Australian Industry Energy Transitions Initiative

Phase 1 Technical Report

JUNE 2021

AUSTRALIAN INDUSTRY ENERGY TRANSITIONS INITIATIVE

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1.0 Introduction

1.1 Background to the initiative

The Australian Industry Energy Transitions Initiative (Australian Industry ETI) brings together some of Australia's largest companies to share knowledge and accelerate action towards achieving net zero emissions supply chains by 2050.

The initiative focuses on five key industrial supply chains:

- Iron and steel
- Aluminium
- Other metals (particularly copper, nickel, and lithium)
- Chemicals (particularly fertilisers and explosives)
- Liquified natural gas (LNG).

The Australian Industry ETI is a valued platform convening Australian industry and business leaders to collectively address the challenges associated with mitigating the worst impacts of climate change.

Throughout 2020, the initiative brought together 14 industry and business partners, including: Australia Gas Infrastructure Group; APA Group; Aurecon; AustralianSuper; BHP; BlueScope Steel; BP Australia; Cbus; Fortescue Metals Group; Orica; National Australia Bank; Schneider Electric; Wesfarmers Chemicals, Energy & Fertilisers; and Woodside. The initiative's work has also benefited from the input of other participants including HSBC Australia and Rio Tinto. It is supported by the Australian Industry Group and the Australian Industry Greenhouse Network, with research partners including CSIRO and the Rocky Mountain Institute.

The Australia Industry ETI is supporting Australian industry to realise the opportunities of a decarbonised global economy by working collaboratively to develop pathways and actions towards achieving net zero emissions in critical supply chains by 2050.

Throughout Phase 1, the initiative has driven research, analysis, engagement and implementation, with a focus on understanding the current status of factors influencing decarbonisation in heavy industry as well as the technical and economic opportunities to drive action towards net zero emissions.

To produce this report, the Australian Industry ETI consulted with a diverse group of over a hundred cross-sectoral stakeholders and received support from global partners, including the Energy Transitions Commission and the Rocky Mountain Institute, along with the Australian Renewable Energy Agency (ARENA) and CSIRO. These consultations were convened by ClimateWorks Australia and Climate-KIC Australia.

Australian Industry ETI partners have contributed to the conclusions, findings and messages of this report, but this report does not necessarily reflect the individual positions of partners in the program.

Figure 1 shows the work and achievements of the initiative to date, along with next steps.

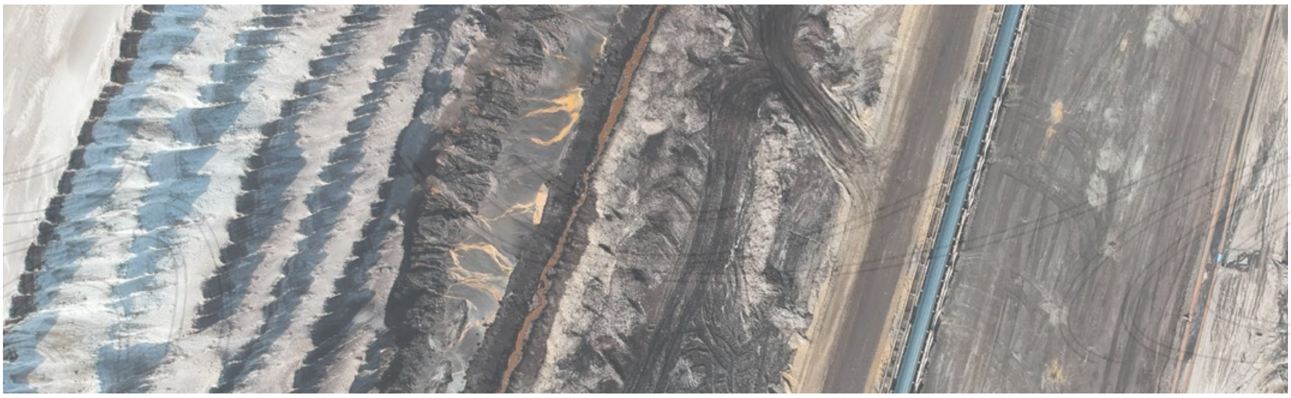
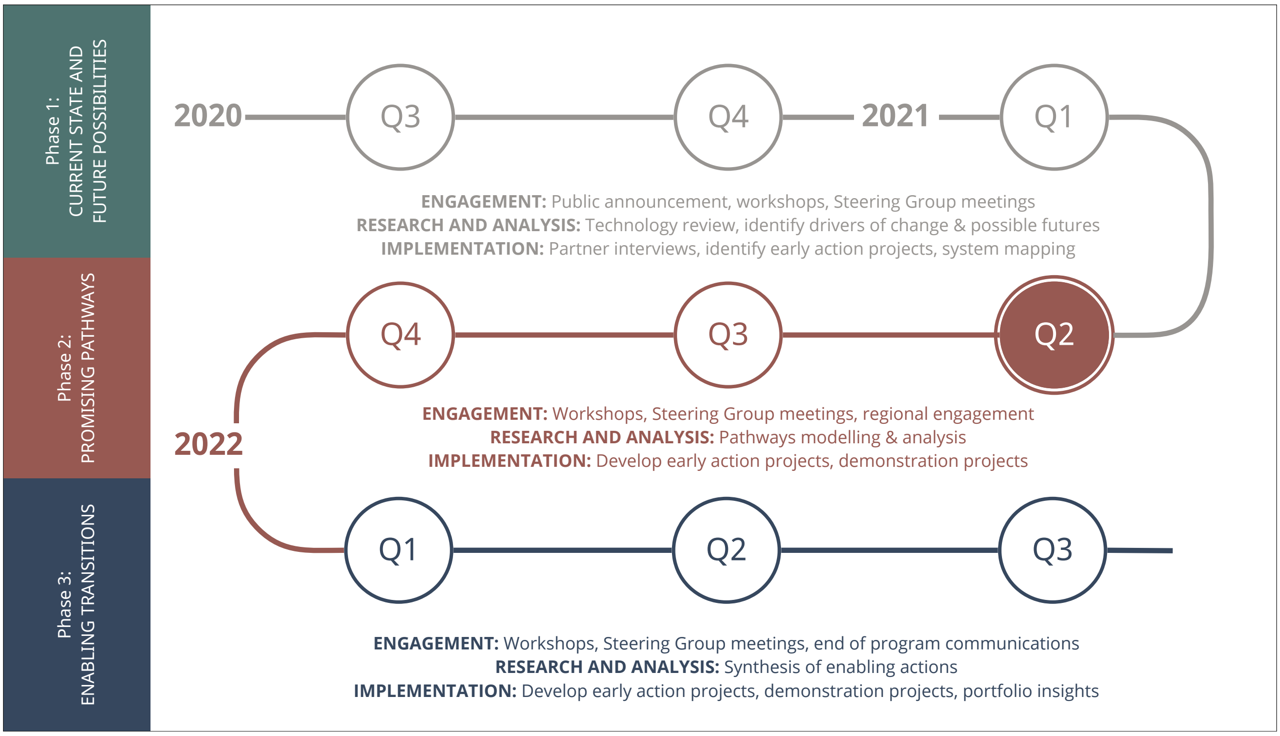


FIGURE 01: Timeline of Australian Industry ETI activities across different phases and workstreams



1.2 Research and analysis workstream

ClimateWorks Australia leads the research and analysis workstream, with support from the Energy Transitions Commission, the Rocky Mountain Institute and CSIRO. This workstream has been designed to provide robust analysis of the transition to net zero in the chosen supply chains. Key activities for research and analysis across the three phases of the Australian Industry ETI are summarised in Table 1.

TABLE 01: Key research and analysis activities throughout the Australian Industry ETI phases

Phases	Key research and analysis activities
Phase 1: CURRENT STATE AND FUTURE POSSIBILITIES	Prioritise opportunities, technologies and challenges: ● Characterise current energy use and emissions in each supply chain. ● Identify and prioritise the most promising emissions reduction technologies, including key challenges and enabling conditions for deployment at scale. ● Summarise existing knowledge of the potential for affordable, reliable, renewable energy to power industry. ● Validate assumptions and findings with industry partners.

Phases	Key research and analysis activities
Phase 2: PROMISING PATHWAYS	Perform pathways modelling and analysis: • Develop credible pathways for industry through techno-economic modelling of the transition options identified in Phase 1. • Consider several regional dynamics, in particular industry composition and key aspects of the energy system, which can be used to understand regional implications of the transition. • Validate assumptions and findings with industry partners. • Identify key external factors (e.g. global demand, government action) that will influence future outcomes. • Analyse the economic and financial implications of the possible pathways to identify trade-offs, pitfalls, and the magnitude of investment challenge.
Phase 3: ENABLING TRANSITIONS	Identify the actions needed to enable net zero emissions transitions: • Identify and prioritise key actions to drive investment and industry development to transition to net zero emissions. • Explore the regional implications for economic transition and competitiveness of Australian industry. • Incorporate insights from other Australian Industry ETI activities.

Throughout Phase 1 of the Australian Industry ETI, a key priority has been to undertake research and analysis with assistance from industry participants to ensure that the knowledge generated builds on the existing knowledge base, is highly relevant and can be deeply embedded within organisations. Insights generated are intended to contribute to overcoming barriers to the transition to net zero.

The focus of Phase 1 has been on understanding key sources of energy use and emissions in the Australian Industry ETI supply chains, identifying promising decarbonisation solutions, and building understanding of the enabling conditions to unlock deployment at scale. Given the importance of energy supply systems in a net zero transition, these have also been a focus of the work completed to date. Wherever possible, efforts have been made to adapt global research for the Australian context to ensure that initial findings reflect the needs of industry, and take into account particular characteristics of Australian supply chains (for example, the energy system, geographical considerations and relative significance of particular supply chain stages).

The research and analysis aims to form a view on technologies most likely to play a major role in supply chain decarbonisation, both over the long term and throughout the transition. These key technologies have been a focus when developing inputs for modelling of energy and emissions baselines, technology performance and costs, and energy supply and costs.

Integration across sectors and supply chains will be vital to the decarbonisation of Australian industry, and this work has also investigated how this can lower costs and change the attractiveness of various solutions. The impact of the integration of industry and energy systems will be substantial and has influenced the prioritisation of decarbonisation technologies.

Detailed research and analysis on global demand has not been a focus of Phase 1 but will form a key input to subsequent phases of the initiative, in particular for pathways development and modelling in Phase 2.

1.3 Scope of the research and analysis

The scope of the Australian Industry ETI research and analysis covers four of Australia's largest emitting and typically considered hard-to-abate supply chains – Iron and steel, Aluminium, Chemicals (ammonia, fertilisers and explosives) and LNG – along with a number of 'Other metals' considered key to global decarbonisation, such as copper, nickel and lithium.

As a globally significant exporter in many of these supply chains, Australia's domestic emissions from production are in some cases far outweighed by downstream emissions either in subsequent processing (for example, iron and steelmaking from exported iron ore) or in end-use (for example, the combustion of exported LNG). While the Australian Industry ETI research does consider these issues, the identification and detailed quantitative modelling of opportunities to reduce emissions does not extend beyond Australia's borders.

In addition, decisions regarding research scope within supply chains were made based on the level of emissions and/or Australia's prominence in global production. For example, although there is some Australian industrial activity in the manufacture of final aluminium products (downstream of crude aluminium production), this was not included in the analysis given Australia is neither a globally significant producer of these products nor are emissions material relative to other parts of the supply chain. On the other hand, the 'Other metals' supply chain was included given Australia's prominence in multiple markets, despite immaterial emissions from these metal sources relative to others such as iron ore. Table 2 below provides a summary of supply chain boundaries in the Australian Industry ETI research and analysis.

TABLE 02: Scope of research and analysis across the Australian Industry ETI supply chains

Supply chain	Within scope	Out of scope[1]
Iron and steel	Processes from iron ore extraction through to production of crude steel	Processes downstream of crude steel production (e.g. casting, steel pipe and tube manufacturing) Downstream (scope 3) emissions from use of exported iron ore or crude steel
Aluminium	Processes from bauxite extraction through to production of crude aluminium	Processes downstream of crude aluminium production (e.g. semi-fabrication of cast and rolled products) Downstream (scope 3 emissions) from the use of exported bauxite or alumina
Other metals	Processes from metal extraction through to on-site processing (e.g. crushing and grinding)	Processes downstream of on-site processing
Chemicals	Processes from hydrogen production through to production of ammonia derivatives (fertilisers and explosives)	Upstream emissions from imported chemicals Downstream (scope 3) emissions from fertiliser use
LNG	Processes from gas production through to gas liquefaction for export	Processes downstream of liquefaction (e.g. international transport) Downstream (scope 3) emissions from the use of exported LNG

As covered above, the purpose of the initiative is to accelerate informed action towards net zero – rather than absolute zero – emissions by 2050 in the focus supply chains. While this implies a potential role for offsets, the intention of the research and analysis workstream is to investigate opportunities for zero emissions solutions within supply chains themselves wherever possible, rather than relying extensively on negative emissions technologies or offsets. Australian Industry ETI analysis undertaken to date provides confidence that most emissions in Australian supply chains can be eliminated with demonstrated or mature technologies. This is particularly important in the context of declining availability of carbon credits over time and limits to nature-based sequestration solutions such as afforestation. As detailed in the remainder of this report, the prospects for near or absolute zero emissions supply chains vary. Complete elimination of non-energy emissions is particularly challenging in certain processes and will potentially require offsets.

1.4. Purpose of this report

This report discusses the current status and future potential for low and zero emissions technologies in Australia's major industrial supply chains, along with energy system analysis relevant to a net zero emissions transition. The forward looking analysis in this report is based on detailed modelling by the ClimateWorks Australia, CSIRO and Rocky Mountain Institute. It is important to note that long-term projections are inherently uncertain, particularly when emerging technologies are involved. Therefore, the analysis presented should not be interpreted as a forecast. Its purpose is to inform further discussion and analysis that can support the development of credible net zero emissions transition pathways. The Australian Industry ETI welcomes stakeholder feedback on the inputs and outputs contained in this report that can support the next phase of analysis and help achieve the intended outcomes of the initiative.

1 While these issues are not within scope in that they are not a focus of detailed research and analysis, they do form part of the overall narrative for a transition of Australia's industrial supply chains. For example, in subsequent phases of work, the Australian Industry ETI will consider the potential for Australian industry to explore new or greater downstream production where opportunities might exist to leverage competitive advantages such as renewable energy. The potential to undertake increased onshore processing and export of value-added products (rather than raw materials) would not reduce emissions in Australia but could have a material impact on global emissions and unlock considerable economic opportunities for domestic producers.

2.0 Overview of a net zero emissions transition for Australian industrial supply chains

2.1 Summary findings

Research and analysis for Phase 1 of the Australian Industry ETI has sought to understand major sources of energy and emissions in the focus supply chains and identify the most prospective long-term opportunities to reduce emissions towards zero. Table 3 provides an overview of the relevance of different decarbonisation pillars to each supply chain, highlighting the potential solutions to drive emissions reductions over the long term.

The supply and uptake of zero emissions energy is arguably the most critical aspect of a net zero transition, with solutions that cut across all sectors of the economy. Replacing fossil fuel-based electricity with renewables provides immediate abatement benefits to already electrified processes, which are a major source of emissions in many industrial supply chains. Moreover, renewable power builds the case for future electrification of other processes, which are often an abatement opportunity in their own right due to greater efficiency of electric equipment compared to equipment using direct fuel combustion. While electrification is an increasingly promising decarbonisation strategy, there are technical challenges in certain industrial processes, particularly for high-heat applications that currently rely predominantly on coal and gas. Switching these processes to zero emissions fuels such as hydrogen or biomass is technically possible, dependent on adequate and cost-effective energy supply. Together, the technological solutions relating to supply and uptake of zero emissions energy and feedstocks are able to eliminate the majority of emissions in all supply chains.

In all supply chains, the optimisation of material and energy use has an important near-term role to play in reducing emissions and can also improve competitiveness due to lowering energy and other input costs, but is not sufficient for a net zero transition. In metals supply chains (Iron and steel, Aluminium, Other metals), material efficiency can help decrease overall demand for production of virgin products, with flow-on effects to energy use and emissions in all stages of the supply chain. Increased recycling presents an immediate and considerable opportunity for abatement in metals supply chains, but is limited by scrap availability and collection. For Chemicals, efficiencies in the use of downstream products such as fertilisers and explosives would similarly reduce upstream emissions, although the potential impact is less significant than in metals given the absence of product circularity. International research indicates that Australia performs poorly relative to other countries in implementing energy efficiency in the industry sector, suggesting more can be done by the sector as a whole (American Council for an Energy-Efficient Economy, 2018). As such, deploying best available technologies is another effective way of reducing energy use and emissions in the near term.

Non-energy emissions (emissions that are not related to the use of fossil fuels as an energy source) are a feature of supply chains such as Iron and steel, Chemicals and LNG. These can be partially addressed through material efficiency, reducing the need for emissions-intensive inputs, but in most cases the major abatement solutions are unique to supply chains. Opportunities include the uptake of zero emissions feedstocks in place of carbon-based products (for example, hydrogen or biomass feedstocks in conventional steelmaking), equipment upgrades (for example, to prevent methane leakages in gas production), operational improvements (for example, reducing the need for venting and flaring), specific technology uptake (for example, nitrous oxide abatement in Chemicals), or complete process switch (for example, alternative steelmaking methods eliminating the need for coking coal). Often, these measures derive no economic benefit through material or energy savings, presenting additional challenges compared to other decarbonisation options.

For process emissions that cannot be eliminated through other means, a net zero transition implies that these must be either captured and stored or offset through other means, such as negative emissions technologies. These options are most relevant to supply chains with significant non-energy emissions that are typically more challenging to abate, although there are emerging opportunities, such as using mining waste to store carbon.

In the Australian Industry ETI research and analysis, potential technologies have been identified to eliminate the vast majority of emissions in each of the focus supply chains. Encouragingly, analysis has found that most of these technologies are mature and available for deployment now. Other major solutions, such as green hydrogen for use in steel production, are expected to be available for commercial production around 2035 (HYBRIT 2018).

TABLE 03: Abatement opportunities across decarbonisation pillars for the Australian Industry ETI supply chains

		Iron and steel	Aluminium	Other metals	Chemicals	LNG
Pillar 1: Material, energy and service efficiency	Material efficiency	There are multiple measures to optimise mine sites and plants which, alongside uptake of best available technologies can drive significant reductions in material and energy use. Increased recycling is another major opportunity, particularly for metals supply chains, with impacts throughout multiple processes. Downstream efficiencies or demand reductions also greatly impact supply chain energy use and emissions. For example, downstream energy efficiency and electrification could reduce and potentially replace gas use in certain sectors.				
	Energy efficiency					
Pillar 2: Zero emissions energy and feedstocks supply **Pillar 3: Electrification and other fuel switching**	Zero emissions electricity	Iron ore haulage Decarbonise existing electricity use EAF run on scrap or DRI Green hydrogen production* Ore electrolysis*	Decarbonise existing electricity use (smelting) Process heat for alumina refining*	Decarbonise existing electricity use (comminution) Additional electrification opportunities	Green hydrogen production Electrified process heat	Electrified liquefaction
	Other zero emissions fuels	Iron ore haulage	Process heat for alumina refining*	Process heat in metals refining*		Blue hydrogen production
Pillar 4a: Non-energy emissions abatement	Process improvements		Inert anode for smelting*		Nitrous oxide abatement	Reduction in venting, flaring and leaks
	Zero emissions feedstocks	Green hydrogen use in DRI-EAF process*			Green hydrogen use in ammonia production	Blue hydrogen production
Pillar 4b: Capture or offset residual emissions	CCS of process emissions	BF-BOF with CCS*			CCS of SMR emissions	CCS of reservoir gas
	Negative emissions technologies	Mineral carbonation (waste rock)*	Mineral carbonation (mine tailings)*	Mineral carbonation (waste rock)*	CO_2 feedstock from NETs*	

* These technologies are currently classified as having a technology readiness level (TRL) of 1-6 and require further research, development and demonstration (ARENA 2019a).
BF: blast furnace; BOF: basic oxygen furnace; CSS: carbon capture and storage; DRI: direct reduced iron; EAF: electric arc furnace; LNG: liquified natural gas; NETs: negative emission technologies; SMR; steam methane reforming.

(light grey)	Immaterial or uncertain role
(beige)	Potential role in transition to zero or near-zero emissions options
(grey-green)	Important role in near term abatement but insufficient for net zero emissions
(dark green)	Long term, zero or near-zero emissions potential

In all supply chains, deployment of these mature and demonstrated technologies can achieve more than 85% emissions reductions, as shown in Table 4. This means that the technical capability exists, or is currently being explored, to enable deep decarbonisation and that barriers to uptake are more related to economic, policy, capital, or other system-wide factors. Accelerated demonstration and deployment of these solutions can help drive costs down in the near term through learning-by-doing and economies of scale. For those emerging technologies that could address residual emissions in the supply chains, there is a greater short-term need for research and development to provide proof of concept or demonstration at scale.

TABLE 04: Major abatement opportunities, technological and commercial readiness, and residual emissions in the Australian Industry ETI supply chains

Supply chain	Major abatement opportunities (blue shading indicates commercial readiness)[2]	Abatement potential from 'Demonstration' and 'Deployment' technologies	Residual emissions areas (TRL<7)
Iron and steel	Uptake of best available technologies and process optimisation Renewable electricity for currently electrified processes Green hydrogen for DRI-EAF steel production Battery-electric or fuel-cell powered trucks Breakthrough technologies for ore electrolysis CCS for blast furnace steel production	~95%	Emissions from the use of explosives in iron ore mining
Aluminium	Uptake of best available technologies and process optimisation Electrification or other fuel switching for low temp heat in alumina refining Other fuel switching (biomass or hydrogen) for high-heat in alumina refining Renewable electricity for currently electrified processes (particularly smelting) Electrification or concentrated solar thermal for high temp heat in alumina refining Carbon anode alternatives	~92%	Carbon anode use, pending commercial viability of alternative technologies
Other metals	Uptake of best available technologies and process optimisation Renewable electricity for currently electrified processes Additional electrification of mine site operations Electrification or other fuel switching (biomass or hydrogen) for high-heat applications in metals processing	~100%	None or immaterial
Chemicals	Uptake of best available technologies and process optimisation Renewable electrolysis for hydrogen production Electrification of process heat CCS for SMR hydrogen production Nitrous oxide abatement CO_2 feedstock from negative emissions technologies (to offset eventual emissions released from urea-based fertilisers)	~85%	Residual nitrous oxide emissions Emissions from application of urea-based fertilisers, in the absence of using CO_2 feedstock from negative emissions technologies

2 Commercial readiness categories are based on Figure 2 of ARENA's 'Commercial Readiness Index' (ARENA 2014)

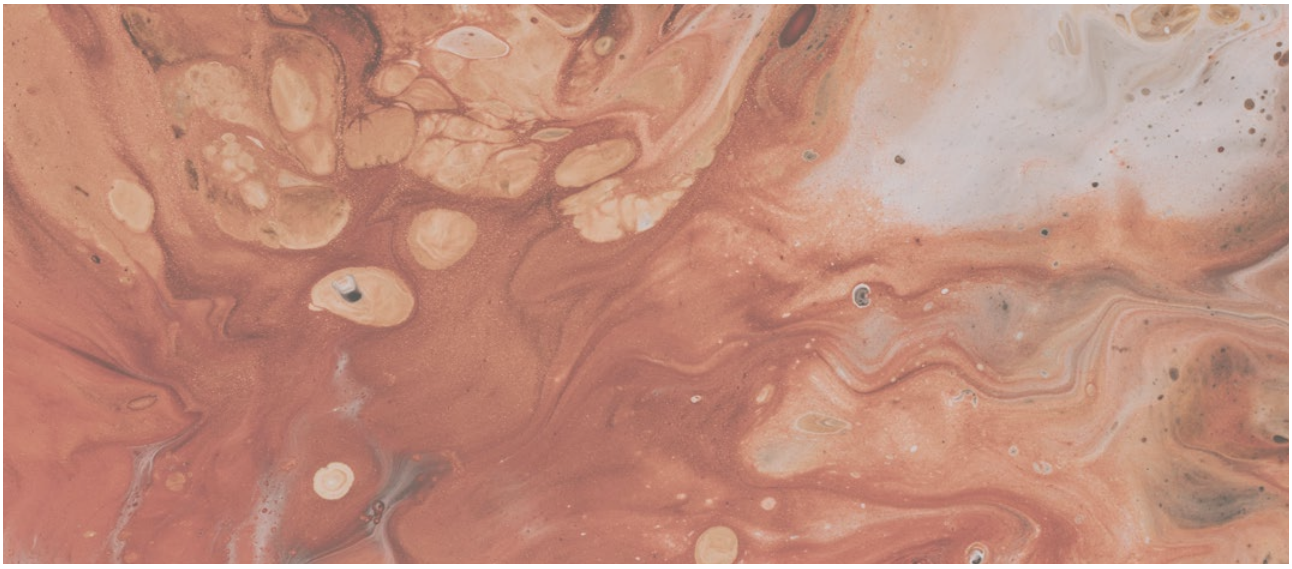
LNG	CCS for reservoir gas Leak detection and removal Operational improvements to eliminate venting and flaring Renewable-powered electric liquefaction	>90%	Operational emissions unable to be captured and stored Scope 3 emissions from use of exported LNG (not included within scope but a significant issue for the supply chain)
DRI: direct reduced iron; EAF: electric arc furnace; CSS: carbon capture and storage; LNG: liquified natural gas; SMR; steam methane reforming; TRL: technology readiness level.			

Research and development	Demonstration	Deployment
TRL 1-6, pre-commercial stage	TRL 7-9, pilot or commercial scale-up stage	TRL 9, supported or competitive commercial

- **Iron and steel** – Uptake of zero emissions electricity presents immediate benefits for existing electricity use while also opening opportunities for decarbonised iron ore haulage using battery-electric trucks. Renewable electricity also enables the production of zero emissions hydrogen for potential use in haulage (where electrification might be more challenging) or in the production of direct reduced iron that can then be coupled with an electric arc furnace (also powered by renewables). Switching from blast furnace-basic oxygen furnace (BF-BOF) to electric arc furnace (EAF) steelmaking also eliminates the need for coking coal and associated non-energy emissions. These technologies (battery-electric and fuel-cell trucks, direct reduced iron, electric arc furnaces) are either at or approaching commercial maturity, but the timing of their deployment will be largely determined by the capacity to expand energy systems to deliver affordable, reliable, zero emissions electricity and hydrogen (likely around 2030). In the meantime, carbon capture and storage (CCS) technologies may have a role to play in addressing emissions from current iron and steelmaking methods, although there are uncertainties regarding potential scale and commercial viability of this solution. Continued development of more nascent technologies such as iron ore electrolysis could in the future provide an alternative zero emissions iron and steelmaking option without some of the barriers facing other frontrunners. There is also an emerging opportunity to use the waste rock from iron ore mining to sequester CO_2 through mineral carbonation, which could offset residual emissions from within the iron and steel supply chain or elsewhere. Currently, emissions from the use of explosives in iron ore production have no viable zero emissions alternative.
- **Aluminium** – There are three main emissions sources in the aluminium supply chain: process heat for alumina refining, electricity use for aluminium smelting and the use of carbon anodes in electrolysis. For alumina refining, zero emissions alternatives for process heat such as hydrogen and biomass are technically feasible but may be constrained by costs and availability in the near term. The prospects for electrified process heat are improving but may face challenges at higher temperatures, while concentrated solar thermal is another area of interest but is likely more suitable for greenfield developments due to land requirements. Given aluminium smelting is already electrified, switching supply from a coal-dominated grid to renewable electricity has the potential to reduce emissions from this process entirely. Technically, the technologies exist to enable this transition; however, the magnitude of energy used in smelting, requirements for near-continuous supply and sensitivity to energy prices are major challenges in managing the transition to high shares of variable renewable energy. Innovations to improve the thermal insulation of electrolytic pots are being trialled, which would provide smelter operators greater ability to dynamically manage energy use for longer periods of time in response to grid demand, improving energy system flexibility and supporting the transition to renewables. However, these technologies are yet to be proven commercially viable at scale and there are currently limited market signals to incentivise installation. Alternatives to carbon anodes used in smelting have also been developed but are not yet commercially viable. These emissions are therefore considered especially hard to abate and, in the near term, may require some form of offsetting to achieve a net zero supply chain. Mineral carbonation of waste bauxite residue is one emerging opportunity for the aluminium supply chain to store CO_2 from other sectors of the Australian economy.
- **Other metals** – Many processes in metals extraction and processing are already electrified but powered by grid electricity or on-site generation, both of which are dominated by fossil fuels and therefore emissions-intensive. Switching to 'hybrid' generation arrangements of wind and solar power with storage are the major opportunity, both to decarbonise existing electricity use as well as unlock additional opportunities for electrification such as in

haulage and refining. For high-heat applications in metals refining, other zero emissions fuels such as hydrogen or biomass are technically possible but may be constrained by costs and availability in the near term. Mineral carbonation is also an opportunity for some metals due to large quantities of otherwise worthless ultramafic rock (with high magnesium and iron content) produced during ore extraction. This could be used to offset residual emissions within this supply chain or in other sectors.

- **Chemicals** – The major source of emissions in the chemicals supply chain is the gas-based production of hydrogen as an ammonia feedstock. Switching from the dominant steam methane reforming process to renewable electrolysis for hydrogen production is the most promising opportunity to eliminate these emissions over the long term. However, this is dependent on the cost-effective supply of large quantities of renewable electricity and will also be determined by the extent and speed of cost reductions for electrolysers. Renewable electrolysis is currently expected to be the lowest cost form of hydrogen production around 2040. In the meantime, coupling carbon capture and storage (CCS) with steam methane reforming could be used to address a large share of emissions. The other main source of supply chain emissions is the release of nitrous oxide emissions due to chemical reactions in the production of ammonia derivatives such as ammonium nitrate. Opportunities exist to reduce more than 95% of these emissions, but there are currently limited incentives for chemicals producers to deploy these technologies given they derive no economic benefits in the absence of a penalty on emissions or a ‘green premium’ on low emissions products.
- **Liquified natural gas (LNG)** – Given relatively large emissions from direct fuel combustion, electricity use and non-energy sources, multiple strategies will be required to decarbonise the production of LNG. There are operational improvements and best-practice technologies that can address a large portion of emissions from venting, flaring and leakages, while CCS can also be used for reservoir CO_2 during gas processing. Switching from gas turbines to electric drives coupled with renewable power is the primary opportunity in liquefaction but may face challenges for brownfield applications due to complexity for retrofits. Hydrogen is an option to replace gas in turbines, although this would also likely require retrofits or upgrades to existing equipment. CCS is similarly unsuitable given limited space in most brownfield sites and dilute exhaust streams from turbines. Downstream emissions (scope 3 for Australia) from the use of exported gas are particularly significant for the LNG supply chain, at approximately six times the level of scope 1 and 2 emissions. In a context of global decarbonisation, scenarios aligned to 1.5 degrees generally see demand for gas peaking and declining before 2050, which would decrease Australia’s domestic emissions through reduced production and export of LNG but also present significant long-term transition risks to gas producers (IPCC, 2018, ETC, 2020). Widespread uptake of carbon capture and utilisation or storage (CCUS) for the use of gas in export countries could mitigate some of these risks and provide a longer term role for LNG in global energy markets, but this faces considerable uncertainty in terms of performance, cost and ability to scale, particularly in the face of ever-declining costs of alternative technologies and energy sources. Existing assets and gas resources from LNG producers may be used to produce blue hydrogen – that is, hydrogen produced from the steam methane reforming of natural gas with CCS used for emissions – if domestic offtake and export markets for this fuel develop as part of the transition to decarbonisation, significantly reducing the downstream emissions from gas. The range of economic, social and geopolitical factors mean there is significant uncertainty about the long- and medium-term impacts of decarbonisation on the supply chain, some of which will be investigated in Phase 2 of the Australian Industry ETI.



2.2 The importance of Australian industrial supply chains

The five supply chains of focus in the Australian Industry ETI make a significant contribution to Australia's economy. Collectively, these supply chains are responsible for 12.3% of Australia's GDP, generate exports worth over $160 billion per annum to the Australian economy and employ 2.9% of Australia's workforce (Australian Bureau of Statistics, 2021). This economic importance is amplified in regional areas with a strong focus on these supply chains (or components of them). For example, in the Pilbara, Western Australia, iron ore mining represents a 45.6% share of employment in the region, while in Gladstone, Queensland, alumina, aluminium, LNG and chemicals represent 11.3% of total employment.

Most of the initiative focus areas are heavily export-focused and play a key role in global supply chains, summarised in Table 5.

TABLE 05: The importance of Australian industry in global supply chains

Product	% Production exported[3]	Australia's global significance
Iron ore	94%	Largest producer and exporter
Bauxite	38%	Largest producer, second largest reserves
Alumina	87%	Second largest producer, largest exporter
Aluminium	91%	Sixth largest exporter by value
Gas (LNG)	71%	Second largest exporter of LNG
Other metals (select examples)	Production and export quantities are available from DISER (2021)	Copper – Fifth largest producer, third largest reserves (USGS 2021b) Nickel – Fourth largest producer, second largest reserves (USGS 2021d) Lead – Second largest producer, largest reserves (USGS 2021c) Lithium – Largest producer, fourth largest reserves (The World Bank 2017)

This prominence in global supply chains means that certain Australian industries are indirectly connected to (albeit not technically responsible for) a much larger share of global emissions than is recorded in national or company inventories. For example, annual emissions from downstream use of exported iron ore in blast furnaces are more than 50 times higher than annual emissions in the entire domestic iron and steel supply chain[4]. Alumina refining and aluminium smelting are similarly emissions-intensive, with estimated emissions from overseas processing of exported bauxite and alumina nearly five times Australia's annual emissions from domestic bauxite, alumina, and aluminium production[5]. As a fossil fuel, emissions from the combustion of exported LNG are around six times higher than those incurred from the production of the LNG itself[6].

This provides opportunities for Australian industry to influence global emissions by engaging in activities that reduce the needs for emissions-intensive processes overseas. Examples include improving iron ore quality before shipping[7], new or increased production of value-added products (for example, retaining bauxite and alumina for additional aluminium production and export), or product substitution (for example, producing and exporting blue hydrogen rather than natural gas). The potential for these activities to reduce global emissions is contingent on the ability of Australian industry to decarbonise relevant processes, for example by leveraging competitive advantages in renewable energy. In the case of blue hydrogen production, this would involve Australia 'onshoring' (by capturing and storing) emissions that would otherwise be incurred overseas from the combustion of gas.

3 (DISER 2021, DISER 2020b, Australian Aluminium Council 2021)

4 Internal Australian Industry ETI calculation of domestic supply chain emissions. Global downstream emissions based on export quantities from DISER (2021) and emissions intensity of blast furnace production in China, South Korea and Japan (Global Efficiency Intelligence 2019)

5 Internal Australian Industry ETI calculation of domestic supply chain emissions. Global downstream emissions based on energy intensity and fuel mix for alumina and aluminium production in importing companies (World Aluminium 2020b) and emissions factors from BP (2019)

6 Internal Australian Industry ETI calculation of domestic supply chain emissions. Global downstream emissions based on 2018-19 LNG production from DISER (2020f) and emissions factors from BP (2019). Calculations assume all exported LNG is combusted and does not consider possible methane emissions from venting or leakages, which would significantly increase the overseas emissions component.

