



Optimizing cross-border CCS policy: an integrated energy–carbon–cost framework for source–host credit allocation

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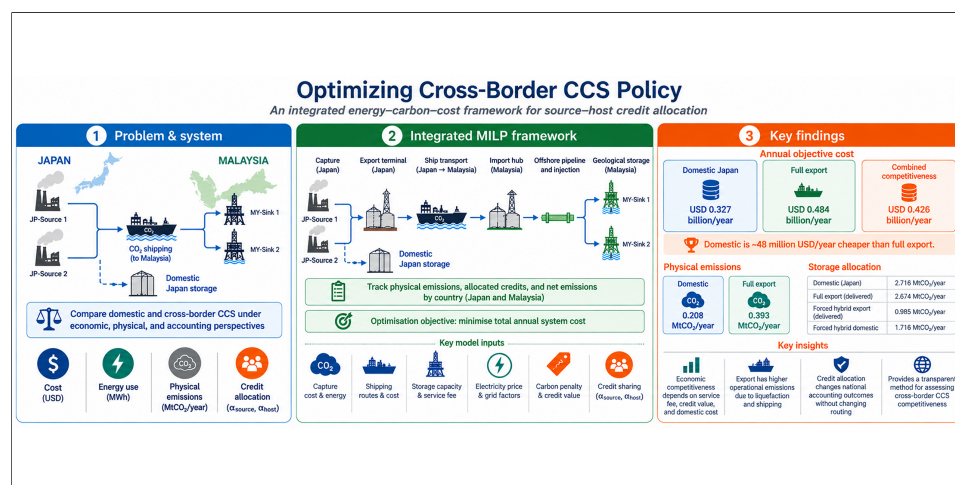
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Abstract

Cross-border carbon capture and storage (CCS) can support industrial decarbonisation where emissions and storage resources are unevenly distributed. Existing optimisation studies mainly minimise techno-economic cost and rarely integrate energy penalties, country-level emissions accounting, domestic-versus-export allocation, and source–host credit sharing. This study develops a mixed-integer linear programming framework that selects domestic or export storage, shipping routes, offshore pipelines, and sinks while tracking operational emissions, costs, and source–host credit allocation. An anonymised Japan–Malaysia case includes two Japanese sources, two Malaysian sinks, and a domestic screening pathway. Domestic Japanese storage costs USD 0.327 billion/year, compared with USD 0.484 billion/year for full export. Under the Combined Competitiveness scenario, a combination of a lower Malaysian service fee, equal source–host credit sharing, and an upper-end published domestic-storage cost selects full export to MY-Sink 1 at USD

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0.426 billion/year, with the capability of storing 2.674 MtCO₂/year after shipping loss. Credit ownership changes economic and national accounting outcomes without changing routing. Malaysian storage and injection, shipping, and credit values give the largest local sensitivity responses. In summary, the framework provides a transparent method for assessing cross-border CCS competitiveness, operational emissions, and sink selection.

INTRODUCTION

Deep decarbonisation requires mitigation options for residual and process-related emissions from cement, steel, refining, chemicals, petrochemicals, and power generation. Carbon capture and storage (CCS) can address these hard-to-abate emissions through an integrated chain of capture, conditioning, transport, injection, monitoring, and geological storage. Deployment is increasing, but current and announced capacities remain below those required for net-zero pathways^[1,2], which suggests the need to strengthen efficient full-chain planning.

CCS optimisation has traditionally focused on source–sink matching, transport-network design, pipeline sizing, storage allocation, and capacity expansion^[3–5]. Several studies improved the representation of shipping, ports, offshore pipelines, and storage logistics^[6–9]. These models establish a strong engineering basis for network design, but most emphasise techno-economic configuration. Energy-related emissions are often treated indirectly or assessed after optimisation, and the benefit of verified storage is rarely allocated explicitly between participating jurisdictions.

This limitation is important for cross-border CCS. Capture electricity, maritime transport, offshore pipeline transfer, and injection generate emissions in different countries, so stored CO₂ and net mitigation are not equivalent. The source country may seek recognition for avoided industrial emissions, whereas the host country provides storage capacity, infrastructure, monitoring, and long-term stewardship. Existing environmental studies support full-chain assessment^[10–12], while continuing advances in capture materials demonstrate the broader development of efficient CO₂ separation technologies^[13]. However, optimisation models seldom connect energy use, national emissions balances, route and sink decisions, and source–host benefit allocation within one formulation.

In this study, four related gaps are addressed: incomplete representation of full-chain energy penalties; limited country-level physical-emissions accounting; absence of an explicit rule for allocating the verified storage benefit without double counting; and limited comparison of optimised export pathways with a domestic-storage alternative. Addressing these gaps, an integrated energy–carbon–cost framework is required which links physical flows, infrastructure choices, operational emissions, policy values, and jurisdictional accounting. Therefore, this study develops a mixed-integer linear programming framework with four contributions. It integrates capture, shipping, offshore-pipeline, and injection energy with CO₂ flows; formulates physical, credited, and net-emissions balances for source and host countries; introduces α -source and α -host shares for hypothetical source-claim, host-claim, and shared-credit cases; and compares domestic storage with cross-border export within a common scenario structure. The framework is demonstrated using an anonymised Japan–Malaysia system with two Japanese sources and two Malaysian offshore sinks.

METHODOLOGY

Generalised problem statement and system boundary

The optimisation problem is formulated as a general framework for cross-border CCS network design and operation. The proposed framework accommodates CCS systems involving multiple CO₂ emission sources, domestic and foreign storage alternatives, transport routes, infrastructure options, jurisdictions, and policy

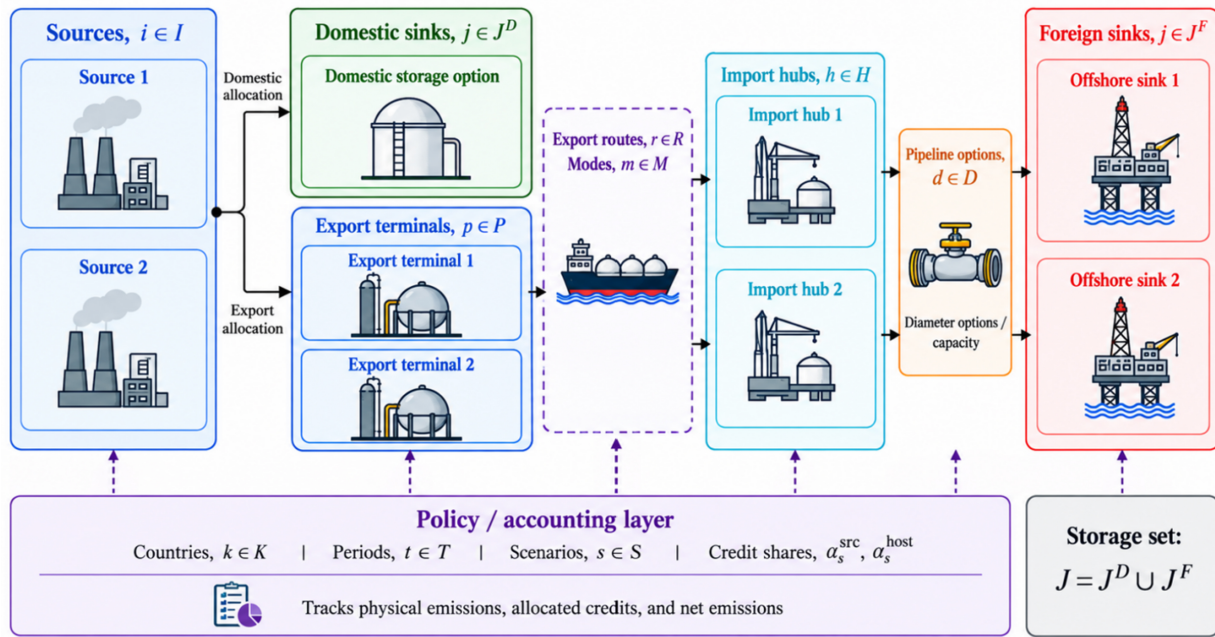


Figure 1. General CCS superstructure from source to storage. CCS: Carbon capture and storage.

scenarios. The case-specific source locations, storage sites, transport distances, costs, capacities, and policy parameters are introduced later in the case study section.

Given a set of CO₂ emission sources $i \in I$, candidate storage sinks $j \in J$, transport routes $r \in R$, transport modes $m \in M$, countries or jurisdictions $k \in K$, operating periods $t \in T$, infrastructure options $d \in D$, and policy scenarios $s \in S$, the model determines the least-cost configuration and operation of the CCS chain. The storage set J may be divided into domestic storage alternatives J^D and foreign or cross-border storage sinks J^F . A general CCS superstructure is depicted in Figure 1.

Therefore, captured CO₂ can be allocated either to domestic storage or to cross-border export routes. The cross-border pathway links source-country capture and export activities with host-country import, transport, injection, and geological storage activities. This structure allows the same optimisation framework to evaluate domestic-versus-export storage decisions, route and sink selection, infrastructure sizing, energy use, emissions accounting, and carbon-credit allocation.

The decision problem is to determine the amount of CO₂ captured, uncaptured, transported, lost, injected, and stored; the routes, modes, sinks, and infrastructure options selected; the energy consumed by capture, conditioning, transport, and injection; and the country-level physical emissions, allocated credits, and net emissions. The objective is to minimise total annual system cost, including capture, transport, storage, energy, infrastructure, risk or access premiums, carbon penalties, and carbon-credit benefits, while satisfying mass-balance, capacity, loss, storage, energy, accounting, and policy constraints. Table 1 summarises the general sets and system elements used in the optimisation framework.

The generalised superstructure provides the basis for the mixed-integer linear programming (MILP) formulation. The model includes continuous variables for CO₂ capture, export flow, domestic storage, hub flow, stored CO₂, energy use, physical emissions, allocated credits, and net emissions. Binary variables indicate route and sink activation, while integer variables represent infrastructure-sizing decisions such as the number of offshore pipelines selected for each sink. The objective function and constraints are presented in the following subsections.

Table 1. Generalised sets and system elements in the cross-border CCS optimisation framework

Set/element	Symbol	Description
CO ₂ sources	$i \in I$	Emission sources where CO ₂ can be captured
Storage sinks	$j \in J$	Candidate geological storage alternatives
Domestic storage sinks	$j \in J^D$	Storage alternatives located in the source country
Foreign storage sinks	$j \in J^F$	Storage alternatives located in the host country
Transport routes	$r \in R$	Feasible source–hub–sink transport pathways
Transport modes	$m \in M$	Available CO ₂ transport modes
Export terminals	$p \in P^E$	Loading or export-port systems
Import hubs	$h \in H$	Receiving hubs before storage transport
Countries/jurisdictions	$k \in K$	Source and host accounting jurisdictions
Time periods	$t \in T$	Operating or representative time intervals
Infrastructure options	$d \in D$	Discrete infrastructure choices
Scenarios	$s \in S$	Policy, market, and operational cases

CCS: Carbon capture and storage.

