



Integrated Workflow for Idle Well Reactivation in a Mature Oil Field

M Irhas Effendi^{1*}, Sayoga Heru Prayitno², Hariyadi³, Tegar Aditia Putra⁴, Devina Putri⁵, Farah Arya Hanifan⁶

¹ Management Economics Department, Faculty of Economics and Business, UPN Veteran Yogyakarta

^{2,3,4,5,6} Petroleum Engineering Department, Faculty of Mineral Technology and Energy, UPN Veteran Yogyakarta

Received : September 08, 2026

Revised : September 21, 2026

Accepted : September 26, 2026

Online : October 7, 2026

Abstract

Declining production in mature oil fields increases the value of reactivating idle wells, but legacy records, uncertain well integrity, and produced-water constraints complicate candidate selection. This study develops a transparent, fit-for-purpose workflow for Banyuasin Field, Cepu, Indonesia. The applied-development method combines an archival data audit, a reproducible production-evidence score, field-verification gates, well-specific intervention planning, and pilot monitoring. Historical records cover 22 drilled wells, and the reactivation plan identifies 18 candidates: 14 production wells and four injection wells. The quantitative pre-screen gives equal emphasis to Dutch-era and 2014-2017 traditional-mining cumulative production, with an additional continuity term for wells supported by both periods. BNA-22 (67.3), BNA-17 (63.2), BNA-21 (48.2), and BNA-20 (40.3) form the strongest production-evidence group and correspond to the documented first-priority wells. BNA-21 and BNA-22 illustrate different verification needs, involving possible wellbore obstruction and construction or cement-integrity uncertainty, respectively. A 15 BOPD per-well production gain and a 15% annual decline are retained only as pre-pilot planning assumptions, not measured results. The contribution is a low-data workflow that separates auditable production ranking from mandatory field-safety gates while integrating production and injection functions within one reactivation system.

Keywords: *Idle well reactivation, Mature oil field, Candidate screening, Well integrity, Production optimization*

INTRODUCTION

Indonesia's crude-oil lifting has declined over the long term, increasing the importance of extracting additional value from mature assets (Saragih, 2024). Idle wells can provide incremental production with shorter lead times than new drilling, as illustrated by reactivation programs in Nigeria and Malaysia (Ekpenyong & Joseph, 2022; Bakar et al., 2023). The opportunity, however, is constrained by uncertainty: long shut-in periods can leave incomplete production histories, uncertain barrier conditions, degraded access, and fluid-handling problems. Well-integrity management is therefore central to any mature-field reactivation program because safe return to service depends on confirming barriers, zonal isolation, and operating limits (Yakoot et al., 2021).

Recent studies increasingly use structured screening, integrated diagnostics, and machine learning to prioritize idle wells (Prayitno et al., 2025, 2026). These approaches are valuable when production, log, reservoir, and integrity data are sufficiently complete. Their limitation is their dependence on data. Petroleum machine-learning reviews identify incomplete, inconsistent, and field-specific data as major constraints on generalization and interpretability (Lawal et al., 2024). In legacy fields, this creates a practical gap: a screening system must remain auditable even when some variables are unavailable, while still preventing historical production from being treated as

Copyright Holder:

© Irhas, Sayoga, Hariyadi, Tegar, Devina, & Farah. (2026)

Corresponding author's email: m_irhaseffendi@upnyk.ac.id

This Article is Licensed Under:



proof of current deliverability.

Banyuasin Field in Cepu combines Dutch-era production records with later traditional-mining data, while the development plan separates production wells from those intended for produced-water handling (PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta, 2025). This study aims to develop a reproducible workflow that audits legacy data, produces an explicit ranking of production evidence, applies field-condition and HSE gates before intervention, and integrates production with injection functions. Its novelty lies in separating quantitative ranking from non-negotiable verification gates, preserving transparency without assigning artificial precision to unavailable data.

