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Draft 2025 IASR Stage 2 Consultation

Submission to AEMO, 31 March 2022

The Centre for Applied Energy Economics and Policy Research (CAEEPR) is a collaborative partnership between Griffith Business School and energy sector participants in Australia's National Electricity Market.

CAEEPR aim to maximise the energy sector's potential to achieve emission reductions and contribute to inclusive, sustainable, and prosperous businesses and communities while building capacity in electricity economics. CAEEPR uses a national electricity market model to develop and analyse different scenarios to assess different policy positions for generator dispatch and transmission efficiency.

CAEEPR's sub aims/objectives that are most relevant to this submission:

- Supporting the transition to more sustainable and less carbon-intensive power generation and transmission system and address the accompanying policy, economic, technical and political challenges within the industry.
- Provide thought leadership and industry engagement strategies that our members can design and deliver best practice energy services with reduced emissions.
- Create and uphold advanced Electricity Market models for analysing wholesale spot and future markets, power system reliability, integration of dispatchable and intermittent resources, and network capacity adequacy.

This submission has been prepared by Andrew Fletcher who is an Industry Adjunct Research Fellow at CAEEPR. The views expressed in this submission are entirely the author's and are not reflective of CAEEPR.

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Introduction

I welcome the opportunity to provide feedback to AEMO on the Draft 2025 IASR Stage 1, released in December 2024. This submission further builds on the author's 2024-25 GenCost and Draft 2025 Stage 1 IASR Consultation Submission, continuing the theme of improving transparency, the accuracy of technology build cost projections and modelling of hydrogen.

This submission identifies several areas where improvements could be made to inputs and assumptions. AEMO is applauded for its request in the Draft IASR that, *"where possible, submissions should provide evidence that supports any views or claims that are put forward"* and the recommendations in this submission are supported by a substantial evidence base of research and analysis.

The frame of reference for this submission is AER's forecasting guidelines, with (Australian Energy Regulator, 2023) stating that:

"*The AER's forecasting guidelines require AEMO's forecasting practices and processes to have regard to the following principles:*

- *forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased manner;*
- *the basic inputs, assumptions and methodology that underpin forecasts should be disclosed; and*
- *stakeholders should have as much opportunity to engage as is practicable, through effective consultation and access to documents and information."*

The submission identifies several opportunities to improve the IASR and underlying consultant modelling reports.

CONTENTS

1. Improving transparency

1.1 CSIRO Climateworks Centre Multi-Sectoral Modelling (CSIROCC MSM)

CSIROCC MSM determines carbon budgets and electrification demand growth, which are critical ISP inputs and it is regrettable that it has not been released for consultation. While it is acknowledged that many inputs to the CSIROCC MSM are included in other IASR consultant reports and selected outputs of the CSIROCC MSM are included in the IASR, other inputs and outputs from CSIROCC MSM have not been disclosed.

Stakeholders have not been provided an opportunity to engage with the basic inputs and assumptions that underpin electrification demand forecasts for home and commercial buildings, industry and non-road transport. AEMO is encouraged to provide a stakeholder consultation opportunity for these matters once the Draft CSIROCC MSM report is finalised. A consultation opportunity is warranted given:

- High degree of Stakeholder interest, which is evidenced by the large amount of modelling that has been produced for the public domain that includes or is focussed on modelling of electrification and alternatives, including:
    - Castles & Cars: savings in the suburbs through electrify everything – technical study (Griffith, Ellison, Calisch, & Cass, 2021)
    - Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy, for APGA and ENA (ACIL ALLEN, 2024)
    - The Role of Gas Infrastructure in Australia's Energy Transition, for APA Group, Australian Gas Infrastructure Group, and Jemena (Boston Consulting Group, 2023)
    - Net Zero Australia – The University of Melbourne, the University of Queensland and Princeton University (Net Zero Australia, 2023)
    - Climateworks Centre Decarbonisation Scenarios 2023: Paris Agreement Alignment for Australia (Li, Lauren, Murugesan, & Whelan, 2023)
    - CSIRO Pathways to Net Zero Emissions – An Australian Perspective on Rapid Decarbonisation (CSIRO, 2023A)
- CSIRO acknowledged in the relevant Forecasting Reference Group that the TIMES model underlying the CSIROCC MSM underestimates required firming generation capacity due to the modelling not being time sequential. As a result, CSIROCC MSM underestimates the cost of firmed renewable electricity and the cost of fuel-switching to electrification. The lower firming generation capacity can be seen by comparing modelling outcomes from the 2024 ISP (based on time sequential modelling) to outcome from other TIMES modelling. In addition gas generation volumes from the 2024 ISP are a multiple of gas generation volumes from the 2022 CSIROCC MSM (CSIRO & Climateworks Centre, 2022) and other TIMES modelling.
    - AEMO 2024 ISP Step Change scenario: 0.35x 2050 ratio of firming generation capacity to renewables. By 2049-50 the NEM is forecast to have 86GW of rooftop solar PV capacity, 127 GW of utility-scale wind and solar generation capacity and 75 GW of firm dispatchable capacity, including 15GW of gas-powered generation. On average gas generation represents 2.7% of generation volumes from 2041-2050.
    - CSIROCC MSM 2022 Step Change scenario: Figure 1 shows that gas generation volumes are immaterial form 2041-2050 that they aren't visible on the chart.
    - Climateworks Centre Decarbonisation Scenarios 2023: Paris Agreement Alignment for Australia (Li, Lauren, Murugesan, & Whelan, 2023). 0.13x 2050 ratio of firming generation capacity to

renewables. Renewable electricity generation capacity of 363–398 GW by 2050 and 44–55 GW of battery capacity, with gas-powered generation not disclosed.

- CSIRO Pathways to Net Zero Emissions – An Australian Perspective on Rapid Decarbonisation (CSIRO, 2023A). 0.25x 2050 ratio of firming generation capacity to renewables. Per Figure 2 CSIRO Rapid Decarbonisation Scenario (1.5°C carbon budget) assumes ~240GW of wind and solar and ~60GW of firm dispatchable capacity.

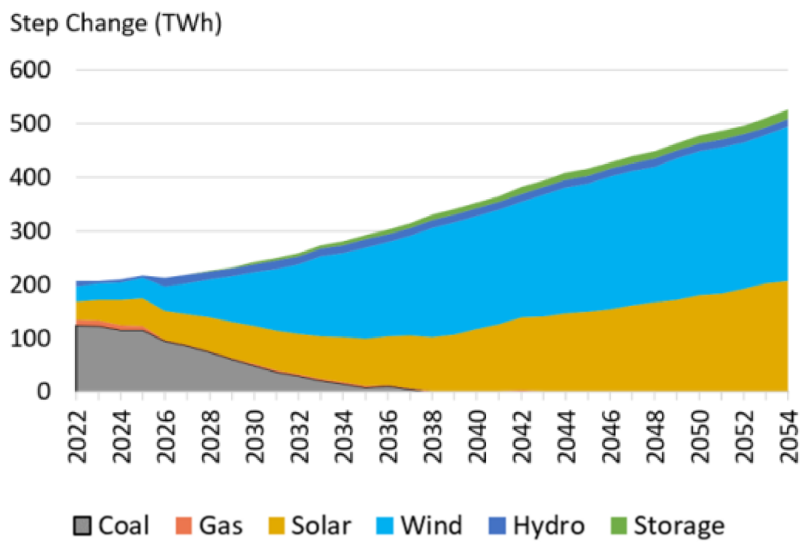


Figure 1: CSIROCC MSM 2022 – Step Change Generation Mix | Source: (CSIRO & Climateworks Centre, 2022)

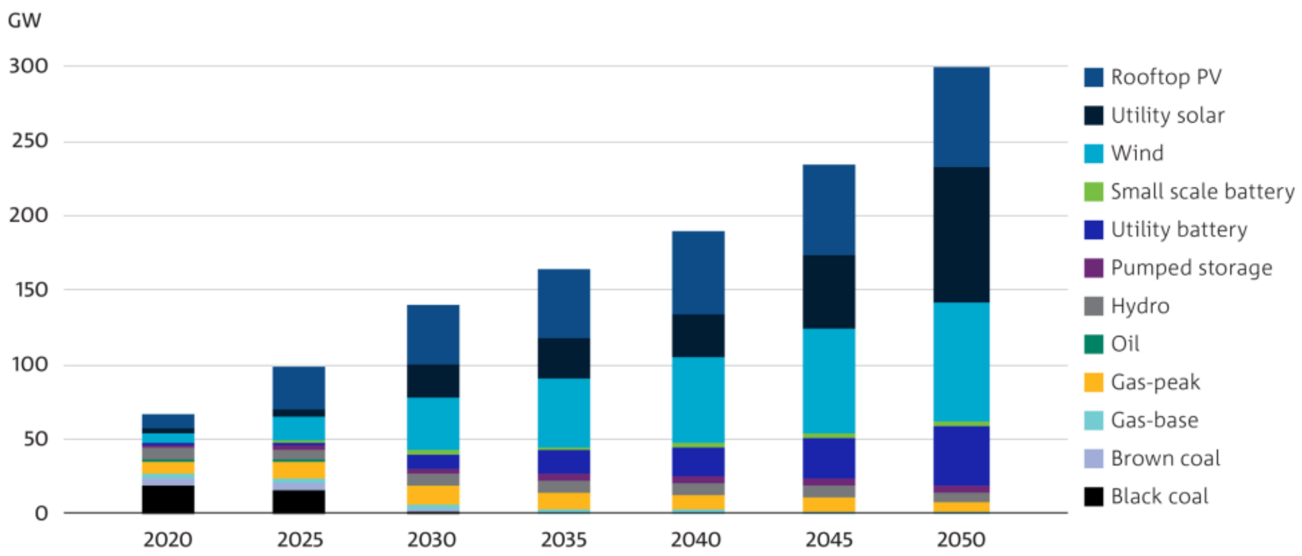


Figure 2: Electricity capacity installation by technology type for the CSIRO Rapid Decarbonisation Scenario (1.5°C carbon budget) | Source: CSIRO Pathways to Net Zero Emissions – An Australian Perspective on Rapid Decarbonisation (CSIRO, 2023A)

Per requests at Forecasting Reference Group webinars CSIROCC/AEMO is encouraged to disclose generation capacity build and generation volumes within the CSIROCC MSM report. While this data does not serve as inputs to the ISP, it is important in assessing the validity and potential magnitude of bias in electrification demand forecasts.

Regarding the use of energy in industry 2022 CSIROCC MSM states that:

"AusTIMES can implement energy efficiency and electrification of technologies based on capital costs, equipment lifetime and fuel costs, if it is economically attractive. Assumptions on costs and savings are derived from a variety of sources and are updated over time." (CSIRO & Climateworks Centre, 2022)

Similar descriptions apply for home buildings and commercial buildings. CSIROCC are encouraged to disclose relevant input assumptions and their sources for industry, home and commercial buildings in the same manner as other modelling, such as (Griffith, Ellison, Calisch, & Cass, 2021) and (ACIL ALLEN, 2024), as well as input assumptions and sources for non-road transport.

