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Screening Potential CO_2 Storage Reservoirs Basin Using Petrophysical Evaluation: Case Study in Field X, Central Sumatra Basin

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ABSTRACT

This study was conducted to determine the feasibility of the Menggala Formation in the Central Sumatra Basin as a potential reservoir candidate for Carbon Capture and Storage (CCS) based on the analysis of key petrophysical parameters. Well log analysis was conducted by determining reservoir depth, effective thickness, effective porosity, Net-to-Gross (NTG), and Storage Capacity as reservoir suitability indicators. The results show that the reservoir depth ranges from 1662.48 to 1805.14 m, with an average of 1705.108 m, thus meeting the requirements for CO_2 storage under supercritical conditions. The average effective porosity is 15.54%, effective thickness is 23.38 m, and the NTG value is 0.211. The storage capacity calculation uses 3 assumptions that represent the conditions of the reservoir. Although there are lateral variations among the wells, the Menggala Formation generally meets the criteria as a candidate CO_2 reservoir for further reservoir analysis. However, further studies, including evaluation of the integrity of the cap rock (seal), are needed to ensure long-term reservoir feasibility.

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1. INTRODUCTION

Global climate change represents one of the most significant challenges confronting the world today. This phenomenon is primarily driven by the escalation of greenhouse gas emissions, which is closely linked to economic growth and the increasing demand for energy at both national and global scales, particularly due to the persistent reliance on fossil fuels (Syahrial et al., 2022). Based on data from the World Bank, Indonesia's carbon dioxide (CO_2) emissions reached approximately 675 million tons in 2023, indicating a consistent upward trend in national emissions each year (World Bank, 2023). This condition poses a serious challenge for Indonesia in achieving its Net Zero Emission (NZE) target by 2060, which refers to a state where the total amount of greenhouse gas emissions released is balanced by the amount absorbed or removed (Nasir and Bengi., 2024).

One of the effective mitigation mechanisms for reducing CO_2 emissions in the energy and industrial sectors is Carbon Capture and Storage (CCS). Carbon Capture and Storage (CCS) is a process involving the injection of CO_2, which may originate from power plants or other large industrial facilities, through pipelines into geological formations that meet CCS reservoir criteria, where it is intended to be stored permanently (Kheshgi et al., 2012). Several types of reservoirs are

considered suitable for CO_2 injection, including saline aquifer formations, depleted oil and gas reservoirs, as well as deep, unmineable coal seams (Ajayi et al., 2019a). Within the Central Sumatra Basin, several reservoirs can be classified as potential CCS reservoirs. One formation considered particularly promising for CO_2 storage is the Menggala Formation, which is predominantly composed of sandstone. Nevertheless, prior to CO_2 injection, further evaluation is required to determine whether the reservoirs within the basin meet the established criteria for CCS suitability. According to Ramírez et al., (2010) ,the criteria for an effective CCS reservoir consist of several key parameters (Table 1).

Table 1. CCS Reservoir Criteria for sandstone reservoir (Ramírez et al., 2010)

Parameter	Threshold
Capacity	≥ 4 Mt for gas/oil and ≥ 2 Mt for aquifers
Thickness reservoir	10 m
Depth top reservoir	≥ 800 m
Porosity reservoir	Aquifers: > 10%
Permeability reservoir	Aquifers: an expected permeability of 200 mD or more
Thickness seal	≥ 10 m. Both simple seals as well as complex caprock have been taken into account
Seal composition	Salt, anhydrite, shale or claystones
Reservoir composition	Aquifers: sandstones Hydrocarbon fields: limestone, sandstone, siltstone, carbonates
Initial pressure	Overpressure areas excluded
Salt domes	Relevant for aquifers. Traps located alongside/near salt domes/walls have been excluded because there is a high risk of salt cementation

In accordance with the aforementioned criteria, a preliminary reservoir evaluation is necessary to assess the potential for CO_2 storage in the Central Sumatra Basin, with particular emphasis on determining the suitability of the Menggala Formation as an injection site. In this study, the analysis is carried out using a petrophysical approach, incorporating parameters such as shale volume (Vshale), effective porosity, net-to-gross (NTG), Storage Capacity to evaluate the potential of the Menggala Formation as a candidate reservoir for CCS in Sumatra.

