Optimization Study of Oil Production Allocation in an Operating Area in the East Kalimantan Region

Nugroho Marsiyanto [1,a*], Dieskha Bilqis Jannah [2]

[1] Prodi Teknik Perminyakan, Universitas Bhayangkara, Bekasi, Indonesia, 17143
[2] Prodi Teknik Perminyakan, Universitas Pertamina, Jakarta, Indonesia, 12220
Email : [a]nugroho.marsiyanto@dsn.ubharajaya.ac.id*

Received (12 June 2025), Revised (22 December 2025)

Abstract. Accurate oil production allocation is a critical aspect of upstream field management because it directly affects well performance evaluation, operational planning, and technical decision-making. However, in an upstream oil field in East Kalimantan, significant discrepancies are still found between allocated production and actual production. The deviation ranges from 12–15%, which exceeds the common industry tolerance of 5–10%. These issues are mainly caused by limited measurement facilities, the absence of test separators, insufficient personnel for routine well testing, and inaccurate BS&W values used in allocation calculations. This study aims to optimize oil production allocation by improving the accuracy of individual well contribution calculations without requiring additional infrastructure or manpower. The method applied in this study combines Nodal Analysis to model well performance with the implementation of BS&W correction factors to account for variations in fluid composition that affect clean oil volume calculations. The data used in this study include historical production data, pressure data (reservoir, pump intake, discharge, and wellhead), well test data, BS&W data, fluid PVT data, and ESP system data. The results show that the combined application of Nodal Analysis and BS&W correction can significantly reduce allocation deviation, in some cases to below 10%. This method provides a practical and low-cost solution that can be applied to similar field conditions to improve oil production allocation accuracy.

Keywords: Optimization, Production Allocation, Nodal Analysis, Allocation Deviation, Well Performance Analysis

INTRODUCTION

The oil and gas industry plays a vital role in global energy supply, yet increasing challenges such as price volatility and the energy transition have intensified the need for efficient and cost-effective upstream operations. Therefore, resource optimization is essential to maintain sustainable production performance [1].

Oil production allocation is a critical optimization process used to determine each well's contribution when production from multiple wells is commingled before surface measurement. Accurate allocation is required for reliable well performance evaluation, reservoir management, and production planning. However, in many mature fields, allocation accuracy is limited by the lack of individual well measurement facilities [2].

In an upstream oil field in East Kalimantan, oil production from multiple active wells is commingled, while routine well testing is constrained by the absence of test separators and limited manpower. As a result, current allocation results show deviations of 12–15% from theoretical values, exceeding the industry tolerance of 5–10%. Previous studies have shown that allocation inaccuracies are often influenced by errors in Basic Sediment and Water (BS&W) measurements, especially in wells with high and fluctuating water cut. Several researchers have suggested that BS&W-based correction factors, derived from well performance and historical data, can improve allocation accuracy without additional facilities [3].

Nodal Analysis is a well-established method for evaluating well performance by analyzing the interaction between the reservoir, wellbore, artificial lift system, and surface facilities [4]. While nodal analysis has been widely applied for production optimization and artificial lift evaluation, its integration with BS&W-based correction methods for improving oil production allocation remains limited in existing studies [5]. The objective is to reduce allocation deviation to within acceptable industry limits using existing data and infrastructure, providing a practical and low-cost solution for similar field conditions.

METHODOLOGY

Accurate production allocation and well performance analysis are essential for effective reservoir management. This study applies a structured methodology to identify the causes of allocation deviation and improve allocation accuracy. Pareto analysis is first used to analyze Risk Priority Number (RPN) to rank the dominant causes and determine the main improvement priority.

Based on the Pareto results, the allocation method is identified as the primary source of deviation. Therefore, Nodal Analysis is applied as the main quantitative method to evaluate well performance and develop a BS&W-based correction factor. The analysis is conducted using PROSPER, a specialized well performance simulation software designed for well performance evaluation in ESP-lifted wells. PROSPER allows integrated simulation of reservoir inflow, tubing performance, and ESP operation, making it suitable for pressure matching and BS&W sensitivity analysis [6].