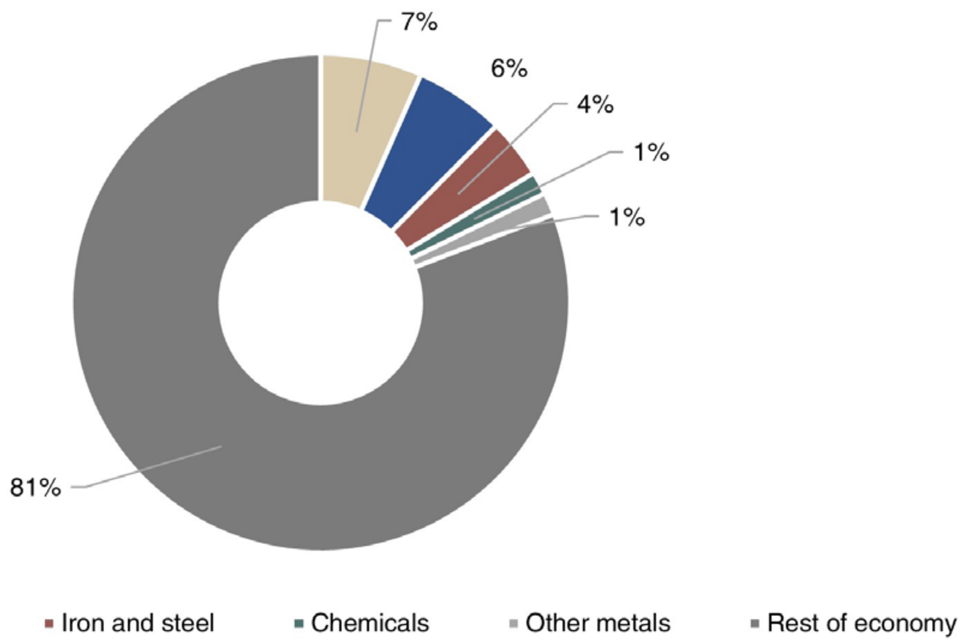
7 Through drying, beneficiation, agglomeration and pre-reduction (Hobson 2021)

Phase 1 research and analysis has focused on opportunities to reduce existing emissions from production within Australian Industry ETI supply chains. As such, the potential for changes in supply chain participation through some of the above measures has not been covered in detail. However, future phases of work will explore the potential economic and global emissions benefits of Australia undertaking different or enhanced roles in various supply chain processes.

2.3 Sources of energy use and emissions

Industry is a broad term encompassing numerous sectors across mining and manufacturing, each with highly specialised processes and unique characteristics, challenges, and opportunities. Mining and manufacturing[8] accounts for 38% of Australian final energy use, 41% of electricity consumption (DISER 2020c, 2020d) and around 42% of total emissions (ClimateWorks Australia 2020). Taken collectively, the Australian Industry ETI supply chains represent an estimated 20% of domestic emissions (Figure 2).

FIGURE 02: Contribution of the Australian Industry ETI supply chain to Australia's domestic emissions



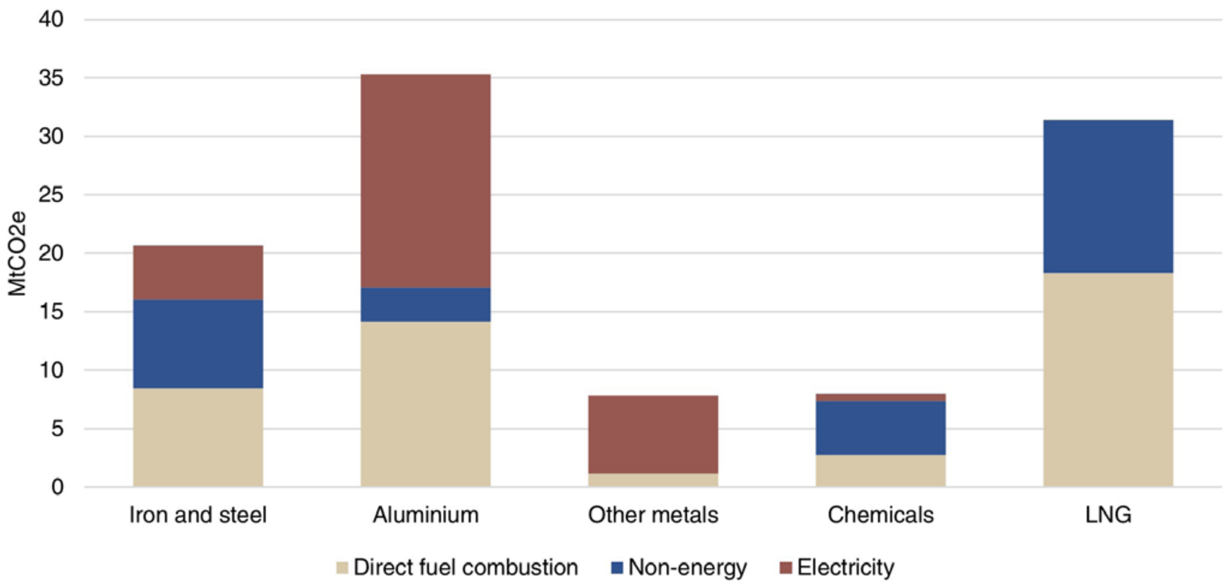
While the supply chains considered within the scope of the initiative share commonalities, they remain complex and diverse from an energy and emissions perspective. The Australian Industry ETI supply chains feature multiple emissions sources of varying magnitude and proportion:

- Direct fuel combustion – emissions from the combustion of fossil fuels at company facilities (for example, boilers, turbines, process heat, haulage).
- Electricity – emissions associated with the use of electricity, either generated on site or purchased elsewhere.
- Non-energy – emissions from leakages, operational venting and flaring and other industrial processes at company facilities.

Estimated emissions for the Australian Industry ETI supply chains are shown in Figure 3. Emissions from the production of LNG are most significant, with large contributions from direct fuel combustion, electricity, and non-energy sources. Aluminium supply chain emissions are dominated by electricity use in smelting and gas and coal use in alumina refining, while the Iron and steel supply chain produces significant non-energy emissions from the conversion of metallurgical coal to coke in coking ovens, and subsequent use of the coke produced as a reductant in the blast furnace. Emissions from the Chemicals and Other metals supply chains are relatively smaller, although together they contribute nearly 3% to domestic emissions.

8 As defined in the ANZSIC classifications

FIGURE 03: Emissions by source in the Australian Industry ETI supply chains

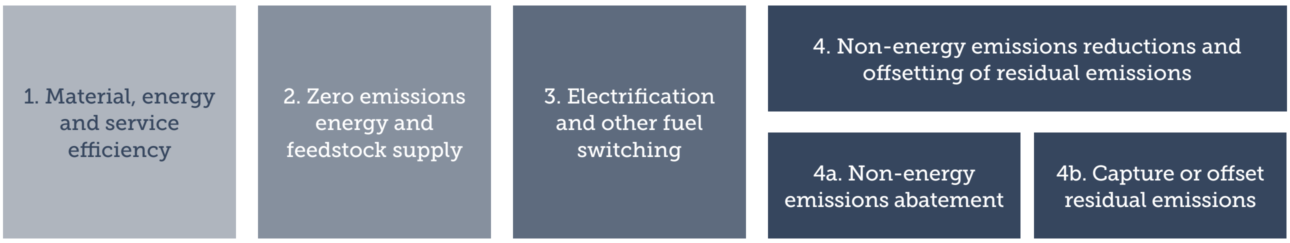


2.4 Pillars of decarbonisation

Given the size and diversity of emissions sources in the Australian Industry ETI supply chains, a net zero transition will require multiple decarbonisation strategies. Some of these strategies are relevant across all supply chains, while others will be more specific to particular supply chains. The initiative considers four decarbonisation 'pillars' as key to a net zero transition, summarised in Figure 4.

This is a variation on the 'four pillars approach' typically used by ClimateWorks Australia (2019), to allow more detailed exploration of key challenges facing the Australian Industry ETI supply chains. The main changes include expanding Pillar 2 to include the supply of other zero emissions fuels and feedstocks alongside decarbonised electricity and separating Pillar 4 into two parts to distinguish between non-energy emissions abatement and the capture or offset of emissions generated.

FIGURE 04: Decarbonisation pillars for a net zero transition



The significance of the Australian Industry ETI decarbonisation pillars will vary across and within supply chains. For example, Pillar 4a is not applicable to the Other metals supply chain given immaterial non-energy emissions, whereas it is critical to the net zero transition of Chemicals and LNG. The capacity for individual companies to pursue a particular decarbonisation strategy can also vary widely depending on the pillar. In particular, the challenge of zero emissions energy and feedstocks supply (Pillar 2) may depend on numerous factors in the broader system, beyond the control of any one company, rather than requiring the deployment of a particular technology (as in Pillars 1, 3 or 4, for example).

Although not strictly designed as such, the pillars can be thought of as roughly sequential, increasing in difficulty (that is, declining in technological or commercial maturity) from Pillar 1 through to Pillar 4. For example, near-term material and energy efficiency improvements (Pillar 1) can often be achieved through uptake of best available technologies without relying on considerable breakthroughs, in many cases delivering economic value through short payback periods.

Similarly, the technologies already exist to produce zero emissions energy and feedstocks (Pillar 2), although there are other commercial and scale challenges to overcome. The technological availability and commercial viability of technologies in Pillars 3 and 4a can vary widely depending on supply chain, with Pillar 4b providing a 'balancing' function to achieve net zero in the event that other pillars are unable to eliminate emissions.

Although presented above as discrete categories, the decarbonisation pillars also interact and reinforce each other (IDDRI 2015). For example, material and energy efficiency in Pillar 1 lowers overall energy demand, thereby assisting the task of energy supply in Pillar 2. Electrification or uptake of other zero emissions fuels in Pillar 3 is contingent on supply in Pillar 2, while electric technologies are frequently more energy efficient than thermal combustion engines, which supports Pillar 1. This demonstrates the importance of action across all decarbonisation pillars to reduce emissions as much as possible in the transition to net zero industrial supply chains.

Pillar 1: Material, energy and service efficiency

In all industrial supply chains, material and energy efficiencies are a critical part of overall productivity by reducing the quantity of product inputs and energy required. These measures also serve to reduce demand for emissions-intensive processes and are therefore an important pillar of decarbonisation.

Material efficiency improvements can be achieved in industrial supply chains through:

- improved design of end products to require less input material or increase durability (thereby reducing production cycles) and recyclability
- novel processes such as additive manufacturing to reduce unnecessary use of materials and losses in production
- substituting low emissions alternatives for emissions-intensive materials; for example, using low emissions aluminium and low emissions advanced high strength steel in light weighting passenger vehicles, reducing the need for more emissions-intensive materials
- material recovery and reuse in place of primary production
- improved asset utilisation through sharing economies and new business practices.

In addition to energy reductions through material efficiency, there are a range of technological and process changes that can directly improve energy efficiency. Examples of improvements for different energy services include (Henzler et al. 2017):

- steam – increased boiler efficiency, minimised blowdowns, optimised steam distribution
- motor drives – energy-efficient motors, variable speed drives, repairs
- pumping systems – system control and regulation, optimised motors, and transmission
- compressed air systems – reduced leaks, optimised controls, and supply
- heating – efficient load management, heat pumps, heat recovery and use
- cooling – chillers and cooling systems, improved compressor parts, evaporative cooling.

Whereas other decarbonisation pillars are typically dominated by a handful of major technologies that may involve whole asset replacement or very high capital costs, material and energy efficiency improvements are often the result of numerous smaller processes and efficiency solutions with the potential for significant energy reductions when combined. For example, recent analysis suggests that the compounding effects of material efficiency measures could reduce emissions in the most emissions-intensive industrial sectors (such as aluminium and steel) by 40% globally by 2050 (ETC 2017).

Although efficiency improvements alone are insufficient for absolute zero emissions, they play a vital role in reducing the overall burden of shifting to zero emissions processes and technologies in a context of finite resources – both physical and capital. Given challenges with deploying zero emissions energy at scale, 'no-regret' actions such as energy-efficient technology upgrades can in effect free up energy use in other areas of the economy, often with very short payback periods on investment where the costs of upgrade are offset by energy savings. Table 6 provides a summary of energy productivity opportunities in the mining and manufacturing sectors (Australian Alliance for Energy Productivity 2016a, 2016b).

TABLE 06: Energy productivity opportunities in mining and manufacturing

Energy productivity opportunities	Mining	Manufacturing
Traditional energy management	Opportunities throughout all mining processes, including ore characterisation, comminution, haulage, ventilation and data and management practices	Energy-efficient plant and equipment Metering, reporting, and benchmarking Improved maintenance practices
Systems optimisation	Smart blasting Characterisation of ore and target mineral size Optimal processing strategy Whole of site operations	Lean manufacturing Process changes Waste reduction, recovery, and processing
Business model transformation	Autonomous mining Truck-less mines Real-time 'big data' transformation	Additive manufacturing Advanced materials Process intensification

Rather than explore multiple material and energy efficiency technologies in individual detail, the Australian Industry ETI analysis and modelling will generally assess a 'suite' of efficiency solutions that incrementally reduce demand for energy over time, up to an identified potential saving. Exceptions to this are individually significant or easily separated solutions such as widespread recycling, which can be directly modelled through impacts on demand for certain products.

Pillar 2: Zero emissions energy and feedstocks supply

The production of zero emissions energy and feedstocks is a vital pillar of decarbonisation in industry, as in most areas of the economy. This acts as a direct decarbonisation option for those processes already using a particular energy type (for example, electricity), as well as unlocking opportunities for fuel switching to capitalise on zero emissions inputs (see Pillar 3 below). The zero emissions energy and feedstock sources considered in the initiative are renewable electricity, 'green' hydrogen produced via zero emissions electrolysis, and biomass products such as biodiesel and biogas.

Electricity is already a relatively large source of industrial energy use, comprising just over one-fifth of all energy use. For certain industrial sectors such as non-ferrous metals manufacturing (predominantly aluminium) and metals mining, electricity makes up more than one-third of all energy use. Together, these sectors account for slightly over half of all industrial electricity consumption in Australia (DISER 2020 – Table F and Table H).

For heavy industry such as aluminium smelting and steelmaking, the need for continuous power requires that electricity is sourced from the grid. As such, the decarbonisation trajectory of these grid-connected processes is contingent on developments in the broader energy system. Since 2010, the share of renewable electricity in Australia's power generation has more than doubled to 20%, predominantly driven by wind and solar which have increased six-fold during that time to comprise 12% of total electricity produced (DISER, 2020e). This trend is expected to improve with declining costs of renewable energy technologies, covered in more detail in the Section 4.1 – Electricity generation.

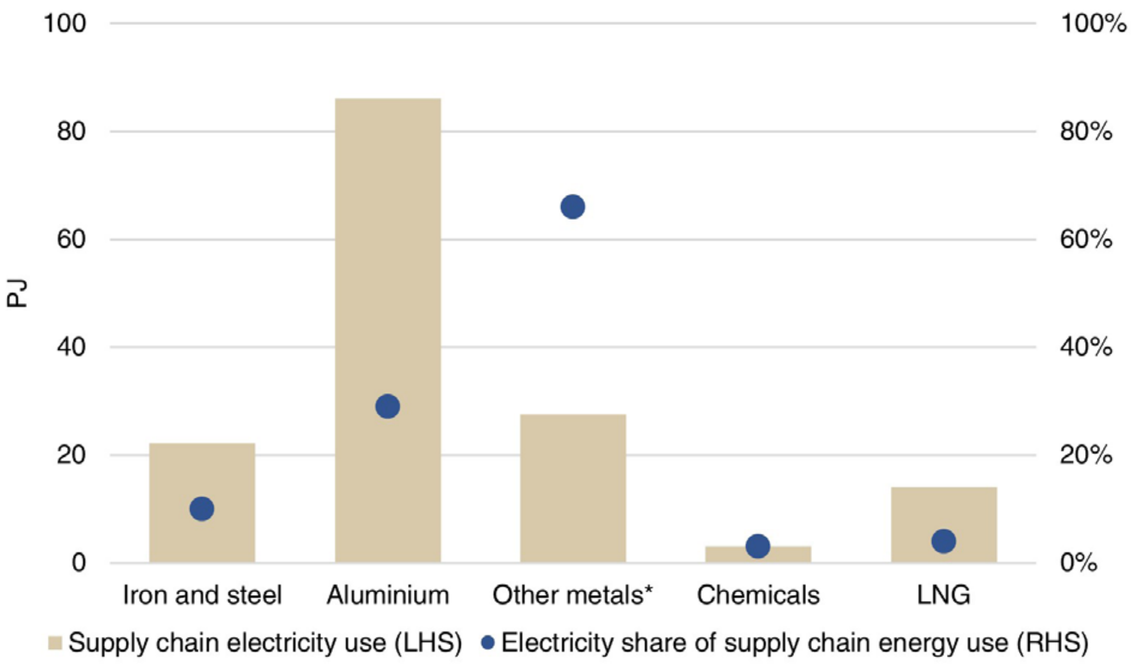
Other industries such as metal ores or LNG production may be grid-connected or, due to their often remote location, may generate off-grid power on-site through fossil-fuel powered equipment or through 'hybrid' renewable energy arrangements of wind and solar PV. Technically, off-grid power use provides companies with greater ability to access zero emissions energy and feedstocks through investments in distributed renewable energy or other arrangements such as power purchase agreements. However, numerous factors will determine the feasibility of off-grid power generation at brownfield and greenfield sites (covered more in the Section 3.3 – Other metals).

Figure 5 shows the role of electricity in the current energy mix of the Australian Industry ETI supply chains. The aluminium supply chain is by far the largest electricity consumer in aggregate terms, responsible for 9%[9] of total electricity use in Australia (DISER, 2020e). This accounts for around a third of aluminium supply chain energy use, driven by the electricity-intensive nature of smelting. LNG production is another major electricity consumer, primarily through on-site generation for facilities and liquefaction equipment. The Iron and steel supply chain also consumes a relatively large amount of

9 Figures based on Australian Industry ETI calculation of supply chain electricity and Australian Energy Statistics (DISER 2020c, DISER 2020e)

electricity, roughly split between mining processes and steelmaking (particularly scrap-based production), although this only represents around 11% of total supply chain energy use. Despite large quantities of electricity consumption in the Australian Industry ETI supply chains, there is significant scope – with the exception of Other metals which derives around 80% of energy from electricity – for much higher rates of electrification in many key industrial processes (discussed in Section 3 – Supply chain detail).

FIGURE 05: Current electricity use in the Australian Industry ETI supply chains



*Other metals includes copper, nickel, lithium and zinc

Consumption of zero emissions energy sources such as wood waste and bagasse is currently limited in Australia, accounting for just 6% of industry energy use – almost entirely in manufacturing industries such as food or wood processing that utilise proximate waste streams (DISER 2020c) – and around 4% nationally. In the Australian Industry ETI supply chains, use of bio-based energy or feedstocks is currently non-existent or negligible. The modelling approach for the production of bioenergy resources is discussed in Section 4.3 – Biomass.

Hydrogen is another fuel that releases zero emissions when used, with potential applications in hard-to-abate areas of the economy such as industry. Australia's hydrogen consumption is very small relative to other fuels, used predominantly in petroleum refining and chemical products such as fertilisers and explosives. Currently, Australia's hydrogen is produced through the steam methane reforming (SMR) process, which uses natural gas as a feedstock and emits approximately 9 $MtCO_2e$ per Mt of hydrogen. The various hydrogen production methods and emissions implications are covered in Section 4.2 – Hydrogen.

Pillar 3: Electrification and other fuel switching

Although some industrial processes consume large amounts of electricity, energy use in Australian supply chains remains primarily based on fossil fuels such as coal and gas. Implicit in a net zero transition is the need to replace these fossil fuels with zero emissions alternatives through electrification and other fuel switching, as examined in Box 1. Practically, this allows industrial processes to benefit from the expanded production of zero emissions energy sources covered in Pillar 2 above.

There are a number of emerging and mature technologies enabling the switching of industrial processes to electricity or alternative fuels. Recent estimates suggest that almost half of all fuel consumed for industrial heat can be electrified with already available technologies, servicing demand up to approximately 400°C (Roelofsen 2020). For example, electric boilers and heat pumps are available cost-competitive options for heat production.

For very high-heat processes where electrification is not possible, hydrogen and bioenergy are often viable alternatives. Concentrated solar thermal technologies are also emerging to supply heat at 800–1000°C (NSW Chief Scientist 2020).

Electric boilers and heat pumps could also be utilised in high-heat processes for pre-heating or alongside waste heat recycling to improve the overall efficiency of services. Several processes in the Australian Industry ETI supply chains such as alumina production and steelmaking require very high temperatures, so will likely require a blend of electrification and other fuel switching solutions in a net zero transition.

Capital costs of available alternative heat technologies are roughly comparable with conventional industrial equipment (Roelofsen 2020). Therefore, when replacing old equipment or setting up a new site, energy costs will be the primary determinant of the financial attractiveness of electrification and fuel switching. Expected reductions in the cost of renewable electricity and hydrogen would therefore considerably improve the economics of associated technologies. This would be even more pronounced in the context of a penalty on emissions that further increases the relative cost of fossil fuels.

At high rates of electrification and variable renewable energy production, measures to enhance process flexibility will become increasingly important, particularly in energy-intensive industries requiring continuous flow production that are not well-suited to intermittent energy supply. Material and energy efficiency improvements (Pillar 1) and demand response capabilities can play a vital role in helping to manage energy demand and supply for energy-intensive industries.

BOX 01:

The importance of zero emissions energy and feedstocks in a net zero transition

Preliminary analysis for the Australian Industry ETI suggests that the supply of zero emissions energy (Pillar 2) and uptake through electrification and other fuel switching (Pillar 3) are the most critical aspects of a net zero transition for Australian industrial supply chains. This assessment is based on the identified abatement potential of technologies covered in detail in relevant supply chain sections, as shown in Table 7.

TABLE 07: Preliminary assessment of potential abatement from zero emissions energy and feedstocks in the Australian Industry ETI supply chains

Supply chain	Plausible role of zero emissions energy and feedstocks in net zero transition		Estimated emissions reduction potential by 2050 from energy solutions only
	Electricity	Hydrogen	
Iron and steel	Trolley assist Battery-electric trucks Electric arc furnace Electrolytic steel production	Hydrogen fuel-cell trucks Direct reduced iron production Hydrogen injection in blast furnace	~95%
Aluminium	Trolley assist Battery-electric trucks Process heat in alumina refining	Hydrogen fuel-cell trucks Process heat in alumina refining	~92%
Other metals	Trolley assist Battery-electric trucks Renewable-powered mine operations Process heat	Hydrogen fuel-cell trucks	~100%
Chemicals	Process heat	Hydrogen produced via renewable electrolysis[10]	~65%
LNG	Electrified liquefaction	Uncertain role for hydrogen in reducing LNG production emissions[11]	~65%

In metals production, energy solutions such as renewable electricity and hydrogen alone can achieve more than 90% supply chain decarbonisation. This is the result of low shares of non-energy emissions in metals production relative to other supply chains such as LNG and Chemicals. The current process that dominates Australian steel production does have considerable non-energy emissions, although these would be eliminated through a change to renewable electricity or hydrogen-based processes (see Section 3.1 – Iron and steel for further discussion). Even in non-metals supply chains with higher shares of non-energy emissions, targeted energy solutions remain a key component of a net zero transition.

10 Switch from gas-based steam methane reforming in the production of hydrogen feedstock for ammonia

11 This refers specifically to the use of hydrogen in the LNG supply chain. The potential near-term role for the use of gas with CCS (>90% capture to produce) low emissions hydrogen is covered elsewhere in this report

Pillar 4a: Non-energy emissions abatement

As discussed above, non-energy emissions are a feature of industrial supply chains – particularly those in the initiative (with the exception of Other metals) – and are a primary reason for these supply chains being considered hard to abate. Non-energy emissions are generally classified as industrial processes or fugitives, as follows:

- Industrial process emissions – resulting from the use of carbon-based feedstocks in the production of industrial materials, such as the use of coal as a reductant in ironmaking.
- Venting – emissions resulting from process or equipment design or operational practices in the production of natural gas.
- Flaring – emissions from the controlled burning of gas during extraction to reduce the risk of ignition or to eliminate product unsuitable for use.
- Leakages – unintentional emissions from equipment such as valves, seals, and tanks.

Sources of non-energy emissions in the Australian Industry ETI supply chains are presented in Table 8. Industrial process emissions occur in numerous industries dependent on carbon-based feedstocks such as aluminium (carbon anodes), iron (coking coal) as the precursor for steel and chemicals (natural gas-based hydrogen input). Many of these could be eliminated through straight replacement, or ‘drop-in’, of zero emissions feedstocks such as hydrogen or bioenergy (covered in Pillar 2). For example, green hydrogen produced via renewable electrolysis could bypass the need for gas-based steam methane reforming as an input to ammonia production, thereby eliminating process emissions. Other applications of zero emissions feedstocks require wholesale process or technology change, such as in the replacement of coal with hydrogen as a reductant in ironmaking (see Section 3.1 – Iron and steel). In the case of process emissions from carbon anodes or other chemical reactions in producing ammonia derivatives, specific abatement technologies would need to be deployed, such as inert anodes or abatement catalysts (covered in detail in Section 3.2 – Aluminium and Section 3.4 – Chemicals).

Fugitive emissions comprise nearly a third of emissions in the LNG supply chain produced in Australia, rapidly growing since 2015 reflecting increases in production and high flaring activity associated with the initial years of LNG projects (DISER 2020a). Flaring emissions are expected to stabilise in coming years as LNG facilities move to a steady state of operations, while venting will increase alongside projected growth in production to 2030. Technologies and process improvements to address fugitive emissions in the LNG supply chain are covered in Section 3.5 – Liquified natural gas.

TABLE 08: Estimated non-energy emissions in the Australian Industry ETI supply chains

Supply chain	Non-energy emissions source ($MtCO_2e$, share of supply chain emissions)	Abatement potential
Iron and steel	Explosives in iron ore mining (0.6, 3%) Coking coal feedstock in ironmaking (8.2, 36%)[12]	There are no commercially proven technologies available to eliminate emissions from the use of explosives Switching away from BF-BOF steelmaking would eliminate the need for coking coal and associated emissions
Aluminium	Carbon anodes (2.9, 8%)	Inert anodes could eliminate non-energy emissions in smelting, although this technology is still at an early stage of development
Other metals	Immaterial emissions from use of explosives	
Chemicals	Gas feedstock in SMR hydrogen production for ammonia (2.4, 30%) Chemical reactions during production of ammonia derivatives (1.8, 23%)	Switching to green hydrogen instead of hydrogen produced from natural gas would eliminate upstream ammonia emissions Primary, secondary or tertiary technologies exist to eliminate emissions from chemical reactions
LNG	Venting (7.1, 20%) Flaring (4.6, 13%) Leakages (0.1, <1%)	Regular leak detection and repair can eliminate 80% of leakage emissions Vented gas can be captured and re-injected, or alternatively venting equipment can be replaced with alternatives that do not require venting Flaring is often necessary for operational safety, however emissions can be reduced through optimising process control, and ensuring good function of flares to prevent methane emissions

12 Coking coal is used as both a reductant (non-energy) and energy source in BF-BOF iron and steelmaking. The Australian Industry ETI analysis classifies emissions from the use of coking coal as non-energy emissions.

Pillar 4b: Capture or offset residual emissions

Where there are residual emissions not able to be eliminated through Pillars 1 to 4a, a net zero transition requires that these be captured through other means or offset against 'negative emissions' elsewhere in the economy. There are several mature and emerging technologies to capture or draw down CO_2 emissions, with varying levels of applicability and scalability within industrial supply chains.

Carbon capture and storage (CCS) refers to the capture and permanent geological storage of carbon dioxide. CCS is technically viable with industrial-scale projects globally and is a potentially cost-effective way to eliminate emissions in particularly hard-to-abate processes such as iron and steelmaking and chemicals (ETC 2017). There are, however, some major uncertainties with regards to storage capacity, ongoing cost reductions and social licence. In addition, difficulties encountered by recent large-scale developments (for example, delays and underperformance of Chevron's Gorgon CCS project in Western Australia) have led to questions about the ability to cost-effectively store significant amounts of emissions. The IEA considers scaled up demonstration and deployment of CCS as critical for uptake, but recently assessed development as off-track in both power generation and industry (IRENA 2019a). In the absence of strong financial incentives, the economics of CCS are also challenging as emitters bear the cost of securing storage locations and establishing infrastructure for the capture, transport and storage of carbon (NSW Chief Scientist 2020).

Carbon capture and use (CCU) refers to the capture and utilisation of CO_2 as an input to more valuable products such as plastics or concrete. CCU overcomes some of the cost challenges of CCS by establishing a market and value for carbon dioxide, thereby reducing dependence on other incentives such as a financial penalty on emissions (although this would also greatly assist the economics of CCU). A key consideration is the length of time the captured CO_2 is utilised for – applications such as enhanced oil recovery or production of CO_2 based fuels and chemicals could allow the CO_2 to be re-released, depending on the formation type or specific chemical product. Other applications such as use in building materials and concrete allow a more permanent storage of the CO_2 (Hepburn 2019).

Negative emissions technologies (NETs) aim to decrease concentrations of CO_2 in the atmosphere through transfer to a geological, biological or mineral medium (Cook & Arranz 2019). Examples of NETs include afforestation, soil carbon sequestration, bioenergy with CCS (BECCS), direct air capture (DAC), mineral carbonation and enhanced weathering. These are summarised in Table 9. Most NETs are currently expensive, with many still under development, and they will likely require further support or incentives for widespread deployment. Some of these options are, however, closely related to the supply chains that make up the Australian Industry ETI, and in some areas are already being investigated in Australia; for example, mineral carbonation (Azadi 2019).

TABLE 09: Examples of negative emissions technologies[13]

Technology or technique	Description	CO_2 removal mechanism	CO_2 storage medium
Afforestation/ reforestation	The planting of trees to fix atmospheric carbon in biomass and soils	Biological	Soils/vegetation
Biochar	Converting biomass to biochar and using the biochar as a soil amendment	Biological	Soils
Bioenergy with carbon capture and storage (BECCS)	Removal of CO_2 from the air by plants into biomass, combustion of the biomass to produce energy and CO_2 which is captured	Biological	Deep geologic formations
Direct air capture (DAC)	Removal of CO_2 from ambient air by engineered systems	Physical/chemical	Deep geologic formations
Enhanced weathering (mineral carbonation)	Enhancing the weathering of minerals, where CO_2 in the atmosphere reacts with silicate minerals to form carbonate rocks	Geochemical	Rocks
Modified agricultural practices	Adopting agricultural practices such as no-till farming to increase carbon storage in soils	Biological	Soils
Ocean (iron) fertilisation	Fertilising the ocean to increase biological activity to pull carbon from the atmosphere into the ocean	Biological	Ocean
Ocean alkalinity	Adding alkalinity to the oceans to pull carbon from the atmosphere via chemical reactions	Chemical	Ocean

13 (Herzog 2018)

The cost-effectiveness of CCS, CCU and NETs can be expected to improve with scale, and this could be facilitated by hub-style models that group demand and reduce individual costs for all users by enabling shared transport and storage infrastructure. An example of this is the Northern Lights CCS hub in Sweden, which describes itself as delivering carbon storage as a service (Northern Lights 2021). NETs could also be deployed in a more cost-effective way when developed specifically for a zero emissions industrial hub, and tailored to meet regional needs (Cook & Arranz 2020).

Within the Australian Industry ETI supply chains, the majority of emissions can be eliminated through current or emerging technologies and, as such, CCU/S are generally seen as potential transitional options for emissions reduction while other technologies develop and become commercially viable. This is the case for emissions from using fossil fuels to provide heat (for example, blast furnace emissions in Iron and steel, process heating emissions in Aluminium and Other metals) and emissions from using fossil fuel feedstocks in chemical reactions (for example, steam methane reforming in Chemicals). These applications of CCS would vary in capture cost, due to the more or less dilute nature of the emissions sources (a concentrated CO_2 stream is much cheaper to capture). The longer-term solutions for these emissions sources involve the use of electrification or alternative renewable heat sources and alternative processes using zero emissions hydrogen, and are expanded upon in specific supply chain sections in this report.

There are some emissions sources that may require ongoing CCU/S, however, especially within the gas supply chain. Gas extraction produces a concentrated stream of CO_2 which has to be separated from the rest of the process stream and is often vented to the atmosphere, so CCU/S is seen as a long-term solution to reduce emissions from this area of the supply chain.

NETs have some potential applications in each of the Australian Industry ETI metal supply chains, due to the materials being produced as waste at mine sites. Enhanced weathering of tailings at nickel mines is already naturally occurring, and there is research into enhancing this process (Wilson et al. 2014) and investigation into other mine site wastes that will also allow mineral carbonation, such as red mud produced from bauxite mines (Azadi 2019) or iron ore mine site waste. Mineral wastes containing magnesium or calcium are chemically bound with CO_2 in the mineral carbonation process to produce environmentally benign materials that can be used in a number of applications, from mine site fill to building and construction materials such as plasterboard and paving stones. The economic value of the product can help overcome some of the financial barriers to dealing with both the CO_2 and mine site wastes (Azadi 2019).

Urea-based fertilisers are another application that will require the use of NETs for complete decarbonisation. These fertilisers require CO_2 as a feedstock and emit the CO_2 again shortly after use. Sourcing the feedstock via NETs – for example, direct air capture (DAC) or BECCS – would allow these products to be net zero emissions (de Pee et al. 2018).

NETs feature prominently in IPCC scenarios limiting global warming to below 2°C, with successful and large-scale deployment of some form of NET assumed in 86% of emissions scenarios modelled (European Academies Science Advisory Council 2018). Given their centrality to these outcomes and theoretical potential, NETs are worthy of continued research, development, and deployment where possible. However, as with CCS technologies, there are numerous uncertainties regarding technology cost, performance, availability and environmental impacts, as well other limiting factors that may constrain uptake (for example, suitable geological reservoirs or land availability for afforestation). Moreover, the ability for offsets to substitute for direct abatement will diminish over time due to declining carbon credits and the non-permanence of negative emissions from nature-based solutions (ETC 2020).[14]

As such, the initiative adopts the position that every effort should be made to move as close to zero emissions within supply chains as possible, thereby reducing dependence on highly uncertain technological breakthroughs. Although there are also considerable challenges with decarbonising industrial supply chains, solutions to address a large share of emissions are technologically mature and relatively well understood. Continued development of CCS and NET solutions should therefore occur alongside, rather than at the expense of, targeted supply chain abatement.

14 All natural ecosystems tend eventually towards a carbon-neutral balance of emissions and absorption after the build-up period (30 to 40 years for reforestation)

3.0 Supply chain detail

3.1 Iron and steel

3.1.1 Supply chain structure and context

Iron ore production

Australia is a major player in the global iron and steel supply chain, primarily as the world's largest producer and exporter of iron ore. Australia produced 919 Mt of iron ore in 2019, accounting for 38% of global production, followed by Brazil (17%) and China (14%) (US Geological Survey 2021a). In that year, more than 90% of Australia's iron ore production was exported, with China (82%), Japan (7%) and South Korea (6%) the primary markets (DISER 2021). Most of Australia's iron ore reserves occur in Western Australia (92%), with around 5% in South Australia and minor amounts in New South Wales and Tasmania (Summerfield 2020).

Australia's reserves include both hematite and magnetite iron ore. The vast majority (96%) of Australian current iron ore exports are high-grade hematite (56–62% iron content) from the Pilbara region in Western Australia – known as 'direct shipping ores' – that do not require extensive processing beyond initial crushing and screening before use in blast furnace iron and steelmaking (Summerfield 2020).