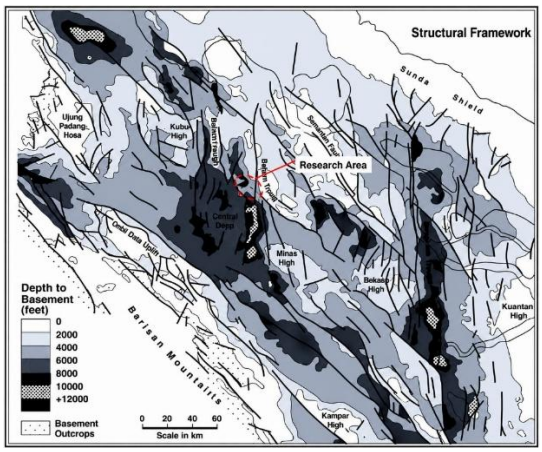


Figure 1. Structural Framework

The Central Sumatra Basin is a back arc basin. Which has two dominant structural patterns, namely N-S and NW-SE orientations. The N-S oriented structure was formed earlier in the Paleocene, so it is considered older when compared to the NW-SE oriented structure. However, throughout the Tertiary period, both structures remained active (Eubank &

Makki., 1981). Heidrick & Aulia., (1993) divides the tectonic phase of the Central Sumatra Basin into 4 phases, namely F0, F1, F2, F3. The F0 (Syn-Rift) phase occurred in the Pre-Tertiary period, the F1 (Syn-Rift) phase occurred in the Eocene - Oligocene period, the F2 (Sagging) phase occurred in the Early Miocene - Middle Miocene period, and the F3 (Post Rift) phase occurred in the Middle Miocene - Recent

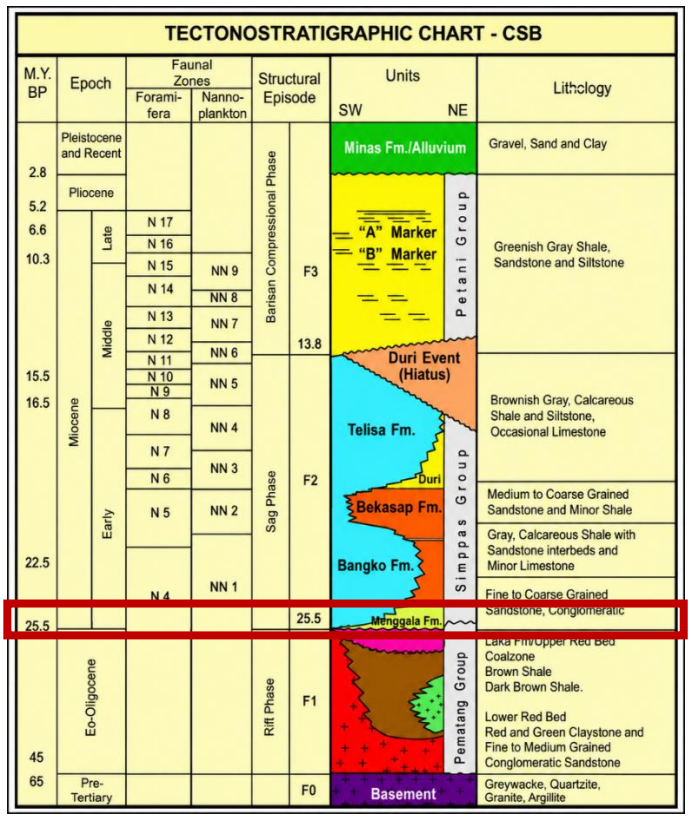


Figure 2. Stratigraphy of Central Sumatra Basin (Heidrick & Aulia., 1993)

Central Sumatra Basin consists of three main stratigraphic groups: the Pematang Group, the Sihapas Group, and Petani Group (Figure 1). The Pematang Group was deposited during the syn-rift phase, while the Sihapas and Petani Groups formed during the post-rift phase. Menggala Formation is part of the Sihapas Group and was deposited in the early Lower Miocene. It is composed of fine- to coarse-grained sandstone and conglomerate, with depositional environments interpreted as fluvial and deltaic systems. The Lower Menggala Formation was deposited mainly in the central part of the basin and is absent in structurally elevated areas (Fardiansyah et al., 2021).

Stratigraphically, the Menggala Formation overlies the Pematang Formation and is overlain by the Bangko Formation. The upper part of the Sihapas Group is dominated by marine sediments, characterized by fining-upward sandstone deposited in a shallow marine environment (De Smet & Barber., 2005). The Menggala, Bekasap, and Bangko Formations represent the main reservoirs in the Central Sumatra Basin due to their relatively thick sandstone lithology (Willis & Fitris., 2012). The Telisa Formation overlies the Bekasap Formation and consists of brownish-gray calcareous shale, siltstone, and occasional limestone. It was deposited in a marine environment, representing the maximum transgression phase, and is widely distributed across the Central Sumatra Basin (De Smet & Barber., 2005).

