CO_2 transport and storage feasibility and cost study for ASEAN

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Highlights:

- Plenty of storage capacity identified in ASEAN to fulfill the region's CCS needs
- A handful of high-quality reservoirs identified to serve as sequestration hubs
- Cost for new-build CO_2 transport and sequestration from Singapore range from US$48-$450 per ton
- National and international policy and regulatory frameworks needed for regional CCS

Abstract

Carbon Capture and Storage (CCS) technology is expected to a play a significant role in reducing CO_2 emissions globally. The first steps for successful deployment include identifying CO_2 storage potential, determining CO_2 injection rates, evaluating of CO_2 transport options, estimating associated costs, and facilitating policy and regulatory frameworks. To evaluate the CCS feasibility in Southeast Asia, we first identify the CO_2 storage sites in several member countries of the Association of Southeast Asian Nations (ASEAN). Storage potential is estimated at 11.7 Gt in 234 oil and gas fields, 24.2 Gt in 42 field-scale saline formations, and 275 Gt in basin-scale saline formations. Using the hydrocarbon production data, we calculate the CO_2 injection rates in 126 fields and find that 23% of the evaluated fields support injection rates greater than 0.4 Mt/well/year. We evaluate two types of CO_2 transportation solutions: via pipeline and via shipping. Our case study with CO_2 sourced from Singapore and transported to regional sequestration sites shows strong technical feasibility with transport and storage costs ranging from US$48/ton to US$450/ton. We assess the policy environment of selected countries in ASEAN and suggest potential pathways to enable robust CCS supply chains.

Introduction

As the global population continues to grow and societies pursue economic prosperity for their citizens, the demand for access to affordable energy has never been greater. Energy is essential for human development, improving quality of life, greater life expectancy, reducing poverty and leading to higher levels of education. This is particularly true of Southeast Asia, where economic development and energy demand growth is expected at a faster pace compared to OECD nations (IEA, Southeast Asia Energy Outlook 2019). Although there is a long history of hydrocarbon production in Southeast Asia, the challenge is to satisfy this growing energy demand while reducing the risks of climate change.

Numerous technologies have potential to help society address this dual challenge. Technical advancements have already significantly improved energy efficiency and helped unlock diverse and abundant sources of energy. No technology or energy type can be ignored. Instead, the world must harness a variety of energy sources and technology advances, guided by policies that fully reflect the costs and benefits, consumer preferences and the need to provide affordable energy for all.

To achieve the Paris Agreement's goal of limiting global temperature rise to 2^0C above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5^0 C, require substantial and rapid reductions in greenhouse gas (GHG) emissions. Among the 38 Gt of global carbon dioxide (CO_2) emission today, 1.5 Gt comes from Southeast Asia. To meet the sustainable development target, Southeast Asia would need to cumulatively reduce CO_2 emission by 13 Gt between 2019 and 2040 (IEA, Southeast Asia Energy Outlook 2019). Carbon Capture and Storage (CCS) technology is expected to a play a significant role in this effort. The United Nations Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA) agree that CCS is one of the most important low-carbon technologies required to achieve societal climate goals (IPCC 2018, IEA 2020). CCS is also one of the few technologies that could enable decarbonization of some of the more challenging carbon-intensive industries such as refining, chemicals, cement, and steel sectors.

One of the first steps to evaluate regional CCS options is to identify and determine the storage potential of suitable geological formations. Several studies of CO_2 storage have been performed in North America (NETL 2015) (Brennan 2010), Europe (Poulsen, et al. 2014), Australia (Carbon Storage Taskforce 2009), and China (Dahowski, et al. 2009). However, CO_2 storage studies in Southeast Asia have been limited to-date. The Asia-Pacific Economic Cooperation (APEC) (APEC 2005) assessed storage potential in a few selected basins in Indonesia, Malaysia, and Thailand, in which a total volume of 7.8 Gt was reported. In a global study, IEAGHG (IEAGHG, 2009) provides CO_2 storage estimate of about 25 Gt in depleted oilfields in Indonesia, Malaysia, and Brunei, with a strong emphasis on enhanced oil recovery. The World Bank (World Bank 2015) conducted a study to update storage capacity in Indonesia and identified about 2.0 Gt of storage capacity in both saline aquifers and depleted oil and gas (O&G) fields in select basins. Hedriana et al. (Hedriana, Sugihardjo and Usman 2017) estimate about 1.2 Gt of total storage capacity in the O&G fields and about 14.8 Gt in saline formations in the South Sumatra and Java basins. Several other researchers (Iskandar, Usman and Sofyan 2013), (Choomkong, et al. 2017), and (Minh and Hoang 2017) estimated storage capacities in Indonesia (600 Mt), Thailand (2.3 Gt), and Viet Nam (1.2 Gt), respectively. Hasbollah et al. (Hasbollah 2019) studied the CO_2 storage potential of Malay basin and concluded that about 84 to 114 Gt of storage capacity exists in the Malay basin alone. The most comprehensive study from the Asian Development Bank (ADB 2013) documents the storage potential in four Association of Southeast Asian Nations (ASEAN) member countries, namely Vietnam, Thailand, Philippines, and South Sumatra in Indonesia. This study estimates about 50 Gt of storage in saline formations and 3.5 Gt storage in depleted O&G fields in the four selected countries. However, the ADB study is limited by its selection of the four countries, notably excluding Malaysia and much of Indonesia that potentially have significant storage capacity both in their depleted O&G fields and in their massive sedimentary basins. Furthermore, the ADB estimated storage capacity in depleted O&G fields appears small, suggesting that all available data may not have been used. Existing studies reported storage capacities that vary widely with respect to each other, due to issues such as different data sources, different screening criteria, and different methodologies for storage estimation. Results of many of these studies are not reproducible, making their evaluation challenging and qualitative. In addition, very few storage screening studies considered injectivity of the storage sites, resulting in large uncertainties in their engineering and economic feasibility.

Moreover, a regional CCS feasibility study requires a holistic approach including CO_2 emission sources, CO_2 transportation and storage, as well as overall economic feasibility. Assuming concentrated industrial CO_2 are captured from known point sources, the cost of which is excluded from this study, transportation options and injectivity at the storage sites play the key role in determining the cost of the CCS project. The ADB study (ADB 2013) performed source-sink matching within the geographic boundary of each selected country, primarily based on distance and availability of existing pipeline infrastructures. In contrast, a hub approach based on overall evaluations of regional resources has the potential to enable faster and more efficient use of shared infrastructure for large-scale CCS projects. Similarly, although some countries have made progress to regulate and facilitate investments in CCS within their own boarders, an international regulatory framework as well as legislative and financial support are still lacking.

Aiming to provide quantitative assessment options for CCS in the ASEAN region, we extract comprehensive O&G production data, select suitable hydrocarbon fields based on straightforward screening criteria, and provide different levels of CO_2 storage capacity estimation as well as injectivity estimation at the hydrocarbon fields based on consistent, robust, and hence fully reproducible methodologies. Inspired by the recent developments in shipping concepts and technologies, we consider flexible CO_2 transport by pipeline and ship, perform a high-level techno-economic analysis over the transport-storage-monitor project workflow, and present a case study to link Singapore emissions with potentially suitable storage sites across the ASEAN region. Finally, we provide a high-level overview of current policies and aspirations of select countries within ASEAN in order to assess gaps in the policy and regulatory framework needed to catalyze and sustain a robust CCS supply chain within ASEAN. By making the data and source information publicly available, we hope to improve the technical readiness, facilitate regional policy making, and foster a collaborative ecosystem for CCS in Southeast Asia.

CO_2 storage capacity estimation

We evaluate the storage capacity in two categories: depleted O&G reservoirs and saline formations (at field scale and basin scale) as shown in Figure 1. Although the methodologies for the two categories are both volumetric analyses, the underlying methods are different. When estimating storage capacity in depleted O&G reservoirs, we consider a pore fluid replacement process where the injected CO_2 is expected to reoccupy the pore space from which the hydrocarbons were produced. Efficiency of such pore volume replacement can be highly variable (40% - 95%) depending on the hydrocarbon type and the reservoir rock properties. For each selected field, we have accessed extensive subsurface data from multiple sources including C&C Reservoir Reports (C&C Reservoirs 2021), Wood Mackenzie's databases (Wood Mackenzie, Wood Mackenzie Asset Search 2021, Wood Mackenzie, Wood Mackenzie Upstream DataTool 2021) and published literature for reservoir physical properties and hydrocarbon production information. Such data include maps, seismic sections, geological interpretations, pressure, temperature, drilling and production histories. The CO_2 storage estimates for depleted O&G reservoirs derived from production data combined with subsurface reservoir data provide the most reliable storage estimates as they are based on replacing the known volume of produced hydrocarbons. These storage options are also potentially the most accessible for project development in the near future, particularly for those fields that are at or near end of field life, although further due diligence will be required to confirm suitability as challenges may exist including wellbore integrity due to reservoir depletion, reservoir compaction and associated subsidence, among others. In addition, we estimate the injectivity of CO_2 based on peak production data. A simple cost model is then used to estimate the cost of storage, including injection, monitoring, and abandonment costs.

When estimating storage capacity in saline formations, we focus on estimating the accessible pore volume which is a small fraction of the total theoretical pore space. When CO_2 is injected into the saline formation, the storage potential depends on structural trapping, dissolution, residual trapping, and reservoir connectivity relevant for potential pressure buildup. The limited well-formation contact, the small density difference between CO_2 and water, and the heterogeneity of the reservoir formation could significantly reduce the storage efficiency in saline formations to 1% - 10% of the total pore volume (Bachu 2015). To account for different degrees of uncertainty, we estimate storage capacity in saline formations at two different scales: field scale and basin scale.

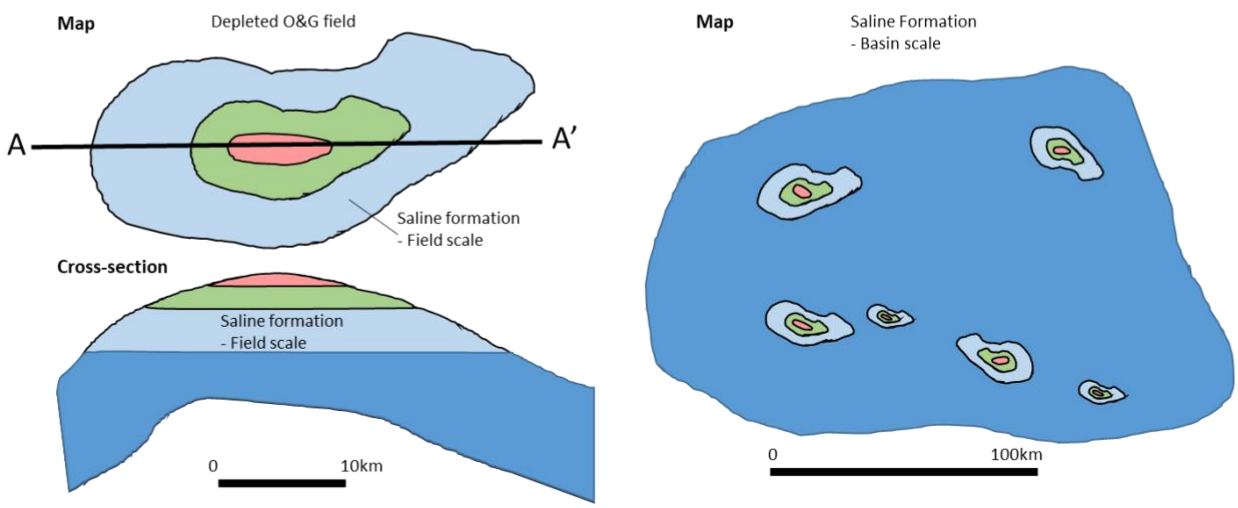


Figure 1: Schematic depiction of the field scale O&G reservoir along with field and basin scale saline formations. The basin scale is orders of magnitude larger than the field scale.

Most hydrocarbon field reservoirs are connected to saline formations down dip and beneath the hydrocarbon-water contact that span a much wider area (see Figure 1). Such connectivity helps hydrocarbon production as the pressurized water within these bounding aquifers provides additional pressure support, increasing hydrocarbon recovery in oil reservoirs. A strong aquifer drive during production indicates better connectivity and communication between the hydrocarbon reservoir and the larger aquifer, allowing for pressure dissipation during CO_2 injection. The proximity of such aquifers to the depleted hydrocarbon reservoirs could enable shared or repurposing of existing infrastructure providing potential for reduced storage costs. We estimate the size of the reservoir-associated saline formations at the field scale based on the production area, the strength of aquifer drive support and additional geological information. The reservoir properties from the fields are extrapolated and considered to be representative of the connected saline formations. Albeit less certain, CO_2 storage capacity estimated in the saline formations at the field scale provides a good approximation of the total storage volumes that are accessible in known hydrocarbon fields.

It is estimated that CO_2 storage potential in regional saline formations is orders of magnitudes larger than that in the O&G fields (Bachu 2001). Based on regional geological models and reservoir distribution maps, we average and extrapolate the average reservoir properties from well measurements at the limited scattered field locations across the basin in order to estimate the storage potential at the whole basin scale. Although highly uncertain, such theoretical estimation offers important insights into the physical limits of the pore volume that may be available for large-scale long-term storage projects.

For each of the three types of storage, in depleted O&G fields, in field-scale saline formations, and in basin-scale saline formations, we provide two estimates: the conservative estimate and the optimistic estimate. The range spanned by the two estimates reflects overall uncertainty in storage estimates. We detail the methodologies and the results for these two estimates for different storage types in the subsequent sections.

CO_2 storage capacity in depleted O&G reservoirs

Methodology

Based on the reliable production data from the O&G reservoirs, we adapt the USGS methodology (Brennan 2010) to convert production data to CO_2 storage capacity. We estimate the conservative CO_2 storage capacity (SC_{csv}) assuming the pore space occupied by the produced O&G can be replaced by CO_2:

$$\mathrm{SC}_{csv} = \left(\mathrm{E}_{\mathrm{oil}}^{min} * KR_{oil} * FVF_{oil} + \mathrm{E}_{\mathrm{gas}}^{\mathrm{min}} * KR_{gas} * FVF_{gas}\right) * \rho_{CO_2},$$

where KR_{oil} and KR_{gas} are the known produced volumes of oil and gas, approximated by the estimated ultimate recovery (EUR) volume of oil and gas, respectively; FVF_{oil} and FVF_{gas} are the formation volume factors, accounting for the volume changes of oil and gas between the reservoir and surface conditions, respectively; $\mathrm{E}_{\mathrm{oil}}^{min}$ and $\mathrm{E}_{\mathrm{gas}}^{\mathrm{min}}$ are the minimum CO_2 storage efficiency factors in the depleted oil and gas zones, respectively. ρ_{CO_2} is the CO_2 density at reservoir conditions. FVF_{oil} is strongly affected by the dissolved gas in the oil, ranging from 1.2 to 2.2 in the O&G fields in the ASEAN region (Gharbi and Elsharkawy 2003). The large FVF_{oil} in many cases are caused by associated dissolved gas contained in the reservoir. FVF_{gas} and ρ_{CO_2} are both determined by the temperature (T) and pressure (P) at the given reservoir depth. With a higher geothermal gradient in ASEAN region, we often observe higher reservoir temperature compared to the O&G fields in the United States, North Sea, and many other places around the world. We use the CO_2 density handbook (Anwar and Carroll 2016) to derive ρ_{CO_2}. Subsequently, we use the density ratio between surface CO_2 ($\rho^0_{CO_2}$) and reservoir CO_2 (ρ_{CO_2}) as a good approximation for the $FVF_{gas} = \rho^0_{CO_2}/\rho_{CO_2}$.

