iJRASET
International Journal For Research in
Applied Science and Engineering Technology

INTERNATIONAL JOURNAL FOR RESEARCH

IN APPLIED SCIENCE & ENGINEERING TECHNOLOGY

Volume: 13 **Issue:** VI **Month of publication:** June 2025

DOI: https://doi.org/10.22214/ijraset.2025.72411

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 7.538
Volume 13 Issue VI June 2025- Available at www.ijraset.com

Geomechanical Optimization of Mud Weight Design and Fracture Risk Prediction in D1 and X1 Fields, Central Niger Delta

Adiele O[1], Okengwu K[2], Ugwueze C[3]
Department of Geology, University of Port Harcourt

Abstract: This study employs an integrated geomechanical approach using exclusively secondary data to evaluate safe mud weight windows and fracture risk in two Niger Delta fields—D1 and X1. Secondary datasets, including drilling reports, wireline logs, leak-off tests, and formation pressure measurements, were analyzed to estimate key geomechanical parameters: pore pressure, minimum horizontal stress, overburden stress, and fracture gradients. Results indicate that both fields exhibit a normal faulting stress regime, with D1 displaying a wider mud weight window (8.65–13.5 ppg) compared to X1 (8.27–11.35 ppg). Wellbore stability analysis showed that instances of mud losses and kicks corresponded with periods when actual mud weight exceeded or fell below the predicted safe window, validating the model. A comparative analysis revealed that X1 poses a higher drilling risk due to overpressure and narrower margins. This study demonstrates that secondary data, when properly calibrated, can effectively guide mud weight design and mitigate wellbore instability in mature fields.
Keywords: Mud weight optimization, fracture gradient, pore pressure, wellbore stability, geomechanics, Niger Delta, drilling risk, normal faulting regime, pressure window.

I. INTRODUCTION

Optimizing mud weight design and predicting fracture risk are critical elements of geomechanical planning in hydrocarbon drilling, particularly in geologically complex and overpressured basins like the Niger Delta. Inadequate mud weight can lead to wellbore collapse or kicks, while excessive weight may induce formation fracturing and lost circulation—both of which contribute to non-productive time and increased operational costs (Aadnøy & Looyeh, 2019). A robust geomechanical framework that integrates stress modeling, pore pressure evaluation, and field data is therefore essential for safe, efficient drilling operations.

The Niger Delta Basin, one of the world's most prolific hydrocarbon provinces, is characterized by interbedded sand-shale sequences, high pore pressure zones, and varying stress regimes (Doust & Omatsola, 1990). These features complicate drilling, especially in Tertiary formations where shale instability and overpressured sands are prevalent (Ikporo & Sylvester, 2020). Geomechanical modeling, when supported by borehole imaging and pressure testing, offers a powerful approach for predicting formation behavior and guiding mud weight selection to maintain wellbore integrity (Zoback, 2010; Fjaer et al., 2008). This study applies a geomechanical optimization workflow to two onshore fields—D1 and X1—located in the central Niger Delta. Despite their proximity and shared depositional history, these fields exhibit contrasting geomechanical characteristics: D1 demonstrates relatively stable conditions and higher fracture resistance, whereas X1 is marked by overpressure, narrow mud weight windows, and frequent wellbore instability events. Understanding these contrasts is critical for field-specific mud weight design and risk mitigation.

The study integrates drilling reports, wireline logs, borehole imaging, and direct pressure measurements to build calibrated geomechanical models. Borehole breakout patterns, leak-off test data, and resistivity anomalies are used to constrain in-situ stress conditions and pore pressure trends. These models enable the definition of optimal mud weight windows and the prediction of fracture initiation thresholds.

II. LITERATURE REVIEW

Drilling through overpressured and mechanically unstable formations, such as those in the Niger Delta, demands precise control over mud weight to maintain borehole integrity while avoiding unintentional fracturing. Various studies over the past few decades have laid the groundwork for understanding the complex interplay between in-situ stress, pore pressure, and rock mechanics—each offering insight into how drilling parameters can be optimized for both safety and efficiency.

In their seminal work, Zoback (2010) presented a comprehensive framework for geomechanical modeling in sedimentary basins. He outlined how stress regimes—particularly the magnitude and orientation of horizontal stresses—influence borehole stability and fracture propagation. His concepts of the stress polygon and safe mud weight windows are particularly important in this context, as they guide the identification of pressure thresholds within which a well can be safely drilled. His principles remain a cornerstone for wellbore stability analysis, especially in basins like the Niger Delta where narrow drilling margins are common. Expanding on these theoretical foundations, Aadnøy and Looyeh (2019) approached the topic from a more practical angle. Their work highlights how mud weight must be continuously adjusted in response to real-time feedback from the formation. According to their study, failure to adapt to dynamic conditions—especially in zones of rapid pore pressure escalation—can lead to severe mud losses or even formation breakdown. Their methodology supports the idea that integrating leak-off test (LOT) results, mechanical earth models, and rock failure envelopes is essential to formulating an effective mud weight strategy. This is particularly relevant to the X1 field, where drilling challenges have been more frequent compared to D1.

