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To: Department of Climate Change, Energy, the Environment and Water

RE: Review of the National Hydrogen Strategy

Thank you for the opportunity for the Institute for Energy Economics and Financial Analysis (IEEFA) to present its submission to this consultation.

Regards

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Submitted via email.

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Key points

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How can Australia enable decarbonisation through the development of a clean hydrogen industry?

1. Is prioritising the decarbonisation of ammonia production the most prospective way to achieve both hydrogen industry growth and industrial decarbonisation in the short term?
2. What other actions in the other sectors, will have the greatest decarbonisation impacts?
3. What sectors are best placed to be early adopters of hydrogen?
4. Are there specific barriers that may limit hydrogen uptake in each of these sectors?
5. What are the actions required to overcome those barriers and realise the opportunities?

Prioritising decarbonisation of ammonia production makes financial sense

Ammonia production already relies on hydrogen, which makes it a prime candidate for the use of green hydrogen. Only limited additional costs are required to allow the direct use of hydrogen as a feedstock rather than using gas as a feedstock.[1]

There is already significant ammonia production capacity in Australia, with about 1.8 million tonnes (Mt) of annual production.[2] This could create a source of demand for green hydrogen at scale.

Using hydrogen for domestic production of green iron is also a promising decarbonisation opportunity

Australia is not a major steelmaker, but it is the world's largest exporter of iron ore, giving it a highly significant position in the global steel supply chain. Australia's Pilbara region is blessed with high renewable energy resources as well as abundant iron ore. Green iron could be produced via direct reduced iron (DRI) processes adjacent to the places where iron ore and renewable energy for producing green hydrogen are available. Green iron could be shipped cost-effectively to other countries for low-carbon steelmaking in electric arc furnaces (EAFs) and finishing processes, instead of freighting both iron ore and hydrogen separately at higher cost.

Potentially, the full steelmaking process using Australian iron ore, green hydrogen and renewable energy could be completed onshore via DRI-EAF, with low-carbon crude steel exported instead of iron. However, many nations are likely to be reticent to fully offshore their steelmaking capacity and may strategically prefer to import green iron that could be processed into steel domestically via EAFs that could be powered by renewable energy. Some major steelmakers are now considering replacing the import of iron ore with the import of green iron.

According to H_2 Green Steel executive vice president Kajsa Ryttberg-Wallgren, it is crucial for the future to prioritise the production of green iron in regions with competitive advantages. Breaking the traditional ironmaking process within the steel value chain is unavoidable, especially considering the impracticality of producing DRI in many European Union (EU) countries given the

[1] Climateworks Centre. Pathways to industrial decarbonisation. February 2023. Page 114.
[2] Ibid. Page 108.

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available renewable energy resources and the cost of importing green hydrogen. Noting that cost was key in a low-margin industry, Ryttberg-Wallgren stated: "You will be out of cost. So they want to buy green iron, or HBI [hot briquetted iron, blocks of sponge iron] from places in the world where it makes sense to produce it."[3]

HBI is a compressed form of DRI that is compacted at the discharging point of DRI shaft furnaces. It is an established product that does not react with oxygen in the atmosphere, making it safe for shipping. Compared to DRI, HBI has a higher density (5,000kg/m^3), making it more efficient for transportation and storage purposes.[4] HBI is a bulk export product that can be shipped in a similar way to iron ore.

Moreover, it has better mechanical strengths, another factor that makes it a better option for transport and storage.[5] HBI has the highest quality among the iron ore metallics, with a metallisation rate above 90%. As a result, it is the best ore-based metallic that can be used in EAFs to produce high-quality steel.

The export of HBI is a well-established pathway. In 2021, 8Mt of gas-based HBI was shipped overseas and a further 15Mt was transported by train or inland vessel.[6] HBI production and transportation offer energy efficiency and eliminate energy losses that may occur when hydrogen and iron ore pellets are transported separately. Green iron exports would take the form of HBI created from DRI that has been produced using green hydrogen (H_2 DRI), powered by renewables.[7]

Recent analysis identified that iron and steel are likely to be early movers in the global energy transition, and that Australia has a high potential for exports of hydrogen-based green iron.[8]

Direct hydrogen exports do not make financial sense

The potential for direct hydrogen exports has been questioned due to hydrogen's physical properties.[9] It is the lightest element and has a very low volumetric energy density compared with other sources of energy. This is problematic when it comes to transporting and storing hydrogen. Its small molecules can leak easily, and compressing it for transportation and storage poses a real engineering challenge.

The IEEFA team analysed the viability of the Victorian Hydrogen Energy Supply Chain (HESC) project, which relies on the gasification of Australia's brown coal resources into hydrogen for shipping to Japan. They found that:

"The conversion process required for shipping is energy-intensive. HESC is proposing liquefaction, produced by cooling to -253 degrees [Celsius], and the process energy is equivalent to a loss of more than 30% of the energy content of the hydrogen, according to US Department of Energy.