1.2 Hydrogen cost estimates

AEMO is commended for its efforts to address material issues identified with hydrogen modelling in the author's Draft 2024 ISP Consultation Submission. However, per requests at Forecasting Reference Groups webinars there the transparency of the outcomes of hydrogen modelling should be improved, including disclosing levelized cost of hydrogen outcomes. This includes disclosing both ACIL ALLEN and CSIROCC MSM hydrogen cost estimates per recommendations in the author's Draft 2025 Stage 1 IASR Consultation Submission. AEMO is also encouraged to publish hydrogen cost estimates as a generic HYBLEND fuel cost estimate for each NEM state assuming 100% hydrogen blending, within the IASR workbook.

As levelized cost of hydrogen is not disclosed in the ACIL ALLEN report or in IASR documentation the level of transparency is not sufficient to assess internal consistency of this modelling, particularly whether the modelled uptake of decarbonisation alternative is consistent with least cost modelling. For example, ACIL ALLEN assume 50% of alumina calcination fuel switches to green hydrogen, however the modelled cost of green hydrogen is not able to be easily compared to alternatives such as biomethane. Based on AEMO data the implied carbon price is $496/kg[1] for fuel switching from natural gas to hydrogen, before considering the cost of new equipment. This is higher than the 2050 Value of Greenhouse gas emission reduction of $422/t CO_2e and may not be competitive with alternatives such as continuing to use natural gas and using engineered carbon removals as an offset.

The only method for assessing hydrogen cost estimates is to calculate them based on HYBLEND fuel costs from the Stage 2 Draft 2025 IASR workbook. With the cancellation of projects such as the Hydrogen Jobs Plan (South Australia) (MacLennan, 2025), there may be no way for stakeholders to assess the validity of hydrogen costs estimates in the Final IASR.

Figure 3 shows that driven by higher electrolyser capex estimates and the inclusion of hydrogen storage and transport, 2050 hydrogen cost in the Draft 2025 IASR are around double the cost of the 2024 ISP. The Draft 2025 IASR estimate is also around 50% higher than the PEM green hydrogen cost projection produced by CSIRO for the National Hydrogen Strategy 2024 (Australian Government - DCCEEW, 2024), which are consistent with 'farm gate' hydrogen cost estimate. CSIRO modelling for the National Hydrogen Strategy 2024 estimates that the cost of blue hydrogen is below $4/kg H_2 for most of the projection period, materially below the Draft 2025 IASR green hydrogen cost estimate. Should changes recommended in the author's 2024-25 GenCost and Draft 2025 Stage 1 IASR Consultation Submission and Section 4 of this submission be implemented, this gap could increase materially.

Figure 3 also shows hydrogen cost estimates from an ACIL ALLEN report produced for AGPA and ENA, using the same methodology and similar inputs to that of AEMO (ACIL ALLEN, 2024), demonstrating that hydrogen cost estimates are readily available from ACIL ALLEN's modelling.

[1] Calculated based on the AEMO IASR workbook 2050 Step change hydrogen cost estimate of $37.6/GJ and ACIL ALLEN's 2050 cost estimate for natural gas for industrial customers of $12/GJ, a 51.5kg$CO_2$e/GJf or burning natural gas implied from the IASR workbook for OCGT for 2025-26.

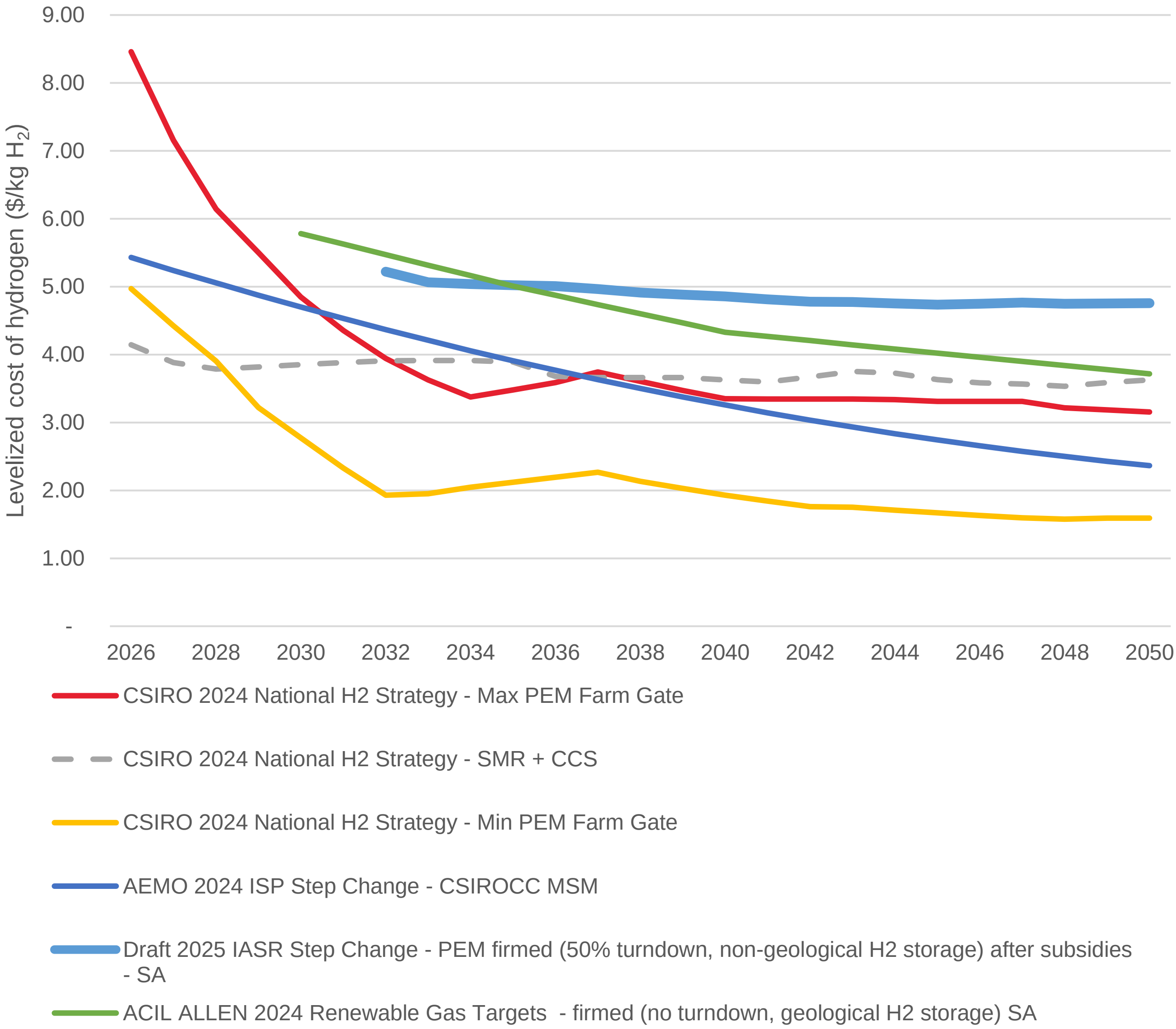


Figure 3: Selected levelized cost of hydrogen projections

Source: (Australian Government - DCCEEW, 2024) (ACIL ALLEN, 2024), 2024 AEMO ISP, (Australian Energy Market Operator, 2025)

Calculation notes: Where relevant, hydrogen cost per GJ is converted to hydrogen cost per kg using a ratio of 7.525, which is calculated assuming a hydrogen LHV of 120MJ/kg H_2 and a ratio of natural gas HHV to LHV of 1.107 (Aurecon, 2024A)

1.3 Hydrogen storage duration

On the IASR Stage 2 Webinar AEMO disclosed that the ACIL ALLEN hydrogen modelling found 3-6 days of hydrogen storage were required, with this cost inserted into the CSIROCC MSM. AEMO is encouraged to disclose this information in the ACIL ALLEN report and the IASR, particularly as it is relevant for informing the hydrogen balancing assumption in the ISP Methodology.

1.4 Blue hydrogen emission factors

Blue hydrogen has higher lifecycle CO_2e than green hydrogen, however it is not possible to easily identify what emission have been assumed for blue hydrogen in the previous version of the CSIROCC MSM. Greater transparency of these assumptions is encouraged.

1.5 CSIRO Electric vehicle projections

Consistent with the author's 2024 Forecasting Assumption Update Submission there is insufficient detail to assess whether full value chain costs of FCEV have been assessed by CSIRO. The basic inputs and assumptions that underpin FCEV projections, particularly trucks, such as vehicle capex, assumed hydrogen production costs, hydrogen storage and refuelling costs have not been disclosed. CSIRO is encouraged to disclose this information, including to allow stakeholders to assess internal consistency with hydrogen cost projections from ACIL ALLEN and CSIROCC MSM.

2. Sensitivities

Matters for consultation: Sensitivities (Section 2.4)

- *Do you have any further views on the proposed sensitivities?*
- *What additional uncertainties are valuable to explore with sensitivity analysis?*

2.1 Alternative CER uptake

A 100% weighting to CSIRO CER projections is recommended for Step Change, with Green Energy Markets used as a sensitivity. Refer to the author's Draft 2025 Stage 1 IASR Consultation Submission for evidence supporting this recommendation.

AEMO is encouraged to release load and CER traces and any other required inputs, such that stakeholders can replicate CER sensitivities in PLEXOS.

2.2 Technology neutral discount rate

A sensitivity with a technology neutral discount rate is recommended. This will allow for a consistent comparison of cost benefit analysis results with previous versions of the ISP and allow the impact of the change from a technology neutral discount rate to technology specific cost of capital estimates/ discount rates to be assessed. This is on the assumption that AEMO implement its proposed change to move to technology specific discount rates.

It is noted that moving to technology specific cost of capital assumption has the potential to materially improve cost benefit analysis for regulated transmission, with the proposed discount rate changing from 7.0% for the 2024 ISP to 3.0% for the 2026 ISP.

3. Hydrogen

3.1 Inclusion of blue hydrogen as a potential production technology in CSIROCC MSM for Step Change and Progressive Change

Blue hydrogen (SMR +CCS) should be included as a hydrogen production technology in CSIROCC MSM. Figure 3 shows that estimates of firmed green hydrogen costs have increased significantly since the 2023 IASR (represented by 2024 ISP). CSIRO CC MSM incudes Hydrogen Headstart policy support in its green hydrogen modelling, however this does not appear to be sufficient to make green hydrogen cost competitive with blue hydrogen.

Scenario descriptions for hydrogen should be based on techno-economic modelling outcomes, inclusive of policy support mechanism, rather than green hydrogen demand being assumed to conform with scenario descriptions. Selectively excluding a technology is not technology agnostic and may have an impact on the extent to which a least cost transition pathway is the outcome of ISP modelling. If AEMO persists with excluding blue hydrogen as a potential technology, it should include this in scenarios descriptions. Assumptions of additional policy support, including implied prohibitions on blue hydrogen, should be disclosed in in scenarios descriptions. Best practice would be to include an estimate of the economic costs of any assumed blue hydrogen prohibitions in the IASR to enable stakeholder engagement and inform governments about the potential additional cost of the policy beyond existing commitments.