LITERATURE REVIEW

The mature-field literature is consistent on one point: reactivation is not a simple reopening activity. Successful cases combine diagnosis of the inactivity mechanism, confirmation of well integrity, and an intervention aligned with the well's expected value. Ekpenyong and Joseph (2022) demonstrate that rigless restoration can return a damaged idle well to service when structural integrity is addressed first. Hani and Sutresno (2025) show that low-capital bailer cleanout is effective when debris and scale dominate, whereas Kristanto et al. (2026) show that water-channeling problems require log-based diagnosis and remedial action. These studies indicate that intervention type follows diagnosis; production history alone is insufficient.

Post-reactivation readiness is equally important. Artificial-lift selection must reflect current well performance rather than a uniform field rule (Janadeleh et al., 2024), and produced-water treatment or reinjection must be planned as part of the production system because water load can become the operational constraint in mature assets (Liu et al., 2021; Ghafoori et al., 2022; Rajbongshi & Gogoi, 2024). Consequently, production and water-handling candidates are technically interdependent.

Structured qualifier matrices and integrated screening frameworks improve consistency by combining evidence from production, reservoir, and integrity (Bakar et al., 2023; Prayitno et al., 2026). Machine learning can extend this logic to large candidate sets (Prayitno et al., 2025), but incomplete and inconsistent petroleum data limit robustness and transferability (Lawal et al., 2024). In a legacy field, a fully data-intensive score can therefore create false precision. This study uses numerical weights only for variables documented across all candidates and treats integrity, access, HSE, and fluid handling as mandatory verification gates.

RESEARCH METHOD

Data Sources, Audit, and Data Treatment

The study uses an applied-development design based on the Banyuasin reactivation plan, historical well-production records, candidate depth and function data, field-survey documentation, and well sketches (PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta, 2025). The archive records 22 drilled wells and two production periods: Dutch-era operations and traditional mining during 2014-2017. The reactivation plan includes 18 operational candidates, comprising 14 production candidates and four injection candidates.

Data were checked by well identifier, production volume, and duration. The conversion factor was 1 STB = 0.158987 m³. STB values were used for calculations, and m³ values for unit checking. Average daily production equals cumulative STB divided by production months x 30 days. Blank entries were treated as unavailable; records without duration were excluded from rate calculations. In the evidence score, a missing production record contributes zero only to that evidence component, indicating absence of documented evidence rather than zero reservoir

potential.

Production candidates were first compared using a three-component evidence score. Dutch-era cumulative production and traditional-mining cumulative production were normalized by the maximum value among the 14 production candidates. A continuity indicator equals 1 if a valid production record exists in both periods and 0 otherwise. The production-evidence score is $S = 100[0.40(D_i/D_{\max}) + 0.40(T_i/T_{\max}) + 0.20C_i]$. Equal 40% weights prevent either historical period from dominating the pre-screen, while the 20% continuity term rewards evidence that persists over time. The formula is intentionally limited to variables available for the full candidate set.

Table 1. Screening logic used in the revised workflow

Component	Type	Weight/rule	Decision use
Dutch-era cumulative production	Quantitative	40%; normalized to field maximum	Historical productivity evidence
Traditional-mining cumulative production	Quantitative	40%; normalized to field maximum	More recent production evidence
Cross-period continuity	Quantitative	20%; 1 = both periods, 0 = otherwise	Consistency of documented production
Well identification/integrity	Field gate	Pass, verify, or defer	No intervention before barrier condition is verified
Access and HSE readiness	Field gate	Pass, verify, or defer	Confirms safe location and well-control readiness
Fluid-handling readiness	Field gate	Pass, verify, or defer	Confirms oil separation and water disposal/injection route

The field gates prevent the numeric pre-screen from serving as final engineering approval. Wells with uncertain wellhead or casing conditions, unsafe access, unresolved well-control concerns, or no fluid-handling route are deferred until verified. Injection candidates are not ranked by oil-production score because their role is produced-water management; acceptance requires injectivity, integrity, and disposal-compliance testing. The original plan's Priority 1-3 classes are retained as documented field priorities and compared with the quantitative evidence score. Verified intervention cost data were not available for all candidates, so economics were excluded from the selection score rather than treated as an assessed criterion. Cost per incremental barrel and payback are reserved for post-pilot evaluation.

