EPRI

2025 TECHNICAL UPDATE

Powering Japan's Hydrogen Future

Australia's Coal Advantage with CCS

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ABSTRACT

This study evaluates production of low-carbon hydrogen in Japan from imported Australian black coal with high CO_2 capture at a reference Japanese site. Captured CO_2 is conditioned for ship transport and geological storage offshore in Malaysia. Methods are data-driven and traceable to a documented assumptions register, established reference designs, and public data sources.

The report presents a techno-economic analysis of plant performance and cost with parallel USD and JPY reporting; a life-cycle assessment of well-to-hydrogen greenhouse-gas intensity across defined temporal snapshots; and a market and delivery review for Japan. Marine logistics are modeled with baseline and future-state fuels for both coal delivery and CO_2 shipping. The deployment section outlines port interface requirements, long-lead equipment considerations, and the cross-border CO_2 transport framework under the London Protocol. Sensitivity cases for key variables are documented in the body of the report.

Keywords

CCS
Feasibility
Gasification
Hydrogen
Japan
Maritime

EXECUTIVE SUMMARY[1]

This study explores how Australia's high-quality black coal, paired with carbon capture and storage (CCS), could underpin Japan's ambitious hydrogen transition. The analysis demonstrates that coal-to-hydrogen with CCS offers a clean, reliable, and cost-competitive pathway to help Japan meet its hydrogen supply targets, while reinforcing Australia's role as a trusted energy partner.

The process involves producing hydrogen in Japan from imported Australian coal, capturing 92.5% of the associated carbon dioxide (CO_2), and transporting that CO_2 by ship to offshore geological storage sites in Malaysia. This approach delivers hydrogen with a carbon intensity that meets Japanese subsidy guidelines for clean fuels. Importantly, it does so without the additional costs and complexities associated with long-distance hydrogen shipping or ammonia cracking.

The cost of producing hydrogen through this method is estimated to be under USD $4 per kilogram, including capture, transport and storage of CO_2. This makes the pathway competitive with other emerging supply options such as renewables-based hydrogen and natural gas reforming with CCS. The technologies required – coal gasification, carbon capture, CO_2 shipping and offshore storage – are already in use around the world, meaning the technical risks are low. The central challenges lie instead in permitting, bilateral arrangements under the London Protocol for cross-border CO_2 storage, and timely execution.

For Japan, the scale of ambition is enormous. The Japanese Government has set targets of:

- 3 million tonnes of hydrogen supply annually by 2030
- 12 million tonnes by 2040, and
- 20 million tonnes by 2050.

Meeting these targets requires multiple supply chains to come online quickly. At the scale examined in this study, a build program of around twelve plants would be sufficient to deliver Japan's 2030 hydrogen goal. Coal with CCS therefore offers Japan a scalable option that can be deployed in the near-term, alongside renewable hydrogen and ammonia imports, helping diversify supply and reduce reliance on a single technology or pathway.

For Australia, the opportunity is equally significant. This model demonstrates how coal – one of Australia's most valuable exports – can be transformed into a clean fuel that supports both

[1] The Executive Summary was prepared by the Low Emission Technology Australia (LETA) and is included here for completeness. It reflects LETA's perspective and does not replace the detailed analysis presented in this report.

domestic jobs and regional decarbonization**.** By ensuring that coal can be part of Australia's net zero future, this pathway strengthens Australia's trading relationship with Japan while reinforcing our role as a supplier of reliable, low-emissions energy.

Ultimately, the findings show that coal-to-hydrogen with CCS is not a rival to renewables but a complementary option. It provides a credible pathway to scale up hydrogen supply quickly, at costs within the range of global benchmarks, and with emissions performance that qualifies as "clean" under Japanese policy settings. For decision-makers in both countries, this represents a practical and politically durable pathway that secures trade, delivers jobs, and accelerates emissions reductions in heavy industry.

TECHNICAL SUMMARY

Introduction

This study evaluates the feasibility of producing low-carbon hydrogen in Japan using imported Australian black coal with high CO_2 capture. Captured CO_2 is conditioned for ship transport and stored offshore in Malaysia. The simulated reference site is Takehara, Hiroshima Prefecture, selected for its industrial infrastructure and grid compatibility. The process configuration includes oxygen-blown entrained-flow gasification, sour shift, acid gas removal, and multi-stage CO_2 compression for low-pressure, low-temperature (LP/LT) ship loading.

Key Metrics Snapshot

- Levelized Cost of Hydrogen (LCOH): < USD $4/kg (¥606/kg)
- CO_2 Capture Rate: 92.5%
- Carbon Intensity (CI): < 3.4 kg CO_2/kg H_2 (meets Japanese subsidy threshold)

Techno-Economic Analysis

The TEA models a coal-to-hydrogen facility using NETL Case 5 and IGCC references. Capital costs are escalated to mid-2025 USD and localized to Japan using documented cost factors. Operating costs include coal delivery, purchased electricity, hydrogen purification, and CO_2 transport/storage tariffs. Results are reported in USD and JPY using a fixed exchange rate.

- LCOH remains below USD $4/kg (¥606/kg), competitive with other supply options.
- CO_2 compression adjusted for LP/LT shipping reduces auxiliary power requirements.
- Plant H_2 Production: ~2,000 tonnes/day.

Life-Cycle Assessment

The LCA uses the GREET+ model to quantify well-to-hydrogen GHG emissions across coal mining, shipping, gasification, CO_2 compression, and offshore storage. Temporal snapshots for 2025–2050 are included. Marine fuels evaluated include heavy fuel oil (HFO), liquefied natural gas (LNG), and green ammonia.

- The carbon intensity (CI) of hydrogen production remains below the 3.4 kg CO_2/kg H_2 threshold in every scenario modeled.
- CI is lowest when green ammonia is used as the marine fuel for coal shipping, reflecting its much lower upstream emissions compared to LNG or HFO.

- Marine fuels evaluated in the LCA
  - Coal shipping to Japan: 0.1% sulfur Heavy Fuel Oil (HFO), Liquefied Natural Gas (LNG), Green Ammonia
  - CO_2 shipping to Malaysia: LNG (baseline) and Blue Ammonia

Market Context

Japan targets 3 Mt H_2 by 2030, scaling to 20 Mt by 2050. Subsidy eligibility requires CI ≤ 3.4 kg CO_2/kg H_2 and production ≥ 1,000 t/year. Cost targets are ¥330/kg by 2030 and ¥220/kg by 2050. Coal gasification with CCS is a viable pathway alongside renewables and ammonia imports.

- ~15 plants at reference scale and capacity factor could meet 2030 target.
- Existing infrastructure from retiring coal plants can be leveraged.
- Utilities are pursuing diverse strategies including imports and on-site electrolysis.

Opportunities and Barriers

Deployment depends on legal, logistical, and infrastructure readiness. Cross-border CO_2 transport is constrained under the London Protocol but can proceed via bilateral agreements. LP/LT CO_2 carriers are under development; current vessel designs are medium scale. Malaysia's CCS legislation supports offshore storage, but public acceptance and MRV frameworks are critical.

- Bilateral agreements required for CO_2 export/import.
- Shipyard capacity and vessel standardization are key challenges.
- Malaysia's CCS Act 2025 provides regulatory support.
- Public outreach and stakeholder engagement needed for durable support.

ACRONYMS

Abbreviation	Definition
AGR	Acid Gas Removal
ANL	Argonne National Laboratory
ASU	Air Separation Unit
BFD	Block Flow Diagram
BC	Black Carbon
CCS	Carbon Capture and Storage
CF	Capacity Factor
CH_4	Methane
CI	Carbon Intensity
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
d	Day
EIA	Environmental Impact Assessment
ESIA	Environmental and Social Impact Assessment
FEED	Front End Engineering Design
FID	Final Investment Decision
GHG	Greenhouse Gas
H_2	Hydrogen
HFO	Heavy Fuel Oil
HHV	Higher Heating Value
HVAC	Heating, Ventilation, and Air Conditioning
IEA	International Energy Agency
JPY	Japanese Yen
LCA	Life Cycle Assessment
LCO_2	Liquid Carbon Dioxide
LCOH	Levelized Cost of Hydrogen
LNG	Liquefied Natural Gas
LP/LT	Low Pressure, Low Temperature
MRV	Monitoring, Reporting, and Verification
Mt	Million tonnes
MW	Megawatt

Abbreviation	Definition
MW_e	Megawatt Electrical
kW	Kilowatt
kW_e	Kilowatt Electrical
kWh	Kilowatt-hour
kWt	Kilowatt-thermal
NAR	Net As Received
NEM	National Electricity Market (Australia)
Mtpa	Million Tonnes Per Annum
NETL	National Energy Technology Laboratory
N_2O	Nitrous Oxide
nm	Nautical mile
NO_x	Nitrogen Oxides
OC	Organic Carbon
O&M	Operations and Maintenance
PM_{10}	Particulate Matter with aerodynamic diameter ≤10 µm
$PM_{2.5}$	Particulate Matter with aerodynamic diameter ≤2.5 µm
SO_x	Sulfur Oxides
STO	Submerged Turret Offloading
TEA	Techno-Economic Analysis
TG	Tail Gas
TGTU	Tail Gas Treating Unit
TOC	Total Overnight Cost
TPC	Total Plant Cost
T&S	Transport and Storage
USD	United States Dollar
VOC	Volatile Organic Compounds
WTG	Well-To-Gate
WTH	Well-To-Hydrogen

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. PROJECT INTRODUCTION

Introduction

This study evaluates the technical, economic, environmental, and deployment feasibility of producing low-carbon hydrogen in Japan from imported Australian black coal with high CO_2 capture and transporting the captured CO_2 by ship for offshore geological storage in Malaysia. The simulated reference site is the Takehara area in Hiroshima Prefecture of Japan, chosen for established coal import logistics, an industrial shoreline suitable for new loading infrastructure, and grid access compatible with a net power-importing facility. The process configuration centers on oxygen-blown entrained-flow gasification with sour shift and acid gas removal, followed by multi-stage CO_2 compression sized for ship loading under low-pressure, low-temperature conditions. Hydrogen is produced at high purity for plant-gate delivery to Japanese end uses, and CO_2 is conditioned for maritime transport and permanent storage.

The analysis is strictly data-driven. All boundary choices, data sources, and parameter values are governed by a documented assumptions register that records the design basis, fuels and logistics conventions, site and cost localization factors, and the baselines used across the work. Results presented in this report are traceable to that register for transparency and auditability.

Project Methodology

Techno-Economic Analysis (TEA)

The TEA models an integrated gasification with capture facility at the Takehara site using block flow diagrams and material and energy balances adapted from NETL reference reports. Performance modeling reflects local utilities and logistics. Capital costs are derived from established references suitable for feasibility studies, escalated to a single cost year, then localized with documented labor, productivity, and site factors. Operating costs follow the assumptions register, including delivered coal, a flat purchased-power input for the net import requirement, hydrogen purification to plant-gate specification, and a baseline tariff for CO_2 transport and storage. Results are reported in USD with parallel JPY values using one documented exchange-rate convention. Sensitivity cases are defined in the register and executed in the report body.

Life-Cycle Assessment (LCA)

The LCA quantifies well-to-gate greenhouse gas emissions within clearly defined system boundaries that include upstream coal mining, processing and rail transportation to Australian port, coal shipping to Japan, on-site coal gasification with high CO_2 capture, and maritime transport and storage of CO_2. Temporal snapshots reflect how system conditions evolve over time. Marine logistics are represented with HFO as the baseline fuel for both the coal delivery leg and LNG as baseline fuel for CO_2 shipping leg, with alternative cases for low-carbon fuels

documented separately. Numerical baselines such as voyage distances and operating assumptions are taken directly from the assumptions register for transparency and reproducibility. Results confirm that the modeled configuration achieves a carbon intensity consistent with Japanese subsidy thresholds for clean hydrogen.

Market Context and Delivery Considerations

This section compiles public information on Japan's hydrogen demand signals, sectoral use cases, and indicative price markers that frame viability, then links these to delivery requirements that govern real-world execution. It addresses interface needs for low-pressure CO_2 loading and unloading, long-lead procurement for gasifiers, air separation, acid gas removal, and compression, and the permitting touchpoints associated with CO_2 export from Japan and import for storage in offshore Sarawak, Malaysia. Barriers and opportunities are organized by theme, such as port infrastructure, shipping capacity, storage readiness, equipment lead times, and offtake specification alignment. Forward-looking considerations include the development of larger low-pressure CO_2 carriers and direct offshore injection systems, which are expected to improve cost and scalability over time.

Across all sections, one design basis is applied consistently for Takehara. Boundary choices, data sources, parameter values, reporting conventions, scenario naming, and the sensitivity framework are governed by the assumptions register to keep methods auditable and results traceable. USD and JPY reporting uses the same exchange-rate convention throughout.

2. TECHNO-ECONOMIC ANALYSIS

Key Cost Point

Clean hydrogen can be produced from coal gasification with overall carbon recovery of 92.5% at a levelized cost below $USD 4/kg (¥JPY 606/kg).

Key Benchmarking Point

The Coffeyville, Great Plains, and Qilu projects have demonstrated that large-scale production of low emissions hydrogen using carbon capture is technically and commercially feasible.

Introduction

Existing research knowledge bases were leveraged to provide foundational cost and performance benchmarks for adaptation in this study and to produce a process configuration to develop cost estimates and performance for coal gasification with carbon capture for hydrogen production as well as evaluate technology options and costs for maritime CO_2 shipping.

The techno-economic analysis (TEA) of the coal-to-hydrogen process utilized two U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) references — one that assessed cost and performance of select hydrogen production plants utilizing fossil fuel resources as primary feedstocks including coal gasification with CO_2 capture [1] and one that assessed the specific gasification technology of interest, but in an integrated gasification combined cycle (IGCC) application [2]. Additional details on how both these references were utilized in the TEA are provided in the following sections.

An additional NETL reference, NETL_CO2_S_COM_Offshore [3], was utilized to assess CO_2 storage costs specifically for an offshore setting. CO_2 transport costs were assessed using a similar and recent study [4] conducted by EPRI that estimated CO_2 shipping capital and operational costs from Japan to Malaysia. The assumptions and details of how these references were utilized are described in the following sections.

Design Basis

Coal Specification

Table 1 includes the coal specification [5] that was used for the analysis. Note in Table 1 that the proximate and ultimate analyses were provided on an air-dried (AD) and dry, ash-free (DAF) basis, respectively. For this study, the coal bases for the proximate and ultimate analyses were converted to an as-received (AR) basis as shown in the third column of the table.

Coal Price

A coal price of $USD115/tonne was used in the analysis based on the 2025 price forecast in LETA's May 28, 2025, Queensland Thermal Coal Price Forecast Final Market Report.

Plant Site

LETA evaluated several of the Japanese Advanced CCS locations in the region that are establishing carbon capture, utilization, and storage (CCUS) hubs, including a few coal power stations. These sites provided foundational cost and performance benchmarks for adaptation in this study. The analysis drew on insights from the Japan Organization for Metals and Energy Security (JOGMEC) Japanese Advanced CCS Project. The specific site selected for simulation of the techno-economic analysis was JPOWER's Takehara Thermal Power Station. Takehara provided an ideal location for the study since it had an existing coal unloading and handling facility as shown in Figure 1.

Figure 1. Google Map view of JPOWER's Takehara Thermal Power Station

Table 1. Coal specification

Sample Number	SQ32							
Total Moisture	7.20%			**ASH ELEMENTAL ANALYSIS**			**ASH FUSION TEMPERATURES (°C)**	
				Silicon Dioxide (SiO_2)	46.10%		Initial Deformation	1240
PROXIMATE ANALYSIS				Aluminum Oxide (Al_20_3)	17.80%		Spherical	1280
AR, AD, D, DAF	AD	AR		Iron Oxide (Fe_20_3)	14.62%		Hemispherical	1290
Inherent Moisture	1.30%	7.20%		Calcium Oxide (CaO)|	11.49%		Flow	1320
Ash	19.90%	18.71%		Magnesium Oxide (MgO)	2.48%			
Volatile Matter	19.10%	17.96%		Sodium Oxide (Na_20)	0.24%		**HARDGROVE GRINDABILITY**	75
Fixed Carbon	59.70%	56.13%		Potassium Oxide (K_20)	1.21%		Chlorine (% AD)	0.06%
Total	100.00%	100.00%		Titanium Oxide (TiO_2)	0.62%			
Specific Energy (MJ/kg) HHV	27.63	25.98		Manganese Oxide (Mn_30_4)	0.14%			
				Sulphur Trioxide (SO_3)	3.75%			
ULTIMATE ANALYSIS				Phosphorus Pentoxide (P_20_5)	0.66%			
AR, AD, D, DAF	DAF	AR		Barium Oxide (BaO)	0.03%			
Total Carbon	88.10%	65.27%		Strontium Oxide (SrO)	0.04%			
Hydrogen	4.57%	3.39%		Zinc Oxide (ZnO)	0.01%			
Nitrogen	1.70%	1.26%		Undetermined (100-all above)	0.81%			
Sulphur	0.90%	0.67%		Total	100.00%			
Oxygen (by difference)	4.73%	3.50%						
Ash		18.71%		Silica to alumina ratio (SiO_2/Al_20_3)	2.59			
Moisture		7.20%		Silica ratio (100 SiO_2/SiO_2+Fe_203+CaO+MgO)|	61.72			
Total	100.00%	100.00%		Fe_20_3+CaO	26.11%			

Coal-to-Hydrogen Process

The coal-to-hydrogen process design used in this TEA is a combination of two DOE/NETL process designs. The NETL H_2 study [1] [6] was the primary basis of the process design, with modifications based on the slurry-fed NETL IGCC study [2] [7]. The combination of these two designs is summarized as a LETA H_2 process and shown as a BFD in Figure 2.

