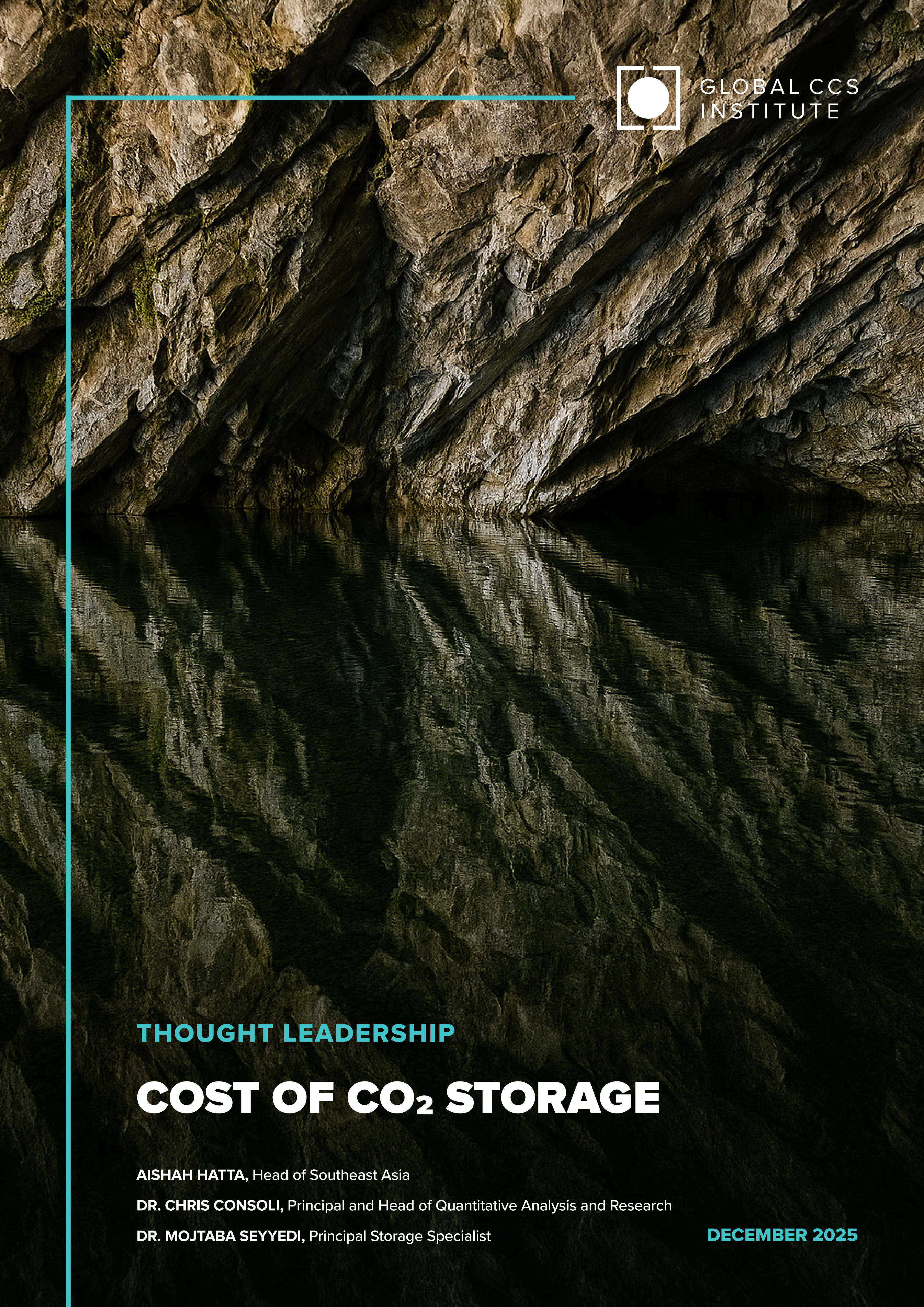

THOUGHT LEADERSHIP

COST OF CO_2 STORAGE

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CONTENTS

HOW TO NAVIGATE THIS REPORT

This report is designed to provide clarity for a broad audience while ensuring technical rigour for those who need it. The main report focuses on the key findings, figures, and practical implications of CO_2 storage cost analysis. Supplementary documents provide additional depth and detail for readers who want to explore the technical underpinnings.

Main Report – This presents the core results, figures, and discussion of cost drivers. It highlights the role of boundary conditions, reservoir properties, and project location, supported by clear visuals and practical takeaways. This is the primary document for decision-makers, policymakers, and financiers who need the "so what" insights without excess technical detail.

Supplementary Analysis – These documents contain the full methodology, assumptions, input parameters, and sensitivity studies. It is intended for technical specialists who want to verify or further interrogate the modelling and data.

1.0 KEY POINTS

Storage costs are highly site-specific.

While many factors affect the cost of storage, this study focused on five key drivers: settings (onshore or offshore), reservoir quality, reservoir thickness, fracture pressure, and boundary conditions.

The cost estimates presented here are derived from a limited set of site-specific scenarios and should not be generalised globally; rather, they are intended to illustrate how these drivers influence the cost per tonne of CO_2 stored.

Boundary conditions are decisive.

Boundary conditions are the main cost factor. Under open boundary conditions, where pressure can dissipate across the boundary, projects can be up to four times cheaper than under closed conditions, as pressure relief helps maintain injectivity and enables more CO_2 to be stored over the project's life.

Onshore storage costs are low.

For the onshore scenarios considered, costs were estimated to range from US$2-15/t$CO_2$, remaining below US$60/tCO_2 even in less favourable conditions.

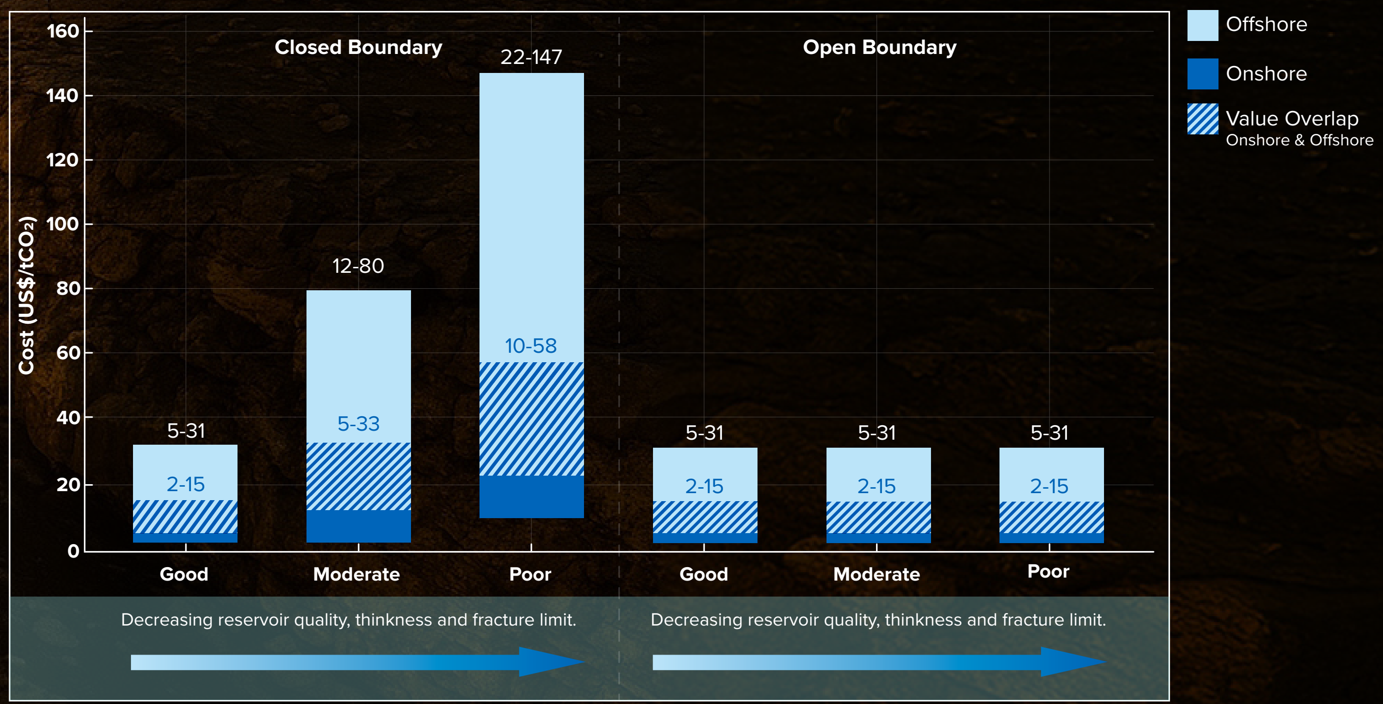
Offshore storage is more expensive but still viable.