While pure magnetite contains a higher iron content than hematite, the presence of impurities decreases ore grade and requires a second stage of processing to extract the magnetite and produce a concentrate. For use in blast furnaces or direct-reduction facilities, additional processing of the concentrate[15] is required to produce magnetite pellets with an iron content of 65–70%, increasing production costs. Although a small share of current exports, magnetite ores represent 37% of Australia's total Economic Demonstrated Resources,[16] equivalent to more than 18,000 Mt or 20 resource years based on 2020 production levels (Summerfield 2020). If direct-reduction facilities become more widespread globally, increased demand for higher grade ores may become a critical challenge. Further work is required to better understand the potential to produce direct-reduced iron from the more prevalent hematite ores and the implications for Australia's role in the global iron and steel supply chain. This is a key area of interest to explore in subsequent phases of the Australian Industry ETI.

Iron and steelmaking

Given such a high share of iron ore production is exported, Australia is a minor player in later stages of the iron and steel supply chain, producing around 5.5 Mt of steel in 2019 – just 0.3% of global crude steel production. Australia mostly produces steel for the local market, via two different production methods: the integrated ore-based steelmaking process using blast furnaces-basic oxygen furnaces (BF-BOF), which produces around 73% of Australia's crude steel; and the scrap-based process using electric arc furnaces (EAF), accounting for remaining production (Worldsteel Association 2020).

Australia's steel industry is very concentrated, with production dominated by two companies. BlueScope's Port Kembla Steelworks in New South Wales is the largest manufacturer of flat steel in Australia, with an annual production capacity of approximately 3 Mt at its integrated BF-BOF steelmaking operations (BlueScope, 2021). GFG Alliance operates three Australian steel facilities, producing around 1.1 Mt at its Whyalla Steelworks in South Australia (BF-BOF operation run on locally produced hematite and magnetite), and a combined 1.2 Mt from its EAF facilities in Sydney (NSW) and Laverton (Victoria) in 2018 (GFG Alliance 2018). In 2020, GFG Alliance revealed plans to transform its Whyalla Steelworks into a vertically integrated[17] 'GREENSTEEL' facility, with new direct reduced iron (DRI) and EAF processes in preparation for an eventual transition from gas to green hydrogen (for the DRI process) in the early 2020s (GFG Alliance 2020). In addition, Fortescue has recently announced plans to start building a green steel pilot plant this year, with ambitions for a commercial plant in the Pilbara in the next few years powered entirely by variable renewable energy such as wind and solar (Forrest 2021).

15 Agglomeration and thermal treatment

16 Economic Demonstrated Resources (EDR) is a measure of the resources that are established, analytically demonstrated or assumed with reasonable certainty to be profitable for extraction or production under defined investment assumptions. Classifying a mineral resource as EDR reflects a high degree of certainty as to the size and quality of the resource and its economic viability (ABS 2010).

17 A vertically integrated business model is one that consolidates multiple supply chain steps under one company's ownership and control. For example, a steel producer might vertically integrate its operations by also producing upstream inputs such as raw material (iron ore) and energy.

3.1.2 Energy use and emissions

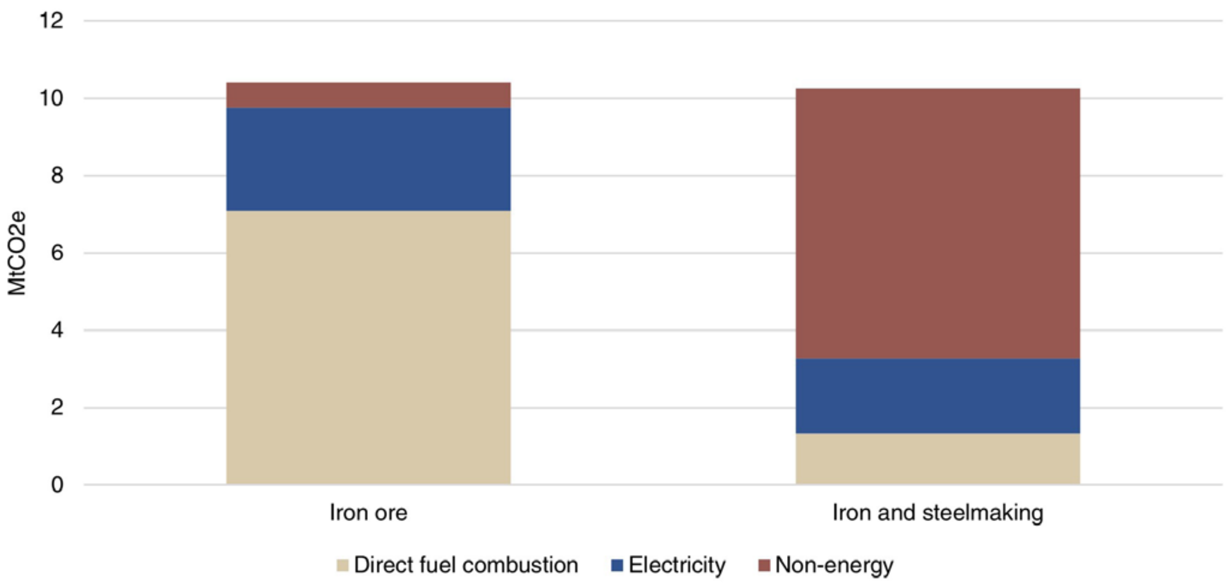
Iron ore production

Although the processes involved in iron ore production are far less energy- and emissions-intensive than those in later stages of iron and steel production, the composition of Australia's iron and steel supply chain (high iron ore production, limited steelmaking) drives significant emissions from a number of processes (Figure 6). Emissions from the mining and haulage of iron ore are estimated at 10.4 $MtCO_2e$ in 2019–2020, accounting for around 50% of all domestic supply chain emissions. These are primarily (68%) from the use of diesel in vehicles and machinery, followed by electrified mining processes (26%) and the use of explosives (6%).

Iron and steelmaking

Despite relatively low levels of Australian activity, domestic emissions from iron and steelmaking represent approximately half of the supply chain emissions at 10.2 $MtCO_2e$ in 2019–2020. This is due to the energy-intensive nature of dominant BF-BOF processes and considerable non-energy emissions from the use of coking coal as a reductant. Per tonne of steel, BF-BOF facilities in Australia emit an estimated 2.3 $MtCO_2e$, compared to 0.9 $MtCO_2e$ for EAF production, with the latter largely determined by the electricity source (as electricity comprises 85% of energy use in EAF production). Energy use for process heat – around a third of iron and steelmaking emissions – is currently dominated by fossil fuels, either through gas and coal in blast furnaces or EAF production powered by largely coal-based grid electricity. For both steelmaking processes, the emissions intensity of Australian production is considerably higher than the global average of 2.0 MtCO2e and 0.4 MtCO2e for BF-BOF and EAF respectively (Ellis & Bao 2020).

FIGURE 06: Emissions sources in the Iron and steel supply chain



3.1.3 Decarbonisation options and challenges

Table 10 summarises the major abatement opportunities within the Iron and steel supply chain, described in more detail below for specific supply chain stages and processes. The uptake and supply of zero emissions energy and feedstocks is a critical component of a net zero transition, in particular for the long-term application of electricity and hydrogen in both iron ore production and steelmaking. Given challenges in cost effectively deploying key technologies in the near term, there is also the potential for optimisation of existing processes and uptake of other transition options to help reduce emissions, although these are unlikely to be sufficient for a net zero outcome.

TABLE 10: Abatement opportunities across decarbonisation pillars for the Iron and steel supply chain

		Iron ore production	Steelmaking
Pillar 1: Material and energy efficiency	Material efficiency	Mine site and plant optimisation Uptake of best available technologies Increased scrap-based production in EAF	
	Energy efficiency		
Pillar 2: Zero emissions energy and feedstocks supply **Pillar 3: Electrification and fuel switching**	Zero emissions electricity	Iron ore haulage	Decarbonise existing electricity use EAF run on scrap or DRI Green hydrogen production* Ore electrolysis*
	Other zero emissions fuels	Iron ore haulage (biomass)*	Biomass or hydrogen use in BF-BOF process
		Iron ore haulage (hydrogen)	Green hydrogen use in DRI-EAF process*
Pillar 4a: Non-energy emissions	Process improvements		
	Zero emissions feedstocks		Biomass or hydrogen use in BF-BOF process
			Green hydrogen use in DRI-EAF process*
Pillar 4b: Capture or offset residual emissions	CCS of process emissions		BF-BOF with CCS*
	Negative emissions technologies	Mineral carbonation (waste rock)*	

* These technologies are currently classified as having a TRL of 1-6 and require further research, development and demonstration. CCS: carbon capture and storage; EAF: electric arc furnace; DRI: direct reduced iron; BF-BOF: blast furnace basic oxygen furnace.

Immaterial or uncertain role	Potential role in transition to zero or near-zero emissions options	Important role in near term abatement but insufficient for net zero emissions	Long term, zero or near-zero emissions potential

Iron ore production

As emissions in iron ore production mining and haulage are predominantly energy-based, decarbonised energy supply, electrification and other fuel switching are the most critical pathways to net zero emissions.

With diesel-based haulage accounting for more than half of emissions in iron ore production, finding zero emissions alternatives is a primary challenge. There are a handful of technologies that offer prospects of decarbonising mine site haulage, summarised below:

- **Trolley assists** – Already a commercially mature technology, the use of overhead electric lines to power haulage vehicles has the potential to reduce diesel use and emissions by up to 30% without requiring changes to trucking fleets or electricity source (Muralidharan 2019). At higher shares of renewable electricity and if coupled with other zero emissions haulage technologies (such as battery-electric vehicles), the flexibility and emissions benefits of trolley assists have the potential to increase significantly.
- **Battery-electric trucks** – The prospects for battery-electric vehicle technology (BEV) applications in heavy vehicles have improved considerably in recent years, with several underground vehicles now commercially available. Battery-electric trucks produce no operational emissions if charged using renewable electricity and are less emissions-intensive than diesel at just 25% renewable generation (Muralidharan 2019). While there are currently no commercially available electric mine haulers for open-pit applications, there are several vehicles being tested in mine sites globally. For example, Fortescue Metals Group has recently announced plans to design and build a battery-electric mining haul truck alongside a fast charging unit, with a view to decarbonising

haulage fleets in the Pilbara, Western Australia (Fortescue 2021). Major barriers to uptake of BEVs for mine haulage are battery size requirements, charging infrastructure and operational adjustments due to idling while charging. A complete shift to renewable electricity generation (discussed below) would also be required for these vehicles to be considered a zero-emissions haulage option. Given these challenges, battery-electric trucks are not expected to be commercially available until after 2025. Combining battery-electric trucks with trolley assists could allow vehicles to be charged during operation, thereby mitigating some of these challenges and driving earlier deployment at scale.

- **Hydrogen fuel-cell trucks** – Hydrogen fuel-cell electric vehicles (FCEVs) are an alternative option to fully decarbonise mining haulage. FCEVs are already commercially available in the light vehicle market but are increasingly being used in heavier applications such as trains and trucks, suggesting promise for mining haul trucks. The primary advantage of FCEVs is their theoretical ability to meet the power requirements of heavy machinery with reduced battery weight when compared to BEVs (although combining with trolley systems could reduce battery needs for BEVs). Major uncertainties regarding the uptake of FCEVs in haulage relate to the cost outlook for hydrogen production – particularly green hydrogen which will be largely determined by cost trajectories of variable renewable generation and electrolyser technologies (see Section 4.1 and 4.2). Anglo American is planning to pilot a hydrogen-powered large mining truck in South Africa in the second half of 2021 by converting a Komatsu 930E to a fuel-cell and lithium ion battery-powered prototype. This will be the first and largest full power FCEV mining truck in the world (Moore 2020).
- **Biodiesel** – While BEV and FCEV technology and energy costs decline to become more competitive, drop-in biodiesel could represent a transition option for mine haulage. Although readily deployable with low CAPEX requirements, the initiative considers biodiesel unlikely to feature prominently in mine haulage over the long term given potential costs of transportation and competing needs in other sectors for finite sustainable supply (see Section 4.3). The most commonly used blend of biodiesel is B20, which replaces 20% of diesel with naturally derived, zero emissions fuel, leading to a proportionate reduction in emissions. Blends such as B20 are advantageous in that they can be used in existing engines with no modifications, allowing immediate uptake once the fuel is sourced. Incorporating higher blends of biodiesel may require some equipment and vehicle modifications but could lead to considerable emissions reductions if managed.

Relative to other metals such as nickel, copper and gold that are typically processed at mine sites, hematite iron ore requires very little on-site processing after extraction. As such, iron ore is typically less electricity-intensive than other metals per tonne of ore produced. However, the considerable quantity of Australian iron ore production results in an estimated 2.7 $MtCO_2e$ from electricity use – around a quarter of total emissions from iron ore mining and haulage. More detailed discussion of the opportunity for decarbonised power generation at Australian mine sites will be covered further in Section 3.3.3, with more general discussion on the transition of Australia's electricity system covered in Section 4.1.

Iron ore mine site waste is also a candidate for mineral carbonation, as introduced in 'Pillar 4b' of Section 2.4, due to the presence of silicate minerals and magnetite (Ramli et al. 2021). Research into mineral carbonation of the waste rock is at the prototype and pilot stage, but when developed the process will provide a mechanism for carbon capture and use (CCU), and production of environmentally benign building and construction materials with economic value that can reduce the cost of dealing with CO_2 emissions.

Iron and steelmaking

There are numerous opportunities to reduce emissions in steelmaking, each with varying abatement potential, technological readiness, and commercial feasibility. Although the technical prospects for alternative iron and steelmaking technologies are improving, high capital and operating costs are the key barrier to deployment at scale in the next decade. A transition towards zero emissions steelmaking will likely require the early retirement of existing assets and deployment of more costly technologies to capture future emissions benefits from anticipated developments in renewable electricity and hydrogen. For steelmakers in a highly competitive global market, this is a major commercial and strategic decision. Currently, there are limited incentives for steelmakers to retire blast furnaces early. Maintaining existing furnaces with periodic relines has capital costs in the order of AU$700–800 million (BlueScope 2021) while new steelmaking facilities cost upwards of AU$1,900 million alone[18] (IEA 2019b), without considering other plant infrastructure. Additionally, different decarbonisation technologies require varying levels of infrastructure change, while major process changes may introduce uncertainty regarding raw materials and energy supply driven by regional variability (Keys et al. 2019). To date, the companies demonstrating greatest ambition through strategies and investments in decarbonising steel production are those aiming to vertically integrate operations across the entire supply chain – covering iron ore (with suitable grade for direct reduction), renewable electricity, and green hydrogen production through to zero emissions steelmaking.

18 Assuming capital cost of AU$770 per tonne of steel and 2.6 Mt based on annual capacity at BlueScope's Port Kembla facility

Given these challenges and current production methods in Australia, a pathway to net zero emissions is likely to require a combination of optimising existing processes, utilising transition options such as bioenergy and CCS, and investment in transformational zero emissions technologies and energy when available.

Some of the nearer term and transition options for steelmaking are summarised below:

- **Material and energy efficiencies** – There are immediate opportunities for abatement in steelmaking through material and energy efficiencies, with BHP (Ellis & Bao 2020) estimating potential reductions of up to 20% from a combination of high-quality inputs (iron ore, coal, scrap) and process optimisation. A cost advantage of these measures is their use of existing BF-BOF facilities. For example, emissions reductions of 5–10% could be achieved through modifying blast furnaces to remove CO_2 from top gas and reinject remaining gas (TGR-BF), reducing demand for coke and providing an opportunity for CO_2 storage (by creating a more concentrated CO_2 waste stream) (Toktarova et al. 2020). TGR-BF has the benefit of utilising all current site processes; however, installation would involve considerable outage periods, and the recent closure of a pilot plant operated by ArcelorMittal has raised concerns about the prospects for scaling this technology (Keys et al. 2019).
- **Switching existing electricity use to renewables** – Electricity provides a reasonable amount of existing energy to steelmaking plants, even those that do not use an EAF such as BlueScope's Port Kembla steelworks. Switching this electricity away from a fossil fuel based grid to renewables would eliminate around 9% of BlueScope's current emissions. Australia-wide, decarbonising existing electricity use would remove around 19% of emissions from the Iron and steel supply chain.
- **Increased scrap-based secondary production using EAF** – Increased recycling and scrap-based production could also reduce steelmaking emissions in Australia as it displaces the need for primary steel production and uses the lower emissions EAF process. As electricity is the main energy source for an EAF facility, the already significant emissions benefits of scrap-based steel production will only improve with progress towards very high shares of renewable electricity generation – whether through a gradual grid transition, renewable-based power purchasing agreements or more favourable economics for on-site renewable generation at steelmaking facilities. The main challenges to harnessing low emissions EAF production are the need for affordable electricity supply and high-quality scrap, the latter of which is particularly challenging in a highly competitive market characterised by high prices, limited availability, and contamination from elements such as copper and tin (Venkataraman et al. 2019). Australia's relatively small population and low annual steel production is likely to constrain the scope for significant increases in local secondary production over the long term.
- **Biomass in BF-BOF process** – As an alternative fuel and feedstock, biomass has numerous potential applications in BF-BOF steelmaking, representing a significant emissions reduction opportunity if derived from renewable sources. The most feasible application for biomass is as an alternative fuel to coal in blast furnaces, although it can also be used to replace fossil fuels in sintering[19] and pelletising, or as a substitute for coke or coal-based char (Toktarova et al. 2020). Widespread uptake of biomass has the technical potential to reduce emissions by up to 50% in integrated steelmaking, although in practice the feasible reduction potential is likely to be considerably lower (Ellis & Bao 2020). As with other energy-intensive industries, a primary concern regarding the use of biomass is ensuring sustainable supply, particularly given competing needs in other areas of the economy. As discussed in Section 4.3 – Biomass, the Australian Industry ETI analysis assumes there is limited scope for meaningful increases in biomass supply and by extension assumes a minor role for biomass in steelmaking processes.
- **Hydrogen injection in BF-BOF process** – Hydrogen can be used in blast furnaces as a reducing agent and heat source to partially replace some of the coal used. However, injection rates are limited to around 20% due to cooling effects of hydrogen (RFC Ambrian Limited 2021).

Each of the above solutions have a potential role to play in a net zero transition of steelmaking, but are insufficient as long-term solutions due to technical limits (for example, process optimisation reducing but not eliminating emissions) or barriers in the Australian context (for example, supply of biomass or scrap steel). Achieving near-zero or zero emissions in steelmaking will require either the extensive capture of CO_2 from current production methods or alternative means of iron ore reduction that bypass the use of blast furnaces:

- **Carbon capture and use/storage** – Post-combustion CCS for blast furnaces could reduce CO_2 emissions from existing plants without major modifications, removing 50–60% of emissions if combined with top gas recycling, or over 80% if combined with a biomass-based blast furnace (Toktarova et al. 2020).

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19 Process of fusing particles together using a combination of pressure and heat without melting the materials

- **Natural gas-based direct reduced iron** – The conversion of iron ore into direct reduced iron (DRI) using natural gas as a reductant (NG-DRI) is a proven process used in the Middle East and North America. In this process, iron ore is reduced via a gas-solid reaction, producing DRI that can be further processed into steel in an EAF (NG-DRI-EAF). The emissions intensity of NG-DRI-EAF is around 0.864 $MtCO_2e$ per tonne of steel, a reduction of 50%[20] compared to BF-BOF production (Bartlett & Krupnick, 2021). NG-DRI-EAF therefore provides a major opportunity to reduce emissions in the short-term, while also opening opportunities for zero emissions production through an eventual switch to green hydrogen. However, there are several major barriers to adoption of NG-DRI-EAF in Australia. These include the considerable capital requirements for DRI facilities, an absence of EAF facilities (in the case of BlueScope's Port Kembla operations), the unsuitability of hematite ores for direct reduction, significantly higher electricity supply and infrastructure requirements to support EAF facilities, high electricity prices, low levels of renewable electricity in key jurisdictions and challenges in procuring necessary quantities of gas on the east coast due to both high prices and limited pipeline infrastructure in relevant regions.
- **Hydrogen direct reduced iron** – A DRI-EAF production pathway using pure hydrogen as a reductant (H2-DRI-EAF) is emerging as the most promising long-term option for decarbonising steel production. If both the hydrogen input and electricity are based entirely on renewables, this would nearly eliminate emissions from the steelmaking process. Although a H2-DRI-EAF approach is currently considered the most viable option for zero emissions steelmaking, market entries are not expected until around 2035 (HYBRIT 2018). Hydrogen already comprises the majority of reducing agents within NG-DRI processes (Ellis & Bao 2020) and it is expected that existing facilities could be run on pure hydrogen with little or no modification (Wood & Dundas 2020). The major challenges and uncertainties regarding zero emissions H2-DRI are the economics of securing required quantities of green hydrogen and running an EAF on renewable energy (Hoffman et al. 2020). Estimates suggest that in the absence of a 'green premium' or emissions penalties, green hydrogen costs in the range of $1–2/kg would be required to compete with conventional production methods (Ellis & Bao 2020). More detail on the outlook for hydrogen production costs is discussed in Section 4.2 – Hydrogen.
- **Electrolytic steel production (electrowinning)** – An alternative to both the BF-BOF and DRI-EAF production routes is the reduction of iron ore directly into steel using electrolytic processes. These processes are attractive as they offer a potential 'hedge' against the possibility of sustained uncompetitive costs for hydrogen, on which the viability of a H2-DRI route hinges. Electrowinning is a mature process for extracting certain metals from their ores using electricity and is already widely used in producing lead, copper, and rare-earth elements. A method of electrowinning steel directly from iron ore via low-temperature electrolysis (IEA 2020d) has been demonstrated at laboratory scale, with the European SIDERWIN initiative led by ArcelorMittal developing the technology and aiming for validation at pilot scale by 2022 (Venkataraman et al. 2019). Early studies suggest this technology could eliminate process emissions in steelmaking and reduce energy use by 31% relative to conventional production (SIDERWIN 2021).
- **Electrolytic steel production (molten oxide electrolysis)** – Molten oxide electrolysis (MOE), also known as pyro-electrolysis, is another emerging technology for steelmaking, similar to that used in the Hall-Héroult process for producing aluminium from alumina. MOE involves dissolving iron ore at very high temperatures (around 1600°C) and passing an electrical current through a liquid electrolyte solution to produce liquid iron, which is then coupled with scrap metal or another carbon input in an EAF to create liquid steel (West 2020). This technology could be emissions-free and is expected to require less energy compared to low-temperature electrolysis routes such as electrowinning but faces a number of technical challenges in reaching the commercial stage and is not likely to be available until after 2030. Boston Metal, an American company, has patented an inert anode and is aiming to demonstrate MOE technology at industrial scale, with funding support from a number of companies including BHP (Mining Magazine 2021).

The key technologies that can allow Iron and steel supply chain decarbonisation are shown in Table 11, including indicative timelines for deployment, technology readiness level and maximum potential for emission abatement.

20 Data from International Energy Agency (2019), US Energy Information Administration (2020), assumes grid emissions intensity of 0.1827 Mt CO_2e/PJ. Emission intensity if reduced by a further 35% if renewable energy is used (Bartlett & Krupnick, 2021)

TABLE 11: Summary of abatement technologies in the Iron and steel supply chain

Process	Incumbent technology/ process	Abatement technology/ process	Technology status[21]	Year deployable	Maximum abatement potential
Iron ore production	Diesel or gas-powered electricity generation	Grid-connected electricity	Deployment	2020	Dependent on grid generation mix
		Renewable electricity generation	Deployment	2020	100% reduction in indirect emissions
	Diesel-powered mining equipment	Electric-powered equipment	Deployment	2020	100%, dependent on electricity source
	Diesel-powered trucks	Trolley assist	Demonstration	2020	30% with existing haulage fleet. Supports deployment of alternative haulage technologies
		Battery-electric trucks	Demonstration	After 2025	100% if powered with renewable electricity
		Fuel-cell electric trucks	Demonstration	After 2025	100% if powered with green hydrogen
	Production of waste rock	Mineral carbonation using waste rock	Research and development	After 2025	NET, dependent on waste specifics
Steelmaking	Grid-powered electricity use	Renewable electricity generation	Deployment	2020	100% reduction in indirect emissions
	Conventional blast furnace production route (BF-BOF)	Uptake of best available technologies and process optimisation	Deployment	2020	30% reduction in energy use and emissions
		BF-BOF with CCS retrofit	Demonstration	2025	50–60% if combined with top gas recycling
		Natural gas DRI-EAF	Deployment	2020	68% reduction if using renewable electricity
		Hydrogen DRI-EAF	Demonstration	2035	98% if powered with renewable hydrogen
		Increased scrap-based production via EAF	Deployment	2020	56% reduction in energy use compared to BF-BOF. Abatement potential will depend on electricity source and availability of scrap
		Electrowinning	Research and development	2030	87%
		Molten oxide electrolysis	Research and development	2030	100%

21 Based on Technology Readiness Level and Commercial Readiness Index (ARENA 2019b, ARENA 2014)

3.2 Aluminium

3.2.1 Supply chain structure and context

Bauxite mining

Australia is the world's largest producer of bauxite and home to the second largest reserves (approximately 22%, World Bank 2017). Australia produced 107 Mt of bauxite in 2019–20, with 41 Mt (38%) exported at a value of $1.7 billion (DISER 2021), as shown in Figure 7. There are currently five large bauxite mines in Australia operated by three companies: Alcoa (two mines in Western Australia), Rio Tinto (one mine in the Northern Territory, one in Queensland) and South32 (one mine in Western Australia).

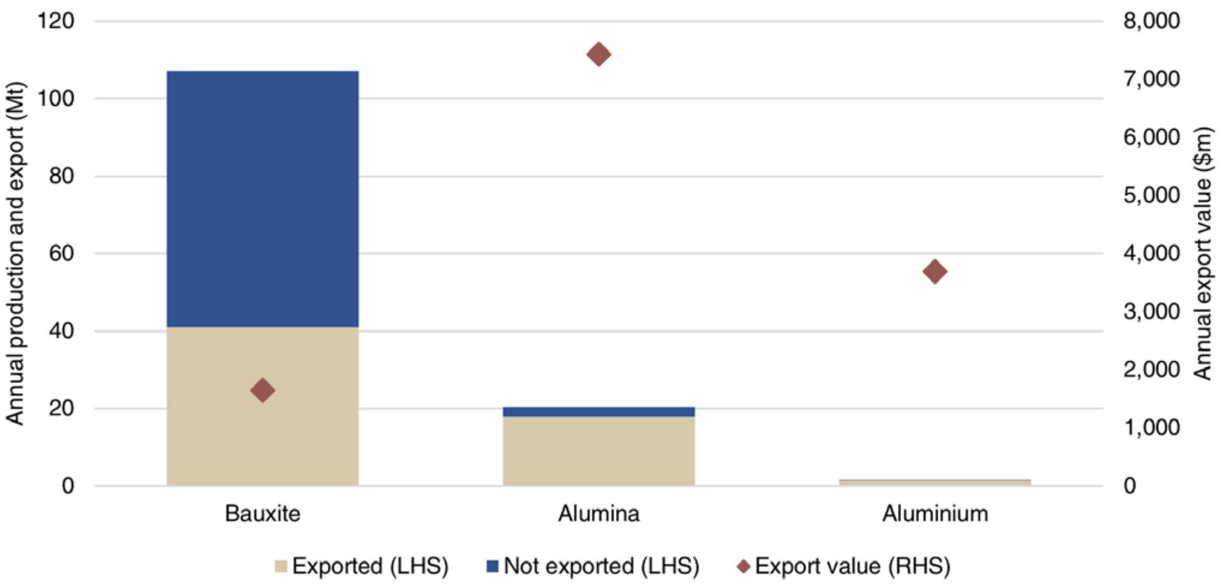
Alumina refining

Australia is the second largest producer and largest exporter of alumina globally, with 87% of domestic production exported. Together, China (63%) and Australia (15%) account for most of the global output. In 2019–20, Australia exported 17.9 Mt of alumina worth $7.4 billion (DISER 2021). There are six alumina refineries operated by the same three companies as for bauxite mining: Alcoa (three refineries in Western Australia), Rio Tinto (two refineries in Queensland, one of which is a joint venture with RUSAL) and South32 (one refinery in Western Australia). Alumina refineries are generally located on or near coastlines to facilitate export of alumina or transport to aluminium smelters.

Aluminium smelting

Australia is the sixth largest exporter of crude aluminium by value, accounting for around 5% of global exports in 2018 (Rusmet 2019). In 2019–20, around 91% of Australia's 1.57 Mt of aluminium was exported, with a value of $3.7 billion (DISER 2021). Major export markets are Japan, South Korea and the US. There are four aluminium smelters in Australia: Alcoa's operations in Victoria, Rio Tinto operations in Tasmania and Queensland, and a joint venture between Rio Tinto Alcan, CSR and Hydro Aluminium operating Tomago Aluminium in New South Wales. The location of Australia's smelters tend to be based on the availability and proximity to historically low-cost electricity sources.

FIGURE 07: Export quantity and value of Australian bauxite, alumina, and aluminium in 2019–20[22]



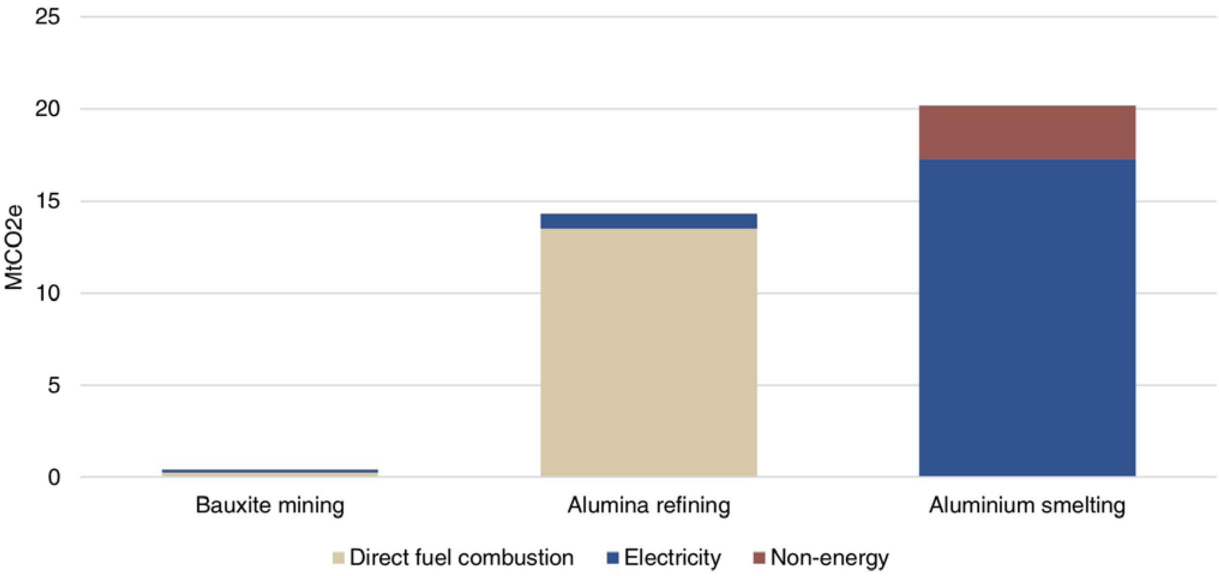
3.2.2 Energy use and emissions

The Aluminium supply chain is one of the largest sources of emissions in Australia, responsible for around 4% of national emissions in 2020 (DISER 2020a). The majority of emissions are due to aluminium smelting (58%) and alumina refining (41%), which are both based on the use of fossil fuels – either through direct combustion for heat or electricity generation

22 Calculated from DISER (2021)

(Figure 8). Aluminium smelting in particular is a major consumer of electricity, accounting for around 11% of electricity use in the National Electricity Market (NEM) in 2019–2020 (Australian Aluminium Council 2021, Australian Energy Regulator 2021a).

FIGURE 08: Emissions sources in the Aluminium supply chain



Bauxite mining

Most bauxite occurs close to the surface and with relatively small quantities of overburden (waste rock). This means that the majority of bauxite can be mined and processed without beneficiation (crushing, grinding and further treatment of bauxite ore to concentrate minerals). As such, energy use and emissions in the production of bauxite are entirely from mining and haulage processes.

Energy use from bauxite mining and haulage totalled an estimated 4.7 PJ in 2019–2020. Most of this energy was from the use of diesel in mining (2.3 PJ) and haulage (1.5 PJ), with the remainder (0.8 PJ) from electricity in mining. This resulted in emissions of around 0.43 $MtCO_2e$, which are far outweighed by emissions in other areas of the Aluminium supply chain.

Alumina refining

The process of refining alumina from bauxite ore is energy intensive, requiring around 10.3 GJ of energy and two tonnes of bauxite per tonne of alumina produced through the Bayer process. The two major steps in alumina refining are digestion and calcination, both of which use process heat that is currently derived from fossil fuels. Digestion requires steam at temperatures ranging from 145–265°C (Donoghue et al. 2014) which consumes around two-thirds of the thermal energy required in alumina refining (ARENA 2019a). Calcination uses the remaining one-third of thermal energy through the production of heat above 800°C from gas, generally using either gas suspension calcination or circulating fluidised bed calcination. All of Australia's alumina refineries have combined heat and power generation (cogeneration) facilities which use coal, gas, or biomass fuels.

Aluminium smelting

Crude aluminium is produced from alumina through electrolysis, otherwise known as the Hall-Héroult smelting process. This is a highly energy-intensive process in which near-pure alumina is dissolved at around 950°C in a molten salt bath, through which an electric current is then passed. This process uses around 14.4 MWh of electricity and two tonnes of alumina per tonne of crude aluminium produced (Australian Aluminium Council 2021). As aluminium smelting is a 'continuous flow' operation that is not well-suited to interruption[23], it requires a constant supply of power, which is

23 Power supply interruptions for two to three hours can be managed by the smelter, but cause instability in the process. Longer power losses cause the cells to cool substantially and eventually 'freeze', causing loss of capacity and requiring significant remediation to resume operation, with costs in the order of $50 to 70 million for an average smelter (Australian Aluminium Council 2005)

currently provided entirely through grid electricity produced predominantly from coal. This results in around 10.8 tCO_2e of electricity-related emissions per tonne of crude aluminium (Australian Aluminium Council 2021), although this would vary depending on smelter location and the emissions intensity of nearby grids. Recycled aluminium does not require electrolysis. Instead, the metal is simply re-melted, using only 5% of the energy required to produce aluminium from raw ore.

The Hall-Héroult process also uses carbon anodes to conduct electricity and improve overall efficiency, consuming around 450 kg per tonne of aluminium produced (Rivedal 2018). This produces carbon dioxide, with carbon anodes responsible for around 1.6 tCO_2e per tonne of aluminium (Australian Aluminium Council 2021), or 13% of total emissions from smelting.

3.2.3 Decarbonisation options and challenges

Table 12 summarises the major abatement opportunities within the Aluminium supply chain, described in more detail below for specific supply chain stages and processes. Emissions in the Aluminium supply chain originate from a handful of processes, involving direct fuel combustion, electricity and non-energy sources. As such, there are important abatement options across most pillars of decarbonisation, with the supply and uptake of zero emissions energy of particular significance.

