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Mr Daniel Westerman
Chief Executive Officer
Australian Energy Market Operator

Lodged by email: ISP@aemo.com.au

Dear Mr Westerman

Submission to Draft 2024 Integrated System Plan

The Centre for Independent Studies (CIS) appreciates the opportunity to provide a submission to the Australian Energy Market Operator.

The CIS is a leading independent public policy think tank in Australia. It has been a strong advocate for free markets and limited government for more than 40 years. The CIS is independent and non-partisan in both its funding and research, does no commissioned research nor takes any government money to support its public policy work.

We are deeply concerned that the ISP that is presented in this Draft ISP is not a fit analysis to support AEMO's most important public policy and regulatory functions. The first is to inform public policy regarding the choice and mix of technologies underpinning Australia's future electricity system, and the second is to develop the Optimal Development Path (ODP) and give approval for major transmission investments.

AEMO has emphasised the importance of clearly communicating the purpose of the ISP and how the analysis is performed. Yet AEMO erroneously claims that the ISP addresses total system costs and finds the least cost pathway for the energy transition. Distributed PV, distribution network upgrades, and Consumer Energy Resources are among the largest, most critical components of the modelled energy system, and are ignored in the ISP. Numerous other elements of the energy system — including subsidies for existing coal plants, and state-government mandated transmission projects — are also omitted. If AEMO is implying that it is not its job to factor in all these costs, then it should publicly clarify that the Optimal Development Path does not represent the "least cost pathway," but is only the least cost among a limited number of options that is not representative of the full suite of pathways available to policymakers.

Since coal plants are not considered a long-term option because of emissions targets, and nuclear energy is off the table because of federal legislation, the ISP has effectively omitted the modelling of the only credible alternatives to renewables, storage and gas that could be used as a baseline for comparison.

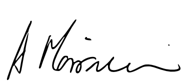
There is a circular logic in the way the ISP is represented by AEMO and the federal Energy Minister. On the one hand, it is used to inform policymakers of the alleged least cost option for building transmission for the grid. On the other hand, its analysis factors in the decisions of those same policymakers in determining the least cost option. Ministers can therefore point to the ISP as justification for why their priority projects and economic incentives are the least cost option for the grid — despite the fact that the ISP does not test those policy decisions in any way but rather takes them as a given. The result is that consumers are left paying for a more expensive grid because the full suite of options available to policymakers has not been tested.

The only way to break this cycle is for AEMO to either include in the ISP's total system costs the full suite of costs listed above and therefore properly test the full range of options available to policymakers, or else make clear that its role is to only look at transmission, not the whole system, and let the government create or appoint another body to determine whole-of-system costs.

The ISP also has a crucial role to play with regards to the Feedback Loop. We emphasise that the passing of Feedback Loop notices for both HumeLink and VNI West based on the unscrutinised draft ISP is both in breach of the National Electricity Rules, and also a breach of public trust that due process and consultations will be adhered to in the energy transition. The minimum mandated consultation under NER 5.22.15(c) is a 30 day consultation, as specified in the Forecasting Best Practice Guidelines. This is the only opportunity that the public has to scrutinise the optimal development path prior to it being used for the Feedback Loop, which is the final and only protection for consumers from over-investment in transmission.

We further find that the ISP and the analysis in Appendix 6 does not support the advancement of HumeLink according to the schedule proposed by TransGrid, and the modelling of benefits associated with a substantially different timeline is grossly deceptive. Other inconsistencies and omissions in the cost benefit analysis cast doubt on the objectivity of the analysis. The Feedback Loop Notices for HumeLink and VNI west, and the Update Notice to the 2022 ISP should be recalled and proper consultation concluded on the draft, so that the public scrutiny of the Draft ISP can be used and the final 2024 ISP suitably amended before significant costs are passed on to consumers.

Yours sincerely



Aidan Morrison

Director

Centre for Independent Studies Energy Program

1. Sunk costs not included

Snowy 2.0 (including delays) not accounted for

When first announced in 2017, the Snowy 2.0 pumped hydro project had an estimated cost of $2 billion and was expected to deliver its first power in 2021.[1] As of December 2023, the costs have blown out to $12 billion[2] and it is now expected to be first delivering power in 2028,[3] though doubts have been raised over even this revised timeline.[4]

In the 2022 ISP, potential schedule slippage for Snowy 2.0 was not modelled, despite AEMO being aware of "a potential delay to the delivery schedule of Snowy 2.0, which would reduce the reserves available to New South Wales consumers when HumeLink is commissioned."[5] This means HumeLink was made actionable with the "latest delivery date" July 2026[6] despite a strong possibility (which eventuated) that it would not be able to serve one of its primary functions (connecting Snowy 2.0 to the grid) for another few years.

AEMO pushed HumeLink over the line into "actionable" largely by relying on its role of ensuring grid reliability, if Bayswater Power Station were to close earlier than projected. It is unclear why AEMO would model the benefits of HumeLink under different coal plant shutdown scenarios and not model the benefits of HumeLink under different Snowy 2.0 delivery timelines — which are arguably much more relevant. AEMO stated this lack of modelling was because HumeLink will "still be delivering its market benefits", such as improving "access for consumers to stored energy across the entire Snowy scheme, to renewable energy in southern New South Wales, and to imports from South Australia (via Project EnergyConnect) and Victoria (via VNI and VNI West)."[7] Yet there is no modelling in the 2022 CBA to confirm the quantitative difference to net market benefits between HumeLink being actionable when Snowy 2.0 is late versus on time.

As Panos Priftakis, Head of Wholesale Regulation at Snowy Hydro, pointed out: "AEMO is effectively treating Snowy 2.0 as a sunk-cost," sending "all the wrong investment signals".[8] $5 billion has now been sunk in Snowy 2.0, but $7 billion is still yet to be spent and another roughly $10 billion on transmission.[9]

Despite being flagged in the 2022 ISP consultation, this questionable treatment of Snowy 2.0 remains in the Draft 2024 ISP, which "did not include an analysis of delayed Snowy 2.0 delivery"

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[1] Tom Lowrey, 2023. Snowy Hydro expansion hits reset button as costs blow out to $12 billion. ABC.
[2] Ted Woodley, 2023. Consumers have been sold a pup on Snowy 2.0's exorbitant 'plug'. The Australian.
[3] Tom Lowrey, 2023. Snowy Hydro expansion hits reset button as costs blow out to $12 billion. ABC.
[4] Ted Woodley, 2023. Government snowed again, if it believes Snowy 2.0 is a commercial investment. Renew Economy.
[5] 2022 ISP, p 88.
[6] 2022 ISP, p 13.
[7] 2022 ISP, p 88.
[8] Panos Priftakis, 2022. Addendum to the Draft 2022 ISP Submission. Snowy Hydro.
[9] Sophie Vorrath, 2023. "Australia's biggest engineering debacle:" Snowy 2.0 costs double again to reported $12bn.

because AEMO considers it to be “a committed project that comes in 2028”.[10] The failure to consider that Snowy 2.0 could still be cancelled, and $6 billion of capital investment diverted to a more efficient purpose, is a deep flaw of the ISP.

We submit that AEMO should commit to fixing this omission in the Final 2024 ISP by conducting sensitivity testing around delays in Snowy 2.0’s delivery of (for example) 2 years, 5 years and 8 years, as well as testing the impact of this project not being completed. This would help ensure that the ODP takes into account whether continuing with building Snowy 2.0 and the required transmission (including HumeLink) lowers the overall cost of the system compared to stopping the projects.

Committed and anticipated transmission not included

The 2024 ISP includes committed and anticipated transmission projects in the modelling for “all development paths, scenarios and sensitivities”, effectively treating them as sunk costs, with no alternatives being considered.[11]

The NER states that a TNSP must perform an RIT-T on “actionable” projects under the ISP.[12] However, recent rule changes allowing this cost benefit analysis to be sidestepped by state governments implementing entirely different processes mean that committed and anticipated projects are included in the 2024 ISP without proper scrutiny.

For example, the NSW Government’s new Transmission Efficiency Test allows transmission projects to proceed without going through the RIT-T,[13] instead being subjected by the AER to the much weaker test of whether the operator’s proposed capital costs for development and construction are “prudent, efficient and reasonable”.[14] Similarly, the amendment made in 2020 to the National Electricity (Victoria) Act 2005 allows the Victorian Minister to bypass the RIT-T and approve augmentations of the transmission system by specifying an alternative test.[15] This essentially allows boondoggles to be built as long as they are built efficiently.

One of the clearest examples of this is the Central-West Orana REZ Transmission Link. The project was deemed actionable in the 2020 ISP and was expected to be completed by Transgrid in 2024-25.[16] Under the NER, Transgrid was required to complete the PADR by the date set out

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[10] Saliw Cleto, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 57:52. AEMO Stakeholder Relations, YouTube.
[11] Draft 2024 ISP, p 56.
[12] National Electricity Rules Version 204. 5.16A.4 Regulatory investment test for transmission procedures.
[13] NSW Department of Planning, Industry and Environment, 2020. NSW Electricity Infrastructure Roadmap.
[14] Australian Energy Regulator, 2022. Revenue determination guideline for NSW contestable network projects.
[15] National Electricity (Victoria) Amendment Act 2020. 16Y Order modifying regulatory arrangements relating to declared transmission system augmentations and related services. 2 (d).
[16] 2020 ISP, p 84, 87.

in the ISP:[17] December 2021.[18] The PADR had to include a statement and accompanying detailed analysis showing that the project satisfied the RIT-T.[19] But this never happened.

Instead, the NSW Government, acting through EnergyCo, took over responsibility for the Central-West Orana REZ Transmission Link from Transgrid in January 2022.[20] Responsibility for regulatory approval of cost recovery was shifted from the AER's RIT-T to the NSW Government's Transmission Efficiency Test.[21]

In the Draft 2024 ISP, the project is now considered "anticipated", effectively treating it as a sunk cost despite the fact that it never passed the RIT-T.[22] This means electricity consumers will be left to foot the bill on this transmission project and any others that use the much weaker Transmission Efficiency Test instead of the RIT-T,[23] with no consideration given as to whether these projects are ultimately in the long-term interest of consumers.

We submit that AEMO should not treat committed and anticipated projects as sunk costs by including them in all development paths, scenarios and sensitivities until they have gone through the RIT-T process — regardless of whether they are declared by states as priority projects. They should instead be tested as actionable and future projects are tested; with different combinations across different CDPs. This will ensure:

- the ISP can properly inform governments as to the true costs of development paths involving those projects, and
- the long-term interests of consumers are protected by subjecting all projects to a rigorous cost benefit analysis.

Furthermore, the NER states that AEMO must issue an ISP update if there is no credible option for an actionable ISP project that satisfies the RIT-T.[24] This raises the question of whether AEMO has breached the NER by passing off responsibility for approving questionable projects to state governments instead of issuing an ISP update when actionable projects are set to fail the RIT-T.

We submit that AEMO should issue an ISP update in accordance with the Rules when there is no credible option for an actionable ISP project that satisfies the RIT-T.

[17] National Electricity Rules Version 204. 5.16A.4 Regulatory investment test for transmission procedures.
[18] 2020 ISP, p 84, 87.
[19] AEMO, 2021. Central-West Orana REZ Transmission Link Non-Network Options.; National Electricity Rules Version 204. 5.16.4 Regulatory investment test for transmission procedures.
[20] Transgrid, 2023. Central-West Orana REZ Transmission - Wollar substation upgrade.
[21] Transgrid, 2022. NSW Transmission Annual Planning Report 2022.
[22] Draft 2024 ISP, p 56.
[23] Australian Energy Regulator, 2023. Transmission Efficiency Test and revenue determination guideline: non-contestable network infrastructure projects.
[24] National Electricity Rules Version 204. 5.22.15 ISP updates.

Annual capital costs and subsidies for coal not included

Coal plants provide a crucial service to a renewables-heavy grid — reliability. The Draft 2024 ISP assumes that some coal plants will stay open well into the 2030s[25] in order to firm the transition to an almost all-renewables grid. However, the ISP treats that capital entirely as a sunk cost. This treatment ignores that as more renewables enter the system, spot prices for electricity tend to be very low in the daytime when solar floods the energy system, and coal generators — which cannot easily respond by ramping down output — find it harder to viably operate financially.[26] As GenCost states, the minimum run requirements of coal plants are around 30-50% of rated capacity,[27] which creates problems when the share of wind and solar becomes too high. If coal generators cannot expect to remain financially viable every year from running at or near capacity, they will close; unless they agree to — or are forced to — remain open with government subsidies covering costs.

To keep the Eraring Power Station open, the NSW Government would have to pay Origin Energy an estimated $200-400 million a year.[28] If no deal is reached, new legislation would allow the NSW Energy Minister to force the generator to remain open for three years, with the AER to decide on the compensation payable.[29] The Victorian Government made a commercial-in-confidence "safety net" deal with Energy Australia to guarantee that Yallourn Power Station would remain open until 2028, likely involving "underwritten power prices or a last-resort investment guarantee" to help cover the $200 million to $300 million operating costs.[30] None of these state government subsidies are included in the ISP's analysis. Coal generation is therefore treated as a sunk cost instead of as a cost incurred by a mostly-renewables system that simultaneously depends on it for reliability while undermining its financial viability.

