Criticality of data for permanent CO2 storage in deep geological formations

Partha Pratim Mandal*, Adil Mirda, and Swarandeep Sahoo, IIT(ISM) Dhanbad, India
partham@iitism.ac.in

Keywords

Data, carbon capture, and storage, aquifers, capacity, rock-physics, geomechanical modelling, monitoring

Abstract

Carbon capture and storage is going to be a major driver for India's emission reduction target by 2070. CO2 can be stored in deep geological formations where critical infrastructures are built for the hydrocarbon industry. A comprehensive data catalog is required when evaluating the feasibility of potential CO2 storage in those formations. In this paper, a multi-faced data-intensive approach is demonstrated to map out capacity, containment, injectivity, and monitorability aspects of CO2 sequestration in Sognefjord formation of Smeaheia field, Norwegian North Sea. Based on the above case study and literature information to overcome the data limitation in Indian sedimentary Basins, an India-specific subsurface CO2 storage screening workflow is proposed.

Introduction

India made a commitment to reach a net-zero emission target by 2070 during COP26 [1]. The conversion of captured CO2 into usable chemicals, products, and carbon mineralization is a realistic approach to meeting the United Nations Sustainability Development Goals (SDGs), while another option is the permanent storage of CO2 in deep geological formations for India's economic growth. According to IEA, 2023, the industry needs to rapidly increase commercial carbon capture and storage (CCS) activity by 20 times before the end of this decade. It requires data-driven screening of subsurface geological formations, associated risk analysis, mitigation plans, and deployment of monitoring technology. Permanent storage of CO2 in subsurface formations i.e., depleted oil and gas reservoirs and saline aquifers depends upon three technical criteria: (i) Capacity (ii) Containment, and (iii) Injectivity. Monitoring is necessary to understand injected CO2 plume movement and its risk potential. Geophysical techniques such as time-lapse seismic, vertical seismic profiling, and rock-physics modelling may be some of the potential tools available for monitoring purposes of long-term CO2 injection. Few researchers [2–4] supplied a first order estimate of CO2 storage capacity in the Indian sedimentary basin in the range of 262 to 656 Gt. Among them, referred authors [4] declassified storage estimates into separate segments as enhanced oil recovery with CO2 injection (EOR), enhanced coalbed methane recovery (ECBMR), permanent storage in depleted reservoirs, saline aquifers, and basalt formations. Considering CO2 injection is not reverse engineering of hydrocarbon production, assessment of storage capacity, caprock integrity, geomechanical stability and risk analysis of the selected formation with changes in temperature, hydrostatic pressure, and modification of in-situ stress magnitudes are crucial before proceeding for commencement of any CCS project.

Accessibility of sound geophysical databases from major oil & gas companies restricts a comprehensive field trial feasible CO2 storage site assessment of India's deep geological formation by any independent research organization. In this drawback, we proposed a digitization route to access reliable datasets, and reports from published literature to carry forward CO2 screening program of geological formations. However, before formally implementing workflow in any Indian sedimentary basin, in this paper we presented an example case study demonstrating CO2 storage prospect evaluation of Smeaheia field where Equinor planned 20 million tons/year CO2 injection [5,6]. We mapped data criticality and predicted missing data through machine learning algorithms from two studied wells penetrating the target Sognefjord formation. Then a 1-D geomechanical model is built and followed by a discussion associated with challenges from containment and injectivity scenarios. Rock-physics modelling is performed to investigate if the variation of elastic properties from long-term CO2 sequestration into the reservoir can be predicted through time-lapse seismic. Decoding the data challenges and knowledge accumulation, an extensive workflow is proposed for CCS screening of India's sedimentary basin through accumulation of knowledge from literature, policy document, CCS whitepaper, and ongoing global CCS projects.

Geology

Smeaheia field (Figure 1) is located on the Horda Platform in the Norwegian North Sea [5]. Two regional faults namely Vette and Øygarden offer lateral sealing of the reservoir. Among observed multiple sandstone strata, Sognefjord is the potential formation in terms of high porosity for CO2 storage screening. The low permeability claystone rock of Draupne formation is the caprock of the storage site. Two structural closures Alpha and Beta are identified within the area. Seal analysis and 3D seismic data interpretation further confirmed eastbound Øygarden fault forms a seal of the identified reservoir in the Beta structure. Well 32/2-1 inside Beta structure, penetrated the target formation at 902 m depth and reached a total depth of 1300 m while Well 32/4-1 inside Alpha prospect reached Sognefjord formation at 1238 m with a total depth of 3186 m. The reservoir is proven to be brine saturated. For subsequent CO2 storage feasibility analysis, well 32/2-1 is used.

