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Draft 2025 IASR Stage 1 Consultation

Submission to AEMO, 11 February 2025

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. While aspects of this submission has drawn on the market knowledge and expertise of CAEEPR members, the views expressed in this submission are entirely the author's and are not reflective of CAEEPR.

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Executive Summary

I welcome the opportunity to provide feedback to AEMO on the Draft 2025 IASR Stage 1, released in December 2024. The author's CSIRO GenCost 2024-25 Consultation Draft submission forms an integral part of this submission, with multiple references to it and thus should be considered as an attachment.

AEMO's ongoing efforts to improve the various modelling methodologies, as well as the input and assumptions that drive the ISP are commended. It is recognised that the ISP is a highly complex modelling exercise and the complexity, breadth and detail of the IASR and underlying consultant modelling reports has increased materially in successive IASR. AEMO has identified several *"matter for consultation"* in the Draft IASR which demonstrates that it seeking to engage with stakeholders regarding key inputs and assumptions that drive ISP outcomes.

This submission identifies a number of 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 a number of opportunities to improve the IASR and underlying consultant modelling reports including by:

- Customer energy resources
    - Greater transparency of assumed policy support for CER BESS, that is in excess of current policies.
    - Only CSIRO CER projections should be used for Step Change, with Green Energy Markets (GEM) used as a sensitivity. Both consultants' projections are potentially optimistic as the solar PV build cost projections are sourced from CSIRO GenCost, which does not model rooftop solar PV separately from utility scale solar PV. In addition GEM's CER BESS projections assume rapid build cost reduction and system size increases (kWh) that result in overly optimistic CER projections.
- Green Energy scenario variants – Green Energy Industries variant recommended
    - While this variant is preferred as it is more plausible, internal consistency of the foundational assumption of green hydrogen commercial viability should be tested. The simplest approach to achieve this is to allow steam methane reformation with carbon capture utilisation and storage (blue hydrogen) as a production pathway in the CSIROCC MSM for the Green Energy scenario.
    - Evidence put forward supporting this variant includes that:
        - Developer interest in green hydrogen as an energy carrier is diminishing.
        - Electrolyser build cost projections from GenCost and IEA are likely materially underestimated.

        - Draft IASR green hydrogen firming and transport costs have been materially underestimated.
        - GenCost build cost projections and IEA green hydrogen demand projections are based on models that are unlikely to accurately capture green hydrogen firming costs.
        - Lower WACC assumption for renewables in IEA WEO, implies significant policy support for green hydrogen through subsidised renewable energy.
        - Significant uncertainty around developable capacity of wind resources impacts size of potential green hydrogen development.

- Green Energy scenario
    - Alumina production volumes should grow under Green Energy Exports scenario.
    - No green iron production should be allocated to states with no existing iron ore mines or steel production.
- Hydrogen modelling – ACIL ALLEN renewable gas projections
    - Improvements are recommended to AEMO's proposed methodology to capture the full cost of firming green hydrogen beyond the cost of hydrogen storage, including the oversizing of other hydrogen value chain components and additional cost faced by hydrogen use case due to variability of supply.
    - Several input assumption changes are recommend including:
        - Modelling hydrogen supply for green iron and alumina uses cases assuming inflexible hydrogen demand.
        - Amending REZ transport costs estimates to include costs such as Line Pipe.
        - Using Australian industry consultant estimates for hydrogen storage.
        - Applying Locational cost factors, which appear not to have been applied.
        - Applying Cost escalation consistent with large energy infrastructure projects to historical cost estimates.
- Locational factors
    - Moving to REZ locational cost factors is supported as it helps explain build cost differential seen in renewable energy projects.
    - Greater transparency of calculation methodology is encouraged.
    - Equipment cost factor should be based on distance to ports with existing wind turbine import capability, rather than distance to capital city.
    - Split of equipment and installation should be technology specific and based on projections from CSIRO GenCosts.
- Demand side participation (DSP)

- NEM DSP study is recommended for current load as reference documents for US and Europe are dated, based on markets with limited solar PV and load compositions which could be materially different to the NEM.

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1. Customer Energy Resources

Matters for Consultation

- *What uncertainties are valuable to explore with sensitivity analysis?*
- *Are the CER forecasts suitable for their respective scenarios? What strategic factors do you consider may influence CER projections?*
- *Do you have any comments regarding the draft build cost projections?*

1.1 Greater transparency of assumed policy support for CER BESS, that is in excess of current policies

Transparency within the IASR scenario descriptions within section "3.1 policy settings" and "3.3.7 consumer energy resources" regarding hypothesised Commonwealth Government subsidies for CER BESS within consultant CER projections and the quantification of the cost of such policy support within consultant reports is recommended. These policy assumptions are not technology agnostic and are a key driver of the uptake of CER BESS, as well as CER solar PV (refer to Section 1.1) in consultant projections models.

For Step Change this is assumed to be equivalent to 20% and 25% of upfront capex for CSIRO and Green Energy Markets (GEM) respectively. Both consultants assume that this hypothesised subsidy is in addition to NSW Consumer Energy Strategy battery subsidies, which increase the effective level of Government subsidisation for CER BESS in NSW to higher levels. CSIRO quantify the NSW subsidies as between $1,600-$2,400 for a 13.5kwh battery and $250 to $400 for VPP participation, which can be claimed twice, with at least 3 years in-between claims.

While the scenario description for Step Change mentions government support for transport electrification, there is no mention of government support for CER and AEMO is encouraged to disclose that substantial new Commonwealth Government subsidies for CER BESS are assumed. CSIRO highlight the need for such subsidies to achieve CER BESS uptake in alignment with scenario narratives for Step Change and Green Energy (pg 25, (CSIRO, 2024B)). GEM highlights that Commonwealth government subsidies for CER BESS are a key driver of the combined solar and battery system uptake (pg 71, (Green Energy Markets, 2024A))

Assumptions of government policy support in excess of existing policies should be disclosed in the IASR. Selectively subsidising 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. Additional policy support assumptions should be explicitly included in the explanation of the CER modelling in the IASR, to enable stakeholder engagement and inform governments about the potential additional cost of the policy beyond existing commitments. To enable this level of engagement it is recommended that in consultant CER projection reports that for CER BESS:

- Where government policy support is assumed to emerge the total and annual cost of these subsides is quantified.
- Capex per kWh including and excluding subsidised should be disclosed, noting that GEM already discloses this information for CER solar PV in Figure 5-18 of (Green Energy Markets, 2024A).

1.2 Only CSIRO CER projections should be used for Step Change, with GEM used as a sensitivity

Both consultants' projections are potentially optimistic as the solar PV build cost projections are sourced from CSIRO GenCost, which does not model rooftop solar PV separately from Utility Scale Solar PV. In addition GEM's CER BESS assumed rapid build cost reduction and system size increases (kWh) that result in overly optimistic CER projections.

AEMO is recommend to use CSIRO only for Step Change and either of CSIRO or GEM only for Green Energy scenario, to maintain the integrity of drivers of CER uptake. If a weighting to GEM is retained for the Step Change and Green Energy scenarios a consistent one third weighting across rooftop solar PV, Battery and VPP is recommended. For the scenario chosen as most likely, a sensitivity is recommended using the GEM CER projections. AEMO are also encouraged to increase the disclosure of individual consultant CER projections and the transparency of their key assumptions within the IASR, given that the consultants projections are dramatically different.

1.2.1 Both consultant projections are potentially optimistic as solar PV build costs projections are not modelled separately from utility Scale Solar in CSIRO GenCost

This section provides a summary of a relevant section of the author's CSIRO GenCost submission and AEMO are encouraged to refer to this document for further detail.

CSIRO GenCost is the source of Rooftop solar PV build cost for each consultant's CER projections.

GenCost models utility scale solar PV and rooftop solar PV as one technology, except a 25% reduction in balance of plant is applied for utility scale solar PV.

To the best of the author's knowledge a full current Australian rooftop solar PV build cost breakdown data is not publicly available. CSIRO project that rooftop solar PV build cost will fall from current figure of $1,336/kW DC to $612/kW DC by 2050. To achieve CSIRO's projected $724/kW DC reduction in build cost by 2050 a large reduction in balance of system (eg. racking, cabling) and labour costs is implied, which could be optimistic. Discussions with Australian residential and C&I solar experts suggests that due to cost reductions, hardware now represents a relatively small portion of build cost with:

- Wholesale prices for solar modules currently A$200/kW DC.
- Australian residential inverter costs varying by brand, with the cost of a 5kW SMA inverter in the range of $340/kW AC to $400/kW AC, with Chinese brands around half this cost (Solar Choice, 2025B)

Other issues include:

- The large cost differential per kW between utility scale (central) and rooftop solar PV inverters (string) and lower learning rates experienced for rooftop solar PV inverters.
- Literature showing Balance of System learning rates for rooftop solar PV are lower than assumed by GenCost for both scale and rooftop solar PV.
- Increasing rooftop solar PV system size had been a driver of reducing build costs, however average system size is forecast to plateau in CSIRO (CSIRO, 2024B) and Green Energy Markets (Green Energy Markets, 2024A) CER projections in the future and GenCost does not consider this.

1.2.2 Green Energy Markets CER BESS build cost projections are overly optimistic

Green Energy Markets assumed that under Step Change and Green Energy Exports scenarios the build cost premium of CER BESS to utility scale BESS falls from over 100% currently to 11% by 2032 and 40% for Progressive Change. Green Energy Markets view is that this assumption represents, *"a similar narrow differential as is currently achieved in Australia with distributed solar versus utility-scale solar (a 11% premium)."*

Green Energy Markets Rooftop Solar PV premium appear to be based on comparing module capacity (DC), which is favourable to Rooftop Solar PV, versus comparing on generation capacity (AC)

Figure 1 shows that the Rooftop Solar PV build cost premium, has varied from 21% to 28% based on CSIRO data and comparing generating capacity (AC), far higher than Green Energy Market's assumed premium of 11%, which appears to be based on solar PV module capacity (DC). Rooftop Solar PV (AC) is estimated by applying a ratio of 5kw inverter capacity to 6.6kW DC of solar PV module capacity to the DC cost estimate. Further details around what drives this common Rooftop PV system size can be found at (Solar Choice, 2024).

Green Energy Markets appears to convert Utility Scale connection capacity (AC) to Solar PV module capacity (DC) using DC/AC ratio of 1.2 consistent with (Aurecon, 2024A).

Comparing on an AC basis is fairer, as rooftop solar PV inverters are considerably higher cost than utility scale solar PV inverters and utility scale solar PV farms typically oversize inverter capacity in order to comply with reactive power requirements, such that inverter capacity is typically equivalent to solar PV module capacity (DC) (Aurecon, 2024A).

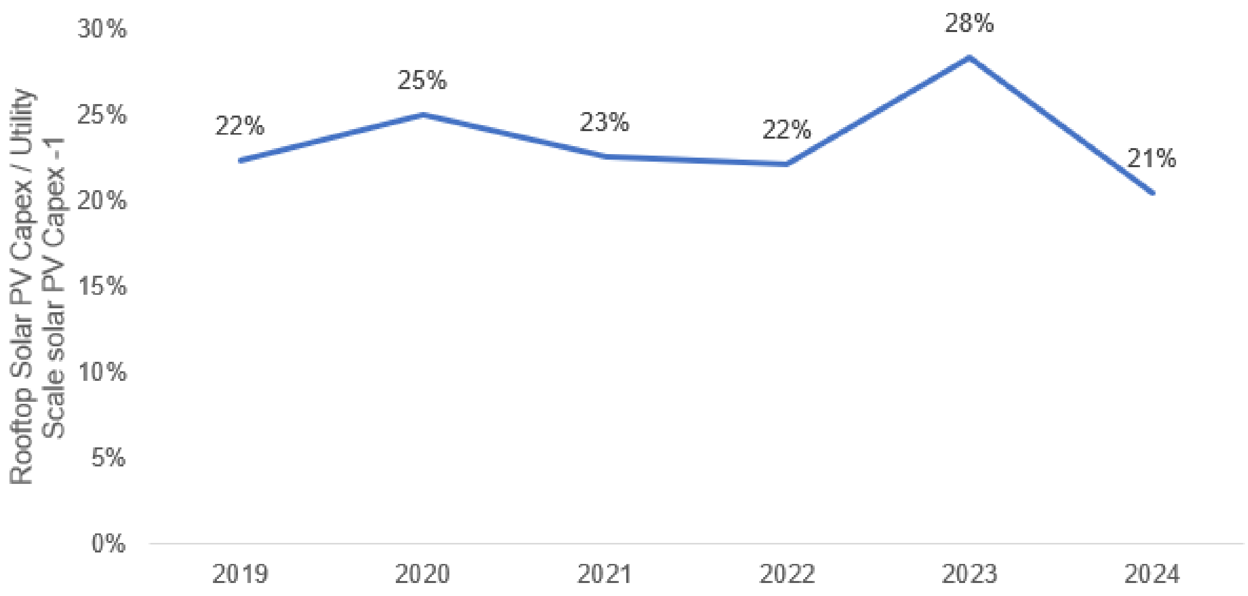

Figure 1: Residential to utility scale solar PV build cost premium – AC:AC | Source: (CSIRO, 2024A)

There is limited evidence of convergence of residential and utility scale BESS build cost

Figure 2 shows residential and utility scale BESS build costs over the last 5.5 years. Driven by lithium carbonate prices (Aurecon, 2024A), builds costs for 2hr utility scale BESS have fluctuated, though they have fallen by 34% over the 5 years to Jun-24, and 17% in the 12 months to Jun-24.

Over the past 5 years the CER BESS cost premium has fluctuated in a range of 30% to 159%. The premium was at its lowest of 30% in July 2019 and its highest of 159% in July 2020. The premium then reduced, reaching 84% in July 2023, but has since risen to 136% in July 2024.