We submit that AEMO should include the cost of capital for legacy generators in the overall system costs as a way of estimating the necessary coal subsidies that will be needed to ensure coal generation remains at the projected levels into the 2030s. The subsidies required to compensate for less viable operating profiles are a fundamental part of system costs as, without them, the forecast demand will not be able to be met during peak periods.

A related issue arises with the reliance on peaking gas, which continues all the way through to 2050.[31] In the Draft 2024 ISP webinar, AEMO highlighted the "greater need for capacity of gas"

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[25] Draft 2024 ISP, p 10.
[26] Angela Macdonald-Smith & Patrick Durkin, 2021. Taylor demands energy suppliers 'step up' to fill Yallourn shortfall.
[27] 2022-23 GenCost, p 52 footnote.
[28] Michael McGowan, 2023. Eraring should remain open beyond 2025: Minns government energy review. The Sydney Morning Herald.
[29] Giles Parkinson, 2023. State energy ministers give themselves power to force coal generators to stay open. Renew Economy.
[30] Angela Macdonald-Smith & Patrick Durkin, 2021. Taylor demands energy suppliers 'step up' to fill Yallourn shortfall.
[31] Draft 2024 ISP, p 10.

coupled with “a lower utilisation of gas”,[32] meaning that while the grid increasingly relies on the ramping abilities of gas during peak periods, the amount of gas being used is forecast to decrease. Indeed, the only reason there are no reliability breaches resulting in unserved energy in the ISP scenarios is because AEMO allows the model to “build flexible gas to take into account those chances of unserved energy.”[33] This means that, while gas is increasingly fundamental to ensuring system reliability into the future, it makes less and less economic sense for investors to build new gas plants, as they will rarely be used apart from wind and solar droughts. To solve this problem, AEMO admitted that they “expect that some [market] reforms would be required to achieve that scale of use” but that this is for a “subsequent analysis.”[34]

We submit that determining the amount of subsidies or other costs associated with market reform to ensure sufficient gas capacity going forward should not be left for a subsequent analysis but should be completed by AEMO as part of the 2024 ISP to ensure total system costs include the cost of ensuring flexible gas at the levels projected.

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[32] Eli Pack, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 28:31. AEMO Stakeholder Relations, YouTube.
[33] Saliw Cleto, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 0:17. AEMO Stakeholder Relations, YouTube.
[34] Andrew Turley, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 54:19. AEMO Stakeholder Relations, YouTube.

2. The ISP relies heavily on CER but excludes its costs

Costs to individuals for installing their own solar and batteries, along with indirect costs of government subsidies, are all excluded

The 2022 ISP heavily relies upon DER to make up the lion's share of storage capacity and the majority of solar capacity, with total DER growing to nearly five times today's levels by 2050 in the Step Change scenario.[35] This is despite several submissions to the Draft 2022 ISP consultation process flagging that this uptake is too high,[36] particularly for DER storage — including by the Clean Energy Council, who called it a "significant overestimate."[37] AEMO has effectively ignored the concerns raised regarding the overreliance on DER in the Draft 2024 ISP, with the renamed CER still making up the lion's share of storage, especially coordinated CER storage.[38]

AEMO has little direct control over the amount of CER in the system, and does not attempt to optimise this part of the system, stating that they "have not included costs for household or residential batteries and solar PV because those are decisions that households and businesses make on their own so we take those as an input"[39] already happening 'out there'.[40] But the implication of this is that the benefits of the ODP listed in the Executive Summary include avoiding "$17 billion in additional costs to consumers", without any mention of the crucial fact that the "annualised capital cost of all generation, storage, firming and transmission infrastructure", estimated at $121 billion,[41] does not include the cost of CER.[42]

Though AEMO states that their approach to CER in the model "complies with the cost benefit analysis for AEMO for doing the ISP,"[43] as Energy Consumers Australia puts it in their submission to the 2022 ISP consultation, treating CER as an input is not "integrated" and "fails to meet the ambition of NER 5.22.2"[44] (that is, establishing a whole of system plan for the efficient development of the power system that achieves power system needs over at least 20 years for the long term interests of consumers)[45]. In response to a Senior Consultant at Aurecon questioning whether it was reasonable to consider the "very high level of coordinated CER energy storage" as a "static input trace" given its dependency on "system price volatility" and

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35 2022 ISP, p 39.
36 2022 ISP Consultation Summary Report, p 35.
37 Nicholas Aberle, 2022. Clean Energy Council submission on AEMO's draft Integrated System Plan 2022. Clean Energy Council.
38 Draft 2024 ISP, p 62.
39 Samantha Christie, 2023. 1:15. Draft 2024 Integrated System Plan publication webinar part 2. AEMO Stakeholder Relations, YouTube.
40 Samantha Christie, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 59:30. AEMO Stakeholder Relations, YouTube.
41 Draft 2024 ISP, p 14.
42 AEMO, 2023. Draft 2024 ISP Webinar Presentation.
43 Samantha Christie, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 1:15. AEMO Stakeholder Relations, YouTube.
44 Lynne Gallagher, 2022. 2022 Draft Integrated System Plan. Energy Consumers Australia.
45 National Electricity Rules Version 204. 5.22.2 Purpose of the ISP.

whether CER storage should be "co-optimised in the future,"[46] AEMO responded that the ISP "doesn't try to dictate what consumers do" but rather adapts to "that consumer preference" but that "whether or not it should be co-optimised in the future is part of an ongoing review."[47]

The terms of reference for this Australian Government review include that the ISP should better address "the changing nature of energy demand including through electrification, uptake of electric vehicles, modified consumption patterns, and consumer energy resources needed to achieve emissions reduction targets."[48] While this is a step in the right direction, merely addressing CER as part of energy demand rather than as a generation and storage system cost that should be optimised will perpetuate the exclusion of any meaningful analysis of its role in the system.

In the words of Engineers Australia, the exclusion of CER in the NPV analysis is a "limitation" which means that "while the NPV costing of Scenarios provided in the ISP is useful for comparing variations in transmission development pathways, it does not convey the total impact on future delivered electricity costs."[49] If the ISP is truly "a plan that's meant to be for consumers to adapt the power system in a way that supports them,"[50] and "CER are being taken up at such a rate that they are having a strong influence in the ISP"[51] — as AEMO has stated — then treating CER as "just another NEM resource"[52] and determining the optimal amount of CER to drive down total system costs (and therefore costs to consumers) should be a high priority.

We submit that AEMO should model CER as a system cost to provide consumers and governments with the information they need to understand the trade-offs between large-scale generation and storage and small-scale CER for overall system costs. This would ensure policy settings and incentives discourage levels of CER that drive up overall system costs, protecting the long-term interests of consumers.

Heavy reliance on rooftop solar while excluding costs

The Draft 2024 ISP assumes that by 2050 under the Step Change scenario, 79% of detached homes in the NEM will have rooftop solar[53] and distributed solar will increase from 15 GW to 69 GW, delivering one third of renewable capacity.[54] In the ODP, distributed solar will rise from 19

[46] Thomas MacDonald, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 2:30. AEMO Stakeholder Relations, YouTube.
[47] Eli Pack, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 3:15. AEMO Stakeholder Relations, YouTube.
[48] Australian Government, 2023. Terms of reference for the review of the Integrated System Plan. Department of Climate Change, Energy, the Environment and Water.
[49] Jane MacMaster, 2022. Draft 2022 Integrated Systems Plan consultation. Engineers Australia.
[50] Eli Pack, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 3:15. AEMO Stakeholder Relations, YouTube.
[51] Samantha Christie, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 9:55. AEMO Stakeholder Relations, YouTube.
[52] Jane MacMaster, 2022. Draft 2022 Integrated Systems Plan consultation. Engineers Australia.
[53] Draft 2024 ISP, p 47.
[54] 2022 ISP, p 38.

GW to 86 GW by 2050.[55] When determining the forecast uptake of rooftop solar in the Draft 2024 ISP model, AEMO explicitly takes into account government policies that provide financial incentives for consumers (e.g., Small Technology Certificates, feed-in tariffs).[56] However, because these policies are already considered “locked in”, they are not included as a system cost. Capital, installation and maintenance costs associated with rooftop solar are also excluded, but nonetheless borne by consumers.

This raises doubt about whether promoting rooftop solar over utility-scale solar farms is the best choice for the grid in terms of cost and reliability. Solar farms in sunny inland areas in Queensland and New South Wales are less prone to shading from clouds compared to rooftop solar in coastal cities,[57] suggesting that solar farms would be more reliable than rooftop solar, especially given their connection to the grid is easier to control. Engineers Australia has flagged the problem of rooftop solar potentially increasing the cost of grid energy because it reduces minimum demand and limits the viability of existing generators, while creating a greater need for new generators that have faster ramping capabilities.[58]

There is also the question of whether administration and maintenance costs would be significantly reduced for solar farms where all the panels are co-located, instead of being dispersed amongst millions of households. GenCost has identified rooftop solar as having similar capital costs as large scale solar,[59] though solar farms are given a 25% discount to take into account economies of scale,[60] but this still does not address the question of reliability and ease of maintenance and coordination. Since AEMO claimed in the Draft ISP Consumer Advocate pre-submission webinar that one of the key purposes of the ISP is to provide detailed information to policymakers, AEMO should not take policies such as STCs and feed-in tariffs for granted.

We submit that AEMO should factor rooftop solar into the ISP's overall system costs and model varying proportions of rooftop solar. This would offer policymakers precise information to evaluate the costs and benefits of promoting rooftop solar installations. To determine whether incentivising rooftop solar rather than utility-scale solar farms is beneficial for the grid as a whole, the ISP needs to compare the total costs of each technology; including the costs of subsidies and how much consumers pay for capital, installation and maintenance.

Heavy reliance on CER storage while excluding costs

In the 2022 ISP, DER storage was expected to grow significantly alongside rooftop solar, reaching three quarters of dispatchable capacity in Step Change by 2050.[61] Most domestic solar systems were forecast to be supported by batteries by 2050 and EV ownership was forecast to

[55] Draft 2024 ISP, p 44.
[56] AEMO, 2022. Forecasting Approach – Electricity Demand Forecasting Methodology. p 65.
[57] 2022 ISP, p 52.
[58] Jane MacMaster, 2022. Draft 2022 Integrated Systems Plan consultation. Engineers Australia.
[59] Draft 2023-24 GenCost, p 14.
[60] Draft 2023-24 GenCost, p 25.
[61] 2022 ISP, p 55.

surge to a staggering 99%.[62] The rapid increase in DER storage was meant to reduce the need for firming from coal and gas and shallow utility-scale storage.[63]

Multiple stakeholders raised concerns during the consultation process about why the 2022 ISP relied on DER storage to offset the need for utility-scale batteries — given this might not be the best option for keeping down whole-of-system costs and ensuring grid reliability. As GE Hydro pointed out in its submission, “there are economies of scale in relation to storage that mean the $/MWh of installed capacity will tend to be much cheaper for larger systems than small ones” — so it is unclear why the ISP would favour more expensive home batteries rather than utility-scale storage.[64] DER storage can dispatch electricity for only about two hours at full discharge[65] and an Aurecon study referenced by GenCost shows that small-scale home batteries cost twice as much as large-scale battery projects.[66]

The Draft 2024 ISP has failed to address stakeholder concerns raised in the 2022 ISP consultation process. The Draft has only marginally lower projections of CER, with a forecast 97% EV ownership by 2050.[67] There is a significant 34-fold increase in residential and commercial batteries by 2050.[68] CER continues to offset the amount of utility-scale storage in the grid, as AEMO has stated that the post-2040 decrease in shallow utility-scale storage occurs because at that time they expect only a small number of investors to replace their ageing battery assets if the predicted dramatic increase in CER occurs.[69]

The Step Change scenario “relies on a very strong contribution from consumers”, with “rapid and significant continued investments in CER which are highly orchestrated through aggregators”[70] in order to “maximise system efficiency”.[71] Yet AEMO does not seek to include the costs to consumers of investing in these complex systems.

We submit that AEMO should include the costs of home battery systems to consumers, including capital, installation and maintenance costs, in their total system costs. Without including these costs, it is unclear how AEMO can claim that the ODP is a “least cost” pathway for the energy transition.

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62 2022 ISP, p 39.
63 2022 ISP, p 55.
64 Martin Kennedy, 2022. GE Hydro Response to Draft 2022 Integrated System Plan (ISP).
65 Draft 2024 ISP, p 62.
66 Draft 2023-24 GenCost, p 48; Aurecon 2023, 2023 costs and technical parameter review, December 2023.
67 Draft 2024 ISP, p 47.
68 Draft 2024 ISP, p 47.
69 Eli Pack, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 27:48. AEMO Stakeholder Relations, YouTube.
70 2023 IASR, p 4.
71 2023 IASR, p 17.