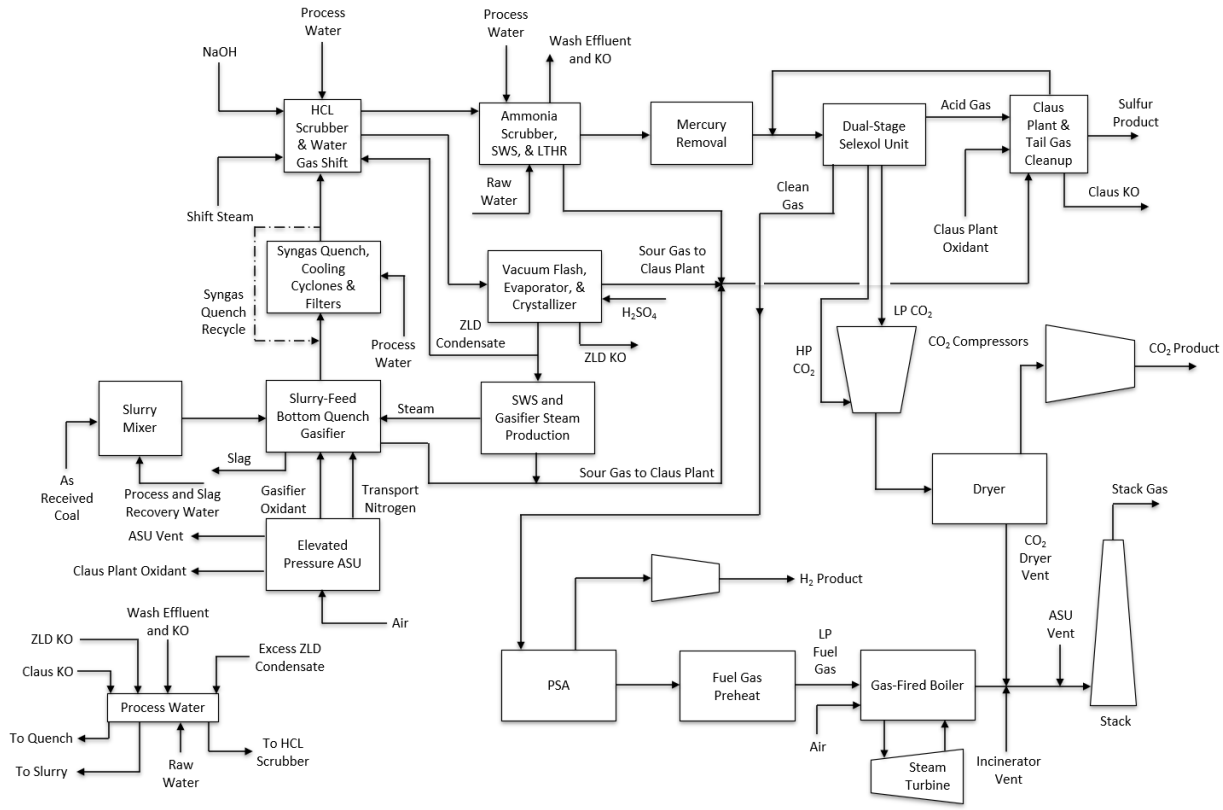

Figure 2. BFD of LETA H_2, slurry-fed, entrained flow, quench gasification hydrogen production process

The NETL H_2 case 5 is based on two dry-fed quench gasifiers[2], feeding 5,600 tonne/d of Illinois #6 coal, producing 660,000 kg/d of H_2. This case reported an overall carbon removal of 92.5%, which is being used as the basis for this study. For a higher conversion to less than 1% CO slip, an additional CO shift reaction stage would be required, which was not considered for this study.

[2] Since 2018, an Air Products offering – formally a Shell gasifier.

The NETL IGCC process, Case B5B-Q is based on two slurry-fed gasifiers[3], feeding 5,257 tonne/d of Illinois #6 coal. This case was leveraged to capture the gasifier performance and quench equipment required and was incorporated into the LETA H_2 process design.

Hydrogen and CO_2 Product Specifications and Delivery Pressures

The hydrogen product specification from Case 5 of the NETL H_2 study, shown in Table 2, was assumed to be the same for this study.

Table 2. Hydrogen product specification

Characteristic	Specification
H_2 Purity (vol%)	99.90 (min.)
CO_2 (ppm)	A
CO (ppm)	A
H_2S (ppb)	10 (max.)
H_2O (ppm)	A
O_2 (ppm)	A
Pressure (kPa)	6,479

[A]The maximum total concentration of all oxygen-containing species is 10 ppm

CO_2 transport from Japan to Malaysia was based on low pressure, low temperature ship transport. Based on the Capital Gas Ship Management Corporation's analog, this would put the CO_2 pressure at range of 0.7–1.0 MPa, so a CO_2 delivery pressure of 1.0 MPa was used.

Cost Basis

The factored cost estimate approach used in the analysis is commensurate with an AACE Class 5 cost estimate. Capital costs from the NETL H_2 and IGCC studies, both based in December 2018 USD, were escalated to mid-2025 USD using Chemical Engineering Plant Cost Index (CEPCI) [8] values. After the capital costs were escalated to 2025 USD at a U.S. plant site, the costs were translated to the Japan site location using location factor adjustments for equipment, materials, and labor and then converted to JPY.

The study-specific financial parameters used in the economic analysis are presented in Table 3. The purchased electricity cost used was based on the retail electricity price for businesses as of December 2024 and includes the cost of power, distribution and transmission, and all taxes and fees [9]. The discount rate of 3% was based on a power generation cost analysis [10] performed by the Ministry of Economy, Trade, and Industry (METI) when they developed the 7th National

[3] Since 2019 an Air Products offering – formally a GE gasifier.

Strategic Energy Plan, which was approved by the Japanese Cabinet in February 2025. Although the METI study used a 40-year economic life assumption for thermal plants, this study used a 30-year economic life, which was more appropriate for a gasification with CCS project.

Table 3. Financial parameters

Item	Value
Purchased Electricity Cost, $USD/MWh (¥JPY/MWh)	19.80 (2,999)
Discount Rate, %	3.0
Economic Life, years	30

Overall Gasification Heat and Material Balance

Heat and material balance data from both the NETL hydrogen and IGCC studies were used to develop the overall heat and material balance for the coal-to-hydrogen facility with CO_2 capture. The overall heat and material balance data is summarized in Table 4.

Table 4. Overall gasification heat and material balance

Item	Units	Quantity
LETA Coal Thermal Input	kWt	1,651,082
LETA Coal HHV (AR)	MJ/kg	25.98
LETA Coal Flow Rate	kg/h	228,802
LETA Coal Flow Rate (AR)	tonne/day	5,491
LETA H_2 Production Rate	kg/hr	28,418
	tonne/day	682
Carbon Balance		
Total Carbon in Feed Coal	tonne/day	3,082
Carbon in CO_2/Carbon in Coal		92.5%
Carbon in CO_2	tonne/day	2,851
CO_2 Product	tonne/day	10,447
Carbon in Slag/Carbon in Coal		0.5%
Slag Production		
Ash	tonne/day	1,027
Carbon in Ash	tonne/day	15
Total Slag	tonne/day	1,043
Sulfur Production	tonne/day	37

Auxiliary Power

The plant power summary data from Case 5 of the NETL H_2 study was used as the basis for estimating the power balance for the coal-to-hydrogen facility. Due to differences in the design basis between this and the NETL H_2 study, a few adjustments were made to the auxiliary loads for the air separation unit (ASU) main air and booster compressors, CO_2 compression, and H_2 compression.

Air Separation Unit

Case 5 of the NETL H_2 study used two Air Products dry-fed gasifiers while this study is based on two Air Products slurry-fed gasifiers. Because the oxygen requirement for slurry-fed gasifiers is approximately 5% higher than dry-fed gasifiers, the power requirement for the main air and booster compressors was increased by the same percentage.

CO_2 Compression

The CO_2 delivery pressure was reduced from 15.27 MPa to 1.0 MPa due to ship transportation as opposed to pipeline. The reduction in power requirement for the low- and high-pressure CO_2 compressors is calculated in Table 34 in the Appendix, which shows that the total CO_2 compression power is reduced to 8,113 kW.

H_2 Compression

Although the H_2 delivery pressure is unchanged from the reference case, the total H_2 gas flow rate was increased slightly from 27,500 to 28,418 kg/hr. The increase in power requirement for the H_2 compressor is calculated in Table 35 in the Appendix, which shows the total power is increased to 10,766 kW.

Complete Power Balance – LETA H_2 Process Design

The LETA case power balance is shown in Table 5. Based on a total gross power output of 109,000 kW and total auxiliary power load of 128,150 kW, the net power is -19,150 kW, indicating that 19.15 MW of purchased electricity is required at design load.

Table 5. Power balance

Item	LETA Case		Item	LETA Case
Power Summary				
Steam Turbine Power, MWe	109			
Total Gross Power, MWe	109			
Auxiliary Load Summary			**Auxiliary Load Summary (continued)**	

Acid Gas Removal, kWe	11,640		Miscellaneous Balance of Plant[A], kWe	2,520
Air Blower, kWe	780		N2 Compressors, kWe	2,390
Air Separation Unit Auxiliaries, kWe	1,000		O2 Pump, kWe	330
Air Separation Unit Main Air Compressor, kWe	**68,990**		Quench Water Pump, kWe	330
Air Separation Unit Booster Compressor, kWe	**5,421**		Shift Steam Pump, kWe	310
Ammonia Wash Pumps, kWe	120		Slag Handling, kWe	550
Circulating Water Pumps, kWe	3,340		Slag Reclaim Water Recycle Pump, kWe	0
Claus Plant TG Recycle Compressor, kWe	1,240		Slurry Water Pump, kWe	0
Claus Plant/TGTU Auxiliaries, kWe	250		Sour Gas Compressors, kWe	140
CO_2 Compression, kWe	**8,113**		Sour Water Recycle Pumps, kWe	0
Coal Handling, kWe	460		Steam Turbine Auxiliaries, kWe	90
Coal Milling, kWe	2,180		Syngas Recycle Compressor, kWe	880
Condensate Pumps, kWe	150		Syngas Scrubber Pumps, kWe	120
Cooling Tower Fans, kWe	1,730		Process Water Treatment Auxiliaries, kWe	1,310
Dryer Air Compressor, kWe	80		Transformer Losses, kWe	950
Feedwater Pumps, kWe	1,600			
Gasifier Water Pump, kWe	40		**Total Auxiliaries, kWe**	128,150
Ground Water Pumps, kWe	330		**Total Auxiliaries, MWe**	128
Hydrogen Compressor, kWe	**10,766**		**Net Power, MWe**	-19.15

Note increase in auxiliary loads for ASU Main Air and Booster Compressor, CO_2 Compression, and H_2 Compressor.

[A] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads.

Capital Cost Estimate

The capital cost estimates from both the NETL IGCC and H_2 studies were used as the basis for the estimate, and the aggregated estimate based in December 2018 USD and U.S. location is shown in Table 6. Note that Plant Areas 1–4 used costs associated with the Air Products slurry-fed gasifier, while costs for the remaining Plant Areas were based on the NETL H_2 study. Also note that total engineering cost is approximately 16% of bare erected cost (BEC) and project contingency is approximately 20% of the sum of BEC and engineering costs; these percentages were used to translate costs to the Japan location.

The capital costs in Table 6 were then adjusted to account for the 3.3% higher H_2 production rate in the LETA case. For the adjustment, a scaling exponent of 0.7 was used and applied to the Equipment, Materials, Labor, Engineering, Process Contingency, and Project Contingency values for Plant Areas 5–14. The adjusted capital costs are shown in Table 7.

The adjusted capital costs in Table 7 were then escalated to mid-2025 USD using the CEPCI Index values from December 2018 (605.2) and mid-2025 (786.1). Escalation was applied to Equipment, Materials, Labor, Engineering, Process Contingency, and Project Contingency values for all Plant Areas. The escalated capital costs are shown in Table 8.

The escalated capital costs in Table 10 were then translated to a Japan location by reviewing data from the 2023 Richardson International Cost Factors [11], 2023 Compass Global Construction Cost Yearbook [12], and the 2025 Arcadis International Construction Costs [13]. Based on the review of the references, the following assumptions for cost factors were used in translating the costs shown in Table 9:

- Equipment Cost Factor: 1.10.
- Material Cost Factor: 1.10.
- Labor Rate Factor: 0.70.
- Labor Productivity Factor: 1.20.
- Overall, Labor Cost Factor: 0.84.

Using the 2024 average USD to JPY currency conversion rate of 151.45 Yen/USD [14], the translated costs in Table 9 were converted to JPY shown in Table 10.

Table 6. LETA capital costs in $1,000 of December 2018 USD in U.S. location

Plant Area	Description	Equipment	Materials	Labor	Bare Erected Costs	Engineering Costs	Process Contingency	Project Contingency	Total Plant Costs
1	Coal Handling	39,933	87	10,424	50,444	7,567	0	11,602	69,613
2	Coal Prep & Feed	16,881	4,221	8,583	29,685	4,453	0	6,827	40,965
3	Feedwater & Misc BOP	82,946	9,105	55,245	147,296	22,094	0	49,159	218,549
4	Gasifier, ASU & Aux.	440,909	30,541	274,548	745,998	121,557	86,694	147,147	1,101,396
5	Syngas Cleanup	386,428	16,078	199,668	602,174	90,326	48,134	148,018	888,652
6	Hydrogen Production	25,306	296	2,590	28,192	4,229	0	6,484	38,905
7	Gas Boiler, Ducts, Stack	4,857	773	2,016	7,646	1,147	0	1,818	10,611
8	Steam Turbine & Acc.	33,440	2,599	6,619	42,658	6,399	0	9,981	59,038
9	Cooling Water System	19,493	5,414	9,967	34,874	5,231	0	6,833	46,938
10	Slag recovery & Handling	5,112	506	3,612	9,230	1,384	0	1,765	12,379
11	Accessory Electric Plant	30,926	1,530	9,643	42,099	6,315	0	7,771	56,185
12	Instrument & Control	14,943	386	3,788	19,117	2,868	824	3,737	26,546
13	Site Improvements	3,009	2,354	15,806	21,169	3,175	0	7,303	31,647
14	Buildings & Structures	0	5,731	6,869	12,600	1,890	0	2,174	16,664
	Total	1,104,183	79,621	609,378	1,793,182	278,635	135,652	410,619	2,618,088

Table 7. LETA capital costs in $1,000 of December 2018 USD in U.S. location adjusted for increased H_2 production

Plant Area	Description	Equipment	Materials	Labor	Bare Erected Costs	Engineering Costs	Process Contingency	Project Contingency	Total Plant Costs
1	Coal Handling	39,933	87	10,424	50,444	7,567	0	11,602	69,613
2	Coal Prep & Feed	16,881	4,221	8,583	29,685	4,453	0	6,827	40,965
3	Feedwater & Misc BOP	82,946	9,105	55,245	147,296	22,094	0	49,159	218,549
4	Gasifier, ASU &Aux.	440,909	30,541	274,548	745,998	121,557	86,694	147,147	1,101,396
5	Syngas Cleanup	395,419	16,452	204,314	616,185	92,428	49,254	151,462	909,329
6	Hydrogen Production	25,895	303	2,650	28,848	4,327	0	6,635	39,810
7	Gas Boiler, Ducts, Stack	4,970	791	2,063	7,824	1,174	0	1,860	10,858
8	Steam Turbine & Acc.	34,218	2,659	6,773	43,651	6,548	0	10,213	60,412
9	Cooling Water System	19,947	5,540	10,199	35,685	5,353	0	6,992	48,030
10	Slag recovery & Handling	5,231	518	3,696	9,445	1,416	0	1,806	12,667
11	Accessory Electric Plant	31,646	1,566	9,867	43,079	6,462	0	7,952	57,492
12	Instrument & Control	15,291	395	3,876	19,562	2,935	843	3,824	27,164
13	Site Improvements	3,079	2,409	16,174	21,662	3,249	0	7,473	32,383
14	Buildings & Structures	0	5,864	7,029	12,893	1,934	0	2,225	17,052
	Total	1,116,364	80,451	615,441	1,812,256	281,496	136,791	415,177	2,645,720

Table 8. LETA capital costs in $1,000 of mid- 2025 USD in U.S. location

Plant Area	Description	Equipment	Materials	Labor	Bare Erected Costs	Engineering Costs	Process Contingency	Project Contingency	Total Plant Costs
1	Coal Handling	51,869	113	13,540	65,522	9,829	0	15,070	90,421
2	Coal Prep & Feed	21,927	5,483	11,149	38,558	5,784	0	8,868	53,210
3	Feedwater & Misc BOP	107,739	11,827	71,758	191,324	28,698	0	63,853	283,875
4	Gasifier, ASU &Aux.	572,701	39,670	356,613	968,984	157,892	112,608	191,131	1,430,614
5	Syngas Cleanup	513,614	21,370	265,385	800,369	120,055	63,976	196,735	1,181,136
6	Hydrogen Production	33,635	393	3,442	37,471	5,621	0	8,618	51,710
7	Gas Boiler, Ducts, Stack	6,456	1,027	2,680	10,163	1,525	0	2,416	14,103
8	Steam Turbine & Acc.	44,446	3,454	8,798	56,698	8,505	0	13,266	78,469
9	Cooling Water System	25,909	7,196	13,247	46,352	6,953	0	9,082	62,387
10	Slag recovery & Handling	6,795	673	4,801	12,268	1,840	0	2,346	16,453
11	Accessory Electric Plant	41,105	2,034	12,817	55,955	8,393	0	10,329	74,677
12	Instrument & Control	19,861	513	5,035	25,409	3,812	1,095	4,967	35,283
13	Site Improvements	3,999	3,129	21,008	28,136	4,220	0	9,707	42,063
14	Buildings & Structures	0	7,617	9,130	16,747	2,512	0	2,890	22,149
	Total	1,450,056	104,498	799,402	2,353,956	365,638	177,679	539,277	3,436,551

Table 9. LETA capital costs in $1,000 of mid-2025 USD in Japan location

Plant Area	Description	Equipment	Materials	Labor	Bare Erected Costs	Engineering Costs	Process Contingency	Project Contingency	Total Plant Costs
1	Coal Handling	57,056	124	11,373	68,554	10,648	0	15,840	95,043
2	Coal Prep & Feed	24,120	6,031	9,365	39,515	6,138	0	9,131	54,784
3	Feedwater & Misc BOP	118,513	13,009	60,277	191,799	29,792	0	44,318	265,910
4	Gasifier, ASU &Aux.	629,971	43,637	299,555	973,163	151,161	107,807	224,865	1,456,995
5	Syngas Cleanup	564,975	23,507	222,924	811,406	126,035	67,163	187,488	1,192,092
6	Hydrogen Production	36,999	433	2,892	40,323	6,263	0	9,317	55,904
7	Gas Boiler, Ducts, Stack	7,101	1,130	2,251	10,482	1,628	0	2,422	14,532
8	Steam Turbine & Acc.	48,891	3,800	7,390	60,081	9,332	0	13,883	83,295
9	Cooling Water System	28,500	7,916	11,128	47,543	7,385	0	10,986	65,913
10	Slag recovery & Handling	7,474	740	4,033	12,246	1,902	0	2,830	16,978
11	Accessory Electric Plant	45,215	2,237	10,766	58,218	9,043	0	13,452	80,714
12	Instrument & Control	21,847	564	4,229	26,641	4,138	1,189	6,156	38,124
13	Site Improvements	4,399	3,442	17,647	25,488	3,959	0	5,889	35,336
14	Buildings & Structures	0	8,379	7,669	16,048	2,493	0	3,708	22,249
	Total	1,595,061	114,948	671,498	2,381,507	369,917	176,159	550,285	3,477,869

Table 10. LETA capital costs in ¥Million of mid-2025 JPY in Japan location

Plant Area	Description	Equipment	Materials	Labor	Bare Erected Costs	Engineering Costs	Process Contingency	Project Contingency	Total Plant Costs
1	Coal Handling	8,641	19	1,723	10,383	1,613	0	2,399	14,394
2	Coal Prep & Feed	3,653	913	1,418	5,985	930	0	1,383	8,297
3	Feedwater & Misc BOP	17,949	1,970	9,129	29,048	4,512	0	6,712	40,272
4	Gasifier, ASU &Aux.	95,409	6,609	45,368	147,386	22,893	16,327	34,056	220,662
5	Syngas Cleanup	85,566	3,560	33,762	122,887	19,088	10,172	28,395	180,542
6	Hydrogen Production	5,603	66	438	6,107	949	0	1,411	8,467
7	Gas Boiler, Ducts, Stack	1,075	171	341	1,588	247	0	367	2,201
8	Steam Turbine & Acc.	7,405	575	1,119	9,099	1,413	0	2,103	12,615
9	Cooling Water System	4,316	1,199	1,685	7,200	1,118	0	1,664	9,983
10	Slag recovery & Handling	1,132	112	611	1,855	288	0	429	2,571
11	Accessory Electric Plant	6,848	339	1,631	8,817	1,370	0	2,037	12,224
12	Instrument & Control	3,309	85	641	4,035	627	180	932	5,774
13	Site Improvements	666	521	2,673	3,860	600	0	892	5,352
14	Buildings & Structures	0	1,269	1,161	2,430	378	0	562	3,370
	Total	241,572	17,409	101,698	360,679	56,024	26,679	83,341	526,723

CO_2 Transportation and Storage

The technoeconomic assessment for CO_2 transport and storage builds upon the capture and compression results described in the preceding section. For the transport analysis, the approach follows the methodology and key parameters outlined in an EPRI study evaluating ship-based CO_2 delivery from Osaka Bay, Japan, to offshore Malaysia for direct offshore injection [4]. Storage cost estimates are developed using the NETL_CO2_S_COM_offshore model, which incorporates site development, well drilling, injection, monitoring, and operational costs for offshore geological storage [3]. Together, these models provide a consistent framework to quantify transport and storage costs under the defined scenario. Figure 3 displays the portion of the CCS infrastructure value chain that is included in the cost estimates.