Objective function

The objective function minimises the total annual system cost. It includes CO₂ capture, shipping and port services, annualised offshore-pipeline construction, host-country injection, storage and service charges, domestic transport and storage, pipeline and injection electricity, carbon penalties, and country-specific credit benefits.

The capture-cost coefficient is treated as an all-inclusive monetary proxy. Therefore, capture electricity is used to calculate physical emissions but is not charged separately in the objective function. Liquefaction and reconditioning electricity are treated in the same way because their monetary costs are already included in the corresponding port-service coefficients. This treatment prevents the same energy requirement from being counted twice.

$$\min Z = C^{\text{cap}} + C^{\text{ship+port}} + C^{\text{pipe,fix}} + C^{\text{store+service}} + C^{\text{dom}} + C^{\text{elec}} + C^{\text{pen}} - B^{\text{credit}} \quad (1)$$

where Z is the total annual objective cost; C^{cap} is the capture cost; $C^{\text{ship+port}}$ is the shipping and port-service cost; $C^{\text{pipe,fix}}$ is the annualised offshore-pipeline construction cost; $C^{\text{store+service}}$ is the host-country injection, storage and service cost; C^{dom} is the domestic transport and storage cost in the source country; C^{elec} is the separately charged offshore-pipeline and injection electricity cost; C^{pen} is the carbon-penalty cost; and B^{credit} is the monetary benefit obtained from the allocated storage credit.

The carbon-credit benefit is calculated using country- and scenario-specific credit values:

$$B_s^{\text{credit}} = H \sum_{k \in K} \sum_{t \in T} P_{k,s}^{\text{credit}} Cr_{k,t,s} \quad (2)$$

where B_s^{credit} is the total annual credit benefit under scenario s ; H is the horizon-to-year scaling factor; K is the set of participating countries; T is the set of representative operating periods; $P_{k,s}^{\text{credit}}$ is the credit value applied by country k under scenario s ; and $Cr_{k,t,s}$ is the verified storage credit allocated to country k in period t under scenario s .

This formulation allows the same physical amount of stored CO₂ to have different monetary values depending on the credit value and the share assigned to the source and host countries. Credit allocation affects economic and accounting outcomes but does not change the physical storage location.

The expanded annual objective function is:

$$\begin{aligned} \min Z = H & \left[\sum_{i \in I} \sum_{t \in T} c_i^{\text{cap}} x_{i,t} + \sum_{r \in R} \sum_{t \in T} c_r^{\text{ship+port}} f_{r,t} + \sum_{j \in J^F} \sum_{t \in T} c_{j,s}^{\text{store+service}} z_{j,t} \right. \\ & + \sum_{i \in I} \sum_{t \in T} c_{i,s}^{\text{dom}} d_{i,t}^{\text{dom}} + \sum_{j \in J^F} \sum_{t \in T} c_{k\text{host}}^{\text{elec}} (E_{j,t}^{\text{pipe}} + E_{j,t}^{\text{inj}}) \\ & + \sum_{k \in K} \sum_{t \in T} P_{k,s}^{\text{pen}} \text{PE}_{k,t} - \sum_{k \in K} \sum_{t \in T} P_{k,s}^{\text{credit}} \text{Cr}_{k,t,s} \left. \right] \\ & + \sum_{j \in J^F} \sum_{d \in D} C_{j,d}^{\text{pipe, fix}} n_{j,d} \end{aligned} \quad (3)$$

where c_i^{cap} is the capture-cost coefficient for source i ; $x_{i,t}$ is CO₂ captured from source i in period t ; $c_r^{\text{ship+port}}$ is the shipping and port-service cost for route r ; $f_{r,t}$ is the gross CO₂ flow on route r ; $c_{j,s}^{\text{store+service}}$ is the injection, storage, and service-cost coefficient for foreign sink j under scenario s ; $z_{j,t}$ is CO₂ stored at sink j ; $c_{i,s}^{\text{dom}}$ is the domestic transport-and-storage cost for source i ; $d_{i,t}^{\text{dom}}$ is CO₂ assigned to domestic storage; $c_{k\text{host}}^{\text{elec}}$ is the host-country electricity price; $E_{j,t}^{\text{pipe}}$ and $E_{j,t}^{\text{inj}}$ are offshore-pipeline and injection electricity use; $P_{k,s}^{\text{pen}}$ is the carbon-penalty value for country k ; $\text{PE}_{k,t}$ is the physical-emission total assigned to country k ; $P_{k,s}^{\text{credit}}$ is the credit value for country k ; $\text{Cr}_{k,t,s}$ is the allocated storage credit; $C_{j,d}^{\text{pipe, fix}}$ is the annualised construction cost of pipeline option d for sink j ; $n_{j,d}$ is the number of pipelines installed; I , R , J^F , D , K , and T are the sets of sources, routes, foreign sinks, pipeline options, countries, and operating periods, respectively; and H converts representative-period values into annual values.

Variable operating costs are multiplied by H , whereas annualised pipeline-construction costs are added once outside the scaling term. Capture, liquefaction, and reconditioning electricity contribute to physical emissions but are not charged separately because their monetary costs are included in the corresponding capture and port-service coefficients.

Mass balance and physical constraints

The physical constraints conserve CO₂ from its source to domestic or foreign storage. They also enforce capture limits, route capacities, transport losses, injection capacities, storage limits, import restrictions, and infrastructure-selection requirements.

The source balance divides gross emissions into captured and uncaptured CO₂:

$$x_{i,t} + u_{i,t} = E_{i,t} \quad \forall i \in I, t \in T \quad (4)$$

where $x_{i,t}$ is CO₂ captured from source i in period t ; $u_{i,t}$ is uncaptured CO₂ released from source i ; $E_{i,t}$ is the gross CO₂ emission from source i ; I is the set of emission sources; and T is the set of operating periods.

The technical capture fraction limits the share of source emissions that can be captured:

$$x_{i,t} \leq \eta_i E_{i,t} \quad \forall i \in I, t \in T \quad (5)$$

where η_i is the maximum technically achievable capture fraction for source i ; $E_{i,t}$ is the gross source emission; and $x_{i,t}$ is the captured quantity.

The installed capture capacity provides a separate physical limit:

$$x_{i,t} \leq \bar{X}_{i,t} \quad \forall i \in I, t \in T \quad (6)$$

where $\bar{X}_{i,t}$ is the installed capture capacity available at source i in period t , and $x_{i,t}$ is the amount captured. The capture fraction is not applied to $\bar{X}_{i,t}$ because technical capture efficiency and installed equipment capacity represent different constraints.

Captured CO₂ can be allocated to domestic storage or cross-border export:

$$x_{i,t} = \sum_{r \in R_i} f_{r,t} + d_{i,t}^{\text{dom}} \quad \forall i \in I, t \in T \quad (7)$$

where R_i is the set of export routes connected to source i ; $f_{r,t}$ is the CO₂ exported through route r ; and $d_{i,t}^{\text{dom}}$ is the CO₂ assigned to domestic storage in the source country.

Export flow is permitted only when the corresponding route is activated:

$$f_{r,t} \leq \bar{F}_{r,t} y_r \quad \forall r \in R, t \in T \quad (8)$$

where $f_{r,t}$ is the export flow on route r ; $\bar{F}_{r,t}$ is its maximum transport capacity; and y_r is a binary variable equal to 1 when route r is activated and 0 otherwise.

CO₂ arriving at the host-country import hub is calculated after shipping losses:

$$h_{j,t} = \sum_{r \in R_j} (1 - \lambda_r^{\text{ship}}) f_{r,t} \quad \forall j \in J^F, t \in T \quad (9)$$

where $h_{j,t}$ is the CO₂ arriving at the import hub serving foreign sink j ; R_j is the set of routes supplying sink j ; λ_r^{ship} is the shipping-loss fraction for route r ; and $f_{r,t}$ is the gross exported quantity.

The quantity stored at a foreign sink is calculated after offshore-pipeline losses:

$$z_{j,t} = (1 - \lambda_j^{\text{pipe}}) h_{j,t} \quad \forall j \in J^F, t \in T \quad (10)$$

where $z_{j,t}$ is the CO₂ stored at foreign sink j ; $h_{j,t}$ is the CO₂ entering the offshore pipeline; and λ_j^{pipe} is the offshore-pipeline operating-loss fraction.

The case study uses $\lambda_j^{\text{pipe}} = 0$, meaning that all CO₂ entering the offshore pipeline is assumed to reach the sink. This does not mean pipeline leakage is physically impossible. It means that no unsupported routine-loss value is imposed when project-specific operating-loss data are unavailable. The equation permits a verified non-zero value in future applications.

Hub flow cannot exceed the foreign-available injection capacity of the selected sink:

$$h_{j,t} \leq \bar{Q}_{j,s}^{\text{avail}} w_j \quad \forall j \in J^F, t \in T \quad (11)$$

where $\bar{Q}_{j,s}^{\text{avail}}$ is the injection capacity available for imported CO₂ at sink j under scenario s ; w_j is a binary variable equal to 1 when sink j is activated and 0 otherwise; and $h_{j,t}$ is the hub flow supplied to that sink.

Annualised storage cannot exceed the available geological capacity:

$$H \sum_{t \in T} z_{j,t} \leq \bar{S}_j \quad \forall j \in J^F \quad (12)$$

where H is the horizon-to-year scaling factor; $z_{j,t}$ is stored CO₂ in period t ; and $\bar{S}_j$ is the storage capacity assigned to sink j over the modelled horizon.

The host-country import cap limits total cross-border delivery:

$$H \sum_{r \in R} \sum_{t \in T} f_{r,t} \leq \bar{M}_s^{\text{import}} \quad (13)$$

where $\bar{M}_s^{\text{import}}$ is the maximum annual import allowance under scenario s ; $f_{r,t}$ is the gross export flow; and H converts representative-period flow into an annual quantity.

A minimum-export constraint is applied only in scenarios designed to require cross-border participation:

$$H \sum_{r \in R} \sum_{t \in T} f_{r,t} \geq M_s^{\text{min}} \quad (14)$$

where M_s^{min} is the minimum annual export requirement under scenario s ; $f_{r,t}$ is the export flow; and H is the annual scaling factor. When $M_s^{\text{min}} = 0$, the model is not required to export CO₂.

Hub flow cannot exceed the installed offshore-pipeline capacity:

$$h_{j,t} \leq \sum_{d \in D} \bar{P}_d n_{j,d} \quad \forall j \in J^F, t \in T \quad (15)$$

where $\bar{P}_d$ is the capacity of pipeline-diameter option d ; $n_{j,d}$ is the integer number of pipelines of option d installed for sink j ; and D is the set of available pipeline options.

