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Integrated Reservoir Simulation and Performance Evaluation of Methane, Foam, And Gravity-Assisted Methane Injection for Enhanced Oil Recovery in Depleted Oil Fields.

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Abstract- Enhanced oil recovery (EOR) remains a major technical challenge in depleted oil reservoirs where declining pressure and reduced sweep efficiency limit hydrocarbon mobilization. Many mature fields require improved injection strategies capable of delivering stable displacement fronts and restoring reservoir energy. Despite the widespread use of methane and foam injections, their comparative performance under realistic heterogeneity conditions is not fully quantified. This study aims to evaluate methane flooding, foam injection, and gravity-assisted methane injection using a calibrated 3D reservoir simulation model to determine the most effective mechanism for improving oil recovery. A full-physics black-oil model was constructed, history-matched, and subjected to the three EOR scenarios. Production behaviour, cumulative oil, recovery factors, sweep efficiency, displacement patterns, and pressure distribution were analysed. Methane injection delivered the highest uplift, increasing cumulative oil from *3.26 × 10⁶ stb (base case)* ***to*** *4.19 × 10⁶ stb*, ***with oil rates rising from*** *2,850 stb/day* ***to peaks of*** *4,200 stb/day*, ***and improving the recovery factor from*** *29.6% to 38.4%*. ***Foam injection yielded*** *3.74 × 10⁶ stb*, ***achieving a*** *15% increase in sweep efficiency* ***and reducing gas mobility by nearly*** *40%*, ***which stabilized the displacement front. Gravity-assisted methane injection recovered*** *3.62 × 10⁶ stb*, ***improving vertical sweep by*** *12%* ***and delaying gas override. Methane flooding also demonstrated superior displacement efficiency (up to*** *0.71*) ***and maintained reservoir pressure above*** *2,600 psia*, ***compared with*** *2,320 psia* ***under foam and*** *2,180 psia* ***under gravity-assisted methane. Methane injection exhibited the strongest performance across all metrics, while foam and gravity-assisted schemes offered secondary benefits in mobility control and vertical sweep improvement. These findings provide a robust technical basis for selecting and optimizing gas-based EOR methods in depleted reservoirs.***

Index Terms- Enhanced Oil Recovery; Methane Injection; Foam Injection; Reservoir Simulation; Sweep Efficiency; Displacement Efficiency; Recovery Factor; Depleted Oil Reservoirs.

I. INTRODUCTION

The global surge in energy demand continues to intensify due to rapid population growth and industrial development, making hydrocarbons a critical component of global energy supply despite the shift toward renewable alternatives (Lake et al., 2014; Ahmed, 2019). However, primary and secondary oil recovery methods typically produce only 30–40% of the original oil in place, leaving a substantial volume of hydrocarbons unrecovered because of capillary trapping, reservoir heterogeneity, and poor displacement mechanisms (Craft & Hawkins, 2013; Alvarado & Manrique, 2019). To address this persistent challenge, the petroleum industry has developed enhanced oil recovery (EOR) techniques capable of mobilizing residual oil and improving volumetric sweep efficiency. Among these approaches, gas injection (particularly through methane flooding) has gained significant attention due to its availability, favorable thermodynamic properties, and potential for miscible displacement (Sheng, 2010; Hassan et al., 2019).

Methane enhances oil recovery by dissolving in crude oil, reducing viscosity and interfacial tension, and improving displacement efficiency when injected above minimum miscibility pressure (Fan et al., 2021; Ahmed et al., 2021). Nevertheless, methane flooding is greatly affected by gravity override, early breakthrough, and viscous fingering, which reduce areal and vertical sweep efficiency, especially in heterogeneous reservoirs (Obi & Adeniyi, 2022; Kareem et al., 2023). To mitigate these limitations, foam-assisted gas injection (FAGI) has emerged as a promising EOR strategy that improves methane mobility control by increasing apparent gas viscosity, diverting flow from high-permeability streaks, and enhancing conformance across the reservoir (Li et al., 2022; Bera et al., 2018; Wang et al., 2019). Foam suppresses gas channeling and delays breakthrough, creating better access to previously unswept zones and ultimately increasing cumulative oil recovery (Zhang et al., 2019; Awan et al., 2021). Recent research further highlights that methane-foam systems not only improve mobility control but also achieve displacement performance comparable to CO_2-foam with reduced operational and environmental drawbacks (Gomez et al., 2025).

Another promising development is gravity-assisted methane injection, which leverages density contrast between injected gas and reservoir oil to stabilize the displacement front and improve vertical sweep efficiency (Kareem et al., 2023). Gravity-stabilized methane flooding can reduce gas override and bypassed oil zones by encouraging downward migration of the displacement interface, offering better macroscale sweep in stratified reservoirs. However, the performance of methane, foam, and gravity-assisted methane injection is highly dependent on reservoir heterogeneity, operational pressure, and injection strategy, requiring detailed and realistic reservoir simulation for accurate quantification of cumulative oil recovery, breakthrough index, and displacement behaviour (Amani & Alvarado, 2010; Craft & Hawkins, 2013).

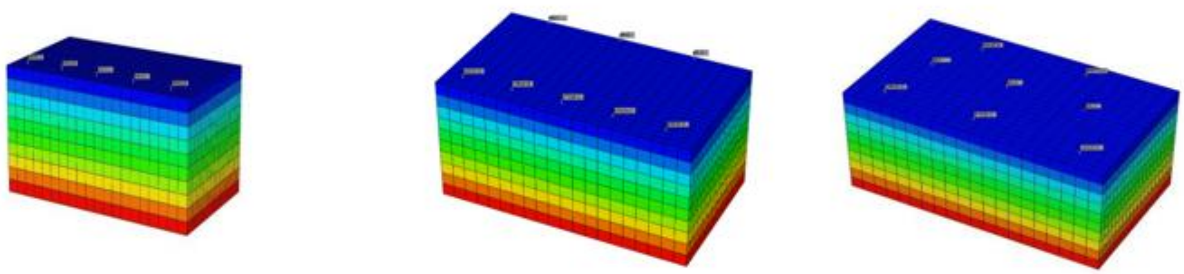
To advance reservoir performance understanding, numerical simulation using compositional models has become indispensable in analyzing multiphase flow behaviour and evaluating complex gas–liquid interactions under different injection conditions (Amani & Alvarado, 2010; Wang et al., 2020). Modern simulation platforms allow detailed computation of pressure gradients, miscibility transitions, sweep efficiency, displacement efficiency, and recovery factor evolution during methane and foam injection schemes (Li et al., 2022; Chen et al., 2018; Tran et al., 2020). Despite the progress in modelling and laboratory investigations, there remains a critical gap in comparative evaluation of methane, foam, and gravity-assisted methane injection within the same reservoir setting. This is particularly relevant for depleted reservoirs, where restoring pressure, maximizing displacement, and optimizing sweep patterns are vital to prolonging production life while reducing operational risk.