For the offshore scenarios examined, under favourable conditions, offshore costs can be close to those onshore, ranging from US$5-31/t$CO_2$. In constrained settings, it can go up to US$147/t$CO_2$; open boundaries help to reduce costs and narrow this range.

Worst-case costs are avoidable with early action.

Early site screening and effective operational reservoir pressure management can help mitigate high-cost outcomes associated with closed systems and poor reservoir conditions.

Figure 1 - Snapshot of the key drivers' impacts on CO_2 storage costs.



This figure compares onshore (dark blue) and offshore (light blue) storage under closed and open boundary conditions. Costs escalate sharply in closed systems as formation quality, thickness, and fracture pressure gradient decrease — reaching up to US$147/t$CO_2$ offshore in poor-quality reservoirs. In contrast, open systems remain stable, with both onshore and offshore clustered between US$2-31/t$CO_2$. Boundary conditions, more than reservoir quality alone, are the dominant driver of storage cost variability.

2.0 INTRODUCTION

As CCS deployment scales up, understanding the cost of CO_2 storage is essential for sound policy, investment, and planning. The cost is shaped by a mix of subsurface conditions (e.g. porosity, permeability, depth, boundary behaviour), surface and infrastructure requirements (e.g. drilling, monitoring, onshore vs offshore), and regulatory and external factors (e.g. permitting, liability, fiscal terms). The analysis focuses on five key drivers — reservoir quality, boundary conditions, reservoir thickness, fracture pressure gradient, and setting — to show how they shape cost, holding other factors constant. The results are indicative, highlighting why simplistic assumptions such as offshore is always too expensive or all aquifers cost the same are misleading and how different factors combine to drive storage cost.

3.0 APPROACH

This study estimates the cost of CO_2 storage for saline formations by testing how the selected key drivers affect project economics (Table 1). The analysis combines reservoir simulation to capture injection rate, number of wells, pressure build-up, and plume area with a lifecycle cost model to assess the full storage cost from exploration through post-closure.

The reservoir simulations were performed on a 3D saline aquifer model (Figure 2). While the full methodology is detailed in the Supplementary Analysis, this section outlines the key inputs and assumptions. The key inputs listed in Table 1 reflect a realistic range of subsurface and operational scenarios. In particular, the boundary-condition cases are treated as end-member scenarios, ranging from an idealised infinite-acting open aquifer to a fully closed system with no external pressure support. Real storage sites typically lie between these extremes, with finite connected aquifer volumes and partial pressure communication, but analysing these end-members provides useful bounds on likely cost outcomes.

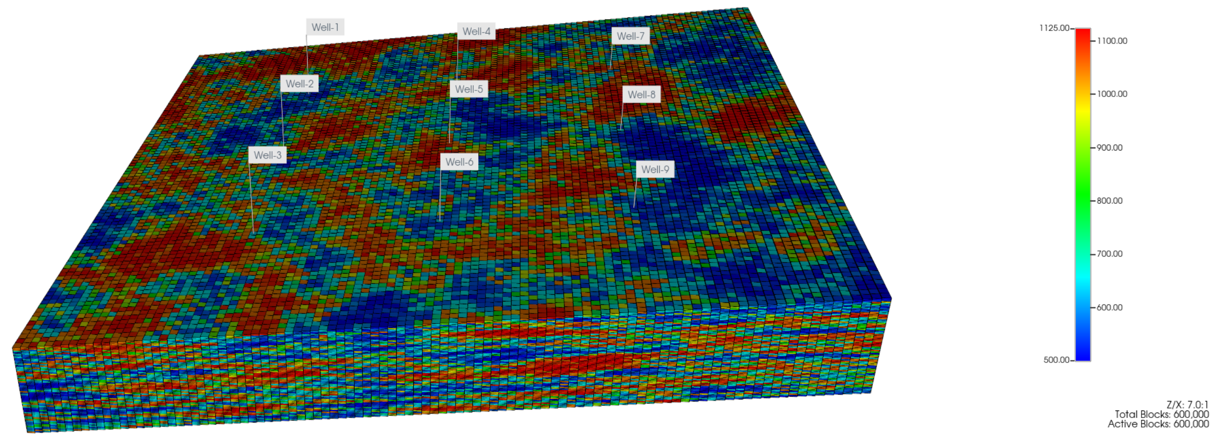
The results are expressed as cost-per-tonne ranges (US\$/tCO_2) to illustrate variability under different geological and operational settings and to highlight which factors have the most significant cost impact. The reported cost values in this study refer only to the storage component. Capture, transport, fluid conditioning, and well design optimisation are excluded (see Supplementary Analysis for the full exclusion list).

The full methodology, including the exclusion list, parameter tables, and sensitivity analyses, is provided in the Supplementary Analysis.

Table 1 - Selected key drivers for this study.

KEY DRIVER	DESCRIPTION	DATA USED IN SCENARIOS
Reservoir quality	Ability of the formation to store and transmit CO_2 (porosity+permeability)	Good : 20-30% porosity, 500-1,000 mD Poor: 10-15% porosity, 50-100 mD
Boundary conditions	Whether pressure can dissipate into the surrounding formations	Open: pressure dissipates Closed: pressure builds
Reservoir thickness	Vertical extent of the injection zone within the storage formation	Thick : 180 m Thin: 90 m
Fracture pressure gradient (FPG)	Change in pressure tolerance with depth before rock failure	Higher: 0.7 psi/ft Lower: 0.6 psi/ft
Setting	Setting of the project, reflecting infrastructure and logistics	Onshore vs Offshore (limited to 150 m water depth)

Figure 2 - Permeability distribution in a good-quality reservoir.