TABLE 12: Abatement opportunities across decarbonisation pillars for the Aluminium supply chain

		Bauxite mining	**Alumina refining**	**Aluminium smelting**
Pillar 1: Material and energy efficiency	Material efficiency	Upstream impacts from increased secondary production		Secondary production from scrap
	Energy efficiency	Mine site and plant optimisation Uptake of best available technologies		Demand response, improved cell design
Pillar 2: Zero emissions energy and feedstocks supply **Pillar 3: Electrification and fuel switching**	Zero emissions electricity	Trolley assist, battery-electric trucks	Electrified Bayer process*	Decarbonise existing electricity use
	Other zero emissions fuels	Biodiesel truck haulage	Biomass use in Bayer process heat	
		Hydrogen truck haulage	Green hydrogen use in Bayer process heat*	
Pillar 4a: Non-energy emissions	Process improvements			Carbon anode alternatives*
	Zero emissions feedstocks			
Pillar 4b: Capture or offset residual emissions	CCS of process emissions		Bayer process with CCS*	
	Negative emissions technologies	Mineral carbonation (mine tailings)*		

*These technologies are currently classified as having a TRL of 1-6 and require further research, development and demonstration.
CCS: carbon capture and storage

Immaterial or uncertain role	Potential role in transition to zero or near-zero emissions options	Important role in near-term abatement but insufficient for net zero emissions	Long term, zero or near-zero emissions potential

Bauxite mining

Given energy use and emissions in bauxite production are entirely from mining processes and haulage, the decarbonisation options for iron ore production presented in Section 3.1.3 also apply here.

Alumina refining

Although the energy intensity of Australia's alumina refineries are around the global average (World Aluminium 2020a), there are near-term opportunities to unlock further energy and emissions benefits through deployment of mature technologies. However, many of these technologies are more suited to greenfield builds for which there may be limited scope in Australia. These include the following:

- **Tube digestion** – Tube digestion consists of just 3 or 4 tubes within a larger pipe, as opposed to traditional shell and tube heat exchangers which use bundles of several hundred small diameter thin-walled pipes. This can reduce the energy intensity of digestion processes by up to 15% (Hatch 2020), while also saving costs due to decreased equipment complexity and maintenance (Kelly et al. 2016). This technology is likely to be economically viable for greenfield sites only, as conversion from existing digester design would require complete redesign and plant rebuild (Chan et al. 2019).
- **Optimising calcination energy use** – Fluidised bed calcination and gas suspension calcination are considered the best available technologies for calcination, offering energy savings of around 60% compared to conventional rotary kilns (Chan et al. 2019). Both are mature technologies, but there is ongoing research to optimise performance, in terms of both alumina quality and energy use (Brough 2020). These technologies do not currently allow the elimination of fossil fuel-based emissions, but there is research underway to allow retrofit of renewable powered energy sources (either electricity or hydrogen) (Nathan 2021).

While the above technologies could play an important role in reducing emissions in the short-to-medium term, they will not be sufficient for a net zero emissions pathway. The key opportunity to eliminate emissions in the alumina processing step is replacing the fossil fuels (gas and coal) currently used for heating in digestion and calcination. Alternative technologies and energy sources are outlined below:

- **Mechanical vapour recompression (MVR)** – MVR reduces the amount of gas-fired steam generation required for digestion by upgrading waste steam (ARENA 2019a), with the potential to reduce emissions from this process by up to 100% if powered by renewable energy (Chatfield 2020). Similarly to waste heat optimisation and heat pumps, it uses electricity to recompress steam and reduce the heating load, lowering the operating fuel costs (Martin 2005). To eliminate emissions completely, steam required at start-up would also need to be provided by renewable energy. This is a developing technology for alumina processing with only a few small installations in alumina refineries globally; however, it is widely used in other industries, including pulp and paper processing and there is a trial underway at a refinery in Western Australia to investigate the technical and commercial feasibility of using MVR powered by renewable energy to produce process heat (ARENA 2021). Scale strongly impacts cost-effectiveness – estimates are that cost must be below US$115–230/kW to be cost competitive, and for small systems cost can be as high as US$1150/kW (Bantle et al. 2018). The economics for MVR systems in Australia are predicted to be competitive for greenfield sites, but retrofit requires significant capital investments ($2–5 billion) and is challenging due to the space required for installation (Chatfield 2020).
- **Concentrated solar thermal for process heat** – Replacing a portion of the gas used in alumina production with concentrated solar thermal (CST) is a promising opportunity currently being investigated in Australia (ARENA 2019a). CST for power and heating is already used in Australia (Sundrop 2016), although this is at a smaller scale than would be required for an alumina plant. Analysis suggests that for low-temperature processes such as digestion, new CST is already cost competitive with existing gas. At the higher temperatures required by the calcination process, a new CST installation would be considerably more expensive, but per unit costs can be expected to decline as scale increases. This technology is being developed in Australia for application to alumina calcination – replacing up to half the heat requirement (Kraemer 2020). All of the refineries in Australia are located in either good or very good solar resource areas (~2100–2500 kWh/m2/year) (ARENA 2020), but considerable land requirements are likely to be a major barrier to uptake.
- **Biomass cogeneration for steam** – Combined heat and power (CHP) plants are a mature technology used globally that are more efficient than combined cycle plants[24] and enable further reductions in steam generation emissions through the use of biomass as a fuel. Biomass cogeneration plants can achieve overall efficiencies of up to 70–90% (IRENA 2015) compared to combined cycle plants in the range of 30–50% (Colley 2010). During 2017, a pre-

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24 A combined cycle power plant uses both a gas and a steam turbine to produce up to 50% more electricity from the same fuel than a traditional simple cycle plant. The waste heat from the gas turbine is sent to the steam turbine, which generates extra power (GE 2021).

feasibility trial of a 30% biomass fuel load was completed at the South32 Worsley alumina operation in Western Australia (South32 2020), driving a proportionate reduction in emissions compared to an entirely fossil fuel based load. Despite technical feasibility, future widespread adoption of biomass for steam generation may be constrained by limited feedstock availability and the considerable heat requirements for alumina plants (ARENA 2019a).

- **Hydrogen for process heat** – Hydrogen is able to replace gas firing in boilers for the production of low-temperature heat in the digestion process. Hydrogen-ready boiler technology is available but expensive, and retrofit may incur additional costs (Worcester-Bosch 2020). As boilers require semi-regular replacement, there may be an opportunity for new equipment installation at the end of asset life. The economics of this substitution will be highly dependent on the cost trajectory for hydrogen. Hydrogen may also be an alternative for gas use in alumina calcination, but research in this area is still at an early stage (TRL 2–3) (Nathan 2021). As hydrogen emits zero emissions when used, this solution has the potential to eliminate calcination emissions, depending on technical and retrofit considerations.
- **Electrification of process heat** – Electric boilers can be used to generate steam and provide the low heat demand for alumina refineries and are already commercially available. There are currently limited technology options for electrification of the high temperature heat requirement for calcination (needing temperatures of around 1000°C), but there is research underway (TRL 2–3) to allow retrofits to current systems to use electricity (Nathan 2021). Increased electrification of alumina refineries combined with demand response could further supplement electricity reliability (Australian Aluminium Council 2020b).

The Bayer process of converting bauxite ore into alumina also creates a significant amount of waste known as red mud, resulting from a loss of iron from the bauxite ore. Approximately 1.0–1.5 tonnes of red mud are produced per tonne of alumina, presenting an environmental issue due to fine particle size, alkalinity and toxicity (Stanford 2016). Red mud also contains significant quantities of untapped metallic constituents such as iron, aluminium, titanium, sodium, and silicon. While red mud is currently mostly stacked and stockpiled, there are opportunities to extract metallic constituents (Ujaczki et al. 2018) and reuse the waste in the cement industry (Gleeson 2020) or use the residue to sequester CO_2 (Stanford 2016). Alcoa has developed a process of direct carbonation using CO_2 from industrial gas streams that reduces the alkalinity of red mud for use in cement and road construction (Tran 2016). Application of this process across all Australian facilities could store around 0.6 $MtCO_2e$ per year, equivalent to 2% of supply chain emissions.[25]

Aluminium smelting

Energy use in aluminium smelting is already completely electrified. As such, sourcing zero emissions supply of electricity is the primary decarbonisation challenge facing this stage of the supply chain. This is a major challenge for several reasons. First, as discussed above, aluminium smelting is highly energy intensive and requires near-constant power. Converting existing electricity demand to renewables would require a significant expansion of the electricity sector to meet demand and considerable amounts of storage or other flexibility measures to guarantee energy reliability. This is further complicated by the fact that most Australian smelters, unlike for global competitors such as Norway and Russia, are not located in proximity to hydro resources that could provide zero emissions, constant electricity. Switching the entire 22.6 TWh (Australian Aluminium Council 2021) of grid electricity consumed by smelters in 2019 to renewables represents a 70% increase in the total amount of Australia's variable renewable generation (wind and solar PV) in 2018–19 (DISER 2020e). Clearly, this is a significant shift in the scale of the energy system and demands coordination and planning between the electricity system and the aluminium sector.

Costs are another major barrier to uptake of zero emissions electricity in aluminium smelting. Energy is a very significant component of overall aluminium costs (estimated in the range of 30-40%) (Australian Aluminium Council, 2020a), with the viability of Australian smelters already threatened by globally uncompetitive, expensive power. Historically, the competitive advantage of Australia's smelters was based on an ability to contract directly with the lowest cost energy supplier, typically coal-fired power plants that had run down capital costs and were able to provide cheap energy to cover operational costs only. This arrangement is challenged by the ongoing transformation of Australia's electricity grid as coal-fired generation exits the system and is replaced by variable renewable energy generation (covered in Section 4.1 – Electricity generation). As competitors and customers decarbonise, the basis of competitiveness will need to shift to diverse and high-quality renewable resources. All of Australia's current smelter facilities are located near identified Renewable Energy Zones, with the delivered cost of electricity from these areas dependent upon other potential parallel system developments. As detailed further in Section 4.4, the need for reliable renewable energy supply – typically achieved through energy storage including batteries and pumped hydro – is by far the largest driver of electricity costs.

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In a global context where all smelters are using low emissions electricity, Australian smelters may be able to compete using firmed renewables. However, it will be important to find every opportunity to minimise storage costs. Energy system flexibility through demand management reduces the need for storage, and aluminium smelters are one potential source.

As major consumers of energy, aluminium smelters could theoretically play a key role in energy system flexibility through demand side response (DSR), adjusting their operations – or load shedding – at times where energy demand exceeds supply. DSR is a high-value opportunity, the economics of which will be driven by, among other factors, the existence of supportive market mechanisms and sufficiently high payment for demand side response to compensate production losses. AEMO's Reliability and Emergency Reserve Trader (RERT) mechanism allows large energy users to be paid for providing DSR during critical shortfalls in energy reserves (AEMO 2020b).

DSR has been provided by smelters in the past but is currently limited due to associated costs and risks for smelters depending on the duration of energy modulation (Australian Aluminium Council 2017). Currently, smelters are not able to sustain production downtime for more than a few hours. This inflexibility was evidenced by a five-hour power outage at the Portland smelter in Victoria in 2016 that curtailed production to 27% of plant capacity and took months before full production was restored (Judd 2016). Innovations to improve the thermal insulation of electrolytic cells (pots) are being trialled, which would provide smelter operators greater ability to dynamically manage energy use in response to grid demand for longer periods of time (IEA 2020b). One piece of analysis suggests that retrofitting such technology to allow a 20% modulation of power in Australian smelters (at an assumed cost of $50M per smelter) would pay itself off in just over two years (Wong et al. 2020). However, this is yet to be proven commercially viable at scale and there are currently limited price signals to incentivise installation in the Australian context.

Increased secondary production through recycling is another major opportunity to reduce emissions from aluminium production as it bypasses the need for energy- and emissions-intensive electrolysis. Recycling is a key part of the global aluminium supply chain, with new and old scrap[26] providing 33% of production in 2018 (World Aluminium 2019). The energy intensity of primary aluminium production is around ten times higher than from reusing new and old scrap. Secondary production also tends to cost less, with scrap availability the key constraint. However, recycling is currently limited in Australia due in part to insufficient scale of aluminium production and uncompetitively high labour costs. The small amount of aluminium that is captured for reuse is currently exported. If one-third of Australia's aluminium supply shifted to secondary production (in line with the global average), this would reduce emissions by an estimated 7 $MtCO_2e$/year (19%)[27] through avoided alumina production and smelting. A number of technologies are being investigated to further improve the efficiency and reduce energy use from recycling but have not yet been commercialised (Kadolkar et al. 2004, Chan et al. 2019, DeYoung et al. 2011, US Department of Energy, Energy Efficiency and Renewable Energy 2020).

Other than emissions from the generation of electricity used for smelting, the other key source of emissions in the aluminium smelting process is from the production and use of carbon anodes, which can contribute up to 15% of the emissions from the smelting process (Australian Aluminium Council, 2021), depending on the emissions intensity of the smelter's electricity source. These emissions come from the use of fossil fuels (including coal coke and pitch) in the manufacture of the anodes and the emissions produced during the use of the anodes, mainly carbon dioxide. Smelting can also release perfluorocarbons (PFCs) if there are process upsets, called anode effects, which account for approximately 13% of anode-related emissions. There are a range of solutions proposed for the decarbonisation of these emissions and the consensus is a combination of these will be the most effective solution once the technologies have been further developed:

- **Inert anodes** – Inert anodes have been under investigation since the current aluminium refining process was first developed, but there have been limited successes to date in finding suitable materials. There are two large-scale projects being undertaken, one by Rusal (Rusal 2021) and the other a joint venture between Rio Tinto and Alcoa called ELYSIS (ELYSIS 2021), both aiming for commercialisation before 2025. Inert anodes are not consumed, so have a significantly longer lifetime than carbon anodes which are replaced each month. However, they would have a slightly higher energy use due to the higher voltage required (U.S. Department of Energy, Energy Efficiency & Renewable Energy 2007), which has the potential to outweigh the benefits of the technology if renewable energy is not used. The operating cost is estimated to be reduced, but there is very limited information available. Retrofit costs would be spread over time as the anodes would be incrementally installed, with some cell modifications required. The anode produces oxygen during operation, which could be captured and sold (Haraldsson & Johansson 2018).

26 New scrap is that arising during the production of aluminium products before being sold to the final user, while old scrap results from the collection and/or treatment of products after use (International Aluminium Institute 2009).

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- **Wettable cathodes** – Wettable cathodes are a technology that replaces the smelting reaction cell with a new design and material (titanium diboride) that allows a reduced distance between the anode and cathode (ACD), allowing a reduction in energy consumption of up to 20% (U.S. Department of Energy, Energy Efficiency & Renewable Energy 2007). Wettable cathodes have been trialled at industrial scale but are not yet commercial, and estimated costs are unavailable (Pawlek 2010).
- **Novel cell designs** (combinations of other developments) – There are a number of novel cell designs proposed to reduce emissions and energy use in smelting, with key concepts being:
  - Combined inert anodes and wettable cathodes – this could allow the increased energy use of the inert anode to be offset by energy efficiencies provided by the wettable cathode (U.S. Department of Energy, Energy Efficiency & Renewable Energy 2007).
  - Multipolar cells – Multipolar electrode configurations could greatly increase the productivity of the cell by using multiple electrodes in a single reactor, but this arrangement would require a stable ACD, and could only be applied with inert anodes.
  - Vertical electrode cells – These cells build on the multipolar cell and use several alternating anode/cathode electrodes in a vertical arrangement with a different electrolyte which allows lower temperatures in the cells. There is a predicted 25–30% reduction in energy usage, increased productivity per cell, and the elimination of anode effects (Haraldsson & Johansson 2018). There have been a number of trials of this technology, but high costs or closures of sites have halted progress (U.S. Department of Energy, Energy Efficiency & Renewable Energy 2007).

Other alternatives to conventional aluminium production are at an early stage of development:

- **Carbothermic reduction** – This process reacts alumina with carbon at high temperatures to form aluminium and carbon monoxide. It is estimated to be 20–30% more energy efficient (Dialogue on European Decarbonisation Strategies [DEEDS] 2019) and have capital costs 50% lower (Balomenos et al. 2011) than the Hall-Héroult process. However, the process would still produce substantial emissions due to reductant use and high-heat requirements that would have to be mitigated, increasing capital and operational costs (White et al. 2012). Studies have suggested that both of these emissions sources could be abated through the use of concentrated solar thermal for heating, and biomass-based reductants (Balomenos et al. 2011). The technology readiness level is currently considered as TRL 2–3, and not expected to be available before 2050 (DEEDS 2019).
- **Production from kaolin clay** – The concept of using kaolin clay as a raw material (rather than bauxite) predates the Hall-Héroult process, but is still considered TRL 1–2 (DEEDS 2019). The process involves the chlorination and electrolytic reduction of the clay, and is estimated to be 12–46% more efficient (U.S. Department of Energy, Energy Efficiency & Renewable Energy 2007). Benefits of this process include the ability to use a new source of inexpensive and widely available ore, and a faster and more efficient conversion process. In addition, smaller electrolytic cells could be used, and these would not have the limitations of needing continuous operation (like the current process requires). This allows producers to take advantage of demand response cycling to reduce electricity costs.

The key technologies that can allow Aluminium supply chain decarbonisation are shown in Table 13, including indicative timelines for deployment, technology readiness level and maximum potential for emission abatement.

TABLE 13: Summary of abatement technologies in the Aluminium supply chain

Process	Incumbent technology/ process	Abatement technology/process	Technology status[28]	Year deployable	Maximum abatement potential
Bauxite mining	Diesel or gas-powered electricity generation	Grid-connected electricity	Deployment	2020	100%, dependent on grid generation mix
		Renewable electricity generation	Deployment	2020	100% reduction in electricity emissions
	Diesel-powered mining equipment	Electric-powered equipment	Deployment	2020	100%, dependent on electricity source
	Diesel-powered trucks	Trolley assist	Demonstration	2020	30% with existing haulage fleet. Supports deployment of alternative haulage technologies
		Battery-electric trucks	Demonstration	2030	100% if powered with renewable electricity
		Fuel-cell electric trucks	Demonstration	2022	100% if powered with green hydrogen
Alumina refining	Conventional digestion	Tube digestion	Deployment	2020	15% reduction in energy use
	Low temp process heat for digestion	Mechanical vapour recompression	Demonstration	2022	100% of steam generation related emissions, if powered with renewable electricity
		Electrification for steam generation	Deployment	2020	100% of steam generation related emissions, if powered with renewable electricity
		Biomass for steam generation	Demonstration	2020	30% of steam generation emissions can be replaced by biomass (demonstrated, could increase as technology develops)
		Hydrogen for steam generation	Demonstration	2020	100% of steam generation emissions, if green hydrogen is used
	High temp process heat for calcination	Electrification of calcination	Research and development	Highly uncertain	100% of calcination emissions, if powered with renewable electricity
		Concentrated solar thermal for calcination	Research and development	Highly uncertain	50% of calcination emissions (could increase as technology develops)
		Hydrogen for calcination	Research and development	2025	100% of calcination emissions, if green hydrogen used
	Disposal of red mud	Reuse of red mud: • cement feedstock • CO_2 sequestration	Demonstration Research and development	2020 Highly uncertain	NET, dependent on waste specifics
Aluminium smelting	Grid-connected electricity	Renewable electricity generation	Deployment	2020	100% reduction in electricity emissions
	Carbon anodes	Inert anodes and other novel cells designs	Research and development	2024	100% of non-energy emissions from smelting
	Conventional production via Hall-Héroult process	Scrap-based production	Deployment	2020	95% reduction in energy use compared to primary production
	Inflexible production	New cell design allowing greater demand side response	Demonstration	2022	No direct abatement impact, but this provides greater system flexibility and assists the transition to zero emissions, reliable electricity

28 Based on Technology Readiness Level and Commercial Readiness Index (ARENA 2019b, ARENA 2014)

3.3 Other metals

3.3.1 Supply chain structure and context

The Other metals supply chain in the Australian Industry ETI covers a range of metals produced in Australia (excluding iron ore, covered under Section 3.1 – Iron and steel, and bauxite, covered under Section 3.2 – Aluminium). These include copper, nickel, lithium, and zinc, among others. Although not typically considered hard to abate in the same manner as other Australian Industry ETI sectors, these metals are expected to feature prominently in a global low carbon transition, and Australia is an important part of global supply chains both in terms of current production quantities and identified resources for future extraction.

Growing focus on environmental, social, and corporate governance is likely to be a key consideration in future metals supply. The metals and mining sector is increasingly exposed to concerns around emissions, water use, deforestation and impacts on local communities. In particular, mining companies have been under recent shareholder and consumer pressure to address scope 3 emissions. This push for socially and environmentally conscious metals production is likely to increase under global decarbonisation amid greater focus on supply chain transparency and product provenance. It will therefore be vital to ensure that metals mining, refining and waste management processes are meeting the expectations of consumers and investors.

As an input to renewable energy and other low carbon technologies, Other metals will play a primary role in a global net zero transition. Figure 9 provides a summary of key metals for different decarbonisation technologies and Australia's relative share of global reserves.

FIGURE 9: Australian production of key metals and possible end use technologies[29]

	Aus % of global reserves	Wind	Solar PV	Concentrating solar power	CCS	Nuclear	LEDs	Electric vehicles	Energy storage	Electric motors
Cobalt	15%	○	○	○	◍	○	○	●	●	○
Copper	12%	●	●	◍	●	◍	◍	●	○	●
Lead	40%	◍	◍	○	○	◍	○	○	○	○
Lithium	11%	○	○	○	○	○	○	●	●	○
Manganese	15%	◍	○	○	●	○	○	●	◍	○
Nickel	24%	◍	○	◍	●	◍	●	●	◍	○
Silver	15%	○	◍	●	○	◍	◍	◍	○	○
Zinc	32%	●	◍	◍	○	○	○	○	○	○

The relative importance of the mineral for each low carbon technology is indicated by shading (black=high, grey=moderate, white=low).

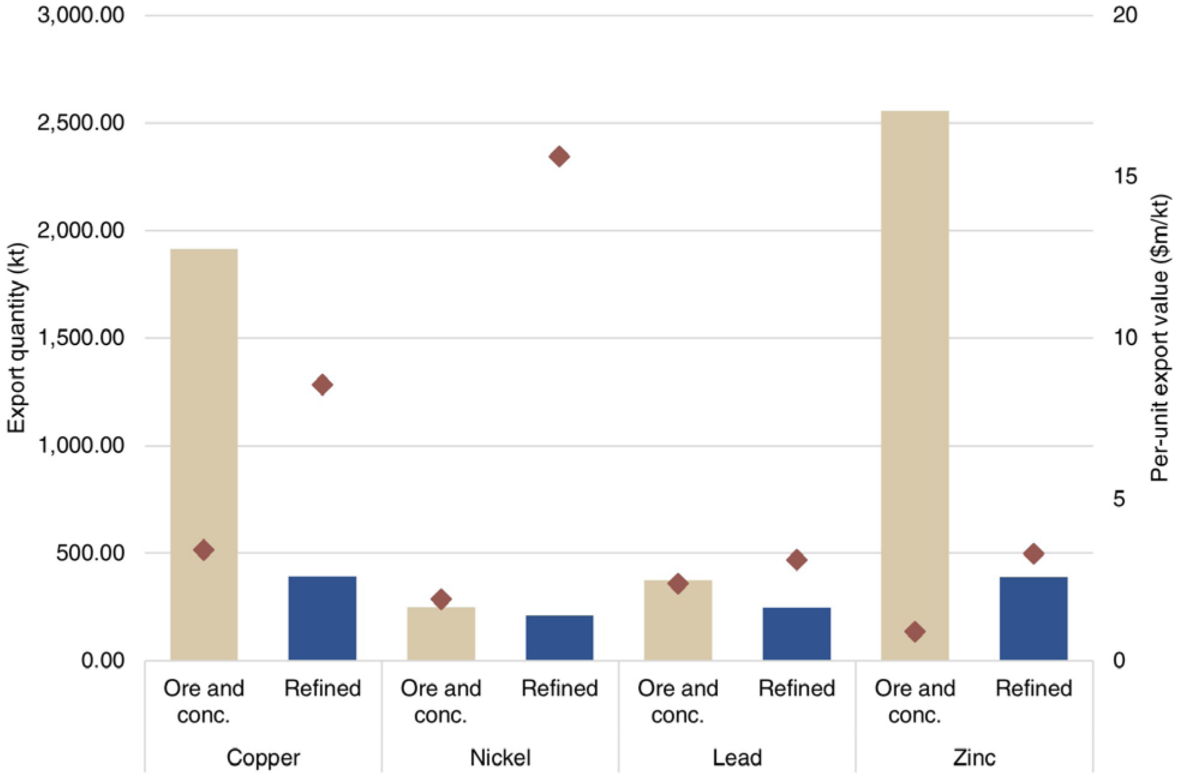
Copper is extracted from either sulphide or oxide ores, with the majority of mined deposits in Australia (and globally) being sulphide ores (Geoscience Australia 2021a). Nickel resources in Australia are predominantly located in laterite deposits (69%); however, the large majority of nickel production is from nickel sulphide ores due to the historic complexity and cost of processing laterite ores (Geoscience Australia 2021b). Zinc ores commonly also contain lead, silver and, in some cases, copper, and zinc is often extracted and processed as a co-product with these other metals (Geoscience Australia 2021c). Lithium resources in Australia are nearly all located in Western Australia, with >99% of Economic Demonstrated Resources. The majority of these resources are within five main deposits, including the largest producing spodumene deposit globally (Geoscience Australia 2021d).

A characteristic of Other metals is their relatively low production quantities and high unit values. This is demonstrated by Figure 10, which shows annual exports and unit values in 2019–20 for a selection of Other metals: copper, nickel, lead and zinc. Australia exports each of these metals in both ore and concentrate form, and as refined metals. Although wide variations in the metal content of ores and concentrates makes comparisons with refined metal (typically above 99.5% purity) inadequate on tonnage alone,[30] these results provide a sense of the magnitude of material being produced and exported. Of note is the considerably higher per-unit value of refined metals, owing to their far greater concentration.

29 Adapted from The World Bank (2017) and the IEA (2021)

30 For example, the copper content of all copper products exported in 2019-20 (includes ores and concentrates, slags, residues, intermediate products, refined copper, copper powder and flakes) was 928 kt, 392 kt of which was refined copper (typically 99.99% purity). This leaves the remaining 536 kt of exported copper content distributed among 1,914 kt of ores and concentrates – a concentration of around 28%. This ranges widely for different metals: non-refined nickel, lead and zinc exported in 2019-20 had concentrations of 15%, 80% and 45% respectively.

FIGURE 10: Quantity and per-unit value of exported copper, nickel, lead and zinc in 2019–20[31]



Note: Bars represent export quantity and correspond to the left-hand vertical axis. Points represent per unit export value and correspond to the right-hand vertical axis.

Exports of bauxite and iron ore in 2019–20 were 41 Mt and 860 Mt respectively, compared to a combined total of just 6 Mt for copper, nickel, lead and zinc (DISER 2021). However, the combined export value of these four metals totalled around $19 billion, compared to $2 billion for bauxite and $102 billion for iron ore. The considerably higher per-unit value of Other metals is evidenced by the fact that although iron ore exports were more than 136 times higher than these Other metals, this factor declined to just over five when comparing the value of exports. Even looking at just the exported value of Other metals ores and concentrates (that is, excluding higher value refined metal exports) the value amounts to just over $10 billion, far higher than bauxite and around a tenth the value of exported iron ore.

The methods used throughout different stages of the Other metals supply chain can vary widely both across and within metals types, depending on specific mine site and ore characteristics. There are numerous factors that drive variations in energy intensity within Other metals, with emissions then determined by the available energy sources. These factors include (The Warren Centre 2020):

- variations in deposit type, ore grade and composition – for example, declining ore grades increase the depth and amount of material mined and processed to produce a given quantity of final product
- geographic location – transport requirements, access to energy sources
- waste to ore ratios – large amounts of waste rock must be transported, currently based on diesel haulage
- material movement methods – equipment reliability and efficiency, haulage distances, level of electrification
- mining method and equipment requirements – differing energy intensity and equipment used in open cut and underground mining (for example, ventilation, lighting, haulage)
- processing method and output (for example, pyrometallurgical vs hydrometallurgical processing).

31 DISER 2021

Mining

Both open cut and underground mining methods are used within the Other metals supply chain, due to the range of metals mined and variability in types of deposits. In Australia, both copper and zinc are mostly extracted through underground mining, whereas nickel mines use either open cut or underground mining depending on the deposit (Geoscience Australia 2020e). Lithium can be mined through either type of mining, but the majority of lithium mines in Australia are open cut.

Open cut mining involves drilling, blasting and digging deposits before removing and transporting ores with heavy machinery such as draglines, shovels and trucks. This method produces large amounts of 'overburden' or waste rock and is preferable when ore deposit characteristics (for example, grade, size, location) make removing overburden cost-effective.[32] Underground mining has significantly less impact on the surface environment than open cut mining and produces much lower quantities of non-ore materials that must be removed. Shafts, tunnels and block cave methods are all used in metals mining to allow access to underground resources for personnel, trucks and machinery. All of the activities associated with open cut and underground mining – including haulage – are classified as 'mining' processes in the Australian Industry ETI analysis.

Beneficiation

After mining, metal ores undergo a process of 'beneficiation' to improve their economic value by removing gangue minerals,[33] producing a higher-grade product (ore concentrate) and waste streams known as tailings. Beneficiation can be achieved through the milling process of comminution, and then separation, both of which are typically undertaken at or in proximity to mine sites to reduce transportation costs. Comminution involves reducing ore size through crushing and grinding to physically liberate valuable minerals from the rest of the ore, with energy use closely tied to ore grade (lower grades ores require more energy input). Once these minerals have been liberated, they undergo a series of separation steps[34] to produce mineral concentrates.

Processing

Following beneficiation, the concentrate is either exported or processed further to prepare the metal for final use in product manufacturing. In Australia the majority of Other metals are not processed beyond the mineral concentrate stage – approximately 52% of copper, 48% of nickel, nearly 100% of lithium and 65% of zinc production are exported as concentrates (DISER 2021, Department of Mines, Industry Regulation and Safety 2020).

There are multiple processing operations, classified as pyrometallurgical (for example, smelting, roasting, reduction), hydrometallurgical (for example, digestion, leaching) or electrometallurgical (for example, electrolytic refining). Hydrometallurgy is often better suited to lower grade ores, and electrometallurgy is usually the last stage in metal production and is preceded by either pyrometallurgical or hydrometallurgical operations. These processes are usually undertaken away from mine sites at refining plants or smelters. The Australian Industry ETI analysis considers all domestic operations downstream of beneficiation as 'processing'. The variability across the metals considered in this supply chain leads to a wide range of processing techniques, which can even differ within a metal type. As an example, copper processing methods depend on whether the ore is a sulphide or an oxide, the former of which is crushed and concentrated through froth flotation, then further concentrated through pyrometallurgy (smelting and refining); the latter is concentrated through hydrometallurgy (through leaching, then solvent extraction and electrowinning). Similarly nickel sulphide ores are generally processed in a flash furnace, and refined through leaching, solvent extraction and electrowinning, while nickel laterite ores are often dried and partially reduced in a rotary kiln furnace and then smelted using a submerged electric arc furnace, or processed through hydrometallurgical processes, such as high pressure acid leaching (HPAL).

3.3.2 Energy use and emissions

As discussed, the processes used to produce Other metals can differ considerably between and within metal types, driving variances in the energy and emissions intensities of different metals. To individually model each metal considered within Other metals and capture this richness at multiple supply chain stages would be a major undertaking, and not within scope of the Australian Industry ETI research and analysis. As such, imperfect generalisations regarding energy intensity, fuel use and emissions will be made for specific metals where possible on the basis of available literature,

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32 For example, open cut operations are the most economical way of mining highly disseminated, low grade ores.

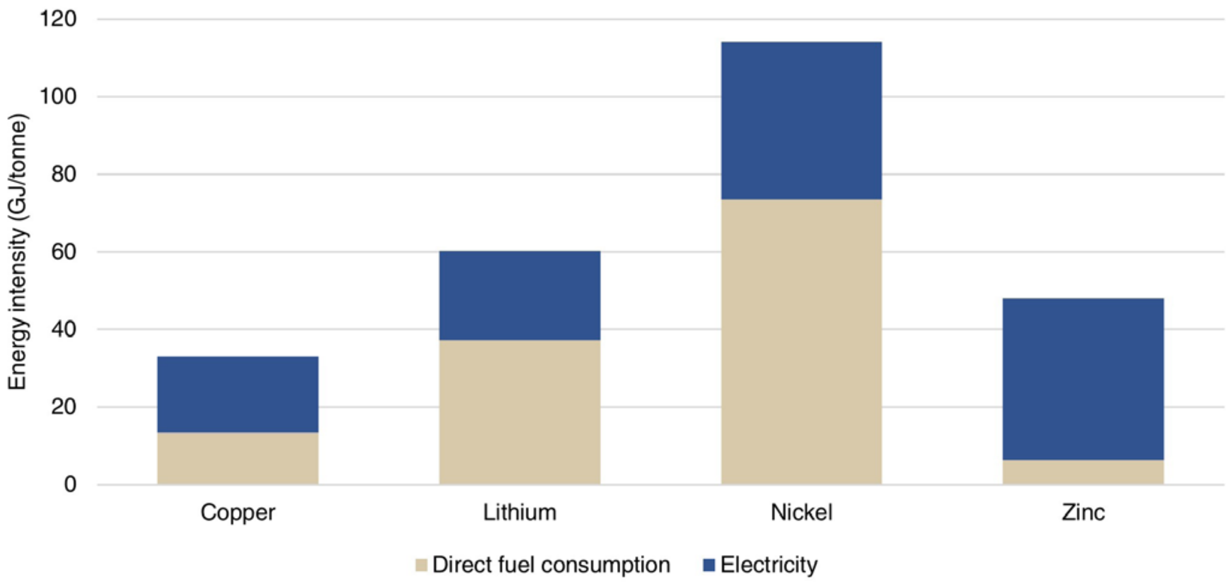
33 Commercially worthless material that surrounds, or is closely mixed with, a wanted mineral in an ore deposit.

34 Processes include gravity concentration, magnetic separation, electrostatic separation and flotation

which will by necessity represent an average of numerous mine sites. Where appropriate, the issues or challenges facing specific metals will be addressed individually in text, rather than modelled separately.

Figure 11 below shows the magnitude and composition of energy use for a selection of Other metals, for mining, beneficiation and processing supply chain steps. As a generalisation,[35] fossil fuels are assumed to be used mostly in mining (predominantly haulage) and processing stages such as refining, while electricity dominates intermediary stages of beneficiation – in particular crushing and grinding processes that account for more than half of electricity consumption in Other metals supply chains. Electricity is also the primary energy source in mine ventilation (for underground mining) and dewatering, where those processes are required in the production and export of various metals.

FIGURE 11: Energy intensity for mining, beneficiation and processing in select Other metals – copper, lithium, nickel and zinc



Mining

Other metals mining in Australia requires predominantly underground mine sites, with non-haulage energy uses distinguishing the supply chain from iron ore and bauxite mining, which are typically based on open cut mining methods. Underground mining has an additional need for electric-powered fans and pumps for ventilation and dewatering that are not required at an open cut mine. Diesel-based haulage represents the largest share of energy use in Other metals mining,[36] with ventilation (for underground mining), drilling and dewatering also reasonably energy-intensive. In underground mining, the drilling energy use is proportionately higher than open cut (Norgate & Haque 2010), run predominantly on electricity and diesel.

Beneficiation

Processes within the beneficiation stage are highly electrified, with comminution (crushing and grinding) the most electricity-intensive mine site process, estimated to contribute up to 36% of mine site energy demand at gold and copper mines (Ballantyne & Powell 2014). Due to the remote nature of most mines, this electricity is provided by on-site diesel or gas generation, with associated emissions intensities of 0.05 and 0.07 Mt CO_2e/PJ (Department of Environment and Energy 2017). Electricity use in beneficiation is also nationally significant, with comminution in Australian copper and gold mines alone accounting for around 1.3% of Australia's total electricity consumption (Ballantyne & Powell 2014).