The total quantity of crude oil estimated in the reservoir before production or oil initially in place (OIIP) is significantly larger than the estimated ultimate recoverable quantity $(\mathrm{EU}R)_{oil}$. Data show that the median recovery factor ($\mathrm{EU}R_{oil}/\mathrm{OIIP}$) is around 40% in the ASEAN region and it may be possible to increase this recovery factor with enhanced oil recovery (EOR) technology. We use an optimistic recovery rate (ORR) between 65% and 75%. Since the current average recovery rate for gas is already close to 80%, we assume that the ORR is 100% for gas reservoirs. Therefore, we use the following equation to estimate the optimistic CO_2 storage capacity:

$$SC_{opt} = \left(\mathrm{E}_{\mathrm{oil}}^{\mathrm{max}} * ORR * OIIP * FVF_{oil} + \mathrm{E}_{\mathrm{gas}}^{\mathrm{max}} * GIIP * FVF_{gas}\right) * \rho_{CO_2}.$$

Many factors determine storage efficiency for depleted O&G reservoirs. Compared to the depleted oil reservoirs, depleted gas reservoirs are often considered uninvaded by the aquifer water because the remaining gas in place can expand to fill the voided volume. As such the injected CO_2 can simply reoccupy the produced gas pore volume by recompressing the remaining gas restoring the reservoir pressure. Therefore, the efficiency factor for depleted gas reservoirs $\mathrm{E}_{\mathrm{gas}}$ is set between 0.9 and 1. In contrast, estimation of storage efficiency for depleted oil reservoirs $\mathrm{E}_{\mathrm{oil}}$ is significantly more challenging, depending on the applications of enhanced oil recovery (EOR) technology (water flood or other EOR method), and reservoir conditions after depletion (whether or not invaded by aquifer water). Besides the known EOR history, we determine the efficiency factor in the oil zone based on the aquifer drive felt during production. If an oil reservoir is strongly supported by its associated aquifer, it is more likely to be invaded by aquifer water after production. Table 1 summarizes the efficiency factors we use in this study.

Table 1: Efficiency factors for CO2 storage estimation in depleted oil (Eoil) and gas (Egas) reservoirs.

Reservoir type	Aquifer drive	E^{Min}	E^{Max}
Oil	Default	0.3	0.9
	Weak	0.8	0.9
	Normal	0.4	0.6
	Strong	0.3	0.4
Gas	Default	0.9	0.95

Data sources, field screening, and workflow

We mainly use data from two sources: C&C Reservoirs' reports (C&C Reservoirs 2021) and the Upstream O&G database from Wood Mackenzie (Wood Mackenzie 2021). C&C Reservoirs' reports provide detailed information, including all reservoir parameters discussed above, porosity, permeability, drilling history, O&G production history, geological sections and maps, as well as other relevant information concerning reservoir quality, distribution and connectivity. The C&C Reservoirs' reports cover 62 of the fields assessed in the ASEAN region. The Wood Mackenzie database provides succinct summaries of cost, production, reserves, and economics data for more than 2700 fields in the region. Additional data are also obtained including numbers of field development wells and peak production rates from selected Wood Mackenzie Asset Reports. To fill in missing data entries for a small number of fields, we search published literature and openly available databases. We set the following four screening criteria to select potential fields for further analysis:

1. Fields are either on-shore, or off-shore in water depths of less than 150 meters.
2. Fields are either onstream or have ceased production.
3. Pressure and temperature of the main producing formations are within the ranges required for supercritical CO_2.

4. We only considered fields with CO_2 storage capacity > 5 Mt. This cutoff is set at 0.5 Mt for the Philippines given the typically smaller fields found there.

The application of above criteria reduces the number of suitable fields from 2782 to 234. We then calculate the storage capacity using the USGS methodology outlined in the previous subsection. When field-specific pressure and temperature data are not available, regional pressure and geothermal gradients from basin-scale data are used. The screening workflow is summarized in Figure 2.

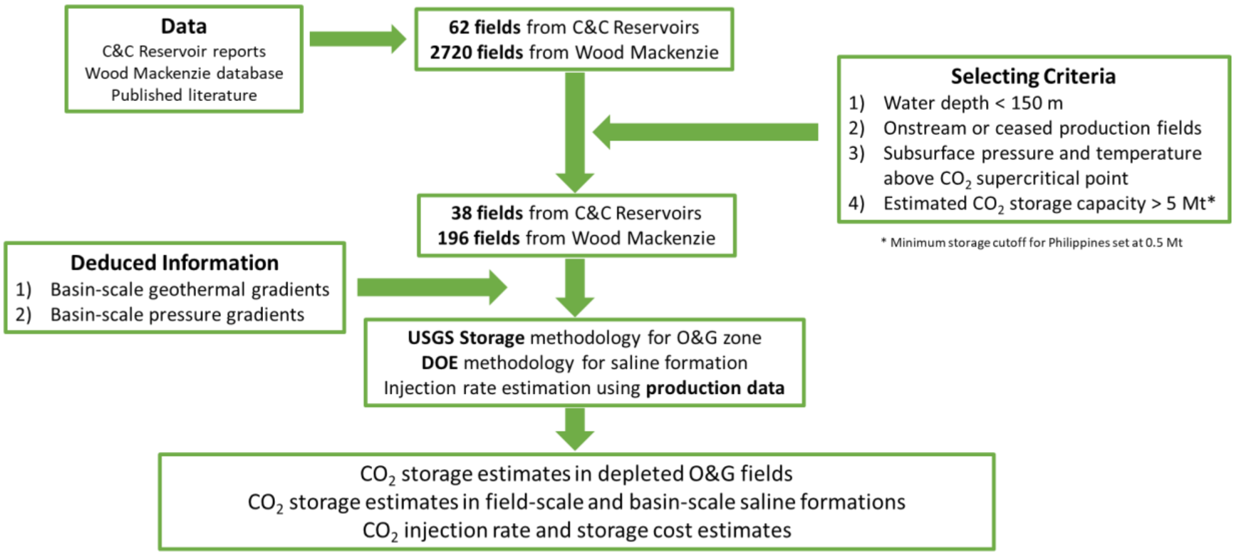


Figure 2: Workflow for CO_2 storage capacity estimation in the ASEAN region.

Results and discussion

Figure 3 summarizes the estimated conservative and optimistic CO_2 storage capacity in O&G reservoirs by country in ASEAN. The difference between the conservative and the optimistic estimates is caused by differences in the assumed recovery and storage efficiency, which reflect our understanding and estimation of the reservoir pressure conditions, EOR technology, and/or injection management strategies. The total storage capacity in the O&G field reservoirs in the selected countries provides a conservative estimation of 11.7 Gt. Indonesia has the greatest assessed storage potential for CCS in O&G reservoirs due to its significant hydrocarbon resource endowment with a large number of highly productive O&G fields. In addition, Malaysia, Thailand, and Brunei provide significant CO_2 storage capacity. Together, these four countries account for more than 90% of the assessed ASEAN regional CO_2 storage capacity in O&G reservoirs.

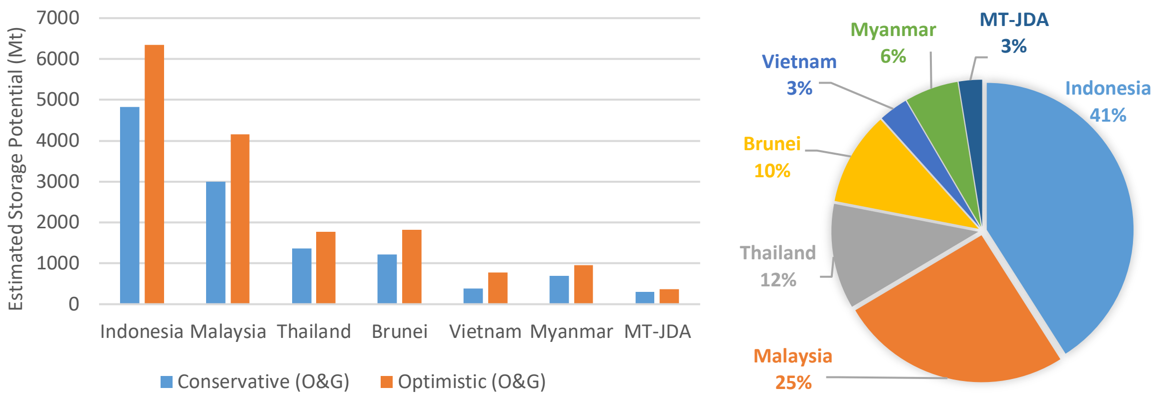


Figure 3: Left: Estimated conservative and optimistic CO_2 storage capacity by country/region in ASEAN O&G fields. Right: Percentage of the estimated conservative storage capacity in each country/region with respect to the total conservative storage estimation.

Table 2 lists the top ten fields with the largest estimated CO_2 storage capacity within the depleted O&G zones. Five fields are in Indonesia, two in Malaysia, and one each in Brunei, Thailand, and Myanmar. Columns Depth to T are shown as examples of the data collected in order to calculate in-situ CO_2 density, FVF for gas, and subsequently the conservative and optimistic estimates of the CO_2 storage volume. As shown, the largest CO_2 storage sites collocate with the largest gas fields in the region. These fields have the potential to be developed into regional sequestration hubs, where the excess storage capacity can be monetized to store CO_2 captured from sources in other countries.

Table 2 Top 10 fields with largest estimated CO_2 storage capacity in the O&G zone (Cons. = Conservative, Opt.* = Optimistic)*

Field	Basin	Country	Depth	EUR liquid	EUR gas	STOIIP	STGIIP	P	T	ρ_{CO2}	FVF_G	Cons.*	Opt.*
			(m)	(MMbbl)	(km³)	(MMbbl)	(km³)	(MPa)	(°C)	(kg/m³)	(%)	(Mt)	(Mt)
Tunu	Kutei	Indonesia	3500	950	606	0	714	35	132	608	0.31	1115	1334
Vorwata	Bintuni	Indonesia	2000	87	483	217	509	28	108	602	0.31	817	965
Arun	North Sumatra	Indonesia	3063	856	428	981	476	49	177	619	0.30	808	969
SW Ampa	Sarawak	Brunei	2200	900	345	2,296	402	20	93	518	0.36	610	821
Badak	Kutei	Indonesia	1676	26	184	0	226	26	96	630	0.30	316	423
Luconia F6	Sarawak	Malaysia	1400	78	149	0	198	15	61	597	0.31	259	371
Yadana	Moattama	Myanmar	1200	0	150	0	189	18	61	638	0.29	253	354
Bongkot	Malay	Thailand	1061	990	138	2,476	147	10	70	268	0.70	249	313
Suban	South Sumatra	Indonesia	2485	48	118	120	123	30	154	483	0.39	202	238
E11	Sarawak	Malaysia	1373	33	119	82	125	18	85	520	0.36	201	238

CO_2 storage capacity of saline formations – methodology and results

According to the USDOE's approach (Goodman, Sanguinito and Levine 2016), storage capacity in saline formations is determined by multiplying many factors together to estimate the pore volume accessible to injected CO_2:

$$SC_{sal} = \mathrm{E} \times \mathrm{A} \times h \times \phi \times \rho_{CO_2}$$

This estimation is more challenging because it requires additional geological information, including the distribution, thickness h, area A, and porosity ϕ of the saline formations across the sedimentary basins beyond the hydrocarbon producing fields. In addition to these physical parameters, the USDOE's approach (Goodman, Sanguinito and Levine 2016) also requires inputs to calculate the storage efficiency factor,

$$E = E_a \times E_h \times E_\phi \times E_v \times E_d$$

where E_a, E_h, and E_ϕ are the net-to-gross (N:G) ratio for formation area, column thickness, and porosity, respectively. We separate the estimation of storage capacity in saline formations at two different scales, in order to account for the differences in the parameter uncertainties.

We use the CO2-SCREEN tool developed by US-DOE-NETL (Goodman, Sanguinito and Levine 2016) to calculate the storage capacity in saline formations. The storage efficiency E is calculated using Monte Carlo sampling based on the distributions determined by the input efficiency factors and the depositional environment. Details of these efficiency factors are provided in the following subsections when field-scale and basin-scale storage capacities are estimated separately. We take the P_{10} and P_{90} outputs of the stochastic estimations of the storage capacity as the conservative and optimistic estimates for each formation, respectively.

Field-scale saline formation CO_2 storage capacity estimation

At the field scale, we focus on the reservoir formations that are assumed to be directly associated with known hydrocarbon reservoirs to constrain the uncertainties in the physical properties. Based on the detailed data provided in the C&C Reservoir reports and other openly available data sources, we extract information including production area (A_p), column height (h), porosity ($\emptyset$), reservoir pressure and temperature. We assume that the average reported properties in the producing areas can be extrapolated to the reservoir formation across the whole field. The least constrained parameter with greatest influence is the connected formation area, which may vary by an order of magnitude between our two different estimation methodologies for O&G fields and saline formations. In this study, we determine the formation area according to the aquifer drive observed during hydrocarbon production. We assumed three multiplicative factors f_a, 5, 10, and 20, to estimate the connected field-scale saline formation area from the production area corresponding to weak, medium, and strong aquifer drive documented in the reports, respectively. These factors are chosen empirically and could be better quantified where detailed reservoir models are available. They serve as a robust measure to include the available information and our understanding of the sedimentary systems within the scope of this study.

At the field scale, we derive the N:G factors for formation area with higher confidence, and hence set P_{10} and P_{90} of N:G E_a at 0.9 and 0.95, respectively. C&C Reservoirs' reports and other published literature often document N:G factors for column thickness, E_h, which are readily used in our calculations. Since the porosity data are often reported in reservoirs that were commercially exploited for hydrocarbon production, it is our assessment that the sampled (and reported) porosity is biased towards the higher end compared to the porosity distribution across the whole basin. Additionally, the field properties are extrapolated down dip into deeper parts of the basin. Hence, the distribution of reservoir facies away from well control is less constrained and therefore less certain. Therefore, we set E_ϕ with a median value around 69%. Multiplication of these three parameters is referred as geological efficiency factor E_{geo}.

The E_v and E_d are the volumetric and microscopic displacement efficiency, respectively. The volumetric displacement describes the process where CO_2 replaces water in the volume immediately surrounding an injection well and contacted by CO_2 due to buoyancy. The microscopic displacement accounts for the pore space that is occupied by the irreducible in-situ fluids. Without performing reservoir simulations to refine these displacement efficiency factors, we follow the studies by (Goodman, Sanguinito and Levine 2016) and use the averaged efficiency factors according to depositional and lithological environment (Table 3).

Table 3: List of displacement efficiency factors for storage capacity estimation in saline formations.