2. METHODS

This study was conducted using a quantitative approach through log-based petrophysical analysis to screen reservoirs for CO_2 storage. The petrophysical parameters analyzed include shale volume (Vsh), total porosity ($\emptyset_{tot}$), effective porosity ($\emptyset_{eff}$), net thickness, Storage Capacity. These

values were subsequently compared with the CCS thresholds by Table 1. The study area is located in the Central Sumatra Basin, in the central part of Sumatra Island, with a northwest–southeast (NW–SE) structural trend. This basin is a back-arc basin filled mainly with Tertiary siliciclastic sediments and has a complex stratigraphy influenced by tectonic activity (Sukanta & Endharto., 2022).

This study utilized well and seismic data. The well data consisted of four wells, namely A, C, P, and T (Table 2). The available well log data included gamma ray (GR), neutron porosity (NPHI), density (RHOB), spontaneous potential (SP), caliper (CALI), sonic (DT), and check-shot data. The seismic data used in this study comprised 3D PSTM (Post-Stack Time Migration) data with Inline ranges of 5150–5600 and Xline ranges of 5100–6200. Since permeability data were unavailable, the reservoir quality evaluation focused on petrophysical parameters derived from the available well log data.

Table 2. Data list used in this study

Well	DT	GR	NPHI	RHOB	SP	CALI	Checkshoot
A	√	√	√	√	X	X	√
C	√	√	X	√	√	√	√
P	√	√	X	√	√	√	√
T	√	√	√	√	√	√	√

2.1 Shale Volume

Shale volume was calculated to assess the distribution of shale within the reservoir, where Vsh was subsequently used as a correction factor in the effective porosity calculation. The calculation of Vsh began with the determination of the gamma ray index (IGR) based on gamma ray (GR) log data, calculated in Equation (1). (Magoba & Opuwari., 2020). The GR log records the natural radioactivity of formations penetrated by the well, primarily derived from uranium (U), thorium (Th), and potassium (K) (Muchamad et al., 2019).

$$IGR = \frac{GR.Log - GR.Min}{GR.Max - GR.Min} \quad (1)$$

$GR.Min$ = minimum gamma ray value
$GR.Max$ = maximum gamma ray value
$GR.Log$ = gamma ray log reading

The calculated IGR values were subsequently used to estimate shale volume (Vsh) using the Larionov Tertiary equation (Equation 2), which is appropriate for the Tertiary-aged formation investigated in this study. This model is appropriate for relatively young sedimentary formations, so that there is no overestimation in estimating the volume of shale in this formation. Overestimation can occur due to differences in the conditions of the old and tertiary layers (Alkaki et al., 2025). and provides a nonlinear correction for shale content (Larionov., 1969).

$$Vshale = 0.083(2^{3.7xIGR} - 1) \quad (2)$$

2.2 porosity

Porosity is defined as the ratio between the pore volume and the total volume of the rock. Total porosity includes all pore spaces within the rock, while effective porosity only represents interconnected pores that contribute to fluid flow and storage (Asquith & D. Krygowski., 2004). Total porosity was determined from the density log using the standard density-porosity relationship (Equation 3).

$$\emptyset_{tot} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \quad (3)$$

ρ_{ma} = density of the rock matrix
ρ_b = bulk density obtained from the density log
ρ_{fl} = density of the formation fluid

Subsequently, effective porosity was calculated by correcting the total porosity for shale volume.

$$\emptyset_{eff} = \emptyset_{tot} x (1 - V_{Shale}) \quad (4)$$

Total porosity is used to calculate effective porosity using the equation (4). Effective porosity was used as the primary parameter in evaluating reservoir suitability for CO_2 storage, as only interconnected pore spaces contribute to storage capacity and CO_2 injectivity. Net pay determination was carried out by applying a predefined effective porosity cutoff. Intervals that met the established criteria were classified as effective reservoir zones for CO_2 injection.

