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2026 ISP Methodology Consultation – Issues Paper

Submission to AEMO, 22 November 2024

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 analyzing 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 and Huyen Nguyen, who are Industry Adjunct Research Fellows at CAEEPR. The views expressed in this submission are entirely the authors' and are not reflective of CAEEPR.

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Other issue – improving industrial demand side modelling

Importance of developing models and data inputs for sector coupling of industrial decarbonisation load

The authors Draft 2024 ISP Consultation Submission recommended that for the 2026 ISP that appropriate models and data inputs for sector coupling of industrial decarbonisation load be developed. Particularly as sector coupling involving industrial load has been comparatively underdeveloped and in the 2024 ISP Step Change scenario industrial decarbonisation load is assumed to grows to 20% of NEM demand by 2050.

AEMO's efforts to improve the modelling of hydrogen within the input models (multi-sector modelling and ACIL ALLEN hydrogen modelling) and in the 2026 ISP are commended, however clarity around how the input models interact and will be used in the 2026 ISP is encouraged.

We acknowledge that the integration of demand side flexibility, via co-optimisation modelling would be highly complex and the incidence or predictability of future loads and associated demand-side flexibility of those loads is highly uncertain. However substantial industrial decarbonisation loads are included in the ISP and assumptions around the degree of flexibility or inflexibility of these loads could materially impact the ODP.

A modelling methodology that allows a more simplistic representation of demand flexibility for major current and future potential electrification loads would represent a suitable development for the 2026 ISP. For major current and future forecast industrial load, demand response could be modelled based on assumptions such as demand response price, duration constraints, ramping constraints and minimum monthly and/or annual load factors based on industry. Pg 62 of (Fletcher, et al., 2023) discusses the concept of a levelized cost of load curtailment, which should vary by industry and for green ammonia could be materially less than $300/MWh minimum price trigger in the Demand side participation forecast methodology. Discussion with NZ energy market analysts also reveal that the demand response price of the NZAS demand response contract (Tio Tinto, 2024) is also materially lower than $300/MWh.

It is noted that this recommendation aligns with the authors Electricity Demand Forecasting Methodology Consultation Submission, that recommends that large industrial loads are disaggregated into key major industries where current or future forecast load is material and flexibility input assumptions are or may become available in the future.

Responses to Consultation Questions

1. Do you consider that the proposal to develop a gas supply expansion model appropriately addresses the action in the Energy Ministers' response to the Review of the ISP for additional gas analysis to be incorporated in the ISP? If yes, why? If not, why not, and how could this action otherwise be achieved?

No comment.

2. Do you agree with the proposal for AEMO to develop at least one gas development projection per ISP scenario, and apply the projection as an input to the capacity outlook model? If yes, why? If not, what method would you recommend for the inclusion of gas development projections in the ISP?

No comment.

3. What alternative approaches should AEMO consider for enhancing the incorporation of gas in the ISP to address the action in the Energy Ministers' response?

No comment.

4. What improvements could be made to AEMO's proposed approach to increase consideration of gas availability, considering gas transportation and storage capacity?

No comment.

5. What improvements could be made to AEMO's proposed approach in its capacity outlook models to improve the representation of fuel usage for gas generation, particularly for mid-merit capacity?

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No comment.

6. **What are your views on AEMO's proposed inclusion of distribution network capabilities and their impact on CER within the ISP model? What further enhancements could be made?**

No comment.

7. **Do you agree with AEMO's proposals to improve its hydrogen electrolyser load modelling, or have further enhancements to suggest? Please provide any supporting evidence.**

AEMO's efforts to improve the modelling of hydrogen in the ISP models and consultant inputs models are welcomed.

Further clarity on disaggregation of hydrogen demand recommended

Per the authors 2024 Electricity Demand Forecasting Methodology Consultation Submission domestic demand is recommended to be split at a minimum between transport, green ammonia, green fuels (methanol and e-fuels), green iron, alumina calcination and cement. These use cases have different marginal abatement costs for using hydrogen, different potential demand flexibility and the industrial process use cases have different electricity requirements. This split is on the assumption that ISP consultant input models forecast such hydrogen demand eventuating.

It is noted that the ACIL ALLEN's draft Renewable gas outputs presented at FRG#8 contains hydrogen use cases classifications which have the potential to confuse stakeholders. The presentation includes an export use case, while the green ammonia and methanol use case appears to also include export demand as it is calculated based on an assumed percentage of global demand. It is recommended that any export green ammonia and methanol use case demand is appropriately named.