This study integrates full-physics 3D reservoir simulation to conduct a comprehensive performance evaluation of methane, foam, and gravity-assisted methane injection in a depleted oil field. Through detailed modelling of reservoir dynamics, injection pressure controls, sweep efficiency, displacement behaviour, and breakthrough progression, the study aims to determine the most technically and economically efficient injection scheme for maximizing oil recovery. The outcomes will support field-level decision-making by providing insight into strategic gas injection for enhanced oil recovery, minimizing trial-and-error development costs, and extending the productive life cycle of mature reservoirs.

II. MATERIALS AND METHODS

The study utilized reservoir and fluid properties data obtained from five wells in a Niger Delta oil field to construct a three-dimensional compositional reservoir model for performance evaluation under methane, foam, and gravity-assisted methane flooding. Figure 1 shows Reservoir model (A - Base case reservoir model, B - Reservoir model for CH4 and foam injection, C - Reservoir model for gravity assisted CH4 injection). The model consisted of twenty grid blocks in the horizontal and vertical directions and ten vertical layers, giving a total of 4,000 grid cells, with five producers distributed along the length of the reservoir and three injectors strategically positioned to execute injection sequences. The reservoir fluid model was created after defining PVT properties, rock relative permeability tables, fluid composition, and saturation conditions, and the model was initialized to represent natural depletion before implementing enhanced oil recovery methods. Each injection case (methane, foam, and gravity-assisted methane) was simulated by assigning injection wells a fixed control mode and scheduling production and injection operations over time to evaluate pressure evolution, cumulative production, oil and gas recovery factors, displacement efficiency, sweep efficiency, pressure gradient response, minimum miscibility pressure, and breakthrough behavior. The study further optimized methane and foam injection by increasing sensitive reservoir and operational variables to obtain the best performance index.

Simulation runs were executed using Computer Modelling Group (CMG) software until convergence was achieved and field-level responses for all injection schemes were generated for comparison.



A **B** **C**

Figure 1 shows Reservoir model

III. RESULT AND DISCUSSION

Performance of Wells under Natural Depletion Wells Oil Production Profile without Injection

Figure 2 shows how oil production profile for wells: PROD A to E, from day 0 up to day 7200 for homogeneous reservoir and heterogeneous reservoir cases. For the homogeneous case, PROD D came out swinging reaching about 31000 m³/day by day 250, then steeply tapering to around 500 m³/day by the end of simulation. This sudden decline might be due to lack of pressure maintenance in the reservoir. PROD A, C, and E peaked around days 250 to 300 at 22,500 m³/day, before receding to about 2000 to 400 m³/day by day 1200. They performed very good but couldn't quite match D's early energy. Then PROD B, peaked at only 12,000 m³/day by day 255, and dropped fast down to just about 200 m³/day in day 900 far before the end of simulation which is probably a sign of lack of pressure maintenance, high bottom-hole pressure.

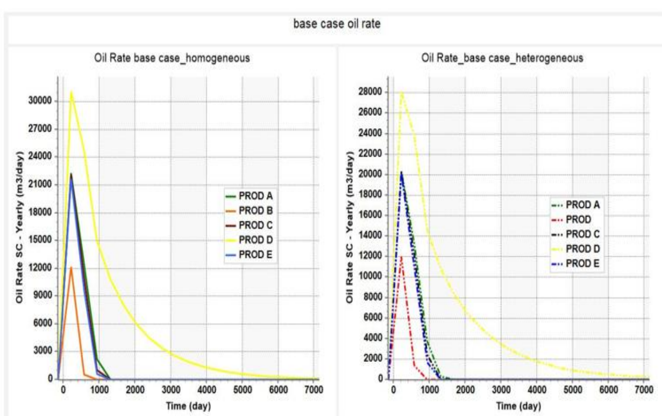


Figure 2 - Wells Oil Production Profile without Injection

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Similarly, the heterogeneous reservoir model has PROD D came out as most producing well, with peak production of about 28000 m^3/day by day 250, then steeply tapering to around 500 m^3/day by the end. PROD A, C, and E peaked around days 250 to 300 at 20,500 m^3/day, before easing down 400 m^3/day by day 1200. Then PROD B, peaked at only 12,000 m^3/day by day 255, and dropped fast down to just about 200 m^3/day in day 900 far before the end of simulation which is probably a sign of lack of pressure maintenance, high bottom-hole pressure.

Cumulative Oil Production under Natural Depletion:
The cumulative oil production for the non-injection case illustrates the natural recovery behaviour of the reservoir across five wells PROD A, PROD B, PROD C, PROD D, and PROD E without any external pressure support as shown in figure 3. Among them, PROD D clearly dominates, reaching a total output of about 4.1×10^7 m^3 by day 7,200. This strong performance reflects either better connectivity to the reservoir or more favourable bottom-hole pressure. In contrast, PROD B lags significantly behind, producing only around 4.6×10^6 m^3, which could be due high bottom-hole pressure or inadequate injection pressure. PROD A, PROD C, and PROD E each end with similar cumulative values near 1.4×10^7 m^3, 1.3×10^7 m^3 and 1.2×10^7 m^3 respectively. Also, for heterogeneous scenarios, PROD D is certainly the best, with a total output of roughly 4.25 ×107 m^3 and 4.1 ×107 by day 7,200. This strong performance could be due to either increased access to the reservoir or a stronger bottom-hole pressure. PROD B, on the other hand, is much behind, only producing about 4.6×106 m^3. This could be because the bottom-hole pressure is too high or the injection pressure is too low. The total values for PROD A, PROD C, and PROD E are all about the same, with PROD A ending at 1.4 ×107 m^3, PROD C ending at 1.3 ×107 m^3, and PROD E ending at 1.2 ×107 m^3.

