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Simulation of Hydrate Formation Risk and Mitigation in Field X Deep Offshore Production Systems Using Olga

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Abstract

Flow assurance is critical in deepwater production systems, where gas hydrates threaten operational integrity. This study evaluates gas hydrate risk and mitigation for a retrograde gas condensate reservoir in Niger Delta's Field X, which experienced production decline exceeding 90%. Using integrated Multiflash-OLGA simulations, high innate gas hydrate risk due to fluid composition (high CH_4, H_2S, CO_2) and seabed conditions (−4°C) were identified. The riser and downstream sections were most vulnerable, entering the hydrate window within 10–12 hours during shutdown. Treatment with 40 wt% Monoethylene Glycol (MEG) concentration was appropriate for steady-state operation while hybrid inhibition was essential for transient scenarios such that 40% MEG + 20% Methanol (MeOH) was highly effective but 40% MEG + 40% MeOH ensured full 24-hour shutdown protection. Results strongly implicate hydrates in the field's decline and demonstrate that a dual-inhibitor strategy balances technical and economic needs for deepwater flow assurance.

Keywords: *Flow assurance; Gas hydrate risk; Multiflash-OLGA simulation; Monoethylene glycol; Methanol; Deepwater; Niger Delta.*

1. Introduction

The global energy landscape has witnessed a significant shift towards deep and ultra-deepwater exploration and production as conventional onshore and shallow-water reserves mature and decline. Nigeria's Niger Delta basin, a prolific hydrocarbon province, exemplifies this trend, with its deepwater assets constituting a critical component of the nation's energy security and economic stability. However, the exploitation of these deepwater resources is beset with a suite of complex technical challenges, collectively termed flow assurance, which encompasses the strategies and technologies required to ensure the uninterrupted and economical flow of hydrocarbons from the reservoir to the processing facility [1-2].

The deepwater environment is characterized by extreme conditions—low seabed temperatures (often as low as -4°C to 0°C) and exceedingly high hydrostatic pressures (exceeding 10 MPa)—that create a perfect storm for flow assurance issues [3-4]. Among these, the formation of natural gas hydrates is arguably one of the most severe and economically daunting risks. Gas hydrates are crystalline, ice-like solid compounds that form when water molecules encapsulate small gas molecules such as methane, ethane, or carbon dioxide under specific conditions of low temperature and high pressure [5-6]. Once nucleated, hydrates can agglomerate, accumulate, and ultimately plug flowlines and subsea equipment, leading to substantial production downtime, severe safety hazards, and exorbitant remediation costs that can run into hundreds of millions of dollars [7-8].

The problem is particularly acute in the Niger Delta due to the compositional nature of the produced fluids, which often contain significant amounts of formation water, light hydrocarbons, and in some cases, aggravating acidic components like carbon dioxide (CO_2) and hydrogen sulphide (H_2S) that can shift the hydrate equilibrium conditions to higher temperatures, thereby enlarging the region of hydrate stability [9-10]. The risk is further amplified during transient operational events such as planned shutdowns, unplanned trips, and subsequent restarts. During these periods, the flowing fluids undergo significant thermal and hydraulic transients, which tend to occur within the hydrate formation envelope [11-12].

The industry's traditional approach to hydrate management has often relied on conservative, rule-of-thumb application of thermodynamic inhibitors, primarily monoethylene glycol (MEG) and methanol (MeOH). This approach, while sometimes effective, is frequently suboptimal, leading to either chemical overuse (increasing operational expenditure, OPEX) or under-dosing (increasing risk of catastrophic blockages) [13-14]. The advent of advanced dynamic multiphase flow simulators, such as OLGA, coupled with robust thermodynamic software like Multiflash, has revolutionized flow assurance engineering. These tools enable a proactive, physics-based, and field-specific approach, allowing engineers to model complex transient scenarios, accurately predict hydrate formation zones, and precisely optimize mitigation strategies before they are deployed in the field [15-16].

Despite the availability of these sophisticated tools, there remains a discernible gap in their detailed, field-specific application and validation within the context of Nigerian deepwater fields. Much of the published literature remains either generic or theoretical, lacking the integration of real-field data and the practical operational insights necessary for direct implementation [17-18].