AEMO provide the following justification for excluding blue hydrogen (SMR +CCS) from the Draft 2025 Stage 2 IASR.

… *"Steam methane reforming with CCS was excluded as an option in the 2023 IASR, due to stakeholder feedback.*

The 2024 multi-sectoral modelling allowed the potential development of steam methane reforming with CCS in the Step Change and Progressive Change scenarios. The multi-sectoral modelling also found that electrolysis was lower cost over the assumed plant lifetime. AEMO proposes to continue to focus on electrolysis technologies within ISP modelling, and to assume no growth in steam methane reforming hydrogen production above existing levels."

However, understanding of the cost of green hydrogen has evolved since the publication of the 2023 IASR as demonstrated by Figure 3. Figure 3 shows that in addition to 2025 Draft IASR CSIROCC hydrogen cost projections, firmed hydrogen cost projections from ACIL ALLEN's Renewable Gas Target modelling commissioned by AGPA and ENA (ACIL ALLEN, 2024), are also higher than CSIRO's blue hydrogen cost projections. This result is despite ACIL ALLEN assuming the availability of low-cost geological hydrogen storage.

The inputs assumptions and methodology of green hydrogen modelling undertaken for AGPA and ENA appears to be closely aligned with the modelling ACIL ALLEN has undertaken for the 2025 Draft IASR. Key exceptions are that for Draft 2025 IASR, ACIL ALLEN assume turndown of hydrogen demand used cases to 50% vs no turndown for AGPA and ENA. In addition, modelling undertaken for AGPA and ENA includes a speculative assumption around the availability of lower cost geological hydrogen storage, while modelling for the 2025 IASR assumes non-geological hydrogen storage. As the two sets of modelling share similar input assumptions and methodology, both are subject to the issues identified in the author's 2024-25 GenCost and Draft 2025 Stage 1 IASR Consultation Submission and Section 4 of this submission, which if addressed would increase green hydrogen cost projections.

The 2023 IASR Consultation Summary report (Australian Energy Market Operator, 2023) states that:

"*AEMO has considered this feedback and agrees that SMR may be inconsistent with the decarbonisation objectives of the scenarios. While future investment in SMR may occur, AEMO considers that the ISP modelling would be improved with concentration on green hydrogen options for domestic and international use."*

AEMO's rationale did not consider that the 2024 IEA World Energy Outlook (International Energy Agency, 2024) assumes that by 2050 that 20% of low-emissions hydrogen production consumption relates to fossil fuels with CCUS for State Policies Scenario (maps to Progressive Change), 22% the Announced Pledges Scenario (maps to Step Change) and 18% for Net Zero Emission by 2050 (maps to Green Energy Exports). ISP scenarios are aligned to IEA World Energy Outlook scenarios, while assumptions in CSIROCC MSM, such as maximum electrification uptakes are directly linked to IEA World Energy Outlook scenario outcomes (Reedman, 2024).

3.2 Plausibility of the Green Energy Industries scenario

The author recommends that AEMO exclude both Green Energy Exports and Green Energy Industries from ISP cost benefit analysis. Consistent with the author's Draft 2025 Stage 1 IASR Consultation Submission it is noted that, *"The commercial viability of green hydrogen is a foundational assumption for the Green Energy Exports scenario...."* (Australian Energy Market Operator, 2023). Further to the submission recent information casts further doubt on this foundational assumption and the plausibility of the Green Energy Industries scenario, including hydrogen cost projections released in the Draft 2025 Stage 2 IASR workbook.

Noting that carbon costs are not considered, Figure 4 shows that green hydrogen costs projections from the Draft 2025 IASR Stage 2 are higher than CSIRO's blue hydrogen cost estimates produced for the National Hydrogen Strategy 2024 (Australian Government - DCCEEW, 2024). Should changes recommended in the author's 2024-25 GenCost and Draft 2025 Stage 1 IASR Consultation Submission and Section 4 of this submission be implemented, this gap could increase materially.

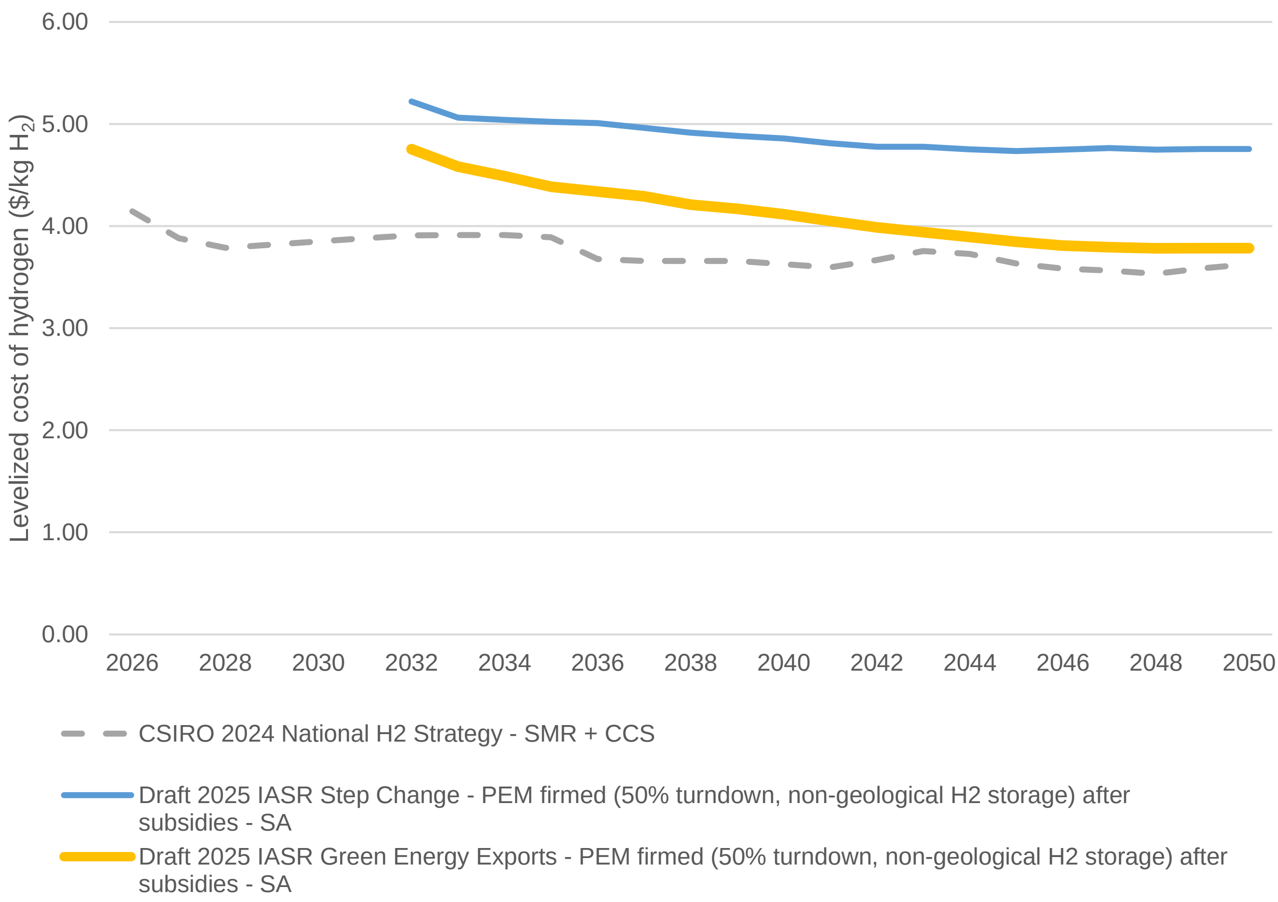


Figure 4: Green Energy Exports - Selected levelized cost of hydrogen projections	Source: (Australian Government - DCCEEW, 2024) (ACIL ALLEN, 2024), (Australian Energy Market Operator, 2025)

Calculation notes: Where relevant, hydrogen cost per GJ is converted to hydrogen cost per kg using a ratio of 7.525, which is calculated assuming a hydrogen LHV of 120MJ/kg H_2 and a ratio of natural gas HHV to LHV of 1.107 (Aurecon, 2024A)

International competitiveness/commercial viability of green steel production via a hydrogen DRI production path must be a foundational assumption of the Green Energy Industries scenario. The IASR, through ACIL ALLEN's hydrogen modelling, assumes 43% of green iron production occurs in the North West Interconnected System. However, Figure 5 from recent Deloitte analysis (Deloitte, 2025) shows that the Pilbara green iron production is not internationally competitive due to high locational cost factors and additional cost associated with porcessing hematite iron ore. Refer to Section 4.1.1 for further discussion of Deloitte's analysis.

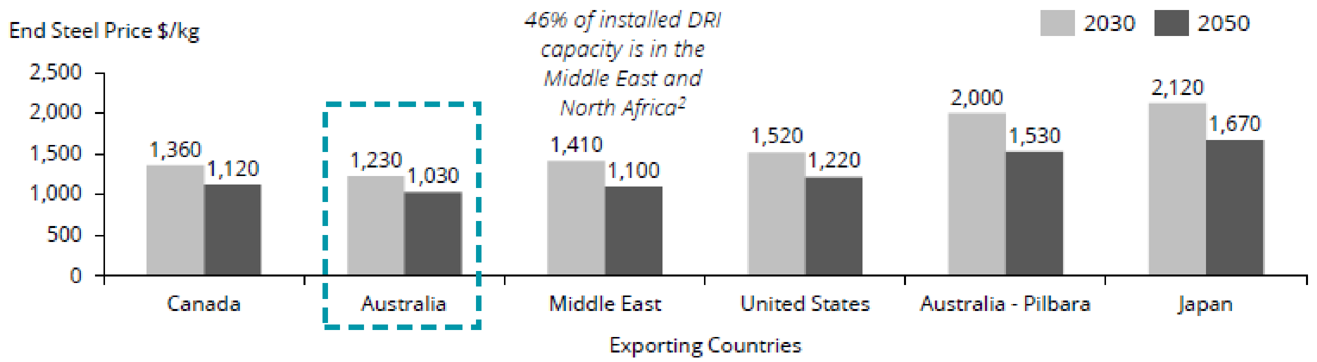


Figure 5: Comparison of future delivered end-steel prices by iron-producing country (DRI), with steel production (EAF) occurring in Japan in 2030 and 2050

Source: Mined the gap: Australia's place in the emerging green iron value chain (Deloitte, 2025)

Other recent news and analysis further reduces the plausibility of the Green Energy Scenarios including:

- A March 2025 report by the Hydrogen Council (peak advocacy body for hydrogen industry) finds that the effective implementation of existing policies could support the business case for the uptake of ~8 Mt p.a. of clean hydrogen globally by 2030 (Hydrogen Council and McKinsey & Company, 2025). This compares to the 66Mtpa by 2030 for IEA's Net Zero Emissions by 2050 Scenario, which maps to the Green Energy scenarios (International Energy Agency, 2024).
- Per discussion in Section 5.2, the Green Energy scenarios are made increasingly implausible by the removal of policy support for hydrogen refuelling stations in the 2025-26 Commonwealth Budget (Commonwealth Treasury, 2025).