Methodology

CCS screening of deep geological formations requires a multi-faced approach that is equivalent to hydrocarbon exploration. This starts with the identification of suitable datasets, their significance, and limitations, then finding the data 'gaps' which deemed crucial for CO2 storage assessment [6]. The CCS screening workflow (Figure 2) can be divided into three phases (i) Data criticality (ii) Site screening (Capacity, Containment, and Injectivity) (iii) Monitoring.

All necessary multidisciplinary datasets such as 3D seismic data, horizons, fault sticks, velocity, well-logs, temperature and pressure data, laboratory rock deformation data, and all related reports are available in Smeaheia region for CO2 storage evaluation [5]. An in-depth investigation of the reservoir's petrophysical properties (total porosity from bulk density log, water saturation – Archie's equation, and volume of shale from GR log with sand and shale cut-off technique), the thickness of the reservoir (68 m at 32/2-1 well and 114 m at 32/4-1 well), storage efficiency, and areal distribution of the reservoir (seismic horizons tied with well tops) are done to estimate volumetric storage capacity in giga tons (Gt) [5].

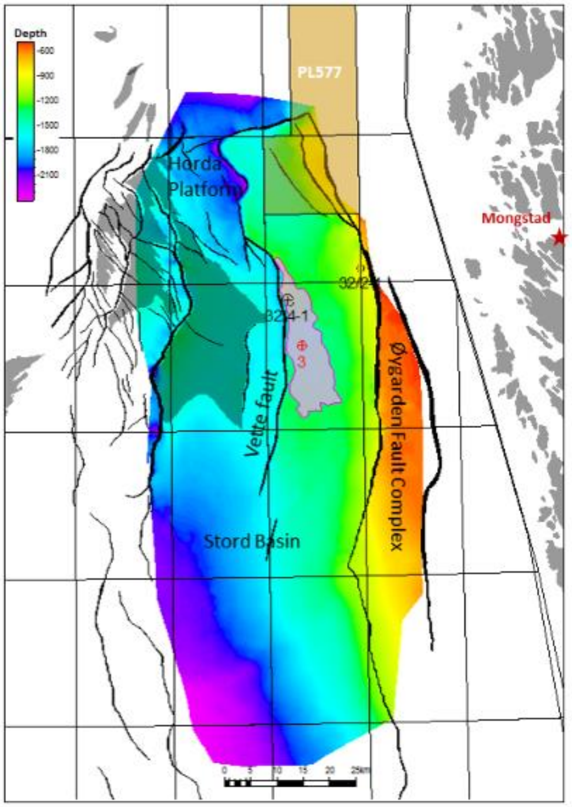


Figure 1: Location map of Smeaheia field, Norwegian North Sea. Modified from [5]

A geomechanical model is built for 32/2-1 combining multiple data sources with a normal faulting stress regime and isotropic horizontal stress consideration [7]. Procedure of 1-D and 3-D geomechanical model building was covered in great length by authors [7]. The model consists of in-situ stress magnitudes (Vertical stress – S_v, minimum horizontal stress – S_{hmin}, and maximum horizontal stress – S_{Hmax}), pore pressure, elastic (Young's modulus, Poisson's ratio), and mechanical properties (UCS, friction coefficient). Eaton's model is deployed for pore pressure estimation. An empirical static-dynamic conversion is used to obtain static elastic properties of caprock and reservoir. The poro-thermo-elastic [8] equation is used to model effective stress path evaluation with uniaxial boundary conditions from CO2 injection into the studied reservoir as a reliable numerical method. The effective horizontal stress change $\Delta\sigma_h$ and thermal stress change $\Delta\sigma_T$ are described by the perturbation of temperature Δt and pressure Δp from injection activity as described by

$$\Delta\sigma_h = \frac{\nu}{1-\nu}\Delta P \qquad (1)$$

in which ν is Poisson's ratio and the value of Biot's coefficient is assumed one.

$$\Delta\sigma_T = \beta\frac{E}{1-\nu}\alpha\Delta T \qquad (2)$$

in which β is the thermoelastic constant, E is Young's modulus, and α is the thermal expansion coefficient.