Meanwhile, Moos and Zoback (1990) were among the first to exploit borehole imaging to identify breakouts and fractures for the purpose of stress analysis. They demonstrated that borehole breakouts align with the direction of minimum horizontal stress and can be used to constrain stress magnitudes. This technique has since become standard in geomechanics and is highly applicable to this study, where FMI logs from both D1 and X1 are used to diagnose instability and support mud weight decisions. Their work adds empirical value to what was previously a theoretical modeling effort.

Focusing more closely on the Niger Delta, Ikporo and Sylvester (2020) provided valuable field-specific data. They used well logs to construct mechanical earth models (MEMs) for Tertiary formations and found that even minor deviations in mud weight could trigger formation failure, particularly in weak shales. Their findings reveal that generalized models for mud weight planning often fall short in this region, reinforcing the need for a customized approach—one that is informed by stress distribution, formation strength, and real-time drilling feedback. This is precisely the gap this study aims to bridge through a comparative evaluation of the D1 and X1 fields.

The mechanical behaviour of reservoir rocks has been comprehensively discussed by Fjaer et al. (2008), who outlined how elastic parameters like Young's modulus and tensile strength control fracture initiation and propagation. Their findings suggest that brittle formations with low tensile strength are more likely to fracture under slight overbalance pressures. In the case of X1, where such brittle intervals are present, understanding these mechanical thresholds is critical to avoid unnecessary losses and non-productive time. Their work provides the quantitative framework for fracture prediction used in this study.

Adding another layer, Tingay et al. (2009) emphasized the importance of integrating image log interpretation with stress and pressure analysis. In their regional work, they combined drilling-induced fractures, breakout patterns, and leak-off pressures to map horizontal stress orientations across sedimentary basins. Lastly, Okechi and Onyejekwe (2016) analyzed drilling-induced instability in overpressured shales in the eastern Niger Delta. Their field case studies revealed how poorly calibrated mud weight windows often led to lost circulation or stuck pipe. They advocated for the integration of geomechanical modeling with real-time monitoring to ensure better predictive control. This study builds on their recommendations by comparing two fields with contrasting histories, drawing on similar tools—image logs, LOT data, and stress models—to optimize drilling performance.

III. MATERIALS AND METHOD

This study applied an integrated geomechanical workflow to optimize mud weight design and predict fracture risks in two Niger Delta fields—D1 (onshore) and X1 (offshore). The methodology included (1) study area characterization, (2) secondary data acquisition, (3) geomechanical model construction (pore pressure, stress, and fracture gradient estimation), (4) mud weight window definition, (5) wellbore stability analysis, and (6) comparative evaluation.

A. Study Area Description

- Location and Geological Setting: The D1 and X1 fields are situated within the central Niger Delta basin, a progradational clastic system dominated by alternating shale and sand intervals. Both fields exhibit a normal faulting stress regime ($\sigma v > \sigma H > \sigma h$). The D1 field generally displays relatively uniform pore pressures and higher fracture gradients, while the X1 field shows more pronounced overpressure, especially in sandy intervals, accompanied by lower fracture thresholds. Figure 1 shows the Niger Delta basin map highlighting the study areas.