Necessary financial incentives for coordinated CER are not included as a cost

As Snowy Hydro pointed out in its submission, the 2022 ISP made the "error of assuming perfectly controllable DER storage",[72] with a significant 76% of NEM storage capacity being coordinated DER in the Step Change scenario by 2050.[73] Utilising coordinated DER requires the much more difficult coordination of a dispersed network of millions of small batteries, as opposed to coordination of a few larger batteries.[74] These difficulties are referenced by AEMO in their acknowledgement that integration of DER will depend on many factors, including system planning, technology standards, customer preferences and economic incentives,[75] yet no economic incentives for DER storage — particularly coordinated DER — are modelled as costs to the overall system.

Additionally, Energy Consumers Australia flagged in the 2022 ISP consultation that the risk labelled "Securing social license for DER" should be labelled "Demonstrating the system security benefits of controlled DER to consumers".[76] This is because, while many consumers are choosing to install rooftop solar and home batteries, fewer are happy for their energy resources (which give them a sense of self-sufficiency and independence from the grid) being controlled by a third party for the sake of "system security". If system security were the main goal, it raises the question as to why utility-scale storage and solar farms would not be seen as a better alternative to coordinated DER.

In the Draft 2024 ISP, coordinated CER makes up 65% of NEM storage capacity by 2050.[77] This level of coordinated CER is still very high. Shifting consumers from controlling their own CER to allowing their CER to be coordinated by a VPP remains a "very hard" problem, as Russell Williams, Company Secretary of Electrify Boroondara, said in the Draft 2024 ISP Consumer Advocate capacity building webinar.

Economic incentives for CER are still referenced by the AEMO, with the "optimistic outlook for coordinated CER storage" requiring "continual reforms of tariffs, market incentives and policies."[78] It is assumed that financial incentives will be provided by aggregators for "orchestration of battery charging and discharging profiles" which will reduce consumer investment costs, apparently at no cost to the overall system.[79] State and federal economic incentives are taken into account in the forecast uptake of CER storage, yet these are not counted as costs in the ISP.[80] The Draft 2024 ISP explicitly references consumers taking

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72 Paul Broad, Managing Director and CEO. 2022 Draft ISP Consultation. Snowy Hydro.
73 2022 Final ISP results workbook - Step Change - Updated Inputs, Summary tab, CDP12.
74 Jane MacMaster, 2022. Draft 2022 Integrated Systems Plan consultation. Engineers Australia.
75 2022 ISP, p 39.
76 Energy Consumers Australia, 2022. Submission to AEMO's 2022 Draft Integrated System Plan.
77 Draft 2024 ISP, p 63.
78 Eli Pack, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 26:44. AEMO Stakeholder Relations, YouTube.
79 2023 IASR, p 71.
80 AEMO, 2022. Forecasting Approach – Electricity Demand Forecasting Methodology. p 66.

advantage of “financial incentives to add smart functionality and coordinate their batteries through VPPs” but makes no effort to factor this cost in.[81]

Saving money on electricity is one of the most important reasons for joining a VPP program for most people.[82] In fact, the Project EDGE report referenced by the ISP as demonstrating “the potential of coordinated CER” states that the perceived benefit of facilitating carbon emissions reductions was “less valued by consumers” than “a reliable supply of power, saving money and receiving good service.”[83] This is at odds with the way VPPs operate, as they are incentivised to sell power from customer’s batteries back to the grid during critical peak periods (when spot prices are highest), which will generally align with the periods in which the customer most wants to use the energy for their own household.

Therefore, the common view held by customers — that they appreciate the “additional financial benefits” of VPP participation and ability to “support the grid”, “so long as sufficient power remained to cover their household’s energy requirements”[84] — will put them in direct opposition to the financial interests of VPPs. This explains the Project EDGE findings that “industry needs to develop a stronger case to encourage greater participation in VPPs” and “accelerating VPP adoption will likely require a greater proportion of customers perceiving they are benefitting more than aggregators.”[85] Judging by the lack of interest exhibited by 47% of consumers in Figure 1, expected uptake of coordinated DER will not happen unless consumers are given significant financial incentives to relinquish their ability to remain independent and self-sufficient.

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[81] Draft 2024 ISP, p 63.
[82] Acil Allen, 2022. Barriers and enablers for rewarding consumers for access to flexible DER and energy use. Report to Energy Security Board.
[83] AEMO, 2023. Project EDGE Final report Version 2. p 81.
[84] AEMO, 2023. Project EDGE Qualitative insights into the experiences of customers participating in a Virtual Power Plant field trial. p 15.
[85] AEMO, 2023. Project EDGE Final report Version 2. p 89.

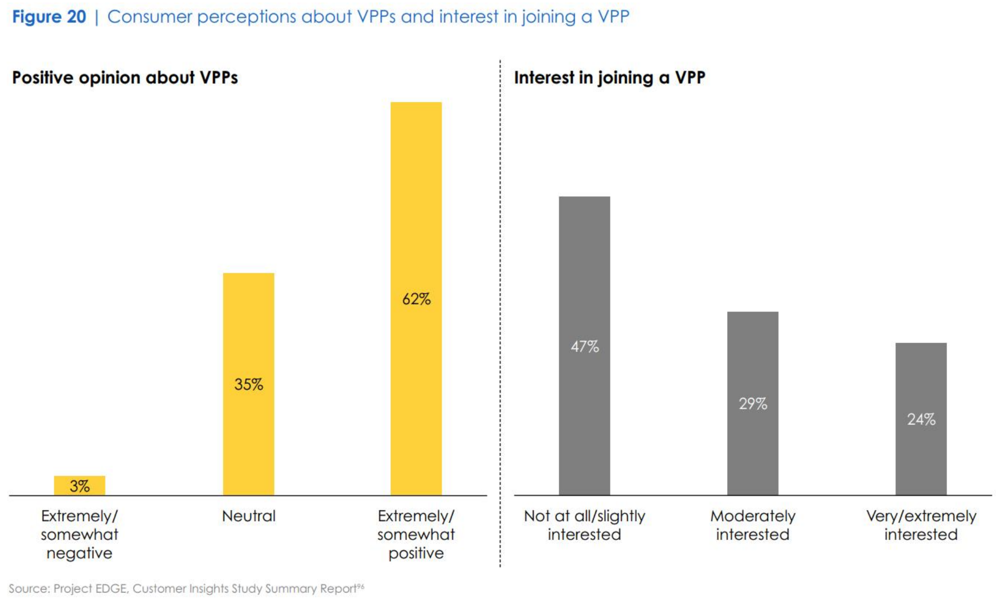

Figure 1. Consumer perceptions about VPPs and interest in joining a VPP from Project EDGE surveys.[86]

Government policies should not be taken for granted as they can and do change; they should also be included as a cost to the system. The 2023 IASR incorporates financial incentives for EV purchases to determine uptake in different scenarios, including South Australia's $3000 subsidy for new EVs,[87] which ended in January 2024.[88] In order to understand how the true costs of CER (particularly coordinated CER) will impact consumer decisions — and therefore CER uptake — if government policies change, modelling should include scenarios without financial incentives such as government subsidies.

We submit that AEMO should include as a system cost an estimate of the necessary incentives (including existing government subsidies) required to drive sufficient consumer investment in CER storage, and particularly coordinated CER storage, to reach the projected levels of CER up until the end of the ISP horizon under each scenario. Without modelling incentives as a system cost, higher penetration of CER may appear unrealistically desirable to policymakers as a way to reduce long-term costs to consumers compared to utility-scale storage.

Sensitivity analysis insufficient to test benefits of high CER uptake

Given stakeholder concerns over the unrealistically high level of DER uptake and coordination in the 2022 ISP, AEMO conducted a sensitivity analysis to see how reduced uptake and coordination affected CDP rankings in the 2022 ISP.[89] This analysis showed no change in CDP rankings,[90] which AEMO used to justify their selection of the ODP, given its transmission

[86] AEMO, 2023. Project EDGE Final report Version 2. p 87.
[87] 2023 IASR, p 27.
[88] Government of South Australia, 2023. Incentives for electric vehicles.
[89] 2022 ISP Consultation Summary Report, p 36.
[90] 2022 ISP, p 90.

projects were apparently not sensitive to changes in DER storage uptake or the resulting distribution network constraints.[91] However, this sensitivity analysis only changed the total DER storage capacity from around 45 GW[92] to around 35 GW[93] in 2050 (i.e. from the Step Change projections to the Progressive Change projections[94]), meaning that the vast majority of total storage capacity was still DER.

AEMO has stated that the Final 2024 ISP will include a Low CER Orchestration sensitivity test, but this will not test reduced uptake of CER, only reduced participation in VPP programs,[95] thus perpetuating the exclusion of a meaningful analysis of CER's overall net benefit to the grid compared to utility-scale solar and storage.

We submit that AEMO should include a sensitivity analysis for different CER levels, comparing overall system costs and transmission project prioritisation at the projected high levels of CER as well as a scenario in which the vast majority of storage is utility-scale.

Assumed behavioural changes not costed

Along with reliance on batteries and rooftop solar paid for by consumers, the 2022 ISP also relied on consumers changing their behaviour to suit the needs of the grid, thus incurring opportunity costs that are once again not included in the total system costs. The Energy Security Board (ESB), which AEMO is collaborating with on integrating CER,[96] released a report stating that consumers can be "rewarded" for being flexible in their demand by shifting usage to times when prices are cheaper.[97] This added inconvenience means that instead of the grid working to serve the needs of consumers, consumers must bear the opportunity cost of changing their usage patterns to suit a grid largely dependent on the peaks and troughs of solar output.

This is especially important for EV owners, as according to the 2021 IASR Step Change scenario, over 92% use "convenience charging" (see Figure 2), i.e., charging at home immediately upon arrival after work during peak time.[98] In order to get the percentage of residential convenience charging down to the expected 31% in 2050,[99] a discount would need to be provided. Research suggests less than 17% of EV owners would consider changing their charging time to between 10am and 2pm (i.e., when solar output is at its peak) without an incentive.[100]

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[91] 2022 ISP, p 99.
[92] 2022 Final ISP results workbook - Step Change - Updated Inputs, Summary tab.
[93] 2022 Final ISP results workbook - Step Change - Low Distributed Storage, Summary tab.
[94] 2022 ISP Consultation Summary Report, p 36.
[95] 2023 IASR, p 71.
[96] 2022 ISP, p 99-100.
[97] Energy Security Board, 2021. Clean and smart power in the new energy system.
[98] Electric Vehicle Council, 2022. EVC Submission to AEMO 2022 Integrated System Plan.
[99] 2022 ISP, p 31.
[100] Patrícia Lavieri & Gabriel J M Oliveira, 2021. Electric Vehicle Charging Consumer Survey: Insights Report. University of Melbourne.

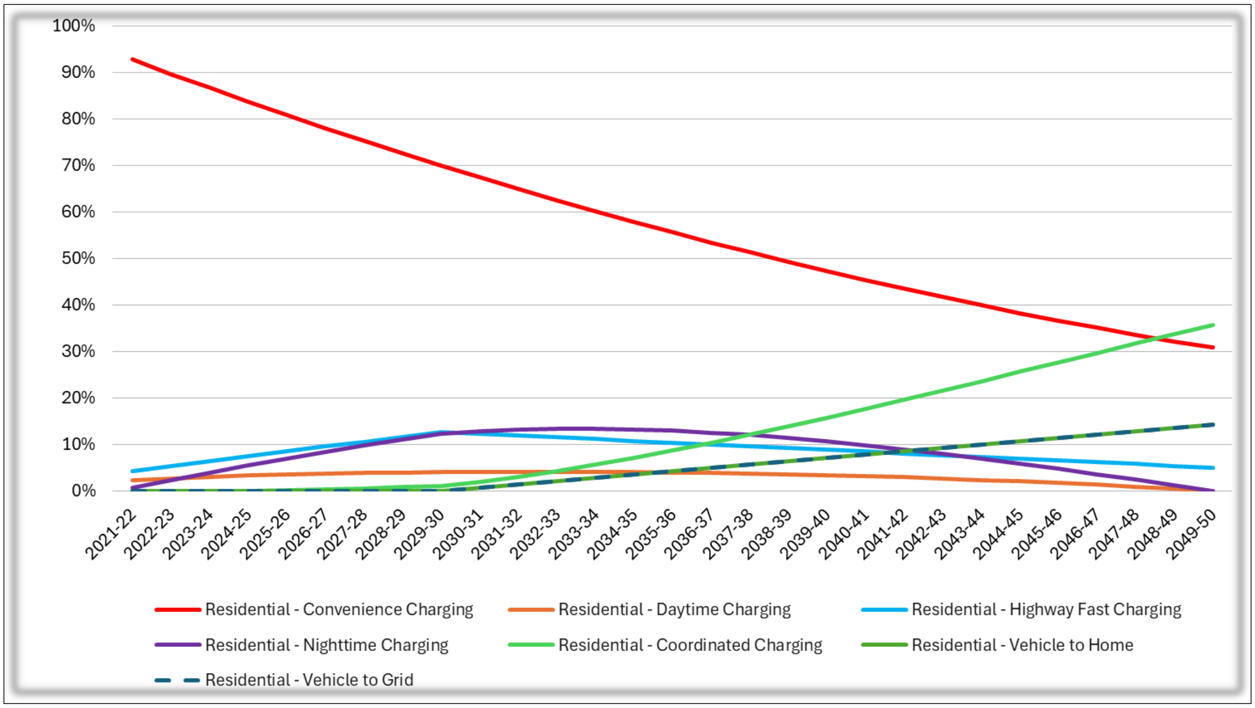

Figure 2. Percent of EV charging over time by charging types under Step Change in 2021 IASR.[101]

Concerns were raised about the assumed behavioural changes built into the 2022 ISP's model during consultation. The Electric Vehicle Council warned AEMO that available dispatchable storage from vehicle to grid was too high, given that between 3-7pm (when load ramps up), many vehicles will be at work or in transit.[102] This meant that the opportunity cost of consumers overhauling their schedules to have their EV home in time (and with enough charge left) to meet the needs of the grid in the evening peak was essentially being modelled for free.