When looking into the monitoring part, time-lapse seismic technology can be considered over a small area near the injection well. To confirm if this technique can predict reservoir dynamics depends upon the amount of elastic property change of the reservoir over time. Different mathematical models (critical porosity, contact cement, stiff sand, and soft sand model) that connect the petrophysical properties of rock (water saturation, porosity, and volume of shale) with their elastic properties (AI, V_p/V_s) are tested to get the best-fitting rock-physics model [9]. The reservoir rock is a mixture of predominantly quartz matrix and clay minerals. Voight-Reuss-Hill (VRH) average is used to compute elastic properties of the rock composite. For fluid substitution, Gassmann's equation is selected. The in-situ physical properties of reservoir fluids (brine and supercritical CO2) as calculated from Batzle-Wang relationships are summarized in Table 1.

Table 1: In-situ physical properties of fluids at reservoir condition

Fluid type	**Density (kg/m^3)**	**Bulk modulus (GPa)**
Brine	1025	2.68
Supercritical CO2 - fluid	330	0.15

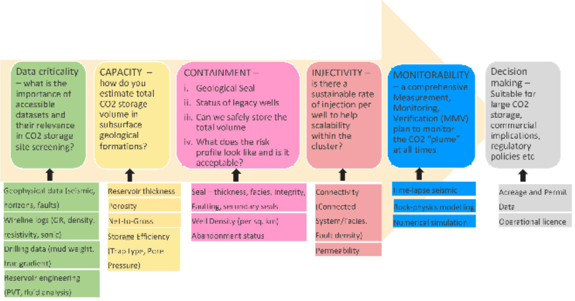


Figure 2: CCS screening workflow of subsurface geological formations. Adopted from [6]

Results and Discussion

Shear wave velocity V_s is lacking in wells 32/2-1 and 32/4-1. Shear wave log is an essential component for geomechanical and rock-physics modelling. With the application of multiple machine learning algorithms (Random Forest, Artificial Neural Network, and multi-linear regression), we forecasted the shear wave log for both wells utilizing nearby four wells that have lithological similarity as training and validation datasets. Random Forest is selected for blind test prediction because it produced the highest R^2 accuracy and the lowest mean-square error value on validation data. Gardner's empirical equation calculates missing density logs in the shallower depth interval. A depth profile of V_p and V_s (Figure 3) is plotted for 32/2-1 well intersecting primary formations. A Mohr circle [10] depicting temperature and pressure influence on Sognefjord formation's analytical stress path evolution because of CO2 injection is drawn based on the poro-thermo-elastic equation (Figure 4). Input geomechanical properties used in Mohr-Coulomb analysis are derived from the 1-D GM (Figure 5) at the injection point from Sognefjord and caprock information from public databases of Draupne formation. The Mohr circle analysis indicates thermal effects counter-balancing poroelastic effects therefore less chances of failure and related micro-seismicity generation from injection. In-situ V_p, V_s, and density logs of 32/2-1 well are brought to a common fluid denominator (reservoir is brine saturated) and then these brine saturated logs are subsequently replaced with supercritical CO2 for every 10% change in CO2 saturation of Sognefjord formation.

The most porous formation with high permeability is preferable when evaluating storage capacity. Sognefjord formation has the highest porosity ranges between 25 to 35% among other sandstone strata. Petrographic analysis reveals that the reservoir rock is comprised mostly of unconsolidated sand, a very low volume of quartz cement, and poorly developed authigenic clays.

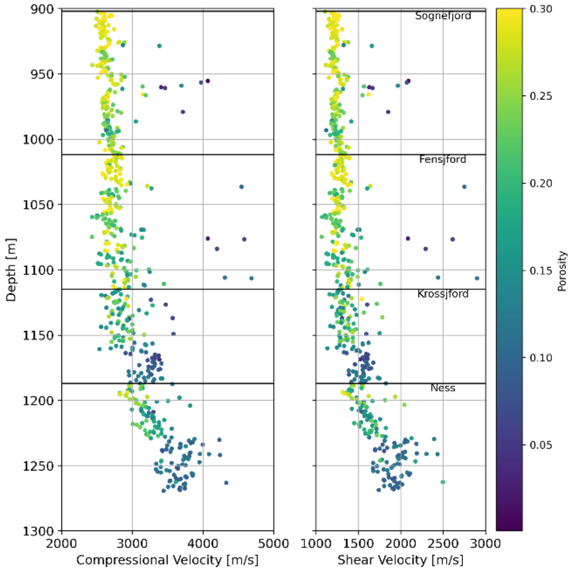


Figure 3: Depth profile of compressional and shear wave velocity colour-coded with total porosity.