[1] The "good" and "poor" are relative descriptors . "Poor" in this context does not mean the reservoir is unsuitable for storage, but rather represents less favourable properties relative to the "good" case.

[2] The terms "thick" and "thin" are relative to the two cases considered. A 90 m reservoir is not necessarily "thin" in all geological contexts, but is used here as the lower-thickness scenario for comparison.

4.0 WHICH FACTORS MATTER MOST?

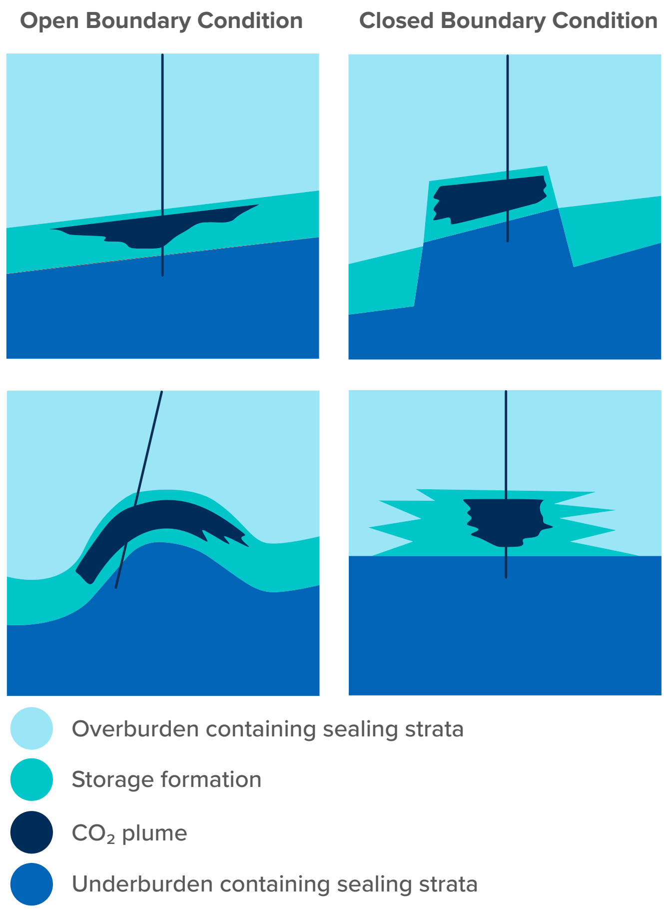
Boundary conditions

Boundary conditions are the biggest cost driver — closed systems can be four times more expensive than open ones. Boundary conditions are controlled by the geology.

Closed boundary conditions occur when the storage formation is hydraulically isolated by sealing faults or stratigraphy. With restricted fluid movement, pressure builds quickly, limiting CO_2 injection rates and storage capacity. This raises the cost per tonne of CO_2 stored.

Open boundary conditions occur when the reservoir is connected to surrounding formations or aquifers, allowing fluids and pressure to dissipate. This natural pressure relief keeps injection pressures lower, enabling higher injection rates, greater storage capacity, and reduced costs.

Figure 3 - The different boundary conditions.



Costs

Boundary conditions are the most decisive cost factor. Reservoir properties like quality, thickness, and fracture pressure gradient (FPG) play a role, but the dominant factor is whether the system is open or closed. Closed boundaries can push costs up to four times higher than open systems.

Closed boundaries escalate costs.

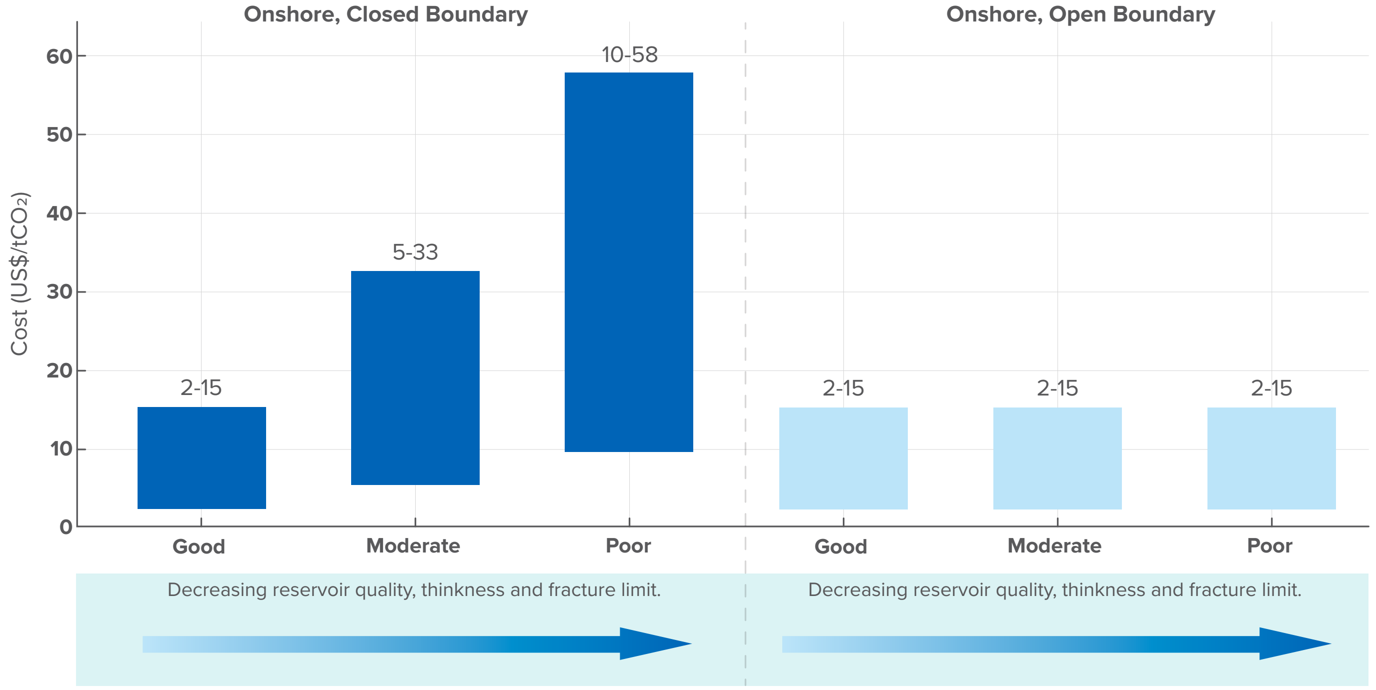
Costs rise sharply as reservoir quality, thickness, and fracture pressure gradient decrease. Here, the best case represents an onshore thick, good-quality reservoir with a high FPG tolerance:

- Best case: US\$2-15/tCO_2
- Moderate case: US\$5-33/tCO_2
- Worst case: US\$10-58/tCO_2

Open boundaries stabilise costs.

Onshore open boundary sites remain consistently low, US\$2-15/tCO_2, regardless of reservoir quality, thickness, or fracture pressure gradient.

Figure 4 - Onshore CO_2 storage costs and impact of boundary conditions.



