logs, resistivity logs, density logs, and neutron logs. These data were used to identify productive zones and calculate petrophysical parameters such as porosity, water saturation, and shale volume. In addition, depth and layer thickness data from log interpretation were used to prepare isopach maps and calculate gas reserves (OGIP) and remaining reserves. All of these data were obtained from the acquisition and interpretation by the Wailawi Field operator. Meanwhile, the secondary data included historical production data, such as cumulative production (N_p) and production time (t), reservoir fluid data and PVP analysis reports, as well as geological maps, stratigraphic data, and regional geological information for the field. This secondary data were obtained from the internal archives of the field operator company, technical reports, and previous relevant, scientifically accountable studies. The use of secondary data was important because most information regarding reservoir conditions had been historically documented. The research flow diagram that described the author's workflow in solving this research problem can be seen in Figure 1.

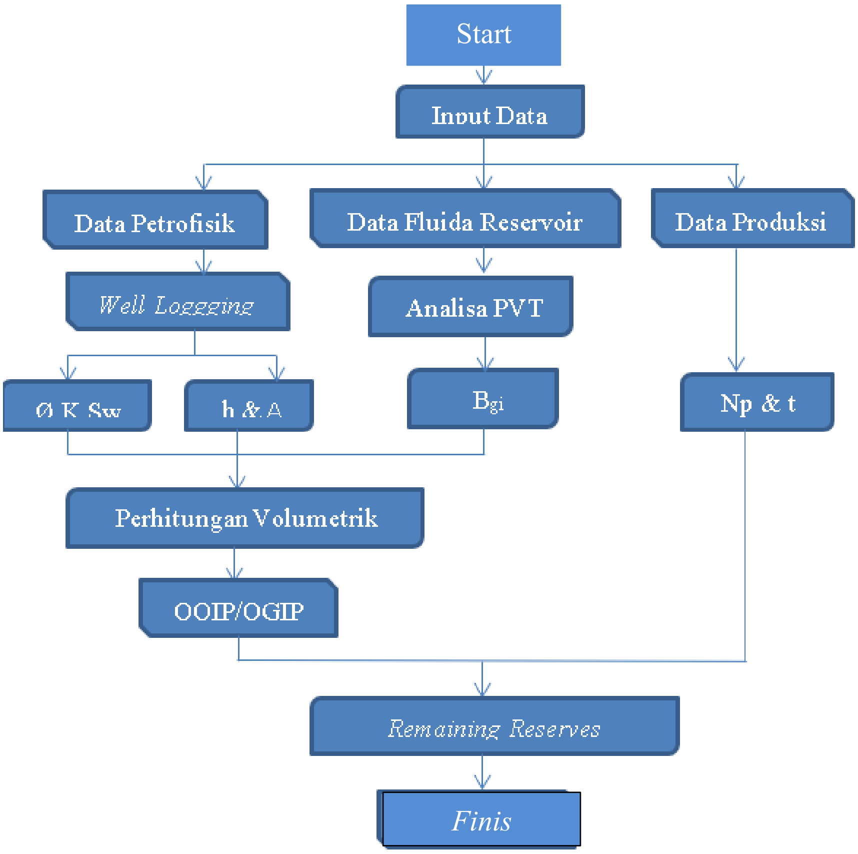

Figure 1. Research Flow Chart

Source: Research flowchart developed by the author based on well log data and volumetric analysis methodology (2025)

Tools and Materials

In this study, the tools and materials used consist of hardware, software, and technical data that are the basis of the analysis.

1. **Research Tools**

The tools used in this study include;

a. Computer/Laptop Devices Used for *well log data processing*, petrophysical analysis, and backup calculations.
b. *Supporting* software such as Microsoft Excel, Petrel, or ArcGIS (for volumetric calculations, contour mapping, and reservoir visualization).
c. Documentation Equipment Printers, scanners, and data storage (flash disks/HDDs) to support the archiving of research results.

2. **Research Materials (Materials Needed)**

The research materials used include;

Data *Well Log*

1. Well Production Data
2. Data PVT (*Pressure Volume Temperature*)
3. Structure and *Isopach Maps*
4. Previous Study Reports

RESULTS AND DISCUSSION

This research was carried out with the aim of determining the remaining hydrocarbon reserves in the wells in the Wailawi field based on *well log data*. Before determining the remaining reservoir reserves, the first stage that must be known is *Original Gas in Place* (OGIP) with the volumetric method. In this study, 3 well data were used, namely WA-1, WA-1A and WA-2 Wells.

Petrofisik Analysis

Petrophysics analysis is carried out using software (*Interactive Petrophysics*) to interpret log data qualitatively and quantitatively. Qualitative interpretation was performed by observing *log gamma ray* (GR) response, resistivity (ILD and LLD), neutrons and density to determine lithology, reservoir zone, and fluid type. Meanwhile, quantitative analysis is carried out automatically by the software through the application of standard petrophysical equations to obtain the parameters *of shale volume* (Vsh), porosity (Φ), water saturation (Sw), and permeability (k) obtained from several potential zones indicated as hydrocarbon carrier layers found in wells WA-1, WA-1A and WA-2 in the Wailawi Field in appendices 1 to 15.

A. Log Data Preparation and Quality Control

The process of making or analyzing petrophysics starting from the availability of data, data accuracy, data acquisition, data collection, data collection to quality control of data taken from primary and secondary sources greatly affects the method of analysis and final results. The following is table 1 regarding the accuracy of classified data.