Pipeline construction is linked to sink activation:

$$n_{j,d} \leq \bar{N}_d w_j \quad \forall j \in J^F, d \in D \quad (16)$$

where $n_{j,d}$ is the number of pipelines installed; $\bar{N}_d$ is the maximum allowable number of parallel pipelines of option d ; and w_j is the sink-activation variable. This constraint prevents pipelines from being installed for an inactive sink.

Energy modelling

Energy use is linked directly to CO₂ flow at each operating stage. Capture and export-terminal liquefaction take place in the source country. Import-terminal reconditioning, offshore-pipeline transport, and injection take place in the host country. Domestic storage requires capture electricity together with the electricity used for domestic pipeline transport and injection.

Electricity use is first calculated in physical units and is then converted into emissions using the appropriate country grid-emission factor. Capture, liquefaction and reconditioning electricity are used for emissions accounting but are not charged separately because their costs are included in the corresponding service coefficients. Offshore-pipeline and injection electricity for the foreign-storage pathway are priced separately.

Capture electricity is proportional to the amount of CO₂ captured:

$$E_{i,t}^{\text{cap}} = a_i^{\text{cap}} x_{i,t} \quad \forall i \in I, t \in T \quad (17)$$

where $E_{i,t}^{\text{cap}}$ is capture electricity use at source i ; a_i^{cap} is the capture-electricity coefficient; and $x_{i,t}$ is captured CO_2 .

Offshore-pipeline electricity depends on pipeline distance and transported CO_2 :

$$E_{j,t}^{\text{pipe}} = a_j^{\text{pipe}} D_j^{\text{pipe}} h_{j,t} \quad \forall j \in J^F, t \in T \quad (18)$$

where $E_{j,t}^{\text{pipe}}$ is offshore-pipeline electricity use; a_j^{pipe} is the distance-based pipeline-energy coefficient; D_j^{pipe} is the offshore-pipeline distance to sink j ; and $h_{j,t}$ is the CO_2 entering the pipeline.

Injection electricity is proportional to the amount of CO_2 stored:

$$E_{j,t}^{\text{inj}} = a_j^{\text{inj}} z_{j,t} \quad \forall j \in J^F, t \in T \quad (19)$$

where $E_{j,t}^{\text{inj}}$ is injection electricity use; a_j^{inj} is the injection-energy coefficient; and $z_{j,t}$ is the quantity injected and stored.

Shipping emissions are proportional to the gross quantity exported:

$$\text{SE}_t = \sum_{r \in R} a_r^{\text{ship}} f_{r,t} \quad \forall t \in T \quad (20)$$

where SE_t is direct shipping-related CO_2 emissions in period t ; a_r^{ship} is the shipping-emissions coefficient for route r ; and $f_{r,t}$ is the gross CO_2 flow transported through that route.

These energy requirements are included in the physical-emissions calculation but are not charged separately in the objective because their monetary contributions are included in the port-service coefficients.

Carbon accounting framework

The carbon-accounting framework separates physical operational emissions from allocated storage credits. This distinction is necessary because the country generating and capturing the CO_2 may differ from the country providing transport, injection, and geological storage services.

The model first calculates the physical emissions assigned to each participating country:

$$\text{PE}_{k,t} = \text{UE}_{k,t} + \text{EE}_{k,t} + \text{SE}_{k,t} \quad \forall k \in K, t \in T \quad (21)$$

where $\text{PE}_{k,t}$ is the total physical emission assigned to country k ; $\text{UE}_{k,t}$ is uncaptured source emissions assigned to that country; $\text{EE}_{k,t}$ is grid-related emissions from CCS energy use occurring in that country; and $\text{SE}_{k,t}$ is direct shipping emissions assigned to that country under the modelled accounting boundary. Under the adopted boundary, $\text{SE}_{k^{\text{src}},t} = \text{SE}_t$ and $\text{SE}_{k^{\text{host}},t} = 0$ because direct shipping emissions are assigned to the source country.

For the source country, physical emissions comprise uncaptured source emissions, grid emissions from capture and liquefaction, direct shipping emissions, and the energy-related emissions from domestic transport and injection when domestic storage is selected:

$$PE_{k^{src},t} = \sum_{i \in I(k^{src})} u_{i,t} + \gamma_{k^{src}} \left[\sum_{i \in I(k^{src})} E_{i,t}^{cap} + a^{liq} \sum_{r \in R} f_{r,t} + (a^{pipe} D^{dom} + a^{inj}) \sum_{i \in I(k^{src})} d_{i,t}^{dom} \right] + SE_{k^{src},t} \quad (22)$$

where $PE_{k^{src},t}$ is the physical-emission total for the source country; $I(k^{src})$ is the set of emission sources located in the source country; $u_{i,t}$ is uncaptured CO_2 ; $\gamma_{k^{src}}$ is the source-country grid-emission factor; $E_{i,t}^{cap}$ is capture electricity; a^{liq} is the liquefaction-energy coefficient; $f_{r,t}$ is exported CO_2 ; a^{pipe} is the domestic pipeline-energy coefficient; D^{dom} is the assumed domestic pipeline distance; a^{inj} is the injection-energy coefficient; $d_{i,t}^{dom}$ is CO_2 assigned to domestic storage; and $SE_{k^{src},t}$ is direct shipping emissions assigned to the source country.

The domestic-storage emissions calculation includes the same quantified operating stages used for the export pathway: capture, pipeline transport, and injection. Monitoring is included in the monetary domestic-storage benchmark, but no separate monitoring-electricity value is added because the supporting source does not provide a defensible coefficient.

For the host country, physical emissions comprise electricity-related emissions from import-terminal reconditioning, offshore-pipeline transport and injection:

$$PE_{k^{host},t} = \gamma_{k^{host}} \left[a^{rec} \sum_{j \in J^F} h_{j,t} + \sum_{j \in J^F} (E_{j,t}^{pipe} + E_{j,t}^{inj}) \right] \quad (23)$$

where $PE_{k^{host},t}$ is the host-country physical-emission total; $\gamma_{k^{host}}$ is the host-country grid-emission factor; a^{rec} is the import-terminal reconditioning-energy coefficient; $h_{j,t}$ is the CO_2 received at the import hub serving sink j ; $E_{j,t}^{pipe}$ is offshore-pipeline electricity; $E_{j,t}^{inj}$ is injection electricity; and J^F is the set of foreign storage sinks.

The anonymised foreign sinks use the same host-country grid-emission factor because they are assumed to operate within the same host-country electricity system. This value is a country-level case-study input rather than a site-specific measurement.

Net accounting emissions are calculated after the allocated storage credit is deducted from physical emissions:

$$NE_{k,t,s} = PE_{k,t} - Cr_{k,t,s} \quad \forall k \in K, t \in T, s \in S \quad (24)$$

where $NE_{k,t,s}$ is the net accounting-emission balance for country k under scenario s ; $PE_{k,t}$ is the country's physical operational emissions; and $Cr_{k,t,s}$ is the verified storage credit allocated to that country.

A negative value of $NE_{k,t,s}$ indicates that the allocated accounting credit exceeds the physical emissions generated by the modelled CCS operations. It represents an accounting outcome and should not be interpreted as physically negative emissions.

Credit-sharing mechanism

The credit-allocation formulation is defined using an explicit source–sink mapping to avoid ambiguity in the allocation of verified stored CO_2 . Let $A_{i,j}$ be a binary mapping parameter equal to 1 if captured CO_2 from source i can be allocated to storage sink j , and 0 otherwise. The variable $z_{i,j,t}$ represents the amount of CO_2 from source i that is finally stored in sink j during period t , after transport and storage losses have been accounted for. This source–sink-specific storage variable ensures that the verified stored CO_2 is traced from its originating source to its final storage location.

The country-level credit allocated to country k in period t under scenario s is therefore expressed as:

$$Cr_{k,t,s} = \sum_{i \in I} \sum_{j \in J} A_{i,j} z_{i,j,t} [\alpha_s^{src} \delta_{i,k}^{src} + \alpha_s^{host} \delta_{j,k}^{host}] \quad \forall k, t, s \quad (25)$$

where $Cr_{k,t,s}$ is the CO₂ storage credit allocated to country k in period t under scenario s , A_{ij} is the source–sink mapping parameter, $z_{i,j,t}$ is the verified CO₂ stored at sink j from source i , α_s^{src} is the share of the storage credit allocated to the source country, and α_s^{host} is the share allocated to the host storage country. The binary indicator $\delta_{i,k}^{src}$ equals 1 if source i is located in country k , and 0 otherwise. Similarly, $\delta_{j,k}^{host}$ equals 1 if storage sink j is located in country k , and 0 otherwise.

To prevent double counting, the source and host credit shares are constrained as:

$$\alpha_s^{src} + \alpha_s^{host} = 1 \quad \forall s \in S \quad (26)$$

This formulation ensures that each unit of verified stored CO₂ is allocated only once across the participating countries, subject to $\alpha_{source} + \alpha_{host} = 1$. A value of $\alpha_{source} = 1$ assigns the full storage benefit to the source country, whereas $\alpha_{host} = 1$ assigns it entirely to the host country. Intermediate values represent shared-benefit arrangements. The α parameters affect the allocation and monetary value of the verified storage benefit but do not change the physical CO₂ flows or stored quantities. These cases are hypothetical policy scenarios used to test model behaviour and are not interpreted as established international carbon-accounting practices. In practice, the allocation rule would depend on bilateral agreements, domestic regulations, contractual terms, MRV requirements, infrastructure contributions, liability allocation, and agreed responsibilities for CO₂ transport and long-term storage.

JAPAN–MALAYSIA CCS SYSTEM CASE STUDY

Case study system and network configuration

The case study represents an anonymised Japan–Malaysia cross-border CCS system with two Japanese CO₂ source nodes, JP-Source 1 and JP-Source 2, and two Malaysian offshore storage sink nodes, MY-Sink 1 and MY-Sink 2. The pairing reflects a policy-relevant Asian source–host configuration: Japan represents a geographically compact industrial source country that may face a mismatch between future capture volumes and conveniently accessible domestic storage, whereas Malaysia represents a host country with emerging offshore storage ambitions. More broadly, the case illustrates how uneven distributions of industrial emissions and geological storage resources can motivate regional CO₂ transport and storage cooperation^[1,2]. JP-Source 1 represents a Japanese industrial CO₂ source with access to marine export infrastructure. JP-Source 2 has different source and route characteristics, which allows the model to test whether multiple sources converge on the same Malaysian sink or select different sinks as costs, capacities, and transport conditions change. Two Malaysian offshore sinks, MY-Sink 1 and MY-Sink 2, differ in their transport requirements, injection capacities, and commercial conditions. The export network contains four feasible routes: JP-Source 1–MY-Sink 1, JP-Source 1–MY-Sink 2, JP-Source 2–MY-Sink 1, and JP-Source 2–MY-Sink 2. A domestic Japanese storage alternative, JP-Domestic Sink, is also included to compare cross-border export with a non-export pathway. Figure 2 shows the network and Table 2 summarises the modelling role of each node and route.

