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EVALUATION AND OPTIMIZATION OF NEW GAS WELL DEVELOPMENT TO ENHANCE PRODUCTION PERFORMANCE IN THE ANGGANA FIELD, PERTAMINA HULU INDONESIA ZONE 9, EAST KALIMANTAN

Rahmady Rusdiantje[1], Boni Swadesi[1], Nur Suhascaryo[1]
Afiliasi : [1]Petroleum Engineering, Universitas Pembangunan Nasional "Veteran" Yogyakarta
e-mail : sayarahmady@gmail.com

Abstract. *The Anggana Field, located in Kutai Kartanegara Regency, East Kalimantan, is part of Pertamina Hulu Indonesia (PHI) Zone 9, which manages several mature oil and gas fields in the Mahakam region. The discovery of new gas reserves in Anggana presents an opportunity to enhance production, but the existing surface facilities were primarily designed for oil handling and are limited in gas capacity. This study focuses on the technical optimization of gas transportation from Anggana by using PIPESIM software to simulate network performance and flow assurance under different pipeline configurations. Simulation scenarios were designed to evaluate two configurations: (1) a tie-in to the existing Sanga-Sanga gas network and (2) a dedicated pipeline from Anggana to the Lempake Booster Station. The simulation assesses pressure drop, temperature profile, and flow stability across both systems. Results show that the tie-in configuration increases upstream backpressure and reduces throughput, while the dedicated pipeline provides stable pressure distribution and maintains flow assurance without exceeding design limits. This technical analysis demonstrates that PIPESIM is a reliable tool for evaluating production network performance and supports decision-making in brownfield gas developments.*

Keywords: *flow assurance; gas network simulation; pipeline optimization; production network*

INTRODUCTION

Indonesia's gas industry is facing challenges in optimizing production from mature fields while ensuring the reliability of existing infrastructures. Pertamina Hulu Indonesia (PHI) Zone 9 manages several aging assets including Sanga-Sanga, Badak, Nilam, and Anggana. The Anggana field, located in close proximity to Sanga-Sanga infrastructure, is expected to deliver new gas volumes to support existing processing facility throughput. However, integrating new production into aging pipelines poses operational challenges including pressure interaction, thermal losses, potential hydrate formation, and unstable multiphase flow.

Gas transportation networks in brownfield developments frequently encounter capacity limitation, increase backpressure, and heighted flow assurance risks as new production sources are introduced. These constrains are especially critical in mature assets such as Sanga-Sanga, where declining reservoir pressure must be balanced against infrastructure limits to optimize recovery and sustain plant inlet conditions. Simulation-based evaluation is therefore required to determine whether the existing gathering system can accommodate incremental supply or whether new infrastructure is required. This work aims to provide an engineering-driven basis for field development decision-making through steady-state flow modeling in PIPESIM. The output includes comparative assessments of pressure distribution, hydraulic stability, and flow assurance behavior for candidate development concepts.

Gas gathering systems form a crucial part of hydrocarbon production facilities, connecting multiple wells to central processing stations. Their design requires careful evaluation of flow dynamics, including pressure loss, temperature variation, and multiphase flow characteristics. According to the Gas Processors Suppliers Association (GPSA) Engineering Data Book (2004), accurate estimation of these parameters is essential to ensure safe, efficient, and continuous operation. Stewart (2014) and Stewart (2016) emphasized that the design of gas-handling and transportation facilities must incorporate factors such as elevation, pipe diameter, and fluid composition to prevent operational inefficiencies. These parameters govern the overall flow regime and

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influence pressure behavior along the network, making hydraulic modeling a vital tool in gas production system design.

Steady-state simulation is commonly applied to evaluate gas flow behavior under stable conditions. It allows engineers to analyze pressure and temperature profiles without considering time-dependent variations. Rahmawati et al. (2012) and Camponogara et al. (2017) highlighted the importance of integrating production and surface network modeling for effective system optimization. Similarly, He et al. (2019) proposed methodologies for optimal gathering pipeline design in mature oilfields to improve operational performance. In such modeling efforts, software tools like PIPESIM are widely used due to their robust capability in predicting multiphase flow parameters using empirical and mechanistic correlations. The Beggs–Brill correlation, as referenced in the GPSA Data Book (2004), provides reliable estimates of frictional pressure losses in gas-condensate systems and is suitable for the steady-state network evaluation performed in this study.

Flow assurance addresses issues that could disrupt the continuous and stable transportation of fluids within a production network. According to Gupta and Sincar (2015, 2016), common challenges include hydrate formation, paraffin deposition, liquid holdup, and slug flow, which can lead to reduced throughput or equipment damage. These phenomena are especially critical in gas-condensate systems, where temperature reduction and pressure drops can induce phase transitions. The API RP 14E guideline provides recommended limits for erosional velocity to prevent internal pipe damage. Managing these parameters within safe ranges through simulation and monitoring ensures system reliability. Studies such as Nugroho et al. (2018) also demonstrated how applying surface compression (e.g., wellhead compressors) can alleviate liquid loading problems and stabilize flow in mature wells, an approach conceptually similar to maintaining backpressure control within gas networks.