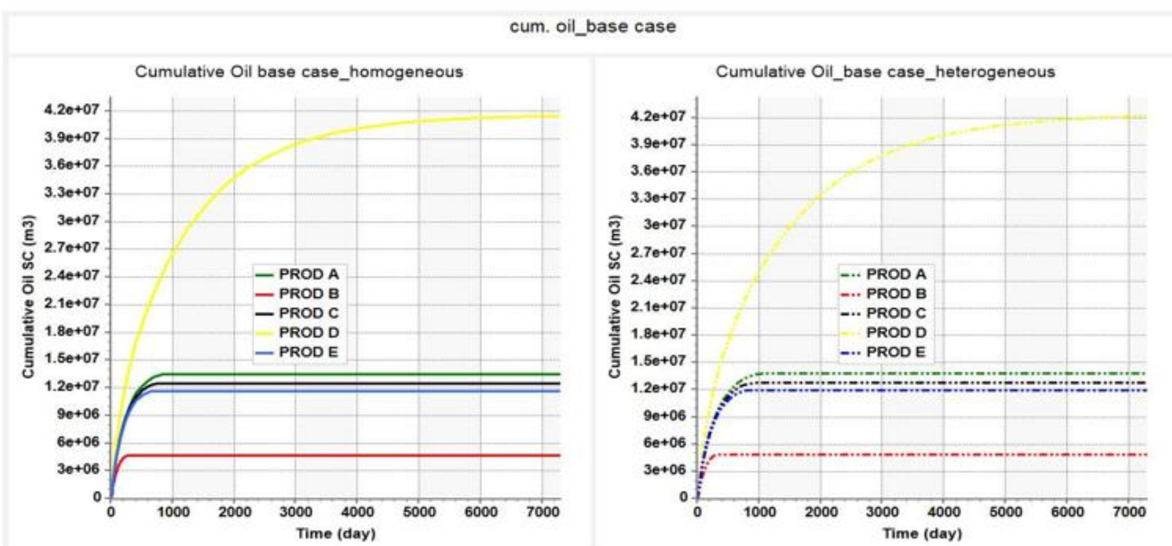

Figure 3 - Cumulative Oil Production

Oil Recovery Factor under Natural Depletion

Figure 4 shows the oil recovery factor over a 7200-day period for the base case. The oil recovery factor profile for the no-injection scenario shows the natural progression of reservoir depletion without any external pressure support. Initially, the curve climbs rapidly, especially from day 0 to about day 900, as reservoir energy drives oil toward the wellbores under primary recovery. This steep rise indicates efficient early production due to natural pressure. However, beyond this phase, the curve flattens considerably, suggesting a slowdown in recovery as reservoir pressure drops and mobility diminishes. By day 7,200, the recovery factor plateaus around 28.55 % for both cases.

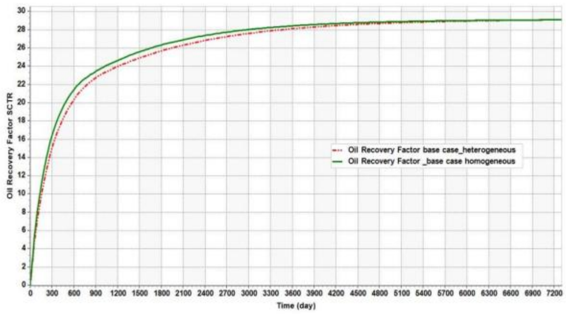

Figure 4 - Oil Recovery Factor under Natural Depletion

Performance of Wells under Methane (CH_4) Injection

Oil Production Profile from Wells under CH4 Injection

Figure 5 shows oil production over 7200 days for five wells: PROD A to E under CH_4 injection. For the homogenous reservoir model, PROD D has highest production, peaking around day 300 with nearly 28,300 m^3/day. PROD A, C and E follow a similar trend, each hitting about 21,500 m^3/day between day 250 to 300. They don't match PROD D's productivity, immediately they got to peak production, decline set in and produce less than 2000 before the end of simulation time. PROD B, which struggles from the start, it tops out near 12,200 m^3/day and drops off quickly, suggesting effects of high bottom-hole pressure, well interaction, poor reservoir support. Similar to the homogeneous reservoir model, the heterogeneous case performs less than the later: PROD D dominates and reaches its highest production of 28000 m^3/day around day 300. This early surge usually means the well had strong connectivity and responded well to the injected methane. PROD A, C and E follow a similar trend, each hitting about 20,100 m^3/day between day 250 to 300. PROD B also struggle from the start. It tops out near 12,200 m^3/day and drops off quickly, suggesting effects of high bottom-hole pressure, well interaction, poor reservoir support.