Based on this modeling framework, the required input data include historical production data, well test data, pressure data (reservoir, pump intake, discharge, and wellhead), BS&W measurements, fluid PVT properties, and ESP system parameters. The analysis workflow consists of data validation, nodal model construction, pressure matching, BS&W sensitivity analysis, and correction factor determination. The flowchart illustrates the improved oil production calculation incorporating BS&W correction factors.

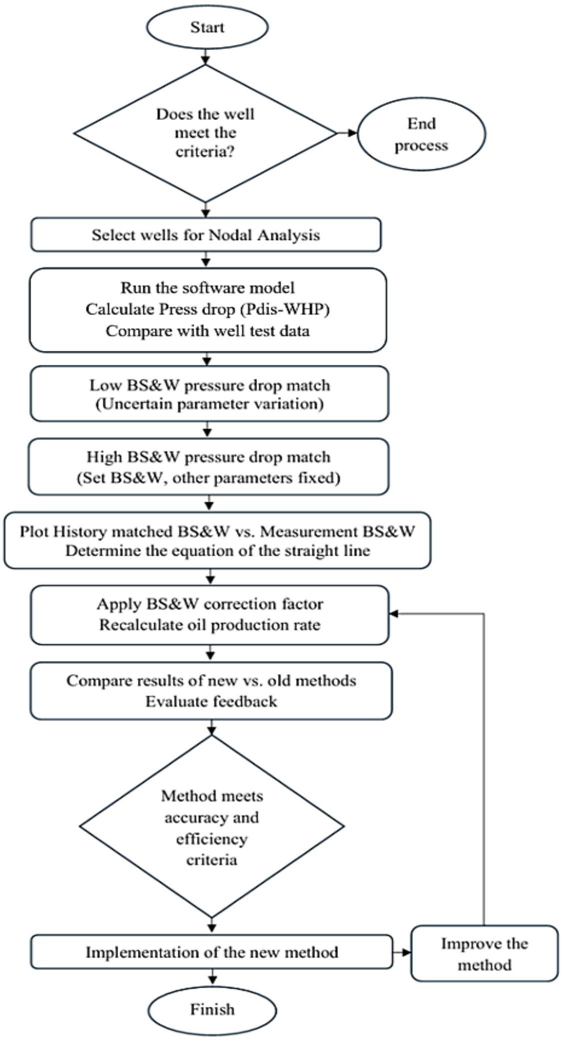


Figure 1. *Workflow Diagram*

RESULTS AND DISCUSSION

4.1 Root Cause Identification

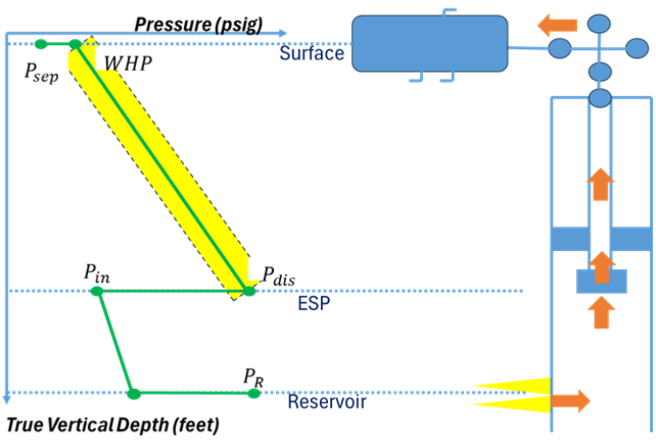


Figure 2. *Nodal Analysis Approach in the BS&W*

This diagram presents a nodal analysis of the pressure profile of an oil well equipped with an Electric Submersible Pump (ESP), from the reservoir to the surface facilities. It illustrates how pressure changes with depth, starting from the reservoir at the bottom and continuing upward to the surface [7]. The diagram highlights the key pressure points used in the analysis, including reservoir pressure (PR), pump intake pressure (Pin), pump discharge pressure (Pdis), wellhead pressure (WHP), and separator pressure (Psep).

The yellow highlighted section between **Psep** and **Pdis** represents the pressure gain across the ESP, showing how the pump increases pressure to lift fluids from deep underground to the surface [8]. The right side of the diagram visually represents the wellbore, showing the reservoir, ESP, and surface facilities, along with arrows indicating the direction of fluid flow. Overall, this is a Nodal Analysis diagram, which is used in production engineering to analyze the performance of the well system.