Sedimentary Environment	Volumetric Displacement factor (Ev)	Microscopic Displacement factor (Ed)
Clastic: Unspecific	0.16	0.35
Clastic: Delta	0.19	0.39
Clastic: Fluvial	0.19	0.34
Limestone: Reef	0.36	0.28
Limestone: Shelf	0.44	0.31

Due to the limited understanding of CO_2 storage mechanisms in fractured reservoirs, we limit our estimation to fields with conventional sandstone and carbonate reservoirs for which C&C Reservoir reports are also available. This reduces the number of fields under study to 42. Figure 4 shows the estimated CO_2 storage capacity in field-scale saline formations by country in the ASEAN region. The conservative estimate of total accessible CO_2 storage capacity in these 42 fields is approximately 26.2 Gt. Such a large storage volume with higher confidence (compared to most basin-scale storage capacity estimates previously reported) provides a solid foundation for future evaluations of CCS supply chains and ecosystems in the ASEAN region. Estimates are small for Vietnam because the larger fields comprise fractured reservoirs based on the available data and hence they are excluded.

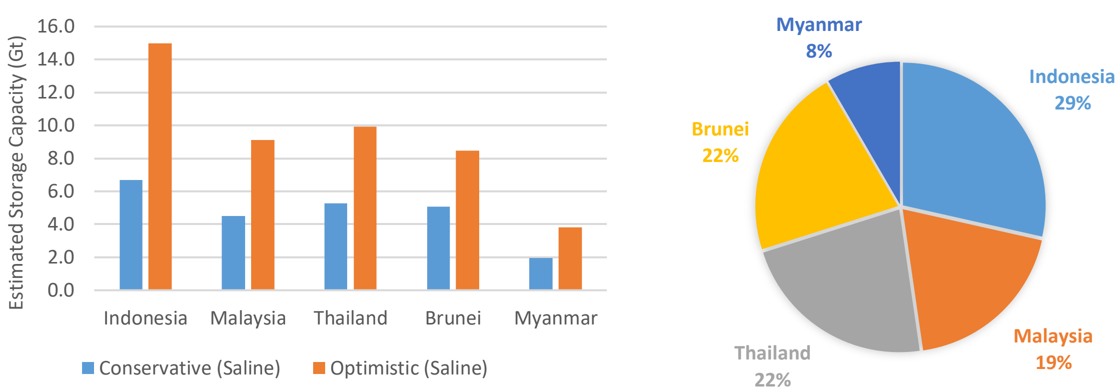


Figure 4: Left: Estimated conservative and optimistic CO_2 storage capacity by country/region in field-scale saline formations. Right: Percentage of the estimated conservative storage capacity in each country/region with respect to the total conservative storage estimation.

In Table 4, we list the top ten fields that host the largest CO_2 storage capacity in their associated saline formations. Data collected in this table are derived from the C&C Reservoir reports and published reservoir studies. The Bongkot field in Thailand has the largest reservoir-associated saline formation, with an estimated formation area of 2250 km^2 and 1960 m gross sand thickness. The produced O&G reservoirs exhibited mixed strong and weak aquifer drive. The large sedimentary sequence provides ample pore space for CCS. The associated saline formation at Bongkot field alone is estimated to provide 6.8 Gt of CO_2

storage capacity, out of the 81 Gt capacity across the whole Malay Basin reflective of its large areal distribution and reservoir thickness. Our methods for storage estimation in O&G zones and their associated saline formations represent our understanding of the trade-off effects in the reservoir system. When aquifer drive is weak for hydrocarbon production, reservoir conditions in the depleted O&G zone may be amenable for CO_2 storage, but the contribution from its immediately connected saline formation area is more limited and potential for pressure buildup is higher. For each field, the estimated storage in the O&G zone and its associated saline formation are not overlapping. Therefore, the summation of these two should be considered as the total accessible CO_2 storage potential within each field, when both estimates are available.

Table 4: Top 10 fields with largest estimated CO_2 storage capacity in the field-scale saline formations (Cons. = Conservative, Opt.* = Optimistic)*

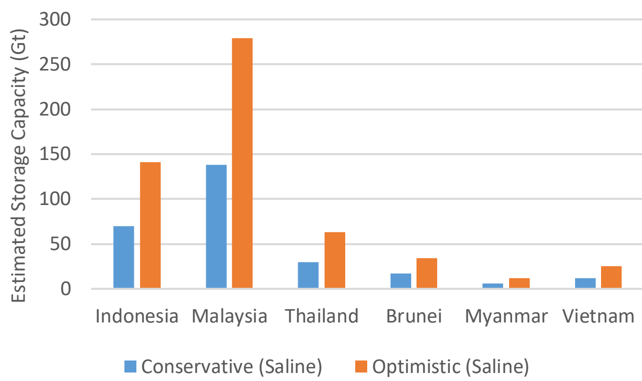
Field	Basin	Country	Depth (m)	Aquifer Drive	A (km^2)	H (m)	Φ (%)	Dep. Env.	Avg. E (%)	P (Mpa)	T (°C)	Cons.* (Mt)	Opt.* (Mt)
Bongkot	Malay	Thailand	1044	Weak	2250	1960	22	Fluvial	1.58	10	70	6,755	9,722
SW Ampa	Baram Delta	Brunei	1800	Strong	1254	1800	23	Delta	1.57	30	81	4,559	7,378
Tunu	Kutei	Indonesia	500	Weak	3000	2560	13	Delta	0.79	35	132	2,941	7,003
Erawan	Pattani	Thailand	1219	Moderate	3500	1399	20	Fluvial	1.04	26	180	2,490	5,109
Zawtika	Moattama	Myanmar	1870	Strong	810	1330	27	Delta	1.24	16	67	1,379	2,652
Badak	Kutei	Indonesia	1067	Strong	1220	2718	25	Delta	0.37	26	96	1,097	2,930
Angsi	Malay	Malaysia	1530	Weak	1447	617	25	Delta	1.57	23	150	895	1,777
Jasmine	Pattani	Thailand	762	Strong	520	968	32	Fluvial	2.41	15	102	849	1,692
Seligi	Malay	Malaysia	1294	Strong	1690	850	20.5	Fluvial	1.03	18	102	807	1,803
Baronia	Sabah	Malaysia	945	Weak	202	2076	26	Delta	1.57	24	96	669	1,342

Basin-scale saline formation CO_2 storage capacity estimation

At the basin scale, saline formation areas are derived from published basin outlines combined with reservoir distribution and thickness maps utilizing the associated geological models and regional cross-sections. Statistics for other physical parameters such as porosity, pressure, and temperature are obtained from data from the O&G field reservoirs within the basin. This process represents a strong sampling bias because the economically feasible O&G fields are more likely found in structural highs with higher porosity and permeability, with higher associated pressures due to hydrocarbon accumulation. Therefore, these parameters are assigned with higher uncertainties for the basin-scale calculations.

We use the same CO2-SCREEN tool (Goodman, Sanguinito and Levine 2016) and the same displacement efficiency factors (Table 4) for the storage capacity estimation in basin-scale saline formations. The N:G area parameters for each basin are derived statistically from the regional environment of deposition maps and assessed at the lower end for more conservative estimates. Compared to the 0.9 – 0.95 range used for field-scale estimations, N:G area parameters for most basins are set between 0.2 and 0.4, unless more detailed areal information is available. The N:G thicknesses are averaged across the reported values in the O&G field reservoirs. We use a relative constant N:G porosity around 0.69 across all basins to reflect the same "water-displacement" mechanism.

Figure 5 shows the estimated CO_2 storage capacity in basin-scale saline formations in each ASEAN country. Compared to Figure 3, the basin-scale estimates are an order of magnitude larger than the field-scale estimates as expected. An estimate of 275 – 555 Gt of total storage volume is available in the regional saline formations across the major ASEAN countries, of which Indonesia, Malaysia, and Thailand account for more than 85% of the total volume. As shown in Table 4 and Figure 9, the Malay, Sabah, and Kutei Basins are the three largest owing to the massive sedimentary systems that provide potential to be developed into significant CCS hubs. Clearly, our assessments are severely biased towards those basins that have been developed for O&G production due to the propensity of available geological data. Other sedimentary basins, such as those in eastern Indonesia, have not been investigated in this study due to the lack of available data. Their feasibility to provide additional CO_2 storage in the subsurface should be considered in future studies.



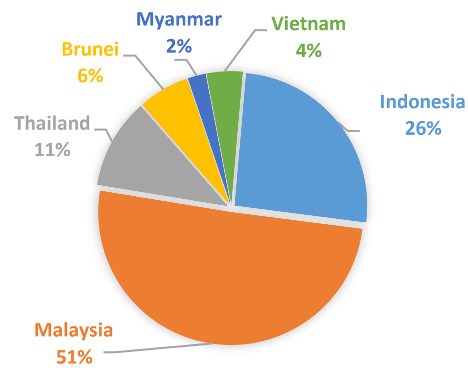


Figure 5: Left: Estimated conservative and optimistic CO_2 storage capacity by country/region in basin-scale saline formations. Right: Percentage of the estimated conservative storage capacity in each country/region with respect to the total conservative storage estimation.

CO_2 injection rates

A key factor affecting CO_2 storage cost is the injectivity potential of the reservoir formation. The injectivity potential of a reservoir is ultimately determined by many complex factors such as permeability of the reservoir, thickness, depth and pressure, as well as the injection well design. Due to the intractable complexity and heterogeneity in formation quality and engineering design, we use well-averaged peak production data in each reservoir to approximate the single-well injectivity rate. Based on existing C&C Reservoir reports, field data contained in Wood Mackenzie Asset Reports and published literature, we obtain peak gas production rates in million cubic feet of gas per day (MMCFD) and/or oil production rates in barrels of oil per day (BOPD). Assuming that early-stage production yielded minimal in-situ water and that all producing wells (N_w) performed equally well, we convert the peak daily production rates to maximum yearly produced volume (v_{pk}) and estimate the single-well average CO_2 injection rate r_{inj} (in Mt/year/well (MTA per well)) using the equation below. The Factor F is a conversion factor to account for different types of units.

$$r_{inj} = v_{pk}/N_w * \rho_{CO_2} * \mathrm{F}$$

The 126 evaluated O&G fields in ASEAN region were developed over six decades, during which time production technology and wellbore design have improved significantly. As our methodology utilizes the real production data, it also reflects the historical limitations of the production technology available at the time. Additionally, hydrocarbon production rates may be limited by the hydrocarbon column heights in O&G fields. CO_2 injection wells may be optimized to include larger boreholes and longer completion intervals including reservoir sections beneath the hydrocarbon-water contacts. We therefore expect that better injection rates may be achieved for modern CCS projects in the depleted O&G fields. Nonetheless, such historic and empirical data provide realistic lower bounds for CCS economic analysis and project planning.

The left panel in Figure 6 shows the histogram of the estimated CO_2 injection rates. Among the 126 evaluated fields, only 12 fields can inject more than 1 MTA per well, based on historical production data. Almost half of the evaluated fields can inject less than 0.1 MTA per well (Figure 6, right panel). Such low injectivity is primarily due to poor reservoir quality, and results in high injection, storage, and monitoring cost for CCS projects. Only considering the storage capacity and storage cost, the top five most suitable fields for CCS projects in the region are Jintan in the Sarawak Basin, Malaysia, Badak in Kutei Basin, Indonesia, Benchamas in the Pattani Basin, Thailand, Bach Ho in the Cuu Long Basin, Vietnam, and Yadana in the Moattama Basin, Myanmar.

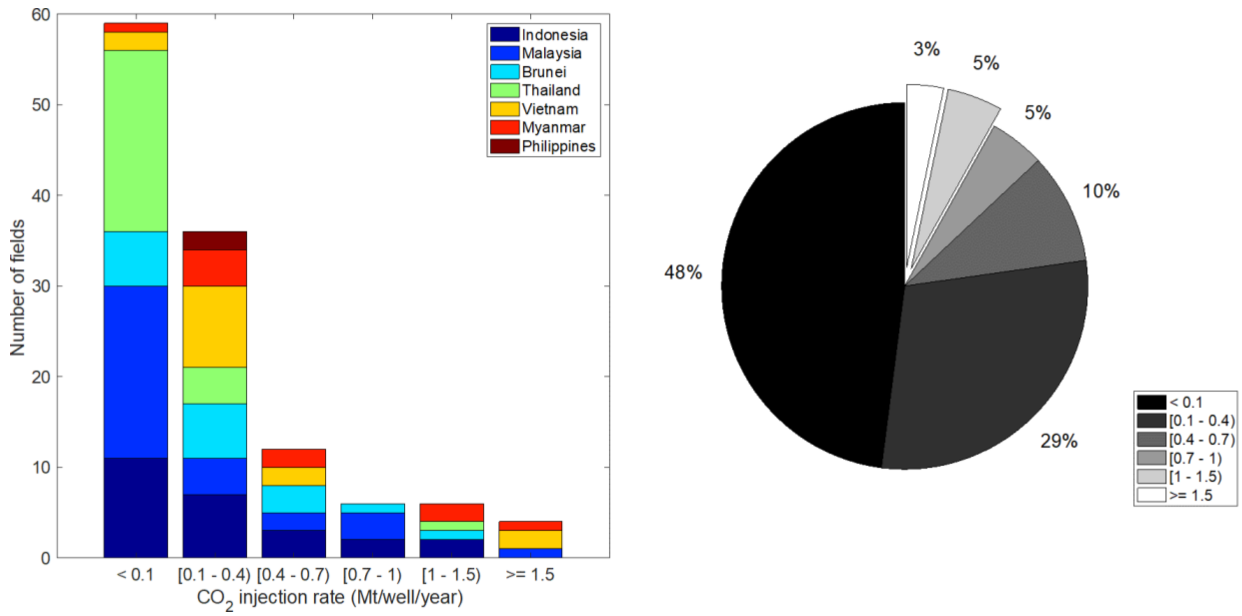


Figure 6: Ranges of estimated CO_2 injection rates (left) in each country and the relative proportion of injection rates (right) in ASEAN O&G fields. Almost half of the evaluated fields have average well injection rates less than 0.1Mt/well/year.

CO_2 storage costs

Storage costs at a CCS site consist of three major components: injection well costs, monitoring costs, and abandonment costs. Injection well costs are further divided into capital expenses (Capex) and operational expenses (Opex); while monitoring and abandonment costs are included only as Opex. Although existing infrastructure at depleted O&G fields may be repurposed for CO_2 injection and monitoring, their availability, readiness, and engineering integrity are difficult to evaluate without field-specific details. To provide a high-level and conservative estimation of the subsurface costs, we assume all wells associated with the CCS projects are new wells. We also assume each field is developed independently without infrastructure and cost sharing. For onshore wells, the projected single-well cost is estimated between US

$12 and US $17 million. The estimate increases to US $35 and US $49 million for each offshore well for the water depths considered. We note that the well cost estimates are generalized for the purposes of this study. Well cost estimates are highly dependent on the well location, well design specifics dictated by the local geological conditions and the number of wells. Well cost estimates can also vary widely depending on the availability of suitable drilling rigs impacting mobilization and demobilization as well as changing market conditions. We assume each injection well is accompanied by one monitoring well, one 3D/4D seismic monitoring survey every 5 years, and subsequent full abandonment at the end of the project life. Figure 7 shows the flowchart for subsurface storage cost estimation.