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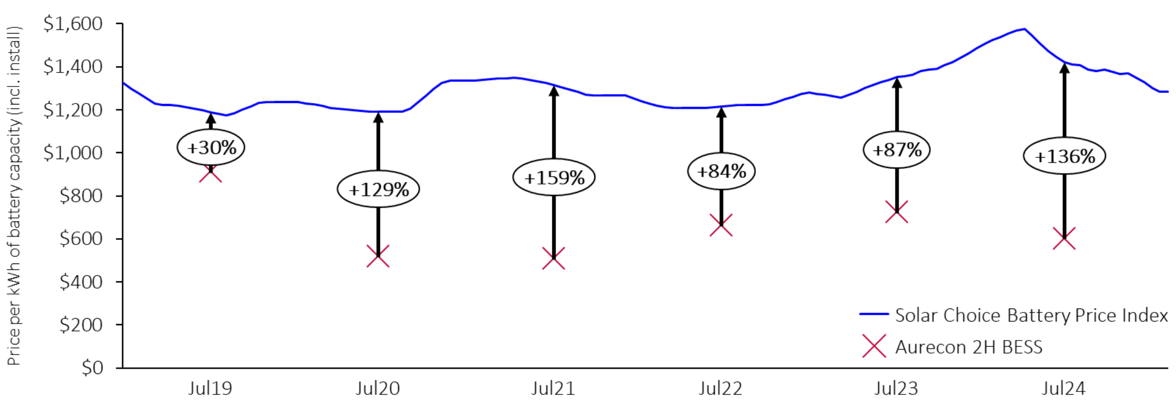


Figure 2: Solar Choice National Battery Price Index (Residential) and Aurecon 2h BESS build cost – (EPC plus land and development)

Source: *(Aurecon, 2024A)*, *(Aurecon, 2024B) (Aurecon, 2022B)*, *(Aurecon, 2022A)*, *(Aurecon, 2021)*, *(Aurecon, 2019)*, *(Solar Choice, 2025A)*

Installation cost is materially higher for CER BESS, with limited potential for cost reductions, while inverter costs are also materially higher

Installation cost are 1.7x higher for CER BESS than utility scale BESS, with limited potential for future labour cost saving per installation.

US residential battery inverter costs are A$700/kW compared to A$124/kW for utility scale. Australian sources suggest costs in the range ~$350/kW-$600/kW (Solar Choice, 2025A) (Solar4Ever, 2025) and while noting these figures may include some retail margin, they are a multiple of US utility scale costs.

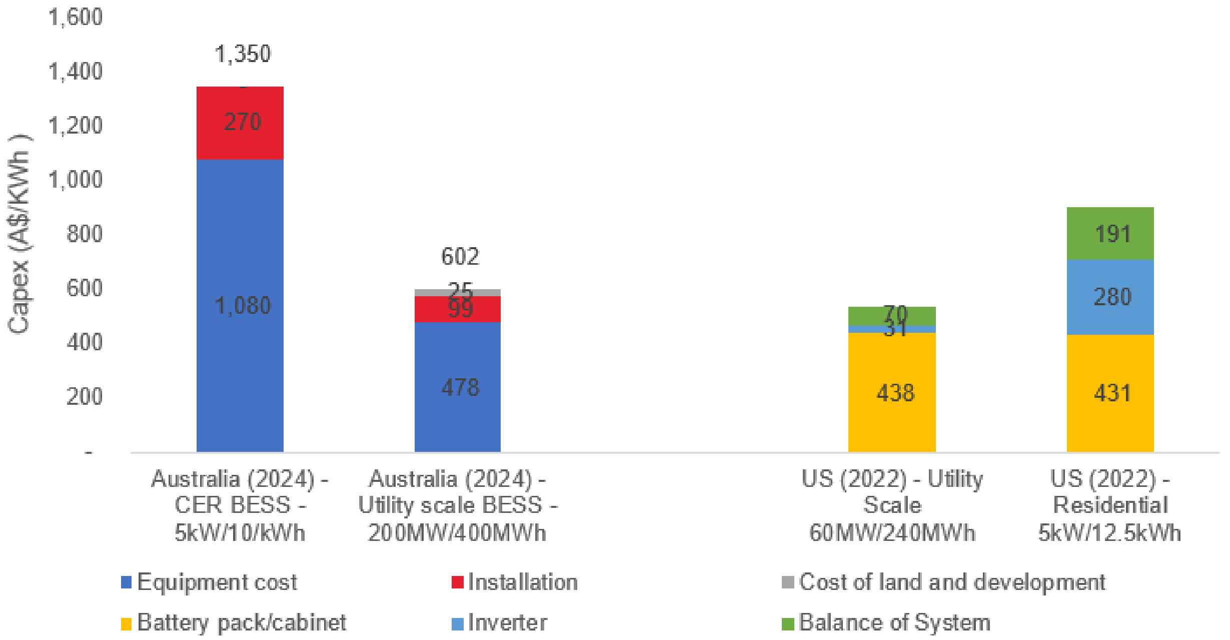


Figure 3 : Australian BESS build costs and US BESS hardware and Balance of System cost

Source: (Aurecon, 2024A) (NREL, 2025A) (NREL, 2025B)

Inverters represent a large portion of CER battery build cost and rooftop PV inverters have experienced lower learning rates than utility scale

Figure 4 shows that since 2010 residential inverters (string inverters) have experienced a 43% reduction in cost while utility scale inverters (central inverters) have experienced an 85% reduction in cost. Deployment growth does not appear to be an explanatory factor. IEA data shows that from 2015 to 2022 residential solar PV capacity grew by 400%, while the aggregate of utility scale and commercial and industrial grew by 403% (International Energy Agency, 2025B). A similar trend could occur with battery/hybrid inverters.

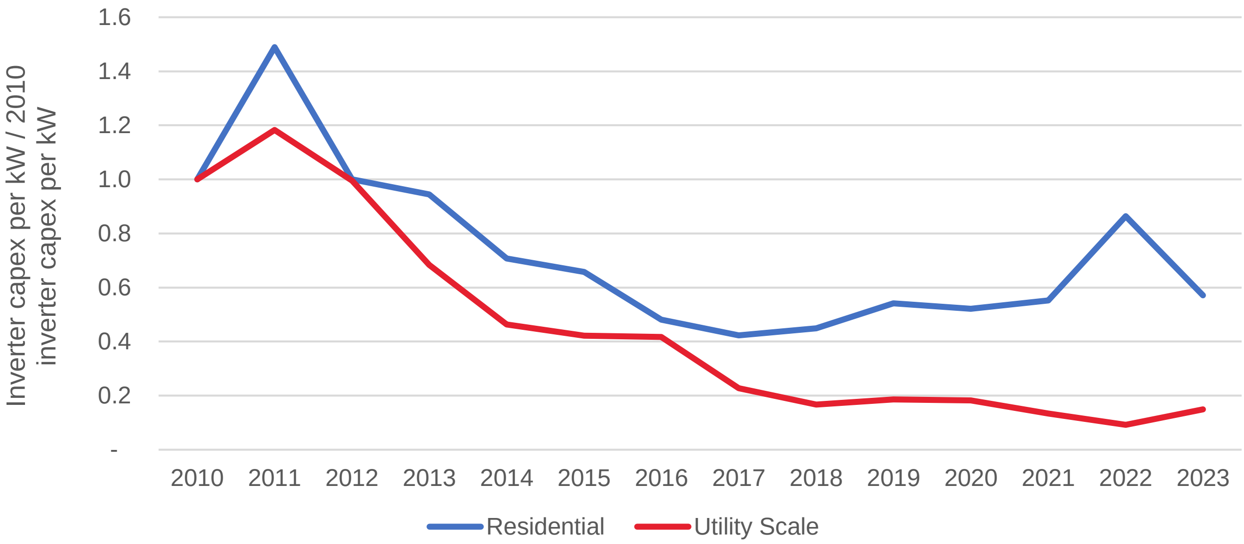


Figure 4 : US utility and residential inverter cost reduction (real) since 2010 | Source: (NREL, 2025C)

1.2.3 Maintaining integrity of drivers

As outlined in the Draft 2025 IASR Stage 1 a key differentiator of GEM's projections compared to CSIRO is dramatically more optimistic projections for:

- CER BESS system.
    - GEM assume that average CER BESS size increase from 10KWh at the start of the projection to 20kWh by 2040 (this conflicts with Pg 61 of the IASR that states that 20kWh is reached by 2050).
    - CSIRO assume battery size will plateau at 11.9kWh and 13.5kWh in the mid 2030s for Progressive Change and Step Change respectively. CSIRO assume BESS size will increase proportionally in size with solar PV system size, which increases from 8.6kw for 2024 to 9.3kW and 10.6kW respectively for Progressive Change and Step Change in mid 2030s. (this detail is not included in the IASR)
- CER BESS capex
    - Figure 5 shows GEM's projected CER BESS capex declines rapidly, and for Step Change scenario, in the first half of the 2030s it is around a third of CSIRO's capex projection and in the longer term around half of CSIRO's projection.

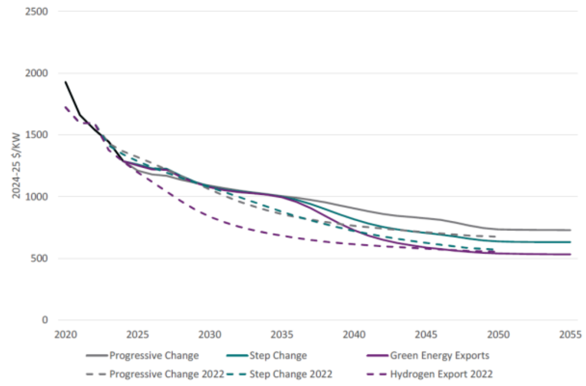


Figure 4-1 Assumed capital costs for rooftop and small-scale solar installations by scenario (excluding STCs or other subsidies)

Figure 4-5 Assumed capital cost per kWh for residential battery system by scenario (Incl. GST)

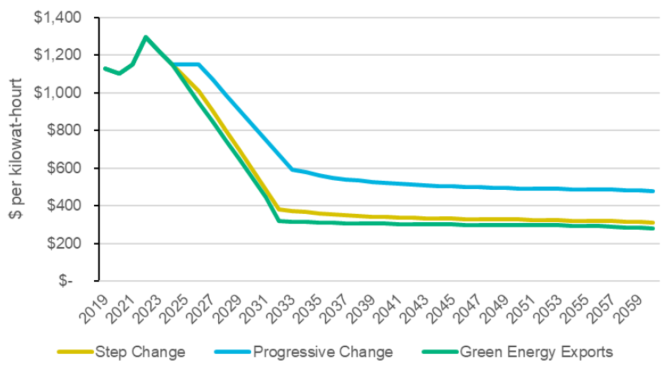
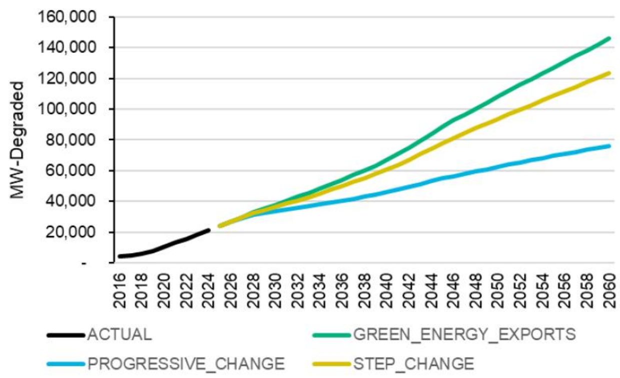


Figure 5: Consultant CER BESS capex projections (left-GEM) (right-CSIRO)	Source: (CSIRO, 2024B) (Green Energy Markets, 2024A)

Figure 6 shows that these assumptions result in large differences in CER projections with GEM's Step Change 2050 installed CER solar PV and CER BESS projection ~1.7x and ~3x higher respectively than those of CSIRO.

Given the large difference in CER projections and key drivers AEMO is encouraged to improve the disclosure of CER projections in the IASR and the transparency of key BESS assumptions in consultant reports and in the IASR. Ideally the IASR would include comparison charts for CER projections and key assumption projections.

Figure 5-1 NEM cumulative degraded megawatts of solar PV by scenario



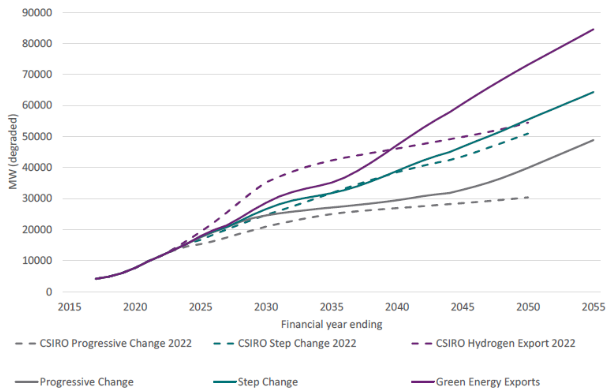
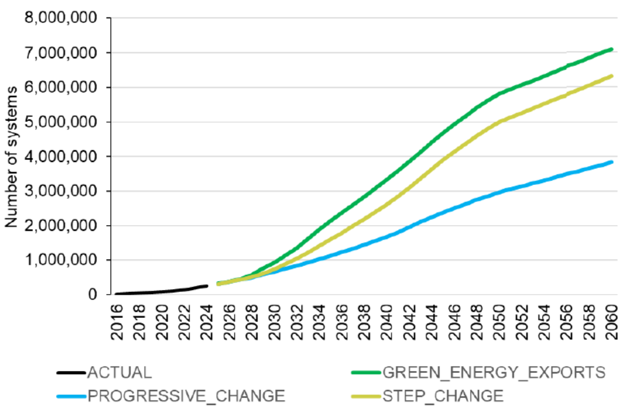


Figure 5-2 Projected capacity of residential small-scale (<100kW) solar PV in the NEM and SWIS

Figure 5-10 NEM cumulative number of battery systems by scenario



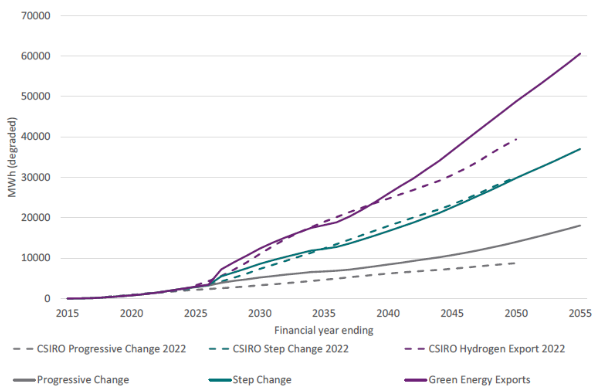


Figure 5-6 Projected capacity of small-scale residential batteries in the NEM and SWIS

Figure 6: Consultant CER projections (left-GEM) (right-CSIRO)	Source: *(CSIRO, 2024B) (Green Energy Markets, 2024A)*

Drivers of CER uptake are different between consultant projection models, as CER BESS pass a combined cost and size inflection point within GEM's projections where they become a driver of solar PV installs (see Pg 71-72 (Green Energy Markets, 2024A))). Thus it is questionable that weighting CER projections will maintain the integrity of CER drivers and a differential weighting magnifies this issue.

The proposed differential weightings will impact the modelling of DNSP CER network investment. A potential unintended consequence of AEMO's proposed differential weighting is higher CER network curtailment outcomes, due to a lower ratio of CER BESS degrade capacity (MWh) to CER solar PV degraded capacity (MWh) compared to using consistent weightings.

