

RESEARCH ARTICLE

Enhancing CO₂ Storage Safety and Efficiency through Advanced Geomechanical Modeling and Integrated Monitoring Systems

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Abstract

Geological-scale carbon dioxide (CO₂) storage is a crucial technology for decarbonization, but its implementation faces significant challenges related to geomechanical risks and long-term containment safety, particularly in depleted hydrocarbon reservoirs such as those found Offshore North West Java (ONWJ). This report analyzes a proactive framework for effectively managing these risks. The central thesis of this analysis is that these risks can be mitigated through the synergistic integration of advanced coupled Thermal-Hydraulic-Mechanical-Chemical (THMC) geomechanical modeling with a real-time integrated monitoring system. The analysis shows that the THMC model is capable of accurately predicting potential fault reactivation, reservoir subsidence, and CO₂ plume migration, allowing for optimization of injection parameters to maintain subsurface stability and sustain long-term injectivity under evolving reservoir conditions. Well integrity, a major potential leakage pathway, is identified as a critical element requiring more robust design, materials, and Plugging and Abandonment (P&A) protocols than conventional standards. Field validation through controlled experiments and advanced monitoring technology has demonstrated the ability to detect minor leaks with localized and reversible environmental impacts. This integrated and predictive approach is considered an essential prerequisite for ensuring the security of permanent storage, building public trust, and accelerating the implementation of Carbon Capture and Storage (CCS) as a pillar of climate change mitigation.

Keywords: CO₂ storage, Geomechanics, THMC (Thermal-Hydraulic-Mechanical-Chemical) Modeling, Risk Mitigation, Monitoring

1. Introduction

Global climate mitigation targets demand rapid decarbonization across hard-to-abate industrial sectors. Carbon Capture and Storage (CCS) is widely recognized as a critical technology for reducing point-source emissions and enabling negative-emission pathways such as BECCS and DACCS (Askarova et al., 2023; IEA, 2024). Despite its strategic importance, large-scale deployment faces persistent technical barriers, primarily subsurface geomechanical instability, long-term containment security, and legacy infrastructure vulnerabilities (Song et al., 2023; Rutqvist, 2012).

Current risk management often relies on reactive "detect-and-respond" strategies, which are insufficient for permanent storage where delayed intervention can cause irreversible leakage or induced seismicity (Dean et al., 2020; Oldenburg and Unger, 2003). In mature basins like Indonesia's Offshore North West Java (ONWJ), decades of hydrocarbon extraction have altered in-situ stress fields, induced severe compaction, and compromised legacy well integrity (Wijaya et al., 2022). These geomechanical legacy risks are frequently overlooked in conventional site assessments. Moreover, the limited integration of high-fidelity geomechanical modeling with real-time verification hinders the development of scalable risk frameworks for Indonesian CCS projects (Alam et al., 2023; Erfando and Herawati, 2023).

To address these gaps, this study proposes a proactive "predict-and-prevent" framework integrating two synergistic pillars: (1) advanced coupled Thermal-Hydraulic-Mechanical-Chemical (THMC) modeling to forecast subsurface responses before, during, and after injection (Vilarrasa et al., 2013; Swadesi et al., 2025), and (2) a risk-based, integrated monitoring network for continuous verification and early anomaly detection (Ma et al., 2024; Zumhari et al., 2025).

Beyond geomechanical stability, CO₂ injectivity—the formation's capacity to accept CO₂ at safe pressure differentials—remains a critical operational constraint. Injectivity decline due to near-wellbore salt precipitation, fines migration, or stress-induced permeability changes can severely limit storage rates and project economics (Alam et al., 2023; Valluri et al., 2020). The proposed framework explicitly addresses this by coupling THMC simulations with real-time pressure monitoring, enabling dynamic injection optimization that balances storage targets with subsurface safety limits. The specific objectives are to: (i) quantify THMC model accuracy in predicting fault reactivation, plume migration, and surface deformation; (ii) develop a well integrity and Plugging & Abandonment (P&A) protocol optimized for permanent CO₂ containment; and (iii) design a scalable monitoring strategy applicable to both depleted reservoirs and saline aquifers. By bridging predictive geomechanics with empirical verification, this framework

establishes a technically robust and socially credible pathway for safe, large-scale CCS implementation in Indonesia.