3.3 Minimum electrolyser utilisation factors

Matters for consultation: Production cost and capabilities (Section 3.12.1)

- *Do you agree with the assumed minimum electrolyser utilisation factors?*

Minimum electrolyser utilisation factors should be based on electrolyser utilisation factors from ACIL ALLEN hydrogen modelling, with a small discount of 5%-10% applied. This will ensure internal consistency and that contemporary capex input projections are used. This approach is likely to result in higher minimum electrolyser utilisation factors than AEMO has proposed.

Electrolyser capex projections are the key determinant of minimum electrolyser utilisation factors. Should changes recommended in the author's 2024-25 GenCost and Draft 2025 Stage 1 IASR Consultation Submission and Section 4 of this submission be implemented ACIL ALLEN's estimates of electrolyser utilisation factors could increase materially.

3.4 Hydrogen export commodity use case inter-annual demand variability and seasonality

Inter-annual variation in export hydrogen production and seasonal variation in hydrogen production are modelling artefacts, that aren't supported by any techno-economic rationale and don't consider costs outside of the electricity system incurred to enable this variability. Such variation should be removed from CSIROCC MSM and ISP modelling. AEMO disclosed on the Stage 2 IASR webinar that ACIL ALLEN's hydrogen modelling found 3 to 6 days of hydrogen storage, which could not facilitate inter-annual demand variability and seasonality. Thus CSIROCC MSM and ISP modelling implies that inter-annual demand variability and seasonality is driven by variability in green iron production.

The author's Draft 2024 ISP Consultation Submission highlighted significant inter-annual variation and seasonality in export electrolyser utilisation factors and production and requested that these patterns and drivers be explained and clarified in AEMO documentation. To date the only rationale that AEMO has put forward for this variability was in the 2025 Stage 2 IASR webinar that this variability was an outcomes of CSIROCC MSM and that this was the same as previous CSIROCC MSM. If AEMO is to persist with inter-annual variability and seasonality and assumptions, they are encouraged to provide a rationale and supporting evidence base. The following section presents evidence as to why current variability assumptions within CSIROCC MSM and ISP modelling for hydrogen export commodities are flawed.

3.4.1 Export hydrogen commodity demand seasonality

Monthly hydrogen load for the Green Energy Industries scenario should be flat, as assuming significant seasonality in green iron production is speculative.

Per Figure 6 the Green Energy Industries scenario assumes significant seasonality in hydrogen demand for commodity export production (green iron), with a similar pattern observed for the Green Energy Exports scenario. This seasonality implies plant turndowns of up to ~40% and/or seasonal shutdowns. Section 4.2.1 of the author's Draft 2025 Stage 1 IASR Consultation Submission there isn't a developed industry or academic literature supporting partial-flexibility assumptions for green iron and thus it should be assumed to be a constant hydrogen load. For instance green iron modelling from both (Wang & Walsh, 2024) and (Deloitte, 2025) assume constant DRI production.

The CSIROCC MSM outcomes implies hydrogen direct reduce iron/ hot briquette iron (DRI/HBI) plant utilisation factors of 84% in 2040 and 80% in 2050. In addition to cost impacts from lower DRI plant utilisation factors, if technically possible, which is not supported by the literature, production seasonality could have other cost impacts including:

- Value chain cost impacts from lower utilisation including mine and port infrastructure, equipment, seasonal labour costs and potential storage/stockpile requirements and associated inventory financing cost.
- There is no evidence that EAF customers and final steel customers are willing to accept seasonal variation in supply.
    - Providing a constant supply of HBI would require substantial volumes of HBI storage. While HBI may be safely stored in uncovered stockpiles (International Iron Metallics Association, 2020) the cost and practicality of seasonal HBI storage could be material including land requirements and financing cost for holding this inventory. As the majority of levelized cost of hydrogen relates to iron ore and hydrogen, the financing cost for holding DRI inventory seasonally could be a large impost on a HBI producers balance sheet. HBI represents a form of embodied energy storage and the multi sector modelling appears to be assuming significant volumes of 'free storage', which in turn is implied in AEMO ISP modelling.
    - While it is conceivable that southern hemisphere green HBI production could be matched with northern hemisphere green HBI production to provide more consistent supply, seasonal operation appears not to be considered in the literature.

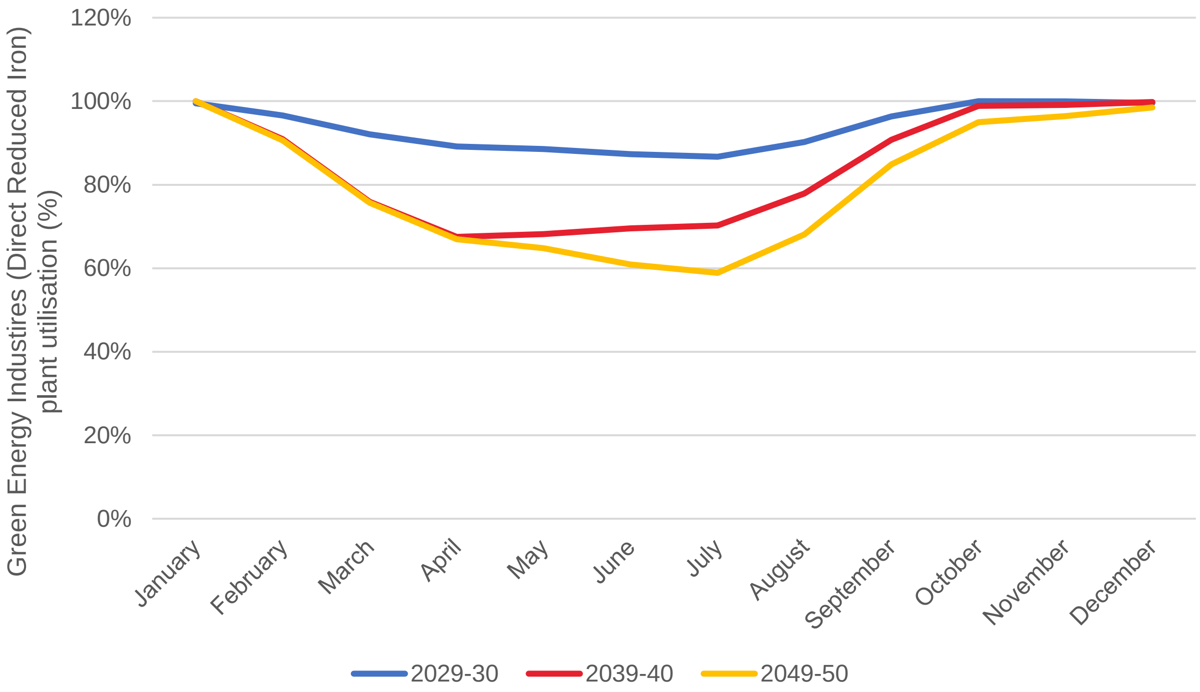


Figure 6: Green Energy Industries - Implied Direct reduced iron plant utilisation factor

Source: (Australian Energy Market Operator, 2025)

3.4.2 Export hydrogen commodity demand Interannual variation

While electrolyser utilisation factors may vary from year to year, no inter-annual variability should be assumed for export hydrogen demand/production for the Green Energy Industries scenario as doing so would be speculative. The same reasons outlined in Section 3.4.1 for seasonal variation also apply for inter-annual variation.

Figure 7 from the author's Draft 2024 ISP Consultation Submission highlights significant inter-annual variation in export hydrogen production.

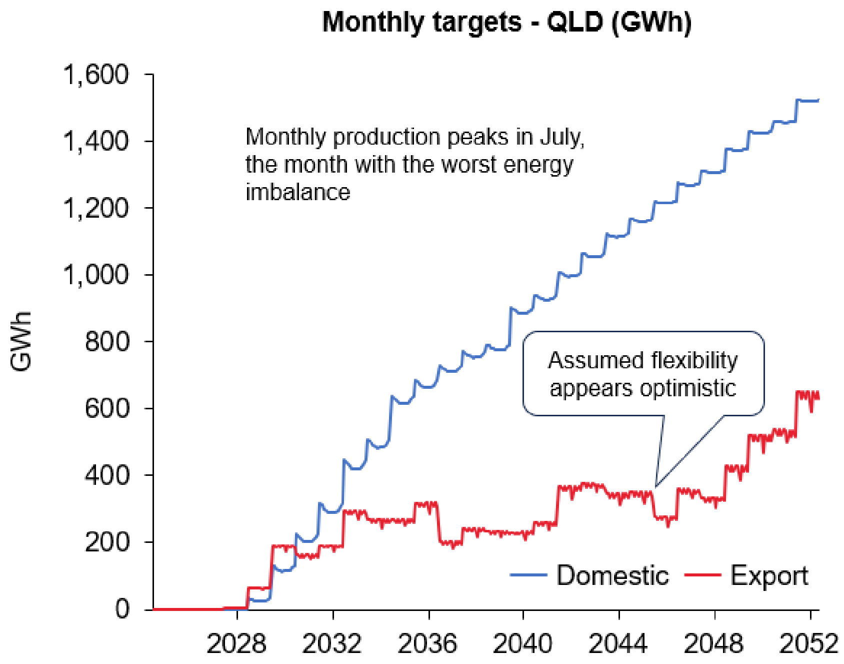


Figure 7: Draft 2024 ISP - Monthly targets of flexible hydrogen load in Queensland

Source: (Fletcher & Nguyen, Draft 2024 ISP Consultation Submission, 2024A)

3.5 On-grid electrolyser portion

Matters for consultation: Sensitivities (Section 3.3.6)

- *Do you agree with the assumed portion of on-grid electrolysers by region?*

For QLD and SA a 50% and preferably lower initial proportion of on-grid electrolysis declining to zero percent by 2050 is recommended. A 50% and preferably lower initial proportion aligns more strongly with HyResource projects. Hydrogen HeadStart has so far been only provided to the Murchison Green Hydrogen Project, which is an off-grid project (ARENA, 2025).

For Queensland more than half the electrolyser capacity of major live hydrogen projects from HyResource are off-grid or not specified:

- On-grid
  - CQH2 2,240MW (not live)- Queensland State Government has withdrawn further funding (McKenna, 2025), with Iwatani and Kansai Electric Power leaving consortium (Hydrogen Insight, 2025).
  - H2 Hub Gladstone 3,000MW
- Off-grid and not specified
  - Edify Green Hydrogen Project 1,000MW – First Stage (17.6MW) is behind the meter (CSIRO, 2024B)
  - Han-Ho H2 Hub – 3,000MW - The proposed project would facilitate development of the Collinsville Green Energy Hu and is located in the Northern Queensland Renewable Energy Zone (CSIRO, 2023B)

For South Australia the off-grid 6,000MW Cape Hardy Green Hydrogen Project (CSIRO, 2025) represents the vast majority of live hydrogen project electrolyser capacity from HyResource, with the 250MW Hydrogen Jobs Plan cancelled recently (MacLennan, 2025).