A growing body of research has focused on optimizing hydrocarbon field operations by integrating subsurface and surface facility models. Almedallaha and Walsh (2019a, 2019b) and Almedallaha et al. (2020) introduced optimization frameworks for pipeline routing and production scheduling to improve system efficiency, while Demissie et al. (2017) and Gao et al. (2015) developed multi-objective models for gas pipeline operations under uncertainty. Despite these advances, most studies rely on generalized input data or conceptual cases rather than calibrated field data. The present study aims to bridge this gap by developing a field-calibrated steady-state model for the Sanga-Sanga gas gathering network, using real operational data to assess the hydraulic and flow assurance implications of integrating new wells from the Anggana field. This approach provides a more realistic assessment of network performance and supports decision-making in brownfield system development.

Simulation and gap analysis are required to evaluate whether the existing Sanga-Sanga gathering system can hydraulically accommodate additional gas from Anggana without exceeding pressure limits or compromising flow assurance. Given the ageing state of the network and the interaction between multiple inlet nodes, analytical calculations alone cannot capture the nonlinear pressure–flow behavior. A field-calibrated model was therefore selected to minimize uncertainty by ensuring that simulated pressures match actual field measurements within an acceptable deviation (<2%). This calibration enables the simulation to reliably represent real operating conditions and ensures that scenario evaluations reflect realistic system responses.

METHODS

This study was structured into sequential stages encompassing data acquisition (Table 1 and 2), model development (Figure 1), scenario simulation, and technical evaluation. Field data including wellhead pressures, gas compositions, pipeline lengths, and diameters were obtained from the Anggana and Sanga-Sanga assets. PVT analysis was conducted to determine gas properties and thermodynamic behavior, serving as key inputs for model initialization. Using these validated datasets, a steady-state base model of the existing Sanga-Sanga gas network—connecting the NKL, Site B, and SP-998 gathering stations to the Lempake Booster Compressor—was constructed in PIPESIM.

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Two development scenarios were subsequently evaluated to assess network performance under future integration plans. Scenario 1 considered a tie-in configuration in which new Anggana wells are routed into the current Sanga-Sanga network, whereas Scenario 2 proposed a dedicated 3-inch pipeline directly linking Anggana production to the Lempake facility. Each scenario was assessed based on pressure distribution, flow stability, and flow assurance criteria, including temperature and velocity profiles.

The Beggs–Brill correlation was applied for multiphase flow prediction with heat transfer modeling enabled to ensure accurate representation of thermohydraulic conditions within the system. The Beggs–Brill correlation was selected because it provides reliable predictions for multiphase gas–liquid flow over a wide range of pipeline inclinations, diameters, and flow regimes. This correlation is widely used in steady-state pipeline modeling and is recommended in the GPSA Engineering Data Book for gas-condensate systems typical of East Kalimantan fields. Considering the terrain, fluid properties, and operational envelope of the Sanga-Sanga system, Beggs–Brill offers the most appropriate balance of robustness and computational stability for this study.

RESULTS AND DISCUSSION

Existing Network Performance

Based on existing Sanga-Sanga gas network and input data from current gas well, a simulation is generated and obtained the result close to the actual condition (Figure 2 and Table 3). The deviation between actual and simulation condition is in threshold for the simulation model to represent actual condition. Therefore, it can be concluded that the simulation model can be considered representative of actual condition in the field. Simulation of the existing Sanga-Sanga network showed that the system operates close to its hydraulic limit. Flow from NKL and SP-998 exhibits pressure losses exceeding 12% of total inlet pressure, particularly during high-demand periods.

Table 1. Existing Sanga-Sanga Well Condition

Site	Well	Length (meter)	Pipe Diameter (inch)	Flow Rate (MMscfd)	Actual Condition FLP (psig)
SP 998	NKL-998a	1540	3	0.2112	200
	NKL-998b	1650	3	0.4173	160
	NKL-998c	144	3	0.2118	155
	NKL-998d	1150	3	0.384	155
SP NKL	NKL-SP1	2950	3	0.4904	200
	NKL-SP2	1400	3	0.7731	300
	NKL-SP3	2030	3	0.255	180
SP Site B	NKL-B1	1260	3	0.0195	190
	NKL-B2	826	3	0.4024	230
	NKL-B3	1210	3	0.7524	200
	NKL-B4	658	3	0.3909	185