1.3 GEM CER projections – Standalone Solar PV revenue stack

Clarification is sought regarding the standalone solar PV revenue stack as the analysis provided by GEM in FRG#8 (Green Energy Markets, 2024B) is unable to be reconciled with solar system revenue projections in GEM's CER projection report.

The analysis provided on pg 21 of GEM FRG#8 presentation shows a NSW residential customer with a solar PV and a BESS in 2035. From the analysis $635 of revenue per standalone solar PV system can be implied:

- Solar self-consumption: ~$400 per system based on ~3,100kWh (12.9c/kWh avoided costs)
- Solar exports: ~$231 per system
  - Solar exports: ~$110 per system based on 2,900kWh (3.8c/kWh export revenue)
  - Charge to battery (as no battery assume exported to grid): ~$121 per system based on 3,200kWh (3.8c/kWh price assumed)

Total revenue per system $635 is materially lower than Figure 7 (GEM Figure 5-17) of around $900 for Step Change and clarification as to what is driving this difference would be welcomed.

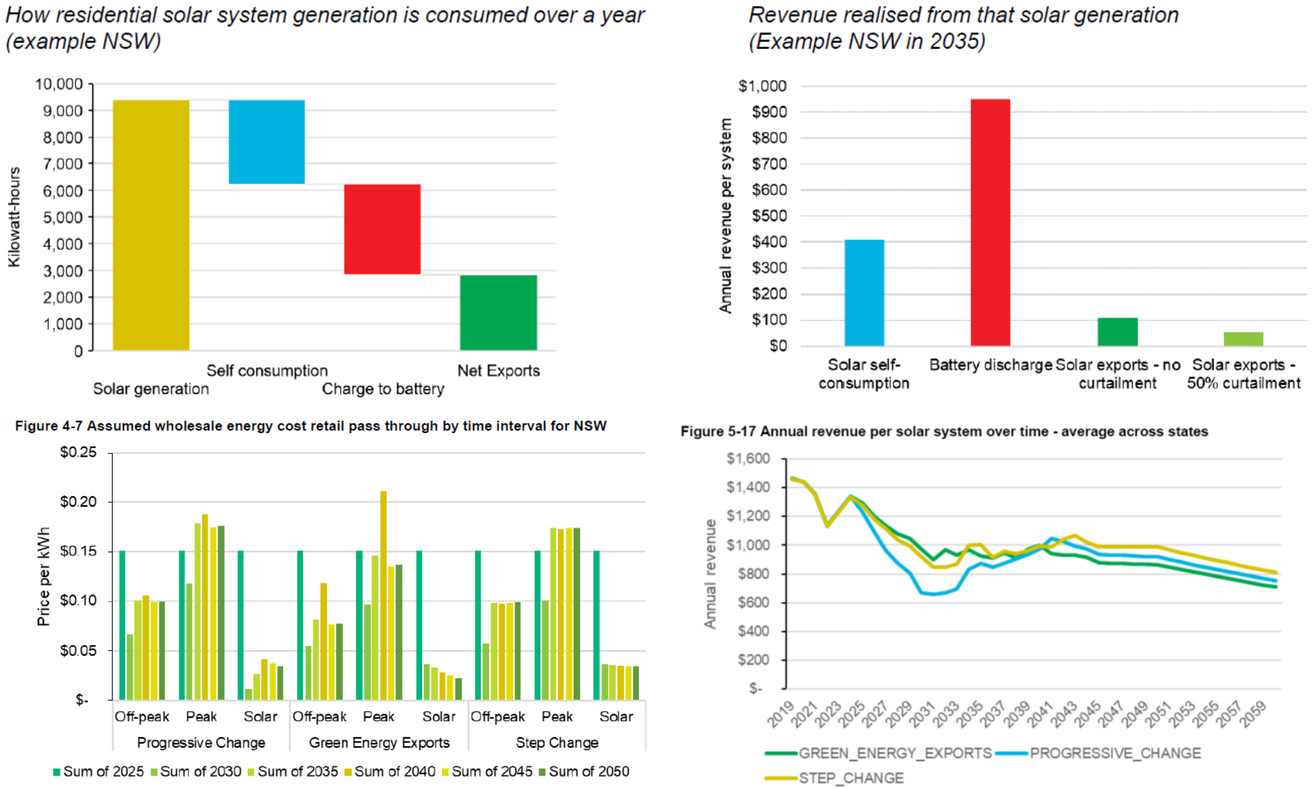


Figure 7: Green Energy Markets solar value stack | Source: *(Green Energy Markets, 2024A)*

2. Green Energy scenario variants

Matters for Consultation

- *Which of the two described scenario variants for the Green Energy scenario is the more appropriate variant for application as the scenario in AEMO's 2025 IASR scenario collection (depending on the planning analysis, AEMO may apply the alternate variant in sensitivity analysis)*
- *Do you have any alternative views on the electrolyser cost curve?*
- *Do you have specific feedback on the proposed REZ resource limits?*

2.1 Green Energy Industries scenario variant preferred, however internal consistency of foundational assumption of green hydrogen commercial viability should still be tested

Green Energy Industries variant is the preferred scenario as it is the most plausible out of the two variants, due to lower green hydrogen growth.

"The commercial viability of green hydrogen is a foundational assumption for the Green Energy Exports scenario...." (Australian Energy Market Operator, 2023). Section 2 discusses several material methodological and assumption issues which challenge this foundational assumption. While these issues challenge both variants, their impact is greatest on the more ambitious Green Energy Exports scenario.

AEMO is encouraged to demonstrate the plausibility of this foundational assumption and that the assumptions for the scenario are internally consistent, i.e. do the underpinning assumptions form a cohesive picture in relation to each other? The simplest approach to achieve this is to allow steam methane reformation with carbon capture utilisation and storage (blue hydrogen) as a production pathway in the CSIROCC MSM for the Green Energy scenario.

It is recommended that transparency is provided to ensure assumptions (policy and others) are technology agnostic and that the cost of any modelled policy support can be explicitly considered. By way of example, increasing WACC for blue hydrogen (if undertaken) would impact the outcomes of modelling.

Both Green Energy Exports and Green Energy Industries scenario variants use the IEA World Energy Outlook as the basis for forecasts and potential biases in their green hydrogen forecasts are subject of discussion and analysis in Section 2.

2.2 Developer interest in green hydrogen as an energy carrier is diminishing

Consistent with global trends, Australian green hydrogen export development activities are faltering, with no major projects as yet reaching financial close and a number of high profile exits including:

- Oct 2024: Origin Energy's announced that it was exiting the Hunter Valley Hydrogen Hub development project and all hydrogen development activities (Origin Energy, 2024)
- Sep 2024: Woodside announced it was shelving the 1.7GW H2Tas green hydrogen and renewable ammonia project and the 600MW Southern Green Hydrogen project in New Zealand (PV Magaznie, 2024B).
- July 2024: Fortescue announcing it was slashing 700 jobs, merging its mining and energy divisions and putting on hold plans to produce 15mtpa of renewable hydrogen by 2030 (WA today, 2024).

Of the major Australian green hydrogen export projects that have publicly released FEED study summaries, many have been abandoned or shelved by project sponsors such as:

- Feb 2025: H2Kwinana – Hydrogen and biofuel plant both shelved (Milne, 2025).
- Feb 2025: CQH2 – Queensland State Government has withdrawn further funding (McKenna, 2025).
- Nov 2024: Fortescue Gibson Island – project officially abandoned and site sold (PV Magazine, 2024A).

2.3 Electrolyser build cost projections from GenCost and IEA are likely materially underestimated

Figure 8 shows recent build cost estimates based on detailed studies on actual projects as well as how current generic electrolyser build cost estimates and projections have changed over time for CSIRO, BNEF and IEA. Build cost estimates from detailed studies on actual projects are 60-80% higher than CSIRO GenCost (Aurecon) generic build cost estimates, with the same issue apparent for IEA and BNEF. Given that current build cost input assumptions for projections models are materially lower than for detailed studies, projected values are likely materially underestimated. Even so, CSIRO's projections are optimistic vs other high-profile electrolyser build cost projections:

- For Step Change Scenario:
    - CSIRO's 2050 projections for Alkaline are 27% lower than IEA and are less than half of BNEF's.
    - CSIRO's 2050 projections for PEM are 19% higher than IEA and 24% lower than BNEF
- For Green Energy Scenario:
    - CSIRO's 2050 projections for Alkaline are 62% lower than IEA and 77% lower than BNEF's.
    - CSIRO's 2050 projections for PEM are 29% lower than IEA and 57% lower than BNEF's.

For further discussion and analysis refer to the author's 2025-25 Gencost Consultation Submission.

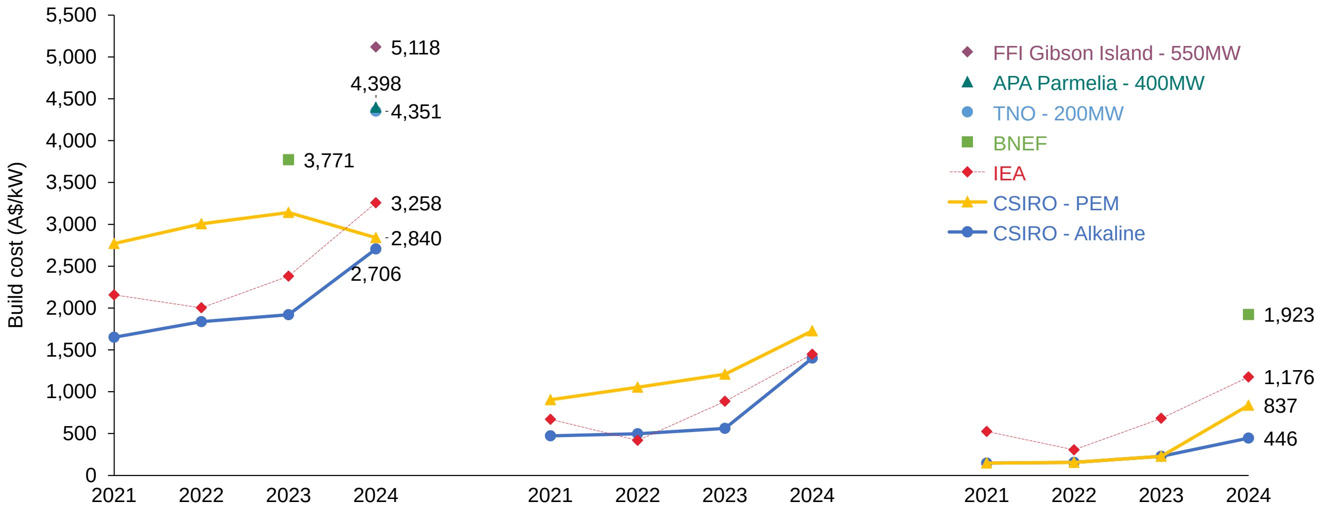


Figure 8 : Green Energy electrolyser projections for CSIRO (NZE by 2050) and IEA (Net Zero Emissions) compared to BNEF and project capex estimates based on detailed studies

Source: (CSIRO, 2024A) (CSIRO, 2024D) (CSIRO, 2023) (CSIRO, 2022) (International Energy Agency, 2024A) (International Energy Agency, 2023) (International Energy Agency, 2022) (International Energy Agency, 2021) (Department of Energy - United States of America, 2024) (TNO, 2024; Tengler, 2024) (APA Group, 2024) (Fortescue, 2024)

Notes:

- Current figures are nominal $, while projections are real $2024
- AUD/USD exchange rate: 2024 – 0.65, 2023 - 0.663, 2022 - 0.689, 2021 – 0.752, 2020 -0.6863 USDE/EUR exchange rate: 2024 - 0.93
- 2024 WEO estimates were released in 2024 and are includes as 2024 in the chart, however they contain 2023 estimates. Hence the 2023 AUD/USD exchange rates is applied to them.
- BNEF and IEA do not have separate Alkaline and PEM projections. APA Parmelia is Alkaline, Fortescue Gibson Island PEM and TNO do not have separate Alkaline and PEM.

2.4 Draft IASR green hydrogen firming and transport costs have been materially underestimated

Refer to Section 4.

Of particular note is ACIL ALLEN's arbitrary assumption that green iron and alumina calcination is able to turn down to 50% of rated capacity. The turndown assumption materially reduces the cost of green hydrogen, including hydrogen storage, particularly as it allows the green hydrogen production to exhibit seasonality. Green iron (direct reduced iron) and alumina calcination are both high temperature processes, which typically have challenges with cycling and there isn't a developed industry or academic literature supporting partial-flexibility assumptions (in contrast to green ammonia). While there may be some potential to introduce partial-flexibility into the alumina calcination process (Furlong, Armstrong, & Hogan, 2024), there is a high level of uncertainty around this.

2.5 GenCost build cost projections and IEA green hydrogen demand projections are based on models that are unlikely to accurately capture green hydrogen firming costs

2.5.1 Overview

AEMO is commended for its efforts to improve the modelling of hydrogen within the ISP, including its attempts to better recognise the cost of firming green hydrogen through the ACIL ALLEN and CSIROCC MSM modelling.

However, AEMO is proposing to use build costs estimates based on CSIRO GenCost GALLME model and green hydrogen demand forecasts from the IEA WEO, that don't accurately capture green hydrogen firming costs. These models are unlikely to accurately estimate the cost of constantly supplying green hydrogen and may be internally inconsistent, with ACIL ALLEN hydrogen modelling and CSIROCC MSM.

2.5.2 CSIRO GenCost

GALLME could be underestimating green hydrogen cost, overestimating its competitiveness against blue hydrogen, leading to earlier uptake and greater deployment of electrolysers. As capex projections are based on a learning model, with deployment the key driver of electrolyser capex, the model bias/error has the potential to create a positive feedback loop, leading to green hydrogen demand being over-estimated and electrolyser build cost being materially underestimated.

Further discussion and analysis of this issue in relation to GenCost can be found in the author's 2024-25 Gencost Consultation submission, (Fletcher & Nguyen, 2024 Forecasting Assumption Update Submission, 2024D) and (Fletcher & Nguyen, Draft 2024 ISP Consultation Submission, 2024A)

2.5.3 IEA World Energy Outlook

The hydrogen production and supply module of the GEC Model, that determines green hydrogen demand forecasts, is not a time sequential model and is unlikely to accurately estimate the cost of supplying a constant supply of green hydrogen.

The hydrogen production and supply module of the GEC Model covers the production of merchant hydrogen and hydrogen-based fuels. The TIMES cost-optimisation modelling framework called is used. Based on demands for merchant hydrogen and hydrogen-based fuels from the end-use sectors, electricity and heat generation sector, refineries and biofuel production, the hydrogen supply module determines a least-cost technology mix to cover these demands. The model optimises the allocation of hydrogen demand between different hydrogen production technologies including green hydrogen (grid connected and islanded electrolysers) and fossil fuels with CCUS (including steam methane reformation of natural gas).