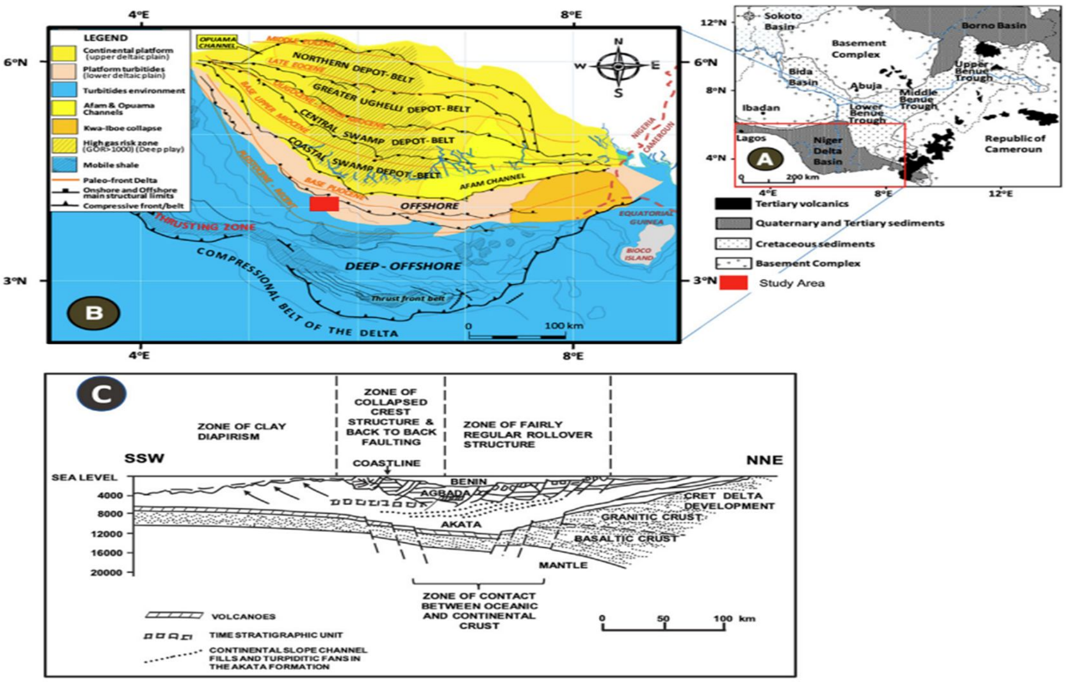

Figure 1: Map of the Niger Delta Basin showing the study area.

B. Data Acquisition

All data used were secondary, obtained from operator databases under confidentiality agreements.
Key datasets included:

- Drilling Reports: Daily records of mud weights (MW), pump rates, and wellbore instability events (losses, kicks).
- Wireline Logs: Gamma Ray (GR) for lithology, Resistivity (RT) for fluid detection, Density (RHOB), and Sonic (DT) logs for mechanical and pore pressure analysis.
- Direct Pressure Measurements: Leak-Off Tests (LOT), Mini-Frac tests, Modular Formation Dynamics Tester (MDT), and Pressure-While-Drilling (PWD) data.
- Geological and Seismic Data: Structural horizons tied to well tops and core data for lithofacies and porosity calibration.

C. Geomechanical Model Construction

Log Conditioning and Lithology Identification:

- Logs were depth-matched to True Vertical Depth (TVD) using deviation surveys.
- Spikes were removed using a 3–5 ft running median filter.
- Lithology was identified by cross-plotting GR (>80 API shale cutoff) and RT (<2 Ω·m) to distinguish shale from sand.

Pore Pressure Estimation:

- Shale pore pressure was calculated via Eaton's sonic method, calibrated against MDT and PWD pressure data.
- Sand pore pressure was inferred from resistivity anomalies, density log deviations, and direct pressure tests.
- All pressures were converted to gradients (psi/ft) for consistent analysis.

Overburden Stress (σv):

- Calculated by integrating bulk density (RHOB) logs over depth using the formula:

$\sigma v(z)=\int_0^z \rho(z')g\, dz'$

where $g=0.052$psi

- Missing density intervals were filled using regional averages or sonic-density correlations.

Minimum Horizontal Stress (σh):
- Direct LOT and Mini-Frac measurements provided stress calibration points.
- Empirical relationships (Zoback et al., 2003) were tuned for each field: $\sigma h(z)=a\sigma v(z)+bPp(z)$
- Calibration minimized residuals with test data.

Fracture Gradient (FG) Determination:
- Derived primarily from LOT and Mini-Frac results.
- Where unavailable, FG was estimated from drilling loss events using Equivalent Circulating Density (ECD).
- Empirical models supplemented sparse data with safety margins (5–10%).
- FG gradients were converted to equivalent mud weights.

D. Mud Weight Window Definition
The safe mud weight window at depth zzz was defined as:
- Lower bound: Pore pressure gradient to prevent kicks.
- Upper bound: Fracture gradient to prevent losses.
- Converted to mud weights using:

MW=Gradient (psi/ft)0.052

Typical ranges:
- D1: 8.65 ppg (lower) to 13.5–15.6 ppg (upper)
- X1: 8.27 ppg (lower) to 11.35 ppg (upper)

E. Wellbore Stability Analysis
- ECD was calculated incorporating static mud weight and annular pressure losses:

$ECD(z)=MWstatic(z)+\Delta Pann(z)0.052\times TVD(z)$

Loss and kick events from drilling reports were correlated with mud weight windows and ECD curves to validate fracture gradient predictions and pore pressure estimates.
- Stability plots displayed gradients, mud weights, ECD, lithology, and key pressure test markers.

F. Comparative Evaluation (D1 vs. X1)
- Summary statistics for pore pressure, stresses, and fracture gradients were compiled and compared.
- Confirmed normal faulting stress regime in both fields.
- Illustrated mud weight window variations, showing X1's window to be consistently narrower than D1's.

G. Statistical and Sensitivity Analyses
- Pearson correlation quantified the relationship between mud weight window exceedance and fluid loss severity.
- Monte Carlo simulations (n=1000) assessed uncertainty in key inputs (RHOB, sonic trends, LOT pressures), producing confidence intervals for pore pressure and fracture gradients.

H. Software and Tools
- Geomechanical modeling performed using Schlumberger Techlog and Landmark StressCheck.

I. Assumptions and Limitations
- Data gaps in X1 necessitated interpolation of fracture gradients in some intervals.
- Assumed lateral homogeneity; local heterogeneities may impact stresses.
- ECD calculations assumed steady-state flow, excluding transient effects.
- Empirical stress correlations may not fully capture subsurface variability in low-data zones.