4. Installation cost escalation factors

4.1 Quantum of installation cost escalation factors

Matters for consultation: Impacts of planning, environmental and supply chain considerations (Section 3.5.6)

- *Do you consider the installation cost escalation forecasts for each technology to be reasonable?*

To ensure consistency with ISP scenario descriptions and internal consistency with CSIROCC MSM and ACIL ALLEN modelling, increased costs of steel, concrete, cable and freight, due to decarbonisation should be reflected in installation cost escalation factors.

The application of installation cost escalation factors is welcomed and aligns with recommendations in section 4.3 and 5.5 of the author's 2024-25 GenCost Consultation Submission. The submission highlights that other Oxford Economics Research (Oxford Economics Australia, 2024A) and construction industry sources (Rider Levett Bucknall, 2024) forecast that construction escalation will continue to exceed CPI.

Potential increases in installation costs due to decarbonisation are far larger than the 10% increase in installation cost escalation projected by Oxford Economics by 2045, which is driven by other factors. Oxford Economics find that materials and freight represent 50% of installation cost for gas transmission, 46% for utility scale solar PV and 35% for onshore wind. A 50-100% real increase in these costs could lead to installation cost escalation of 25%-50% for gas transmission, 23%-46% increase for utility scale solar PV installation and 17.5%-35% increase for onshore wind installation.

Decarbonisation costs for materials and freight could vary materially by ISP scenario, due to different industry decarbonisation projections. For instance the 2024 World Energy Outlook assumes that by 2050 coking coal demand will reduce by 25% under the State Policies Scenario (maps to Progressive Change), 80% under Announced Policies Scenario (maps to Step Change) and 92% under Net Zero Emissions by 2050 Scenario (maps to Green Energy) (International Energy Agency, 2024).

If Oxford Economics are unable to update their analysis to include decarbonisation cost for materials and freight for the 2024-25 GenCost due to time constraints, AEMO is encouraged to commission such analysis for the 2025-26 GenCost. Draft 2025-26 GenCost technology build cost projections could then be used as an input to the Final 2026 ISP, potentially as a sensitivity.

The following sections provide decarbonisation cost evidence for steel, concrete and freight, while similar findings could also apply to cables.

4.1.1 Steel

4.1.1.1 Production

The decarbonisation of steel production could lead to a ~50-100% increase in 2050 steel cost. Renewable energy and green hydrogen costs are a key driver of green steel production cost representing roughly half of costs (HILT CRC, 2025). Figure 8 from recent modelling from (Deloitte, 2025) shows that 40% ($492) of 2030 costs for green steel via H2-DRI-EAF relate to energy. As electricity required for EAF is only 0.8MWh/tn (Vogl, Ahman, & Nilsson, 2018), most of energy costs relate to green hydrogen.

Depending on technology Oxford Economics identify that steel represents between 2% (PHES) and 27.5% of installation costs (gas transmission), with 20% for utility scale solar PV installation costs.

Section 4.5.6 of the author's 2024-25 GenCost Consultation Submission discusses that IEA assumes that moving to decarbonised steel will result in a ~50% increase in steel cost in 2050:

"The current levelized cost of conventional iron-based steel production is in the range of US$510-US$610/t, below current prices of US$755/t, suggesting a reversion to pre-COVID steel prices is possible. However, the Upper range of innovative iron-based steel production is US$820-US$850 depending on scenario, above the current price of US$755/t. However, IEA's forecasts should be treated with caution as per Section 2 they use current electrolyser capex estimates that is materially lower than detailed studies and as such electrolyser capex projections are likely to be materially underestimated. The author's Draft 2025 IASR Stage 1 Consultation Submission discusses further reasons as to why IEA's green hydrogen costs projections, which is relevant for green hydrogen DRI-EAF, could be optimistic."

Figure 8 shows that 2030 forecasts for a green steel production pathway for (H2-DRI-EAF) of $1,230/tn, assuming $5.2/kg H_2, is 83% higher than a traditional blast furnace steel production route (BF-BOF) of $670/tn (Deloitte, 2025). The large cost gap is despite assumed policy support for green steel from Hydrogen HeadStart (A$1.50/kg$H_2$), the hydrogen production tax incentive (A$2.00/kg$H_2$) and Powering the Regions Fund grant of 50% off capex (Deloitte, 2025). This policy support reduces modelled 2030 hydrogen costs from ~$6.5/kg H_2 to ~$5.2/kg H_2. The green hydrogen modelling driving Deloitte's green steel cost projections may be optimistic as:

- Based on conversations with the author, Deloitte's analysis is based on close to 'farm gate' hydrogen costs, with limited hydrogen storage assumed. Deloitte project hydrogen cost for South Australia of ~$3.0/kg H_2 in 2050, compares to CSIROCC MSM Step Change cost projection of $4.76/kg, implied from the 2050 fuel cost of HYBLEND for SA Hydrogen Jobs Plan. It is noted that the CSIROCC MSM cost estimate assumes 50% hydrogen use case turndown, while Deloitte assume a 100% utilisation factor for DRI. Thus, costs could be materially higher than CSIROCC MSM cost projection.
- The level of hydrogen cost projections imply that optimistic electrolyser capex projections that are similar to CSIRO and IEA are used.

While Deloitte's green hydrogen projections could be optimistic other assumptions appear reasonable, including DRI and the inclusion of significant locational cost factors for the Pilbara. Thus Deloitte's 2030 cost estimates for SA, which are based on a green hydrogen cost of $5.2/kg H_2 and result in a green steel cost premium of 83%, could provide a reasonable estimate of a 2050 cost premium.

It is acknowledged that there are a range of other sources that point to lower green steel premiums, however for such modelling input assumptions and methodologies are often poorly defined and/or they rely on optimistic assumptions including use of 'farm gate' hydrogen estimates, not applying locational cost factors, optimistic electrolyser, hydrogen storage and DRI capex assumptions. This applies to both Australian and international literature.

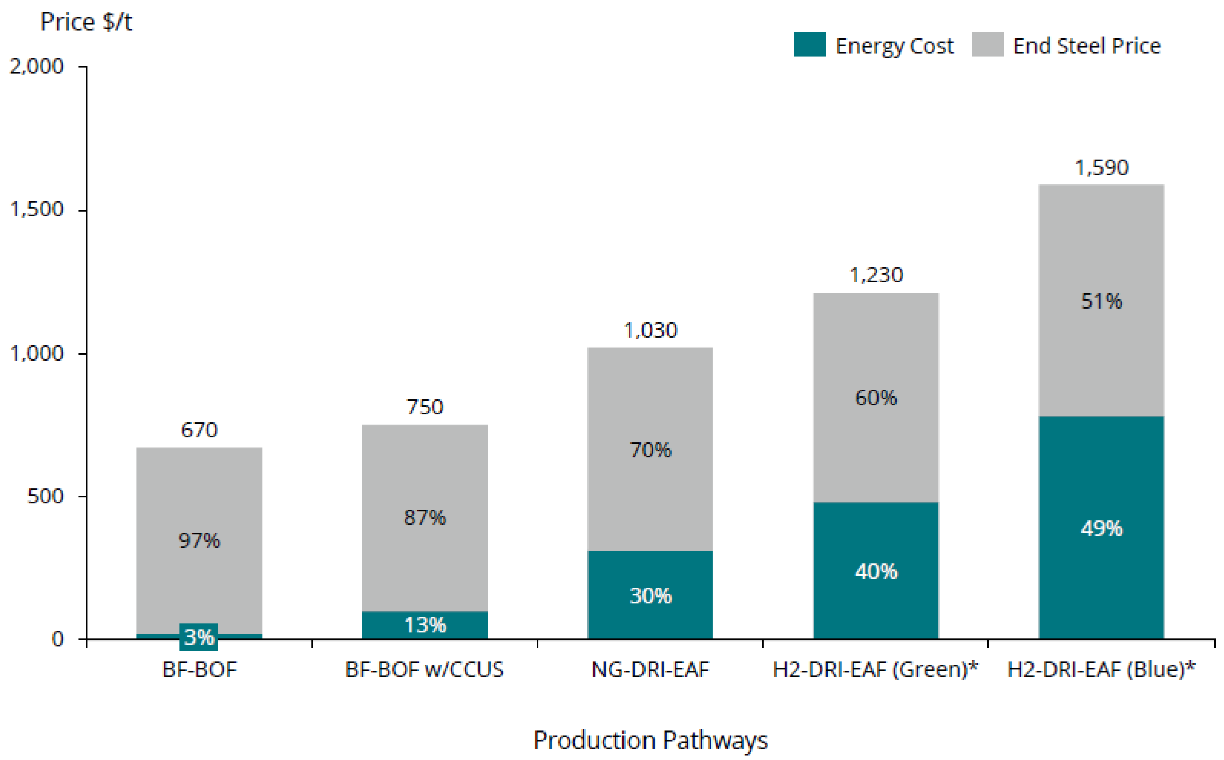


Figure 8: Comparison of future Australian delivered end-steel prices by production route (H2-DRI-EAF, NG-DRIEAF, BF-BOF, BF-BOF-CCUS) when exporting to Japan, with energy share of cost illustrated for 2030, excluding transport

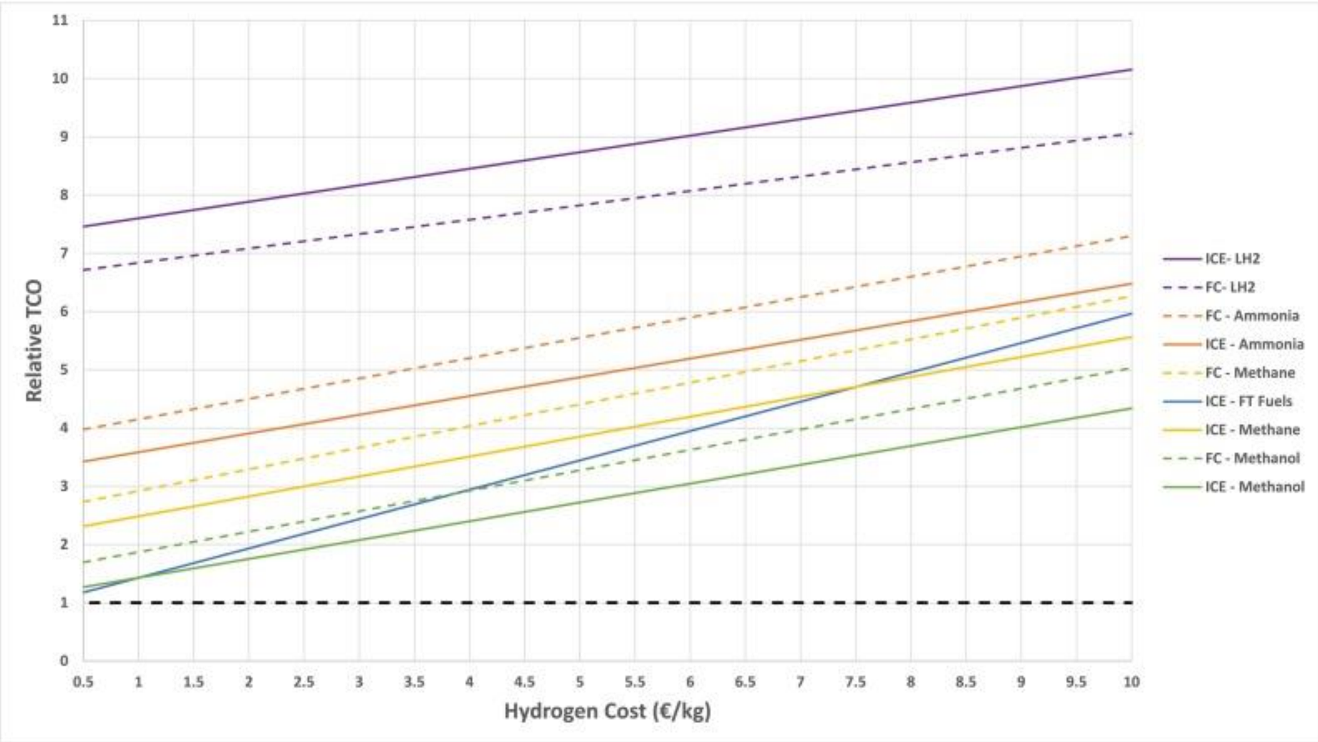
Source: Mined the gap: Australia's place in the emerging green iron value chain (Deloitte, 2025)