2.3 Net To Gross

The effective thickness (Net Pay) was subsequently compared with the total formation thickness (Gross Thickness) to calculate the Net-to-Gross (NTG) ratio(Falade et al., 2024). The calculated parameters ($\emptyset_{eff}$ and net thickness) were compared with the CCS reservoir suitability thresholds presented in Table 1 A reservoir was classified as suitable if the effective porosity, net thickness, and depth met the established CCS criteria.

$$NTG = \frac{Net\ Pay}{Gross\ Thickness} \quad (5)$$

2.4 Storage Capacity

Storage capacity is the ability or capacity of a geological formation that acts as a reservoir in storing a certain amount of fluid.

$$SC = GRV\ x\ NTG\ x\ \emptyset\ x\ \rho CO_2\ x\ S_{eff} \quad (6)$$

GRV = Gross Rock Volume
NTG = Net to Gross
$\emptyset$ = Effective Porosity
ρCO_2 = CO_2 Density
S_{eff} = Storage Efficiency

Estimating CO2 storage capacity using equation (6) requires a storage efficiency (Seff) value. Storage efficiency is used to adjust storage capacity to a more realistic estimate. Storage efficiency is a combination of various factors, as evidenced by numerous previous publications. Storage efficiency values can vary from <1% to >20%. This indicates that there is no universally applicable set of factor values (Keiding et al., 2024). Thus, in this study, the storage efficiency value is given in three assumptions, namely minimum, medium, and maximum assumptions.

Table 3. Storage Efficiency

Assumption	Storage Efficiency
Assumption 1	0.05
Assumption 2	0.1
Assumption 3	0.2

Accurate storage efficiency values are still difficult to determine during this initial screening. Therefore, determining an accurate storage efficiency range requires further analysis, such as rock formation heterogeneity, fluid analysis simulations, and other methods.

2.5 Well to Seismic Tie

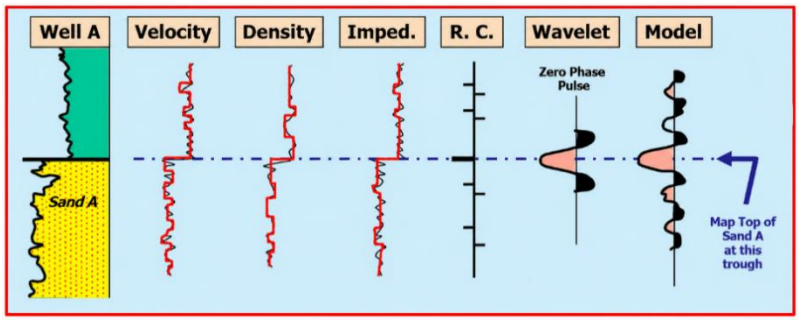
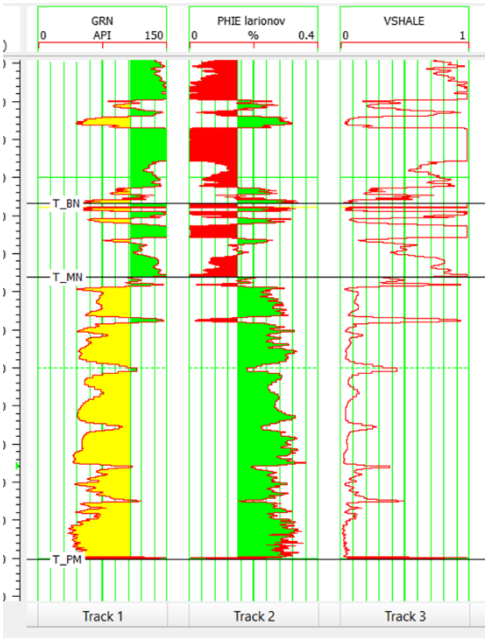


Figure 3. Well To Seismic Tie *(Ngeri A & Dieokuma., 2025)*

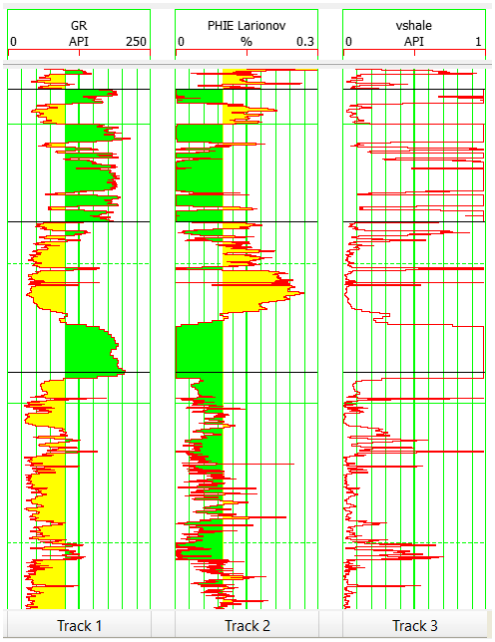
Well-to-seismic tie is a process of correlating well data with seismic data. This correlation process is necessary to obtain accurate seismic data interpretation. The well-to-seismic tie process is carried out by generating a synthetic seismogram using density, velocity, and wavelet data. As a result, a high correlation value is obtained between the synthetic seismogram and the seismic data (Ngeri A & Dieokuma., 2025).