General cost modelling assumptions for CO_2 transport and storage included:

- Port to direct injection configuration.
- Transport from Osaka Bay to Kasawari Field, offshore Sarawak, Malaysia (one-way distance of 2,726 nautical miles)
- An injection rate of 3.80 Mtpa.
- Project lifetime of 30 years.
- Capital recovery period of 30 years.
- Discount rate of 3%.
- Fluid is supplied at appropriate thermodynamic conditions for transport by a low pressure, low temperature (LP/LT) ship.
- Fluid is compliant with CO_2 purity specifications required for LP/LT CO_2 ship.

Figure 3 Illustration of the CCS value chain with shipping and offshore direct injection that was included in cost modeling (EPRI, 2025).

Buffer Storage

In ship-based CO_2 transport systems, buffer storage at or near the export terminal plays a critical role in maintaining continuous capture and compression operations while accommodating the variable schedule of ship arrivals. Without sufficient buffer capacity, any disruption or delay in ship loading could force a curtailment of capture operations, resulting in reduced system

utilization and higher unit costs. Buffer storage enables decoupling of capture from transport, providing operational flexibility to handle ship scheduling constraints, port congestion, or short-term outages.

For this assessment, buffer storage capacity is assumed to be 22% of the system's daily or multi-day transport capacity, consistent with values adopted in existing large-scale CO_2 shipping projects such as Northern Lights. This capacity is sized to store liquefied CO_2 at the specified shipping pressure and temperature—in this case, LP/LT conditions at a density of 1,150 kg/m³—providing adequate coverage for expected ship turnaround times and minor delays. The assumed buffer capacity reflects a balance between operational resilience and additional capital cost for storage infrastructure.

Loading Facilities

Loading facilities serve as the critical interface between the onshore buffer storage and the LP/LT CO_2 carriers. For this assessment, the loading system is assumed to include insulated transfer pipelines, cryogenic loading arms, and associated pumping equipment capable of maintaining product temperature and pressure during transfer. Design capacity is sized to allow a vessel to be loaded within the operational window defined by port scheduling while meeting safety and environmental standards for cryogenic liquid handling. The system configuration and throughput are matched to the LP/LT ship capacity and frequency of loading, ensuring compatibility with the buffer storage inventory and minimizing berth occupancy times.

CO_2 Shipping

The CO_2 shipping analysis is based on the use of LP/LT vessels modeled after Capital Gas Ship Management Corporation's 26,400 m³ capacity design, which are the only low-pressure ships ordered at present and are expected to be delivered in 2025 and 2026 [4]. At the specified shipping conditions of approximately 6.5 bar and –50 °C, the cargo density is assumed to be 1,150 kg/m³, yielding a per-vessel payload of approximately 30,360 tonnes of liquid CO_2 per voyage. This vessel class has been selected for its large cargo capacity and anticipated operational efficiency over long-haul marine routes. Although companies are currently developing working concepts for larger capacity LP/LT CO_2 vessels comparable to LNG ships, the 26,400 m^3 was used as an analog given its availability today.

For the defined transport scenario, the shipping route from Osaka Bay, Japan, to the offshore Malaysia injection site is 2,726 nautical miles one way. Assuming an average service speed of 12 knots, the one-way sailing time is approximately 9.45 days, with a total round-trip time of 18.9 days excluding port operations. To meet the continuous delivery requirements of the project while maintaining operational resilience, the cost model assumes the deployment of eight LP/LT vessels. This fleet size has been determined to balance shipping cycle times, berth availability, and the required throughput of CO_2 to the offshore injection site, while also providing contingency capacity in the event of unplanned maintenance or port delays.

The costing approach incorporates capital and operating expenses for the LP/LT ships, including vessel acquisition, crew, fuel, maintenance, and port charges, as well as voyage-based costs that

scale with distance and sailing speed. The analysis also assumes optimal scheduling to coordinate ship arrivals with available injection capacity, minimizing demurrage and port congestion. This framework ensures alignment between the shipping operation, buffer storage capacity, and offshore injection rate to deliver reliable, continuous CO_2 transport over the assessed project lifetime.

Direct Injection

Direct injection refers to the process of transferring liquefied CO_2 directly from an offshore injection-equipped LP/LT carrier into a subsea well without the need for intermediate onshore storage or processing. In this configuration, the onboard treatment system raises the pressure and temperature of CO_2 to meet reservoir injection requirements, after which the CO_2 is transferred through a connection to a subsea base via a buoy and mooring system.

For this assessment, the direct injection system is assumed to use a submerged turret offloading (STO) arrangement, whereby a buoy moored to the seabed provides a stable, weather-tolerant interface between the vessel and the subsea pipeline to the injection well. Upon arrival, the carrier engages with the buoy's mating cone, enabling rapid and secure connection for offloading. The costing approach assumes continuous injection during the vessel's berth, integration of all required pumping and conditioning equipment on board, and operational compatibility with the LP/LT cargo conditions specified in the shipping analysis.

CO_2 Storage

The offshore CO_2 storage assessment is based on direct injection into a subsurface reservoir near the Kasawari field, located offshore Sarawak, Malaysia, in the Central Luconia geologic province. This region is characterized by a broad, stable continental shelf and Late Miocene carbonate build-ups forming prominent four-way dip conical closures, which provide well-defined structural traps suitable for long-term CO_2 containment. The reservoir units in these carbonate buildups typically exhibit high porosity and permeability, offering favorable injectivity while the overlying tight carbonate and shale sequences act as competent seals to minimize migration risk.

For this analysis, the injection system is assumed to be located offshore, with subsea wells connected to a central subsea manifold. The wells are designed to receive CO_2 directly from offshore injection–equipped LP/LT carriers via STO system. Injection occurs in the dense-phase or supercritical state following onboard conditioning to achieve the necessary downhole pressure and temperature for compatibility with reservoir conditions. The system layout allows for multiple injection wells to be operated in parallel and enables distribution of the CO_2 injection rate to maintain reservoir pressure within acceptable limits and avoid geomechanical risks.

Cost estimates for the offshore storage system were developed using the NETL_CO2_S_COM_Offshore model, which accounts for all major capital and operating components, including well drilling and completion, subsea infrastructure, injection control systems, and monitoring, reporting, and verification (MRV) facilities. Geological parameters were adjusted to match conditions in the Central Luconia province, including reservoir depth, thickness, permeability, and temperature, to ensure realistic injectivity and capacity estimates. The offshore configuration also incorporates continuous MRV to ensure that CO_2 plume behavior remains within the anticipated storage footprint to support both regulatory compliance and long-term containment assurance.

CO_2 Transport and Storage: Capital and Operational Expenses

The capital and operational costs for each component of the CO_2 transport and storage system were estimated using the methodologies outlined in the referenced EPRI shipping cost framework and the NETL_CO2_S_COM_Offshore storage model. Capital expenses (CAPEX) represent the total installed cost for each system component, while operational expenses (OPEX) are annual recurring costs for operation, maintenance, labor, and consumables. To compare these costs on an equivalent annual basis, capital costs were annualized using the Capital Recovery Factor (CRF) method.

This approach ensures that all cost elements, including capital-intensive (e.g., CO_2 ships, buffer storage tanks) or operating-intensive (e.g., offshore injection), are expressed on a consistent annualized basis. The resulting unit costs (USD per tonne of CO_2) were calculated by dividing the total annual cost by the annual CO_2 throughput for the project.

Table 11 Summary of modeled costs for CO_2 transport and storage.

Value Chain Item	Capital Expenses	Operational Expenses (annually)	Total Cost (annually)	Unit Cost (per ton of CO_2)
Buffer Storage, USD	42,564,268	1,519,440	3,691,037	0.97
Loading Facilities, USD	2,500,000	75,000	202,548	0.05
CO_2 Ships, USD	631,600,000	77,200,000	109,423,764	28.81
Conditioning and Direct Injection, USD	288,693,600	14,814,540	29,543,474	7.78

Total: CO_2 Transport, USD	**965,357,868**	**93,608,980**	**142,860,823**	**37.61**
Total: CO_2 Storage, USD	**209,205,084**	**46,250,000**	**56,923,488**	**14.99**

Operation and Maintenance Cost Estimate

O&M costs were estimated for one year of normal operation and included both fixed and variable O&M costs. O&M costs include operating labor, total maintenance, and overhead components. A summary of the key performance and cost metrics used in the O&M cost calculations are presented in Table 12.

Table 12.Summary of performance and cost metrics used in the O&M cost estimate

Item	Value
TPC, in 2025 $USD (¥JPY)	3,436,550,689 (520,465,601,849)
H_2 Production, kg H_2/d	682,046
Capacity Factor, %	80.00
Electric Power Import, MWe	19.15
Sulfur Production, tonne/d	37
Slag Production, tonne/d	1,043
Recovered CO_2, tonne/d	10,447

Operating and Maintenance Labor

It was assumed that O&M staffing and labor rates in Japan are similar to the U.S. [15]. The O&M costs were first estimated for a "generic" U.S. site location, utilizing operating labor rates that were representative of the electric power industry and included all applicable fringe benefits, insurance, taxes, etc., and then translated to a Japanese site location.

Fixed O&M Costs

Fixed O&M costs are composed of the following components:

- Operating labor costs.
- Maintenance labor costs.
- Administrative and support labor and other overheads.
- Property taxes and insurance (PT&I).

O&M labor is based on the number of personnel required to operate and maintain the plant per shift, the number of shifts, and the labor rate, supervision, and overhead.

For this study, PT&I was assumed to be zero.

Variable O&M Costs

Consumables are normally the principal components of variable O&M costs, including chemicals and other materials that are generally consumed in proportion to energy output. For this study, the variable O&M costs are comprised of the following:

- Maintenance materials.
- Consumables.
- Waste disposal.
- Annual slag disposal.
- By-Product sulfur sales.
- Annual electric power cost.
- Annual CO_2 T&S cost.

A summary of the annual fixed and variable O&M costs for the LETA case is shown in USD Table 13 and in JPY in

Table 14.

Table 13. Summary of annual fixed and variable O&M costs for LETA case in USD

LETA Case O&M Costs					
Operating Labor Rate (Base)	50.00	$USD/hr			
Operating Labor Burden	30%	% of Base			
Labor O-H Charge	25%	% of Labor			
Operating Labor	17.0	per shift			
Total Number of Shifts Req'd	4.2				
Total Maintenance Cost	2.50%	% of TPC			
Maintenance Labor Cost	1.00%	% of TPC			
Maintenance Materials Cost	1.50%	% of TPC			
			Annual Cost	**Annual Unit Cost**	**Annual Unit Cost**
Fixed O&M Costs			**$USD**	**$USD/kg H_2/day**	**$USD/kg H_2**
Annual Operating Labor Cost			9,653,280	14.153	0.048
Maintenance Labor Cost			34,365,507	50.386	0.173
Admin& Support Labor			11,004,697	16.135	0.055
Prop Tax & Insurance			0	0.000	0.000
Total Fixed O&M			**55,023,484**	**80.674**	**0.276**
			Annual Cost		**Annual Unit Cost**

Table 13 (continued). Summary of annual fixed and variable O&M costs for LETA case in USD

Variable O&M Costs			$USD		$USD/kg H_2
Maintenance Materials			51,548,260		0.259
Consumables			14,728,568		0.074
Waste Disposal			648,890		0.003
Annual Slag Disposal Cost			0		0.000
By-Product Sulfur Sales			-1,176,104		-0.006
Annual Electric Power Cost			2,657,174		0.013
Annual CO_2 T&S Cost			160,487,392		0.806
Total Variable O&M			**228,894,180**		**1.149**
Annual Coal Cost			**184,395,946**		**0.926**
Total Annual Operating Cost			**468,313,609**		**2.351**

Table 14. Summary of annual fixed and variable O&M costs for LETA case in JPY

LETA Case O&M Costs					
			Annual Cost	Annual Unit Cost	Annual Unit Cost
Fixed O&M Costs			**¥JPY**	**¥JPY/kg H_2/day**	**¥JPY/kg H_2**
Annual Operating Labor Cost			1,461,989,256	2,144	7
Maintenance Labor Cost			5,204,656,018	7,631	26
Admin & Support Labor			1,666,661,319	2,444	8
Prop Tax & Insurance			0	0.000	0.000
Total Fixed O&M			8,333,306,593	12,218	42
			Annual Cost		Annual Unit Cost
Variable O&M Costs			**¥JPY**		**¥JPY/kg H_2**
Maintenance Materials			7,806,984,027		39
Consumables			2,230,641,635		11
Waste Disposal			98,274,345		0
Annual Slag Disposal Cost			0		0
By-Product Sulfur Sales			-178,120,966		-1

Table 14 (continued). Summary of annual fixed and variable O&M costs for LETA case in JPY

Variable O&M Costs			¥JPY		¥JPY/kg H_2
Annual Electric Power Cost			402,429,017		2
Annual CO_2 T&S Cost			24,305,815,487		122
Total Variable O&M			**34,666,023,545**		**174**
Annual Coal Cost			**27,926,766,013**		**140**
Total Annual Operating Cost			**70,926,096,150**		**356**

Levelized Cost of Hydrogen

The levelized cost of hydrogen (LCOH) represents the average annual cost per unit of hydrogen produced and was estimated for three discount rates—3% based on the assumption in the METI power generation cost analysis reference and sensitivity cases at 6% and 8% to assess the impact of higher rates.

Key inputs to the LCOH calculation are summarized in Table 15.

Table 15. Summary of key inputs to the LCOH calculation

Item	Value
Hydrogen Production, kg H_2/d	682,046
Assumed Capacity Factor, %	80
Annual Hydrogen Production, kg H_2/yr	199,157,312
Plant Life, yr	30
Total Plant Cost (TPC) (Japan Location), 1,000's of mid-2025 $USD (1,000's of mid-2025 ¥JPY)	3,477,869 (526,723,260)
Assumed Owner's Cost (TOC/TPC), % of TPC	23
Total Overnight Cost (TOC), 1,000's of mid-2025 $USD (1,000's of mid-2025 ¥JPY)	4,277,779 (647,869,630)

The additional inputs and the calculation of LCOH are presented in Table 16 and Figure 3 in USD and in Table 17 and Figure 5 in JPY.