2. Methods

The analytical framework for ensuring CO₂ storage security is based on a systematic methodology that integrates predictive modeling, rigorous well integrity assessments, and integrated monitoring systems. This multifaceted approach is designed to identify, quantify, and mitigate risks throughout the CCS project lifecycle.

2.1 Coupled Geomechanical Modeling (THMC)

The foundation of the predictive framework is fully coupled Thermal-Hydraulic-Mechanical-Chemical (THMC) geomechanical modeling. This methodology simultaneously resolves the interactions between thermal, hydraulic, mechanical, and chemical processes in the subsurface (Vilarrasa et al., 2013; Akai et al., 2021). The injection of supercritical CO₂, which is often cooler and less viscous than formation fluids, triggers interrelated responses: temperature changes affect rock stress and fluid viscosity; pore pressure alterations modify effective stress and drive fluid flow; stress redistribution induces rock deformation or fracturing; and chemical reactions between CO₂, brine, and minerals gradually alter porosity and permeability (Song et al., 2023; Cinar and Riaz, 2014).

Modeling workflow begins with constructing a full-scale 3D geological model using 3D seismic interpretation, well logs, core-derived petrophysical properties, and regional stress tensor data (Alam et al., 2023; Swadesi et al., 2025). The numerical platform (e.g., TOUGH-FLAC or COMSOL Multiphysics) applies the following boundary and initial conditions:

- Initial Conditions: Far-field tectonic stress state, hydrostatic pore pressure gradient, and geothermal temperature profile.
- Boundary Conditions: No-flow lateral boundaries, constant overburden stress at the top, and prescribed injection/production fluxes at well nodes.
- Calibration Procedure: Model parameters are calibrated against historical production data, pressure transient tests, and microseismic event catalogs to ensure geological realism and reduce predictive uncertainty (Rutqvist, 2012; Zhang et al., 2022).

The calibrated model is deployed for three critical applications:

- Fault Reactivation Prediction: Shear slip potential on pre-existing faults is evaluated using the Mohr-Coulomb failure criterion under evolving pore pressure and effective stress conditions. The model identifies the maximum allowable injection pressure before fault reactivation occurs (Espinoza and Santamarina, 2010; Kwon and Santamarina, 2016).
- CO₂ Plume Migration Forecasting: Multiphase flow simulations track the lateral and vertical spread of the CO₂ plume, pressure/temperature evolution over decades to centuries, and interactions with geological heterogeneities such as intra-formational shale baffles (White et al., 2012; Doughty and Pruess, 2011).
- Surface Subsidence and Deformation Analysis: Poromechanical coupling predicts reservoir compaction and potential vertical deformation (uplift or subsidence) at the surface or seafloor, ensuring the mechanical integrity of overburden infrastructure and wells (Birkholzer et al., 2009; Wijaya et al., 2022).

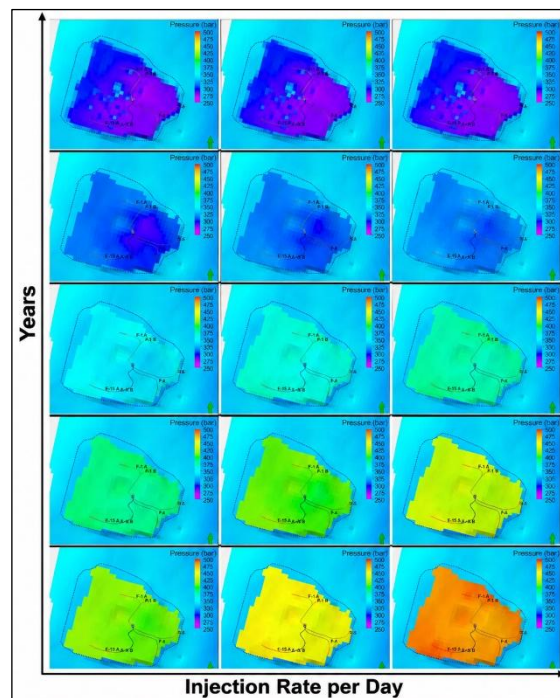


Fig. 1. THMC simulation results showing reservoir pressure distribution under three different CO₂ injection rates. The pressure contours illustrate the spatial and temporal propagation of pore pressure during the injection phase (2025–2045). Elevated pressure zones indicate areas approaching geomechanical thresholds, providing a basis for optimizing injection envelopes to prevent fault reactivation or caprock fracturing. Source: Alam et al. (2023).