3. RESULT AND DISCUSSION

3.1 Display data well



Well A



Well C

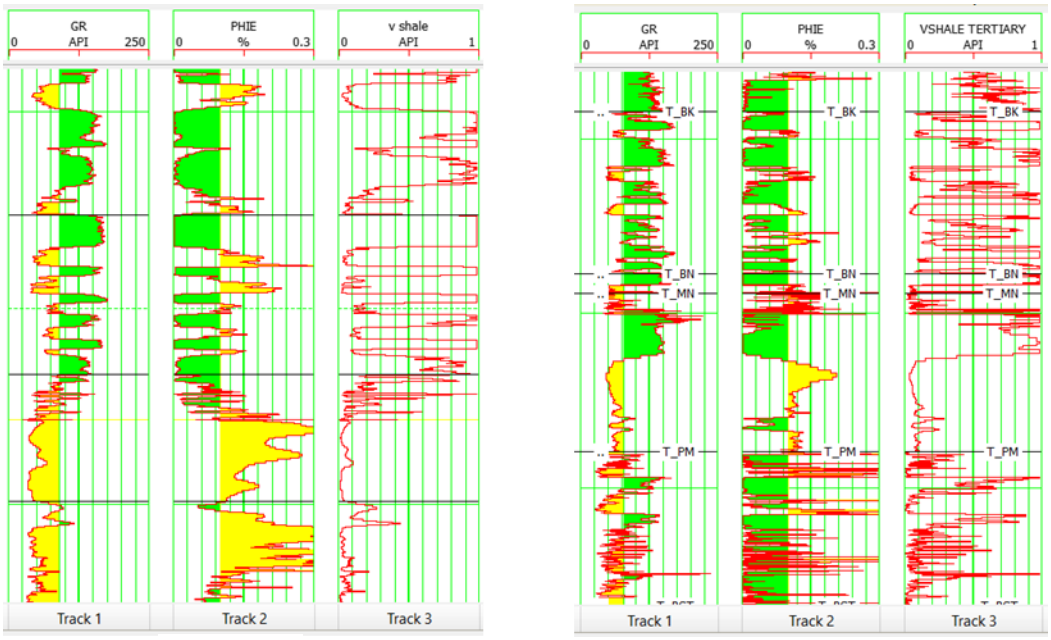


Figure 4. Display log data from Well A, C, P, and T. The data set including parameters gamma-ray, porosity effective, and Vshale.

Figure 4 presents the well log data for Well A and Well T. Each well contains RHOB, NPHI, and GR data. These log data are required to perform quantitative analysis in order to obtain gamma ray index values, shale volume, and effective porosity. Based on Figure 4, the gamma ray values in Well A range between 10 and 200 API. The cutoff determination was carried out using histogram analisys (Indah et al., 2022), thereby allowing the separation of sand lithology (shown in yellow) from shale lithology (shown in green). Similarly, Well T exhibits GR values ranging from 0 to 250 API, and the cutoff determination was also conducted using the histogram analysis value.

The cutoff for effective porosity was determined using the effective porosity criteria described by Ramírez et al. (2010) This approach was applied to directly eliminate layers that do not meet the minimum criteria for a CO_2 reservoir.

The well data (Figure 4) reveal a significant difference between Well A and Well T. Well A exhibits a relatively uniform distribution of sandstone, as indicated by the GR log, which shows that the Menggala Formation is predominantly composed of sandstone with only minor shale interbeds (Figure 4). In contrast, Well T shows a GR log with numerous shale interbeds. This variation may affect the average porosity values as well as the net thickness available for potential CO_2 storage.

