Technology List and Perspectives for Transition Finance in Asia

1st Version

September 2022

Introduction

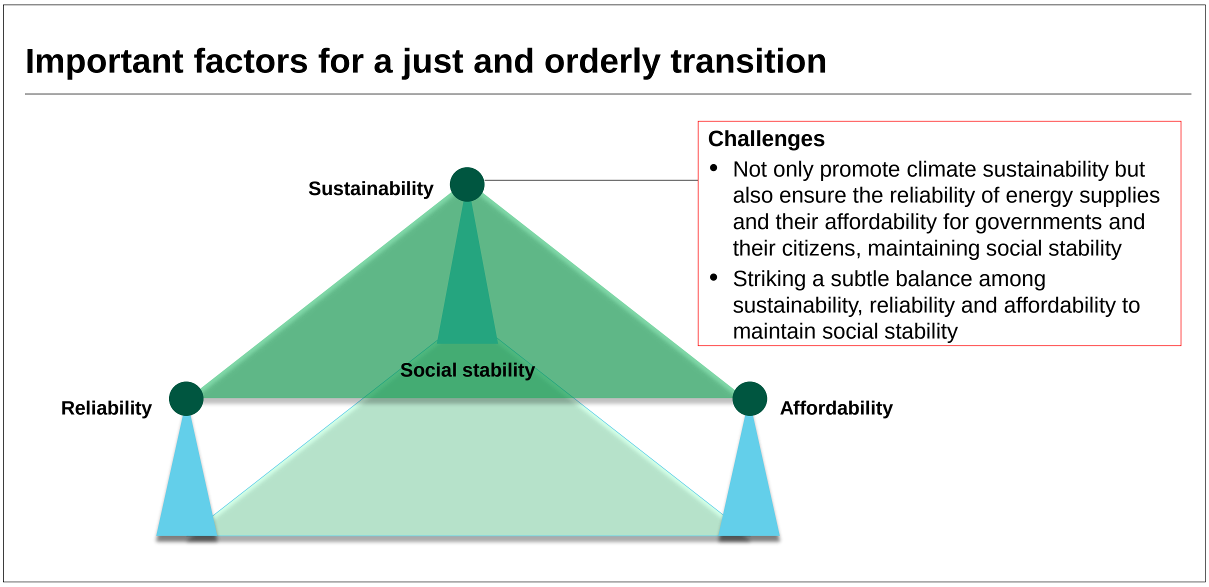
The importance of transition technology and finance in Asia

The urgent need for decarbonisation is globally recognised, though significant uncertainty remains regarding how countries will make the transition to net-zero CO_2 emissions within the timeframe set out in the Paris Agreement.

There are numerous opportunities to reduce CO_2 emissions in Asia. These, however, must take account of the continent's growing demand for energy to support its economic development – consumption is likely to grow by more than 30% between 2020 and 2040.[1] It is also important to recognise that some countries, particularly those in South and Southeast Asia, currently rely heavily on emission-intensive energy sources such as coal, while some have limited ability to develop renewable energy, for instance because of weather conditions or geography.

The transition to net-zero will have to safeguard energy supplies against this backdrop, which means that climate sustainability cannot be the sole consideration when choosing technologies that will reduce emissions. The transition to net-zero emissions should be 'just and orderly', meaning that it should be sustainable, affordable, and reliable if it is to avoid abrupt dislocation and potentially social instability (Exhibit 1).

Exhibit 1: Important Factors for a Just and Orderly Transition[2]



Source: Asia Transition Finance Study Group.

As widely recognised, green technologies – that is, those with zero-emissions throughout their operation – are important components of the technology solution package. In addition, there is broad acknowledgement that the net-zero transition will also have to include so-called transition technologies which reduce carbon emissions but do not completely eliminate them, and this is particularly the case to achieve the transition in a just and orderly manner. Financial institutions

[1] IEA (2021) World Energy Outlook, www.iea.org/statistics. Forecast is based on existing policy frameworks and those under development in each country.

[2] Developed by the ATF Study Group.

will play an important role in mobilising private capital to fund both sets of technologies, but to date there has been little guidance on what constitutes a transition technology.

The need for guidance on what constitutes a transition technology

Various governments and international organisations have established standards and guidelines to ensure financial flows are consistent with a pathway towards net-zero CO_2 emissions. However, these tend to focus on green technologies rather than transition technologies and often have limited geographic relevance. For example, green technologies are the focus of the European Union's (EU) taxonomy for sustainable development. And because the EU's decarbonisation pathway is steeper than Asia's, it rejects some of the technologies Asia is likely to consider. Likewise, Singapore is developing a taxonomy that includes green and some transition technologies and Japan has published a technology roadmap for a just and orderly transition. Yet these may not be appropriate for other Asian countries, many of which have yet to develop a decarbonisation pathway or supporting references that help define transition technologies. The Association of Southeast Asian Nations (ASEAN), meanwhile, is developing a regional perspective. The ASEAN Taxonomy Board (ATB) published its first version of taxonomy in 2021, recognising the criticality of establishing a regional common taxonomy for sustainable finance to succeed across the region. The taxonomy aims to foster credibility and secure global acceptance, but does not yet include thresholds and the list of eligible activities that could be used to assess if a technology in a targeted project is aligned with the Paris Agreement as a part of a transition finance suitability assessment.

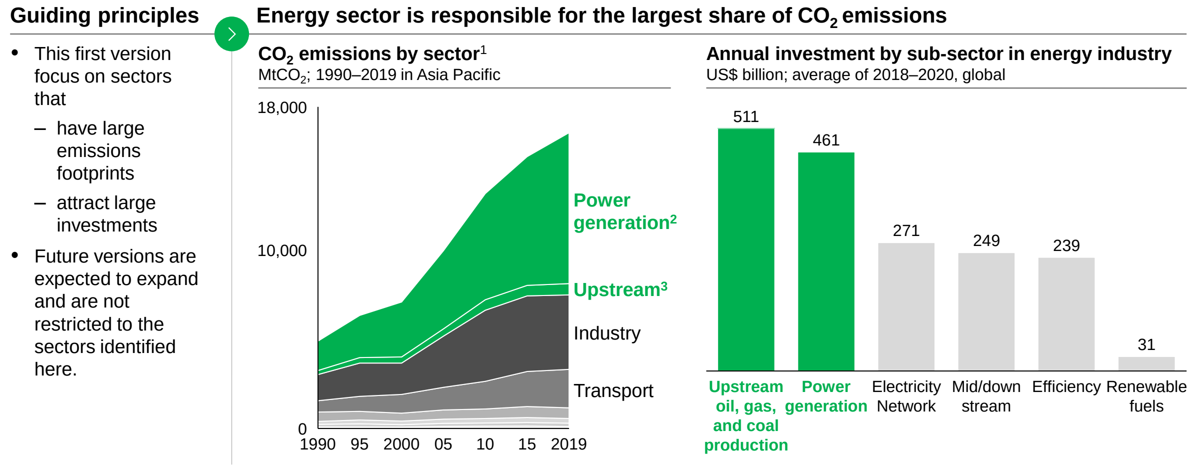
Other initiatives seek to explain relevant green and transition technologies at an industry level. But as they are not specifically for a financial audience, they seldom include guidance on how to evaluate the technologies when considering transition finance – an intrinsically complex task. The International Energy Agency's (IEA's) Energy Technology Perspective is a case in point.

The result is that many financial institutions still hesitate to fund transition technologies in Asia, thereby hampering efforts to decarbonise economies. This document seeks to help unlock that funding and so facilitate the just and orderly transition to net-zero emissions. The document examines each candidate technology in a manner that will help financial institutions make an initial assessment of its suitability for transition finance.

How to use the framework

Not all potential transition technologies are examined in the first version of this report. The focus is on technologies that will have most impact on reducing emissions, and for that reason it focuses primarily on the power sector and related upstream activities that together account for more than 50% of the region's CO_2 emissions. Future versions of this report will revise and widen its scope, and lack of inclusion here does not disqualify a technology from being considered as a transition technology (Exhibit 2).

Exhibit 2: Focus of First Version



1. IEA data excludes non-fuel emissions, such as land-use change and forestry
2. Include the following; emissions from electricity production, combined heat and power plants and heat plants.
3. Include the following: emissions from fuel combusted in oil refineries, for the manufacture of solid fuels, coal mining, oil and gas extraction and other energy producing industries

Source: IEA, Greenhouse Gas Emissions from Energy (August 2022); IEA, World Energy Investment 2020.

Importantly too, the framework is not a tool for making a final decision on whether to provide transition finance. It does not consider a particular technology's suitability as a transition technology in a particular context, for example, and does not indicate the potential financial performance of a particular technology. Rather, the framework is intended to help stakeholders gain an overview of potential transition technologies, functioning as an interim reference until such time as more Asian governments publish technology roadmaps or taxonomies.

Finally, although the framework is intended primarily as a guide for financial institutions, it may also prove useful to other organisations in both the public and private sectors. It could, for example, assist corporations seeking to decarbonise their operations or identify new business opportunities, and it could assist policy makers in understanding the technology landscape in Asia and so informing their technology roadmaps, taxonomies, and decarbonisation policies.

The criteria for inclusion in the technology list and the assessment framework

The first version of this report considers technologies that meet two criteria, described below, and it gives guidance on how to assess their suitability for transition technology with reference to six elements of a just and orderly transition to net-zero emissions.

The technologies included

This version focuses on technologies that meet the following two criteria:

- As mentioned earlier, they pertain to the power sector and related upstream activities such as the production and treatment of gas (Exhibit 3).
- They drive decarbonisation by directly reducing CO_2 emissions, but they are not zero-emission technologies. The latter, such as renewable energy or green hydrogen production, are green technologies, and clear guidelines exist that help financial institutions consider their suitability for funding. Zero-emission technologies are therefore excluded from consideration here. Excluded too are technologies that may be part of the

value chain of a transition technology but do not themselves reduce CO_2 emissions. Hence, while use of low-carbon fuels such as hydrogen and ammonia are within the scope of the analysis as they have a direct impact on emissions, the transportation of those fuels is not.

Exhibit 3: Coverage of Technology by Sectors and by Technology Types

Sector and Technology: The First Version Covers Upstream and Power Sector Under Transition Technology (May Expand in Future Revisions)

NON EXHAUSTIVE

Included in the first version | Not included in the first version

	Energy sector activities				Other sectors
	Upstream (fuel production)	**Power (electricity generation)**	**Mid-stream**	**Downstream**	**End-use**
Green/ zero emission technology	Green hydrogen/ ammonia production Biogas production	Hydro, Solar, Wind, Geothermal, Biomass, BECCS, Nuclear, green fuel etc.	**Power transmission and distribution** • Storage system • Grid interconnectors, smart grid **Fuel transport** • Pipeline • Low carbon fuel shipping and storage • LNG terminals to promote electrification or fuel switching	**Retail** • EV charging • Low carbon hydrogen fuel station **Services to end users** • Provision of energy efficiency services to end users (e.g. ESCO[1])	**Industry** • Cogeneration/CHP[2] • Electrification **Transport** • EVs, FCVs • Sustainable fuels (e.g., biofuels) • Hybrid **Buildings** • Smart metering • Insulation • Heat pumps **Agriculture** • Electrification of machines
Transition technology	Fugitive emissions reduction (LDAR) Process electrification Blue ammonia/hydrogen production CCUS in gas production	CCGT (for coal avoidance or higher efficiency conversion) Waste to energy power plant Biomass or low-carbon fuels (ammonia, hydrogen) co-firing CCUS in coal/gas power plant			
Brown technology	Coal mining Oil extraction	Unabated coal-fired[3] Unabated oil-fired (incl. diesel)	Note that the distinction between green/zero emission and transition technology becomes blur after mid-stream		

1. Energy Service Company
2. In majority of cases of cogeneration/CHP, heat generated during electricity generation is transferred to neighboring manufactures or building, saving their heat consumption. Therefore, the emission reductions occur in industry or building sector and thus is categorized in industry.
3. Given that the Glasgow climate pact stipulated the phase-down of unabated coal power, this document assumes any type of coal fired plants without co-firing or CCUS falls under unabated, regardless of its efficiency (subcritical, super critical, ultra supercritical, integrated gasification combined cycle (IGCC) etc.)

Source: ERIA.

Ten major technologies meet these criteria, though they may differ by their emission intensity and hence their suitability for deployment at different stages of the decarbonisation trajectory. They can be split into the following groups:

- **Early decarbonisation** transition technologies have lower emission intensity than a legacy technology but still emit greenhouse gases (GHGs). They can be deployed in the early phases of a country's transition pathway and may be retired before reaching net-zero emissions.
- **Partial emissions reduction** transition technologies have lower emission intensity than early decarbonisation ones but still emit GHGs. They can be deployed in the early and middle phases of a country's transition pathway.
- **Deep decarbonisation** transition technologies have near-zero emissions or are likely to have zero emissions in the near future and are essential for achieving net-zero emissions. They can be deployed throughout a country's transition pathway.

The elements assessed

Guidance is given on how to assess each technology's suitability for transition technology with reference to six elements of a just and orderly transition to net-zero emissions. Three pertain to the technology (the technology characteristics) and three to an additional, broader set of considerations.

Technology characteristics

The following characteristics of a technology determine the extent to which it contributes to a just transition to net-zero emissions.

- **Emissions impact.** This relates to the sustainability element of a just transition, measuring the extent to which the technology directly reduces emissions and so contributes to the decarbonisation of a project, company, and country.
- **Reliability.** This relates to the need to safeguard energy supplies, assessing the maturity of a technology. One that is commercially available at scale is likely to be more reliable than one still being piloted, for example.
- **Cost.** The cost of the technology will influence the affordability of the transition, be that the cost of abatement for upstream technologies or the lifetime cost of energy for power sector technologies.

Additional considerations

Three additional considerations will help financial institutions determine whether a technology is suitable for transitional technology.

- **Lock-in prevention considerations.** Will the technology enable a transition to net-zero emissions within a Paris Agreement-aligned timeframe, or are other plans in place to avoid becoming locked in with non-compliant assets?
- **Do No Significant Harm (DNSH) considerations.** Will the technology negatively impact other environmental objectives, such as a healthy ecosystem, biodiversity, resource resilience and a circular economy? And what preventative measures could be implemented?
- **Social considerations.** Will the technology negatively impact society by, for example, reducing job opportunities?

Various data sources are used to guide the assessment of the six elements. The emissions impact of a technology is estimated using the Intergovernmental Panel on Climate Change report, analysis by The Institute of Energy Economics, Japan (IEEJ, hereafter), and a literature search of relevant case studies. Affordability is based on IEEJ analysis, reports by the Danish Energy Agency and the International Renewable Energy Agency, and relevant case studies. Reliability is gauged using the IEA's Technology Readiness levels.

The three additional considerations – lock-in prevention, DNSH, and social considerations – draw on literature searches.

Ten potential transition technologies: the analysis

Exhibit 4 shows the ten technologies considered in this document (the first version). In the second part of this report, we describe each technology and detail the considerations required to assess its suitability for transition technology.

Exhibit 4: The Ten Technologies Considered

The first version of the document prioritises technologies based on
- Direct and sizable impact on emissions reduction
- Neither zero emissions/green, nor brown
- Involving sizable deployment scale or investments

Technology tier	Sector: Power (Electricity generation)	Sector: Upstream (Fuel production)
Early decarbonisation	1 CCGT[1] (coal avoidance, higher efficiency conversion) 2 Waste to energy power plant	6 Leak detection and repair (LDAR) for fugitive emissions reduction
Partial emissions reduction	3 Biomass co-firing 4 Low-carbon ammonia co-firing 5 Low-carbon hydrogen co-firing	7 Process electrification in gas production and processing
Deep decarbonisation	8 CCUS[2] in coal/gas power plant	9 Blue hydrogen and blue ammonia production 10 CCUS in gas processing

1. CCGT = Combined cycle gas turbine
2. Carbon capture, utilisation, and storage

Source: ERIA.

The Way Forward

Transition technologies will be essential to both promote and accelerate the decarbonisation of Asia's economies, but many financiers still hesitate to fund them in the absence of clear guidance on what constitutes a transition technology. This report will, we hope, play an important role in unlocking that funding. It will help financiers and other stakeholders understand certain potential transition technologies, and it provides for the first time a clear framework to guide their assessment of a technology's suitability for transition finance. Importantly, that assessment includes not only the technology's ability to reduce CO_2 emissions but the extent to which it will contribute to a just and orderly transition to net-zero emissions in Asia.

We hope you find it useful, and we look forward to expanding our work soon to cover additional sectors and technologies.

Technology List and Perspectives for Transition Finance in Asia

Economic Research Institute for ASEAN and East Asia (ERIA)

Version 1 (September, 2022)

Introduction

Details of Potential Transition Technologies

Appendix

Background and objectives

Background

- Decarbonisation is an urgent need. Transition technologies supplement green ones and play a critical role in achieving a just and orderly energy transition
- Whilst the importance of transition technologies is widely recognised, industry stakeholders face a series of hurdles when assessing how to move forward with potential transition projects:
  - Most Asian countries have not developed a decarbonisation pathway or supporting references to define 'transition technologies'
  - Evaluating transition technologies is intrinsically complex, hinging on the differential emissions impact over time and in the local context
- To facilitate a just and orderly transition in Asia, ERIA sees the importance of developing an assessment framework for transition technologies in Asia

Objectives

- This document functions as an interim reference until governments in Asian countries establish their technology roadmaps or taxonomies.
- This document provides simplified views on major transition technologies. Readers are encouraged to use this as an entry point to gain an overview of transition technologies
- Financial and industry stakeholders can use this as a reference when assessing whether a technology meets the important elements of just and orderly transition and is suitable for transition finance
- This is meant to be a living document, to be updated and expanded as context and technologies evolve

The document aims to provide a framework for assessing transition technology suitability, rather than a rigid classification

The document

- Provides **a framework** for assessing a potential transition technology
- Provides **relevant, practical information** on various potential transition technologies in **a fact-based manner**
- Focuses upon major potential transition technologies, initially in a limited number of sectors. (Other sectors will be addressed in future updates.)

The document

- Does **not** provide **absolute criteria** for what constitutes a transition technology.
- Is **not restricted to** offering a set of **principles**; it provides example information on individual technologies
- Is **not an exhaustive list** of potential transition technologies in Asia

How to use: this document can be used by different stakeholders under multiple scenarios

ILLUSTRATIVE NON-EXHAUSTIVE

Example scenarios where the document can be used are…		The document can be used to …
Financial institutions	What technologies should be considered for financing arrangements?	• Identify potential transition technologies to finance • Understand the nature of a transition technology, including environmental impact and other considerations, such as lock-in preventions
Corporations	What business opportunities could arise during decarbonisation? What levers are out there to decarbonise their operations?	• Learn what could be considered transition technologies for the sake of business discussion • Plan potential projects or better understand consideration points for execution
Policymakers	What technologies could be relevant to achieving just and orderly transition?	• Understand the technology landscape in Asia quickly and use it as a reference to build technology roadmaps, taxonomies, and decarbonisation policies

Introduction

The scope of this document (the 1st version)

How the technologies are assessed

Details of Potential Transition Technologies

Appendix

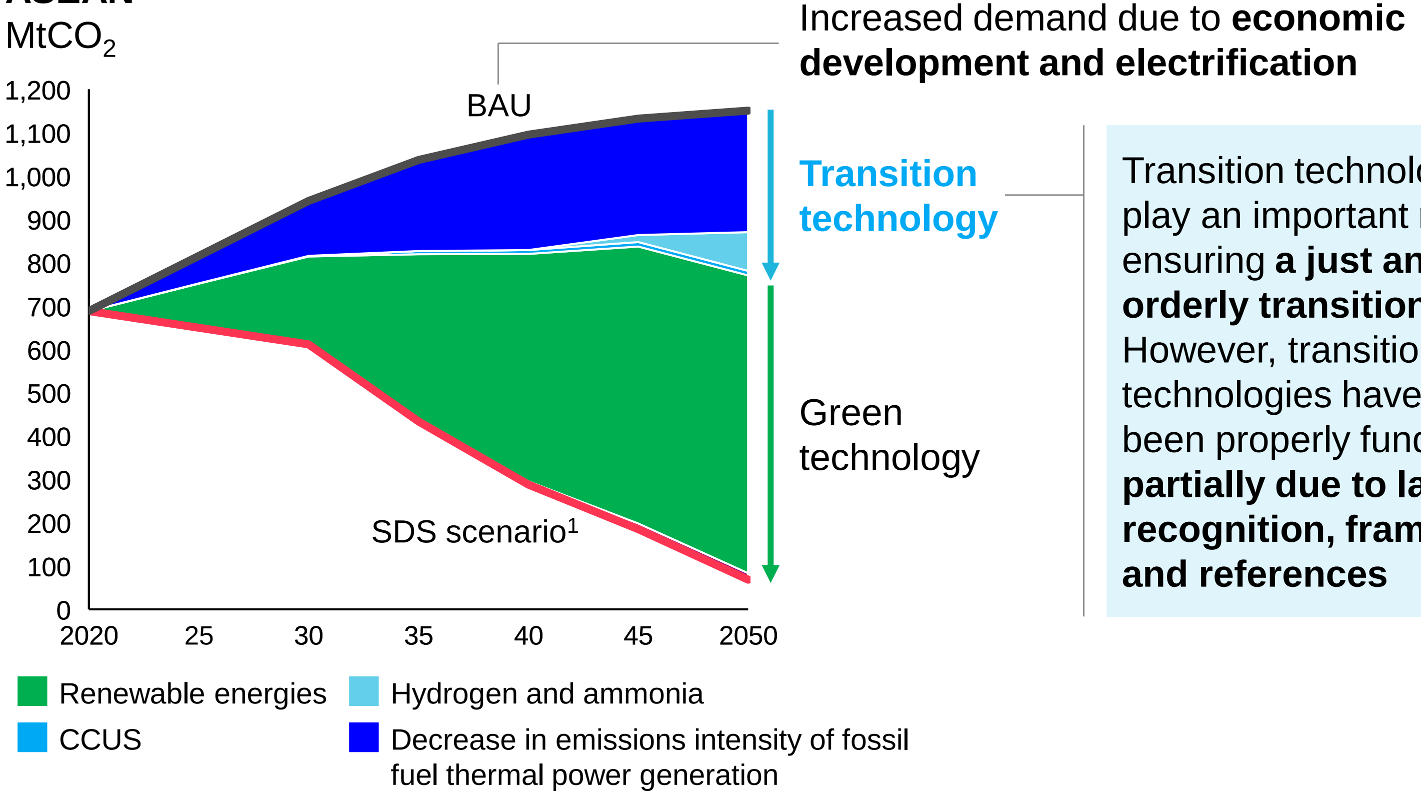
Transition technologies play a critical role in achieving decarbonisation in Asian countries

Major challenges in Asia

- **Diverse starting points** for decarbonisation (e.g. several countries are dependent on coal)
- **Varying natural resource endowments** for renewable energy
- **Difference in economic growth stages**

Transition technologies complement green ones for successful decarbonisation – ASEAN power example

Power generation CO_2 emissions in ASEAN[1]
$MtCO_2$



Transition technologies play an important role in ensuring **a just and orderly transition.** However, transition technologies have not been properly funded, **partially due to lack of recognition, frameworks, and references**

1. IEA Sustainable Development Scenario.
Note: BAU, business as usual. RE, renewable energy. CCUS, carbon capture, utilisation, and storage.

Source: IEA World Energy Outlook 2021, Asia Transition Finance Guidelines

The first version focuses on transition technologies with direct impact on the highest emissions sectors

Applicable sectors

In this first edition, the document covers technologies applicable to **the power (electricity generation) and its upstream (fuel production),** which together accounts for more than 50% of CO_2 emissions in Asia[1]

Features of technology

The document covers technologies that:

- Have **direct impact to carbon emissions reduction**
- Are **not green/zero emissions technology** (those with zero carbon emissions through operation)

!

- This is **the first version** of the Assessment Perspectives for Transition Technologies in Asia. Though the scope of this document is limited as above, **it may expand** in future revisions
- This document is **not an exhaustive list** of potential transition technologies. Lack of inclusion in this document **does not disqualify** technologies from being considered as transition technologies

1. Detail on the next page

Source: IEA 'Greenhouse Gas Emissions from Energy' (Aug, 2022)

Sector coverage initially focuses on power generation and related upstream fuels productions, but may be extended in future versions

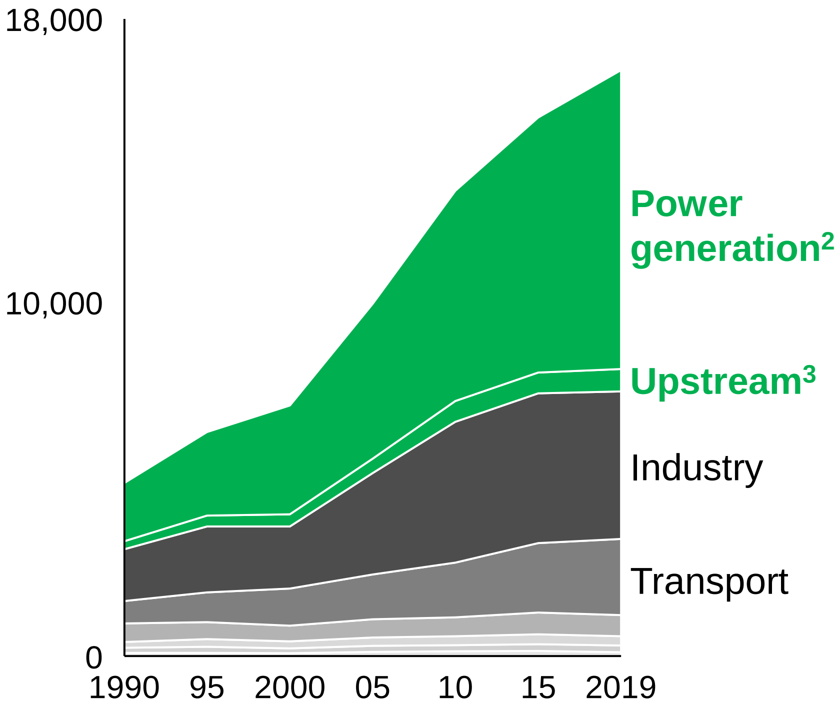
Guiding principles

- This first version focus on sectors that
  - have large emissions footprints
  - attract large investments
- Future versions are expected to expand and are not restricted to the sectors identified here.

Energy sector is responsible for the largest share of CO_2 emissions

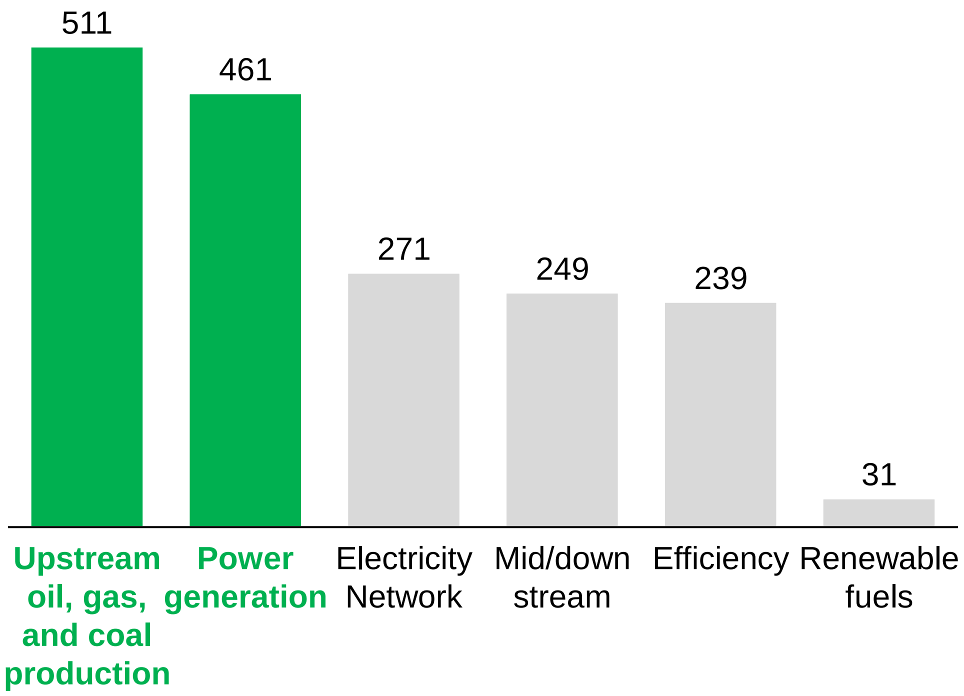
CO_2 emissions by sector[1]

$MtCO_2$; 1990-2019 in Asia Pacific



Annual investment by sub-sector in energy industry

USD Billion; average of 2018-2020, global



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Source: IEA 'Greenhouse Gas Emissions from Energy' (Aug, 2022) and IEA 'World Energy Investment 2020'

Technology: this document covers transition technologies, in contrast to intrinsically 'green' and 'brown'

POWER SECTOR EXAMPLE - ILLUSTRATIVE

Classification of technologies/solutions relative to fulfilling decarbonisation goals

Focus of this document (the first version)

Green technologies Zero or near-zero emissions	• Renewable energy (solar, wind, biomass, small hydro, geothermal…) • Battery storage & other storage solutions • Grid interconnections, grid flexibility • BECCS[1] • Direct air carbon capture • Large hydro and nuclear (subject to DNSH[2] considerations)	Focus of green finance taxonomies
Transition technologies Significantly lower emissions	• Coal avoidance by early retirement and/or gas power generation • Inefficient plant phase out or upgrade (e.g. OCGT[3] to CCGT[4]) • Co-firing of low-carbon fuels • Venting and fugitive emissions reduction by leak detection and repair • Process electrification in gas production and processing • Low-carbon fuels production (ammonia, hydrogen) • CCUS[5]	Focus of this document
Brown technologies	• Unabated coal-fired power generation[6] • Unabated oil (including diesel)-fired power generation	Progressively restricted from financing

! The first version covers technologies that have direct impact on emissions reduction and does not cover enabling technologies, such as energy storage and grid extension

1. Bioenergy with Carbon Capture and Storage
2. Do no significant harm
3. Open-cycle gas turbine
4. Combined-cycle gas turbine
5. Carbon capture, utilisation, and storage
6. Given that the Glasgow climate pact stipulated the phase-down of unabated coal power, this document assumes any type of coal fired plants without co-firing or CCUS falls under unabated, regardless of its efficiency (subcritical, super critical, ultra supercritical, integrated gasification combined cycle (IGCC) etc.)

Sector and technology: the first version covers upstream and power sector under transition technology (may expand in future revisions)

NON EXHAUSTIVE

Included in the first version | Not included in the first version

	Energy sector activities: Upstream (fuel production)	Energy sector activities: Power (electricity generation)	Energy sector activities: Mid-stream	Energy sector activities: Downstream	Other sectors: End-use
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Brown technology	Coal mining Oil extraction	Unabated coal-fired[3] Unabated oil-fired (incl. diesel)			

Note that the distinction between green/zero emissions and transition technology becomes blur after mid-stream

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1. Energy service company
2. In majority of cases of cogeneration/CHP, heat generated during electricity generation is transferred to neighboring manufactures or building, saving their heat consumption. Therefore, the emissions reductions occur in industry or building sector and thus is categorised in industry.
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Technology tiering: transition technologies can be classified in 3 tiers based on decarbonisation level and deployment timeline

POWER SECTOR EXAMPLE - ILLUSTRATIVE

Three tiers of transition technologies and their definitions

Sample transition solutions/ technologies in power sector

Emissions intensity

Early decarbonisation

Transition technologies that have lower emissions intensity than a legacy technology, but still emits GHGs. Can be deployed in the early phases of a country's transition pathway and may be retired or shifted to partial emissions reduction or deep decarbonisation technologies before reaching carbon neutral.

- Coal avoidance:
  - Early retirement of legacy assets
  - Coal to gas substitution
- Inefficient plants phase out/upgrade (e.g. OCGT to CCGT)

Partial emissions reduction

Transition technologies that have even lower emissions intensity than an early decarbonisation technology, but still emits GHGs. Can be deployed in early to mid phase of a country's transition pathway.

- Co-firing of biomass or low-carbon fuels
  - Biomass or low-carbon fuel (ammonia or hydrogen)
  - Venting and fugitive emissions reduction
- Process electrification in gas production and processing

Deep decarbonisation

Transition technologies that have near-zero emissions or are likely to have zero emissions in near future, and thus are essential for achieving decarbonisation. Can be deployed in mid-to-late phase of a country's transition pathway.

- CCUS
- Green/blue low-carbon hydrogen or low-carbon ammonia full fuel shift

Year

First version scope: 10 covered technologies

Transition technology scope for the first edition

Covered in 'Power' section in this document

Covered in 'Upstream' section

Covered in 'CCUS' section

The first version of the document prioritises technologies based on

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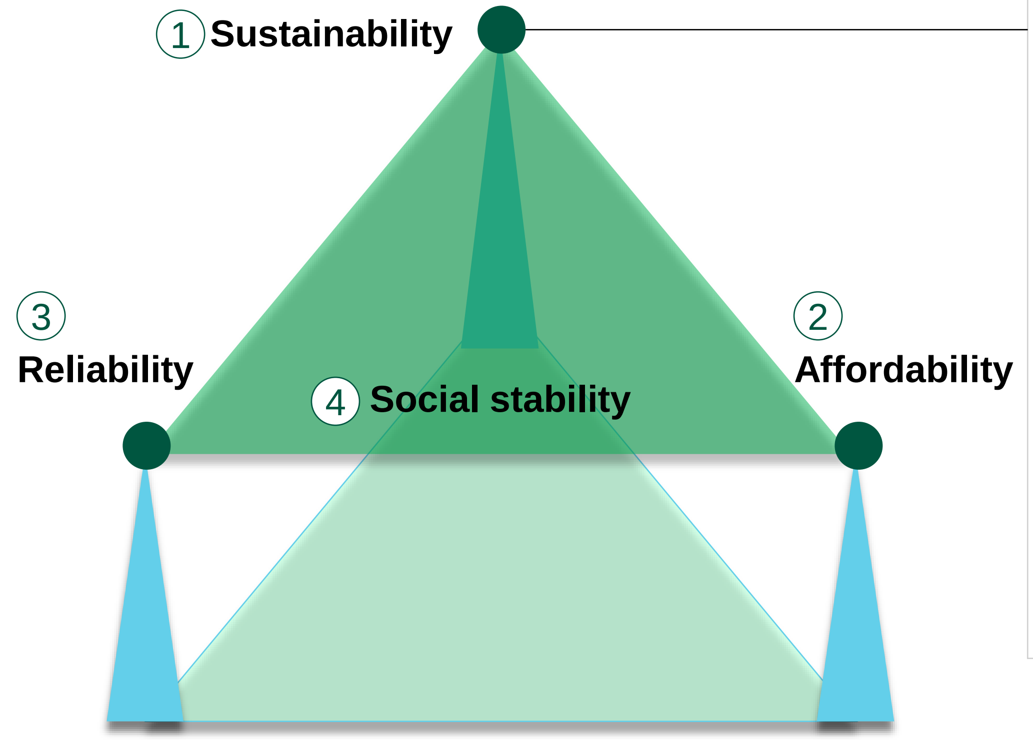
Transition technologies are assessed on 6 framework dimensions to address important factors for a just and orderly transition

Deep dive

Important factors for a just and orderly transition



Challenges

- Not only promote climate sustainability but also ensure the reliability of energy supplies and their affordability for governments and their citizens, maintaining social stability
- Striking a subtle balance amongst sustainability, reliability and affordability to maintain social stability

6 key framework dimensions

1
- Emissions impact
- Lock-in prevention considerations
- DNSH[1] considerations

2 Affordability

3 Reliability/maturity

4 Social considerations

1. Do no significant harm

Source: Asia Transition Finance Guidelines

Assessments along the 6 framework dimensions leverages specific questions and data sources

ILLUSTRATIVE

	Framework dimensions	Description	Reference
Technology characteristics	**Emissions impact**	GHG emissions intensity and/or reduction impact required to contribute to decarbonisation of a country or company	IPCCs, IEEJ
	Affordability	Estimated cost for technology	IEA, IEEJ, DEA, IRENA etc.
	Reliability/ maturity	Readiness for technology (e.g. commercial at scale, pilot, etc.).	Technology Readiness Level[1] by IEA (deep-dive page to follow)
Additional considerations	**Lock-in prevention considerations**	Eventual emissions reduction plan to reach zero or near-zero emissions.	EU Taxonomy and ASEAN Taxonomy for Sustainable Finance[2]
	DNSH considerations	'Do No Significant Harm' to environmental objectives other than GHG emissions.	
	Social considerations	Mitigate the negative effects of transition activities to the society, e.g. unemployment	

1. IEA, ETP Clean Energy Technology Guide
2. All the environmental objectives in EU taxonomy are covered in the 6 framework dimensions. All environmental objectives and essential criteria in ASEAN Taxonomy for Sustainable Finance are similarly covered in the 6 framework dimensions.