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[3] Hydrogen insight. 'Coal-based steel will have an advantage over hydrogen-derived green steel due to EU carbon allowance scheme'. 26 June 2023.
[4] IIMA. Hot Briquetted Iron (HBI).
[5] Australian Financial Review. How Sweden's dash for green steel could trigger a Pilbara revolution. 9 December 2022.
[6] Agora Industry. 15 Insights on the Global Steel Transformation. June 2023. Page 22.
[7] Primetals. The new age of HBI. 28 February 2023.
[8] EY. Seizing Australia's energy superpower opportunities. April 2023. Page 8.
[9] BloombergNEF. Liebreich: The Unbearable Lightness of Hydrogen. December 2022.

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"Shipping from Victoria to Japan over a 9,000km, 21-day journey is challenging for hydrogen. Beyond the significant capital expenditure required for a large new-generation fleet, there are significant hydrogen losses en route. The hydrogen lost for boil-off and fuel use for propulsion for the 9,000km journey could be up to 40% of the cargo and boil-off could be as high as 9 times that of the equivalent loss experienced in LNG [Liquefied Natural Gas] shipping.

"Finally, the delivery and regasification at the receiving port is expected to consume another 5% of the energy content of the cargo. Whilst there are other forms of transporting hydrogen over long distances, each with their own issues, these will remain the technological barriers to effective long-distance shipping of hydrogen.

"The [International Energy Agency] IEA's Energy Technology Perspectives 2023 report examined transportation of hydrogen using various forms of shipping such as liquid hydrogen (LH_2), ammonia and liquid organic hydrogen carrier (LOHC) and over varying distances. It found that transport costs of delivering liquid hydrogen in 2030 was US$2.0-3.7/kg H_2 for an 8,000km trip in the NZE [Net Zero Emissions by 2050] Scenario. The cost was lower for other forms, but they also contain other complexities and energy conversion costs. Importantly, the expected cost of transportation alone for Japan's 9,000km shipping journey would likely exceed the target price for delivered cost of hydrogen of US$3/kg into Japan – even if the production of hydrogen itself was free.

"Given the scale of the shipping issue, commercial successes will prioritise the location of the hydrogen production – close to end use, over the supply of low-cost hydrogen delivered over long distances, such as with HESC."[10]

Of more than 25 Australian export-oriented hydrogen projects being considered in Australia, at least 18 are considering converting hydrogen to ammonia for shipping. The IEA has estimated that in 2030 the costs of shipping ammonia would be lower than shipping LH_2 at around US$2.0-2.5/kg H_2.[11] However, the cost of transforming the ammonia back into hydrogen would be prohibitive in the coming decade. "Ammonia cracking is currently carried out at high temperatures and is therefore highly energy-intensive, consuming roughly 30% of the fuel's energy content. Ammonia cracking at lower temperatures (less than 450°C) is less energy-intensive but involves the use of catalysts made with expensive precious metals. The use of low-temperature ammonia cracking with no or limited use of such precious metals, which is not yet commercial, accelerates in the NZE Scenario after 2030."[12] In the near term, shipping ammonia would make sense when it can be used in ammonia form at the destination, rather than for conversion back to hydrogen.

Using hydrogen in gas distribution networks does not make financial sense

IEEFA recently released a report investigating the use of hydrogen and biomethane in gas distribution networks, which found that:

"Electrification would cost less than switching to biomethane or hydrogen. Moreover, there are serious technical constraints to relying on biomethane or hydrogen for household energy use; by

[10] IEEFA. Hydrogen Energy Supply Chain project viability remains uncertain in wake of Hydrogen Headstart scheme for green hydrogen. 3 July 2023.
[11] IEA. Energy Technology Perspectives 2023, January 2023. Page 321.
[12] IEA. Energy Technology Perspectives 2023, January 2023. Page 319.

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contrast, electric appliances for cooking, space heating and water heating are mature and already widely used by many Australian households.

"[…] when it comes to satisfying household energy needs, running electric appliances at home is four times cheaper than using biomethane, and more than ten times cheaper than using hydrogen due to their high relative efficiencies.

"[…] Whole-of-system studies consistently show electrification, coupled with energy efficiency improvements, to be the lowest-cost option for decarbonising the built environment. State and territory governments are recognising this; the ACT and Victorian governments have now both banned gas connections to new residential developments. The Victorian government is also offering significant incentives for households to replace their gas appliances with electric appliances.

"Electric home appliances are technologically mature, readily available, affordable and reliable. Millions of households across Australia today already do not use any fossil gas, instead relying on electricity to heat their homes and water as well as for cooking their food. Furthermore, many homes that are connected to the gas distribution network use electric appliances to meet one or more of their cooking, space heating or water heating needs. While there are some circumstances where households may need to upgrade their electrical wiring to switch from fossil gas to electricity, a full upgrade to three-phase power is likely to only be necessary for particularly energy-intensive homes.