IV. RESULT

The table 1 and figure 1 compares planned mud weight (MW) windows with actual MW used and associated well losses. Wells DB-01 and WW-02 stayed within the planned MW window and had no losses. DB-03, DB-07, DB-08, WE-1, and WWST-4 used MW above the maximum limit, resulting in various levels of losses. WE-1 and DB-07 experienced total or severe losses due to significantly exceeding the MW tolerance and approaching or surpassing fracture pressure.
Overall, exceeding the planned MW window, especially near the fracture pressure, correlates with increased wellbore losses.

Table 1: Shows planned mud window vs actual mud weight used compared to well losses.

Well Name	Pore Pressure (ppg)	Minimum MW (ppg)	Maximum MW (ppg)	MW Used (ppg)	Well Status	MW Tolerance	Fracture Pressure (ppg)
DB-01	8.4	8.6	9.1	8.9	No losses	-0.3	9
DB-03	8.8	8.9	9.5	9.6	20m3/hr losses	0.1	9.3
DB-07	8.4	8.7	8.7	9.9	Severe losses 332m3/hr	1.2	9.2
DB-08	8.3	8.6	8.5	9.5	Losses 12m3/hr	1	9
WW-02	8.1	8.4	8.9	8.9	No losses	0	9.4
WE-1	8.6	8.9	9.7	10.4	Total losses	0.7	9.9
WWST-4	8.4	8.7	8.7	9.9	12m3/hr losses	1.2	9.4

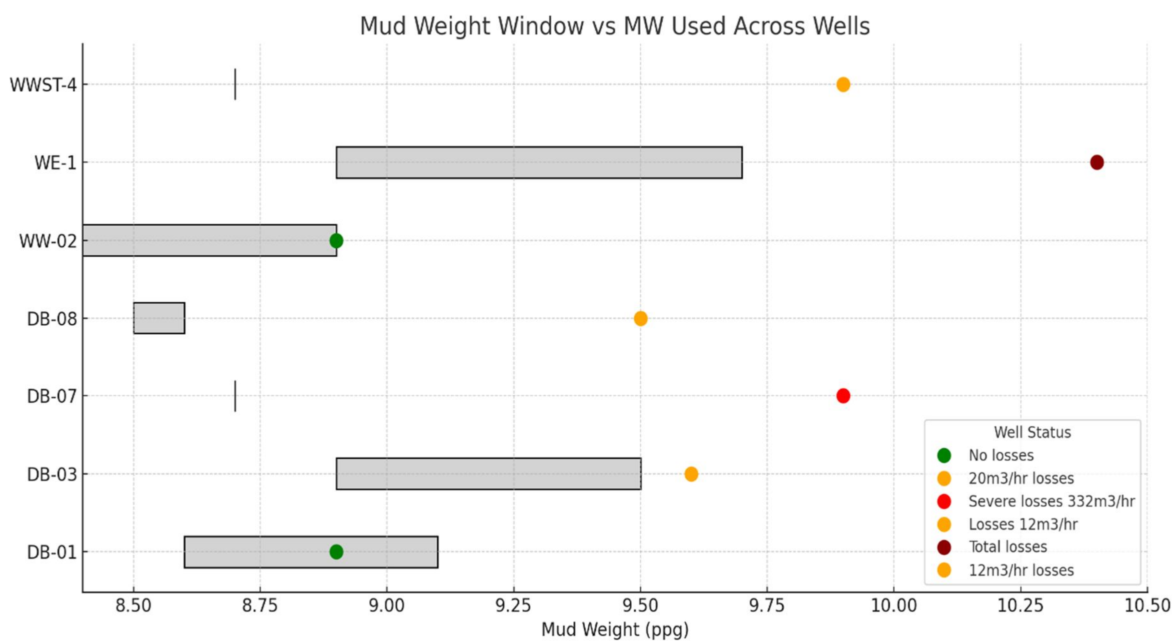

Figure 1: mud weight window (safe range) with the actual mud weight used.

Figure 2 presents average gradients for pore pressure (0.45 psi/ft), minimum horizontal stress (0.70 psi/ft), and vertical stress (0.80 psi/ft) in the D1 field. These values define the safe mud weight window—between pore pressure and minimum horizontal stress—critical for avoiding kicks and wellbore fractures. The dominance of vertical stress indicates a normal faulting regime. Overall, the data supports careful mud weight selection to maintain wellbore stability and minimize drilling risks.