【Reference】Reliability dimension is assessed with the Technology Readiness Levels[1] (TRL, hereafter) published by IEA

	Level	Description
Mature	**11**	Proof of stability reached – Predictable growth
Market uptake	**10**	Integration required at scale – Solution is commercial and competitive, but requires further integration efforts
	9	Commercial operation in relevant environment – Solution is commercially available. requires evolutionary improvement to stay competitive
Demonstration	**8**	First of a kind commercial – Commercial demonstration. Full- scale deployment in final conditions
	7	Pre-commercial demonstration – Prototype working in expected conditions
Large prototype	**6**	Full prototype at scale – Prototype proven at scale in conditions where it will be deployed
	5	Large prototype – Components proven in conditions where it will be deployed
Small prototype or lab	**4**	Early prototype – Prototype proven in test conditions
	3	Concept requires validation – Solution must be prototyped and applied
	2	Application formulated – Concept and application have been formulated
	1	Initial idea – basic principles have been derived

1. IEA, ETP Clean Energy Technology Guide

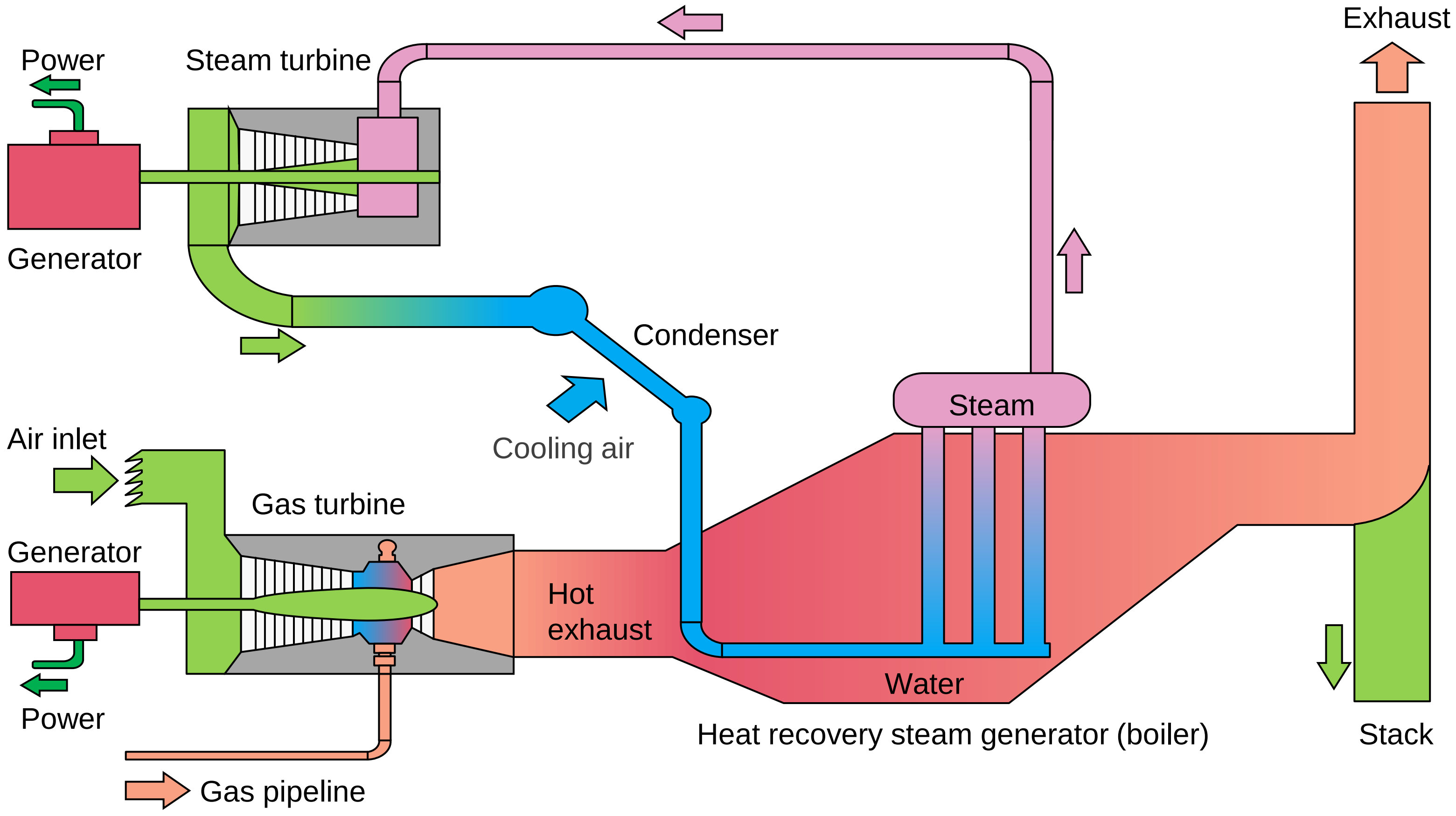
【Reference】Framework for DNSH and Social considerations

Framework dimensions	Considerations/Key questions		Reference
DNSH conside-rations	**Protecting healthy ecosystems and biodiversity**	• Would the technology be detrimental to the health and resilience of ecosystems and biodiversity? What preventative measures should be implemented? • Beside GHG, would the technology lead to a significant increase in the emissions of pollutants into the air, water, or land? What preventative measures should be implemented?	EU Taxonomy and ASEAN Taxonomy for Sustainable Finance
	Promotion of transition to circular economy	• Would the technology run on sustainably-sourced raw materials? • Would the technology increase the generation, incineration, or disposal of waste? What measures should be taken to avoid or minimise waste?	
Social conside-rations	**Are there plans to mitigate the negative social impacts of the technology?**	• Would the technology lead to negative changes in job opportunities?	
		• Would the technology lead to negative changes in working environments?	

5 major potential transition technologies in the power (electricity generation) sector are featured

- Combined cycle gas turbine (CCGT)
- Waste to energy (WtE) power plant
- Biomass co-firing
- Low-carbon ammonia co-firing
- Low-carbon hydrogen co-firing

Combined Cycle Gas Turbine (CCGT) – Technology schematics and overview



Combined cycle gas turbine (CCGT) power plants utilise two thermodynamic cycles:

- Gas turbine
- Steam turbine (utilising exhaust heat of gas through a heat recovery steam generator)

A CCGT power plant can achieve higher thermal efficiency of about 60% when compared to about 40% for open cycle gas turbines (OCGT) and coal power plants

Generating capacity can vary from around 300 to over 1,000 MW per plant, depending on configuration and number of units

Plant availability is typically over 80% as per international benchmarks, with a technical life of over 25 years

Source: Literature search

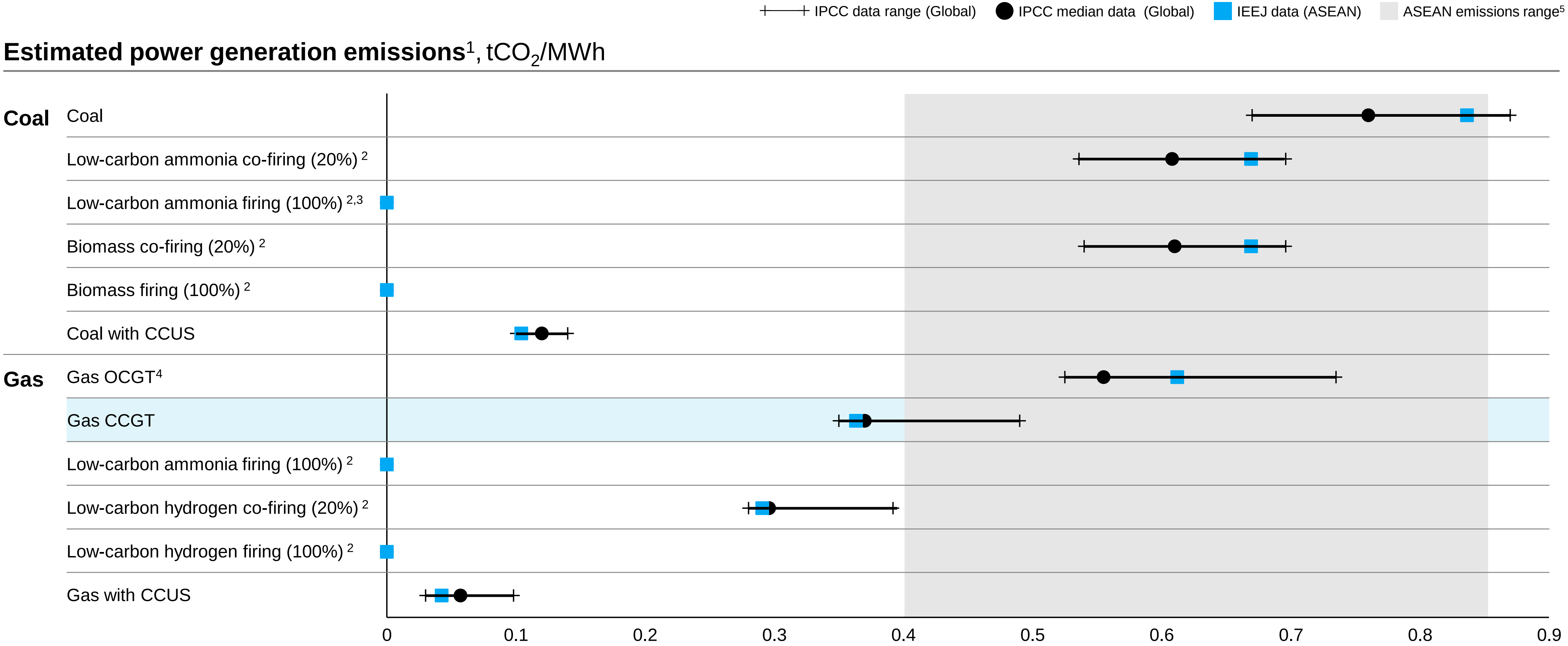
Combined Cycle Gas Turbine (CCGT) – Transition suitability assessment overview

Framework dimensions	Description
Emissions impact	• **Lowest emissions factor amongst fossil fuel thermal power generation[1] (**0.35-0.5 tCO_2/MWh), below average emissions factor in most ASEAN countries • **Comparative emissions reduction** if displacing OCGT plants and legacy/upcoming coal plants • Load flexibility characteristics can **support intermittent renewable generation uptake**
Affordability	• **LCOE[2] dependent on load factor and gas price**; historical range of 60-120 USD/MWh[1] estimated for ASEAN, competitive at least for mid-merit use within most power systems • **Higher incidence of variable fuel costs** vs. upfront CAPEX in LCOE. Actual economics are sensitive to fuel price fluctuations
Reliability	• **Commercialised technology** with 55-60% thermal efficiency, availability typically over 80%, technical life over 25 years • **Installed at scale** (total capacity of 1,822 GW globally in 2020)
Lock-in prevention considerations	• **Long term Paris-alignment requires one of the following pathways:** transition to co-firing/full-firing with low-carbon fuels, retrofitting with CCUS, retirement or shift to peaking/reserve use within largely decarbonised power systems • **Inflexible long-term gas/power procurement contracts** may hinder transition
DNSH considerations	• **Methane emissions from purchased gas** must be monitored and addressed to limit indirect GHG emissions • **Environmental assessment on ecosystems** required - especially for released waste-water from cooling, and pipeline or LNG jetty/regas infrastructure • Residual heat or cold energy could be productively deployed, depending on specific plant location
Social considerations	• **HSE[3] practices** to be verified, e.g. HSE policies in line with local regulation and industry standards, HSE track record of operating entity in other plants (if available)

1. Historical estimate assuming 40-60% load factor and a range of local ASEAN gas input prices – future values highly sensitive to inputs and variable by country
2. Levelised cost of electricity
3. Health, safety, and environment

Emissions impact – CCGT emissions intensity range is generally below grid average for ASEAN countries

Estimated power generation emissions[1], tCO_2/MWh

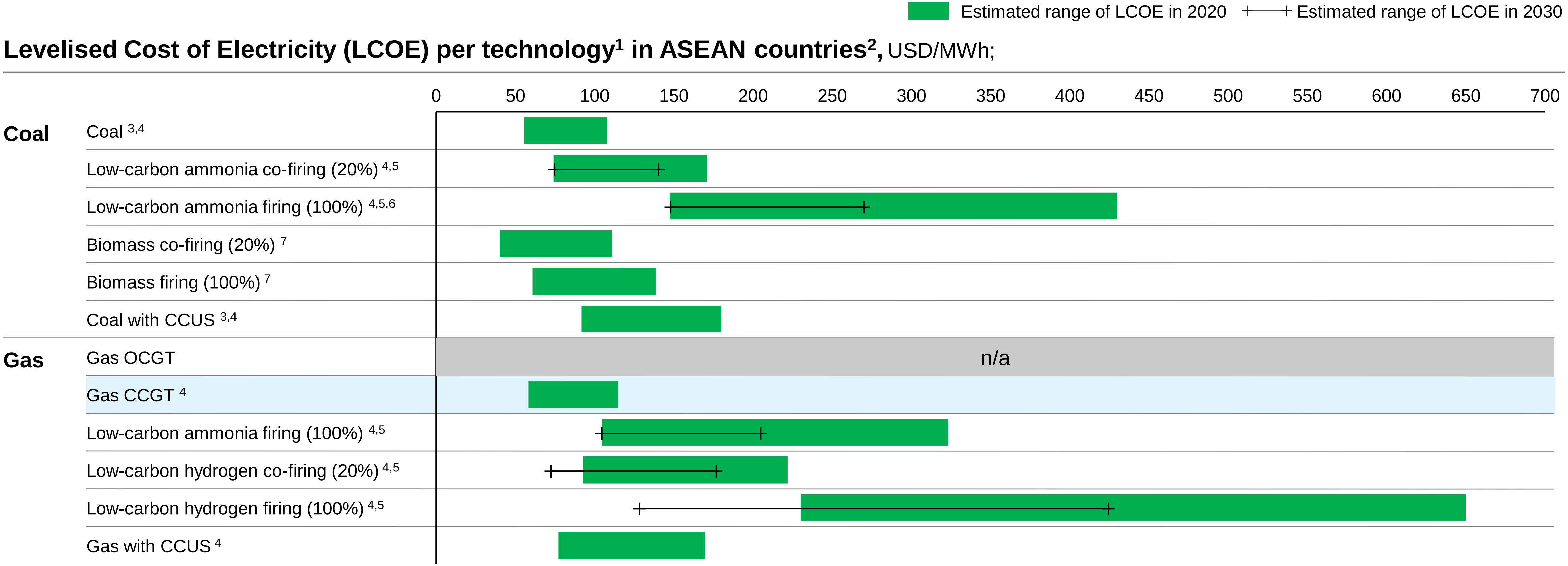


1. Direct emissions for power generation only; other lifecycle emissions not included; IPCC data for 2018; IEEJ data for 2017
2. Emissions for co-firing/firing of biomass or low-carbon fuels are estimated based on the co-firing/firing ratios and the base emissions in respective Coal or Gac CCGT
3. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
4. Emissions for OCGT are estimated based on CCGT emissions and the efficiency of OCGT over CCGT
5. The range of the emissions intensities of ten ASEAN member states (see the 'country-specific power generation emissions' section in the appendix)

Source: IEEJ, IPCC Annex III Technology-specific cost and performance parameters (2018)

Affordability – LCOE is highly sensitive to input gas prices, but is competitive at least for mid-merit use within most power systems

Levelised Cost of Electricity (LCOE) per technology[1] in ASEAN countries[2], USD/MWh;



1. Direct emissions from power generation only; other lifecycle emissions not included
2. Data in Indonesia is used as representative
3. LCOE range for subcritical and supercritical coal fired power plants are shown here
4. LCOE is calculated based on technology data from the DEA using uncertainty range for investment and O&M costs. Coal and gas fuel costs are based on historical range in 2017-2021 from World Bank and Enerdata (coal as 60~140 USD/Mt, gas as 6~11 USD/mmbtu), low-carbon ammonia cost is based on IEA's estimates as of 2018 (240~790 USD/t) and as of 2030 (240~450 USD/t). Hydrogen costs are based on IEEJ and Hydrogen Council's estimates as of 2020 (4~11 USD/kg) and as of 2030 (2~7 USD/kg). Assumptions on other parameters include technical lifetime (coal: 30 years, gas: 25 years), discount rate (8%), capacity factor (coal: 60%, gas: 40~60%), and thermal efficiency (coal: 41%, gas: 56%). Please note that LCOE is highly dependent on fuel cost, and LCOEs shown here are based on fuel costs as written above and do not reflect the current LCOEs. In particular, LCOE here does not reflect recent gas and coal price surge after Ukraine incidents.
5. Additional costs for ammonia/hydrogen co-firing and firing are based on incremental costs by fuel mix and additional CAPEX is not considered.
6. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
7. Data from IRENA report, LCOEs for biomass co-firing during 2010-2021. The 5th and 95th percentile amongst reported power plants are indicated.

Source: IEEJ, DEA Technology data for the Indonesian power sector (2021), IRENA Renewable Power Generation Costs (2021), World Bank Commodity Prices (2022), Enerdata Global Energy & CO_2 Database - POLES-Enerdata model - EnerFuture scenarios (2021), Hydrogen Council Hydrogen Insights Report (2021), and IEA The Future of Hydrogen (2019)

Reliability – CCGT technology has been commercialised for decades, with sizeable installed base globally and in Asia

Estimated commercialisation status

- **Commercialised technology** with 55-60% thermal efficiency, availability typically over 80%, technical life over 25 years
- **Installed at scale** (total capacity of 1,822 GW globally in 2020)

Recent project examples

Details

CCGT power plant at Batangas by SMC Global Power

- In 2021, SMC Global Power began construction of a **power plant with 4 CCGT units at a total 1,313 MW capacity** in Batangas, which is expected to be completed by 2024.
- Electricity generated from this power plant will be supplied to Meralco based on a long-term electricity supply contract. This contract is notable in that it is the **first-time a gas-fired power plant has replaced coal to be awarded greenfield baseload capacity in the Philippines**

Son My 1 CCGT power plant at Binh Thuan by EDF

- In 2018, Electricité de France (EDF) has signed MoU on the development of **Son My 1 powerplant with 3 CCGT units with total 2,250 MW capacity** at Binh Thuan by 2028.
- The Son My 1 power plant was **initially planned as coal-fired power plant, but switched to gas-fired power plant** to align with the national Power Development Plan (PDP VIII) of Viet Nam, which indicates a shift to gas and renewables from coal to lower carbon emissions

Source: IEA, literature search

Lock-in prevention – Three possible long-term decarbonisation pathways, with inflexible gas/power contracts a possible risk

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	• Three paths exist for CCGT to be zero or near-zero emissions; – Path 1: Co-firing/firing of low-carbon fuels to achieve progressively lower GHG emissions intensity – Path 2: Retrofitting with CCUS – Path 3: Retiring or switching to peaking use / ancillary services provision (reserve) • Transition-suitable newbuild CCGT plants should articulate an envisioned pathway as part of their proponents' strategy, or relevant countries' long term power plans
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	• Path 1: Co-firing/firing with low-carbon fuels, such as ammonia and hydrogen – To be discussed in detail in 'Low-carbon ammonia co-firing' and 'Low-carbon hydrogen co-firing' sections. – Current high costs of low-carbon ammonia/hydrogen. Technological maturity is in early commercialisation or pilot phases. • Path 2: Retrofitting with CCUS – To be discussed in detail in 'CCUS in coal/gas fired power plant' section – Abatement cost estimated at 90-160 USD/tCO_2 as of 2017. Technologically in an early commercialisation phase (TRL 8-9), with concerns on transport and long-term storage of CO_2. • Path 3: Retiring or switching to peaking use / ancillary services provision (reserve) – Long-term gas procurement contracts may hinder retirement or reduced usage of CCGTs, especially if Take-or-Play clauses with high thresholds are present – Power purchase agreements (PPAs) with very long tenures and minimum utilisation commitments may also hinder retiring or reduced usage of CCGT

Source: Literature search, Global CCS Institute Global cost of carbon capture and storage 2017 Update.

DNSH/social considerations – Methane emissions in the gas value chain and waste heat discharge can be the main environmental concerns

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• Waste heat running into river/sea from a gas power plant may cause negative impacts on local ecosystems. Temperature monitoring and control of wastewater should be in place • Environmental viability assessment (or equivalents) should be conducted for major new infrastructure installations associated with the CCGT plant – including LNG regas terminal/jetties or gas pipelines • Non-GHG pollutants in exhaust gas streams should be monitored and mitigated (e.g. through filtering or leakage prevention systems)
	Transition to circular economy	• Gas should be sourced from suppliers who measure, disclose, minimise, and potentially offset GHG emissions along the value chain - including methane • Assessments should be conducted on whether residual heat from the CCGT plant or cold energy from the regas terminal (when present) could be used for heating/cooling, eliminating additional dedicated energy needs
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Positive employment impact expected from new CCGT plants across the construction and operation phases (engineering, fuel procurement, plant operation and maintenance) • HSE practices to be verified, e.g. HSE policies in line with local regulation and industry standards, HSE track record of operating entity in other plants (if available)

Source: Literature search

4 types of waste-to-energy power generation

Waste-to-Energy technologies for power generation

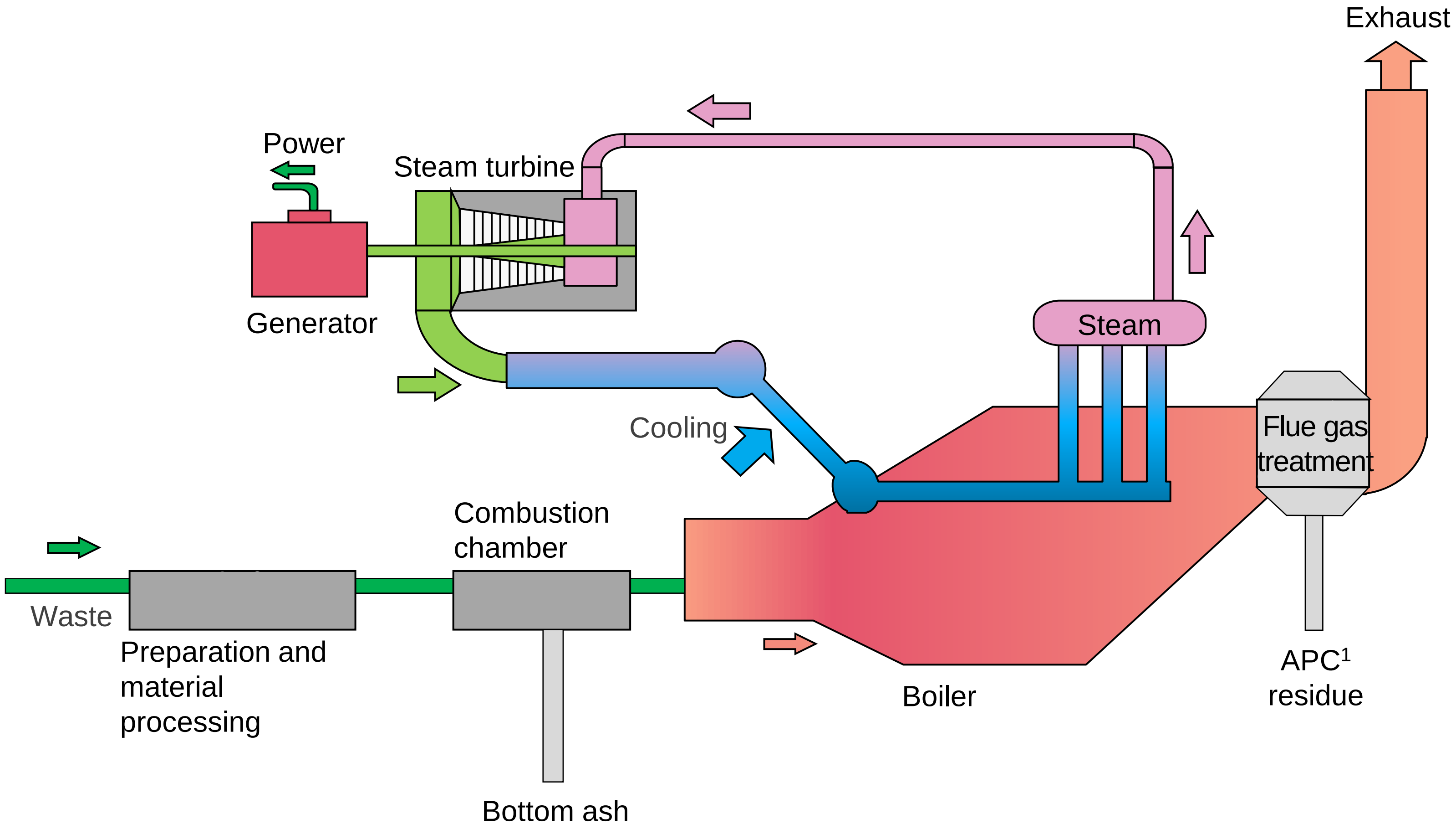
Focused in this document

Waste treatment	Technology	Feedstock	Details
Incineration	**Direct combustion (incineration)**	MSW[1], RDF[2], agricultural residues, energy crops, wood residues	• **Waste is burned in a controlled process** to produce high-pressure steam to rotate turbines that electricity. Steam can be also used in district heating and cooling • Plant is typically designed to **treat mixed and largely untreated domestic waste** • Three types of combustion technologies can be applied: grate system, fluidised bed, and rotary kiln
	Thermochemical gasification		• **Syngas is converted from carbon in organic waste** and burned to produce heat energy • Producing gas from waste consists of four zones inside a gasifier: drying, pyrolysis, combustion, and reduction
	Anaerobic digestion	Agricultural waste, industrial waste, energy crops, food waste	• Biogas is produced in a chamber by **decomposing organic waste** • **Gas turbines** are used to generate electricity using biogas • Biogas can be upgraded to bio-methane with higher methane content of up to 98% to substitute natural gas
Landfill	**Landfill gas capture**	MSW, RDF, agricultural resides, energy crops, wood residues	• Plant **consists of extraction system and flaring system,** of which landfill gas consists of 35-55% methane generated by anaerobic digestion of organic matter • The plant extract gas from landfills using **vertical/horizontal perforated pipes and ditches**

1. Municipal solid waste
2. Refuse-derived fuel

Source: ADB Waste to energy in the age of the circular economy (Nov. 2020)

Waste-to-energy power generation (direct combustion) – Technology schematics and overview



Waste-to-Energy (WtE) generation utilises **waste as feedstock** to generate thermal for generation

- **MSW[2] is used** amongst other forms of waste, including agricultural/wood residues and RDF[3]
- **Emissions impact depends on waste components**: biogenic (plant-based) vs non-biogenic (e.g. plastic)

Energy efficiency is lower than fossil fuel generation (up to 30%)

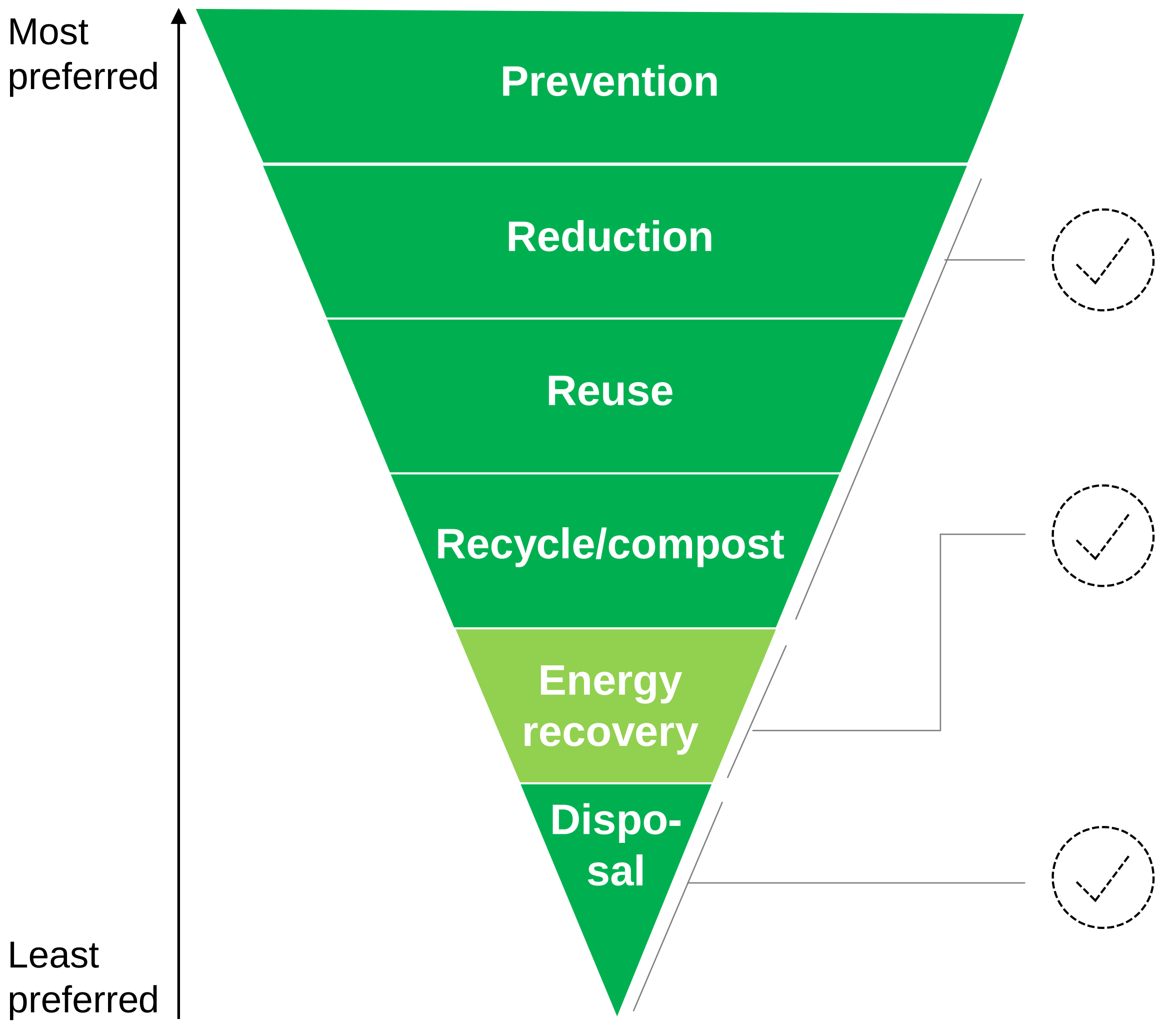
Transition plans must be aligned with waste management, including increased recycling and additional emissions reduction by e.g. CCUS

1. Air Pollution Control
2. Municipal Solid Waste
3. Refuse Derived Fuel

Source: Literature search, EIA, ADB Waste to energy in the age of the circular economy (Nov. 2020)

[Reference] Waste management principles must be reviewed before WtE to be considered as a transition technology

Measures of waste management



Target of waste-to-energy

The 3Rs[1] must be prioritised before considering energy recovery

Recovery through thermal (e.g. direct combustion), thermochemical (e.g. gasification) and biochemical conversion (e.g. anaerobic digestion) is available

Landfills are a common practice, varying from open dumping to sanitary landfills. Some countries still rely on open burning and disposal on the street etc.