No reasonable basis for applying minimum utilisation factors

Applying minimum utilisation factors developed for electrolyser operation is not recommended. Provided daily balancing of production requirements is used AEMO's approach to modelling electrolyser operation is reasonable for use cases with a flat hydrogen demand profile. The trend of decreasing electrolyser load factors within the 2024 ISP, which is shown in the authors 2024 Draft 2024 ISP Consultation Submission, is driven by declining electrolyser capex and is consistent with a range of techno-economic analysis (CEFC & Advisian, 2021; Fletcher, et al., 2023). Applying minimum utilisation factors would be inconsistent with the approach taken in the proposed ACIL ALLEN hydrogen modelling.

Improving electrolyser cost assumptions

Evidence has emerged that electrolyser capex has been materially underestimated in public estimates such as the CSIRO GenCosts (2023: $A1,919/kw alkaline), with a key driver the insufficient appreciation of the full scope of system costs.

I. BNEF: In June 2024, BNEF increased its 2023 electrolyser system cost estimate to US$2,000-US$3,000/kw (Bhavnagri, 2024) (Tengler, 2024). BNEF acknowledged that many public estimates, including their own had underestimated capex by 50-70%. The key root causes identified by BNEF were:
    - Developers underestimating indirect costs (infrastructure, storage, compression, contingencies etc). While we are the view that hydrogen storage should be modelled separately, storage and compression accounted for less than ~US$300/kw of the capex estimate
    - Electrolyser manufacturing capacity exists only on paper and is mostly in China. Combined with inadequate workforce, suppliers of stack subcomponents such as catalysts and membranes aren't expanding as quickly as makers of the stacks themselves, restricting effective manufacturing capacity
    - Utilities and labour costs are higher for Western manufacturers

II. IEA: In October 2024 IEA (IEA, 2024) revised 2023 electrolyser and 2030 capex projections revised upward. For the 2023 estimate, *based on newly available data from more advanced projects and to include contingency costs, resulting in an increase of about 20% (BNEF 2024, TNO 2024).*

Global Hydrogen Review – 2023	Global Hydrogen Review - 2024

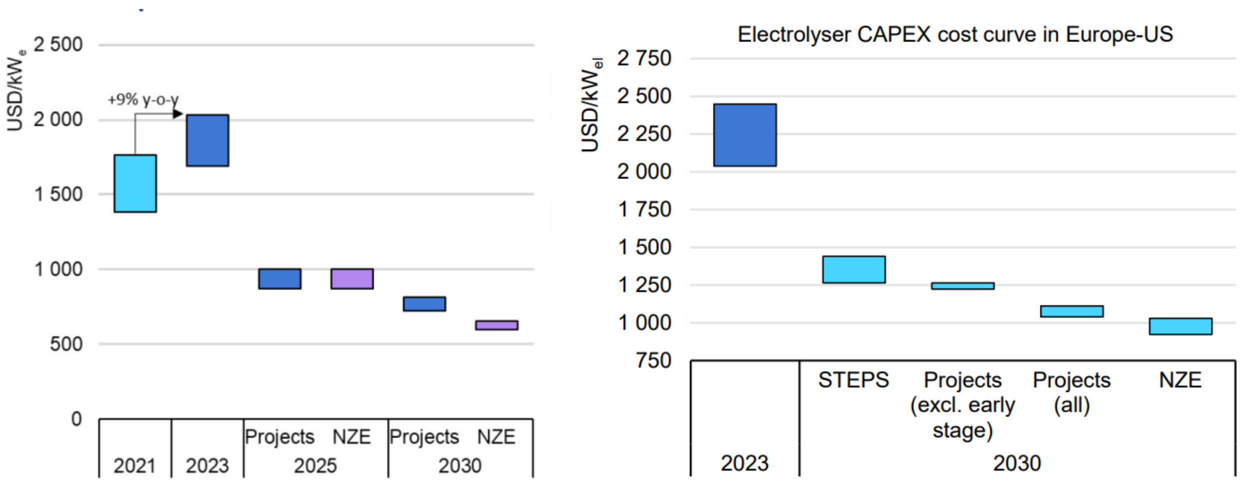

Figure 1: IEA electrolyser capex estimates

III. Ramboll: in November 2023 Ramboll, a global architecture, engineering, and consultancy company, released a whitepaper on achieving affordable green hydrogen production plants (Ramboll, 2023). Ramboll has worked on more than 30 power-to-X projects across the US and EU and the whitepaper highlights that public estimates of hydrogen projects capex were 2-3x too low and discusses the key driver of this bias. They find that electrolyser stacks represent a small portion of hydrogen project costs, with other components such as BOP, offsites & utilities and construction indirect representing a larger portion of capex.