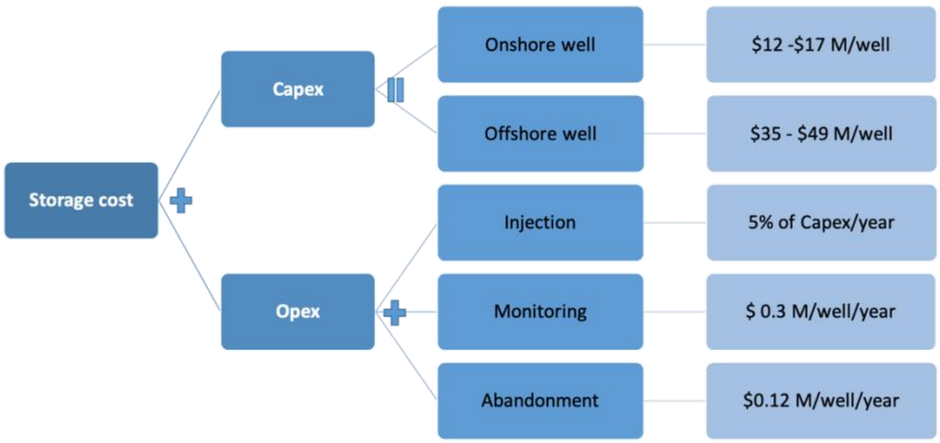


Figure 7: Flowchart for subsurface storage cost estimation.

Figure 8 provides the estimated subsurface storage unit costs ($/tonne) for a 25-year CCS project assessed for three capacity scenarios (1 or 2 or 5 MTA). Due to the relatively low reservoir quality, many ASEAN fields have higher estimated subsurface storage costs when compared to other CCS feasibility studies (IPCC 2005). As the size of the project increases from 1 MTA to 5 MTA, fewer fields can host such large projects. Meanwhile, we also observe cost reductions for those large gas fields in Indonesia and Malaysia as the injectivity is also typically higher per well, requiring fewer wells overall.

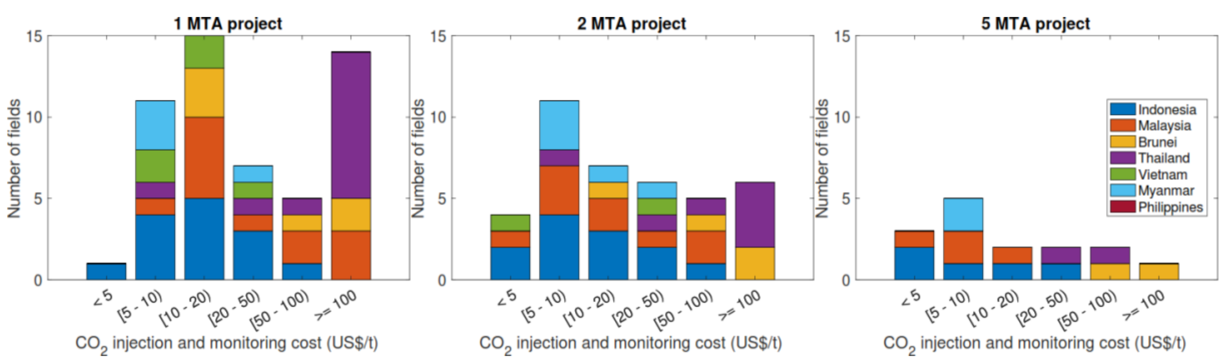


Figure 8: Estimated subsurface injection, storage, and monitoring costs (US$/t) for 1 MTA (left), 2 MTA (middle), and 5 MTA (right) 25-year CCS projects in ASEAN O&G fields.

CO_2 storage summary

In this section, we provide a selective basin-level summary in Table 5 and a comprehensive regional-level summary in Figure 9.

Table 5 lists the major basins that could store substantial amounts of CO_2 in each ASEAN country. For each basin, the field-scale numbers are summed over all available field volumes. The number of fields available for field-scale saline formation storage estimation is a subset of those assessed for O&G storage estimation due to limitations on the availability of additional data required to adequately estimate the storage capacity of saline formations. For the field-scale estimations, storage capacities calculated in the O&G zone and in the saline formation are not overlapping. When a specific field is investigated for an actual CCS project, the sum of these two estimates, when available, is considered as the total accessible CO_2 storage volume. Clearly the ranges of O&G zone CO_2 storage capacity estimates in megatons (Mt) are smaller compared to the basin-scale saline formation estimates in gigatons (Gt), reflecting the difference in the size and their perceived uncertainties.

Table 5: Summary of storage capacities of O&G fields and saline formations at field-scale and basin-scale for major basins in ASEAN region (Cons. = Conservative, Opt.* = Optimistic)*

		Field-Scale CO_2 Storage Capacity						Basin-Scale CO_2 Storage Capacity	
		O&G Zone			Saline Formation			Saline formation	
Basin	Country	No. Fields	Cons. (Mt)	Opt. (Mt)	No. Fields	Cons.* (Mt)	Opt.* (Mt)	Cons.* (Gt)	Opt.* (Gt)
Malay	Malaysia	34	1,166	1,635	6	2,019	3,525	64	138
	Thailand	9	362	434	1	6,401	13,047	16	35
	MT-JDA	8	302	363	N.A.	N.A.	N.A.	1	2
Sarawak	Malaysia	30	1,558	2,033	2	629	1,368	28	52
Sabah		14	271	479	5	1,162	2,410	46	89
Kutei	Indonesia	12	1,908	2,526	4	3,381	10,950	32	67
South Sumatra		15	486	676	1	41	78	13	23
North Sumatra		8	964	1,155	1	36	67	5	8
Baram Delta	Brunei	12	469	778	1	199	497	15	28
Pattani	Thailand	24	849	1,081	1	2,483	5,061	12	23
Moattama	Myanmar	8	560	735	2	1,291	3,357	3	7
Rakhine		1	119	177	1	708	1,226	2	5
Nam Con Son	Vietnam	5	182	239	N.A.	N.A.	N.A.	11	23
Palawan	Philippines	2	1	3	1	9	16	0.4	0.8

Figure 9 projects the locations of the three types of estimated CO_2 storage capacities on an ASEAN regional map. The majority of the O&G fields are offshore. Each bubble denotes a selected O&G field, and its size indicates the total accessible storage volume consisting of the volume in the O&G reservoir (brown slice) and the volume in the field-scale saline formation (green slice). Those locations without an associated field-scale saline formation storage assessment may be due to limitations on the availability of data for those selected field locations precluding the assessment. The horizontal and vertical bars in each bubble denote the injectivity and the cost for subsurface storage at each field. Larger bubbles with a longer horizontal bar and a shorter vertical bar are potentially ideal locations for future CCS projects, providing larger storage capacity and better injectivity at lower cost. Clusters of these bubbles suggest that CCS projects that access multiple fields from an integrated hub could be considered in Indonesia (North and South Sumatra, Kutei Basin), Peninsula and East Malaysia, offshore Thailand, Brunei and Vietnam. Basin-scale storage capacity estimation is shown as color shading within each basin outline, where darker colors indicate larger storage volume. It is evident that the sedimentary systems in the ASEAN region host significant CO_2 storage volume potential.

Data from IEA's CO_2 emissions reporting (IEA 2021) indicates that the total CO_2 emissions in ASEAN from fuel combustion in the industrial and power sectors was about 1,000 million tons per year in 2018. Assuming about 15% of these point source CO_2 emissions would be mitigated through CCS, the annual CO_2 storage capacity need is about 150 Mt. The available storage volume, in 10s of gigatons, appears to meet the sequestration needs of the region for many decades.

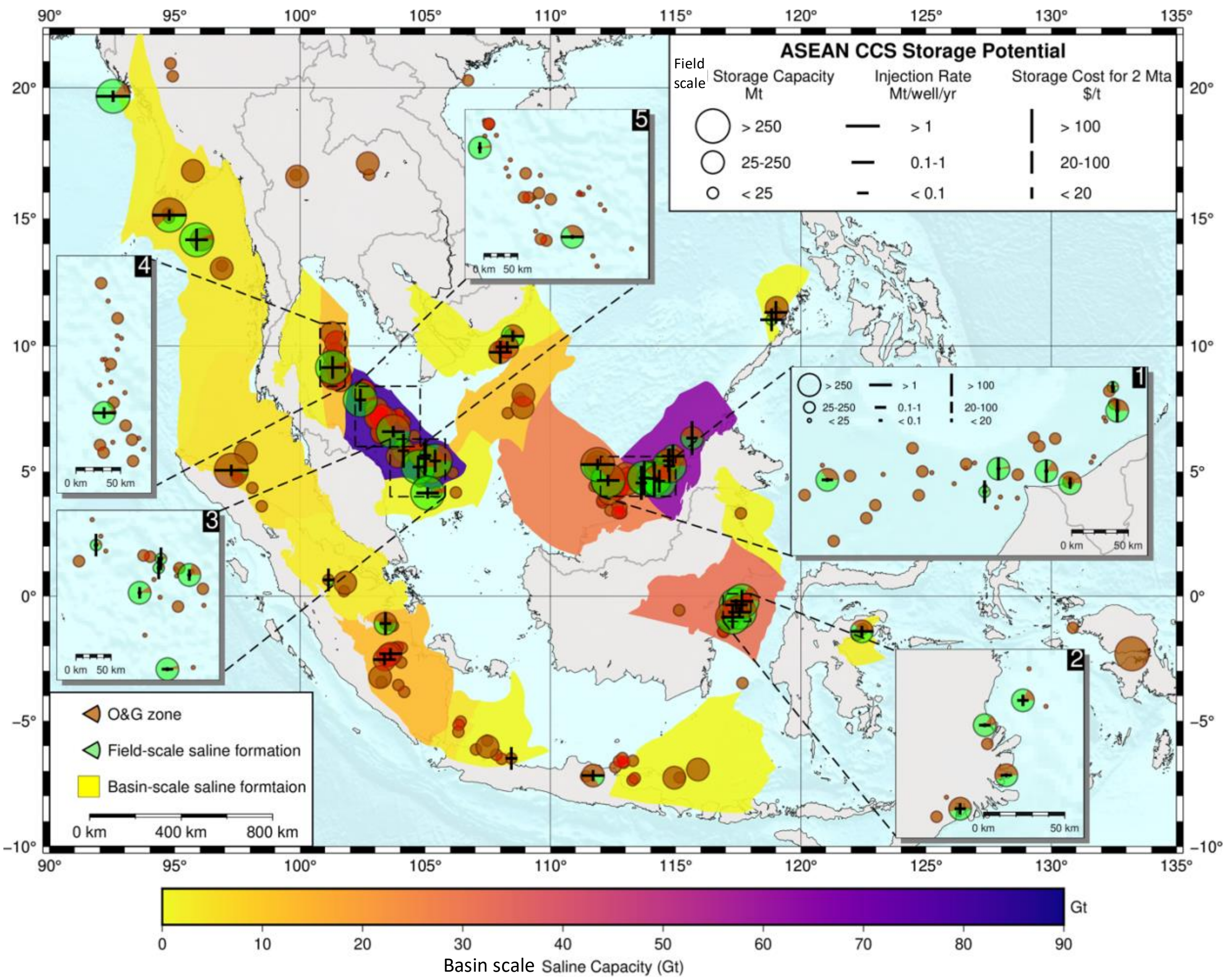


Figure 9: Map of estimated storage capacity in ASEAN region. Center of each bubble denotes the location of an existing O&G field. Its size denotes the total accessible storage capacity for CO_2, including in the depleted O&G zone (brown slice) and in the field-scale saline formation (green slice). The horizontal and vertical bars in each bubble denote the estimated injection rate (Mt/well/yr) and the estimated subsurface storage cost ($/t). The basin scale estimated volumes are depicted in color projected onto the basin outlines. All inserts are zoomed-in areas and share the same scales for storage capacity, injection rate, and cost as shown in insert (1).

CO_2 Transport

Given the geographic distribution of potential CO_2 sequestration options, we seek to assess the feasibility of transporting CO_2 from regional sources. Ultimately, we envisage a robust, diverse supply chain facilitating transport from multiple CO_2 export sources to various CO_2 sequestration sinks. In this paper we focus on transport from an assumed Singapore export terminal in order to determine 0th order cost estimates of various options. We consider transport via pipeline and ship and assume that CO_2 sources have already been captured, concentrated and gathered. As such, this analysis includes the supply chain from CO_2 compression and dehydration through transport, storage, and monitoring.

CO_2 can exist in gaseous, liquid, solid and supercritical/dense phases depending on its temperature and pressure, as shown in Figure 10. CO_2 can exist in all three phases at a point called the 'triple point' at (5.2 bar, -56°C). Depending on the mode of transport, CO_2 is processed to different phases at different pressure and temperature points.

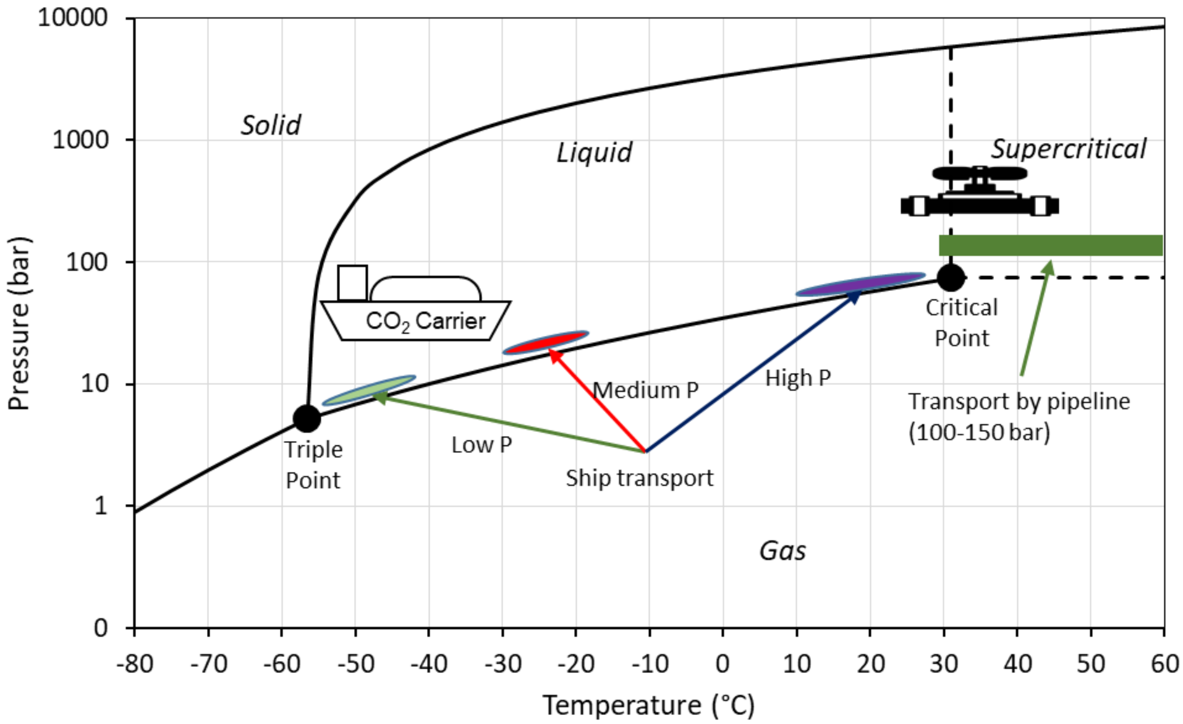


Figure 10: CO_2 phase diagram with the critical point at 31.1°C, 73 bar. The green rectangle indicates the pressure and temperature range for a typical CO_2 pipeline. It is common to transport CO_2 at higher temperatures to prevent hydrate formation in the injection well head when choked. The colored oblong bubbles represent regions for proposed large scale CO_2 shipping transport.