"Hydrogen is not a simple drop-in replacement for fossil gas in existing gas networks because it has very different physical characteristics. It has a much lower energy density, and smaller molecular size that can lead to increased leakages. It is more flammable and can embrittle and weaken steel where it is used in parts of the network (particularly in transmission pipelines). Put simply, existing infrastructure, appliances and safety protocols are often unsuitable for higher levels of hydrogen. The low energy density is a particular problem, as gas volumes would need to be increased by 3.2 times in networks to deliver the same amount of energy from hydrogen as from fossil gas.

"These challenges make hydrogen a particularly costly and difficult pathway for residential buildings, as noted in an international meta-review of 32 studies, which found: 'Existing independent research so far suggests that, compared to other alternatives such as heat pumps, solar thermal and district heating, hydrogen use for domestic heating is less economic, less efficient, more resource intensive, and associated with larger environmental impacts.'[13]

"Even if hydrogen can be piped to homes, there are substantial barriers at the point of consumption. Current gas appliances in Australian homes are likely compatible only for blends of up to 10% hydrogen by volume (3% by energy). It is unknown whether they function safely and reliably beyond that level, with current trials in the United Kingdom examining the feasibility of 20% blends. However, it is clear that a largely or entirely hydrogen gas supply would need specially designed appliances suited to its particular characteristics. Such appliances are not

[13] Joule. Is heating homes with hydrogen all but a pipe dream? An evidence review. 19 October 2022. Volume 6, Issue 10. Pages 2225-2228.

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available in the Australian market and it is highly uncertain when they would become available, and at what cost.

"[…] Furthermore, a full switch over from fossil gas to hydrogen presents an enormous logistical challenge. If networks wish to exceed the current hydrogen limits of what appliances and pipelines can manage, an abrupt switch would be required for all users to switch from a fossil gas-based energy supply to a new hydrogen-based energy supply."[14]

How could Australia further activate its hydrogen and related industries?

6. Should Australian governments adopt a more sector driven approach to hydrogen industry development?
7. Should Australian governments adopt national hydrogen production, use and/or export targets for hydrogen?
8. If targets are adopted, what type of activities and/or sectors should this target be tailored towards? For example, production targets, demand targets for sectors such as transport or a renewable gas target. Please describe how such targets would attract investment.
9. Should Australian governments use regulatory mandates to drive demand for hydrogen? If mandates were adopted, what type of activities and/or sectors could mandates be directed towards? Please describe how such mandates would attract investment.
10. What are the most significant supply chain barriers being faced by Australia's hydrogen industry? Where should Australian governments focus efforts on securing elements of supply chains needed to enable the accelerated growth of the hydrogen sector?
11. Should Australia develop and support local manufacturing capabilities to secure the hydrogen supply chain? What are the specific areas of opportunity (e.g. fuel cell or electrolyser manufacturing or hydrogen transportation related manufacturing)?
12. What are the barriers to developing and supporting local manufacturing capabilities?
13. What is the role of industry and governments to ensure the hydrogen industry has access to an appropriately sized and skilled workforce?
14. In addition to electrolysers, where do you see a role for domestic hydrogen related manufacturing to address supply chain risks and ensure Australia meets its decarbonisation targets such as hydrogen buses/heavy vehicles?

Australia must accelerate development of green iron technologies compatible with Pilbara iron ore

Australian iron ore – the nation's biggest export – risks losing ground to other nations in the accelerating global shift towards green iron and low-carbon steel if research and development projects are not sped up. A recent report from the Minerals Research Institute of Western Australia (MRIWA) found that a global steel industry shift away from coal towards DRI on a

[14] IEEFA, 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023

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pathway to net zero emissions steelmaking presents "a material, structural change to Western Australia's iron ore industry, and the economy more broadly". It also highlighted that, in a scenario where the steel technology transition is accelerated, Western Australia's iron ore industry would be "in a precarious position assuming no change to the current product mix".[15]

Australia faces a distinct disadvantage due to the quality of its hematite iron ore compared with other nations. DRI-based steelmaking currently requires ores with a high iron content, typically 67% or more. Most of the Pilbara's commercial deposits contain between 56% and 62% iron, currently suitable only for incumbent, highly carbon-intensive blast furnace technology.

Australia faces growing international competition, with steelmakers thinking about the offshoring of green iron production in South America, Africa and the Middle East. Although Australia currently leads the world in iron ore exports, other nations and regions have the opportunity to combine their higher-grade iron ore and renewable energy resources to produce green iron for export in response to future demand growth.

IEEFA recently published two analyses that looked at 'Opportunities and challenges for the Pilbara amid the accelerating steel technology transition', and at 'Unlocking the potential of magnetite ore for Australia's iron and steel transition'. The first of the two analyses, on the Pilbara, noted that:

"Technology solutions may be part of the answer to the Pilbara ore quality issue. A number of technologies are developing to enable the use of lower-grade ores in DRI-based green steel production."