Insights

The geology of a reservoir, including its tectonic setting and depositional environment, determines whether it has open or closed boundary conditions. For instance, a large deltaic sedimentary system in a tectonically stable area is more likely to host extensive, open storage reservoirs. However, boundary conditions are highly site-specific, meaning two neighbouring reservoirs can have different boundary types. While boundary conditions are fixed geological features, their impact on project economics varies depending on the project. In practice, the binary framing of open-closed represents a spectrum through semi-closed systems, as evident in the cost increase from open system equivalence to double or even quadruple the costs per tonne.

Large projects, injecting several million tonnes of CO_2 each year, are more vulnerable to the limitations of closed systems because high injection volumes quickly build pressure. Smaller projects with much lower injection volumes and rates experience more moderate pressure increases and are less likely to breach pressure constraints.

These insights highlight the importance of early site characterisation and an injectivity test. Understanding boundary behaviour from the start allows project designers to plan effective pressure management, such as exploring additional injection zones, using brine production wells, or implementing staged injection plans. These measures can reduce the challenges of closed systems and make projects more cost-effective over their lifetime.

Onshore versus offshore: the impact of setting

Onshore storage generally costs less – but offshore projects can achieve comparable economics under favourable conditions.

The setting is one of the most significant cost impacts across all scenarios. Costs may double from the best-case to worst-case scenarios. The primary reason is that offshore operational complexity, marine logistics, and advanced specialised infrastructure are required throughout the lifecycle of offshore storage. Despite higher costs, offshore storage remains competitive with onshore when boundary conditions and reservoir quality are favourable.

Costs

The cost of a storage site is constrained by the geological setting. Globally, there are 868 sedimentary basins, of which 565 are offshore or have offshore portions. Although this does not mean that most storage sites will be offshore, it does indicate that, in some regions, specifically much of the Asia-Pacific region and Western Europe, onshore storage will be limited.

Onshore storage offers predictable and lower costs.

Onshore costs remain consistently low, in the range of US$2-15/t$CO_2$. Even in less favourable onshore conditions, i.e. closed boundaries and poor quality or thin reservoirs, costs remain below US$60/t$CO_2$. Lower drilling, infrastructure, and monitoring costs make these projects ideal for early deployment and regional hub development.

Offshore storage is higher but still competitive.

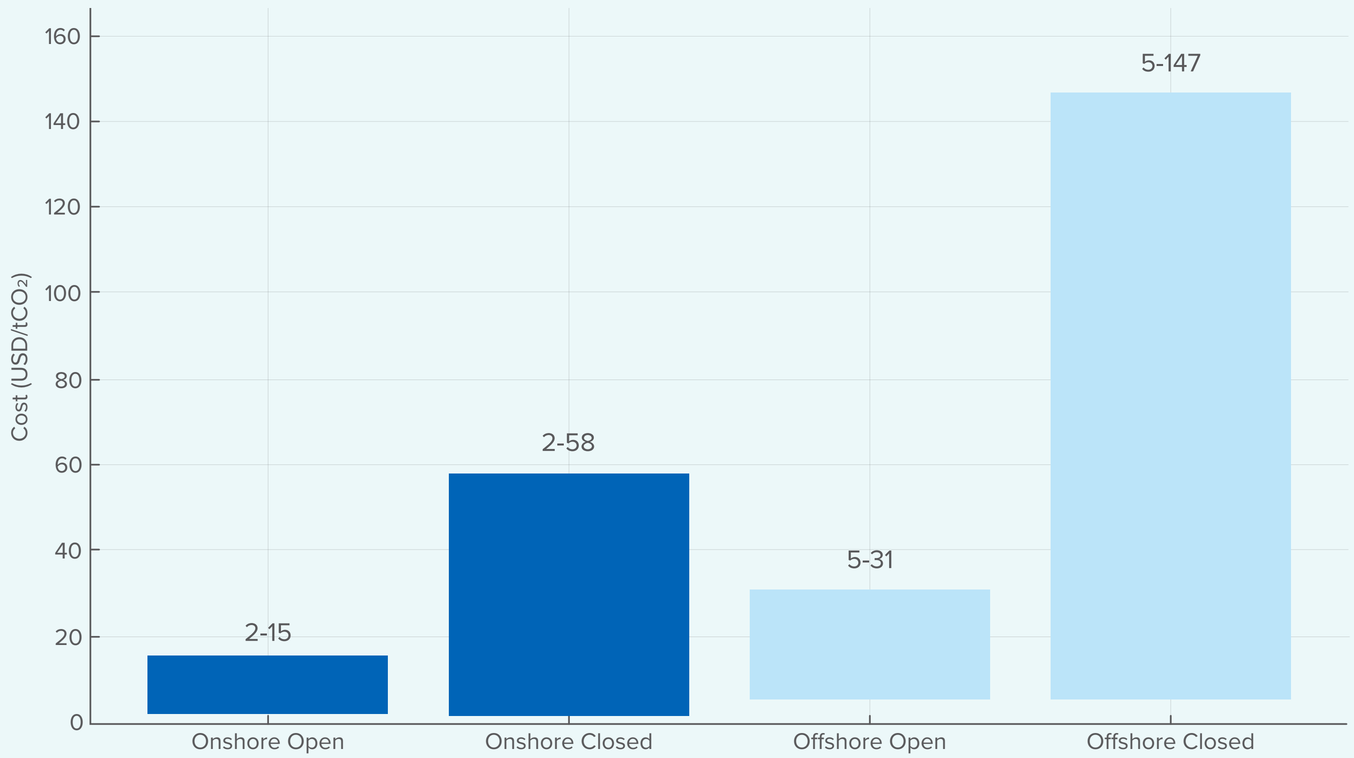
Offshore projects have a higher base cost at US$5/t$CO_2$, with a range that extends to US$31/t$CO_2$ for open boundary conditions, and to US$147/t$CO_2$ in the most constrained scenarios (closed boundary, poor and thin reservoirs, low FPG). However, favourable offshore sites with open boundaries are cost comparable to onshore settings.

Insights

The cost distribution for each setting shows that offshore storage can be economically viable, especially when favourable sites are identified and prioritised early. These lower-cost sites include good reservoir properties with open boundary conditions.

The CO_2RE database (GCCSI, 2025) shows that most storage projects worldwide are currently located onshore. This reflects progress in the United States and Canada. The region has the largest number of developing and operational projects – 382 of 742 worldwide as of June 2025. North American projects are primarily onshore. Despite the potential for higher costs, regions such as the North Sea and Europe demonstrate that offshore CO_2 storage can be cost-effective with favourable boundary conditions. In addition, the development of offshore storage projects may benefit from a stronger social licence to operate, with fewer social and political obstacles.

Figure 5 - Cost of storage for onshore and offshore with different boundary conditions.