Petrophysical analysis of core samples from the Sognefjord reported 34% average porosity (intergranular and hybrid pores) and excellent permeability of the order ~ 20 to 5000 mD while overlying claystone dominated Draupne formation revealed low permeability [5]. Compaction-driven porosity reduction is obvious from the increasing magnitude of V_p and V_s logs in Figure 3 as we go deeper into subsequent formations. Previous studies referred to variations of sonic logs (compressional and shear) depending upon the depth of interest and study location in the North Sea [10]. Shallower reservoir depth (~ 900 m) may be risky since supercritical CO2 can be converted to gaseous phase (Figure 3). Reservoir connectivity to nearby Troll field could be the other risk factor due to uncertain nature of pressure depletion.

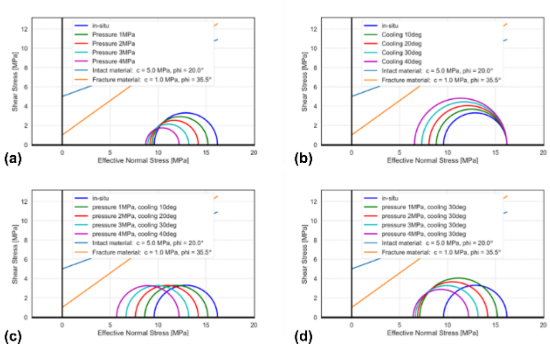


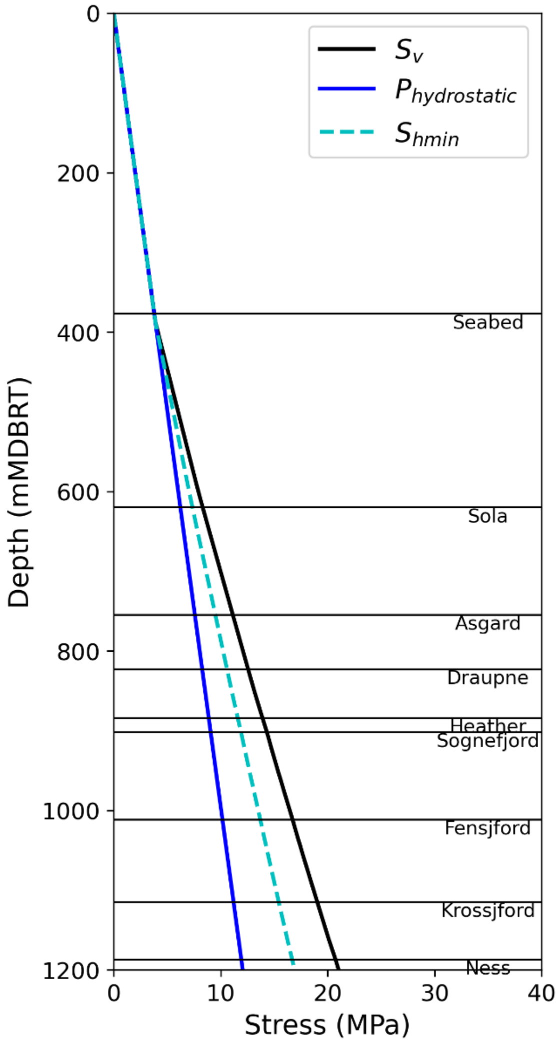
Figure 4: Stress path evolution of Sognefjord formation under (a) increasing pressure (b) temperature (c) combination of temperature and pressure (gradual temp. decrease) (d) combination of temperature and pressure (constant temp. decrease). Modified from [10].

This recommends site-specific geomechanical modelling (Figure 5) which allows knowledge transfer for global effective CO2 injection and risk mitigation. Outcomes of this geomechanical model allow safer CO2 injection planning (conservative pressure – lower bound) and mitigate injection-induced micro-seismicity risks if any from the linearized Mohr-Coulomb failure envelope analysis of pre-existing faults/fracture network. Mohr-Coulomb analysis pointed out stability of identified fault/fracture network from overburden Draupne formation.