While the GEC model module considers hydrogen storage and turndowns on hydrogen uses cases such as ammonia plants, it isn't a time sequential model and instead uses thirty typical sample days from one weather year. Compared to time sequential modelling using multiple years of weather data the GEC model module is unlikely to capture the cost of oversizing hydrogen storage and other hydrogen value chain components to mitigate dunkelfaute, seasonal energy imbalances and inter-annual variability. This additional cost is likely to be material and for further detail see the author's Draft 2025 IASR Stage 1 Consultation Submission.

To reflect the variability of solar PV and wind for hydrogen production, the hydrogen module divides a year in four typical days, which are again divided into eight time slices of three-hour duration. Since this resolution is *still too coarse to fully reflect the variability, the ETHOS model suite of Jülich Systems Analysis at Forschungszentrum Jülich, with more detailed time resolution (30 typical periods with 24 typical time slices), has been used. The ETHOS model suite determines, for each location and its hourly solar PV, onshore and offshore wind capacity factors, the cost-optimal capacities for solar PV, wind and electrolysers as well as the need for flexibility options, such as hydrogen storage, battery storage or curtailment. This hourly analysis for a single year can take into account operational constraints of subsequent synthesis processes, such as minimum load constraints for Haber-Bosch or Fischer-Tropsch synthesis processes.* (International Energy Agency, 2024B)

2.6 Lower WACC assumption for renewables in IEA WEO, implies significant policy support for green hydrogen through subsidised renewable energy

Figure 9 Shows estimates for 2023 levelized cost of energy for onshore wind and utility scale solar PV for IEA and CSIRO (excluding locational cost factors). CSIRO's LCOE range for onshore wind is higher than IEA, while IEA is at the bottom of CSIRO's range for utility scale solar PV. IEA build cost estimates for Australia could not be located, however WACC is a key driver of the divergence in LCOE estimates. The World Energy Outlook (International Energy Agency, 2024B) assumes that:

"The weighted average cost of capital (pre-tax in real terms) is assumed to be 9% in the OECD and 8% in non-OECD countries unless otherwise specified, for example with revenue support policies, onshore wind and utility-scale solar PV at 4-7%, and offshore wind at 5-8% depending on the region."

The assumptions are based on renewable projects where price risk is transferred to a Government offtaker:

"models where prices paid for solar generation are defined largely by policy mechanisms, which support the vast majority of deployment worldwide." (International Energy Agency, 2024B)

These figures compare to Oxford Economics survey data estimates for utility scale solar PV and onshore wind WACCs of 7.0% and 7.5% respectively (Oxford Economics Australia, 2024B). While these survey estimates are supposedly for merchant projects they assume 55% and 54% gearing respectively for onshore wind and utility scale solar PV (Oxford Economics Australia, 2024B). When compared to an optimal gearing of 64% for an onshore wind farm with 75% of contracted output from (Gohdes, Simshauser, & Wilson, 2023), these survey results appear overly optimistic.

Ultimately the lower WACC assumption for renewables implies that material policy support is provided to green hydrogen projects through subsided renewable energy. This assumption is not technology agnostic.

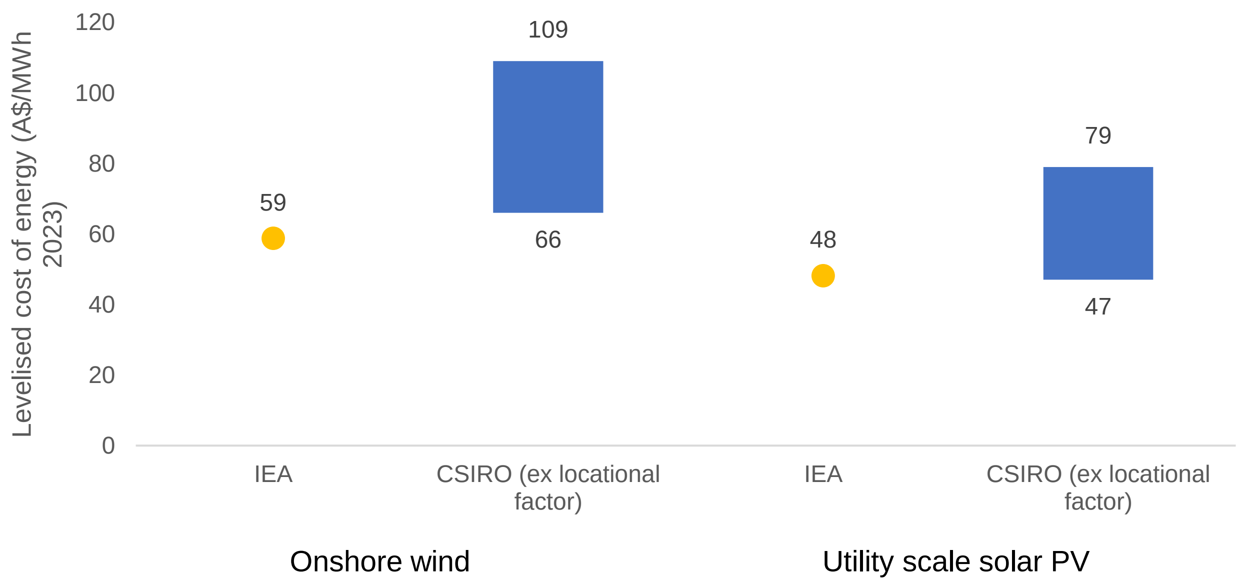


Figure 9 : 2023 Onshore wind and utility scale solar PV LCOE – IEA vs CSIRO GenCost | Source: (International Energy Agency, 2024B) (CSIRO, 2024D)

2.7 Significant uncertainty around developable capacity of wind resources impacts size of potential green hydrogen development

The author's 2026 ISP Methodology Issues paper Consultation Submission (Fletcher & Nguyen, 2026 ISP Methodology Consultation – Issues Paper, 2024C) highlights that there is uncertainty around the developable capacity and capacity factors of wind resources within REZ due to a range of social, environmental, technical and economic constraints. To address this the authors recommended that AEMO consider adding a validation step for its wind resource quality determination methodology that compares modelled developable resource footprints and capacity against data for proposed projects from subscription services such as https://renewmap.com.au/. Proposed project data should also be used to validate AEMO build limits and the level of build limit breach assumed possible by incurring a cost penalty.

REZ close to load centres with sufficient current or planned network capacity may have been fully prospected by developers. Fitzroy REZ is a prime example, as per Figure 10, even in August 2021 proposed wind farm footprints covered practically the entire ridge of potentially developable higher wind speed areas west of Gladstone. Proposed wind project capacity at this time was similar to the build limit of 3,500MW for the Fitzroy REZ and this does not consider that wind project capacity typically declines over the project development cycle. The 2024 ISP Step Change results in 3,500MW of wind being built by 2050 consistent with the build limit, while under the 2024 ISP Green Energy Exports scenario 7,550MW of wind is assumed to be developed by 2050.

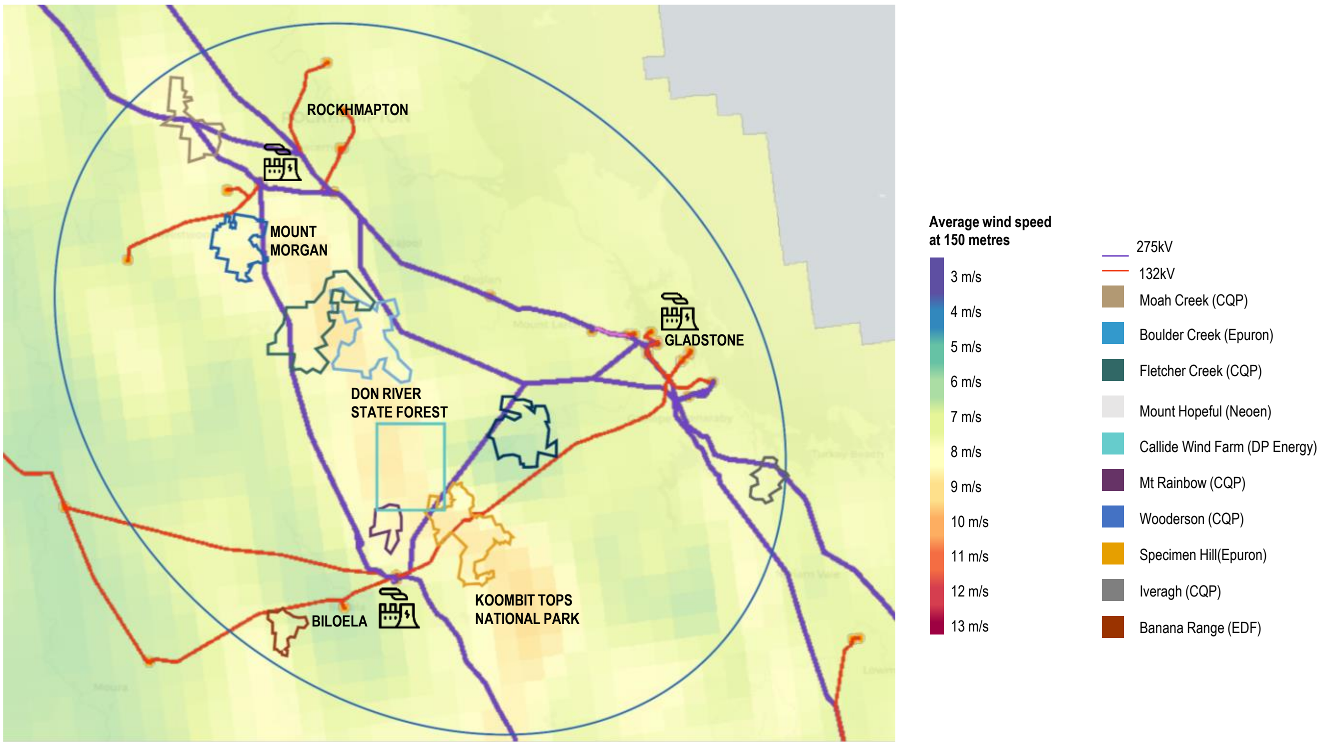


Figure 10 : Fitzroy REZ Wind Project Footprints | Source: National Map and proponent websites (August 2021)

The uncertainty associated with the assumption of breaching build limits is demonstrated in the Queensland Government's *Enabling Queensland's hydrogen production and export opportunities* report (Queensland Hydrogen Coordination Unit / Advisian, 2022). The study assumes that wind resources within REZ are allocated first to domestic decarbonisation consistent with the 2022 ISP Step Change scenario, with unallocated wind resources available for a potential export green hydrogen industry. In contrast to the approach in the AEMO ISP the study assumes that REZ wind build limits can't be breached, by paying a penalty. Instead to facilitate material hydrogen export volumes, the study assumes transport capacity would need to be built (electricity transmission or hydrogen pipelines) to access renewables in remote inland REZ such as Barcaldine REZ.

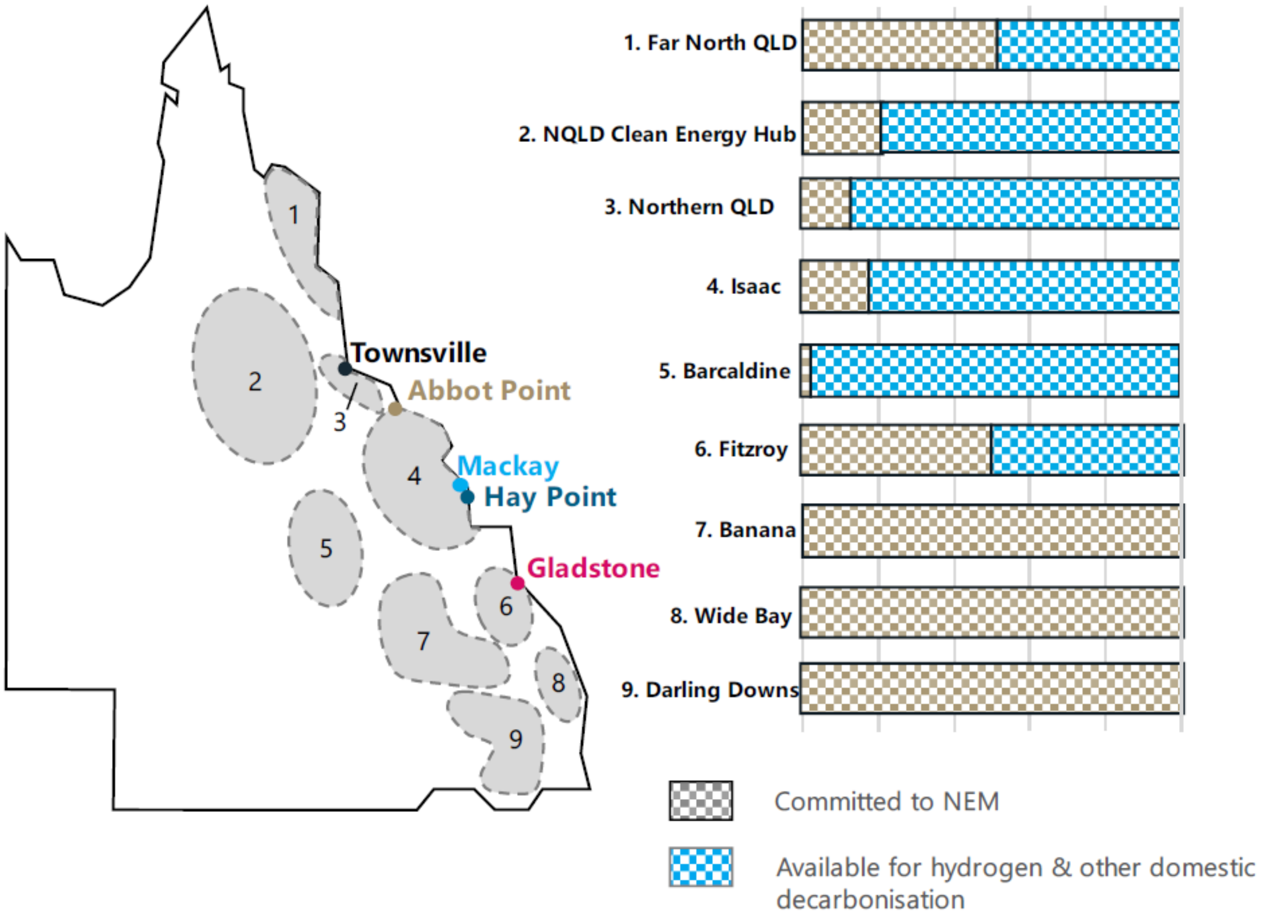


Figure 11 :REZ commitments | Source: (Queensland Hydrogen Coordination Unit / Advisian, 2022)

Of the 10GW of electrolyser capacity proposed across QLD more than half is located in Gladstone (CSIRO, 2024C) with the vast majority of this capacity focussed on export markets. Assuming the Step change scenario and that wind build limits can't be breached consistent with (Queensland Hydrogen Coordination Unit / Advisian, 2022), wind will need to be accessed from inland REZ for these projects. The wind resource quality of QLD inland REZ such as Banana (E resource quality rating) and Barcaldine (D resource quality rating) could be poor, locational cost factors are high and there will be additional transport cost for hydrogen pipelines to Port of Gladstone. Consequently these projects could be relatively high cost.