3.2 Porosity Estimation

Effective porosity directly represents the interconnected pore volume available for CO_2 storage; therefore, higher $\emptyset_{eff}$ values generally correspond to greater potential storage capacity (Rasool et al., 2023). Based on the results presented in Table 3, the average effective porosity of the four wells is 15.54%. Well A has the highest porosity (26.82%), indicating that the formation in this well is dominated by fine- to coarse-grained sandstone (Figure 1), which possesses relatively good pore connectivity. In contrast, Well T shows the lowest effective porosity value (9.17%), which may be influenced by a higher shale content, thereby reducing pore connectivity and effective pore space.

Referring to general reservoir quality classifications that categorize porosity values of 10–20% as moderate to good (Koesoemadinata., 1980), the average value of 15.54% falls within this range, indicating a potentially significant storage capacity. However, good porosity does not

necessarily correspond to good permeability; therefore, further confirmation through permeability analysis and storage capacity estimation is required for a more comprehensive feasibility evaluation.

Table 4. Resume of porosity estimation in this study

Well	Formation	PHIE(AVG)
A	MN	0.268205411
C	MN	0.139732901
P	MN	0.121806114
T	MN	0.091706284
Average		0.155362678

3.3 Depth Identification

The reservoir depth ranges from 1662.48 to 1805.14 m, with an average depth of 1705.11 m across all wells (Table 4). At these depths, both pressure and temperature naturally increase with increasing depth (Bachu, 2000). In general, the supercritical phase is achieved at depths greater than 800 m (Ajayi et al., 2019a). According to Siringoringo et al. (2025), the Central Sumatra Basin exhibits a temperature gradient ranging from 30 to >120°C/km, which is higher compared to other basins. Based on the principle that temperature increases with depth, the reservoir at an average depth of approximately 1705.11 m is estimated to fall within the supercritical stability range.

This condition represents one of the most important factors in the process of subsurface CO_2 storage, as higher pressure and greater depth allow CO_2 to exist in the supercritical phase. The supercritical phase is characterized by CO_2 having a high density similar to that of a liquid while retaining gas-like mobility (Ajayi et al., 2019). These properties enhance volumetric storage efficiency and support more optimal reservoir capacity. The high density enables a greater mass of CO_2 to be stored within the same pore volume, while the retained gas-like mobility facilitates the injection process of CO_2 into the formation.

Table 5. Summarized of depth of top-base reservoir target

Well	Depth (m)
A	1662.48
C	1658.52
P	1694.29
T	1805.14
Average	1705.108

3.4 Net To Gross Calculation

The average Net-to-Gross (NTG) value of 0.211 indicates that approximately 21.1% of the gross interval of the Menggala Formation consists of effective reservoir zones. Well A exhibits a very high NTG value (0.277), indicating sandstone dominance with good porosity, whereas Well T has a low NTG value (0.168), suggesting a significant shale content within the formation at that location. This variation in NTG among wells reflects lateral heterogeneity, which may influence reservoir continuity and CO_2 distribution.

According to Ajayi et al. (2019) reservoir thickness and lateral continuity strongly affect storage capacity and injectivity performance. The combination of adequate porosity and effective thickness in the Menggala Formation demonstrates promising potential at the initial screening stage.