35 Per data for copper life cycle analysis in Norgate and Haque (2010)

36 For example, while generalisations across metal types are challenging, loading and haulage represents 42% of energy use from mining operations in copper (all processes before beneficiation) per Norgate and Haque (2010)

Processing

Pyrometallurgy involves heating at high temperatures, which is generally achieved through use of fossil fuels such as gas or diesel, in either a reverberatory smelter or oxygen flash smelter, which achieves a 'matte' of about 65% purity (Chan et al. 2019) and a slag formed from the waste materials. While requiring the additional input of oxygen, the oxygen flash smelting process is up to 30% less energy intensive and has lower fuel consumption than the reverberatory smelter, which has been gradually phased out globally since the 1970s (Kulczycka et al. 2017). The slag residue is either discarded, or depending on the materials, can be used as a building material component (Dietz 2014).

The next stages of pyrometallurgical processing include using air to drive off further impurities to produce 'blister' metal (>98% purity), called converting, and then an electrolytic refining process to achieve >99.5% purity (which can also be considered a method of electrometallurgy). There is a significant amount of electricity required for these two process steps, and hence the emissions intensity of the process is directly linked to the power source for the processing site.

Hydrometallurgy describes a process in which crushed ores are mixed with a leaching solution which dissolves the metal being extracted and leaves the remainder of the ore-containing material as a residue. The leach solution then undergoes the solvent extraction process, which removes impurities, and concentrates the metal content. This is followed by electrowinning, which uses an electric current to deposit the metal at a cathode (which can also be considered a method of electrometallurgy). The entire process is performed at significantly lower temperatures than pyrometallurgical processes, which reduces fossil fuel consumption and eliminates the formation of sulphur dioxide emissions, but does generate effluent which needs to be treated (Chan et al. 2019). Over the long term as ore grades decline and producers aim to reduce emissions, hydrometallurgy is predicted to become more widely used due to the increased energy efficiency and highly electrified nature of the process (Wyns & Khandekar 2019).

The leaching process allows extraction of metallic compounds from ores through selective dissolution in solvents (which vary depending on the ore to be liberated), and on average contributes to approximately 22% of mine site energy usage (Coalition for Energy Efficiency Comminution 2021), as gas and electricity consumption. Similarly to beneficiation, the metal being extracted, ore grade and specifics of the mine sites heavily influence the final energy usage and emissions from the process, as well as the type of solvent and leach process required (solvents include sulphuric acid, cyanide and ammonia).

3.3.3 Decarbonisation options and challenges

Table 14 summarises the major abatement opportunities within the Other metals supply chain, described in more detail below for specific supply chain stages and processes. Considerable variability in production characteristics makes it challenging to generalise decarbonisation pathways for Other metals. The optimal paths to decarbonisation are likely to be specific to individual deposits with tailored process engineering, but there are a range of high-level technologies and strategies discussed below that can set the broad context for these diverse mine sites.

TABLE 14: Abatement opportunities across decarbonisation pillars for the Other metals supply chain

		Mining	Beneficiation	Processing
Pillar 1: Material and energy efficiency	Material efficiency	Mine site and plant optimisation Uptake of best available technologies		Secondary production from recycled materials
	Energy efficiency			Plant optimisation Uptake of best available technologies
Pillar 2: Zero emissions energy and feedstocks supply	Zero emissions electricity	Electric equipment Trolley assist Battery-electric trucks	Decarbonise existing electricity use Further electrification options	Decarbonise existing electricity use Direct electrolysis* Electrification of process heat
Pillar 3: Electrification and fuel switching	Other zero emissions fuels	Biodiesel truck haulage		Biomass for high-heat processes
		Hydrogen truck haulage		Hydrogen for high-heat processes

Pillar 4a: Non-energy emissions	Process improvements			
	Zero emissions feedstocks			
Pillar 4b: Capture or offset residual emissions	CCS of process emissions			
	Negative emissions technologies	Mineral carbonation (waste rock)*	Mineral carbonation (mine tailings)*	
* These technologies are currently classified as having a TRL of 1-6 and require further research, development and demonstration.				

	Immaterial or uncertain role		Potential role in transition to zero or near-zero emissions options		Important role in near term abatement but insufficient for net zero emissions		Long term, zero or near-zero emissions potential

Mining

Although not as significant as iron ore or bauxite mining (due to the lower quantities of metals produced), haulage remains an important source of emissions to decarbonise. The technological solutions for decarbonising haulage covered in detail in Section 3.1.3 also apply to Other metals mining.

Zero emissions electricity supply is key to decarbonising already electrified drilling equipment (covered in more detail under 'Beneficiation' below), while eliminating the remaining emissions through the electrification of fossil fuel based mining equipment will play a major role in reducing mine site emissions. Key technologies to electrify mining processes include electric drilling, large electric drilling rigs and electric shovels, all of which are either under development or currently commercially available. Benefits extend beyond emissions reduction from diesel use, and include a safer and healthier environment for operators and reduced shaft ventilation and cooling requirements, as well as reduced maintenance (Gleeson 2020, Epiroc 2021).

The other key development in emissions reduction for metals mine sites is mineral carbonation, as introduced in 'Pillar 4b' of Section 2.4. In particular, nickel mine site tailings are being investigated in Australia for passive sequestration of CO_2 via enhanced weathering of mineral waste (Wilson 2014). The mine site tailings are already sequestering up to 11% of the mine's annual emissions and research to increase the rate of CO_2 sequestration is being undertaken.

Beneficiation

To decarbonise those mining processes that are already electrified, and to unlock emissions benefits of future additional electrification, sourcing zero emissions alternatives to on-site fossil fuel generation is a critical component of the transition for Other metals.

As discussed in Section 4.1, due to their often remote locations, many mine sites source their electricity from on-site fossil fuel generation (predominantly diesel) rather than being connected to electricity grids.[37] As a result of dramatic cost reductions in recent years, 'hybrid' arrangements of renewable generation technologies such as wind and solar PV combined with storage are becoming an increasingly attractive option on economics alone. The commercial prospects for these solutions are likely to improve with continued cost reductions and increased value placed on 'green' production processes.

Along with proximity to regional electricity markets, there are many other factors determining the economic viability of off-grid hybrid power generation. These include land availability, access to finance, brownfield constraints (for example, legacy contracts or infrastructure that might limit options or increase costs of integration) and life of mine.[38] A number of commercial agreement models exist to overcome some of these limitations, including:

- owner built and operated – owner constructed and operated by owner
- lease agreement – power plant constructed by third party, infrastructure is leased and operated by mine
- power purchase agreement – contract between two separate entities regarding the purchase and supply of electricity.

37 Half of all Australian mines that process on-site are not connected to the primary electricity markets (ARENA 2018)

38 As of 2017, hybrid power generation at scale was not economically viable for mine life shorter than 3 years (ARENA 2018)

For high unit value commodities such as Other metals, CAPEX and OPEX from power generation are relatively low in both absolute terms and as a proportion of production costs. This means that where energy costs may be a limiting factor in other industries, energy reliability is the primary concern for mining processes in Other metals. Currently, many mines operate continuously with limited fluctuations in load profile (ARENA 2018). Load shifting is a way that metals producers can introduce greater flexibility into the system and manage power supply and demand. This involves scheduling electricity-intensive activities during times of high solar irradiance to capitalise on PV output. In some instances, this affords greater operational freedom and overall higher throughput – for example, Sun Metals zinc refinery in Queensland was able to increase production by 5% and reduce OPEX by 15% by operating greater smelting capacity during peak PV hours (ARENA 2018). As discussed in Section 4.2, hydrogen could also perform an important energy storage function for off-grid mines due to its application in multiple processes around a mine site and as a backup fuel for electricity generation (Jackson & Molloy 2018).

Globally, there are several recent examples of mine sites developing or installing large-scale renewables and storage systems (Kirk & Lund 2018). Examples in Australia include a 56 MW microgrid project delivering 70% of the Agnew Gold Mine's power requirements (Maisch 2020). The emissions imperative of procuring renewable electricity at mine sites can be expected to increase significantly with higher levels of electrification through widespread deployment of the trolley assist, BEV or FCEV technologies discussed in Section 3.1.3.

Processing

Despite the variety in specific techniques, each of the major processing methods of pyrometallurgy, hydrometallurgy and electrometallurgy have key decarbonisation technologies that can be applied. Electricity is the primary source of energy for electrometallurgy and for leaching processes in hydrometallurgy. As such, decarbonised electricity is also a major opportunity to partially eliminate emissions from Other metals processing.

In addition to this, technologies that can be applied to reduce emissions from earlier pyrometallurgical processes include the following:

- **Waste heat recovery** – Waste heat recovery can be applied to smelting, involving the capture and reuse of heat from the furnace, further reducing the energy input required for heating during other steps in the process.
- **Top submerged lance** – Top submerged lance technology is an example of a best available technology for smelting a range of metals, including copper, nickel and zinc (Hughes et al. 2008). A stainless-steel lance is submerged in the furnace crucible and can deliver process gases or fuels/feedstocks to the furnace. The lance allows batch type operation, which allows smaller scale operations, and provides operational flexibility, lower energy consumption and emissions reductions through better process control (Hoang et al. 2009). There are a number of additional modifications to the process that may be used to reduce overall smelting emissions by up to 80%, including oxygen enrichment (where increasing the oxygen input by 2% can reduce CO_2 emissions by 40% and lower fuel consumption and off-gas volume) and dry feed injection (which improves energy efficiency and enables emissions reductions of up to 60%) (Metso:Outotec 2019).
- **Replacing fossil fuel-based heat** – Depending on the process there are a range of options to replace fossil fuel generated heat, including the use of electricity based high temperature heat such as induction furnaces or plasma arc furnaces (a technology in an early stage of development), and electric boilers and heating in auxiliary processes (Wyns & Khandekar 2019). Hydrogen could also be used as a fuel for current smelting/furnace processes, but there would likely be a need for retrofits including sensors, burners or different metals used in equipment. The high cost of hydrogen has hindered hydrogen to heat projects (RFC Ambrian 2021).
- **Direct electrolysis** – A method of direct electrolysis processing for copper has been developed recently (TRL 2–3), which is similar to the Hall-Héroult smelting process for aluminium. This process is significantly more energy efficient and eliminates the use of fossil fuels for heating and the production of indirect greenhouse gas emissions such as sulphur dioxide (Paiste 2017) through the smelting and converting process. Further development of this novel process could enable a significant reduction in emissions and energy use for copper production in the future (Wyns & Khandekar 2019).
- **Rotary kiln electric furnace** – Processing of nickel laterite ores through an electric rotary kiln and then electric arc furnace is a currently available technology that is not widely used – the large majority of nickel is produced from sulphide deposits due to the relative cost and complexity of processing laterite ores. This is, however, a highly electrified possible future pathway, and while being relatively energy intensive, could allow for emissions reductions when paired with renewable energy (Wei et al. 2020).
- **Post-combustion CCS** – There is potential to apply post-combustion CCS to the smelting process; however, as discussed previously, the dilute nature of post-combustion exhaust leads to higher costs and there are currently limited economic incentives to implement this technology in Other metals.

For hydrometallurgical processing, another key incremental improvement available to mine sites is optimisation via process design changes to use the least amount of solvents and increase the energy efficiency of the reaction, both of which will assist in reducing overall emissions. Despite being a relatively mature processing method there are also ongoing investigations into energy and efficiency improvements in hydrometallurgy, as well as innovative new processes. These include the following:

- **Bioleaching** – Bioleaching is an environmentally friendly and economic method to process low-grade ores and industrial effluents for metal extraction and can be applied to copper, nickel and zinc, among other metals. It involves the use of microorganisms such as bacteria or archaea to extract the metals. To date, bioleaching to recover metals from high-grade ores is very limited due to slow kinetics. Key bioleaching processes include dump, heap and stirred tank bioleaching. Further research will be vital to improve the reaction kinetics and understand how bioleaching can be combined with other approaches to enhance metal recovery rate (Sajjad et al. 2019).
- **Atmospheric acid leaching** – Atmospheric acid leaching is a hydrometallurgical process used for nickel laterite ores that requires fewer inputs and milder conditions (lower temperatures and pressures) than pressure acid leaching; however, it generally has a much lower extraction efficiency. There is research into additives and surfactants that can be used to improve efficiency in the atmospheric leaching process, making this a more useful alternative process (Zhang et al. 2019).

Another important consideration for Other metals is the potential for material recovery and reuse. Increased rates of recycling can serve as an important decarbonisation strategy by avoiding a number of energy- and emissions-intensive supply chain steps.

The potential for material recovery and reuse will be largely determined by the length of product life, which can vary widely. Metal products are used in a number of different applications, from long-lived infrastructure (for example, power lines, bridges) where they are locked up for decades, to consumer durables (for example, cars, computers and refrigerators), short-life consumables (for example, aluminium packaging) and direct dissipation uses (for example, zinc for galvanic protection).

Many of the uses of Other metals in a decarbonising world will be in relatively short service life products. For example, whereas nickel has typically been used in stainless steel with a service life of decades, in batteries it will return for recycling in less than 10 years. Similarly, traditional lithium uses were often dissipative (for example, aluminium smelting, lubricants) or longer lived (for example, ceramics). However, as the battery industry generates greater levels of demand, lithium will also be available for recycling in under 10 years. At their end of life, varying portions of the metals in these products will be recycled, dissipated or disposed of in the environment. The metals returned from recycling (secondary flows) then serve to replace some portion of primary demand.

The increasing circularity of Other metals and scrap recycling volumes will be important drivers to monitor for the Australian metals production and export markets. Domestic processing of collected scrap decreased significantly – from 67% in the early 2000s to 41% in early 2010s – while the export of scrap increased accordingly (Golev & Corder 2016). Technological improvements and policy support will play critical roles in how the Australian metals recycling industry develops to meet demand from low-carbon technologies, in particular bringing down costs and encouraging innovation.

The characteristics of the metals themselves also play an important role in the scale of recycling achievable. For example, copper is easily recycled and used across a wide range of new energy technologies, which will contribute to increasing levels of demand, scrap availability and recycling. Nickel is similarly important in energy storage technologies and increasing recycling rates suggest a medium to longer term suppression of demand due to availability of recycled metal. Lithium currently has limited recycling potential, but there is significant research being undertaken in this area and processes have recently been commercialised (for example, the Spoke & Hub process developed by Li-Cycle [2021]).

The key technologies that can allow Other metals supply chain decarbonisation are shown in Table 15 below, including indicative timelines for deployment, technology readiness level and maximum potential for emissions abatement.

TABLE 15: Summary of abatement technologies in the Other metals supply chain

Process	Incumbent technology/ process	Abatement technology/ process	Technology status[39]	Year deployable	Maximum abatement potential
Mining – haulage	Diesel-powered trucks	Trolley assist	Demonstration	2020	30% with existing haulage fleet. Supports deployment of alternative haulage technologies
		Battery-electric trucks	Demonstration	2030	100% if powered with renewable electricity
		Fuel-cell electric trucks	Demonstration	2022	100% if powered with green hydrogen
Mining – non haulage	Diesel-based digging and drilling equipment	Electric hydraulic drilling	Deployment	2020	100%, dependent on electricity source
		Large electric drilling rigs	Deployment	2020	100%, dependent on electricity source
		Electric-hydraulic shovels	Deployment	2020	100%, dependent on electricity source
	Electrified mining processes[40] (run on fossil fuel-based power)	Grid-connected electricity	Deployment	2020	Dependent on grid generation mix
		Renewable electricity generation	Deployment	2020	100% reduction in indirect emissions
Beneficiation	Electrified crushing and grinding (run on fossil fuel-based power)	Grid-connected electricity	Deployment	2020	Dependent on grid generation mix
		Renewable electricity generation	Deployment	2020	100% reduction in indirect emissions
Processing	Incremental efficiency improvements	Advanced material and energy efficiency through best available technologies and processes[41]	Deployment	2020	16% reduction in energy use by 2050[42]
	Fossil fuel for heat or feedstock in metals processing	Electrification of heat, e.g. plasma arc furnace	Research and development	Highly uncertain	100% reduction in emissions from heat, dependent on electricity source
		Alternative processes (e.g. direct electrolysis of copper)	Research and development	Highly uncertain	100% reduction in emissions from heat and feedstocks, dependent on electricity source, 50% energy savings
		Hydrogen for heat	Demonstration	2025	100% of furnace fuel emissions, if green hydrogen used
	BAU metals recovery	Enhanced metals recovery – developments in bioleaching, atmospheric acid leaching	Research and development	Uncertain	Energy and materials efficiency improvements, not currently quantified

39 Based on Technology Readiness Level and Commercial Readiness Index (ARENA 2019b, ARENA 2014)

40 These include electric digging and drilling, mine ventilation and dewatering

41 Includes multiple energy saving options such as combustion optimisation, increased recycling, waste heat and gas recovery, increased monitoring and maintenance

42 Average of identified economic (13%) and technical (21%) potential savings by 2050 (Wyns & Khandekar 2019)

3.4 Chemicals

3.4.1 Supply chain structure and context

The chemicals industry is relatively diverse and therefore emissions and energy use vary widely between different processes. For the Australian Industry ETI, focus is placed on ammonia production and the explosives and fertiliser industries, which both require ammonia as the key input.

Australia produced 2.6 Mt of ammonia in 2018, approximately 1.8 Mt of ammonium nitrate and 0.4 Mt of nitrogen-based fertilisers (DISER 2020b, Fertilizer Australia 2021). Ammonia is the raw material for both explosives (in the form of ammonium nitrate) and fertilisers (as urea, urea-ammonium nitrate or ammonia applied directly).

The large majority of ammonium nitrate is manufactured locally, whereas approximately 70% of Australia's nitrogen-based fertilisers are imported. Australia's ammonia export value was approximately US$73 million in 2019 (Trendeconomy 2021), whereas the export market for fertilisers is very small. While small in magnitude when compared to some of the other supply chains featured in the initiative, both explosives and fertilisers play a vital role in the productivity of both the mining and agriculture sectors in Australia.

3.4.2 Energy use and emissions

The majority of energy use in explosives and fertiliser manufacture is due to the manufacture of ammonia, which has a reasonably high energy intensity of 35 PJ/Mt (Bazzanella & Ausfelder 2017). Some of the chemical reactions involved in ammonium nitrate manufacture generate more energy than is consumed (called exothermic reactions), which is then reused within the plant to reduce energy consumption in other areas of the process, leading to a much lower overall energy intensity of 0.7 PJ/Mt (Kermeli et al. 2017).

Non-energy emissions are a major challenge for chemicals manufacturing in Australia, with the non-energy emissions from the production of ammonia, nitric acid and titanium dioxide, as well as other smaller products, making up nearly half of the total emissions (DISER 2020b). The majority of these non-energy emissions are captured within the scope of the Australian Industry ETI Chemicals supply chain, coming from the production of ammonia (47%) and nitric acid (36%) (DISER 2020b). The large majority of energy emissions in the Chemicals supply chain are due to gas use for process heat. Figure 12 illustrates this breakdown of emission sources in the supply chain.

Ammonia

To produce ammonia, hydrogen is traditionally produced from gas (or LPG) via steam methane reforming (SMR) in primary and secondary reformers, which is then combined with nitrogen via the Haber-Bosch process. The process creates a large output stream of CO_2 which accounts for approximately two-thirds of CO_2 emissions from ammonia production. Combustion for process heat in SMR makes up the other third of the emissions from ammonia production.

Ammonia nitrate (explosives)

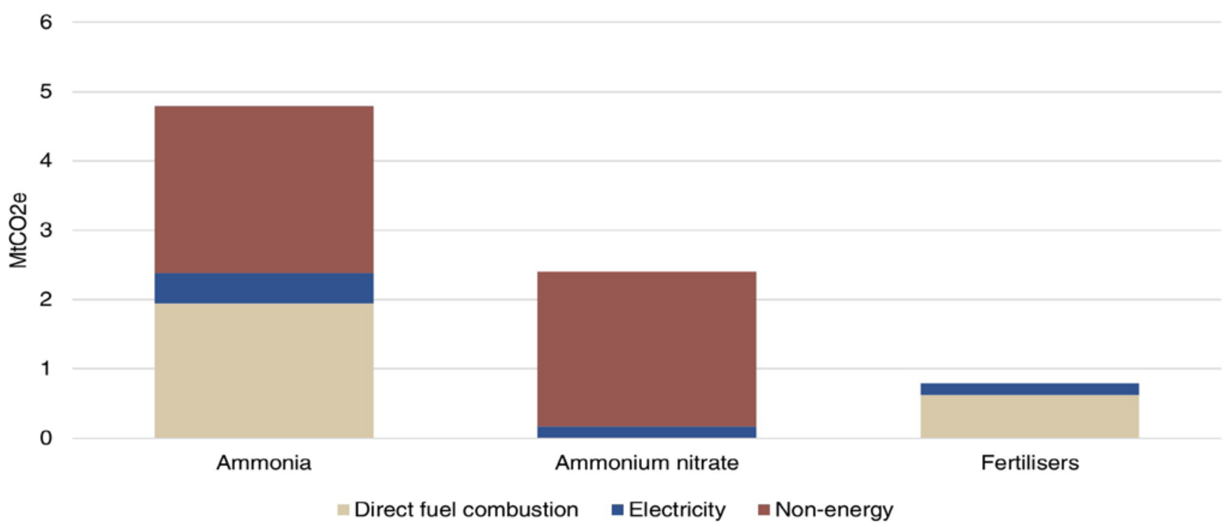
The production of ammonium nitrate requires intermediary nitric acid to be produced by mixing vapourised ammonia with compressed air and reacting over a catalyst to form nitrogen oxides. The process gas that is formed is cooled and reacted with water in an absorption column to form nitric acid. The gases leaving the absorption column have significant levels of nitrogen oxides (a potent greenhouse gas) and are generally treated to capture some of these emissions before discharge to the atmosphere. This process generates the large majority of the non-energy emissions in the explosives supply chain and is a key area of focus for emissions reduction.

Ammonium nitrate is subsequently produced by reacting vapourised ammonia with nitric acid to produce an ammonium nitrate solution. The solution can then be used to generate solid ammonium nitrate in the form of prill (small 1–3mm solid balls) in a prilling tower, or left in solution to be used to manufacture explosive emulsions. The majority of emissions from this process are due to the energy use.

Urea and other nitrogen-based fertilisers

Urea is the most common form of fertiliser used in Australia, produced through reaction of ammonia and CO_2 (often sourced from the ammonia production process), and then can be further combined with ammonium nitrate to form another fertiliser, urea ammonium nitrate (UAN).

FIGURE 12: Emissions sources in the Chemicals supply chain



3.4.3 Decarbonisation options and challenges

Table 16 summarises the major abatement opportunities within Chemicals, described in more detail below for specific supply chain stages and processes. Given the integral use of ammonia in the later supply chain stages and the energy and emissions intensity of conventional ammonia manufacturing, decarbonisation of ammonia production is the most important step for a net zero transition.

TABLE 16: Abatement opportunities across decarbonisation pillars for the Chemicals supply chain

		Ammonia	**Explosives and fertilisers**
Pillar 1: Material and energy efficiency	Material efficiency	Efficiencies in downstream products	Reduced demand for primary metals extraction, optimised fertiliser use
	Energy efficiency	Haber-Bosch improvements	Optimised waste heat recovery
Pillar 2: Zero emissions energy and feedstocks supply	Zero emissions electricity	Haber-Bosch process heating	
Pillar 3: Electrification and fuel switching	Other zero emissions fuels		
Pillar 4a: Non-energy emissions	Process improvements	Switch from SMR to novel ammonia production process*	Abatement catalysts for nitric acid production
	Zero emissions feedstocks	Hydrogen via 100% renewable electrolysis Biomethane SMR	CO_2 from biomethane based ammonia production or DAC (considered carbon neutral)*
Pillar 4b: Capture or offset residual emissions	CCS of process emissions	SMR with CCS	
	Negative emissions technologies		

*These technologies are currently classified as having a TRL of 1-6 and require further research, development and demonstration. CCS: carbon capture and storage; DAC: direct air capture; SMR: steam methane reforming

	Immaterial or uncertain role		Potential role in transition to zero or near-zero emissions options		Important role in near term abatement but insufficient for net zero emissions		Long term, zero or near-zero emissions potential

Ammonia

Converting the hydrogen source used in the Haber-Bosch process from natural gas to green hydrogen would reduce a significant portion of emissions due to the elimination of the fossil fuel feedstock currently used. Using green hydrogen as feedstock would, however, increase the energy use required for production by nearly 30% due to the high electricity demand of the electrolysis process (Bazzanella & Ausfelder 2017), so the process would only reduce emissions from ammonia production if the electricity came from a decarbonised source such as renewables. Alternatives to green hydrogen include using biomethane for the hydrogen source or capturing the CO_2 produced from the conventional production process, as detailed below.

- **Green hydrogen production via water electrolysis** – The creation of hydrogen in the ammonia production process currently relies on steam methane reforming (SMR), but this process could be decarbonised through the use of electrolysers with renewable electricity, eliminating the need for the fossil fuel feedstock and the combustion related emissions from the process (Queensland Nitrates Pty Ltd 2020). Hydrogen production could either be on-site or external, and a retrofit of parts of the plant would be necessary to change the feedstock. The prospects for green hydrogen production via water electrolysis are covered in detail in Section 4.2.
- **Biomethane as a gas substitute** – Biomethane could also serve as a zero emissions substitute for natural gas in the SMR process, but challenges regarding availability and cost of biomass resources may hinder widespread use of this solution (see Section 4.3). Moreover, biomethane would potentially require some retrofit, while biomass gasification facilities are also needed for the production of biomethane (either on-site or elsewhere), with significant associated investment costs.
- **CCS for ammonia production** – CCS could be applied to the CO_2 output from the SMR process with relative ease and at low cost, but capturing the emissions from combustion for process heat in SMR is much more difficult due to the lower concentration of carbon dioxide.

A key focus for innovative alternative ammonia production methods is reducing the scale, temperatures and pressures required. Enabling this, while using renewable energy and allowing variable rates of operation, is the key goal for research. Some examples of emerging technologies include:

- electrified SMR (electrification of process heat) (Rouwenhorst 2019)
- solid state ammonia synthesis (direct production of ammonia from nitrogen and water without intermediate steps) (Batool, 2019)
- plasma electrocatalytic or microwave processes (using plasma reaction in water to generate ammonia directly from atmospheric nitrogen) (Arpa-e 2016, Sun 2021)
- membrane reactors (different catalysts selectively controlling the formation of nitrogen and hydrogen on either side of a membrane, at ambient pressure) (Arpa-e 2018)
- methane splitting (directly splitting methane into hydrogen and solid carbon through pyrolysis) (Philibert 2020).

The above technologies are yet to reach commercialisation, and many are still being proven at lab scale. They do provide promising opportunities for ammonia production in the long term, however, potentially enabling a significant reduction in the energy use and emissions from this process.

Ammonia is currently largely used as a feedstock in Australia but is also an energy carrier and zero emissions fuel when used. In the longer-term ammonia could form part of a renewable energy export industry when produced from green hydrogen. Ammonia already has established trading and shipping vessels, and the chemical form has a higher energy content than hydrogen, allowing a higher energy output for the same volume transported (contains 70% more hydrogen per unit of volume) (RFC Ambrian 2021). In addition, producing ammonia through green hydrogen could also help de-risk the scaling up of green hydrogen production capacity by providing additional domestic demand, which is a vital tool for decarbonisation across multiple sectors (see Section 4.2).

Ammonium nitrate (explosives)

Due to the exothermic nature of the processes involved in the manufacture of ammonium nitrate, there is limited additional fuel usage and consequently few energy-related emissions. Energy intensity and efficiency measures have been incrementally developed over time, with the process considered to be at a high level of maturity. Material efficiency through more effective blasting techniques on mine sites is an ongoing aim of the sector, and can also contribute to lowered emissions for metals supply chains due to reduced processing requirements. The key emissions reduction area in this section of the supply chain is nitrogen oxide (NOx) emissions from nitric acid production, but there are currently limited commercial imperatives to implement changes due to lack of energy savings associated with emissions reduction technologies and the lack of emissions penalties. The three most common abatement solutions involve using catalysts at different stages of the manufacturing process, as detailed below.

- **Primary abatement (from production processes)** – Modifications to the process or the catalysts used in the production of nitric acid can assist to suppress the formation of nitrous oxide. This can enable a significant reduction in emissions where the process is not already optimised in this area. Changes could include modifications to the size of vessels or the geometry or materials used in the oxidation catalyst (for example, modified platinum gauze or non-platinum based catalysts) (United States Environmental Protection Agency 2010).
- **Secondary abatement (from gas after production)** – Secondary abatement allows the removal of nitrous oxide from the process stream immediately following the initial chemical reaction. This is performed through catalytic decomposition, where an additional catalyst (often made up of cylindrical base metal pellets) causes the separation of nitrous oxide (N_2O) to nitrogen and oxygen in the high-temperature process gas. Using secondary catalysts can have technical implications for the process conditions due to the increase in pressure that is caused, but new versions are being developed that have a smaller impact on plant operation, allowing more widespread use (United States Environmental Protection Agency 2010, Kamphus 2014).
- **Tertiary abatement (on the exhaust flow)** – There are two main types of tertiary abatement that can be applied to the process exhaust, using either nitrous oxide and nitrogen oxide abatement (using a zeolite catalyst) or non-selective catalytic reduction (typically using a platinum, vanadium pentoxide or titanium catalyst). Both of these abatement technologies require installation of a separate reactor, called a ‘scrubber’, and each has a number of options depending on the specific plant conditions, such as the exhaust concentration, temperature and emissions reduction required (Kamphus 2014). These options have higher capital costs than secondary abatement and may also require expensive retrofit work to achieve appropriate temperatures for the process gas being treated (CSBP 2010).

Urea and other nitrogen-based fertilisers

As urea production is generally highly integrated with ammonia production it is difficult to identify separate energy and emissions reductions opportunities. If the process is considered on its own, approximately 3.29 GJ of steam per tonne of urea is required (usually provided by excess steam from ammonia production) (Bazzanella & Ausfelder 2017). To reduce energy use emissions, this steam demand could be electrified which, if combined with decarbonised ammonia production (as the feedstock), would result in zero emissions urea production. However, if urea is produced from green hydrogen-based ammonia, the CO_2 byproduct (from the SMR process) that is currently used as a feedstock would no longer be available and an additional source of CO_2 would be required.

Regardless of the source of ammonia (green or fossil based), under all production routes urea emits carbon dioxide once applied as a fertiliser. Elimination of these emissions would require either a change to an alternative fertiliser (for example, nitrate based) or an alternative source of CO_2 that could be considered net zero (for example, CO_2 captured from biogas based ammonia production or CO_2 captured directly from the air) (de Pee et al. 2018), as detailed below.

- **Bio-based feedstocks for fertilisers** – Either wet or dry biomass could be used in the production of ammonia, each of which requires a separate process path to create urea (pyrolysing or gasification). The CO_2 from the ammonia manufacturing process is then captured and used for urea production. This is a form of BECCS; for more details, see ‘Pillar 4b’ discussion in Section 2.4.
- **Direct air capture (DAC) for urea CO_2 feedstock** – Green ammonia could be combined CO_2 from with DAC to produce decarbonised urea (including the emissions from use). This technology is still in early stages of development and is not considered to be cost competitive in the short term.

The key technologies that can allow Chemicals supply chain decarbonisation are shown in Table 17, including indicative timelines for deployment, technology readiness level and maximum potential for emissions abatement.

TABLE 17: Summary of abatement technologies in the Chemicals supply chain

Process	Incumbent technology/ process	Abatement technology/ process	Technology status[43]	Year deployable	Maximum abatement potential
Ammonia	SMR and Haber-Bosch	Electrified steam generation	Deployment	2020	100% reduction in emissions from fuel use for steam production, dependent on electricity source
		Green hydrogen feedstock	Demonstration	2020	100% reduction in feedstock and process emissions, dependent on electricity source
		SMR with CCS	Deployment	2020	85–95% reduction in process emissions, dependent on capture rates
		Biomethane SMR	Demonstration	2020	100% reduction in feedstock and process emissions
Ammonium nitrate	Nitrous oxide emissions	Primary abatement	Deployment	2020	30–85% emissions reduction depending on plant characteristics
		Secondary abatement	Deployment	2020	70–90% emissions reduction depending on plant characteristics
		Tertiary abatement	Deployment	2020	>80% emissions reduction depending on plant characteristics
Fertilisers	Fossil based steam generation	Electrified steam generation	Deployment	2020	100% reduction in emissions from fuel use for steam production, dependent on electricity source
	CO_2 feedstock from ammonia production	Utilisation of CO_2 from DAC or BECCS for carbon neutral urea	Research and development	After 2030	100% reduction in emissions following application

3.5 Liquefied natural gas

3.5.1 Supply chain structure and context

The research and analysis included in the Liquefied natural gas (LNG) supply chain is categorised as:

- Gas production – includes extraction and processing. Only energy and emissions from the gas produced specifically for LNG are considered within the scope of the initiative. As such, this supply chain does not include energy and emissions from the production and distribution of gas for domestic consumption.
- Liquefaction and export – includes liquefaction, storage and ship loading for export.

As a fossil fuel, LNG brings added complexity regarding its role in a global net zero emissions economy. In addition to being a large source of both global energy use and emissions through its production, LNG also produces considerable emissions when consumed as an energy source in overseas markets, primarily for power generation in China, South Korea and Japan.

A net zero transition implies a phasing out of fossil fuels such as gas. However, the speed and scale of this transition will vary considerably by geographic region, along with numerous interacting, dynamic and uncertain factors. Detailed analysis of the future global outlook for LNG is beyond the scope of the initiative, but there is a large amount of recent work assessing this issue in detail that can be drawn on. This report will include some of this discussion below under 'Consumption of exported gas'.

43 Based on Technology Readiness Level and Commercial Readiness Index (ARENA 2019b, ARENA 2014)

Gas production

In Australia around 70% of total gas is produced via conventional extraction, the remainder being largely coal seam gas. Gas producing and exporting areas are located mostly in the north of Australia, with the majority of production in north-west Western Australia (~60%) and Queensland (~30%) (Department of the Environment and Energy 2019). Domestic gas networks are split into three main regions (Eastern, Western and Northern), aligning with the major production basins and pipeline infrastructure.

The majority of large gas projects in the development pipeline are backfill projects, adding new wells to existing LNG infrastructure, rather than greenfield developments. This is a change of pace to the previous decade, which saw investments of over $230 billion largely building new export infrastructure. The impact of COVID-19 on LNG prices and a current global oversupply have largely been responsible for the deferral of final investment decisions for new greenfield proposals (DISER, 2020g).

Gas liquefaction and export

In 2019 Australia was the second largest exporter of LNG globally, exporting 104.7 billion cubic metres (77 million tonnes), approximately 71% of all gas produced (Department of the Environment and Energy 2019). Recent statistics suggest that despite making up just 3.8% of the world's gas production, Australia represents 26.3% of the global LNG export market (BP 2020). The majority of these exports are sent to Japan (40%), China (37%) and South Korea (10%) (DISER 2021).

The market is shared between multiple major operators and has seen significant growth over the past decade, with a number of projects considered world-leading at the time of construction. Key players include Woodside, Chevron, Shell, ConocoPhillips, Santos and Origin. Despite delays due to challenging market conditions and COVID-19, as of October 2020 the Australian LNG, gas and petroleum industries had over $124 billion of projects in the investment pipeline (DISER 2020g), the majority of which utilise existing infrastructure rather than being greenfield projects.