"Fortescue, in collaboration with Mitsubishi Corporation, Voestalpine and Primetals Technologies, has entered into a Memorandum of Understanding to assess and further develop HYFOR (hydrogen-based fine-ore reduction that does not require pelletising) and Smelter reduction technologies, which could potentially address the issue of Pilbara's lower-grade iron ores. Fortescue also recently claimed a breakthrough and considerable progress in zero-carbon metallics production on a large scale in Western Australia. Fortescue is keen to find green steel technology solutions for its iron ore as it has committed to reach net zero Scope 3 carbon emissions by 2040. In contrast, the other Pilbara majors Rio Tinto and BHP have no measurable Scope 3 emissions targets."

"An increased focus on magnetite iron ore – which is more easily beneficiated to [Direct Reduction] DR-grade – may also be part of the answer although it's far less available in the Pilbara than hematite. Fortescue's new Iron Bridge project in the Pilbara will produce magnetite of DR-grade but will likely be blended into a blast-furnace grade product, at least initially."[16]

The magnetite paper stated that: "Magnetite ores represent 38% of Australia's economic demonstrated resources of iron ore, of which 81% are in Western Australia, while only 3% of the states' exports come from magnetite ores."

[15] Minerals Research Institute of Western Australia. Western Australia's Green Steel Opportunity. 19 June 2023. Page 36-37
[16] IEEFA. Opportunities and challenges for the Pilbara amid the accelerating steel technology transition. 27 March 2023.

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"[…] To meet carbon emissions targets and manage Scope 3 emissions associated with iron ore mining, Australia should maximise investment in magnetite mines both for domestic use and export."[17]

As the Pilbara study noted: "Pressure is growing on Australia as other nations are seeking to develop green steel/iron industries. Nippon Steel is considering Brazil as well as Australia, as Brazilian iron ore giant Vale is the key global producer of DR-grade iron ore. Vale aims to triple its high-grade iron ore production to 100 million tonnes by the end of this decade." [18]

It will be important for Australia to proactively address this risk if it wants to compete in the green iron race.

How can we ensure our hydrogen industry attracts the necessary investment?

15. What in addition to the commercial cost gap is preventing Australian hydrogen projects progressing beyond a financial investment decision?
16. What signals are effective overseas and can apply to unlock greater investment?
17. Are there any other measures needed to unlock investment in the development of the Australian hydrogen industry including from international and Australian institutional investors?
18. When would it be appropriate to take a 'tech neutral' approach to developing hydrogen, and when would a more directed approach be warranted?
19. What further regulatory work is required as we accelerate the development of the hydrogen industry? What barriers do you currently see?

Urgent action is required to capture Australia's hydrogen potential

A recent analysis by EY flagged that more work is needed to realise Australia's hydrogen potential. "This advantage is conditional, not automatic or absolute. While the shift to net zero creates new potential strengths, existing potential weaknesses remain. Australia has no room for complacency and project approvals processes, relative capital requirements, and labour costs will continue to be watchpoints for major investments."[19]

With growing competition from other regions, in particular the United States, Canada and the EU, Australia needs to accelerate its efforts to capture the opportunities created by its natural advantage.[20]

[17] IEEFA. Unlocking the potential of magnetite ore for Australia's iron and steel transition. 12 May 2023.
[18] IEEFA. Opportunities and challenges for the Pilbara amid the accelerating steel technology transition. 27 March 2023.
[19] EY. Seizing Australia's energy superpower opportunities. April 2023. Page 8.
[20] Clean Energy Council. Australia at risk of being locked out of global superpower race. 1 March 2023.

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The Australian government should not support hydrogen production based on fossil fuels plus carbon capture and storage

There are at least five export-oriented hydrogen projects being considered in Australia that rely on carbon capture and storage (CCS) for achieving a 'clean' production rating, including: Glencore Surat Hydrogen Project; Darwin Clean Hydrogen Hub; WA Supply Chain of Low Carbon Ammonia (Mitsui); Mid West Clean Energy Project; and Hydrogen Energy Supply Chain (HESC).

CCS has a poor track record globally and presents very significant risks for Australia. Last year, IEEFA conducted a review of 13 flagship CCS projects globally comprising about 55% of the total nominal capture capacity operating worldwide.[21] It found that failed or underperforming projects considerably outnumbered successful examples (***Figure 1***).

Figure 1. Performance of flagship CCS projects globally

Carbon Capture and Storage (CCS) projects' poor report card

Project	Capacity (MtCO2 p.a.)	Performance
Natural Gas processing		
1986 Shute Creek	7	Lifetime under-performance of 36%
1996 Sleipner	0.9	Performing close to the capture capacity
2004 In Salah	1.1	Failed after 7 years of operation
2007 Snøhvit	0.7	Performing close to the capture capacity
2019 Gorgon	4	Lifetime under-performance of ~50%
Industrial sector		
2000 Great Plains	3	Lifetime under-performance of 20–30%
2013 Coffeyville	0.9	No public data was found on the lifetime performance.
2015 Quest	1.1	Performing close to the capture capacity
2016 Abu Dhabi	0.8	No public data was found on the lifetime performance.
2017 Illinois Industrial (IL-CCS)	1	Lifetime under-performance of 45–50%
Power sector		
2014 Kemper	3	Failed to be started
2014 Boundary Dam	1	Lifetime under-performance of ~50%
2017 Petra Nova	1.4	Failed after 4 years of operation

Source: IEEFA. The Carbon Capture Crux: Lessons learned. September 2022.