WtE can become transitional technologies but one should consider the following waste management principles

- **Prioritise recycling and composting**
- **Use incineration with WtE** to reduce disposal amounts, especially in urban area
- **Add landfill gas recovery** if available

1. Reduce, reuse, recycle

Waste-to-energy power generation – Transition suitability assessment overview

Framework dimensions	Description
Emissions impact	• Must be carefully assessed and consider **GHG emissions by waste combustion**, **emissions reduction by substituting landfill or untreated waste**, and **grid emissions intensity**. • All the above factors vary by situation. Careful, recurring assessments are required to judge if the WtE power plant qualifies as a transition technology • Components of waste and its separation must be monitored to minimise waste combustion emissions
Affordability	• **LCOE range is (50 - 250 USD/MWh)** and is dependent on factors such as feedstock costs (incl. sorting costs), capacity, and efficiency
Reliability	• Conventional technologies (MSW[1] direct combustion, landfill gas recovery, and anaerobic digestion) are **at commercial scale** • **Thermochemical gasification** is at early commercialisation stage. **CCUS** requires further R&D to capture small-scale emissions source
Lock-in prevention considerations	• **Must have plan of reduced usage in line with the societal shift towards circular economy** • **Transition plans must consider the increased rates of waste biogenic components in combination with gasification technologies and CCUS**
DNSH considerations	• **3Rs and composting should be prioritised** as a waste management method • **Air pollution beyond GHG (particulate matter, heavy metal, dioxin)** must be properly addressed • Use incineration with WtE to reduce disposal amounts, especially in urban areas • Add **landfill gas recovery** if available
Social considerations	• HSE risks, especially **waste treatment and air pollution,** must be properly addressed based on HSE policy across value-chain • **Waste collection/treatment may stimulate local employment** in entire waste value-chain and **improve public health** in local community

1. Municipal solid waste

Emissions impact – Three emissions changes have to be considered when assessing emissions impacts of waste management and power generation

Considerations

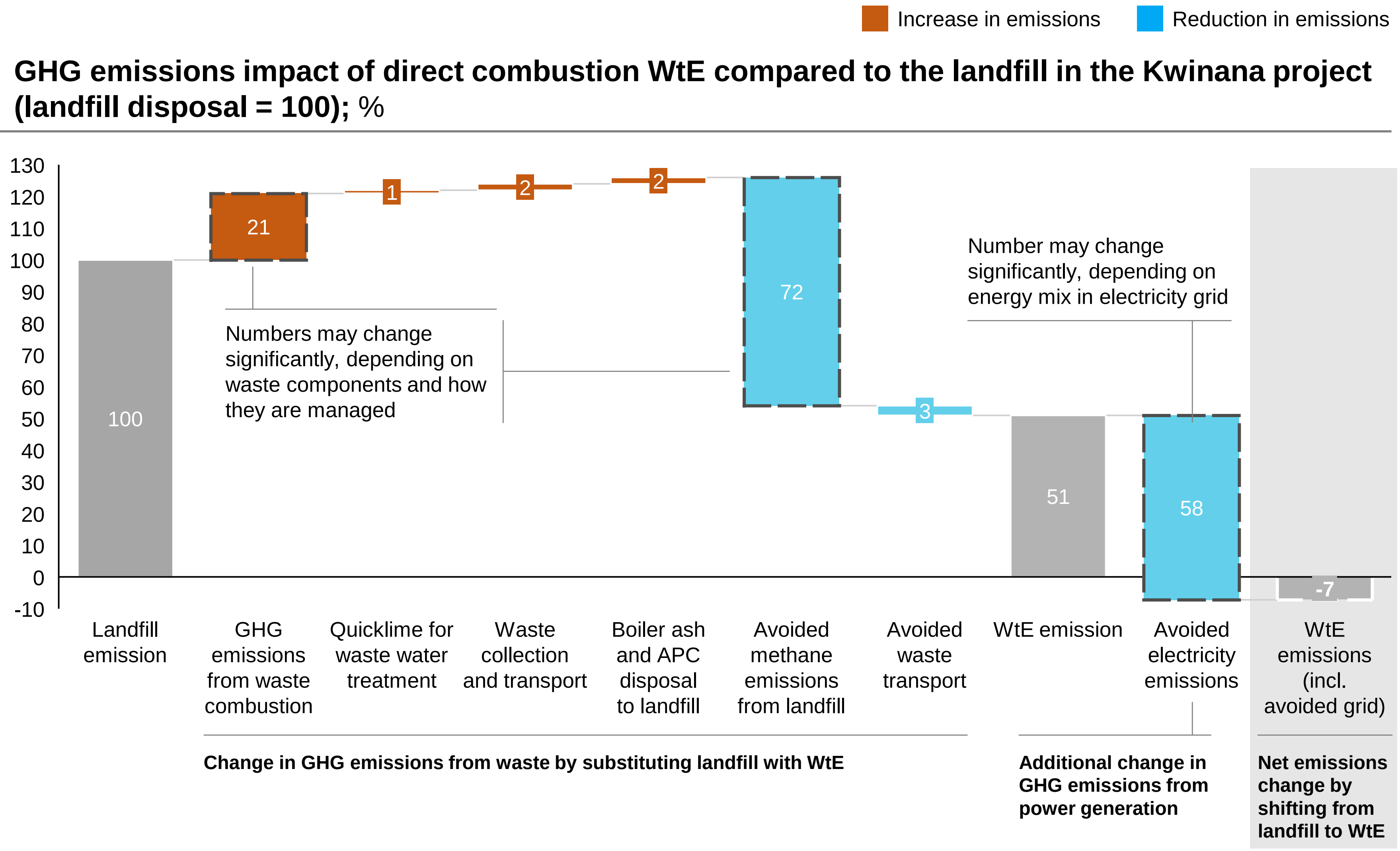
WtE could have both **positive and negative impacts.** The net effect must be carefully assessed

Specific considerations include:

- Potential positive impacts: **emissions reduction from baseline** (e.g. methane emissions in landfill)
- Potential negative impacts: **waste combustion emissions**
- Grid emissions intensity

The circular economy must be assessed so as not to hinder the 3Rs. You will find this consideration point under DNSH

GHG emissions impact of direct combustion WtE compared to the landfill in the Kwinana project (landfill disposal = 100); %

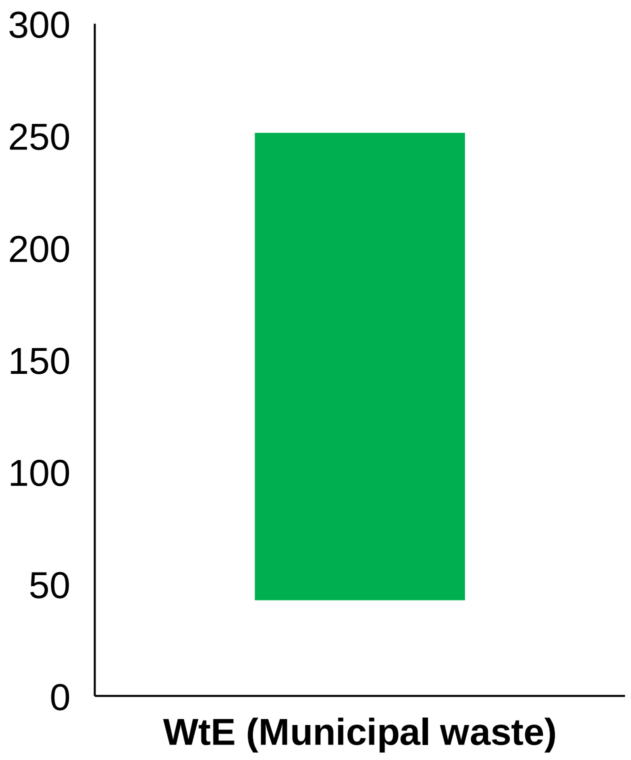


Source: ARENA Kwinana waste to energy project (2018), Frontier economics Assessing emissions from waste to energy (2021)

Affordability – Direct combustion WtE is more often installed for waste management purposes, as power generation costs tend to be higher vs. fossil fuel thermal plants

- **WtE LCOE tends to be higher** than fossil fuel thermal power plants
  - Waste to energy power plants are often constructed to solve waste management issues rather than on electricity price competitiveness.
  - Municipal waste is not a suitable fuel. It generally has low energy content, high moisture, and heterogenous composition.
- **LCOE varies significantly** by installation and feedstock costs (incl. sorting costs), capacity, and efficiency (e.g. matching the plant size to the feedstock amount). Operations and maintenance (O&M) costs tend to have lower impact.

LCOE range[1]
USD/MWh; 2000-22, globally



1. LCOE range based on 5th percentile and 95th percentile of 48 renewable municipal waste power plant projects are shown

Source: ADB Waste to energy in the age of the circular economy (2020), IRENA Renewable Power Generation Costs (2021), US DOE Waste-to-Energy from Municipal Solid Wastes (2019)

Reliability – Technology is mature, but commercialisation depends on the supply of waste, economics, and availability of alternative waste management systems

Estimated commercialisation status

- **Technologies are mature**
- Typical generation capacity is in the range of **below 100MW**
- **Commercialisation** of individual cases depends on **the supply of waste and its economic feasibility**

Recent project examples

Details

New WtE plant in Bangkok

- **Thailand's Metropolitan Energy Authority** has signed a MoU with private firm Newsky Energy Thailand on co-investment arrangements for **two new waste-to-energy power plants in Bangkok**
- Each will generate **35 MW of electricity using 1,000 tons of waste as fuel each day**
- Construction will start later in 2021, and the new plants are slated to come online in the electricity grid in 2024.
- Investment cost is approximately THB 10 billion (USD 320.1 million)

WtE plant with CCU in Saga City

- **Saga City has MSW waste-to-energy plant of 4.5MW**
- Since 2016, **a Toshiba-designed CO_2 capture plant has operated at this site capturing 10 tonnes/day** for use in the local agricultural sector.
- In 2022, Saga City, Saga University, Itochu Enex, and Fuji Oil began a demonstration project to **utilise captured CO_2 for enhanced soybean cultivation**

Source: Literature search

Lock-in prevention considerations – Reduced usage has to be considered as the society shifts toward circular economy

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	• Three pathways to be zero or near-zero emissions; increase biogenic (non-fossil related) components from waste, CCUS, and retiring – Path 1: Further CO_2 reductions can be achieved by targeting biogenic components of waste through gasification or enhanced combustion systems – Path 2: Near-zero emissions can be achieved using bio-methane with gas turbines or retrofitting CCUS – Path 3: Reduce usage in line with the societal shift towards circular economy • Waste management should prioritise recycling and compositing, and use others for WtE feedstock
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	• Targeting waste biogenic components – Requires gasification or mechanical biological treatment to form RDF, which has higher heat content with appropriate waste sorting – Requires financial support and understanding from the local government for an enhanced waste treatment system • Retrofitting CCUS – Currently not economical. Technologically, in early commercialisation phase (TRL 8-9). • Reducing usage – Unused capacity of WtE plants should not encourage incineration over 3Rs and composting of waste (see DNSH consideration next page). – Similarly, when installing a new WtE plant, the plant size has to be properly determined to prevent plant overcapacity.

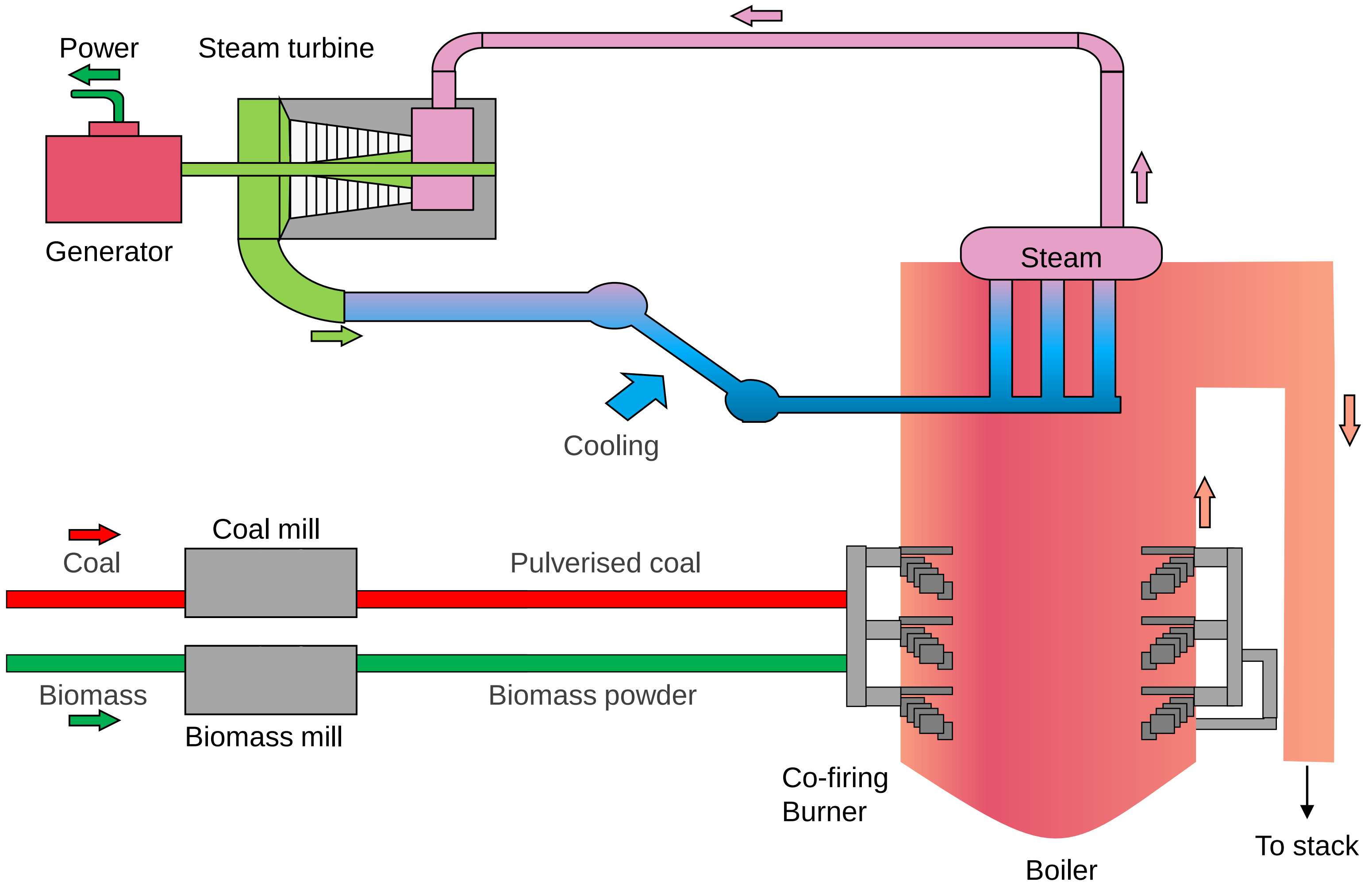
Source: Literature search

DNSH/social considerations – Prioritisation of 3Rs and composting over WtE is needed to promote transition to circular economy

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protecting healthy ecosystems and biodiversity**	• Air pollution (particulates, heavy metals, dioxins) from exhaust should be mitigated by setting filters • Location of final disposal must be evaluated based on local regulations and environmental assessments
	Transition to circular economy	• WtE should not hinder below waste management principle – Prioritise 3Rs and composting – Use incineration together with WtE to reduce amount of disposal especially in urban area – Add landfill gas recovery if available
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Waste collection/treatment may stimulate local employment in the entire waste value-chain • HSE risks must be properly addressed, especially for waste treatment and air pollution impacts on human health

Source: Literature search

Biomass co-firing – Technology schematics and review



Biomass (e.g. wood, agricultural residues, grasses) can be co-fired with coal in a coal-fired power plant with adjustments in the combustion chamber.

Depending on the quality of input biomass and the resulting substitution ratio, the co-firing system can produce electricity with little to no loss in efficiency.

The suitable co-firing ratio varies across feedstock options:

- Agricultural residues – modest: higher ash content and problematic ash compositions
- Wood - higher: tends to have lower ash content (only higher grade and more expensive wood materials are currently suitable for pure biomass firing)

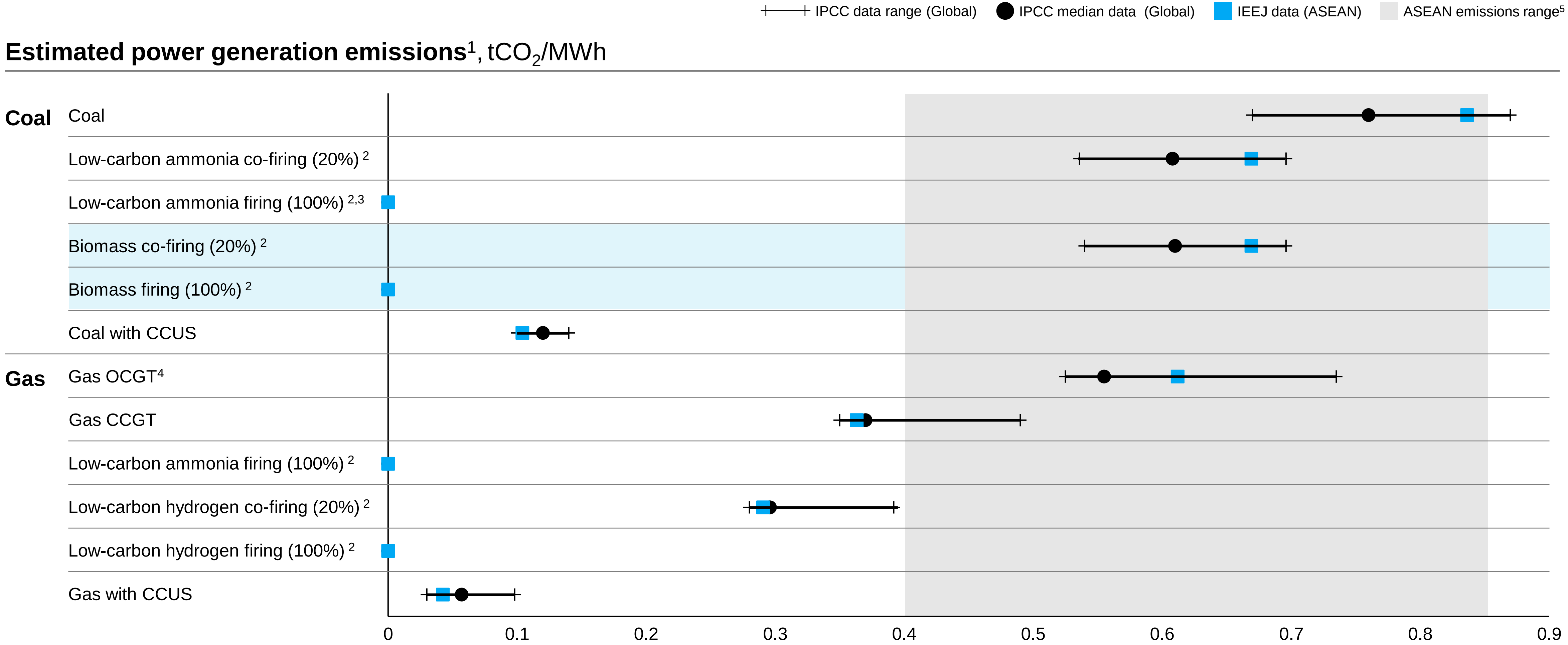
Source: Literature search

Biomass co-firing – Transition suitability assessment overview

Framework dimensions	Description
Emissions impact	• **Emissions reduction directly proportional** to co-firing ratio and net lifecycle emissions of the biomass source; an estimated emissions intensity range of **0.55-0.70 tCO_2/MWh** with **20% co-firing** and reaches **zero emissions with 100% firing.**
Affordability	• **LCOE highly subject to biomass type**, which affects feedstock costs and pre-treatment costs, and proximity to the biomass sources
Reliability	• **Commercialised technology, with pilots implemented** on a limited scale (adopted in 228 plants worldwide) and co-firing ratio up to 100% in several cases
Lock-in prevention considerations	• **Increasing the co-firing ratio** or **combining with CCUS (BECCS)** required for deep decarbonisation • **Further R&D** required for BECCS
DNSH considerations	• **Sustainably sourcing biomass** so as to avoid potential deforestation • Monitoring and mitigating **non-GHG air pollution (PM 2.5)** from biomass combustion • Coupling biomass co-firing/firing with forestation to promote transition to a circular economy
Social considerations	• Verifying HSE practices (e.g. Are HSE policies in line with local regulations and industry standards? What (if available) is the HSE track record of operating entity in other plants?).

Emissions impact – Reduction is directly proportional to the co-firing ratio attained with the potential to reach zero emissions with pure firing

Estimated power generation emissions[1], tCO_2/MWh

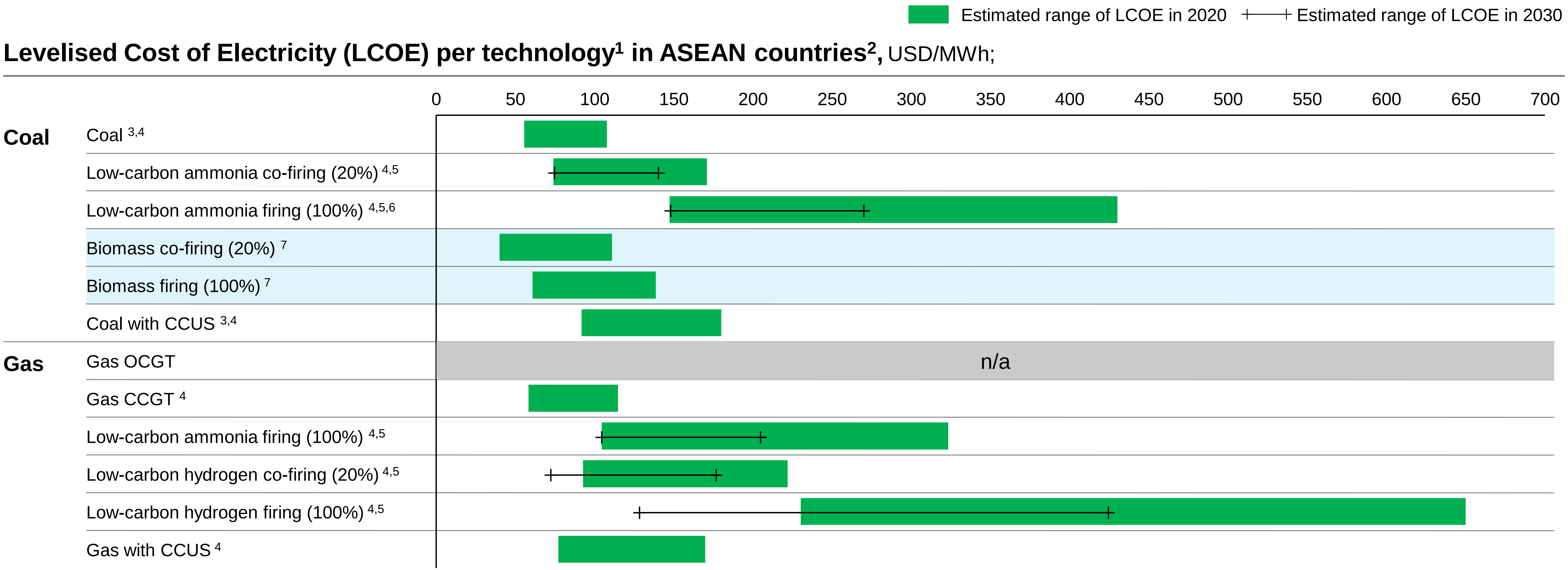


1. Direct emissions for power generation only; other lifecycle emissions not included; IPCC data for 2018; IEEJ data for 2017
2. Emissions for co-firing/firing of biomass or low-carbon fuels are estimated based on the co-firing/firing ratios and the base emissions in respective Coal or Gac CCGT
3. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
4. Emissions for OCGT are estimated based on CCGT emissions and the efficiency of OCGT over CCGT
5. The range of the emissions intensities of ten ASEAN member states (see the ‘country-specific power generation emissions’ section in the appendix)

Source: IEEJ, IPCC Annex III Technology-specific cost and performance parameters (2018)

Affordability – LCOE highly sensitive to price of input biomass

Levelised Cost of Electricity (LCOE) per technology[1] in ASEAN countries[2], USD/MWh;



1. Direct emissions from power generation only; other lifecycle emissions not included
2. Data in Indonesia is used as representative
3. LCOE range for subcritical and supercritical coal fired power plants are shown here
4. LCOE is calculated based on technology data from the DEA using uncertainty range for investment and O&M costs. Coal and gas fuel costs are based on historical range in 2017-2021 from World Bank and Enerdata (coal as 60~140 USD/Mt, gas as 6~11 USD/mmbtu), low-carbon ammonia cost is based on IEA's estimates as of 2018 (240~790 USD/t) and as of 2030 (240~450 USD/t). Hydrogen costs are based on IEEJ and Hydrogen Council's estimates as of 2020 (4~11 USD/kg) and as of 2030 (2~7 USD/kg). Assumptions on other parameters include technical lifetime (coal: 30 years, gas: 25 years), discount rate (8%), capacity factor (coal: 60%, gas: 40~60%), and thermal efficiency (coal: 41%, gas: 56%). Please note that LCOE is highly dependent on fuel cost, and LCOEs shown here are based on fuel costs as written above and do not reflect the current LCOEs. In particular, LCOE here does not reflect recent gas and coal price surge after Ukraine incidents.
5. Additional costs for ammonia/hydrogen co-firing and firing are based on incremental costs by fuel mix and additional CAPEX is not considered.
6. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
7. Data from IRENA report, LCOEs for biomass co-firing during 2010-2021. The 5th and 95th percentile amongst reported power plants are indicated.

Source: IEEJ, DEA Technology data for the Indonesian power sector (2021), IRENA Renewable Power Generation Costs (2021), World Bank Commodity Prices (2022), Enerdata Global Energy & CO_2 Database - POLES-Enerdata model - EnerFuture scenarios (2021), Hydrogen Council Hydrogen Insights Report (2021), and IEA The Future of Hydrogen (2019)

Reliability – Biomass co-firing/firing has been commercialised for decades, with recent pilot projects of BECCS

Estimated commercialisation status

- Biomass co-firing with coal and pure firing has already been **commercialised at scale**. It has been in use for over 20 years and continues to be further developed.
- However, commercialisation in individual cases depends on the supply of biomass and its economic feasibility.
- Biomass cofiring with CCUS (BECCS) is in early commercialisation stage; **TRL 8**

Recent project examples

	Details
Pure biomass firing (with CCUS) at the Toshiba Energy Systems & Solutions Mikawa power plant	• In 2020, Toshiba Energy Systems & Solutions (Toshiba ESS) converted its 50MW Mikawa power plant from a coal-fired to 100% biomass-fired plant and commenced operations. • The Mikawa power plant also has CCUS facilities and is the world's first bioenergy power plant with a large-scale Carbon Capture and Storage (BECCS) capability. It captures over 50% of total emissions, which makes it a negative-emissions plant, given that biomass is carbon neutral.
Pure biomass firing (with CCUS) at Drax's power plants	• During 2012-16, Drax converted four of its six 660MW power plants from coal-fired to 100% biomass-fired plants (and closed the remaining two units). • Drax is piloting CO_2 capture in these plants and expects its first BECCS system to become operational by 2027.

Source: Literature search

Lock-in prevention considerations – While reaching zero or negative emissions is foreseeable, sourcing greater amount of biomass could be a hurdle

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	2 paths exist for biomass co-firing to be zero or near zero emissions • Increasing the co-firing ratio • Combining with CCUS. In particular, pure biomass firing with CCUS (BECCS) has negative emissions and desirable
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	Path 1: Increasing the co-firing ratio • Companies need proactive plans for securing greater amounts of biomass to accommodate higher co-firing ratios. Path 2: Combining with CCUS (BECCS) • Discussed in greater detail in the 'CCUS in coal/gas-fired power plants' section • BECCS technology is in the early commercialisation phase. • Companies need to identify and enter into contracts for CO_2 storage space and transportation means.

Source: Literature search

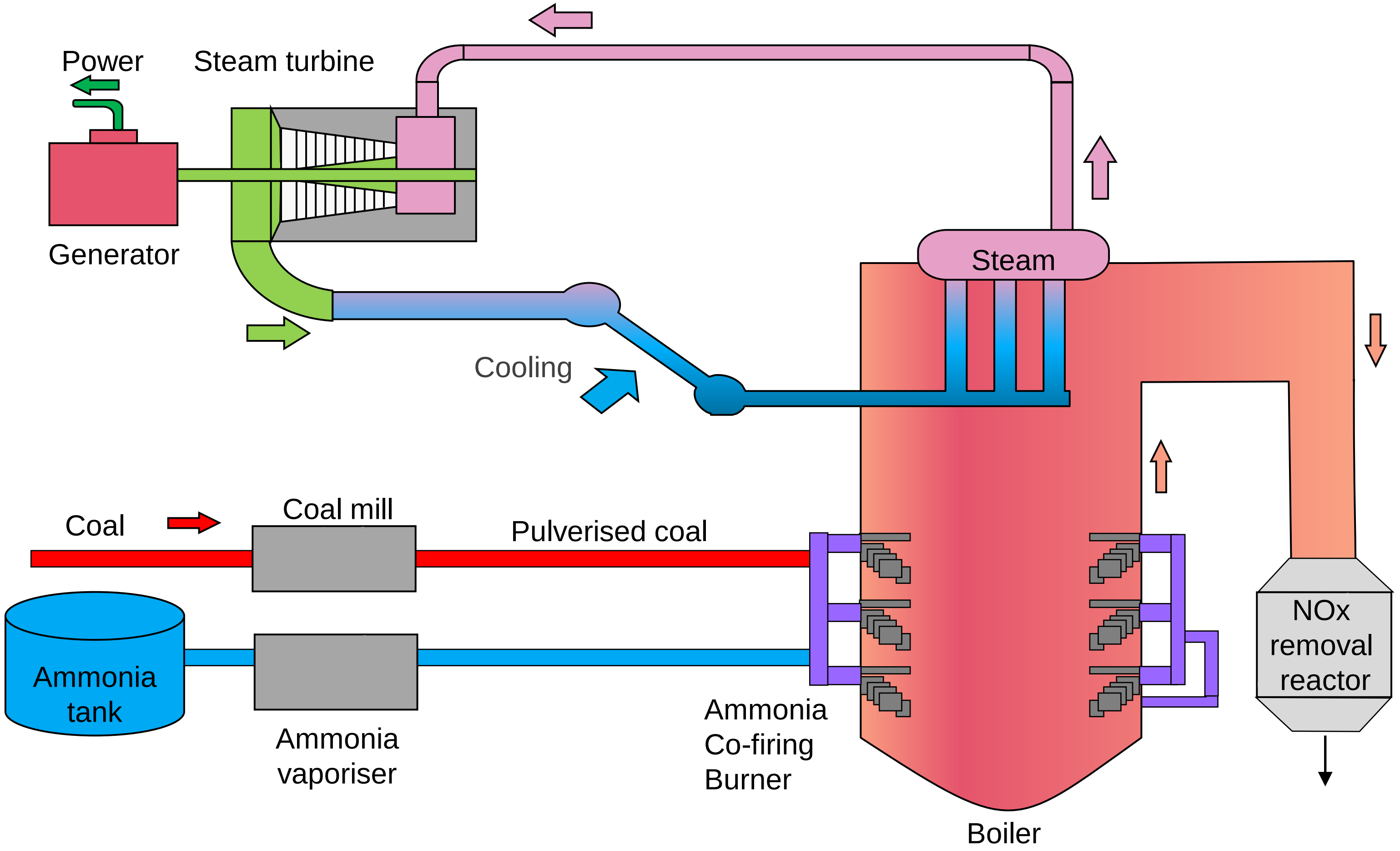
DNSH/social considerations – Release of PM2.5 needs to be mitigated, while ensuring sustainable sourcing of the biomass fuel

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• Biomass combustion emits pollutants (e.g. PM2.5); their release into the air has to be monitored and mitigated.
	Promotion of transition to circular economy	• Biomass needs to be sustainably sourced, and potential deforestation has to be monitored. • Companies are encouraged to have plans and budgets for contributing to forestation and for promoting societal transition to a circular economy.
Social considerations	**Plans to mitigate the negative social impact of the technology**	• There are potential positive impacts in terms of an increase in employment and supply-chain development for the local biomass industry due to biomass supply and pre-treatment requirements. • Worker exposure to air pollutants (e.g. PM2.5) should be monitored and workers should be given regular health checkups. • HSE risks must be properly addressed.

Source: Literature search

Low-carbon ammonia co-firing – Technology schematics and review (1/2)

Cofiring in coal-fired power plant (steam turbine)



Low-carbon ammonia co-firing can be done in a coal-fired power plant with modifications to the existing boiler and investment in additional facilities, such as ammonia tanks and vaporisers.

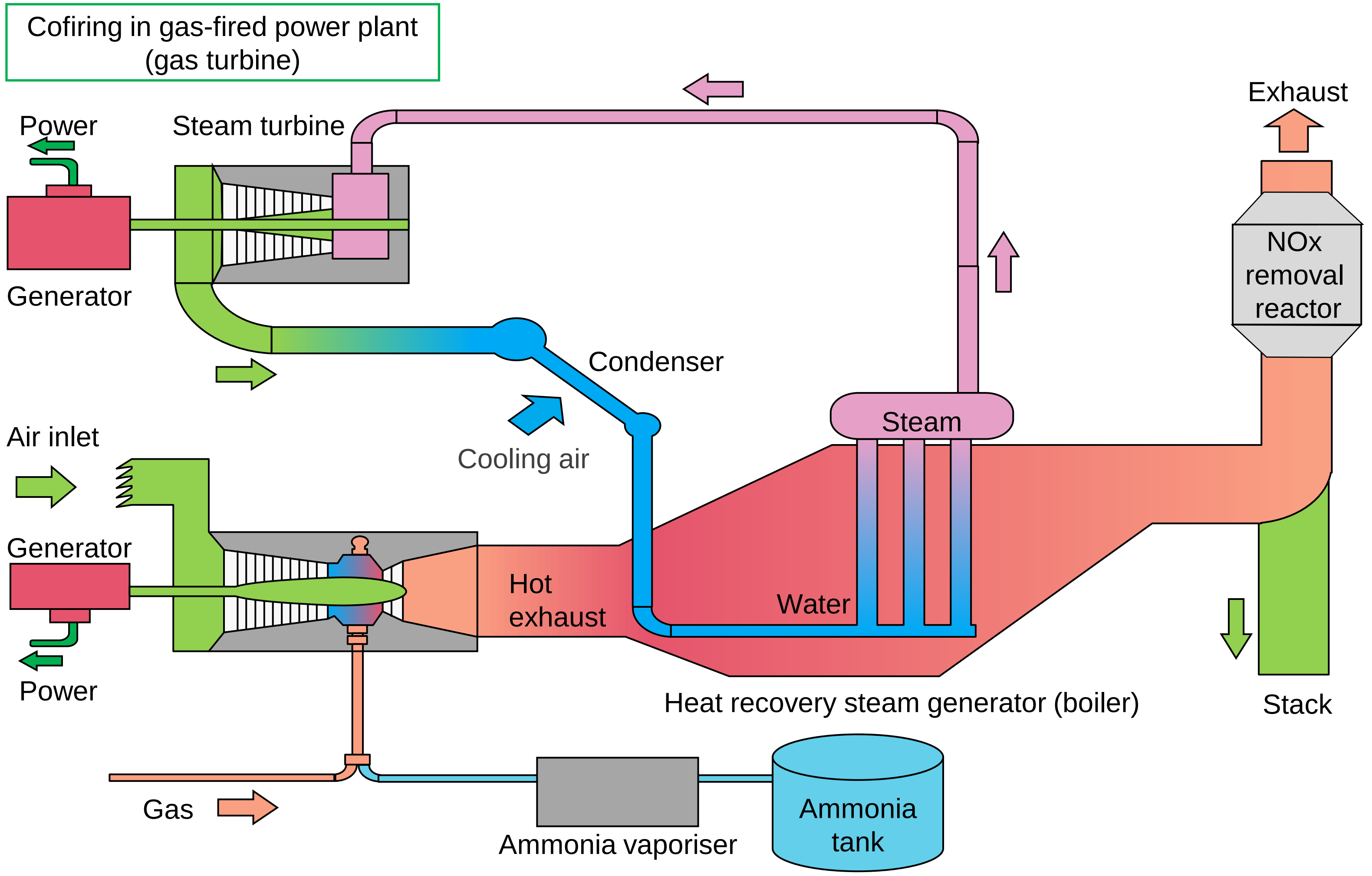
As for the boiler, ammonia should first be mixed with pulverised coal before it enters the burner zone together with combustion air.

Optimising boiler design for a stable flame and NOx reduction is key to ammonia co-firing.

Advancement in technology may enable higher co-firing ratios. However, when co-firing ratios exceeds a certain threshold, replacing the steam turbine with gas turbine may be beneficial due to the higher thermal efficiency of a gas turbine over a steam turbine.

Source: Literature search

Low-carbon ammonia co-firing – Technology schematics and review (2/2)



Low-carbon ammonia co-firing at a higher co-firing ratio and full ammonia firing (100%) can be done in gas-fired power plants with modifications to the burner and combustion systems and investment in additional facilities, such as ammonia tanks.