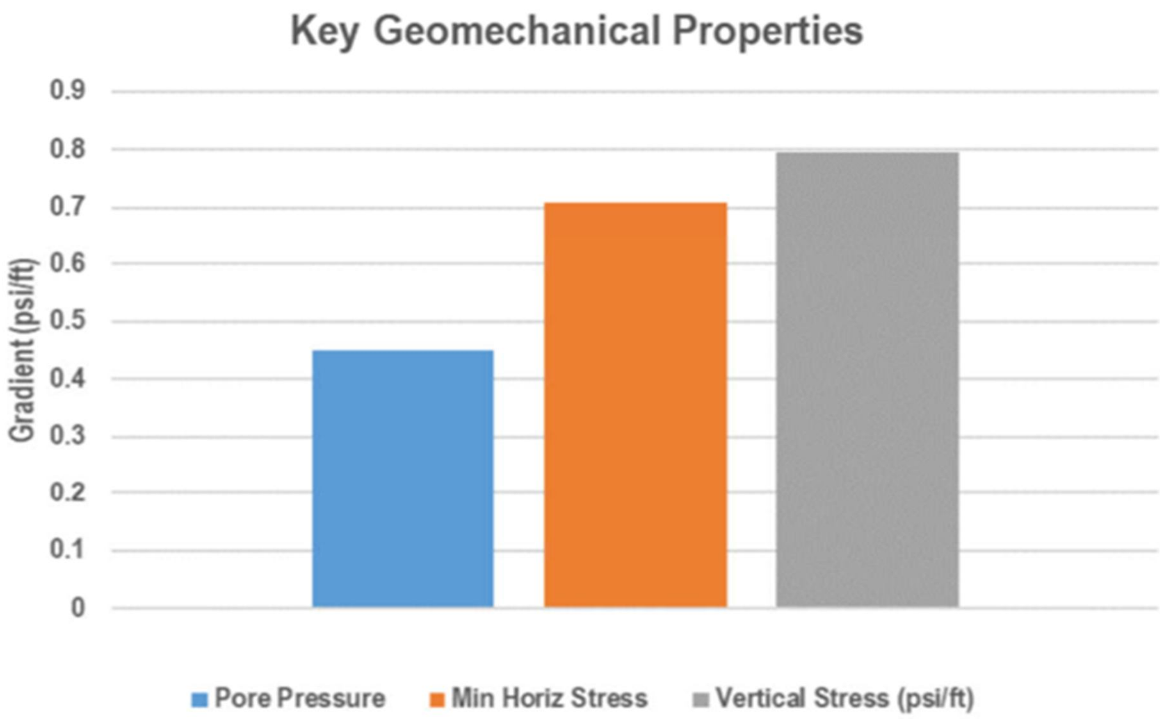

Figure 2: Average gradient values of pore pressure, minimum horizontal stress, and vertical stress in the D1 field.

Table 2 presents a comparative summary of key geomechanical properties between the D1 and X1 fields and Figure 3 a barchart comparing the mid-range geomechanical properties of the D1 and X1 fields. Both fields exhibit a normal faulting (NF) regime, characterized by vertical stress exceeding horizontal stresses—typical of sedimentary basins like the Niger Delta. The pore pressure gradients in D1 are relatively consistent and lower (0.42–0.46 psi/ft), particularly in both shales and sands. In contrast, the X1 field shows higher and more variable pore pressures, especially in sands (up to 0.60 psi/ft), indicating possible overpressured zones. This has implications for kick tolerance and early well control measures.The minimum horizontal stress in both fields is generally similar in shales; however, X1 displays lower values in sands (0.65–0.69 psi/ft), suggesting it may be more prone to tensile fracturing, especially if mud weights are not carefully controlled.X1 also has higher vertical stress (up to 0.91 psi/ft), pointing to a denser or thicker overburden. Despite this, its fracture gradient is lower (0.59–0.69 psi/ft) compared to D1 (0.80–0.81 psi/ft), indicating a narrower safe mud weight window. This increases the risk of lost circulation if fracture limits are exceeded.

Overall, the data suggests that X1 is more geomechanically sensitive than D1, requiring more conservative and precise mud weight management to avoid drilling hazards such as kicks and formation breakdown.

Table 2: Summary of key geomechanical properties of the Study Area.

Geomechanical Properties	D1 Field	X1 Field
Pore Pressure in Shales (psi/ft)	0.42 – 0.46	0.43 – 0.70
Pore Pressure in Sands (psi/ft)	0.43 – 0.46	0.55 – 0.60
Minimum Horizontal Stress in Shales (psi/ft)	0.62 – 0.80	0.70 – 0.80
Minimum Horizontal Stress in Sands (psi/ft)	0.65 – 0.81	0.65 – 0.69
Vertical Stress (psi/ft)	0.73 – 0.86	0.86 -0.91
Dominant Stress Regime	NF	NF
Fracture Gradient	0.80 – 0.81	0.59 – 0.69

ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 7.538
Volume 13 Issue VI June 2025- Available at www.ijraset.com