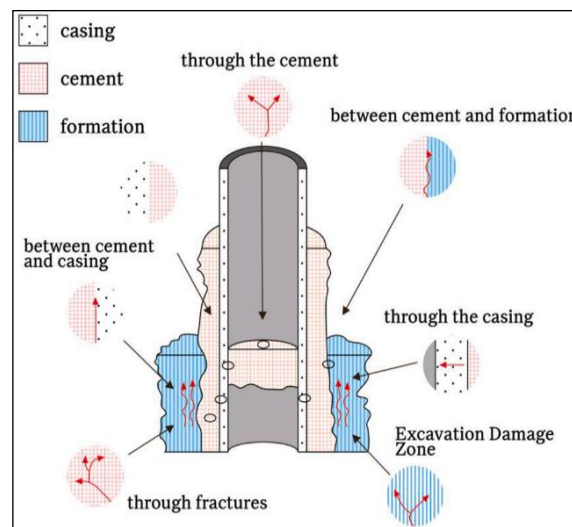


Fig. 2. Schematic of potential CO₂ migration pathways from subsurface storage formation to atmosphere, including: (a) fault reactivation, (b) caprock fracturing, (c) wellbore leakage via cement degradation or casing failure, and (d) diffuse seepage through permeable overburden. Red arrows indicate high-risk anthropogenic pathways requiring prioritized monitoring. Source: Song et al., 2023. Geomechanical challenges during geological CO₂ storage: A review

2.2 Well Integrity Assessment Framework

Injection and legacy wells represent the most probable anthropogenic leakage pathways. Therefore, a rigorous well integrity assessment is integrated into the risk framework (Oldenburg and Unger, 2003). This assessment combines literature-based degradation kinetics with numerical stress-strain modeling to evaluate long-term barrier performance:

- Caprock Integrity Analysis: Detailed characterization of caprock capillary entry pressure, permeability, and mechanical strength. Geomechanical simulations evaluate how injection-induced stress perturbations may reactivate existing fractures or generate new microcracks (Bachu, 2015; Erfando and Herawati, 2023).
- Cement Degradation Evaluation: Well cement exposed to acidic brines (formed when CO₂ dissolves in formation water) undergoes carbonation and mechanical weakening. Laboratory-derived reaction rates are integrated into the model to simulate long-term permeability evolution. Distributed Temperature Sensing (DTS) data from fiber-optic cables are used to validate cement bonding quality and detect micro-annuli formation during hydration and operational phases (Wildenschild et al., 2021; Dean et al., 2020).
- Annular Pressure Monitoring Protocol: Continuous monitoring of pressure in casing annuli serves as an early leak indicator. Unexplained pressure buildup suggests breach in cement, casing joints, or packers. For CCS wells, this protocol accounts for corrosive CO₂-rich environments, thermal cycling from cold injection, and sustained high pressures, aligning with ISO 27914:2017 design requirements (Jenkins et al., 2015; Syahrul et al., 2025).

2.3 Framework Integrated Monitoring Technology

The verification pillar employs a suite of monitoring technologies integrated into a risk-based Concept of Operations (CONOP). This ensures that surveillance intensity matches subsurface risk distribution:

- Risk-Based Zoning: High-risk zones (e.g., injection well clusters, fault intersections, legacy wellbores) are monitored continuously with high-resolution sensors, while lower-risk areas undergo periodic regional surveys (Ma et al., 2024; Atkinson et al., 2023).
- Seabed and Geochemical Technologies: Static seabed landers equipped with pH, pCO₂, and dissolved oxygen sensors provide long-term baseline data. Autonomous Underwater Vehicles (AUVs) with side-scan sonar and methane/CO₂ sniffers conduct wide-area leak detection, capable of identifying bubble plumes at flow rates as low as 10–50 L/min (Dean et al., 2020; Zumhari et al., 2025).
- Microseismic and Fiber-Optic Networks: Distributed Acoustic Sensing (DAS) and geophone arrays detect microseismic events indicative of fault slip or fracture propagation. Real-time data streams are fused into a centralized analytics dashboard for automated anomaly detection and dynamic model updating (Jenkins et al., 2015; Zhang et al., 2022).