Tabel 2. New Anggana Gas Well Potential

Sumur	Layer	Parameter Reservoir						Initial Pressure	IGIP
		Depth mTVDSS	Fluid	Netpay (m)	Por (fraksi)	Sw (fraksi)	Perm (mD)	(psi)	MMSCF
Ang-002	C-2	400	G	6	0.23	0.55	54	527	156.1
	D-9	818	G	4	0.14	0.64	10	1400	143.0
	D-10	865	G	13	0.17	0.48	8	1654	884.2
Ang-004	C-2	400	G	6	0.23	0.55	54	527	156.1
	D-10	865	G	13	0.17	0.48	8	1654	884.2
Ang-003	C-2	405	G	6	0.22	0.56	34	518	142.6
	D-9.1	849	G	3	0.14	0.56	6	1500	131.6
Ang-001	D-7.1	766	G	2	0.14	0.64	3	964	46.0
	D-10	865	G	13	0.17	0.48	8	1654	884.2

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	D-17.1	947	G	6	0.15	0.68	6	1700	232.9
Ang-005	D-18.1 (DST-2)	1415	G	6	0.14	0.62	6	3010	433.4
	D-18.1A (DST-1)	1618	G	6	0.19	0.58	12	3440	701.8

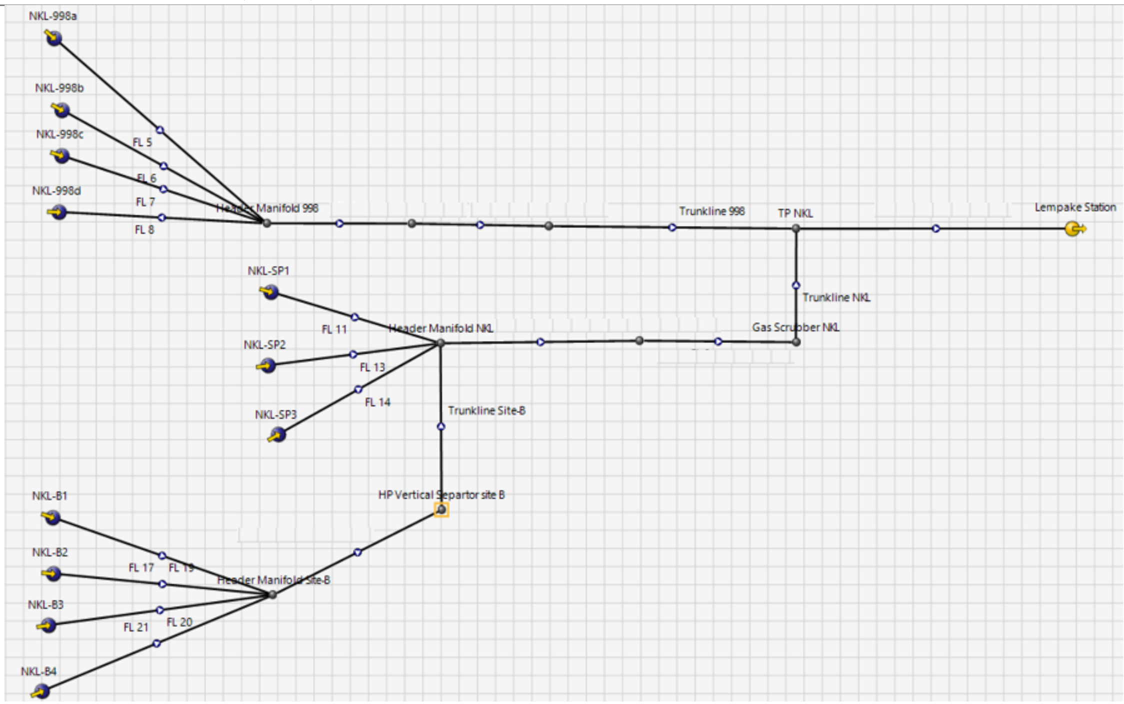

Figure 1. Existing Sanga-Sanga Gas Network

Dedicated Line Scenario Results

In the option of adding a new pipeline, the Anggana gas well will be directly channeled to the booster compressor station in Lempake. In this condition, it is necessary to build a distribution pipeline from the manifold in the Anggana field to Lempake. The estimated distance from the Anggana field to Lempake is 20 km. In addition to the construction of the distribution pipeline from Anggana to Lempake, the construction of a flowline is also required from the five Anggana gas wells to the Manifold in Anggana. The data listed in Table 4 represents estimates of three conditions during gas flow at the Anggana well. These conditions are low, medium, and high case.