Priority wells follow a well-specific sequence of location preparation, well-control readiness, reopening or cleanout, integrity logging where required, production testing, lift selection, oil-water separation, crude transport, and produced-water routing. The pre-pilot scenario assumes 15 BOPD incremental production per well and a 15% annual decline over five years. The 15 BOPD value falls within the observed field-average range of 18.96 BOPD for Dutch-era records and 6.84 BOPD for traditional-mining records; the 15% decline remains a planning parameter, not a fitted decline curve. For four Priority-1 wells, $Q_t = 4 \times 15 \times 0.85^{(t-1)}$. Pilot evaluation will replace these assumptions with measured production, water cut, downtime, and cost data.

FINDINGS AND DISCUSSION

The archived production table confirms a productive petroleum system but also highlights the unevenness of the evidence base. Sixteen of the 22 drilled wells were reported as historical oil producers. Dutch-era cumulative production totals 599,109 STB (95,096.67 m³), and traditional-mining activities recorded 54,949.42 STB (8,722.13 m³), for a combined recorded cumulative

production of 103,818.80 m³ across the two periods. BNA-17 has the largest Dutch-era cumulative production (203,112 STB), whereas BNA-22 dominates the later traditional-mining record (32,312.43 STB). BNA-21 has the highest calculated Dutch-era average rate at approximately 73.29 BOPD, while BNA-22 reaches approximately 41.43 BOPD in the later period. These signals justify using both periods in the preliminary score.

Table 2. Historical production records for Banyuasin wells

Well	Local STB	Local m3	Local months	Dutch STB	Dutch m3	Dutch months
BNA-01	171.96	27.30	9	6,930.00	1,100.00	18
BNA-02	-	-	-	10,710.00	1,700.00	41
BNA-03	123.19	19.55	7	19,010.00	3,017.46	69
BNA-04	2,793.76	443.45	5	25,200.00	4,000.00	35
BNA-05	4,652.84	738.55	20	63,470.00	10,074.60	114
BNA-06	-	-	-	441.00	70.00	5
BNA-07	628.31	99.73	12	126.00	20.00	5
BNA-08	812.89	129.03	15	2,520.00	400.00	5
BNA-09	-	-	-	-	-	-
BNA-10	-	-	-	-	-	-
BNA-11	-	-	-	-	-	-
BNA-12	2,113.44	335.47	23	25,200.00	4,000.00	81
BNA-13	-	-	-	-	-	-
BNA-14	-	-	-	2,520.00	400.00	26
BNA-15	-	-	-	-	-	-
BNA-16	1,125.11	178.59	20	-	-	-
BNA-17	2,556.26	405.76	31	203,112.00	32,240.00	187
BNA-18	0.00	-	-	-	-	-
BNA-19	741.07	117.63	19	-	-	-
BNA-20	1,992.20	316.22	24	90,640.00	14,387.30	148
BNA-21	4,925.96	781.90	36	112,140.00	17,800.00	51
BNA-22	32,312.43	5,128.96	26	37,090.00	5,887.30	44
Total	54,949.42	8,722.13	-	599,109.00	95,096.67	-

Source: [PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta \(2025\)](#); converted from the original image table into editable format.