Consumption of exported LNG

Australian LNG production is highly dependent on global demand. Within the past year, nearly 90% of Australia's export markets have signalled ambition towards net zero emissions by mid-century, implying phasing out of fossil fuels such as gas. The speed of this transition and the impact on Australian supply will depend largely on the end uses of gas in each of these markets and the availability of zero emissions alternatives.

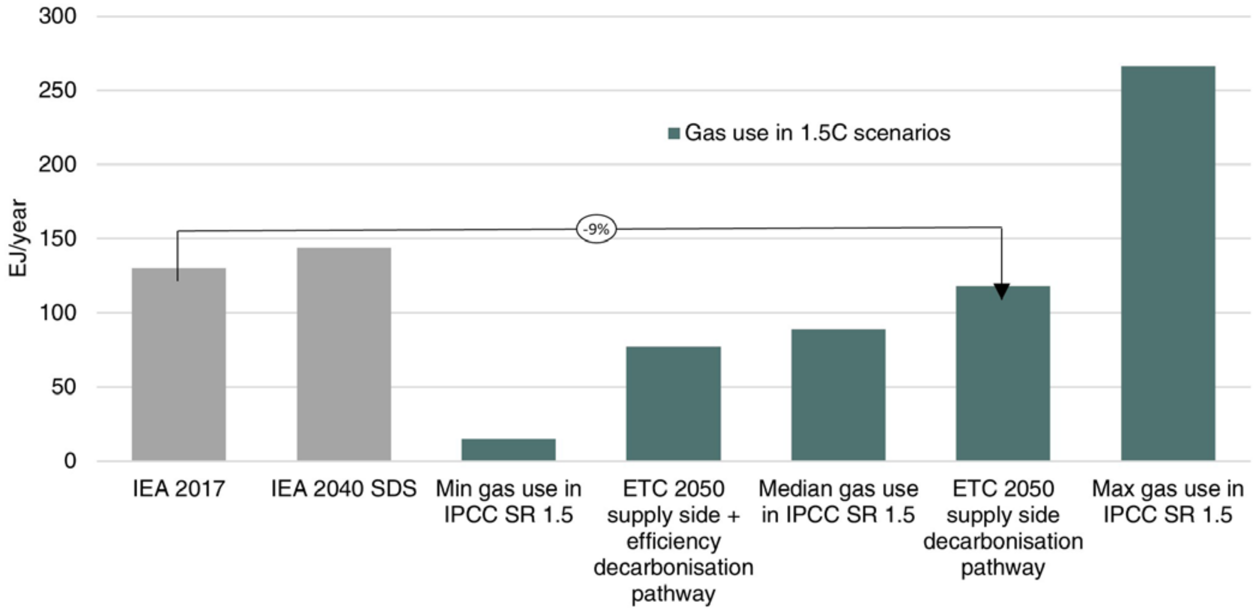
In the near term, gas use in overseas electricity generation could increase as coal is displaced, although this will face strong competition from the lower emissions alternatives of renewable and nuclear generation. The nature of this transition may vary widely by region; for example, Japan and South Korea are constrained in their power generation options, with limited access to renewable energy sources compared to China. In recent years China and Japan have seen around a 5% decline in the share of fossil fuel (coal and gas), with renewables and nuclear filling the gap. South Korea's transition has been marked by a decline in nuclear share, replaced by a combination of gas and renewables (BP 2020).

Many current gas uses could be replaced by electrification or other fuels, with mature electric technologies available to replace gas demand in residential, commercial and transport applications, which contribute up to 30% of Australia's exported LNG use. Around 40% of exported LNG is used for power generation, and in the short term this demand could increase due to increased electrification (BP 2020). Industry demand makes up the majority of remaining LNG use in export markets, and in the near term, gas could be further deployed in industry as a lower emissions option than coal and oil. However, this would be competing against mature zero emissions solutions using electricity, bioenergy and hydrogen.

In the longer term, overall demand for gas is expected to decline by 2050, under most global decarbonisation scenarios. The IEA does expect global gas demand to increase over the long term (IEA 2018), but other research suggests a much more limited role, particularly under higher levels of decarbonisation, as shown in Figure 13. Recent analysis of emissions reductions in line with 1.5 degrees of warming indicates reductions of up to 88% in global demand for gas by 2050 (ETC 2018). Trends leading to these conclusions include technological development of gas replacement options at scale and uncertainty regarding the emissions benefits of gas over coal, once accounting for methane emissions generated during gas production.

In end uses (other than power generation), gas can increasingly be replaced by electrification or zero emissions fuels such as bioenergy or hydrogen. However, gas could remain an important interim fuel while these solutions become cost competitive (for example, natural gas DRI in preparation for H2-DRI as covered in Section 3.1 – Iron and steel). For applications with limited alternatives, the long-term use of gas is likely to be contingent on CCS or offsets.

FIGURE 13: Estimates of future gas demand under global decarbonisation scenarios

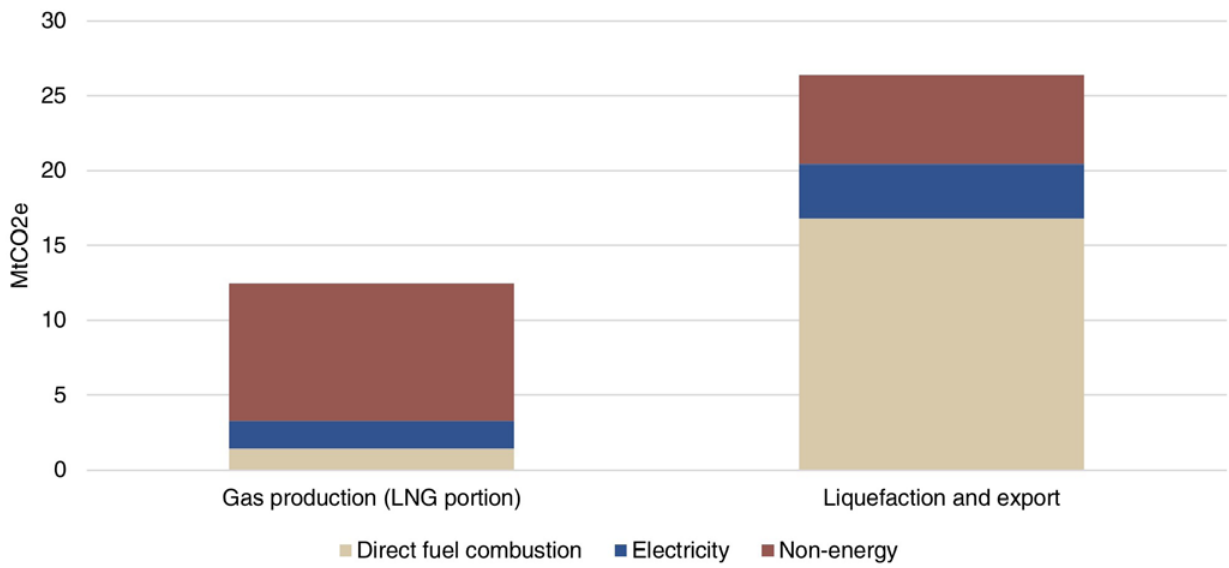


3.5.2 Energy use and emissions

The production and liquefaction of gas for export is one of Australia's single largest sources of emissions, generating around 7% of national emissions. For the Australian Industry ETI research, the LNG supply chain has been defined as energy use and emissions from LNG liquefaction and export, in addition to a proportionate allocation (based on overall production) of the emissions upstream of LNG facilities (that is, extraction and processing related emissions), as shown in Figure 14. This definition excludes domestic supply and the relative portion of upstream emissions that are related to this.

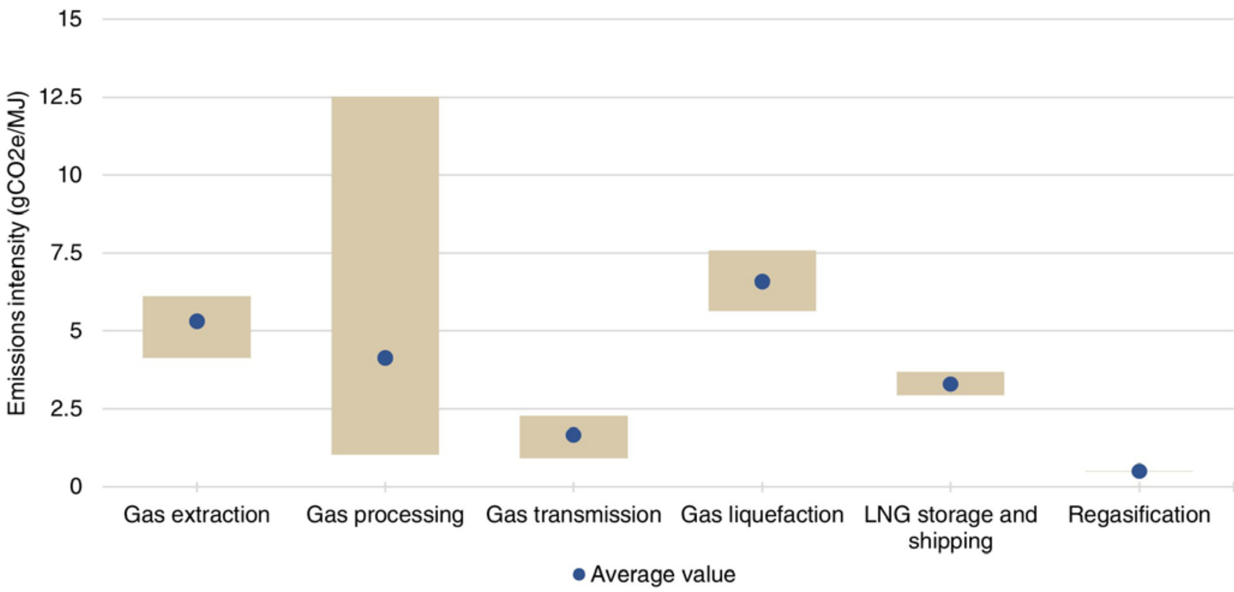
The processes associated with production and export of LNG are highly energy-intensive, with LNG plants alone responsible for approximately one-quarter of Australian gas consumption for both thermal and electrical energy generation. Energy emissions in the supply chain are driven by a handful of processes – predominantly the use of gas for liquefaction (supplied from operations) and power generation for gas field and LNG facilities. Non-energy emissions are also considerable, due in particular to leakages, venting and flaring during the extraction and processing of gas.

FIGURE 14: Emissions sources in the LNG supply chain



The emissions intensity of supply chain processes can vary significantly depending on gas field and plant characteristics, as shown in Figure 15. This variability is driven by a number of factors, both natural (for example, variations in quantity and composition of available gas) as well as technological (for example, specific liquefaction technologies and plant design, types of seals, profiles of pneumatic controllers) (Gan et al. 2020). Unconventional gas extraction is particularly emissions-intensive due to large numbers of individual wells and associated higher energy requirements for compression (Lafleur et al. 2016).

FIGURE 15: Variation in emissions intensity of different LNG supply chain steps[44]



Gas production

While the large majority of energy use within the supply chain is in the liquefaction and export stage (see below), gas extraction and processing is responsible for a significant share (over 30%) of supply chain emissions. These emissions are mainly from non-energy sources (that is, fugitive emissions and venting or flaring of gas) and occur during extraction from wells and during processing stages to remove water, CO_2 and other contaminants. A portion of these emissions (based on a ratio of exported LNG to domestic gas) are considered to be part of the LNG supply chain.

The main cause of fugitive emissions is leakage or unintentional release from gas pipelines or equipment, whereas venting is a release of gas by design either during routine operations or maintenance of the plant equipment. In conventional gas production, this includes the stream of CO_2 separated from reservoir gas, which can be up to 15% of a LNG plant's lifetime emissions (Woodside 2011). Flares are generally installed for safety reasons on higher-pressure blowdown or emergency pressure relief valves but can also be used on lower-pressure systems to reduce methane emissions through combustion of the gas, resulting in CO_2 emissions instead. There is an additional emissions source when a well is first developed, with 'blowback' gas often being vented to the atmosphere.

Gas liquefaction and export

In the liquefaction stage of the LNG supply chain, energy used is generally supplied by gas from the operations itself, either directly (for example, using gas turbines for compression requirements, with an energy efficiency of between 29–43%) or through an on-site power plant (commonly a combined cycle gas turbine, with an energy efficiency of up to 60% for the latest technology). The liquefaction process represents the greatest energy requirement in the supply chain, using an average of 9% of total energy throughput (Lewis Grey Advisory 2017).

Due in large part to energy requirements, the liquefaction process also has the highest emissions intensity, with an average of 6.6 kt CO_2e/PJ (Gan et al. 2020), followed by extraction (5.3 kt CO_2e/PJ) and gas processing (4.1 kt CO_2e/PJ). In addition to energy-related emissions, non-energy emissions such as leaks, venting and flaring generate up to 33% of emissions from gas liquefaction and export.

44 Chart produced using source data for Australian gas field production supplied to China from Figure 1 of Gan et al. (2020). Range of emissions intensities across LNG supply chain stages are represented by blue bars, red points represent average value.

Consumption of exported LNG

While not technically included in national accounts or those of Australian LNG producers, the emissions associated with the end use of exported gas are globally significant and therefore a relevant issue to consider in the context of a global net zero transition. The use of the 77 Mt of Australian LNG exports in 2019 (DISER, 2020) amounts to around 200 $MtCO_2e$ – more than five times the emissions incurred during production. While each Australian Industry ETI supply chain has varying degrees of scope 3 emissions, this challenge is by far the greatest in the LNG supply chain.

3.5.3 Decarbonisation options and challenges

Table 18 summarises the major abatement opportunities within LNG, described in more detail below for specific supply chain stages and processes. In all stages of the supply chain, the suitability of solutions for emissions reduction depends heavily on the application (for example, space can be at a premium in brownfield operations, especially those that are offshore), with many sections of the plant unable to be altered without significant downtime and retrofit costs, while greenfield sites have a wider range of options available to reduce emissions through plant and piping design and equipment selection.

TABLE 18: Abatement opportunities across decarbonisation pillars for the LNG supply chain

		Gas production	Gas liquefaction and export	Consumption of exported LNG
Pillar 1: Material and energy efficiency	Material efficiency			
	Energy efficiency		Waste heat recovery, aeroderivative turbines^	Energy efficiency of downstream gas demand
Pillar 2: Zero emissions energy and feedstocks supply	Zero emissions electricity	Electrified valves and pumps	Electrified valves and pumps, electrified liquefaction^	Electrification of downstream gas demand
Pillar 3: Electrification and other fuel switching	Other zero emissions fuels		Blue hydrogen for power generation or gas turbine fuel	Blue hydrogen replacement of downstream gas demand
				Bioenergy replacement of downstream gas demand
Pillar 4a: Non-energy emissions	Process improvements	LDAR, upgrade existing devices, install emissions control devices		
	Zero emissions feedstocks			
Pillar 4b: Capture or offset residual emissions	CCS of process emissions	CCS for reservoir gas	Post-combustion CCS	Post-combustion CCS
	Negative emissions technologies			

^ Likely suitable for greenfield applications only.
CCS: carbon capture and storage.

(light grey)	Immaterial or uncertain role
(beige)	Potential role in transition to zero or near-zero emissions options
(light teal)	Important role in near term abatement but insufficient for net zero emissions
(dark teal)	Long term, zero or near-zero emissions potential

Gas production

Non-energy sources (such as from leaks, venting and flaring) make up the bulk of emissions in the gas extraction and processing stages of the supply chain. As such, the main focus for emissions reduction technologies for current sites is in leak detection and repair (LDAR), replacement or upgrades for leaking/venting equipment, capture and storage of emissions and re-injection of vented gas. These options are generally considered 'no-regrets' actions with short paybacks given they generate improvements in efficiency and productivity. While flaring makes up a reasonable portion of fugitive emissions in the Australian LNG supply chain, this source is best reduced through operational measures due to the role the flaring plays in plant safety.

- **Leak detection and repair (LDAR)** – There are a range of technologies being used for LDAR, ranging from manual inspections, to newer drone and satellite fugitive emissions monitoring and infrared emissions monitoring. These newer technologies provide a more effective way to detect leaks, especially in remote areas. However, there appears to be relatively low uptake in Australia, likely due to a lack of providers, lack of regulations and the low value attributed to fuel or energy that LNG producers are able to access through their own operations. Quarterly inspections are estimated to reduce leakage emissions by up to 80% (ICF International 2015).
- **Replacement of venting/leaking equipment** – Replacement of equipment that regularly vents during operation or leaks gas (including some valves, pumps and equipment used during ship loading) will also reduce fugitive emissions and increase productivity. For leaks and venting, the most suitable decarbonisation technology is electrification of valves and pumps. This work is generally already undertaken as part of regular asset upgrade and maintenance processes, but upgrades tend to be done to sections of a site at a time, so it takes a number of rounds before all valves/pumps are electrified. For boil-off gas (low-pressure gas released during loading and shipping), installation of vapour recovery equipment can reduce emissions, but this incurs the added cost of recompression of the gas.
- **CCS for reservoir CO_2 venting** – The main pathway to reduce emissions associated with the processing stage of conventional gas extraction is CCS. Following gas extraction there is a process to separate and purify the gas, removing water and other impurities and generating a concentrated waste stream of CO_2. The amount of CO_2 emissions from the processing stage is dictated by the composition of gas in the basin and, as such, varies widely. This is one of the cheapest applications of CCS technology currently, due to the concentrated stream of CO_2 produced from the reservoir gas separation processes and is estimated to be able to capture up to 80% of vented gas at full operation. However, in the absence of a demand driver or penalty on emissions, this solution currently has a high cost and delivers no economic value. In a globally competitive market and in the absence of government support, this additional cost could place Australian LNG producers at considerable disadvantage. Development timelines of CCS projects are another challenge – typically in the order of 7 to 10 years – meaning abatement benefits are slow to materialise. Technological developments over the next decade are predicted to reduce this cost as capture mechanisms become better understood and learnings are applied from previous developments. In addition, costs are predicted to decline through economies of scale, via development of hubs or other partnerships to increase the volume of CO_2 transported and stored (IEA 2020c).
- **Flaring** – Within the LNG industry, flaring is largely used as a safety measure; for example, when a high-pressure event occurs, flaring allows any subsequent methane releases to be burnt and converted into CO_2, which has a smaller global warming potential than methane. A well-functioning flare can significantly reduce methane emissions, but optimising process controls to reduce the number of pressure-release events and subsequent flaring is also important in reducing overall emissions.
- **Greenfield well development technology options** – Complete decarbonisation of LNG production will require 'green completions' when new wells are developed. This process involves the capture of any CO_2 and methane emissions from new wells which would typically be vented. The process is becoming common in onshore Canadian LNG plants chasing emissions reduction opportunities. There are also a range of options to reduce emissions from new subsea gas fields; for example, design of subsea pipelines to utilise reservoir gas pressure to deliver raw gas directly to the processing plant and minimise upstream processing. Solutions such as this are highly dependent on location and any brownfield infrastructure.

Gas liquefaction and export

Electrification is a key decarbonisation technology across all supply chains and presents a large opportunity in the energy-intensive liquefaction process. Alongside the implementation of renewable electricity, the largest opportunity for decarbonising liquefaction is the replacement of gas-fired turbines with lower emissions alternatives. This is considered best-practice for new LNG sites, but presents a significant technical and commercial challenge for a brownfield site.
A summary of technology options is provided below:

- **Energy efficiency improvements** – Energy efficiency in LNG plants is a major opportunity for emissions reduction (especially in brownfield plants), with best-practice technologies available including waste heat recovery and cryogenic liquid expanders. Waste heat optimisation is estimated to enable up to a 19% reduction in emissions (CSIRO 2017) when applied to gas-fired power generation. LDAR and upgrades to leaking or operational venting equipment (see 'Gas production' above) are also highly applicable to enable emissions reduction in LNG plants.
- **Decarbonisation of on-site electricity generation** – Decarbonisation of the plant power source (generally gas-fired power generation) through generation or purchase of renewable energy could enable significant reduction in the electricity use emissions from the site. CCS is also a possibility for applications where electricity is generated on-site using combined cycle gas turbine (CCGT) generators; however, due to the low CO_2 concentration in the exhaust stream, the cost is higher than in other applications. Despite this, post-combustion CCS for CCGT generation is currently seen as a solution for sites that want to install electric drives but have very limited access to grid or renewable generation options.
- **Post-combustion CCS for gas turbines** – CCS is not considered to be a cost-effective option to directly decarbonise currently installed gas turbines due to the limited space in most brownfield sites and the cost and size of capture units required for the dilute exhaust streams from the turbines. However, future developments may improve the prospects for this technology.
- **Aeroderivative turbines** – Aeroderivative turbines (for liquefaction) still consume gas directly, but are more fuel efficient than conventional gas turbines, with a 13–15% increase in thermal efficiency. This provides a reduction of ~25% in overall plant emissions (CSIRO 2017), but doesn't allow for complete decarbonisation of the process step as the application of post-combustion CCS is not regarded as economic. This technology is unlikely to be installed in new LNG plants due to emissions intensity but could be a solution for extending the life of an older facility, due to the lower relative complexity of the retrofit when compared to electrification. The three LNG plants built in Gladstone, Queensland, in 2014 use this technology.
- **Electric drives** – Electric liquefaction drives have higher capital expenditure requirements than gas turbines but have a short payback period when the value of fuel gas saved is taken into account. The plants also have the advantage of reduced maintenance requirements, recirculation losses and downtime. However, the scale and complexity of works to retrofit the technology is significant and, as such, this would mainly be considered for greenfield sites. The power source for the drives dictates the decarbonisation potential, and even when powered by an on-site combined cycle gas turbine, the emissions intensity of the plant is reduced by 30% compared to conventional gas turbines (ABB 2006). If powered by 100% storage-backed renewables, this technology enables the decarbonisation of the major source of energy-related emissions from the LNG supply chain. However, the remote location of many LNG plants in Australia means that on-site generation is usually required, which presents a further challenge in terms of both capital cost and space requirements for renewables. The technology has been successfully implemented in Norway at the Snohvit LNG facility and is suitable for both onshore and offshore sites.
- **Hydrogen as replacement fuel** – If costs of blue or green hydrogen production drop significantly in Australia, there is potential to use hydrogen in current LNG facilities either for power generation or as fuel for gas turbines to significantly reduce site emissions. This will be contingent on a low-cost supply of hydrogen and will likely require retrofits or upgrades to equipment to allow high levels of hydrogen penetration in equipment designed for gas (for example, preventing hydrogen embrittlement in steel equipment). If blue hydrogen was produced on site, it would also generate an additional stream of CO_2 to provide greater scale for CO_2 transport and storage projects.

Consumption of exported LNG

Due to LNG's function as an energy source and the fact that emissions from the end use of gas far outweigh those incurred during production, the most significant opportunities to reduce LNG supply chain emissions – with the exception of CCS – are those that reduce demand for the product itself in sectors such as power generation, buildings and industry.

There are a number of measures that could reduce future energy demand throughout the global economy, falling under material and energy efficiency, electrification or other fuel switching. Each of these measures can be expected to negatively impact overall demand for gas, although the extent of this will vary considerably by sector and geography. For example, buildings can be entirely electrified with mature or demonstrated technologies (ClimateWorks 2020), whereas this is considered more challenging in industrial processes requiring gas for high-temperature heat (as detailed throughout this report). In high-temperature heat applications (as well as applications using gas as an industrial feedstock), hydrogen or biomass could theoretically replace demand for gas. Similarly, although gas is expected to play a very limited role in Australia's future electricity sector, the outlook is less clear in countries such as Japan and South Korea that do not have access to the same high-quality renewable energy resources as Australia. This implies a potentially ongoing role for gas in these markets, although large-scale uptake of hydrogen (potentially supplied by

Australia) provides a possible zero emissions alternative. CCS and offsetting provides another avenue for customers to reduce emissions, with the use of offsetting to provide 'carbon neutral' LNG shipments growing in popularity (Poten & Partners 2020).

Detailed research and analysis of global demand for Australian Industry ETI supply chain products was not included within the scope of Phase 1. However, the above dynamics will be considered as part of Phase 2 modelling to understand how global trends might impact the future outlook for Australian industry decarbonisation and competitiveness.

The key technologies that can allow LNG supply chain decarbonisation are shown in Table 19, including indicative timelines for deployment, technology readiness level and maximum potential for emissions abatement.

TABLE 19: Summary of abatement technologies in the LNG supply chain

Process	Incumbent technology/ process	Abatement technology/process	Technology status[45]	Year deployable	Maximum abatement potential
Gas production	Venting reservoir CO_2	CCS for reservoir CO_2	Demonstration	2020	Current Australian examples of up to 40%, estimated potential of up to 80%
	Standard management of leaks	LDAR	Deployment	2020	80% reduction in emissions due to leaks
		Replacement of venting/ leaking equipment	Deployment	2020	100% reduction of equipment emissions
	Flow back release in well completions	Green completions	Deployment	2020	90% reduction in vented emissions
Liquefaction and export	Gas turbines	Waste heat recovery	Deployment	2020	Up to 30% reduction in energy use emissions
		Post-combustion CCS	Demonstration	2020	Up to 85–90% reduction in combustion emissions, varying technology readiness levels for different processes
		Aeroderivative turbines	Deployment	2020	24–27% reduction in energy use emissions
		Electric drives	Deployment	2020	100% of turbine energy use emissions, depending on power source
	Gas-fired power generation	Renewable energy	Deployment	2020	100% of energy use emissions, when combined with electrification on site
	Standard management of leaks	LDAR	Deployment	2020	80% reduction in emissions due to leaks
		Replacement of venting/ leaking equipment	Deployment	2020	100% reduction of equipment emissions
	Venting during ship loading	Vapour recovery systems	Deployment	2020	Up to 100% reduction in flaring emissions

45 Based on Technology Readiness Level and Commercial Readiness Index (ARENA 2019b, ARENA 2014)

4.0 Energy system analysis

Box 1 and accompanying discussion in Section 2.4 establishes the importance of Pillar 2 – zero emissions energy and feedstocks – in a net zero transition for industrial supply chains. This section expands on Pillar 2, providing an overview of current state and future outlook for the production of electricity, hydrogen and biomass in Australia for use as an energy source or feedstock.[46] As the challenge of decarbonising the energy system is not specific to any particular industry, this analysis is not split by supply chain. The section concludes with discussion on the importance of effectively integrating energy supply and demand, with a particular focus on the benefits this might confer on key industrial regions in Australia.

4.1 Electricity generation

4.1.2 Context

Australia's electricity grid has moved to higher shares of renewable generation in recent years, although it remains dominated by fossil fuels. Generation mix varies considerably by region, which drives differences in grid emissions intensity, shown in Table 20.

Tasmania stands out as a particularly low emissions grid, primarily due to considerable hydroelectricity resources supplying 80% of the state's generation (DISER 2020e). South Australia's electricity supply has recently moved to high shares of renewable generation, exceeding 50% annually for the first time in 2018–19, up from just 15% at the turn of the decade. On the other hand, Australia's most populous states – Victoria, New South Wales and Queensland – are largely coal-based, with Victoria's current reliance on brown coal (71% of total generation) resulting in a particularly emissions-intensive grid. However, these states are also trending gradually away from fossil fuels, with renewable generation in Victoria, New South Wales and Queensland accounting for a combined 18% in 2018-19 compared to just 6% in 2009-10 (DISER 2020e). Nationally, variable renewables (wind and solar PV) contributed around 12% of generation in 2018-19 – led by wind (6.7%), small-scale solar PV (4.2%) and large-scale solar PV (1.4%).

The ongoing transition of Australia's electricity grid has been largely driven by global developments in renewable energy technologies, in particular wind and solar PV that have achieved remarkable and sustained cost reductions in recent decades, as well as policies such as renewable energy targets. The CAPEX of renewable generation has benefited in

TABLE 20: Current (2020) grid emissions intensity in Australian regions[47]

Region	Emissions factor (tCO_2e/MWh)
Australia, all grid connected	0.72
VIC	0.87
QLD	0.78
NSW & ACT	0.77
WA – SWIS[48]	0.66
NT – DKIS[49]	0.64
WA – NWIS[50]	0.58
SA	0.30
TAS	0.15

46 Hydrogen and biomass have multiple applications as energy sources for heat or power and as a feedstock in certain industrial processes

47 (DISER 2020a)

48 South-West Interconnected System

49 Darwin-Katherine Interconnected System

50 North-West Interconnected System

particular from technological innovation,[51] supply chain efficiencies and economies of scale from market growth (World Economic Forum 2020). This is a trend expected to continue. Widespread use of reverse auction mechanisms globally has also played a key role, with bid prices reducing by around 76% and 17% from 2010 levels for solar PV and wind projects respectively (Martín et al. 2020).

For batteries, their modular scale, wide variety of uses and cost reductions already achieved, suggest a similarly strong cost reduction pathway is likely. Already since 2010, lithium-ion battery costs have declined by 90% for electric vehicles and around two-thirds for stationary applications (IEA 2020a), with further improvements expected.

For concentrated solar thermal (CST) – which uses sunlight to generate heat – potential cost reductions are anticipated due to supply chain improvements, increased competition, reduced financing costs and 'learning-by-doing' driving greater technical efficiencies (ARENA 2018). Research is also underway to broaden the range of applications for CST and combine it with solar PV to reduce costs and target applications where the energy is required.

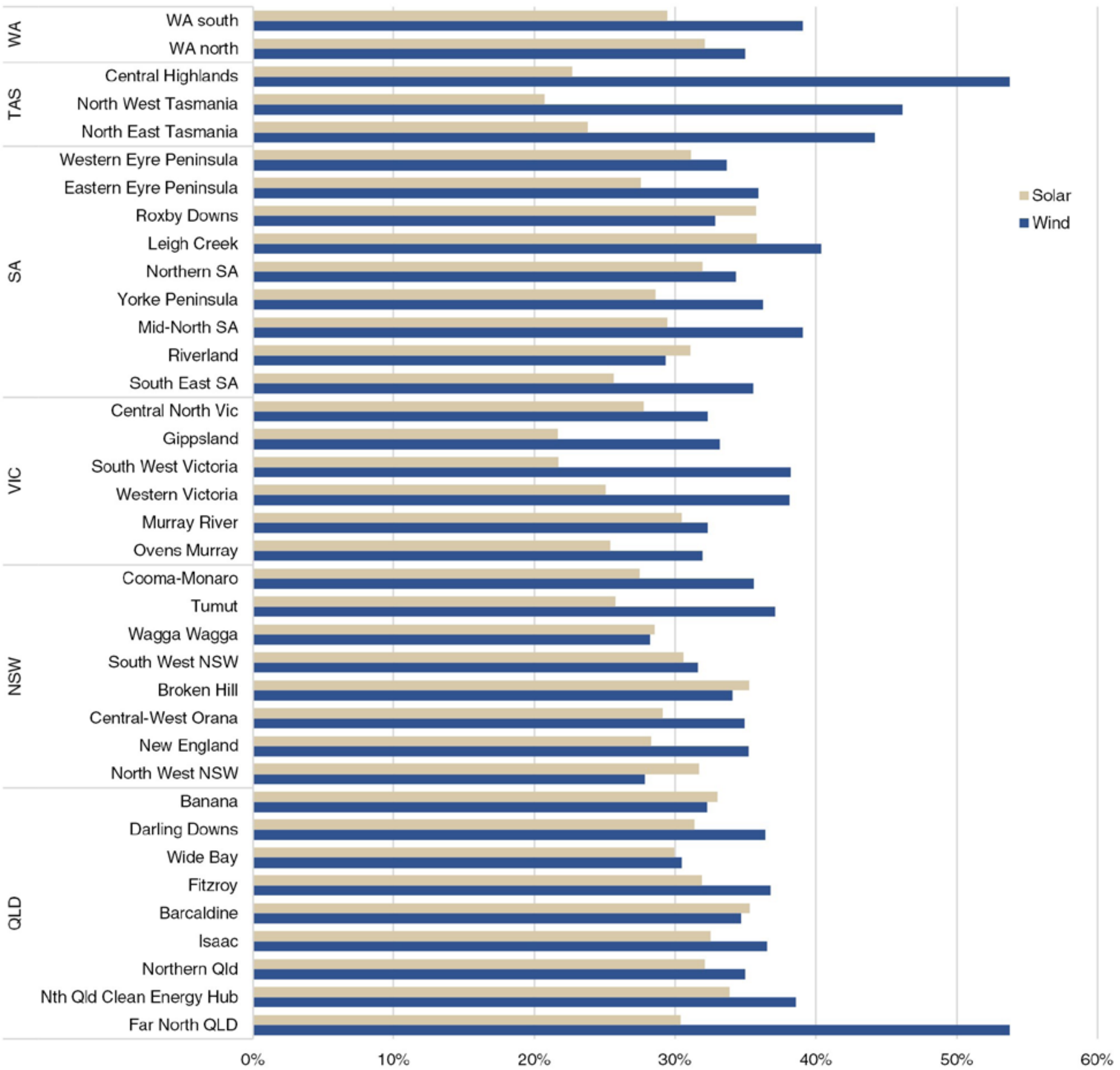
A considerable amount of recent attention has focused on Australia's potential to capitalise on natural competitive advantages in renewable energy production (Ueckerdt et al. 2019, WWF 2021). Australia benefits from both abundant solar radiation and strong onshore wind resources, with some four million square kilometres recently assessed as having solar and wind resources coexisting alongside each other (Grattan 2020). This potential to combine wind and solar PV generation in relative proximity is a key advantage, as it partially addresses issues of natural variation in generation profiles of individual renewable resources, reducing (but not eliminating) the need for expensive storage to provide system stability.

Capacity factors[52] and distance between generation source and demand or use will partly determine transmission and generation costs. Figure 16 presents estimated capacity factors for wind and solar PV generation by Australian region. In some regions such as Far North Queensland and Tasmania, wind power exhibits capacity factors above 50%, with reasonable solar potential nearby. In a number of other regions, wind capacity factors are close to 40% and solar PV capacity is over 30%, suggesting significant potential for hybrid variable renewable generation arrangements. For comparison, the best-performing grid-scale wind and solar plants in Australia in 2020 had capacity factors of 45% and 29% respectively (Leith 2021).

51 For example, improved module efficiency for solar PV and larger turbines with greater power output for wind generation

52 Capacity factors refer to the percentage of actual output out of the total possible output of a generation asset (Tran 2017)

FIGURE 16: Estimated capacity factors for solar and wind generation, by Australian region[53]



Along with its abundance of renewable resources, Australia's population density and distribution is another key advantage, with ample land mass to service domestic energy needs through renewable generation (AERA 2019). This presents serious constraints in other countries within the Asia-Pacific region such as Japan and South Korea that are highly dependent on energy imports, opening the door to a number of renewable energy export opportunities. Potential exports of renewable energy resources include renewable hydrogen, direct electricity via undersea cables, renewable energy based products (for example, green production of energy-intensive metals such as steel and aluminium) and components for clean energy technologies (WWF 2020).

4.1.2 Future outlook

A net zero emissions economy will require a vastly different and far larger electricity system compared to today. With electrification of industry alongside large-scale production of hydrogen from electricity, the world would need three to four times as much electricity generation as present according to some analysis (ETC 2020). If Australia was to realise the opportunity of being a major exporter of hydrogen as outlined in the most optimistic scenarios of the National Hydrogen Strategy, the total electricity generation required would be five times greater than the size of the National Electricity Market (Deloitte 2019).