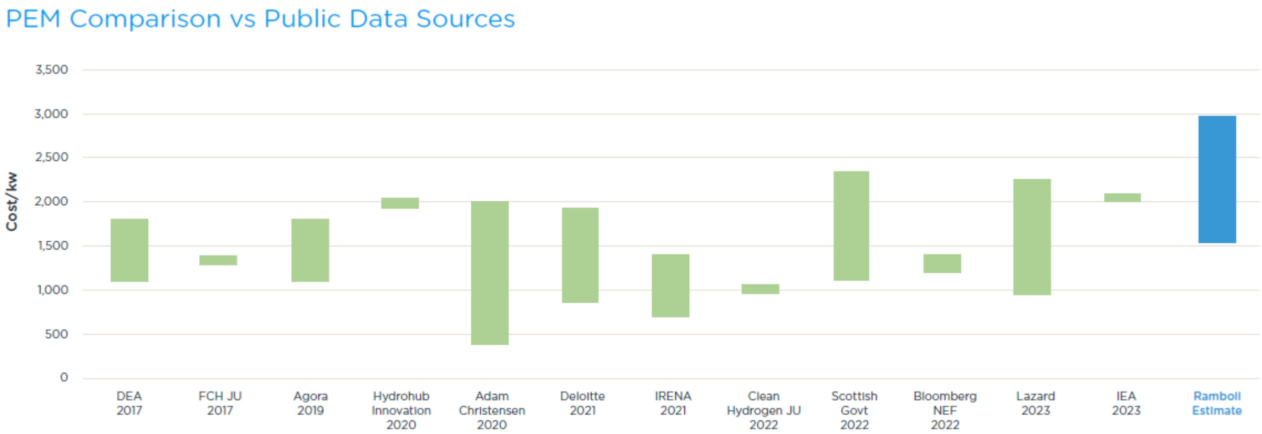

Figure 2: Ramboll estimates for PEM electrolysers hydrogen production plant CAPEX from estimates of system size 10MW - 1GW

<u>If balancing assumption approach used, daily balancing of electrolyser load supported</u>

Rather than using a balancing assumption we recommend including the hydrogen storage cost in the Single Step Long Term model combined with an assumed flat hydrogen demand profile to optimise electrolyser capacity. This would be consistent with the approach taken in the proposed ACIL ALLEN hydrogen modelling.

If a balancing assumption were used, daily is supported. Greater transparency around modelled electrolyser load factors in the ISP is encouraged, including a comparison to islanded electolyser load factors from the ACIL ALLEN hydrogen modelling.

Ideally for hydrogen demand relating to green ammonia the potential partial flexibility of this production process would be incorporated into the ISP consistent with the authors 2024 Draft 2024 ISP Consultation Submission. However, integrating this partial flexibility into the ISP modelling is technically challenging and it is not clear that green ammonia demand will be meaningful in the 2026 ISP Step Change and Progressive Change scenarios.

Assuming hydrogen use cases have a fixed demand profile, daily balancing implies non-geological hydrogen storage, which is consistent with proposed NEM hydrogen projects. A monthly balancing period is not prudent as it implies low-cost geological hydrogen storage. Geological hydrogen storage options are location dependent and subject to cycling constraints and technical risks. In addition, most geological hydrogen storage options are yet to be deployed commercially.

8. What are your views on AEMO's proposal to test previously-actionable projects for actionability at the project proponent's timing within the actionable window, and at a later re-start timing?

No comment.

9. Do you agree with AEMO's approach to model storage devices with headroom and footroom energy reserves and imperfect energy targets in the time-sequential modelling component? What improvements should be made to model energy storage limits to better reflect actual behaviour and address issues of 'perfect foresight'? Please provide any supporting evidence.