Case-study data and parameterisation

Inputs are grouped as fixed engineering and country data, literature-derived benchmarks, anonymised system assumptions, derived route values, and scenario settings. Table 3 identifies each group's provenance, MILP role, and scenario dependence, distinguishing model inputs from contextual information.

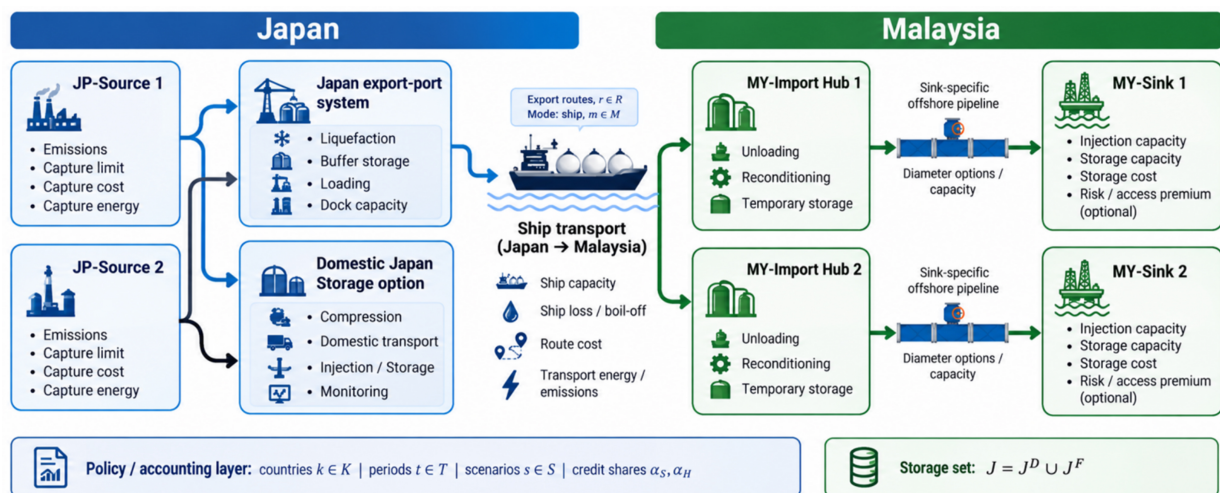


Figure 2. Cross-border CCS superstructure from Japan to Malaysia. CCS: Carbon capture and storage.

Table 2. Node descriptions in the Japan–Malaysia case study

Node/route	Description
JP-Source 1	Japanese CO ₂ source node 1
JP-Source 2	Japanese CO ₂ source node 2
MY-Sink 1	Malaysian offshore storage sink 1
MY-Sink 2	Malaysian offshore storage sink 2
MY-Import Hub 1	Malaysian import hub 1
MY-Import Hub 2	Malaysian import hub 2
Domestic Japan	Domestic Japan storage sink
JP-Source 1–MY-Sink 1	Export route from JP-Source 1 to MY-Sink 1
JP-Source 1–MY-Sink 2	Export route from JP-Source 1 to MY-Sink 2
JP-Source 2–MY-Sink 1	Export route from JP-Source 2 to MY-Sink 1
JP-Source 2–MY-Sink 2	Export route from JP-Source 2 to MY-Sink 2

Table 3. Classification, provenance, modelling role, and scenario dependence of case-study inputs

Parameter group	Parameters	Provenance	Model role
Source data	Emissions; capture limits	Literature-supported	Mass balance; capture limits
Capture	Cost; energy coefficient	Literature-supported	Cost; energy
Country	Electricity price; grid factor	Public data; proxy	Energy cost; emissions
Carbon policy	Penalty; credit value	Policy; market proxy	Cost; accounting
Domestic Japan	Compression; transport; storage; monitoring	Literature aggregate	Domestic pathway
Malaysian sinks	Capacity; injection; reservation	Anonymised assumptions	Storage constraints
Sink costs	Storage; injection	Literature-supported	Cost
Transport	Distance; cost; loss; emissions; pipeline	Assumed geometry; literature	Routing; cost; emissions
Commercial	Service fee; risk premium	Scenario assumptions	Cost; sink choice
Physical access	Import cap; minimum export	Scenario assumptions	Access constraints
Credit allocation	α source; α host	Hypothetical scenarios	Benefit allocation

Table 4. Source- and country-level case-study parameters

Model input	Value used	Unit	Basis	Reference
JP-Source 1 emissions	0.4	MtCO ₂ /year	Anonymised assumption	Case-study design
JP-Source 2 emissions	2.4	MtCO ₂ /year	Anonymised assumption	Case-study design
Maximum capture fraction	0.97	dimensionless	High-capture assumption	Bennæs et al. ^[9]
Capture cost	100.00	USD/tCO ₂	Industrial literature-range proxy	Yu et al. ^[14] ; Roussanaly et al. ^[15]
Capture electricity	0.100	MWh/tCO ₂	Physical emissions only; cost embedded	Beiron et al. ^[16]
Japan electricity price	86.00	USD/MWh	Japan cost input	Isogai et al. ^[17]
Malaysia electricity price	53.45	USD/MWh	Common host electricity-price proxy	Sarawak Energy ^[18]
Japan grid-emission factor	0.421	tCO ₂ /MWh	Official-data proxy	ANRE/METI ^[20]
Malaysia grid-emission factor	0.199	tCO ₂ /MWh	Common host-grid proxy for both anonymised sinks	Energy Commission Malaysia ^[21]
Japan credit value	18.62	USD/tCO ₂	Market proxy	JPX/TSE ^[22] ; Bank Negara Malaysia ^[23]
Malaysia credit value	12.32	USD/tCO ₂	Market proxy	Bursa Malaysia/BCX ^[24]
Japan carbon penalty	26.85	USD/tCO ₂	Explicit policy proxy	Policy context ^[19]
Malaysia carbon penalty	0	USD/tCO ₂	No verified numerical penalty applied	Case-study setting

Source- and country-level parameters

The annual source emissions are anonymised case-study assumptions: JP-Source 1 emits 0.4 MtCO₂/year, and JP-Source 2 emits 2.4 MtCO₂/year. The maximum capture fraction is 0.97, following a high-capture precedent in Bennæs et al.^[9]. The capture cost is set at USD100/tCO₂ as an industrial proxy within published capture-cost evidence^[14,15]. Capture electricity is set at 0.100 MWh/tCO₂^[16] and is used only for physical emissions. Japan's electricity price is USD 86/MWh^[17], while Malaysia's electricity price remains USD 53.45/MWh^[18]. Monetary values use USD 1 = MYR 4.06. Japan's carbon penalty is a stated policy proxy of USD 26.85/tCO₂^[19]; Malaysia is assigned zero. Table 4 distinguishes literature-based values, public-data proxies, and explicit case-study assumptions.

Storage-system parameters and domestic Japan benchmark

Domestic Japanese storage is represented as a screening pathway which compares export from capture at the source, transport through a 200 km onshore pipeline to injection, storage, and monitoring. The distance is an explicit case-study assumption, while the pipeline cost method, pipeline electricity, injection electricity, and storage-and-monitoring value are supported by published sources^[17,25–30].

The domestic downstream cost is USD 18.33/tCO₂. It comprises USD 4.11/tCO₂ of annualised pipeline construction, USD 0.11/tCO₂ of pipeline electricity, and the published Japanese storage-and-monitoring value of USD 14.10/tCO₂^[17]. Capture is added separately at USD 100/tCO₂. Combined Competitiveness uses a higher downstream value of USD 64.23/tCO₂; the same pipeline cost plus the USD 60/tCO₂ upper-end onshore storage value reported in the storage-cost literature^[28]. The higher value is used as a stress-test setting. Table 5 shows each component and calculation.

The energy boundary is kept consistent with the cost boundary. Capture electricity is not charged separately because it is already included in the all-inclusive capture cost. Domestic pipeline electricity is included in the downstream coefficient, and injection electricity is used to calculate physical emissions but is treated as embedded in the storage-and-monitoring value. No separate monitoring-electricity term is added because the cited Japanese benchmark does not report one; monitoring is retained within the monetary boundary described in the monitoring literature^[31]. This avoids inventing an unsupported coefficient and prevents double counting.

Table 5. Literature-supported domestic Japan benchmark inputs

Domestic component	Value used	Unit	Basis
Capture cost	100.00	USD/tCO ₂	Industrial literature-range proxy ^[14,15]
Capture electricity	0.100	MWh/tCO ₂	Physical emissions only ^[16]
Hypothetical pipeline distance	200	km	Case-study geometry; cost method ^[30]
Annualised pipeline construction	4.11	USD/tCO ₂	0.30-m pipeline; 7.5% capital charge ^[30]
Pipeline electricity	0.11	USD/tCO ₂	0.0013 MWh/tCO ₂ × USD86/MWh ^[17,25]
Storage and monitoring	14.10	USD/tCO ₂	Japan benchmark ^[17]
Base downstream total	18.33	USD/tCO ₂	Pipeline construction, electricity, storage and monitoring
Higher downstream total	64.23	USD/tCO ₂	Combined competitiveness only; upper storage range ^[28]

All calculations should be based on unrounded values.

Table 6. Malaysian sink capacities, availability, costs, and pipeline distances

Sink parameter	MY-Sink 1	MY-Sink 2	Unit	Basis
Total storage capacity	80	70	MtCO ₂	Anonymised assumption
Gross injection capacity	3.7	5.0	MtCO ₂ /year	Anonymised assumption
Domestic reservation	0	0	MtCO ₂ /year	Disabled in all reported cases
Foreign-available capacity	3.7	5.0	MtCO ₂ /year	Full stated injection capacity
Storage and injection	27.07	27.07	USD/tCO ₂	Composite proxy within offshore range ^[28,29]
Offshore-pipeline distance	190.6	205.8	km	Hypothetical geometry
Routine pipeline loss	0	0	fraction	No verified project coefficient applied

The two Malaysian sinks are represented separately because of distinct geological inventories, annual injection rates, and route characteristics. MY-Sink 1 has 80 MtCO₂ of storage and 3.7 MtCO₂/year of injection capacity; MY-Sink 2 has 70 MtCO₂ and 5.0 MtCO₂/year. These capacities are anonymised case-study assumptions.

Table 6 distinguishes geological storage inventory from annual injection availability. Total storage capacity limits the amount stored over the project horizon, whereas injection capacity limits annual throughput. Keeping these constraints helps to separate and prevent a large geological inventory from being interpreted as unlimited yearly injection. The Malaysian storage-and-injection coefficient is represented as a composite USD 27.07/tCO₂ proxy within published offshore-storage ranges^[28,29].

Transport and infrastructure parameters

Table 7 summarises the transport and infrastructure inputs. The anonymised route geometry produces shipping distances of 4,690.7–5,830.7 km and offshore-pipeline distances of 190.6 km to MY-Sink 1 and 205.8 km to MY-Sink 2. Each source–sink route has a separate shipping distance, variable cost, and loss factor. After unloading, the model applies sink-specific pipeline distance and capacity. This structure lets the MILP compare the cost and delivered CO₂ of each complete route instead of selecting a sink from distance alone.