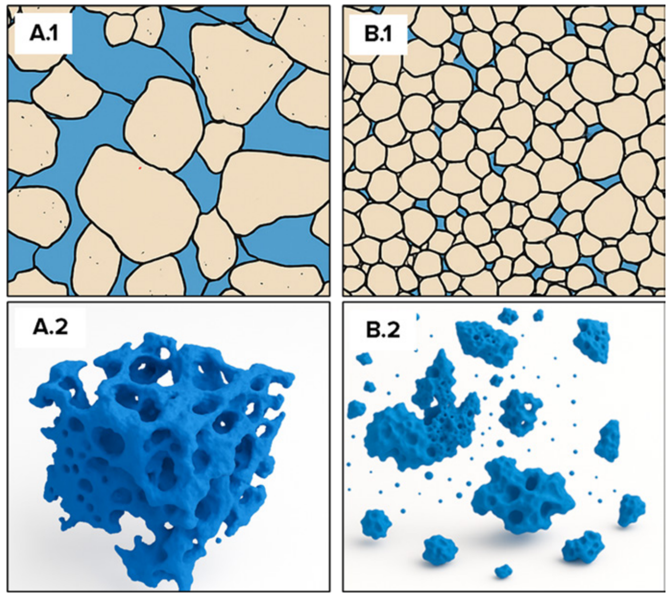
Impact of reservoir properties on storage costs

Properties such as reservoir quality, thickness, and FPG show a moderate influence on overall costs.

Cost is sensitive to reservoir quality under closed boundary conditions – Figure 7. The increase in overall costs of about 40-60% is due to the reduced injectivity and capacity of poor-quality reservoirs. This difference is not observed under open boundary conditions, where the system allows for natural pressure dissipation, mitigating the negative impacts of lower reservoir quality, with cost outcomes remaining similar regardless of reservoir quality.

Reservoir quality reflects the porosity and permeability of the storage formation (Figure 6). We characterise formations with 20% porosity and 500 mD permeability or higher as good, and less than 15% porosity and 100 mD as poor – Table 1.

Figure 6 - The porosity and permeability difference between a good (A) and a poor (B) sandstone. Images A1 and B1 are 2D schematics of a reservoir showing grains of sand (beige) and pore space (blue). The 3D images A.2 (good) and B.2 (poor) are hypothetical interpretations of the connected pore space for the two sandstones.



A thin reservoir (90 m) results in a moderate increase in storage costs for closed boundary conditions compared to a thick reservoir (180 m). Thin reservoirs constrain the available storage volume and reduce injectivity. For open boundary conditions, this effect is minimal, with the cost remaining unchanged as injection rates do not need to be limited by pressure constraints.

The effect of a low FPG (0.6 psi/ft) on storage cost is comparable to a thin reservoir under closed boundary conditions. The lower fracture pressure restricts the maximum allowable injection pressure. Therefore, less CO_2 can be injected over the project's operational lifetime before pressure constraints are reached. Open boundary settings mitigate this cost impact, with costs remaining effectively the same between a higher FPG and a lower FPG case.

Costs

Reservoir properties, while secondary to the principal cost drivers of boundary conditions (open versus closed) and setting (onshore versus offshore), are significant indicators of likely cost. Site selection for good quality, thick reservoirs with a high FPG tolerance results in the most cost-effective storage.

High reservoir quality reduces costs under closed boundary conditions.

Under open boundary conditions, the cost remains unaffected by the reservoir quality, with values consistently low and stable at approximately US$2-15/t$CO_2$ (offshore: US$5-31/t$CO_2$). However, under closed boundary conditions, poor-quality reservoir costs increase to US$3-21/t$CO_2$ (offshore: US$8-48/t$CO_2$). This highlights the buffering effect of open boundary systems, which mitigate pressure buildup and support injectivity, thereby lowering cost.

A thick reservoir improves injectivity, storage capacity, and reduces cost for closed boundaries.

A thin reservoir increases the cost to US$4-23/t$CO_2$ in an onshore reservoir with closed boundary conditions (offshore: US$8-50/t$CO_2$). For open boundary conditions, storage costs remain unchanged.

A low fracture pressure gradient increases costs and reduces capacity.

Under closed boundary conditions, for the high FPG onshore scenario, the cost is US$2-15/t$CO_2$, but rises to US$4-23/tCO_2 for a low FPG. Open boundary conditions mitigate this, with costs remaining effectively the same for both high and low FPG scenarios (US$2-15/t$CO_2$). The offshore environment approximately doubles the costs across the different scenarios.

High cost scenarios are still manageable.

In the highest cost onshore scenario, where poor reservoir quality, thin reservoir, and low FPG coincide under closed boundary conditions, the estimated storage cost is US$10-58/t$CO_2$. This represents a fourfold increase compared to the best-case scenario (US$2-15/t$CO_2$).

Insights

Comparable to boundary conditions, the reservoir properties of quality, thickness, and FPG are highly site-specific and determined by the geology. For all the studied parameters, the worst-case costs can be avoided through early site screening, characterisation and corrective actions. The most expensive costs driven by closed boundaries, poor quality, thin reservoirs, and low FPG can be anticipated and mitigated through early site screening, characterisation, and design interventions. Understanding these parameters upfront allows for more accurate cost projections and reduces the risk of unforeseen subsurface challenges during development and deployment. Pressure management and multi-zone injection strategies offer practical options to reduce costs and improve project feasibility.

Figure 7 - CO_2 storage cost range by scenario and setting. The primary drivers of cost are onshore vs offshore and open boundaries vs closed boundaries; reservoir quality, thickness, and fracture pressure gradient are secondary.

CO_2 Storage Cost Range by Scenario and Setting, US$ per tonne

	Onshore Setting – Open	Onshore Setting – Closed	Offshore Setting – Open	Offshore Setting – Closed
Poor Q + Thin + Low FPG	$15	$58	$31	$147
	$2	$10	$5	$22
Poor Quality + Thin	$15	$33	$31	$80
	$2	$5	$5	$12
Low Frac Pressure Gradient	$15	$23	$31	$50
	$2	$4	$5	$8
Thin Reservoir	$15	$23	$31	$50
	$2	$4	$5	$8
Poor Quality Reservoir	$15	$21	$31	$48
	$2	$3	$5	$8
Base Case	$15	$15	$31	$31
	$2	$2	$5	$5

$150 $100 $50 $20 $10 $5 $2

5.0 KEY COST DRIVERS AND PRACTICAL TAKEAWAYS

This analysis indicates that the boundary conditions for the storage formation are the most critical driver of CO_2 storage costs. For open boundary conditions, costs remain relatively stable at around US$2-15/t$CO_2$ onshore and $5-31/t$CO_2$ offshore even when reservoir properties such as quality, thickness, or fracture pressure gradient vary.

Closed boundary systems effectively double costs, with unfavourable storage conditions doubling the cost again. The highest cost scenarios — poor reservoir quality, thin formations, low fracture pressure gradient, and closed boundaries — can escalate costs to US$58/t$CO_2$ onshore and US$147/t$CO_2$ offshore.

An offshore storage setting typically carries higher costs due to infrastructure complexity and logistics, often more than doubling the equivalent onshore cost. However, the analysis also shows that offshore costs for sites with open boundaries and reasonable reservoir quality can be comparable to onshore projects. This is particularly important in regions where onshore options are limited by geography or land use constraints.

Practical takeaways

This analysis examines how a selected subset of key drivers influence CO_2 storage costs in the scenarios considered. While many other factors can affect project economics, understanding the drivers assessed here can help developers, policymakers, and financiers identify comparatively lower-cost opportunities and design projects that are more likely to be economically competitive.

Boundary conditions are the most critical driver.

Open systems consistently deliver lower and more predictable costs. Site screening and well injectivity testing help to ascertain boundary behaviour at the earliest stage.

Offshore costs range from low to high depending on the scenario.