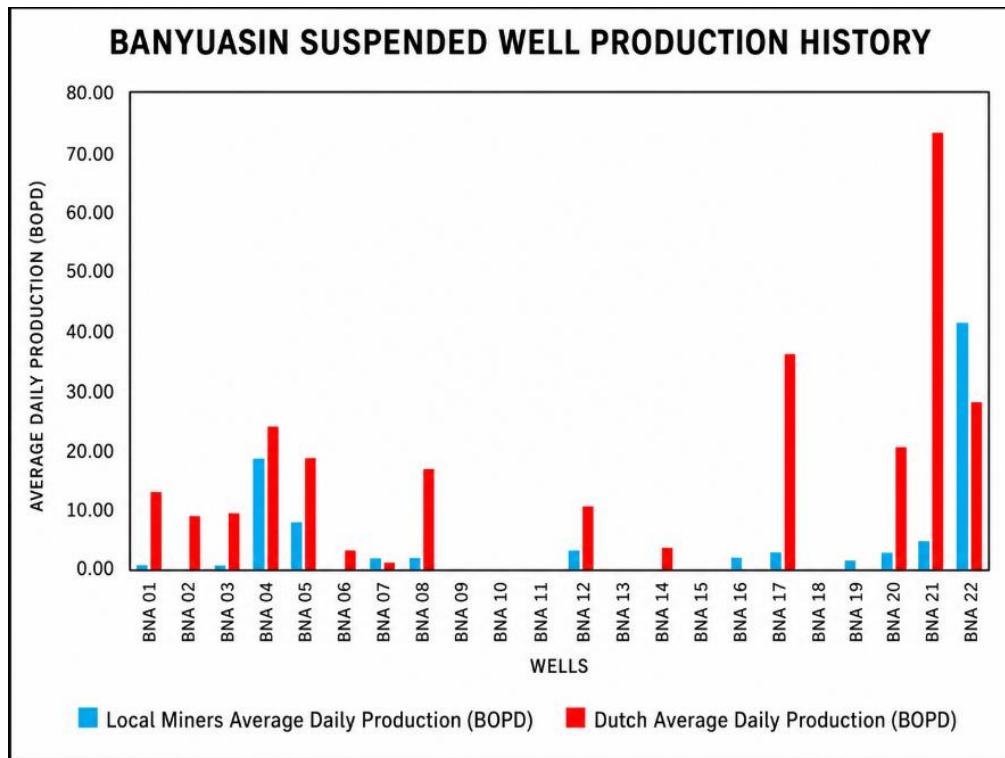


Figure 1. Historical average daily production by well

Source: author calculation from Table 2; rate = cumulative STB / (production months x 30 days).

Figure 1 highlights the complementary nature of the two periods. Dutch-era data identify wells with sustained historical productivity, whereas later traditional-mining data reveal wells that still responded under more recent, relatively simple production conditions. The figure is therefore used as a screening aid rather than as evidence of current deliverability.

The plan includes 14 production and four injection candidates. The pre-screen ranks BNA-22 (67.3), BNA-17 (63.2), BNA-21 (48.2), and BNA-20 (40.3) highest, aligning with the documented Priority-1 group. This agreement suggests that the two-period production record captures an important part of the field-selection logic, but not all of it. BNA-05, for example, scores 38.3 yet remains Priority 3, showing that integrity, access, and other field information can override historical production evidence.

Table 3. Candidate function, production-evidence score, and documented field priority

Well	Depth (m)	Function	Evidence score	Field priority
BNA-17	563	Production	63.2	Priority 1
BNA-20	312	Production	40.3	Priority 1
BNA-21	303.7	Production	48.2	Priority 1
BNA-22	321.6	Production	67.3	Priority 1
BNA-01	79.5	Production	21.6	Priority 2
BNA-06	83.5	Production	0.1	Priority 2
BNA-07	136.2	Production	20.8	Priority 2
BNA-08	201	Production	21.5	Priority 2
BNA-12	116	Production	27.6	Priority 2
BNA-02	151.7	Production	2.1	Priority 3
BNA-05	307.5	Production	38.3	Priority 3
BNA-14	137	Production	0.5	Priority 3
BNA-13	72.5	Production	0.0	Priority 3

BNA-P04 (P001D)	109.5	Production	0.0	Priority 3
BNA-19	87	Injection	N/A	Injection support
BNA-10	98	Injection	N/A	Injection support
BNA-15	100	Injection	N/A	Injection support
BNA-11	21	Injection	N/A	Injection support

Source: depth, function, and field priority from [PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta \(2025\)](#).