4.1.1.2 Shipping

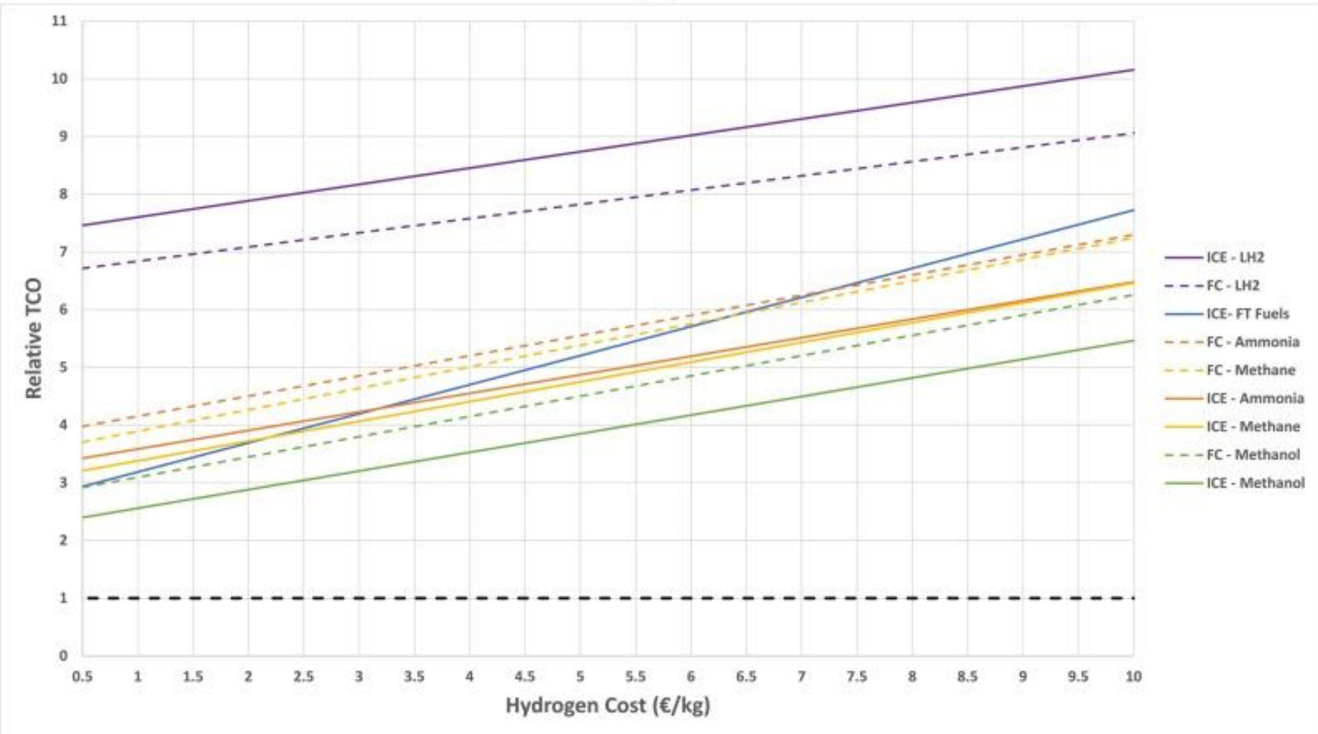
While a small cost component of the steel value chain, the cost of shipping decarbonisation is high as it is driven by the cost of alternative liquid fuels such a green hydrogen, blue hydrogen and direct air capture (DAC). (Wang & Walsh, 2024) assume that the cost of shipping DRI pellets from South Australia to China is A$25/tn, while the DRI-EAF process generally assumes a conversion rate of 1.2 tonnes of DRI per 1 tonne of crude steel (Benavides, et al., 2024). This is equivalent to a cost of $30/tn steel, or 4.5% BF-BOF steel production cost

(Gray, O'Shea, Smyth, Lens, & Murphy, 2024) estimate decarbonisation cost for deep sea container shipping using power-to-x-fuels, whose cost is driven by the cost of hydrogen and carbon capture. At a cost of €2.50 /kg H_2 (~A$4.30/kg H_2), similar to the CSIROCC MSM cost projection for Step Change for 2050 (A$4.76/kg H_2) and a carbon capture cost of €20/tCO_2, methanol using as internal combustion engine is the lowest cost power-to-x fuel option, though total cost of ownership is almost double that of the fossil fuel reference vessel. If the carbon capture price was increased to €500/tCO_2 methanol remains the lowest cost power-to-x fuel option, though total cost of ownership is triple that of the fossil fuel reference vessel.

A doubling of shipping cost could result in a 4.5% increase in steel cost vs BF-BOF and a tripling a 9% increase.



(a)



(b)

Figure 9: Relative total cost of ownership of alternative marine electrofuels compared to the fossil fuel reference vessel for a carbon capture price for fuel synthesis of (a) €20/tCO_2 and (b) €500/tCO_2

Source: (Gray, O'Shea, Smyth, Lens, & Murphy, 2024)

4.1.2 Concrete

Regarding cement, which is a key input to concrete, (International Energy Agency, 2023) states that:

"While a range of different low-emission technologies are under development, current estimates put low-emission cement at a 75% premium versus conventional cement production, on average."

Depending on technology Oxford Economics identify that concrete represents between 0% (offshore wind) and 20% of installation costs (PHES), with 10% for onshore wind installation costs.

4.1.3 Freight

Freight cost escalation should include the cost of transitioning to zero emission trucks. Depending on technology, Oxford Economics identify that freight represents between 5% and 10% of installation costs. Total cost of ownership for medium and heavy trucks could increase with decarbonisation, particularly due to longer range requirements for transport to regional areas where generation projects are typically located. For instance (Wang, et al., 2024) finds that for the heavy goods vehicle sector the total cost of ownership is 11-33% higher for battery electric vehicles than internal combustion vehicles and 37-78% higher for fuel cell electric vehicles than internal combustion vehicles.

Increase in total cost of ownership could potentially be derived from CSIRO's Electric Vehicle Projections 2024 report, noting that key input assumptions (eg. vehicle and fuel costs assumptions) and outputs of this modelling (total cost of ownership) are not disclosed. CSIRO project that by 2050 for New South Wales 41% of sales of articulated trucks and 4% of rigid trucks will be FCEV. FCEV is at best a niche, high-cost decarbonisation option and the assumption that 41% of articulated trucks sales will be FCEV demonstrates the cost challenges with decarbonising freight in Australia. For instance, The Seventh Carbon Budget for the UK assumes no FCEV uptake, including for heavy duty vehicles (Climate Change Committee, 2025).

4.2 Consistent application of escalation factors to all technologies

Consistent application of escalation factors to other technologies not included in GenCost is recommended such as hydrogen and natural gas pipelines, including where used for energy storage and electricity transmission. Oxford Economics produces relevant installation escalation factors for these technologies, however the Draft Stage 2 IASR states that:

"These installation cost forecasts will be provided as an input to CSIRO's GenCost modelling to inform assumptions used in GenCost around the impact of issues around supply chains on future technology build costs."

5. Electric Vehicle Projections

5.1 FCEV passenger and light commercial vehicles

FCEV should be removed as a model option for residential and commercial vehicles for Step Change and Progressive Change as FCEV sales are declining in these categories, there is limited refuelling station development occurring and CSIRO projections do not show them reaching a critical mass, achieving a market share of 0.6% in 2050.

CSIRO state that:

"Historically the number of models available, refuelling services and pricing of FCEVs has made little progress. It is expected that there will eventually be a period where significant progress is achieved because there are still car manufacturers investing in FCEVs. Their consumer appeal is that they can fit into the familiar liquid refuelling paradigm."

While car manufactures are currently offering FCEV passenger vehicles, sales have declined by more than 20%pa over the past two years with 12,866 FCEV sold globally in 2024 (Collins, 2025A). In 2023, six FCEVs were sold in Australia compared to 98,436 BEVs (Driving Insights, 2024).

In addition to declining sales a number of hydrogen refuelling stations have closed in recent (Barnard, 2024) including recent announcement of the closure of 22 fuel stations in Germany (Randall, 2025). Australia has only 13 hydrogen refuelling stations (CSIRO, 2024A).

5.2 FCEV Trucks

CSIRO's moderation in FCEV projections compared to the 2023 IASR does not reflect the level of negative market development over the past 2 years for hydrogen and FCEV, including stalled refuelling network development, FCEV truck manufacturer bankruptcies and major mining companies announcing preference for BEV. For Step Change CSIRO assumes that in 2050 43% of articulated truck sales are FCEV, down from 70% for the 2023 IASR. This compares to Seventh Carbon Budget for the UK, which finds no role for FCEV in passenger vehicles or heavy-duty vehicles (Climate Change Committee, 2025).

Development of hydrogen refuelling network has stalled. In March 2022 Queensland, New South Wales and Victoria announced a tri-state collaboration on a renewable hydrogen refuelling network for heavy transport and logistics along Australia's eastern seaboard (de Brenni, 2022). As part of the Driving the Nation Fund, in 2022 the Commonwealth Government committed up to $80 million to be co-invested with state and territory governments to help decarbonise heavy transport with a roll out of hydrogen refuelling networks on key freight routes (Australian Government - DCCEEW, 2025). The 2025-26 budget reduced this funding by $75m, the full amount of uncommitted funds (Commonwealth Treasury, 2025).

There have been recent bankruptcies of high-profile FCEV truck manufactures Nikola (Associated Press, 2025) and Hyzon (Collins L. , 2025B).

Major mining companies are focussed on BEV rather than FCEV (Hanley, 2023) with renowned hydrogen advocate Fortescue announcing it had placed a US$2.8bn order for 360 for electric mining equipment and vehicles from from Liebherr in September 2024 (Martin, 2024).