CO_2 Pipeline Transport

CO_2 can be transported through a pipeline in liquid, supercritical or gaseous phase. The low density and high pressure drop of the gaseous phase would require larger pipes for transporting equivalent amounts of CO_2 (IEAGHG, 2010). In a liquid or supercritical state, CO_2 density is typically 300-500 times higher than in a gaseous state; therefore, large quantities of CO_2 can be transported in smaller size pipelines. Supercritical CO_2 also has very low viscosity and hence is well suited for pipeline transport.

Pipeline design and operation for the transport of CO_2 in the context of CCS differs from that of pipeline considerations for natural gas transportation. This is mainly due to the complexities introduced by the thermodynamic behavior of CO_2, presence of impurities, and higher operating pressure (above CO_2 critical pressure). The typical operating window for transporting CO_2 by pipelines (DNV-RP-J202 2010), depicted in Figure 10, ranges from 100 bar to 150 bar, thus it is necessary to ensure that any infrastructure built is capable of bearing the high pressures according to design codes.

When supercritical CO_2 flows in a pipeline, the pressure should be maintained above the critical pressure to prevent formation of liquid, gas or two-phase flow conditions, which can cause operational problems such as slugging and cavitation in pumps/compressors. As a result, CO_2 will have to be compressed to a high pressure at the inlet to make up for head losses along the pipeline. If the head losses are excessive, booster stations should be installed along the pipeline to repressurize CO_2.

Further, when considering pipeline options for CO_2 transport, consideration must be given to pipeline integrity, resistance to fracture propagation and corrosion, flow assurance, operation, health, and safety. These additional requirements make the repurpose of existing O&G pipelines challenging and the cost of new CO_2 transport pipelines higher than conventional O&G transport pipelines.

CO_2 Ship Transport

CO_2 transport by ship has been practiced for more than 20 years in small quantities (e.g., 1,000-2,000 m^3) for industrial and alimentary purposes (IEAGHG 2020). For many CCS projects, much larger volumes of CO_2 ships (e.g., 7,500 m^3 to 50,000 m^3) are required to reduce unit transport costs. Unlike the pipelines, it is challenging to design large ship tanks that can withstand high pressures. It is more cost effective to maintain CO_2 in liquid state with refrigeration (Seo, et al. 2016), thus CO_2 in ships is commonly transported in liquid state at low to medium pressures. Based on the design pressure and temperature, CO_2 ships are grouped into three categories as shown in Figure 10: Low Pressure, Medium Pressure, and High Pressure (IEAGHG 2020).

Currently, liquefied petroleum gas (LPG) is transported at medium pressure and the ship size is about 10,000 m^3. It is possible to adapt such ship designs for transporting CO_2 to take advantage of the approved designs and existing shipyard operations. Although larger low-pressure ships (e.g. 50,000 m^3) could be designed and constructed for future projects, in this study we assume a ship size of 10,000 m^3 for all the shipping cost estimates.

Besides pipeline transport, we consider two concepts for ship-based CCS depending on the onshore or offshore location of the sinks as illustrated in Figure 11. The initial stage is common between the two scenarios in which the emitted CO_2 source is assumed to be captured and gathered to a dehydration and liquefaction system before it is stored in a temporary storage tank. From there it is loaded onto a CO_2 carrier by a cargo handling system and transported to the storage site. This loading terminal, although ignored by published studies, incurs a large cost element that is not negligible. For an offshore storage site (Figure 11a), CO_2 is injected directly through the offshore platform. For an onshore storage site (Figure 11b), CO_2 is unloaded to onshore storage tanks for pipeline transport before injecting through the wellhead. The differences in the last stretch of the transport may result in significant cost differences.

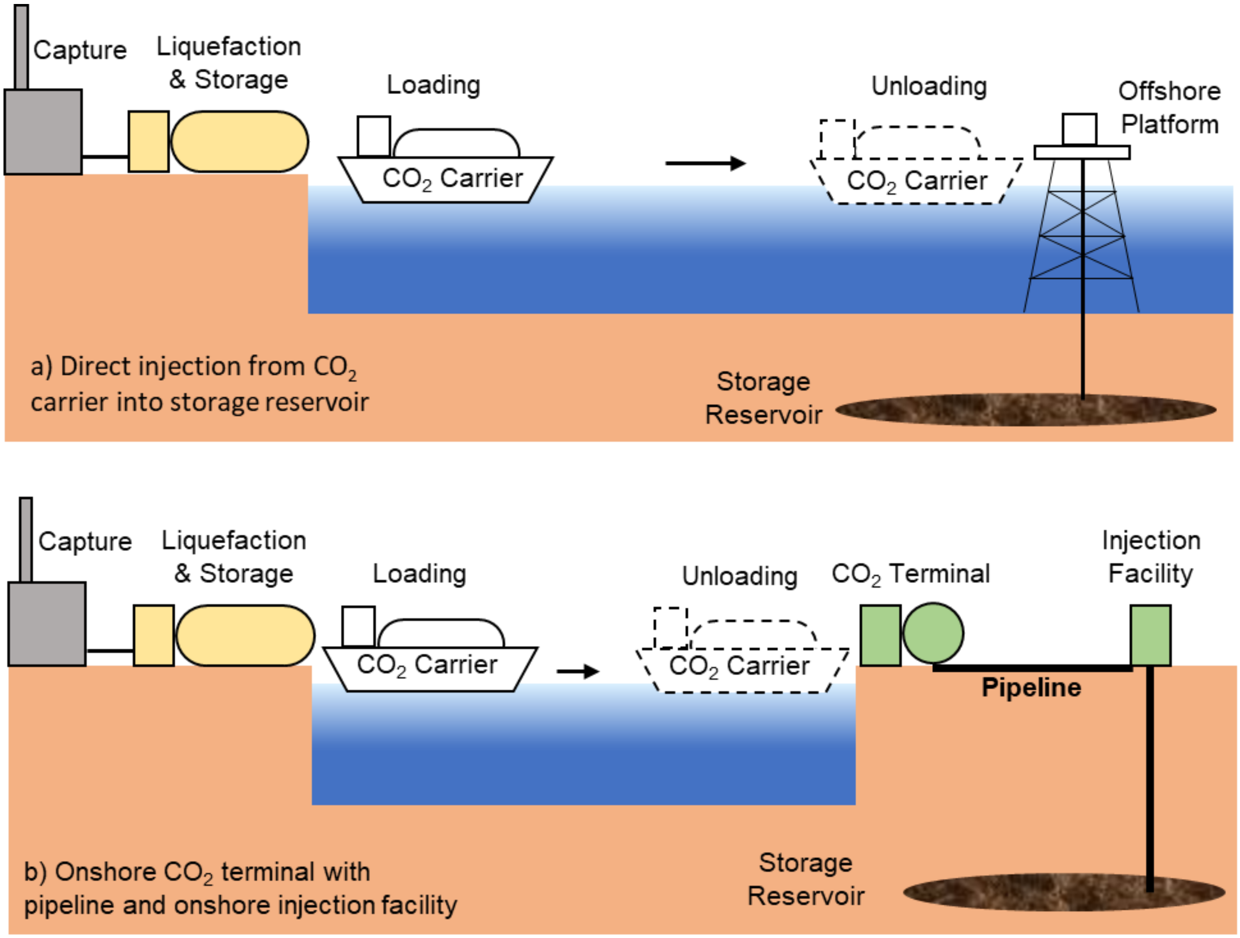


Figure 11: Two concepts of ship-based CCS were considered, a) direct injection from ship and b) offload from ship to onshore CO_2 receiving terminal and then transport by pipeline to an injection facility.

Integrated Cost Model

CO_2 capture cost estimates are well covered in previous studies (National Petroleum Council 2019). We therefore exclude CO_2 capture and assume a high concentration, low pressure CO_2 feed is available. Furthermore, while it may be possible to reuse existing O&G infrastructure in order to provide potential significant cost savings for a CCS project, such assessments must be made carefully on a case-by-case basis. Therefore, this paper only considers green-field CCS project development where cost estimates are based on the construction and installation of new infrastructure. Hence, our integrated cost model includes CO_2 compression for pipelines or liquefaction for ships, transport via onshore or offshore pipeline, and storage. The methodology adopted in the cost model is consistent with the assumptions and costs reported in the report prepared for the Department for Business, Energy and Industrial Strategy (BEIS) (Element Energy 2018). The key model parameters used in the cost model for both pipeline and ship transport are listed in Table 6.

Table 6: Key model parameters for CO_2 transport

Parameter	Value
CO_2 purity	>95%
CO_2 capacities considered	1-2-5 MTA
Project life	25 years
Weighted average cost of capital	8%
Fixed O&M costs (Pipeline)	0.5% capex for onshore, 1.5% Capex for offshore
Pipeline size scales with capacity	6 inches for 1 MTA 12 inches for 2-5 MTA
Ship capacity	10,000 m^3
Ship speed	15 knots

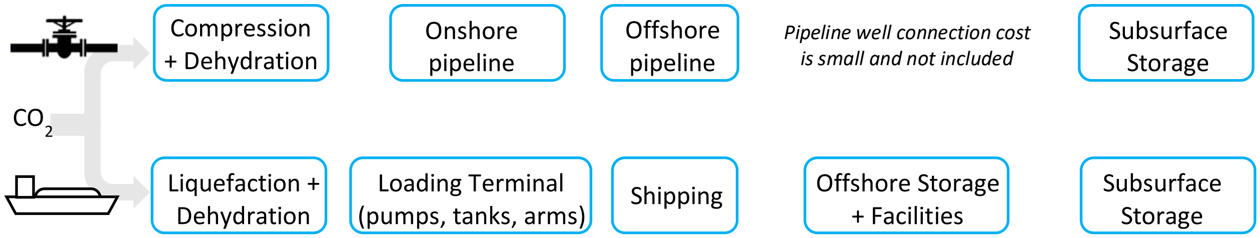
The elements contributing to the integrated cost model are depicted in Table 7. We separate the contributing elements into Capex and Opex costs when such data are available. Pipeline transport costs include costs of dehydration and compression of the CO_2 into its supercritical phase, the pipeline network, and subsurface storage. Capex of a pipeline network includes the costs related to pipeline construction, pipe material, pipe laying, and compression equipment, which depend on parameters such as the wall thickness required to contain CO_2 at the maximum pressure in the pipe, choice of pipe material, and terrain factors. Opex of a pipeline network includes electricity, labor and maintenance costs. While onshore and offshore pipeline costs were modeled similarly, offshore systems are clearly more expensive.

Similar to pipeline transport, transport via ship requires converting the CO_2 into its dense phase. Compared to pipeline transport, ship transport costs do not rise as quickly with increasing transport distance (Bai and Bai 2014). As a result, transporting CO_2 by ship could potentially be a cost competitive option for CCS in Southeast Asia. Moreover, ship transport routes can be altered during operation to divert injection to different available storage sites. Therefore, once a robust set of regional sequestration opportunities exist, ship transport could provide more flexibility than pipeline transport. These additional benefits make marine transport of CO_2 attractive beyond lower cost for certain distances.

Capex of CO_2 shipping includes primarily the costs of the ships, which are determined by the size and number of ships required. Other elements of Capex for CO_2 shipping relate to acquisition and installation of compression and liquefaction equipment. Opex of CO_2 shipping includes costs of electricity, fuel, labor, and maintenance. In contrast to pipeline transport, Opex is significantly higher than Capex for CO_2 ship transport. Transport of CO_2 via ship also incurs significant costs at the CO_2 source from infrastructure required for loading the CO_2 onto ships, and at the sink, from infrastructure required for delivering the CO_2 to the sequestration site if it is offshore as depicted in Figure 11a. The loading facilities include a temporary storage tank, loading pumps, vapor return arm with compressions, and extension of port facilities. The number of ships required for each case was calculated based on the volume of the project and the distance between source and sink. The cost of 10,000 m^3 ship and other cost elements were adopted from IEAGHG (2020) and Element Energy (2018). Unit cost of shipping costs for different sizes of projects are shown in Table 7. In case of shipping to an offshore well, $15.36/ton of facilities cost was adopted based on IEAGHG (2020). The same unit cost was used for 1, 2, and 5 MTA projects.

Finally, the costs of subsurface storage must be included. All these elements are added together to provide the total unit cost ($/ton). The sensitivity of this total cost is then explored versus CO_2 volumetric project capacity, 1, 2, and 5 MTA, as well as transport distance.

Table 7: The main cost elements in the integrated cost model vary by flow rate and distance. It is assumed that cost of capital is 8% and 60% contingency to account for cost uncertainty and owners costs



<table>
<tr><th>Cost Element</th><th>Unit Cost Model Approach</th><th>Reference</th></tr>
<tr><td>Compression+ Dehydration</td><td>
<table>
<tr><th>Capacity (MTA)</th><th>Total Unit Cost $/ton</th></tr>
<tr><td>1</td><td>24.4</td></tr>
<tr><td>2</td><td>22.3</td></tr>
<tr><td>5</td><td>21.8</td></tr>
</table>
</td><td>Similar to costs for Natural Gas from Table 2-7 (National Petroleum Council, 2019)</td></tr>
<tr><td>Liquefaction + Dehydration</td><td>
<table>
<tr><th>Capacity (MTA)</th><th>Capex (M$)</th><th>Opex (M$)</th><th>Total Unit Cost $/ton</th></tr>
<tr><td>1</td><td>63</td><td>15</td><td>20.9</td></tr>
<tr><td>2</td><td>87</td><td>27</td><td>17.6</td></tr>
<tr><td>5</td><td>161</td><td>63</td><td>15.6</td></tr>
</table>
</td><td>Similar to estimates from (IEAGHG 2020) Unit costs contain embedded 8% cost of capital.</td></tr>
<tr><td>Onshore pipeline</td><td>
<table>
<tr><th colspan="3">Capex(x) = A*contingency*annuity*x and Opex(x) = A*x where x = distance in km</th></tr>
<tr><td>Capacity (MTA)</td><td>Capex (M$)</td><td>Opex (% of Capex)</td></tr>
<tr><td>1</td><td>A = 0.5536 M$/km</td><td>0.4</td></tr>
<tr><td>2</td><td>A = 0.8106 M$/km</td><td>0.4</td></tr>
<tr><td>5</td><td>A = 1.3417 M$/km</td><td>0.4</td></tr>
</table>
</td><td>Consistent with (National Petroleum Council, 2019). Calculated costs also include 60% contingency due to uncertainties of terrain and 8% cost of capital.</td></tr>
<tr><td>Offshore pipeline</td><td>
<table>
<tr><th colspan="3">Capex(x) = A*contingency*annuity*x
Opex(x) = A*x, where x = distance in km</th></tr>
<tr><td>Capacity (MTA)</td><td>Capex (M$)</td><td>Opex (% of Capex)</td></tr>
<tr><td>1</td><td>A = 0.8292 M$/km</td><td>1.5</td></tr>
<tr><td>2</td><td>A = 1.2141 M$/km</td><td>1.5</td></tr>
<tr><td>5</td><td>A = 2.0096 M$/km</td><td>1.5</td></tr>
</table>
</td><td>1.5x onshore pipeline costs. Calculated costs also include 60% contingency due to uncertainties of terrain and 8% cost of capital.</td></tr>
</table>