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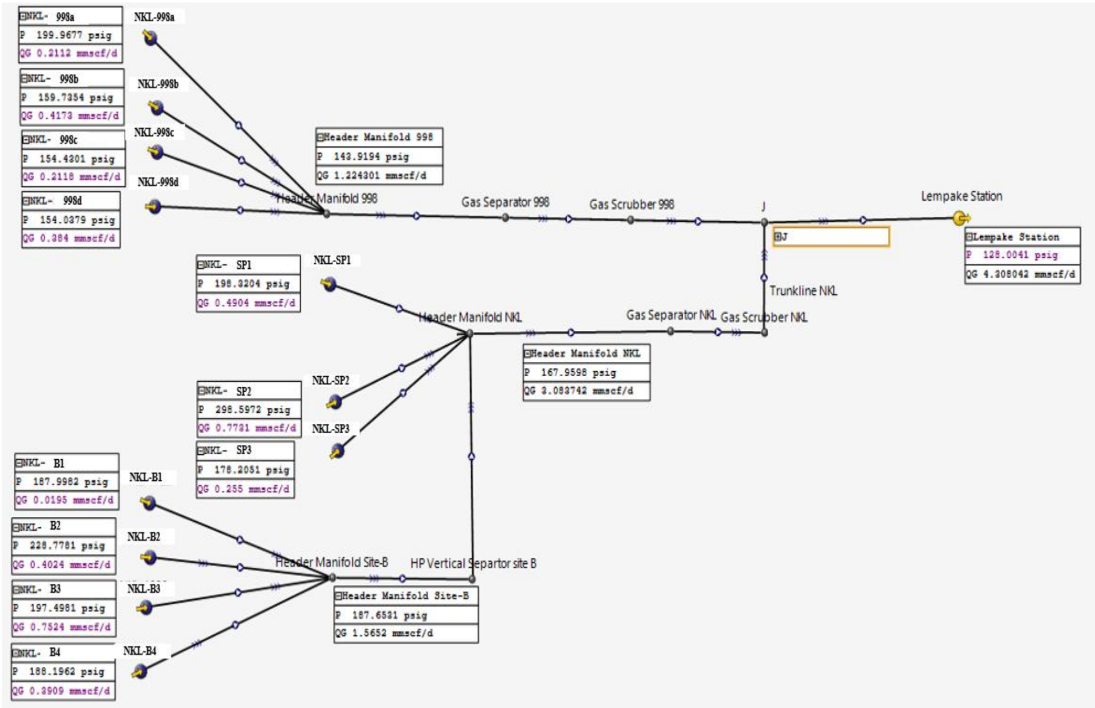

Figure 2. Sanga-Sanga Gas Network Model Result

Tabel 3. Actual Vs Simulation Result Gas Network Model

Well	Length	Pipe Diameter	Flow Rate	Actual Condition	Simulation Result FLP	Deviation	Acceptance Condition
	(meter)	(inch)	(MMscfd)	FLP (psig)	(psig)	(%)	(dev < ±2% = ok)
NKL-998a	1540	3	0.2112	200	200	0.00	Ok
NKL-998b	1650	3	0.4173	160	159.7	0.19	Ok
NKL-998c	144	3	0.2118	155	154.4	0.39	Ok
NKL-998d	1150	3	0.384	155	154	0.65	Ok
NKL-SP1	2950	3	0.4904	200	198.3	0.85	Ok
NKL-SP2	1400	3	0.7731	300	298.6	0.47	Ok
NKL-SP3	2030	3	0.255	180	178.2	1.00	Ok
NKL-B1	1260	3	0.0195	190	188	1.05	Ok
NKL-B2	826	3	0.4024	230	228.8	0.52	Ok
NKL-B3	1210	3	0.7524	200	197.5	1.25	Ok
NKL-B4	658	3	0.3909	185	188.2	-1.73	Ok

Tabel 4. Anggana Gas Flowrate Condition

Sumur	Length to Manifold	Flowrate		
		Low Case	Normal Case	High Case
	meter	MMscfd	MMscfd	MMscfd
Ang-002	1981	0.23	0.27	0.2
Ang-004	1976		0.2	
Ang-003	1000		0.3	0.16
Ang-001	1401		0.23	0.46
Ang-005	494	0.29		0.7

Based on the case used (low, medium, high case), the length of the pipe from the Anggana gas well-manifold- booster compressor station, and the required wellhead pressure (350 psig), a gas distribution simulation can be modeled to determine the appropriate pipe size. The simulation model used to determine the pipe size can be seen in Figure 3. The results of the Anggana gas distribution simulation using a dedicated line to the booster station. Lempake compressor for each case can be seen in Table 5.

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Based on the simulation results of Anggana gas flow to the Lempake booster compressor station using a dedicated line, the pipe that can represent the flow conditions during low, medium, and high cases is a 3-inch pipe. This is because in medium and high case flow conditions, the pressure at the wellhead exceeds the value determined from the sub-surface calculation (350 psig). The pressure value at the wellhead exceeds 350 psig indicating the use of the pipe size used, results in significant backpressure. This can result in the gas not flowing from the production well. Flow assurance evaluation confirms that the dedicated line reduces liquid holdup, prevents slugging, and maintains gas velocity within safe operational limits.