With open boundaries and good-quality reservoirs, offshore projects can achieve costs comparable to onshore storage. This is particularly relevant in regions with limited onshore options.

Reservoir quality, thickness, and fracture pressure gradient matter for closed boundary systems.

These parameters escalate the cost when pressure cannot dissipate.

Early site characterisation pays for itself.

Investment in reservoir data, boundary conditions characterisation, and fracture analysis helps avoid worst-case scenarios that can multiply costs. The project design and monitoring plan need to evolve as understanding of the site deepens.

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6.0 SUPPLEMENTARY ANALYSIS

Supplementary 1 – Scope and Assumptions

1. Broader factors

While this study focuses on five primary drivers (setting, boundary conditions (BC), reservoir quality, thickness, and fracture pressure gradient), CO_2 storage costs are influenced by a wider set of factors (but not limited to):

- Subsurface factors: porosity, permeability, thickness, depth, injectivity, fracture pressure, reservoir pressure, temperature, boundary conditions, geomechanics and containment features.
- Project scale: Larger projects would be expected to benefit from economies of scale, achieving lower storage costs (US$/t$CO_2$), whereas smaller projects would likely experience higher unit costs.
- Surface and infrastructure factors: water depth, drilling and completion of wells, monitoring, settings (offshore/onshore) and facilities.
- Regulatory and external factors: permitting, liability frameworks, environmental compliance, fiscal terms, and societal acceptance.

This study could be expanded by testing additional factors or varying the base assumptions to assess their impact on storage costs.

2. Exclusions and Simplifications

To maintain clarity and comparability, several elements are excluded:

- CO_2 capture, transport, and fluid conditioning (e.g., compressors, pumps).
- Intra-field pipelines between wells within the storage site.
- Design optimisation scenarios, including well design, placement strategies, and monitoring strategies during operation or operational aspects.
- Pressure management, e.g. a brine production and disposal system.
- Variation in reservoir depth (depth held constant at 2,500 m).
- Facilities downtime and fluctuation of CO_2 supply.
- Deepwater offshore settings – offshore costs are limited to water depths of up to 150 m, where jack-up rigs are assumed.
- Site-specific factors include regulatory compliance, financial structure, taxation, incentives, insurance, liability, and social costs
- Legacy wells - Legacy wells are not considered here, as this study focuses on greenfield, deep saline formations, and it is assumed there are no legacy wells. The existence of legacy wells (plugged and abandoned exploration and appraisal wells, as well as production wells) is a known cost to CO_2 storage operations. Costs include remediation, well plugging and abandonment, and ongoing monitoring around legacy wells. In contrast, legacy wells can reduce costs during the exploration phase by reducing the number of wells required overall, and could be reused as injection or monitoring wells.
- Reuse of infrastructures such as wells or platforms.

3. Uncertainty and Accuracy

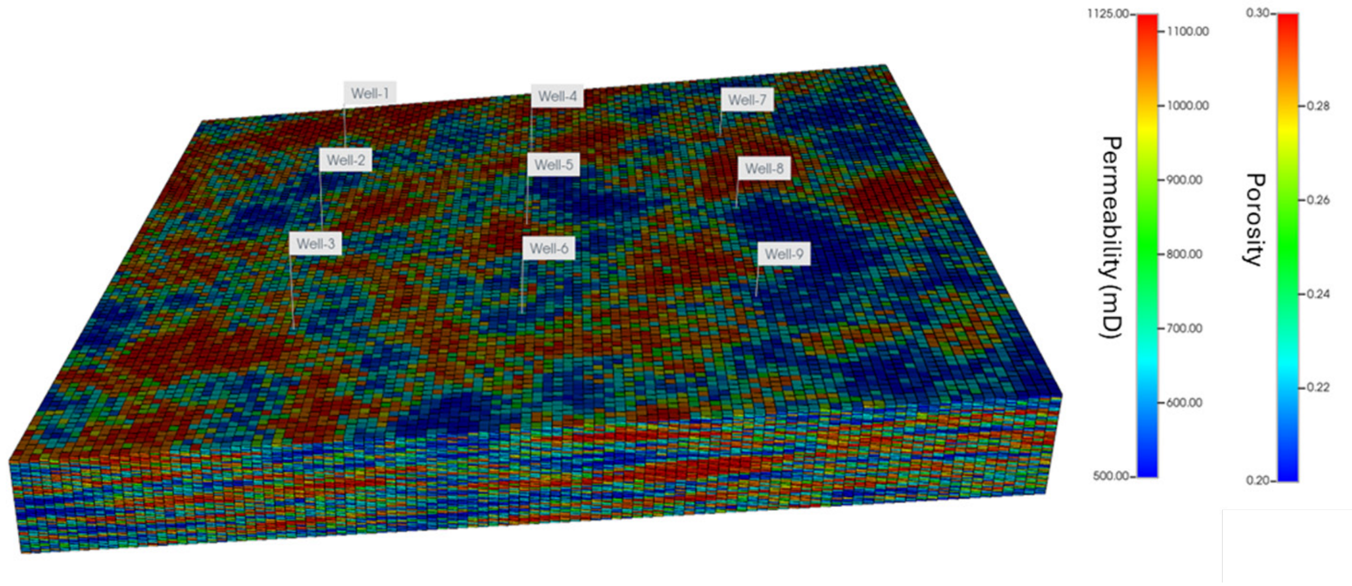
- Results represent Class 5 cost estimates, consistent with early conceptual studies.
- Accuracy is approximately -50% to +100%. This study uses a contingency of 100%.
- Costs should be used for comparative analysis, not investment decisions.

Supplementary 2 – Modelling

This study provides a scenario-based assessment of CO_2 storage costs in onshore and offshore saline aquifers, underpinned by reservoir simulation and lifecycle cost modelling. Using the Global CCS Institute's CO_2 Storage Cost (GCOST) model, coupled with detailed reservoir simulation performed with the CMG commercial reservoir simulator, the study explores how five primary factors impact storage economics.

A generic reservoir model was developed to simulate a typical saline aquifer system (Figure S1). The results therefore reflect this specific configuration. More complex geometries, for example, structurally compartmentalised settings, would be expected to affect pressure dissipation, plume migration, and ultimately storage cost.

Figure S1 - Permeability and porosity distribution in the good-quality reservoir.



The main model data are summarised Table S1.

Table S1 - Reservoir model data summary.

PARAMETERS	VALUE*
Depth	2,500 m
Fluid density	1,020 kg/m3
Reservoir Temperature	92 °C
Porosity	Good: 20-30% Poor: 10-15%
Permeability	Good: 500-1,125 mD Poor: 50-112.5 mD
Vertical permeability	10% of horizontal permeability
Rock Compressibility	5×10−6 1/kPa
Max BHP of the Injector	90% of the fracture initiation pressure
Fracture pressure gradient (FPG)	Base case: 0.7 pis/ft Low case: 0.6 pis/ft
Thickness	Base case: 180 m Low case: 90 m
Area	100 km² (i.e. 10 km x 10 km)
Injection period	20 years
Post-Closure Monitoring period	50 years
Maximum CO_2 injection rate	1 Mtpa per well
Well design	Vertical well with a 60 m perforation interval at the midpoint of the reservoir thickness
Injection well patterns	A maximum of nine wells, arranged in a Cartesian pattern across the reservoir

* These parameters are not attributed to any specific project but are supported by the Global CCS Institute's CO_2RE database.