A more recent IEEFA analysis of Norway's Sleipner and Snohvit projects, two of the three successful CCS examples in the review, demonstrated that CCS is not without material ongoing risks that may ultimately negate some or all the benefits it seeks to create.[22]

"The subsurface areas of Sleipner and Snøhvit are among the most studied geological fields in both oil and gas and CO_2 storage globally. […] Despite the studies, experience and passage of

[21] IEEFA. The carbon capture crux: Lessons learned. 1 September 2022.
[22] IEEFA. Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales? 14 June 2023. Page 4.

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time, the security and stability of the two fields have proven difficult to predict. In 1999, three years into Sleipner's storage operations, CO_2 had already risen from its lower-level injection point to the top extent of the storage formation and into a previously unidentified shallow layer. Injected CO_2 began to accumulate in this top layer in unexpectedly large quantities. Had this unknown layer not been fortunate enough to be geologically bounded, stored CO_2 might have escaped.

"At Snøhvit, problems surfaced merely 18 months into injection operations despite detailed pre-operational field assessment and engineering. The targeted storage site demonstrated acute signs of rejecting the CO_2. A geological structure thought to have 18 years' worth of CO_2 storage capacity was indicating less than six months of further usage potential. This unexpected turn of events baffled scientists and engineers while at the same time jeopardizing the viability of more than US$7 billion of investment in field development and natural gas liquefaction infrastructure. Emergency remedial actions and permanent long-term alternatives needed to be, and were, identified on short notice and at great cost."[23]

The troubled track record of CCS and the high risk that storage of CO_2 will not be permanent mean hydrogen projects relying on CCS could lead to additional emissions and decarbonisation costs for Australia, putting its emissions reduction targets at risk.

Hydrogen created from fossil fuels with CCS also presents high financial risks. IEEFA analysed the viability of the Victorian HESC project, which relies on the gasification of Australia's brown coal resources into hydrogen for shipping to Japan, and found that the project faces very high financial risks:

"Of all the various forms of hydrogen production, using coal to produce hydrogen is the most emissions-intensive, creating 18 to 20 times more CO_2 than the amount of hydrogen produced. The project's "clean" blue hydrogen label relies on plans to capture 90% of emissions.

"[The CCS component of the project] alone is likely to require billions in investment, based on the Gorgon project experience. The Gorgon project has cost A$3.2 billion to date, and has injected just 6.5 million tonnes over the first six years of operation. CarbonNet is designed to store 4 million tonnes per year (Mtpa) of CO_2.

"Coal-based hydrogen is currently less expensive to produce than renewable hydrogen – by up to half as much. By 2030, that is set to change. As renewable energy scales up, its costs are expected to fall, as are the costs of electrolysers used to produce the renewable hydrogen; so much so that by 2030, just when the HESC reaches full-scale production, it will be based on a more expensive technology. BloombergNEF forecasts that green hydrogen made with renewable energy will be cheaper than coal-based hydrogen everywhere by 2030.

"The IEA has projected the cost of a large-scale brown coal-to-hydrogen project to be on par with renewable energy-based hydrogen by 2030. From then, the cost of renewable-based hydrogen will continue to fall. Australia's Clean Energy Finance Corporation agrees that green hydrogen will be cheaper than blue hydrogen by this date. Meanwhile, coal-mining costs could continue to

[23] IEEFA. Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales? June 2023. Pages 5-6.

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rise. HESC will struggle to prove commercially viable in the medium term as it competes with other suppliers of hydrogen beyond the initial short-term off-take agreement with Japan."[24]

Coal mining has traditionally been a plentiful low-cost extraction resource, particularly open-cut thermal coal mines. However, in recent times mining costs have increased, with labour shortages and major climate events interrupting production. Cost increases of 50% were not uncommon in most recent financial results reporting.[25]

Coal-to-hydrogen feasibility studies that are based on historical mining costs will underestimate the cost of the hydrogen feedstock, potentially by a wide margin. In addition, hydrogen production is slated to commence from 2030 onward – when coal mines will be further depleted, and domestic power plants will be entering retirement. The probable material decrease in coal mining production volumes will likely have further impacts on coal mining costs.

How can we ensure our hydrogen industry develops in a way that benefits all Australians?