<u>Development of feedback loop to capacity outlook model encouraged if additional cost of imperfect foresight to ODP demonstrated</u>

Page 57 of the 2023 ISP methodology states that the intention of the time sequential model is to "validate the outcomes of the capacity outlook model, and feeds information back into it". While it is acknowledged that any potential cost of imperfect foresight would be reflected in the cost benefits analysis, one solution often put forward to mitigate imperfect foresight is additional gas generation capacity and gas generation volumes. Assuming that the emission budget is a binding constraint in the capacity outlook model, additional gas generation volume in the time sequential model could breach this constraint and as a result the relevant ISP scenario may not be consistent with NER 5.22.3 (b). In the case that imperfect foresight results in an additional GPG, AEMO are encouraged to consider this in the gas development projection for the relevant scenario.

<u>Refinement of approach that incorporates aspect of both AEMO proposals recommended</u>

A key aspect of imperfect foresight that requires further attention is weather forecasting errors as weather forecasts can be highly uncertain and inaccurate beyond a few days. This can cause longer duration storage to completely run out during a dunkelflaute and leading to unserved energy or excessive gas generation. Powerlink Queensland develops a novel approach to exploring the potential impact of imperfect weather forecasting in (Boegheim, et al., 2024). Further details of this research are available from Powerlink Queensland and we encourage AEMO to engage with Powerlink regarding this research and the potential for collaboration in implementing this approach in the 2026 ISP.

(Boegheim, et al., 2024) explores the impacts of imperfect foresight through a ST model of a future QLD electricity system (2024 ISP, 2035 Step Change) based on FY24 weather forecasts and actuals. Storage dispatch is based on a rolling 10 day time horizon, with 6hr binding and 9.75 day non-binding. Forecast methods include perfect foresight, a single deterministic forecast and an ensemble/stochastic forecast, which minimises expected cost across a range of possible outcomes. Limited details are available, but the stochastic forecast appears to have lower USE than the deterministic forecast.

Such a modelling approach could be used to explore:

- What if any additional gas peaking generation capacity was required to partially mitigate the risk of imperfect weather forecasting and any additional gas generation volumes, for deterministic and stochastic forecasts
- As a simpler alternative to stochastic forecasts, whether and what level of minimum storage target could be applied in the time sequential model, that could inform footroom assumptions in the capacity outlook model. AEMO is encouraged to explore whether such assumptions could be time varying in order to not unnecessarily impact storage duration in periods where imperfect foresight does not represent a cost to the energy system.

- Other potential methods for mitigating imperfect foresight, including improved forecasting
- By examining dispatch using historical (imperfect) forecasts, the lookahead in the ST can be reduced to replicate a similar amount of unserved energy. This dispatch outcome is then used to inform capacity addition in the LT.

Testing of multiple ISP scenarios and sensitivities encouraged to explore impact of imperfect foresight

Exploring the impact of imperfect foresight on multiple scenarios and potentially sensitivities lower volumes of CER could provide more meaningful analysis on the potential materiality of imperfect foresight. The limited impact of imperfect foresight analysis in the 2024 ISP Step Change scenario could be the result of an over supply of storage and renewables driven by policy assumptions, CER and monthly balancing assumption for electrolysers. If Step Change were selected as the most likely scenario in the 2026 ISP then Progressive Change is recommended to be tested, with results presented also. Potential sensitivities could have lower CER orchestration assumptions.

There is limited literature available on the impact of imperfect foresight on energy system costs, however (Salmon & Bañares-Alcántara, 2023) demonstrates the potential impact on islanded green ammonia production. The paper uses a model predictive control (MPC) approach to shows how a green ammonia plant can be operated with imperfect foresight, using a time horizon/ lookaheads of 14, 24 and 48hrs. The paper shows that the additional cost penalty for imperfect foresight with low ammonia plant flexibility could be greater than 10%.

10. What risks should AEMO consider when assessing how inverter-based resources (IBR) can complement synchronous machines in providing system strength and inertia?

No comment.

11. Do you agree with AEMO's approach for uplifting cost and modelling representation for system security services in the ISP? If not, what alternative methods would you recommend? Please provide any supporting evidence.

No comment.

12. Do you agree with AEMO's proposal to model more than two wind resource quality tranches for geographically large REZs? If not, what alternatives should AEMO consider?