Allocation deviation results from multiple interconnected factors rather than a single cause. These include human resource limitations, inadequate facilities, geographical challenges, unsuitable calculation methods, and equipment issues, indicating that a comprehensive solution is required to improve allocation accuracy.

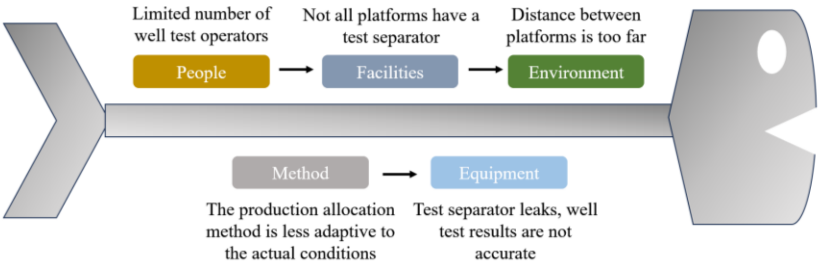


Figure 3. *Fishbone Diagram*

The diagram identifies factors contributing to inaccurate production allocation by grouping them into five categories: People, Facilities, Environment, Method, and Equipment. The fishbone diagram shows that allocation deviation results from multiple interconnected factors rather than a single cause. These include human resource limitations, inadequate facilities, geographical challenges, unsuitable calculation methods, and equipment issues, indicating that a comprehensive solution is required to improve allocation accuracy.

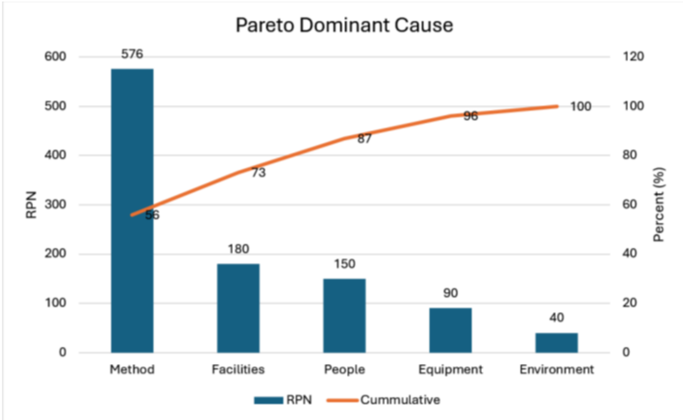


Figure 4. *Pareto Diagram of Dominant Causes*

A Pareto analysis using the Risk Priority Number (RPN) shows that most oil production allocation deviations are caused by inaccurate allocation methods (RPN = 576), followed by facility limitations (RPN = 180) and a lack of field personnel (RPN = 150). These three factors contribute to 87% of the total causes. Among them, the allocation method has the highest impact and is therefore prioritized for improvement. Unlike facility upgrades or manpower additions, which require high costs and long implementation times, improving the allocation method can be implemented using existing data and analytical approaches. By applying BS&W correction and nodal analysis, allocation accuracy can be significantly improved in a shorter time frame without additional infrastructure, making this approach the most effective and practical solution for production optimization [9].

4.3 Optimal Solution to Reduce Allocation Deviation

Each alternative is analyzed based on four main aspects, namely cost, implementation time, level of accuracy produced, and the final conclusion regarding the feasibility of implementing each solution.

Table 1. *Comparison Table of Alternative Solutions to Reduce*

No	Aspect	Test Separator Facility Addition	Addition of Operator Personnel	Re-formulation of Allocation Method
1	Cost	Rp 3.500.000.000	Rp 480.000.000	Rp 0
2	Time	24 Months (Study Engineering, Procurement & Execution Project)	3 Months (Recruitment Process)	2-3 Months (Allocation Method Review)
3	Accuracy	Well test frequency increases, allocation deviation decreases	Well test frequency increases, allocation deviation decreases	Allocation deviation decreased without the need to increase test activities
4	Conclusion	Not selected due to high cost and platform capacity	Not selected due to additional operational costs	Chosen for small cost and improved accuracy

To reduce oil production allocation deviations in this operating area, three alternative solutions were evaluated: adding test separator facilities, hiring additional operators, and reformulating the production allocation method. The goal was to identify the most effective and efficient option in terms of cost, time, and accuracy.