Table 1. Data Availability and Data Classification

Well Name	GR	RHOB	DRHO	NPHI	DT	CALI	SP	Deep Res	Medium Res		shallow Res		PROX	PEF	Bs	Checkshot
								ILD	ILM	MSFL	SN	SFLU				
Sumur-1	ada	ada	ada	ada	ada	ada	ada	ada			ada		ada			
Sumur-1A	ada	ada	ada	ada	ada	ada	ada	ada		ada		ada		ada	ada	
Sumur-2	ada	ada	ada	ada	ada	ada	ada	ada		ada		ada		ada		ada

Source: Primary and secondary data from Wailawi Field operator (processed by author, 2025)

B. Volume of Shale (Vsh)

Determination Volume of Shale (Sigh) It is carried out to determine the content of clay or shale material in reservoir rocks that can affect the porosity and permeability of formations. The value of Vsh is obtained from the results of the reading log gamma ray (GR) by comparing the values gamma ray to the reference value of the net rock (GRclean) and pure shale rock (GRshale). The Vsh Calculation Method uses calculations linear equation with software thus making it easier and faster to obtain results volume of Shale By Log Gamma Ray (Purba et al., 2012). In general, the calculation uses linear equations:

$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

Where:

IGR/Vsh : shale gamma ray Index
GR : gamma ray log responds (v/v)
GRcn : Clean GR log (GRMin) (v/v)
GRsh : shale GR log (GR Max) (v/v)

To obtain more accurate results, corrections are made to the type and age of the rocks using empirical equations such as Larionov or Steiber. The results of this Vsh interpretation are used to distinguish clean sand and clayy zones, as well as to be the basis for determining cut-off and evaluating reservoir quality at the next stage of petrophysical analysis.

C. Porosity (Ø) and Water Saturation (Sw)

The calculation of porosity and water saturation in pemeable rocks has a mathematically / numerical relationship so that the formula equation can calculate the porosity and saturation of water, in the application of the calculation of the parameters is calculated using *software* to facilitate and speed up the calculation process which is often long. In general, the calculation of porosity and water saturation uses linear equations in Figures 4.1 and 4.2:

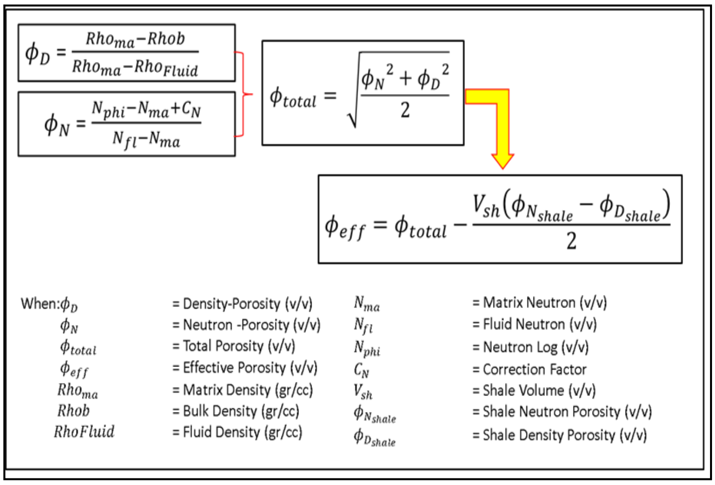

Figure 2. Porosity equation (Island) using software

Source: Porosity equation applied in Interactive Petrophysics software (Purba et al., 2012)

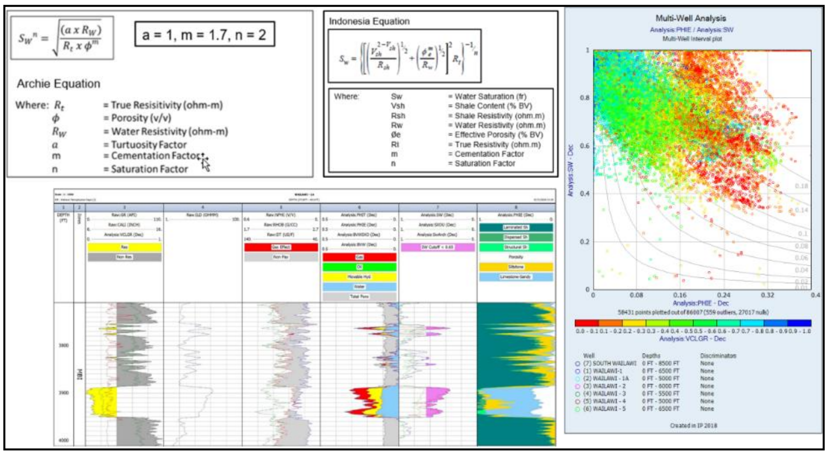

Figure 3. Calculation of Water Saturation (Sw) using software

Source: Water saturation equation based on Archie model implemented in software (Kumar, 2010).

Permeability by Rock Type

The determination of permeability (k) is carried out to determine the ability of reservoir rocks to flow fluids, which is an important parameter in the evaluation of the productivity of a layer. The permeability value can be estimated indirectly from the results of the analysis of the porosity (Φ) and water saturation (Sw) logs using empirical equations such as the Eastern equation (1968), namely:

$$k = a\frac{\phi^b}{S_{wi}c}$$

where, K = Permeability, (md)

Island = porosity (%)

Sw = Water saturation (%)

where A, B, and C are empirical constants determined based on rock type and reservoir conditions. Generally, the value of the constant is taken as *a = 1000*, *b = 4*, and *c = 2* for sandstone. This process is carried out after determining basic petrophysical parameters such as effective porosity and water saturation. The results of the permeability calculation are used to identify zones with good fluid flow ability and support the determination of productive zones in reservoirs.

D. Petrophysical Analysis Results of Wells W-1, W-1A and W-2

In Attachments 1 to 5 of the log chart of the results of the petrophysical analysis of the Wailawi-1 well, there are 11 Potential Zones indicated as hydrocarbon-carrying layers. Table 4.2 shows the variation in reservoir rock characteristics in each zone in the Wailawi-1 well. From the results of the interpretation of gamma ray logs, density, neutrons, and resistivity, the main petrophysical parameters in the form of porosity (Φ), water saturation (Sw), shale volume (Vsh), and permeability (k) were obtained for each interval that has exceeded *the standard cut-off* limit . The software automatically integrates log data with a specific limit value to separate the clean *sand* zone from the non-reservoir zone.