Table 16. LCOH calculation in $USD

Item	Units	Discount Rate (constant $)		
		3%	6%	8%
CO_2 T&S Cost at selected discount rate	$USD/tonne CO_2	52.61	60.30	66.05
Carrying Charge Factor		0.0510	0.0726	0.0888
Annual Capital Charge	$USD /Yr	218,249,101	310,775,967	379,984,103
Annual Fixed O&M	$USD /Yr	55,023,484	55,023,484	55,023,484
Annual Variable O&M (excl. CO_2 T&S Cost)	$USD /Yr	68,406,788	68,406,788	68,406,788
CO_2 T&S Cost	$USD /Yr	160,487,392	183,945,823	201,486,262
Annual Coal Cost	$USD /Yr	184,395,946	184,395,946	184,395,946
Total Annual Cost	$USD /Yr	686,562,711	802,548,007	802,548,007
Levelized Cost of Hydrogen				
Capital Charge	$USD /kg H_2	1.10	1.56	1.91
Fixed O&M	$USD /kg H_2	0.28	0.28	0.28
Variable O&M	$USD /kg H_2	0.34	0.34	0.34
CO_2 T&S Cost	$USD /kg H_2	0.81	0.92	1.01
Coal Cost	$USD /kg H_2	0.93	0.93	0.93
Total LCOH	$USD **/kg H_2**	**3.45**	**4.03**	**4.47**

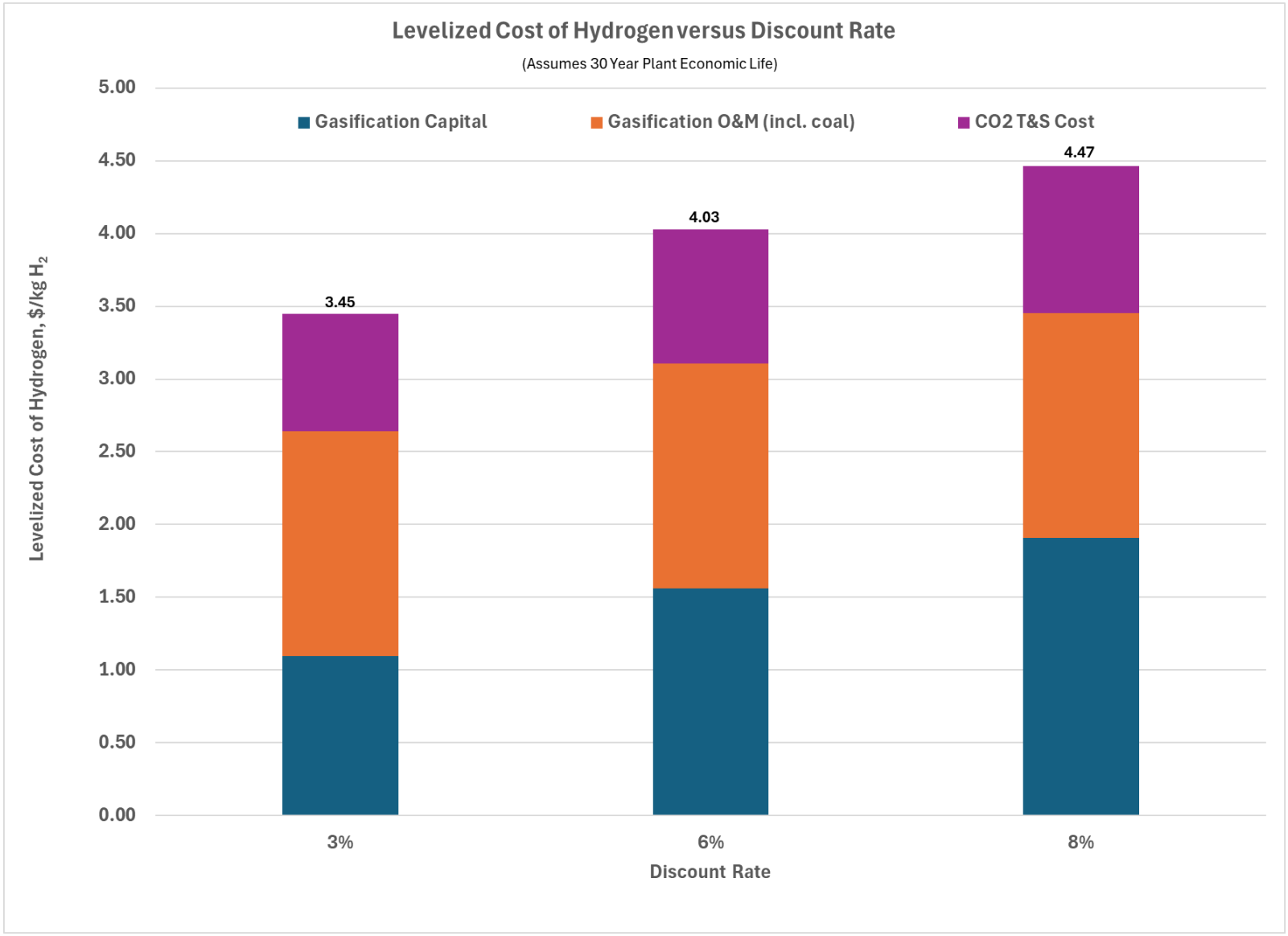

Figure 4. LCOH vs. discount rate in $USD

Table 17. LCOH calculation in ¥JPY

Item	Units	Discount Rate (constant $)		
		3%	6%	8%
Levelized Cost of Hydrogen				
Capital Charge	¥JPY/kg H_2	166	236	289
Fixed O&M	¥JPY/kg H_2	42	42	42
Variable O&M	¥JPY/kg H_2	52	52	52
CO_2 T&S Cost	¥JPY/kg H_2	122	140	153
Coal Cost	¥JPY/kg H_2	140	140	140
Total LCOH	**¥JPY/kg H_2**	**522**	**610**	**676**

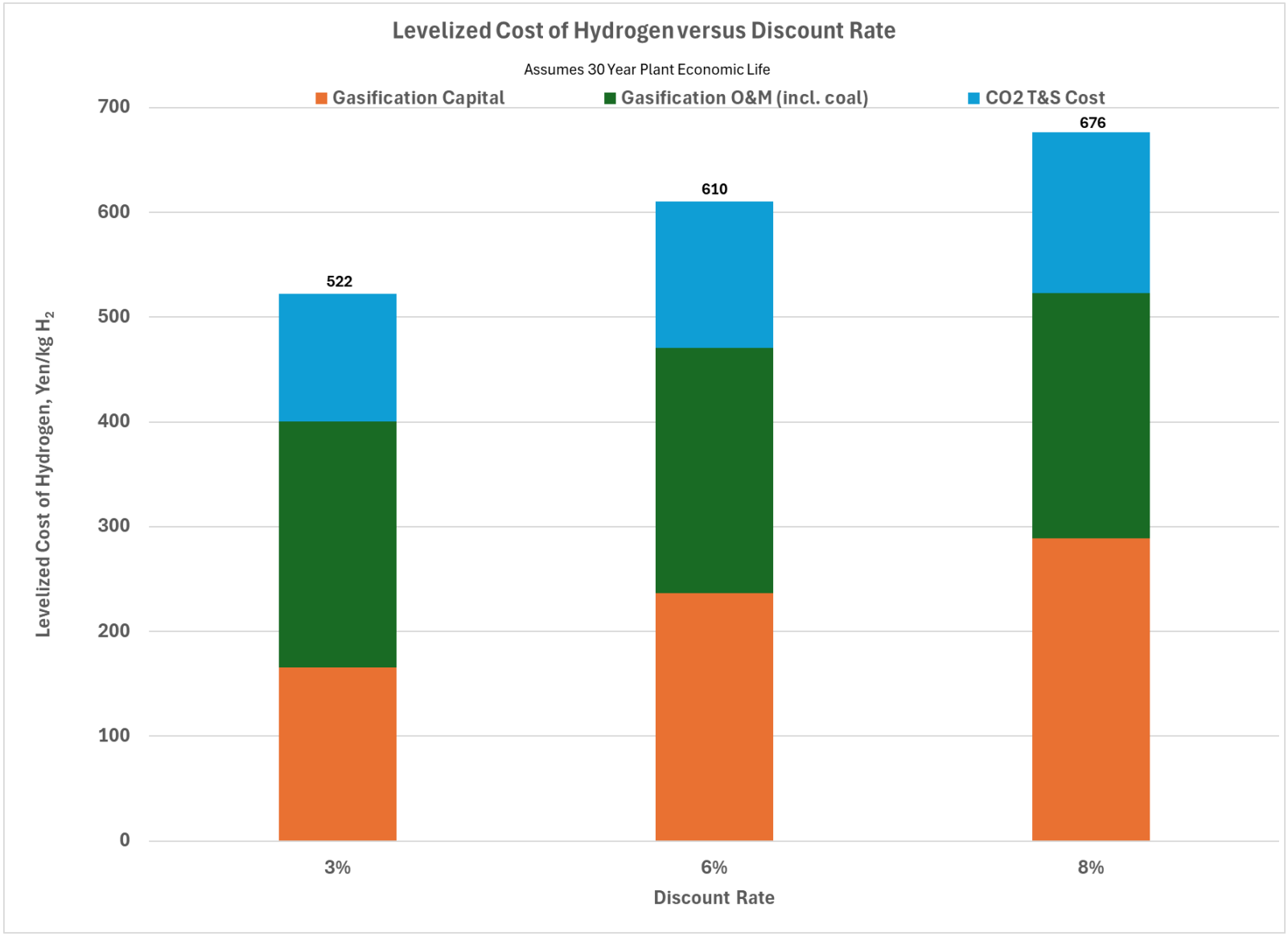

Figure 5. LCOH vs. discount rate in ¥JPY

Technology Readiness and Market Status of Coal-to-Hydrogen

H_2 production from coal gasification uses mature technologies that have been used by the chemical and fertilizer industries for decades, particularly in China. These technologies and processes include gasification, syngas upgrading through the water-gas or CO-shift reaction, CO_2 capture using physical adsorption techniques like Selexol or Rectisol, and hydrogen purification achieved with pressure swing absorption and are all commercially mature and have been widely deployed.

Air Products is a major player in coal gasification, having acquired Shell Global Solutions International's coal gasification technology licensing business in 2018 and General Electric Company's gasification business from GE Power in 2019. The GE Quench gasification technology is used at the Eastman Chemical coal gasification plant at Kingsport, Tennessee, which has been in operation since 1983. GE Radiant Syngas Cooler (RSC) gasifiers were selected for the Cool Water IGCC demonstration in the 1980's and have been repurposed for use at Coffeeville Resources' gasification plant in Kansas to produce hydrogen for ammonia manufacture. The GE RSC gasifiers were also selected for the Sinopec Qilu fertilizer plant in Zibo, China, which began operation in October 2008.

Prior to Air Products' acquisition, Shell had licensed over 20 gasification projects in China, the first being the jointly owned Sinopec/Shell installation in Yueyang, commissioned in December 2006 [16]. There are several other commercial coal and petroleum coke gasification technologies used in the production of H_2 including CB&I's E-Gas gasifier, which is used in Reliance Industries' Jamnagar polygeneration project in Gujarat, India and Air Liquide's Lurgi Mark IV gasifier, which is used in Dakota Gasification Company's Great Plains Synfuels Plant.

The Coffeeville, Great Plains, and Qilu projects have demonstrated that large-scale production of low emissions hydrogen using carbon capture is technically and commercially feasible [17].

Buffer storage for liquefied CO_2 at export terminals is based on established cryogenic liquid storage technology, adapted from industrial gas and LNG applications. This is a mature technology with decades of operational experience in comparable conditions, and scaling to CO_2 applications is not expected to present significant technical challenges. Similarly, subsea storage and injection infrastructure, including injection wells, manifolds, and monitoring system, relies on conventional offshore oil and gas technologies with a high level of readiness.

Large-scale LP/LT CO_2 carriers, while under active development by shipbuilders such as Capital Gas, remain in the early stages of commercialization. No vessels of this class are yet in long-term commercial operation. Direct injection from offshore-equipped LP/LT carriers is at a similar readiness level, with the concept demonstrated at pilot scale but not yet proven at commercial capacity. The associated STO systems are derived from LNG and offshore oil technologies, which are technically mature, but their integration with CO_2 carriers is still novel.

3. LIFE CYCLE ANALYSIS

Key Information Points

The main value chain steps in the life cycle analysis are coal mining and processing, rail transportation of coal to the Australian port, coal shipping from Australia to Japan, coal gasification with carbon capture in Japan and CO_2 shipping from Japan to Malaysia.

The CI calculations include all the upstream emissions associated with coal mining, processing rail transportation and coal shipping. The emissions associated with H_2, and CO_2 compression energy requirements are also included in the CI calculations.

This study includes HFO (0.1% sulfur), LNG, and green/blue ammonia as representative marine fuels. HFO is selected due to its widespread use in the maritime sector, LNG is considered an emerging alternative with lower emissions, and green/blue ammonia is evaluated as a prospective zero-carbon fuel for future marine applications.

Key Technical Point

CI of H_2 is highly dependent on the type of marine fuel used for coal shipping from Australia to Japan (Table 18). Additionally, as the years progress the change in the CI of H_2 is minimal.

Table 18: Key insights information from LCA

GHGs	Units	2025	2030	2040	2050
HFO 0.1%S	$KgCO_2e/KgH_2$	1.82	1.80	1.79	1.79
LNG	$KgCO_2e/KgH_2$	2.28	2.26	2.25	2.25
Green Ammonia	$KgCO_2e/KgH_2$	1.58	1.58	1.58	1.58

The emissions associated with CO_2 shipping are not included in the CI calculations but are presented and discussed in this study.

Overview of the Argonne National Lab GREET model

The GREET+ model was employed in this study to conduct a detailed life cycle assessment (LCA) quantifying greenhouse gas (GHG) emissions associated with key stages of the coal-to-hydrogen pathway. These stages include upstream coal transportation, hydrogen production via coal

gasification, and downstream CO_2 compression, transportation, and geological sequestration. Developed by the Life Cycle Analysis team at Argonne National Laboratory (ANL), the GREET+ model builds upon the well-established GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) framework and reflects the collaborative efforts between ANL and the International Energy Agency (IEA). The model analyzes the energy and the GHG emissions impact of various technologies in different regions of the world through 2050.

The GREET + model was built upon the Excel platform of the R&D GREET® 2022 rev1 model and ANL's previous efforts on two regional GREET versions, i.e., China-GREET for China and MENA-GREET for Middle East and North Africa (MENA). GREET+ model analyzes 16 regions and countries, including Canada, the USA, Mexico, Brazil, Central and South America region A, Central and South America region B, the European Union, China, India, Japan, South Korea, Southeast Asia and Oceania, MENA, Central and South Africa, the UK, and Norway.

The assumptions, methodology, and results on individual life cycle analysis stages are discussed in the section below. A temporal analysis of GHG emissions was conducted for the benchmark years 2025, 2030, 2040, and 2050 as part of this study.

Evaluation of GHG emissions impact across the value chain

As discussed in the previous sections, black coal mined and processed in Australia is shipped to Japan where the coal is gasified to produce hydrogen and CO_2. The process description for coal gasification and CO_2 capturing are described in the techno-economic analysis of this report. The CO_2 captured is compressed to meet the shipping requirements. Captured CO_2 is transported to Malaysia for sequestration. The process stages considered in the LCA of the value chain are shown in Figure 6.

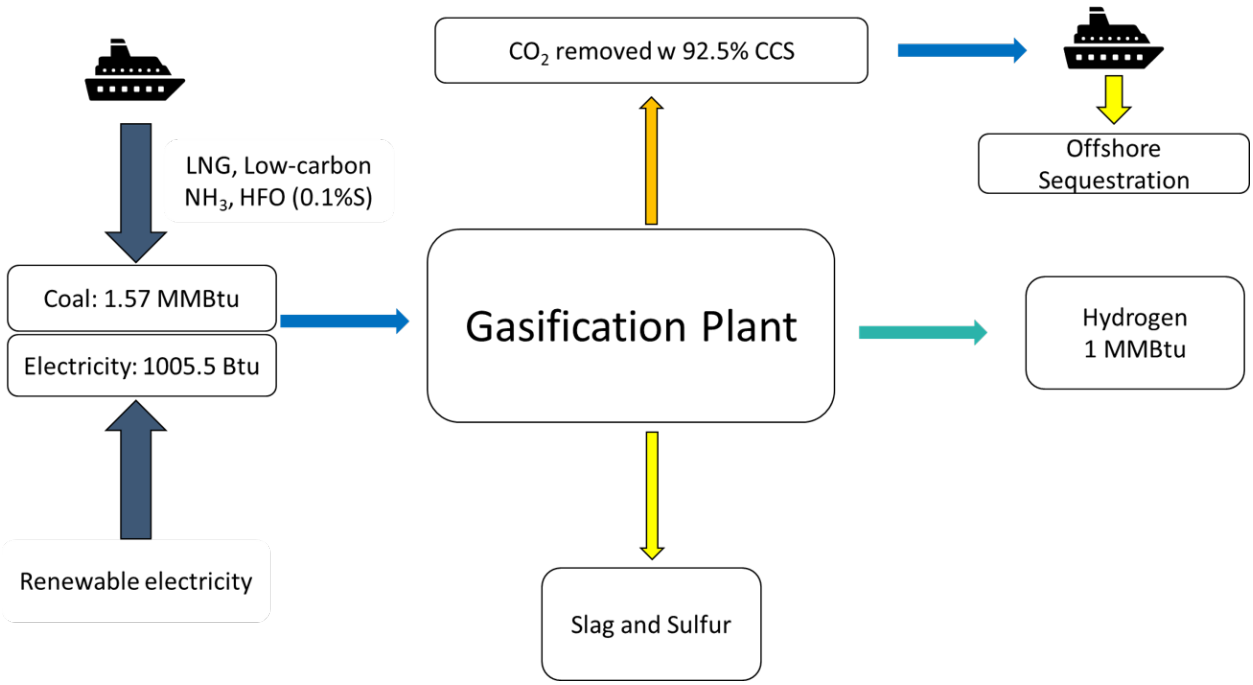

Figure 6. Process stages in the value chain for life cycle analysis

Coal Processing and Transportation in Australia

In this stage of the value chain, black coal is mined, processed and transported to the Australian port. The main assumptions for this stage are derived from the report *Greenhouse Gas Emissions Study of Australian CSG to LNG* [18]:

- By 2040, the Australian National Electricity Market (NEM) is projected to derive most of its energy supply from renewable sources, including solar, wind, and hydro, driven by decarbonization policies and grid modernization initiatives.
- Furthermore, it is assumed that the configuration and generation mix of the Australian electricity grid remains relatively stable between 2040 and 2050, with no substantial changes in infrastructure, capacity, or energy policy.
- Coal is transported approximately 400 kilometers by a diesel-powered rail from the mine site to a bulk export terminal at a Queensland port for international shipment.

The Well-to-Gate (WTG) emissions for coal mining, processing and transportation emissions within Australia are shown in Table 19. These data include VOC, CO, NO_x, PM_{10}, $PM_{2.5}$, SO_x, BC, OC, CH_4, N_2O, CO_2, and GHGs per MJ of coal.

LCA Results: WTG emissions associated with coal mining, processing, and transportation demonstrate that integrating renewable energy sources into the Australian electricity grid results in an approximate 6% reduction in overall GHG emissions.

Table 19: Well-to-Gate (WTG) emissions associated with coal mining, processing and transportation in Australia

	Units	2025	2030	2040	2050
VOC	mg/MJ	6.75	6.75	6.75	6.75
CO	mg/MJ	1.11	1.07	1.06	1.06
NO_x	mg/MJ	2.27	2.20	2.18	2.18
PM_{10}	mg/MJ	8.01	7.99	7.99	7.99
$PM_{2.5}$	mg/MJ	1.07	1.06	1.06	1.06
SO_x	mg/MJ	6.42	6.41	6.41	6.41
BC	mg/MJ	0.03	0.03	0.03	0.03
OC	mg/MJ	0.03	0.03	0.03	0.03
CH_4	mg/MJ	50.63	50.55	50.53	50.53
N_2O	mg/MJ	0.01	0.01	0.01	0.01
CO_2	mg/MJ	781.80	674.23	642.14	641.69
CO_2 (w/ C in VOC & CO)	mg/MJ	804.57	696.94	664.84	664.38
GHGs	mg/MJ	2316.85	2206.40	2173.49	2173.00

Shipping of Coal to Japan

In this stage of the process, black coal from Australia is shipped to Japan via Panamax ship. This study includes HFO (0.1% sulfur), LNG, and green/blue ammonia as representative marine fuels. HFO is selected due to its widespread use in the maritime sector, LNG is considered an emerging alternative with lower emissions, and green/blue ammonia is evaluated as a prospective zero-carbon fuel for future marine applications. The main assumptions associated with coal shipping are:

- Coal is transported in a Panamax ship with a payload of 57,541 wet tonne.