The Draft 2024 ISP has failed to adequately address this stakeholder feedback. In the 2023 IASR, the starting point for the Step Change scenario in 2022-23 is revised to around 73% convenience charging, which drops to below 36% by 2050, while coordinated charging rises from 0% to around 32% (see Figure 3), slightly lower than the 36% forecast in the 2021 IASR. Though the 2023 model assumes current convenience charging rates are much lower than the 2021 model, a significant proportion of EV owners will need to be convinced to change their behaviour in order to meet the forecast targets. The question of how many EVs would sign up to be used as grid storage and how much they would be paid was raised by Alan Wong, Head of Commercial at Green Peak Energy, in the Draft 2024 ISP consultation, but no cost estimates were provided by AEMO.[103]

[101] 2021 IASR workbook, Battery & Plug-in EVs tab.
[102] Electric Vehicle Council, 2022. EVC Submission to AEMO 2022 Integrated System Plan.
[103] Alan Wong, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 1:09:45. AEMO Stakeholder Relations, YouTube.

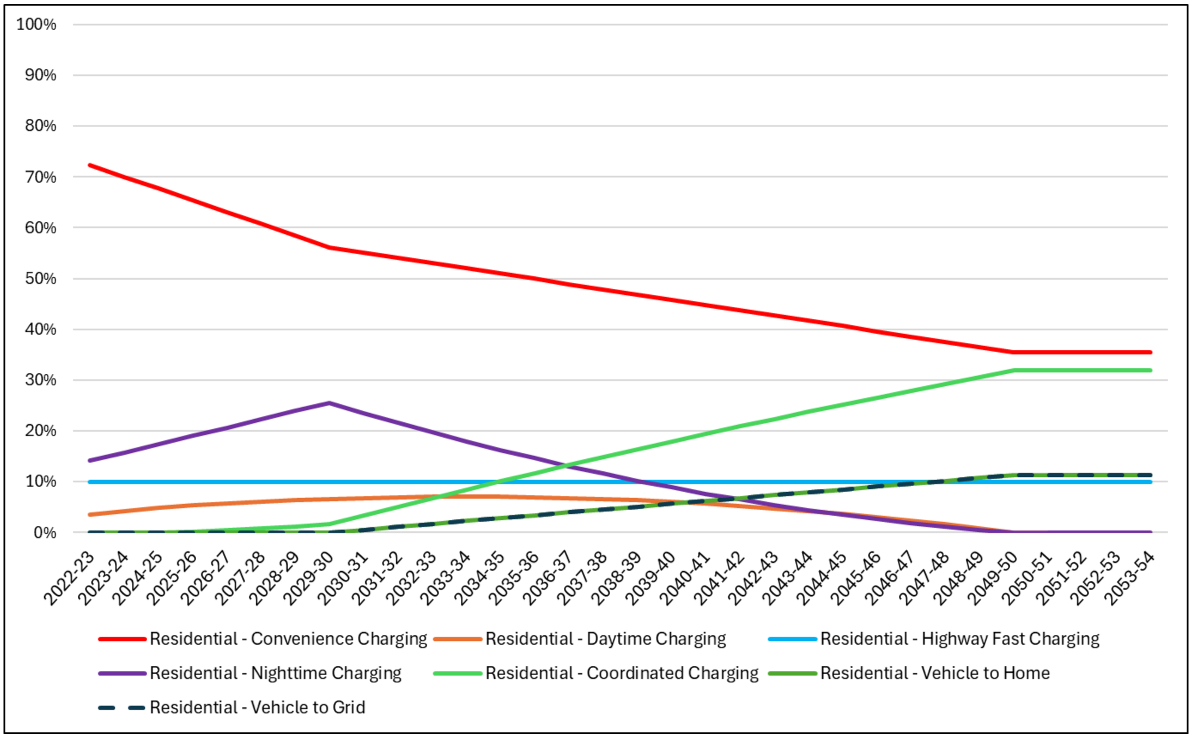

Figure 3. Percent of EV charging over time by charging types under Step Change in 2023 IASR.[104]

The Draft 2024 ISP specifically mentions consumers' ability to reduce peak demand on the grid by charging EVs "outside the morning and evening peaks, preferably through the peak solar daylight" and discharging back to the home or the grid "when needed",[105] with a vague mention of the "right incentives and systems" that will encourage EV owners to allow coordination of their assets.[106] Yet nowhere are these costs estimated in the ISP model—consumers are simply assumed to change their behaviour for free.

We submit that AEMO should model the estimated costs of the necessary incentives required to shift EV consumer behaviour so convenience charging reduces and coordinated charging increases to the projected levels. These incentives should be included in the total system costs, given that the modelled system will rely on a proportion of EV batteries being available to discharge at the grid's convenience instead of the owner's convenience.

Distribution network upgrade costs ignored

Just as the 2022 ISP ignored the costs of DER, it also ignored the added costs of distribution network upgrades, which are also ultimately borne by consumers. The 2022 ISP assumed that all DER generation can be exported into the network, yet failed to adequately address the costs

[104] Data was calculated by taking the average of values given for each state in each year from 2023 IASR EV Workbook, BEV_PHEV_Charge_Type (%) tab.
[105] Draft 2024 ISP, p 27.
[106] Draft 2024 ISP, p 34.

associated with the necessary upgrades of the distribution network. As Engineers Australia pointed out in their consultation submission, once DER penetration hits a certain threshold, this creates “highly significant” engineering challenges that require additional investments and “have the potential to seriously undermine the National Electricity Objective.”[107]

Likewise, Hydro Tasmania highlighted the issue of “limitations in the ability of distribution networks to ‘host’ increasing shares of DER,” as is already occurring in Queensland where high shares of rooftop solar have been installed.[108] These limitations include the need to mitigate over-voltage and thermal overloads, as well as the need to address phase balancing and under-frequency control, and update protection settings. Hydro Tasmania also flagged that one of the two datasets used to project rooftop solar did not consider distribution network constraints, leading to an unrealistically high forecast of DER uptake.

The cost of distribution network upgrades is significant, with Energeia estimating in their DER project paper the total cost of mitigating over-voltage due to solar installations over the next 20 years as being between $0.7 to $1.1 billion, “depending on the level of DER-adoption”.[109]

Despite this, the Draft 2024 ISP continues to brush over the costs associated with distribution network upgrades, to the surprise of consumer representatives.[110] As the Consumer Panel said in their report on the 2023 IASR, “While AEMO describe the ISP as a ‘whole of system’ plan, it is in practice, a ‘whole of transmission’ plan with limited involvement of distribution networks, even those with substantial subtransmission assets.”[111] The apparent avoidance of “$17 billion in additional costs to consumers” listed as a benefit of the ODP in the Executive Summary of the Draft 2024 ISP[112] is misleading as it does not take into account distribution network upgrade costs.[113]

In the webinar for the Draft 2024 ISP consultation, the Queensland Electricity Users Network flagged the “huge reliance on CER storage going forward”, asking what the AEMO had done to “understand the impact on the distribution network of VPPs simultaneously discharging, i.e., the impact of the ISP’s CER storage forecasts on the distribution networks.”[114] Robert Barr, former National President of the Electric Energy Society of Australia, also asked whether total system costs had been used in developing the ODP, “including distribution network costs and behind the meter solar PV and batteries.”[115] AEMO’s response was that they had “worked extensively

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107 Jane MacMaster, 2022. Draft 2022 Integrated Systems Plan consultation. Engineers Australia.
108 Colin Wain, 2022. Hydro Tasmania response to the 2022 Draft Integrated System Plan. Hydro Tasmania.
109 Energeia, 2020. Distributed Energy Resources Enablement Project – Discussion and Options Paper.
110 Russell Williams, Company Secretary of Electrify Boroondara. Draft 2024 ISP Consumer Advocate capacity building webinar.
111 2024 ISP Consumer Panel, 2023. ISP Consumer Panel Report on AEMO’s Inputs Assumptions and Scenarios Report (IASR) for the 2024 Integrated System Plan – Final Report.
112 Draft 2024 ISP, p 14.
113 AEMO, 2023. Draft 2024 ISP Webinar Presentation.
114 Jennifer Brownie, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 58:37. AEMO Stakeholder Relations, YouTube.
115 Robert Barr, 2023. 2023. Draft 2024 Integrated System Plan publication webinar part 2. 0:58. AEMO Stakeholder Relations, YouTube.

with distribution networks in the preparation of the IASR report in order to test with them whether or not these CER uptakes and projections made sense for their networks."[116]

Indeed, to address concerns over the impact of DER on distribution networks, AEMO has established a working group with DNSPs and Energy Networks Australia to "strengthen the links between the ISP and distribution network planning processes."[117] The AER has also developed a framework for assessing DER integration expenditure so that DNSPs can carry out cost benefit analyses on distribution network upgrades.[118] And yet despite AEMO acknowledging that "significant innovation will be needed in the NEM's market arrangements and distribution networks to optimise the benefits of DER investment", they have not quantified this cost.[119]

The "significant innovation" referenced by AEMO is particularly important to handle the huge forecast increase in EVs. The rate at which EV drivers charge at their convenience is a key driver of distribution network augmentation costs[120] and public charging of EVs in general can increase grid loads by up to 78% during peak hours, requiring distribution network upgrades to manage the large increase in demand.[121] Shifting EV owners from convenience charging in the evening at home to charging during the day at work would require significant investment in public chargers if 97% EV penetration is to be reached with 32% coordinated charging.

Yet, AEMO does not count these costs, but instead "assumes that distribution networks will be appropriately augmented to facilitate the level of CER penetration and operation in any given planning scenario."[122] Ausgrid has stated that the "the cost drivers for export services are typically voltage related" meaning that "marginal expenditure typically occurs on low voltage distributors" which raises even more doubts about why CER is being relied upon when much of these costs could be avoided by using solar farms and utility-scale storage connected to transmission or the high-voltage part of the network.[123]

We submit that AEMO should include in the ISP model the costs of distribution network upgrades required to manage the forecast increases in CER uptake. Given the uncertainties around which parts of the distribution network will require upgrading (which is largely based on where consumers install the most CER), AEMO should do sensitivity testing for upgrades of varying cost across different areas.

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[116] Samantha Christie, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 59:29. AEMO Stakeholder Relations, YouTube.
[117] 2022 ISP, p 100.
[118] Australian Energy Regulator, 2022. DER integration expenditure guidance note.
[119] 2022 ISP, p 99.
[120] Electric Vehicle Council, 2022. EVC Submission to AEMO 2022 Integrated System Plan.
[121] M. Pagani et al., 2019. User behaviour and electric vehicle charging infrastructure: An agent-based model assessment. Applied Energy, Volume 254, 113680.
[122] 2023 IASR, p 72.
[123] Ausgrid, 2023. Ausgrid's Tariff Structure Statement Compliance Document 2024-29.

3. Asset end-of-life costs are excluded

Solar panel, wind turbine and battery disposal and recycling costs not included

AEMO claims to include disposal and recycling costs of generation assets, stating in the Draft 2024 ISP webinar that "yes, we include them and it's an additional cost when you retire assets."[124] However, this is demonstrably false in both the 2022 and Draft 2024 ISP despite being raised during stakeholder consultation on the 2022 ISP.[125]

In the 2022 ISP, retirement and rehabilitation costs are quantified only as an input for coal and gas, despite the earliest wind farm closures expected in 2027 and 2029, with some battery projects and solar farms expected to close by the mid-2030s.[126] These costs had not been changed since the 2020 ISP, which are based on a 2018 GHD report.[127] Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, and battery storage was excluded because the disposal cost data was not known.

In the 2024 ISP, pumped hydro, single-axis tracking solar and wind retirement and rehabilitation costs are included in addition to coal and gas.[128] Large-scale battery retirement costs are still excluded because "disposal cost data is not known".[129] Retirement costs are also not included for biomass, solar thermal and offshore wind allegedly because they would take so long to build, even if started now, "retirement costs would be incurred beyond the end of the ISP modelling horizon."[130] This is flawed reasoning. Just because a cost happens far in the future doesn't mean it can be disregarded; it would be foolish for investors to start a project not knowing how much they will have to pay to decommission and rehabilitate the land once the plant reaches the end of its life.