Adding test separators was the most expensive option and requiring about 24 months to implement. Hiring operators was faster (around 3 months) but it still costs a lot in recruitment and salary expenses. In contrast, reformulating the allocation method had no additional cost and could be completed within 2–3 months using existing data and technical analysis.

All three options could improve allocation accuracy, but reformulating the method stood out for its ability to significantly reduce deviations through data correction and performance analysis (e.g., BS&W correction and Nodal Analysis), without needing new equipment or extra manpower. Ultimately, the reformulation of the allocation method was chosen as the optimal solution due to its cost-efficiency, quick implementation, and effectiveness.

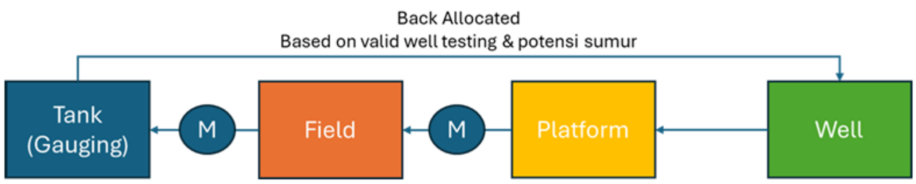


Figure 5. *Back Allocated Method Diagram*

Back allocation process used in oil and gas production systems, where oil flows from individual wells through platforms and field facilities to a final measurement point, typically a tank or gauging system. Along this path, production from multiple wells is commingled, making direct measurement of individual well contributions impossible after mixing.

Production starts at the wells, where output is estimated using well characteristics and periodic well test data. Fluids are then combined at the platform level and further aggregated at the field level. The total production is ultimately measured at the tank system, which is considered the most accurate measurement point, even though meters may exist upstream [10]. Because individual well rates cannot be measured after commingling, back allocation is applied to redistribute the total measured production to each well based on valid well test results and well production potential.

The diagram illustrates the back allocation process used in oil and gas production systems, where oil flows from individual wells through platforms and field facilities to a final measurement point, typically a tank or gauging system. Along this path, production from multiple wells is commingled, making direct measurement of individual well contributions impossible after mixing.

Production starts at the wells, where output is estimated using well characteristics and periodic well test data. Fluids are then combined at the platform level and further aggregated at the field level. The total production is ultimately measured at the tank system, which is considered the most accurate measurement point, even though meters may exist upstream.

Because individual well rates cannot be measured after commingling, back allocation is applied to redistribute the total measured production to each well based on valid well test results and well production potential. This method is essential for monitoring well performance, production planning, and accurate reporting.

To build a reliable production model, appropriate candidate wells were carefully selected. These wells have BS&W histories covering both low and high values, operate above bubble point pressure to ensure fluid stability, and have properly functioning ESP sensors to provide reliable data.

Wells with fluctuating BS&W values were considered suitable for nodal analysis. Well test data from 2020 to the present was reviewed to identify consistent BS&W variations. Wells meeting these criteria were selected for simulation, with their details presented in the following table.

Table 2. *Candidate Wells for Nodal Analysis*

Well	Production Day	Lowest BS&W (%)	Production Day	Highest BS&W (%)
XY-1	10/07/2022	53	15/12/2024	80
XY-2	17/10/2020	27	19/12/2024	52
XY-3	31/08/2022	3	08/11/2023	40
XY-4	03/01/2022	10	06/12/2024	35

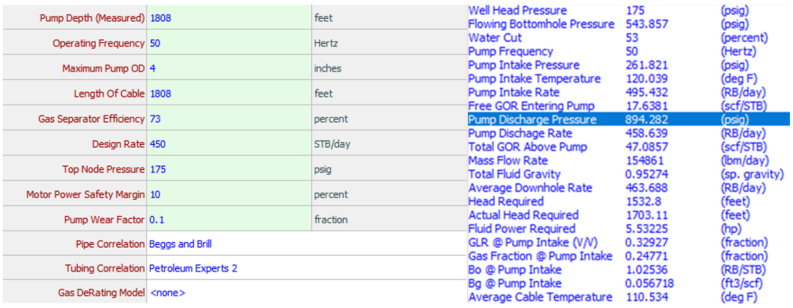
Well test analysis showed that several wells equipped with ESP pumps experienced varying BS&W levels over time. To select suitable simulation candidates, the lowest and highest BS&W values for each well were recorded.