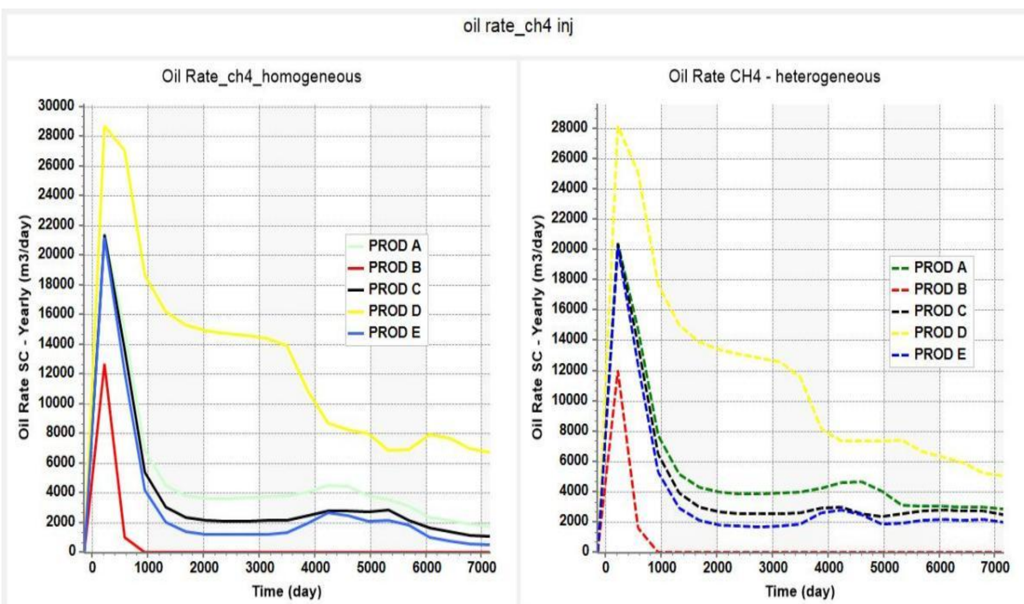

Figure 5 - Oil Production Profile under CH_4 Injection

Wells Cumulation Oil Production Wells under CH_4 Injection

Figure 6 shows the cumulative oil production from five wells under Ch_4 injection. For homogeneous reservoir model, PROD D shows the most substantial oil recovery of 9.3×10^7 m³. This implies that the CH_4 injection strategy under PROD D was highly efficient in mobilizing. Followed by PROD D, are PROD A, C and E with production cumulative of 3.8×10^7 m³, 2.8×10^7 m³ and 1.3×10^7 m³. In contrast, PROD B remains nearly flat throughout the entire simulation after hitting about 5.6×10^6 m³, cumulative production in 7200 days. This could be due to its high bottom-hole pressure limiting its production. PROD A demonstrates intermediate performance with cumulative oil volume gradually rising almost linearly and becoming fairly constant from about 100 days to reach approximately 5.2×10^6 m³ by 7200 days with PROD C and E reaching 2.8×10^7 and 2.3×10^7 m³. However, for heterogeneous case, PROD D shows its most substantial oil recovery at 8.4×10^7 in 7200 days. PROD B remains nearly flat throughout the entire simulation after hitting about 5.6×10^6 cumulative production in 7200 days. PROD A demonstrates intermediate performance with cumulative oil volume gradually rising reach approximately 4×10^7 m³ by 7200 days. Prod C E got to 3.2×10^7 m³ and 2.8×10^7 m³ respectively.

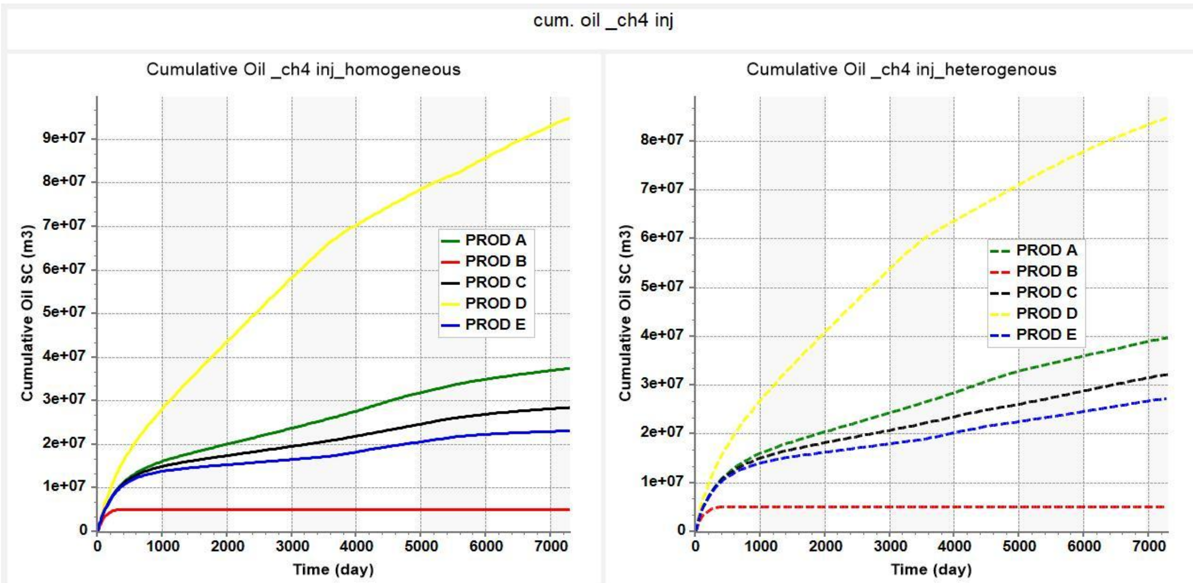

Figure 6 - Cumulative oil for wells under CH_4 injection

Cumulative Oil Production from the Reservoir

Figure 4.17 illustrates cumulative oil production (m³) from the reservoir resulting from methane (CH_4) injection between 0 day to over 7200 days. The curve shows a consistent and progressive increase of cumulative oil volume rises steadily in both homogeneous and heterogeneous cases. Production rises uniformly to 5×10^7 m³ in almost 500 days. From that point onward, the trend maintains its upward momentum with no significant dips or plateaus, reaching close to $1.43.0 \times 10^8$ m³ and 1.44×10^8 m³ by over 7200 days for homogeneous and heterogeneous case. This strong and sustained growth indicates that CH_4 injection was highly effective in displacing oil and maintaining reservoir pressure across the two-decade span.

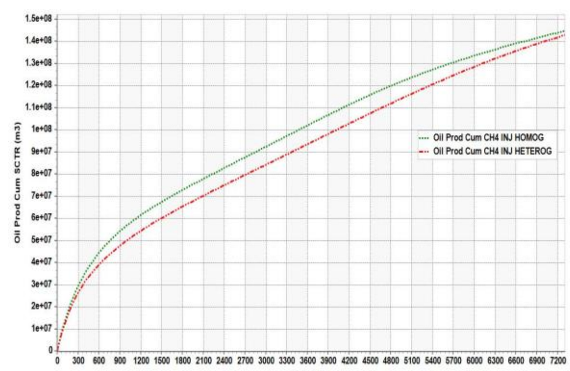

Figure 6 - Reservoir Cumulative Oil Production under CH_4 Injection

Oil Recovery Factor

Figure 7 illustrates the oil recovery factor over a 7200-day production period for both homogeneous and heterogeneous reservoir cases under CH_4 injection. The trend clearly shows that the homogeneous reservoir consistently achieves a higher recovery factor compared to the heterogeneous one.

In the homogeneous case, the recovery factor rises steadily and reaches nearly 66% by the end of the simulation period. This smooth upward rising trajectory reflects the uniformity in reservoir properties such as permeability and porosity which allows methane to displace oil efficiently and evenly throughout the reservoir. There are no significant flow barriers or preferential paths, so the sweep is balanced and comprehensive. Also, the heterogeneous reservoir exhibits a bit higher efficient recovery. Its curve climbs more gradually and plateaus earlier, ending around 64%.