The 3-inch pipeline was selected because it maintains wellhead pressure below the maximum allowable limit of 350 psig across all flow cases. Simulations show that a 2-inch line generates excessive backpressure—exceeding 600–1000 psig in medium and high cases—resulting in non-flowing wells. The 3-inch line provides the optimal hydraulic balance by keeping pressure losses low, preventing operational bottlenecks, and ensuring that the Anggana wells can flow naturally without requiring additional compression. This demonstrates that 3 inches represents the minimum feasible diameter that satisfies both hydraulic and flow assurance constraints.

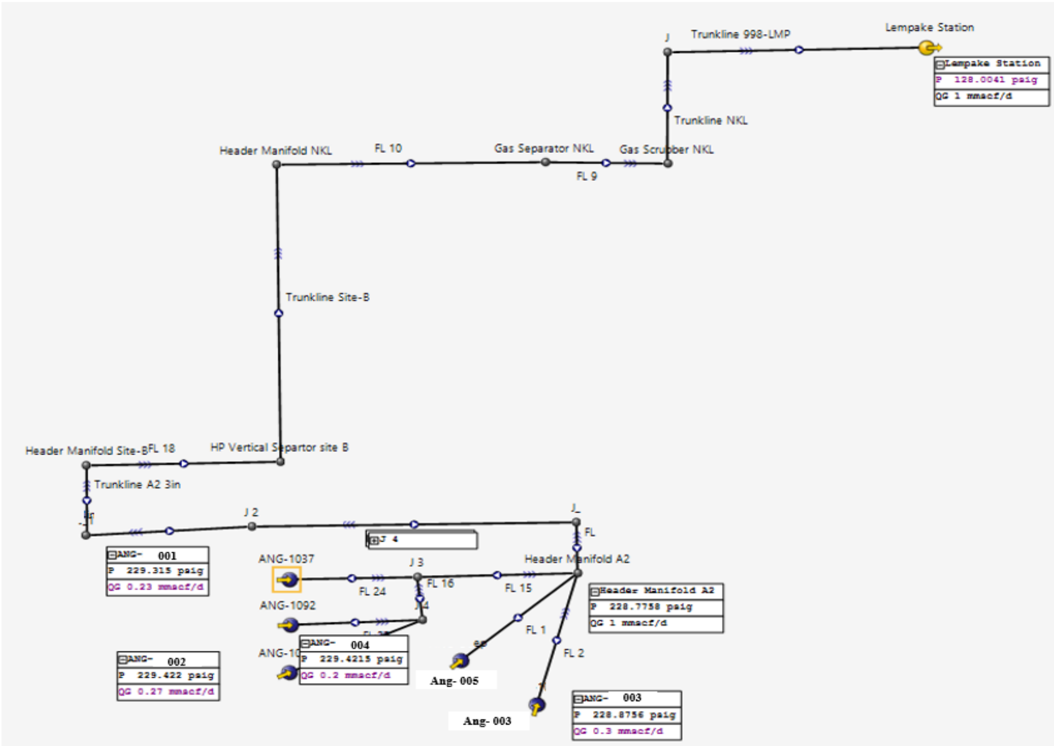

Figure 3. Simulation Model Anggana Gas Dedicated Line

Tabel 5. Simulation Result of Anggana Gas Dedicated Line

Sumur	**FTHP**	**Pressure Well Head (psig) Vs Line size (inch)**						**Remarks**
		Low Case		Normal Case		High Case		
	(Psig)	2"	3"	2"	3"	2"	3"	
Ang-002	350	304.8	162.1	696.2	229.4	1004.9	313.9	Use 3 inch Pipe
Ang-004	350			696.2	229.4			Use 3 inch Pipe
Ang-003	350			696	228.9	1004.8	313.6	Use 3 inch Pipe
Ang-001	350			696.2	229.3	1004.9	313.9	Use 3 inch Pipe
Ang-005	350	304.8	162			1004.8	313.8	Use 3 inch Pipe

Tie-in Scenario Results

When Anggana wells are tied into the existing system (Figure 4), the network experiences significant pressure buildup at the upstream nodes. This leads to an 40% increase in backpressure (for high case) and approximately 35% reduction in total gas throughput due to flow redistribution (for low case). The summary of effect Anggana tie in to installed network is shown in Table 6.