Retirement costs are still based on the 2018 GHD report in the Draft 2024 ISP, meaning the data used is not only incomplete but now over 5 years old. Costs include "decommissioning, demolition, site rehabilitation and any on-going monitoring required" and are "plant specific", being "significantly influenced by local statutory rules and regulations and the provisions under the development approval."[131] Because cost estimates are based on GHD's "in-house data", there is no way to assess the veracity of the analysis or whether these decommissioning cost estimates can be extrapolated across the board.[132] There is no attempt to incorporate recycling

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[124] Saliw Cleto, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 11:03. AEMO Stakeholder Relations, YouTube.
[125] Independent Engineers and Scientists, 2022. Response to Draft AEMO 2022 Integrated System Plan.
[126] 2021 Inputs and assumptions workbook, Retirement tab.
[127] GHD, 2018. AEMO costs and technical parameter review. Report Final Rev 4.
[128] 2023 IASR Assumptions Workbook, Retirement tab.
[129] 2023 IASR, p 94.
[130] 2023 IASR, p 94.
[131] 2023 IASR, p 94.
[132] GHD, 2018. AEMO costs and technical parameter review. Report Final Rev 4.

costs and thus presumably the ISP modelling assumes that all waste from solar panels, wind turbines and large-scale batteries is either abandoned on-site, or perhaps just sent to land-fill.

This omission of disposal and recycling costs is highly problematic given the legislative environment in Australia. In Victoria and South Australia, all electronic waste has been banned from entering landfill, including solar panels and batteries, which must be recycled or stored until they can be recycled.[133] Western Australia has announced that they will implement similar restrictions, and Queensland is in the consultation phase.[134] Because "industry has made insufficient progress to better manage the environmental impacts" of solar panels and battery storage systems, the Australian Government is developing "a mandatory product stewardship scheme to reduce waste".[135] This scheme is currently in development and could make solar panel manufacturers and importers liable for recycling costs through either arranging recycling themselves or paying membership fees to the national scheme to cover "collection, transport, processing, recycling, disposal, education, compliance, reporting and governance",[136] none of which are included as costs in the Draft 2024 ISP.

The costs of recycling solar panels go beyond financial costs — they also present an environmental cost. The FRELP method, which aims to recover as much of the solar panel material as possible, results in (for every tonne of solar panel recycled) the emission of 2 kg of nitrous oxide, as well as 14 kg of contaminated glass, 2 kg of hazardous fly ash, 306 kg of liquid waste and 50 kg of hazardous sludge, all of which must be disposed of in landfill.[137] Not only do these outputs present a hazard to human health and the environment, they also incur a greater cost in the processing and eventual disposal due to their toxicity. Carbon dioxide emissions from the process of disposal and recycling should also be accounted for to fairly compare emissions from solar panels to other generation technologies, especially given the recycling requirement in many states.

Similarly for wind turbines, which are especially hard to dispose of given their size, the lack of consideration of these end-of-life costs is concerning. Wind turbine blade waste is projected to grow from current rates of about 10,000 tonnes per year to about 20,000 tonnes per year in 2030 and around 300,000 tonnes per year by 2050.[138] It is unclear what recycling responsibilities will be placed on wind farm owners to deal with these millions of tonnes of

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133 Parliament of Australia, 2023. Question on notice no. 102. Portfolio question number: 92. 2020-21 Budget estimates. Environment and Communications Committee, Climate Change, Energy, the Environment and Water Portfolio.

134 Department of Climate Change, Energy, the Environment and Water, 2023. Wired for change: Regulation for small electrical products and solar photovoltaic system waste.

135 Department of Climate Change, Energy, the Environment and Water, 2023. Minister's product stewardship priority list.

136 Department of Climate Change, Energy, the Environment and Water, 2023. Wired for change: Regulation for small electrical products and solar photovoltaic system waste.

137 Cynthia Latunussa et al., 2016. Life Cycle Assessment of an innovative recycling process for crystalline silicon photovoltaic panels. Solar Energy Materials and Solar Cells. Volume 156, pp 101-111, ISSN 0927-0248.

138 Peter Majewski, 2022. How to manage future waste from wind turbine blades. Energy Magazine.

cumulative waste,[139] but since 85% of wind turbines (i.e. the body excluding the blades) can be recycled,[140] governments may pursue similar policies to those used for solar panel waste. Regardless, the costs of transport and disposal are likely to be significant and should not be ignored.

The effect of not including these crucial asset life costs is that the retirement/rehabilitation cost estimates the Draft 2024 ISP uses for coal and combined cycle gas turbines are several times higher than that of the underestimated solar and wind costs (see Figure 4).

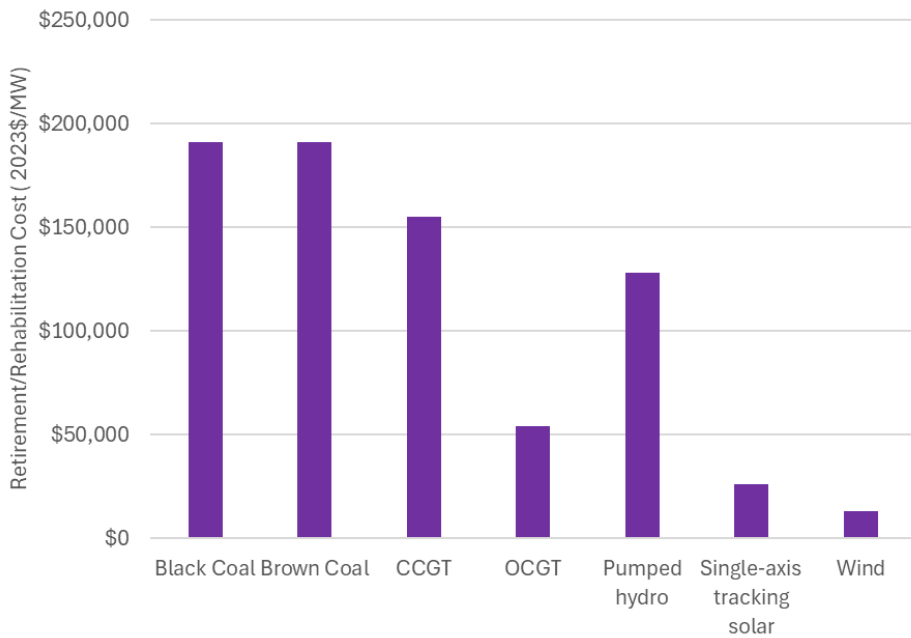

Figure 4. Retirement/rehabilitation cost estimates of different generation technologies in the Draft 2024 ISP.[141]

Another source of waste not currently costed in the ISP is that of Consumer Energy Resources (which as a whole are considered “free” as far as the ISP is concerned). The Department of Climate Change, Energy, the Environment and Water has stated that CSIRO does not know what the total cost of recycling large household and EV batteries would be due to “relatively low levels… reaching end of life in Australia.”[142] With CER projected to make up the lion’s share of NEM storage capacity in future decades,[143] this is likely to be a significant cost to the energy system.

[139] Parliament of Australia, 2023. Question on notice no. 102. Portfolio question number: 92. 2020-21 Budget estimates. Environment and Communications Committee, Climate Change, Energy, the Environment and Water Portfolio.
[140] Douglas Broom, 2021. These bike shelters are made from wind turbines. World Economic Forum.
[141] 2023 IASR Assumptions Workbook, Retirement tab.
[142] Parliament of Australia, 2023. Question on notice no. 213. Portfolio question number: SQ22-000887. 2022-23 Budget estimates October and November. Environment and Communications Committee, Climate Change, Energy, the Environment and Water Portfolio.
[143] Draft 2024 ISP p 10

We submit that AEMO should include in total system costs the estimated costs of disposal, and particularly recycling, for all wind turbines, solar panels and batteries, including CER.

Transmission replacement costs not included

The 2022 ISP assumed that transmission developments are only 1% p.a. of their capital investment cost, an assumption which is largely hidden; only being highlighted in the Consultation Summary Report — in which doubts are raised over the accuracy of this figure by EnergyAustralia.[144] Despite these concerns, the Draft 2024 ISP contains the same assumption, which has been flagged through the 2023 consultation process by the ISP Consumer Panel, Transgrid and Simon Bartlett AM, a former electrical engineering professor at the University of Queensland and former Australian Chair of Electricity Transmission.[145]

Bartlett's submission to the Draft 2023 Inputs, Assumptions and Scenarios Report consultation pointed out the flaws in how AEMO quantifies transmission costs.[146] He argued that, since most capex spent by TNSPs over the past 5 years has been to refurbish and replace ageing transmission assets, both opex and capex should be considered for total annual expenditure on transmission assets over their lifecycle. Using benchmarking data from the AER,[147] he estimated the undepreciated total value of transmission assets for each TNSP and took the sum of opex and capex as a percent per annum of total value. The resulting average is 3.3% — a much higher figure than the assumed 1%. When applied over the life of transmission projects, this results in actionable ISP projects having $5 billion more in net benefits than if the more realistic 3.3% value had been assumed.

Bartlett also flagged that AEMO has assumed 3.5% p.a. for ongoing operating costs alone in the Western Renewables Link Project Assessment Conclusions Report,[148] still much higher than the assumed 1%. The AEMO response to this criticism expressed disagreement with how Bartlett treated depreciation but failed to respond to the broader point that capex, not just opex, needs to be included in the annual ongoing costs of new transmission projects.[149]

We submit that AEMO should adopt a figure of at least 3% for total annual expenditure on transmission assets over their lifecycle to more accurately account for both opex and capex.

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144 AEMO, 2021. 2021 IASR Consultation Summary Report. p 87.
145 AEMO, 2023. 2023 Transmission Expansion Options – Consultation Summary Report. p 29-30.
146 Simon Bartlett, 2022. RE Draft 2023 Inputs, Assumptions and Scenarios Report (IASR) – Comments from Simon Bartlett.
147 Australian Energy Regulator, 2022. Annual Benchmarking Report Electricity transmission network service providers. p 44.
148 AEMO, 2019. Western Victoria Renewable Integration – Project Assessment Conclusions Report. p 22.
149 AEMO, 2023. 2023 Transmission Expansion Options – Consultation Summary Report. p 29-30.

4. Full reliability requirement not modelled

Reliability requirement not fully tested in the ISP model

There appears to be some confusion over whether or not the ISP is designed to ensure reliability of the energy system. Zoe Konovalov, the General Manager – Capacity Investment Scheme, Electricity Division, Department of Climate Change, Energy, the Environment and Water, has stated that "the original intent of the ISP" was, in fact, an "exercise in transmission planning" and the ISP was "not ever intended to be an exercise that would give reliability requirements across jurisdictions."[150] Upon this being raised in the Draft 2024 stakeholder consultation, AEMO has asserted that "the ISP does need to model power system needs and that includes meeting reliability requirements" as "part of the obligations on AEMO when we prepare the ISP."[151]

Unfortunately, AEMO's attempt to address reliability under the ODP is insufficient to ensure blackouts are kept below the stated goal of 0.002% of total annual energy needs, and below 0.0006% annually in each region up to 2028.[152] AEMO states that although extended VRE droughts are rare, they are "extremely difficult to predict in duration and intensity" over the longer term.[153] AEMO claims that "delivering geographical diversity of generation and firming resources is a strong benefit of the transmission expansions forecast in the ISP and will improve system resilience"[154] despite the fact that "occasionally weather systems across larger areas of the NEM can reduce overall availability" regardless of geographical diversity of VRE resources.[155]

AEMO admits that "in cases where stored energy and other dispatchable generation is insufficient to meet demand, demand side participation (DSP) and demand response may be deployed".[156] This essentially means that consumers will be forced to cooperate with an unreliable supply of electricity by reducing their demand to avoid blackouts during a solar and wind drought that lasts long enough for batteries to run out.