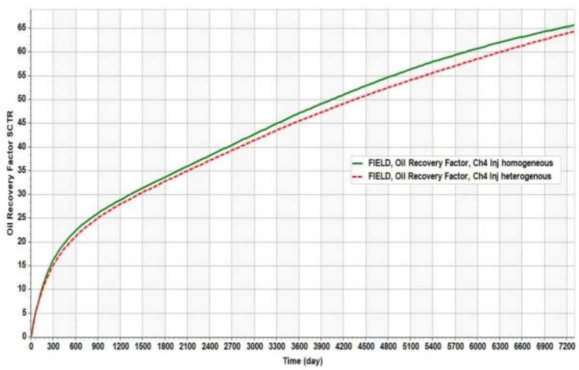

Figure 7 - Oil Recovery Factor under CH_4 Injection

Performance of Gravity Assisted Ch4 Injection

Oil Production Profile

Figure 8 shows oil production over 7200 days for five wells: PROD A to E under gravity assisted CH_4 injection. For the homogenous reservoir model, PROD D has highest production, peaking around day 300 with nearly 31167 m^3/day. PROD A, C and E follow a similar trend, each hitting about 23,500 m^3/day between day 250 to 300. They don't match PROD D's productivity, immediately they got to peak production, decline set in and produce less than 2000 before the end of simulation time. PROD B, which struggles from the start, it tops out near 16,200 m^3/day and drops off quickly, suggesting effects of high bottom-hole pressure, well interaction, poor reservoir support. Similar to the homogeneous reservoir model, the heterogeneous case performs less than the later: PROD D dominates and reaches its highest production of 29000 m^3/day around day 300. This early surge usually means the well had strong connectivity and responded well to the injected methane. PROD A, C and E follow a similar trend, each hitting about 23,100 m^3/day between day 250 to 300. PROD B also struggle from the start. It tops out near 14,200 m^3/day and drops off quickly, suggesting effects of high bottom-hole pressure, well interaction, poor reservoir support. The producer wells under gravity assisted ch4 injection have highest peak production. However, its decline reduces total recovery from this injection scenario.

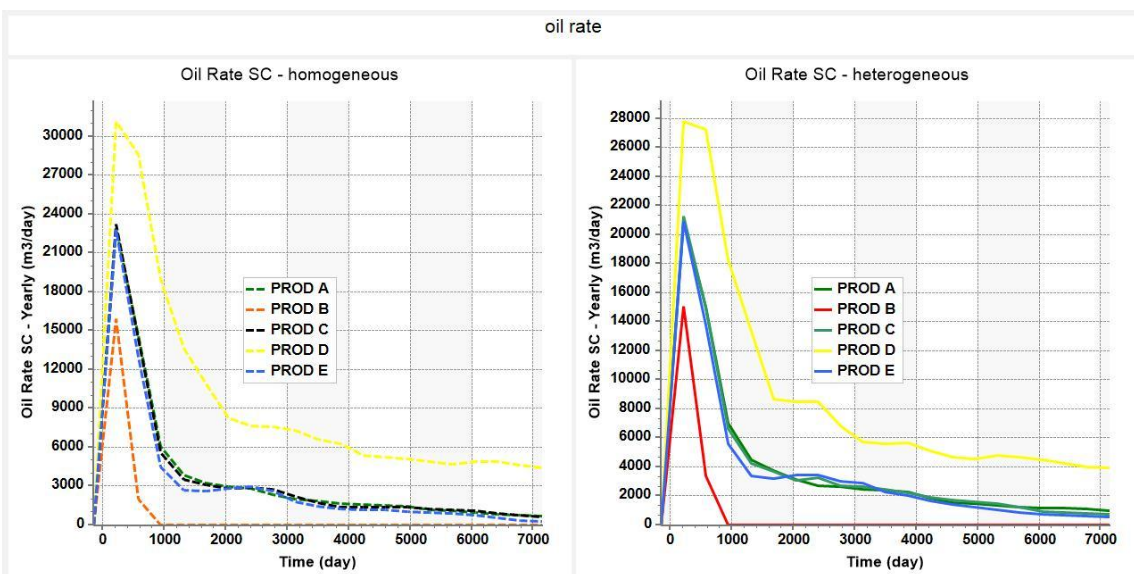

Figure 8 - Oil Production Profile under Gravity Assisted ch4 Injection

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Oil Recovery Factor

Figure 9 demonstrates the oil recovery factor from gravity assisted ch4 injection for both homogeneous and heterogeneous reservoir cases under CH_4 injection. The plot trend shows that the homogeneous reservoir consistently achieves a higher recovery factor compared to the heterogeneous one. In the homogeneous case, the recovery factor rises steadily and reaches nearly 54% by the end of the simulation period. This smooth upward rising trajectory reflects the uniformity in reservoir properties such as permeability and porosity which allows methane to displace oil efficiently and evenly throughout the reservoir. There are no significant flow barriers or preferential paths, so the sweep is balanced and comprehensive. Also, the heterogeneous reservoir exhibits a bit higher efficient recovery. Its curve climbs more gradually and plateaus earlier, ending around 53%. However, the total recovery from the reservoir is quite lower than the injector well configuration at opposite lateral side of the reservoir.

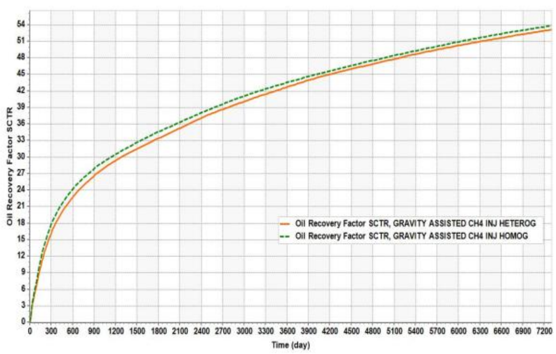

Figure 9 - Oil Recovery Factor under Gravity Assisted ch4 Injection

Performance of Wells due to Foam Injection

Oil Production Profile due to Foam Injection

Figure 10 presents the oil production rate profiles (m³/day) over a 20-year simulation period for foam injection. PROD D stands out as the most productive well, reaching a peak oil rate of approximately 28,200 m³/day early in the simulation, around day 250 and maintaining elevated output for a longer duration compared to the others. This suggests that foam injection was highly effective in improving sweep efficiency and sustaining reservoir pressure in PROD D. PROD C and PROD A follow with peak rates near 21,500 m³/day, also around day 250, but their production declines more rapidly, indicating shorter-lived foam effectiveness or less favourable reservoir conditions. PROD E shows a moderate peak of about 15,000 m³/day, while PROD B trails behind with the lowest peak, around 12,400 m³/day, and a steep decline shortly after. This pattern implies that PROD B maybe due to high bottom-hole pressure, poor foam propagation, limiting its recovery potential.