3. Green Energy scenario - Alumina, aluminium and hydrogen production allocations between states

Matters for Consultation

- *Are the scenarios, and the scenario collection, suitable for use in AEMO's planning publications including the 2026 ISP? Does the scenario collection support the exploration of a diverse range of possible futures that could occur over the planning horizon?*

The Green Energy Industries variant "*includes development of a hydrogen industry, focusing on value-add hydrogen products such as green iron and steel, for domestic and export.*"

However the scenario is narrowly focussed on green iron and steel, with no alumina refining growth assumed, despite this being an existing major export industry.

The decarbonisation of alumina is relatively simple and there is the potential for production process to be fully electrified. Current Alumina refineries energy usage is split between digestion (64%), calcination (31%) and other (5%) (ARENA & Deloitte, 2022). Electrification through mechanical vapour compression has the potential to increase the energy efficiency of digestion, which represent 64% of alumina refinery use, in a similar fashion to heat pumps for low temperature heat. There is uncertainty around technology pathways for calcination, with trials for both hydrogen fuelled and electric calcination announced by industry (Australian Aluminium Council, 2024B).

3.1 Alumina production volumes should grow under Green Energy Exports scenario

For the Green Energy Industries scenarios it is recommend that given Australia's bauxite and renewable energy endowment, alumina production grows at double projected global growth, however all of this growth is allocated to Queensland. This allocation reflects bauxite mining constraints in WA.

The World Energy Outlook projects that global aluminium production will grow from 108Mtpa in 2023 to 151Mtpa (a 40% increase and 1.3% CAGR) based on the Stated Policies Scenario (International Energy Agency, 2024A). Projected aluminium production growth under more ambitious climate policy scenarios may be lower due to the adoption of material efficiency such as reducing scrap in production, product material efficiency and recycling (International Energy Agency, 2025A).

Australia is the second largest bauxite miner by production and in 2023 produced around 98mtpa (25% of global production), with around 60% (59mtpa) used domestically and 3.5bn tonnes of reserves (U.S. Geological Survey, 2024; Australian Aluminium Council, 2024A). The Weipa (QLD) mining complex produced 35.1mt of bauxite in 2023 (Rio Tinto, 2024A) and includes the Amrun mine which made its first shipment in 2018 and has a current production capacity of 22.8mtpa with an option to increase this up to 50mtpa (Queensland Government - State Development, Infrastructure and Planning, 2023) (Rio Tinto, 2024B).

ACIL ALLEN assumes that alumina production remains at current level of 18.2mtpa in all scenarios. ACIL ALLEN consider Australian alumina production growth as too speculative due to:

- Australia is already the world's second largest alumina producer and processes a high proportion of bauxite to alumina domestically.
- Concerns around domestic bauxite due to the expected closure of Gove in 2030 (11.6mt production in 2023) and risk around expanding Darling Scrap bauxite mining in WA jarrah forests.

While it is accepted that expanding bauxite mining in WA faces challenges, the Amrun mine (QLD) has an option to expand capacity by 27.2mtpa to 50mtpa. After conservatively deducting the 11.6mtpa production of, net expansion opportunity would be 11.2mtpa, which could support ~4.3mtpa of alumina production in QLD, 57% of current QLD production and 3% of global production. This is before considering bauxite exploration opportunities.

3.2 Aluminium smelter load growth should not occur in Step Change

An evidence base has not been identified that supports NEM aluminium smelter load growth for the Step Change scenario. If this load growth is to be included, evidence supporting cost competitiveness NEM vs alternative global locations should be provided.

3.3 Alumina calcination should be assumed to be electrified due to cost and efficiency issues with hydrogen

For Step Change and Green Energy scenario no green hydrogen demand for alumina calcination is recommended due to competition with electrification. Section 2 raises a number of issues that materially impact the potential commercial viability of green hydrogen and in addition electrification is far more energy efficient for heat.

While there is uncertainty around technology pathways for calcination (Australian Aluminium Council, 2024B), Figure 12 shows the energy efficiency of high temperature heat delivered via hydrogen could be 47% around half that of heat via direct electrification of 90%. While electrolysis efficiency is projected to improve, much of the low efficiency of other value chain components is not addressable by technology breakthroughs.

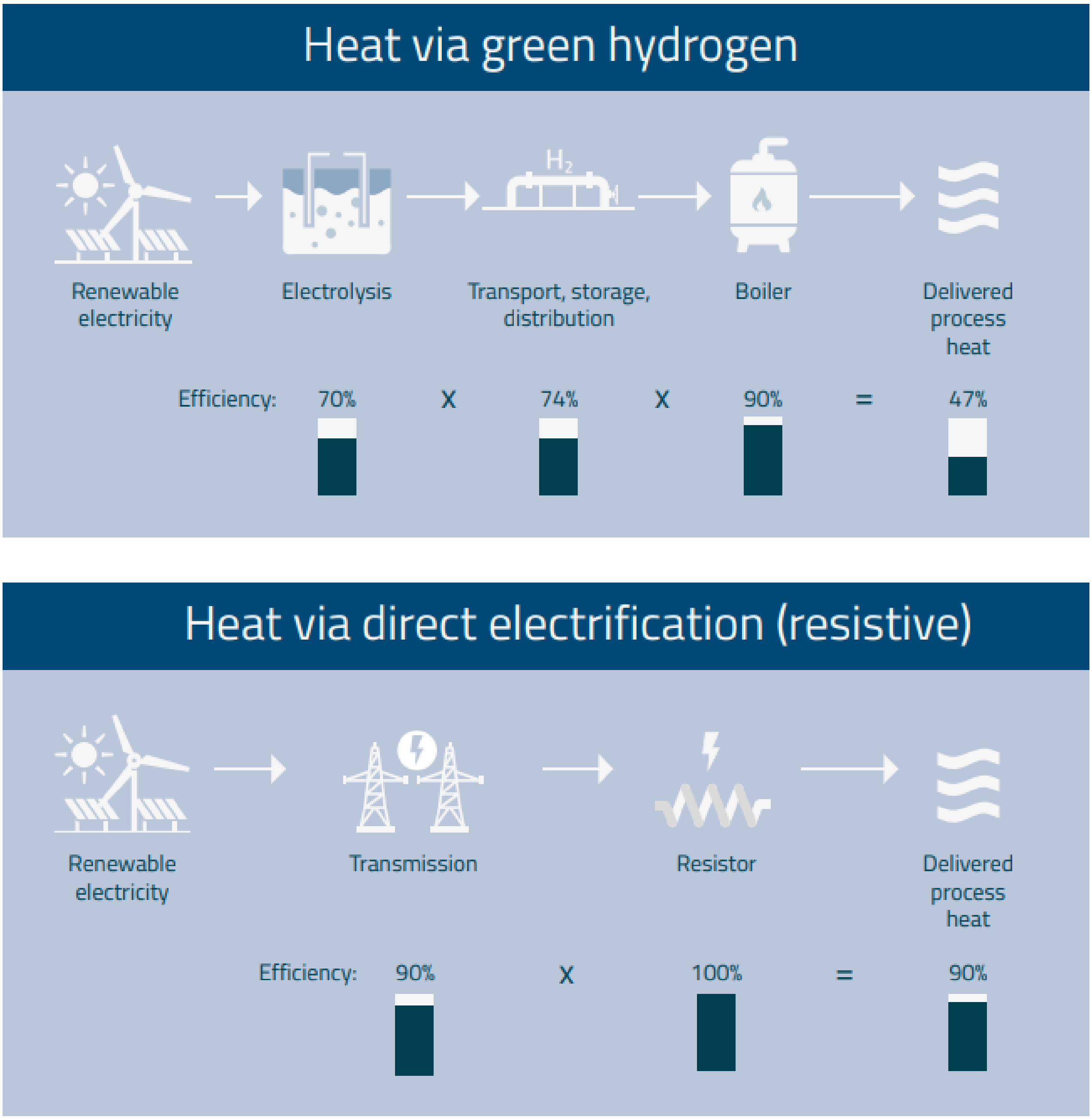


Figure 12: Efficiency losses of hydrogen combustion for heat compared to direct electrification | Source: (Future Cleantech Architects, 2024)

3.4 No green iron production should be allocated to states with no existing iron ore mines or steel production

No hydrogen production for green iron is recommended for states with no existing iron ore mines or steel production. ACIL ALLEN state on pg. B-19 that:

"While the assessment included iron ore resources as one factor in determining green iron production location, as the cost of transporting iron ore is small in the context of overall green iron production costs, we assumed that iron ore could be moved to a location outside of the state in which it was mined for further processing to green iron."

However, in addition to higher shipping costs, separating mining and green iron production locations could add material cost due to additional loading and unloading facilities, general port infrastructure and other infrastructure upgrades and additional stockpiling requirements to mitigate risk. While green iron is at the demonstration stage, projects are typically co-located with existing iron ore mining value chains (See (CSIRO, 2024C) (Government of Western Australia, 2024)).

ACIL ALLEN assume that QLD represents 18% of green iron production, compared to 53% for WA (existing iron ore mining), 12% for SA (existing iron ore mining and steel production) and 6% for NSW (existing steel production) and 10% for other states that have no existing iron ore mining or steel production. Except NSW, which has steel production, state allocation for green hydrogen production and green iron production are similar. This suggests having existing iron ore mines within a state had little impact on state iron ore allocations.

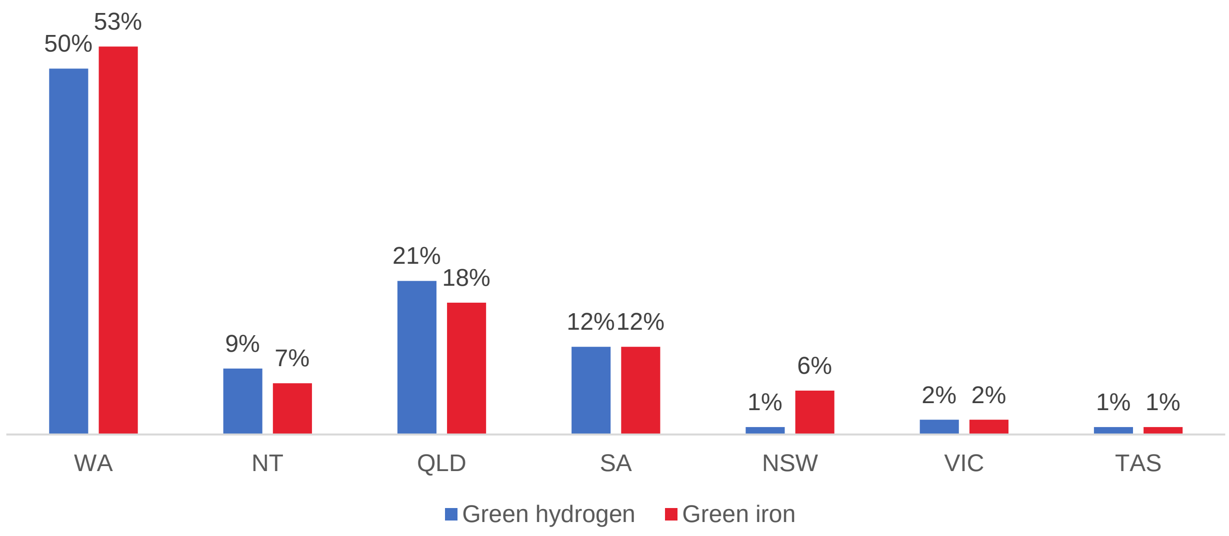


Figure 13: Share of Australian green hydrogen and green iron production by region | Source: (CSIRO, 2024C), ACIL ALLEN

While a green iron project is proposed for Gladstone, it is in the early stages of development and there is a high degree of uncertainty. The project would involve a new mine and proposed activities will include a detailed evaluation and testing of the ore deposit to prove its quality and scale (Quinbrook Infrastructure Partners, 2024). The project involves using hydrogen produced by CQH2, for which the Queensland State Government withdrew further funding in Feb 2025 (McKenna, 2025).

3.5 Greater proportion of hydrogen production for green ammonia and hydrogen export should be allocated to WA

A greater proportion of projected hydrogen production for green ammonia and hydrogen export should be allocated to WA to be more consistent with proposed projects (HyResoure) and to consider competition in Queensland for renewable resources for alumina refining growth.

ACIL ALLEN state on pg. B-10 that:

"We then broke Australian green hydrogen production down to the regional level with the split set out in based on the volume of proposed green hydrogen and green ammonia projects in each region[8], the level of solar and wind generation available in each region, and broad assessments of constraints around social licence, port infrastructure and workforce availability."

Figure 14 shows that ACIL ALLEN has allocated higher proportion of hydrogen production to QLD and SA than WA. HyResource figures are based on electrolyser capacity and where this is not available the author has estimated this capacity as 6% of renewable capacity.