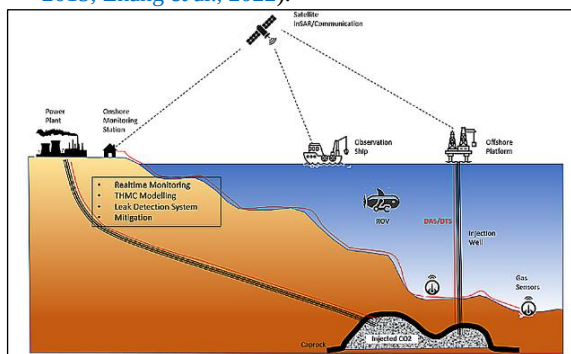


Fig. 3. Conceptual workflow for risk-based integrated monitoring of sub-seabed CCS, linking predictive THMC modeling (left) with multi-technology verification (right). High-risk zones (injection wells, faults) receive continuous monitoring via fiber-optic DAS/DTS and seabed landers; regional coverage via periodic AUV

surveys. Data streams feed a centralized analytics dashboard for real-time anomaly detection and adaptive management.

Table 1. Geomechanical Risk and Mitigation Matrix for CO₂ Storage.

Risk	Predictive Modeling Tools	Monitoring & Verification Tech.	Mitigation Strategy
Fault Reactivation	THMC modeling coupled with Mohr-Coulomb failure criteria	Microseismic monitoring (real-time) using DAS; 4D seismic survey	Managing injection rate/pressure below reactivation threshold; site selection
Overburden Failure	Geomechanical overburden integrity model; inlet capillary pressure analysis	4D seismic survey to map integrity; monitoring pressure above the zone	Site selection with thick & competent overburden; managing pressure gradients
Well Leak	Geochemical reaction models; well stress analysis	Continuous Annulus Pressure (SAP); Cement Bond Logs (CBL); DTS	CO ₂ -resistant materials (cement, steel); robust P&A design; well intervention
Induced Seismicity	THMC modeling coupled with rate- and state-dependent friction; stress perturbation analysis	Microseismic monitoring (real-time) using DAS; 4D seismic survey	Managing injection rate/pressure below seismic threshold; traffic light system
Reservoir Subsidence / Compaction	Historical geomechanical model (production-subsidence); THMC modeling	InSAR for surface deformation; downhole compaction monitoring	Managing reservoir pressure (e.g., water injection); adaptive well design

Abbreviations: THMC = Thermal-Hydraulic-Mechanical-Chemical; DAS = Distributed Acoustic Sensing; SAP = Sustained Annulus Pressure; CBL = Cement Bond Log; DTS = Distributed Temperature Sensing; InSAR = Interferometric Synthetic Aperture Radar; P&A = Plugging and Abandonment.

Source: Authors' synthesis.

To synthesize this analytical framework, Table 1 presents a matrix linking key geomechanical risks with their triggering mechanisms, predictive modeling tools, monitoring technologies, and appropriate mitigation strategies.

Table 1 the relationship between major geomechanical risks and the corresponding approaches used to predict, monitor, and mitigate them. For each identified risk—such as fault reactivation, overburden failure, well leakage, and reservoir subsidence—the table outlines suitable predictive modeling tools to assess failure mechanisms, monitoring and verification technologies to detect early warning signs, and mitigation strategies to reduce or control the risk. Overall, the table highlights an integrated risk management framework that connects modeling, real-time monitoring, and engineering controls to ensure safe and reliable subsurface operations.