Simulations were run to test four specific factors that impact the overall costs of a CO_2 storage project over its entire lifecycle:

1. Injection rates
2. Total CO_2 stored
3. Plume area
4. Optimal number of injection and monitoring wells.

The simulation results were then integrated into GCOST and applied to each stage of the CO_2 storage lifecycle, from exploration to post-closure, for both onshore and offshore settings. Representative scenarios were developed to evaluate the influence of geographical, geological, infrastructure, and operational requirement factors on CO_2 storage cost. Low- and high-cost estimates were created for each scenario.

Storage site characteristics

The storage site is assumed to be a saline reservoir with a 1-degree dip angle from west to east. The impacts of boundary conditions, reservoir quality (porosity and permeability), reservoir thickness and fracture pressure on storage capacity, injectivity, and the optimal number of wells required were analysed – all of which ultimately affect the cost of CO_2 storage per tonne of CO_2 stored.

The boundary conditions were considered either closed or open at the bottom, with the latter connected to an infinite-acting aquifer.

The reservoirs exhibit mild heterogeneity, modelled using a spherical variogram with the same spatial correlation structure across all scenarios to ensure comparability.

For good-quality reservoirs, porosity ranges from 0.2 to 0.3. To represent poor-quality reservoirs while maintaining the same heterogeneity type for direct comparability, porosity values were reduced to half their original values. Permeability was parameterised as a function of porosity to reflect the characteristics of good- and poor-quality reservoirs, without altering the underlying heterogeneity. Permeability in the Z-direction is set to 10% of horizontal permeability. Figure S1 in the report presents the permeability and porosity distribution in the good-quality reservoir. The same heterogeneity type exists for the poor-quality reservoir.

Injection and post-injection duration

The injection period is assumed to be 20 years, followed by a 50-year post-injection monitoring period. According to the Global CCS Institute's CO_2RE database, a 20-year injection period aligns with the average duration of medium- to large-scale CO_2 storage projects worldwide. The 50-year post-injection period follows the monitoring requirements set by the US Environmental Protection Agency (EPA).

Injection well patterns

For each modelling scenario, the optimal number of wells required to efficiently utilise the reservoir's storage capacity was initially assessed. The study considered a maximum of nine wells, arranged in a Cartesian pattern across the reservoir. A higher number of wells was not considered, as most projects in the CO_2RE database pipeline fall below this threshold. Figure S1 in the report illustrates the distribution of the injectors along with their names.

Only the required number of wells remained open when evaluating scenarios with fewer than nine wells. For example, if three wells were open, only wells 1 to 3 were active. Note that well placement optimisation is not part of this study.

For each modelling scenario, the optimal number of injection wells was first identified based on maximising cumulative CO_2 storage by the end of the injection period. However, if increasing the number of wells resulted in only a marginal gain in cumulative CO_2 stored relative to the substantial rise in infrastructure costs, additional wells were not selected. For example, while increasing from four to five wells might significantly boost storage, adding a sixth well may provide only a small incremental increase that does not justify the added cost.

Well constraints

The maximum gas injection rate is set at approximately 1 Mtpa, closely representing the average rate per well in Class VI permit applications in the US (ccusmap.com) and CO_2RE database for global averages. The maximum BHP of the injectors is set at 90% of the fracture initiation pressure, which is the threshold established by the EPA for Class VI applications.

Example of modelling results

Closed BC- Good reservoir quality - Thickness 90 m

Three scenarios were evaluated to determine the optimal number of wells for a reservoir with a thickness of 90 m under closed boundary conditions. Figure S2 shows cumulative CO_2 injected over time for 4, 5, and 6-well scenarios under closed boundary conditions over the 20-year injection period for each case. The results for this specific scenario indicate that five wells strike the best balance between maximising CO_2 storage and managing the cost of storage. Adding more than five wells offers limited benefit, as the storage capacity is primarily constrained by the system's pressure limits, a characteristic of closed boundary conditions. The marginal increase in CO_2 injected (approximately 5 Mt with a sixth well) does not justify the additional infrastructure and operational costs, making it an inefficient option.

Figure S2 - Cumulative CO_2 injected over time for 4, 5, and 6-well scenarios under closed boundary conditions.