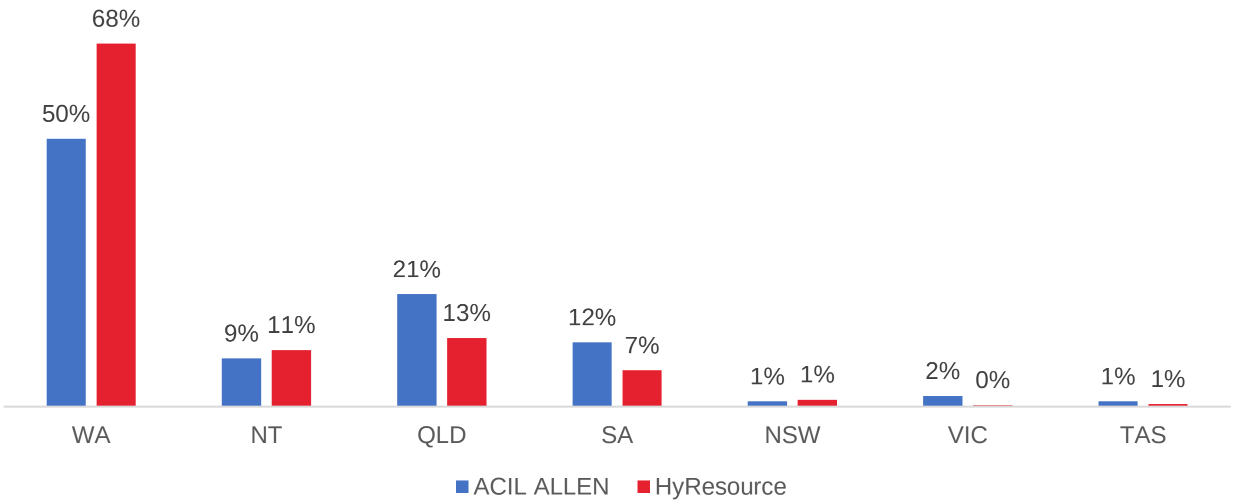


Figure 14: Share of Australian green hydrogen production by region | Source: (CSIRO, 2024C) (ACIL ALLEN, 2024)

4. Hydrogen modelling – ACIL ALLEN renewable gas projections

AEMO is commended for its efforts to improve the modelling of hydrogen within the ISP. Section 4 explains opportunities to further improve AEMO's (and ACIL Allen's) proposed methodology and input assumptions, identifies the rationale to do so – to avoid material under-estimation of green hydrogen costs - and provides recommendations for simple implementable solutions.

Estimates of green hydrogen costs are important as:

- In Step Change and Progressive Change scenarios green hydrogen cost is compared to blue hydrogen in CSIROCC MSM to determine green hydrogen demand, which drives electricity system load growth.
- *"The commercial viability of green hydrogen is a foundational assumption for the Green Energy Exports scenario...."* (Australian Energy Market Operator, 2023). In Section 2.1 the author contends that AEMO should provide evidence that this foundational assumption is plausible and assumptions for the scenario are internally consistent.

4.1 AEMO's proposed methodology for estimating green hydrogen costs has the potential to materially underestimate green hydrogen costs

ACIL ALLEN's consultant report states that:

"The storage and transport components of this cost modelling were extracted and used as inputs to CSIRO's multi-sector modelling, alongside CSIRO's own modelled estimates of the other cost elements of hydrogen" (PgB1 (ACIL ALLEN, 2024)).

Key issues with AEMO's proposed methodology are that:

1. Adding a storage cost from a time sequential model that uses multiple years of renewable energy traces (ACIL ALLEN) to a model based on a fully flexible hydrogen demand profile, or a model that represents time as 16 load blocks (CSIRO Multisector model), has the potential to materially underestimate green hydrogen cost. This is because the cost of oversizing of other hydrogen value chain components is not captured.
2. CSIROCC MSM does not account for the additional cost that a variable green hydrogen supply will have on ammonia production costs such as of oversizing plant capacity and ammonia storage, to maintain constant deliveries to customers.

This section recommends simple solution to address these potential material biases, including using ACIL REZ hydrogen cost estimates as inputs to the CSIROCC MSM and applying cost premiums to CSIROCC MSM hydrogen cost estimates. AEMO is encouraged to provide transparency of both ACIL ALLEN and CSIROCC MSM hydrogen cost estimates.

While it is acknowledged that this approach may not capture potential sector coupling benefits highlighted in (Fletcher & Nguyen, Draft 2024 ISP Consultation Submission, 2024A), the magnitude of these benefits is uncertain, related to electrolyser build costs reductions and location specific..

4.1.1 Firming green hydrogen requires hydrogen storage and oversizing of other hydrogen value chain components

Figure 15 demonstrates that for an islanded hydrogen value chain the cost of a constant hydrogen supply is around double that of a fully flexible hydrogen supply and that 2022 CSIROCC MSM hydrogen cost estimates are closer to the cost of a fully flexible hydrogen supply.

Adding a storage cost from a time sequential model, using multiple years of renewable energy traces (ACIL ALLEN) to a model based on a fully flexible hydrogen demand profile, or a model that represents time as 16 load blocks (CSIROCC MSM), has the potential to materially underestimate green hydrogen cost. This is because in addition to hydrogen storage cost, a hydrogen value chain optimised to deliver a firmed demand profile is likely to oversize renewables and electrolyser capex, relative to a fully flexible hydrogen demand profile.

Figure 15 shows the capex for oversizing of other value chain components (renewables and electrolysers) for supplying a constant hydrogen supply compared to the capex for a fully flexible hydrogen supply ranges from 22%-136% for QLD, depending on REZ and year. The oversizing premium increases over time, noting that this analysis is based on GenCost Consultation Draft 2022-23 (December 2022), which had materially lower electrolyser and wind capex projections, than the 2024-25 Draft (December 2024). Figure 17 shows that Capex for oversizing of other components (renewables and electrolyser) for constant supply is 28%-200% of storage capex for a constant supply.

The simplest solution to address this issue is to use ACIL ALLEN's hydrogen cost estimates as an input to the CSIROCC MSM, which although not disclosed, are calculated in determining hydrogen storage costs. AEMO is encouraged to explain if there are constraints to using this approach. An alternative approach that would achieve the same outcome would be to add ACIL ALLEN storage costs plus a premium to CSIROCC's hydrogen cost estimates.

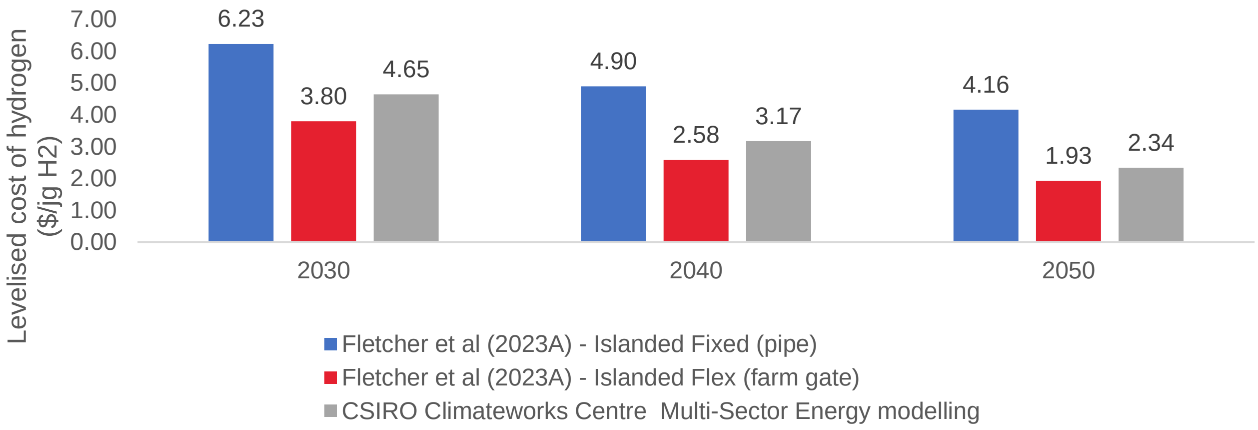


Figure 15: LCOH projection ($/kg H2) - 2022 CSIRO Climateworks Centre MSM | Source: (Fletcher & Nguyen, Draft 2024 ISP Consultation Submission, 2024A)

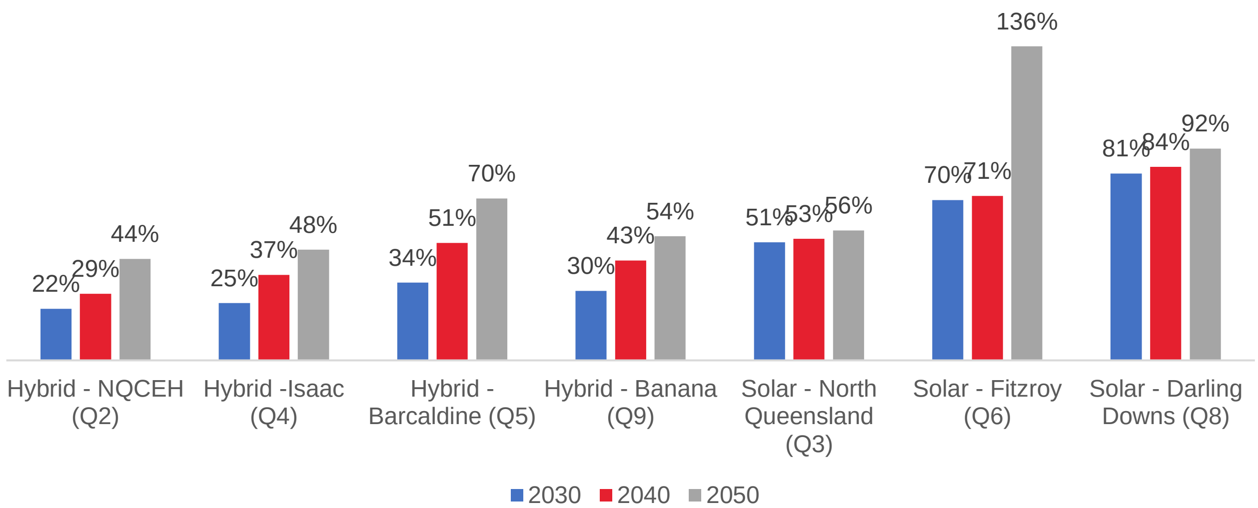


Figure 16: Capex for oversizing of other components (renewables and electrolyser) for constant supply / total capex for flexible hydrogen supply | Source : pg102 (Fletcher A. , et al., 2023)

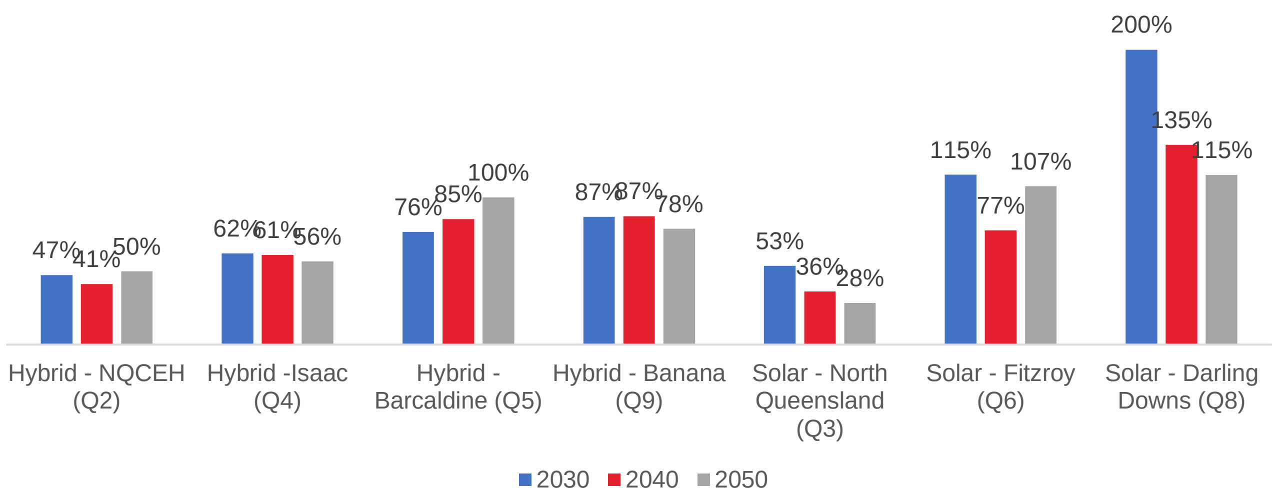


Figure 17: Capex for oversizing of other components (renewables and electrolyser) for constant supply / Storage capex for constant supply | Source: pg102 (Fletcher A. , et al., 2023)

4.1.2 Variable hydrogen supply results in ammonia plant oversizing and ammonia storage costs

To estimate the future cost of green ammonia, ideally the full value chain (including green ammonia plant and ammonia storage) should be optimised, consistent with global and Australian literature (Nayak-Luke & Bañares-Alcántara, 2020) (Fasihi, Weiss, Savolainen, & Breyer, 2021) (Wang, et al., 2023) . It is acknowledged that AEMO's budget is limited as is the number of consultants with the capability to undertake this analysis. It is anticipated that due to these constraints that AEMO proposes a simplified approach that optimises the hydrogen value chain (renewables, electrolyser and hydrogen storage) and does not account for changes in optimal hydrogen value chain when considering the fixed cost of the ammonia plant, nor additional costs to ensure constant delivery of ammonia to customers (required additional ammonia plant capacity due to lower load factor and ammonia storage).

The author's understanding of the CSIROCC MSM is that it compares different hydrogen production pathways for hydrogen production for Step Change and Progressive change including green hydrogen, steam methane reformation (SMR) and SMR with carbon capture storage and thus any premium would need to be applied to green hydrogen costs.

Figure 18 shows ammonia plant load (Haber Bosch) for an ammonia value chain that provides a constant supply of ammonia to customers ranges from 81% to 91% for QLD REZ, depending on REZ and year. Figure 18 shows the additional capital cost of oversizing ammonia plant (Haber Bosch) capacity and ammonia storage varies from 5%-9% for QLD REZ, depending on REZ and year. No material pattern is observed over time or between solar and hybrid value chains. Thus a 7% premium is recommended to be applied to green hydrogen costs within CSIROCC MSM, for the green ammonia use case.