- Each shipment delivers 42,500 tonne of coal to Japan, traversing a route of 3,988 nautical miles from the Australian port.
- Marine fuels evaluated in this study comprise 0.1% sulfur HFO, LNG, and Green Ammonia, with the assumption of production in Southeast Asia and Oceania region.
- The load factor, time in mode, and engine rating for the ship are 0.8, 279 hrs. and 8,698 kW.

The well-to-hull (WTH) emissions associated with coal shipped per trip for the marine fuels HFO 0.1%S, LNG and Green Ammonia are shown in the Table 20, Table 21 and Table 22 for the benchmark years 2025, 2030, 2040, and 2050. These data include VOC, CO, NO_x, PM_{10}, $PM_{2.5}$, SO_x, BC, OC, CH_4, N_2O, CO_2, and GHGs. These emissions include not only combustion emissions of fuel but also the upstream emissions associated with production and conversion of the fuel.

Table 20. WTH emissions for coal shipped with HFO 0.1%S as marine fuel

HFO 0.1%S	Units	2025	2030	2040	2050
VOC	kg/Trip	1168.5	1167.0	1166.5	1166.5
CO	kg/Trip	2566.1	2560.7	2559.1	2559.0
NO_x	kg/Trip	24116.1	24104.5	24101.0	24100.9
PM_{10}	kg/Trip	1317.8	1315.5	1314.8	1314.8
$PM_{2.5}$	kg/Trip	1210.4	1209.4	1209.1	1209.1
SO_x	kg/Trip	1076.6	1063.0	1058.7	1058.6
BC	kg/Trip	181.3	181.3	181.3	181.3
OC	kg/Trip	470.4	470.3	470.3	470.3
CH_4	kg/Trip	5012.1	4974.0	4961.8	4960.3
N_2O	kg/Trip	73.9	73.6	73.5	73.5
CO_2	kg/Trip	1581419	1564866	1559682	1559206
CO_2 (w/ C in VOC & CO)	kg/Trip	158909	1572527	1567340	1566863
GHGs	kg CO_2e/Trip	1758619	1740847	1735276	1734752

Table 21. WTH emissions for coal shipped with LNG as marine fuel

LNG	Units	2025	2030	2040	2050
VOC	kg/Trip	1223.3	1222.6	1222.3	1222.3
CO	kg/Trip	3259.0	3256.5	3255.8	3255.8
NO_x	kg/Trip	4450.1	4444.8	4443.2	4443.2
PM_{10}	kg/Trip	100.2	99.2	98.9	98.9
$PM_{2.5}$	kg/Trip	91.9	91.4	91.3	91.3
SO_x	kg/Trip	210.5	204.2	202.3	202.2
BC	kg/Trip	10.8	10.8	10.8	10.8
OC	kg/Trip	31.1	31.0	31.0	31.0
CH_4	kg/Trip	15099.9	15082.5	15077.0	15076.4
N_2O	kg/Trip	35.1	34.9	34.9	34.9
CO_2	kg/Trip	1131510	1123954	1121604	1121414
CO_2 (w/ C in VOC & CO)	kg/Trip	1140443	1132882	1130530	1130340
GHGs	kg CO_2e/Trip	1599991	1591880	1589355	1589147

Table 22. WTH emissions for coal shipped with Green Ammonia as marine fuel

Green Ammonia	Units	2025	2030	2040	2050
VOC	kg/Trip	87.4	87.1	89.9	89.6
CO	kg/Trip	1964.8	1442.0	1443.0	1442.7
NO_x	kg/Trip	1200.8	1190.3	1217.5	1216.8
PM_{10}	kg/Trip	249.0	270.0	276.5	276.4
$PM_{2.5}$	kg/Trip	87.3	96.5	99.3	99.3
SO_x	kg/Trip	397.2	525.8	565.6	565.7
BC	kg/Trip	15.5	15.7	15.8	15.8
OC	kg/Trip	32.9	33.9	34.1	34.1
CH_4	kg/Trip	-121.0	209.0	302.0	293.3
N_2O	kg/Trip	22.3	24.8	25.0	25.1
CO_2	kg/Trip	-103183	44538	86832	84183
CO_2 (w/ C in VOC & CO)	kg/Trip	-99823	47076	89379	86730
GHGs	kg CO_2e/Trip	-97330	60078	105219	102315

Table 23. WTH emissions associated with HFO 0.1% S including feedstock, conversion and combustion

HFO 0.1%S	Units	2025	2030	2040	2050
VOC	g/MJ	0.1	0.1	0.1	0.1
CO	g/MJ	0.1	0.1	0.1	0.1
NO_x	g/MJ	1.3	1.3	1.3	1.3
PM_{10}	g/MJ	0.1	0.1	0.1	0.1
$PM_{2.5}$	g/MJ	0.1	0.1	0.1	0.1
SO_x	g/MJ	0.1	0.1	0.1	0.1
BC	g/MJ	0.0	0.0	0.0	0.0
OC	g/MJ	0.0	0.0	0.0	0.0
CH_4	g/MJ	0.3	0.3	0.3	0.3
N_2O	g/MJ	0.0	0.0	0.0	0.0
CO_2	g/MJ	87.2	86.2	85.9	85.9
CO_2 (w/ C in VOC & CO)	g/MJ	87.6	86.6	86.3	86.3
GHGs	g CO_{2e}/MJ	96.9	95.9	95.6	95.6

Table 24. WTH emissions associated with LNG including feedstock, conversion and combustion

LNG	Units	2025	2030	2040	2050
VOC	g/MJ	0.07	0.1	0.1	0.1
CO	g/MJ	0.19	0.2	0.2	0.2
NO_x	g/MJ	0.26	0.3	0.3	0.3
PM_{10}	g/MJ	0.01	0.0	0.0	0.0
$PM_{2.5}$	g/MJ	0.01	0.0	0.0	0.0
SO_x	g/MJ	0.01	0.0	0.0	0.0
BC	g/MJ	0.00	0.0	0.0	0.0
OC	g/MJ	0.00	0.0	0.0	0.0
CH_4	g/MJ	0.89	0.9	0.9	0.9
N_2O	g/MJ	0.00	0.0	0.0	0.0
CO_2	g/MJ	66.51	66.1	65.9	65.9
CO_2 (w/ C in VOC & CO)	g/MJ	67.04	66.6	66.4	66.4
GHGs	g CO_{2e}/MJ	94.04	93.5	93.4	93.4

Table 25: WTH emissions associated with green ammonia including feedstock, conversion and combustion

Green Ammonia	Units	2025	2030	2040	2050
VOC	g/MJ	0.01	0.01	0.01	0.01
CO	g/MJ	0.11	0.08	0.08	0.08
NO_x	g/MJ	0.08	0.08	0.08	0.08
PM_{10}	g/MJ	0.01	0.02	0.02	0.02
$PM_{2.5}$	g/MJ	0.01	0.01	0.01	0.01
SO_x	g/MJ	0.03	0.04	0.04	0.04
BC	g/MJ	0.00	0.00	0.00	0.00
OC	g/MJ	0.00	0.00	0.00	0.00
CH_4	g/MJ	-0.01	0.01	0.02	0.02
N_2O	g/MJ	0.00	0.00	0.00	0.00
CO_2	g/MJ	-5.24	3.02	5.39	5.25
CO_2 (w/ C in VOC & CO)	g/MJ	-5.06	3.17	5.54	5.39
GHGs	g CO_{2e}/MJ	-4.89	3.93	6.46	6.31

Table 26. Fuel consumption for marine fuels HFO 0.1% S, LNG and Green Ammonia

Total fuel consumption	HFO 0.1%S	LNG	Ammonia
MJ per trip	18269566	17018401	18531387
J/MT-km per trip	46156.3	42995.4	46817.8

The emissions associated with production and combustion of fuel for all the marine fuels are show in Table 23, Table 24, and Table 25. The amount of fuel required for each trip is estimated based on the engine rating, time in mode, and load factor. The amount of fuel required for each of the marine fuels is shown in the Table 26.

The WTH emissions associated with HFO 0.1%S include production emissions that account for the upstream emissions associated with oil extraction, recovery, transportation and storage at production facilities. Whereas the conversion emissions will include the transportation and distribution of the fuel to the point of end-use. Combustion-related emissions are influenced by the emission factor, fuel consumption, and energy usage.

The WTH emissions associated with LNG include the processing stages NG recovery, processing and transportation to the LNG production facility emissions. This will also include the emissions associated with methane leakage. The bottom-up and top-down hybrid approach is applied for methane leakage rate estimation. The Southeast Asia and Oceania region has lower methane leakage rates compared to United States (shown in Table 27) due to stringent regulations. The GREET + model accounts for the differences in methane leakage rate for CH_4 recovery and CH_4 pipeline transportation stages. These assumptions in the GREET + model are congruent with the CSIRO report [19].

Table 27. Comparison of methane leakage rates in USA and Southeast Asia and Oceania regions

	Unit	USA	Oceania
Recovery – CH_4 Leakage and Venting	g CH_4/MMBtu NG	189.38	105.17
Recovery – Completion CH_4 Venting	g CH_4/MMBtu NG	0.56	0.56
Recovery – Workover CH_4 Venting	g CH_4/MMBtu NG	0.00	0.00
Recovery – Liquid Unloading CH_4 Venting	g CH_4/MMBtu NG	4.83	4.83
Well Equipment – CH_4 Venting and Leakage	g CH_4/MMBtu NG	76.75	76.75
Gathering and Boosting – CH_4 Venting and Leakage	g CH_4/MMBtu NG	31.19	31.19
Processing – CH_4 Venting and Leakage	g CH_4/MMBtu NG	0.00	0.00
Transmission and Storage – CH_4 Venting and Leakage	g CH_4/MMBtu NG/680 miles	52.74	82.18
Distribution – CH_4 Venting and Leakage	g CH_4/MMBtu NG	28.31	24.59

The LNG conversion emissions will include the storage and transportation stages: storage at the production plant, transportation from plant to the bulk terminal, and storage at the bulk terminal. Similar to production emissions, the conversion emissions will include emissions associated with LNG leakage. The LNG leakage rate for these stages is estimated from boil-off rate, boil-off gas recovery rate and number of days in a specific stage. The daily boil-off rate is assumed to be 0.1%, with an 80% recovery rate of boil-off gas across all stages. This analysis assumes 5 days of storage and 3 days of marine transport. Additionally, GREET + model accounts for the emissions leakages in the storage at the bulk terminal [19] for LNG delivery (15.67 gCH_4/MMBtu), manual vent (13.43 gCH_4/MMBtu), boil-off gas from station tank (11.19

gCH_4/MMBtu), station continuous (2.24 gCH_4/MMBtu), fuel tank (11.19 gCH_4/MMBtu), and fuel nozzle (2.24 gCH_4/MMBtu).

The WTH emissions associated with green ammonia include production, transportation and distribution of the fuel to the point of end-use. These emissions also include combustion-related emissions are influenced by the emission factor, fuel consumption, and energy usage.

The green ammonia production emissions are negligible as hydrogen is produced from electrolyzer, and electricity powered by solar. The embodied carbon emissions associated with solar powered electricity or electrolyzers are excluded in this study. Additionally, the production of green ammonia includes nitrogen generation via air separation units (ASUs), which require substantial electricity input. It is assumed that this electricity is sourced from solar power.

The ammonia synthesis process yields a net surplus of electricity, which, for the purposes of this study, is assumed to generate grid credits. However, as the Australian electricity grid transitions toward higher renewable penetration over time, the marginal emissions intensity of the grid decreases, thereby reducing the value of these electricity credits in subsequent years.

LCA Results: The WTH emissions for shipping coal indicate that HFO as fuel will emit higher GHG emissions compared to LNG and ammonia. Among the three fuels, ammonia will exhibit the lowest WTH GHG emissions. However, the change in WTH emissions is negligible among the benchmark years 2025, 2030, 2040, and 2050 for all the fuels.

Coal Gasification

In this stage of the process, black coal from the Australia that reaches Japan is gasified to produce H_2 and CO_2 along with by-products such as sulfur and slag. The details of the gasification process are discussed in the TEA of this report. The coal properties such as LHV and carbon content in the GREET+ model have been modified to match the assumptions in this report. The assumptions for coal gasification, LCA of well-to-gate (WTG) emissions, and estimation for carbon intensity (CI) of H_2 life cycle analysis are:

- The upstream emissions associated with coal mining, processing and rail coal transportation to port in Australia in addition to the upstream emissions associated with coal transportation via ship are considered.
- The electricity required for coal gasification is powered by renewable electricity.
- The downstream emissions associated with H_2 compression for end-use and CO_2 compression for shipping are included in the electricity requirements for coal gasification. The H_2 and CO_2 temperature and pressure are discussed in the TEA section of this report.
- The downstream emissions associated with sulfur or slag processing and transportation as well as CO_2 shipping for sequestration are not included in the CI of H_2 calculations.
- As stated in the TEA section, 92.5% of the CO_2 produced in the gasification process is captured for sequestration.

The inputs for coal gasification LCA are 1.57 MMBtu Coal/MMBtu of H_2 and 1000.5 Btu Electricity/MMBtu of H_2. The water required for the process is discussed in the TEA section of this report. From the above assumptions, the CI of hydrogen calculated will include upstream emissions of coal shipping, coal gasification process emissions, carbon capture related emissions, and H_2 and CO_2 compression energy use. Similar to the other value chain stages of LCA, CI of H_2 was estimated for the benchmark years 2025, 2030, 2040, and 2050.

LCA Results: The WTG emissions of coal gasification and CI of H_2 are shown in theTable 28, Table 29, and Table 30 below for the benchmark years 2025, 2030, 2040, and 2050. These data include VOC, CO, NO_x, PM_{10}, $PM_{2.5}$, SO_x, BC, OC, CH_4, N_2O, and CO_2. As renewable electricity (solar or wind) powers H_2 and CO_2 compression, the CI of H_2 is dependent on gasification process emissions and coal shipping upstream emissions. Upstream coal emissions vary depending on the type of marine fuel used by the vessel. Consequently, the CI of H_2 will also differ based on the marine fuel employed during coal shipping.

Table 31 presents the contribution of upstream emissions to the overall CI, with LNG exhibiting the highest upstream emissions, followed by HFO and green ammonia. Following the similar order, CI of H_2 is highest for LNG (2.28 $kgCO_2e/kgH_2$) followed by HFO (1.82 $kgCO_2e/kgH_2$) and green ammonia (1.58 $kgCO_2e/kgH_2$). Higher LNG emissions are primarily due to methane leakage throughout the LNG supply chain. However, switching marine fuel from HFO to LNG significantly reduces nitrogen oxides (NOx) and particulate matter emissions. However, the change in WTG emissions is negligible among the benchmark years 2025, 2030, 2040, and 2050 across all the fuels.

Table 28. Carbon intensity of H_2 with HFO 0.1%S as the marine fuel for coal shipping

HFO 0.1%S	Units	2025	2030	2040	2050
VOC	mg/MJ	13.20	13.20	13.20	13.20
CO	mg/MJ	8.20	8.15	8.13	8.13
NO_x	mg/MJ	7.22	7.10	7.06	7.06
PM_{10}	mg/MJ	46.86	46.82	46.81	46.81
$PM_{2.5}$	mg/MJ	15.91	15.90	15.89	15.89
SO_x	mg/MJ	25.44	25.44	25.43	25.43
BC	mg/MJ	1.58	1.56	1.56	1.56
OC	mg/MJ	0.31	0.31	0.31	0.31
CH_4	mg/MJ	80.53	80.41	80.37	80.37
N_2O	mg/MJ	7.15	7.09	7.07	7.07
CO_2	g/MJ	11.06	10.89	10.84	10.84
CO_2 (w/ C in VOC & CO)	g/MJ	11.12	10.95	10.90	10.90
GHGs	gCO_{2e}/MJ	15.47	15.28	15.22	15.22
GHGs	**$KgCO_2e/KgH_2$**	**1.82**	**1.80**	**1.79**	**1.79**

Table 29. Carbon intensity of H_2 with LNG as the marine fuel for coal shipping

LNG	Units	2025	2030	2040	2050
VOC	mg/MJ	13.20	13.20	13.20	13.20
CO	mg/MJ	8.28	8.23	8.21	8.21
NO_x	mg/MJ	8.20	8.08	8.05	8.05
PM_{10}	mg/MJ	18.90	18.87	18.86	18.86
$PM_{2.5}$	mg/MJ	14.18	14.17	14.17	14.17
SO_x	mg/MJ	23.85	23.85	23.84	23.84
BC	mg/MJ	0.35	0.34	0.34	0.34
OC	mg/MJ	0.06	0.06	0.06	0.06
CH_4	mg/MJ	79.91	79.78	79.75	79.75
N_2O	mg/MJ	21.49	21.46	21.45	21.45
CO_2	g/MJ	11.06	10.89	10.84	10.84
CO_2 (w/ C in VOC & CO)	g/MJ	11.12	10.95	10.90	10.90
GHGs	gCO_{2e}/MJ	19.36	19.18	19.13	19.13
GHGs	**$KgCO_{2}e/KgH_2$**	**2.28**	**2.26**	**2.25**	**2.25**

Table 30. Carbon Intensity of H_2 with green ammonia as the marine fuel for coal shipping

Green Ammonia	Units	2025	2030	2040	2050
VOC	mg/MJ	13.20	13.20	13.20	13.20
CO	mg/MJ	6.66	6.61	6.60	6.60
NO_x	mg/MJ	6.36	5.50	5.47	5.47
PM_{10}	mg/MJ	14.28	14.24	14.27	14.27
$PM_{2.5}$	mg/MJ	14.39	14.41	14.42	14.42
SO_x	mg/MJ	23.84	23.85	23.86	23.86
BC	mg/MJ	0.62	0.80	0.85	0.85
OC	mg/MJ	0.07	0.07	0.07	0.07
CH_4	mg/MJ	79.91	79.79	79.75	79.75
N_2O	mg/MJ	-0.15	0.31	0.45	0.43
CO_2	g/MJ	11.06	10.89	10.84	10.84
CO_2 (w/ C in VOC & CO)	g/MJ	11.11	10.94	10.89	10.89
GHGs	gCO_{2e}/MJ	13.45	13.41	13.39	13.39
GHGs	**$KgCO_{2}e/KgH_2$**	**1.58**	**1.58**	**1.58**	**1.58**

Table 31. Coal shipping emissions contribution to the carbon intensity of H_2

GHGs	Units	2025	2030	2040	2050
HFO 0.1%S	$KgCO_2e/KgH_2$	0.42	0.41	0.40	0.40
LNG	$KgCO_2e/KgH_2$	0.71	0.70	0.69	0.69
Green Ammonia	$KgCO_2e/KgH_2$	0.27	0.27	0.26	0.26

CO_2 Shipping for Sequestration

In this stage of the process, the captured and compressed CO_2 from the gasification process is transported via ship to the offshore sequestration location. The main assumptions associated with CO_2 shipping are:

- CO_2 is transported on a ship with a payload of 10,000 wet tonne.
- Each shipment delivers 8,625 tonnes of CO_2 for sequestration, traversing a route of 2,651 nautical miles from Japanese port.
- Marine fuels evaluated in this study comprise LNG and Blue Ammonia, with the assumption of production in Southeast Asia and Oceania region.
- Blue ammonia is included in this study as an emerging fuel in the years 2040 and 2050.
- The load factor, time in mode, and engine rating for the ship are 0.8, 221 hrs. and 8,698 kW.