Shipping loss is calculated from distance, ship speed, the 12-hour boil-off period, and the published boil-off assumption^[9]. The model values storage and credits using the amount that arrives after shipping loss. No routine offshore-pipeline loss is added in the numerical case. Port, line-haul shipping, pipeline construction, electricity, and storage services remain separate cost terms which make the route comparison auditable.

Table 7. Transport and infrastructure parameters

Transport/infrastructure input	Value used	Unit	Basis/supporting source
Ship speed	14	Knots	Bennæs et al. ^[9]
Ship boil-off rate	0.001	Fraction per 12-hour period	Bennæs et al. ^[9]
Shipping-emissions coefficient	0.013	tCO ₂ emitted/tCO ₂ transported	Approximately 1.3% ^[9]
Liquefaction cost	4.31	USD/tCO ₂	Roussanaly et al. ^[17] ; Bennæs et al. ^[9]
Reconditioning cost	1.56	USD/tCO ₂	Roussanaly et al. ^[17] ; Bennæs et al. ^[9]
Port-handling cost per terminal	0.20	USD/tCO ₂	Roussanaly et al. ^[17] ; Bennæs et al. ^[9]
Liquefaction electricity	0.134	MWh/tCO ₂	Isogai et al. ^[17]
Reconditioning electricity	0.00271	MWh/tCO ₂	Isogai et al. ^[17]
Shipping cost coefficient	0.00443	USD/(tCO ₂ ·km)	Case-study assumption; dataset ^[32] ; context ^[9,33–35]
Pipeline electricity	0.0000065	MWh/(tCO ₂ ·km)	Jaramillo et al. ^[25]
Injection electricity	0.007	MWh/tCO ₂	Ottenbros et al. ^[26]
Capacity of 0.10-m pipeline	35,100.83	tCO ₂ /month	Bennæs et al. ^[9]
Capacity of 0.15-m pipeline	78,961.67	tCO ₂ /month	Bennæs et al. ^[9]
Capacity of 0.20-m pipeline	140,342.50	tCO ₂ /month	Bennæs et al. ^[9]
Capacity of 0.30-m pipeline	315,785.83	tCO ₂ /month	Bennæs et al. ^[9]
Pipeline-construction correlation	0.533 + 0.019Q	Million EUR/km	Serpa et al. ^[30]
Construction-cost currency conversion	5.00	MYR/EUR	Fixed case-study financial assumption
Annual capital charge	7.5	%/year	Case-study financial assumption
Offshore-construction factor	2.0	Dimensionless	Serpa et al. ^[30]
Effective offshore-construction cost after factor	1.333–1.490	Million USD/km	Calculated from Serpa et al. ^[30] and stated currency assumptions
Maximum parallel pipelines per diameter	5	Pipelines	Non-binding numerical upper bound
Shipping-loss factor: JP1 → S1	0.0167	Fraction	Calculated from Bennæs et al. ^[9]
Shipping-loss factor: JP1 → S2	0.0187	Fraction	Calculated from Bennæs et al. ^[9]
Shipping-loss factor: JP2 → S1	0.0151	Fraction	Calculated from Bennæs et al. ^[9]
Shipping-loss factor: JP2 → S2	0.0169	Fraction	Calculated from Bennæs et al. ^[9]

The shipping-cost coefficient of USD 0.00443/(tCO₂·km) is treated as a case-study assumption informed by published CO₂ shipping-cost studies^[9,33–35], giving route-specific line-haul costs of USD 20.80–25.85/tCO₂ for the assumed shipping distances. Liquefaction, reconditioning, and terminal-handling costs are based on the component cost rates reported by Bennæs et al.^[9] which are € 3.50/tCO₂ for liquefaction, € 1.27/tCO₂ for reconditioning, and € 0.163/tCO₂ for loading or unloading. Under the model conversion basis of RM5/€, these correspond to RM 17.50, RM 6.35, and RM 0.82/tCO₂, respectively. Due to the handling occurring at both the export and import terminals, the total port-conditioning cost is RM 25.49/tCO₂. At the reporting exchange rate of RM 4.06/USD, this equals USD 6.2783/tCO₂. Therefore, the complete shipping-and-port range is USD 27.08–32.13/tCO₂ after calculation.

Pipeline construction uses the published flow–cost correlation^[30], MYR 5.00/EUR conversion, 7.5% annualisation, and a 2.0 offshore factor. The base cost of USD 0.666–0.745 million/km becomes USD 1.333–1.490 million/km offshore. Four diameter options (0.10–0.30 m) are used, with a non-binding limit of five parallel pipelines per diameter. Pipeline electricity is 0.0000065 MWh/(tCO₂·km) scaled from 6.5 kWh/tCO₂ over 1,000 km^[25], and injection electricity is 0.007 MWh/tCO₂^[26]. No separate pipeline variable-cost coefficient is used.

Export uses 0.134 MWh/tCO₂ for liquefaction in Japan and 0.00271 MWh/tCO₂ for reconditioning in Malaysia^[17]. These coefficients affect emissions, while their electricity costs remain embedded in the port costs. Pipeline and injection electricity are priced separately. Both anonymised sinks use the same host-country electricity price and grid-emission factor.

Engineering assumptions

Assumptions include the 200-km domestic pipeline, anonymised source and sink capacities, shipping cost coefficient, currency conversion, annual capital charge, and numerical pipeline limit. Literature-based energy and emission coefficients are listed in Table 7. All reported cases set the MY-Sink 1 reservation, sink premiums, Malaysian carbon penalty, and routine offshore-pipeline loss to zero.

Flows, energy use, variable costs, and accounting quantities are calculated on a monthly-average basis. Annual source emissions and injection capacities are divided by 12 before entering monthly constraints, while monthly operating terms are multiplied by 12 for annual reporting. Annualised fixed infrastructure costs are added once. This consistent conversion prevents fixed costs from being repeated and keeps every flow and capacity on the same time basis. Seasonal vessel schedules, outages, and changing monthly injectivity are outside the deterministic model.

The principal case-study inputs are summarised in the main manuscript, while the complete numerical dataset, source–sink route matrix, scenario-specific parameter settings, and parameter-provenance classification are available in the Zenodo repository^[32]. The all corresponding parameters are provided in the Supplementary Materials.

Scenario design

The scenario design is divided into four categories to represent the main decision dimensions in cross-border CCS, which include physical pathway selection, commercial and policy support, access constraints, and accounting allocation. This structure allows the analysis to examine how each dimension affects the economic competitiveness, CO₂ allocation, and distribution of verified-storage benefits between the source and host countries.

Reference pathways represent the two basic CCS options considered in the model, which are exporting CO₂ to Malaysia or storing it domestically in Japan. The commercial and policy-support scenarios then examine whether changes in economic conditions can improve the competitiveness of cross-border storage. The Low-Fee case reduces the Malaysian storage-service fee, while the Credit Support case introduces a storage-related credit benefit. Combined Competitiveness applies three favourable conditions together, which are a lower Malaysian storage-service fee, equal sharing of the storage credit between Japan and Malaysia, and higher domestic storage cost in Japan. Both domestic storage and export remain available, which allows the model to determine which pathway is preferred under these conditions.

The physical-access category examines whether an allocation requirement changes this decision. In the Forced Hybrid case, at least 1.0 MtCO₂/year must be exported to Malaysia, while the remaining CO₂ may still be stored in Japan. This represents a participation or access requirement.

The credit-allocation scenarios focus only on how the verified-storage benefit is shared between the two countries. The physical export system is kept unchanged, while the allocation parameters are varied. The Source Claim case assigns the full benefit to Japan ($\alpha_{\text{source}} = 1$), Shared Credit divides it equally (0.5, 0.5), and Host Claim assigns the full benefit to Malaysia ($\alpha_{\text{host}} = 1$). In all cases, $\alpha_{\text{source}} + \alpha_{\text{host}} = 1$ to ensure that the same storage benefit is counted only once. Credit Support and Combined Competitiveness use equal sharing between the two countries.

Table 8. Scenario categories, scenario names, settings, and analytical purposes

Scenario category	Scenario name	Pathway	Import cap (MtCO ₂ /year)	Min. export (MtCO ₂ /year)	MY fee (USD/tCO ₂)	Japan downstream cost (USD/tCO ₂)	Setting
Reference pathways	Base export	Export	8.7	0	12.32	NA	No credit; no reservation or premium
Reference pathways	Domestic Japan	Domestic	0	0	NA	18.33	200 km screening pathway
Commercial and policy support	Low fee	Export	8.7	0	6.16	NA	Lower Malaysian service fee
Commercial and policy support	Credit support	Export	8.7	0	12.32	NA	Credits; $\alpha_{\text{source}} = \alpha_{\text{host}} = 0.5$
Commercial and policy support	Combined competitiveness	Both	8.7	0	6.16	64.23	Low fee; shared credits; upper-end domestic cost
Physical-access constraints	Forced hybrid	Both	8.7	1.0	12.32	18.33	Minimum export requirement
Credit-allocation cases	Source claim	Export	8.7	0	12.32	NA	$\alpha_{\text{source}} = 1; \alpha_{\text{host}} = 0$
Credit-allocation cases	Shared 50:50	Export	8.7	0	12.32	NA	$\alpha_{\text{source}} = 0.5; \alpha_{\text{host}} = 0.5$
Credit-allocation cases	Host claim	Export	8.7	0	12.32	NA	$\alpha_{\text{source}} = 0; \alpha_{\text{host}} = 1$

No storage credit is applied in the Reference, Low-Fee, or Forced Hybrid cases. When the credit mechanism is enabled, the benefit for each tonne stored is calculated from the shares assigned to Japan and Malaysia and their respective credit values. The credit changes the economic value of storage but does not change the physical location of the stored CO₂. MY-Sink 1 reservation and sink risk premiums are set to zero in all reported scenarios. Table 8 summarises the inputs changed in each scenario; all other model inputs remain unchanged.

RESULTS AND DISCUSSION

Overall scenario performance and pathway selection

This section examines how changes in economic support, physical-access conditions, and credit allocation affect the total system cost and selected CCS configuration. Table 9 presents the selected pathway, storage sink, CO₂ flow, operational emissions, and annual objective cost according to the four scenario categories defined in Section “Scenario design”.

Under the reference assumptions, Base Export has an annual objective cost of USD 0.484 billion, compared with USD 0.327 billion for the Domestic Japan benchmark. Both pathways capture 2.716 MtCO₂/year. However, the export pathway stores 2.674 MtCO₂/year in Malaysia after shipping losses, whereas the domestic pathway stores the full captured amount in Japan.

Commercial and policy support reduces the cost disadvantage of cross-border storage. The Low-Fee, Credit Support, and Combined Competitiveness cases reduce the annual objective cost to USD 0.468 billion, USD 0.443 billion, and USD 0.426 billion, respectively. In the Combined Competitiveness case, the model selects full export to MY-Sink 1 instead of the upper-end domestic alternative available within that scenario.