This study, therefore, aims to bridge this gap by conducting a detailed, integrated simulation study of hydrate formation risk and mitigation for a specific deepwater asset in the Niger Delta—Field X. The well of interest, A5000X, has experienced a perplexing production decline of over 90%, strongly suspected to be related to undiagnosed hydrate blockages. The objectives are fourfold: (1) to quantitatively assess the innate hydrate risk under steady-state and transient conditions using integrated OLGA-Multiflash simulations; (2) to identify the most vulnerable sections of the production system; (3) to evaluate and optimize the performance of various inhibition strategies (MEG, MeOH, and hybrid blends); and (4) to develop a robust, economically viable hydrate management strategy that can be implemented to restore and safeguard production. The findings from this work are intended to provide a validated, replicable framework for flow assurance management in similar deepwater assets, not only within the Niger Delta but also in other deepwater provinces worldwide.

2. Experimental section

2.1. Field and fluid overview

The study focuses on Field X, a deep offshore Niger Delta asset producing from the A5000X retrograde condensate reservoir. Production began in 2000, but recent operations have reported >90% decline, pointing to flow assurance challenges beyond natural reservoir depletion. Fluid composition was characterized by laboratory Pressure, Volume, Temperature (PVT) analysis, which was input to Multiflash®, a thermodynamic fluid property modelling software. The major fluid components are shown in Table 1.

Table 1. Fluid composition of A5000X reservoir.

Component	Mole %	Component	Mole %
Methane (C1)	88.02	Hexane (C6)	0.02
Ethane (C2)	3.46	C7+	2.12
Propane (C3)	2.12	CO_2	3.52
n-Butane (C4)	0.09	H_2S	0.07
n- Pentane (C5)	0.04	H_2O	0.54

2.2. Pipeline and facility geometry

The production system consists of a 50 km, 6-inch subsea pipeline connected to a subsea manifold and an 8-inch, 1.5 km riser; summarized and illustrated in Table 2.

Table 2. Pipeline and riser configuration.

Section	Length (km)	Diameter (in.)	Elevation (m)	Notes
PIPE-1	20	6	0	Upstream Pipeline
PIPE-2	15	6	0	Midstream
PIPE-3	15	6	0	Downstream to manifold
RISER	1.5	8	+1500	Riser

2.3. Simulation workflow and model setup

A structured, two-phase simulation workflow was adopted to ensure a comprehensive and accurate analysis, moving from thermodynamic equilibrium analysis to dynamic flow simulation.

Phase 1: Thermodynamic Analysis using Multiflash

The first phase involved thermodynamic screening using Schlumberger's Multiflash software.

1. Fluid Characterization: The composition in Table 1 was input into Multiflash.
2. Equation of State (EOS) Selection: The Peng-Robinson Advanced (PRA) cubic equation of state was selected (in Multiflash) for its improved accuracy in modeling phase behavior of retrograde condensate systems, particularly for predicting dew points and liquid drop-out [19].
3. Hydrate Model Selection: The Infochem hydrate model (in Multiflash), was used for its proven reliability in predicting hydrate phase equilibrium for both Structure I and II formers and its ability to accurately account for the effects of thermodynamic inhibitors [20].
4. Phase Envelope Generation: Hydrate equilibrium curves (hydrate formation temperature vs. pressure) were generated for multiple scenarios:
    - Base case (no inhibitor)
    - With MEG injection (20 wt%, 40 wt%, 60 wt%)
    - With hybrid MEG + MeOH injection (20% MEG + 10% MeOH, 20% MEG + 20% MeOH, 40% MEG + 20% MeOH, 40% MEG + 40% MeOH)
5. Data Export: The generated thermodynamic data and hydrate equilibrium tables were exported in .tab format for direct use within the OLGA dynamic simulator.

Phase 2: Dynamic Flow Simulation using OLGA

The second phase involved building and running dynamic multiphase flow models using the OLGA simulator.