3. Results and Discussion

This section presents a critical synthesis of geomechanical risks, predictive modeling outcomes, and field validation data. Rather than treating leakage and monitoring as isolated operational issues, the discussion interprets these findings

through the lens of the proposed "predict-and-prevent" framework, highlighting the mechanistic linkages between subsurface stress evolution, long-term containment security, and scalable risk management.

3.1. Legacy Risks in Depleted Reservoirs: Geomechanical Memory and Integrity Compromise

Depleted hydrocarbon reservoirs, such as those in the Offshore North West Java (ONWJ) basin, are frequently targeted for CO₂ storage due to proven trapping mechanisms and existing infrastructure. However, prolonged production fundamentally alters the subsurface stress regime, creating geomechanical "legacy risks" that cannot be overlooked. Field data from the Parigi limestone and Ardjuna carbonate formations reveal seafloor subsidence ranging from 3.5 m to over 10 m due to reservoir compaction (Wijaya et al., 2022). This volumetric loss is not merely a geometric change; it triggers significant stress redistribution within the overburden and along legacy wellbores. The resulting differential stress induces casing buckling, microfracture propagation, and caprock strain, effectively converting historical production pathways into potential CO₂ leakage conduits (Birkholzer et al., 2009; Rutqvist, 2012).

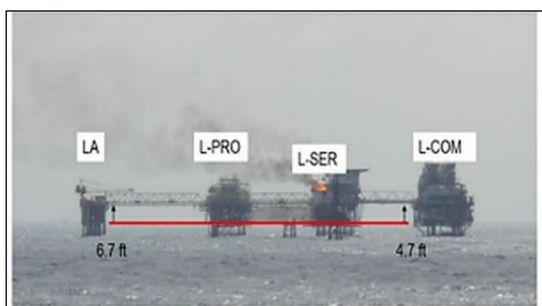


Fig. 4. Offshore platforms in the ONWJ block, Indonesia, showing cumulative seafloor subsidence >3.5 m due to reservoir compaction from prolonged hydrocarbon production (1970s–2020s). Inset: time-series InSAR data confirming vertical displacement rates of 15–25 cm/yr in the Parigi limestone formation. This legacy deformation complicates well integrity and P&A operations for prospective CCS reuse. Source: Wijaya et al. (2022); satellite data: ESA Sentinel-1.

Unlike pristine saline aquifers, depleted reservoirs possess a complex stress history that must be quantitatively reconstructed before injection. The compaction-induced loss of pore volume reduces available storage capacity, while the transfer of effective stress to overlying formations exacerbates well integrity challenges. These findings underscore that conventional site-screening methods, which focus primarily on static trap geometry, are insufficient for mature basins. A comprehensive geomechanical audit—integrating historical production data with dynamic stress modeling—is mandatory to identify pre-existing weaknesses and design adaptive injection strategies that avoid reactivating legacy damage.

3.2. Predictive Modeling Insights: Validating the Predict-Prevent Framework

Confidence in long-term storage security hinges on the ability to forecast CO₂ behavior across operational and geological timescales. Coupled THMC simulations from the Volve field dataset demonstrate that reservoir pressure evolution is highly predictable and manageable when modeled with dynamic boundary conditions. By simulating pressure propagation from the injection well, operators can establish safe injection envelopes that remain below fault reactivation and caprock fracturing thresholds (Akai et al., 2021; Vilarrasa et al., 2013). The model also accurately captures near-well thermal effects (Joule-Thomson cooling)

and associated vertical displacement, validating the necessity of fully coupled physics over decoupled approximations.