<table>
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Opex(x) = A*x, where x = distance in km</td></tr>
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<tr><td>1</td><td>A = 0.0696
B = 97.8614</td><td>A = 0.0049
B = 6.8175</td></tr>
<tr><td>2</td><td>A = 0.1428
B = 145.4819</td><td>A = 0.0100
B = 11.1178</td></tr>
<tr><td>5</td><td>A = 0.3858
B = 291.7771</td><td>A = 0.0265
B = 24.2012</td></tr>
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</td><td>Approached described in this paper. Calculated costs also include 60% contingency due technology novelty and 8% cost of capital.</td></tr>
<tr><td>Loading Terminal (pumps, storage, tanks, arms)</td><td>
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<tr><td>Capacity (MTA)</td><td>Capex (M$)</td><td>Opex (M$)</td><td>Total Unit Cost $/ton</td></tr>
<tr><td>1</td><td>47.52</td><td>2.38</td><td>6.83</td></tr>
<tr><td>2</td><td>51.04</td><td>2.55</td><td>3.67</td></tr>
<tr><td>5</td><td>61.59</td><td>3.08</td><td>1.77</td></tr>
</table>
</td><td>Capex from 30,000 m^3 capacity at 1,000€ /tCO_2 from figure 4-2 and Table 4-5 and 5% Opex (IEAGHG, 2020). Unit costs contain 8% cost of capital.</td></tr>
<tr><td>Offshore Platform + Facilities</td><td>15.36 $/ton for 1, 2, and 5 MTA</td><td>(IEAGHG, 2020)</td></tr>
<tr><td>Subsurface Storage</td><td>Depends on the geological properties of subsurface formation</td><td>Described in this paper</td></tr>
</table>

Figure 12 shows the unit cost for transporting CO_2 via offshore pipeline and shipping for the 1, 2, and 5 MTA scenarios versus distance. All costs related to transport including compression, loading, unloading, and offshore facilities are included. Only subsurface storage is excluded since it is specific to the geology of the storage site. Pipeline systems are more sensitive to distance as their Capex costs are dominant and rise faster with increasing distance. On the other hand, pipelines can take advantage of economies of scale and cost significantly lower for higher flow rates. Shipping costs are dominated by Opex and thus are less sensitive to project sizes, though this is partly due to our simplified assumption not to scale ship size, but rather only to increase the number of ships for larger projects. Shipping CO_2 is cheaper than pipeline transport for long distances and smaller projects. At a project size of 1 MTA, shipping CO_2 is cheaper than pipeline transport for distances above 300 km. At larger project sizes, pipeline transport unit costs decrease, resulting in further breakeven distances. For a 5 MTA project, shipping CO_2 is cheaper than pipeline transport for distances above 400 km.

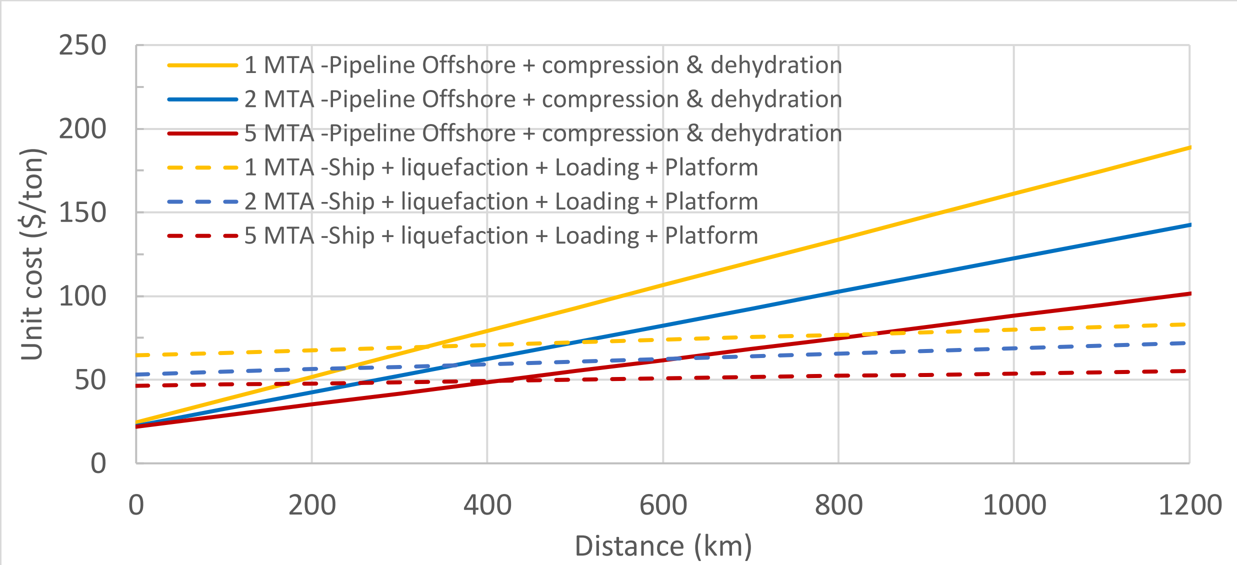


Figure 12: Unit cost for transporting 1, 2, and 5 MTA CO_2 versus distance comparing offshore pipeline and ship transportation based on a project cost model comprising all transport related costs described in Table 7 except for storage. Shipping numbers assume offshore storage.

CO_2 Source-Sink Matching Analysis

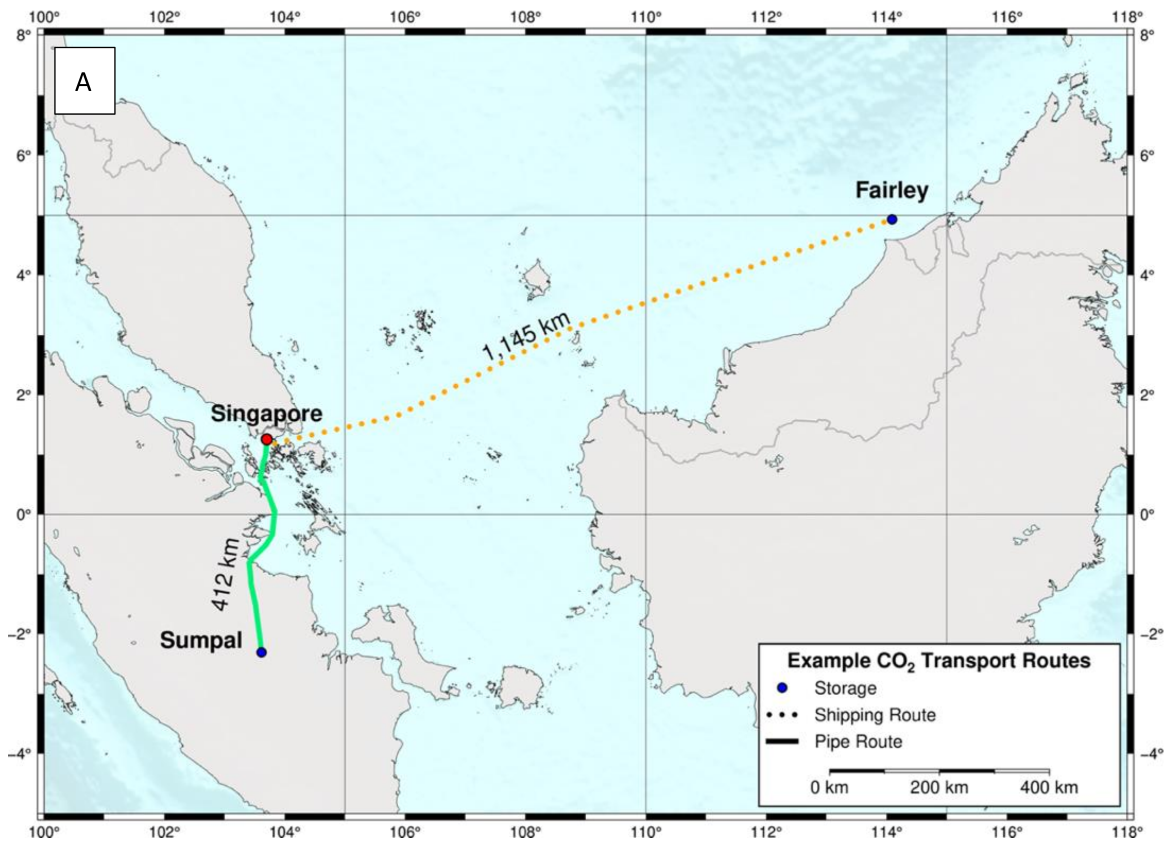
In Southeast Asia where large CO_2 point sources and potential sinks of variable capacities are spread geographically across the region, source-sink matching will be an important mechanism to reduce costs and disruption risks. For cost estimation we focus on sequestration options in depleted O&G fields. This is because our understanding of and confidence in the range of capacity and injectivity in these storage estimates are much higher than basin-scale data.

The planning of an ASEAN CCS hub based on viable sequestration options can be cast as an inventory routing supply chain optimization problem. As an initial step, however, this study focuses on CO_2 captured and exported from Singapore. Singapore's energy and chemicals industries have more than 100 leading global petroleum, petrochemicals, and specialty chemicals companies. It has many point sources of CO_2 from power generation and industrial activities that could potentially be captured and aggregated. For this analysis, it is assumed that the CO_2 emissions from Singapore would be exported from a single port terminal located on Jurong Island. We systematically paired this with field scale sinks in neighboring countries through a point-to-point network.

Given the number of available field-scale sequestration options, there are many theoretical source-sink combinations. A simplified screening process is adopted to provide an initial assessment of the top options for the three project scenarios, transporting and sequestering 1, 2, and 5 MTA of CO_2 to each sequestration site. We do not allow a source to switch sinks over a project's lifetime. Sinks that do not support 50 MT of CO_2 or that exhibit a potential injection rate lower than 0.05 MTA per well are eliminated.

Transport pathways between Singapore and CO_2 sequestration site are estimated based on simplified assumptions that pipelines follow existing pipeline infrastructure where available, run on land or in shallow water following coastlines where applicable. Shipping pathways are estimated from straight lines with obstacle avoidance. Pipeline and shipping routes are then produced using a Geographic Information System software, QGIS (QGIS.org 2021). The routing distances generated by QGIS from the source to each individual storage site is used in the cost model to estimate the pipeline and shipping costs. Subsurface storage costs, as previously described, account for injection, storage, monitoring, and abandonment costs.

To illustrate the methodology and cost calculations, we show examples of the routes and costs from Singapore to two different sinks: Sumpal and Fairley in Figure 13. Sumpal is an onshore storage sink located in South Sumatra, Indonesia, accessible via offshore and onshore pipelines. Sumpal has excellent reservoir quality, and hence incurs very low storage cost. Compared to Sumpal, Fairley is an offshore sink roughly three times farther away from Singapore, located off the coast of Brunei. Clearly, the pipeline option for Fairley is costly due to the construction of long-distance offshore pipelines. The ship option for Fairley, on the other hand, costs less to build and operate the ships, but incurs high facilities costs due to the loading terminal and the offshore platform. In addition, despite a better-than-average reservoir quality at Fairley, its subsurface storage cost is still 2.6 times of Sumpal's storage cost. Consequently, among all scenarios at these two sites, transport of CO_2 by pipeline to Sumpal provides the cheapest option for all three project sizes with costs ranging from \$50/ton to \$81/ton.



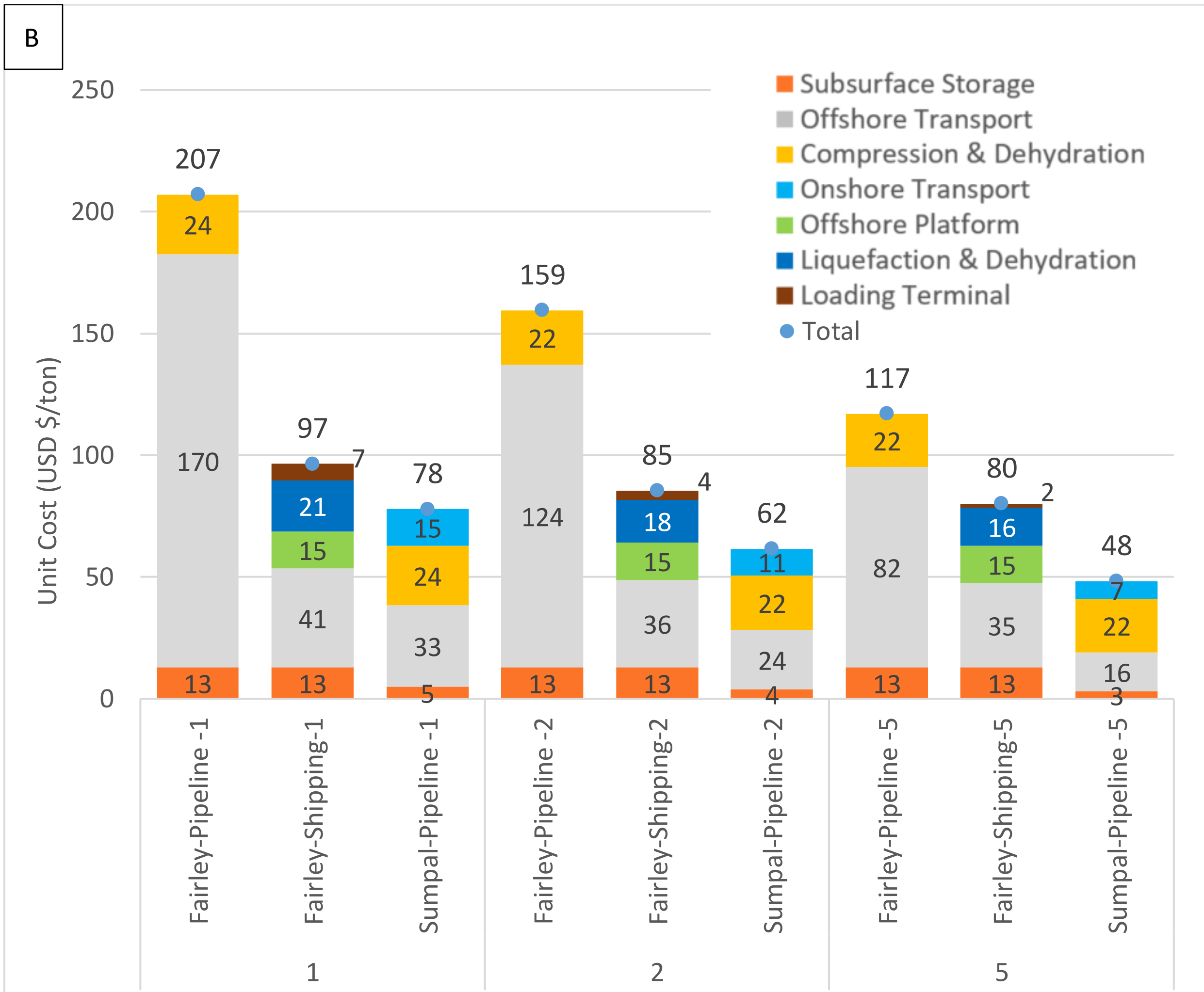


Figure 13: A) Routing examples from Singapore to two storage locations, Fairley offshore Brunei and Sumpal onshore Indonesia. B) Cost element breakdown for CO_2 transport and storage between Singapore and these two sites for 1, 2, and 5 MTA cases. While Sumpal has only a pipeline option (with both onshore and offshore components) Fairley can be reached by both pipeline and ship.