The WTH emissions associated with CO_2 shipped per trip for the marine fuels LNG and Blue Ammonia are shown in the Table 32 and Table 33 for the benchmark years 2025, 2030, 2040, and 2050. These data include VOC, CO, NO_x, PM_{10}, $PM_{2.5}$, SO_x, BC, OC, CH_4, N_2O, CO_2, and GHGs as shown in the Table 32 and Table 33. These emissions include production of the fuel, conversion of the fuel and combustion of the fuel.

The assumptions and leakage rates associated with LNG production, conversion and combustion emissions have been discussed in the coal shipping section of this report.

The blue ammonia was explored as an emerging fuel in this study as a fuel for CO_2 vessel in the years 2040 and 2050. In the blue ammonia production process, both process emissions and combustion emissions are captured. As a result, emissions from blue ammonia production are considered negligible. However, conversion emissions, including those from the transportation of ammonia, significantly contribute to the overall WTH emissions.

LCA Results: The WTH emissions for CO_2 shipping indicate that LNG fuel will emit higher GHG emissions compared to blue ammonia. However, the change in WTH emissions is negligible among the benchmark years 2025, 2030, 2040, and 2050 for all the fuels.

Table 32. Emissions associated with CO_2 shipping with LNG as marine fuel

CO_2 Shipped with LNG	Units	2025	2030	2040	2050
VOC	g/kg	0.1	0.1	0.1	0.1
CO	g/kg	0.3	0.3	0.3	0.3
NO_x	g/kg	0.4	0.4	0.4	0.4
PM_{10}	g/kg	0.0	0.0	0.0	0.0
$PM_{2.5}$	g/kg	0.0	0.0	0.0	0.0
SO_x	g/kg	0.0	0.0	0.0	0.0
BC	g/kg	0.0	0.0	0.0	0.0
OC	g/kg	0.0	0.0	0.0	0.0
CH_4	g/kg	1.4	1.4	1.4	1.4
N_2O	g/kg	0.0	0.0	0.0	0.0
CO_2	g/kg	106.0	105.9	105.8	105.8
CO_2 (w/ C in VOC & CO)	g/kg	106.8	106.7	106.6	106.7
GHGs	g CO_{2e}/kg	149.8	149.8	149.6	149.7
GHGs	**Kg CO_{2e}/KgCO_2**	**0.15**	**0.15**	**0.15**	**0.15**

Table 33. Emissions associated with CO_2 shipping with blue ammonia as marine fuel

CO_2 Shipped with Blue Ammonia	Units	2040	2050
VOC	g/kg	0.5	0.5
CO	g/kg	0.6	0.6
NO_x	g/kg	0.3	0.3
PM_{10}	g/kg	0.0	0.0
$PM_{2.5}$	g/kg	0.0	0.0
SO_x	g/kg	0.1	0.1
BC	g/kg	0.0	0.0
OC	g/kg	0.0	0.0
CH_4	g/kg	1.4	1.4
N_2O	g/kg	0.0	0.0
CO_2	g/kg	62.3	63.2
CO_2 (w/ C in VOC & CO)	g/kg	64.8	65.7
GHGs	g CO_{2e}/kg	106.6	107.5
GHGs	**Kg CO_{2e}/KgCO_2**	**0.11**	**0.11**

Carbon Flow through the Value Chain

The carbon emissions at various stages – coal mining, processing and rail transport in Australia, coal shipping from Australia to Japan, coal gasification with carbon capture in Japan and CO_2 shipping from Japan to Malaysia – of the life cycle analysis value chain for HFO, LNG, and green ammonia are shown in Figure 7, Figure 8, and Figure 9, respectively. As shown in the techno-economic section and Table 4 of this report, the amount of carbon in coal is 3,802 tonne/day which is converted to CO_2, stack gas, and ash. The carbon in CO_2, ash, and stack gas are also shown in the Table 4. This data was used as basis for creating the Sankey diagram carbon flow.

As shown in these figures, carbon emissions from coal mining, processing, and rail transport in Australia are primarily driven through use of diesel and electricity, which serve as the main energy sources during these stages. Carbon emissions in the shipping of coal and CO_2 are primarily driven by the type of shipping fuel. Though large amounts of coal (42,500 tonne) are shipped using HFO as the fuel, the overall carbon emissions are lower compared to CO_2 shipped (8250 tonne) with LNG as the fuel. This is attributed to the difference in density of the shipping

goods. The highest carbon emissions occur when HFO is used for coal shipping and LNG is used for CO_2 shipping, followed by the scenario where LNG is used for both coal and CO_2 shipping. In contrast, the use of prospective zero-carbon fuels results in the lowest carbon emissions.

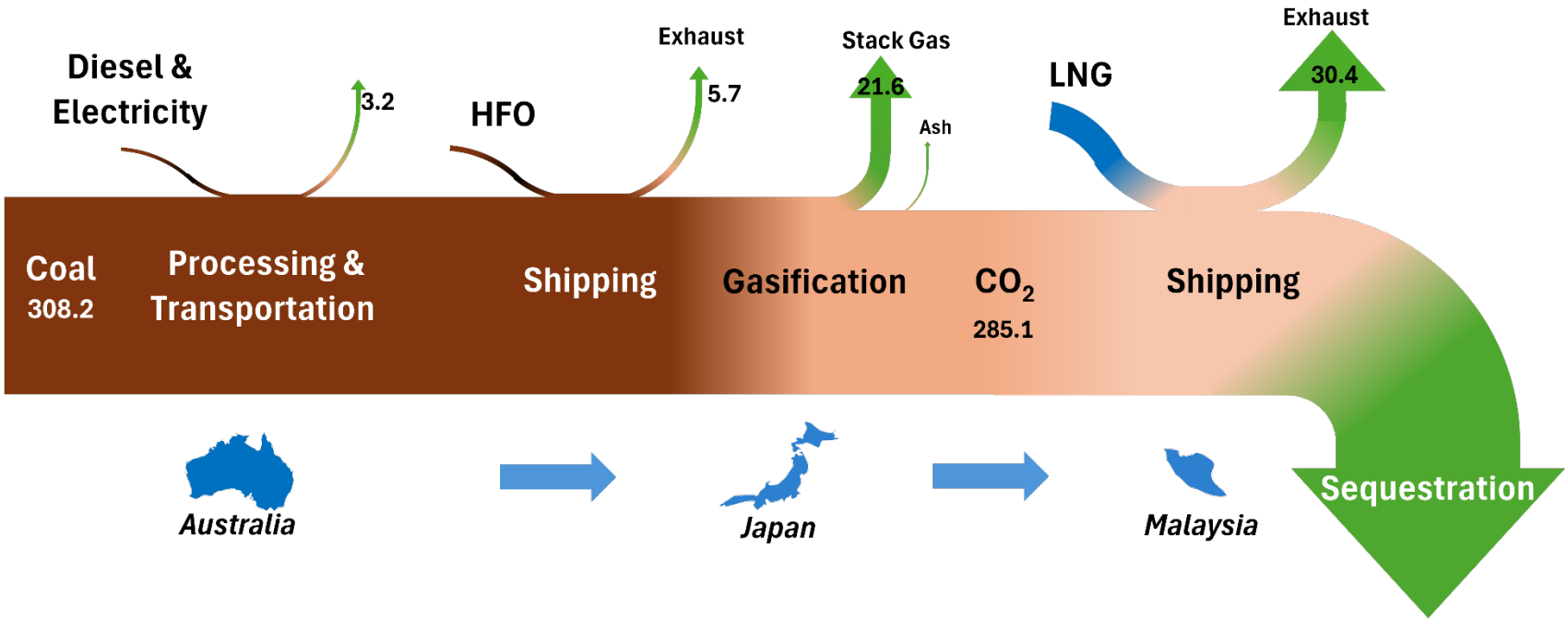

Figure 7: Carbon flow through the life cycle analysis value chain with HFO as coal shipping fuel and LNG as CO_2 shipping fuel on a per tonne/day of carbon basis

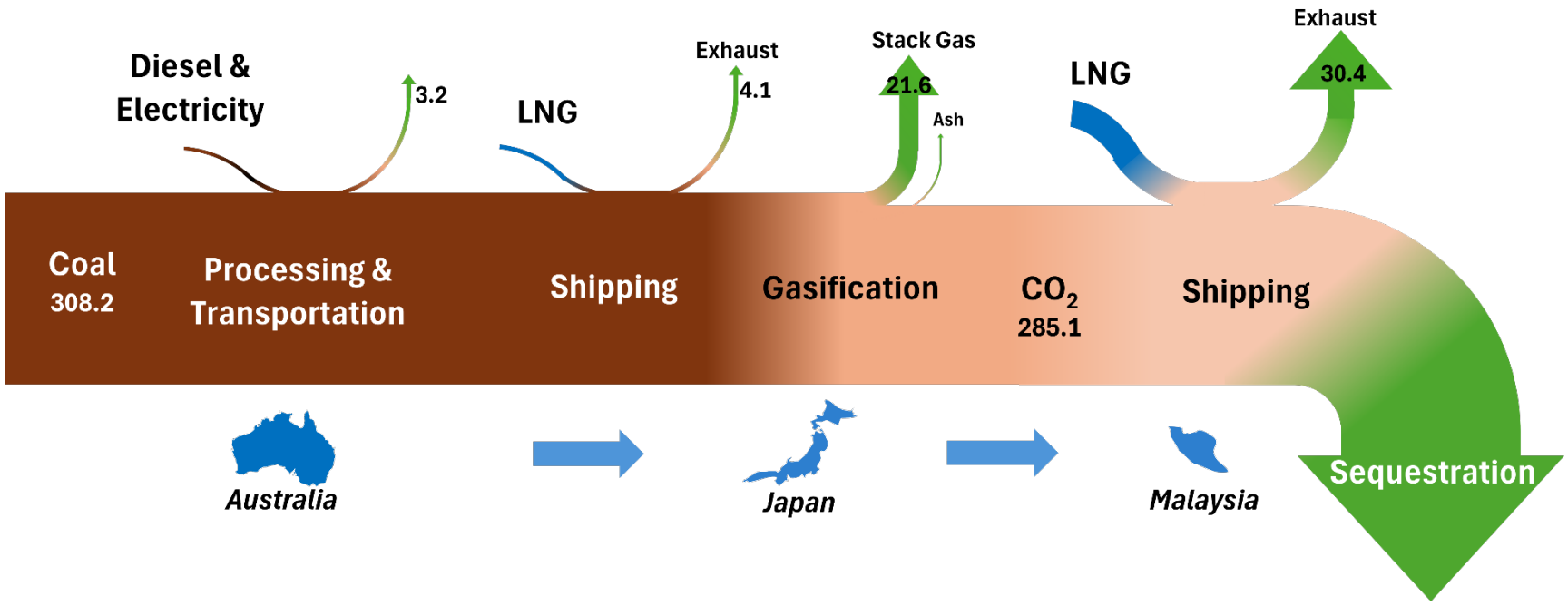

Figure 8: Carbon flow through the life cycle analysis value chain with LNG as coal shipping fuel and LNG as CO_2 shipping fuel on a per tonne/day of carbon basis

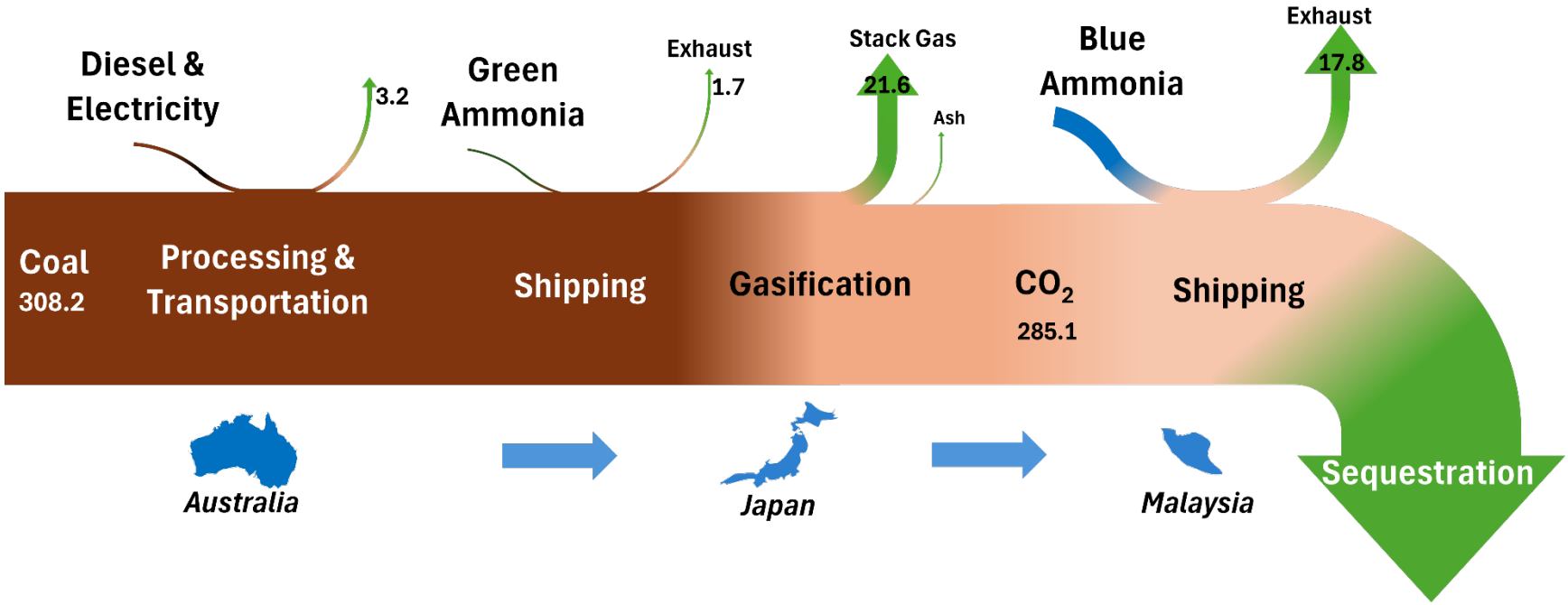

Figure 9: Carbon flow through the life cycle analysis value chain with green ammonia as coal shipping fuel and blue ammonia as CO_2 shipping fuel on a per tonne/day of carbon basis

4. JAPAN HYDROGEN DEMAND MARKET OUTLOOK

Key Information & Benchmarking Point

Japan targets 3 Mt H_2 by 2030, scaling to 20 Mt by 2050; subsidy program worth JPY 3 trillion incentivizes low-carbon hydrogen. Approach mirrors global CCS and hydrogen strategies but faces land constraints for renewables.

Key Cost and Technical Point

Cost targets: 330 JPY/kg by 2030 and 220 JPY/kg by 2050; subsidy eligibility requires CI ≤ 3.4 kg CO_2/kg H_2. Coal gasification with CCS remains a viable pathway; ~14 plants could meet 2030 hydrogen demand target.

Key Observation Point

Large-scale projects face delays and cancellations; smaller projects with confirmed offtake show higher resilience.

Introduction

As a part of Japan's decarbonization strategy, hydrogen and ammonia are being pursued as fuels for the industrial, transportation, and power sectors. METI has published guidance on how Japan's hydrogen strategy is evolving with their decarbonization goals, and what domestic and international policies will impact the metrics used to set these targets.

Japan's present day energy mix is largely dependent on fuel imports, with 87% of Japan's total energy supply coming from imported fuels in 2023 [20]. Oil derived fuels are the primary import, followed by coal and then natural gas. The majority of Japan's domestic energy supply is derived from renewable sources, with nuclear comprising the majority followed by biofuel/waste fuel sources, then wind, solar, and hydroelectric.

Japan's 7th Strategic Energy Plan (2025) [21] and Green Transformative Decarbonization Power Supply Bill (2023) [22] sets decarbonization targets of 73% from 2013 GHG levels by 2040. This strategy includes refurbishing and bringing nuclear reactors back online that had been shut down after the Fukushima incident in 2011 and increasing solar and wind capacities. While there is this push domestically to build out more renewable capacity, Japan is land constrained, which limits how much capacity they can add via solar and onshore wind. Offshore wind capacity is expected to increase wind utilization in Japan from 0.14 GW in 2022 to 10 GW in 2030 [23]. Solar initiatives include incentives for adding rooftop solar, including 50% of government buildings by 2030, for a solar increase from 79 GW in 2022 to 108 GW by 2030.

Projected Hydrogen Demand in Japan

From METI's Overview of Basic Hydrogen Strategy (2023) [24], Japan aims to expand total hydrogen consumption to around three million tonnes per year by 2030, 12 million tonnes by 2040, and 20 million tonnes by 2050. These targets include hydrogen carriers such as ammonia. Cost targets are currently set around 30 yen/Nm^3 (330 yen/kg[4]) for 2030 and 20 yen/Nm^3 (220 yen/kg) by 2050 for hydrogen, and 15-20 yen/Nm^3 (167-222 yen/kg) for hydrogen utilized in ammonia synthesis. These cost targets reflect current cost projections for LNG imports, with the goal of achieving cost parity between the two fuels.

For hydrogen to be a player in a decarbonization strategy, it will need to be delivered below a certain carbon intensity (CI). The current guidance is to refer to the CI calculation outlined by the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) [25], which outlines Lifecycle Assessments for the main hydrogen production pathways available today. These assessments are done well-to-gate, which include emissions associated with any process feedstocks to the fuel delivery to the end user. These guidelines will make it critical that hydrogen is produced with either low to no carbon methods or with fossil-based methods paired with CCS.

To incentivize low-carbon hydrogen projects, the Japanese government created a hydrogen subsidy [26]. The subsidy sets a CI target at 3.4 kg CO_2/kg H_2. The subsidy can be applied to any costs associated with hydrogen production, including feedstock imports and fuel transport costs, making it accessible to most production technologies. The projects must be large enough to produce at least 1000 tons/year by 2030 and for the duration of the subsidy award, and at least some of this hydrogen produced should be for hard to abate sectors such as industrial customers and transportation fuels. The amount awarded will vary by project and will use the cost of conventional products like LNG as a benchmark to determine how much to give; the goal is for a hydrogen producer's project costs to be similar to an equivalent LNG import operation. This subsidy will be paid out over 15 years, and total government investment will be JPY 3 trillion, or roughly 19 billion USD.