6. Biomethane

6.1 Current levelized cost assumptions

Having different current cost estimates for biomethane by scenario is illogical and highlights uncertainty around theoretical cost estimates for biomethane, a technology which is in its infancy in Australia with only one demonstration plant operating (Jemena, 2024).

ACIL ALLEN identify two sources for cost estimates:

- Australia's Bioenergy Roadmap Bioenergy Roadmap (Enea Consulting and Deloitte, 2021A), which for 2020 estimates costs of $12/GJ for biomethane from Landfill Gas and $25/GJ for Biomethane from Anaerobic Digestion.
- Biomethane Potential in AGIG's Network Catchment and Associated Co-benefits (Australian Gas Infrastructure Group and Blunomy, 2024), released in August 2024. Figure 10 shows cost estimates for a range of feedstocks including Landfill Gas, which has an estimated cost of $10.2/GJ.

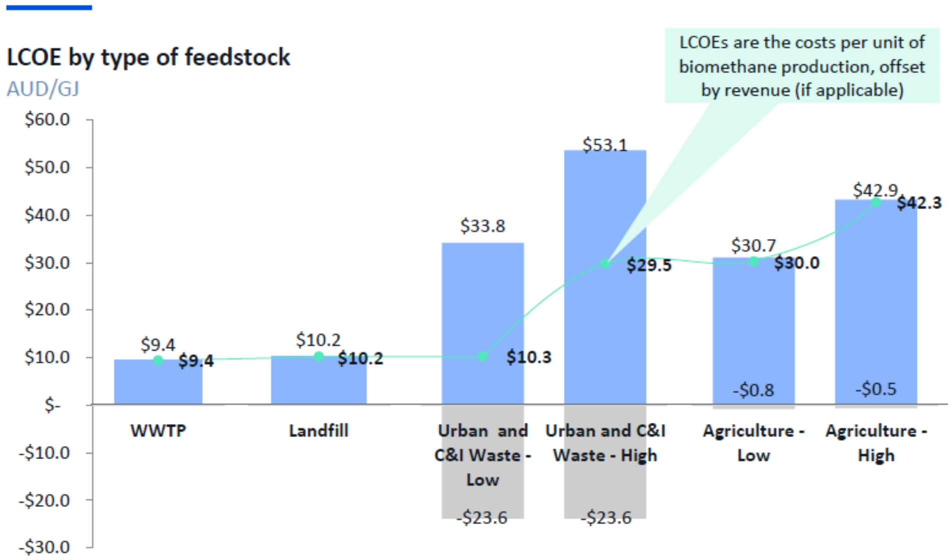


Figure 10: Biomethane levelized cost of energy by feedstock

Source: Biomethane Potential in AGIG's Network Catchment and Associated Co-benefits (Australian Gas Infrastrucure Group and Blunomy, 2024)

Cost estimates and developable resource estimates in (Australian Gas Infrastructure Group and Blunomy, 2024) should be treated with caution as it is not an independent report, with feedstock volume estimates representing AGIG's view rather than that of the Blunomy (specialist consultant, formerly known as Enea Consulting) and costs estimates are based on a high-level analysis:

- *"Blunomy developed an approach to granularize the anaerobic digestion feedstock streams available using land-use datasets to support AGIG's view of the biomethane potential of feedstocks within the catchment of their network assets".*

- *"LCOE figures are derived from a preliminary modelling exercise that employs generalised assumptions about cost structures. Figures do not consider potential opportunity costs and may vary based on local conditions. LCOEs do not assume revenues from biogenic carbon dioxide from the biogas upgrading process."*

6.1.1 Landfill gas

Current landfill gas cost should be based off Australia's Bioenergy Roadmap (Enea Consulting and Deloitte, 2021A) 2020 estimates of $12/GJ, escalated to June 2024.

6.1.2 Anaerobic digestion - wastes

Current anaerobic digestion cost estimate for waste feedstocks should be based off estimates from European industry survey data from (Biomethane Industrial Parnership Europe, 2023) which show an average production cost of €87/MWh (A$42/GJ) for 2021, then escalated to June 2024. The figure is 68% higher than Australia's Bioenergy Roadmap estimates a 2020 cost of $25/GJ for Biomethane from Anaerobic Digestion (Enea Consulting and Deloitte, 2021A). Rather than use high level theoretical cost estimates, which could be subject to behavioural biases including optimism bias, actual industry data is more likely to result in accurate cost estimates. Refer to (Flyvbjerg, 2021) for a discussion of behaviour biases and 'reference class forecasting'.

The Biomethane Industrial Partnership performed a first-of-a-kind data exercise to collect real cost data from the biomethane industry based on an anonymous survey process (Biomethane Industrial Parnership Europe, 2023). Survey data accounted for 10% of European biomethane production. Feedstocks includes MSW/Food waste ± Industrial waste (inc. ABP) & WWTP sludge, manure and energy crops. The study found strong economies of scale, especially in the capital costs. The cost of biomethane production in 2021 was on average €87/MWh (A$42/GJ) for producers of ~ 540 Nm3/h, and €54/MWh ($A26/GJ) for producers of >1200 Nm3/h.

The study also found that despite feedstock costs ranging from -€94/MWh to €43/MWh when cost of pre-treatment and other costs incurred by feedstock mix choice were considered, the "total feedstock related costs" are comparable for differing feedstock mixes (Biomethane Industrial Parnership Europe, 2023).

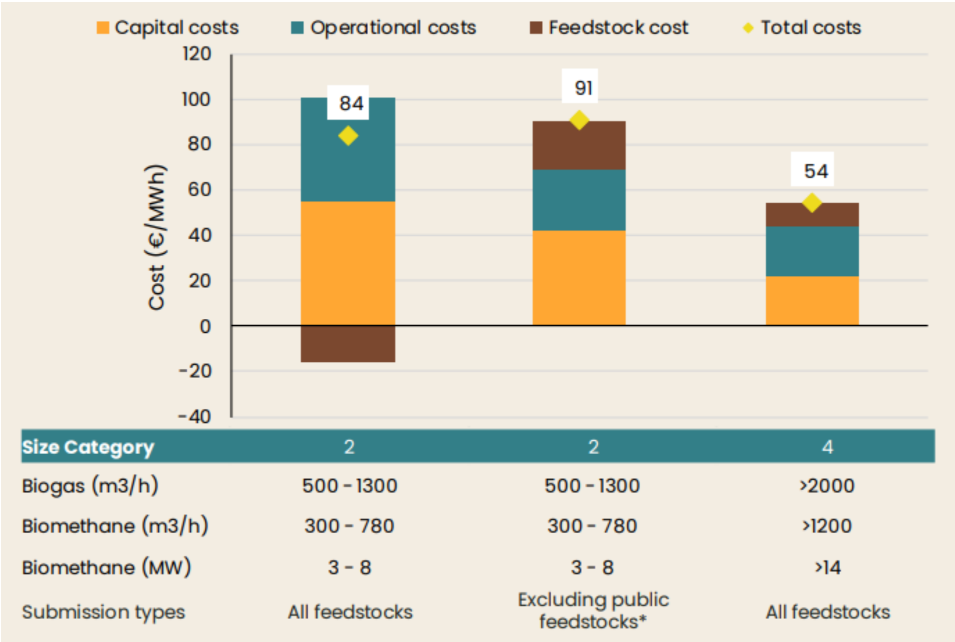


Figure 11: Total cost of biomethane production and upgrading for European producers (2021), based on industry survey data

Source: (Biomethane Industrial Parnership Europe, 2023)

6.1.3 Anaerobic digestion – crop residues

A similar premium as is recommended to be applied to waste (68%) should be applied to crop residues, to reflect that actual European costs are materially higher than Australian theoretical cost estimates.

There should be a significant premium between crop residues and waste, including to reflect the seasonal availability of crop residue feedstock. For instance:

- (Enea Consulting and Deloitte, 2021A) state that: "*interannual variability due to climate and water availability along with seasonal variability will affect consistent supply. This means that ensuring consistent supply for bioenergy production may require access to multiple feedstocks.*"
- (Hosseini, Culley, Zecchin, Maier, & Ashman, 2024) evaluates the viability of biomethane production from agricultural wastes for injection into gas pipelines in the Griffith regional area of NSW. Cost estimates are produced using single feedstocks and multiple feedstocks, referred to as co-digesting. Key insights include that:
    - *"Results indicate that a single centralized plant co-digesting food waste, poultry bedding materials and winery wastes is the most favorable scenario in terms of the levelized cost of energy (LCOE) and net carbon emissions saved."*
    - *"the availability of feedstock throughout the year is a key challenge for rural sites considering bio-methane grid injection."*
    - *"With a distributed set of plants, specifically assigned to a type of feedstock, 60 % are only in operation for half of the year."*

6.2 Cost reduction assumptions

Lower cost reductions in biomethane should be projected as ACIL ALLEN trajectories are not consistent with industry literature.

ACIL ALLEN cost projections decline in line with Bioenergy Roadmap projections however, this reduction largely contradicts the discussion in the report (Enea Consulting and Deloitte, 2021B):

- *“Biomethane production is mature and costs are not expected to decline significantly over the next decade. However, although mature overseas, there is currently no commercial application in Australia, meaning there may be scope for costs to decline as the industry grows.”*
- *… “cost reductions for bioenergy may be limited compared to other forms of energy. This is due to the maturity of most processing technologies and the dispersed nature of bioenergy resources that require collection and transport.”*

Other literature finds limited cost reduction potential:

- A report produced by Common Futures for the European Biogas association (Common Future and European Biogas Association, 2024) states that *“This report considers biomethane as a 2040 abatement option at assumes average production cost level of €70/MWh (A$33/GJ), the average 2021 cost of production of a large and a medium scale installation, and assumes that this cost level will be relevant for 2040.”*
- A Oxford Institute for Energy Studies & Sustainable Gas Institute study (Lambert & Oluleye, 2019) finds that, *“the learning rate for biomethane production based on three scenarios is low (4-5 per cent) as most of the components for biogas upgrade have reached commercial application.”*

6.3 Potentially recoverable resource – Anaerobic digestion

6.3.1 Potentially recoverable resource

ACIL ALLEN should assume recoverable to theoretical potential ratios consistent with (Enea Consulting for Sustainability Victoria, 2021), as this is the only publicly available detailed independent assessment of recoverable potential. Estimates from (Enea Consulting for Sustainability Victoria, 2021) are more accurate than sources identified by ACIL ALLEN as they take a granular approach to assessing recoverable potential, including only feedstocks suitable for anaerobic digestion and taking into account recovery rates based on non-energy competing uses and capture constraints of feedstocks.

ACIL ALLEN identify a range of sources that are used to inform biomethane volumes. These reports are typically focussed on technical potential, for instance (Enea Consulting and Deloitte, 2021C) states that:

“As previously highlighted, this is a preliminary resource estimate. A more detailed assessment considering the technical and economic constraints outlined in this section would provide a more accurate view of this potential.”

“In particular, Australia’s cropping industries may experience reduced predictability of seasons and rainfall, plant stress and crop losses and changes in regional suitability to certain production systems. These impacts will vary by crop, location and season.”