A comparison between current oil production allocation data and well test results serves as a key reference for evaluating the new allocation method. Applying BS&W corrections to ESP-equipped well tests is expected to improve allocation accuracy. This comparison highlights the discrepancy between current allocations and corrected results, helping assess how effectively BS&W correction can enhance the allocation process.

4.4 Production Model Making

Nodal analysis requires several input parameters, including PVT data such as solution GOR, oil gravity, and water gravity; IPR data such as reservoir pressure and layer-specific PVT data; and ESP system data, including pump depth, operating frequency, and cable length. Additional inputs include deviation surveys, downhole equipment details, and average heat capacity.

Well XY-1 was selected as a case study to clearly demonstrate the analysis while maintaining efficiency. The initial step involved matching the tubing pressure drop during a low BS&W period with simulation results by adjusting uncertain parameters, such as GOR and the tubing coefficient, while assuming the measured BS&W was accurate. The well test data used included a BS&W of 53%, a discharge pressure of 894 psi, and a wellhead pressure of 175 psi. The software inputs used to match the simulated discharge pressure with the well test data are shown in the following figure.



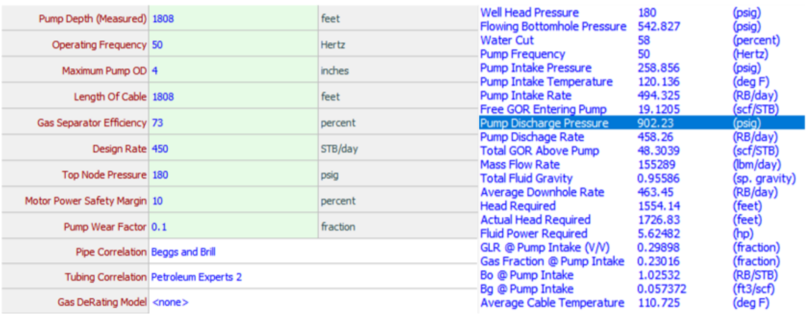
Pump Depth (Measured)	1808	feet
Operating Frequency	50	Hertz
Maximum Pump OD	4	inches
Length Of Cable	1808	feet
Gas Separator Efficiency	73	percent
Design Rate	450	STB/day
Top Node Pressure	175	psig
Motor Power Safety Margin	10	percent
Pump Wear Factor	0.1	fraction
Pipe Correlation	Beggs and Brill	
Tubing Correlation	Petroleum Experts 2	
Gas DeRating Model	<none>	

Well Head Pressure	175	(psig)
Flowing Bottomhole Pressure	543.857	(psig)
Water Cut	53	(percent)
Pump Frequency	50	(Hertz)
Pump Intake Pressure	261.821	(psig)
Pump Intake Temperature	120.039	(deg F)
Pump Intake Rate	495.432	(RB/day)
Free GOR Entering Pump	17.6381	(scf/STB)
Pump Discharge Pressure	894.282	(psig)
Pump Dischage Rate	458.639	(RB/day)
Total GOR Above Pump	47.0857	(scf/STB)
Mass Flow Rate	154861	(lbm/day)
Total Fluid Gravity	0.95274	(sp. gravity)
Average Downhole Rate	463.688	(RB/day)
Head Required	1532.8	(feet)
Actual Head Required	1703.11	(feet)
Fluid Power Required	5.53225	(hp)
GLR @ Pump Intake (V/V)	0.32927	(fraction)
Gas Fraction @ Pump Intake	0.24771	(fraction)
Bo @ Pump Intake	1.02536	(RB/STB)
Bg @ Pump Intake	0.056718	(ft3/scf)
Average Cable Temperature	110.534	(deg F)

Figure 6. *Input Data for Pdis Matching on Low BS&W and Pump Duty Output*

To match the well test discharge pressure (Pdis) of 894 psi, several input parameters were applied, including a pump depth of 1808 ft, a maximum pump outer diameter of 4 inches, a cable length of 1808 ft, a gas separator efficiency of 73%, and a design rate of 450 STB/day. This parameter set successfully reproduced the measured discharge pressure and was then used to analyze BS&W trends in well XY-1.