Relying on "market settings that incentivise storage operators to reserve energy for discharge during high demand periods"[157] to ensure sufficient ramping capability during an extended VRE drought will not be enough to shore up supply. This is because, as AEMO explains, the "lack of foresight as to when high price events will occur may cause shallow storages to discharge before the time of maximum value or retain energy for future periods when the market

[150] Department of Climate Change, Energy, the Environment and Water, 2023. CIS Public Consultation webinar – August 2023 – Transcript.
[151] Samantha Christie, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 1:11:00. AEMO Stakeholder Relations, YouTube.
[152] Draft 2024 ISP, Appendix 4: System Operability, p 6.
[153] Draft 2024 ISP, Appendix 4: System Operability, p 7.
[154] Draft 2024 ISP, Appendix 4: System Operability, p 21.
[155] Draft 2024 ISP, Appendix 4: System Operability, p 7.
[156] Draft 2024 ISP, Appendix 4: System Operability, p 20.
[157] Draft 2024 ISP, Appendix 4: System Operability, p 20.

opportunity is perceived to be greater."[158] Although AEMO explored various ways of modelling imperfect foresight for storage operators, this was not included in the capacity outlook models for the Draft 2024 ISP.[159] Without this being included in the model itself, it is unclear whether the amount of storage forecast in the ODP under Step Change is sufficient to ensure grid reliability over the modelling horizon. There is also a vague reference to "strategic reserves in dispatchable capacity, and energy reservation of deep storages" potentially being required to "provide appropriate resilience to forecasting errors, imperfect foresight, unavailability risks and fuel supply risks" but what these additional reserves would look like is unclear.[160]

AEMO's ISP model is based on "12 years of weather data covering a broad range of weather patterns" but it is "not guaranteed that this historical period includes the worst possible VRE drought conditions."[161] Although AEMO claims that "the NEM is forecast to operate reliably through VRE droughts observed in recent history", and that they have validated the ISP model "with differing levels of foresight to ensure that the plan is not perfectly constructed to only meet the objectives of the weather that is forecast at a particular point in time",[162] this validation has apparently only used the 12 years of weather data from 2010-11 to 2021-22.[163] Given that the ISP modelling horizon is over 30 years, AEMO should include at least 30 years of historical weather data to be able to claim that the full reliability requirement is met. This ensures there is enough capacity to withstand a one-in-30-year event, rather than just a one-in-12-year event.

Likewise, AEMO mentions the risk of 2.2 GW of gas energy being curtailed in 2038-39, equivalent to 15% of total NEM GPG installed generation capacity, but the model only includes one-in-10-year NEM and one-in-20 year east coast gas system winter conditions.[164] Gas constraints should be modelled for one-in-30 year events, given the ISP modelling horizon is over 30 years.

AEMO forecast reliability outcomes for the Draft 2024 ISP but the Draft's Figure 32 indicates this was only done for the years 2029-30, 2034-35, 2039-40 and 2044-45.[165] This means there is no guarantee of meeting the reliability standard for every year not analysed, particularly those following 2044-45 up until the end of the modelling horizon. Given it's clear in the cost benefit analysis that the costs of Demand Side Participation and Unserved Energy begin to rise just after the end of this window, it appears this selective choice of years masks that the model does indeed actually fail to meet reliability standards, even with the installed capacities having the benefit of effective perfect foresight (see Figure 5).

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[158] Draft 2024 ISP, Appendix 4: System Operability, p 31.
[159] Draft 2024 ISP, Appendix 4: System Operability, p 33.
[160] Draft 2024 ISP, Appendix 4: System Operability, p 26.
[161] Draft 2024 ISP, Appendix 4: System Operability, p 23.
[162] Andrew Turley, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 1:06:30. AEMO Stakeholder Relations, YouTube.
[163] Draft 2024 ISP, Appendix 4: System Operability, p 21.
[164] Draft 2024 ISP, Appendix 4: System Operability, p 41.
[165] Draft 2024 ISP, Appendix 4: System Operability, p 43.

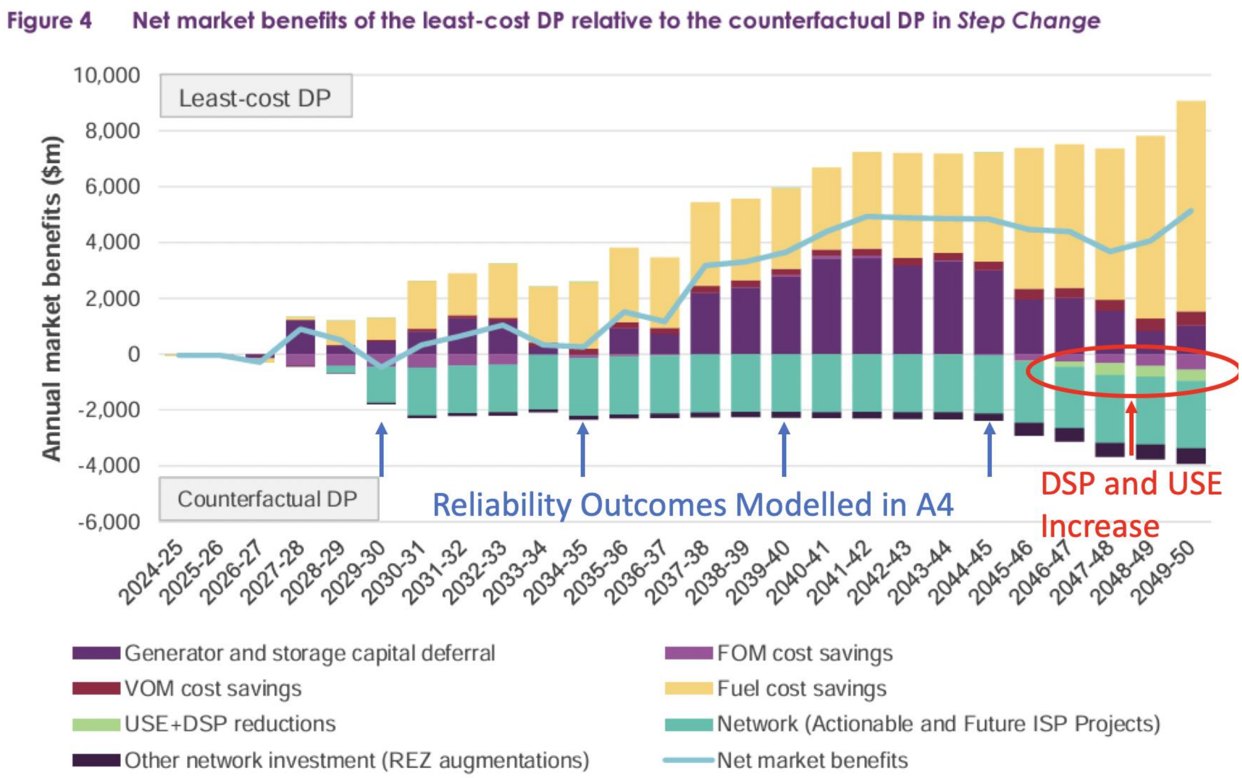

Figure 5. Net market benefits of the least-cost DP relative to the counterfactual DP under Step Change, with years sampled for reliability analysis indicated.[166]

The analysis also used fewer simulated random generator outage patterns than the ESOO to "manage simulation complexity".[167] This is not a valid reason for conducting a less rigorous analysis than the ESOO, given that AEMO claims meeting reliability requirements is "part of the obligations on AEMO" for the ISP.[168]

AEMO allows the model to "build flexible gas to take into account those chances of unserved energy,"[169] but assumes "perfect foresight" of VRE output and demand for each day.[170] The model not only assumes perfect foresight within each day but also across years, as evidenced by the pattern of flexible gas capacity exhibited in the Draft 2024 ISP model (see Figure 6).

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[166] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 24.
[167] Draft 2024 ISP, Appendix 4: System Operability, p 43.
[168] Samantha Christie, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 1:11:00. AEMO Stakeholder Relations, YouTube.
[169] Saliw Cleto, 2023. Draft 2024 Integrated System Plan publication webinar part 2. 0:17. AEMO Stakeholder Relations, YouTube.
[170] Draft 2024 ISP, Appendix 4: System Operability, p 30.

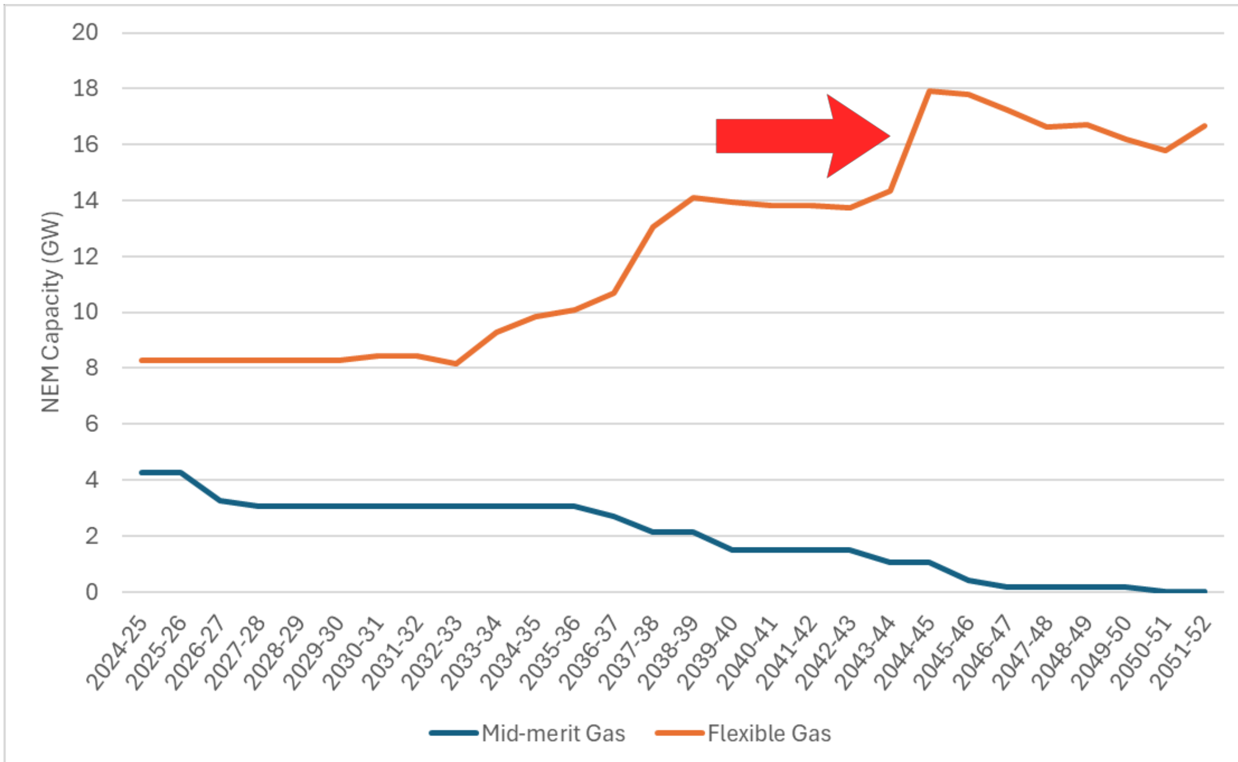

Figure 6. Gas capacity for mid-merit gas and flexible gas across the NEM in the Draft 2024 ISP ODP under Step Change.[171]

There is a sudden increase of 4 GW in one year to ensure there is a peak of 18 GW of capacity in 2045 — the exact year in which solar capacity factors across most solar farms experience a marked drop (see Figure 7). This appears to show a high degree of overfitting in the model to make generation, and the timeline of gas plant builds in particular, fit exactly to a specific sequence of weather years. If a different sequence of weather years were used, e.g., with the bad solar year occurring a few years earlier, there may not be enough flexible gas capacity to ensure grid reliability.

[171] Draft 2024 ISP results workbook - Step Change, Summary tab, CDP 11 (ODP).

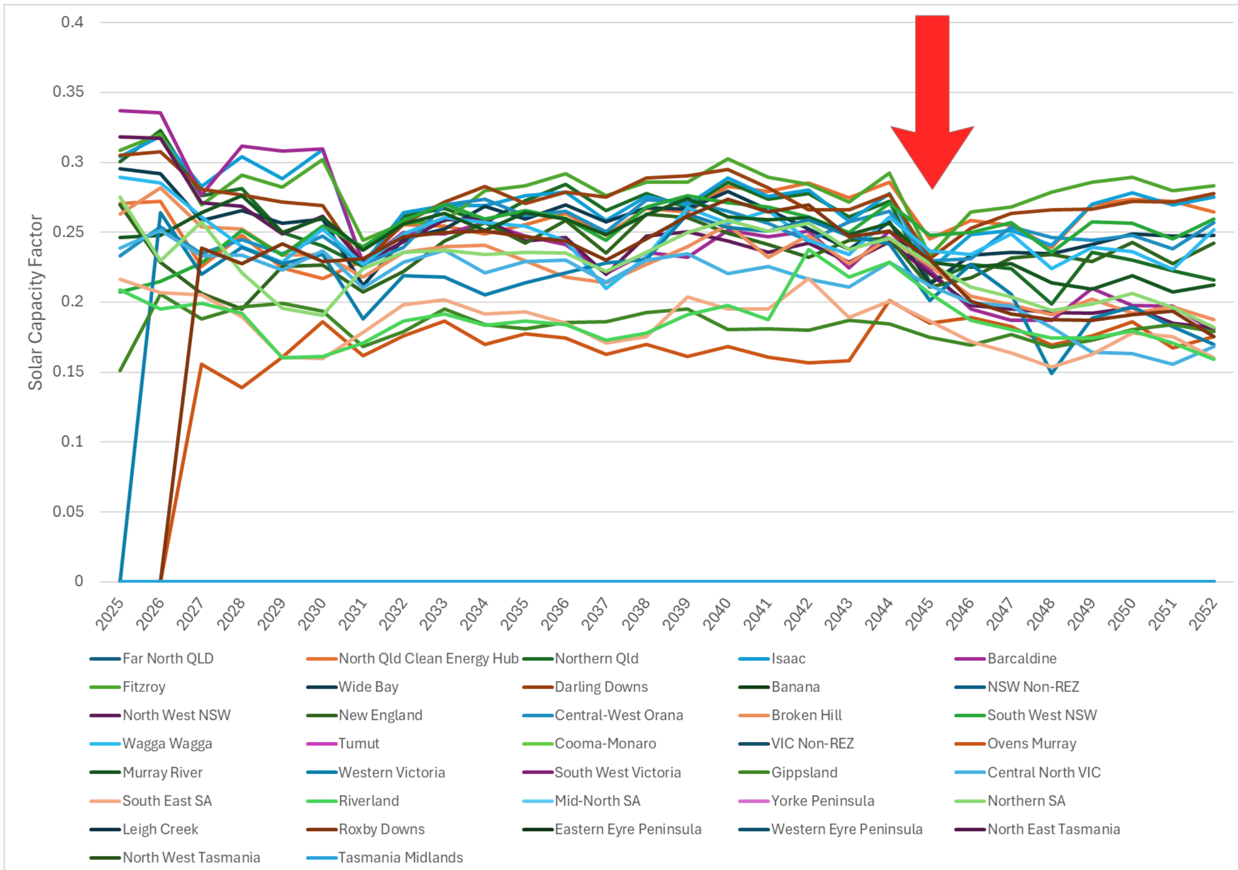

Figure 7. Solar capacity factors for solar farms across the NEM in the Draft 2024 ISP ODP under Step Change.[172]