1. Model Geometry: The entire production system was modeled, comprising three serial pipeline segments (totaling 50 km, 6-inch diameter) and a vertical riser (1.5 km, 8-inch diameter). The pipelines were modeled with insulated walls to represent typical subsea insulation, with a low thermal conductivity of 0.135 W/m·K.
2. Fluid Model: The exported Multiflash .tab files were imported into OLGA to ensure consistent and accurate fluid properties and hydrate predictions.
3. Hydrate Kinetics Model: OLGA's CSMHyK (Colorado School of Mines Hydrate Kinetics) module was activated to simulate the rate of hydrate formation, hydrate volume fraction, and the key risk indicator: the temperature margin (ΔT = flowing stream temperature; 'TM' - hydrate equilibrium temperature 'HYDTM').
4. Simulation Scenarios: Three distinct operational scenarios were modeled:
    - The Steady-State scenario: Simulated 12 hours of continuous production to establish stabilized flow, temperature, and pressure profiles. No valve restrictions were applied.
    - The Shutdown scenario: Simulated a full production halt by closing both the wellhead inlet valve and the riser outlet valve. The model was run for 24 hours to capture the complete cooldown of the system to the ambient seabed temperature.
    - The Restart scenario: Simulated the resumption of production after the 24-hour shutdown by reopening both valves. This 24-hour simulation captured the critical warm-up phase and the displacement of cold, potentially hydrate-laden fluids.
5. Inhibitor Evaluation: For each operational scenario, the simulations were run for the suite of inhibitor cases defined in the Multiflash phase. The performance was evaluated by monitoring ΔT and hydrate volume fraction at key locations: the inlet (PIPE-1), midline (PIPE-2), outlet (PIPE-3), and the riser base.

3. Results and discussions

The Multiflash analysis provided the fundamental thermodynamic basis for assessing hydrate risk. Figure 1 presents the phase envelope for the uninhibited base fluid, vividly illustrating the severe risk. The hydrate stability envelope (HYDTM curve) lies entirely within the operating pressure range of the system and at temperatures significantly above the seabed temperature of -4°C. This confirms that under stagnant or low-flow conditions, the entire pipeline system is at risk of hydrate formation. The presence of H_2S (3.52 mol%), a known strong hydrate former, shifts the equilibrium curve to higher temperatures, further exacerbating the risk, a finding consistent with Jai *et al.* [9].

The subsequent phase plots (Figures 2 to 4) demonstrate the effect of inhibition with MEG. As expected, increasing the MEG concentration progressively suppresses the hydrate envelope, shifting it to lower temperatures at a given pressure. The shift from 0% to 20% MEG is significant (Figure 2), and the shift from 20% to 40% MEG (Figure 3) provides substantial additional suppression. However, the shift from 40% to 60% MEG (Figure 4) is markedly less pronounced, clearly demonstrating the law of diminishing returns and highlighting the economic inefficiency of using very high MEG concentrations, as noted by Riesto [13] and Ndubuise *et al.* [21].

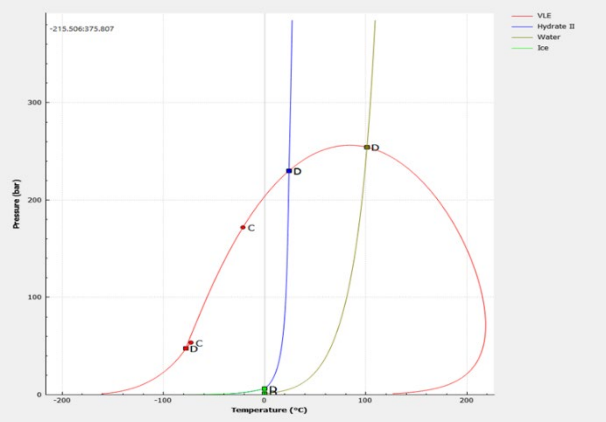

Figure 1. Hydrate phase envelope for Well A5000X base fluid (no inhibitor) showing high risk within operating pressure and seabed temperature range.

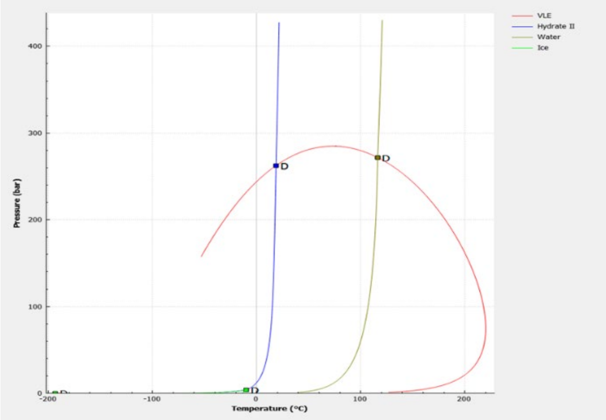

Figure 2. Phase envelope with 20% MEG injection.