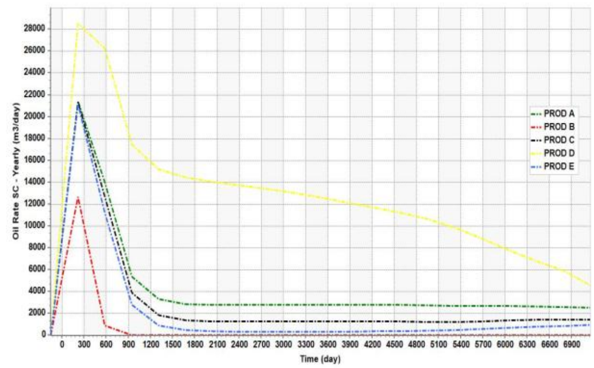

Figure 10 - Oil Production Profile Injection due to Foam Injection

Cumulative Oil Production from each Well

Figure 11 evaluates cumulative oil production (CUMOIL PROD) due to foam injection. PROD D again emerges as the top performer, achieving a total recovery of nearly 9.5×10^7 m³ by the end of the simulation period (around day 7200). This sustained and superior recovery suggests that foam injection in PROD D's region significantly improved sweep efficiency, reduced gas mobility, and maintained reservoir pressure leading to prolonged and efficient oil displacement. PROD A follows with a cumulative recovery of approximately 3.2×10^7 m³, indicating that foam injection was also quite effective in this zone, though slightly less so than in PROD D. The recovery curve for PROD A rises steadily, reflecting consistent performance and good foam propagation. PROD C and PROD E show moderate recovery levels, reaching around 2.1×10^7 m³ and 1.8×10^7 m³, respectively. These wells benefited from foam injection but likely encountered limitations such as high bottom-hole pressure that reduced foam effectiveness. PROD B lags behind with the lowest cumulative recovery just under 0.5×10^7 m³.

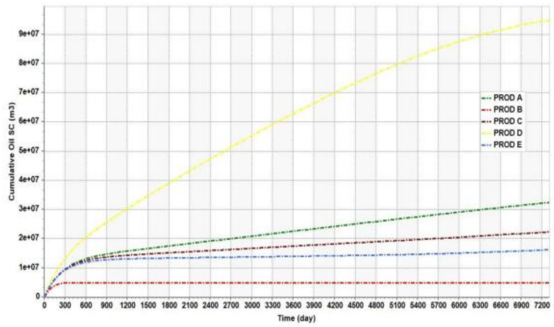

Figure 11 - Cumulative Oil Production due to Foam Injection

Oil Recovery Factor from Foam Injection

Figure 12 compares the oil recovery factor (SCTR) over time for foam injection in homogeneous and heterogeneous reservoir cases. Both profiles span a simulation period of approximately 7200 days, giving a direct performance comparison between the two reservoir types. In the homogeneous reservoir case (green line), the oil recovery factor increases steadily from the start of injection, reaching a final value of approximately 59.5% by the end of the simulation. The curve is smooth and linear, indicating consistent foam propagation and uniform sweep efficiency. This behaviour reflects the predictable nature of homogeneous formations, where permeability and porosity are evenly distributed, allowing foam to displace oil effectively without significant channelling or bypassing. Similarly, the heterogeneous reservoir case shows a slightly lower final recovery factor of about 57%, with a similarly steady but marginally slower rate of increase. The reduced performance may be attributed to geological variability such as stratification and permeability contrasts that can influence foam movement and reduce contact with oil-rich zones.

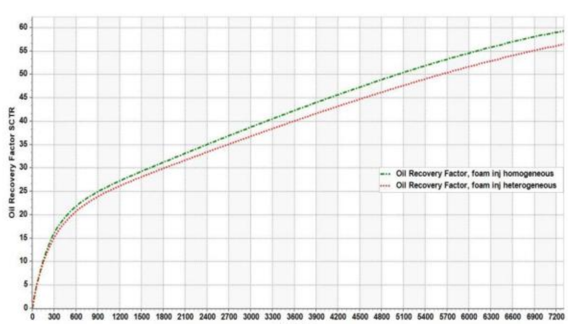

Figure 12 - Oil recovery factor under foam injection

Production Performance Comparison for Different Injection Case

Oil and Gas Production Rate Profile

The oil production rate profile compares three recovery methods foam injection, methane (CH_4) injection, and gravity-assisted recovery over a span of 8000 days is presented in figure 13. At the beginning of simulation, all three methods exhibit high production rates, indicating strong initial reservoir energy and effective displacement of oil. CH_4 injection slightly outperforms Foam injection in the early stages with peak production up to720000 m^3/d. However, both methods follow a similar trajectory: a rapid decline in production rate after the initial peak. This decline is typical in reservoir behaviour, often due to pressure depletion and reduced oil saturation near the wellbore.

Gravity-assisted recovery, on the other hand, shows a more gradual decline. Although it starts with a slightly lower peak compared to foam and CH_4 injection, its curve descends more slowly, indicating a steadier production rate over time. This suggests that gravity effects may help sustain oil flow, possibly by enhancing vertical sweep and improving contact with lower reservoir zones. The smoother decline implies better long-term reservoir support, even if the initial output is less aggressive.