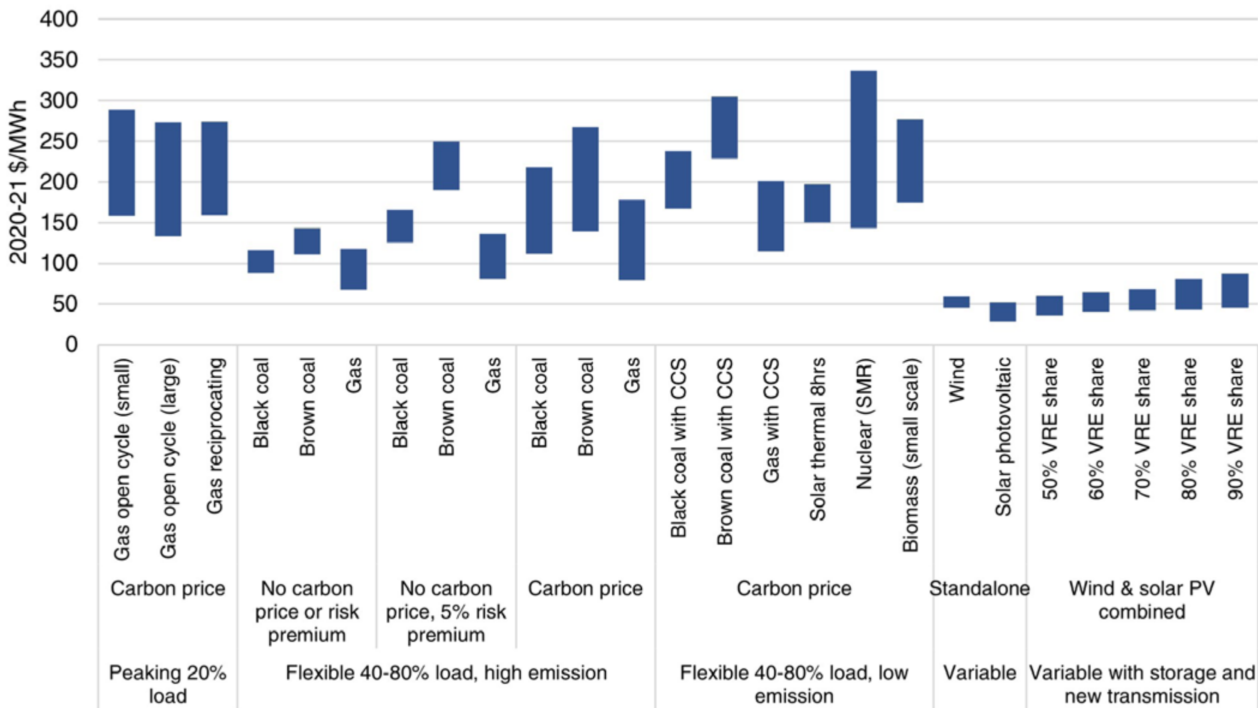
To explore the future outlook for the electricity system, the Australian Industry ETI draws on the latest data from GenCost, a collaboration between CSIRO and AEMO that updates electricity and generation storage costs annually (Graham et al. 2020). Key outputs of GenCost analysis are levelised costs of electricity (LCOE) that show the relative competitiveness of different electricity generation technologies.

53 CSIRO analysis using AEMO Integrated System Plan (2020a) input and assumptions workbook – 'medium' values

Wind and solar PV generation without transmission or storage costs are already the lowest cost option for new generation, with costs expected to decline further out to 2050. The most recent GenCost modelling has gone further by determining the integration costs (such as transmission and storage) associated with meeting demand with increasing variable renewable energy shares. With this new data, CSIRO concludes that new variable generation will be cost-competitive from 2030 even with additional transmission and storage costs included (Figure 17).

Flexible fossil-fuel generation technologies such as coal and gas are the next most competitive options, but face risks over time given all Australian states have legislated or aspirational net zero emissions targets. This additional risk is represented in GenCost either through a direct carbon price or a 5% risk premium on borrowing costs. Whatever approach is used to capture this risk, the result is a considerably higher LCOE for coal and gas generation in 2050, although this is less pronounced for gas given its relatively lower emissions intensity. Additional information is available in Appendix A data tables for GenCost 2020–21.

FIGURE 17: Calculated LCOE (levelised cost of electricity) by technology and category for 2030



Wind and solar PV costs are projected to continue declining to 2050. Variable solar PV is expected to reach $20–$40/MWh and wind $40–$55/MWh, depending on the local capacity factor. As such, if an end user only requires variable renewable energy at least cost then the long run cost at a high capacity factor solar site is $20/MWh. However, for 24/7 reliable electricity solar and wind technologies would be combined. Consequently, a reasonable expected average for the variable renewable energy component (combined wind and solar without storage) might be $30-$48/MWh. Transmission, storage and system security costs need to be added to this variable component to meet electricity demand. This could add up to a maximum $40/MWh increasing non-linearly with the variable renewable energy share unless substantial demand management is available. Hydrogen is an example of a potential large demand management source, as discussed in Section 4.4.

4.2 Hydrogen

4.2.1 Context

Hydrogen has been used in industrial applications for more than a century, primarily in the production of ammonia in chemicals manufacturing. There are multiple processes for producing hydrogen at varying stages of technological and commercial maturity. Hydrogen derived from fossil fuels – commonly referred to as grey hydrogen – represents 96% of global production, nearly half of which is obtained from natural gas (Bethoux 2020). Steam methane reforming (SMR) is the major production route for grey hydrogen, in which a natural gas (methane) feedstock is reacted with very high temperature steam (up to 1000°C – also produced using natural gas) under pressure and in the presence of a catalyst to produce syngas (hydrogen and carbon monoxide). This process emits around 9 tonnes of CO_2 per tonne of hydrogen produced (Muradov 2017).

Coal gasification is another mature method to produce grey hydrogen, in which a carbonaceous feedstock (for example, brown coal or black coal) is subjected to high temperature and pressure in the presence of oxygen and steam to break the feedstock down into syngas. Coal gasification produces around 18% of global hydrogen, and emits 19–24 tonnes of CO_2 per tonne of hydrogen (Muradov 2017).

Hydrogen produced from SMR or coal gasification could be considered a low-emissions fuel if coupled with carbon sequestration technologies to capture a sufficiently high portion of emissions. When CCS is added to grey hydrogen processes, the resulting CO_2 is captured, pressurised and injected into a pipeline to be permanently stored. This is commonly referred to as blue hydrogen. The Hydrogen Energy Supply Chain (HESC) project in Victoria is based on this technology, combining brown coal gasification with CCS. In this project, hydrogen will be liquefied for shipping to Japan in ships that are being designed for this purpose. At full scale, production is expected to be 770 tonnes per day.

Blue hydrogen has been considered a potential bridging solution while the costs of green hydrogen production decrease, but it must overcome similar challenges to those facing CCS and CCU (covered in ‘Pillar 4b’ of Section 2.4). Additionally, blue hydrogen is not zero emissions, with capture rates expected to reach 85–95% at most and current flagship CCS projects achieving far lower capture rates of around a third (IRENA 2019). Given this, the Australian Industry ETI analysis assumes a maximum capture rate of 90% for CCS technologies, with lower capture rates insufficient to be considered blue hydrogen. The potential role for blue hydrogen in a net zero transition hinges on assumptions that CCS can be scaled up, that capture rates and efficiency will greatly improve, and that it will provide long-term storage of the captured carbon (IRENA 2019).

The push for zero emissions fuels and feedstocks is driving momentum in hydrogen produced from electrolysis. Electrolysers use electricity to separate water into hydrogen and oxygen using electrodes, with the potential for complete decarbonisation if the electricity source is based entirely on renewable energy. Proton exchange membrane (PEM) and alkaline electrolysis (AE) are the two most mature electrolyser technologies and both have been considered in the Australian Industry ETI analysis. To date, AE has been more widely deployed, but applications for PEM electrolysis continue to increase. PEM electrolysis is better suited to coupling with variable renewable energy as it has the ability to ramp up and down within tenths of a second. PEM electrolysers are also smaller in size and so are more suited to applications in space-constrained areas, such as in buildings. AE is better suited to a continuous supply of electricity, although research is ongoing to improve operational efficiency and safety with variable renewable energy.

Research and development efforts have driven impressive cost reductions in electrolyser technologies over the past 30 years (Saba et al. 2018), particularly for PEM electrolysers. This is a trend expected to continue through supply chain improvements, higher volume production and – particularly in the case of PEM electrolysers that are considered less mature than AE – continued technological innovation.

Table 21 provides a summary of the hydrogen production processes considered in the Australian Industry ETI analysis: coal gasification, SMR and AE and PEM electrolysis. The following section has additional detail on the outlook for costs of these various hydrogen production methods.

TABLE 21: Hydrogen production processes considered in the Australian Industry ETI[54]

Process	Energy	Feedstock	Technology	TML[55]	Emissions
Thermolysis	Heat	Coal	Coal gasification	10	Emissions due to use of hydrocarbons, although considered low emissions if coupled with CCS (with >90% capture rate)
		Gas	Steam methane reforming (SMR)	10	
Electrolysis	Electricity	Water	Alkaline electrolysis (AE)	9–10	Zero emissions if powered with renewable electricity
		Brine	Proton exchange membrane (PEM)	7–9	

54 Adapted from Table 4 in Dawood (2020)

55 Technology Maturity Level is a modified scale combining the commonly used TRL tool and ARENA’s Commercial Readiness Index (Dawood 2020)

4.2.2 Future outlook

CSIRO has conducted preliminary analysis on the future outlook for different types of hydrogen production in Australia. This analysis is based on an update of the CSIRO National Hydrogen Roadmap modelling, and includes the following key assumptions and limitations:

- Discount rates across all technologies have been held constant and may not reflect the differing commercial risk premia which might be applied
- Carbon capture and storage costs are highly uncertain and may vary significantly by storage fields and associated transport costs
- Gas costs (for the SMR production route) out to 2050 are uncertain and may lie outside the modelled range

Given the wide range in current and projected costs and efficiencies of electrolysers, two scenarios with different assumptions for green hydrogen production have also been examined:

- Base – the IEA (2019b) hydrogen report and Aurecon (2019) were used for the initial cost and performance assumptions. Projections were based on IEA (2019b).
- Alternative – capital costs were sourced from the latest GenCost draft report's 'High VRE' scenario (Graham et al. 2020) and performance assumptions were based on Aurecon (2020). Also included was Bloomberg New Energy Finance's (BNEF) Rest of World optimistic scenario capital cost for AE (BNEF 2019).

The above studies were chosen as they are, with the exception of BNEF (2019), available in the public domain. Initial capital costs under the Alternative scenario are higher than the Base scenario, but this is offset by higher efficiency under the Alternative scenario. The levelised cost of hydrogen ($LCOH_2$) was calculated for both electrolyser types using a variable renewables electricity supply and a firmed electricity supply for comparison purposes. However, at this stage using currently available electrolyser technologies, PEM would be better suited to coupling with variable renewables and AE would be better suited to a firmed electricity source. Given that these technologies are scalable, they can be used for small-scale distributed hydrogen production, close to where it is needed. The $LCOH_2$ from SMR with CCS was calculated using a stranded gas asset,[56] natural gas cost of production. This is lower than typical Australian east and west coast gas prices. The use of a stranded gas asset means a low $LCOH_2$, but it does not include costs associated with delivering hydrogen to the end consumer.

Figure 18 shows the range of costs for different production methods in 2020, 2030, 2040 and 2050. Hydrogen produced via SMR with CCS experiences gradual cost reductions to as low as $1.71/kg in 2050, with gas prices between $3.27/GJ (using a stranded gas asset) and $9/GJ modelled to test the sensitivity of production costs. At the upper bound of gas prices, hydrogen produced via SMR with CCS has a $LCOH_2$ of $2.73/kg in 2050. The drop in $LCOH_2$ after 2020 is due to plants coming online in Norway and England in 2025 and 2028 respectively[57], which reduces the capital cost due to 'learning-by-doing'. Brown coal gasification with CCS follows a similar trajectory, declining from $2.78/kg in 2020 to $1.84/kg in 2050. The drop in the $LCOH_2$ of brown coal gasification with CCS in 2030 is due to the Hydrogen Energy Supply Chain (HESC) project coming online in Victoria with a scale up in plant capacity (Hydrogen Engineering Australia 2020).

As the various electrolyser technologies are currently ramping up in production globally, there is considerable uncertainty in production costs over time between PEM electrolysis and AE. In initial years, for both PEM and AE the upper end of the cost range is due to considerably higher capital costs, but this effect lessens over time as capital costs in both scenarios decline and electricity costs become the more dominant factor. After 2030, the upper end of $LCOH_2$ cost ranges are driven by the firmed electricity price (which is around $30/MWh higher than the variable cost), rather than conservative capital cost assumptions. In both scenarios (and despite much higher capital costs in the Alternative scenario), the $LCOH_2$ of PEM electrolysis with variable electricity is near or below that of the lowest cost SMR with CCS by 2040, in the range of $1.77-$1.82/kg. PEM reaches the lowest production costs of $1.42/kg in 2050 under the Base assumptions with variable renewables electricity. Due to the variable electricity source, the modelled PEM electrolyser route has a lower capacity factor but also a far lower electricity cost. AE hydrogen production, even if assumed to be powered with variable electricity, reaches a lowest $LCOH_2$ of $1.56/kg in 2050 under the Base assumptions. Assuming grid connection (and thus higher electricity costs), $LCOH_2$ of AE ranges from $2.94-$3.05/kg, more than twice the cost of PEM hydrogen production.

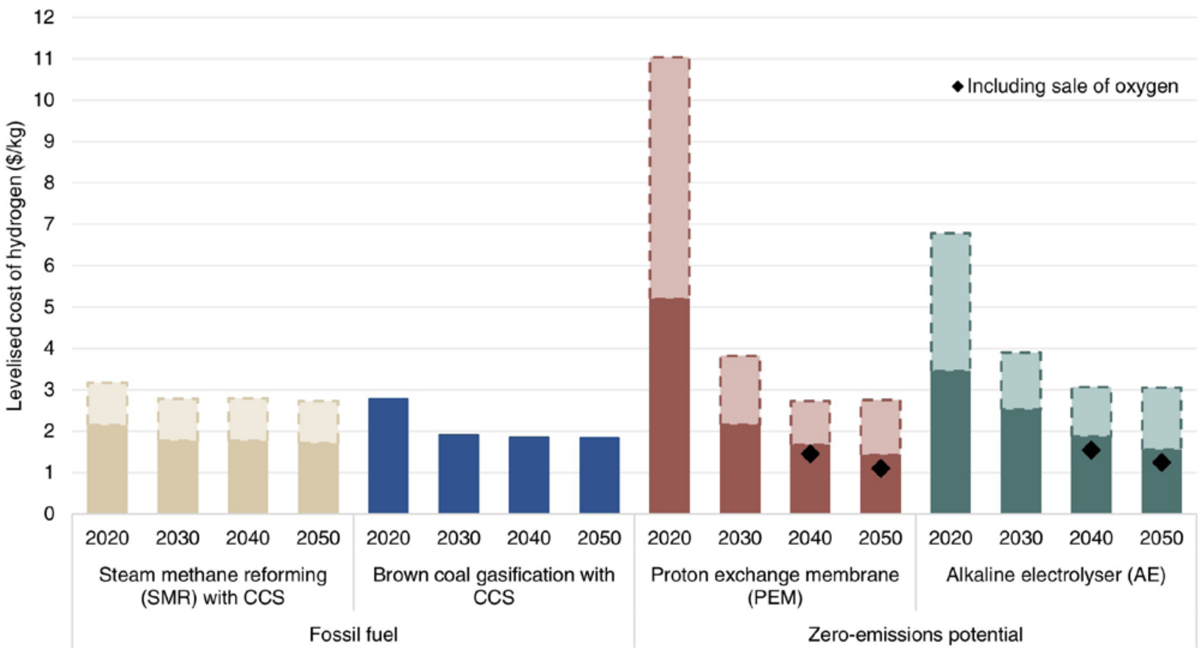
56 Stranded assets are those that, at some point prior to the end of their economic life, are no longer able to satisfy a company's internal rate of return due to changes in market or regulatory conditions (Climate Alliance Limited 2015)

57 The HyDEMO project Norway and the H21 project in England are expected to come online in 2025 and 2028 respectively

In addition to firmed and variable electricity, the Alternative case also assessed the impact of supplying electricity via a power purchasing agreement (PPA). Production using PPA electricity was assumed to have a constant cost of $30/MWh, whereas both firmed and variable costs start off higher in 2020 before variable costs drop below $30/MWh around 2028. This drives more significant reductions in $LCOH_2$ in the early years for both PEM and AE using PPA electricity, with costs approaching $2/kg in 2032 and 2044 respectively. This is more than one to three years earlier than with variable electricity despite PPA electricity costs being higher, due to the fact that variable electricity has a capacity around one-third that of the PPA case, which is grid-connected.

In the Base case, the analysis also included a sensitivity for the sale of oxygen produced during electrolysis with an assumed price of $0.04/kg. This offsets production costs and results in 2050 $LCOH_2$ as low as $1.10/kg and $1.24/kg in PEM and AE respectively, representing a decline of 22% and 20% compared to the 2050 variable renewables case without oxygen sale. Oxygen has numerous uses in various industrial processes such as steelmaking and metals refining, as well as applications in healthcare (UIG 2016). The sale of an oxygen by-product is dependent on the presence of a local buyer so is not considered a core result; however, this analysis provides an example of the potential benefits of coordination within industrial precincts.

FIGURE 18: Projected costs of hydrogen production routes, 2020–2050[58]



The dotted boxes display the range of costs for a particular production method. For SMR, the lower and upper bounds are based on a gas price of $3/GJ and $9/GJ respectively. For PEM and AE, the scenarios comprising a lower and upper bound vary over time. In 2050, the lowest production costs for PEM and AE are both based on capital costs of $206/kw, performance of 43 kWh/kgH2 and variable renewable electricity costs $19.9/MWh (representing the cost of solar PV without storage at the Leigh Creek, SA Renewable Energy Zone). Under these assumptions, PEM electrolysis reaches a low of $1.42/kg in 2050, while AE reaches $1.56/kg, with operating expenses, stack lifetimes and stack replacement costs driving the differences. Detailed assumptions and further results are available in Appendix B of the Technical Report. The black markers in 2040 and 2050 show the impact of selling oxygen as a byproduct of the electrolysis process, which is dependent on the presence of a local buyer.

These results indicate that there are a number of factors impacting the $LCOH_2$ of different production routes. These include costs of capital, fixed operating costs, stack replacement and water used in electrolysis processes. The proportion of these components relative to overall costs can vary considerably between AE and PEM electrolysis over time. The analysis suggests that in 2020, capital costs are the major component of $LCOH_2$ for PEM electrolysis. However, as a result of significant capital cost reductions, by 2050 electricity costs are the dominant parameter. AE has a lower capital cost and efficiency relative to PEM. As such, electricity cost is the parameter that has the most impact on the $LCOH_2$ in every year projected for AE hydrogen production.

There is considerable uncertainty regarding the future outlook for these cost components, and other emerging research suggests that even lower green hydrogen production costs could be achieved in regions such as Australia,

58 CSIRO (2021, unpublished) – internal electricity system and hydrogen cost modelling

and potentially far sooner (ETC 2021). These more optimistic scenarios are based on economies of scale from global expansion of electrolyser capacity, as well as the additional benefits due to greater experience with variable renewable energy needed for hydrogen development. While not reflected in the analysis presented above, this potential upside will be included in the pathways modelled throughout Phase 2 of the Australian Industry ETI.

Additional detail on hydrogen production assumptions and results is available in Appendix B.

4.3 Biomass

4.3.1 Context

Biomass is plant or animal material that can be used to produce electricity or heat. There are multiple processes to convert biomass into higher grade fuels depending on the source, with different biomass types better suited to particular outputs. For example, agricultural crops such as corn and canola can produce liquid biofuels such as ethanol and biodiesel. Wet wastes such as manure are suitable for the production of biogas through anaerobic digestion, with this biogas able to be combusted for electricity and heat or upgraded into biomethane (DELWP 2017). The biomass conversion routes considered in the Australian Industry ETI analysis are as follows:

- **Fatty acid methyl ester (FAME)** – Various bio oils are converted to biodiesel through treatment with alcohol and heat. This technology has been used in Australia for many years to convert used cooking oil into biodiesel. FAME products have a shorter shelf life and may void some vehicle manufacturer's warranties whereas other processes produce fuels to petroleum fuel standards. This process produces 98.5% biodiesel, 1.5% glycerol.
- **Biomass to liquids (BTL)** – Lignocellulosic biomass (plant dry matter) is thermochemically converted to various fuels via the Fischer-Tropsch process, producing 22% diesel, 46% kerosene, 32% naphtha.
- **Pyrolysis** – Lignocellulosic biomass is treated to high temperatures and pressures to produce an oil-based product of 60% distillate, 40% naphtha.
- **Biogas (digestion)** – Waste streams are mixed in tanks and the methane mixture released is biogas. Once the digestion process is complete (generally a few days depending on the waste product and tank conditions), the digestate can be removed and used as a fertiliser and more waste added. Depending on the waste stream, some heat treatment may be required to remove any toxic bacteria. Clean up can be used to treat the biogas so it can be injected into gas pipelines. Biogas is approximately 70% methane, 30% carbon dioxide. Biogas digestion is inexpensive but relies on waste organic matter as a feedstock, limiting its potential.
- **Biogas (gasification)** – Lignocellulosic biomass can also be converted into methane by gasification of the biomass and then putting the gasification product (syngas) through a methanation process. This technology has a high capital cost and there is also a cost associated with the feedstock.

The use of biomass as a fuel or feedstock is currently very limited in Australia, accounting for less than 0.5% of the total energy consumed in Australia in 2018–19 (DISER 2020c). Although there are numerous technical applications for biomass products throughout the economy, its main role is likely to be in applications lacking alternatives for decarbonisation such as electrification or hydrogen. Recent analysis (CSIRO 2019, ETC 2017) suggests a limited role for biomass in power generation or industry, but significant potential in non-road transport sectors such as aviation where electrification or other fuel switching options may be limited.

A key consideration in the use of converted biomass is managing sustainable supply. Biofuels can be classified as first, second or third generation, depending on the biomass source. First generation biofuels are those produced primarily from food crops (for example, grains and oil seeds), and these face challenges regarding feedstock sustainability or competition with food supply. Second generation biofuels are non-food feedstocks that are sustainably produced, for example forest residues, and purpose-grown energy crops such as vegetative grasses and short rotation forests. Second generation feedstocks are still developing as an industry and are generally not yet commercially viable at scale (Alfano et al. 2016). Third generation feedstocks are derived from specialised energy crops (for example, algae). While these can potentially produce more fuel than other feedstocks – and consume carbon dioxide, acting as a sequestration option – they currently require large amounts of fertiliser to grow, negating other benefits (AERA 2019). Municipal or animal waste could provide a sustainable source of biomass but may face challenges achieving necessary scale for widespread use.

4.3.2. Future outlook

Over the past decade CSIRO has undertaken assessments of the Australian potential for sustainable biomass and made projections out to 2030 and 2050 based on expected climate change impacts and land availability. These studies were used to assess the quantity of lignocellulosic biomass and municipal solid waste available for bioenergy production

(Crawford et al. 2012). Table 22 provides estimates of current and future availability for various biomass sources, excluding oil-based feedstocks. Current availability of second and third generation feedstocks is predominantly from stubble, native grasses and plantation forests. There is expected to be limited potential for expanded supply of most biomass sources due to feedstock availability, competition from other sources and the geographical spread of biomass feedstock requiring distributed production. An exception to this is short rotation trees (requiring only three to four years of growth) which comprise around a quarter of projected biomass availability in 2050.

TABLE 22: Current and projected availability of biomass resources in Australia[59]

Feedstock	Current availability (kt)	Availability in 2030 (kt)	Availability in 2050 (kt)
Stubble	27,678	27,678	27,678
Native grasses	19,721	19,721	19,721
Plantation forest	10,907	14,198	12,821
Native forest	7,942	7,942	7,942
Bagasse	5,502	5,502	5,502
Short rotation trees	0	14,661	29,346
Municipal solid waste	6,517	9,044	10,943
Abattoir/animal waste and intensive animal agriculture	234	No projection available	No projection available

Based on the above estimates of future biomass supply, Table 23 presents estimated biofuels production in 2030 and 2050 by different conversion methods. Even at the higher end of estimates, future production potential only represents around one-fifth of total current energy use in Australia. This highlights the challenges with widespread fuel switching to biofuels, strengthening the case for deploying these limited resources to sectors with limited potential for electrification or other alternative fuels.

TABLE 23: Estimated current and future production of biofuels in Australia[60]

Feedstock	Production process	Fuel	2020 Estimate (PJ)	2030 Estimate (PJ)	2050 Estimate (PJ)
Lignocellulosic	Biomass to liquids (BTL)	Conventional fuel replacement	0	648	744
	Pyrolysis	Conventional fuel replacement	0	1,023	1,174
	Gasification and methanation	Biogas	0	848	987
Waste	Digestion	Biogas	16	26	32
Total			16	674 – 1,049	776 – 1,206

59 Estimates are based on modelling and do include expected climate change impacts such as a reduction in rainfall in different regions around Australia. Estimates are not available for oil-based feedstocks e.g. tallow, canola and future crops such as algae and Pongamia. Projections are not available for abattoir/animal waste, sewage treatment plants (STP) and intensive agriculture feedstock quantities.

60 The quantities of feedstock available have not been split between processes. For example, it has been assumed that all lignocellulosic feedstock is sent to biomass-to-liquid, pyrolysis or biogas processes. Hence totals are displayed as a range. Estimates are only available for non-oil feedstock biofuel processes.

Table 24 presents estimated current and future costs of production for biofuels using various processes and feedstocks, compared with oil- and gas-based fuels. This suggests that projected costs of biofuels are expected to remain higher than fossil fuels over the long term. The ranges shown in Table 24 for the processes using lignocellulosic feedstocks (that is, BTL, pyrolysis and gasification and methanation) are based on ranges in the capital cost and feedstock costs. The lowest cost lignocellulosic feedstock is native barks and woodchips. The biogas digestion and FAME ranges are based on feedstock costs, where the lowest cost feedstocks are municipal solid waste and waste oil/tallow respectively.

TABLE 24: Estimated current and future costs of fuel production in Australia

Feedstock	Production process	Fuel (unit)	2020	2030	2050
Bio-oils	Fatty Acid Methyl Ester (FAME)	Biodiesel ($/L)	0.9–4.4	0.9–4.4	0.9–4.4
Lignocellulosic	Biomass to liquids (BTL)	Conventional fuel replacement ($/L)	2.5–2.7	2.0–2.7	1.7–2.7
	Pyrolysis	Conventional fuel replacement ($/L)	2.0–2.1	1.9–2.0	1.4–1.8
	Gasification and methanation	Biogas ($/GJ)	30–34	25–33	20–33
Waste	Digestion	Biogas ($/GJ)	3.7–21	3.7–21	3.7–21
Oil	Refining	Diesel ($/L)	1.25[61]	1.35	1.51
		Petrol ($/L)	1.20	1.30	1.45
Natural gas	N/A	Natural gas ($/GJ)	6.5[62]	6.4	6.4

4.4 The critical role of regional energy and industry integration

An electricity transformation is underway globally and in Australia, with renewable generation shares approaching 100% considered the ‘business as usual’ case by 2050. This is a cost-driven transition, with the speed primarily determined by the rate at which existing fossil generation leaves the system (CSIRO 2019). Although wind and solar PV are the lowest cost generation technologies, system integration becomes critical as supply-demand challenges increase at higher shares of variable renewable generation. This is creating a need both for electricity storage and for electricity demand to follow available generation. This represents a major shift from the historical design paradigm of electricity supply following demand.

Based on current penetration of renewables in the electricity grid, Australia is on the cusp of moving into a new phase of energy system integration[63] requiring the flexibility to respond to supply-demand variability within minutes to hours (IEA 2019a). These challenges are less easily managed with existing resources or practices, requiring additional flexibility measures such as demand side response (DSR)[64] and storage solutions including pumped hydro, utility-scale batteries and behind-the-meter storage. Given the prohibitive costs of providing system reliability through energy storage systems alone, DSR is a particularly attractive and feasible option.

As a major consumer of energy, industry can play a key role in overall energy system reliability through engaging in DSR activities – directly targeting periods of peak energy demand and prices by reducing production at these times. This has the benefit of reducing costs and increasing productivity and revenue generation for participating companies, while saving the electricity system and end users the excessive costs of maintaining these peaks (ClimateWorks Australia 2014). Currently, industrial companies such as aluminium smelters already provide some DSR function, although in the case of aluminium smelters, the service is limited by risks of technical failures caused by lengthy

61 Average national terminal gate price 2019-20 financial year (AIP 2021)

62 Average east coast wholesale price 2019-20 financial year (AER 2021b)

63 For example, see Figure 15 of IEA 2019a

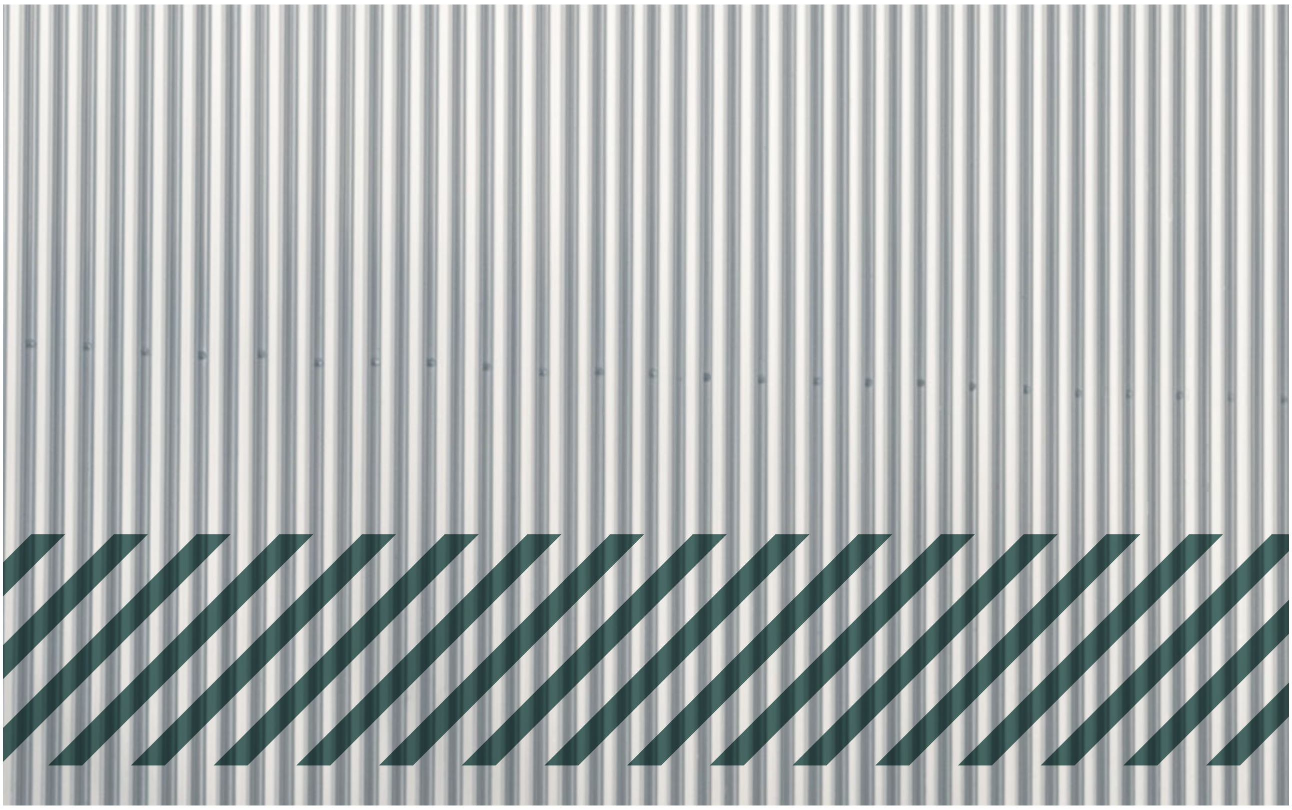
64 Demand side response activities refer to a range of market signals and commercial offerings which seek to incentivise energy users to shift consumption away from peak demand times in the broader energy system (ClimateWorks 2014)

production downtime.[65] Other barriers to uptake of DSR include concerns over loss of throughput, the cost of implementing DSR programs and inadequate commercial incentives to encourage participation. Analysis by ClimateWorks Australia (2014) indicates industrial processes with the largest potential to load shed[66] as a percentage of their peak electricity demand include mining, comminution (crushing and grinding ores) and earth moving and excavation.

Residential and commercial sectors can also assist in balancing electricity grids at high shares of variable renewables. A number of innovations have emerged to support DSR in these sectors through enabling technologies (for example, smart homes, electric vehicle smart charging), new business models (for example, energy-as-a-service), market design (for example, time-of-use tariffs) and system operation improvements (for example, advanced forecasting of wasted renewable generation) (IRENA 2019b).

Another emerging opportunity to help manage variability of supply and demand is establishing a large-scale hydrogen industry built on renewable-powered electrolysers. Electrolysers can provide additional flexibility to energy systems as they are well-suited to ramping up and down very quickly. This allows them to adjust to variable supply-demand profiles, producing hydrogen at times of excess electricity generation or tapering off during periods of high demand. This increases the utilisation of renewable generation assets by making productive use of otherwise wasted electricity. Producing and storing large quantities of hydrogen could also provide important long-term seasonal flexibility to the system, creating a virtuous loop of supporting even higher shares of variable renewable generation (IRENA 2019a). However, a challenge for realising the potential of a hydrogen production integrated electricity system is that electrolysis sourced hydrogen may not be competitive until the 2030s.

Highly electricity-intensive industry, such as aluminium smelters, typically contract directly with lowest cost electricity generators for supply. As we transition from coal to renewables, identifying the new low-cost sources is imperative. Managing electricity costs and ensuring reliable supply are the primary challenges in shifting to very high shares of variable renewable generation. As discussed above, one way of managing variable electricity generation is by deploying storage systems for use in times of surplus demand. While this is a mature and effective technology to firm electricity supply, it comes at considerable cost. Effective integration through a combination of measures discussed above can help address cost and reliability concerns simultaneously, without the need to rely entirely on expensive energy storage.