Furthermore, following the more demanding weather-year in 2044-45, which drives nearly 4 GW of additional peaking gas being installed for that year, the ODP projects that approximately 4 GW of shallow battery storage can be immediately retired the following year, precisely 20 years (the full battery life) after being installed. This creates a significant discontinuity in the overall capacity of installed storage in the NEM, and is clearly an artefact of the particular demands of particular weather years being effectively known with unlimited foresight in the model's optimisation algorithm. A credible and realistic plan for the NEM must account for the fact that it is impossible to know exactly in which year such challenging weather events will arise, and a reliable system will require that we are ready for any weather year every year.

During the 2021 IASR consultation, TasNetworks recommended that AEMO "consider developing synthetic weather traces, while maintaining the consistency between various weather and demand factors, that better reflect the increased frequency of recent trends like bushfires, heavy rainfall events and tropical storms due to warmer ocean water temperatures", as "these events can have a considerable impact on all generation technologies."[173] This would

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[172] Solar capacity factors calculated using data from Draft 2024 ISP results workbook - Step Change, REZ Generation & REZ Generation Capacity tabs.
[173] TasNetworks, Submission on Draft 2021 IASR, p 3.

be a useful analysis to perform to ensure that grid reliability is secured in the face of likely extreme weather events over the ISP modelling horizon.

We submit that, in order to properly test the reliability of the grid under the ODP, AEMO should model the worst weather year over the past 30 years for each year of the modelling horizon to test that the generation capacity installed will always be sufficient to avoid blackouts above 0.002% of total annual energy needs. Alternatively, AEMO should run a stochastic weather model to ensure the ODP never results in the given threshold of unserved energy being exceeded during any year over hundreds (or thousands) of potential weather sequences.

Flaws in exploratory modelling

In the initial testing of the ODP's resilience, AEMO analysed the forecast dispatch mix in June 2040 "during a severe VRE drought event based on a historical severe dark and still weather event observed in June 2019", which lasted three days.[174] A drought lasting only three days was still sufficient to raise the possibility of the gas system becoming "constrained to deliver sufficient gas to operate GPGs, depending on the coincident needs from gas consumers".[175]

AEMO then conducted "exploratory modelling" involving a 'what-if' analysis that used the three-day VRE drought as a base and extended it to eight days, with the worst day being five days longer.[176] However, this analysis contained assumptions that do not appear to align with those of the ODP under Step Change, meaning that AEMO's assertion that "the Draft 2024 ISP ODP delivers resilience during long, dark and still periods"[177] remains unsupported.

The maximum energy output from hydro during a single half-hour period in the analysis was 7.78 GW.[178] However, this is impossible, as the ODP's forecast hydro capacity for the NEM excluding Queensland is 7.05 GW in 2039-40.[179] This limit should have been applied to the model.

Additionally, the maximum storage energy for medium and shallow storage has exceeded the forecast storage energy in AEMO's ISP model. There are 13 half-hour periods in the 8-day analysis in which medium and shallow storage exceeds the forecast storage energy of 77.34 GWh, which comprises medium, shallow and coordinated CER storage across the NEM excluding Queensland,[180] with the maximum storage energy reached being 99.47 GWh, almost 30% more than should be possible.[181] Even including passive CER, which is not able to be depended upon during a VRE drought because it cannot be directed to dispatch when most needed, the storage energy available is only 87.18 GWh,[182] with 9 half-hour periods still

[174] Draft 2024 ISP, Appendix 4: System Operability, p 22.
[175] Draft 2024 ISP, Appendix 4: System Operability, p 22.
[176] Draft 2024 ISP, Appendix 4: System Operability, p 23.
[177] Draft 2024 ISP, Appendix 4: System Operability, p 21.
[178] Draft 2024 ISP chart data, Figure 23 tab.
[179] Draft 2024 ISP results workbook - Step Change, Summary tab, CDP 11 (ODP).
[180] Draft 2024 ISP results workbook - Step Change, Summary tab, CDP 11 (ODP).
[181] Draft 2024 ISP chart data, Figure 23 tab.
[182] Draft 2024 ISP results workbook - Step Change, Summary tab, CDP 11 (ODP).

exceeding this limit in the eight-day analysis.[183] The limits of medium and shallow storage energy in the Draft 2024 ISP model should have been applied to the eight-day model.

Another issue is that the maximum net imports modelled for the eight-day period is 3.07 GW during a half-hour period,[184] which exceeds the current capacity of QNI Connect of 1.22 GW.[185] This is because the model relies on the ISP's "future project" of the QNI Connect upgrade occurring before 2040. However, by exceeding 3 GW, the model is assuming that QNI Connect will be upgraded to the expensive but larger Option 5, which has a total capacity of 3.47 GW, rather than the cheaper but smaller Option 2, which has a total capacity of only 2.92 GW.[186] Given that Option 2 has $921 million more in relative market benefits than Option 5, the reasons for this assumption, which would substantially decrease the benefits of the ODP under Step Change, should be explained. As it stands, the eight-day analysis does not prove the ODP satisfies the reliability requirement of the grid, as the analysis appears to not have modelled the ODP.

Furthermore, DSP is required by the model for a continuous period of 55.5 hours, with the greatest amount in one half hour period being 0.37 GW.[187] This appears to violate the 2-hour limit of continuous DSP operation per day from the reliability-response band included in the IASR, as outlined in the ISP Methodology consultation.[188] The Consumer Panel found this limit to be appropriate but requested "more data and detail sought for application to the 2026 ISP and associated methodology", with a review of the appropriateness for the 2024 ISP "ex-post, as more data and evidence becomes available".[189] The reason for allowing the 8-day model to violate the limit placed on the ISP model should be clarified. Currently, the 8-day analysis does not show that the reliability requirement has been met for the ODP under the constraints modelled on the ISP.

Ultimately, only testing an 8-day VRE drought in 2040 is insufficient to prove that every other year of the modelling horizon maintains the reliability requirement of the grid to the same degree. Other stakeholders have questioned the sufficiency of this analysis, with one asking whether "successive shorter duration renewable droughts" have been modelled, to which AEMO's Manager of Market Operability in System Design replied that "looking at shorter-duration, more regular events is a great idea" and that "we could certainly think about doing that analysis for the final ISP".[190] Modelling such sequences of weather events is important to properly test system reliability under likely conditions that will be experienced in coming

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[183] Draft 2024 ISP chart data, Figure 23 tab.
[184] Draft 2024 ISP chart data, Figure 23 tab.
[185] NS Energy, 2020. Queensland-New South Wales Interconnector (QNI) Upgrade.
[186] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 21.
[187] Draft 2024 ISP chart data, Figure 23 tab.
[188] ISP Methodology Update Consultation Paper, p 21; ISP Methodology Consultation Summary Report, p 4.
[189] 2024 ISP Consumer Panel, Submission to Consultation paper – Update to the ISP Methodology March 2023, p 13-14.
[190] Seb Kilborn, 2023. Draft 2024 Integrated System Plan publication webinar part 1. 1:03:06. AEMO Stakeholder Relations, YouTube.

decades, but will still be insufficient to fully ensure grid reliability under the ODP if only one year is analysed.

We submit that, rather than focusing on individual years, AEMO should focus on ensuring reliability across every year of the ISP model under a likely range of moderate and extreme weather events based on at least 30 years of historical weather data. However, if the 8-day analysis is included in the Final ISP, the errors regarding hydro and storage capacity assumptions, the DSP limit breach and the modelled QNI option should be addressed.

5. Circular logic used to exclude costs and justify policies

Circular logic of only testing scenarios with current government emissions targets

The ISP is used by the government as a source of objective truth to justify policy choices. As Minister Bowen has said, AEMO's Draft 2024 ISP "reiterates what we already know, firmed renewable energy is not just clean, it's the cheapest way to ensure a reliable grid."[191] Likewise, former NSW Energy Minister Matt Kean launched a tender for firming infrastructure, with the NSW Office of Energy and Climate Change anticipating at least 350 MW would be required in the Sydney-Newcastle-Wollongong sub-region based on the 2022 ISP and Energy Security Target Monitor Report.[192] This creates a clear opportunity for circular logic, which is a significant flaw in the ISP process, especially evident in how government targets like renewable energy expansion or carbon emissions reductions are handled. Targets and priority transmission projects identified by state governments, such as Central West Orana, Western Renewables Link, and CopperString, are integrated into the ISP as if they are already achieved or fixed constraints. This treatment allows significant investments to be considered sunk costs within the ISP, effectively inserting them into the counterfactual. Therefore, the ISP only identifies the least expensive method to address these constraints and cannot assess the true cost of the entire system compared to a neutral baseline. The Department of Climate Change, the Environment, Energy, and Water has acknowledged that the Australian Government spreads out system costs through taxes to avoid revealing them in electricity prices.[193] The ISP reduces transparency and accountability by allowing government policy changes to excise significant system costs from the model.

This circularity — where policy shapes the ISP, which then endorses the policy — limits a transparent evaluation of alternatives, potentially entrenching predetermined policy directions without a full accounting of their costs and benefits.

AEMO has consistently failed to properly consider that government policy can change in either direction. A proper cost benefit analysis that genuinely considers the long-term interest of consumers must reflect that public policy can be reversed. We have seen such events recently in Australia, for example the Carbon Tax.[194] The exclusion of any scenario where a net-zero carbon target is not achieved by 2050 overlooks that multiple countries have implemented policies that are expected to result in previously set renewables and carbon emissions reduction

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[191] Chris Bowen, 2023. Energy Market Operator shows firmed renewables the path for a cleaner, cheaper, more reliable grid, DCCEEW.
[192] Matt Kean, 2022. New firming tender to ensure energy reliability. NSW Treasury.
[193] Kirsty Gowans, 2023. CIS Public Consultation webinar – August 2023 - Transcript. 1:19:55. DCCEEW.
[194] Lenore Taylor, 2014. Australia kills off carbon tax. The Guardian.

targets being missed, moderated or removed (e.g., UK,[195] US,[196] Canada,[197] Germany,[198] China[199]). Just as previous ISPs contemplated ambitious carbon reduction mandates as eligible scenarios before they were formally adopted,[200] the Draft 2024 ISP should also consider scenarios where targets are missed, moderated or removed.

It might be reasonable to incorporate very stable public policy, with long-running acceptance, as being a fixture in all scenarios. But if a target/mandate can be increased or established within one or two years, it remains reasonable to assume that it could also be decreased or removed within a comparable timeframe. Removal of generous feed-in-tariffs from rooftop solar shows one such retraction of pro-renewable policies (e.g., Solar Bonus Scheme closed by the NSW Government in 2011 and ended in 2016[201]). Consequently, just as with long-run assumptions about battery prices, and EV uptake, long-run assumptions about government policy cannot be credibly altered quickly in a way that should be assumed permanent and irrevocable.

We submit that the ISP should allow for uncertainty in government policy (including emissions reduction targets) in the long run, and properly assess the risk of under- or over-investment from the consumer's perspective under different targets, including those that are less stringent than Net Zero 2050.