Table 2. Tabulation of Petrophysical Analysis Results of the Wailawi-1 Well

					CUT-OFF PHI & VSH							
Well	**Zone**	**MD (FT)**		**GROSS**	**NET SAND**	**NET/**	**PHI-AVG**	**SW-AVG**	**VSH-AVG**	**k-AVG**	**PHI*H**	**SW*H**
		TOP	**BOTTOM**	**(FT)**	**(FT)**	**GROSS**	**(fr)**	**(fr)**	**(fr)**	**(mD)**	**(fr)**	**(fr)**
W-1	MBD	2331,02	2368,96	37,94	31,23	0,8231418	0,16	0,81	0,33	18,05	4,9968	25,2963
	MBE	2523,95	2583,18	59,23	30	0,5065001	0,17	0,78	0,29	24,43	5,1	23,4
	MBE3	2741,67	2831,91	90,24	90,24	1	0,18	0,76	0,16	30,38	16,2432	68,5824
	MBF	2987,89	3011,97	24,08	20,86	0,8662791	0,18	0,74	0,13	34,77	3,7548	15,4364
	MBG1	3205,39	3218,44	13,05	0	0	-	-	-	-	-	-
	MBG2	3256,38	3279,44	23,06	0	0	-	-	-	-	-	-
	MBG3	3318,43	3371,7	53,27	40,77	0,7653463	0,13	0,92	0,29	5,91	5,3001	37,5084
	MBH	3421,81	3458,44	36,63	0	0	-	-	-	-	-	-
	MBI1	3638,27	3696,27	58	21,48	0,3703448	0,16	0,8	0,23	18,02	3,4368	17,184
	MBI2	3709,31	3731,08	21,77	0	0	-	-	-	-	-	-
	MBI3	3751,86	3788,47	36,61	22,89	0,625239	0,19	0,71	0,11	40,44	4,3491	16,2519
	MBI4	3871,14	3933,93	62,79	35,61	0,5671285	0,16	0,6	0,11	12,44	5,6976	21,366
	LBA	4005,92	4036,27	30,35	0	0	-	-	-	-	-	-
	LBB	4117,64	4157,4	39,76	11,5	0,2892354	0,1	0,74	0,41	0,4	1,15	8,51
	LBC	4180,45	4209,3	28,85	23,8	0,8249567	0,13	0,8	0,21	5,57	3,094	19,04
	LBD	4223,73	4297,49	73,76	32,52	0,4408894	0,16	0,79	0,18	27,63	5,2032	25,6908
		AVG			360,9						58,3256	278,2662
						AVG Rata"					0,161612	0,771034

Source: Petrophysical analysis results from W-1 well log data using Interactive Petrophysics software (processed by author, 2025)

Based on the calculation results shown in Table 2, it is known that the total thickness of the formation layer (*net thickness*) analyzed reaches 360.9 ft with an average *net/gross* value of 0.44 indicating that around 44% of the total formation is a layer of clean sand that has the potential to store fluids. The average porosity value (PHI-AVG) was obtained at 0.1616 (16.16%), which indicates that the rock has a medium to good fluid storage capacity. Meanwhile, the average water saturation value (SW-AVG) reached 0.7710 (77.10%), which means that most of the rock pores are still filled with formation water, but there is still hydrocarbon potential in layers with a Sw value below 70%. The mean permeability value (k-AVG) shows considerable variation, which is between 0.4 to 40.44 mD reflecting the heterogeneity of the rock in the ability to flow fluids. Based on a combination of porosity, water saturation, and permeability values, the most prospective zones as hydrocarbon reservoirs are MB E3, MB F, and MB I3. Overall, the results of the interpretation show that the W-1 well has good reservoir potential with rock characteristics dominated by moderately porous sandstone, good permeability, and worthy of consideration as the main hydrocarbon-producing zone in the formation.

❖ Petrophysical Analysis Results of the Wailawi-1A Well

In Attachments 6 to 10 of the log chart of the results of the petrophysical analysis of the Wailawi-1A well, there are 12 Potential Zones indicated as hydrocarbon carrier layers. Table 4.3 shows the variation in reservoir rock characteristics in each zone in the Wailawi-1 well. From the results of the interpretation of gamma ray logs, density, neutrons, and resistivity, the main petrophysical parameters in the form of porosity (Φ), water saturation (Sw), shale volume (Vsh), and permeability (k) were obtained for each interval that has exceeded the standard cut-off limit. The software automatically integrates log data with a specific limit value to separate the clean sand zone from the non-reservoir zone.

Table 3. Tabulation of Petrophysical Analysis Results of Wailawi-1A Well

Well	Zone	MD (FT)		GROSS	CUT-OFF PHI & VSH							
		TOP	BOTTOM	(FT)	NET SAND (FT)	NET/ GROSS	PHI-AVG (fr)	SW-AVG (fr)	VSH-AVG (fr)	k-AVG (mD)	PHI*H (fr)	SW*H (fr)
W-1A	MB D	2320,16	2354,19	34,03	11,59	0,34058184	0,13	0,83	0,42	0,57	1,5067	9,6197
	MB E	2519,59	2576,84	57,25	13,66	0,23860262	0,15	0,76	0,33	2,07	2,049	10,3816
	MB E3	2808,96	2859,61	50,65	27	0,533070089	0,16	0,65	0,26	3,42	4,32	17,55
	MB F	3027,97	3053,29	25,32	8,5	0,335703002	0,12	0,68	0,36	0,34	1,02	5,78
	MB G1	3212,88	3228,62	15,74	0	0	-	-	-	-		
	MB G2	3261,7	3288,82	27,12	10,05	0,370575221	0,17	0,65	0,24	5,36	1,7085	6,5325
	MB G3	3335,81	3383,85	48,04	9,5	0,197751873	0,14	0,63	0,37	2,96	1,33	5,985