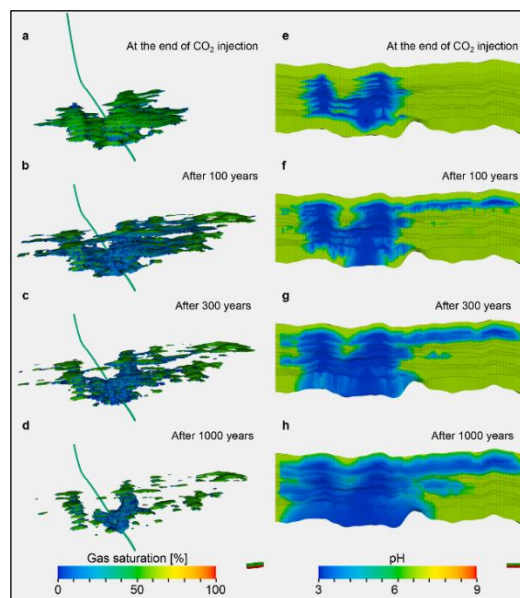


Fig. 5. Simulated supercritical CO₂ saturation (left) and formation brine pH (right) along a N–S cross-section at the Sleipner site, showing plume evolution at 100, 300, and 1000 years post-injection. Buoyancy-driven migration is arrested by intraformational Utsira shale layers; pH reduction near the plume promotes carbonate mineral precipitation (mineral trapping). Model: TOUGHREACT; grid resolution: 50 × 50 × 5 m. Source: Akai et al. (2021).

Long-term plume forecasts from the Sleipner project and the Pearl River Mouth Basin further substantiate the predictive framework. Simulations show that buoyancy-driven upward migration is naturally arrested by intraformational shale baffles and primary caprocks, confirming structural and residual trapping efficiency (White et al., 2012). Geochemical tracking reveals progressive pH reduction due to carbonic acid formation, followed by carbonate mineral precipitation over centennial scales. This mineral trapping mechanism effectively immobilizes CO₂ in a thermodynamically stable solid phase, reducing long-term leakage potential (Doughty and Pruess, 2011). Collectively, these case studies demonstrate that accurate forecasting enables proactive operational control, shifting risk management from reactive anomaly response to predictive parameter optimization.

3.3. Well Integrity and Permanent Containment Protocols

Injection and legacy wells represent the most probable anthropogenic leakage pathways, necessitating a permanence-oriented engineering philosophy. Experimental validation using Distributed Temperature Sensing (DTS) confirms high sensitivity to cement bonding defects during well construction, providing empirical verification of barrier quality (Wildenschild et al., 2021). However, operational integrity alone is insufficient; CCS barriers must withstand centuries of chemical and mechanical stress.

Conventional Plugging and Abandonment (P&A) protocols, designed for economic hydrocarbon containment, are inadequate for permanent CO₂ storage. CCS-specific P&A designs require multi-barrier systems, including extended casing removal, placement of thick cement plugs in competent formations below the primary seal, and utilization of CO₂-resistant materials (Jenkins et al., 2015; Erfando and Herawati, 2023). This shift reflects a fundamental change in risk tolerance: while minor hydrocarbon leaks may be

economically tolerable, CO₂ storage demands near-zero leakage to maintain climate mitigation credibility. Strict adherence to international standards such as ISO 27914:2017 ensures that well design transitions from short-term operational safety to millennial-scale containment security (Oldenburg and Unger, 2003).

3.4. Empirical Validation and Strategic Site Selection

While modeling provides predictive confidence, field validation is essential to demonstrate detection capability and environmental resilience. The QICS controlled release experiment in Scotland revealed that ~85% of injected CO₂ remained trapped or dissolved in sediments, with escaped gas causing highly localized pH reduction within a 25 m radius. Marine ecosystem recovery began within one year post-release, demonstrating that minor, detected leaks are environmentally manageable and reversible (Dean et al., 2020). These results effectively counter worst-case leakage narratives and validate the efficacy of integrated monitoring networks.

However, localized manageability does not negate systemic climate risks. Integrated energy system analyses indicate that a cumulative leakage rate of just 0.1%/year across a global CCS portfolio could negate climate benefits by mid-century (Steyn et al., 2022; Metz et al., 2005). Reconciling these perspectives requires a dual strategy: (i) predictive modeling and robust well design to prevent leakage at the source, and (ii) high-sensitivity monitoring to isolate anomalies before they scale.