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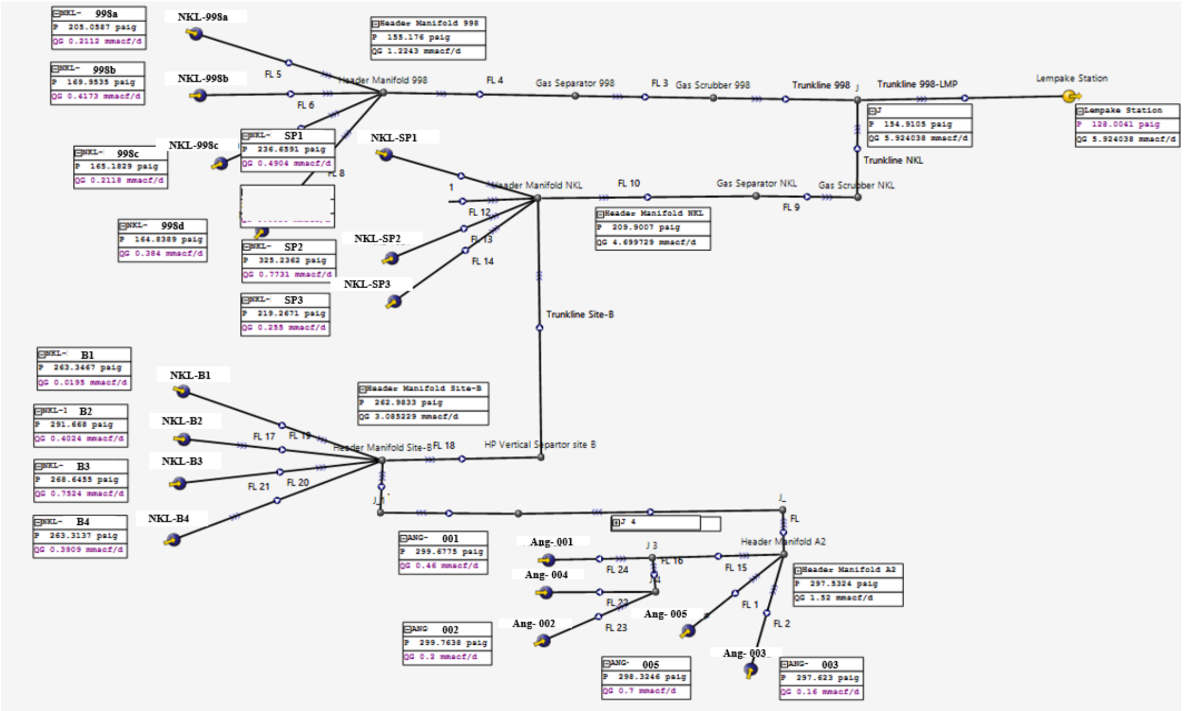

Figure 4. Anggana Gas Well Tie in Configuration to the Installed Gas Network

Table 6. Anggana Gas Well Effect to Installed Gas Network

Site	Flowrate (MMscfd) Before Tie in	After Tie in Flowrate (MMscfd) Low Case	Medium Case	High Case
SP 998	1.2243	0.807	0.807	0.807
SP NKL	1.5185	1.5185	1.2635	1.2635
SP Site B	1.5652	0.0195	0.0195	0.0195
SP Anggana	0	0.52	1	1.52
Total	4.308	2.865	3.09	3.61

In Table 6, assuming that gas wells with pressures greater than their FTHP values will not produce, it can be tentatively concluded that gas production at SP 998, SP NKL, and SP Site B would be greater if the Anggana gas wells were not tied in to the installed gas network. The most affected wells are the gas wells at SP Site B. Table 6 shows a very significant decrease in production, almost reaching a 100% decrease in production.

To mitigate this, while maintaining the flow of the Anggana gas well, several optimizations are required in the flow of the gas wells that are currently producing. The optimization was carried out by simulating the wells that are currently producing (SP NKL gas well, SP Site B, and SP 998) and the Anggana gas well with a new pipe configuration. The simulation results and flow configuration to accommodate the production of the production wells and the Anggana well can be seen in Tables 7–9 and Figure 5.

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Table 7. Modification of Installed Gas Pipeline Network (Low Case)

Site	Well	Length to Manifold (meter)	Pipe Diameter (inch)	Flow Rate (MMscfd)	FLP Simulation Result (psig)	Flowing Pressure (FTHP) psig
SP 998	NKL-998a	1540	3	0.2112	195	270
	NKL-998b	1650	3	0.4173	153.2	160
	NKL-998c	144	3	0.2118	147	300
	NKL-998d	1150	3	0.384	147	530
SP NKL	NKL-SP1	2950	3	0.4904	179	300
	NKL-SP2	1400	3	0.7731	285.1	300
	NKL-SP3	2030	3	0.255	156.6	200
SP Site B	NKL-B1	1260	3	0.0195	183	295
	NKL-B2	826	3	0.4024	225.7	230
	NKL-B3	1210	3	0.7524	192	220
	NKL-B4	658	3	0.3909	183	200
Manifold SP Anggana to Site B		5846.64	4			
Manifold SP Site B to SP NKL		4598	6			
Manifold SP NKL to Tie in SP 998		6431.53	8			
Manifold SP 998 to Tie in SP 998		784	6			
Tie in SP 998 to Lempake		3320	8			
				Flow Rate (MMscfd)	FLP (psig)	Flowing Pressure (FTHP)
			Option Line Size	Low Case	Low Case	psig
SP Anggana	Ang-001	1401	2			350
	Ang-002	1981	2	0.23	189.2	350
	Ang-003	1000	2			350
	Ang-004	1976	2			350
	Ang-005	494	2	0.29	189	350