Well	Zone	MD (FT)		GROSS	CUT-OFF PHI & VSH							
		TOP	BOTTOM	(FT)	NET SAND (FT)	NET/ GROSS	PHI-AVG (fr)	SW-AVG (fr)	VSH-AVG (fr)	k-AVG (mD)	PHI*H (fr)	SW*H (fr)
	MB H	3431,89	3469,47	37,58	0	0	-	-	-	-		
	MB I1	3647,23	3710,14	62,91	20,5	0,325862343	0,21	0,46	0,31	25,96	4,305	9,43
	MB I2	3724,95	3745,92	20,97	0	0	-	-	-	-		
	MB I3	3753,82	3790,47	36,65	13	0,354706685	0,13	0,55	0,32	0,95	1,69	7,15
	MB I4	3887,2	3951,86	64,66	63	0,97432725	0,18	0,59	0,11	4,61	11,34	37,17
	LB A	4014,49	4039,82	25,33	0	0	-	-	-	-		
	LB B	4101,86	4156,77	54,91	7	0,127481333	0,11	0,67	0,36	0,27	0,77	4,69
	LB C	4182,1	4202,2	20,1	15,15	0,753731343	0,15	0,57	0,26	2,1	2,2725	8,6355
	LB D	4206,56	4270,89	64,33	34,69	0,539250738	0,15	0,61	0,24	2,67	5,2035	21,1609
		AVG			**233,64**						**37,515**	**144,085**
						AVG Rata"					**0,1606**	**0,6167**

Source: Petrophysical analysis results from W-1A well log data using Interactive Petrophysics software (processed by author, 2025)

Based on the calculations in Table 3, it is known that the total formation thickness analyzed in the W-1A well reached 233.64 ft, with an average net/gross *value* of 0.39 which indicates that about 39% of the total layer is net sand which has the potential to be a hydrocarbon reservoir. The average porosity value (PHI-AVG) obtained was 0.1606 (16.06%), indicating the ability of the rock to store moderate to good fluids, while the average water saturation (SW-AVG) of 0.6167 (61.67%) indicated that some pore volume has been filled with hydrocarbons, especially in layers with a Sw value below 60%. The mean permeability value (k-AVG) showed considerable variation, which was between 0.27 to 25.96 mD which indicates the difference in fluid flow quality between zones. Based on a combination of porosity, water saturation, and permeability values, the most prospective zones as hydrocarbon reservoirs are MB I4, MB E3, and LB D, Overall, the results of the interpretation show that the formation in the W-1A well has a fairly good reservoir quality with dominant rock characteristics in the form of moderately porous sandstone and medium permeability, and has significant potential to become a major hydrocarbon-producing zone in the research area.

❖ Petrophysical Analysis Results of the Wailawi-2 Well

In Attachments 11 to 15 of the Chart log of the results of the petrophysical analysis of the Wailawi-2 well, there are 14 Potential Zones that are indicated as hydrocarbon carrier layers. Table 4 shows the variation in reservoir rock characteristics in each zone in the Wailawi-1 well. From the results of the interpretation of gamma ray logs, density, neutrons, and resistivity, the main petrophysical parameters in the form of porosity (Φ), water saturation (Sw), shale volume (Vsh), and permeability (k) were obtained for each interval that has exceeded the standard cut-off limit. The software automatically integrates log data with a specific limit value to separate the clean sand zone from the non-reservoir zone.

Table 4. Tabulation of Petrophysical Analysis Results of the Wailawi-2 Well

					CUT-OFF PHI & VSH							
Well	Zone	MD (FT)		GROSS	NET SAND	NET/ GROSS	PHI-AVG	SW-AVG	VSH-AVG	k-AVG	PHI *H	SW *H
		TOP	BOTTOM	(FT)	(FT)		(fr)	(fr)	(fr)	(mD)	(fr)	(fr)
W-2	MBD	3081,4	3120,82	39,42	5	0,1268392	0,15	0,73	0,45	0,25	0,75	3,65
	MBE	3232,62	3275,74	43,12	33,5	0,7769017	0,21	0,9	0,15	2,58	7,035	30,15
	MBE3	3317,59	3345,51	27,92	9,5	0,3402579	0,15	0,71	0,32	0,27	1,425	6,745
	MBF	3740,67	3779,96	39,29	10	0,2545177	0,14	0,97	0,27	0,31	1,4	9,7
	MBG1	3884,26	3940,07	55,81	45,5	0,8152661	0,21	0,67	0,21	3,41	9,555	30,485
	MBG2	3949,23	4020,73	71,5	67,52	0,9443357	0,21	0,68	0,18	2,47	14,179	45,914
	MBG3	4065,62	4098,59	32,97	0	0	-	-	-	-		
	MBH	4148,01	4198,77	50,76	1	0,0197006	0,08	0,95	0,48	0,01	0,08	0,95
	MBI1	4301,67	4339,71	38,04	15,46	0,4064143	0,12	0,78	0,34	0,19	1,8552	12,059
	MBI2	4371,42	4394,28	22,86	12	0,5249344	0,12	0,82	0,32	0,09	1,44	9,84
	MBI3	4479,5	4540,23	60,73	28,75	0,4734069	0,19	0,68	0,27	1,08	5,4625	19,555
	MBI4	4569,05	4618,72	49,67	34	0,6845178	0,14	0,65	0,34	0,47	4,76	22,1
	LBA	4702,09	4750,06	47,97	16,81	0,3504274	-	-	-	-		
	LBB	4810,04	4863,57	53,53	53,53	1	0,28	0,4	0,15	14,98	14,988	21,412
	LBC	4910,58	4965,27	54,69	50,17	0,9173523	0,18	0,63	0,2	1,03	9,0306	31,607
	LBD	5084,49	5241,77	157,28	116,78	0,7424975	0,16	0,65	0,22	0,95	18,685	75,907
	AVG				499,52						90,646	320,07
						AVG Rata"					0,1815	0,6408

Source: Petrophysical analysis results from W-2 well log data using Interactive Petrophysics software (processed by author, 2025)

Based on the calculations in Table 4, it is known that the total formation thickness analyzed in the W-2 well reached 499.52 ft, with an average net/gross value of 0.50, which indicates that about 50% of the total layer is net sand which has the potential to be a hydrocarbon reservoir. The average porosity value (PHI-AVG) obtained was 0.1815 (18.15%) indicating that the rock's ability to store fluids was relatively good, while the average water saturation (SW-AVG) of 0.6407 (64.07%) indicated that some pore volume had been filled with hydrocarbons, especially in layers with a Sw value below 60%.

The mean permeability value (k-AVG) shows variations between zones, ranging from 0.09 to 14.98 mD, which indicates a heterogeneity in the ability of fluid flow in each reservoir layer. Some zones have prominent characteristics, such as MB G1, MB G2, LB C, and LB D, which exhibit high net/gross values accompanied by relatively large porosity and permeability, as well as low shale volume (Vsh). This suggests that these layers have great potential as major hydrocarbon-producing zones.