Specifically, ammonia can be fired solely or together with gas by either

- vaporising as gas and injecting into the burner, or
- directly atomising in the burner

The direct use of ammonia has been successfully demonstrated in micro gas turbines (about 50kW). In larger gas turbines, there are some remaining challenges, such as:

- slow reaction kinetics of ammonia with air
- flame instability
- NOx emissions

Source: Literature search

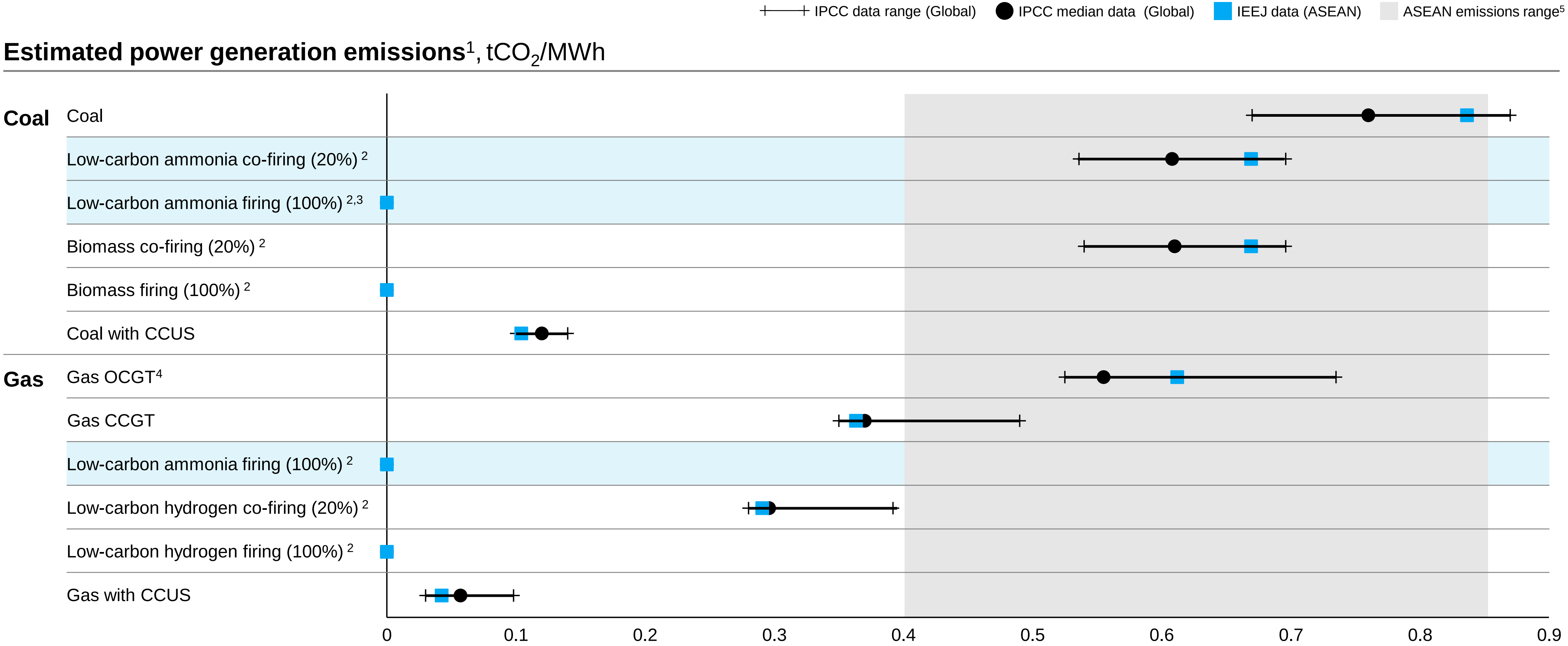
Low-carbon ammonia co-firing – Transition suitability assessment overview

Framework dimensions	Description
Emissions impact	• **Emissions reduction directly promotional** to co-firing ratio and net lifecycle emissions of the ammonia source • Estimated emissions intensity of about **0.65 tCO_2/MWh** with **20% co-firing** and about **0 tCO_2/MWh** with **100% firing** • **Low-carbon fuel co-firing** can both supplement the initial transition to RE[1] generation and also potentially assist in the eventual shift to near zero-emission ammonia firing
Affordability	• Estimated LCOE range of **80-170 USD/MWh** with **20% co-firing** and **150-430 USD/MWh** with **100% firing** in coal-fired power plant, and **100-320 USD/MWh** with **100% firing** in gas-fired power plants **(as of 2020).** • LCOEs are highly subject to low-carbon ammonia fuel prices, which are expected to decline over time; in 2030, they are projected to be **80-140 USD/MWh** with 20% co-firing and **150-270 USD/MWh** with 100% firing in coal-fired power plant, and **100-210 USD/MWh** with 100% firing in gas power plant.
Reliability	• **20% co-firing** is in **the pilot phase (TRL 5)**, and **100% firing is in the pilot or in early prototype phase (TRL 3-4)**
Lock-in prevention considerations	• **Increasing co-firing ratio, shifting from blue ammonia to green ammonia, retrofitting CCUS, or retiring** are required for achieving zero or near-zero emissions • **Technological advancements and the development of an ammonia fuel supply chain are required for achieving higher co-firing ratios.** • Long-term coal supply contracts may hinder retirement or piloting of high co-firing ratios
DNSH considerations	• **Leakage prevention** measures for ammonia are essential given its toxic nature • **Implementation of NOx-abatement measures** are required for reducing air pollution • Low-carbon ammonia sources must be **certified for their low-carbon footprints.**
Social considerations	• **HSE risk management,** including guidelines and training for **ammonia handling,** must be properly addressed. • Co-firing can avoid displacement of local workforce at existing plants

1. Renewable energy

Emissions impact – Favorable for ASEAN countries if co-firing ratio can be improved to well beyond 20%

Estimated power generation emissions[1], tCO_2/MWh

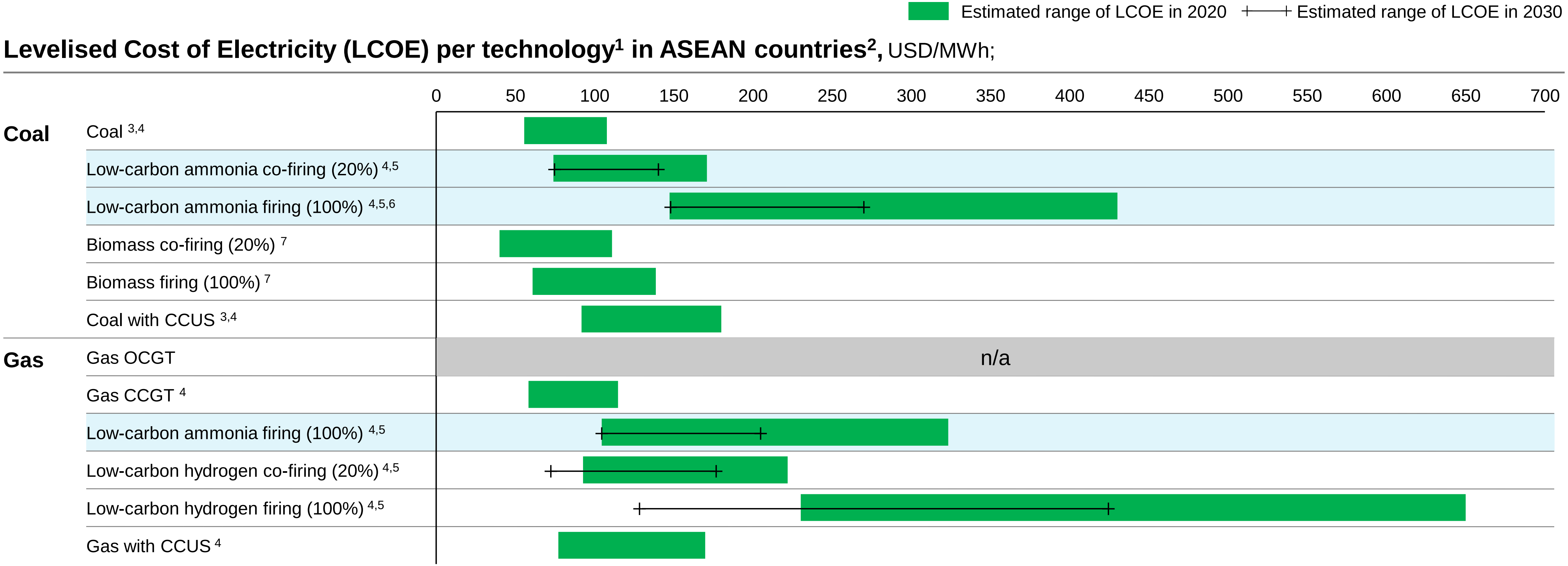


1. Direct emissions for power generation only; other lifecycle emissions not included; IPCC data for 2018; IEEJ data for 2017
2. Emissions for co-firing/firing of biomass or low-carbon fuels are estimated based on the co-firing/firing ratios and the base emissions in respective Coal or Gac CCGT
3. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
4. Emissions for OCGT are estimated based on CCGT emissions and the efficiency of OCGT over CCGT
5. The range of the emissions intensities of ten ASEAN member states (see the 'country-specific power generation emissions' section in the appendix)

Source: IEEJ, IPCC Annex III Technology-specific cost and performance parameters (2018)

Affordability – LCOE highly sensitive to price of input low-carbon ammonia, which may improve with low-carbon ammonia fuel production uptake

Levelised Cost of Electricity (LCOE) per technology[1] in ASEAN countries[2], USD/MWh;



1. Direct emissions from power generation only; other lifecycle emissions not included
2. Data in Indonesia is used as representative
3. LCOE range for subcritical and supercritical coal fired power plants are shown here
4. LCOE is calculated based on technology data from the DEA using uncertainty range for investment and O&M costs. Coal and gas fuel costs are based on historical range in 2017-2021 from World Bank and Enerdata (coal as 60~140 USD/Mt, gas as 6~11 USD/mmbtu), low-carbon ammonia cost is based on IEA's estimates as of 2018 (240~790 USD/t) and as of 2030 (240~450 USD/t). Hydrogen costs are based on IEEJ and Hydrogen Council's estimates as of 2020 (4~11 USD/kg) and as of 2030 (2~7 USD/kg). Assumptions on other parameters include technical lifetime (coal: 30 years, gas: 25 years), discount rate (8%), capacity factor (coal: 60%, gas: 40~60%), and thermal efficiency (coal: 41%, gas: 56%). Please note that LCOE is highly dependent on fuel cost, and LCOEs shown here are based on fuel costs as written above and do not reflect the current LCOEs. In particular, LCOE here does not reflect recent gas and coal price surge after Ukraine incidents.
5. Additional costs for ammonia/hydrogen co-firing and firing are based on incremental costs by fuel mix and additional CAPEX is not considered.
6. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
7. Data from IRENA report, LCOEs for biomass co-firing during 2010-2021. The 5th and 95th percentile amongst reported power plants are indicated.

Source: IEEJ, DEA Technology data for the Indonesian power sector (2021), IRENA Renewable Power Generation Costs (2021), World Bank Commodity Prices (2022), Enerdata Global Energy & CO_2 Database - POLES-Enerdata model - EnerFuture scenarios (2021), Hydrogen Council Hydrogen Insights Report (2021), and IEA The Future of Hydrogen (2019)

Reliability – Co-firing ratios up to 20% are being piloted, while technology is still under development for pure ammonia firing

Estimated commercialisation status

- **Low-carbon ammonia co-firing with coal is currently in the pilot** or earlier phases and classified as below by IEA
  - Co-firing (≦20%): **TRL 5**
  - Firing (100%) : **TRL 3-4**
- Low-carbon ammonia co-firing with coal is still being developed, for example, in Japan. It is **expected to be commercialised by the late 2020s** (for 20% co-firing) as stated by METI, Japan.
- The establishment of an ammonia supply chain and reduction in blue/green ammonia prices are major hurdles to be cleared.

Recent project examples

	Details
20% ammonia co-firing at Hekinan Power Plant by JERA 	• In 2021, JERA started a project on ammonia co-firing at a large-scale commercial coal-fired power plant at Hekinan Thermal Power Station (1GW) • Hekinan Thermal Power Station is expected to demonstrate 20% ammonia co-firing in FY 2023 • Through this project, JERA looks to start operation of the 20% ammonia co-firing in coal-fired power plant by late 2020s
35% ammonia co-firing at Huaneng Yantai Power Plant by China Energy 	• In 2022, China Energy successfully demonstrated ammonia co-firing with coal at Huaneng Yantai Power Plant (40MW) • 35% ammonia was added to coal-fired power plant in Huaneng Yantai Power Plant
Plan to develop a gas turbine that can combust up to 100% ammonia by Mitsubishi Heavy Industry (formerly, Mitsubishi Power) 	• Targeting commercialisation of the novel 100% ammonia-capable gas turbine in or around 2025 • Will be a small-to-medium scale (40MW) gas turbine, suitable for industrial applications and on remote islands.

Source: IEA, literature search

Lock-in prevention considerations – Combinations of multiple paths may be required to reach zero emissions

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	4 paths (or combinations of them) exist to reach zero or near-zero emissions • Path 1: Increasing co-firing ratio • Path 2: Retrofitting CCUS • Path 3: Switching from blue ammonia to green ammonia • Path 4: Retiring
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	Path 1: Increasing the co-firing ratio • Companies need to invest in R&D to achieve technological maturity. Ensuring combustion speed is especially important. Companies may also need to consider replacing steam turbines with gas turbines when a co-firing ratio increases. • Companies need proactive plans for securing contracts of greater quantities of ammonia. Path 2: Retrofitting CCUS • Discussed in detail in the 'CCUS in coal/gas-fired power plants' section Path 3: Shifting from blue ammonia to green ammonia • A company needs to search for green ammonia provider when available, and needs to actively secure green ammonia contract Path 4: Retiring old technology/switching for flexibility purposes • Long-term coal procurement contracts may hinder retirement. • Power purchase agreements, minimum commitments and term lengths in particular, may also hinder retirement.

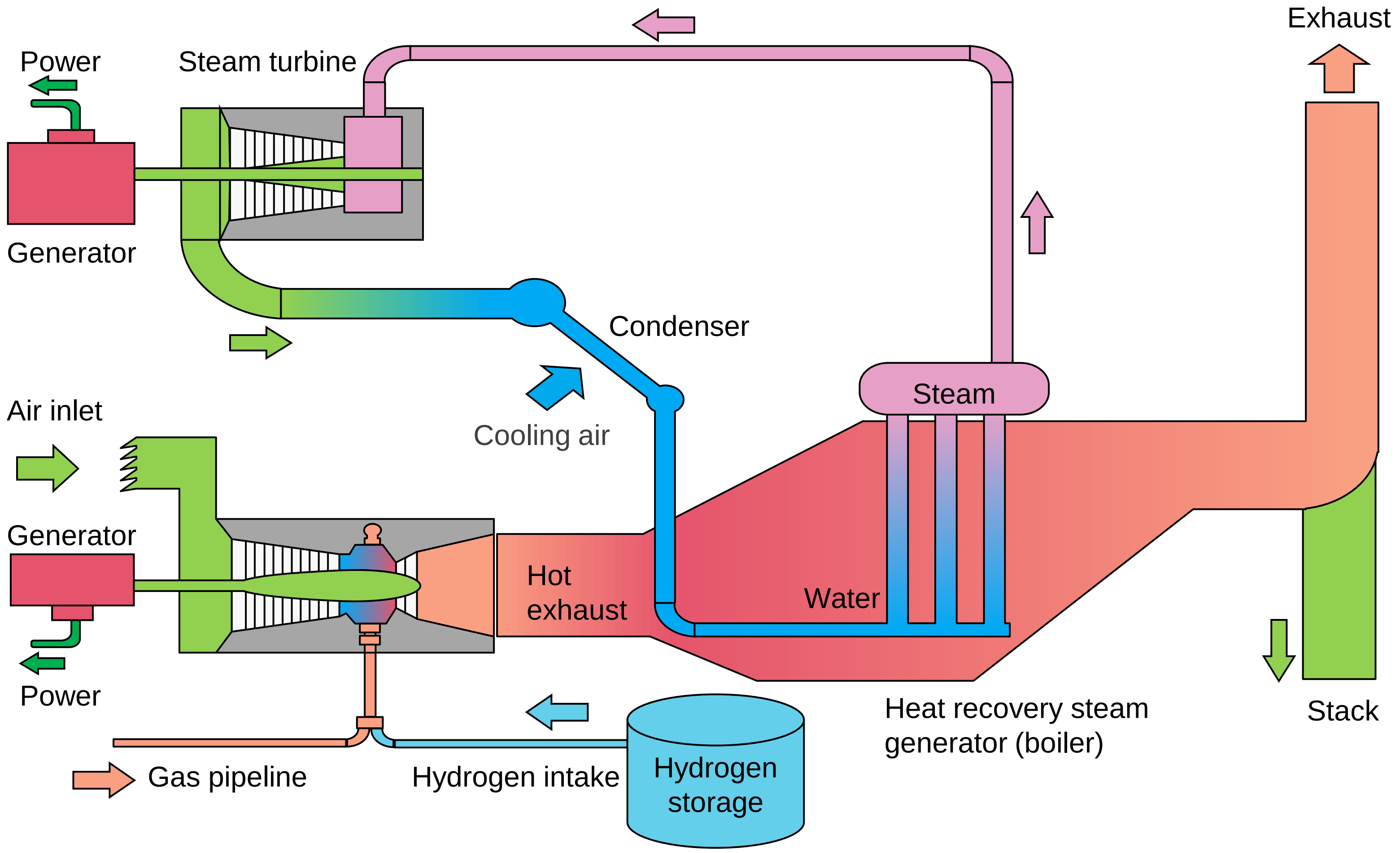
Source: Literature search

DNSH/social considerations – NOx abatement measures and HSE policies/trainings around ammonia handling are required

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• NOx-abatement measures (e.g. low NOx burner, flue gas NOx removal equipment) must be in place. Measures to detect and prevent leakage of ammonia and toxic compounds are also essential.
	Promotion of transition to circular economy	• Companies must source ammonia with a low-carbon footprint. • Measures for the detoxification of collected NOx must be in place.
Social considerations	**Plans to mitigate the negative social impact of the technology**	• There is a potential positive impact in terms of increased demand for skilled workers, e.g. for ammonia procurement, engineering, operations. • Companies must set guidelines and train operators to handle ammonia fuels appropriately. • HSE risks must be properly addressed.

Source: Literature search

Low-carbon hydrogen co-firing – Technology schematics and review



Low-carbon hydrogen can be fired on its own or together with natural gas in a gas-fired power plant with modifications to the burner and combustion systems.

Low co-firing ratio up to 5% can be accommodated in most gas turbines today without major modifications. The current standard gas turbines may run on hydrogen co-firing up to 60% may be possible, while the peripherial infrastructure such as valves and seals need to be updated. The risks include

- Risk of autoignition and flashback
- Risk of combustion instabilities

Pure hydrogen firing is in early pilot phase with several demostration made.

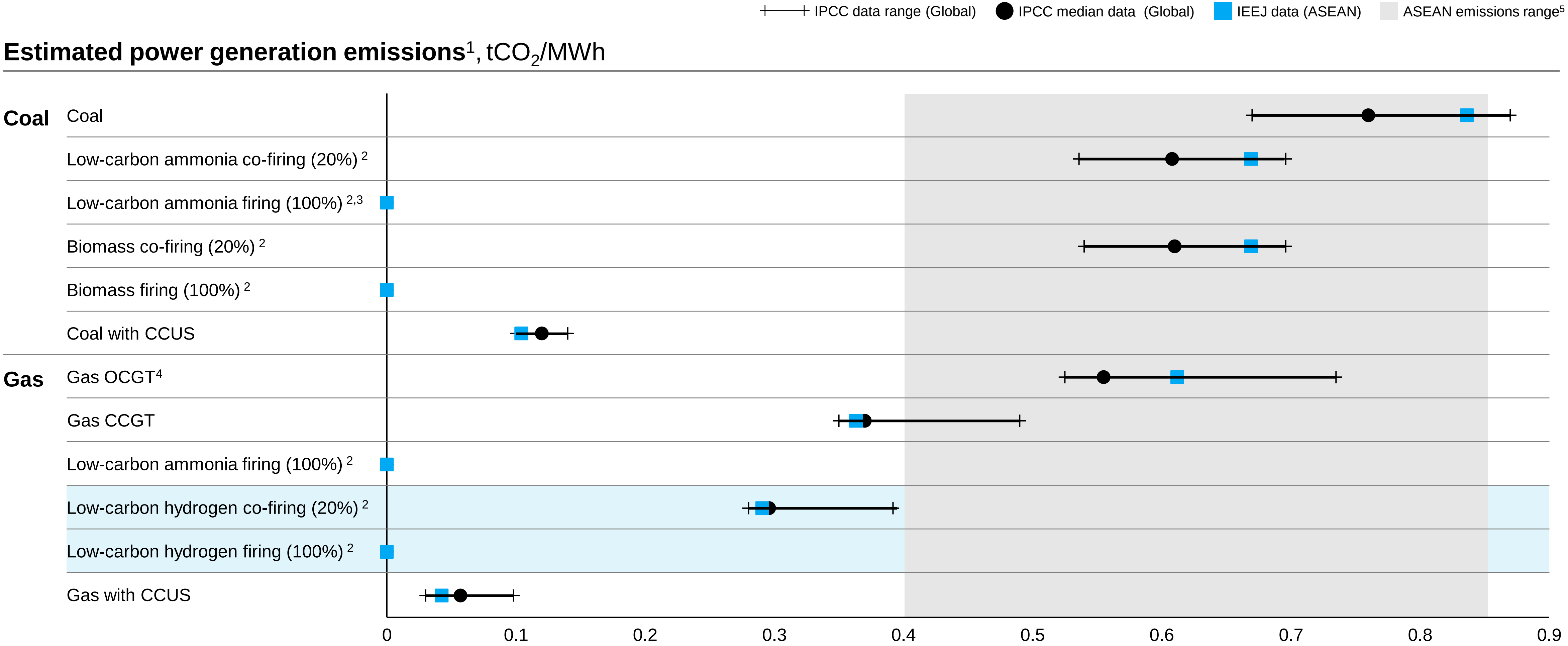
Source: IEA, literature search

Low-carbon hydrogen co-firing – Transition suitability assessment overview

Framework dimensions	Description	
	co-firing (20%)	**Firing (100%)**
Emissions impact	• **Emissions reduction directly proportional** to the co-firing ratio and net life cycle emissions of the hydrogen source; an estimated emissions intensity range of **about 0.3 tCO_2/MWh** with **20% co-firing** • Technology can initially supplement the use of RE for power generation, and the rest of the power station could turn into an RE power station	• Deep decarbonisation technology that can achieve **up to 0 tCO_2/MWh** with **100% co-firing**.
Affordability	• Estimated LCOE range of **90-220 USD/MWh with 20% co-firing** and **230-650 USD/MWh with 100% co-firing (as of 2020).** • However, LCOEs are highly subject to low-carbon hydrogen fuel prices, which are expected to **decline over time**; estimated LCOEs in 2030 are **70-170 USE/MWh** with 20% co-firing and **130-420 USD/MWh** with 100% firing.	
Reliability	• **Early commercialisation (TRL 9)** phase	• In the **pilot phase** (**TRL 7**)
Lock-in prevention considerations	• To be zero or near-zero emissions, **increasing co-firing ratio, shifting from blue hydrogen fuel to green hydrogen fuel, and retrofitting CCUS** are required • **A hydrogen supply chain and infrastructure** need to be developed. • **Long-term gas procurement contracts** may hinder transition	
DNSH considerations	• Low-carbon hydrogen sources must be **certified for their low-carbon footprints.**	
Social considerations	• Appropriate HSE risk management, including **guidelines and training for handling hydrogen,** given its **flammability**, are essential	

Emissions impact – Proportional to co-firing ratio, but the resulting emission is intensity substantially lower than grid average for ASEAN countries

Estimated power generation emissions[1], tCO_2/MWh

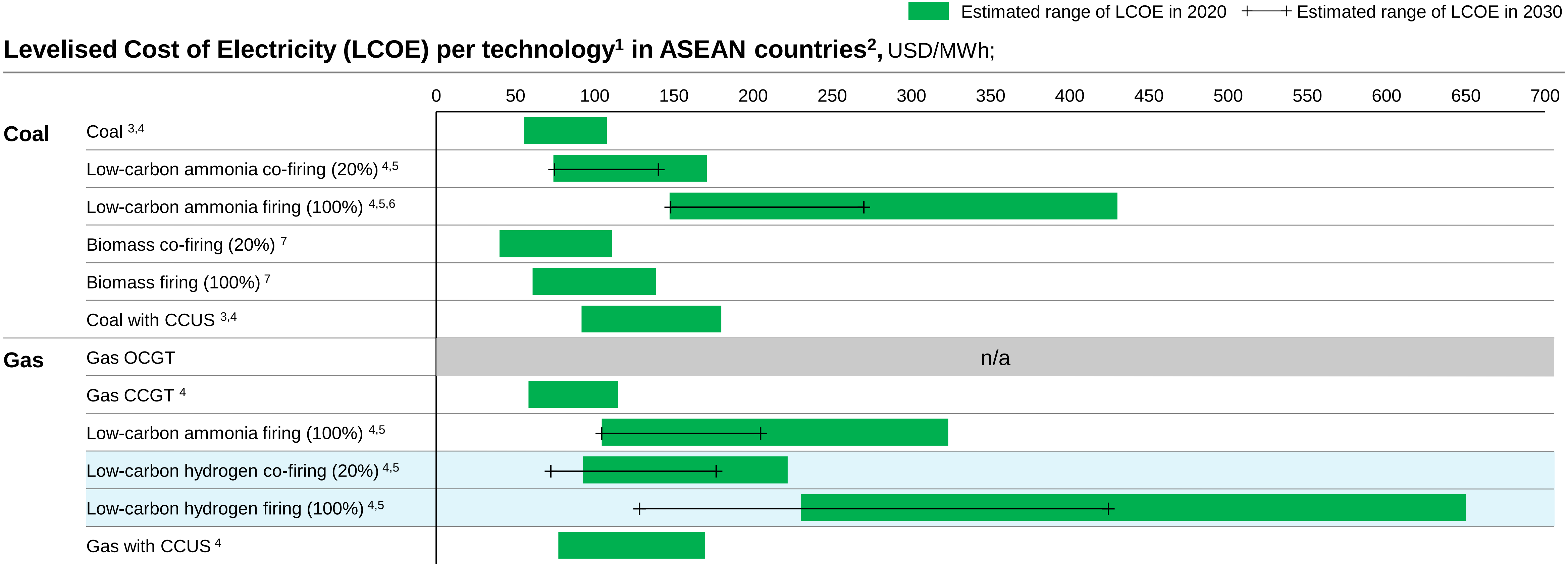


1. Direct emissions for power generation only; other lifecycle emissions not included; IPCC data for 2018; IEEJ data for 2017
2. Emissions for co-firing/firing of biomass or low-carbon fuels are estimated based on the co-firing/firing ratios and the base emissions in respective Coal or Gac CCGT
3. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
4. Emissions for OCGT are estimated based on CCGT emissions and the efficiency of OCGT over CCGT
5. The range of the emissions intensities of ten ASEAN member states (see the ‘country-specific power generation emissions’ section in the appendix)

Source: IEEJ, IPCC Annex III Technology-specific cost and performance parameters (2018)

Affordability – High LCOE due to current cost of low-carbon hydrogen, but significant reductions expected in the coming decade

Levelised Cost of Electricity (LCOE) per technology[1] in ASEAN countries[2], USD/MWh;



1. Direct emissions from power generation only; other lifecycle emissions not included
2. Data in Indonesia is used as representative
3. LCOE range for subcritical and supercritical coal fired power plants are shown here
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5. Additional costs for ammonia/hydrogen co-firing and firing are based on incremental costs by fuel mix and additional CAPEX is not considered.
6. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
7. Data from IRENA report, LCOEs for biomass co-firing during 2010-2021. The 5th and 95th percentile amongst reported power plants are indicated.

Source: IEEJ, DEA Technology data for the Indonesian power sector (2021), IRENA Renewable Power Generation Costs (2021), World Bank Commodity Prices (2022), Enerdata Global Energy & CO_2 Database - POLES-Enerdata model - EnerFuture scenarios (2021), Hydrogen Council Hydrogen Insights Report (2021), and IEA The Future of Hydrogen (2019)

Reliability – Commercial use of up to 30% co-firing is on the horizon, while technology is still under pilot phase for hydrogen pure firing

Estimated commercialisation status

- Low-carbon hydrogen co-firing with gas is currently classified as below by the IEA:
- Co-firing (generic):
  - Early commercialisation
  - **TRL 9**
- Firing (100%) :
  - In pilot phase
  - **TRL 7**
- The establishment of a hydrogen supply chain and significant reduction in the price of blue/green hydrogen are major hurdles to be cleared.

Recent project examples

	Details
Up-to 15% hydrogen co-firing at Snowy Hydro's Hunter power station 	• In 2021, Snowy Hydro ordered two M701F gas turbines from MHI for its Hunter power station, which is set to commence operations in 2023. • M701F turbines are capable of 30% hydrogen co-firing with current technology and can be configured to operate on 100% hydrogen co-firing in the future. • Snowy Hydro aims for 15% hydrogen co-firing in the future.
Up-to 30% hydrogen co-firing by JERA 	• In 2021, JERA started a project to demonstrate the use of low-carbon hydrogen in a gas-fired power plant in Japan. • JERA aims to demonstrate 30% hydrogen co-firing by FY2025. • JERA hopes this project will lead to the commencement of hydrogen co-firing in gas-fired power plants by the 2030s.
Equinor leads UK's H2H Saltend project 	• Equinor's low-carbon hydrogen to Humber Saltend (H2H Saltend) project enables the power plant at Saltend Chemicals Park to switch to a 30% hydrogen and natural gas blend in 2026. • The project is expected to also include carbon capture technology in the future.

Source: IEA, literature search

Lock-in prevention considerations – Needs R&D to improve co-firing ratios, while the evolution of the low-carbon hydrogen market and supply chain are also key

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	3 paths exist to zero or near-zero emissions • Path 1: Increasing co-firing ratio • Path 2: Retrofitting CCUS • Path 3: Shifting from blue hydrogen to green hydrogen
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	Path 1: Increasing the co-firing ratio • Companies need to invest in R&D to achieve technological maturity. Ensuring combustion speed is especially important. Companies must also prepare to potentially replace boilers with gas turbines when the co-firing ratio surpasses 50%. • Companies need proactive plans for securing greater volumes of hydrogen. Path 2: Retrofitting CCUS • Discussed in greater detail in the 'CCUS in coal/gas-fired power plants' section • This is currently not economical. The technology is in the early commercialisation phase (TRL 8-9). Methods for storing and transporting captured CO_2 must be further considered. Path 3: Shifting from blue hydrogen to green hydrogen • A company needs to search for green hydrogen provider when available, and needs to actively secure green hydrogen contract

Source: Literature search

DNSH/social considerations – Mainly centered around wastewater heat and flammability risks, since firing hydrogen emits no pollutants

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• Waste heat running into river/sea from a gas power plant may cause negative impacts on local ecosystems. Temperature monitoring and control of wastewater should be in place • Environmental viability assessment (or equivalents) should be conducted for major new infrastructure installations associated with the hydrogen co-firing • Non-GHG pollutants in exhaust gas streams should be monitored and mitigated (e.g. through filtering or leakage prevention systems)
	Promotion of transition to circular economy	• Companies must source hydrogen with a low-carbon footprint through the entirety of their supply chains, including production, transport, and storage. • Hydrogen pure firing does not generate waste, and can thus contribute to the transition to a circular economy.
Social considera-tions	**Plans to mitigate the negative social impact of the technology**	• Companies must set guidelines and train local operators to handle hydrogen appropriately. • HSE risks must be properly addressed.

Source: Literature search

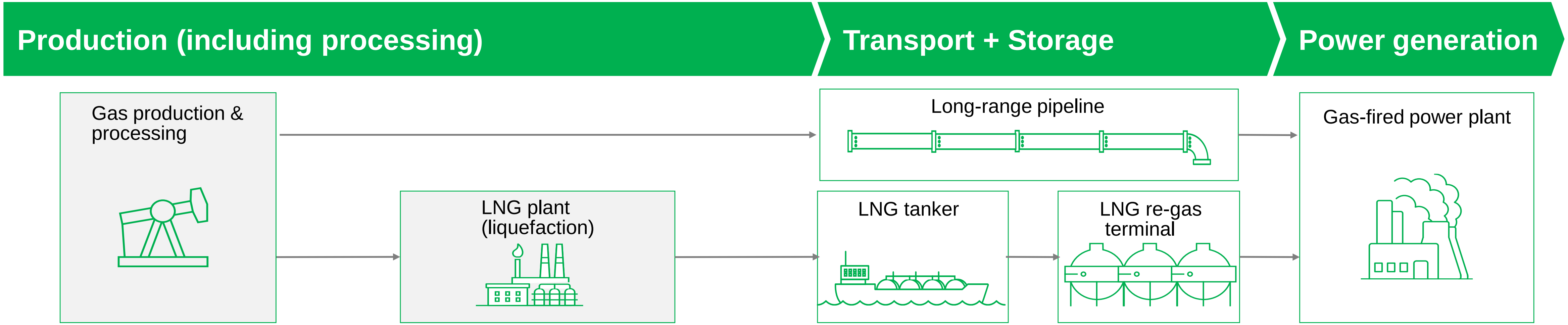
2 major potential transition technologies in the upstream sector are featured

Fugitive emissions: Leak detection and repair

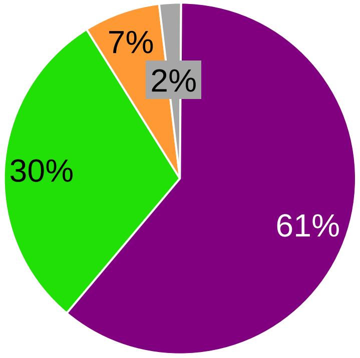
Process electrification in gas production

GHG emissions in gas production and processing derive both from gas combustion and methane leaks

Focused in this document



Source of GHG emissions within production, processing, and transport of gas; %CO_2-eq



- Methane emissions
- Onsite gas combustion for power[1]
- Venting CO_2
- Others

Decarbonisation technologies

- Fugitive emissions: leak detection and repair (LDAR)
- Process electrification in gas production
- CCUS in gas production (Discussed in CCUS section)

The document focuses on 3 upstream technology that resolves more than 80% of upstream emissions

1. During gas production and processing, energy is required to power the drilling equipment, maintain pressure in the reservoir and power additional equipment. This is often powered by onsite combustion of gas, which emits CO_2.

Source: IEA World energy outlook, 2018

Fugitive emissions: Leak detection and repair (LDAR) – Technology schematics and overview

Why is LDAR important?

Methane emissions are the second largest cause of global warming. The oil and gas industry emitted 70 Mt of methane (approximately, 2.1 $GtCO_2$-eq) in 2020

Fugitive emissions accounts for 25% of these emissions. LDAR is a cost-effective strategy to address this issue

Fugitive emissions occur throughout the value chain in pipes and equipment in well site, compressor station, gas plant, etc.