Table 8. Modification of Installed Gas Network (Medium Gas)

Site	Well	Length to Manifold (meter)	Pipe Diameter (inch)	FMedium Rate (MMscfd)	FLP (psig) Simulation Result Medium Case	Site
SP 998	NKL-998a	1540	3	0.2112	195	270
	NKL-998b	1650	3	0.4173	153.2	160
	NKL-998c	144	3	0.2118	147	300
	NKL-998d	1150	3	0.384	147	530
SP NKL	NKL-SP1	2950	3	0.4904	179	300
	NKL-SP2	1400	3	0.7731	285.1	300
	NKL-SP3	2030	3	0.255	156.6	200
SP Site B	NKL-B1	1260	3	0.0195	183	295
	NKL-B2	826	3	0.4024	225.7	230
	NKL-B3	1210	3	0.7524	192	220
	NKL-B4	658	3	0.3909	183	200
Manifold SP Anggana to Site B		5846.64	4			
Manifold SP Site B to SP NKL		4598	8			
Manifold SP NKL to Tie in SP 998		6431.53	8			
Manifold SP 998 to Tie in SP 998		784	6			
Tie in SP 998 to Lempake		3320	8			

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[redacted]				FMedium Rate (MMscfd)	FLP (psig)	FMediuming Pressure (FTHP)
[redacted]			Option Line Size	Medium Case	Medium Case	psig
SP Anggana	Ang-001	1401	2	0.23	178.2	350
	Ang-002	1981	2	0.27	178.3	350
	Ang-003	1000	2	0.3	177.7	350
	Ang-004	1976	2	0.2	178.3	350
	Ang-005	494	2			350

Table 9. Modification of Installed Gas Network (High Case)

Site	Well	Length to Manifold (meter)	Pipe Diameter (inch)	FHigh Rate (MMscfd)	FLP (psig) Simulation Result High Case	Site
SP 998	NKL-998a	1540	3	0.2112	199.2	270
	NKL-998b	1650	3	0.4173	158.8	160
	NKL-998c	144	3	0.2118	153.3	300
	NKL-998d	1150	3	0.384	153	530
SP NKL	NKL-SP1	2950	3	0.4904	188.5	300
	NKL-SP2	1400	3	0.7731	291.5	300
	NKL-SP3	2030	3	0.255	167.5	200
SP Site B	NKL-B1	1260	3	0.0195	163	295
	NKL-B2	826	3	0.4024	214.8	230
	NKL-B3	1210	3	0.7524	169.6	220
	NKL-B4	658	3	0.3909	163.2	200
Manifold SP Anggana to Site B	[redacted]	5846.64	4	[redacted]		
Manifold SP Site B to SP NKL	[redacted]	4598	8	[redacted]		
Manifold SP NKL to Tie in SP 998	[redacted]	6431.53	8	[redacted]		
Manifold SP 998 to Tie in SP 998	[redacted]	784	6	[redacted]		
Tie in SP 998 to Lempake	[redacted]	3320	8	[redacted]		
[redacted]				FHigh Rate (MMscfd)	FLP (psig)	FHighing Pressure (FTHP)
[redacted]			Option Line Size	High Case	High Case	psig
SP Anggana	Ang-001	1401	2	0.46	213.7	350
	Ang-002	1981	2	0.2	213.7	350
	Ang-003	1000	2	0.16	213.5	350
	Ang-004	1976	2			350
	Ang-005	494	2	0.7	213.3	350