20. What actions do you view as being critical to build and maintain community support for Australia's developing hydrogen industry?
21. How should the interests of the emerging hydrogen industry with respect to water be balanced with other users?
22. How else can Australian governments ensure that First Nations communities are resourced to effectively participate, benefit and be empowered by the development of the hydrogen industry?
23. Is there more information that the communities including First Nations communities would like to receive about the renewable energy and hydrogen sector? What information should be provided?
24. What regulatory barriers will become more prominent as we accelerate the development of the hydrogen industry?
25. What market conditions would indicate the need for a hydrogen reserve, price cap or other fuel security measures?
26. How can Government/s ensure that the early strong investment in the sector transitions to government revenue as the sector matures?

Domestic needs should be prioritised to avoid repeating the gas market experience

The development of an LNG export industry has had adverse impacts on Australian consumers, with large price increases and sometimes difficulties in securing gas contracts for domestic use.

[24] IEEFA. Hydrogen Energy Supply Chain project viability remains uncertain in wake of Hydrogen Headstart scheme for green hydrogen. 3 July 2023

[25] IEEFA, Australian coal miners should think carefully about what they do with their inflated cash balances. 9 March 2023.

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This has led to a precarious financial situation for domestic industrial consumers in particular, which are price-sensitive.[26]

It will be important to make sure that the development of an export-focused hydrogen industry in Australia will not be detrimental to the domestic economy. In particular, it will be important to ensure that the production of hydrogen aimed at direct or indirect exports:

- does not impede the domestic electricity transition by competing for skilled personnel, land and materials for renewable electricity generation, storage, transmission and distribution assets;
- does not drive the price of energy (in particular electricity and hydrogen) up domestically; and instead
- contributes to lowering the overall energy system cost.

It might be necessary to put a range of measures in place to ensure this outcome, such as reserve mechanisms or required contributions to the national energy system.

A detailed study into the potential for the Gladstone region to become a green hydrogen exporter highlighted the vast resources requirements. It found that: "The potential of the Gladstone region to export hydrogen appears predominantly limited by the existing grid capacity and the scale of the renewable resource."[27]

The study found that, for Gladstone to become an exporter of 2.82Mtpa of hydrogen, requirements would include: expansion of renewable energy capacity by 75.2 gigawatts (GW); 56-130 gigalitres of surface water and 110-236 gigalitres of sea water per year; between 295 and 785 hectares of land; and significant port upgrades including additional berths to accommodate 110-300 ships per year. Balancing these requirements with the needs of the domestic energy transition and other local needs will be key to ensuring ongoing social licence for these projects.

Many hydrogen projects could have behind-the-meter renewable generation to power electrolysers, but in some cases, electrolysers may be grid-connected. Consideration should also be given to the potential for grid-connected electrolysers to provide services to the National Electricity Market (NEM) and other electricity grids in Australia. Electrolysers that are grid-connected could potentially be operated in a flexible manner, to help with balancing the grid.

The Australian Energy Market Commission (AEMC) noted that, "Electrolysers can ramp up and down quickly, have low minimum operating output, and the flexibility to operate above nameplate capacity for periods. This means they can offer several services of value to the grid: demand flexibility in response to rapidly changing or unexpected market conditions; demand shifting between seasons or periods of high or low VRE [variable renewable energy] output; the relief of minimum demand conditions; frequency control ancillary services (FCAS), voltage control; network support and the relief of network congestion issues. Electrolysers can also sign up for contracts that help market participants manage increasing price volatility in the NEM. Hydrogen can also fulfil a locational role in relation to the provision of a number of these services."[28]

[26] IEEFA. What's a fair price for domestic gas? $12 per gigajoule is too high. 7 December 2022.
[27] Advisian. Queensland Hydrogen Coordination Unit (HCU). Strategic Planning for Hydrogen Production and Export Facilities. Chapter 5: Detailed Opportunity Assessment. P33. Department of Energy and Public Works. Enabling Queensland's Hydrogen production and export opportunities report. October 2022.
[28] AEMC. Hydrogen: the role of the hydrogen production industry in providing system services to the NEM. May 2022.

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Electrolysers could provide a large opportunity for demand flexibility, so ensuring that these potential benefits are assessed and captured is key. IEEFA notes that the financial viability and technical feasibility of running electrolysers at varying load factors would need to be analysed.

Consumers should be protected from muddled messages by the gas industry on 'renewable gas'

Compelling evidence suggests that hydrogen does not make financial sense as a household fuel. State and territory governments including Victoria and the ACT have signalled that electrification is the likely future for households in those jurisdictions, by introducing policies to ensure all new homes will be all-electric. However, a recent IEEFA report found that gas distribution networks are persisting with 'renewable gas' promotional campaigns that may encourage customers to stay on the gas network, locking them into higher costs and asset stranding risks. The report states:

"Gas distribution networks and their industry representative bodies have been promoting the message to households that their gas network infrastructure will continue to be used under a transition to net zero emissions. They have asserted that gas distribution networks will likely be repurposed to deliver 'renewable gas' to homes, derived from either biomethane or hydrogen, instead of the current supply of fossil gas.