LDAR systems measure and quantify fugitive emissions before repairing the leak

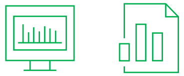
How is LDAR implemented?

Survey

Site surveys performed by drone and satellite imaging. Ground surveys to pinpoint root causes

Quantify

Leaks and emissions are recorded and quantified on the system



Repair

The maintenance team is notified. Repair work is planned and executed depending on the maintenance model and leak threshold

Source: IEA, Carbon Limits, literature search

Fugitive emissions: LDAR – Transition suitability assessment overview

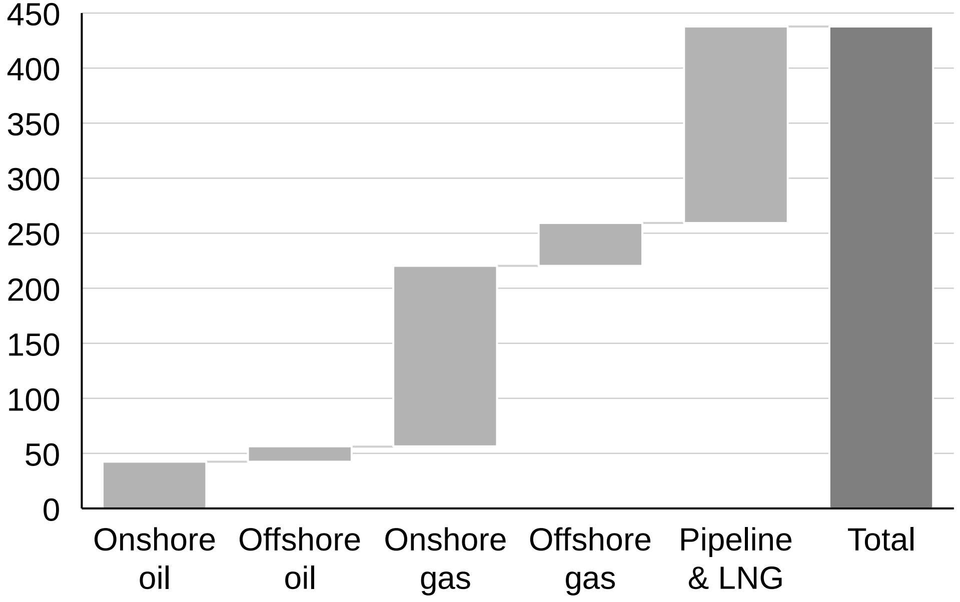
Framework dimensions	Description
Emissions impact	• Fugitive emissions account for **440 MtCO_2-eq methane emissions** (about 440 MtCO_2-eq) in oil and gas production • LDAR is the primary abatement strategy and can achieve **up to 95% leak emissions reduction** (depending on leak detection threshold)
Affordability	• Abatement costs under **3 USD/tCO_2-eq** and is one of the most economical decarbonisation levers
Reliability	• **Commercialised with TRL 11**. The majority of supermajors and national oil companies have implemented LDAR • Further scale is required to achieve OGCI[1] target methane intensity of 0.2% by 2025 from baseline 0.3% in 2017 (500,000 t of methane annually)
Lock-in prevention considerations	• Mitigate prolonged reliance on fossil fuel by ensuring decommission plan in place with clear time horizon defined
DNSH considerations	• Overall positive impact on ecosystem and biodiversity due to reduced methane leaks to the air
Social considerations	• A positive impact is expected. Job opportunities increase for LDAR surveys and maintenance • Must ensure HSE policies and practices are in place to **protect surveyors working in potentially high fugitive emissions concentration areas** (e.g. competency, permit to work process, risk assessment)

1. Oil & Gas Climate Initiative

Emissions impact – 440 $MtCO_2$-eq are estimated globally from fugitive methane emissions. LDAR can abate up to 95%

Fugitive emissions baseline

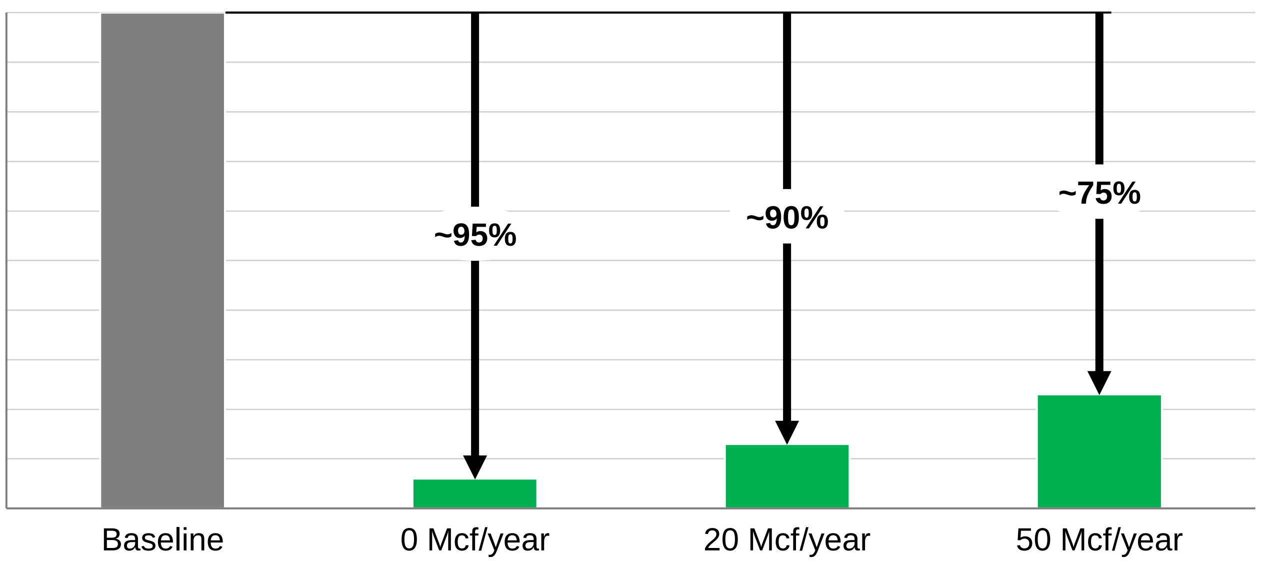
Global annual fugitive methane emissions for upstream oil and gas (O&G) operation, $MtCO_2$-eq



IEA estimated a total of 17.5 Mt of fugitive methane emissions (about 440 $MtCO_2$-eq) from upstream oil and gas operations. These can be addressed with LDAR

Emissions impact by adopting LDAR

Emissions reduction of LDAR at wellsite based on different leak threshold[1]; % (t/t)



An analysis by Carbon Limit considers an optical gas imaging ground survey. All leaks will be fixed, depending on leak intensity (leak threshold of 0, 20 and 50 Mcf/year[2])

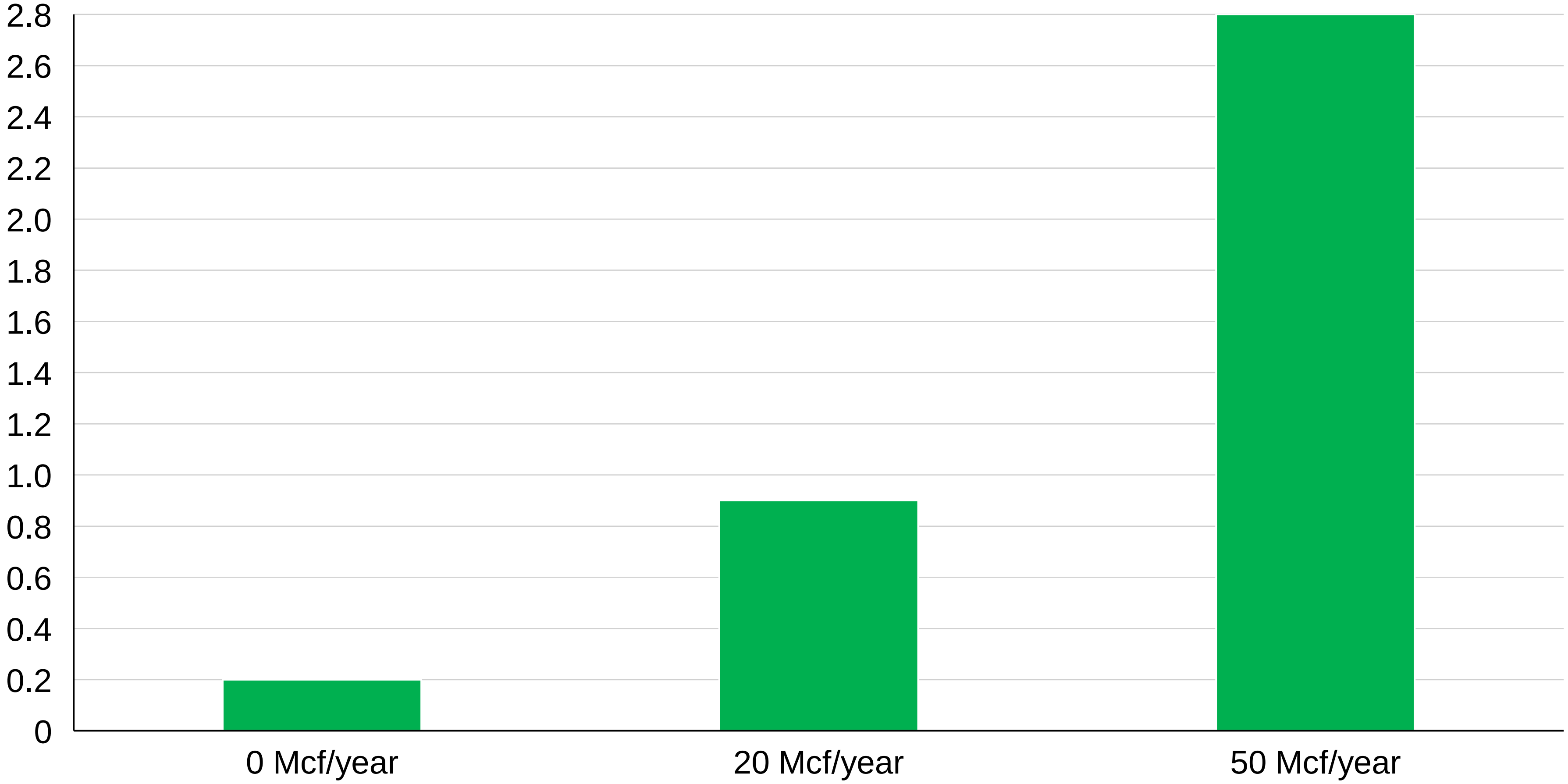
LDAR achieves 75-95% emissions reduction, depending on the leak threshold definition

1. Result from an empirical analysis of LDAR implementation with over ~1800 surveys conducted on different onshore wellsite in USA
2. Mcf/year, thousand cubic feet per year

Source: IEA, Carbon Limit, literature search

Affordability – LDAR is one of the most economical decarbonisation levers, with abatement costs under 3 USD/tCO_2-eq

LDAR abatement costs at wellsite by leak threshold; USD/tCO_2-eq



Resolved leaks contribute to production. Analysis shows it is economical to repair most leaks at the wellsite.

Depending on maintenance philosophy, LDAR abatement cost under 3 USD/tCO_2-eq

1. Cost estimated based on gas price of 4 USD/Mcf, survey cost of 400-1,200 USD per survey and all leak repaired according to leak threshold

Source: Carbon Limit , literature search

Reliability – LDAR solutions are already commercialised, but require further scaling to achieve targets from the Oil & Gas Climate Initiative (OGCI)

Estimated commercialisation status

The technology is **commercialised at scale.** The majority of supermajors and national oil companies have implemented LDAR

Under IEA classification:

- Predictable growth at scale
- **TRL 11**

Further scale is required to achieve OGCI[1]'s target methane intensity[2] of 0.2% by 2025 from baseline 0.3% in 2017 (500,000 tonnes of methane annually)

Recent project examples

Details

Shell partner with Baker to implement drone based LDAR

- After two years of testing Avitas' drone in the Permian area, Shell is planning to roll out methane detecting drones in 2022 throughout its operating area of over 1,300 wells
- The drone is equipped with an optical gas-imaging camera and laser-based detection system. It has been utilised on- and offshore

CNPC's LDAR program across full value chain

- Leak detection and repair pilot campaigns were expanded into Dagang and other oil fields in 2019, which yielded a 12.3% reduction in total methane emissions over the year
- Continuing the success of their downstream operations, LDAR coverage is expanding to all operated sites

1. Oil & Gas Climate Initiative
2. Methane intensity calculated based on total methane emissions as a percentage of total natural gas throughput

Source: IEA, OGCI, literature search

Lock-in prevention/DNSH/social considerations – Limited concerns from LDAR application

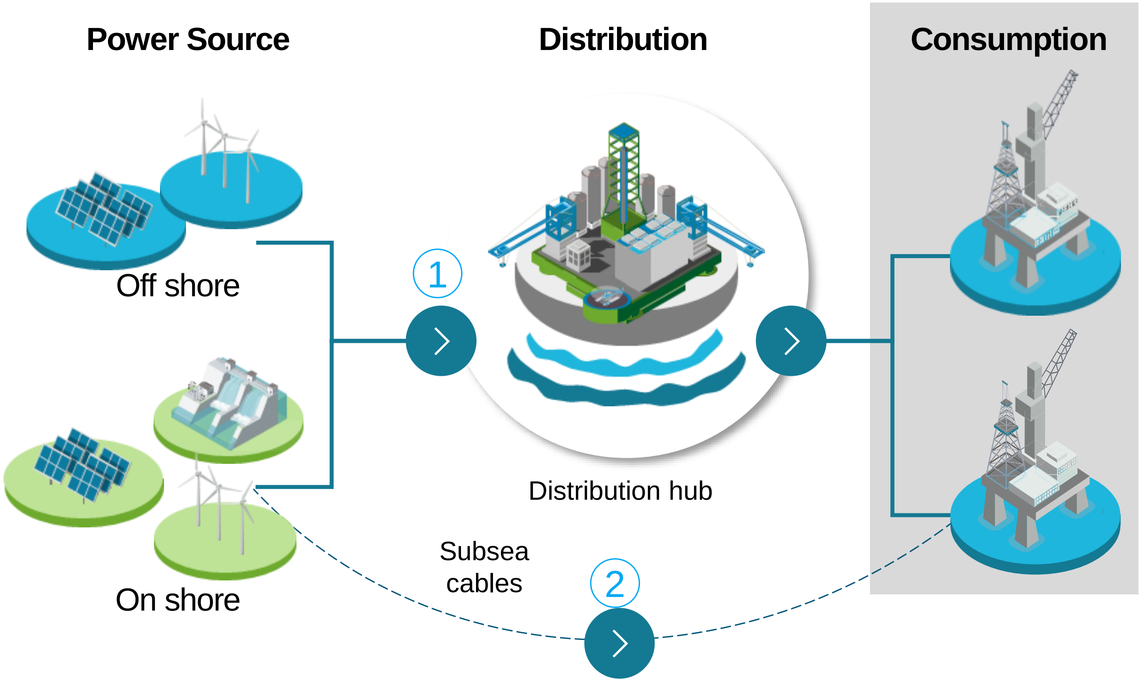
Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for a technology to be zero or near-zero emissions?**	• Mitigating the risk of prolonged reliance on fossil fuels
	What (lock-ins) may hinder the above paths to zero or near-zero emissions?	• An evaluation is required to ensure that a fossil fuel decommissioning plan is in place with clearly-defined time horizon • Long-term gas sale agreements may hinder the fossil fuel decommissioning plan.
DNSH considerations	**Protection of healthy ecosystem and diversity**	• Positive impact by reducing methane leaks, but drones may impact local wildlife. Ensure drone operations comply with local regulations and industry standards
	Promotion of transition to circular economy	• Reduces hydrocarbon leaks and promotes efficient use of natural resources • Ensure equipment and contractors sourced from certified suppliers/vendors who measure, disclose, minimise, and potentially offset GHG emissions along the value chain
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Positive impact on job opportunities are expected. Skilled labor will be required for emissions surveys and repairs • Surveyors working in potentially high fugitive emissions concentration areas will require policies for prevention and mitigation measures (e.g. competency, risk assessment, permit to work process)

Source: Literature search

Process electrification in gas production – Technology schematics and overview

Energy Demand

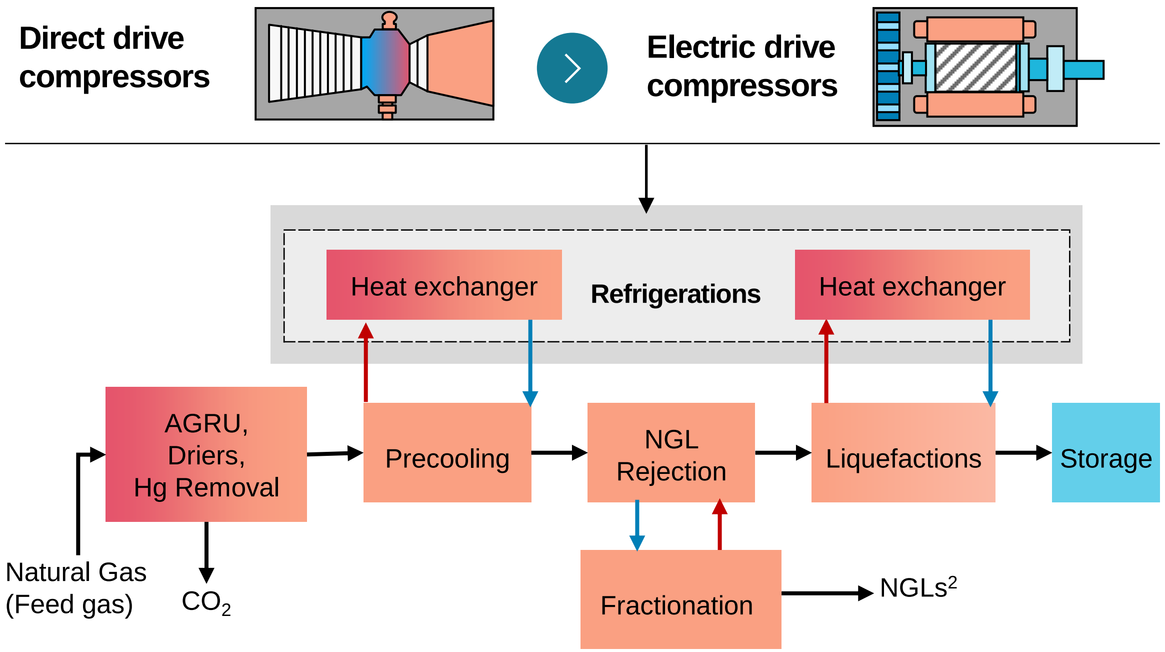
Production platform



Gas production can be electrified through:

1. Offshore power sources which requires a microgrid system consisting of renewable power source, distribution hub and system of cables on top of platform modification
2. Grid integration which requires subsea power cables from shore and platform modification to import and utilise power

LNG liquefaction plant



LNG liquefaction plant runs on **direct drive compressors** for driving refrigerants and gas turbine for power requirements, which constitutes about 70% of plant's CO_2 emissions

Process electrification by replacing direct drive compressors with **electric drive compressors** powered by renewable electricity reduces emissions

1. AGRU = Acid gas removal unit
2. NGL = Natural gas liquid

Source: NSTA Orcadian microgrid electrification concept, 2022; Air Products Decarbonised LNG production via integrated hydrogen fueled power generation, 2021

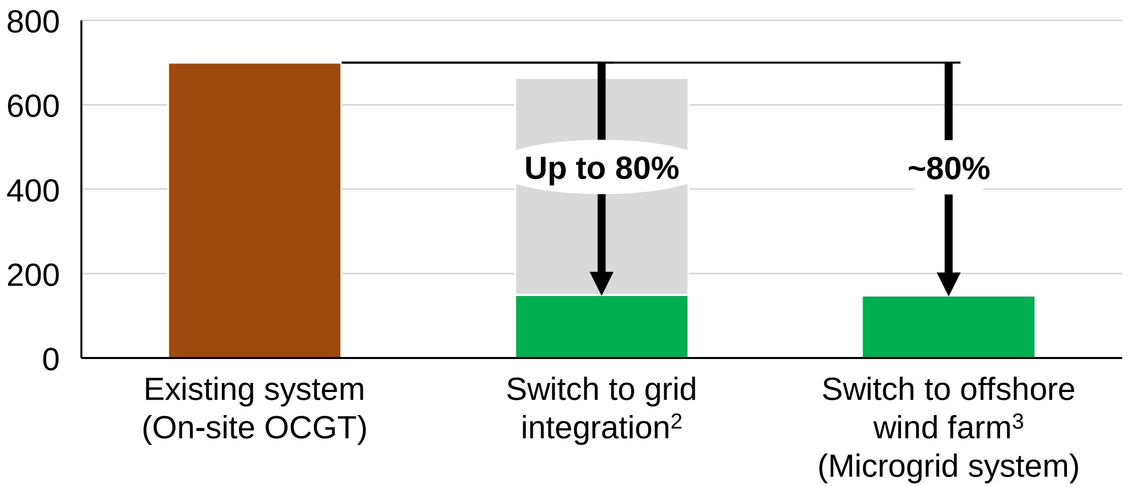
Process electrification in gas production – Transition suitability assessment overview

Framework dimensions	Description: Production platform	Description: LNG plant
Emissions impact	• **Up to 80%** emissions reduction depending on **electrification implementation** and **emissions intensity of local grid**	• **30-70%** emissions reduction depending on availability of renewable energy
Affordability	• Cost highly dependent on **distance to shore, cost of power and platform modification level** • Cost effectiveness can be achieved through large scale implementation thus requiring partnership with operators • Abatement cost of **110-200 USD/tCO_2**	• **Local grid power cost and fuel cost** contributes to majority of production cost and is the key deciding factor for electrification implementation • Availability and growth of **local renewable power supply and cost** need to be considered • Abatement cost of **50-350 USD/tCO_2**
Reliability	• Technology is **commercialised** (TRL 9) but current deployment still limited due to cost and concentrated in the North Sea and North America assets	
Lock-in prevention considerations	• Transition plan for incorporating **full renewable power source** and/or **CCUS** implementation is required for Paris-alignment • Mitigate prolonged reliance on fossil fuel by ensuring decommission plan in place with clear time horizon defined	
DNSH considerations	• Environmental viability assessment against local regulation required for new infrastructure and grid power source to ensure no or minimal harm on ecosystem and biodiversity	
Social considerations	• Positive impact is expected as job opportunity increases due to larger power grid requirement especially in renewable energy sector • HSE risk with regards to remote location operation, especially for windfarm and distribution hub operation, should be assessed and opportunity for unmanned operation should be leveraged	

Emissions impact – Studies show up to 80% GHG reduction, highly dependent on local grid emissions intensity and renewables capacity

Production platform

Emissions intensity by different power source[1]
$kgCO_2/MWh$

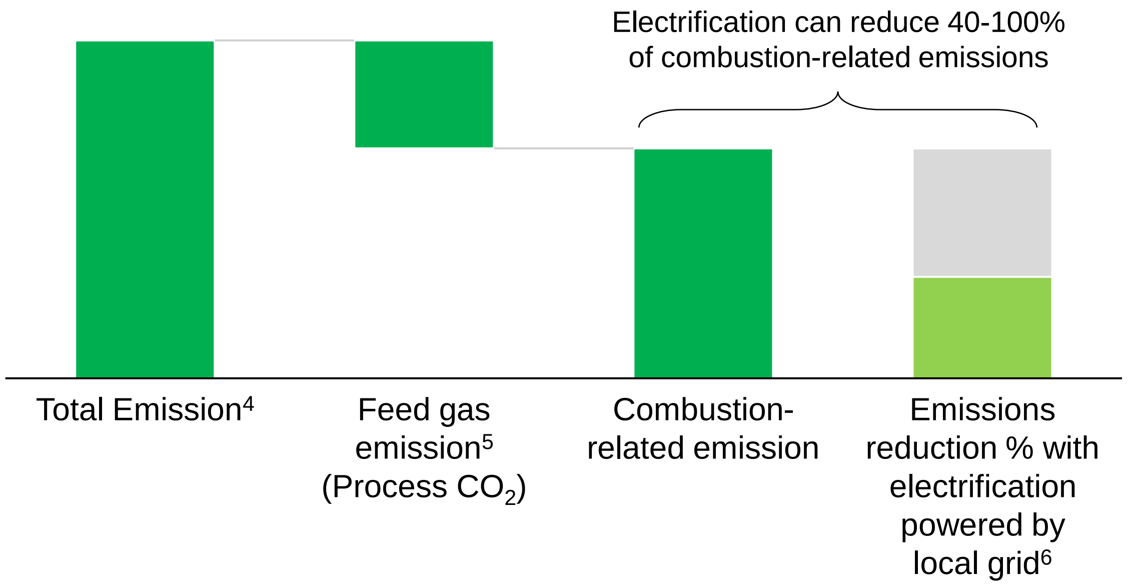


Switching to grid integration can reduce up to 80% of emissions, depending on the emissions intensity of local grid

Microgrid system which incorporates offshore wind farm and distribution hub can potentially reduce emissions by 80% compared to conventional offshore production platform

LNG liquefaction plant

Emissions source breakdown and electrification emissions reduction
% GHG emissions



A typical LNG liquefaction plant has about 70% combustion-related emissions depending on CO_2 concentration in feed gas

Depending on renewable powered grid mix and availability, LNG electrification can potentially reduce all combustion-related emissions

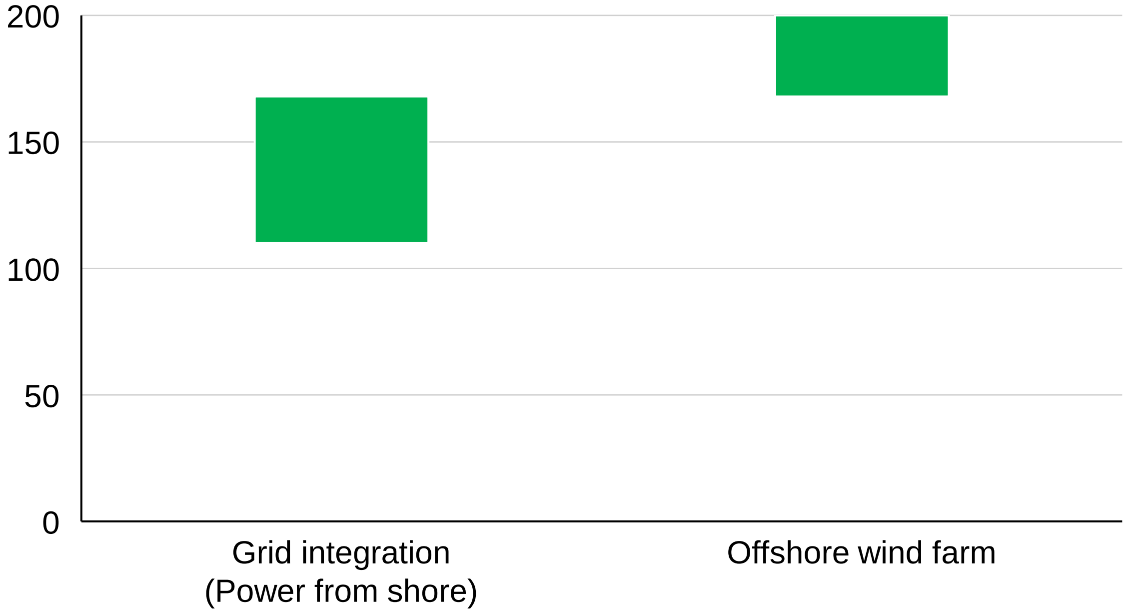
1. GHG emissions estimated with Crondall Energy in-house emissions estimation tool and verified with IOGP and NSTA data
2. Emissions reduction range estimated based on APAC country's power grid
3. Emissions estimated with wind power as primary and back-up gas turbine as secondary power source based on North Sea assets by Orcadian Energy
4. Emissions breakdown and reduction based on an AP-C3MR liquefaction process with 4.5 Mt of LNG production per year & 4mol% CO_2
5. Feed gas emissions represents CO_2 vented from acid gas removal unit and can be reduced via CCUS
6. Emissions reduction depends on renewable energy mix in local power grid

Source: NSTA Orcadian microgrid electrification concept, 2022; Air Products Decarbonised LNG production via integrated hydrogen fueled power generation, 2021; Our world in data Carbon intensity of electricity, 2021

Affordability – Wide range of abatement contingent on local endowment, with offshore applications in particular requiring incentives

Production platform

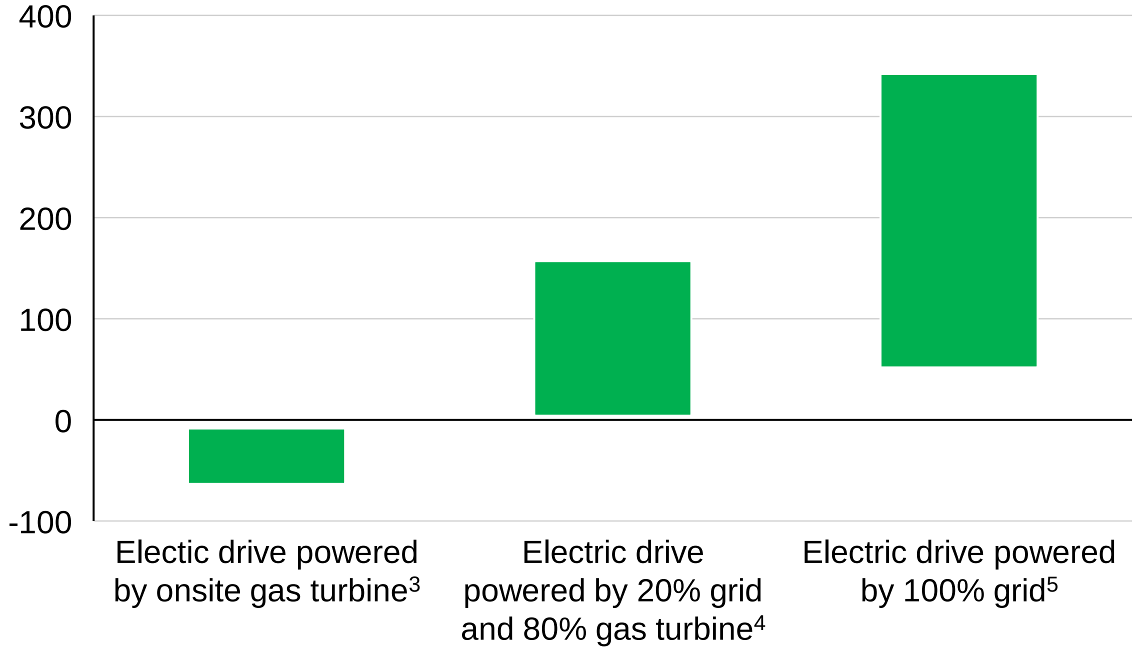
Abatement cost by different technology[1]
USD/tCO_2



Economics of platform electrification depends heavily on implementation design such as distance to shore, cost of power, platform clusters and variability in platform modification

LNG liquefaction plant

Abatement cost by different configuration[2]
USD/tCO_2; 2012



Electric drive powered by onsite gas turbine achieves negative abatement cost from improved availability and energy efficiency. Abatement cost of grid integration depend heavily on local natural gas price and electricity price.