Table 6. Resume of Net To Gross for each wells

Well	Formation	NTG
A	Menggala	0.277
C		0.223
P		0.174
T		0.168
Average		0.211

3.5 Seismic

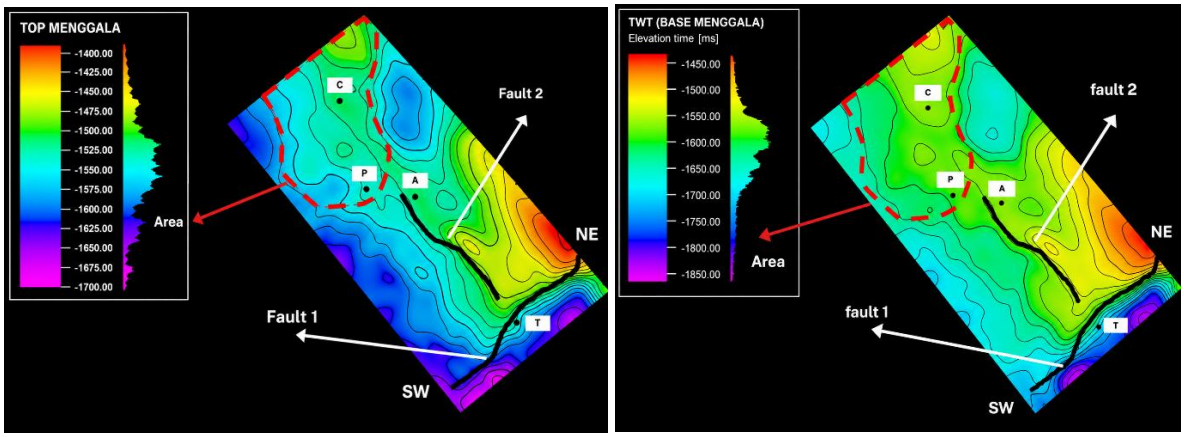


Figure 5. Time Structure Map

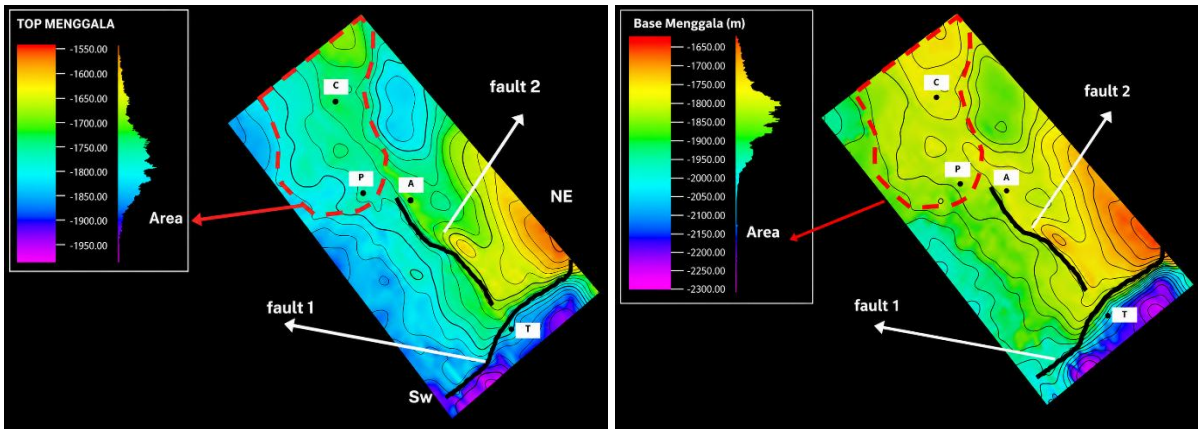


Figure 6. Depth Structure Map

Figure 5 shows a time structure map, which is a structure map in time units. Based on the structure map, two main faults were identified, oriented SW–NE and NW–SE. The presence of faults around the research area is one of the considerations in determining the target area for CO_2 storage. Therefore, the target area was selected in the northern part of Field X, which is relatively far from the fault zone to minimize the potential risk of leakage.

Furthermore, Figure 6 shows the depth structure map (DSM) obtained through the conversion process from the time domain to the depth domain. On the depth structure map, the yellow to red zones indicate areas of structural highs, while the blue to purple zones indicate areas of structural lows. Based on the interpretation of the depth structure map of the top and base of the Menggala Formation, the total formation thickness is 79.58 m. This thickness value is then used as a parameter in calculating CO_2 storage capacity using the volumetric method.

3.6 Storage Capacity Calculation

After obtaining the effective porosity, NTG, and PHIE, the storage capacity will be calculated using equation (6). The results of the storage capacity calculation, based on the three storage efficiency assumptions, show that the results in Table 7 show that a storage efficiency value of 0.05 produces a storage capacity of 8,975. This shows that storage efficiency significantly influences the estimation of CO_2 storage capacity.

Tabel 7. Storage Capacity

Assumption	Thickness (km)	Area (m^2)	Area (km^2)	GRV (km^3)	Seff	CO2 (rho)	Volumetrik Estimation (MtCo2)
1	0.07958	99251300	99.251	7.898	0.05	694.37	8.975
2		99251300			0.1	694.37	17.949
3		99251300			0.2	694.37	35.899

The variation in estimated results for each Seff scenario indicates uncertainty in the calculation of CO_2 storage capacity. Therefore, the volumetric estimates in this study are still preliminary assessments, requiring further studies such as fluid distribution simulations, pressure analysis, and other studies.