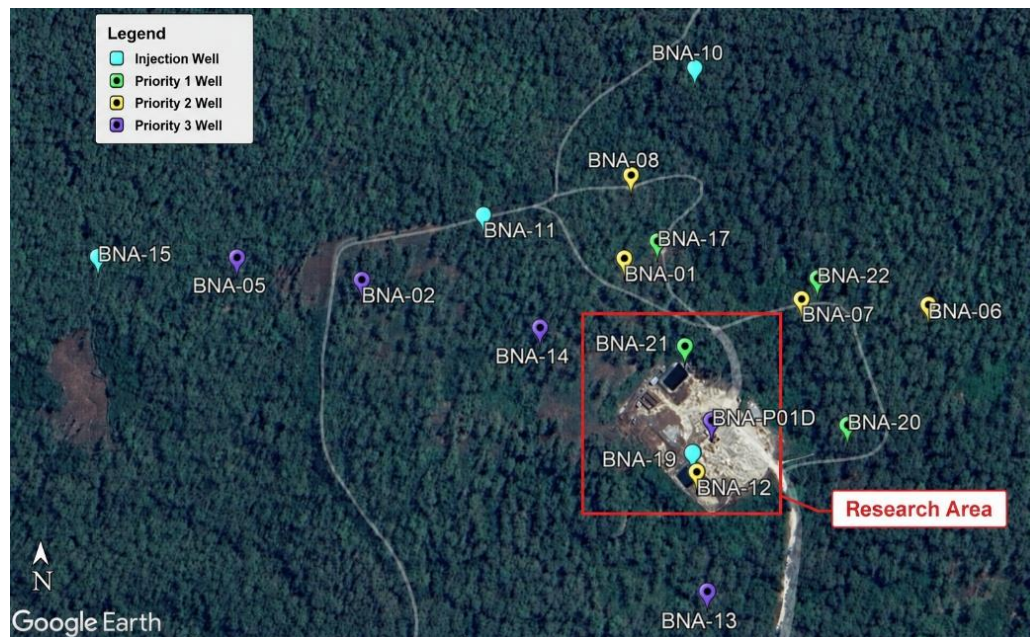


Figure 2. Spatial distribution of reactivation candidates

Source: adapted from [PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta \(2025\)](#).

Figure 2 shows that production and injection candidates occur within the same operating cluster. This spatial relationship supports a field-level workflow in which oil recovery, temporary fluid separation, transport access, and produced-water routing are planned together. The four injection candidates are therefore not secondary outputs of the ranking; they are enabling elements that require separate integrity and injectivity verification.

BNA-21 and BNA-22 illustrate why two wells with strong production evidence can require different interventions. BNA-21 produced 112,140 STB during the Dutch era and 4,925.96 STB during traditional mining. Field documentation still identifies the flange, wellhead, and casing, but the reported fluid level is 18.5 m, and the tag depth is only 22.5 m, compared with the 303.7 m target depth. This large discrepancy is consistent with a possible wellbore obstruction or fill that must be removed and verified before production testing.

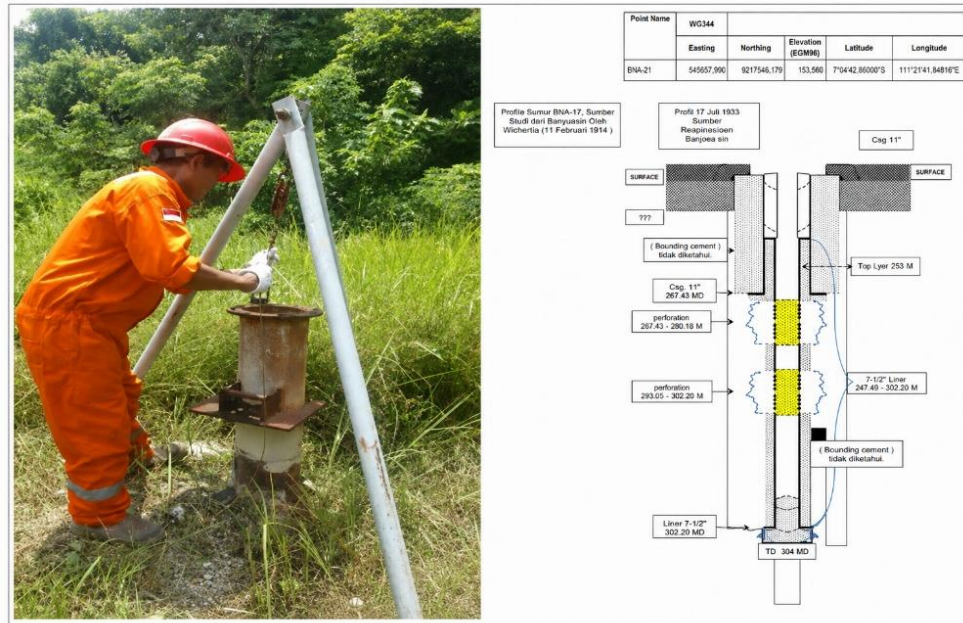


Figure 3. BNA-21 field survey and well sketch

Source: adapted from [PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta \(2025\)](#).