The tubing pressure drop during a high BS&W period was simulated by varying BS&W values while keeping other parameters constant. A subsequent well test recorded a BS&W of 58%, a Pdis of 902 psi, and a wellhead pressure of 180 psi. A simulation using 58% BS&W was then performed with the same input parameters, as illustrated in the following figure.



Pump Depth (Measured)	1808	feet
Operating Frequency	50	Hertz
Maximum Pump OD	4	inches
Length Of Cable	1808	feet
Gas Separator Efficiency	73	percent
Design Rate	450	STB/day
Top Node Pressure	180	psig
Motor Power Safety Margin	10	percent
Pump Wear Factor	0.1	fraction
Pipe Correlation	Beggs and Brill	
Tubing Correlation	Petroleum Experts 2	
Gas DeRating Model	<none>	

Well Head Pressure	180	(psig)
Flowing Bottomhole Pressure	542.827	(psig)
Water Cut	58	(percent)
Pump Frequency	50	(Hertz)
Pump Intake Pressure	258.856	(psig)
Pump Intake Temperature	120.136	(deg F)
Pump Intake Rate	494.325	(RB/day)
Free GOR Entering Pump	19.1205	(scf/STB)
Pump Discharge Pressure	902.23	(psig)
Pump Dischage Rate	458.26	(RB/day)
Total GOR Above Pump	48.3039	(scf/STB)
Mass Flow Rate	155289	(lbm/day)
Total Fluid Gravity	0.95586	(sp. gravity)
Average Downhole Rate	463.45	(RB/day)
Head Required	1554.14	(feet)
Actual Head Required	1726.83	(feet)
Fluid Power Required	5.62482	(hp)
GLR @ Pump Intake (V/V)	0.29898	(fraction)
Gas Fraction @ Pump Intake	0.23016	(fraction)
Bo @ Pump Intake	1.02532	(RB/STB)
Bg @ Pump Intake	0.057372	(ft3/scf)
Average Cable Temperature	110.725	(deg F)

Figure 7. *Input data for BS&W 58% and Pump Duty Output*

Initial calculations showed a discharge pressure (Pdis) of 902 psi, suggesting that the previously used BS&W value may have been underestimated. To match the simulated Pdis with the well test result, a trial-and-error approach was applied by adjusting the BS&W value. It was found that increasing the BS&W to 63% aligned the simulated result with the test data. This adjustment ensures more accurate simulation outcomes that better reflect field conditions, which is critical for reliable oil production allocation and model validity. The adjusted BS&W calculation process is shown in the following table.

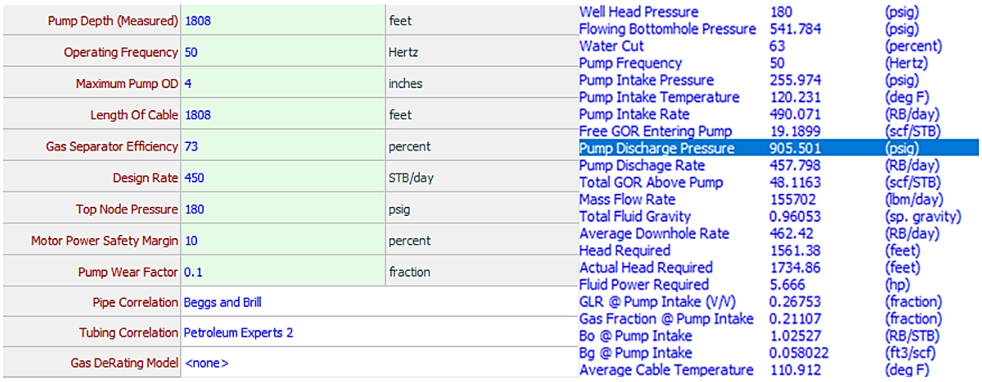


Figure 8. *Input Data for Matching Pdis at High BS&W (BS&W adjustment) and Pump Duty Output*

Table 3. *Pdis Measurement vs. Pdis History Matched XY-1*

Well	WHP (psi)	Measurement			PROSPER		
		Pdis (psi)	Tubing Pressure Drop (psi)	BS&W (%)	Pdis (psi)	Tubing Pressure Drop (psi)	BS&W (%)
XY-1	175	894	719	53	893.47	718.47	53
XY-1	180	905	725	58	905.15	725.15	63
XY-1	150	875	725	62	874.1	724.1	63
XY-1	150	875	725	68	874.8	724.8	66
XY-1	115	844	729	78	844.1	729.1	76
XY-1	145	869	724	79	869.13	724.13	76
XY-1	120	862	742	80	861.5	741.5	85

In most cases, the measured BS&W percentages are similar or slightly lower than the simulated results from the software. At low BS&W levels (such as 53% and 58%), the measured and simulated values tend to be similar. However, as the BS&W increases, especially above 70%, the measured results tend to be slightly lower than the simulated results.