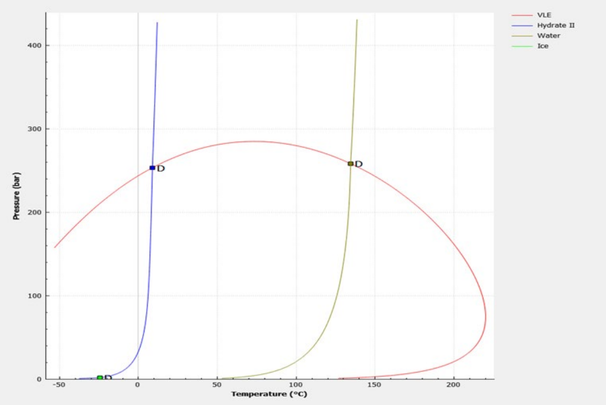

Figure 3. Phase envelope with 40% MEG injection (optimum for steady state).

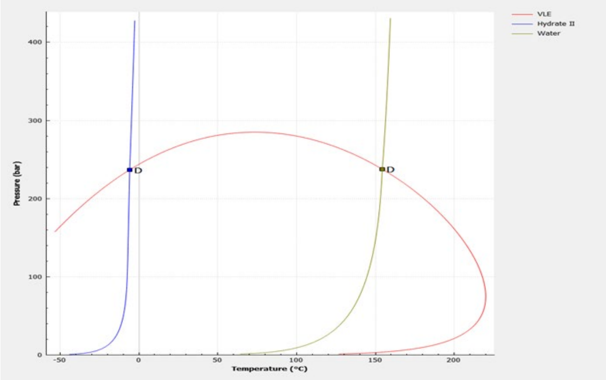

Figure 4. Phase envelope with 60% MEG injection, showing diminishing returns.

A pivotal finding is illustrated in the hybrid inhibitor plots (Figures 5 to 7). Figure 6 shows that a 40% MEG + 20% MeOH blend suppresses the hydrate envelope more effectively than 60% MEG alone (Figure 5). This provides a strong thermodynamic justification for using blended inhibitor strategies, as the MeOH synergistically enhances the suppression effect, allowing for more robust protection without the cost and logistical burden of excessively high MEG concentrations. This aligns with the field recommendations of Ismaila [22] and the experimental observations of Yan [23].

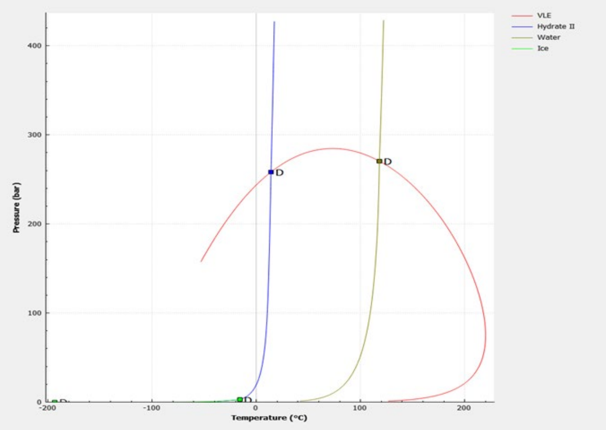

Figure 5. Phase envelope with 20% MEG + 10% MeOH injection.

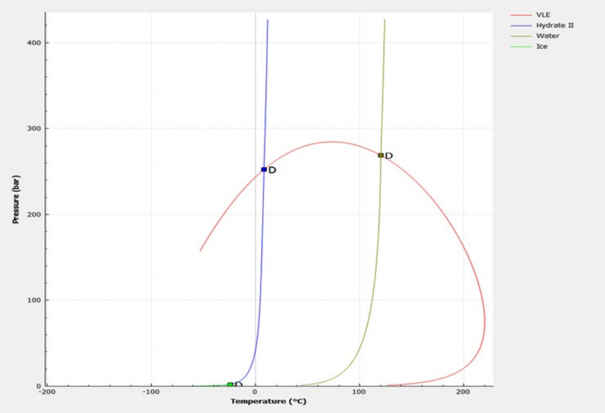

Figure 6. Phase envelope with 20% MEG + 20% MeOH injection.