"These campaigns are inconsistent with the compelling evidence that electrification is the best option for decarbonising household fossil use. Electrification would cost less than switching to biomethane or hydrogen. Moreover, there are serious technical constraints to relying on biomethane or hydrogen for household energy use; by contrast, electric appliances for cooking, space heating and water heating are mature and already widely used by many Australian households.

"Especially concerning is the fact that the messages presented in Victorian gas distribution networks' 'renewable gas' campaigns appear inconsistent with their own statements to regulators, their investment plans, the opinion of the regulator and energy market consumer representatives.

"Victoria's gas distribution networks have requested to recover an additional A$461 million in accelerated depreciation costs from consumers over the next five years, of which A$333 million was granted by the Australian Energy Regulator (AER), equal to nearly 7% of their total asset base. Accelerated depreciation in gas networks was first argued for in 2020 by the Australian Gas Infrastructure Group (AGIG) for its Dampier Bunbury gas pipeline in Western Australia. AGIG argued that the improving economics of renewable electricity, combined with government emissions policies, were likely to lead to a decline in demand for fossil gas supplied through their network, leading to asset stranding risk.

"Meanwhile, the networks have proposed only very modest expenditure, A$19 million, on preparing their networks for hydrogen, which the regulator allowed despite finding that it was non-conforming with respect to the National Gas Laws. An additional A$6 million in proposed operating expenditure is on 'renewable gas' promotional campaigns, to be partially charged back to consumers.

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"[IEEFA] believes that gas distribution networks may be exposing themselves to substantial risks by encouraging consumers to continue to purchase gas appliances under the belief they will be useful under a low-emissions future due to 'renewable gas'. Promotional campaigns have not clearly acknowledged the low likelihood of a significant role for 'renewable gas' in distribution networks, and that the dominant policy direction is towards electrification in homes.

"[…] the size of investments made by customers who continue to buy gas appliances is likely to number in the billions of dollars. […] Governments and regulators should also act to protect consumers, by ensuring that the networks' campaigning activities are lawful under Australian consumer law, and that expenditure on 'renewable gas' activities is not approved where it is not in the long-term interests of energy consumers."[29]

Australia's energy market bodies need clear signals that acknowledge hydrogen is not a viable future household fuel

IEEFA's recent report on hydrogen and biomethane in gas distribution networks noted that gas distribution networks in Victoria recently proposed modest expenditure for 'hydrogen readiness' under their recent Access Arrangement proposals. The Australian Energy Regulator (AER) found this expenditure to be non-conforming with respect to the National Gas Laws, citing the AEMC's view that:

"a safety case is not sufficient to justify expenditure on hydrogen readiness where a service provider has voluntarily decided to introduce hydrogen into its network. The expenditure would need to pass a positive economic benefits test to be conforming capex. [Multinet and AGN have] not, at this stage, provided evidence that the proposed expenditure meets such a test."[30]

Despite this, the AER approved networks' capital expenditure proposals, including the amount for 'hydrogen readiness' activities. IEEFA's report noted: "This decision leaves uncertainty as to whether any non-conforming expenditure on hydrogen readiness would be added to the networks' capital base in the next access arrangement period"[31]

Operating expenditure proposals that included 'renewable gas education programs' were also approved, despite the AER also finding these programs to be non-conforming.

This highlights the current ambiguity around regulatory decisions relating to hydrogen in gas networks. Australia's energy market bodies would benefit from clear signals that recognise hydrogen is not a viable household fuel choice for Australia and does not feature as part of its national hydrogen strategy.

[29] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023.
[30] AER. Draft Decision: Australian Gas Networks (Victoria and Albury) Access Arrangement 2023 to 2028. Attachment 5 – Capital expenditure. December 2022. Page 17.
[31] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023.

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How should we develop the necessary infrastructure needed to support the development of our hydrogen industry?

27. How can the National Hydrogen Infrastructure Assessment be delivered to maximise the value to governments and industry?
28. How can Australian governments ensure the efficient use of existing infrastructure, and delivery of new infrastructure, including common user infrastructure?
29. How should the infrastructure needs of the hydrogen industry be balanced with other infrastructure users e.g. electricity generation?
30. What are the trade-offs (or synergies) of developing a hydrogen industry with other government goals?
31. How can existing gas infrastructure be repurposed to address priority use cases for hydrogen?

Any upgrades to the existing gas infrastructure should be considered very carefully

Most promising hydrogen usages are likely to be highly localised, with large hydrogen production sites associated with large industrial facilities. It remains unclear whether the existing gas infrastructure will overlap with future hydrogen infrastructure needs.