4.5 Well Performance Analysis

To evaluate the accuracy of the simulation results compared to field data, a comparison was made between the measured BS&W values and those obtained through history matching in the simulation. This step aims to assess how well the simulation model represents the actual conditions of the wells under varying water and oil content levels.

The same approach was applied to map the relationship between history-matched BS&W and measured BS&W for wells XY-1, XY-2, XY-3, and XY-4, as shown in the following graph.

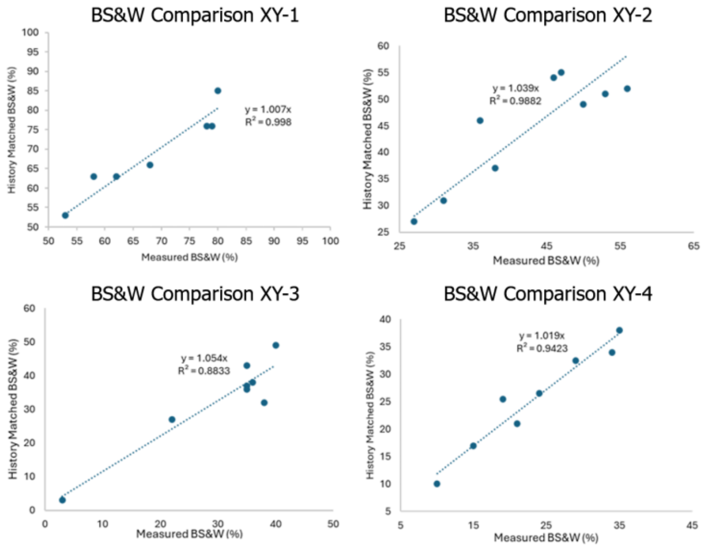


Figure 9. *Plot History Matched BS&W vs. Measured BS&W*

The plot shows BS&W correction factors for four wells, where each measured BS&W value is multiplied by its corresponding factor to improve accuracy. Well XY-1 has the lowest correction factor at 1.007 (≈1% increase), followed by XY-4 at 1.019 (≈2%), XY-2 at 1.039 (≈4%), and XY-3 with the highest at 1.054 (≈5%).

Oil production allocation weighting will be recalculated using well test data with corrected BS&W values. Because the corrected BS&W values are higher than the measured ones, the corresponding oil rates from the well tests must be adjusted. Data from January 12–15, 2025, was used as a sample period to evaluate improvements in allocation accuracy under various operating conditions.

A sensitivity analysis will then be conducted to identify the most representative BS&W correction approach by comparing deviations between total well test results (including potential) and actual production. Deviations from the current method will be compared with those obtained using different correction factors from the four wells (1.007, 1.019, 1.039, 1.054) and the average gradient of 1.029.

Table 4. *Calculation Results New Oil Production Allocation with Various BS&W Correction Factors*

Date	Tot WT + Pot Eks (bbls)	Actual Prod (bbls)	Tot WT (BS&W) Corr + Pott				Deviasi Eks Method	Dev Tot (BS&W) Corr + Pot			
			Corr 1.007	Corr 1.039	Corr 1.054	Corr 1.019		Corr 1.007	Corr 1.039	Corr 1.054	Corr 1.019
12/01/2025	6010	5085	5750	5172	4899	5557	1.68	11.57	1.68	3.80	8.49
13/01/2025	5914	5201	5725	5159	4892	5536	0.82	9.15	0.82	6.32	6.04
14/01/2025	5952	5192	5810	5388	5189	5669	0.07	10.64	3.63	0.07	8.41
15/01/2025	5920	5247	5762	5291	5068	5604	0.82	8.93	0.82	3.53	6.37