AEMO's continued focus on improving the accuracy of wind resource modelling is welcomed. In addition to considering additional wind resource quality tranches for geographically large REZ, we encourage AEMO to consider the following issues relating to wind resource modelling that could have a more material impact on ISP outcomes:

- Incorporating proposed wind project data (eg. https://renewmap.com.au/) into its wind resource assessment
- Incorporating external wake losses into wind resource quality modelling
- Impact of topography on wind project balance of plant

Insufficient detail provided to assess AEMO's proposal
While wind projects tend to be grouped around key transmission network infrastructure and geographic features (eg. ridges, gaps) within REZ, such that multiple wind resource quality tranches could be useful, insufficient detail has been provided to assess the merits of AEMO's proposal. Could a similar modelling outcome be achieved by averaging across different locations within a REZ? AEMO is encouraged to consider whether the potential impact of the proposal is material enough to justify the change, including:

- How many REZ are classified as geographically large REZ and are large capacities of wind developed in these REZ in the Step Change and Progressive Change scenario?
- Is there a material differences in capacity factors between potential resource quality tranche locations in proposed geographically large REZ?
- Would having more wind resource quality tranches result in a material difference in optimal development path and in particular residual demand/ gas generation?

- Is there actual rather than simulated wind generation data showing an inter REZ difference in seasonal generation profile?
  - Is there actual rather than simulated wind generation data showing a difference in correlation with system wind generation during wind droughts?
  - Are wind resource quality tranches linked to specific transmission augmentation options within REZ?
- What is the materiality of this issue compared to other wind resource modelling issues identified such as incorporating proposed wind project data into wind resource assessment, incorporation of external wake losses or site steepness impacting balance of plant capex?

<u>Incorporating proposed wind project data into its wind resource assessment</u>

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. AEMO should 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 3, 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 3,500MW compares to the 7,550MW of wind assumed to be developed by 2050 under the 2022 ISP Green Energy Exports scenario.

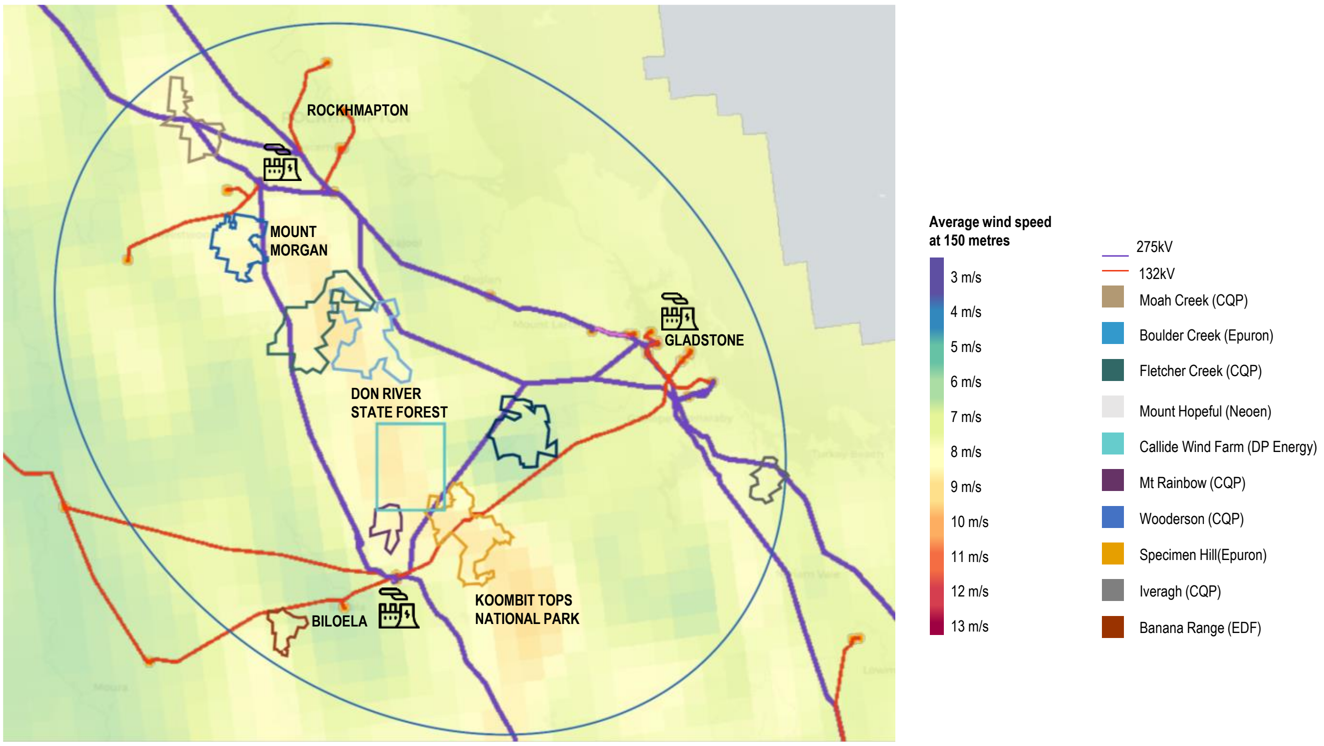

Figure 3 - Fitzroy REZ Wind Project Footprints – Source: National Map and proponent websites (August 2021)

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 was undertaken with engagement with a Technical Working Group that comprised 25 member organisations including all Queensland government owned energy corporations. 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.