1. Abatement cost based on power from shore implementation of John Sverdrup field phase 1 and offshore wind farm of Hywind Tampen project and Orcadian energy proposal for NSTA
2. For a large LNG facility with 5 trains of total 25 Mt per year production, CAPEX annualised over 15 years at 10% discount rate and varying natural gas and electricity prices in Asia Pacific
3. Onsite powered with 60 MW generators on gas turbines with heat recovery for steam turbine
4. Onsite power with 180 MW generators on gas turbines with heat recovery for steam turbine and 250 MW from grid
5. Powered by local grid with 100% renewable energy source

Source: NSTA Orcadian microgrid electrification concept, 2022; Equinor Reducing CO_2 emissions from offshore oil and gas production, 2021; ABB Electrification and energy efficiency in oil and gas upstream, 2012; Enerdata Gas and electricity price database

Reliability – Commercial technology with limited implementation

Estimated commercialisation status

Process electrification relies on existing technology that is commercially available. However, implementation is low and concentrated in North America and North Sea assets, due to its cost

TRL: **9** (assessed by OGTC[1])

Recent project examples

	Details
First world-scale electric LNG plant in North America 	• The Freeport LNG terminal consists of three liquefaction trains producing over 15 Mt of gas per year (commissioned in 2019) • Freeport LNG has successfully implemented an all-electric eDrive system as their main refrigerant compressor drivers and remaining rotating equipment at the PreTreatment Facility, achieving a site combustion reduction of 90% while focusing on environmental stewardship
Johan Sverdrup electrified production platform 	• In 2019, Johan Sverdrup came on stream while being powered from shore to achieve 0.67 kg CO_2 per barrel (compared to average 15 kg per barrel globally) • Sverdrup phase 2 looks into supplying shore power to adjacent fields (such as Sleipner in Utsira High)
Clean power supply contract at Petronas's LNG Complex 	• In 2021, Petronas signed a contract with Sarawak Energy to purchase predominantly renewable power to Petronas's LNG complex in Bintulu • The 90 MW of power supply will start in 2024 for a term of 20 years. • The low-carbon electricity will be used to decarbonise the operations of the LNG complex

1. The Oil and Gas Technology Centre

Lock-in prevention – Three possible long-term decarbonisation pathways, together with transparent decommissioning plans

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	• Three paths exist for process electrification to be zero or near-zero emissions; – Path 1: Fully-renewable grid-powered – Path 2: CCUS implementation to capture process CO_2 and residual emissions – Path 3: Co-firing/firing low-carbon fuels for backup onsite power generation • Mitigating the risk of prolonged reliance on fossil fuels by evaluating transition plans to ensure fossil fuel decommissioning plans are place with clearly-defined time horizon
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	• Path 1: Sourcing fully renewable grid power – Renewable energy power generation is commercialised at scale (IEA TRL 8-11), but the renewable energy supply is expected to be a bottleneck on the local power grid and requires an FI evaluation – Onsite renewable power sources can supplement, but will be CAPEX-heavy and reliant on incentives to be economical • Path 2: CCUS implementation to capture process CO_2 and residual emissions – CCUS technology is commercial, with offset potential for enhanced oil recovery. However, CAPEX is heavy with abatement costs (15-70 USD/tCO_2 requiring low-carbon incentive to compete in the market) – Concern centers around efficacy and long-term storage of CO_2. A monitoring and verification plan is required • Path 3: Co-firing/firing low-carbon fuels for backup onsite power generation to reduce emissions – Co-firing gas turbines is commercialised (IEA TRL 9). Hydrogen fuel gas turbines are maturing (IEA TRL 7), requiring increasing amounts of low-carbon fuel supplies and equipment upgrades overtime and reliant on low-carbon incentive to be economical – Partnerships may reduce low-carbon fuel costs (natural gas to hydrogen), but relies on local availability to achieve cost effectiveness, limiting opportunities

Source: Literature search

DNSH/social considerations – Environmental viability assessment may be required for new infrastructure and grid power source

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• An environmental viability assessment (or equivalent) should be conducted for major new infrastructure associated with process electrification (including offshore windfarms all the way to offshore platform modifications and electric motors to grid connections for LNG plants) • Power sources should be evaluated to ensure no harm is inflicted on the ecosystem or biodiversity. Local regulations and industry standards shall apply, especially for hydropower and windfarms
	Promotion of transition to circular economy	• Ensure equipment and grid power are sourced from certified suppliers who measure, disclose, minimise, and potentially offset GHG emissions along the value chain • Electrification incorporates renewable energy sources, limiting demand for conventional fossil fuels
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Electrification of equipment leads to lower on-site maintenance requirements • Larger power grids are required, increasing job opportunities in the renewable power sector • HSE risks with electrification implementation (especially to maintenance at remote locations). Wind farms and distribution hubs must be assessed on prevention and mitigation measures. Opportunities for unmanned operation should be leveraged

Source: Literature search

Introduction

Details of Potential Transition Technologies

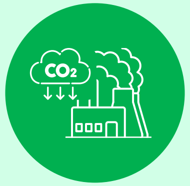
Power

Upstream

CCUS

Appendix

CCUS transition technologies in 3 major applications are featured



CCUS in coal/gas power plant

Blue hydrogen & blue ammonia production

CCUS in gas production

【Reference】 Overview of the Carbon Capture, Utilisation, and Storage (CCUS) Value Chain

Deep dive in subsequent sections




	CO_2 sources	Capture	Transport	Storage & Utilisation
Description	Point sources which generate CO_2 as part of energy generation or process stream	CO_2 capture at post-combustion, pre-combustion, and during combustion (oxy-fuel method).	CO_2 transport mode from emissions site to storage site	CO_2 final injection site CO_2 can be utilised for feedstock and high value products such as cements
Technology options / concepts	High Purity sources • Natural gas production (LNG liquefaction plant) • Chemical production (hydrogen & ammonia production) Low Purity sources • Power plants (coal and gas-fired power plants) • Iron and steel plants	Multiple capture technologies • Liquid solvent (incl. chemical absorption and physical absorption) • Solid absorbent • Membrane separation, etc Conditioning depends on transport mode : Compression or liquéfaction	Optimum value determined by volume, distance, and carrier • Pipeline • CO_2 barge • CO_2 rail • CO_2 truck	Storage: Multiple options based on capacity and logistic considerations • Onshore vs. offshore • Saline aquifers, depleted gas reservoirs Utilisation: End-use for CO_2 such as cement, aggregates, bio-char, specialty chemicals
Cost (USD/tCO_2)		50-140	3-25	3-55[1]
Cost drivers	• CO_2 purity (required) • System complexity (required) • Volume at source gas (i.e., Single large plant or multiple smaller sources) • Composition of source gas (contaminants, by-products)		• Phase /physical prop of CO_2 in transit • Mode of transport — Marine – vessel characteristics (size), port location, distance sailed — Pipelines – pipeline pressure, pipeline characteristics (overground, underground), pipeline length, pipeline location (sea, urban, rural)	• Reservoir depth and temperature • Archetype (onshore / offshore) • Injection rate (volume, location, temperature) • Synfuel plant demand

1. Storage only

Source: Global CCS institute, IEA, literature search

【Reference】CCUS Technical Considerations

CO_2 capture efficiency depends on source concentration

CO_2 conc.	Example situations	CO_2 capture efficiency
High (80%)	Post AGRU (acid gas removal unit) step solvent in LNG processing	High
Low (about 10%)	Post combustion flue gas	Low

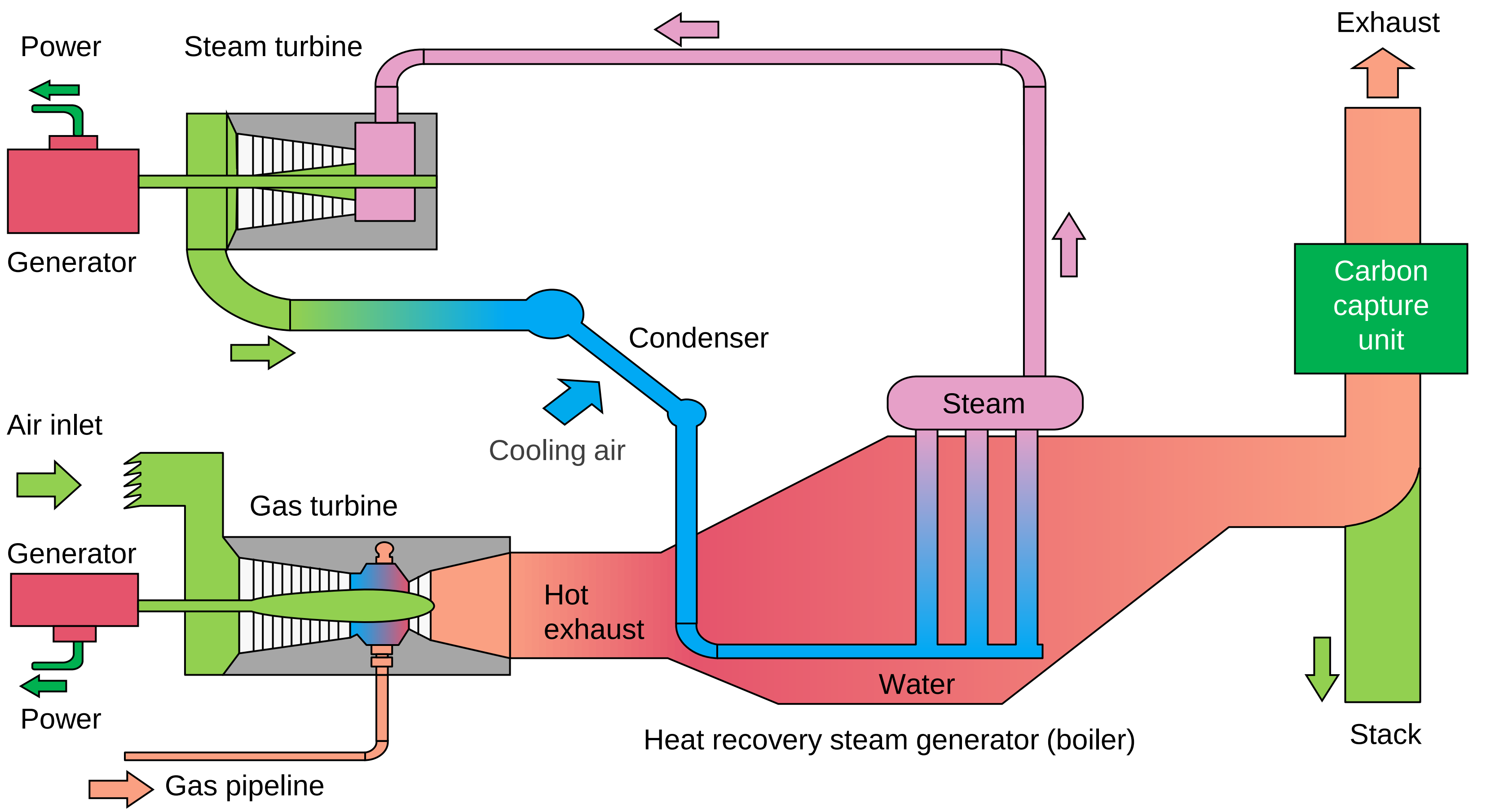
3 major CO_2 capture technologies

Technology	Maturation/usage
Chemical absorption	Most widely used. Amine-based solvents are used. (TRL 9-11)
Physical absorption	Used only in selected cases such as natural gas processing, etc. (TRL 9-11)
Membrane separation	Used in natural gas processing (TRL 9)

Source: Global CCS Institute 'Technology Readiness and Costs of CCS' (2021), IEA, literature search

CCUS in coal- and gas-fired power plant (post-combustion) – Technology schematics and overview

EXAMPLE IN GAS-FIRED POWER PLANT[1]



CCUS in coal- or gas-fired power plant captures CO_2 emitted from power generation instead of releasing it into the atmosphere

There are different approaches, including chemical absorption. There, CO_2 is separated from the combustion flue gas by reaction of CO_2 with a chemical solvent (e.g. amine-based) to form a weakly bonded intermediate compound, which may be regenerated with the application of heat to produce the original solvent (for further operation) and a concentrated CO_2 stream

CCUS in coal- or gas-fired power plant can capture approximately 90% of the CO_2 emitted

1. Carbon capture unit can be similarly fitted to a coal-fired power plant in its exhaust pipe

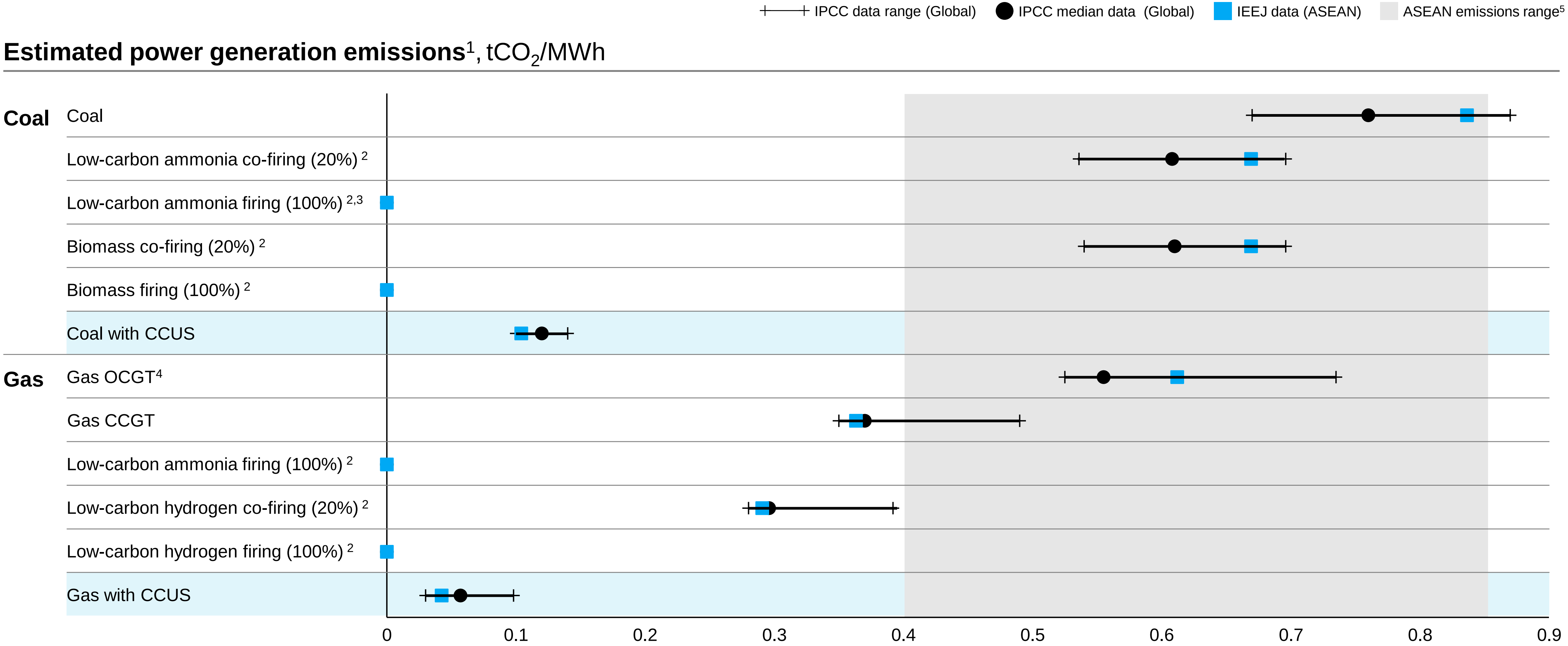
Source: Literature search

CCUS in coal/gas-fired power plant – Transition suitability assessment overview

Framework dimensions	Description
Emissions impact	• **Up to 90% emissions reduction** by retrofitting CCUS in coal or in gas fired power plants, respectively**.** This results in **near-zero emissions (0.03-0.10 tCO_2/MWh)** and emissions factor well below ones of ASEAN countries
Affordability	• Retrofitting CCUS increases LCOE by about **50** and **40 USD/MWh** in **coal and gas** fired power plant, respectively. • LCOE highly dependent on **CAPEX**. Current estimated range of **90-180 USD/MWh in coal-CCUS and 80-170 USD/MWh in gas-CCUS (as of 2020)**, while this could be more competitive once higher carbon prices are set. The cost of CO_2 transport and storage could also increase LCOE, if CO_2 storage location is distant.
Reliability	• Amongst the CCUS methods, post-combustion **chemical absorption** is most matured and in **early commercialisation** (TRL: **8-9**) • Pre-combustion physical absorption and post-combustion membrane polymeric in coal-fired plants are still under pilot or large prototype phase (TRL: 7 and 6, respectively)
Lock-in prevention considerations	2 paths exist for zero or near-zero emissions • Increase CO_2 capture rate; need to invest in **R&D to increase CO_2 capture rate** above 90% • Retire the plants; need to have clear retirement plans which consider timing to retire, finance to demolish, obligations due to procurement or PPA contracts, assessment on environmental stress during demolition, amongst many.
DNSH considerations	• Potential leakage of CO_2 from storage has to be monitored and, if leak is discovered, it has to be repaired. • Waste management should be evaluated according to local regulation to ensure safe disposal of hazardous solvent • Evaluate and incorporate potential utilisation of captured CO_2 to promote circular economy
Social considerations	• Positive impact on job opportunity expected as CCUS requires additional skilled labor across its value chain • HSE risk management needs to be in place, especially around handling of **amine solvent** as it is hazardous

Emissions impact – Retrofitting CCUS can reduce emissions by up to 90%, resulting in well below grid average for ASEAN countries

Estimated power generation emissions[1], tCO_2/MWh

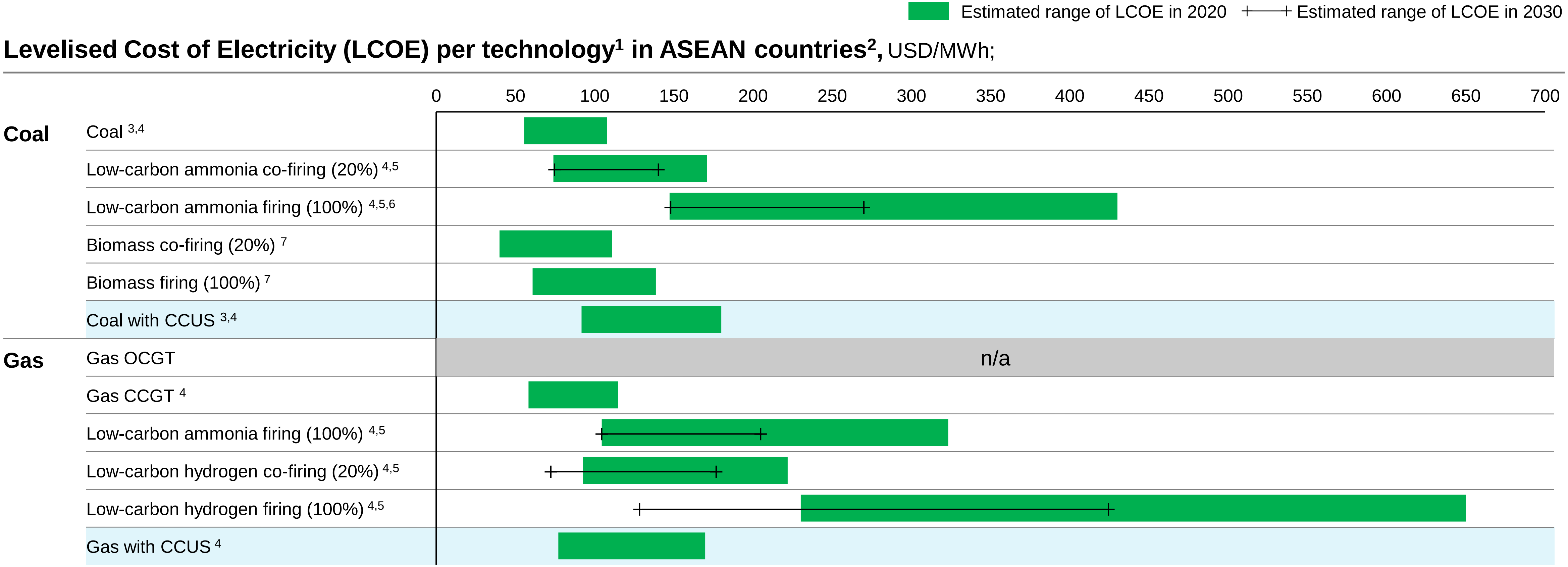


1. Direct emissions for power generation only; other lifecycle emissions not included; IPCC data for 2018; IEEJ data for 2017
2. Emissions for co-firing/firing of biomass or low-carbon fuels are estimated based on the co-firing/firing ratios and the base emissions in respective Coal or Gac CCGT
3. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
4. Emissions for OCGT are estimated based on CCGT emissions and the efficiency of OCGT over CCGT
5. The range of the emissions intensities of ten ASEAN member states (see the 'country-specific power generation emissions' section in the appendix)

Source: IEEJ, IPCC Annex III Technology-specific cost and performance parameters (2018).

Affordability – Retrofitting CCUS increases LCOE by about 50 and 40 USD/MWh in coal and gas fired power plant, respectively

Levelised Cost of Electricity (LCOE) per technology[1] in ASEAN countries[2], USD/MWh;



1. Direct emissions from power generation only; other lifecycle emissions not included
2. Data in Indonesia is used as representative
3. LCOE range for subcritical and supercritical coal fired power plants are shown here
4. LCOE is calculated based on technology data from the DEA using uncertainty range for investment and O&M costs. Coal and gas fuel costs are based on historical range in 2017-2021 from World Bank and Enerdata (coal as 60~140 USD/Mt, gas as 6~11 USD/mmbtu), low-carbon ammonia cost is based on IEA's estimates as of 2018 (240~790 USD/t) and as of 2030 (240~450 USD/t). Hydrogen costs are based on IEEJ and Hydrogen Council's estimates as of 2020 (4~11 USD/kg) and as of 2030 (2~7 USD/kg). Assumptions on other parameters include technical lifetime (coal: 30 years, gas: 25 years), discount rate (8%), capacity factor (coal: 60%, gas: 40~60%), and thermal efficiency (coal: 41%, gas: 56%). Please note that LCOE is highly dependent on fuel cost, and LCOEs shown here are based on fuel costs as written above and do not reflect the current LCOEs. In particular, LCOE here does not reflect recent gas and coal price surge after Ukraine incidents.
5. Additional costs for ammonia/hydrogen co-firing and firing are based on incremental costs by fuel mix and additional CAPEX is not considered.
6. The range for 100% ammonia firing in a steam turbine is shown as it could be technologically possible even though it may not be economically viable
7. Data from IRENA report, LCOEs for biomass co-firing during 2010-2021. The 5th and 95th percentile amongst reported power plants are indicated.

Source: IEEJ, DEA Technology data for the Indonesian power sector (2021), IRENA Renewable Power Generation Costs (2021), World Bank Commodity Prices (2022), Enerdata Global Energy & CO_2 Database - POLES-Enerdata model - EnerFuture scenarios (2021), Hydrogen Council Hydrogen Insights Report (2021), and IEA The Future of Hydrogen (2019)

Reliability (1/2) – CCUS technology in coal power plant is in early commercialisation stage, with recent installation examples seen

Estimated commercialisation status

CCUS in coal-fired power plant is currently classified as below by IEA

	Maturation level
Post-combustion (chemical absorption)	• Early comer-cialisation • **TRL 8-9**
Pre-combustion (physical absorption)	• Under pilot • **TRL 7**
Post-combustion (membrane polymeric)	• Large prototype • **TRL 6**

Cost reduction and finding appropriate CO_2 storage could be potential challenges to overcome

Recent project examples

	Details
Up to 90% CO_2 capture rate and 1 $MtCO_2$/year CCUS on Boundary Dam coal fired plant 	• Since 2014, amine-based post-combustion CCUS is installed in Boundary Dam unit #3 coal-fired power plants in Canada, which produces 115 MW of power. • CO_2 capture rate up to 90% is achieved and 1 million tonnes of CO_2 is sequestered every year. • The project cost $1.24 billon, which is used for CCS installation and plant modernisation
90% CO_2 capture rate is achieved and 4,766 tCO_2/day is stored in Petra Nova Carbon Capture project 	• In 2016 Mitsubishi Heavy Industries, ltd. started Petra Nova Carbon Capture project at a coal-fired power plant in the USA • Mitsubishi Heavy Industries, ltd. Demonstrates CO_2 storage of up to 4,766 tCO_2/day and CO_2 capture rate reaches 90% • Mitsubishi Heavy Industries, ltd. captures CO_2 by chemical absorption (Amine)

Source: IEA, DEA, literature search

Reliability (2/2) – CCUS technology in gas power plant is in early commercialisation stage, with multiple installations planned

Estimated commercialisation status

CCUS in gas-fired power plant is currently classified as below by IEA

	Maturation level
Post-combustion (chemical absorption)	• Early comer-cialisation • TRL 8
Super-critical CO_2 cycle	• Prototype • **TRL 5-6**

Cost reduction and finding appropriate CO_2 storage could be potential challenges to overcome

Recent project examples

	Details
CCUS installation plan in gas-fired power plant in Humber by NZT Power	• By 2025, Net Zero Teesside (NZT) Power plans to start operation of CCUS in 860MW CCGT power plant. NZT Power claims that this plant will be the world's first commercial scale gas-fired power station with carbon capture. • NZT Power plans to capture and store over 95% of the CO_2 emitted, which amounts to 2 $MtCO_2$/year.
Technology prototyping and demonstration study on large-scale CCUS in gas-fired power plant by Chiyoda, JERA and RITE	• In 2022, Chiyoda Corporation (Chiyoda), JERA, and the Research Institute of Innovative Technology for the Earth (RITE) commenced demonstration project on large-scale post-combustion CCUS in gas-fired power plant. • Chiyoda, JERA and RITE plan to develop innovative and economical CO_2 capture and recovery technology and reduce the required area for gas turbine combustion exhaust.

1. Technology Readiness Level; details explained in the appendix
2. Industrial Strategy Challenge Fund

Source: IEA, literature search

Lock-in prevention – Two possible long term decarbonisation pathways, with technological roadblocks and inflexible gas/power contracts possible risks

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	• Two paths exist for zero-carbon emissions – Increase CO_2 recovery rate from current 90% to near 100% – Retire coal or gas power plants
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	• Path 1: Increase CO_2 recovery rate – A company needs to invest in **R&D to achieve higher CO_2 recovery rate** – Availability of **CCUS infrastructure for transportation and storage** is expected to be the bottle neck and thus a company needs to develop partnership to secure them • Path 2: Retiring or switching to peaking use / ancillary services provision (reserve) – **Long-term coal or gas procurement contracts** may hinder retirement or reduced usage of coal or gas power plant – **Power purchase agreements (PPAs)** with very long tenures and minimum utilisation commitments may also hinder retiring or reduced usage of coal or gas power plant

Source: Literature search

DNSH/social consideration – Leakage of CO_2 to atmosphere and handling of hazardous amine solution being potential risks

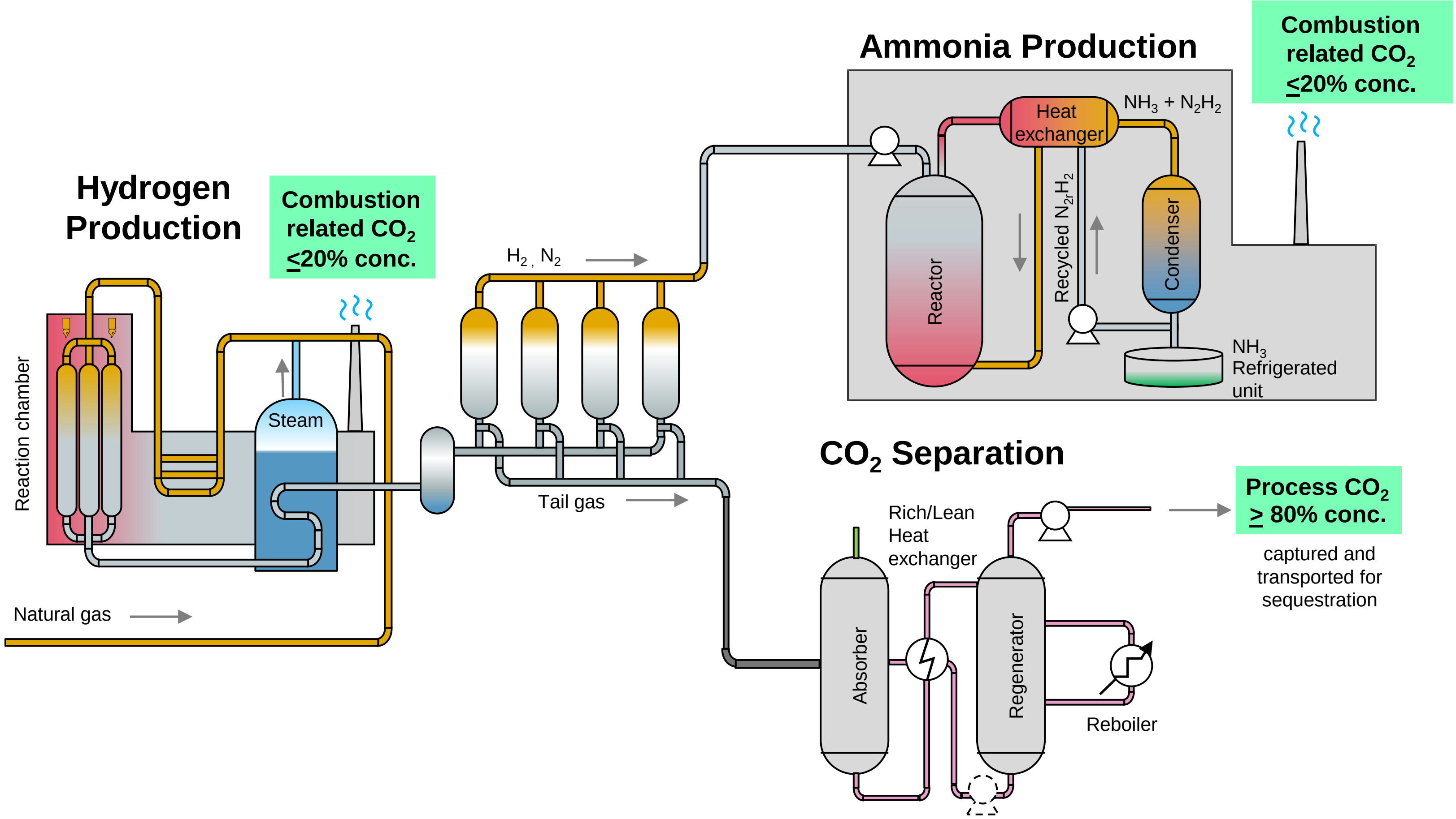
Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystem and diversity**	• CCS monitoring and verification plan needs to be evaluated against local regulation to prevent CO_2 plume migration to surface which includes but not limited to leak detection, atmospheric and subsurface monitoring to ensure CCS operation do not contribute more emissions as it is produced through out CCS value chain • Environmental viability assessment (or equivalents) should be conducted for major new infrastructure installations associated with CCS implementation • Waste management should be evaluated according to local regulation to ensure safe disposal especially solvent waste
	Promotion of transition to circular economy	• Ensure equipment is sourced from certified suppliers who measure, disclose, minimise, and potentially offset GHG emissions along the value chain • Evaluate and incorporate potential utilisation of captured CO_2 such as construction materials (e.g. CO_2 cured cement and construction aggregates), fuel supplements (e.g. synfuel), plastic and chemical raw materials (e.g. polycarbonate and carbon fiber) and fertiliser (e.g. biochar and greenhouse fertilisation)
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Positive impact on job opportunity expected as CCUS requires additional skilled labor across its process chain in capturing, transporting and gas injection • HSE risk with CCUS implementation especially with regards to chemical used in CO_2 separation need to be assessed with prevention and mitigation measures implemented based on local regulation and industry standard

Source: Literature search

Blue hydrogen & blue ammonia production – Technology schematics and overview

Target for CCUS

EXAMPLE IN PRODUCTION OF BLUE HYDROGEN AND AMMONIA FROM NATURAL GAS



Blue hydrogen production emits GHG through process CO_2 and combustion- related emissions

Process CO_2 accounts for about 70% of emissions and is a cost-effective opportunity for CCUS implementation, given high concentration of over 80% CO_2

The remaining 30% are low CO_2 concentration sources of industrial flue gas that is expensive to capture and can be reduced via hydrogen co-firing or replaced with hydrogen fuel turbines

Ammonia production consists of a similar hydrogen production process (simple methane reforming) with the addition of Haber-Bosch synthesis

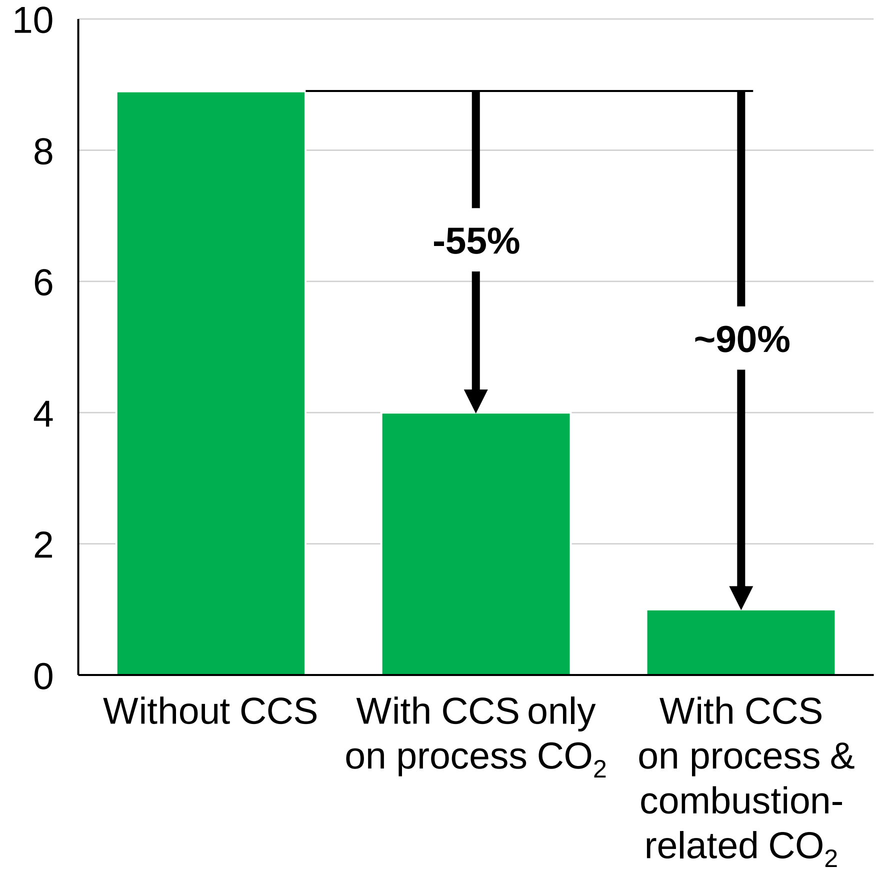
Source: Literature search

Blue hydrogen & blue ammonia production – Transition suitability assessment overview

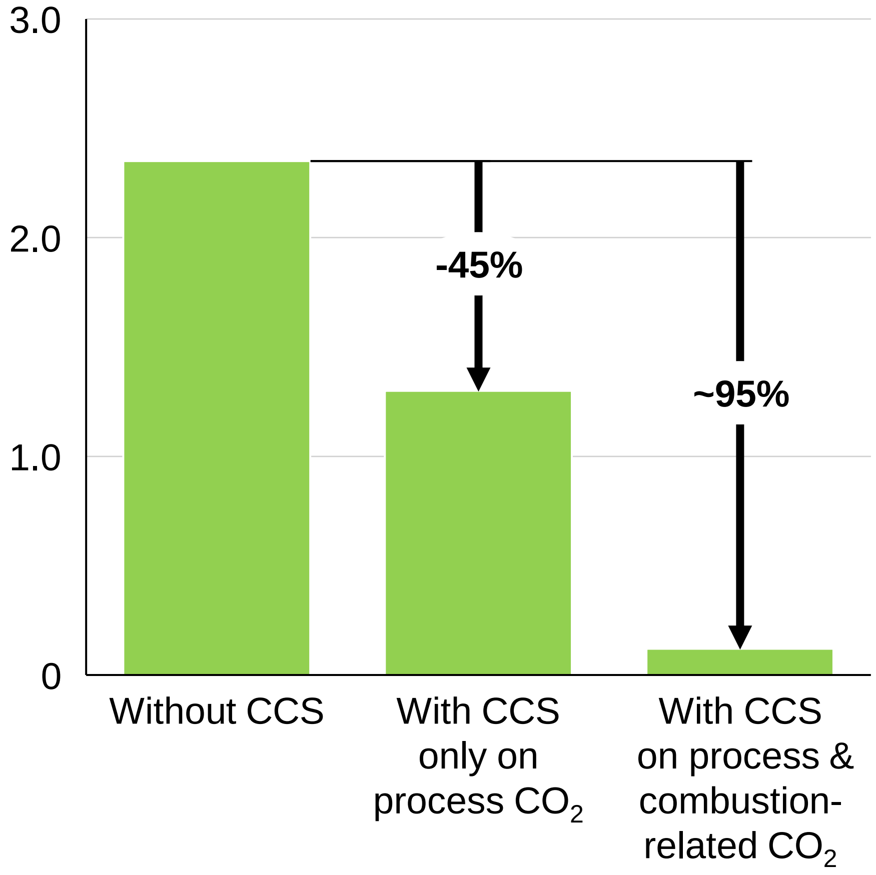
Framework dimensions	Description
Emissions impact	• CCUS implementation for capturing only **process CO_2** can achieve about **50% emissions reduction** while **full CCUS** including combustion related CO_2 capture achieves **up to 95%**
Affordability	• Abatement cost for blue hydrogen ranges from 50-80 USD/tCO_2 while blue ammonia 60-90 USD/tCO_2 depending on scope of capture and associated capture technology
Reliability	• CCUS technology is **commercialised** (blue hydrogen has TRL of 8-9 and blue ammonia TRL of 9-11) but adoption is low, accounting for only 1% of total annual 120 Mt of hydrogen production
Lock-in prevention considerations	• Further R&D required to **improve CCUS capture rate** beyond 90%. • The heat for blue hydrogen and blue ammonia should be provided from a low/zero carbon source. • Retirement of blue hydrogen production should be planned especially if substantial uptake of green hydrogen technology occurs
DNSH considerations	• CO_2 capture rate monitoring and verification plan needs to be evaluated against local regulation to ensure efficacy and prevent CO_2 leak • Evaluate and incorporate potential utilisation of captured CO_2 to promote circular economy
Social considerations	• HSE risk of chemical use of CO_2 separation technology needs be to assessed and measurements in place to be evaluated against industry standard and local regulation

Emissions impact – CCS can achieve up to 90% emissions reduction for hydrogen/ammonia production, depending on scope of capture