Overall, the results of the interpretation show that the formation in the W-2 well has good reservoir quality, with dominant rock characteristics in the form of medium to good porous sandstone and medium permeability, and has significant potential to become a prospective zone for hydrocarbon production in the research area, especially at the Lower Block interval (LB C and LB D) which shows the highest effective porosity and thickness values compared to other zones.

Determination of Area Area (A)

The determination of the area (A) in each well is carried out to find out the size of the drainage area represented by each well. The area of this area is expressed in square meters (m^2) and later converted in acres which is an important parameter in the calculation of rock volume (Vb) and hydrocarbon volume in place (OGIP).

The area of this area is determined using the distribution map of the location of the Wailawi well in Annexes 16 and 17, there are three main well points, namely Wailawi-1, Wailawi-1A, and Wailawi-2 which are located in the area around Lawe-Lawe Village, Penajam District. These three wells are in geographical coordinates between 116°4'0" – 116°4'45" E and 1°9'0" – 1°12'0" S. Each well has a drainage radius of 750 meters, which is indicated by the shaded circle on the map. The Wailawi-1 and Wailawi-1A wells are located very close together, with a distance of less than 400 meters between them, so the drainage area overlaps each other. Meanwhile, the distance between the Wailawi-1/1A and Wailawi-2 clusters is about 1 kilometer to the northwest, with a small portion of the drainage area also intersecting.

The three wells combined together form an exploration area with a total area of about 390 hectares, as shown by the shaded area on the map. Spatially, the overlap of the drainage area indicates a continuous geological relationship and reservoir potential between the three wells. Thus, this map not only depicts the distribution of well locations, but also shows the effective boundaries of production zones that are relevant for resource potential evaluation and integrated field management planning.

a) Data and Method of Calculation of Area (A), Wells W-1, W-1A and W-2 in the Wailawi Field

The parameters in table 4.5 below are used to determine the area area (A) and the effective area allocation per well (W-1, W-1A, W-2). All calculations use drainage radius r = 750 m and the distance between wells as listed below. *The overlap* between the two circles is calculated using the two-circle slice formula and the *overlap distribution* is carried out 50:50 to each of the intersecting wells.

Table 5. Data/Parameters used for area (A)

Parameter	Value
Radius drainage (r) [m]	750.00
Surface area of one circle A_single [m²]	1,767,145.87
Jarak W-1 — W-1A (d1) [m]	385,7122694
W-1 Distance — W-2 (d2) [m]	1209,624435
W-1A Distance — W-2 (d3)[m]	1436,318135

Source: Spatial and well geometry data from Wailawi Field distribution maps (Appendix 16 & 17)

In volumetric analysis, the area used for the calculation of reserves or Original Gas in Place (OGIP) must reflect the effective area that is actually the drainage area of each well. The determination of the area is effectively carried out by considering the possibility of overlap between adjacent well drainage areas.

In this study, each well was assumed to have a circular drainage area with a radius (750 m) (radius of drainage, r). However, because the distance between the wells is relatively close, some of the drainage areas between wells have the potential to overlap. This condition generally occurs in fields with tight well placement patterns or when the boundaries of productive zones have not been fully defined. Because the distance between the centers of the two wells (d) is less than twice the radius of their drainage ($d < 2r$), there is a slice of drainage area between the two wells. The area of the slice is calculated using the geometric formula of a two-circle slice, namely:

❖ Two-circle slice area ($d < 2r$): $A\_overlap = 2\ r^2 \cos^{-1}(d/(2r)) - (d/2)\ \sqrt{(4\ r^2 - d^2)}$

This formula is a derivative of the circular drainage area approach, which is commonly used to estimate the effective area between wells in volumetric calculations.

Furthermore, the combined area of all *drainage* areas is calculated by applying the Inclusion–Exclusion Principle which is used to avoid double calculations on intersecting areas. The equation is as follows:

- The combined total area of the three wells is calculated using the Inclusion–Exclusion principle, namely:

❖ $A\_total = \Sigma\ A\_i - \Sigma\ A\_overlap$

Where Ai is the individual area of each well and A_*overlap* is the area of the slices between wells. This principle is widely used in plane geometry and is also adapted in volumetric analysis for the determination of the combined area of reservoirs.

In order to keep the OGIP calculation per well representative, the area of the slices between wells is divided proportionally equally (50:50) between two adjacent wells. This approach is known as the Equal Drainage Sharing Method, which is an empirical method commonly used in simple volumetric calculations, especially when reservoir simulations or pressure interference tests have not been performed. According to Dake (1994) and Craft & Hawkins (1991), this equitable distribution of area is considered to be representative enough to describe the contribution of each well to a reservoir that has relatively uniform distances between wells. Thus, the effective area of each well (A_{ef}) can be formulated as:

$$A_ef = Ai - 1/2\ \Sigma A_o v_e r l_a p,i$$

where $\sum A$, is the sum of the area of the slice involving the i-well. This value (Aef) is used as the effective area in the calculation of OGIP on each well.

b) Results and Interpretation of Area Area (A)

From the results of the calculation of the geometry of the drainage area of each well, the value of the area area was obtained as shown in Table 4.6. Each well is assumed to have a circular drainage area with a radius (750), and at the distance between adjacent wells there is an overlap area. After correction of the slice area with a 50:50 split between adjacent wells, an effective area (A_ef) was obtained for each well. The results of the calculation of the area area provide an accurate basis for determining the *bulk rock volume* at the next stage.