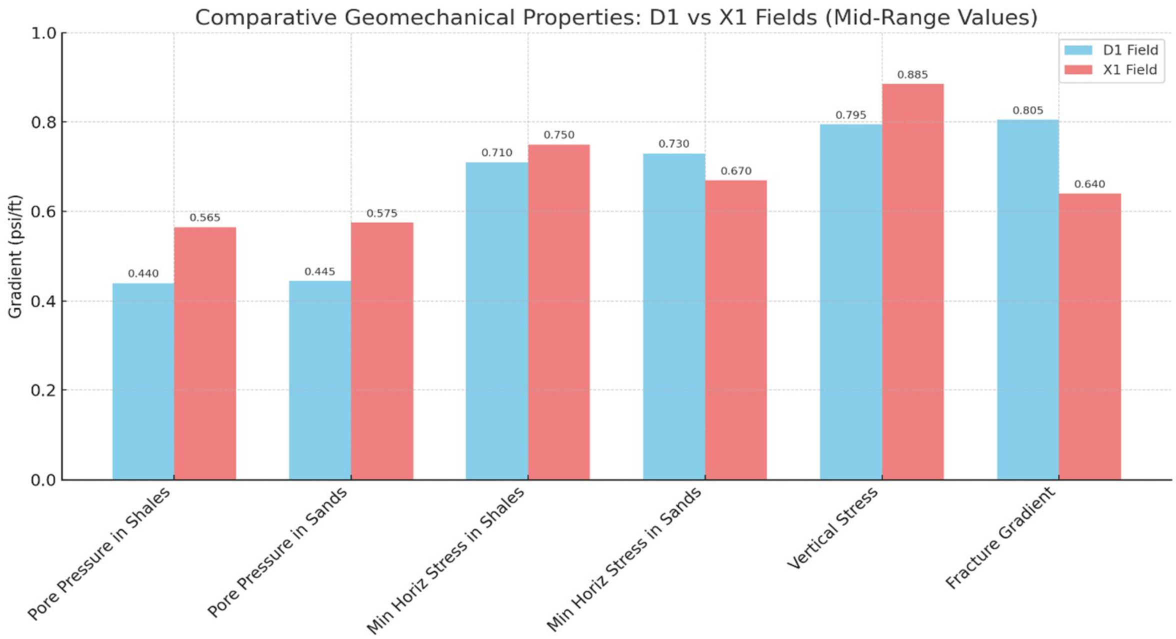

Figure 3: comparing the mid-range geomechanical properties of the D1 and X1 fields.

Figure 4 is a geomechanical well plot (Mud Weight Window plot) showing pressure gradients versus depth. It highlights the safe drilling window between pore pressure and fracture pressure gradients, guiding mud weight selection. The Equivalent Circulating Density (ECD) briefly exceeds the fracture gradient at ~1960 MD, causing lost circulation—a key drilling hazard. Lithology, well trajectory, and real-time markers like LOTs, MDTs, kicks, and losses are also included, making this plot essential for managing wellbore stability and drilling risk.

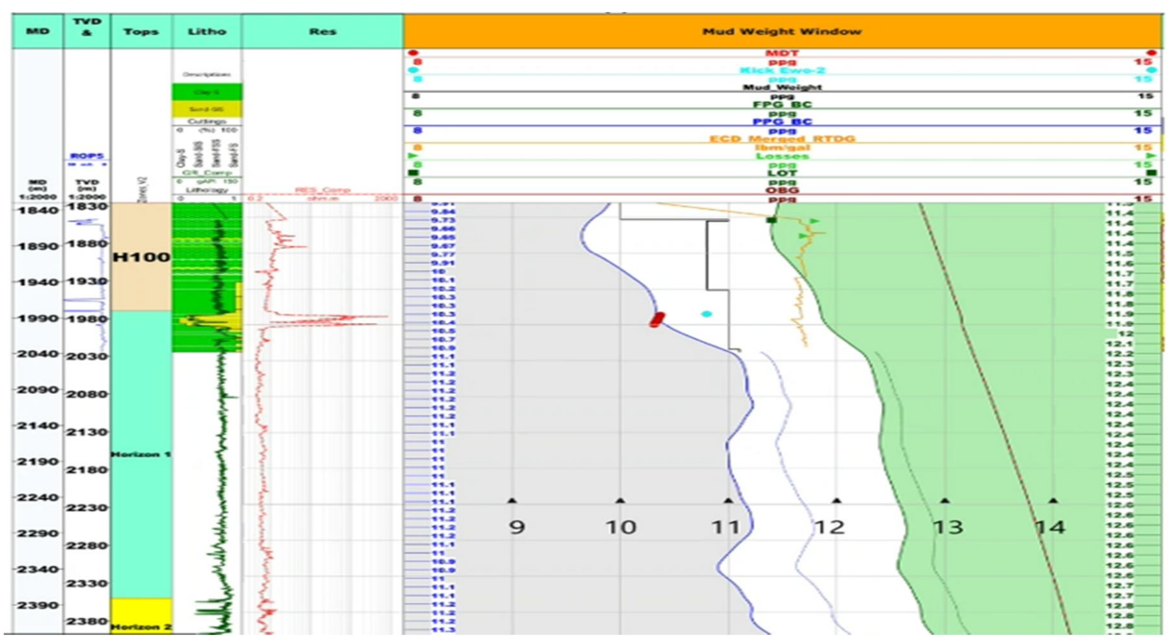

Figure 4: Post drill model and pore pressure profile calibrated using MDT pressure measurement of an exploratory CE-1 Well, X1 Field, Offshore Niger Delta.