[4] 1 Nm^3 of H_2 = 0.0899 kg

The approach to meeting this hydrogen demand varies by utility and their intended customers. Some utilities are not interested in domestic production, preferring instead to invest in projects abroad and import hydrogen and hydrogen carriers such as ammonia and other e-fuels. Others are deploying electrolyzers to customer sites to produce hydrogen to meet their specific needs. J-Power, a wholesale energy provider in Japan, has invested in coal gasification technology and is working on a pilot project at one of their old coal facilities.

Hydrogen Demand Dynamics

Different utilities and industrial entities in Japan are already exploring ways to obtain hydrogen. Some hope to import hydrogen and hydrogen carriers such as ammonia rather than produce domestically, and there are currently no plans to develop hydrogen pipelines in the public record to move large quantities of hydrogen from single source points. Utilities such as Tokyo Gas and TEPCO are turning to PEM electrolyzer technologies for small-scale domestic production. TEPCO is deploying their electrolyzers at industrial sites to use hydrogen directly in boilers for industrial heating applications [27]. Tokyo Gas is testing novel electrolyzer technologies such as AEM [28], and plans to utilize hydrogen to produce e-methane that can be utilized in their existing infrastructure [29], though currently their plan is to obtain the bulk of their hydrogen/e-methane through imports [30].

Fossil-derived hydrogen projects are also underway in Japan. Japanese oil company Inpex has commissioned the country's first blue hydrogen and ammonia pilot in Niigata [31]. This project will produce up to 700 tonnes of blue hydrogen per year, falling short of the subsidy target set by the Japanese government. The project will also capture and sequester CO_2 in a depleted gas field near the project, and the natural gas will be sourced from another gas field domestically.

Others will continue to import fuels from international projects. Marubeni Corporation, an import/export company, plans to import 250,000 tonnes of low-carbon ammonia per year to supply the Kobe Power Plant, which is owned by Kobe Steel, from an ExxonMobil production facility in Texas, US [32]. Ammonia has a mature value chain today resulting from its use as a fertilizer, and international shipping standards and infrastructure are already in place that can be leveraged. There is interest in using ammonia in coal boilers to decarbonize coal assets and extend their useful life, and research is being done to evaluate the impacts of ammonia use on the plant infrastructure, operations, and emissions.

Japan has also looked outside their own boarders to invest in hydrogen projects abroad. With projects in the US and Australia facing uncertainty on receiving government funding they were predicated on (2025), some investors have begun to pull out of these large hydrogen projects. In Australia, the Queensland state government pulled funding for a $AUD12.5 billion plant, which resulted in Japanese partners Kansai Electric and Iwatani pulling out shortly after [33]. Kawasaki exited a coal gasification project in Latrobe due to timeline and cost pressures, further indications that some of these larger projects are not maintaining their momentum. In the US, construction delays and funding uncertainty is slowing down large hydrogen projects as well, and Nippon Sanso Holdings Corp, which invests globally in gas assets, announced they were writing off $USD173 million in investments in an unspecified project where construction was

paused and becoming less likely to continue [34]. Many large projects face uncertainty as to the level of demand for hydrogen once they have finished construction and cite these uncertainties along with high project costs as reasons for delays or cancellations [35].

Smaller projects are less impacted by these uncertainties in demand and often have their hydrogen customers already confirmed and possibly even directly involved with the project. Larger projects are more reliant on multiple large investors, which can drive uncertainty on their funding further and shake confidence in the projects. While many countries have set ambitious targets for decarbonization and aim to utilize hydrogen as part of their strategies, without clearly defined use cases and hydrogen consumers investors in all parts of the world will continue to give pause before getting involved.

Coal Gasification of Hydrogen for Japan's Market

As part of Japan's net-zero strategy, they are aiming to retire about a third of their current coal fleet [36]. Their current coal fleet (2025) is 55 GW of operating capacity, with 9.1 GW of the fleet having been built in the past ten years [37]. Despite constructing new coal plants in the past decade, 4 GW of coal assets have been retired, and 12.2 GW of coal projects were cancelled in that same timeframe.

Coal gasification technologies are utilized today in IGCC plants in Japan to reduce emissions and increase efficiency of coal plants. JERA, the largest coal operator in Japan, has been operating two IGCC units since 2021. J-Power, a major independent power producer in Japan and the next largest coal operator, is actively investing in coal gasification technology for both IGCC use and hydrogen production. In 2009, they partnered with Chugoku Electric Power Co to establish Osaki CoolGen Corp. The goal of this joint venture was to test the integration of fuel cells into IGCC systems to boost efficiency and reduce emissions, which they called the EAGLE concept [38]. The EAGLE concept was scaled up to a 166 MW demonstration test at the retired 250 MW Osaki Power Station, which has ongoing testing to this day. In 2022 they conducted a demonstration project in the Latrobe Valley, Australia, that took brown coal and converted it to hydrogen at a retrofitted coal power site. They then transported liquified hydrogen to Kobe Port Island in Japan for a Toyota hydrogen-for-mobility demonstration. The same gasifier technology is now being utilized at their Matsushima facility, where a 500 MW unit is being repowered as an IGCC.

Japan has set ambitious hydrogen consumption goals, not limited to hard-to-abate sectors as other hydrogen strategies have done. Large coal gasification plants could help meet some of these goals, as they can leverage existing infrastructure from retiring coal plants and utilize gasification technologies developed by Japanese companies. If one were to build gasification plants at the size and capacity factor of the one outlined earlier in this study, roughly 15 plants would meet Japan's 2030 supply target.

5. SYNERGIES AND BARRIERS

Key Information Point

The London Protocol, an international treaty intended to protect marine environment from pollution, incorporates cross border transportation and storage of captured CO_2. As this treaty currently remains to be fully ratified by the broader global community, in the interim, thorough bi-lateral agreements based on the protocol, are necessary to be negotiated among specific stakeholder countries. Recent European CO_2 flagship projects have set a strong precedent and illustrate agreements of this type can be successfully implemented.

Key Benchmarking Point

Several challenges are foreseen when developing a fully optimized fleet of long distance LCO_2 carriers within an accelerated timescale, such as implementing low pressure / low temperature ship designs and the potential for shipyard production bottlenecks. However, while these represent a significant undertaking for shipyards and ship builders, such obstacles have many similarities to those overcome previously when developing the global LNG maritime supply chain market.

Summary of Potential Barriers and Actions

This section provides a summary of the potential barriers to adoption and further actions that would be required to develop this concept. Project specific issues of concern are highlighted and described in detail, these include regulatory and legal frameworks such as compliance with the London Protocol and transfer of liability between international parties, as well as the limited maritime infrastructure, such as shipyard capacities required to construct necessary vessels that are equipped for the shipping of CO_2. Having emphasized these project specific potential barriers and their individual significance, the next steps and pathways forward are presented and discussed. Other more general CCS barriers are also listed and while not unique to this project, these will also be required to be addressed.

Regulatory and legal frameworks

The Global CCS Institute (GCCSI) in its 'CCS Legal and Regulatory Indicator 2023' tracks and scores the development of national legal and regulatory frameworks worldwide. Whilst its highest scorecard goes to Australia, who maintains a strong leadership position in the Asia Pacific region, Malaysia and Indonesia have seen significant improvement by projects announced by state owned oil and gas companies [39].

The London Protocol

Under this current proposal, where Australian coal is exported to Japan for clean hydrogen production via gasification with CO_2 capture and the resulting liquid CO_2 transported to Malaysia for permanent underground storage, it is necessary to consider the cross-border implications of this industrial process disposal and the international protocols in place, or which may need to be agreed.

The 1996 London Protocol is an international treaty to protect the marine environment from pollution caused by dumping waste and other matter into the ocean. In its initial form it defined dumping to include:

> "Any storage of wastes or other matter in the seabed and the subsoil thereof from vessels, aircraft or other man-made structures at sea."

As CO_2 was not listed as a permitted waste stream; geological storage, and /or export to other countries for dumping was not permitted. However, in 2006 recognizing the growing importance of CCS for clean power production and greenhouse gas mitigation, parties agreed:

- CO_2 streams from CO_2 capture processes for sequestration may only be considered for dumping under three conditions:
  1. The disposal must be into sub-seabed geological formation.
  2. Waste stream must consist overwhelmingly of CO_2 (but may contain incidental associated substances).
  3. No wastes of other matter can be added for the purpose of disposing of those wastes.

As a result, a party may issue a permit for the sub-seabed disposal of CO_2 waste stream that meets these requirements. However, cross border transport of CO_2 for the purposes of permanent storage remained prohibited.

In 2009, an amendment was proposed [40] to the protocol to specifically address the export and storage of CO_2 between countries. Whilst this amendment provides clear agreement of responsibilities and actions, the following should be highlighted:

- At the time of writing only a few (around 10) of the 53 countries listed in the protocol have formally ratified this agreement:
  - Namely: Belgium, Denmark, Estonia, Finland, Iran, South Korea, Netherlands, Norway, Sweden, and UK. Note: These do not include Japan or Malaysia

- The protocol still requires 2/3 of the 53 to be formally ratified.

Therefore, in the interim:

- A 2019 provisional application for the 2009 amendment was passed that allows export of CO_2 for geological storage with bi-lateral agreement.
- Belgium and Denmark, and France and Denmark are the only countries that have completed all legal steps to exchange CO_2 for offshore storage today [41]. In April 2024 Norway signed Bilaterals MOUs with Belgium, Denmark, the Netherlands, and Sweden for cross border maritime CO_2 transport [42]
- This framework appears to have been successful and allowed various large cross border CCS projects to proceed such as Europe's Greensand [43] and Northern Lights demonstrations.

In 2023 the pilot project Greensand became the world's first to demonstrate that CO_2 can be successfully agreed to be transported across national borders (from Antwerp in Belgium) and successfully injected and stored offshore in the Nini West oil field, located in Denmark's North Sea waters.

More recently, in August 2025 as part of their flagship Northern Lights project, Equinor with partners Shell and TotalEnergies, also reported CO_2 injection had begun into their storage reservoir under the Norwegian North Sea [44]. Whilst currently sourcing the injected CO_2 from a cement plant capture facility in Norway under phase 1, the expanding project will soon begin handling CO_2 volumes sourced from other European locations. Namely Denmark and the Netherlands, in early 2026.

Pathway forward

As outlined above, the London Protocol is an extremely relevant international treaty which although not yet fully ratified, would present a significant risk if ignored. It would therefore be prudent to consider it in these early development stages of this multi-national clean fuel market development proposal.

Focusing in and applying the protocol to the case in hand, Japan can be clearly identified as the exporter of CO_2, with Malaysia as the country receiving and storing it. Both are interpreted as being the only two parties currently required to coordinate under the protocol to remain compliant. Australia, while obviously the initial source of the coal and carbon, is not construed as being involved in the downstream transboundary CO_2 transport or storage step, and thus not primarily subject to the regulatory requirements that apply specifically to CO_2. That being said, lifecycle GHG accounting should still consider Australia's role for reporting purposes, particularly if a Japanese clean fuel market supply chain was to grow beyond one or two gasification plants into a wider established industry.

With this in mind, an initial interpretation of the recommendations that each country may need to undertake to be compliant with the protocol are as follows:

- Japan (As the recognized exporter of CO_2):

- Must ensure the captured CO_2 stream complies with Annex 1 of the Protocol (i.e., overwhelmingly CO_2, with no additional waste).
- Should aim to enter into a formal bilateral agreement with Malaysia to govern permitting, environmental assessment, and liability—per the structure laid out in the 2009 amendment to Article 6 and related IMO guidance documents.
- Conduct a formal environmental assessment in line with the 2006 Risk Assessment and Management Framework.

- Malaysia (As the recognized Importer and Storage Site):
  - Needs to demonstrate that the offshore site and containment strategy align with the 2007 IMO Guidelines for CO_2 Sequestration.
  - Should jointly define, with Japan, monitoring responsibilities and legal liability in a formal agreement reflecting the 2009 amendment, despite it not yet being in force.
- Australia (As the recognized Coal Exporter):
  - Not bound by the London Protocol for CO_2 transfer, as the CO_2 is captured and transported after Australian coal is gasified in Japan.
  - However, we should still consider reporting on lifecycle emissions related to its coal export for broader GHG inventory purposes.
  - Not required but would be a consideration for transparency and risk management purposes.
  - Note with specific regards to coal slag resulting from the gasification of the coal in Japan. If the slag contains carbon residues or other pollutants that could contribute to environmental impact, we perceive this to be defined as terrestrial waste and handled as in the same way as solid waste from current Japanese coal imports. With the London Protocol concentrating on preventing marine pollution and CO_2, coal slag is not envisaged as applicable. However, this carbon should still be considered as part of the lifecycle emissions accounting per the IPCC guidelines if the overall intent is to account for total GHG emissions from extraction to end-of-life.

Infrastructure and shipyard experience in building for CO_2 transport

The transporting of large quantities of CO_2 from Japan to Malaysia will require significant amount of infrastructure both dockside as well as on the ocean. The maritime industry is beginning to address this issue with specific ships designed exclusively for mass CO_2 transport only now being engineered and constructed.

CO_2 is currently shipped only as a liquid. Liquid CO_2 has much higher density compared to high pressure gaseous CO_2 making it more efficient and less costly to transport. Transporting CO_2 in solid form as dry ice requires complicated systems of transporting, handling, and gasifying before it is injected. CO_2 does not exist as a liquid phase at atmospheric pressure so to transport CO_2 in a liquid state it must be pressurized and cooled to a low temperature.

Several shipbuilders and energy companies are now investing in LCO_2 carriers, designed to transport CO_2 at low temperatures and moderate pressures. These vessels are critical for connecting dispersed CO_2 sources with offshore storage sites or utilization hubs. However, until recently, the only LCO_2 carriers that currently operate were small-scale DNV-classed ships that carry food-grade CO_2 at medium pressure. Various ship owners, shipbuilders and design houses are currently busy working on designs for larger ships, but so far there have been few concrete orders.

Pilot projects and commercial ventures are emerging. For example, Norway's Northern Lights project is pioneering CO_2 shipping as part of its full-chain CCS system, with custom-built LCO_2 carriers expected to begin operations in 2025. Japan's Kawasaki Heavy Industries and Mitsubishi Shipbuilding are also developing CO_2 carriers, targeting regional CCS networks in Asia.

Specifically, TotalEnergies, Shell and Equinor are currently engaged in Phase 1 of Northern Lights in Norway, where they are jointly developing cross-border CO_2 transport and storage for various industries across Europe to store in offshore Norwegian waters. As part of the Norwegian government-funded Longship full-scale CCS pilot scheme they are scheduled for start-up in 2025. Northern Lights has three 7,500 m^3 vessels on order at with the Chinese Dalian Shipbuilding Offshore Co. Ltd. based on medium pressure (15 bara at −28°C) CO_2 onboard storage [45]. (See Figure 10 below).

Figure 10. Northern lights concept of MP Carrier (photo credit Northern lights JV)

Furthermore, In May of this year a Danish led initiative, Project Greensand [46], launched a ship purpose built to transport 400,000 tons of liquefied carbon dioxide each year from onshore capture facilities to the Danish North Sea. Built in the Netherland, to support the EU's first full-scale carbon capture and storage value chain, INEOS Energy and Dutch shipowner and operator Wagenborg Offshore collaborated to make the ship a commercial reality [47].

However, while the ship plays a critical role in laying the foundation for an integrated CCS value chain and with Greensand Phase 1 well underway at the pilot scale, a substantial challenge remains to aggressive scale up to the 8 million tons of CO_2 annually by 2030 target under the

larger ‘Greensand Future’ project. This in turn requires a further 20 or more similar ships to be ordered, built and commissioned within the next 5 years.

Whilst the world may need a dedicated fleet of LCO_2 carriers and terminals over the next decade, from a ship builders’ perspective there are challenges to address in terms of construction, scaling up and optimizing designs.

Scale up of Orders

According to the global independent assurance and risk management company DNV ‘Owners are hesitant to order before there are final investment decisions on projects and volumes to carry’ which in turn leads to a ‘chicken and egg’ scenario in terms of developing the technology and infrastructure in time. There may even be a bottleneck as global shipyards are engaged in building LNG vessels to support the significant capacity growth associated with that supply chain. CCS projects require to join the queue and for those planning injections before 2030, will need to place orders soon to have CO_2 transportation ships available. Shipyards in Japan, China and Korea as well as steel mills are currently engaged in research to identify the appropriate material.

The Race Low Pressure/Low Temperature, Large-Scale CO_2 Transportation

Another technical barrier required to facilitate a step change in cost effective LCO_2 transportation is in transitioning from current medium pressure to low pressure (8 bara and less) tank applications at low (-50°C) temperature. Low pressure is considered the favorable option for long distances and large volumes, essentially enabling larger ship LCO_2 transportation at a lower cost.

With current conventional tank designs the LP regime allows for larger cylindrical tanks and ship sizes using comparable designs typical of LPG ships. This LP regime is preferred as it gives the engineer increased flexibility when designing the optimum ship size, tank construction and tank arrangement. The LP condition requires a tank with a thinner steel wall that is lighter compared to MP tanks.

In 2021 a joint industry project called CETO (CO_2 efficient transport via Ocean) with partners DNV, Shell, Equinor, Total and Gassco was launched to address the challenge of a low-pressure ship and CO_2 liquid cargo tank design [48]. At this low temperature operation with the pressures and significant mass of LCO_2 involved, core challenges were recognized as material strength, including fracture toughness and fatigue resistance and mitigating dry ice formation leading to block up on pipes and tanks during operation. Global Steel manufacturers such as those in Japan, China and Korea were also actively researching optimal material solutions for this application. In addition, other research organizations such as Future Energy Exports Cooperative Research Centre (FEnEx CRC) have been active and published their laboratory research and simulations on LCO_2 boil off and solidification issues [49].

CETO recently concluded in July 2024 in their published Technology Qualifications Report [50] that there were ‘no technical showstoppers to low pressure CO2 ship transport chain’ and that the technology is essentially ready for first use. Their multi-year research efforts (including a

medium scale pilot plant demonstration in the 6 to 9 bar range to investigate dry ice formation issues) resolved that a purpose-built LCO_2 carrier could now be constructed according to the relevant international rules and regulations.

However, this significant study does highlight key aspects of the transport chain that still require additional detailed engineering consideration and attention, specifically material selection for cargo tanks, fatigue and loads due to the liquid CO_2 movement within the tanks (i.e. Sloshing).

The private shipping company, Capital Maritime Group appear to be first in the race to this new market, having ordered and now constructed and launched in May 2025, the world's first large low pressure LCO_2 tanker (22,000 cubic meters) from the Hyundai Mipo Dockyard in South Korea [51]. Thus, obtaining state of the art low pressure, low temperature LCO_2 tankers, capable of long-distance applications with an additional 3 more ships to follow over the next couple of years.