In addition, a recent IEEFA report found that there may be limited benefits to repurposing existing infrastructure, relative to the substantial costs incurred: "Analysis from the Australian Pipelines and Gas Association (APGA) suggests that fully repurposing gas infrastructure to transport hydrogen may require investment equivalent to around 28% of the cost of building a brand new gas pipeline network. However, estimates vary wildly, with Infrastructure Victoria suggesting that in some cases, it may be cheaper to fully replace infrastructure rather than repurposing it."[32]

While some gas distribution networks examined in the report have claimed that their networks can support up to a 10% volumetric blend of hydrogen with minimal investment, it is unclear what this actual investment would be. Furthermore, the different energy densities of hydrogen and fossil gas mean that a 10% volumetric blend will only displace 3% of fossil gas in energy terms. Pursuing low blends of hydrogen therefore offers limited value in supporting the development of a hydrogen industry, or in meeting federal and state emissions reduction goals.

Common-user facilities should be prioritised

With a large number of individual hydrogen projects, consideration needs to be given to developing common-user ports and associated facilities.

[32] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023.

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Current projects tend to preference dedicated facilities. For example, a review by IEEFA of Australian hydrogen export projects reveals that they propose exporting from 17 different ports around Australia.[33]

If exports of hydrogen were to take place despite their poor financial outlook, Australia needs to minimise duplication of infrastructure and consider common-user terminal port facilities.

Export via shipping requires very large fleets so that the continuous flow of hydrogen can be loaded onto ships. It also requires large port facilities with large storage tank or bunkering capacity to allow for port stocks of product ready to be shipped. This would require significant infrastructure development around our ports and coastline.

Furthermore, given the potential hazards to human and marine life posed by hydrogen in its various forms, it makes sense to rationalise these facilities, which will need to operate with strict and high safety standards. Finally, eliminating duplication of facilities will improve land use considerations and reduce the environmental impacts of port expansion and new port development.

Rationalising needs across projects would make sense for other types of infrastructure requirements as well to ensure costs, environmental and land impacts can be minimised, and safety can be maximised.

How can we enable a hydrogen export industry (including the export of goods manufactured with hydrogen)?

32. How can agreements with other nations best support rapid growth to Australia's hydrogen industry?
33. How should Australia ensure that the necessary foreign investment in hydrogen industry, and export projects leads to lasting benefits for all Australians?
34. What other issues should Australian governments consider in relation to revising the National Hydrogen Strategy?

There are many collaboration opportunities with India to support the growth of Australia's hydrogen industry

IEEFA recently highlighted the collaboration opportunities between Australia and India related to the hydrogen value chain:

"The [IEA] has warned that countries need to diversify their solar supply chains. India's efforts to promote a domestic solar PV manufacturing industry have reduced its import dependence on

[33] Based on IEEFA analysis of data from CSIRO. Hydrogen projects map.

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China for solar equipment, which was previously more than 90%. It is also developing its solar export capacity.

“A recent study by [IEEFA] and JMK Research showed that Indian solar module manufacturing capacity could reach 110 [GW] per year by 2026. India will achieve self-sufficiency in solar PV modules at this level and expand exports further.

“Australia also wants to reduce its reliance on imports of solar panels from China and is looking to grow domestic manufacturing. The government has established a A$15 billion National Reconstruction Fund to boost investment in domestic manufacturing projects in future industries, including solar and zero-emissions technologies.

“[…] During Mr [Indian Prime Minister Narendra] Modi’s visit to Australia, the prime ministers agreed to terms of reference on an Australia-India Green Hydrogen Taskforce which will promote bilateral cooperation on green hydrogen.

“India has ambitions to become a global green hydrogen leader as part of its efforts to decarbonise emissions-intensive sectors, including fertiliser and steel production. The government has set a target to produce about 5 million metric tonnes of green hydrogen annually by 2030 under its National Hydrogen Mission.

“Both India and Australia offer opportunities to explore green hydrogen and green ammonia development. India’s Reliance Industries is reportedly planning green hydrogen investments in Western Australia. Indian company TheGreenBillions Limited recently announced plans to invest in Australia in sustainable energy projects, including green hydrogen, supported by the India Australia Strategic Alliance, an industry body for Indian and Australian businesses.

“JSW Future Energy Limited, a JSW Energy subsidiary, has partnered with Fortescue Future Industries to develop green hydrogen projects in India.

“India is likely to drive global steel production growth in the coming decades. In its Stated Policy Scenario, the IEA expects steel production in India to almost double by 2030 and quadruple by 2050. This corresponds to over 150Mt of new steel capacity by 2030-31.

“Accelerating the transition towards green iron and steel technologies will be key to supporting Indian and global emissions reduction objectives.

“As the leading global iron ore producer, with a huge yet untapped economic opportunity in developing a local green iron and steel industry, Australia can continue developing its research and innovation partnership on green steel with India under the updated India Economic Strategy.

“Opportunities include investing in developing technologies to allow green iron and steel production, green hydrogen supply chains to feed into iron and steel production processes, and the capabilities required to operate green iron and steel assets. This presents a sizeable investment opportunity for Australian superannuation funds looking to support the global transition to net zero emissions.”[34]

[34] IEEFA. How India and Australia can help each other on the renewable energy journey. 22 May 2023