ACIL Allen’s volume of potential biomethane production for Victoria pre-2030 implies 80.2PJ of biogas potential, which compares to ACIL ALLEN identified sources including 52PJ for (Enea consulting for Energy Networks Australia, 2022) and 48PJ for (Deloitte Access Economics, 2017).

(Enea Consulting for Sustainability Victoria, 2021) undertake an assessment of Victoria’s

- *“Theoretical biogas potential: according to the maximum amount of organic residues that can be considered available for anaerobic digestion biogas production based on current organic residue production levels.” …*

- *"Recoverable biogas potential: based on the proportion of organic residues that are suitable to anerobic digestion and available after considering non-energy competing uses and capture constraints." … "Capture constraints accounts for separation of organic residues, concentration of anaerobically digestible material in the waste stream and logistics of recovery. It does not account for economically recoverable feedstocks or other technical considerations (such as nutrient balance or opportunities for co-digestion)." … "Both high and low recovery rate scenarios were analysed producing a recoverable biogas potential."*

Figure 12 from (Enea Consulting for Sustainability Victoria, 2021) shows that theoretical potential of 80.6PJ for Victora is similar to ACIL ALLCEN's assumption of 80.2PJ, however ACIL ALLEN' s estimates of high and low recoverable potential are multiples higher. For instance ACIL ALLEN assume pre-2030 AD- waste recoverable potential range of 8.8PJ-19.9PJ depending on scenario compared to 1.3GJ-4.4GJ for the Sustainability Victoria Report. For AD - crop residues ACIL ALLEN assume potential range of 17.6GJ-29.4GJ compared to 9.2GJ-20.5GJ for agriculture for the Sustainability Victoria Report.

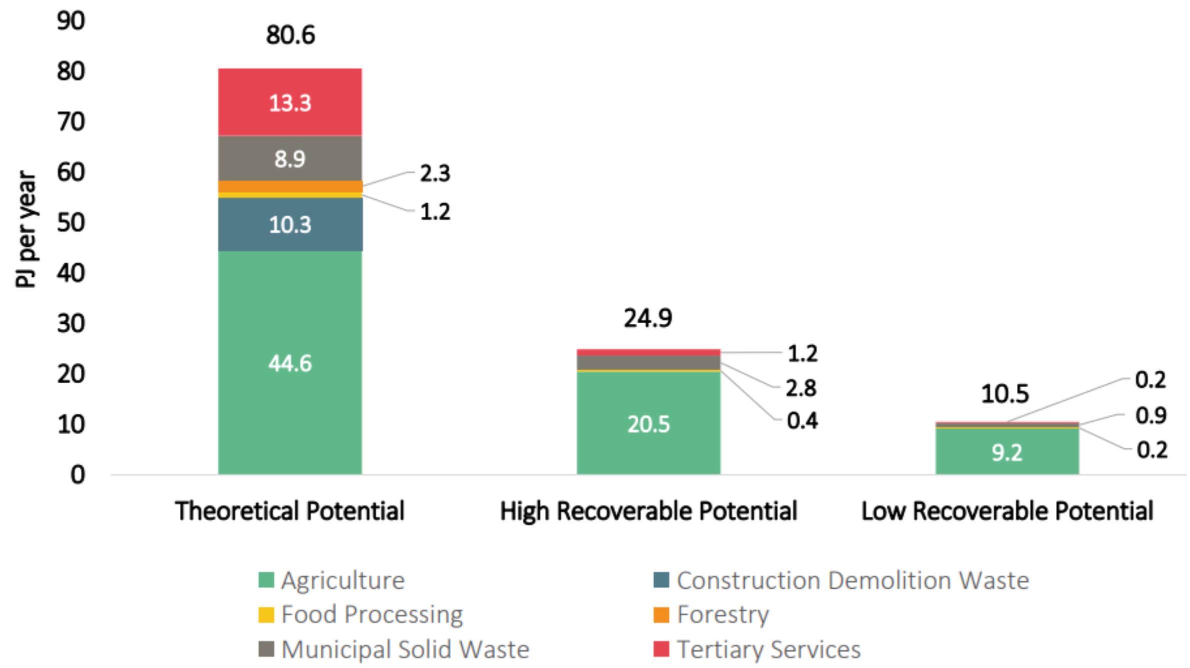


Figure 12: Sector breakdown of Victoria's recoverable biogas potential from anaerobic digestion | Source: Sustainability Victoria – Assessment of Victoria's Biogas Potential (Enea Consulting for Sustainability Victoria, 2021)

6.3.2 Gas network infrastructure constraints

ACIL ALLEN estimates do not appear to consider gas infrastructure constraints, which would further reduce recoverable potential particularly for AD – crop residuals and attempt should be made to incorporate these constraints in recoverable potential estimates. A range of sources show that biogas potential, particularly for crop-residues does not necessarily align with gas network infrastructure:

- Per Figure Figure 13 (Gordon & Morrison, 2023) show that a large proportion of potentially recoverable Victorian biogas feedstock from (Enea Consulting for Sustainability Victoria, 2021) don't align with the gas transmission network. Similarly, (Australian Gas Infrastructure Group and Blunomy, 2024) estimate 62.4PJ of recoverable biogas potential for Victoria under a policy-enabled scenario, with 37.9PJ within AGIG's catchment area.

- (Australian Gas Infrastructure Group and Blunomy, 2024) estimate 62.4PJ of recoverable biogas potential for Queensland under a policy-enabled scenario, with 16.6PJ within AGIG's catchment area. Figure 14 shows that a large proportion of Queensland's biogas potential is concentrated in the Townsville and Mackay areas where there is limited gas infrastructure.

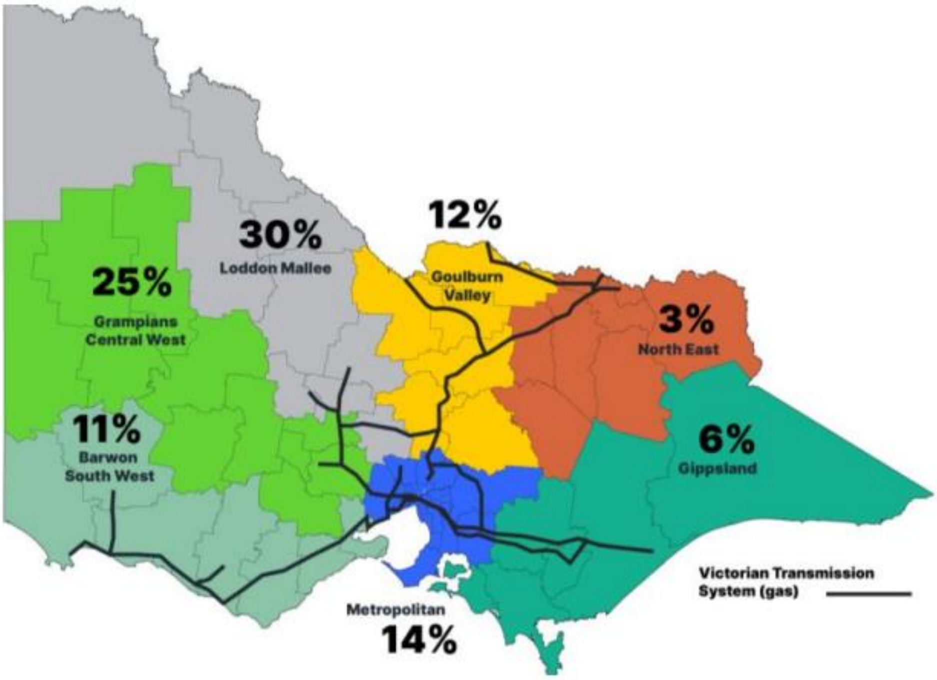


Figure 13: Victoria's biogas sources don't align to its gas transmission network | Source: (Gordon & Morrison, 2023)

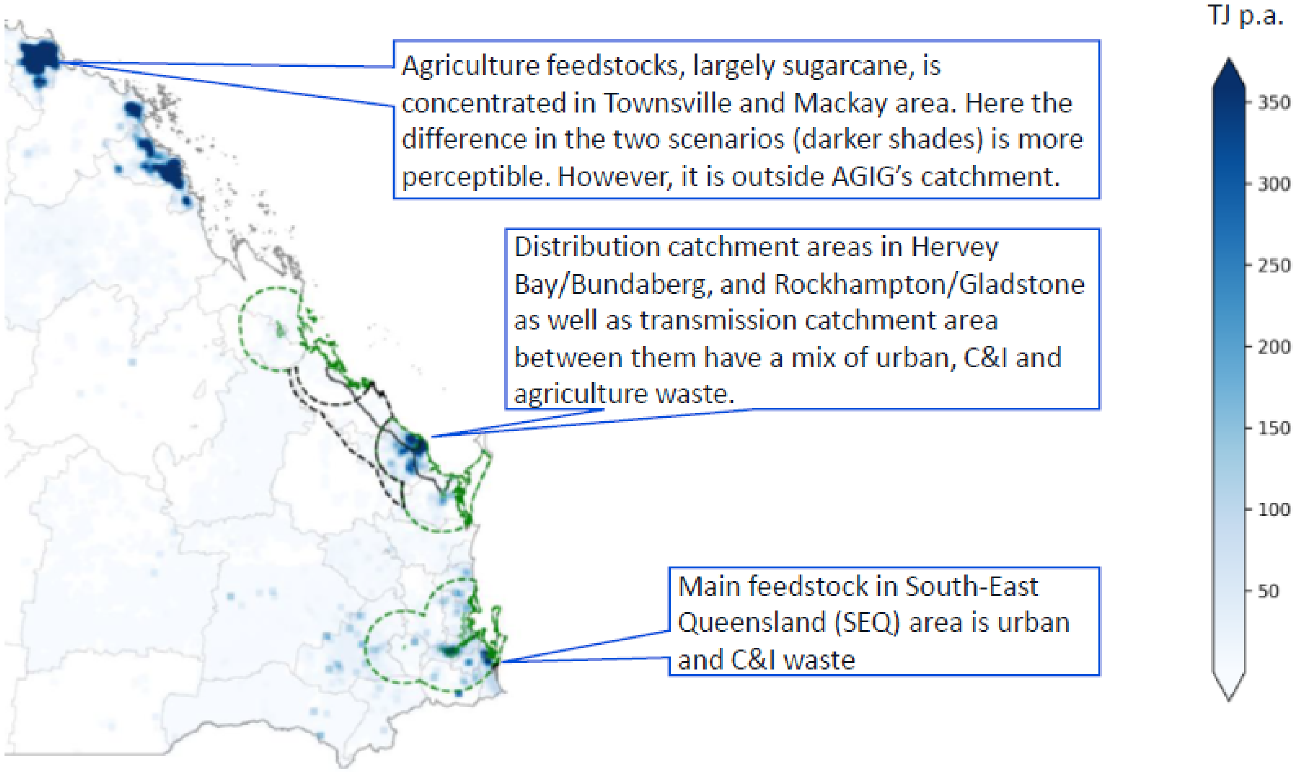


Figure 14: Recoverable biogas potential withing AGIG's catchment under a Policy-enabled scenario

Source: (Australian Gas Infrastructure Group and Blunomy, 2024)

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