Table 9. Overall outcomes by scenario

Panel A. Reference pathways, commercial and policy support, and physical-access constraints							
Scenario category	Scenario name	Objective cost (USD billion/year)	Export to MY (MtCO₂/year)	Domestic storage (MtCO₂/year)	Stored in MY (MtCO₂/year)	Selected sink	Operational emissions (MtCO₂/year)
Reference pathways	Base export	0.484	2.716	0	2.674	MY-Sink 1 (both sources)	0.393
Reference pathways	Domestic Japan	0.327	0	2.716	0	Not applicable	0.208
Commercial and policy support	Low-fee	0.468	2.716	0	2.674	MY-Sink 1 (both sources)	0.393
Commercial and policy support	Credit support	0.443	2.716	0	2.674	MY-Sink 1 (both sources)	0.393
Commercial and policy support	Combined competitiveness	0.426	2.716	0	2.674	MY-Sink 1 (both sources)	0.393
Physical-access constraints	Forced hybrid	0.397	1.000	1.716	0.985	MY-Sink 1	0.276
Panel B. Credit-allocation cases							
Scenario category	Allocation case	α source	α host	Credit benefit (USD million/year)	Objective cost (USD billion/year)	Physical pathway	Flow changed?
Credit-allocation cases	Source claim	1.0	0.0	49.79	0.434	Full export to MY-Sink 1	No
Credit-allocation cases	Shared 50:50	0.5	0.5	41.36	0.443	Full export to MY-Sink 1	No
Credit-allocation cases	Host claim	0.0	1.0	32.94	0.451	Full export to MY-Sink 1	No

All calculations should be based on unrounded values.

Nevertheless, its cost remains approximately USD 99 million/year above the base domestic screening benchmark. Therefore, the result demonstrates that export can become competitive under a coordinated set of favourable conditions, but it does not establish that export is universally cheaper than domestic storage.

All unconstrained export cases select MY-Sink 1 because it has the lower delivered transport cost. The Forced Hybrid case produces a different physical configuration because the minimum-export requirement prevents the model from selecting a fully domestic pathway. It exports 1.000 MtCO₂/year, of which 0.985 MtCO₂/year is stored in Malaysia after shipping losses, while the remaining 1.716 MtCO₂/year is stored in Japan.

Credit allocation changes the distribution and monetary value of the verified storage benefit without changing the physical route or storage location. The Source Claim, Equal Sharing, and Host Claim cases provide annual credit benefits of USD49.79 million, USD41.36 million, and USD32.94 million, respectively. Their corresponding objective costs are USD0.434 billion, USD0.443 billion, and USD0.451 billion. All three cases retain full export to MY-Sink 1. The lower objective under Source Claim occurs because the modelled source-country credit value is higher than the host-country value, rather than because of a change in the physical CCS system.

Overall, the results show that pathway selection depends on the combined effect of commercial conditions, policy support, and physical constraints. Fee reductions and carbon credits improve export competitiveness, while access requirements can directly change the allocation between domestic and cross-border storage.

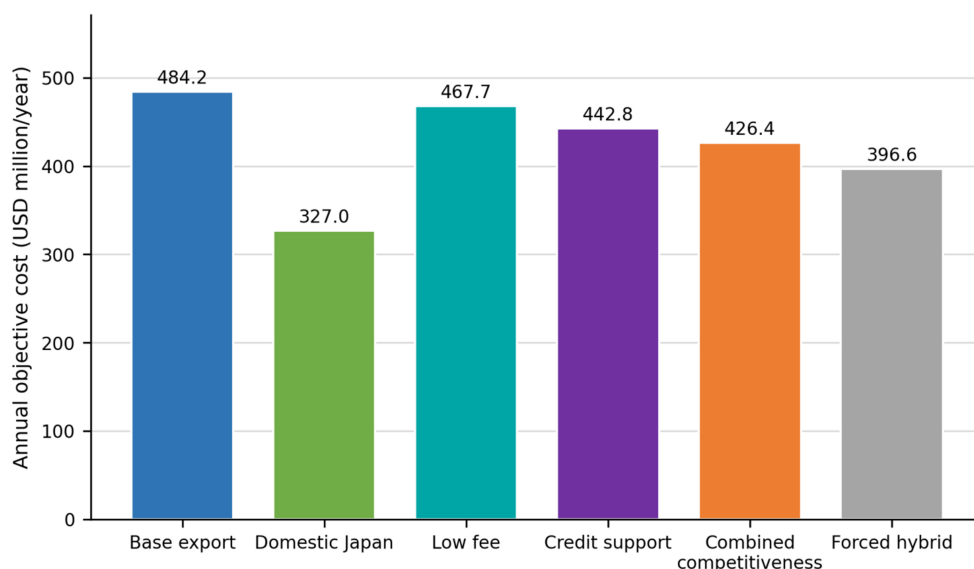


Figure 3. Annual objective cost across principal pathway scenarios.

Credit ownership mainly affects how the economic benefit is shared and does not, by itself, change the selected route. These comparisons should still be interpreted cautiously because domestic storage is represented by an aggregate screening benchmark, whereas the export network is modelled in greater physical detail. Therefore, the results support strategic comparison and identification of switching conditions, rather than a definitive project-level ranking of domestic and cross-border storage.

The emissions reported in Table 9 follow a matched operational boundary covering uncaptured CO₂, electricity-related emissions from capture, conditioning, pipeline transport and injection, and direct shipping emissions.

Economic competitiveness and cost drivers

This section examines the cost difference between domestic and cross-border storage, identifies the main cost components, and compares the modelled values with published CCS cost ranges. Figure 3 shows an annual objective cost of USD 484.19 million for Base Export and USD 326.96 million for Domestic Screening, which gives a difference of USD 157.23 million/year. The Low-Fee and Credit Support cases reduce the export cost to USD 467.72 million/year and USD 442.83 million/year, respectively. Combined Competitiveness further reduces the objective to USD 426.36 million/year and selects export over its upper-end domestic alternative of USD 64.23/tCO₂. However, the base domestic pathway, at USD 18.33/tCO₂, remains cheaper.

Figure 4 compares the objective-cost components per tonne of CO₂ captured. Capture contributes USD 100/tCO₂ in all three pathways. The net objectives are USD 178.27/tCO₂ for Base Export, USD 120.38/tCO₂ for Base Domestic Storage, and USD 156.98/tCO₂ for Combined Competitiveness. The lower service fee and shared carbon-credit benefit reduce the cost of the combined export case. Nevertheless, transport and host-country storage charges keep its objective above the base domestic benchmark.

Recent optimisation studies cover source–sink networks^[36], cluster and system abatement^[37], multi-period supply chains^[38–40], and industrial full-chain deployment^[41,42]. Figure 5 provides a scale check using studies with sufficiently comparable ranges, together with earlier transport and full-chain estimates^[9,15,17,28,43]. Cost

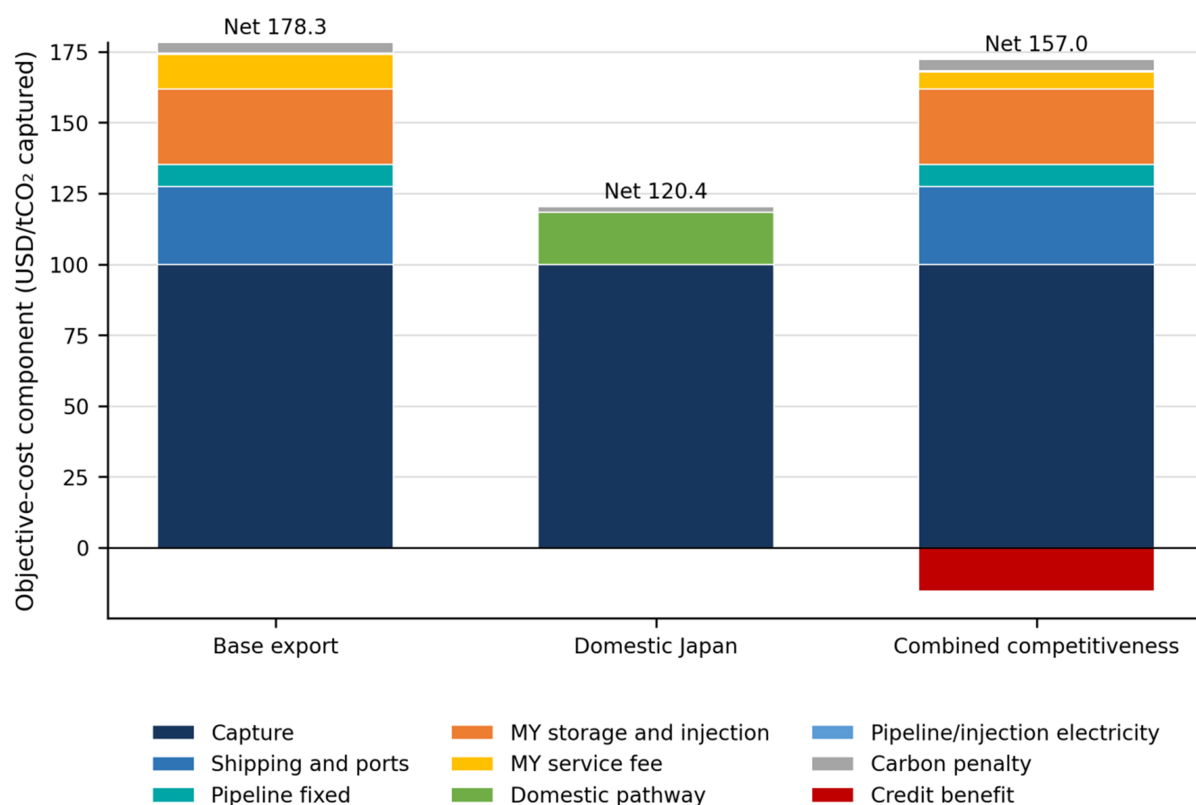


Figure 4. Cost-component decomposition of selected pathways on a common USD/tCO₂-captured basis.