Figure 3 links the surface observation to the well sketch and outlines the proposed diagnostic sequence: safe access and well control first, followed by cleanout or reopening, depth confirmation, integrity checks, and only then a production test. The image therefore serves as evidence for intervention planning rather than proof that the well is currently producible.

BNA-22 presents a different risk profile. Its traditional-mining record is the strongest in the field at 32,312.43 STB over 26 months, equivalent to approximately 41.43 BOPD, while Dutch-era production averaged about 28.10 BOPD. The well is attractive from a production-response perspective, but the available sketch contains uncertainty about construction and cement bonding. This shifts the first verification task from cleanout alone to confirmation of casing condition, cement integrity, and zonal isolation, consistent with mature-field integrity practice ([Yakoot et al., 2021](#); [Kristanto et al., 2026](#)).

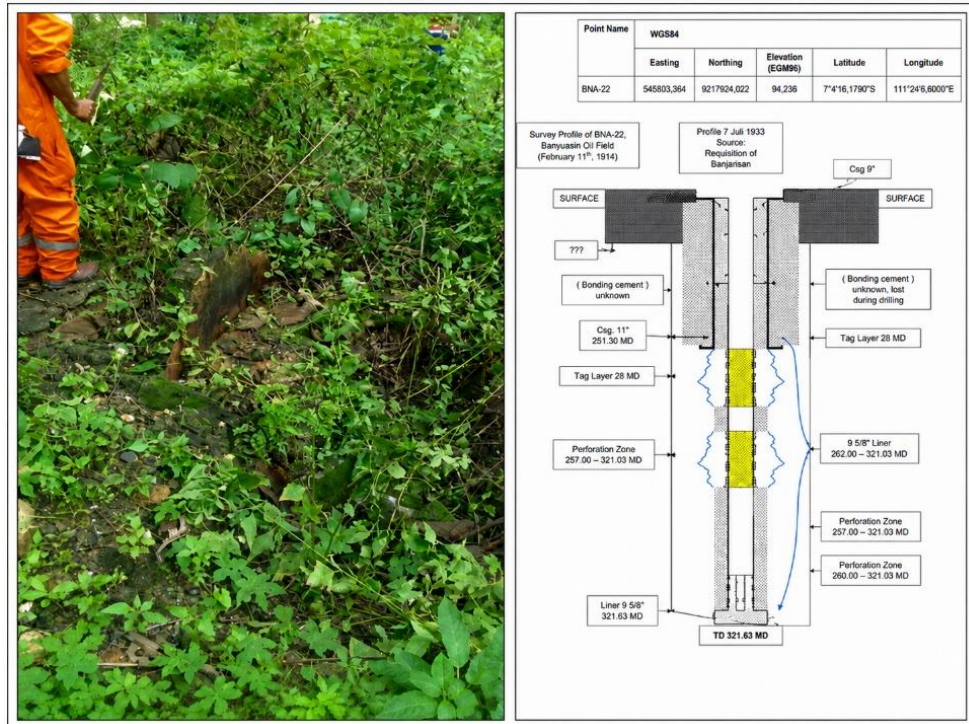


Figure 4. BNA-22 field survey and well sketch

Source: adapted from [PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta \(2025\)](#).

Figure 4 shows that BNA-22 has less certain surface and construction conditions than BNA-21. The comparison demonstrates the practical value of separating evidence ranking from field gates: both wells remain attractive, but they do not receive identical intervention designs.

The resulting workflow is sequential and auditable: archive audit -> production-evidence pre-screen -> integrity/access/HSE gates -> well-specific intervention -> production test -> fluid handling -> monitoring -> standardization. Two features distinguish it from single-domain screening. Numerical weights are restricted to documented variables, so the method remains usable with incomplete legacy data. It also integrates production and injection candidates into a single sequence, linking incremental oil to produced-water capacity rather than treating water handling as a later facility issue.