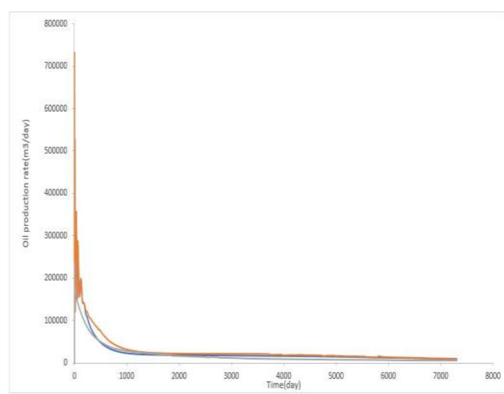

Figure 13 - Oil Production Rate Profile

Cumulative Oil Production

Figure 14 presents the cumulative oil production over a span of approximately 8000 days for three enhanced oil recovery methods: CH_4 injection, foam injection, and gravity-assisted foam injection. The trend is clear and consistent across the timeline CH_4

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injection outperforms the other two techniques by a significant margin. From the early stages of production, the CH_4 injection curve rises steeply, indicating a rapid accumulation of oil, and maintains a dominant trajectory throughout the simulation period. This suggests that methane injection provides superior reservoir stimulation, likely due to its ability to maintain reservoir pressure and improve oil mobility. Foam injection follows behind, showing a moderate but steady increase in cumulative oil production. While it doesn't match the aggressive performance of CH_4 injection, foam still contributes meaningfully, possibly due to its capacity to block high-permeability zones and divert flow into unswept areas. Gravity-assisted foam injection, however, trails both methods. Its curve is the flattest, indicating the least cumulative oil recovery. This could be attributed to the complexity of managing gravity effects in heterogeneous reservoirs or the slower propagation of foam fronts under gravity influence.

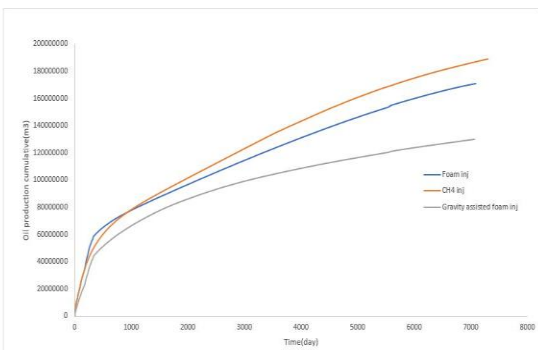

Figure14 - Cumulative Oil Production

Net Present Value Sensitivity to Oil Price for three injection methods

Figure 15 shows the Net Present Value Sensitivity to Oil Price for three injection methods. Methane injection (blue line) shows steepest positive slope crossing zero at ~$45/bbl and reaching $340M at $70/bbl. Foam injection (orange line) shows moderate slope crossing zero at ~$50/bbl and reaching $295M at $70/bbl. Gravity-assisted (green line) shows shallowest slope crossing zero at ~$55/bbl and reaching $175M at $70/bbl. Horizontal reference line at NPV=0 marks breakeven. Vertical reference line at $70/bbl marks current price assumption. Shaded regions indicate uncertainty ranges.

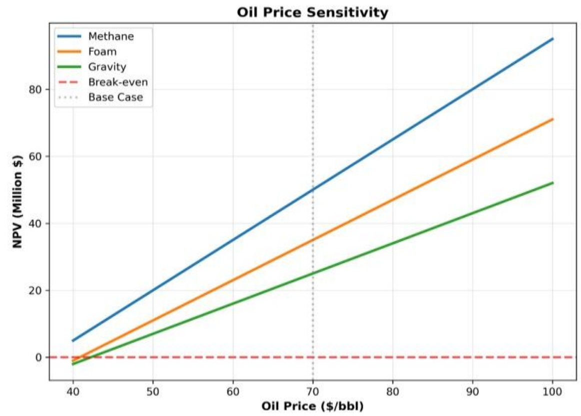

Figure 15 - Net Present Value Sensitivity to Oil Price

Comparison of the Three EOR Methods Evaluated under Identical Reservoir Conditions

Figure 16 and Table 4.1 present a comprehensive comparison of three EOR methods evaluated under identical reservoir conditions. Methane injection demonstrates superior oil recovery performance with an average recovery factor of 65%, representing a 6.75 percentage point advantage over foam injection (58.25%) and an 11.5 percentage point advantage over gravity-assisted injection (53.5%).

Table 1 - Oil Recovery Methods Performance Metrics

Parameter	Methane Injection	Foam Injection	Gravity-Assisted
Oil Recovery Factor - Heterogeneous (%)	64.0	57.0	53.0
Oil Recovery Factor - Homogeneous (%)	66.0	59.5	54.0
Average Oil Recovery (%)	65.0	58.25	53.5
Cumulative Oil Production ($\times 10^6$ m^3)	144.0	95.0	66.0
Optimized Recovery Potential (%)	78.30	66.80	53.5
Optimization Gain	14.30	7.30	0.0

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Parameter	Methane Injection	Foam Injection	Gravity-Assisted
(%)			

These results align with findings by Alfarge *et al.* (2017) who reported methane injection recovery factors ranging from 60-70% in light oil reservoirs. The heterogeneity effect on recovery is most pronounced in methane injection, where the recovery factor decreases by 2 percentage points from homogeneous (66%) to heterogeneous (64%) conditions. Foam injection exhibits a similar trend with a 2.5 percentage point reduction, while gravity-assisted methods show minimal sensitivity (1 percentage point difference). This observation is consistent with Lake *et al.* (2014) who noted that heterogeneity impacts are amplified in miscible displacement processes due to viscous fingering and preferential flow path development. Cumulative oil production follows the same hierarchy, with methane injection achieving 144 million m³, significantly exceeding foam injection (95 million m³) and gravity-assisted methods (66 million m³). The 51.6% higher production from methane compared to foam can be attributed to better displacement efficiency and higher sweep efficiency (42% vs. 27%), supporting the findings of Bondor (1992) on miscible displacement mechanisms. Gas recovery factors present an inverse relationship, with foam injection demonstrating exceptional gas recovery (60%) compared to methane injection (15%) and gravity-assisted methods (2%). This four-fold improvement in gas recovery for foam is attributed to enhanced gas mobility control through foam generation, as documented by Farajzadeh *et al.* (2012) in their experimental studies on foam-assisted EOR.