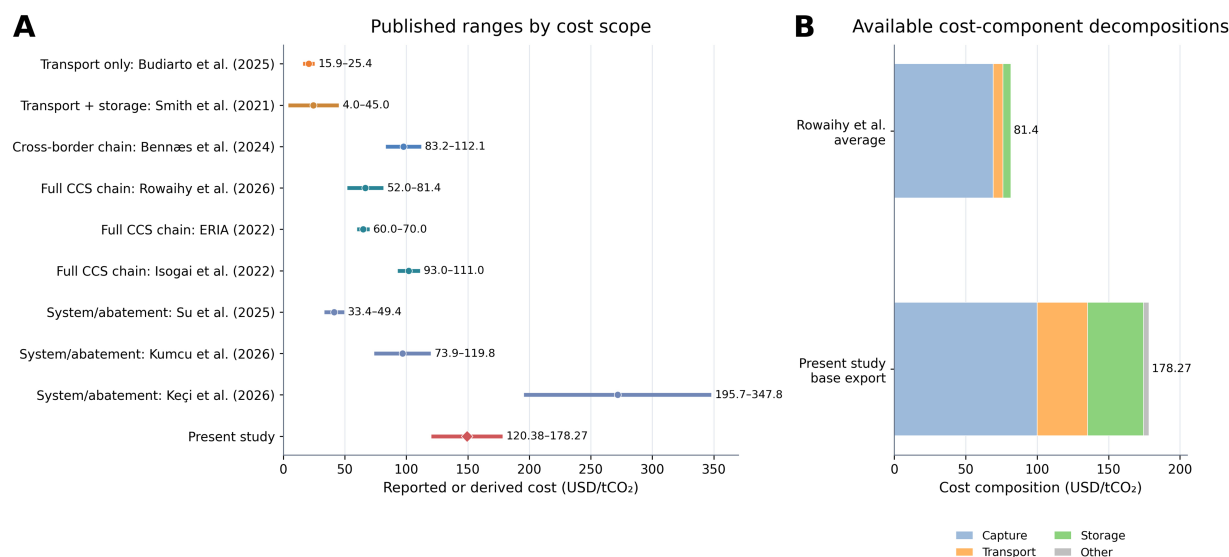


Figure 5. Published CCS/CCUS cost benchmarks by scope and available cost composition. (A) Published ranges by cost scope; (B) Available cost-component decompositions. CCS: Carbon capture and storage; CCUS: Carbon capture, utilisation and storage.

scopes differ, so transport-only estimates cannot be ranked directly against objectives that include capture, conditioning, infrastructure, storage, penalties, and credits.

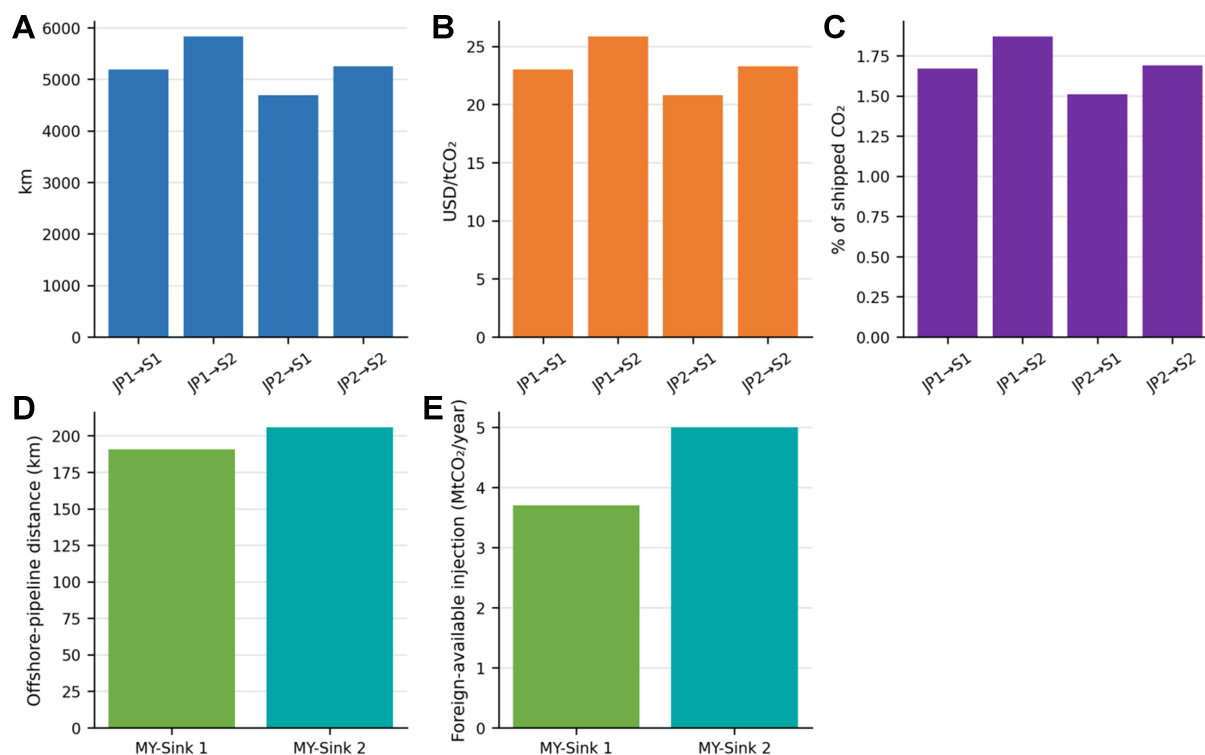


Figure 6. Route and sink performance for the two Japanese sources and Malaysian sinks. (A) Shipping distance; (B) Shipping cost; (C) Shipping-loss factor; (D) Offshore-pipeline distance; (E) Foreign-available injection capacity.

Overall, the results indicate that commercial and policy support can substantially reduce the cost of cross-border CCS, but it does not automatically make export cheaper than the lowest domestic benchmark. The Combined Competitiveness result is best interpreted as evidence of conditional competitiveness in which export becomes the preferred decision only when it is compared with the upper-end domestic alternative under the same scenario. The published ranges support the order of magnitude of the modelled costs, but these do not validate an exact project cost because the estimates depend on source type, transport distance, system capacity, financing assumptions, energy boundaries, and price year. Across the three pathways presented in Figure 4, capture remains the largest single positive cost component.

Network configuration, route and sink selection

Transport and storage characteristics influence route and sink selection. These include shipping distance, line-haul cost, shipping loss, offshore-pipeline distance, and injection capacity. In the Base Export case, both sources deliver CO₂ to MY-Sink 1. Of the 2.716 MtCO₂/year exported, 2.674 MtCO₂/year is stored after a shipping loss of 1.53%. Compared with MY-Sink 2, the route to MY-Sink 1 is 638.3 km shorter and USD2.83/tCO₂ cheaper for JP-Source 1. For JP-Source 2, it is 561.2 km shorter and USD2.49/tCO₂ cheaper. The offshore pipeline serving MY-Sink 1 is also 15.2 km shorter. MY-Sink 1 receives 2.674 MtCO₂/year, which remains below its injection capacity of 3.7 MtCO₂/year. MY-Sink 2 provides a higher injection capacity of 5.0 MtCO₂/year but is not selected because its additional capacity is unnecessary at the modelled flow and does not offset its higher transport cost. Figure 6 compares the route and sink attributes.

Overall, the result shows that lower delivered transport cost determines sink selection when both sinks have sufficient capacity and share the same storage assumptions. However, MY-Sink 2 may become preferable at higher CO₂ flows, under tighter capacity conditions, or if its relative transport and storage costs decrease. Therefore, the selection of MY-Sink 1 should be interpreted as a result of the current case-study configuration.

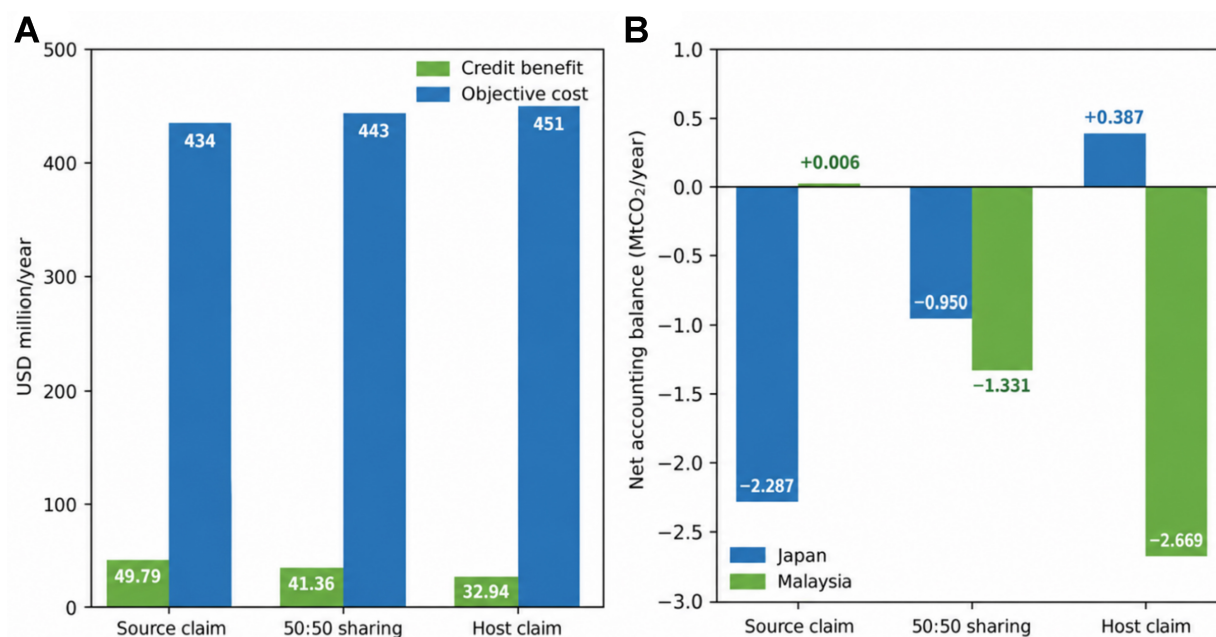


Figure 7. Economic and country-level accounting effects of source–host credit allocation (A) Economic effect; (B) Country-level accounting effect. Accounting balances are calculated from unrounded model outputs and displayed values may not sum exactly because of rounding.

Source–host credit allocation and accounting outcomes

This section explores how alternative credit-sharing arrangements affect the economic benefit and country-level accounting outcomes without changing the physical CCS system. All three α cases physically store 2.674 MtCO₂/year in Malaysia at MY-Sink 1. The Source Claim, Equal Sharing, and Host Claim cases provide annual credit benefits of USD49.79 million, USD41.36 million, and USD32.94 million, respectively. Their corresponding annual objective costs are USD0.434 billion, USD0.443 billion, and USD0.451 billion. The difference arises because Japan has a higher modelled carbon-credit value than Malaysia. Therefore, the allocation of a larger share to Japan produces a greater economic benefit and a lower system objective.

Figure 7 separates physical emissions, allocated storage credit, and the resulting net accounting balance. Under Source Claim, the net balances for Japan and Malaysia are -2.287 and +0.006 MtCO₂/year, respectively. Under Equal Sharing, the corresponding balances are -0.950 and -1.331 MtCO₂/year. Under Host Claim, the net balances become +0.387 and -2.669 MtCO₂/year. In every case, the CO₂ remains physically stored in Malaysia, and only the ownership and monetary value of the accounting benefit change.

Overall, the results show that credit allocation can materially affect the distribution of economic and accounting benefits even when the physical route, storage sink, and stored quantity remain unchanged. The lowest objective under Source Claim reflects Japan’s higher assumed credit value, not a more efficient physical configuration.