Emissions intensity of hydrogen production; $kgCO_2/kgH_2$



Emissions intensity of ammonia production; $kgCO_2/kgNH_3$



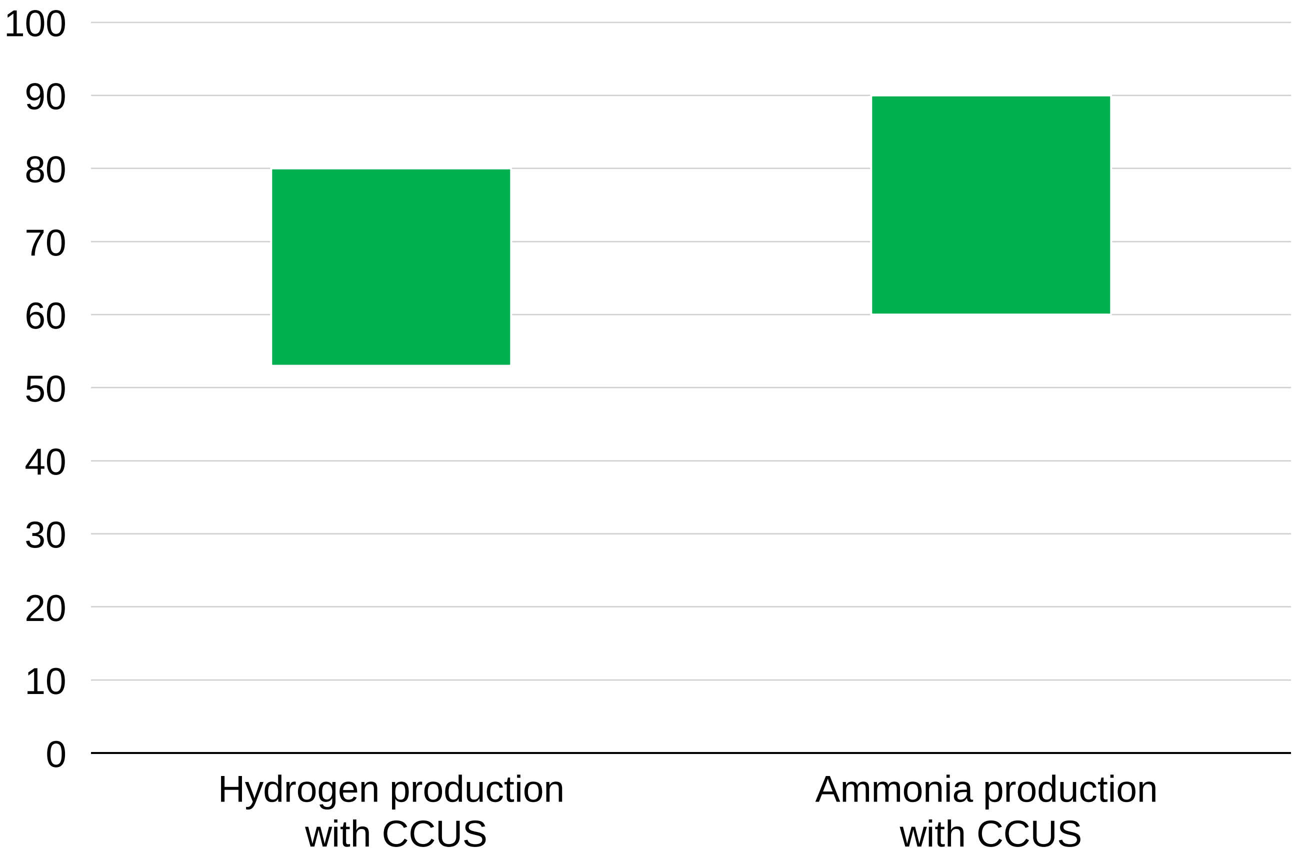
Implementing CCS on process CO_2 with higher concentrations reduces **emissions by about 50%**

Total capture (including process and combustion-related flue gas) reduces **emissions by about 90%**

Source: IEA, literature search

Affordability – Appropriate carbon pricing or end user green premia are required to incentivise blue hydrogen/ammonia implementation

Abatement cost of hydrogen and ammonia production with CCUS; USD/tCO_2



Abatement cost depends on CO_2 capture implementation and associated capture technology

The abatement cost for CCUS in hydrogen production ranges from 55-80 USD/tCO_2, depending on capturing process CO_2 only or full capture.
The abatement cost for CCUS in ammonia production ranges from 60-90 USD/tCO_2

Source: IEA Future of hydrogen, 2019; IRENA Renewable ammonia (2022), literature search

Reliability – Commercialised technology but limited adoption at only 1% of total annual hydrogen production

Estimated commercialisation status

CCUS technology is commercialised but adoption is relatively low accounting for only 1% of total annual 120 Mt of hydrogen production

Under IEA classification:

- Blue hydrogen:
  - Early commercialisation
  - **TRL 8-9**
- Blue ammonia:
  - Physical absorption **TRL 9**
  - Chemical absorption **TRL 11**

Recent project examples

Details

Quest blue hydrogen production at Alberta

- In 2005, Shell commissioned the Quest CCS facility to capture CO_2 from the Scotford Upgrader hydrogen production using amine-based solvents with an annual capacity of about 1 Mt per year.
- CO_2 was then transported via pipeline to Radway field and sequestered in a saline aquifer
- To date, Quest has captured over 6 Mt of CO_2, with an annual capture rate about 80% from hydrogen units

Air Product Port Arthur CCUS project in Texas

- Air Product commissioned Port Arthur CCUS project in 2013, in which two SMRs[1] were retrofitted with vacuum swing adsorption system to separate CO_2 from process gas stream, followed by compression and drying processes
- CO_2 is transported to the Denbury pipeline for transport to Texas EOR[2] projects in West Hasting Fields. The project has a capacity of 1 Mt per year.

1. Steam methane reforming
2. Enhanced oil recovery

Source: Global CCS Institute Blue hydrogen, 2021; IEA Clean energy technology guide,2021; Shell Quest carbon capture and storage project, MIT Energy Initiative Quest; US DOE Air products & chemicals, Inc., Literature search

Lock-in prevention – Two possible long term decarbonisation pathway with risk of substantial green hydrogen uptake

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	• Three paths exist for blue hydrogen and ammonia production to be zero or near-zero emissions; – Path 1: Ensuring high CCUS efficacy and improving CO_2 capture rate up to 99% – Path 2: Utilising low/zero carbon source for heat requirement, to achieve progressively lower GHG emissions intensity – Path 3: Retirement of blue hydrogen production should be planned especially if substantial uptake of green hydrogen technology occurs
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	• Path 1: Ensuring high CCUS efficacy and improving CO_2 capture rate up to 99% – Further R&D is required to improve capture rate up to 99% – A detailed monitoring and verification plan is required to ensure accurate reporting of CCUS efficacy • Path 2: Utilising low/zero carbon source for heat requirement, to achieve progressively lower GHG emissions intensity – Low emissions heat could be obtained by hydrogen co-firing gas turbines, in which the technology is commercialised (IEA TRL 9). • Path 3: Retirement of blue hydrogen production should be planned especially if substantial uptake of green hydrogen technology occurs – Electrolysis technology is maturing with polymer electrolyte membrane and alkaline at TRL 9, and solid oxide electrolyser cell at TRL 7, requiring a full replacement of hydrogen production process in order for transition – Long-term gas procurement contracts may hinder retirement especially if Take-or-Pay clauses with high thresholds are present

Source: Literature search

DNSH/social considerations – Leakage of CO_2 to atmosphere and handling of hazardous amine solution being potential risks

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• CCS monitoring and verification plans must be evaluated against local regulations to prevent CO_2 plume migration to the surface (includes but not limited to leak detection, atmospheric, and subsurface monitoring) to ensure CCS operations do not contribute to emissions in the CCS value chain • Environmental viability assessment (or equivalents) should be conducted for major new infrastructure associated with CCS implementation • Waste management should be evaluated according to local regulations to ensure safe disposal
	Promotion of the transition to a circular economy	• Ensure gas is sourced from certified suppliers who measure, disclose, minimise, and potentially offset GHG emissions along the value chain, such as methane emissions, CO_2 venting, and onsite gas combustion for power. • Evaluate and incorporate potential utilisation of captured CO_2 such as construction materials (e.g. CO_2 cured cement and construction aggregates), fuel supplements (e.g. synfuel), plastic and chemical raw materials (e.g. polycarbonate and carbon fiber) and fertiliser (e.g. biochar and greenhouse fertilisation)
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Positive impacts on job opportunities are expected. CCUS requires skilled labor across its process chain in capturing, transporting, and in gas injection • HSE risks on CCUS implementation (especially with chemicals used in CO_2 separation) must be assessed, with prevention and mitigation measures implemented based on local regulations and industry standards

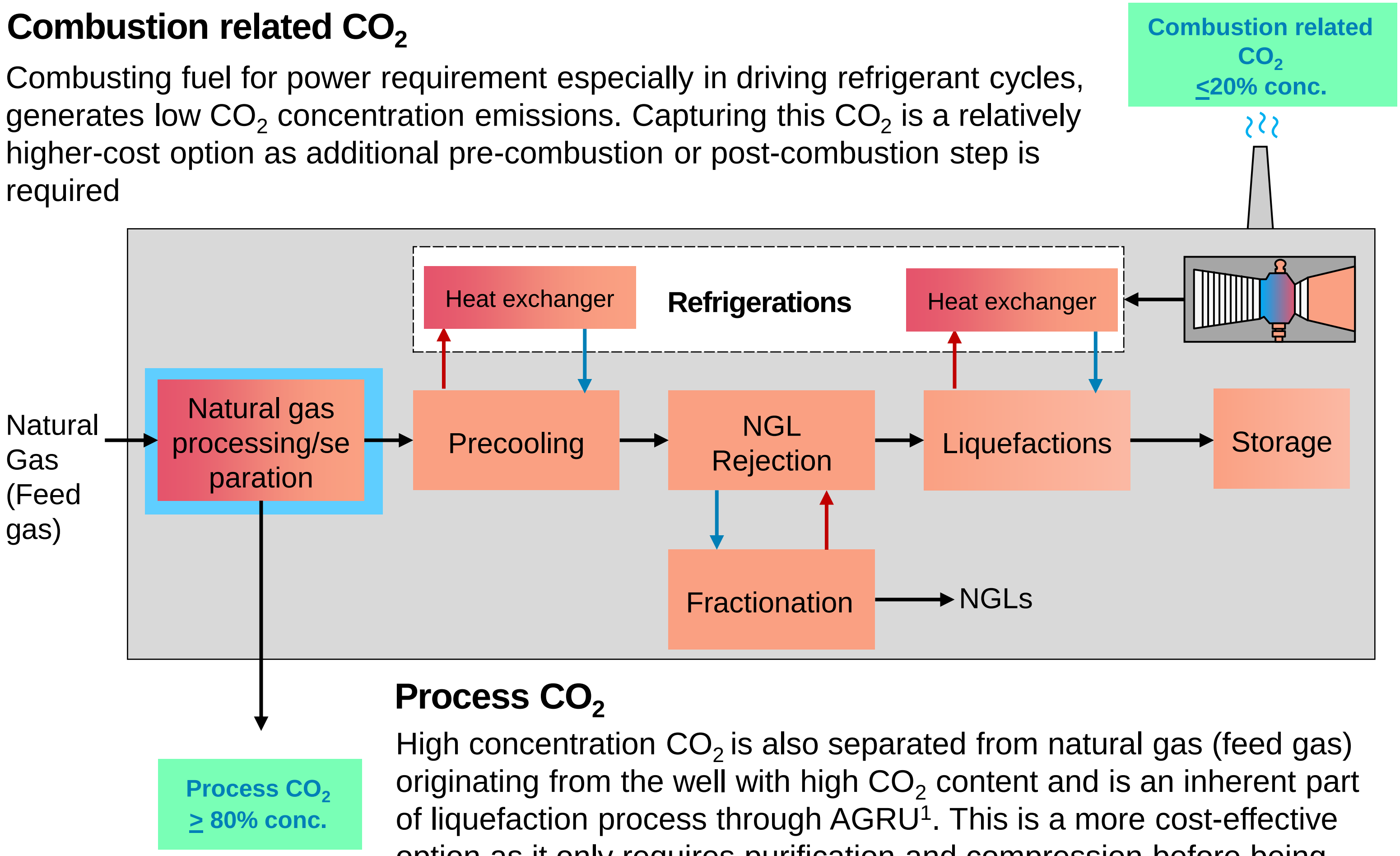
Source: Literature search

CCUS in gas production – Technology schematics and overview (1/2)

Deep dive in next page   Target for CCUS

Combustion related CO_2

Combusting fuel for power requirement especially in driving refrigerant cycles, generates low CO_2 concentration emissions. Capturing this CO_2 is a relatively higher-cost option as additional pre-combustion or post-combustion step is required



Process CO_2

High concentration CO_2 is also separated from natural gas (feed gas) originating from the well with high CO_2 content and is an inherent part of liquefaction process through AGRU[1]. This is a more cost-effective option as it only requires purification and compression before being transported for sequestration

CO_2 capture type

Most mature CO_2 capture technology is solvent-based separation

Solvent-based techniques utilise high-performance chemicals, such as amines-based (MDEA) that selectively dissolve CO_2 from natural gas and release it as heat to regenerate

Storage and utilisation

Once captured, CO_2 is transported to a sink location and stored in variety of geological formations (as below):

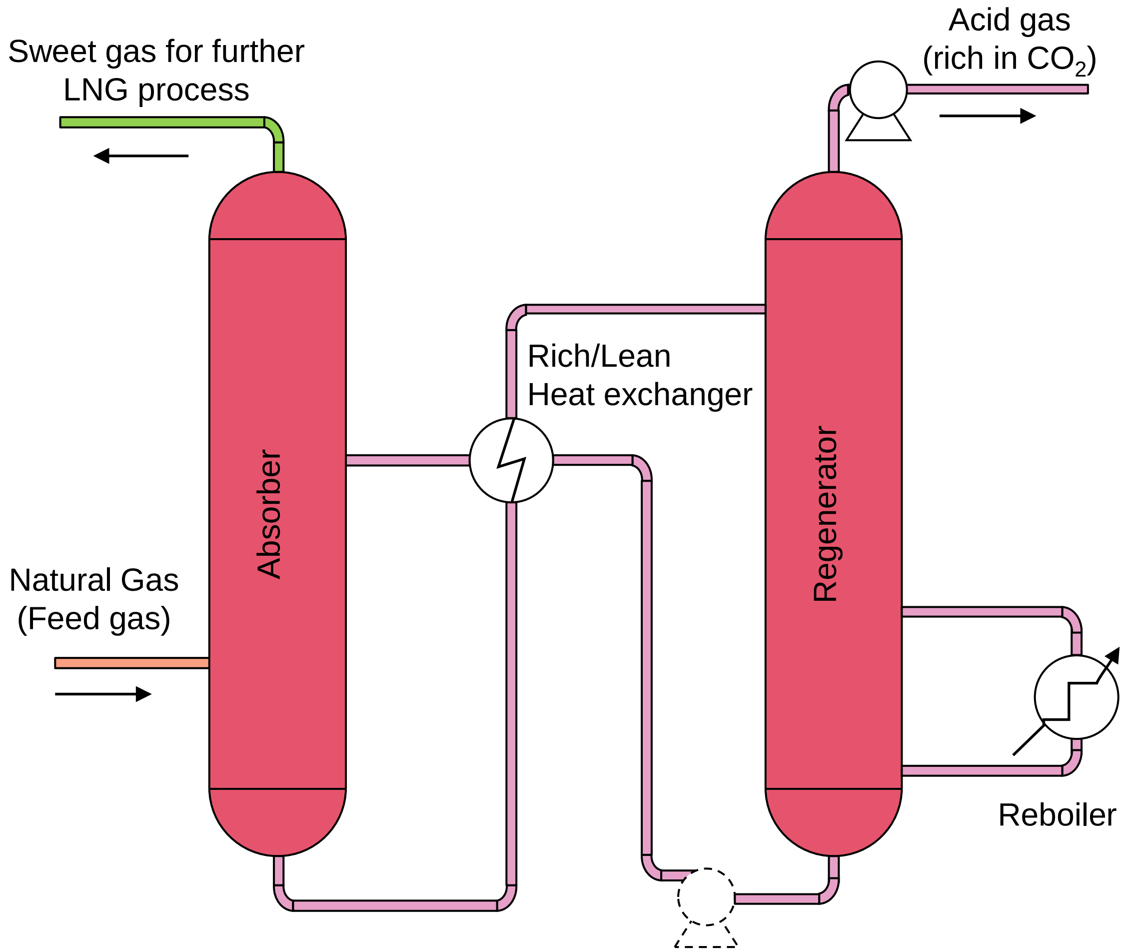
- Saline formation
- Depleted O&G reservoir
- Organic-rich shale

An established and economically-viable CO_2 usage is in enhanced oil recovery. Alternate utilisation includes construction material, synfuel, plastic production, and fertiliser

1. AGRU = Acid gas removal unit; NGL = Natural gas liquid; MDEA = methyl diethanolamine

Source: Air Products Decarbonized LNG production via integrated hydrogen fueled power generation (2021), literature search

CCUS in gas production – Technology schematics and overview (2/2)



Acid Gas Removal Unit (AGRU)

AGRU removes impurities such as H_2S and CO_2 to meet sales requirements and environmental emissions regulations

Natural gas is pumped into an absorber column, where solvent-based capture techniques are applied using amine-based solvent (methyl diethanolamine [MDEA]). Impurities dissolve in this solvent and sweet gas (natural gas without impurities) is piped downstream for further processing into LNG

Solvents containing CO_2 and H_2S are then piped to the regenerator column, where the solvent is regenerated by releasing H_2S and CO_2 via steam, where it can be reused

Depending on the composition of natural gas, the resulting acid gas rich in H_2S and CO_2 goes through sulphur recovery unit to strip H_2S.

For sequestration, the resulting rich CO_2 stream is dehydrated and compressed for transport to the sequestration site

Source: Literature search

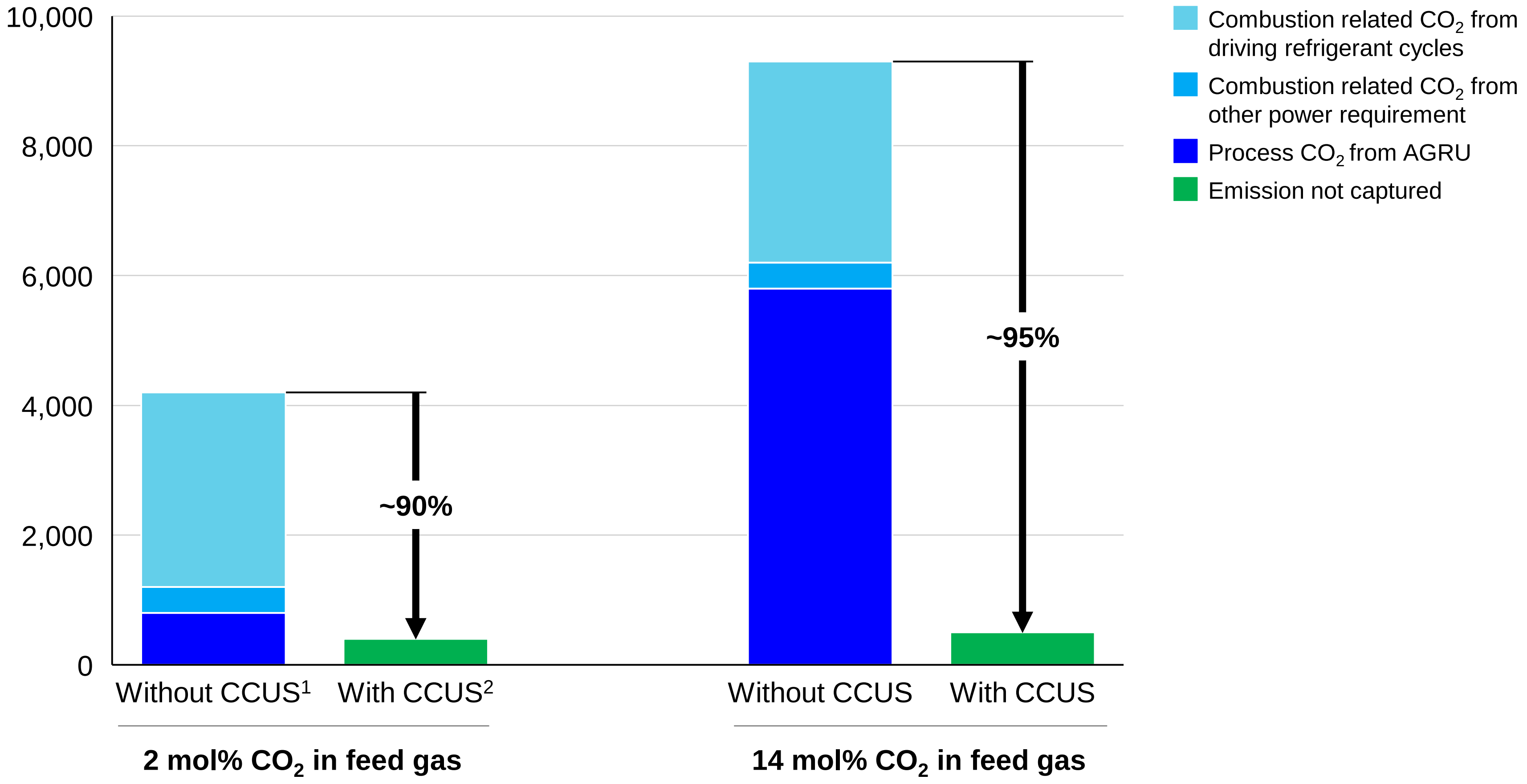
CCUS in gas production – Transition suitability assessment overview

Framework dimensions	Description
Emissions impact	• **Up to 95%** reduction with both **combustion-related and process CO_2 capture**
Affordability	• Implementation opportunities can be phased with first **process CO_2 capture** at AGRU[1], with abatement costs of **15-20 USD/tCO_2** (requires only compression and purification) • **Full CO_2 capture** with post-combustion capture included has an abatement cost of **55-65 USD/tCO_2**
Reliability	• **CCUS technology is mature**, but **adoption is low** (less than 15 projects) • CO_2 capture in natural gas processing by chemical absorption and enhanced oil recovery is at TRL 11
Lock-in prevention considerations	• Further R&D required to improve capture rates beyond 90%, as other methods (such as physical absorption and oxyfuel systems) are under pilot • Mitigate risk of prolonged reliance on fossil fuels through a clearly-defined time horizon
DNSH considerations	• CCUS monitoring and verification plans must be evaluated against local regulations to ensure efficacy and to prevent CO_2 plume migration to the surface • Evaluate and incorporate potential utilisation of captured CO_2 to promote a circular economy
Social considerations	• HSE risk of chemical use of CO_2 separation technology must be assessed and measurements taken to be evaluated against industry standards and local regulations

1. AGRU, acid gas removal unit

Emissions impact – CCUS can reduce emissions up to 95%

CO_2 emissions during gas production with different CO_2 concentrations in feed gas and with or without CCUS; tCO_2/day



In feed gas with low CO_2 content, combustion related CO_2 from **driving refrigerant cycles contributes to about 90% of total emissions**

In feed gas with high CO_2 content, emissions from process CO_2 quickly becomes the **major contributor accounting for about 60% of the total emissions**

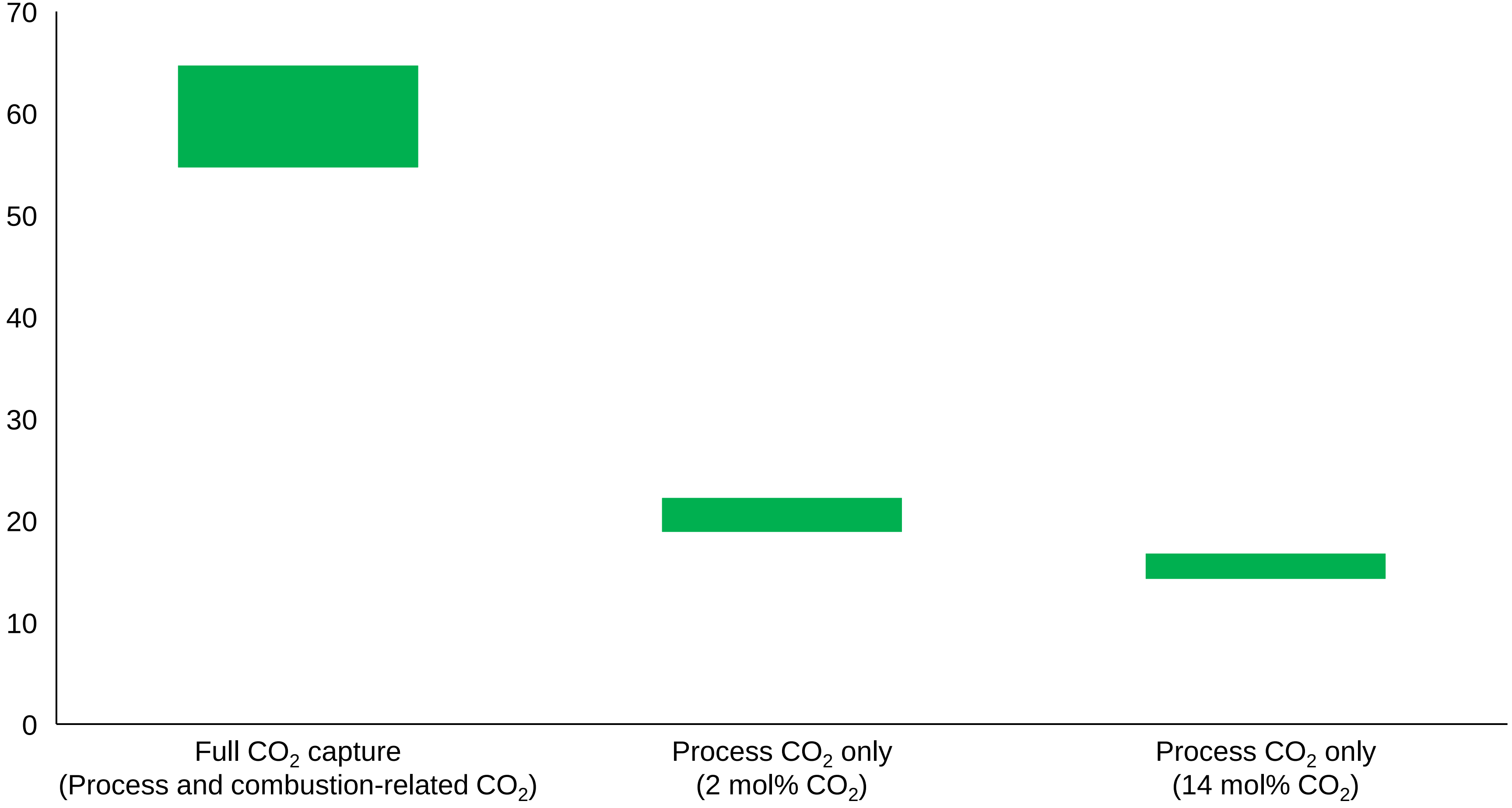
Emissions reduction is around 90% with full CCUS implementation, which includes both combustion-related and process CO_2

1. Based on LNG plant with 4.5 Mt per year production capacity and feed gas CO_2 concentration as indicated without CCUS and assumes liquefaction power requirement of 0.3 kWh/kg of LNG
2. Equivalent LNG plant with capture of both combustion related CO_2 and process CO_2 inclusive of purification and compression

Source: IEA GHG Techno-Economic Evaluation of CO_2 Capture in LNG Plants (2019), Literature search

Affordability – Abatement cost of 55-65 USD/tCO_2 for full capture and 15-20 USD/tCO_2 for process CO_2 only

CO_2 abatement costs by implementation[1]; USD/tCO_2



Implementing full CO_2 capture on both combustion and process CO_2 cost around from 55 to 65 USD/tCO_2

Capturing process CO_2 only is about 70% cheaper at from 15 to 20 USD/tCO_2, which accounts for over 60% of emissions at high feed gas CO_2 content

1. Based on LNG plant with 4.5 Mt per year production capacity and feed gas CO_2 concentration as indicated and assumes liquefaction power requirement of 0.3 kWh/kg of LNG

Source: IEA GHG Techno-Economic Evaluation of CO_2 Capture in LNG Plants (2019), literature search

Reliability – Upstream CCUS technology is commercialised, but with limited implementation

Estimated commercialisation status

The required CCUS technology is commercialised, but implementation is low (less than 15 projects as per IOGP)

Under IEA classification:

- CO_2 Capture:
  - **TRL 11** for natural gas processing
- CO_2 Storage:
  - **TRL 7-11**
  - Enhanced oil recovery is commercialised at scale
- CO_2 Transport:
  - Pipeline **TRL 10**
  - Shipping **TRL 4-7**

Recent project examples

	Details
Gorgon project sequestrates CO_2 from LNG liquefaction plant 	• The Gorgon CCS project was commissioned in 2019 to capture CO_2 from Gorgon LNG post AGRU, which has feed gas containing up to 14 mol% CO_2 • Captured CO_2 is piped over 12km for sequestration at a depth of 2 km in Dupuy formation. The project has a capacity of 3.4-4 Mt of CO_2 capture per year.
Qatargas implements CCS-EOR project at Ras Laffan LNG facility 	• In 2019, Qatargas commissioned the largest CO_2 recovery and sequestration facility in Middle East and North Africa region in the Ras Laffan production of its North Field • Additional CCS facilities in Ras Laffan are expected to start in 2025, which will increase existing CCS capacity to 5 Mt per year (with EOR integration planned)

1. IOGP = International Association of Oil and Gas Producers

Source: IEA CCUS in Clean Energy Transition (2020), IOGP, UNFCC, MITei

Lock-in prevention – Further R&D required to improve capture rates, while a fossil fuel decommission plan is required

Framework dimensions	Considerations/ Key questions	Details
Lock-in prevention considerations	**What are the paths for the technology to be zero or near-zero emissions?**	2 paths exist for gas production to be zero emissions • Path 1: Ensuring high CCUS efficacy and improving CO_2 capture rates to up to 99% • Path 2: Mitigating the risk of prolonged reliance on fossil fuels with CCUS
	What (lock-ins) may hinder the above paths to zero or near-zero emissions? Considerations include • Financially viability • Technological maturity • Sourcing and contracting	• Path 1: Ensuring high CCUS efficacy and improving CO_2 capture rates – Amine chemical absorption is already commercialised. Other methods (physical absorption and oxy-fueling) are under pilot, requiring further R&D to optimise capture routes and improve capture rates to up to 99% – A detailed monitoring and verification plan is required with evaluation to ensure accurate reporting of CCUS efficacy through surface and subsurface monitoring – CO_2 storage capacity and integrity must be accounted for throughout the operational lifetime, with significant margins of error to prevent storage capacity bottlenecks • Path 2: Mitigating the risk of prolonged reliance on fossil fuels with CCUS – Transition plan evaluations are required to ensure fossil fuel decommissioning plans are in place with clearly-defined time horizon

Source: Literature search

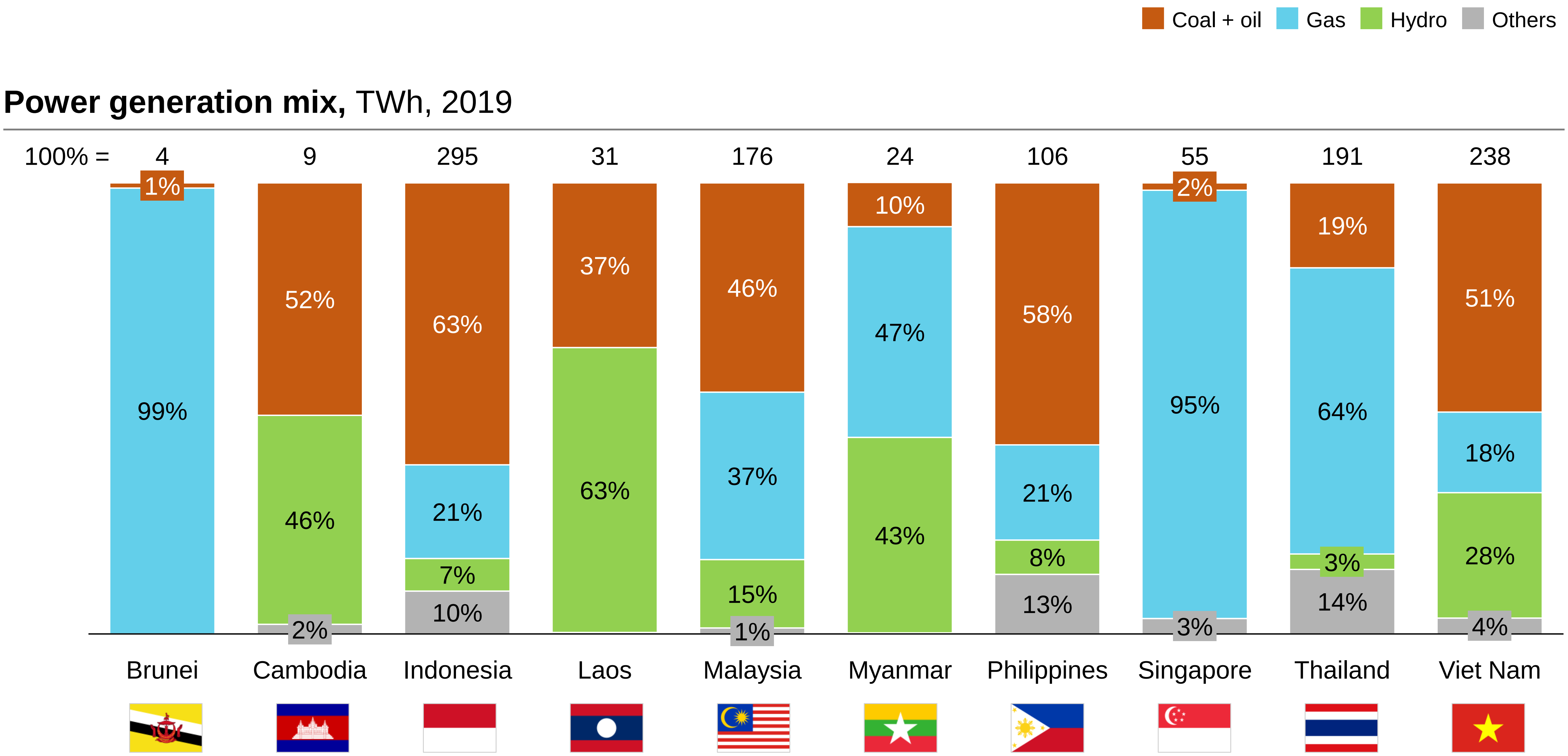
DNSH/social considerations – Leakage of CO_2 to atmosphere and handling of hazardous amine solution being potential risks