For rock-physics model fitting, when using a soft-sand model, the data points follow the $S_w = 1$ (100% water saturation) line in V_p/V_s versus AI cross-plot (Figure 6), satisfying the prior petrophysical information, and we noticed that porosity lines also coincide with the color-coded porosity values. The selection of the soft-sand model is relevant because of unconsolidated sand with negligible presence of quartz cement [5]. At the time of injection, Sognefjord formation has in-situ pressure and temperature above the critical point of CO2. Therefore, the injected CO2 will be in the form of a supercritical fluid. Initially started with a 70:30 ratio of quartz and clay mixture, fluid substitution is performed for every 10% increment of supercritical CO2 to obtain the reservoir rock's saturated bulk modulus, velocity, and density. Given the absence of any direct field data from post-injection to validate, it is observed that modelled P-wave velocity of saturated rock averaged over reservoir interval shows non-linear

Criticality of data for CCS screening of geological formations

behaviour within 20 to 30% of CO2 saturation and thereafter very minimal or no change (Figure 7). Bulk density showed a very weak linear relationship with CO2 saturation. This observation is aligned with other reported studies [11,12]. Therefore, it may be difficult to identify reservoir dynamics above CO2 30% saturation from time-lapse seismic technology.



This case study provides a comprehensive idea of CCS storage screening program irrespective of the geographical location of the field.

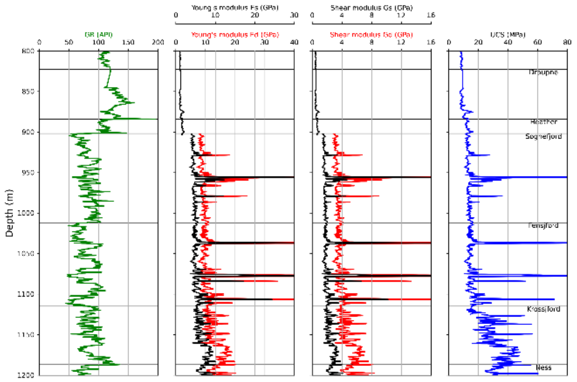


Figure 5: 1-D geomechanical model calibrated with field and laboratory data. Top – In-situ stress profile. Bottom – Static elastic properties of 32/2-1 well. Adopted from [6].

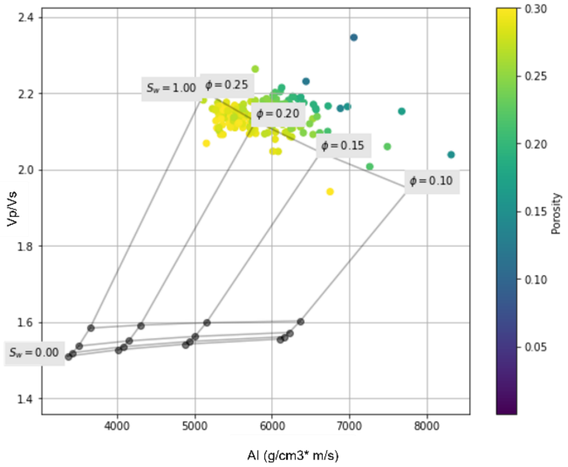


Figure 6: Model fitting of Sognefjord formation with the soft sand rock physics model in Vp/Vs vs AI cross-plot domain.

Given wider variability of subsurface formations, a field specific CCS screening program is necessary. Therefore, we can transfer knowledge from current ongoing CCS projects from different geographical locations (North-Sea, North-west shelf) to Indian sedimentary basins as first-hand information. Authors [] Vishal et al., 2021 reported a country-wide capacity estimation of Indian sedimentary basins. However, none of the published studies go into detailed field screening in terms of reservoir properties, sealing quality, injection, and associated challenges and environmental risk. Here we adopted multiple sources of information such as literature, global CCS projects, CCS whitepaper, NITI Aayog CCUS policy document, and relevant publications when proposing the workflow for CCS storage estimation in Indian sedimentary Basins. Considering the dependency on exploration history data, background field geology and other relevant well engineering data and reports (Table 2 listed critical data requirement) are paramount for implementing CCS prospect evaluation either in depleted oil and gas reservoirs or saline aquifers, it is highly recommended to have access to exploration databases, reports, and well-engineering information. In this aspect, an India-specific CCS screening workflow (Figure 8) is proposed. The proposed workflow can be modified as crucial datasets become accessible.