V. DISCUSSION OF RESULT

This study investigates mud weight optimization and fracture risk prediction across selected fields in the Niger Delta through an integrated geomechanical analysis. The comparison centers on planned versus actual mud weights, associated wellbore losses, and variations in key geomechanical parameters between the D1 and X1 fields.

A. Mud Weight Performance and Wellbore Losses

Table 1 and Figure 1 collectively demonstrate the impact of mud weight management on well integrity. Wells such as DB-01 and WW-02 remained within the planned mud weight (MW) window and experienced no losses, underscoring the importance of adhering to the safe MW range defined by pore pressure and fracture pressure limits. Conversely, wells like DB-07 and WE-1, which significantly exceeded the upper MW boundary (with actual values approaching or surpassing fracture gradients), suffered severe to total fluid losses. These events directly link overbalanced drilling to induced fractures and formation breakdown, highlighting the narrow margin for error in mud weight selection.

B. Geomechanical Constraints in the D1 Field

Figure 2 provides average gradient values for pore pressure (0.45 psi/ft), minimum horizontal stress (0.70 psi/ft), and vertical stress (0.80 psi/ft) in the D1 field. These parameters define a typical normal faulting regime where vertical stress exceeds horizontal components. The safe mud weight window lies between the pore pressure and minimum horizontal stress gradients. The findings suggest that maintaining mud weights within this window is critical to prevent both influx (kicks) and losses due to tensile fracturing.

C. *Comparative Geomechanics: D1 vs. X1 Field*

Table 2 and Figure 3 offer a comparative summary of the D1 and X1 fields. While both exhibit a normal faulting stress regime, the X1 field displays greater variability and sensitivity in its geomechanical parameters. Notably, the pore pressure in X1 is higher and more variable—particularly in sands—suggesting the presence of overpressured zones that increase the risk of kicks. X1 also has a lower fracture gradient (0.59–0.69 psi/ft) compared to D1 (0.80–0.81 psi/ft), implying a narrower safe MW window and a higher susceptibility to lost circulation if fracture limits are exceeded. Despite its higher vertical stress, which implies a thicker or denser overburden, the lower fracture gradient in X1 points to weaker formation integrity or higher natural fracturing.

D. Insights from the Mud Weight Window Plot

Figure 4 visualizes real-time geomechanical behavior through a well plot displaying pressure gradients versus depth. A critical incident occurs near 1960 MD, where the ECD briefly surpasses the fracture gradient, resulting in fluid loss. This validates the theoretical predictions from Figures 2 and 3 and underscores the importance of dynamic mud weight control, particularly in geomechanically sensitive formations. It also reinforces the need for accurate fracture gradient estimation through field data such as LOTs and MDTs.

E. Overall Implications

The integrated analysis suggests that successful mud weight optimization hinges on a precise understanding of local geomechanical conditions. Fields like X1, with narrower mud weight windows and higher pore pressure variability, demand more conservative drilling strategies and tighter operational control. In contrast, D1 offers relatively stable conditions, permitting slightly more operational flexibility. Ultimately, failure to respect the geomechanical limits defined by pore pressure and fracture gradients results in increased non-productive time, well control events, and economic losses.

This comparative study emphasizes that accurate geomechanical modeling, real-time monitoring, and strict adherence to optimized mud weight windows are essential for minimizing drilling risks and enhancing wellbore stability in the Niger Delta.

VI. CONCLUSION

This comparative geomechanical study of Niger Delta fields demonstrates that precise mud weight management, grounded in accurate pore pressure and stress gradient evaluation, is critical for minimizing drilling hazards. The D1 field exhibits relatively stable and narrower pore pressure ranges (0.42–0.46 psi/ft) and higher fracture gradients (0.80–0.81 psi/ft), affording a broader mud weight window and lower incidence of wellbore losses when controls are properly maintained. In contrast, the X1 field shows elevated and more variable pore pressures—particularly in sands (0.55–0.60 psi/ft)—as well as lower fracture gradients (0.59–0.69

psi/ft). These parameters yield a narrower safe mud weight window, making X1 more susceptible to kicks and lost circulation if mud weight overshoots occur. Field incidents from Table 1 and the wellbore stability plot (Figure 4) confirm that exceeding the upper mud weight limit—approaching or surpassing the fracture pressure—directly correlates with formation breakdown and fluid losses. Overall, the study underscores that local geo mechanical variability dictates drilling risk: fields with higher overpressures and lower fracture thresholds require more conservative drilling practices than those with more benign stress regimes.