Table 6. Results and Interpretation of Area Area (A)

Determination of Area Area (A)					
Well	**Radius (r) (m)**	**Distance (d) (m)**	**Slice Area A_overlap m2**	**Luas Area Ef. (m2)**	**Luas Area (acre)**
A_1 (W1–W1A)	750	385,71227	1195018,239	1081967,262	267,3596966
A_2 (W1–W2)	750	1209,6244	175338,9726	1160417,874	286,7452479
A_3 (W1A–W2)	750	1436,3181	18437,74813	1670257,507	412,7292536
A_total			3912642,643		

Source: Drainage area geometry calculation using two-circle slice method (E. W. Weisstein, 2003; Apostol, 1975)

Based on the results of the calculation of the area area, it was obtained that the W-1 Well has an effective area of 267.36 acres, the W-1A Well covers an area of 286.75 acres and the W-2 Well covers an area of 412.73 acres. This value shows that the draining areas of the W-1 and W-1A Wells are quite large because the distance between them is relatively close, while the W-2 Wells are more separate with a small *degree of overlap*. The total combined area of the three wells is about 3.91 km², which is then used as the basis for calculating the Volume of Rocks (Vb) at the next stage.

3. *Volume Bulk* (Vb)

Determination of Bulk Volume (Vb) is the initial stage in volumetric calculation to determine the total volume of reservoir rocks in the productive zone. The Vb value describes the overall volume of the rock (including pores and matrix) within the area and reservoir thickness boundaries identified from geological and petrophysical data.

In this study, the calculation of Volume Bulk (Vb) was carried out based on thickness data (Net Pay/Net Sand) obtained from the results of well log interpretation in three research wells. In addition, area area data (A) derived from the interpretation of the distribution map of the well location in the Wailawi Field was also used, then calculated as the effective area after taking into account the overlapping areas between wells. The calculation of Bulk Volume (Vb) follows the equation:

❖ $Vb = A \times h$

With:

Vb = Volume bulk batuan (acre-ft)
A = Effective area (acre)

h = Effective thickness or Net Pay (ft)

The value of Vb in Table 4.7 is then used as the basis for the calculation of Original Gas in Place (OGIP) in the next stage.

Table 7. Results of Determination of Rock Volume (Vb)

Penentuan Volume Bulk (Vb)				
Well	**Net pay/ Net Sand (ft)**	**Luas Area (A) acre**	**Vb (acre-ft)**	**Vb (ft3)**
W-1	360,9	267,3596966	96490,11451	4203109388
W-1A	233,64	286,7452479	66995,15973	2918309158
W-2	499,52	412,7292536	206166,5168	8980613470

Source: Volumetric calculation based on net pay and effective area data (Craft & Hawkins, 1991)

Based on the calculations in Table 7, it is obtained that the W-2 well has the largest volume of rock bulk, which is about 206,166 acre-ft or equivalent to 8.98 × 10^9 ft^3, due to a greater effective layer thickness and a wider distribution area than the other two wells. Meanwhile, Wells W-1 and W-1A show smaller bulk volumes of 96,490 acre-ft and 66,995 acre-ft respectively which are further used in the Original Gas In Place (OGIP) calculation with each well respectively at the next stage.

At this stage, an evaluation is carried out to determine the amount of remaining hydrocarbon reserves (Remaining Hydrocarbon Reserves) that are still stored in the W-1, W-1A and W-2 Wells. The determination of the remaining reserves is carried out using a volumetric approach, which begins with the calculation of Original Gas in Place (OGIP) as an estimate of the total amount of gas stored in the pores of the reservoir rock before production.

Once the OGIP value is obtained, the next stage is to calculate the cumulative production (Np) that has been removed from the reservoir during the production period. The Np value is obtained through the analysis of the decrease in production rate based on the relationship between the production rate at a given time (q), and the production time interval.

Basically, recoverable reserves are part of the in-place reserves that can be released through wells. The simple relationships used to determine the remaining reserves are as follows:

RR = (OGIP × RF) - Np

Where:

RR = Remaining reserves

OGIP = Original Gas In Place

RF = Recovery Factor (the fraction of the gas that can be produced)

NP = Cumulative current production

Original Gas in Place (OGIP)

Determining the amount of Original Gas in Place (OGIP) is an important stage in evaluating the potential gas reserves of a field. OGIP estimation is carried out to determine the total amount of gas stored naturally in the pores of reservoir rocks before production. The OGIP calculation in this study is based on the results of petrophysical data analysis from several wells, interpretation of structure maps, and reservoir geometry data which includes area area and net thickness (*net pay*) of each productive layer.

The OGIP calculation was performed using the gas volumetric method, assuming the reservoir behaved as an ideal gas and gas saturation was evenly distributed throughout the productive zone. The formula used is:

$$\text{OGIP} = \frac{43560\ Vb\phi\left(1 - Sw\right)}{Bgi}$$

With:

OGIP = Original Gas in Place (SCF)

Vb = Volume Batuan (acre-ft)

Φ = Effective porosity (fraction)

Sw = Saturasi air (fraction)

Bg = Gas formation volume factor (RCF/SCF)

43560 = conversion from acre-ft to cubic feet

The data used in the OGIP calculation in Table 4.8 was obtained from the results of petrophysical analysis and maps of subsurface structures in the Wailawi Field. The data includes Thickness (Net Pay, h) results from the interpretation of gamma ray logs, neutron-density, and resistivity logs in each well, Effective porosity (Φ) obtained from the correlation of porosity logs with Neutron-Density crossplot data, Water saturation (Sw) results of resistivity log analysis with the Archie equation approach, Reservoir area (A**) is** determined from the distribution map of the location of the Wailawi well using the polygon method or drainage radius of each well (750 m), The gas formation volume factor (Bg) is calculated based on the pressure and temperature conditions of the reservoir.

Table 8. OGIP Calculation Results

OGIP Determination (MSCF)					
Well	**(SW) (fr)**	**(Ø)fr**	**Bg**	**Vb (acre-ft)**	**OGIP (MSCF)**
W-1	0,771034081	0,161611527	0,01	96490,11451	15552989133
W-1A	0,616697483	0,160568396	0,01	66995,15973	17961104401
W-2	0,640752122	0,181465607	0,01	206166,5168	58545637822
Total					92059731357

Source: OGIP calculation using gas volumetric method based on petrophysical and reservoir parameters (Dake, 1994)

Based on the calculations in the table above, it was obtained that the W-2 well had the highest OGIP value of 58,545,637,822 MSCF, due to the combination of effective layer thickness (*net pay*) and greater porosity than the other two wells. The W-1A well has an OGIP of 17,961,104,401 MSCF, slightly higher than the W-1 well which is valued at 15,552,989,133 MSCF.