Table 2: Critical data requirement for CO2 storage site screening

Properties	**Critical data**
Dynamic elastic properties (Young's modulus, Poisson's ratio)	Compressional and shear sonic (DT, DTS) and bulk density log
Static elastic properties	Laboratory stress-strain, ultrasonics
Volume of shale	GR, density, and neutron porosity
Pore pressure	Porosity, DT, resistivity; Drilling data - Mud weight, RFT, Drill Stem Test (DST)
Permeability	Porosity log, core measurement, NMR log, empirical equations
Rock strength (UCS, internal friction coefficient, cohesion)	Laboratory stress-strain, empirical equations, Porosity, DT
In situ stress	Density, pore pressure, static elastic, and rock strength properties.
Calibration	Well test data - Leak-off test (LOT), XLOT
Stress orientation	Image logs (presence of borehole breakouts and drilling induced tensile fractures), multi-arm caliper, World stress map (Absence of image logs)
Reservoir thickness	Formation tops, seismic surface
Seal quality	Fault mapping (image log, seismic), Mohr-Columb analysis, fault density
Capacity estimation	Porosity, seismic surface, storage efficiency, reservoir thickness
Injectivity	1-D geomechanical model, fracture pressure, pore pressure, temperature

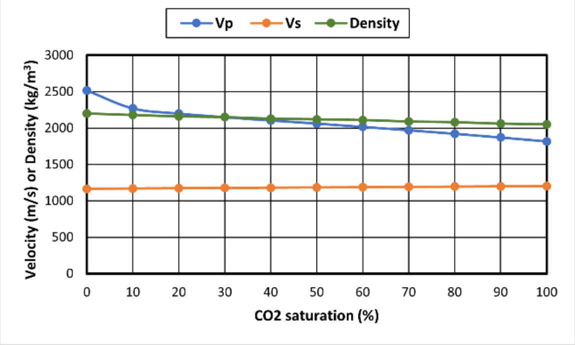


Figure 7: Variation of Vp, Vs, and density of rock saturated with varying proportions of CO2/brine mixture where CO2 is in a supercritical fluid state at reservoir conditions.

Criticality of data for CCS screening of geological formations

Conclusions

A data-driven workflow to investigate carbon capture and storage evaluation of subsurface geological formations is presented. It links storage capacity assessment, caprock integrity evaluation, injection design, and monitorability aspects. Both reservoir and caprock systems of Smeaheia field showed suitability for CO2 injection with less possibility of failure and related micro-seismicity. Accumulating current knowledge and field observations from this case study, CCS whitepaper and relevant literature, a comprehensive screening program is proposed for CCS resource mapping of Indian sedimentary basins.