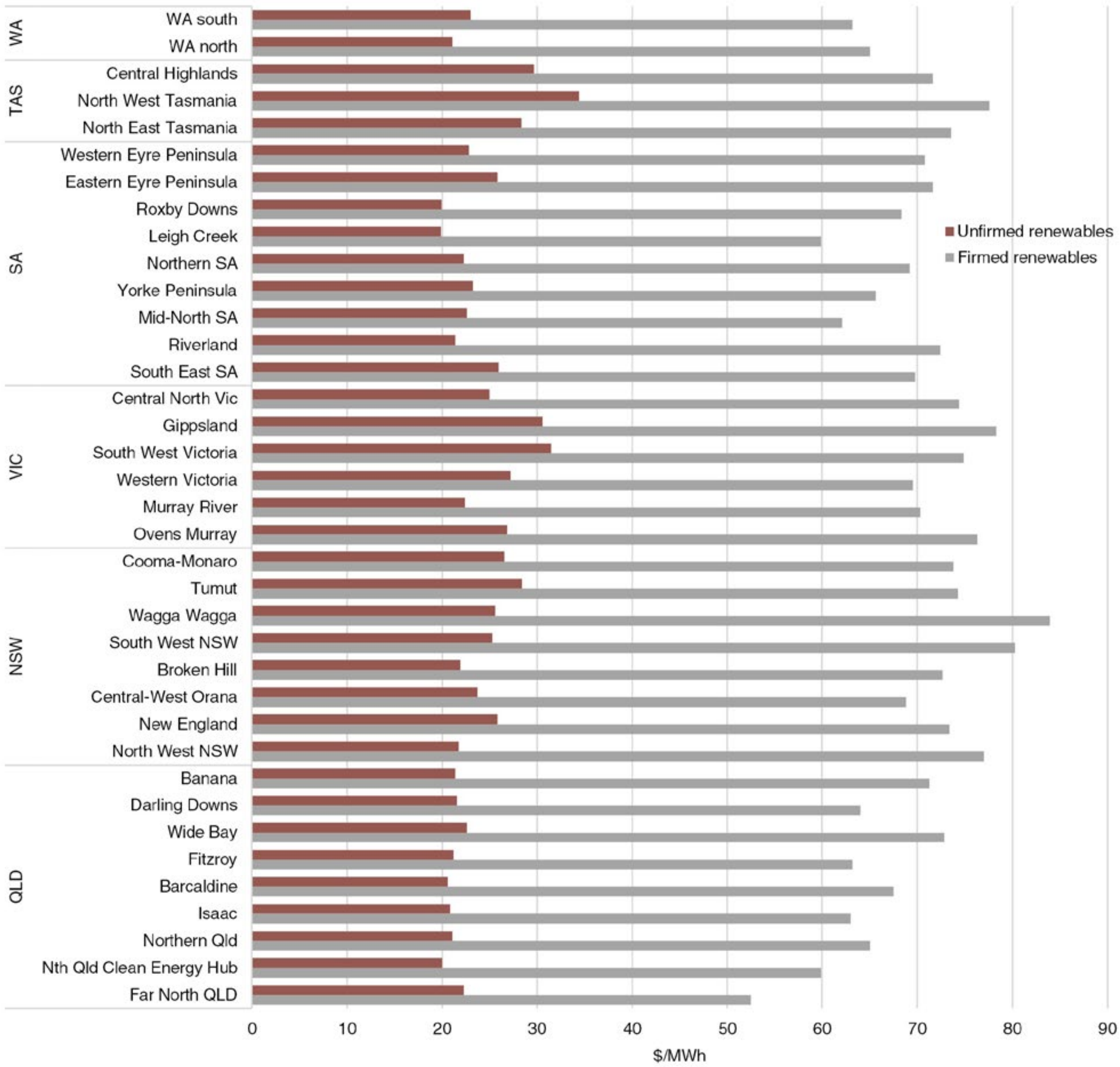
65 A disruption in supply of more than 3 hours can cause potlines to solidify, which can cause catastrophic failure for smelters and incur considerable re-start costs

66 Defined as the ability to shift or shed load for a period of 2-4 hours, five to ten times a year during a network or electricity system peak if a commercial return is offered

Figure 19 below shows the considerable additional costs required to supply 100% available (firmed) renewables in 2050, with LCOEs inclusive of storage in the range of $53-$84 per megawatt hour. Transmission costs associated with integrating renewables will add another $5-7 per megawatt hour. By comparison, variable renewables are connected only to demand points and supply power at their capacity factor (approximately 30–50%) – that is, with zero storage – resulting in LCOEs as low as $20 per megawatt hour. Importantly, for most current industrial production methods, electricity supply at these capacity factors would be unacceptably intermittent. However, these results demonstrate the significant cost benefits that could be unlocked if the need for energy storage could be partially or wholly replaced by other balancing measures.

Preliminary CSIRO analysis has explored four different grid-only electricity system structures with varying degrees of renewable generation and demand flexibility, to better understand implications for storage requirements and system costs. Summary results for these scenarios in 2050 are presented in Table 25. The analysis finds that with low demand flexibility, storage needs rise proportionate to the share of renewables, while increased demand flexibility considerably reduces storage needs. Modelled electricity systems with low demand flexibility produce costs of $50-$90 per megawatt hour, with a 100% renewable system at the higher end of this range due to additional storage. Greater demand flexibility, through vehicle-to-grid integration or large-scale hydrogen production, significantly reduces large-scale storage needs and drives LCOE as low as $20/MWh.

FIGURE 19: Levelised cost of electricity for firmed and variable renewable generation, 2050[67]



67 CSIRO analysis using AEMO Integrated System Plan (2020a) input and assumptions workbook – 'medium' values

TABLE 25: Preliminary CSIRO analysis on different electricity system structures[68]

Electricity system scenarios	Renewables share (2050)	Flexibility of demand	Storage requirements	Cost outcome (2050)
(1) Likely BAU outcome	90%	Low	Proportionally moderate storage to balance supply and demand	Lower end of $50-$90/MWh
(2) Net zero emissions policy with electricity system leading	100%	Low	Proportionally larger storage required to balance supply and demand	Mid to higher end of $50-$90/MWh
(3) Scenario 1 with electric vehicles supporting grid balancing	90%	Medium-high	Minimal additional stationary storage required	$30-$60/MWh
(4) National Hydrogen Strategy high hydrogen demand case[69]	100%	High	Proportionally lower storage of any source required	$20-$30/MWh for hydrogen industry $40-$60/MWh for other consumers

These findings are significant in the context of a net zero transition for industry. Zero emissions electricity is not only a major decarbonisation opportunity in its own right (see Section 2.4), but also a prerequisite for producing green hydrogen (see Section 4.2) – itself a primary solution in supply chains such as Iron and steel and Chemicals where electrification is more challenging (see technology detail in Section 3.1.3 and 3.4.3, and analysis in Box 1 and Box 2). The above CSIRO analysis suggests the potential for a positive feedback loop between low-cost renewable electricity, hydrogen production and, in turn, prospects for deep decarbonisation – driven by effective integration of energy and industrial systems. Hydrogen is particularly well-suited to playing numerous roles in energy integration and decarbonisation as it can be stored for long periods of time, used in a variety of different markets and applications (for example, as an energy source or feedstock) and readily transported on trucks and other vessels (GHD Advisory and ACIL Allen Consulting 2020).

Locating demand centres near energy supply also reduces infrastructure costs. Many of Australia's existing industrial regions are located in proximity to Renewable Energy Zones (REZs)[70] and stand to gain from effective integration of variable renewable energy into the grid. While the hydrogen sector can directly use low cost variable energy (Table 26) most other industries will require firmed energy. However, the presence of a large scale flexible hydrogen industry results in lower cost firmed electricity for all other electricity consumers (with around a $20-$30/MWh premium), which could enhance Australia's industrial competitiveness. Industry can play a critical role in this integration both by engaging in DSR activities and acting as nearby demand centres for hydrogen. The latter would partly address the 'chicken-and-egg' problem facing hydrogen by providing the early demand and certainty required to establish production facilities, infrastructure and distribution networks. Importantly, given their access to deep water ports, many existing industrial regions would be well-suited to develop a hydrogen export industry, which could be a major opportunity for Australia (ACIL Allen Consulting 2018).

68 GenCost data CSIRO (2020, unpublished) – preliminary electricity system modelling

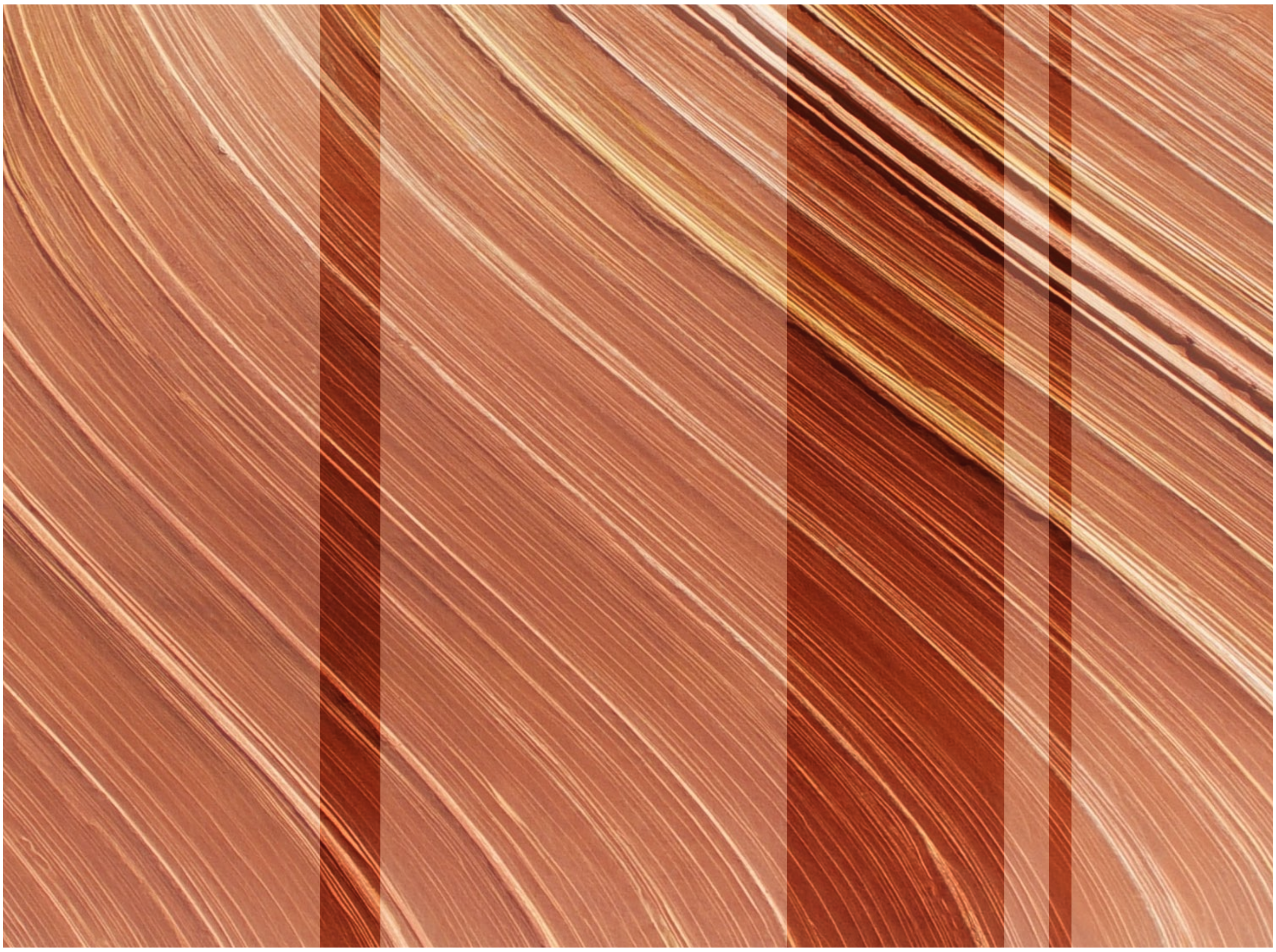
69 COAG Energy Council Hydrogen Working Group 2019

70 Renewable Energy Zones are geographic areas with high-quality variable renewable energy resources, suitable topography and demonstrated interest from project developers. These areas can be used to identify where new transmission lines are needed to enable the development of cost-effective, grid-connected renewable energy.

TABLE 26: Estimated variable renewable energy costs for Renewable Energy Zones in proximity to industrial regions, 2020 and 2050

State	Industrial region	Nearest Renewable Energy Zone	Variable renewable energy cost*: lowest cost / combined wind and solar cost	
			2020 ($/MWh)	2050 ($/MWh)
WA	Pilbara	WA North	$47 / $55	$21 / $35
WA	Kwinana	WA South	$51 / $56	$23 / $37
SA	Whyalla	Northern SA	$50 / $59	$22 / $40
VIC	Portland	South West Victoria	$59 / $65	$31 / $40
NSW	Port Kembla	Tumut	$63 / $64	$28 / $42
NSW	Hunter Valley	New England	$57 / $63	$26 / $42
QLD	Gladstone	Fitzroy/Wide Bay	$49 / $58	$22 / $39

*Based on GenCost data and the solar PV and wind capacity factor published by AEMO for the nearest Renewable Energy Zone. 'Lowest cost' represents solar PV in all regions except South West Victoria 2020 (where wind is currently lower cost). 'Combined wind and solar cost' represents the average cost of wind and solar PV at combined capacity factors in each region, assuming a simplified 50:50 split. In practice, the cost-optimised share of wind and solar generation would be determined by the relative quality of each resource in different regions.



BOX 02:

Impact of low-cost renewable electricity and hydrogen on select Australian Industry ETI supply chains

Preliminary analysis of the Australian Industry ETI has assessed the impact of low-cost renewable electricity and hydrogen on decarbonisation prospects of end-use sectors such as mining haulage, steelmaking and ammonia production.

As shown in Figure 20, at costs below $8/kg, hydrogen represents a cost-effective option for decarbonising mining haulage when compared to conventional fuels such as diesel, gas and biodiesel. Below $6/kg, hydrogen is also more cost-effective than diesel with trolley arrangements. As shown in the Hydrogen Section 4.2, potential costs of producing zero emissions hydrogen are already below each of these thresholds.

FIGURE 20: Preliminary analysis on cost tipping points for the use of hydrogen in mine site haulage

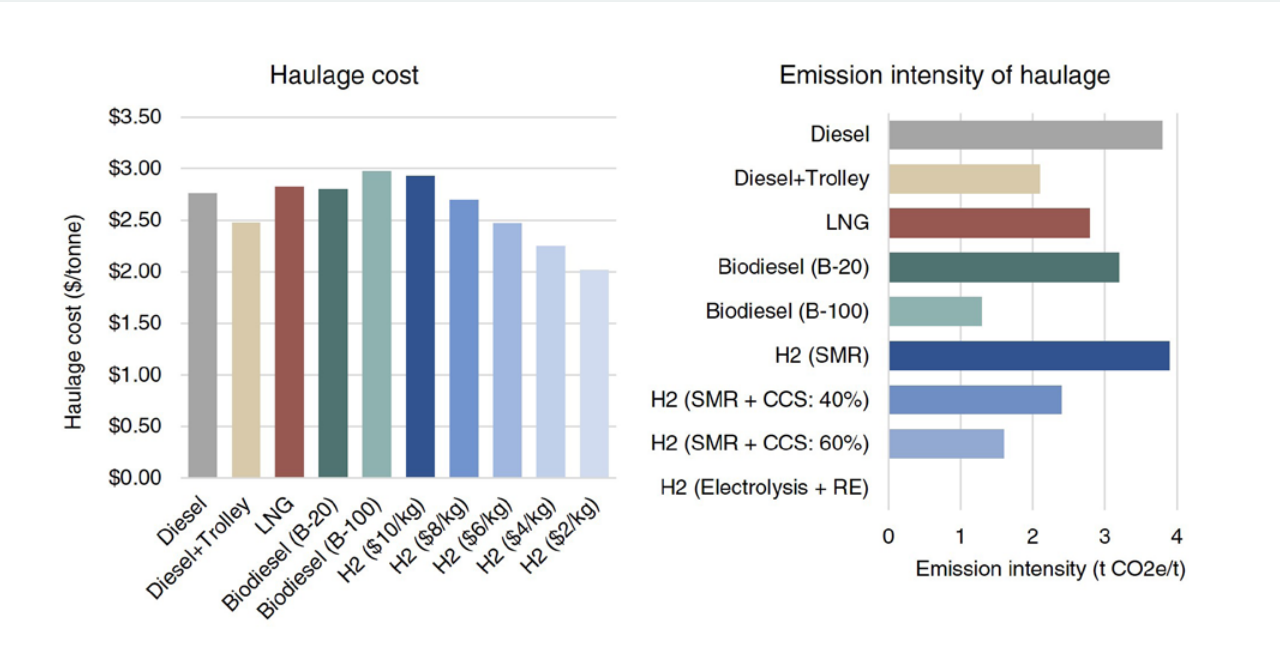
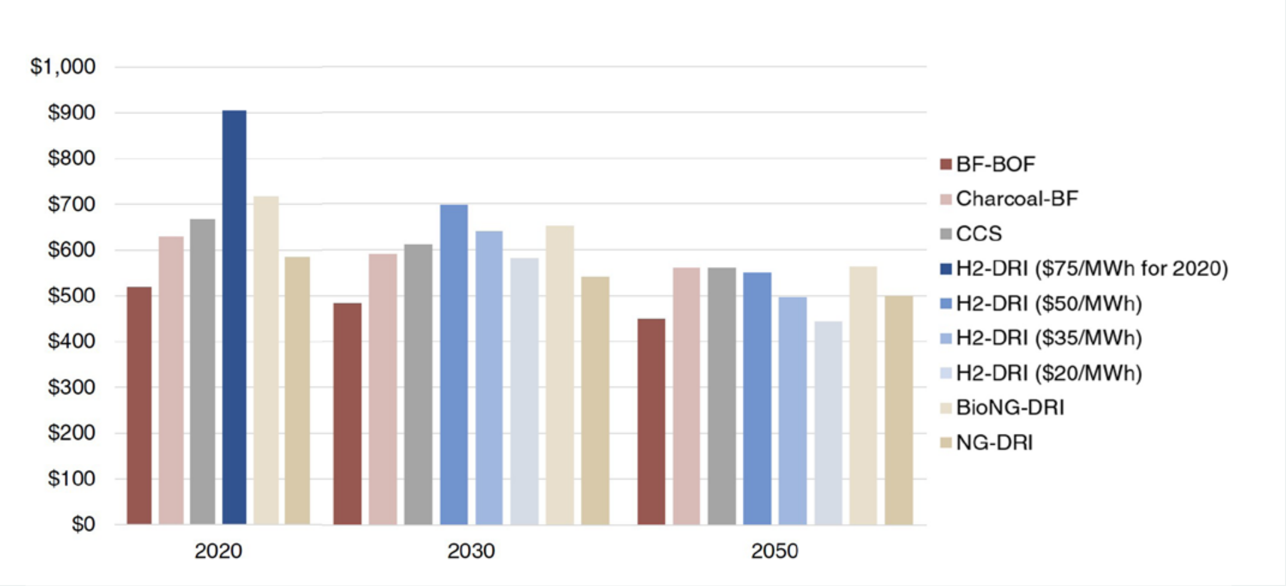


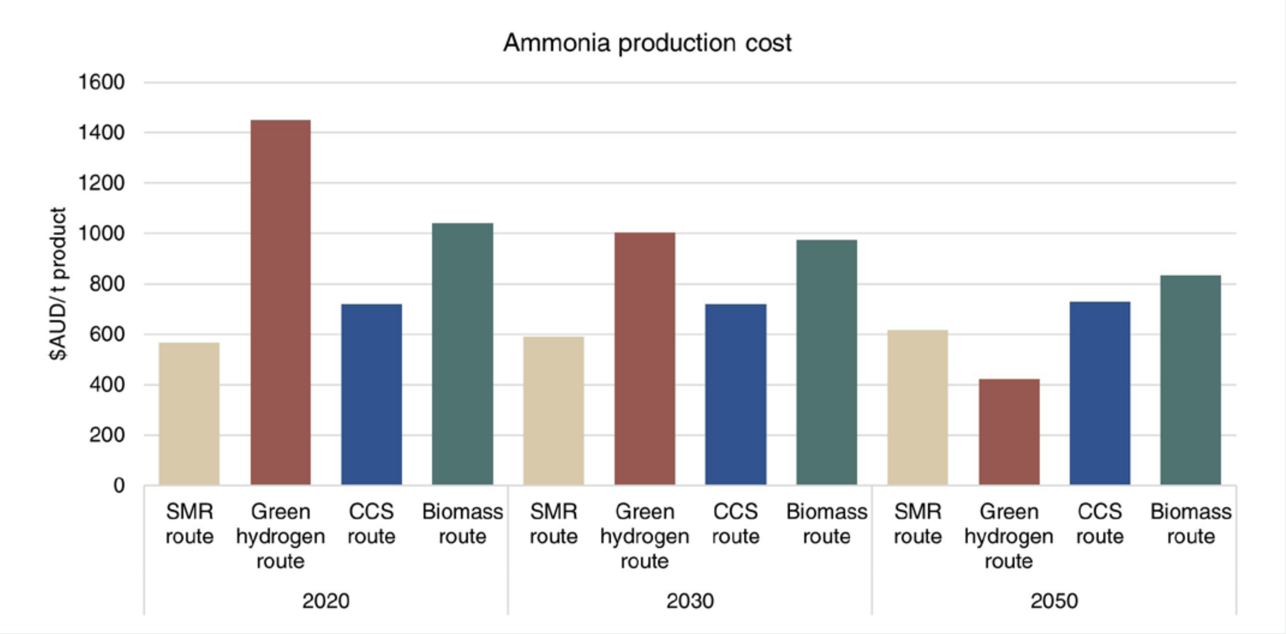
Figure 21 shows that with a $35/MWh electricity price in 2050, hydrogen direct reduced iron electric arc furnace (H2-DRI-EAF) would serve as the cheapest decarbonised steelmaking route, while CCS and a biomethane based natural gas direct reduced iron-electric arc furnace (BioNG-DRI-EAF) route could technically serve as transitional options (although these face other challenges as covered in the Section 3.1 – Iron and steel).

FIGURE 21: Preliminary analysis on abatement options in steelmaking



Similar analysis found that a green hydrogen route would become the lowest cost source of production of ammonia by 2050, if electricity can be delivered with a cost below $35/MWh (Figure 22).

FIGURE 22: Preliminary analysis on abatement options in ammonia production



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Appendix

Appendix A: Electricity system cost assumptions and results

APPENDIX A1: Levelised cost of renewable electricity ($/MWh)

		Firmed renewables LCOE (combined wind and solar PV, with storage)				Variable renewables LCOE (lowest cost*)			
State	**Region**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
QLD	Far North QLD	86.7	58.0	51.7	52.5	42.7*	31.0	26.3	22.3
	North Qld Clean Energy Hub	95.3	65.7	58.9	59.9	44.7	27.8	23.6	20.0
	Northern Qld	103.1	71.2	63.9	65.0	47.1	29.3	24.9	21.1
	Isaac	100.1	69.1	61.9	63.0	46.5	29.0	24.6	20.8
	Barcaldine	105.7	73.8	66.3	67.5	45.5	28.5	24.2	20.6
	Fitzroy	100.7	69.3	62.1	63.2	47.4	29.5	25.0	21.2
	Wide Bay	115.0	79.8	71.6	72.8	50.5	31.4	26.6	22.6
	Darling Downs	102.1	70.3	62.9	64.0	48.2	30.0	25.4	21.6
	Banana	112.5	78.1	70.1	71.3	48.1	29.8	25.2	21.4
NSW	North West NSW	119.8	84.1	75.7	77.0	48.2	30.1	25.6	21.8
	New England	117.3	80.6	72.2	73.4	57.0	35.7	30.4	25.8
	Central-West Orana	109.8	75.5	67.7	68.8	52.5	32.8	27.9	23.7
	Broken Hill	113.2	79.3	71.4	72.6	48.2	30.3	25.7	21.9
	South West NSW	126.0	87.8	78.9	80.3	55.5	34.9	29.7	25.3
	Wagga Wagga	131.7	91.8	82.5	83.9	56.5	35.4	30.1	25.6
	Tumut	120.2	81.7	73.1	74.3	62.6	39.2	33.4	28.4
	Cooma-Monaro	118.3	81.1	72.6	73.8	58.7	36.8	31.2	26.6
VIC	Ovens Murray	123.3	84.0	75.0	76.3	60.4	37.5	31.7	26.8
	Murray River	111.8	77.1	69.1	70.3	50.4	31.2	26.4	22.4
	Western Victoria	114.2	76.7	68.4	69.6	59.1*	38.0	32.1	27.2
	South West Victoria	124.6	82.8	73.7	74.9	59.0*	43.9	37.2	31.4
	Gippsland	128.8	86.4	77.0	78.3	65.6*	42.8	36.2	30.6
	Central North Vic	119.3	81.7	73.1	74.4	56.3	34.9	29.5	25.0
SA	South East SA	113.6	76.9	68.6	69.8	58.4	36.2	30.7	26.0
	Riverland	114.1	79.3	71.2	72.4	48.1	29.9	25.3	21.4
	Mid-North SA	100.6	68.4	61.1	62.1	50.8	31.5	26.7	22.6
	Yorke Peninsula	106.0	72.2	64.6	65.7	52.3	32.5	27.5	23.3
	Northern SA	109.7	75.9	68.1	69.2	49.7	30.9	26.2	22.3
	Leigh Creek	95.1	65.6	58.9	59.9	44.3	27.6	23.4	19.9
	Roxby Downs	106.8	74.7	67.1	68.3	44.4	27.7	23.5	19.9
	Eastern Eyre Peninsula	115.4	78.8	70.4	71.6	57.6	35.9	30.4	25.8
	Western Eyre Peninsula	112.2	77.6	69.6	70.8	51.0	31.8	27.0	22.9
TAS	North East Tasmania	108.8	72.3	64.3	65.4	50.9*	39.4	33.4	28.3
	North West Tasmania	123.8	81.3	72.2	73.3	52.0*	47.8	40.5	34.4
	Central Highlands	104.5	68.3	60.6	61.5	42.4*	39.6	37.0	29.6
WA	WA north	103.1	71.2	63.9	65.0	47.1	29.3	24.9	21.1
	WA south	101.9	69.4	62.1	63.2	51.4	32.0	27.1	23.0

*Represents Renewable Energy Zones where wind is the lowest cost source of variable renewable energy in that year. For all other years, solar PV is lowest cost.

Appendix B: Hydrogen production cost assumptions and results

APPENDIX B1: Technology assumptions

Technology	Metric	Unit	2020	2025	2030	2035	2040	2045	2050	Notes/ references
PEM electrolysis	Capital cost (Base)	$/kw	1944	1358	949	526	292	245	206	Base scenario: Initial cost and performance assumptions based on IEA (2019) and Aurecon (2019). Projections based on IEA (2019).
	Performance (Base)	kWh/kgH_2	52.6	49.7	47	45	43	43	43	
	Capital cost (Alternative)	$/kw	3510	1305	758	485	347	282	245	
	Performance (Alternative)	kWh/kgH_2	50.74	48	45.3	43.4	41.5	41.5	41.5	
Alkaline electrolysis	Capital cost (Base)	$/kw	1264	859	584	413	292	245	206	Alternative scenario: Capital costs sourced from the latest GenCost 'High VRE' scenario (Graham et al. 2021). Performance assumptions based on Aurecon (2020).
	Performance (Base)	kWh/kgH_2	46	45.5	45	43	43	43	43	
	Capital cost (Alternative)	$/kw	2516	1374	1208	982	760	632	555	
	Performance (Alternative)	kWh/kgH_2	46.5	46	45.5	43.4	41.4	41.4	41.4	
Brown coal gasification with CCS	Capital cost	$/GJ capacity	93.8	87.5	58.4	57.8	57.2	56.6	56	Initial cost and performance assumptions based on Mueller-Langer (2007). Projections based on CSIRO analysis
	Performance	%	61.5	65.4	69.5	69.5	69.5	69.5	69.5	
SMR with CCS	Capital cost	$/GJ capacity	49	44.3	35.6	35.6	35.6	35.6	35.6	Initial cost and performance assumptions based on Collodi (2017). Projections based on CSIRO analysis
	Performance	%	71	71	71	71	71	71	71	

APPENDIX B2: Energy cost assumptions

Energy source	Metric	Unit	2020	2025	2030	2035	2040	2045	2050	Notes/references
Renewable electricity (wind and solar)	Firmed renewables LCOE (combined wind and solar PV, with storage)	$/MWh	86.7	74.2	58.0	53.7	51.7	51.0	52.5	$LCOH_2$ calculations are based on the REZs with the lowest LCOE in 2050 for firmed and variable electricity. For firmed renewables, this is the Far North Queensland REZ ($52.5/MWh in 2050). For variable renewables, it is the Leigh Creek REZ in South Australia ($19.87/ MWh in 2050). Firmed renewables include additional costs of storage to provide constant supply of electricity (2 hours storage until 2043 and 6 hours thereafter). Variable renewables do not include any additional costs of storage, with electricity supplied at the capacity factor of variable energy only.
	Renewables PPA	$/MWh	30	30	30	30	30	30	30	
	Variable renewables LCOE (solar PV)	$/MWh	44.3	33.9	27.6	25.2	23.4	21.4	19.8	
Coal	Cost of coal used	$/GJ	0.6	0.6	0.6	0.6	0.6	0.6	0.6	GHD (2018)
Gas	Cost of gas used (lower)	$/GJ	3.3	3.3	3.3	3.3	3.3	3.3	3.3	Cost of production of gas from a stranded gas asset or from a gas producer looking to convert excess gas into hydrogen
	Cost of gas used (mid)	$/GJ	6	6	6	6	6	6	6	As it may not be possible to use a stranded gas asset, sensitivities were included with gas price of $6 and $9
	Cost of gas used (upper)	$/GJ	9	9	9	9	9	9	9	

APPENDIX B3: Additional assumptions

Assumption	Unit	Value	Notes/references
Economic life	years	25	Aurecon (2021) and assumed the same for all technologies
Discount rate	%	5.9	Graham et al. (2021)
Water cost	$/kL	1.82	Bruce et al. (2018)
Water consumption (electrolysis)	L/kg H_2	9	Bruce et al. (2018)
Water consumption (SMR and coal)	L/kg H_2	4.5	Deloitte (2019)
Construction time (electrolysis)	years	1	Aurecon (2021)
Construction time (coal gasification)	years	5	Mueller-Langer (2007) and Bruce et al. (2018)
Construction time (SMR)	years	3	Collodi (2017) and Bruce et al. (2018)
Oxygen by-product sale price	$/kg	0.04	Half of value from Kornbluh (2019)
AE stack replacement cost 2020	$/kW	316	Bruce et al. (2018)
AE stack replacement cost 2050	$/kW	52	Bruce et al. (2018)
AE opex 2020	$/kW.year	50	Aurecon (2019)
AE opex 2050	$/kW/year	45	Aurecon (2019)
Stack degradation factor	%/year	1.4	Bruce et al. (2018)
AE total stack degradation	%/Stack life	83.6	Bruce et al. (2018)
PEM opex	% capex	2.97	Bruce et al. (2018)
PEM stack replacement cost	% of original cost	25	Bruce et al. (2018)
PEM total stack degradation	%/Stack life	86.7	Bruce et al. (2018)
AE stack life 2020	hours	100,000	IEA (2019)
AE stack life 2050	hours	191,681	IEA (2019)
PEM stack life 2020	hours	80,000	IEA (2019)
PEM stack life 2050	hours	216,522	IEA (2019)

APPENDIX B4: Levelised cost of hydrogen ($LCOH_2$) results

Technology	Scenario	Metric	Unit	2020	2025	2030	2035	2040	2045	2050
PEM electrolysis	Base – variable renewables	$LCOH_2$	$/kg H2	7.54	5.15	3.62	2.44	1.77	1.58	1.42
	Base – firmed renewables	$LCOH_2$	$/kg H2	6.89	5.28	3.82	3.08	2.73	2.70	2.75
	Alternative – variable renewables	$LCOH_2$	$/kg H2	11.04	4.85	3.09	2.27	1.82	1.60	1.45
	Alternative – firmed renewables	$LCOH_2$	$/kg H2	8.25	5.04	3.51	2.95	2.69	2.63	2.71
	Alternative – Renewables PPA	$LCOH_2$	$/kg H2	5.20	2.79	2.15	1.82	1.67	1.65	1.62
	Base – variable renewables with sale of oxygen	$LCOH_2$	$/kg H2	7.22	4.83	3.30	2.12	1.45	1.26	1.10
	Base – firmed renewables with sale of oxygen	$LCOH_2$	$/kg H2	6.57	4.96	3.50	2.76	2.41	2.38	2.43
Alkaline electrolysis	Base – variable renewables	$LCOH_2$	$/kg H2	4.69	3.45	2.65	2.15	1.87	1.70	1.56
	Base – firmed renewables	$LCOH_2$	$/kg H2	5.39	4.47	3.48	3.04	2.90	2.86	2.94
	Alternative – variable renewables	$LCOH_2$	$/kg H2	6.79	4.32	3.68	3.04	2.48	2.20	2.02
	Alternative – firmed renewables	$LCOH_2$	$/kg H2	6.29	4.82	3.90	3.41	3.07	2.97	3.05
	Alternative – Renewables PPA	$LCOH_2$	$/kg H2	3.45	2.64	2.51	2.27	2.05	1.99	1.97
	Base – variable renewables with sale of oxygen	$LCOH_2$	$/kg H2	4.37	3.13	2.33	1.83	1.55	1.38	1.24
	Base – firmed renewables with sale of oxygen	$LCOH_2$	$/kg H2	5.07	4.15	3.16	2.72	2.58	2.54	2.62
Brown coal gasification with CCS	Base	$LCOH_2$	$/kg H2	2.78	2.52	1.91	1.88	1.85	1.84	1.84
SMR with CCS	Lower gas price ($3.3/GJ)	$LCOH_2$	$/kg H2	2.15	1.99	1.76	1.76	1.77	1.72	1.71
	Mid gas price ($6/GJ)	$LCOH_2$	$/kg H2	2.63	2.48	2.25	2.24	2.25	2.21	2.19
	Upper gas price ($9/GJ)	$LCOH_2$	$/kg H2	3.17	3.02	2.78	2.78	2.79	2.75	2.73

Glossary

ACD	anode cathode distance
ACT	Australian Capital Territory
AE	alkaline electrolysis
AEMO	Australian Energy Market Operator
B20	20% blend of biodiesel with diesel
BECCS	bioenergy with carbon capture and storage
BEV	battery-electric vehicle
BF	blast furnace
BioNG-DRI-EAF	biomethane based natural gas direct reduced iron electric arc furnace
BOF	basic oxygen furnace
BTL	biomass-to-liquid
BTX	benzene, toluene and mixed xylenes
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CCS	carbon capture and storage
CCU	carbon capture and utilisation
CHP	combined heat and power
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	concentrated solar thermal
DAC	direct air capture
DACS	direct air capture and storage
DISER	Department of Industry, Science, Energy and Resources

DRI	direct reduced iron
DSR	demand side response
EAF	electric arc furnace
EOR	enhanced oil recovery
ETI	Energy Transition Initiative
ETS	emissions Trading Scheme
EU	European Union
EV	electric vehicle
FAME	fatty acid methyl esters
FC	fuel cell
FCEV	fuel-cell electric vehicle
GDP	gross domestic product
GHG	greenhouse gas
H_2	hydrogen
H_2-DRI-EAF	hydrogen direct reduced iron electric arc furnace
HESC	Hydrogen Energy Supply Chain
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
$LCOH_2$	levelised cost of hydrogen
LDAR	leak detection and repair
LNG	liquefied natural gas
LPG	liquefied petroleum gas
Li	lithium
MOE	molten oxide electrolysis
MVR	mechanical vapour recompression
N_2O	nitrous oxide
NEM	National Electricity Market
NET	negative emissions technology

NG-DRI-EAF	natural gas direct reduced iron electric arc furnace
NH_3	ammonia
NO_x	nitrogen oxides
NSW	New South Wales
NT	Northern Territory
OPEX	operating expenditure
Other metals	copper, lithium, nickel and zinc
PEM	proton exchange membrane
PFCs	perfluorocarbons
PHEV	plug-in hybrid electric vehicle
PPA	power purchase agreement
PV	photovoltaic
R&D	research and development
R&DD	research, development and demonstration
REZ	renewable energy zone
RMI	Rocky Mountain Institute
SA	South Australia
SMR	steam methane reforming
T&D	transmission and distribution
TAS	Tasmania
TGR-BF	top gas reinjection for blast furnace
TRL	technology readiness level
UAN	urea ammonium nitrate
US	United States
USD	United States dollar
VIC	Victoria
VRE	variable renewables
WA	Western Australia
ZEV	zero-emissions vehicle

List of figures

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Australian Industry Energy Transitions Initiative

An initiative jointly convened by ClimateWorks Australia and Climate-KIC Australia