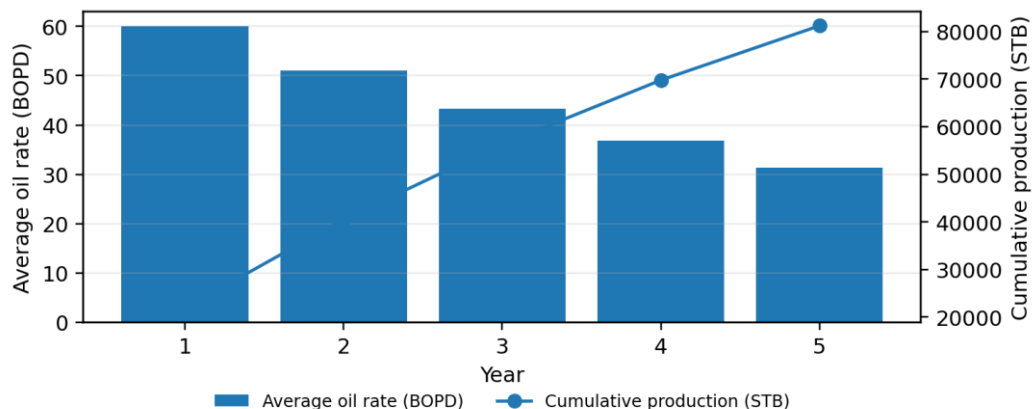


Figure 5. Pre-pilot planning scenario for four Priority-1 production wells

Source: author calculation using 15 BOPD per well and 15% annual decline; these are planning

assumptions, not measured pilot results.

Under the stated assumptions, the four Priority-1 wells start at a combined 60 BOPD and decline to about 31.3 BOPD in year five, yielding approximately 81,200 STB of cumulative production over five years using a simple annual-step calculation. Figure 5 is not a reserve estimate or a forecast validated by decline-curve analysis. Its purpose is to make the planning assumption reproducible and to define what must later be replaced by measured pilot rates, water cut, downtime, and actual operating costs. No payback result is reported at this stage because verified intervention and operating costs are not available for the full candidate set.

CONCLUSIONS

Banyuasin Field has sufficient historical evidence to justify a structured reactivation pilot, but the evidence does not warrant treating all idle wells uniformly. The revised workflow converts available legacy production data into an auditable preliminary score and then requires verification of field conditions, HSE, and fluid handling before intervention. Of 18 operational candidates, 14 are assigned to production functions and four to injection functions. BNA-22, BNA-17, BNA-21, and BNA-20 form the strongest production-evidence group and align with the documented Priority-1 wells. A comparison of BNA-21 and BNA-22 further shows that similar reactivation priorities can arise from different evidence and therefore require different diagnostics. The study's practical contribution is a low-data, field-level workflow that integrates production prioritization with injection and produced-water planning while clearly separating planning assumptions from measured outcomes.

LIMITATION & FURTHER RESEARCH

The study has five main limitations. Historical records for several wells are incomplete and should be reconciled with the original files. Traditional-mining records may have less rigorous measurement control and should be calibrated against pilot-test meters. Surface assessment is partly visual, so pressure tests, depth confirmation, and integrity logging are necessary before sustained operation. Current reservoir-pressure, fluid, and injectivity data are limited and should be collected during the pilot. Finally, the single-field scope requires replication in other mature-field clusters. Economic performance should be calculated only after actual intervention and operating costs, incremental oil, and downtime are observed.

ACKNOWLEDGEMENT

This study was funded by the Institute for Research and Community Service of Universitas Pembangunan Nasional 'Veteran' Yogyakarta.