Physical CO₂ allocation and quantified emissions

A matched operational boundary is applied to compare the emissions generated by domestic, export, and hybrid CCS pathways. The resulting operational emissions are 0.208 MtCO₂/year for Domestic Storage, 0.393 MtCO₂/year for Base Export, and 0.276 MtCO₂/year for Forced Hybrid. Base Export produces the highest operational emissions, mainly because it requires liquefaction electricity and long-distance shipping. Infrastructure-construction emissions and other full life-cycle effects are excluded from this comparison.

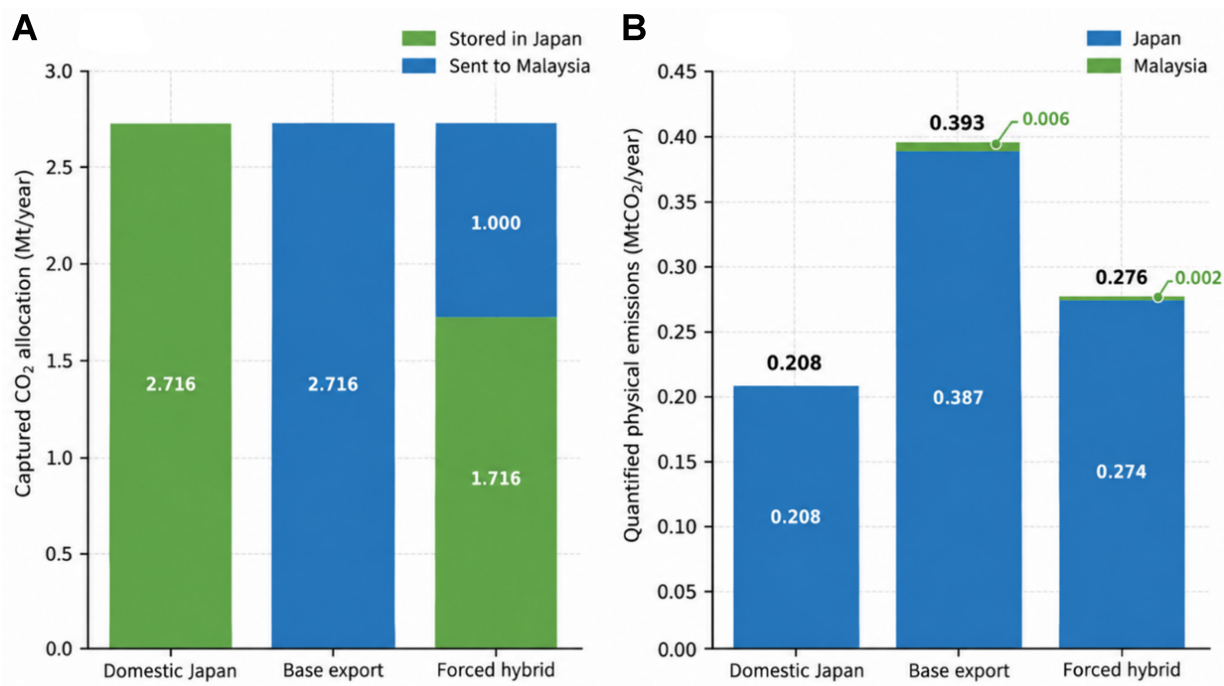


Figure 8. Physical CO₂ allocation and matched-boundary operational emissions. (A) Domestic and export allocation; (B) Quantified operational emissions by country.

The Domestic Japan pathway stores the full captured quantity of 2.716 MtCO₂/year. Base Export sends 2.716 MtCO₂/year to Malaysia and stores 2.674 MtCO₂/year after shipping losses. Forced Hybrid exports 1.000 MtCO₂/year, of which 0.985 MtCO₂/year is stored in Malaysia, while the remaining 1.716 MtCO₂/year is stored in Japan. Figure 8 distinguishes the amount allocated to each pathway, the quantity reaching storage, and the associated operational emissions.

Overall, cross-border export achieves substantial CO₂ storage but produces higher operational emissions and slightly lower delivered storage because of additional conditioning, shipping, and transport losses. Forced Hybrid lies between the fully domestic and fully exported pathways because it uses both systems. These results show the operational trade-off between accessing foreign storage and the additional energy and emissions required for cross-border transport.

Sensitivity analysis

The sensitivity analysis evaluates both cost responsiveness and decision stability around the Combined Competitiveness case. Figure 9 illustrates one-at-a-time (OAT) objective-cost responses. The reference applies a USD 6.16/tCO₂ service fee, equal source–host credit shares, and a domestic downstream cost of USD 64.23/tCO₂, while the domestic reservation and sink-specific premiums are set to zero.

Five inputs are varied separately by $\pm 10\%$: shipping cost, domestic pathway cost, country-specific credit values, service fee, and Malaysian storage-and-injection cost. In the credit test, the Japanese and Malaysian credit values change together by the same percentage. Each endpoint represents a separate MILP optimisation in which only one input changes, while all other inputs and scenario settings remain fixed.

The reference solution selects full export of 2.716 MtCO₂/year to MY-Sink 1, with an annual objective cost of USD 426.358 million. Malaysian storage-and-injection cost produces the largest endpoint range at USD 14.478 million/year. This is followed by shipping cost at USD 11.469 million/year, credit values at USD 8.273

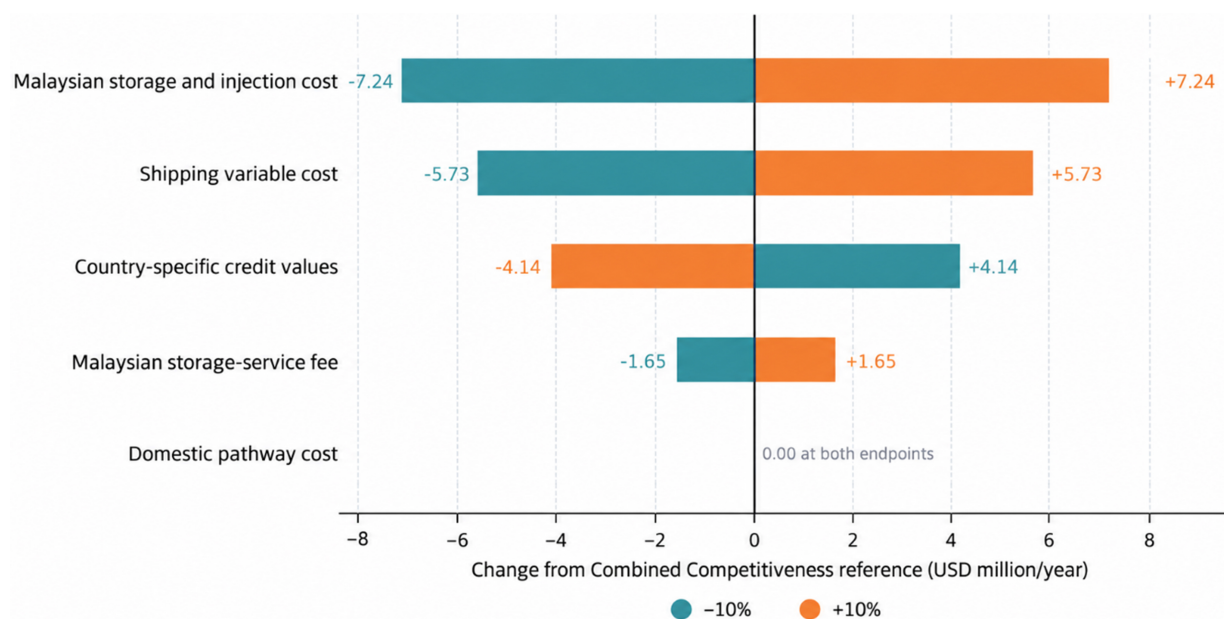


Figure 9. Combined competitiveness $\pm 10\%$ OAT objective-cost response. Each bar connects the -10% and $+10\%$ endpoints relative to the reference objective. OAT: One-at-a-time.

million/year, and the service fee at USD 3.294 million/year. Higher credit values reduce the objective because the credit is treated as an economic benefit. Domestic pathway cost has no local effect because the model retains full export at both endpoints.

None of the $\pm 10\%$ changes alter the selected pathway or sink; every optimisation continues to select full export to MY-Sink 1. This indicates that the Combined Competitiveness decision is locally stable within the tested ranges. However, the result does not show that the decision would remain unchanged under larger variations or simultaneous changes in several inputs. The zero response to domestic cost also does not mean that domestic cost is generally unimportant, as it remains inactive within this limited range.

Overall, the OAT analysis identifies the inputs that have the strongest local effects on the optimised cost and tests whether moderate individual changes alter the infrastructure decision. As a local analysis within a deterministic MILP, it does not account for probability distributions, correlations between uncertain inputs, or combined uncertainty. Wider-range, multi-parameter, or probabilistic analyses would be required to identify switching thresholds and assess broader decision risk.

CONCLUSION

This study develops an integrated MILP framework that links CCS pathway, route and sink selection with cost, operational emissions, and source–host credit allocation. Under the reference assumptions, base domestic storage costs USD 0.327 billion/year, compared with USD 0.484 billion/year for base export. The Combined Competitiveness case selects full export to MY-Sink 1 at USD 0.426 billion/year when compared with the upper-end domestic alternative, although it remains more expensive than the base domestic screening benchmark. Malaysian storage and injection costs, shipping costs, and carbon-credit values have the largest local effects on the objective, while the selected export pathway remains stable within the tested $\pm 10\%$ ranges. Credit allocation changes the distribution of economic and national accounting benefits without changing the physical route or storage location. Future work should apply project-specific data, model domestic and export networks at equal resolution, examine joint uncertainty and switching thresholds, and develop monitoring-linked rules for sharing verified storage benefits.

DECLARATIONS

Authors' contributions

Conceptualization, investigation, data curation, formal analysis, writing - original draft: Ting, J. Z. Z.; Lim, J. S. Methodology, validation, supervision, writing - review and editing: Ting, J. Z. Z.; Lim, J. S. Writing - review and editing: Wan Alwi, S. R.; Abdul Manan, Z.; Wang, B.; Gai, L.

Availability of data and materials

The supporting dataset and model files are available in the Zenodo repository^[32].

AI and AI-assisted tools statement

During the preparation of this manuscript, OpenAI ChatGPT (GPT-5.6, released 2026-07-09) was used to assist with language editing, produce the graphical abstract, and refine [Figures 1](#) and [2](#). The AI tool did not influence the study design, data collection, mathematical formulation, model implementation, numerical analysis, interpretation of results, or the scientific conclusions of the work. All AI-assisted content was reviewed, verified, and revised by the authors, who take full responsibility for the final manuscript.

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Conflicts of interest

All authors declared that there are no conflicts of interest.

Ethical approval and consent to participate

Not applicable.

Consent for publication

Not applicable.

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Supplementary Materials

[Supplementary Materials](#)

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