Figure 14 shows more regional examples of the selected routing options for each source-sink pair. For sinks close to Singapore, pipeline transport is often preferred, routing denoted by the solid lines. For a few special cases of offshore sinks, offshore pipeline and ship transport incur similar costs through the same route denoted by the dashed lines. These sinks locate at roughly the break-even distance as shown in Figure 12. For offshore sinks that are more than 1100 km away, ship, denoted by the dotted lines, is a more cost-effective option for CO_2 transportation.

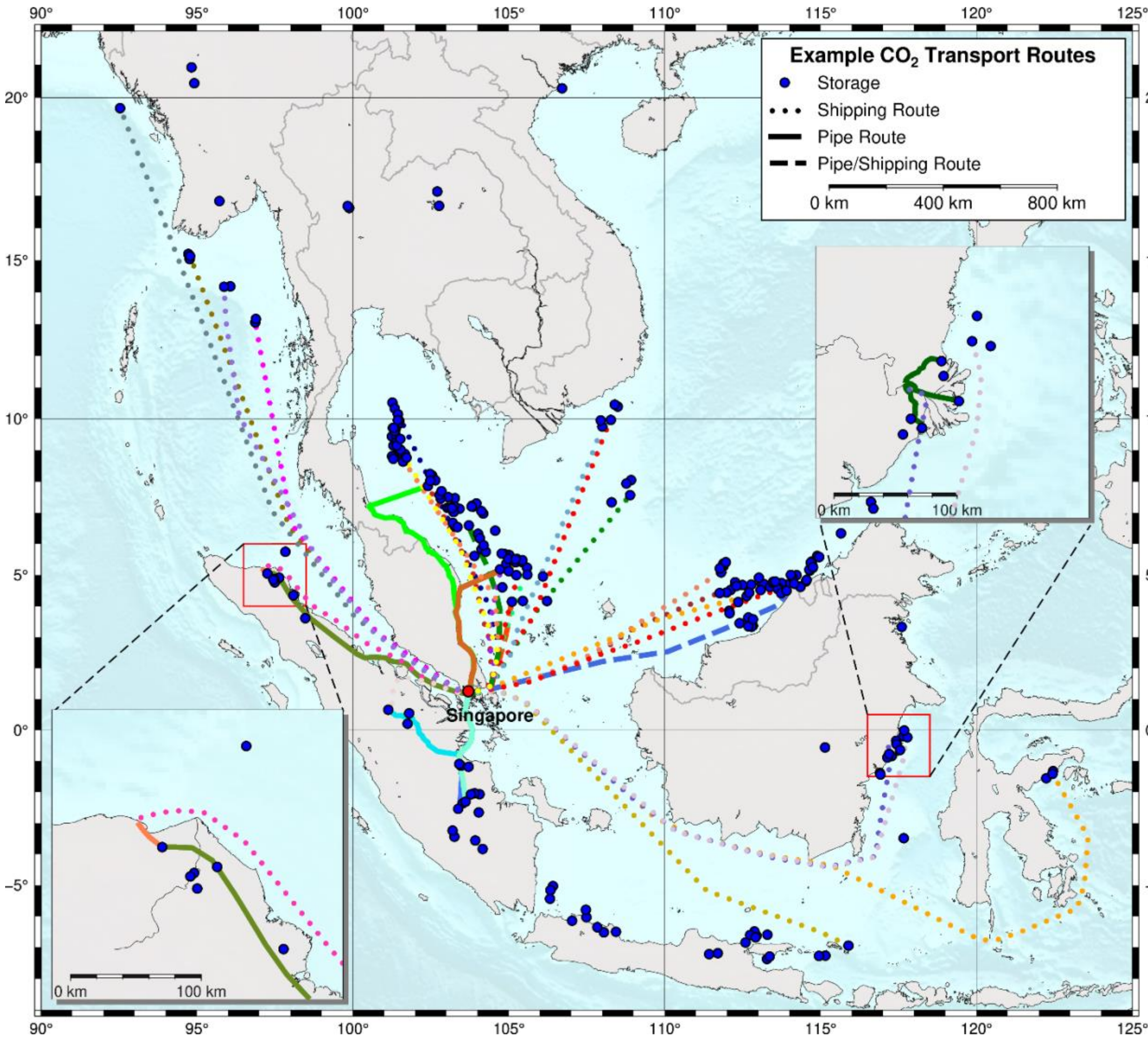


Figure 14: Examples of preferred transport options from Singapore to various sinks. Sinks, particularly onshore sinks, closer to Singapore favor pipeline transport (solid lines). Remote offshore sinks often favor ship transport (dotted lines). Offshore sinks that locate around the break-even distance can be reached by either offshore pipeline or ship at similar cost (dashed lines).

Given uncertainties in the cost elements for each storage option we seek to understand the distribution CO_2 transport and sequestration costs statistically in order to gain insight into cost ranges and identify opportunities for the most impactful cost reduction. In Figure 15 we sort the source-sink pairs of all evaluated potential projects by unit cost (vertical axis) and plot them according to the cumulative CO_2 volume over 25 years (horizontal axis). The bar plots allow us to observe the trend not only for the integrated cost, but also for the contributing elements.

Over this 25-year project period, the integrated unit costs of all source-sink combinations range from about \$50/ton to \$450/ton. The integrated costs are clustered into three regions (marked by A, B, and C in Figure 15. The least expensive options in region A range from \$50/ton to \$75/ton and share some common features. They include CO_2 transported via pipeline or ship to onshore sequestration sites (i.e. no offshore platform costs). For these options, subsurface storage costs do not dominate, suggesting good reservoir quality at these sites. About one-third to one half of the integrated costs are in compression for pipeline or liquefaction and loading costs for shipping, which can be the focus for future cost reduction effort.

The middle range of costs, region B, ranging from \$75/ton to \$150/ton, contains most of the offshore sequestration options accessible via ship transport. Costs for liquefaction, loading, and unloading via an offshore platform comprise about 50% of the total costs. The least expensive options in this group have relatively low sequestration costs, whereas the more expensive options have sequestration costs in excess of 30% of the total costs.

Finally, the most expensive options, region C, ranging in cost from \$150/ton to \$450/ton, are very long-distance pipeline options that, while technically possible, would likely be difficult to pursue without some breakthrough technologies on pipeline costs and durability.

Overall, our data show that the costs to transport and sequester CO_2 from Singapore to regional storage options are well within the range that would allow CCS to contribute significantly to ASEAN CO_2 abatement efforts. It is important to emphasize, however, the very coarse-grained nature of these cost estimates. They do provide a reasonable relative cost for different source-sink matching options, but absolute costs of individual projects are subject to further evaluations of site-specific conditions, reusability of existing infrastructure, as well as technological breakthroughs of CO_2 pipeline and shipping transport.

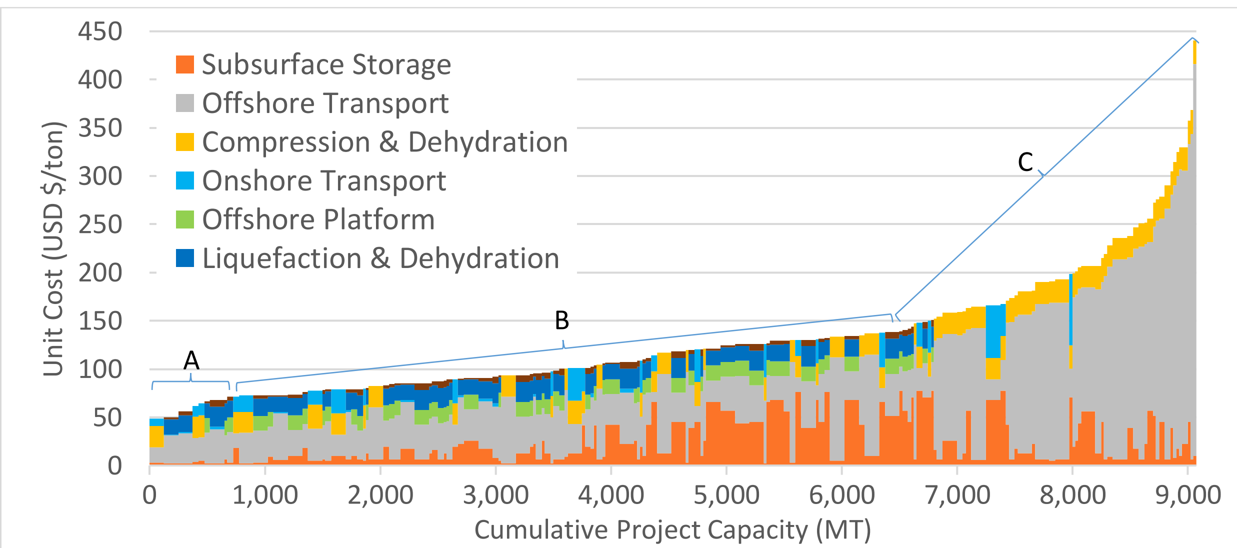


Figure 15: Cost vs. Cumulative Project Volume curve for all options considered in the Singapore CCS hub model for 25-year projects. Projects are sorted by integrated unit cost. Cost elements are denoted by different colors. Bars width indicates individual project size

Policy and Regulatory Considerations

This paper has identified significant carbon storage potential in ASEAN, highlighting the critical role that CCS could play in achieving large scale CO_2 emission reductions across south-east Asia. Realizing this potential will require significant regional co-operation to develop a network of CCS hubs that connect CO_2 sources through transportation networks and storage infrastructure to safely inject and permanently store CO_2 safely in the deep subsurface. We have presented a range of cost estimates to establish the necessary infrastructure, however, there is currently a significant gap between the potential to reduce CO_2 emissions and existing policies required to incentivize CCS in ASEAN Member States (AMS). The deployment of large-scale CCS hubs requires the implementation of durable legal and regulatory frameworks that will produce the greatest emissions reductions at the lowest cost to society.

We summarize the current status of the policy and regulatory frameworks of six AMS that could play a key role in developing a network of CCS hubs in the ASEAN region in Table 8. This includes a break-down of GHG emissions by different sectors, Nationally Determined Contribution (NDC) targets, CCS policies, existence of a carbon tax or Emissions Trading Scheme (ETS), summary of current CCS activities, relevant regulations and legislation and key stakeholders. It demonstrates the tremendous scale of the challenges faced in reducing current emissions for AMS to achieve stated NDC targets. In particular, the power and manufacturing sectors are significant contributors to current emissions in those countries representing sectors to which CCS can be effectively applied. This highlights the critical role CCS can play in providing large scale carbon abatement to support achieving the goals of the Paris Agreement.

Table 8 details that all six AMS do not have CCS formally included in current climate and energy policy. All except Singapore lack a current carbon tax or ETS. Furthermore, without additional supportive policies and regional, multinational alignment on incentivizing net global CO_2 emissions, the current framework is insufficient. While we acknowledge that CO_2 related regulatory frameworks in many countries are evolving rapidly, as of the date of publication, CO_2 is classified as GHG but not as a pollutant in environmental quality related acts, indicating that there is no legally binding commitment on handling CO_2 emissions, either in the form of incentives to capture CO_2 or in the form of penalties for emitting CO_2. Furthermore, CCS is not included in climate change or energy policy, except for a draft of presidential decree for a CCS general framework that was finalized in Indonesia. Law and regulations specifically designed for CCS governing activities, including ownership, license, surface/subsurface rights for CO_2 transport and storage are also absent.

Despite the lack of comprehensive policy and regulatory frameworks to support CCS, early attempts to study the feasibility of CCS in this region date back as early as 2003. These activities are predominantly focused on enhanced oil recovery (EOR) in the absence of other revenue mechanisms or incentives. Such studies and pilot projects include: CCS-EOR study of CCS-EOR at East Kalimantan, Indonesia in 2003 and CO2-EOR feasibility study and pilot test in Rang Dong oil field, Vietnam in 2007 and 2011 respectively (JX Nippon 2011). In 2012, the Indonesian government and PT Pertamina carried out a CSS pilot project with two Japanese firms and ADB at the Gundih Gas Field in East Java. In 2020 a commercial agreement to study development of CCS at a high-CO_2 gas field (K5 Greenfield) offshore Sarawak in Malaysia was signed between JOGMEC, JX NIPPON and PETRONAS. In July 2021 PTTEP announced it was considering a CCS Project to be installed at the Golok Field as part of the development of the Lang Lebah Field in offshore Sarawak Basin in Malaysia. Soon after, PETRONAS announced plans for the Kasawari CCS Project as part of the development of the Kasawari Gas Field offshore Sarawak Basin, awarding a concept engineering design contract to energy consultancy Xodus with start-up planned for 2025. In August 2021, BP and its Tangguh LNG partners announced that the Indonesian O&G regulator, SKK Migas, approved the plan of development (POD) for their CCUS project at the Tangguh LNG complex. Front End Engineering Design (FEED) work is expected to begin in 2022 with start-up targeted for 2026 tied to LNG expansion. These announcements represent initial steps towards what could be the first commercial scale CCS projects with earliest implementation in the 2025 to 2026 timeframe. However, they remain subject to further studies and final investment decisions before these projects become reality.

One of the key drivers for the implementation of successful CCS projects, for example, the Quest CCS Project in Alberta, Canada comes from the provision of direct government grants, made possible through the financial resources collected through established carbon pricing schemes including a carbon tax under the Specified Gas Emitters Regulation, 2007. The carbon tax acts as a penalty to incentivize large emitters to take action while providing a revenue source for financing CCS projects that require significant upfront costs. In the ASEAN context, as mentioned above and summarized in Table 8, Singapore is the only jurisdiction to have implemented a carbon tax. While other countries are exploring the idea of a carbon tax or ETS, they currently lack plans for implementation. At the time of this publication, a proposed ETS is being discussed and considered at a ministerial level and the introduction of a carbon tax as part of economic recovery in Indonesia (Tani 2021), while Vietnam has started implementing a similar tool, Carbon Payment for Forest Environment Services (C-PFES) in 2020. These initiatives could serve as a foundation for a more robust carbon tax system to be developed in this region. The Quest CCS Project example offers insight into how industry could drive CCS policy development. A planning process that is collaborative and responsive to the industry needs, facilitates knowledge sharing with initiatives to remove investment barriers, improve regulatory clarity and de-risk technology adoption is crucial for successful government-industry collaboration on CCS projects.

CCS deployment in ASEAN requires implementation of sound policy and regulatory frameworks to support CCS development. The ASEAN Plan of Action for Energy Cooperation (APAEC) Phase II (2021 – 2025) has highlighted the role of clean coal technology (CCT) and CCUS towards a low carbon economy while balancing energy affordability and security. CCT and other advanced processes to reduce the environmental impact of coal utilization have pointed to CCUS technology as an important contributor (ACE 2015). Meanwhile, some industries, such as pulp mills have been identified as promising candidates for post-combustion CCS (Onarheim 2017). Other than reducing GHG emission to the atmosphere, CCS technology also offers other benefits: non-CO_2 pollutants control, direct foreign investment and technology transfer and diversified employment prospects (Bonner 2017). Furthermore, the potential for net negative emissions or carbon removal is possible when CCUS is paired with biomass feeds providing an additional potential target for consideration. Policy makers in AMS could explore co-benefits and the possibility of implementing CCS through regional collaboration by leveraging the strengths of all countries.