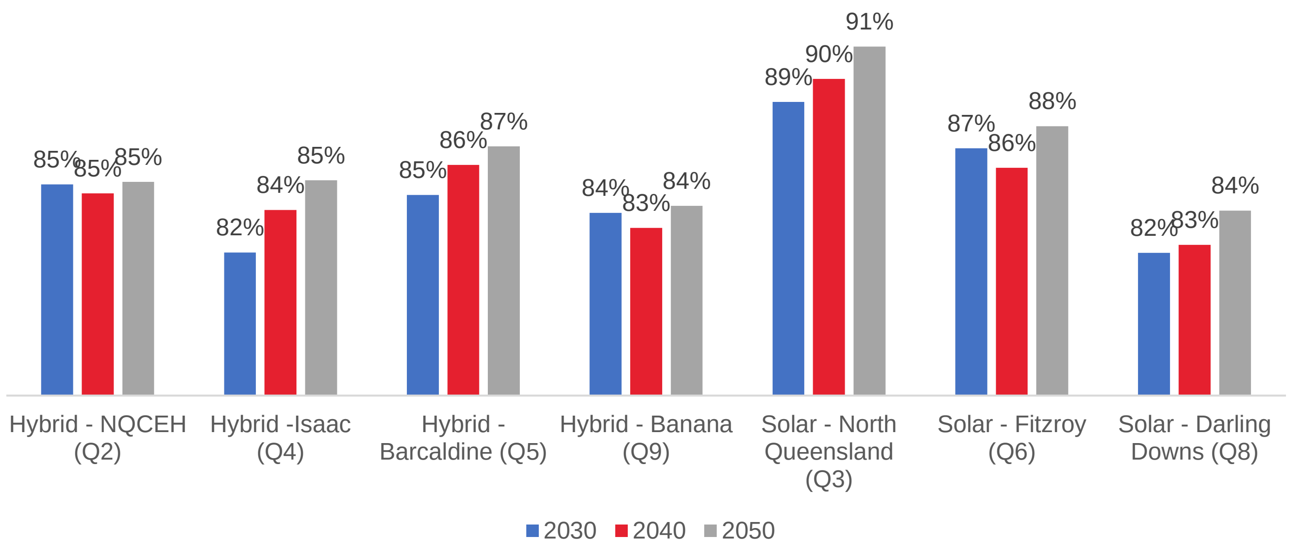


Figure 18: Ammonia plant (Haber-Bosch) load factors for value chain that provides a constant supply of ammonia to customers | Source: pg117 (Fletcher A. , et al., 2023)

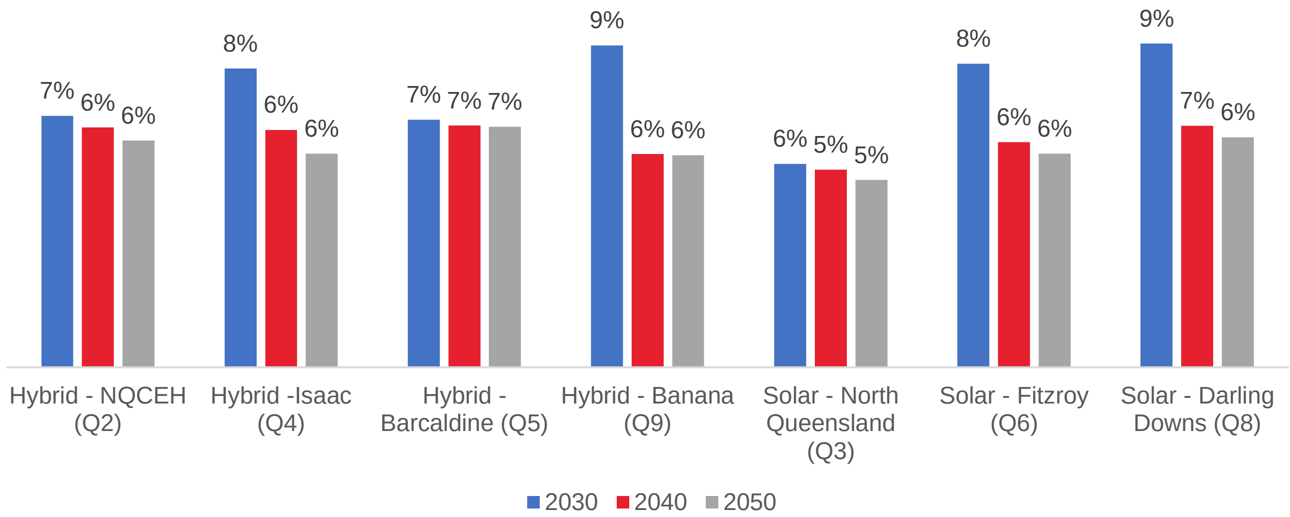


Figure 19: (Ammonia plant oversizing capex + ammonia storage capex) / hydrogen value chain capex | Source: pg117 (Fletcher A. , et al., 2023)

4.2 Input assumptions reduce the cost of green hydrogen

Simple solutions are available to address material issues with input assumptions. Those issues include:

1. Arbitrary partial- flexibility / turndown assumptions are used for green iron and alumina. Hydorgen demand should be inflexible for these use cases.
2. REZ transport costs estimates exclude a range of material costs including Line Pipe costs.
3. Storage cost estimates are materially lower than Australian industry consultant estimates.
4. Locational cost factors appear not to have been applied.
5. Cost escalation consistent with large energy infrastructure projects should be applied.

Each of these issues and solutions are considered in further detail below. In addition it is proposed more generally that inputs from (Australian Pipelines and Gas Association - GPA Engineering, 2021), which are used as the source of REZ transport cost estimates are used across both REZ transport and hydrogen storage.

4.2.1 Green iron and alumina should have inflexible hydrogen demand

In estimating its hydrogen storage cost ACIL ALLEN assumes all hydrogen use cases can reduce demand (turndown) to 50% of nameplate capacity and while this assumption is supported for ammonia, green iron and alumina should be inflexible hydrogen demands (no turndown). The turndown assumption materially reduces the cost of green hydrogen, including hydrogen storage, particularly as it allows the green hydrogen production to exhibit seasonality. The 50% turndown assumption for green iron and alumina calcination is arbitrary, with no evidence provided supporting it. Green iron (direct reduced iron) and alumina calcination are both high temperature processes, which typically have challenges with cycling and there isn't a developed industry or academic literature supporting partial-flexibility assumptions (in contrast to green ammonia). While there may be some potential to introduce partial-flexibility into the alumina calcination process (Furlong, Armstrong, & Hogan, 2024), there is a high level of uncertainty around this.

It is acknowledged that based on the Draft 2025 IASR, impacts to ISP outcomes of the 50% turndown assumption for green iron and alumina may be immaterial as:

- ACIL ALLEN Step Change projections include limited hydrogen consumption for green iron and alumina starting in the 2040s.

- Green hydrogen costs are not a driver for the Green Energy scenario, as consistent with the 2024 ISP, *"The commercial viability of green hydrogen is a foundational assumption for the Green Energy Exports scenario...."* (Australian Energy Market Operator, 2023)

However, in Section 2.1 the author contends that AEMO should provide evidence that the above foundational assumption is plausible and assumptions for the scenario are internally consistent. For the Green Energy scenario the authors recommend disclosing the cost of green hydrogen from the CSIROCC MSM for green ammonia (50% turndown) and a flat profile (green iron and alumina), as well as the cost of blue hydrogen (SMR +CC), were it to be an option in the CSIROCC MSM. For the Step Change scenario blue hydrogen (SMR+CC) should be a hydrogen production option in the CSIROCC MSM.

If separate storage and hydrogen cost estimates based on an inflexible demand profile are not produced for these uses cases, ACIL ALLEN and AEMO are encouraged to appropriately name hydrogen storage and hydrogen cost estimates, to avoid confusing stakeholders. Eg. "Hydrogen (50% turndown)" or "Hydrogen (ammonia use case)".

4.2.2 REZ transport costs estimates exclude a range of material costs including Line Pipe costs

Transport costs have been materially underestimated as they are based on CPI adjusted 2021 cost per inch assumptions from (Australian Pipelines and Gas Association - GPA Engineering, 2021) for installation costs and do not include costs such as Line Pipe cost and shipping, engineering, compression costs, owners, locational factors and the high levels of cost escalation that energy infrastructure projects have experienced in recent years. To address these issues the following recommendations are made:

- Using levelized cost of hydrogen transport estimates from GPA Engineering based on pipeline throughput capacity of 50,000TJ for Step Change.
- Adding compression cost estimates from GPA Engineering of \$0.55/GJ.
- Adding owner costs.
- Applying locational cost factors and infrastructure project cost escalation to aggregate cost estimates.

Figure 20 compares levelized cost of transport estimates from ACIL ALLEN (\$2021) and (Australian Pipelines and Gas Association - GPA Engineering, 2021). GPA estimates show that:

- Hydrogen pipelines experience significant economies of scale based on hydrogen throughput capacity.
- There is a positive relationship between distance and levelised cost of transport, however it is not linear with cost accelerating from 250km to 500km. The non-linear relationship is driven by the cost of increasing pipeline diameter to manage pressure drop over longer distances.
- ACIL ALLEN cost estimates most closely align with GPA Engineering estimates for 250,000GJ/day (0.64Mt H_2 pa) hydrogen throughput and show a linear relationship between distanced and levelized cost of transport. Under Step Change and Green Energy by 2050 ACIL ALLEN projects ~120PJ (0.8Mt) and 2,700PJ (19Mt) of hydrogen production Australia wide respectively. A pipeline with 50,000GJ/day (0.13Mt H_2/ year) aligns reasonably well with the volume of hydrogen production projected in Step Change, considering dispersion of production among states and REZ.

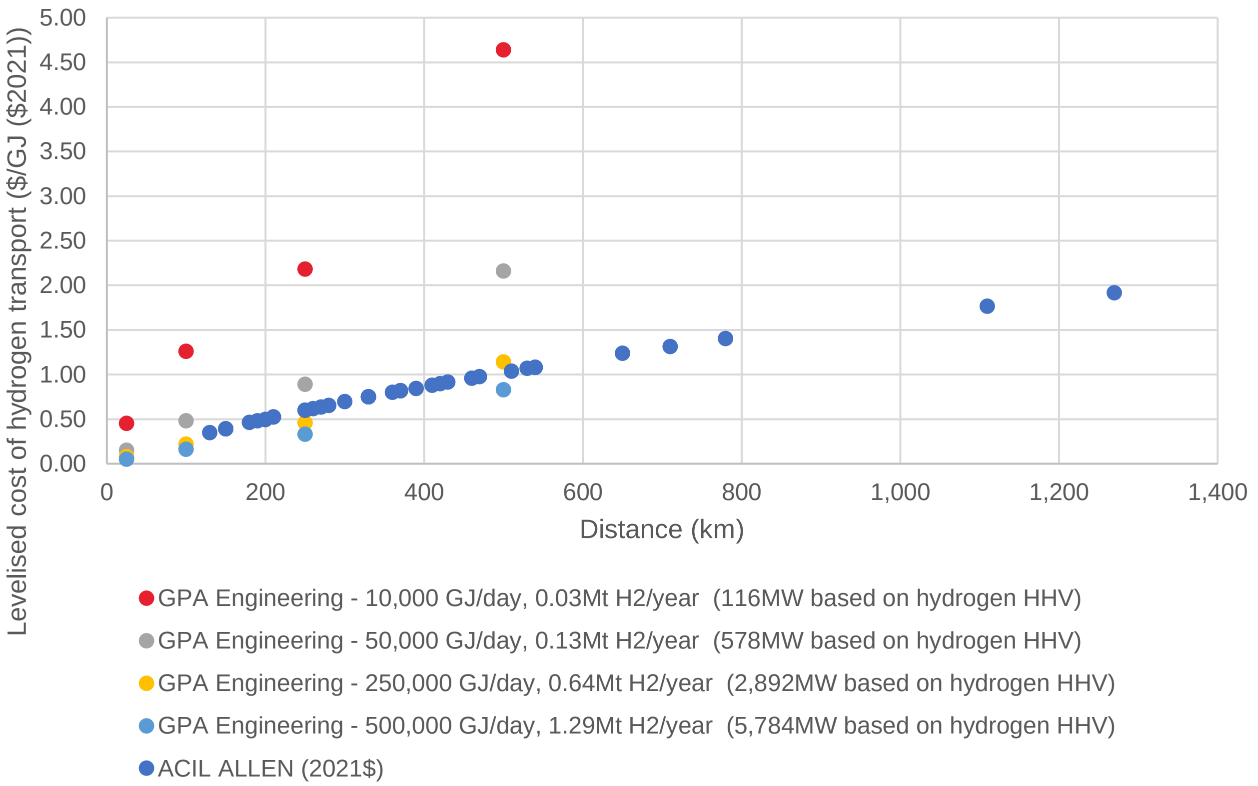


Figure 20: Hydrogen pipeline transport cost estimates (GPA Engineering cost estimates excludes compression cost and owners cost)

Source: (Australian Pipelines and Gas Association - GPA Engineering, 2021) (ACIL ALLEN, 2024)

GPA Engineering do not include owners cost associated with project execution, regulatory and approvals and land acquisition etc (Australian Pipelines and Gas Association - GPA Engineering, 2021) and ACIL ALLEN should make appropriate assumptions for these cost.

4.2.3 Storage cost estimates are materially lower than Australian industry consultant estimates

Pipeline linepack hydrogen storage costs are estimated by utilising a bottom-up US cost estimate from an academic paper (Papadias & Ahluwalia, 2021). ACIL ALLEN source Australian industry consultant estimates for pipeline installation costs (Australian Pipelines and Gas Association - GPA Engineering, 2021) and the same source should be used for hydrogen storage cost estimates. Owners costs should be added to these estimates before applying locational cost factors and infrastructure project cost escalation.

Feedback has been provided by a number of CAEPR members who have gas and hydrogen pipelines expertise that while hydrogen transport costs in (Australian Pipelines and Gas Association - GPA Engineering, 2021) are reasonable, hydrogen storage costs are understated. Their perspective is that due to hydrogen's properties thicker steel may be required than assumed in (Australian Pipelines and Gas Association - GPA Engineering, 2021) and even with thicker steel pipeline life is constrained by a number of storage cycles. While these issues are noted, the report represents the best publicly available cost estimates.

ACIL Allen has estimated the capital cost of pipeline storage as \$887/kg H_2 (\$772/kg H_2 in \$2021), which is materially lower than capex estimates calculated from Appendix 3B of (Australian Pipelines and Gas Association - GPA Engineering, 2021).

Pipeline linepack hydrogen storage could be developed as part of a REZ transport pipeline or a customer lateral pipeline by increasing pipeline diameter and/or pipeline looping (duplication). Hydrogen storage capex input assumptions could be estimated based on either option or a combination of these two options. Table 1 shows that storage capex per kg/H_2 is typically inversely related to storage volume (driven by pipeline diameter) and pipeline distance. Based on Table 1 hydrogen storage capex is estimated as:

- For a 10TJ/day customer, consistent with ACIL ALLEN's assumed customer size, lateral storage cost could be in the range of $1,793/kg H_2 (100km, 10TJ/day, 24hrs) to $2,233/kg H_2 (25km,10TJ/day, 4hrs)

- For a 50TJ/day REZ transport pipeline, consistent with pipeline throughput capacity recommended for Step Change in Section 4.2.2, storage cost is inversely related to distance. For 50TJ/ day H_2 and 24hrs of storage, capex varies from $1,046/kg H_2 (500km distance) to $1,486/kg H_2 (100km distance).