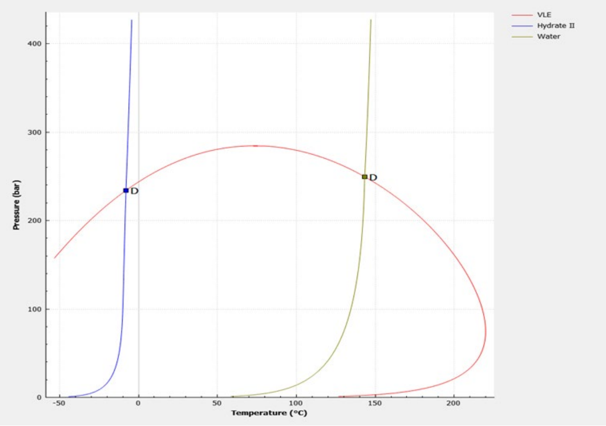

Figure 7. Phase envelope with 40% MEG + 20% MeOH injection (highly effective hybrid blend).

3.1. Steady-state operation results

The OLGA steady-state simulations quantified the thermal journey of the fluid and the resulting hydrate risk during continuous production. The results for the uninhibited (0% MEG) case are summarized in Table 3. While the fluid enters the pipeline from the wellhead at a warm temperature (~15°C), it cools progressively along the flowline due to heat loss to the cold seabed. Consequently, the temperature margin (ΔT) narrows significantly from the inlet (+5.1°C) to the riser base (+0.5°C). This identifies the downstream sections, particularly the riser base, as the most critical and vulnerable zones during steady operation, a phenomenon widely reported in literature due to cumulative heat loss and potential liquid holdup [4, 12].

Table 3. Hydrate risk profile during steady-state operation (0% Inhibitor).

Pipeline Section	Min. fluid temp., TM(C)	Hydrate temp., HYDTM(C)	Temp. margin, ΔT (°C)	Risk classification
PIPE-1 (inlet)	15.2	10.1	+5.1	Safe
PIPE-2 (Mid)	7.5	5.8	+1.7	Narrowing
PIPE-3 (Outlet)	5.1	4.5	+0.6	Marginal
Riser Base	4.8	4.3	+0.5	Marginal

The introduction of inhibitors dramatically improves the safety margin. Table 4 provides a consolidated summary of the minimum temperature margin observed for each inhibitor case. A 20% MEG concentration improves the margin but leaves the riser base in a precarious "Near-Touch" state (ΔT = +0.9°C). A 40% MEG concentration is identified as the clear optimum, providing a safe margin (ΔT > 3°C) across the entire system. Increasing to 60% MEG offers only a marginal improvement in safety margin (ΔT = +5.8°C vs. +5.2°C at the riser base), which does not justify the significant increase in CAPEX (for larger injection/regeneration facilities) and OPEX (for higher chemical consumption and regeneration energy costs). The hybrid blends, as expected, provide even larger margins, but their value is more critical for transient operations.

Table 4. Summary of steady-state mitigation performance (minimum ΔT).

Inhibitor scenario	PIPE-1 ΔT_min (°C)	PIPE-2 ΔT_min (°C)	PIPE-3 ΔT_min (°C)	Riser base ΔT_min (°C)	Overall classification
0% MEG	+5.1	+1.7	+0.6	+0.5	Marginal/Risk
20% MEG	+8.3	+5.2	+1.1	+0.9	Near-Touch
40% MEG	+12.5	+9.8	+5.5	+5.2	Safe (Optimum)
60% MEG	+13.1	+10.5	+6.1	+5.8	Safe+
20% MEG + 10% MeOH	+9.0	+6.5	+3.2	+3.0	Safe
40% MEG + 20% MeOH	+13.8	+11.2	+7.8	+7.0	Safe+

3.2. Shutdown operation results

The shutdown simulations revealed the most severe risk profile. Upon flow stoppage, the trapped production fluids begin a rapid cooldown towards the seabed temperature (-4°C). Without sufficient inhibition, the fluid temperature in the coldest sections of the system (PIPE-3 and riser base) crosses the hydrate equilibrium temperature within a critical timeframe. Table 5 shows the time taken for the temperature margin (ΔT) to reach ≤ 0°C for various inhibitor strategies.

Table 5. Time to hydrate-prone conditions (ΔT ≤ 0°C) during 24-hr shutdown.