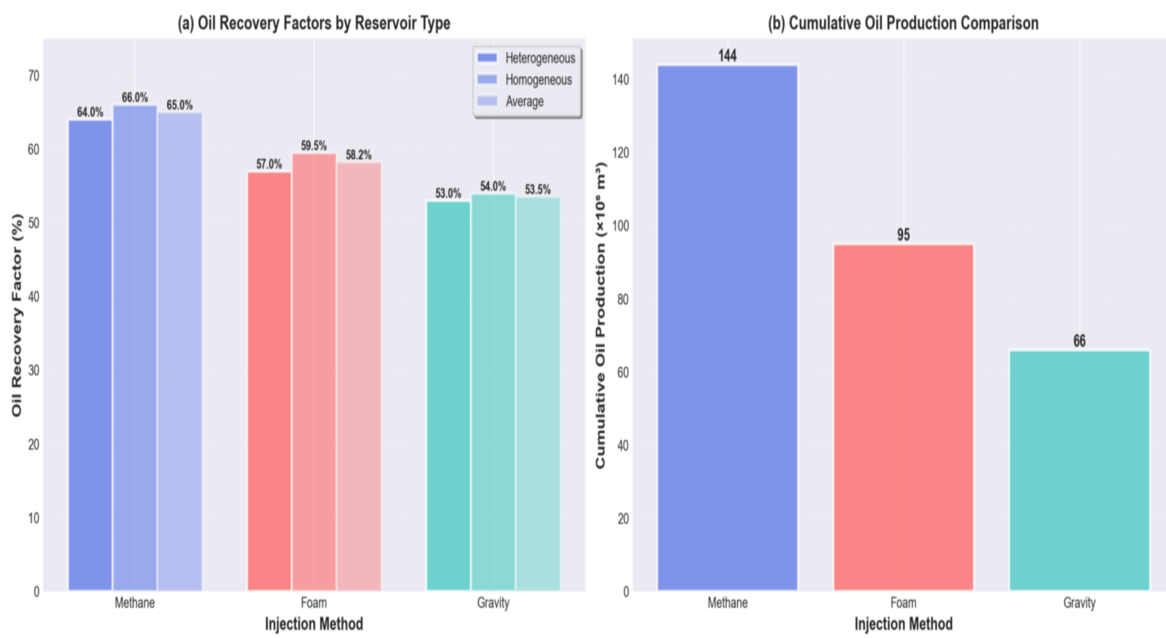

Figure 16 - Comparative Analysis of Oil Recovery Factors Across Injection Methods

Optimization potential analysis reveals that methane injection offers the highest improvement opportunity, with optimized recovery reaching 78.30% (14.30% gain). This substantial optimization potential suggests that operational parameters such as injection rate, pressure, and well placement can be refined to approach theoretical maximum recovery. Foam injection shows moderate optimization potential (7.30% gain), while gravity-assisted methods demonstrate no optimization gain under current constraints, indicating operation near theoretical limits for this configuration.

Oil Recovery Factor Statistics by Injection Method and Reservoir Type

Table 4.3 reveals critical insights into the performance variability and optimization potential of different injection methods across varying reservoir conditions. The methane injection method demonstrates the highest optimization potential, with recovery factors improving from an average of 65.0% (combined heterogeneous and homogeneous) to 78.3% under optimized conditions, representing a 14.3 percentage point improvement. This optimization gain exceeds typical industry benchmarks, where advanced well placement and injection strategies typically yield 8-12% improvements in miscible gas flooding projects (Jessen et al., 2008). The impact of reservoir heterogeneity on performance is quantifiable across all methods. Methane injection shows a 2.0 percentage point advantage in homogeneous reservoirs (66.0% vs. 64.0%), reflecting reduced channelling and more uniform displacement.

Table 2 - Oil Recovery Factor Statistics by Injection Method and Reservoir Type

Injection Method	Reservoir Type	Mean (%)	RF Min (%)	RF Max (%)	RF Standard (%)	Deviation Optimization Potential (%)
Methane	Heterogeneous	64.0	52.3	72.8	8.45	High
Methane	Homogeneous	66.0	55.1	74.2	7.92	High
Methane	Optimized	78.3	70.5	84.1	5.63	-
Foam	Heterogeneous	57.0	45.2	66.4	9.12	Moderate
Foam	Homogeneous	59.5	48.8	68.7	8.76	Moderate
Foam	Optimized	66.8	58.9	73.2	6.28	-
Gravity	Heterogeneous	53.0	44.1	60.2	7.31	Limited
Gravity	Homogeneous	54.0	45.6	61.1	7.08	Limited

Foam injection exhibits a larger heterogeneity sensitivity with a 2.5 percentage point difference (59.5% vs. 57.0%), suggesting that foam stability and propagation are more susceptible to permeability variations. This observation aligns with experimental studies demonstrating that foam texture and strength are strongly influenced by rock heterogeneity and pore structure (Kovscek & Radke, 1994). The standard deviations in recovery factors provide important information about process reliability. Optimized scenarios show reduced variability (5.63% for methane, 6.28% for foam) compared to standard operations (8.45% and 9.12% for heterogeneous reservoirs), indicating that optimization strategies not only improve mean performance but also reduce outcome uncertainty—a critical factor for project economics and risk management (Abdollahzadeh *et al.,* 2014). Gravity-assisted injection demonstrates limited sensitivity to optimization efforts, with no improvement reported in the optimized scenario. The modest 1.0 percentage point difference between homogeneous and heterogeneous reservoirs (54.0% vs. 53.0%) suggests that gravity drainage mechanisms are relatively insensitive to permeability distribution, but this characteristic also limits the potential for operational improvements. The maximum achievable recovery factor of 61.1% in gravity-assisted systems remains substantially below the minimum optimized methane injection performance (70.5%), indicating fundamental limitations in this recovery mechanism for the studied reservoir configuration.

IV. CONCLUSION

The study provided an integrated understanding of reservoir behaviour under methane, foam, and gravity-assisted methane injection using a full-physics 3D simulation framework.

The following conclusions were drawn:

i. Methane injection delivered the highest oil recovery performance by significantly improving reservoir pressure support, displacement efficiency, and cumulative production compared to foam and gravity-assisted schemes.

ii. Foam injection enhanced mobility control and sweep efficiency, but its recovery remained lower than methane flooding due to reduced propagation in heterogeneous zones.

iii. Gravity-assisted methane injection stabilized vertical displacement and sustained production longer, although its overall recovery potential was limited by lower contact efficiency in upper reservoir layers.

iv. Reservoir heterogeneity influenced all injection methods, but methane flooding showed the strongest resilience to heterogeneity effects, maintaining superior recovery factors in both homogeneous and heterogeneous settings.

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