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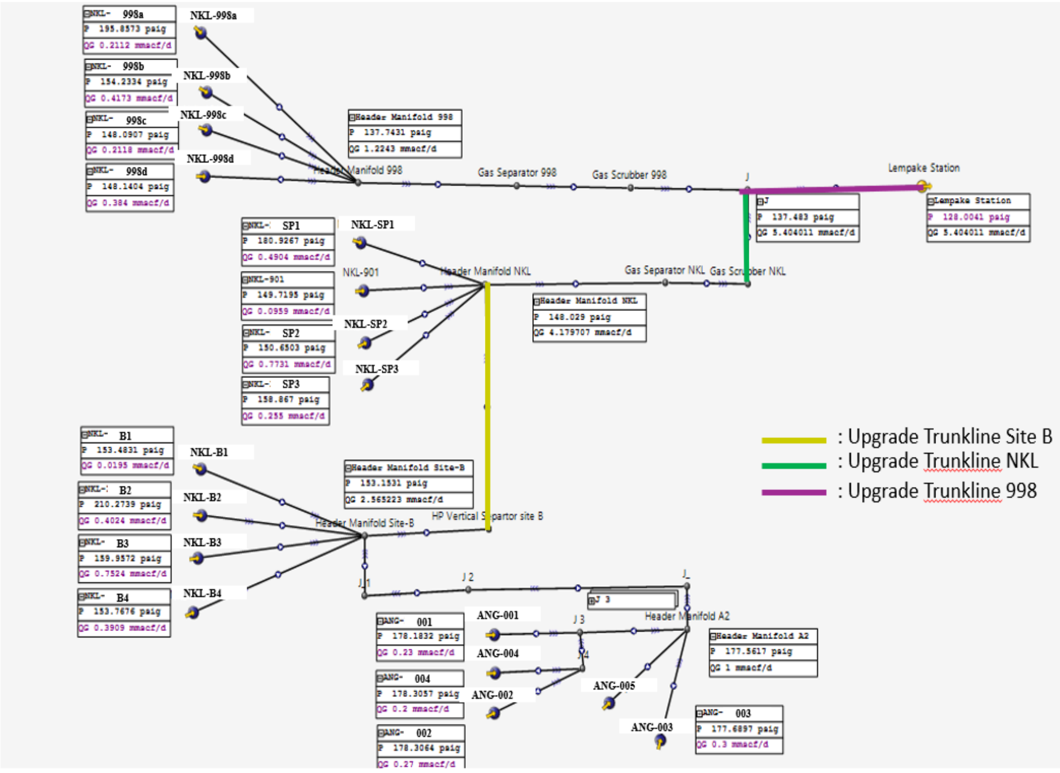

Figure 5. Modification of Installed Gas Network (Medium Case)

Figure 5 shows the modifications made to the installed gas network to accommodate the flow of 1 MMscfd of Anggana gas (medium case). In this case, based on the simulation, pipe replacement is required on three trunklines, namely; the SP Site B trunkline , the SP NKL trunkline , and the SP 998 line upgrading. The pipe replacement that needs to be done on these three trunklines is by replacing the currently installed 6-inch pipe with an 8-inch pipe. The estimated length of pipe that needs to be replaced for this medium case is 14.4 km. Based on the calculations that have been done for each case (Table 7 – 9), the medium and high cases require pipe replacement with the same length, which is approximately 14.4 km. Meanwhile, in the low case, the required pipe replacement is 9.8 km. With the modifications to the installed gas network, the gas production for the Sangasanga area (SP NKL, SP Site B, SP 998, and SP Anggana) can be obtained as listed in Table 10.

Table 10. Sanga-Sanga Gas Obtain After Line Modification

	After Modification Flowrate (MMscfd)			
Flowrate (MMscfd)	Before Tie in	Low Case	Medium Case	High Case
SP 998	1.2243	1.2243	1.2243	1.2243
SP NKL	1.5185	1.5185	1.5185	1.5185
SP Site B	1.5652	1.5652	1.5652	1.5652
SP Anggana	0	0.52	1	1.52
Total	4.308	4.828	5.308	5.828

Comparative Evaluation

When comparing between tie in Anggana well to existing line and construct dedicated line to deliver Anggana well to booster compressor Lempake, the dedicated line configuration performs better in all flow assurance parameters: lower pressure drops, higher throughput, and improved stability. Although this configuration requires higher capital expenditure, its operational reliability and efficiency justify the design choice from a technical standpoint. Tie in Anggana well to existing line may become technically feasible when it combines with partial upgrading pipeline.

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The optimization of the tie-in configuration involves a trade-off between capital cost and system reliability. Although upgrading several trunklines (4-inch to 8-inch replacements) allows the Anggana production to enter the network, this option requires replacing 9.8–14.4 km of pipe, which significantly increases CAPEX. Furthermore, the upgraded system still operates closer to hydraulic limits due to shared line utilisation, presenting higher operational risk compared with a dedicated line. In contrast, the dedicated line requires higher initial investment but eliminates inter-field backpressure interaction, improves flow stability, and provides long-term scalability. These trade-offs reinforce that the dedicated pipeline offers superior operational robustness.

CONCLUSION

The simulation model has been well validated, as indicated by a pressure deviation of approximately 2% from actual data, which remains within acceptable tolerance limits, confirming that the existing Sanga-Sanga gas network is hydraulically constrained and unable to accommodate additional flow from the Anggana Field. Scenario evaluation shows that the tie-in option leads to increased backpressure and reduced throughput, resulting in production losses of 1.4 MMscfd, 1.2 MMscfd, and 0.7 MMscfd for the low, medium, and high cases, respectively, and posing flow assurance challenges throughout the network. In contrast, constructing a 3-inch dedicated line provides smooth, stable, and reliable gas delivery to the Lempake Booster Station across all scenarios, making it the most technically sound solution for optimizing gas transport from Anggana.

Despite its advantages, the optimization presented in this study is limited to steady-state conditions and does not account for transient behaviors such as start-up, shut-in cooling, or pigging operations, which may impact flow assurance. Future work should incorporate dynamic simulation and a full techno-economic assessment to evaluate lifecycle performance under operational variability.

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