While there is significant CO_2 storage potential in the ASEAN region, there is an absence of equal access to geological sequestration sites across AMS. There will be practical challenges for countries like Singapore to engage in CCS projects due to land space constraints and a lack of indigenous storage options. CCS solutions for Singapore will require offshore sequestration options involving the transportation and storage of CO_2 in adjacent countries with excess CO_2 storage capacity. In the absence of a regional framework for CCS development, bilateral arrangements provide a potentially more practical pathway in the near-term although such bilateral arrangements will present their own set of challenges. Petronas's stated interest in monetizing excess CO_2 sequestration capacity to establish itself as a regional CO_2 sequestration hub (Evans 2021), provides opportunities for AMS like Singapore to engage in bilateral arrangements with countries and/or national oil companies interested in commercializing their excess CO_2 storage capacity. Regionally agreed decarbonization targets and alignment on the role that CCS could provide in achieving those targets would support CCS development and collaboration. Additionally, the development of a region-wide capacity trading mechanism providing for transborder CO_2 transportation and storage could help AMS achieve their NDCs.

The ASEAN region is endowed with significant CO_2 storage potential in depleted O&G fields and saline formations. Realizing this potential to achieve large scale carbon abatement requires the implementation of durable legal and regulatory frameworks that will produce the greatest emissions reductions at the lowest cost to society. We recommend governments in the ASEAN region focus on policy and regulations that: 1) establish sufficient financial incentives that place a value on reducing net emissions such as a price on carbon or ETS, provide government grants and incentives, tax credits or other similar mechanisms to drive the necessary investments as carbon markets develop; 2) create clear and supportive legal and regulatory frameworks that provide certainty for accessing storage, enable the capture, transportation, injection and monitoring of CO_2 including derisking long-term liabilities for permanently stored CO_2; 3) foster government to government cooperation to enable trans-border CO_2 transport to support the establishment of a network of CCS Hubs in the region through monetizing excess CO_2 storage capacity; and 4) encourage broad collaboration between industry, governments and key stakeholders to establish CCS Hubs and shared infrastructure to capture synergies and reduce costs through achieving significant economies of scale that will elevate the role of ASEAN in addressing the challenges of climate change and meet NDCs while providing a pathway for continued economic growth and prosperity.

Table 8: Greenhouse Gas Policy Aspects of selected Southeast Asian countries

	Indonesia	**Malaysia**	**Philippines**	**Thailand**	**Vietnam**	**Singapore**
Current Emission (w/o AFOLU/LUCF/LULUCF) [a]	822 MtCO2e (Government of Indonesia (a) 2018)	317 MtCO2e/ 0.286 tCO2/GDP (MESTECC 2018)	192 MtCO2 (World Bank 2016)	354 MtCO2 (MNRE 2017)	322 MtCO2e (Government of Vietnam (a) 2019)	52 MtCO2e (NCCS 2018)
Current Emission (with AFOLU/LUCF/LULUCF)	1,458 MtCO2e (Government of Indonesia (a) 2018)	75,488 MtCO2e/ 0.068 tCO2/GDP (MESTECC 2018)	121 MtCO2 (World Bank 2016)	263 MtCO2 (MNRE 2017)	284 MtCO2e (Government of Vietnam (a) 2019)	52 MtCO2e (NCCS 2018)
Emission (Power)	247 MtCO2e (Government of Indonesia (a) 2018)	131 MtCO2e (MESTECC 2018)	69 MtCO2 (IEA, Philippine Key Energy Statistics 2020)	107 MtCO2 (MNRE 2017)	44 MtCO2e (Government of Vietnam (a) 2019)	20.23 MtCO2e (NCCS 2018)
Emission (Manufacturing & Construction)	88 MtCO2e (Government of Indonesia (a) 2018)	24 MtCO2e (MESTECC 2018)	-	49 MtCO2 (MNRE 2017)	39 MtCO2e (Government of Vietnam (a) 2019)	24.28 MtCO2e (NCCS 2018)
Emission (IPPU)	55 MtCO2e (Government of Indonesia (a) 2018)	18 MtCO2e (MESTECC 2018)	15 MtCO2 (IEA, Philippine Key Energy Statistics 2020)	31 MtCO2 (MNRE 2017)	28 MtCO2e (Government of Vietnam (a) 2019)	-

	Indonesia	Malaysia	Philippines	Thailand	Vietnam	Singapore
NDC target	To reduce GHG emission by 29 % unconditionally and up to 41 % conditionally from the BAU by 2030[b] *BAU reference year: 2010 (Government of Indonesia (b) 2015)	To reduce GHG Emissions Intensity 35 % unconditionally and by 40 % and 45 % conditionally by 2020 and 2030[b] *baseline: 2005 (Government of Malaysia 2015)	To reduce 70 % of GHG emissions from BAU by 2030 (Republic of the Philippines 2015)	To reduce GHG emission by 20 % from BAU by 2030[b] *BAU reference year: 2005 (Government of Thailand 2015)	To reduce GHG emission by 9 % unconditionally and 27 %[b] conditionally by 2030 (Government of Vietnam (b) 2016)	To peak emissions at 65MtCO2e around 2030 and achieve a 36% reduction in Emissions Intensity (EI) from 2005 levels by 2030 (NCCS 2018)
Inclusion of CCS in current policy (climate/energy)	No	No	No	No	No	No
Carbon Tax (CT) / Emission Trading Scheme (ETS) / Partnership for Market Readiness (PMR)	CT proposed but not pursued, ETS to be discussed at ministerial level, PMR participant	CT proposed with no implementation plan, ETS not mentioned, non-PMR participant	CT and ETS proposed but not pursued, non-PMR participant	CT and ETS proposed but not pursued, PMR participant	Carbon Payments for Forest Environmental Services (C-PFES), PMR participant	From S$ 5 / tCO_2e to S$10 – S$15 / tCO_2e by 2030
CCS-specific policymaking/roadmap	Draft of presidential decree for CCS general framework was finalized	No	No	No	No	A series reports released by the National Climate Change Secretariat (NCCS 2018)
Potential financing for CCS	Clean Development Mechanism (CDM)/Article 6, ADB Grant, Joint Crediting Mechanism					

	Indonesia	Malaysia	Philippines	Thailand	Vietnam	Singapore
CCS activities	LEMIGAS carried out preliminary study related to potential of CCS-EOR at East Kalimantan and South Sumatra in 2003 Two Japanese firms are planning a CO2-EOR project at Gundih Gas Field with Indonesian government and PT Pertamina through JCM since 2012 and to be completed by 2025 BP and its Tangguh LNG partners announced that the Indonesian O&G regulator has approved the plan of development (POD) for their CCUS project at the Tangguh LNG complex. Front End Engineering Design (FEED) work is expected to begin in 2022 with start-up targeted for 2026.	JOGMEC, JX Nippon, PETRONAS signed study agreement for developing CCS at high-CO2 gas field – K5 Greenfield CCS project in 2020 PTTEP is reportedly considering a CCS Project to be installed at the Golok Field as part of the development of the Lang Lebah Field, offshore Sarawak Basin (Upstream 2021) PETRONAS are progressing plans for the Kasawari CCS Project as part of the development of the Kasawari Gas Field offshore Sarawak Basin awarding a concept engineering design contract to energy consultancy Xodus (Upstream 2021) Petronas MPM is open to monetizing excess CO_2 capacity (Evans 2021)	No activities	No activities	PETROVIETNAM, JX NIPPON, JOGMEC conducted CO2-EOR feasibility study since 2007 and implemented a pilot test in Rang Dong oil field in 2011	A recent government report on CCU was published. (Navigant 2021). The Low Carbon Energy Research (LCER) grant awards aim to technologies for hydrogen and carbon capture, utilization, and storage (CCUS), to support the decarbonization of the power and industry sectors. announced in October 2021 (A*Star 2021) In 2021 ExxonMobil announced plans to develop a CCS hub concept to capture, transport and permanently store CO2 generated from Singapore's manufacturing facilities for storage in the region.
International commitment	Marine: International Maritime Organization (IMO), United Nations Convention on the Law of the Sea (UNCLOS) Climate: UNFCCC, Kyoto Protocol, Paris Agreement Others: Basel Convention					

Relevant regulation and legislation	- Guidelines for Inventorying and Mitigating Greenhouse Gases in the Energy Sector - Law No. 32/2009 on Environmental Protection and Management and Government Regulation (PP) No. 27/2012 on Environmental Permit - Environmental Impact Assessments: ANDAL (Environmental and Social Impact Assessment/Statement), RKL-RPL (Environmental and Social Management Plans), UKL-UPL (Upaya Pengelolaan dan Pemantauan Lingkungan), SPPL (Statement of Environmental Management and Monitoring Undertaking) - Gas transport (downstream): Government Regulations No. 36/2004 and MEMR Regulation No. 4/2018 regarding Business of Gas in Downstream O&G Budiness Activities - Gas transport (upstream): Law 22/2001 and MEMR Regulation no. 300/1997	- Environmental Quality Act 1974 (EQA): May apply if CO2 determined as pollutants, requiring pollution license, and pollution license has a term of one year - National Land Code and Petroleum Development Act may determine the rights to subsurface use - Under the Petroleum Mining Act, all exploration activity requires a permit or agreement with the appropriate authority - EIA could apply to sub-seabed storage. Approval of the EIA and associated EMP by the Malaysian Department of the Environment (DOE) must be obtained before other required approvals can be progressed - Regulations delegated to Petronas includes (partial or in conjunction to federal and state authority): Pore Space Ownership,	- Philippine Mining Act and Oil Exploration and Development Act - Philippine Environment al Impact Statement System - Right-of-Way Act - Toxic Substances and Hazardous Waste Act / Philippine Inventory of Chemical and Chemical Substances -Clean Air Act, Clean Water Act -Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas	- Petroleum Act - Thai Civil and Commercial Code Section 420 - Thai Civil and Commercial Code Section 1337 - Enhancement and Conservation of the National Quality Act Section 96, 97 - Thai Civil and Commercial Code Section 437 - Hazardous Substance Act - Article 420, Article 1337 - Minerals Act - Factory Act 1992 - Thai Industrial Standard Act 1968 - Public Health Act 1992 - Enhancement and Conservation of Natural Environmenta l Quality Act 1992 - Natural Gas Pipeline Transportatio n Act 2010 - Fuel Oil Control Act 1999	- Environmental Impact Assessment (EIA) laws - Petroleum Law and Mineral Law (exploration/ exploitation/ mining operations) - Decrees and Circulars on the management of wastes and scraps - Chemical Law - Technical and regulatory requirements relevant to CCS projects can be found (e.g. risk assessment)	- Environmental Protection and Management Act - Petroleum (Transport and Storage) Rules - Gas Act - Work Safety and Health Act

	Indonesia	Malaysia	Philippines	Thailand	Vietnam	Singapore
		Jurisdiction over Pipeline and Reservoirs, Storage and transportation		- Energy Industry Act 2007 - Hazardous Substance Act 1992		
Key stakeholders	Government: Ministry of Energy and Mineral Resources (MEMR), Ministry of Environment and Forestry (MEF), Ministry of National Development Planning (BAPPENEAS), Ministry of Finance (KEMENKEU) Companies: PLN (state-owned electricity company), Pertamina (state-owned O&G company), PGN (state-owned gas company) Academic/Expert Institution: Institute of Technology Bandung (ITB), WRI Indonesia	Government: Ministry of Science, Technology and Innovation (MOSTI), Ministry of Energy and Natural Resources, Ministry of Domestic Trade and Consumer Affairs, Ministry of Finance, Economic Planning Unit (EPU), state regulator Companies: PETRONAS	Government: Department of Environment and Natural Resources, Department of Energy, Department of Finance Companies: PNOC (Philippine National Oil Company), Shell (Philippine)	Government: Office of Natural Resources and Environment Policy and Planning (ONEP), Ministry of Natural Resource and Environment (MONRE), Ministry of Energy Thailand (MOE), Ministry of Finance, Energy Policy and Planning Office (EPPO), National Committee on Climate Change Policy, Thailand Greenhouse Gas Management Organisation (TGO), National Energy Policy Council (NEPC) Companies: PTT (state-owned O&G company)	Government: Ministry of Natural Resources and Environment, Ministry of Science and Technology, Ministry of Industry and Trade, Ministry of Finance Companies: PetroVietnam, Petrolimex, EVN (Vietnam Electricity), Vinacomin	Government: National Climate Change Secretariat (NCCS), National Environment Agency (NEA), Ministry of Sustainability and the Environment Companies: ExxonMobil, Shell, Singapore

[a]Agriculture, Forestry and Other Land Use (AFOLU); Land-Use Change, and Forestry (LUCF); Land Use, Land-Use Change, and Forestry (LULUCF).

[b]Indonesia: 29 % reduction equivalent to approx. 0.832 GtCO2 reduction, 41 % reduction equivalent to approx. 1.18 GtCO2 reduction; Malaysia: 35 % reduction equivalent to approx. 0.13 tCO2/GDP; Thailand: 20 % reduction equivalent to 111 MtCO2 reduction; Vietnam: 9 % reduction equivalent to 83.51 MtCO2 reduction, 27 % equivalent to 250.53 MtCO2 reduction.

Conclusions

Using the available geological and production data of the hydrocarbon fields, we provide comprehensive and robust estimates of the CO_2 storage potential of select countries in ASEAN for three categories: depleted O&G reservoirs, field-scale saline formations, and basin-scale saline formations. Collectively the conservative estimates of the storage capacity in O&G fields amount to 11.7 Gt, in field-scale saline formations 24.2 Gt, and in basin-scale saline formations 275 Gt. Although the uncertainties in these estimates increase significantly as the scale of these storage formations increase, such a large total storage potential estimate is consistent with published literature, providing sufficient storage for many decades of CO_2 sequestration in the region. We fill in the blank for the CO_2 injection rate estimation based on the historical average peak well production data. Our results show that only 23% of the evaluated fields can support CO_2 injection rate larger than 0.4 MTA per well. Nonetheless, these injection rate estimates reflect historical production technology that may date back a few decades. Therefore, significant improvements can be achieved with better injection technology and well management, after detailed geological information is evaluated at specific sites.

We envision a regional CCS hub model with CO_2 sources captured at one location such as Singapore and sequestered in the regional sinks. For such scenarios, assuming green field development with all new infrastructure, we provide an integrated cost model combining costs of compression and dehydration, transport, and storage. Considering the geographic locations of source and sinks, we compare transport options using onshore/offshore pipelines and using ships and conclude that ship transport of CO_2 is more cost effective for longer distances and smaller CCS projects. A statistical summary of costs of CCS from Singapore to all feasible regional sinks shows three clusters of cost regions. In the low cost ($50/ton to $80/ton) region, good reservoir-quality sinks are close to Singapore. Infrastructure and transport costs dominate the total cost. In the intermediate cost ($80/ton to $150/ton) region, we observe trade-offs between transport cost and storage cost. In the high cost (> $150/ton) region, distant, low-quality sinks require significant breakthrough in both transport and injection technologies in order to be commercially feasible for future CCS projects.

We highlight the need for a policy framework in which CCS is explicitly addressed amongst AMS. We identify key areas of policy framework design including 1) establishing sufficient financial incentives to reduce net global CO_2 emissions, 2) creation of clear and supportive legal and regulatory frameworks to derisk CCS projects, 3) fostering government to government cooperation that enables transborder CO_2 transport and 4) encouraging broad collaboration between all stakeholders.

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