Specifications and Standardization

Critically, the correct CO_2 composition must be agreed across the full value chain. The impact of impurities in the CO_2 must be mitigated by setting the optimum limits for any stream pollutants and/or installing protective barriers across major components, otherwise potential corrosion issues across the working systems will quickly emerge. Whilst progress is being made, work remains for the industry to collaborate and standardize CO_2 transport specifications and safety protocols.

Comparisons and competition with LNG transport market

As reported by DNV, experts at ECOLOG [45] a mid-stream CO_2 service company, anticipate CCS shipping could ultimately become larger than today's LNG market, especially if the IEA's assumptions on substantial CCS to limit warming are to be believed. The projected global fleet of 800+ vessels that would be required over the next 25 years to service such an LCO_2 industry, while not insurmountable, does however represent a significant undertaking for shipyards and ship builders.

Public and Political Acceptance of CCS in Malaysia

Malaysia is emerging as a regional leader in CCS, underpinned by strong political commitment and recent legislative advances. The enactment of the recent Carbon Capture, Utilization and Storage Act 2025 (Act 870) [52] provides a comprehensive legal framework for CCS activities, including capture, transport, utilization, and permanent storage of CO_2. This legislation establishes:

- The Malaysia Carbon Capture, Utilization and Storage Agency,
- Mandates registration and licensing for CCS operations, and
- Outlines offshore and onshore storage protocols.

Political Acceptance

Political support for CCS appears robust. Malaysia's government views CCS as a strategic tool for climate mitigation and economic growth. The National Energy Transition Roadmap (NETR) and commitments under the Paris Agreement reflect Malaysia's ambition to reduce greenhouse gas intensity by 45% by 2030 [53]. Additionally, the government is offering generous fiscal incentives, including investment tax allowances, import duty exemptions, and income tax reductions for CCS-related activities [54].

Public Acceptance and Barriers

While political momentum is strong, public acceptance remains a key challenge. Barriers include:

- Low public awareness of CCS technologies and their climate benefits.
- Safety concerns about CO_2 leakage and long-term environmental risks.
- Perceived high costs and skepticism about CCS compared to renewables.
- Limited community engagement, leading to mistrust or opposition.

These issues are compounded by the technical complexity of CCS and its relatively low visibility compared to solar or wind energy.

Strategies to Overcome Public Acceptance Barriers

To build broader support, Malaysia can pursue several strategies:

- Stakeholder engagement: Expand town halls and consultations with NGOs, academia, and local communities to foster transparency and trust.
- Public education campaigns: Use media and educational platforms to explain CCS benefits, safety protocols, and Malaysia's climate goals.
- Community co-benefits: Design CCS projects that deliver local employment, infrastructure, or environmental improvements.
- International collaboration: Leverage partnerships with countries like Japan and Singapore to share best practices and build regional confidence.
- Policy incentives: Continue offering financial support to reduce investment risks and signal long-term government backing.

Malaysia's proactive regulatory and fiscal approach positions it well for CCS deployment. However, sustained public outreach and inclusive planning will be essential to ensure durable societal support.

Summary

The barriers to transporting CO_2 from Japan to Malaysia for underground storage are therefore summarized below. The first three listed are unique components of the cross-border nature of

the supply chain and have been discussed in more detail above. The latter are more generic CCS issues that would have to be addressed for any underground CO_2 storage solution irrespective of its cross-boundary nature:

- Regulatory and Legal frameworks
    - Cross-border CO_2 transport is not yet fully governed by international treaties.
    - it is critical for Japan and Malaysia to have bilateral agreements to define liability, monitoring, and verification responsibilities as have been demonstrated in Europe under Greensand and Northern lights project.
    - Compliance with London Protocol amendments (which allow transboundary CO_2 transport for storage) is essential, but not all countries have ratified them.
- Infrastructure and logistics
    - LCO_2 ships are required to comply with the IMO's international gas carrier (IGC) code which dictates the different tanks that can be utilized on board a carrier vessel.
    - Limited designs for optimized large scale, low cost LCO_2 shipping
    - Limited shipyard capacities for constructing CO_2 shipping vessels.
    - Orders required to be placed sooner than later to secure ship construction slots.
    - As well as shipping, Japan currently lacks dedicated CO_2 export terminals and liquefaction facilities at scale.
    - Actual operational experience related to storage, discharge, and transfer of LCO_2 at low pressure, is extremely scarce.
    - Malaysia will also need import terminals, pipelines, and well-characterized geological storage sites.
    - Building this infrastructure requires massive capital investment and long lead times.
- Public and Political Acceptance
    - While political acceptance seems to exist within Malaysia, public perception of CO_2 storage at the grass roots level, especially in offshore or nearshore areas, needs support. Transparent stakeholder engagement will be critical. Current concerns include:
    - Leakage risks
    - Marine ecosystem impacts
    - Environmental justice for local communities
    - Transparent stakeholder engagement is critical.
- Geological Suitability and site characterization
    - Malaysia must have suitable saline aquifers or depleted oil/gas fields with:
    - Adequate porosity and permeability
    - Caprock integrity to prevent leakage.

    - Proven injectivity and storage capacity
    - Detailed site characterization and seismic risk assessments are prerequisites.
- Monitoring, Verification, and Liability
    - Long-term MRV of stored CO_2 is essential for safety and compliance.
    - Clear frameworks for liability in case of leakage or environmental damage must be established.
    - This is especially complex in transboundary projects, where jurisdictional issues arise.

6. CONCLUSION

This study finds the proposed coal-to-hydrogen value chain to be technically and economically feasible under the stated assumptions. The simulated reference configuration is a nominal 682 tonne per day H_2 production plant in Takehara, Japan that achieves approximately 92.5% overall CO_2 capture, with captured CO_2 conditioned for shipment to Malaysia for geological storage.

On cost, the updated analysis confirms that hydrogen can be delivered at a levelized cost competitive with other emerging supply options, remaining below the threshold referenced in Japanese policy guidance. Results are reported in both U.S. dollars and Japanese yen using the study's documented exchange-rate convention. The total plant cost and overnight cost estimates reflect escalated and localized capital costs for Japan, incorporating adjustments for auxiliary power requirements and CO_2 shipping infrastructure. CO_2 transport and storage costs remain consistent with prior assumptions, modeled on a low-pressure, low-temperature shipping configuration with offshore injection.

The baseline case moves captured CO_2 by LP/LT carriers from Japan to offshore Malaysia for permanent storage. The modeled chain includes buffered export storage, ship loading, a multi-vessel LP/LT fleet, and offshore conditioning with direct injection. While the current design basis uses commercially available vessel sizes, forward-looking considerations include the development of larger carriers and optimized injection systems, which are expected to improve cost and scalability over time. Cross-border movement and storage are framed under the London Protocol, with implementation via a bilateral agreement structure that addresses permitting, environmental assessment, monitoring and verification, and liability allocation.

Environmental performance meets current Japanese subsidy guidance on carbon intensity. With LNG as the baseline marine fuel for both coal import and CO_2 shipping, the well-to-gate carbon intensity remains materially below the 3.4 kg CO_2/kg H_2 threshold referenced in current policy materials, supporting eligibility for clean hydrogen incentives.

Market and deployment readiness remain directionally favorable but depend on timely execution. A build program on the order of twelve plants at the reference scale would meet Japan's 2030 hydrogen supply target, subject to siting and supply chain pacing. The primary gating factor is legal: cross-border CO_2 transport for storage remains constrained under the London Protocol until the 2009 amendment is fully ratified. A provisional pathway exists via bilateral agreement, which defines a workable compliance route for Japan as exporter and Malaysia as storage state, and is already enabling analogous projects elsewhere.

In conclusion, the integrated TEA and LCA indicate that a nominal 682 tonne per day H_2 plant, high-capture coal gasification plant at Takehara can deliver hydrogen at competitive cost and carbon intensity while meeting current policy criteria. Delivery at scale will require progress on permitting, bilateral arrangements under the London Protocol, and investment in CO_2 shipping and storage infrastructure, all of which are defined in the body of the report and supported by the assumptions register.

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B. ASSUMPTIONS REGISTER

Task #	Task Descriptor	Assumption ID	Assumption Description	Source	Source Link (if available)	Comments
2	**Techno-Economic Analysis**	2-001	The daily production of 37 metric tonnes of sulfur can be distributed into the domestic market. Given Japan's sulfur production of 3.1 million metric tonnes in 2023, an annual production of approximately 13,000 metric tonnes is manageable.	Statista.com	LINK	
		2-002	Coal Composition	From table 2 and appendix A of the "Survey of the Suitability of Export Thermal Coals for IGCC Use" A report for the CCSD by J.H.		
		2-003	Gasifier H&MB	NETL Baseline Study, Case B5B-Q (assume 2 fully loaded entrained flow quench gasifiers)	LINK	
		2-004	H_2 Production Rate	From Case 5, Shell gasifier with CCS. Adjusted for slightly higher quench gasifier throughput	LINK	

		2-005	92.5% capture of carbon in coal as CO_2	per NETL H_2 report, based on 3-stage shift, Selexol AGR, and PSA	LINK	
		2-006	H_2 delivery pressure = 940 psia	Same as NETL H_2 report	LINK	
		2-007	CO_2Delivery pressure = 145 psia	Suitable for ship transport		
		2-008	Gasification capital cost	Scaled from NETL Baseline Study, Case B5B-Q (assume 2 fully loaded entrained flow quench gasifiers)	LINK	
		2-009	Shift, AGR, and H_2 purif, and BOP capital costs	Scaled from Case 5, Shell gasifier with CCS. Adjusted for slightly higher quench gasifier throughput	LINK	
		2-010	Capital Cost Escalation 2018 to 2025 = 30%	Per Chemical Engineering Plant Cost Index (CEPCI)	LINK	
		2-011	Conversion to Japan labor rates & productivity	2003 Richardson International Cost Factors and 2023 Compass Global	LINK	also see https://compassinternational.net/

				Construction Yearbook		
		2-012	O&M Costs	Scaled from Case 5, Shell gasifier with CCS. Adjusted for slightly higher quench gasifier throughput	LINK	
		2-013	Coal Cost	Coal cost delivered by ship (per 5/23/25 meeting with LETA in Palo Alto)		
		2-014	CO_2transport distance = 2,651 nm (4,910 km)	EPRI 2025 - Maritime CO_2 Shipping TEA	LINK	Osaka Bay to Offshore Sarawak, Malaysia
		2-015	Port-to-direct injection configuration			
		2-016	LP/LT CO_2 Ship capacity = 22,000 m^3	EPRI 2025 - Maritime CO_2 Shipping TEA	LINK	LP/LT ship capacity based on Capital Gas
		2-017	CO_2 injection well diameter = 9 inches	NETL (2025) - Offshore Saline Storage Cost Model	LINK	
		2-018	2D seismic lines per survey = 2	NETL (2025) - Offshore Saline Storage Cost Model	LINK	

		2-019	Total number of stratigraphic wells = 1	NETL (2025) - Offshore Saline Storage Cost Model	LINK	
		2-020	Above zone monitoring well per injection well = 1	NETL (2025) - Offshore Saline Storage Cost Model	LINK	
		2-021	In zone monitoring wells per injection well = 2	NETL (2025) - Offshore Saline Storage Cost Model	LINK	
		2-022	Injection period = 25 years	NETL (2025) - Offshore Saline Storage Cost Model	LINK	
		2-023	Post injection and site colsure length = 50 years	NETL (2025) - Offshore Saline Storage Cost Model	LINK	
		2-024	Injection location = Kasawari CCS, Offshore Sarawak			Geologic parameters tuned to depleted M1 field
		2-025	Operating and maintenance staffing and labor rates in Japan are similar to the U.S.		LINK	
3	**Life Cycle Analysis**	3-001	Distance between Glastone and Takehara is 3988 nm	https://sea-distances.org/		

		3-002	Coal is transported in a Panamax ship with a payload of 57,541 wet tons.	GREET + model 2024		
		3-003	Each shipment delivers 42,500 metric tons of coal to Japan			
		3-004	For coal shipment, marine fuels are produced in Australia			
		3-005	All methane leakage rates are congruent with GREET+ model and CSIRO report		LINK	
		3-006	Embodied emissions for green hydrogen are not considered			
		3-007	Energy used in the gasification and compression process is renewable			
		3-008	CO_2 is transported on a ship with a payload of 10,000 wet tons with a marine fuel produced in Southeast and Oceania region	EPRI 2025 - Maritime CO_2 Shipping TEA	LINK	LP/LT ship capacity based on Capital Gas
		3-009	Each shipment delivers 8,625 metric tons of CO_2	EPRI 2025 - Maritime CO_2 Shipping TEA	LINK	LP/LT ship capacity based on Capital Gas
		3-010	Coal in Australia is transported via diesel-powered rail over a distance of 400 km	Greenhouse Gas Emissions Study of Australian CSG to LNG	LINK	

		3-011	Australian electricity grid mix projection data for 2025, 2030, 2040 and 2050	Greenhouse Gas Emissions Study of Australian CSG to LNG	LINK	Data is adopted from this report
		3-012	Energy for coal mining and processing is provided by diesel/residual oil and electricity	Greenhouse Gas Emissions Study of Australian CSG to LNG	LINK	Data is adopted from this report
		3-013	Emissions associated with slag processing and transportation and CO_2 shipping are not included in the CI of H2 calculations			

4	**Japan Hydrogen Demand Market Outlook**	4-001	Consumption target of 3 million tons/yr in 2030	METI		
		4-002	Consumption target of 12 million tons/yr in 2040	METI		
		4-003	Consumption target of 20 million tons/yr in 2050	METI		
		4-004	Target cost of 30 yen/Nm^3 in 2030	METI		
		4-005	Target cost of 20 yen/Nm3 in 2050	METI		

		4-006	CI of 3.4 kg CO2eq/kg H_2 for H_2 subsidy	METI & JOGMEC	LINK	Flexible price subsidy aiming to make H_2 costs match conventional fossil fuel costs
		4-007	Hydrogen consumption targets include ammonia and other H_2 carriers			

C. TECHNO-ECONOMIC ANALYSIS SUPPORTING TABLES

Table 34. CO_2 compressor calculations

	NETL H_2 Study			LETA Case		
INPUT DATA	**Total CO_2**	**LP CO_2**	**HP CO_2**	**Total CO_2**	**LP CO_2**	**HP CO_2**
Gas flow rate, kg/h	456,083	124,535	331,548	435,290	118,858	316,432
Ave. gas mol.wt.	44.0	44.0	44.0	44.0	44.0	44.0
Cp/Cv	1.28	1.28	1.28	1.28	1.28	1.28
Inlet pressure, kPa	117	117	552	117	117	552
Inlet temperature, C (to each stage)	32	32	32	32	32	32
Final discharge pressure, MPa	15.27	15.27	15.27	1.0	1.0	1.0
Number of stages	8	8	6	4	4	2
Adiabatic efficiency, %	93	93	93	93	93	93
Motor efficiency, %	99	99	99	99	99	99
OUTPUT DATA						
Overall pressure ratio	130.29	130.29	27.69	8.53	8.53	1.81
Compression ratio per stage	1.84	1.84	1.74	1.71	1.71	1.35
Power, kW per stage	5,132	1,401	3,371	4,277	1,168	1,680
Total power, kW	41,057	11,211	20,228	17,108	4,671	3,360
Outlet temperature, C (from each stage)	79	79	74	73	73	54
Total Power, kW	41,471	11,324	20,433	17,281	4,719	3,394
Total Power, kW (LP & HP)			31,757			8,113

Table 35. H_2 compressor calculations

	NETL H_2 Study	LETA Case
INPUT DATA	**Total H_2**	**Total H_2**
Gas Flow Rate, kg/h	27,500	28,418
Ave. Gas mol.wt.	2.0	2.0
Cp/Cv	1.407	1.407
Inlet Pressure, kPa	2820	2820
Inlet Temperature, C (to each stage)	18.3	18.3
Final Discharge Pressure, kPa	6481	6481
Number of Stages	1	1
Adiabatic Efficiency, %	84	84
Motor Efficiency, %	99	99
OUTPUT DATA		
Overall Pressure Ratio	2.30	2.30
Compression Ratio per Stage	2.30	2.30
Power, kW per stage	10,318	10,663
Total Power, kW	10,318	10,663
Outlet Temperature, C (from each stage)	115	115
Total Power, kW	10,418	10,766

Table 36. Power balance comparison

Item	NETL H_2 Study	LETA Case		Item	NETL H_2 Study	LETA Case
Power Summary						
Steam Turbine Power, MWe	109	109				
Total Gross Power, MWe	109	109				
Auxiliary Load Summary				**Auxiliary Load Summary (continued)**		
Acid Gas Removal, kWe	11,640	11,640		Miscellaneous Balance of Plant[A], kWe	2,520	2,520
Air Blower, kWe	780	780		N2 Compressors, kWe	2,390	2,390
Air Separation Unit Auxiliaries, kWe	1,000	1,000		O2 Pump, kWe	330	330
Air Separation Unit Main Air Compressor, kWe	65,800	**68,990**		Quench Water Pump, kWe	330	330
Air Separation Unit Booster Compressor, kWe	5,170	**5,421**		Shift Steam Pump, kWe	310	310
Ammonia Wash Pumps, kWe	120	120		Slag Handling, kWe	550	550
Circulating Water Pumps, kWe	3,340	3,340		Slag Reclaim Water Recycle Pump, kWe	0	0
Claus Plant TG Recycle Compressor, kWe	1,240	1,240		Slurry Water Pump, kWe	0	0
Claus Plant/TGTU Auxiliaries, kWe	250	250		Sour Gas Compressors, kWe	140	140
CO_2 Compression, kWe	31,880	**8,113**		Sour Water Recycle Pumps, kWe	0	0
Coal Handling, kWe	460	460		Steam Turbine Auxiliaries, kWe	90	90
Coal Milling, kWe	2,180	2,180		Syngas Recycle Compressor, kWe	880	880
Condensate Pumps, kWe	150	150		Syngas Scrubber Pumps, kWe	120	120
Cooling Tower Fans, kWe	1,730	1,730		Process Water Treatment Auxiliaries, kWe	1,310	1,310
Dryer Air Compressor, kWe	80	80		Transformer Losses, kWe	950	950
Feedwater Pumps, kWe	1,600	1,600				
Gasifier Water Pump, kWe	40	40		**Total Auxiliaries, kWe**	148,430	128,150
Ground Water Pumps, kWe	330	330		**Total Auxiliaries, MWe**	148	128
Hydrogen Compressor, kWe	10,720	**10,766**		**Net Power, MWe**	-39	-19.15

Note increase in auxiliary loads for ASU Main Air and Booster Compressor, CO_2 Compression, and Hydrogen Compressor.

[A] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads.

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