3.7 Reservoir Screening Evaluation

Based on the integration of the analyzed petrophysical parameters (Table 6), the Menggala Formation in the Central Sumatra Basin meets all the primary CCS reservoir screening criteria, indicating that this formation possesses characteristics favorable for CO_2 storage. In Table 6, a good agreement is observed between the established criteria and the estimated results, with several values exceeding the threshold. For instance, the minimum thickness criterion is 10 m, whereas the target zone thickness at this location ranges around 23.38 m. The average depth of the Menggala Formation is 1705.11 m, which also exceeds the minimum criterion that CO_2 reservoir candidates should be located at depths greater than 800 m, ensuring that injected CO_2 remains in a supercritical state under high temperature and pressure conditions.

Effective porosity varies among the wells. Well T, does not meet the criterion, exhibiting a porosity of 9.17%, which is below the recommended minimum of 10% suggested by Ramírez et al., (2010). The average effective porosity of the Menggala Formation across the four wells is 15.5%, which complies with the porosity criteria recommended by Ramírez et al. (2010). Effective porosity is a key parameter that determines the reservoir's capacity to store CO_2 permanently. Therefore, effective thickness and porosity are closely related in determining storage capacity, where higher values can increase the potential capacity, provided that other parameters such as the storage efficiency factor and reservoir area are adequate.

The storage capacity in this study uses 3 storage efficiency assumptions, this was done due to the limited available data and based on previous research showing that the storage efficiency value can vary from <10% to >20%, depending on geological conditions and reservoir characteristics. The calculation results from the three scenarios show that the CO_2 storage capacity obtained has met the storage capacity criteria set by Ramirez. In addition, the variation in results in each scenario shows that the storage efficiency value has a very significant influence on the reservoir storage capacity estimation. The greater the storage efficiency value used, the greater the resulting CO_2 storage capacity.

Table 8. Evaluation of Reservoir Suitability for CO_2 Storage

Parameter	Threshold CCS	Result		Status
Capacity	≥ 4 Mt for gas/oil and ≥ 2 Mt for aquifers	Assumption 1	8.975Mt CO2	Suitable
		Assumption 2	17.95 Mt CO2	Suitable
		Assumption 3	35.9 Mt CO2	Suitable
Thickness reservoir	10 m	Reservoir Thickness	79.58 m	Suitable
		Net thickness	23.38 m	Suitable
Depth top reservoir	≥ 800 m	1705.108 m		Suitable
Porosity reservoir	Aquifers: > 10%	15.50%		Suitable
Reservoir composition	Aquifers: sandstones Hydrocarbon fields: limestone, sandstone, siltstone, carbonates	Sandstone		Suitable

Based on the preliminary screening, the Menggala Formation can be considered a potential reservoir for CO_2 storage. This assessment is supported by several reservoir parameters that meet the established criteria, including effective thickness, depth, effective porosity, lithology, and storage capacity all of which satisfy or exceed the thresholds recommended by Ramírez et al., (2010. These parameters indicate that the Menggala Formation holds promising potential for storing CO_2 in a supercritical state with adequate storage capacity.

However, this study did not include an evaluation of permeability, caprock integrity, and fault seal integrity. These parameters are crucial for further research to ensure long-term storage safety and minimize the risk of vertical leakage. Therefore, the results of this study are still in the initial screening stage and cannot yet be used as a definitive basis for decision-making regarding full-scale CCS implementation.

4. CONCLUSION

This study shows that the Menggala Formation in the Central Sumatra Basin has petrophysical characteristics that support CO_2 storage as a CCS reservoir. Parameters such as depth, effective porosity, effective thickness, and storage capacity generally meet the criteria established by Ramírez et al. (2010). The target area covers approximately 99,251 km^2 with a NW–SE orientation. Several faults were identified around the target area, necessitating further fault-seal analysis to evaluate storage safety and potential leakage risks.

Storage capacity was calculated using three storage efficiency assumptions, resulting in a minimum storage potential of Sc (0.05) = 8.975 $MtCO_2$, a medium potential of Sc (0.1) = 17.95 $MtCO_2$, and an optimal potential of Sc (0.2) = 35.9 $MtCO_2$. Based on these three scenarios, all storage capacity estimates met the established screening criteria. These results indicate that the reservoir has relatively good quality during the initial screening stage, despite some lateral variation between wells.

Overall, the research results indicate that the Menggala Formation meets the initial requirements for evaluating CCS reservoir feasibility. However, further research on caprock integrity, permeability, and fault-seal integrity is still needed to ensure the safety of long-term storage and the effectiveness of CO_2 retention within the reservoir. Prospectively, these findings can provide a scientific basis for selecting CO_2 injection sites in the Central Sumatra Basin and support the development of carbon emission mitigation strategies in Indonesia.

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