VII. RECOMMENDATIONS

1) Field-Specific Mud Weight Design
- D1 Field: Maintain mud weight between 0.45 psi/ft (pore pressure gradient) and 0.70 psi/ft (minimum horizontal stress gradient) to stay well clear of both kick and fracture thresholds. Real-time ECD monitoring should ensure that circulating densities do not exceed 0.70 psi/ft, given the average fracture gradient of ~0.80 psi/ft.
- X1 Field: Adopt a more conservative mud weight range—ideally between 0.43 psi/ft (lower-end pore pressure) and 0.59 psi/ft (lower-end fracture gradient)—to mitigate the risk of lost circulation. Conduct frequent pore pressure checks (e.g., MPC, D-exponent) to track overpressure zones, especially within sandy intervals.

2) Enhanced Real-Time Monitoring
- Incorporate continuous ECD measurements and routine equivalent static mud weight (ESMW) recalculations to detect any drift toward fracture gradient early.
- Leverage real-time kick detection tools (e.g., automated flow and pressure monitoring) to promptly identify any influx when approaching higher pore pressure intervals in X1.
- Use downhole pressure sensors and look-ahead resistivity logs to refine pore pressure models, particularly where X1 sands show overpressure anomalies.

3) Frequent Calibration of Geomechanical Models
- Perform periodic Leak-Off Tests (LOTs) and Mini-Frac tests at strategic depth intervals to verify fracture gradient predictions.
- Calibrate pore pressure predictions against measured pressures (MDTs) whenever data are acquired, updating the geomechanical model to reflect localized overpressured zones, especially in X1.
- Re-evaluate minimum horizontal stress estimates by integrating extended leak-off test (XLOT) and in-hole stress measurements to reduce uncertainty in the mud weight window.

4) Lithology-Driven Drilling Practices
- Aim for slower drilling rates and controlled hydraulics when drilling through high-risk lithologies—e.g., overpressured sands in X1—to limit surges that could raise ECD above fracture pressure.
- Implement managed pressure drilling (MPD) techniques in sections where the mud weight window is exceptionally narrow, allowing more precise control over equivalent circulating density without raising static mud weight.

5) Casing and Well Design Optimization
- Design casing points in X1 to isolate overpressured intervals earlier, thereby reducing the vertical section exposed to narrow mud weight windows.
- Consider setting intermediate liners or using expandable liners in D1's deeper sections to minimize the risk of screen-outs from narrow fracture gradients as drilling approaches the overburden limit.

6) Integrated Data Sharing and Continuous Learning
- Establish a centralized database for logging pore pressure tests, fracture tests, and loss events. This repository will support continuous model refinement and enable cross-field learning (e.g., lessons from D1 applied to nearby X1 wells).
- Schedule post-drilling workshops to review any losses or kicks in both fields, identify root causes, and update standard operating procedures to reflect evolving geomechanical insights.

By following these recommendations—tailoring mud weight windows to individual field stress regimes, enhancing real-time monitoring, regularly calibrating geomechanical models, and optimizing casing design—operators can significantly reduce drilling non-productive time, mitigate well control risks, and improve overall drilling efficiency in the Niger Delta.

REFERENCES

[1] Aadnøy, B. S., & Looyeh, R. (2019). Petroleum rock mechanics: Drilling operations and well design. Gulf Professional Publishing.

[2] Doust, H., & Omatsola, E. (1990). Niger Delta. In J. D. Edwards & P. A. Santogrossi (Eds.), Divergent/passive margin basins (Vol. 48, pp. 201–238). AAPG Memoir.

[3] Fjaer, E., Holt, R. M., Horsrud, P., Raaen, A. M., & Risnes, R. (2008). Petroleum related rock mechanics (2nd ed.). Elsevier.

[4] Ikporo, B. C., & Sylvester, C. (2020). Geomechanical Modeling for Wellbore Stability Analysis in the Niger Delta. Journal of Petroleum Exploration and Production Technology, 10(1), 275–289. https://doi.org/10.1007/s13202-019-00771-2

[5] Moos, D., & Zoback, M. D. (1990). Utilization of observations of wellbore failure to constrain the orientation and magnitude of crustal stresses: Application to continental, DSDP, and ODP boreholes. Journal of Geophysical Research: Solid Earth, 95(B6), 9305–9325. https://doi.org/10.1029/JB095iB06p09305

[6] Okechi, C., & Onyejekwe, O. C. (2016). Analysis of wellbore instability in over-pressured shale formations: Case study of the eastern Niger Delta. Nigerian Journal of Technology, 35(4), 928–935. https://doi.org/10.4314/njt.v35i4.31

[7] Tingay, M. R. P., Reinecker, J., & Müller, B. (2009). Borehole breakouts, stress magnitudes and rock strength in the Cuu Long and Nam Con Son basins, offshore Vietnam. Marine and Petroleum Geology, 26(7), 1274–1285. https://doi.org/10.1016/j.marpetgeo.2009.02.007

[8] Tingay, M. R. P., Reinecker, J., & Müller, B. (2009). Borehole breakouts, stress magnitudes and rock strength in the Cuu Long and Nam Con Son basins, offshore Vietnam. Marine and Petroleum Geology, 26(7), 1274–1285.

[9] Zoback, M. D. (2010). Reservoir geomechanics. Cambridge University Press.