Overall, the total OGIP from the three wells reached around 92,059,731,357 MSCF, or equivalent to ±92.06 BSCF. This value describes the potential total gas stored in the reservoir before production, and forms the basis for further analysis of the recovery factor and the estimation of remaining reserves at the next stage.

4. Determination of Cumulative Production (Np)

Cumulative production (Np) is the total volume of gas or condensate that has been produced by a well from the beginning of production to a certain observation time. This parameter is used to find out how much reserves have been taken from the reservoir and is the basis for calculating remaining reserves. In this study, the determination of the Np value was carried out by summing up all the actual production data from each well during the production period. The data used were obtained from historical records of field production presented in the form of production rate (q) per unit time, in units of Mscf/day for gas. In general, cumulative production is calculated using the following equation:

$$Np = \Sigma(qi \times Dt)$$

where:

Np = Cumulative production (bbl or Mscf)

qi = Production rate in the first period (Mscf/day)

Dt = Production time interval (days, months/years)

Cumulative production data (Np) for each well was obtained based on the results of the historical production recapitulation of the field presented in Appendix 18. The attachment contains a record of the gas production rate (q) per year from the beginning of the production period to the last observation period. Based on this data, the total volume of gas that has been produced from each well is then summed to determine the cumulative production value (Np), as shown in the following Table 9.

Table 9. Cumulative Production Yield (Np)

Well	Np	Information
W-1	1.386	MSCF/Year
W-1A	9.468	
W-2	12.356	
TOTAL	**23.210**	**MSCF/Year**

Source: Historical production data from Wailawi Field operator (Appendix 18)

The calculations from table 9 show that the total cumulative production of the three wells, namely W-1, W-1A, and W-2 reached 23,210 MSCF/year, with the largest contribution coming from the W-2 well of 12,356 MSCF per year, followed by W-1A of 9,468 MSCF per year, and the smallest of W-1 of 1,386 MSCF per year.

Historically, the three wells have experienced long production periods with shut-in periods before returning to production in recent years.

- The W-1 well began production from December 1983 to October 2011, then experienced a production stop, and resumed production from December 2021 to December 2022.
- The W-1A well and the W-2 well had almost the same production period, namely December 1983 to September 2020, before returning to activity from December 2021 to December 2022.

This condition shows that even though these wells have been producing for a long time, there is still potential for gas that can be produced again after *re-activation*. The relatively large cumulative production value (Np), particularly in the W-2 and W-1A wells, indicates that the two wells have more stable production performance and make a significant contribution to the total field production.

Thus, the results of this Np calculation are an important basis for the next stage, namely the estimation of *recoverable reserves* and remaining *reserves* from each well, which will describe the potential for further production in the future.

5. **Recoverable Reserves (Total R) and Remaining Reserves (RR)**

The determination of the amount of recoverable reserves and remaining reserves is carried out to find out how much volume of gas can still be produced from each well after taking into account the total cumulative production that has occurred.

In general, Recoverable Reserves (Rt_ot_al) are part of the Original Gas In Place (OGIP) reserves that can be produced by considering the efficiency of the recovery (Recovery Factor / RF) applicable in the field. The magnitude of the restored backup can be calculated using the following equation:

❖ Rtotal = OGIP × RF

Information:

- Rt_ot_al = Restored backup (MSCF)
- OGIP = Original Gas In Place (MSCF)
- RF = Recovery Factor (%)

The RF (Recovery Factor) value describes how much of the gas in the reservoir can be produced economically and technically. RF determination can be based on historical field data that has similar characteristics, reservoir simulation results, or literature reference (Irwin, 2015).

Furthermore, to find out the remaining reserves (Rr_em), the relationship between total recovered reserves and cumulative production (Np) is used as follows:

❖ RR = Rtotal − Np

Information:

- R_{rem} = Remaining Reserves (MSCF)
- R_{total} = Recoverable Reserves (MSCF)
- Np = Cumulative production that has been generated (MSCF)

Based on the cumulative production calculations in table 4.9 above, it is known that the three wells—W-1, W-1A, and W-2—have produced a cumulative total production of 23,210 MSCF per month, with the largest contribution coming from the W-2 well. With the OGIP value and Recovery Factor that have been determined beforehand, the value of Recoverable Reserves (Rt_ot_al) is obtained for each well. Furthermore, this value is subtracted by cumulative production (Np) to obtain Remaining Reserves (Rr_em), which is the amount of gas that is still left and can be produced from the reservoir.

Table 10. Calculation Results Recoverable Reserves (R_{total}) and Remaining Reserves (Rr_em)

Recoverable Reserves (Rtotal) and Remaining Reserves (R_{rem})					
Well	**OGIP**	**RF**	**Rtotal**	**For example**	**RR**
	(MSCF)	**%**	**(MSCF)**	**(MSCF)**	**(MSCF)**
W-1	15552989133	85%	13220040763	1.386.000.000	11.834.040.763
W-1A	17961104401	85%	15266938741	9.468.000.000	5.798.938.741
W-2	58545637822	85%	49763792149	12.356.000.000	37.407.792.149
Total	**92059731357**		**78250771653**	**23.210.000.000**	**55.040.771.653**

Source: Reserve calculation based on OGIP, recovery factor (RF), and cumulative production (Irwin, 2015)

Based on the calculation results in table 10, it was obtained that the W-2 Well has the largest reserve value with a total Rvalue of 49,763,792,149 MSCF and a Remaining Reserve of 37,407,792,149 MSCF. This is due to the larger area of the drain area and the thickness of the effective layer than the other two wells.

Meanwhile, the W-1A and W-1 Wells have a total Rvalue of 15,266,938,741 MSCF and 13,220,040,763 MSCF, respectively, with a Remaining Reserve of 5,798,938,741 MSCF and 11,834,040,763 MSCF. The relatively smaller Np value than Rtotal indicates that most of the gas reserves are still stored in the reservoir and have not been fully produced.