Framework dimensions	Considerations/ Key questions	Details
DNSH considerations	**Protection of healthy ecosystems and biodiversity**	• CCUS monitoring and verification plans must be evaluated against local regulations to prevent CO_2 plume migrations to the surface, which includes but is not limited to leak detection, atmospheric, and subsurface monitoring to ensure CCUS operations do not contribute more emissions as it is produced through out CCUS value chain • Environmental viability assessment (or equivalents) should be conducted for major new infrastructure associated with CCUS implementation • Waste management should be evaluated according to local regulations to ensure safe disposal
	Promotion of transition to a circular economy	• Ensure equipment is sourced from certified suppliers who measure, disclose, minimise, and potentially offset GHG emissions along the value chain • Evaluate and incorporate potential utilisation of captured CO_2 such as construction materials (e.g. CO_2 cured cement and construction aggregates), fuel supplements (e.g. synfuel), plastic and chemical raw materials (e.g. polycarbonate and carbon fiber) and fertiliser (e.g. biochar and greenhouse fertilisation)
Social considerations	**Plans to mitigate the negative social impact of the technology**	• Positive impact on job opportunities are expected. CCUS requires additional skilled labor across its process chain in capturing, transporting, and gas injection • HSE risks with CCUS implementation (especially with the chemicals used in CO_2 separation) must be assessed and prevention and mitigation measures implemented based on local regulations and industry standards

Source: Literature search

Power generation mix in ASEAN countries

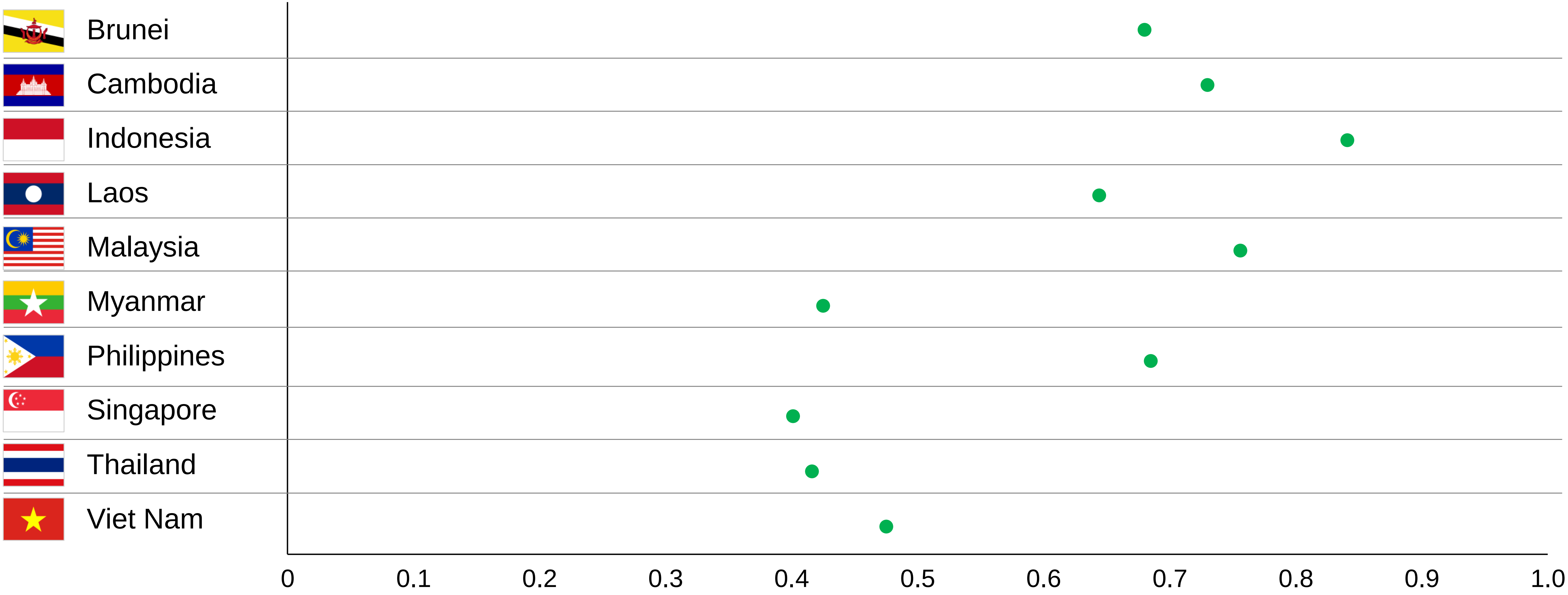
Power generation mix, TWh, 2019



Source: National statistics, International Energy Agency

Estimated power generation emissions intensity by country

Estimated power generation emissions in ASEAN countries[1]; tCO_2/MWh, 2020



1. Emissions for electricity and heat generation in power sector

Source: IRENA Statistical profiles (Aug. 2022)

Indonesia plans to reduce emissions by lowering its dependency on coal and leveraging low emissions technologies such as biomass and CCS

De-carboni-sation targets

- Achieve Net-Zero emissions by 2060 as stated in RUPTL[1]
- Reduce GHG emissions by 29 - 41% by 2030, compared to the business as usual, with the baseline of 2016 (Paris Agreement Pledge)
- Announced in COP26 in 2021 to retire 9.3GW of coal plants by 2030 and completely phase out in 2056

Major policy frameworks

- **'The Electricity Supply Business Plan (RUPTL[1]) 2021-2030'**
  Released by the Government of Indonesia and PLN[2], the national power utility, in 2021
  - Ban new coal buildouts starting in 2022, except already planned ones
  - Promote biomass co-firing (10-20%) in existing coal power plants; new coal-fired power plants operating after 2025 must surpass 30% in co-firing ratio
  - Convert its existing 5,200 units of small-scale diesel power plants into renewable energy based and gas-fired power plants
- **'Long-Term Strategy for Low Carbon and Climate Resilience 2050'**
  Submitted by the Ministry of Environment and Forestry to the UNFCCC[5] in 2021. It expects to nearly decarbonise its power sector by 2050 through;
  - Utilise renewables in large scale
  - Equip most coal powerplants with CCS/CCUS
  - Biomass co-firing in coal power plants are connected to CCS (BECCS)

Forecast of power generation mix[1], TWh

1. Rencana Usaha Penyediaan Tenaga Listrik
2. Perusahaan Listrik Negara, a national power utility company; They also make a pledge on their net zero plans
3. United Nations Framework Convention on Climate Change

Source: Electricity Supply Business Plan (RUPTL)

Malaysia plans to reduce emissions intensity by lowering its dependency on coal and promoting RE

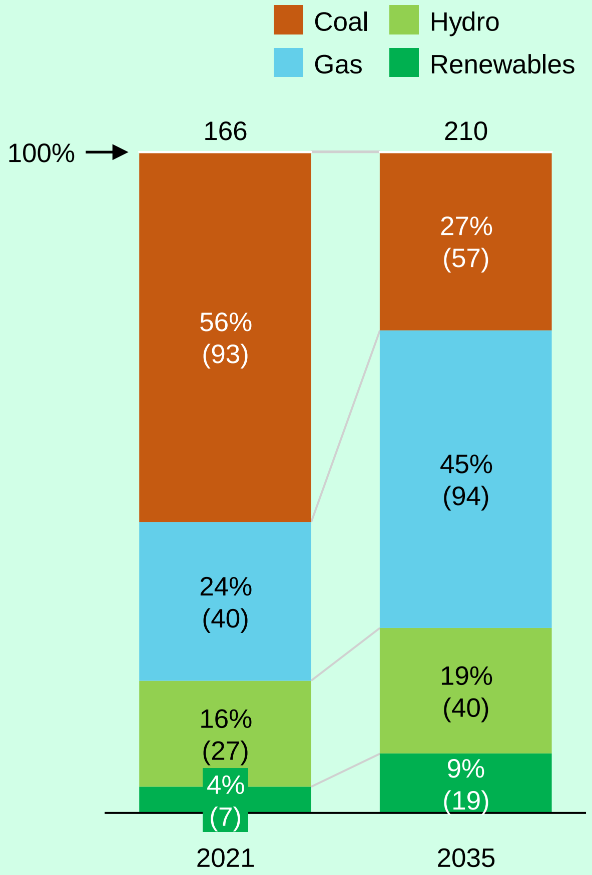
De-carboni-sation targets

- Net zero goal in 2050
- A commitment to reduce GHG emissions by 45% by 2030 (Compared to 2005)

Major policy frameworks

- **'The 12th Malaysia Plan (12MP)'**
  Announced in 2021 by Economic Planning Unit, Prime Minister’s Department outlining a 5-year strategy including sustainability and economic goals
- **'Peninsular Malaysia Generation Development Plan 2020'**
  Published in 2020 by JPPPET[1] , a committee chaired by the Minister of Energy and Natural Resources
  – The RE capacity is projected to increase from 17% to 31% by 2025 and to 40% level by 2035
  – Commitment on sustainable energy pathway will continue with **new RE and CCGT plants** coming into the system post-2030
  – **Coal is projected to reduce** from 37% in 2021 to only 22% in 2039, a net reduction of 4.24 GW
- **'The Malaysia Renewable Energy Roadmap (MyRER)'**
  Published by Sustainable Energy Development Authority (SEDA) to support further decarbonisation of the electricity sector
  – Biomass: Encourage studies on the improvement in bioenergy power generation technology to be conducted
  – Low-carbon hydrogen: Prioritise and roll out cost-effective energy storage solutions such as hydrogen solution

Forecast of power generation mix[1], TWh



1. Jawatankuasa Perancangan dan Pelaksanaan Pembekalan Elektrik dan Tarif

Source: the 12th Malaysia Plan, Report on Peninsular Malaysia Generation Development Plan 2020, the Malaysia Renewable Energy Roadmap

Philippines plans to shift towards lower emissions technologies and has placed a moratorium on new coal plants

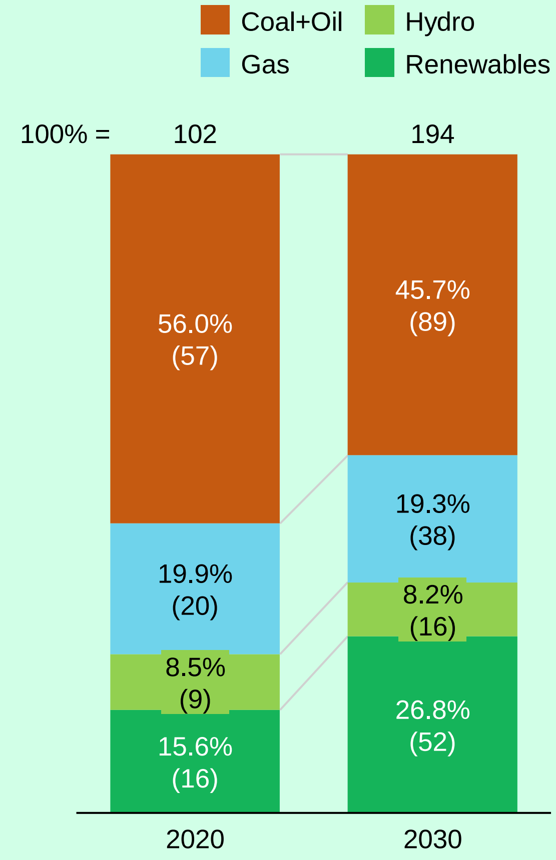
De-carboni-sation targets

- 75% reduction of GHG emissions between 2020 and 2030 compared to business as usual
- Target 35% RE generation mix by 2035

Major policy frameworks

- **'Philippine Energy Plan (PEP) 2020-2040'**
  Issued by the Department of Energy (DOE) in 2022, formulating the transformational plan to bring in more of the clean energy fuels and technologies
  - Implement **a moratorium on new coal-fired power plants** in 2020 and carry **out power plant decommissioning** in order to redesign its power generation mix
  - **Introduce LNG** portfolio to easily adjust its electricity production relative to demand fluctuations. Plan to start its LNG import from 2022
  - **Low-carbon hydrogen potential** is explored by partnering with global companies as alternative resource
  - coal-fired power plants are reproposed into **biomass** waste-to-energy power plants. **Biomass co-fired coal plants** are also discussed
  - Targeting 35% RE generation mix by 2035 from currently 24%, which either stays at 35% until 2050 (RE35 scenario) or increases up to 50% in 2050 (RE50 scenario)

Forecast of power generation mix[1], TWh



1. Power Development Plan 2020-2040, in both RE35 and RE50 high demand scenarios

Source: Philippine Energy Plan (PEP) 2020-2040, Power Development Plan 2020-2040, literature search

Singapore plans to use CCUS to reduce CO_2 emissions from gas-fired plants, while promoting solar generation and low-carbon power imports

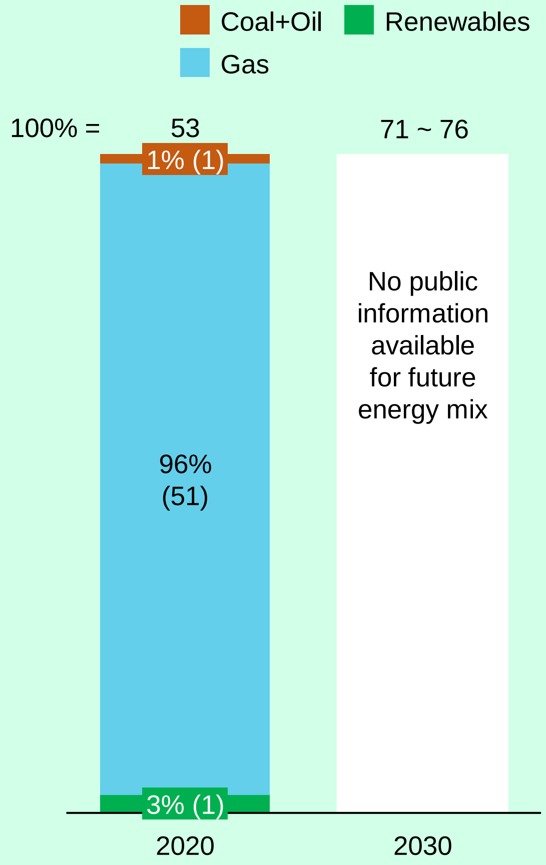
De-carboni-sation targets

- Net zero goal in 2060
- Reduce emissions intensity of GDP by 36% from 2005 levels by 2030
- Reduce carbon emissions to 33 $MtCO_2$-eq by 2050
- Increase solar installed capacity five-fold from 2021 levels by 2030, to meet about 3% of 2030 projected demand

Major policy frameworks

- **'The 4 Switches'**
  Developed by EMA[1] in 2019, the key strategy for the power sector
  - **Natural Gas**: Diversify the gas sources and improve efficiency of power generation
  - Solar: Deploy at least **2 GW of solar** by 2030 and 200 MW of ESS[2] beyond 2025
  - Regional Power Grids: Access more energy options and meet collective energy needs
  - Low-Carbon Alternatives**: Capture CO_2** and convert them into useful products. Explore alternative energy carriers such as **hydrogen**
- **'Charting The Energy Transition to 2050'**
  - The Energy 2050 Committee, commissioned by the EMA, concluded that it is realistic for the power sector to achieve net zero emissions by 2050
  - Develop a **national hydrogen strategy** and work with local and international stakeholders to develop robust hydrogen supply chain
  - Maximise **solar deployment** and use Energy Storage System (ESS) to manage solar intermittency
  - Monitor developments in new supply technologies including **CCUS**
- **Singapore's government announcement**
  - Carbon Pricing (2022) : 5 SGD/tCO_2-eq until 2023 and will be raised to 25 SGD/tCO_2-eq in 2024-2025, and 45 SGD/tCO_2-eq in 2026-2027, with a view to reaching 50-80 SGD/tCO_2-eq by 2030
  - EMS's grant call for **advanced CCGT** by 31 Dec 2023. Grant quantum will be subject to a cap of $44 million

Forecast of power generation mix[1], TWh



1. Energy Market Authority, 2. Energy storage systems

Source: Charting Singapore's Low-Carbon and Climate Resilient Future, Charting The Energy Transition to 2050

Thailand plans to phase out some coal generation, and leverage low emissions technologies such as CCS, Solar, and Bio-energy

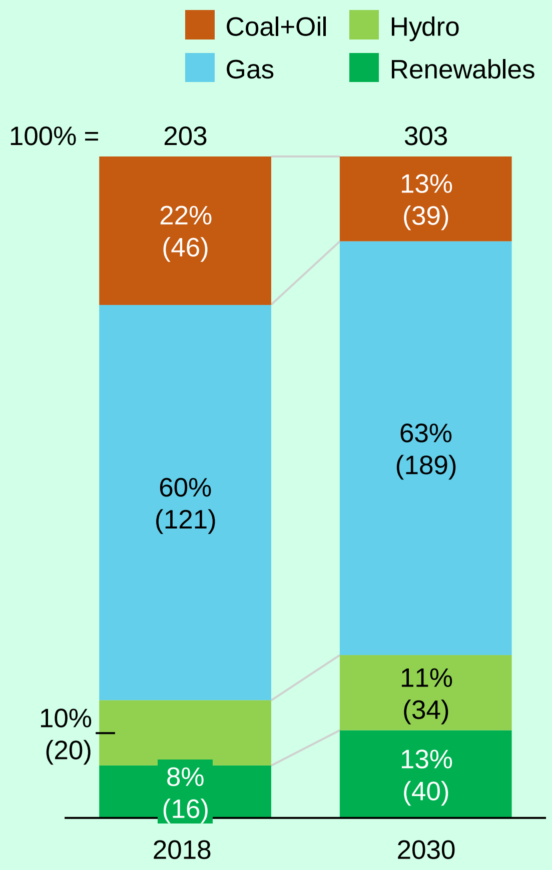
De-carboni-sation targets

- Net zero goal in 2050
- 20% reduction in GHG emissions compared with Business-as-Usual emissions by 2030
- Reduce CO_2 emissions to 271 $kgCO_2$ by 2037
- Increase the RE share to 50% by 2050[1]

Major policy frameworks

- **'Power Development Plan (PDP) 2018 revision 1'**
  National master plan for the development of power system in Thailand published by National Energy Policy Council under the prime minister office
  - reduce the electricity produced from coal to 11%
  - Increase in gas security: Focus on importing more natural gas to increase capacity to 34.8 million metric tons/year by 2027
- **'Alternative Energy Development Plan (AEDP)'**
  Published by the Ministry of Energy to develop appropriate RE production in 2020
  - The **RE target for electricity has been set at 30%** by 2037
  - the proposed installed capacity of solar power generation is 15.6 GW
  - Biofuels are anticipated to take over 44 % of oil consumption by 2021
- **The Mid-century, Long-term Greenhouse Gas Low emissions Development Strategy (LT-LEDS)**
  Submitted to the UNFCCC in 2021 by Thailand government working group with a clear targets and measures to be implemented towards achieving its net zero emissions
  - the deployment of **natural gas with CCS** and **coal with CCS** power plants, will increase to 43% in 2050 when compared to the current technology
  - the share of **renewable electricity** will increase to 33% of total electricity in 2050
  - Bio-energy with CCS (**BECCS**) power plant is needed to achieve the 2-degree target in 2050

Forecast of power generation mix[1], TWh



1. Based on PDP 2018 revision 1

Source: Power Development Plan (PDP) 2018 revision 1, literature search

Viet Nam plans to restrict new coal fired power plants, shifting toward gas and renewables (wind, solar)

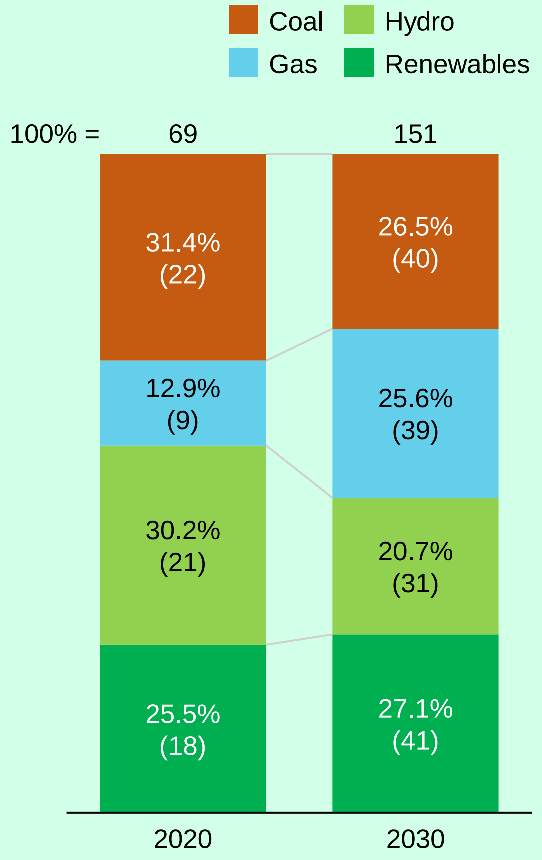
De-carboni-sation targets

- Commitment to reach net zero by 2050 is stated in COP26 in 2021
- Reduce 9% of its GHG emissions compared to business as usual with domestic resources by 2030
(base year of 2014)

Major policy frameworks

- **'Power Development Plan 8'**
The latest draft is released by the Ministry of Industry and Trade (MOIT) in 2022 focusing on the development of power sources, transmission power grids in the period 2021-2030 and a vision to 2045
  - Restrict constructions of **new coal-fired power plants** and shift towards **LNG power plants,** except the coal-fired power plants already under construction during 2021-2025
  - Plan to install **wind power capacity** to generate 18-19 GW by 2030 and install **solar power capacity** to generate 19-20 GW by 2030
- **Long-term strategy on climate change of Viet Nam**
  - Phase out coal-fueled power generation by 2040

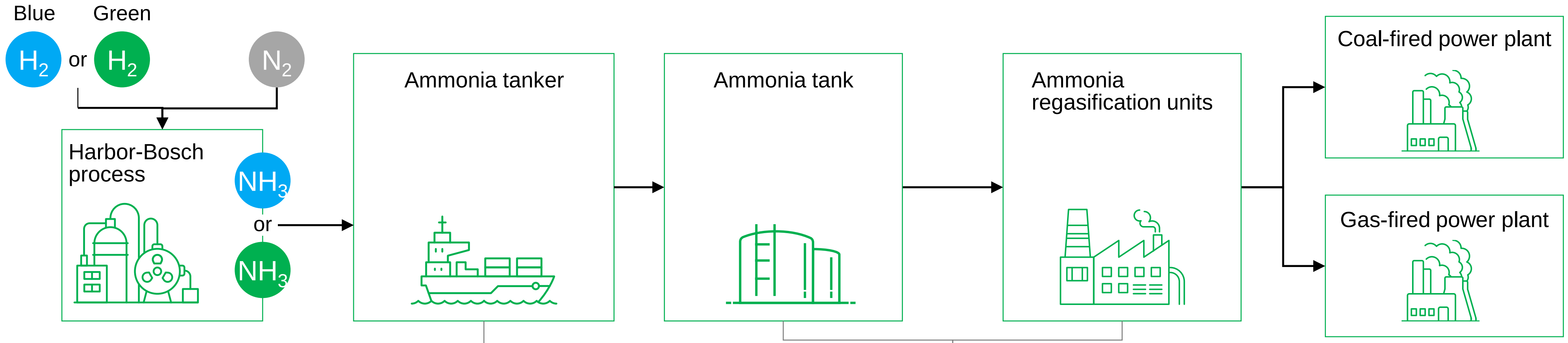
Forecast of power capacity and mix, GW



Source: Viet Nam latest PDP8, 26 April 2022, literature search.

The value chain for low-carbon ammonia fuel is currently in pilot phase

	Production	Transport	Storage	Power generation
Value chain				



Examples of large-scale ongoing projects

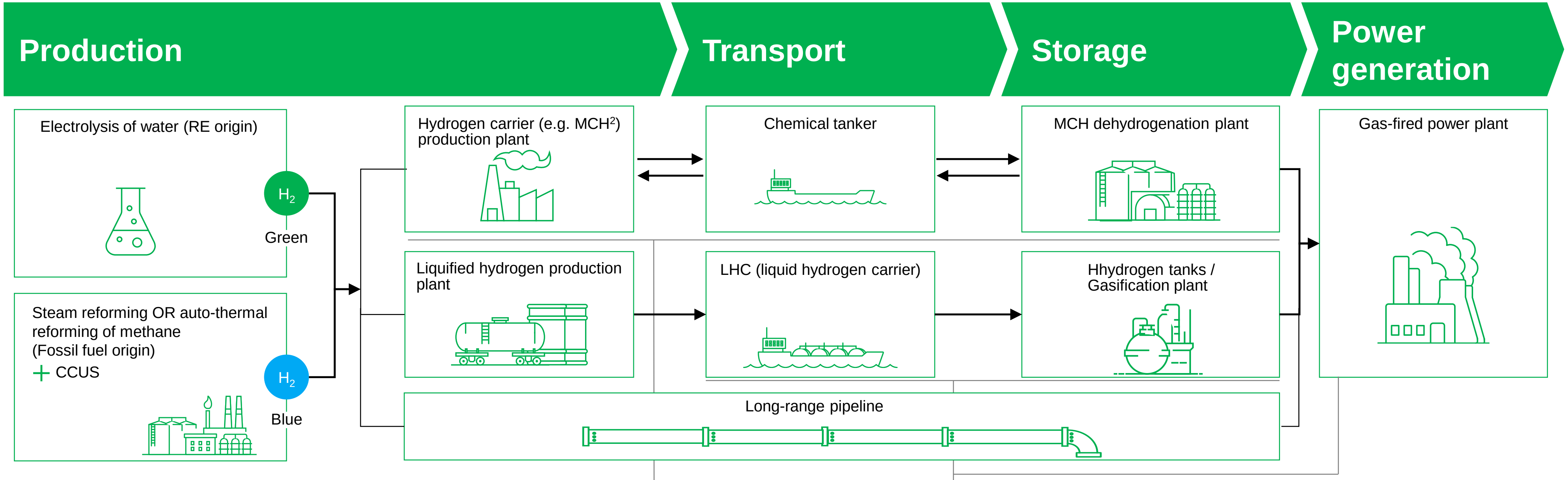
Production	Transport	Storage	Power generation
(details under the 'CCS: Blue ammonia & hydrogen' section)	In 2021, NYK[1] line started a project on development and operation of an ammonia-fueled ammonia gas carrier to lower emissions level	• In 2022, KEPCO[2], Mitsui O.S.K. Lines and Mitsubishi Shipbuilding have completed a concept study on floating storage and regasification unit for ammonia to lower cost • In 2021, IHI[3] started development of a large-scale ammonia receiving terminal/storage to increase ammonia supply chain, to be completed by 2025	(details under the 'Low-carbon ammonia co-firing' section)

1. NYK, Nippon Yusen Kaisha
2. KEPCO, Kansai Electric Power Company
3. Ishikawajima-Harima Heavy Industries Co., Ltd.

Source: Literature search

The value chain for low-carbon hydrogen fuel is currently in pilot phase

Value chain



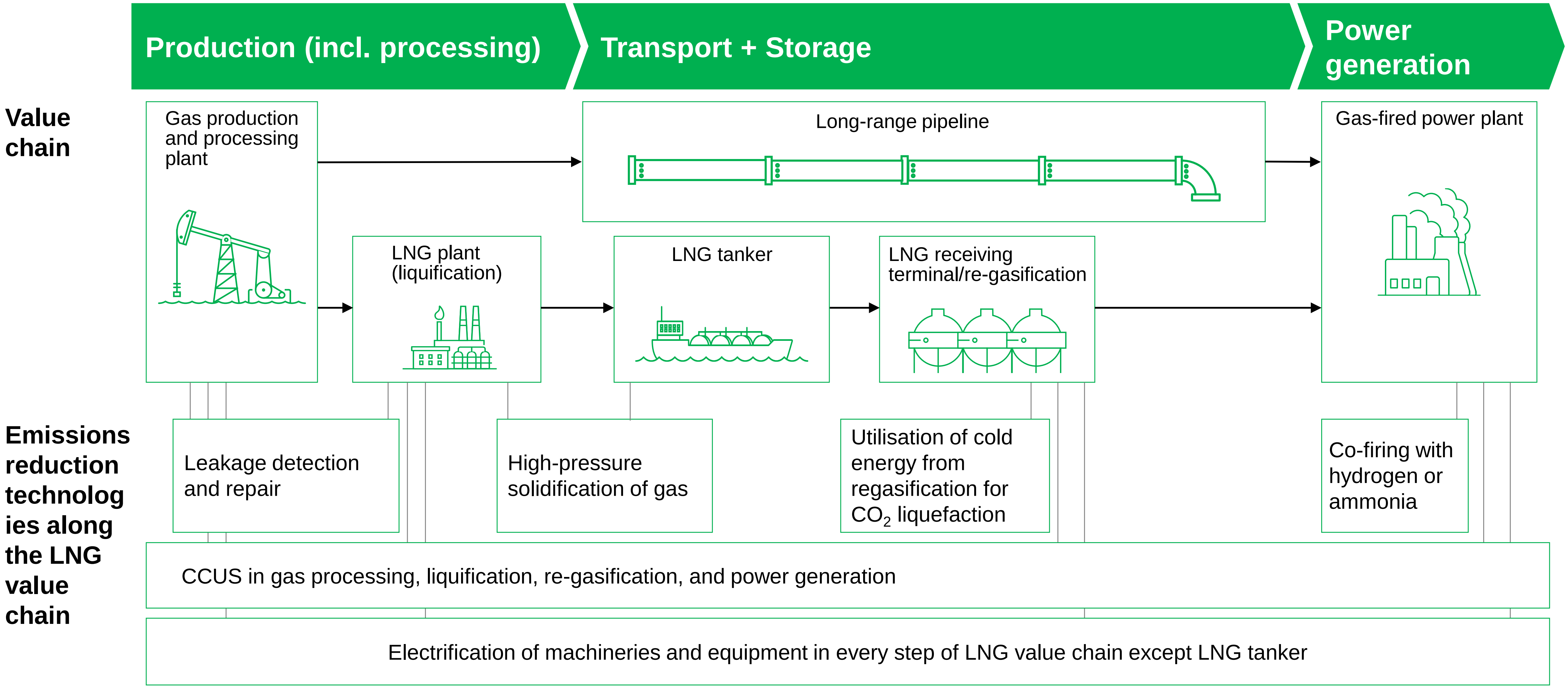
Examples of large-scale ongoing projects

(Details under the 'CCS: Blue ammonia & hydrogen' section)	AHEAD[1] conducted a world's first pilot project on circular hydrogen supply chain using MCH and toluene in 2020. Planning to start commercial operation in the mid of 2020s	HySTRA[4] started a pilot project on liquified hydrogen carrier called 'Suiso frontier (Low-carbon hydrogen frontier)' from Australia to Kobe with KHI[3], J-power, Iwatani Co.	(details under the 'Low-carbon hydrogen co-firing' section)

1. AHEAD, The Advanced Low-carbon Hydrogen Energy Chain Association for Technology Development
2. Low-carbon hydrogen carriers include MCH (methylcyclohexane), ammonia, methanol amongst others.
3. KHI, Kawasaki Heavy Industries
4. HySTRA, CO_2-free Hydrogen Energy Supply-chain Technology Research Association

Source: Literature search

The value chain for gas is well established: further emissions reduction technologies are tested and/or commercialised



Source: Literature search

List of acronyms and abbreviations (1/6)

12MP	12th Malaysia Plan
3Rs	Reduce, reuse, recycle
ABB	ASEA Brown Boveri
AEDP	Alternative Energy Development Plan
AGRU	Acid gas removal unit
AHEAD	Advanced Low Carbon Hydrogen Energy Chain Association for Technology Development
APC	Air pollution control
BAU	Business as usual
BECCS	Bioenergy with carbon capture and storage
CAPEX	Capital expenditure
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage

List of acronyms and abbreviations (2/6)

CCUS	Carbon, capture, utilisation, and storage
CHP	Combined heat and power
DEA	Danish Energy Agency
DNSH	Do no significant harm
EDF	Electricite de France
EMA	Energy Market Authority
EOR	Enhanced oil recovery
ESCO	Energy service company
ESS	Energy storage systems
ETP	Energy Technology Perspectives
EV	Electric vehicle
FCV	Fuel cell vehicle

List of acronyms and abbreviations (3/6)

GHG	Greenhouse gas
HSE	Health, safety, and environment
HySTRA	CO_2-free Hydrogen Energy Supply-chain Technology Research Association
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IHI	Ishikawajima-Harima Heavy Industries Co., Ltd.
IOGP	International Association of Oil and Gas Producers
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
KEPCO	Kansai Electric Power Company
KHI	Kawasaki Heavy Industries
LCOE	Levelised cost of electricity

List of acronyms and abbreviations (4/6)

LDAR	Leak detection and repair
LHC	Liquid hydrogen carrier
LT-LEDS	Long-term Low Greenhouse Gas Emissions Development Strategy
MCH	Methylcyclohexane
MDEA	Methyl diethanolamine
MHI	Mitsubishi Heavy Industries, Ltd.
MITei	Massachusetts Institute of Technology (MIT) Energy Initiative
MoU	Memorandum of understanding
MSW	Municipal solid waste
MyRER	Malaysia Renewable Energy Roadmap
NEDO	New Energy and Industrial Technology Development Organization
NGL	Natural gas liquid

List of acronyms and abbreviations (5/6)

NOx	Nitrogen oxides
NSTA	North Sea Transition Authority
NYK	Nippon Yusen Kaisha
NZT	Net Zero Teesside
OCGT	Open-cycle gas turbine
OGCI	Oil & Gas Climate Initiative
OGTC	The Oil and Gas Technology Centre
PDP	Power Development Plan
PEP	Philippine Energy Plan
PPA	Power purchase agreement
R&D	Research & development
RDF	Refuse-derived fuel

List of acronyms and abbreviations (6/6)

RE	Renewable energy
RITE	Research Institute of Innovative Technology for the Earth
SDS	Sustainable Development Scenario
SEDA	Sustainable Energy Development Authority
SMC	San Miguel Corporation
SMR	Steam methane reforming
TRL	Technology readiness levels
UNEP	United Nations Environment Programme
WtE	Waste to energy

Units of measure (1/2)

% (t/t)	Percent tonne to tonne
Gt	Gigatonne
GW	Gigawatt
$kgCO_2$	Kilogram of carbon dioxide
$kgCO_2/kgH_2$	Kilograms of carbon dioxide per kilogram of hydrogen
$kgCO_2/kgNH_3$	Kilograms of carbon dioxide per kilogram of ammonia
$kgCO_2$/MWh	Kilograms of carbon dioxide per megawatt hour
Mcf/year	Thousand cubic feet per year
$MtCO_2$	Million tonne of carbon dioxide
$MtCO_2$/year	Million tonne of carbon dioxide per year
$MtCO_2$-eq	Million tonnes of carbon dioxide equivalent
MW	Megawatt

Units of measure (2/2)

MWh	Megawatt hour
SGD/tCO_2-eq	Singapore dollar per tonne of carbon dioxide equivalent
t	Tonne
tCO_2/day	Tonnes of carbon dioxide per day
tCO_2/MWh	Tonnes of carbon dioxide per megawatt hour
TWh	Terawatt hour
USD/kg	US dollar per killogram
USD/mmbtu	US dollar per million British thermal units
USD/Mt	US dollar per million tonne
USD/t	US dollar per tonne
USD/tCO_2	US dollar per tonne of carbon dioxide
USD/tCO_2-eq	US dollar per tonne of carbon dioxide equivalent