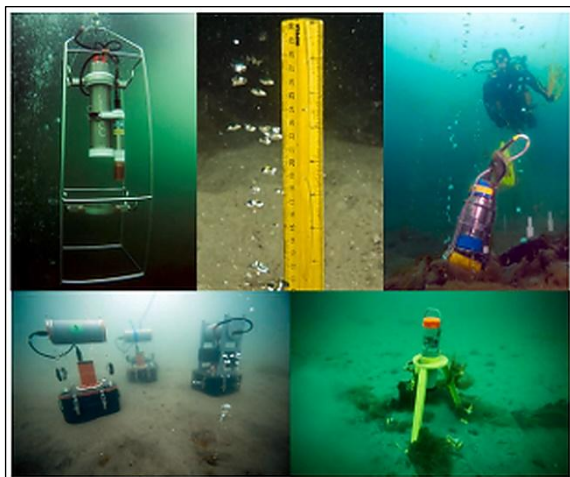


Fig. 6. Integrated CO₂ leak detection framework from the QICS project, combining chemical sensors (pH, pCO₂), acoustic detectors, and Autonomous Underwater Vehicle (AUV) surveys into a unified real-time monitoring system. The system enables early detection (<30 min), precise localization (<5 m accuracy), and quantification of seabed CO₂ seepage. Data fusion allows seamless regulatory reporting and stakeholder communication. Source: Dean et al. (2020).

This analysis highlights a critical conceptual trade-off for national CCS deployment. Depleted reservoirs offer well-characterized stratigraphy and existing infrastructure but carry significant legacy geomechanical risks. Conversely, saline aquifers present geologically pristine conditions with fewer legacy issues but higher exploration uncertainty and development costs (Bachu, 2015; Alam et al., 2023). Indonesia's portfolio of 18,000+ legacy wells and diverse storage basins cannot rely on a single storage typology. A risk-based site selection framework, balancing capacity, cost, and manageable geomechanical risk, is essential. Scalable, autonomous monitoring technologies—such as smart AUVs, fiber-optic DAS/DTS arrays, and AI-driven anomaly detection—will be critical for cost-effective, nationwide

deployment (Zhang et al., 2022; Atkinson et al., 2023; Zumhari et al., 2025). By integrating predictive geomechanics with transparent, scalable verification, Indonesia can accelerate safe CCS implementation while maintaining public trust and regulatory compliance.

4. Conclusions

The safety and long-term efficiency of geological CO₂ storage can be reliably achieved through a synergistic, predictive framework that integrates advanced THMC geomechanical modeling, rigorous well integrity management, and real-time multi-technology monitoring. Rather than relying on reactive anomaly response, this approach enables operators to forecast subsurface stress evolution, optimize injection envelopes, and prevent geomechanical failure before it occurs. Field-validated simulations from mature basins confirm that buoyancy-driven plume migration is naturally constrained by structural and residual trapping mechanisms, while progressive mineral carbonation provides centennial-scale containment security. Well integrity remains the most critical anthropogenic risk; therefore, CCS-specific Plugging and Abandonment (P&A) protocols must exceed conventional hydrocarbon standards by incorporating CO₂-resistant cement, multi-barrier designs, and continuous annular pressure verification. When coupled with risk-based monitoring networks—spanning fiber-optic DAS/DTS, microseismic arrays, and autonomous seabed sensors—this integrated system delivers continuous empirical verification, early anomaly detection, and regulatory transparency.

For Indonesia's CCS deployment, which encompasses over 18,000 legacy wells and diverse storage typologies, this predictive-preventive paradigm transforms risk management from a compliance exercise into a core engineering principle. It directly addresses the technical uncertainties that underlie public skepticism, thereby strengthening the social license to operate and enabling scalable, cost-effective nationwide implementation. A portfolio-based site selection strategy, balancing depleted reservoir capacity with saline aquifer geological certainty, is essential to mitigate legacy stress risks while maximizing storage efficiency.

Future research should prioritize four strategic areas: (i) systematic geomechanical auditing and stress-history reconstruction of legacy wells in mature basins; (ii) development of low-cost, autonomous offshore monitoring platforms (e.g., smart AUVs and modular seabed landers) to reduce long-term operational expenditures; (iii) formulation of self-healing, CO₂-resistant wellbore materials capable of withstanding multi-decadal chemical and thermal cycling; and (iv) integration of AI-driven analytics for real-time model calibration, automated anomaly classification, and dynamic injection optimization. Advancing these priorities will further solidify the technical and economic viability of CCS, positioning it as a cornerstone of Indonesia's net-zero transition and global climate mitigation efforts.

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