REFERENCES

- Bakar, H., Anuar, K. K., Mokhtar, M. K., Idris, K. N., Khalid, R., Abu Bakar, M., & Masoudi, R. (2023). Improving production enhancement and idle well reactivation (PE/IWR) success rate at country level in Malaysia via PE/IWR qualifier matrix approach. SPE Annual Technical Conference and Exhibition. <https://doi.org/10.2118/214775-MS>
- Ekpenyong, V., & Joseph, A. (2022). Idle wells reactivation—The Kenyon International story. SPE Nigeria Annual International Conference and Exhibition. <https://doi.org/10.2118/211955-MS>
- Ghafoori, S., Omar, M., Koutahzadeh, N., Zendejboudi, S., Malhas, R. N., Mohamed, M., Al-Zubaidi, S., Redha, K., Baraki, F., & Mehrvar, M. (2022). New advancements, challenges, and future needs on treatment of oilfield produced water: A state-of-the-art review. Separation and

- Purification Technology, 289, Article 120652.
<https://doi.org/10.1016/j.seppur.2022.120652>
- Hani, B., & Sutresno, W. (2025). Application of bailer technique for idle well reactivation in mature fields: Case study of SLF Field Sumatera. *Scientific Contributions Oil and Gas*, 48(4), 507–517. <https://doi.org/10.29017/scog.v48i4.1994>
- Janadeleh, M., Ghamarpoor, R., Abbood, N. K., Hosseini, S., Al-Saedi, H. N., & Hezave, A. Z. (2024). Evaluation and selection of the best artificial lift method for optimal production using PIPESIM software. *Heliyon*, 10(17), Article e36934.
<https://doi.org/10.1016/j.heliyon.2024.e36934>
- Kristanto, D., Yusgiantoro, L. A., Hariyadi, & Paradhita, W. (2026). An integrated analysis of shut-in well reactivation for oil production optimization in the DLN-11 well. *Scientific Contributions Oil and Gas*, 49(1), 247–266. <https://doi.org/10.29017/scog.v49i1.2012>
- Lawal, A., Yang, Y., He, H., & Baisa, N. L. (2024). Machine learning in oil and gas exploration: A review. *IEEE Access*, 12, 19035–19058. <https://doi.org/10.1109/ACCESS.2023.3349216>
- Liu, Y., Lu, H., Li, Y., Xu, H., Pan, Z., Dai, P., Wang, H., & Yang, Q. (2021). A review of treatment technologies for produced water in offshore oil and gas fields. *Science of the Total Environment*, 775, Article 145485. <https://doi.org/10.1016/j.scitotenv.2021.145485>
- Prayitno, S. H., Hariyadi, Widiyaningsih, I., Cahyaningtyas, N., Helmy, M. F., & Pramuditha, B. (2026). Reducing uncertainty in idle well reactivation: A novel integrated screening framework for mature oil fields. *Scientific Contributions Oil and Gas*, 49(2), 475–485.
<https://doi.org/10.29017/scog.v49i2.2089>
- Prayitno, S. H., Swadesi, B., Hariyadi, Nandiwardhana, D., Jayadianti, H., Imasuly, G. B., Widiyaningsih, I., & Cahyaningtyas, N. (2025). The application of machine learning (DT-Chan-Performance) in determining idle well reactivation candidates at PT Pertamina EP Regional 4 Zone 11 Cepu Field. *Scientific Contributions Oil and Gas*, 48(2), 69–94.
<https://doi.org/10.29017/scog.v48i2.1657>
- PT Wimaya Energy-PSP Migas dan Panas Bumi UPN 'Veteran' Yogyakarta. (2025). Reaktivasi dan produksi sumur-sumur idle Lapangan Banyuasin PT Pertamina EP Regional IV Zona 11 Field Cepu.
- Rajbongshi, A., & Gogoi, S. B. (2024). A review on oilfield produced water and its treatment technologies. *Petroleum Research*, 9(4), 640–656.
<https://doi.org/10.1016/j.ptlrs.2024.06.003>
- Saragih, J. P. (2024). The decline in crude oil production, surge in prices, and the burden of crude oil and fuel imports. *Info Singkat*, XVI(9/I), 11–15.
- Yakoot, M. S., Elgibaly, A. A., Ragab, A. M. S., & Mahmoud, O. (2021). Well integrity management in mature fields: A state-of-the-art review on the system structure and maturity. *Journal of Petroleum Exploration and Production Technology*, 11, 1833–1853.
<https://doi.org/10.1007/s13202-021-01154-w>