References

1. United Nations. *COP26*.; 2022. Accessed September 2, 2023. https://www.un.org/en/climatechange/cop26
2. Dooley JJ, Kim SH, Edmonds JA, Friedman SJ, Wise MA. A first-order global geological CO2-storage potential supply curve and its application in a global integrated assessment model. *Greenhouse Gas Control Technologies*. Published online January 1, 2005:573-581. doi:10.1016/B978-008044704-9/50058-6
3. Holloway S, Garg A, Kapshe M, et al. An assessment of the CO2 storage potential of the Indian subcontinent. *Energy Procedia*. 2009;1(1):2607-2613. doi:10.1016/J.EGYPRO.2009.02.027
4. Vishal V, Verma Y, Chandra D, Ashok D. A systematic capacity assessment and classification of geologic CO2 storage systems in India. *International Journal of Greenhouse Gas Control*. 2021;111:103458. doi:10.1016/J.IJGGC.2021.103458
5. CO2 DataShare webpage. CO2 DataShare. Published 2023. Accessed January 19, 2023. https://co2datashare.org/dataset/smeaheia-dataset
6. Goswami A, Mandal PP. Role of critical data for Geomechanical Modelling & Characterisation of future CO2 Storage Sites. In: Ganguly S, Dimri VP, eds. *Reservoir Characterization, Modelling and Quantitative Interpretation: Recent Workflows to Emerging Technologies*. Elsevier; 2023.
7. Mandal PP, Essa I, Saha S, Rezaee R. Multi-purpose utility of constructing 3D static Geomechanical model in the Ichthys field, Browse Basin. Published online September 15, 2021. doi:10.5281/ZENODO.7686644
8. Fjær E, Holt RM, Horsrud P, Raaen AM, Risnes R. Petroleum related rock mechanics. *Developments in Petroleum Science*. 2008;53:1-515. doi:10.1016/S0376-7361(07)53007-4
9. Mavko G, Mukerji T, Dvorkin J. *The Rock Physics Handbook*. Cambridge University Press; 2009. doi:10.1017/cbo9780511626753
10. CLIMIT. *Induced-Seismicity Geomechanics for Controlled CO2 Storage in the North Sea (IGCCS), CLIMIT Project Final Report KPN-268520/E20*.; 2020.
11. Lumley D, Adams D, Wright R, Markus D, Cole S. Seismic monitoring of CO 2 geo-sequestration: realistic capabilities and limitations. In: *SEG Technical Program Expanded Abstracts 2008*. Society of Exploration Geophysicists; 2008:2841-2845. doi:10.1190/1.3063935
12. Wisman P. S. *Rock Physics Changes Due to CO2 Injection: The CO2CRC Otway Project*. Curtin University; 2021.

Acknowledgments

The authors would like to acknowledge the contribution made by Mr. Abhishek Goswami when designing the CCS workflow program presented here.

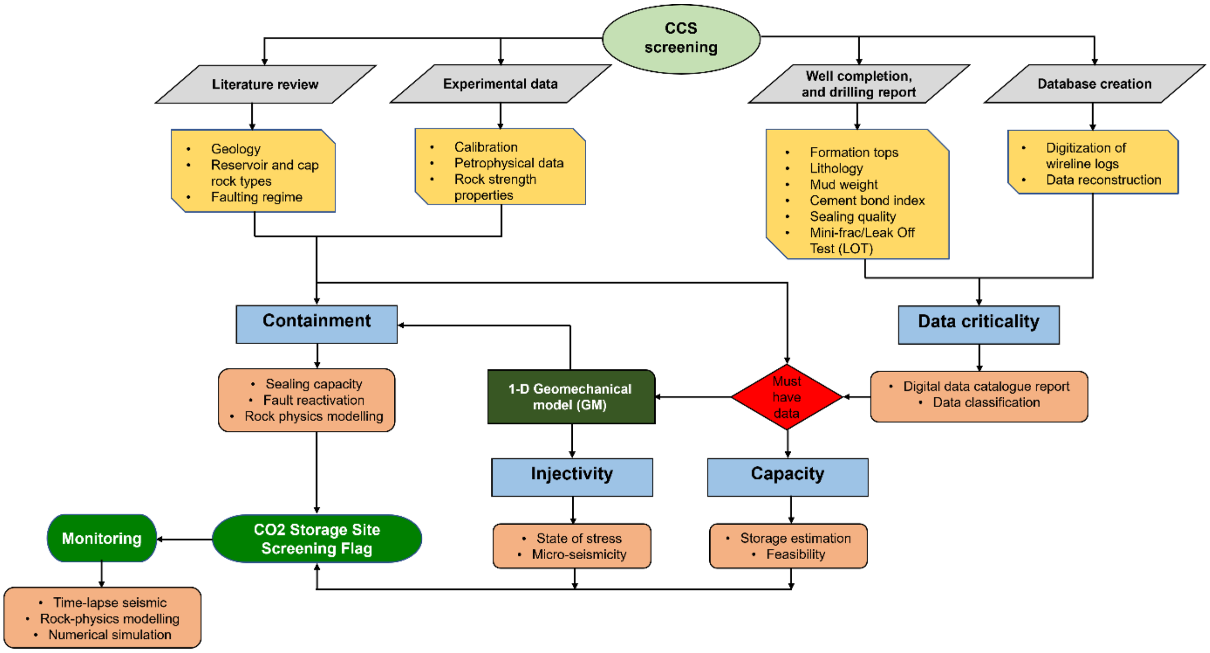


Figure 8: Implementation plan for CO2 storage screening in geological formations of Indian sedimentary basin.