Inhibitor Scenario	Time to ΔT ≤ 0°C (Hours)			
	PIPE-1	PIPE-2	PIPE-3	RISER BASE
20% MEG + 10% MeOH	>24	>24	~12	~10
20% MEG + 20% MeOH	>24	>24	~16	~14
40% MEG + 20% MeOH	>24	>24	>20	~18
40% MEG + 40% MeOH	>24	>24	>24	>24 (Fully Inhibited)

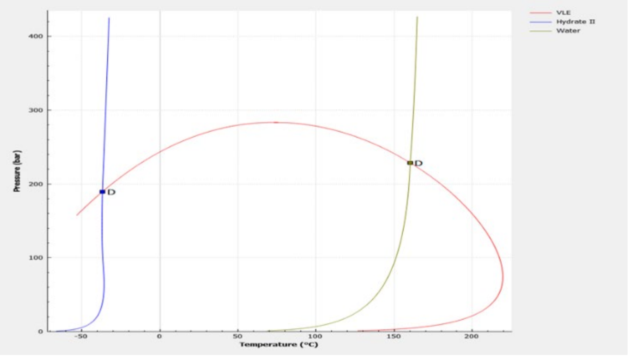

Figure 8. Phase envelope with 40% MEG + 40% MeOH injection (fully protective blend for transients).

The data identifies the riser base as the epicenter of risk during a shutdown, cooling fastest due to its exposure to the water column. While MEG provides a base level of suppression, it is insufficient for extended shutdowns. The addition of MeOH is crucial. The 40% MEG + 40% MeOH blend is the only strategy that provided complete protection throughout the entire 24-hour shutdown period (Figure 8). This validates the practice of "bullheading" or batch injecting a large slug of MeOH into the flowline prior to a planned shutdown, as studied by Okewinike *et al.* [24]. The results underscore the necessity of a dual-chemical strategy: MEG for continuous control and a MeOH slug for transient protection.

3.3. Restart operation results

The restart phase is critically hazardous due to the displacement of the cold fluid slug that has been cooling for hours towards the seabed temperature. As this cold slug is pushed through the system and into the riser, it can spend a prolonged period in the hydrate formation zone, even if the wellhead fluids are warm. The performance of inhibitors was classified based on the simulated hydrate volume fraction and how quickly the system cleared from hydrate-prone conditions, as captured in Table 6.

Table 6. Hydrate risk classification during restart operation.

Inhibitor scenario	PIPE-1	PIPE-2	PIPE-3	RISER BASE
20% MEG + 10% MeOH	Clear fast	Clear fast	Brief Overlap	Brief Overlap
20% MEG + 20% MeOH	Clear fast	Clear fast	Minimal Overlap	Minimal Overlap
40% MEG + 20% MeOH	Clear	Clear	Minimal Overlap	Minimal Overlap
40% MEG + 40% MeOH	Clear	Clear	Clear	Clear

"Clear fast" indicates the section warmed up and became safe within minutes of restart. "Minimal Overlap" indicates a short-lived spike in hydrate risk that quickly dissipated. Only the 40% MEG + 40% MeOH blend ensured a completely safe restart with no hydrate formation predicted across any section of the system. This finding is crucial for operational planning, as a hydrate plug formed during a restart can lead to extended non-productive time and complex remediation operations [8, 12].

The restart risk is captured in Figure 9, showing a momentary HYDFRAC spike following pressure increase, indicating hydrate nucleation. The rapid return to zero confirms a self-mitigating event and 'clear fast' classification for this inhibitor strategy.