	Total capacity (TJ/day)	Flowrate (tonne/h)	Storage duration (hrs)	Storage capacity (t H^2)	Capex ($m)	Capex ($/ kg H_2)
25km	10	3	4	12	26	2,233
	10	3	12	35	75	2,129
	10	3	24	70	119	1,682
	50	15	4	59	94	1,592
	50	15	12	176	287	1,631
	50	15	24	352	635	1,802
	250	73	4	294	395	1,346
	250	73	12	881	1,268	1,439
	250	73	24	1,762	2,577	1,462
	500	147	4	587	807	1,374
	500	147	12	1,762	2,552	1,448
	500	147	24	3,524	4,908	1,393
100km	10	3	24	70	126	1,793
	50	15	24	352	524	1,486
	250	73	24	1,762	2,180	1,237
	500	147	24	3,524	5,041	1,431
250km	10	3	24	70	100	1,419
	50	15	24	352	462	1,312
	250	73	24	1,762	2,180	1,237
	500	147	24	3,524	4,357	1,236
500km	10	3	24	70	52	734
	50	15	24	352	369	1,046
	250	73	24	1,762	1,581	897
	500	147	24	3,524	3,798	1,078

Table 1: Hydrogen Pipeline linepack capex | Source: (Australian Pipelines and Gas Association - GPA Engineering, 2021)

It is noted that pg 25 of (ACIL ALLEN, 2024) state that,

"The high cost of pipeline hydrogen storage relative to underground storage makes our storage cost estimates somewhat conservative, but this is offset by our assumption that hydrogen-using plant will have a degree of demand flexibility, consistent with the expected performance of major hydrogen-using plant such as green ammonia plants."

The author's view is using hydrogen storage costs for non-geological storage is appropriate and has provided analysis to AEMO previously and FRG#8 espousing this view.

4.2.4 Locational cost factors appear not to have been applied

Technology specific locational cost factors should be applied to all hydrogen value chain components.

Renewable Energy

ACIL ALLEN does not state whether locational cost factors are applied to wind and solar generation and to ensure internal consistency, locational cost factors from the Draft 2025 IASR, which are sourced from (Aurecon, 2024A), should be used.

Hydrogen transport and storage

Locational cost factors should be applied to transport and storage cost input assumptions. While GPA Engineering installation costs estimates are based on remote Australian locations, costs primarily driven by site location and access are not, including:

- Mobilisation
- Camp and catering
- Ancillary (IT, PPE, flights, communications).
- Demobilisation

Electrolysers

Locational cost factors should also be applied electrolysers consistent with the Draft 2025 IASR, noting that locational cost factors for electrolysers are yet to be released by AEMO.

4.2.5 Cost escalation consistent with large energy infrastructure projects should be applied

ACIL ALLEN should source cost escalation figures for large energy infrastructure projects to escalate 2021 cost estimates to 2024, rather than lower CPI figures.

ACIL ALLEN escalate 2021 costs by 14.9% based on CPI. Much higher cost inflation has been experienced on major energy infrastructure projects. (Aurecon, 2024A) states that construction costs are up more than 25% over the past five years (to June 2024) vs 21.2% for CPI and has applied nominal cost escalation of 5-7.5% to 2023 estimates vs 3.8% increase in CPI for FY24 (RBA, 2024). Analysis by Oxford Economics shows that construction escalation, as measured by the Engineering Construction Implicit Price Deflator data, has exceed CPI over the past 3 years (Oxford Economics Australia, 2024A).

5. Locational factors

Matters for Consultation

- *Is it appropriate for modelling to shift to locational cost factors derived at a REZ level?*
- *Are the proposed values assigned to REZ locational cost factors reasonable (if relevant, refer to the* additional information provided in the accompanying consultant report)

5.1.1 Moving to REZ locational cost factors supported

Moving to locational cost factors at a REZ level is supported as it helps explain build cost differential seen in renewable energy projects. The methodological approach is an improvement from the previous approach and Rawlinson is the best available source for locational construction premiums.

Figure 21 shows that modelled build cost using Aurecon's REZ based locational cost factors helps explain build costs for four Queensland wind farms that reached financial close in 2024. Actual estimates may be higher than modelled due to difference in estimate boundary, for instance inclusion of transmission connection infrastructure and development/acquisition fees. The authors' 2026 Methodology Issues Paper Consultation Submission raises topography and steepness as a potential driver of higher build cost for Lotus Creek, with (Williamson, 2023) providing some insights into constructability and cost challenges with erecting large turbines on steep sites.

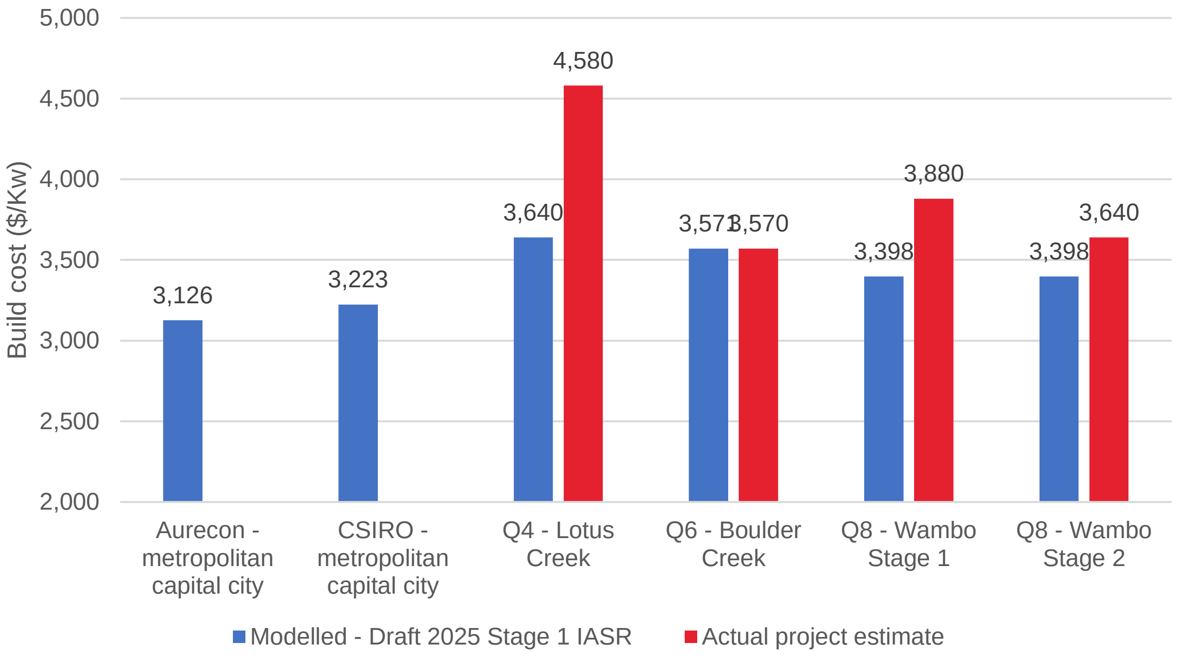


Figure 21: 2024-25 Modelled vs actual Queensland wind farms build cost estimates

Source: (Aurecon, 2024A) (CSIRO, 2024A) (Queensland Treasury, 2024)

5.1.2 Greater transparency of calculation methodology is encouraged

Assessing the proposed methodological changes is difficult as Aurecon's description of how locational factors are applied to installation is ambiguous and doesn't appear to align with figures in the Draft 2025 Stage 1 Inputs and Assumptions Workbook, which is locked/protected. A diagram or worked example showing inputs and how equipment and installation locational factors are applied would help stakeholders understand the calculation methodology.

(Aurecon, 2024A) provide locational cost factors for multiple locations within individual REZ and how they map to figures in the Draft 2025 Stage 1 Inputs and Assumptions Workbook is not disclosed.

Aurecon's estimate of onshore wind build cost is $3,126/kW, while for CSIRO it is $3,223/kW, which flows through into the Draft 2025 Stage 1 Inputs and Assumptions Workbook (Australian Energy Market Operator, 2024).

5.1.3 Equipment cost factor should be based on distance to ports with existing wind turbine import capability

Basing equipment cost factors on distance from capital cities most impact Queensland REZ due to the large geographic expanse of the state, with equipment cost factors of up to 1.15. Given that wind turbines have been imported through ports in Brisbane, Gladstone, Townsville and Cairns these ports are recommended to be used to calculate distances for equipment costs factors for QLD REZ. For other states, ports closer to REZ where wind turbines have been imported should be considered for instance Port of Newcastle for New England REZ.

5.1.4 Split of equipment and installation should be technology specific and based on projections from CSIRO GenCosts

Per Figure 22 proportion of build cost related to equipment, install and land and development is technology specific and varies over time, particularly as each of these components is projected based on different learning rates. CSIRO projects build cost by component, however it does not disclose this information. Improving the transparency of CSIRO GenCost, including by providing a component breakdown of build cost projections is discussed in the authors Draft 2024-25 CSIRO GenCost Consultation submission.

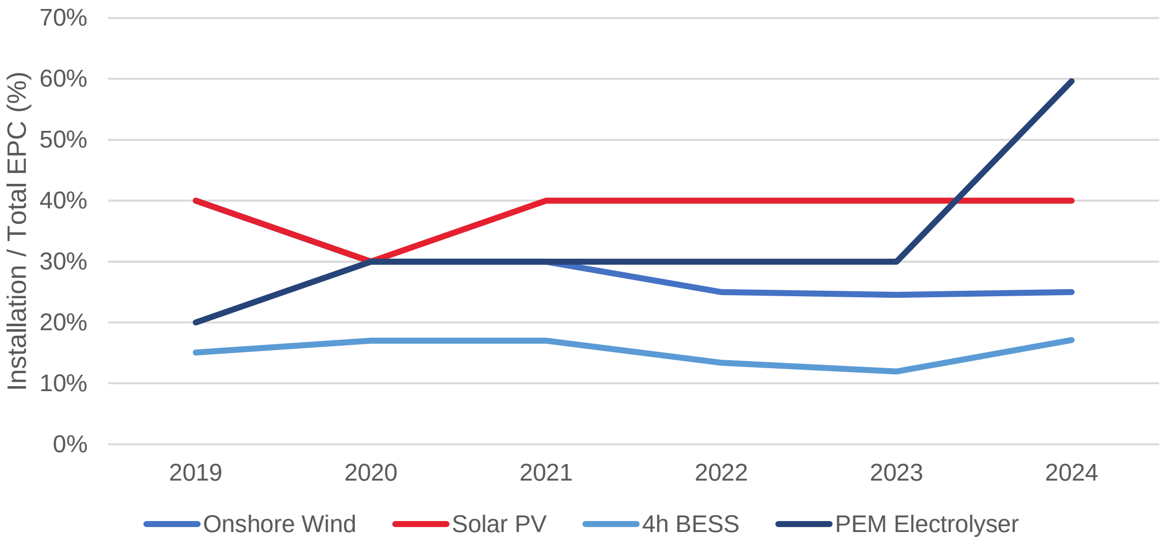


Figure 22: Installation cost as a proportion of EPC by technology over time | Source: (Aurecon, 2024A) (Aurecon, 2024B), (Aurecon, 2022B), (Aurecon, 2022A) (Aurecon, 2021) (Aurecon, 2019)

6. Demand Side Participation

Matters for Consultation

- *Are the long-term DSP settings, grown to meet a target level by scenario informed by international review, suitable for use in AEMO's planning publications?*

6.1 NEM DSP study recommended for current load

The bottom-up study of demand response potential for Europe (siapartners, 2014) provides a suitable methodology for assessing demand response for current loads. However, per the following section it is not a suitable source as:

- It is dated and based on markets with limited rooftop solar PV adoption
- The composition of NEM load is different to Europe

Demand response potential for future decarbonisation loads, such as alumina refineries and the electricity requirement for green iron is uncertain. AEMO is an associated parent of HILT CRC (HILT CRC, 2025) and we encourage them to consider sponsoring a study investigating future decarbonisation load demand flexibility/ demand response that could be used as input into the 2028 ISP.

6.2 Sources for DSP assumptions are dated and based on markets with limited rooftop solar PV adoption

The sources for assumptions are dates and as such are based on systems with little CER penetration:

- United States - (The Brattle Group, Freeman, Sullivan & Co, Global Energy Parnters, 2009)
- Europe - (siapartners, 2014)

These times and markets are not comparable with the Australian energy system which has a higher penetration of rooftop solar PV and thus electricity consumers are likely to have already changed their load shape, reducing the potential for demand response.

It is noted that The Brattle Group prepared a report titled *International Review of Demand Response Mechanisms in Wholesale Markets* for the Australian Energy Market Commission, though it doesn't appear to provide any insights as to future DSP potential (The Brattle Group, 2019)

6.3 DSP assumptions for current load should be informed by the composition of NEM loads not other markets

The DSP assumptions are informed by a bottom-up study of European demand response potential by (siapartners, 2014). The composition of NEM demand is likely to be very different with a relative large capacity of aluminium smelters, whose demand response capability is well understood in the market. Climate difference between the NEM and Europe could also have an influence on the potential capacity and composition of demand response, eg. space heating/cooling and refrigeration.

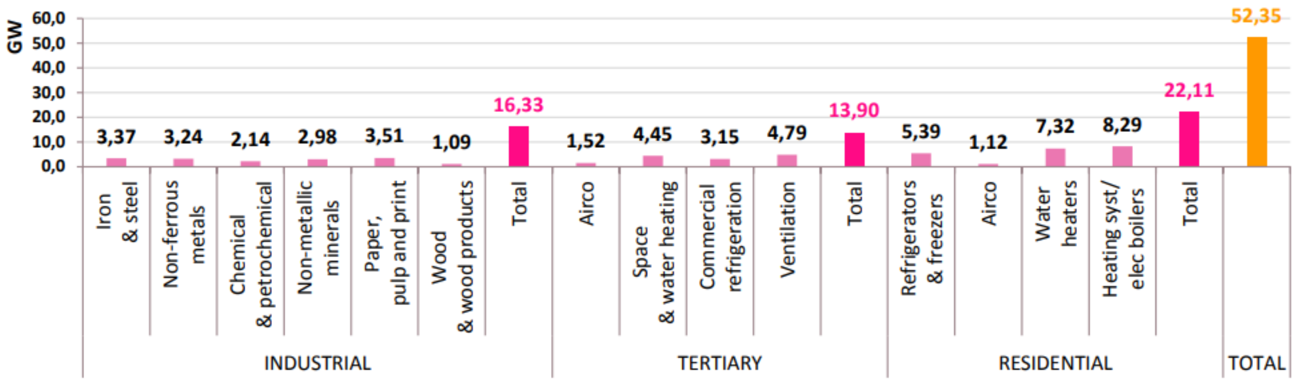


Figure 23: Europe – Composition of Demand Response potential | Source: (siapartners, 2014)

6.4 DSP assumptions for future decarbonisation load is likely to be different than current load

Per the author's submission to a number of AEMO Consultation processes including (Fletcher & Nguyen, 2024 Electricity Demand Forecasting Methodology Consultation, 2024B) the flexibility of future decarbonisation loads is likely to be industry/process specific. Excluding green hydrogen, the two largest potential decarbonisation loads in the NEM are alumina refineries and the electricity requirement for green iron and green steel (eg. Electric arc furnace), which per Section 4.2.1 may have different DSP potential.

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