Table 4 plays a key role in identifying the most optimal correction factor to reduce deviation, with the goal of achieving more accurate, reliable oil production allocation that reflects actual field conditions. The updated allocation method shows a decrease in the

deviation between the total well test results (plus potential) and actual production when applying different BS&W correction factors to data from January 12–15, 2025. The detailed results are as follows:

- **Correction factor 1.007**: Deviation reduced by 2.12% to 3.83%
- **Correction factor 1.039**: Deviation reduced by 9.13% to 13.72%
- **Correction factor 1.054**: Deviation reduced by 5.74% to 12.69%
- **Correction factor 1.019**: Deviation reduced by 4.35% to 6.91%

Although the 1.054 correction factor produced the largest reduction in deviation, the corrected well test results became lower than the actual production, indicating an unrealistic outcome that could cause allocation errors between fields. This result also contradicts the typical expectation that well test results and potential are higher than actual production.

Accurate oil production allocation is critical in the oil and gas industry, and one of the main challenges is ensuring that BS&W measurements truly represent field conditions. While current measurement procedures are generally reliable, minor inaccuracies of about 1–2% are still expected.

The proposed allocation method shows potential for improved accuracy but requires further validation. For this operational area, the use of corrected BS&W values is recommended. Well XY-1 demonstrated the highest accuracy with an R^2 of 0.998. Applying a correction factor of **1.007** reduced estimation errors to **2.12%–3.8%**, which remains within the acceptable API MPMS tolerance (0.01-1%), making it the most reliable option for improving production allocation accuracy.

CONCLUSION

This study identified significant discrepancies between allocated and actual oil production in the East Kalimantan operational area, with deviations of 12–15%, exceeding industry tolerance limits. These results indicate the need for improved production allocation methods to ensure accurate well performance evaluation.

A BS&W-based correction factor method integrated with nodal analysis was applied to four ESP-lifted wells (XY-1 to XY-4), producing correction factors ranging from 1.007 to 1.054. Among them, Well XY-1 showed the highest accuracy, with a correction factor of 1.007 and a strong correlation (R^2 = 0.998). Applying this correction reduced allocation deviation to 3.83%, well within acceptable limits. Higher correction factors also reduced deviation but produced unrealistic results, highlighting the importance of well-specific correction.

Overall, the proposed method provides a practical, low-cost solution to improve oil production allocation accuracy using existing data and infrastructure. This approach is recommended for similar fields with commingled production and limited measurement facilities.

ACKNOWLEDGMENTS

The author would like to express sincere gratitude to all parties who have contributed and provided support in the completion of this journal. For their guidance and valuable insights throughout the implementation of this journal.

REFERENCES

[1] W. C. P. G. J. L. M. Lyons, *Standard Handbook of Petroleum and Natural Gas Engineering*. Gulf Professional Publishing, 2016.
[2] S. Kulchanyavivat, "Collaborative Analytical Technique to Improve Production Allocation," *Offshore Technology Conference*, 2020.
[3] S. Kanshio, "A Review of Hydrocarbon Allocation Methods in the Upstream Oil and Gas Industry," *J. Pet. Sci. Eng.*, 2020.
[4] H. D. Beggs, "Production Optimization using Nodal Analysis," *OGCI & Petroskills*, 2015.
[5] D. Pranondo, "Analisis Sumur dengan IPR Metode Vogel serta Evaluasi Tubing Menggunakan Analisis Nodal pada Sumur TCS," *Jurnal Teknik Patra Akademika*, 2020.
[6] V. K. Kudapa, "Production Enhancement using Prosper Software with Reference to Well Test Matching and Modeling for Good Financial Management," pp. 1–2, 2022.
[7] E. M. Sudjito, "Optimasi Produksi Sumur 'ZL' dengan Menggunakan Artificial Lift Electrical Submersible Pump pada Lapangan 'YY,'" *PETROGAS*, p. 46, 2021.
[8] K. E. Brown, *The Technology of Artificial Lift Methods*, vol. 1. PennWell Books, 2018.
[9] K. Sasseen, G. V. Chilingarian, and J. O. Robertson, "Chapter 1 Introduction to Surface Production Equipment," *Developments in Petroleum Science*, pp. 1–41, 2016.
[10] F. Manning and R. E. Thompson, *Oilfield Processing of Petroleum: Volume 1 - Natural Gas*. Gulf Publishing Company, 2015.