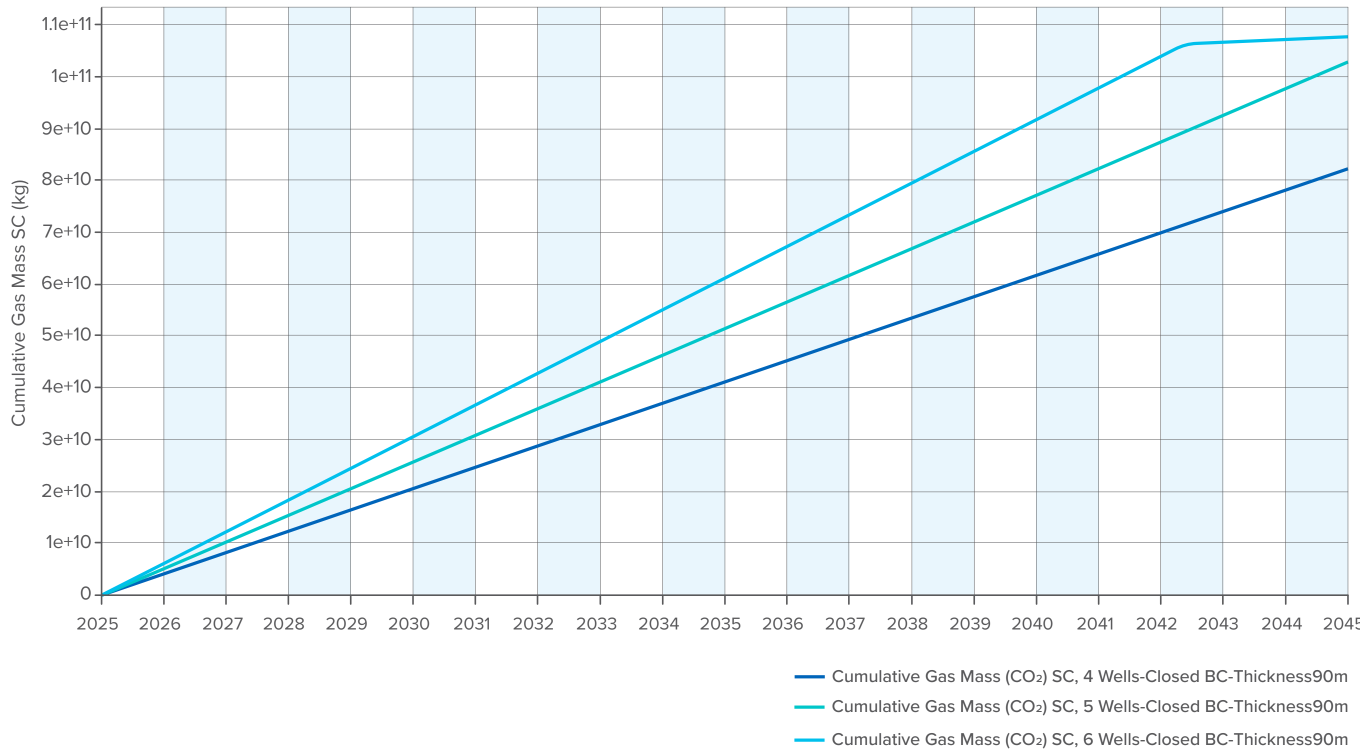


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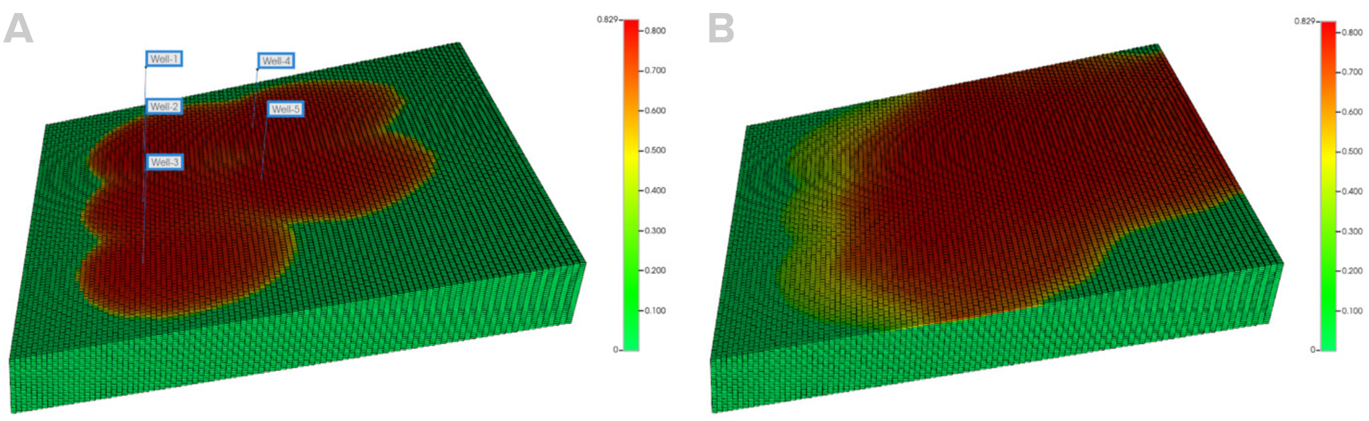
Figure S3 illustrates the CO_2 plume area at the top of the reservoir at the end of the injection period, as well as 50 years post-injection, for the scenario with five injection wells. Post-injection, gas migration occurs as CO_2 moves upward due to gravitational forces, while residual trapping takes place at the trailing edge of the plume due to water imbibition and hysteresis in gas relative permeability.

Figure S3 - Gas plume area at the top of the reservoir by A, end of injection, and B, end of post-injection. Scenario: 5 wells, closed BC, good reservoir quality, thickness 90 m.



Some of the key cost drivers — including the net amount of CO_2 injected per scenario, the number of wells, and the plume area at the end of the injection and post-injection periods (which influences monitoring requirements) — are summarised in Table S2. These modelling outputs are then used as inputs to our cost model to estimate the total cost for each optimum scenario.

Table S2 - Net amount of CO_2 ($MtCO_2$) injected and maximum plume area per scenario.

SCENARIO	NET AMOUNT OF CO_2 INJECTED ($MTCO_2$)	MAX PLUME AREA BY THE END OF INJECTION (KM²)	MAX PLUME AREA BY THE END OF 50 YEARS POST-INJECTION (KM²)
4 wells - Closed BC - Good quality - Thickness 90 m	82.1	47.6	--
5 wells - Closed BC - Good quality - Thickness 90 m	102.6	53.7	79.5
6 wells - Closed BC - Good quality - Thickness 90 m	107.9	58	--

Supplementary 3 – Cost components

Storage costs are unit cost per tonne of CO_2 injected and securely stored. They encompass both capital expenditure (CAPEX), operational expenditure (OPEX), and abandonment expenditure (ABEX) of the new infrastructures across the project lifecycle. The cost estimates presented in this study focus on storage activities and are subject to several defined exclusions. The cost components based on the CO_2 storage lifecycle are listed in Table S3.

Table S3 - Cost components throughout the CO_2 storage lifecycle used in this analysis.

PHASE	COST COMPONENT	UNIT	DESCRIPTION
Exploration and appraisal	3D seismic surveys	$/km²	Acquisition and processing of 3D seismic data to map subsurface geological structures.
	Exploratory drilling	$/metre	Drilling of exploration wells to assess reservoir properties and validate geological models.
	No. of exploration wells	No. of wells/km²	Estimated based on the areal extent of the storage site and screening assumptions.
	Baseline monitoring (excluding seismic)	$/site and $/km²	Establishment of environmental and subsurface baseline conditions (e.g. pressure, groundwater quality).
Site characterisation	Geological sampling, modelling, injection testing	$/site	Includes core sampling, well logging, static/dynamic modelling, injection testing, and coupled flow-geomechanical and geochemical simulation to characterise the site.
Development	Well drilling and completion	$/metre	Drilling and completion of vertical injection wells with a fixed depth of 2,500 m, including casing, cementing, and perforation. Tubing is assumed to be chrome-based. For offshore, the study limits the water depth to 150 m and assumes the use of a jack-up rig for the rig cost. The wait-on-weather days assumption is embedded for the offshore cost basis. The rig rate used was low and high in the 2023-2024 published rate.
	Monitoring wells	No. of wells/km²	Monitoring well costs are assumed to be equivalent to injection wells. One well is allocated per 25 km² of the expected plume area 50 years after injection ceases.
	Surface facilities	$/facility	Construction of well pads, surface equipment, and monitoring systems, as well as platform installation in offshore cases, excludes fluid conditioning, e.g., compressors, pumps, dehydration units, etc. The offshore platform cost is assumed to be for a new unmanned lightweight structure with a weight of less than 1,500 Mt, six well slots that can accommodate up to 12 wells, a three-legged jacket, and a jack-up rig compatible.
Operation	Injection operations	% of CAPEX	Annual operational expenditure for CO_2 injection, including maintenance, labour, and energy, is estimated as a percentage of total CAPEX.
	Operational monitoring (M&V)	$/year	Ongoing monitoring of wellbore pressure, plume migration, and subsurface conditions using real-time and periodic measurement technologies.
Closure and post-closure	Plugging and abandonment (P&A)	% of CAPEX	Decommissioning and permanent sealing of wells using cement plugs, followed by site restoration activities.
	Long-term monitoring (M&V)	% of M&V OPEX	Post-closure monitoring activities include soil gas sampling, periodic seismic surveys, and verification of plume stability.
Financial	Capital recovery factor (CRF)	—	Capital expenditures are annualised using a CRF of 9.86%, based on a 20-year project life and a weighted average cost of capital (WACC) of 7.6% (assumed: 40% equity @ 10% return, 60% debt @ 6% interest).
Contingency	Contingency on total cost	%	A Class 5 estimate is applied at the early conceptual stage for screening purposes. Expected accuracy range is -50% to +100%. Not suitable for final investment decisions without further project definition.

7.0 REFERENCES

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