Overall, the total Recoverable Reserves from the three wells reached around 78,250,771,653 MSCF, with Remaining Reserves of 55,040,771,653 MSCF. This indicates that the field still has a considerable potential for gas reserves, which is around 70% of the total recovered reserves, so that production activities can still continue in the next stage of development.

CONCLUSION

The analysis of well log data, petrophysical parameters, and production data in the Wailawi Field revealed effective porosity ranging from 0.16–0.18 and water saturation (Sw) between 0.61–0.77 across Wells W-1, W-1A, and W-2, indicating gaseous fluid dominance and strong gas storage potential, further supported by net pay thicknesses of 233.64–499.52 ft. Volumetric OGIP calculations yielded a total of 92,059,731,357 MSCF for the three wells, with Well W-2 contributing the highest at 58,545,637,822 MSCF; applying an 85% recovery factor (RF) resulted in total recoverable reserves (Rtotal) of 78,250,771,653 MSCF and remaining reserves (RR) of 55,040,771,653 MSCF, predominantly in Well W-2, confirming the field's significant redevelopment potential. For future research, integrating advanced petrophysical analysis with core samples and formation tests, alongside regular PVP data updates, economic feasibility studies, and optimization via workover, infill drilling, and zone reactivation, would enhance reserve accuracy and support strategic operator decisions.

REFERENCES

Alamu, R. (2025). *Structural Geology : Faults , Folds , and Traps*. *March*.

Bachtiar, A. (2018a). *The Tertiary Paleogeography Of The Kutai Basin And Its Unexplored Hydrocarbon Plays*. *May*. https://doi.org/10.29118/ipa.0.13.g.126

Bachtiar, A. (2018b). *The Tertiary Paleogeography Of The Kutai Basin And Its Unexplored*

Hydrocarbon Plays. *May*. https://doi.org/10.29118/ipa.0.13.g.126

Efrata, M. B., Irawan, D., & Sinurat, P. D. (2025). *Development of a Water Saturation (SW) Calculation Model for Saturation Height Function (SHF) Modeling in the "MBES" Field*. *7*(1), 47–58.

Fitriani, C., MSi, Ss., & Aswad, S. (2019). *Volumetric calculation of hydrocarbon reserves using petrophysical and seismic data on the Tagut Root Formation sandstone reservoir, CTR field, South Sumatra basin*.

Gargula, T. (2024). *Circle-circle intersection . A universal method for solving typical surveying problems*. 1047–1056.

Hartantyo, E. N., & Said, L. (2016). Volumetric and material balance of Havlena-odeh straight lines and estimated production of the enh zone in field X. *SPE Western Regional Meeting Proceedings*, *V*(March 2019), 11–15.

Heri, M., Zajuli, H., & Wahyudiono, J. (2018). Rock-Eval Pyrolysis in Oligocene Age Fine-Grained Sedimentary Rocks from the Pamaluan Formation, Mount Bayan Area, West Kutai Basin, East Kalimantan: Implications for Potential as a Mother Rock. *Journal of Geology and Mineral Resources*, *19*(Geo-Resource), 73–82. http://dx.doi.org/10.33332/jgsm.geologi.19.2.73-82

Irwin, R. W. (2015). Determination of Initial Oil Content and Production Forecasting with Decline Curve Analysis in Field "R." *National Seminar of Scholars 2015*, 411–421.

Kumar, K. C. H. (2010). On the Application of Simandoux and Indonesian Shaly Sand Resistivity Interpretation Models in Low and High Rw Regimes. *8th Biennial International Conference and Exposition on Petroleum Geophysics*, 11. https://spgindia.org/2010/071.pdf

Maulana iqbal. (2016). *Petrophysical Analysis and Reserve Estimation "Kaprasida" Field Baturaja Formation South Sumatera Basin*. 1–49.

Maulana, M. I., Utama, W., & Hilyah, A. (2016). Petrophysical Analysis and Calculation of Natural Gas Reserves in the "Kaprasida" Field of the Baturaja Formation of the South Sumatra Basin. *Journal of Geoscience,* *2*(2), 63. https://doi.org/10.12962/j25023659.v2i2.1918

Prastio, E., & Agusman, A. R. (2021). *Petrophysis*.

Purba, L. R., Dewanto, O., & Mulyatno, B. S. (2012). Estimation of Shale Content (Vsh), Effective Porosity (Ø e) and Water Saturation (Sw) to Calculate Hydrocarbon Reserves in the Field Limestone Reservoir " "PRB" in South Sumatra Using Log and Petrophysical Data. *Exploratory Geophysics*, *4*(3), 1–8.

Rejas Rasheed, & Avinash Kulkarni. (2016). Reserve Estimation Using Volumetric Method. *International Research Journal of Engineering and Technology*, *3*(10), 1225–1229.

United Nations Department of Economic and Social Affairs, P. D. (2022). W. P. P. 2022: S. of R., Raimi, D., Zhu, Y., Newell, R. G., Prest, B. C., & Bergman, A. (2022). Global Energy Outlook 2023: Sowing the Seeds of an Energy Transition. *United Nation*, *9*, 2019–2030. http://dx.doi.org/10.17605/OSF.IO/W3B4Z%0Awww.un.org/development/ desa/pd/.

North, P. P. (2024). *Geology Of The Wailawi Field*. *Consider using the three paragraphs beginning with, "Consider using the three paragraphs beginning with, 'Consider using the three paragraphs beginning with, 'Consider*

Varhaug, M. (2016). The Defining Series: Basic Well Log Interpretation. *Oilfield Review*, 2. www.slb.com/defining

Vidhotomo, E., Juwono, A. M., & Mekarsari, R. (2014). Petrophysical Analysis and Oil Reserve Calculation in the "BEAR" Field of the Central Sumatra Basin (Case Study of PT Chevron Pacific Indonesia). *Brawijaya Physics Student Journal*, *2*(1), 160100.

Worden, R. H., Armitage, P. J., Butcher, A. R., Churchill, J. M., Csoma, A. E., Hollis, C., Lander, R. H., & Omma, J. E. (2018). Petroleum reservoir quality prediction: Overview and contrasting approaches from sandstone and carbonate communities. *Geological Society Special Publication*, *435*(1), 1–31. https://doi.org/10.1144/SP435.21