Incorporation of external wake losses

As greater capacity of wind resources is developed within a REZ the impacts of external wake losses (the effect of turbines from neighbouring wind farms) is likely to increase. This is particularly the case as wind projects tend to be grouped around network connection points and geographic features. As AEMO's methodology calibrates generic new wind farms candidate generation to historical actual wind farm generation it may not capture a potential trend of rising external wake losses as wind REZ resources are built out. External wake losses also have the potential to impact the development of wind resources down prevailing wind of existing wind farms, reducing developable wind resources within a REZ.

2023 IASR pg 119 - *AEMO uses resource-to-power conversion models to estimate VRE generation as a function of meteorological inputs, and calibrates this to historical production levels for existing wind farms. Wind generation availability modelling, for example, uses an empirical machine learning model to estimate generator output as a function of wind speed and temperature, capturing the impacts of high wind and high temperature events observed in historical data. Participant information on generator capabilities during summer peak demand temperatures are overlayed on top of these models.*

2023 ISP Methodology pg *28 - AEMO sets the tranches using a calibration process that aligns the wind resource quality with historical performance. This involves adjusting the settings of the first and second tranches, to align as best as possible with historical wind generation profiles seen in the NEM*

While external wake losses can impact existing and new wind farms, it would be challenging to incorporate such losses to existing wind farms over time. A modelling simplification could be to recognise external wake loss impact for new and existing wind farms as a higher external wake loss on the lower quality wind resource tranche.

AEMO are encouraged to consider the following literature which demonstrates the potential materiality of external wake losses.

- (Stoelinga, Sanchez-Gomez, Poulos, & Crescenti, 2022) includes an assessment of external wake losses for two case study onshore wind farms who have been impacted by new wind farm development. For case study one a new wind farm built 13km away resulted in a SCADA estimated annual average external wake losses of 3.6% for an existing wind farm. For Case Study two a new wind farm built 5km away resulted in an external wake loss of 23.8% of gross energy for an existing wind farm, based on a wind direction that was down-wind from the new wind farm.

- Although offshore wind is not a focus as it development in the ISP is based on a Victorian Government policy assumption, wake induced losses for offshore wind are higher than onshore wind (Pryor & Barthelmie, 2024).

Impact of topography on wind project balance of plant

The Queensland Government Budget was released in June 2024 (Queensland Treasury, 2024) and contains budgeted capex estimates for various QLD wind farms, BESS and OCGT to be 100% owned by Queensland Government owned electricity generation businesses or to be delivered as part of joint ventures with the private sector. The capex for these wind farms is materially higher than 2023-24 CSIRO GenCost figure of $3.04m/MW for 2023 even after applying the locational cost factors listed on pg176-181 of Aurecon's 2023 Cost and Technical Parameters Review):

- Lotus Creek (100%, 285MW) - $1,305.4m, $4.58m/MW (pg 12, pg 46)
- Boulder Creek (50%, 228MW) - $406.9m, $3.57m/MW (pg 12, pg 46)
- Wambo Stage 1 (50% 252MW) - $488.7m, $3.88m/MW (pg 12, pg 50)
- Wambo Stage 2 (50% 254MW) - $462.2m, $3.64m/MW (pg 12, pg 50)

One factor that could be contributing to the higher capex for Lotus Creek is higher balance of plant driven by steep topography. Topography of wind farm sites varies across the NEM with some flat, such as Golden Plains (Victoria), while others are located on ridges. Steeper terrain and associated geotechnical conditions could lead to higher balance of plant including for steep roads and turbine foundations. Steeper terrain could be incorporated into the wind resource quality assessment via a measure such as slope. While it could be challenging to estimate the impact of steepness on wind farm balance of plant or as an adjustment to wind farm capacity factors, a REZ steepness ratings or similar term could be included in the REZ scorecards.

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