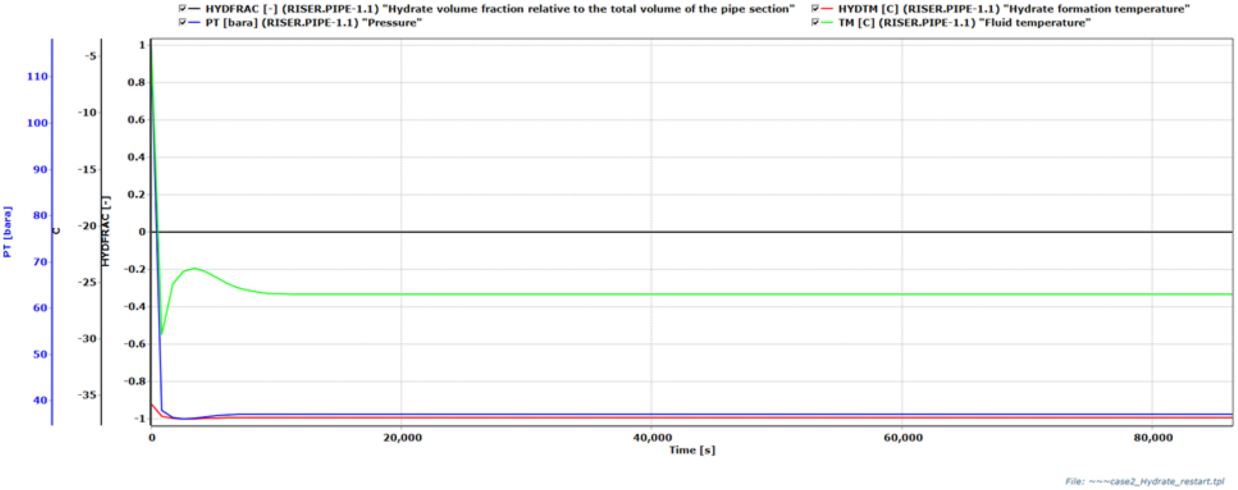

Figure 9. OLGA simulation output during a restart operation in the riser section, showing a brief, self-mitigating hydrate formation event.

3.4. Implications for field performance and economic optimization

The simulation results provide a compelling technical narrative that explains the historical production decline in Well A5000X. The observed vulnerability, especially during shutdown/restart cycles, strongly suggests that undiagnosed hydrate blockages were a primary contributor to the over 90% production loss. The recommended mitigation strategy presents a clear economic trade-off, summarized in Table 7.

The optimal strategy balances CAPEX, OPEX, and risk. Implementing a continuous 40% MEG system, potentially with regeneration, addresses the steady-state risk economically. Supplementing this with a procedure for batch MeOH injection (20-40%) during planned operational changes manages the high-risk transient periods. This hybrid approach is both technically robust and economically prudent, designed to prevent the massive costs associated with production deferment and hydrate remediation.

Table 7. Comparative evaluation of MEG and MeOH for hydrate mitigation.

Parameter	MEG	MeOH	Practical Implications for Field X
Primary use	Continuous, steady state	Batch, transient events	MEG for baseline; MeOH for shutdown/restart
Effectiveness	Strong, dose-dependent	Rapid, potent	MeOH essential for robust transient protection
Recyclability	Recoverable & regenerable	Non-recoverable (lost)	MEG has lower long-term OPEX; MeOH use adds to OPEX
CAPEX impact	High (Regeneration unit)	Low (Simple injection)	Justify MEG regeneration CAPEX with long-term OPEX savings
OPEX impact	Moderate (Energy for regen)	High (Continuous buy)	Justify MEG regeneration CAPEX with long-term OPEX savings
HSE considerations	Lower toxicity, flammability	High toxicity, flammable	Requires stricter safety protocols for MeOH handling
Recommended strategy	Continuous 40% MEG injection	Batch injection for transients	Hybrid approach optimizes cost, safety, and effectiveness

4. Conclusion

High innate risk: the Well A5000X system, with its fluid composition (high gas-to-liquid ratio, presence of CO_2 and H_2S) and deepwater conditions (seabed temp: ~4°C), is inherently prone to hydrate formation, particularly in the downstream pipeline sections and the riser. Transient operations are critical: shutdown and restart operations present the highest risk, with the system cooling into the hydrate formation zone within 10-12 hours during a shut-in event without sufficient inhibition. Effectiveness of inhibitors: a 40 wt% MEG concentration was identified as the cost-effective baseline for providing a safe operating margin (>3°C ΔT) during steady-state production. Higher MEG concentrations (e.g., 60% MEG) offered only marginal improvements, indicating diminishing economic returns. Requirement for a hybrid strategy: for robust mitigation during transient operations (shutdown/restart), a hybrid inhibitor strategy is essential. A combination of 40% MEG + 20% MeOH was found to be highly effective, while a 40% MEG + 40% MeOH blend provided complete protection for a 24-hour shutdown period. Correlation with field data: the historical production decline of over 90% in Well A5000X strongly correlates with the simulated high-risk scenarios, providing compelling evidence that undiagnosed hydrate blockages were a primary contributor to production loss.

5. Recommendations

For Field X, operators should implement a continuous injection of 40% MEG as the standard baseline for hydrate prevention. A procedure for batch injection of MeOH (20-40%) should be developed and used during all planned shutdowns and before restarting the well to manage the high transient risk. The economic feasibility of installing a MEG regeneration unit should be evaluated to reduce the long-term chemical injection cost. A follow-up study investigating the interaction between hydrate and wax deposition in this system is recommended. Further work could explore the sensitivity of the system to water cut variations and different insulation qualities. Future work should focus on creating a real-time monitoring dashboard based on these OLGA results to help operators make quick decisions and prevent blockages.

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