Elimination of only scenario with no binding emissions target

The Slow Change scenario was included in the 2020 ISP[202] and 2022 ISP, in which it "tested the impact of slower than anticipated emission reduction" and "would not reach the economy-wide decarbonisation objectives of Australia's Emissions Reduction Plan".[203] Under the Slow Change scenario, the 2022 ISP's ODP had the least net market benefits of any scenario (only $3.5 billion compared to $15.1 billion in Progressive Change, $24.5 billion in Step Change, and $64.6 billion in Hydrogen Superpower).[204] Under Slow Change, all but two of the 10 major network projects listed had recommended timelines that were more delayed than any other scenario or not recommended at all.[205] This scenario therefore represented a baseline distinct from all other scenarios that was useful for testing the benefits of transmission projects when emissions

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195 Fiona Harvey, 2023. UK likely to miss Paris climate targets by wide margin, analysis shows. The Guardian.
196 Benjamin Storrow, 2022. Hope Dims that the U.S. Can Meet 2030 Climate Goals. Scientific American.
197 Reuters, 2023. Canada's emission cuts unlikely to hit 2030 target, auditor general says.
198 Riham Alkousaa & Christian Kraemer, 2023. Germany set to miss net zero by 2045 target as climate efforts falter. Reuters.
199 Erin Hale, 2023. China promised climate action. Its emissions topped US, EU, India combined. Al Jazeera.
200 2020 ISP, p 20; 2022 ISP, p 31.
201 Energy Matters, 2014. New South Wales Solar Bonus Scheme.
202 2020 ISP, p 32.
203 2022 ISP, p 30.
204 2022 ISP, p 64.
205 2022 ISP, p 80.

targets are missed, as well as testing lower renewables generation, with 69% of all generation coming from renewables in 2030,[206] as opposed to Step Change's 78%.[207]

In the Draft 2024 ISP, AEMO decided to "model the legislated carbon budget to 2030 consistent with the 43% emissions reduction target, as well as a net zero emissions economy (by 2050) as committed policy, across all scenarios", while also modelling "the 82% share of renewable generation by 2030 across all the scenarios".[208] AEMO decided to remove the Slow Change scenario, claiming it is "no longer consistent with the pace of transformation required by the collection of policies facing Australia's energy industry".[209] The justification for its exclusion from the 2023 IASR was that "a majority of stakeholders supported the Slow Change scenario's removal, consistent with its very low relative likelihood in the 2022 ISP".[210] This is demonstrably false.

A majority of stakeholders did not, in fact, support the removal of Slow Change, with 56% either agreeing that the scenario is still relevant or not having an opinion either way (see Figure 8). Likewise, the majority of comments from stakeholders in the 2023 Preliminary Scenarios Webinar were supportive of keeping Slow Change in the analysis, particularly as a "bookend", "benchmark", "baseline" or "counterfactual" to measure against.[211]

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[206] 2022 Final ISP Results Workbook - Slow Change - Updated Inputs, Summary tab.
[207] 2022 Final ISP Results Workbook - Step Change - Updated Inputs, Summary tab.
[208] 2023 IASR, p 28.
[209] 2023 IASR, p 6.
[210] 2023 IASR, p 6.
[211] 2023 Preliminary Scenarios Webinar feedback, p 7-8.

Figure 3 Poll results – Are the previous scenarios still relevant?

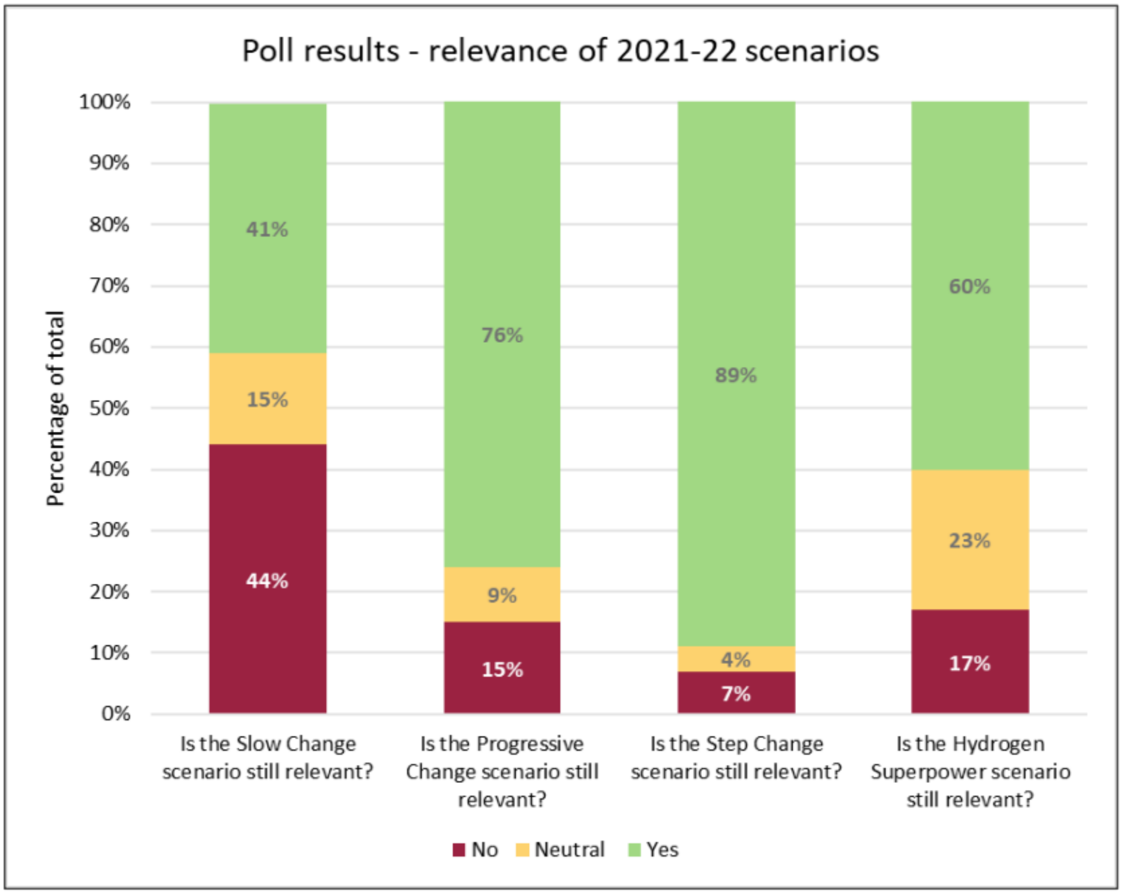

Figure 8. Poll results from 2023 Preliminary Scenarios Webinar feedback regarding the relevance of scenarios in the 2022 ISP to the Draft 2024 ISP.[212]

As one stakeholder put it, "Including this scenario ensures the full range of plausible outcomes are considered. It also provides a baseline comparison,"[213] with another saying it is "necessary to check for regretted investment." Another stakeholder made the important point that without Slow Change, there is "effectively no 'low' case", with other scenarios "being increasingly driven by policy ambitions, while not necessarily accounting for planning feasibility."[214]

Even some stakeholders who pointed out that Slow Change was not likely to occur still supported it remaining, with one saying, "It may not be a likely scenario, but it is important to have a good spread to see the impact of different futures. It also avoids the concern of 'bias'."[215] This need to avoid bias was reiterated by one stakeholder who said "It's likely to be worthwhile including one scenario that is relatively 'pessimistic' in terms of abatement progress, economic

[212] 2023 Preliminary Scenarios Webinar feedback, p 6.
[213] 2023 Preliminary Scenarios Webinar feedback, p 7.
[214] 2023 Preliminary Scenarios Webinar feedback, p 7.
[215] 2023 Preliminary Scenarios Webinar feedback, p 7.

growth, tech costs, etc. in order to get a wide spread of possible scenarios. Scenario planning is not just about what stakeholders want to happen."[216]

The relevance of this scenario given the geopolitical environment was emphasised, with one stakeholder saying, "The scenario may still be relevant for representing the uncertainty in economic recovery post pandemic and into the Russian invasion of Ukraine. It represents a de-prioritization of decarbonization and more emphasis on energy security."[217] The possibility of targets being missed was given as a reason for retaining Slow Change, with one stakeholder saying it is "irrelevant with policies in place, but may be worth it if policies fail" and "could also be valuable with QLD weak RES-e targets (30% by 2030)."[218] The possibility of targets being moderated or removed was also raised, with one stakeholder saying "a consumer-led scenario in constrained policy settings is required" because "we've seen in recent history that policy U-turns can happen completely reversing trends currently underway".[219]

The lack of consistency shown in the decision to remove Slow Change but retain Hydrogen Superpower was highlighted by a stakeholder stating, "By removing Slow Change because it is not in line with the current Australian Government ambitions, the same could be argued for removing Hydrogen Export. Slow Change provides a 'worst case' scenario for outcomes that helps create a more reasonable lower bound for decision makers."[220]

Testing the CDPs against both low and high emissions reduction and renewable generation scenarios is crucial for ensuring the range of plausible scenarios is considered, even if some are considered more likely than others.

While, AEMO "must consider the emissions reduction targets stated in the targets statement"[221] under the current NER, this does not mean the ISP cannot consider the impact of these targets being changed. The appropriate approach would be to reflect public policy commitments in scenario weightings rather than completely removing any scenario that does not fit current policy. Alternatively, a sensitivity analysis could be performed.

Despite AEMO stating that "a key role exists for sensitivity analysis to explore uncertainties pertaining to key assumptions",[222] no sensitivity analysis was performed regarding the uncertainty around carbon emissions targets being missed, moderated or removed (as is occurring in many other jurisdictions, listed in the previous section). AEMO claimed that removing Slow Change "improves the distinction between scenarios and enables greater consideration for complementary sensitivity analysis to test specific settings and key uncertain assumptions considered of high value to AEMO and stakeholders".[223] Yet one of the key uncertain assumptions tested in Slow Change, being failure to meet emissions targets, was not

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[216] 2023 Preliminary Scenarios Webinar feedback, p 8.
[217] 2023 Preliminary Scenarios Webinar feedback, p 7.
[218] 2023 Preliminary Scenarios Webinar feedback, p 7.
[219] 2023 Preliminary Scenarios Webinar feedback, p 7.
[220] 2023 Preliminary Scenarios Webinar feedback, p 20.
[221] National Electricity Rules Version 205. 5.22.3 Power system needs.
[222] 2023 IASR, p 6.
[223] 2023 IASR Consultation Summary Report, p 12.

tested in sensitivity analyses. There was also no sensitivity testing for the new renewables generation target of 82% by 2030, which was included in all models, to see what the impacts of lower renewables penetration would be on the ODP. This is despite multiple stakeholders emphasising the importance of testing policy uncertainties, as outlined above.

We submit that AEMO should include a scenario in the ISP that accounts for carbon emissions reductions and renewable generation falling short of current targets. This ensures testing a range of possible futures and establishes a baseline to evaluate the benefits of the ODP. If this isn't possible, AEMO should conduct sensitivity tests on lower or no emissions reduction targets to measure the impact on the ODP's benefits if targets are missed, moderated or removed. It's crucial to address this to prevent any appearance of bias in scenario selection, especially considering AEMO's inaccurate statements about stakeholder support for removing Slow Change and concerns raised by stakeholders about the need for a baseline scenario.

6. TOOT analysis is inappropriate for determining the benefits of individual projects

Take One Out at a Time (TOOT) analysis is a key method by which the benefits of individual projects are determined, and in turn the thresholds associated with cost increases in transmission projects that “would lead to this project no longer being beneficial”[224]. Therefore, the calculated number here holds significant importance for the ISP's critical functions, including the Feedback Loop, which safeguards consumers against uneconomical projects.

The Draft 2024 ISP reveals that the TOOT analysis is unsuitable for its intended purpose. The sum of TOOT-derived net benefits of just a subset of major transmission projects in the ODP matches the total net benefits of all transmission projects in Step Change, as seen in the counterfactual.

Flow path augmentation timings by CDP

Project	Net Benefits from TOOT $Bn
New England REZ Transmission Link 1	4
New England REZ Transmission Link 2	
Sydney Ring Option 1	4.2
Sydney Ring Option 2	
Gladstone Grid Reinforcement	4.9
Queensland SuperGrid North Option 1	
Queensland SuperGrid North Option 2	
HumeLink	1
Project Marinus Stage 1	0.3
Project Marinus Stage 2	
QNI Connect Option 2	
QNI Connect Option 5	
Queensland SuperGrid South Option 1	
Queensland SuperGrid South Option 5	2.2
VNI West	0.7
Mid-North South Australia Upgrade	
New England REZ Extension	
Tasmanian Central Highlands REZ Upgrade	
TOTAL	17.3

Table 1. Net Benefits of projects from Appendix 6 of Draft 2024 ISP.

Note that in this case we have considered the $7.1 billion combined value of SuperGrid South with Gladstone Reinforcement spread across those two projects.

[224] ISP Methodology 2023, p 104.

Even with the $7.1 billion combined values of SuperGrid South and Gladstone Reinforcement, the total $17 billion net benefits of the ODP are reached before accounting for Queensland Supergrid North or QNI Connect. Projects like REZ expansions and grid reinforcements in Victoria are also excluded from this total. This discrepancy arises from a misunderstanding of how network effects can distort the perceived values of individual components within a system. Consequently, careful consideration needs to be given to the network effects that certain system elements generate when combined. Because their value might be greater than their individual parts when combined as a whole, their individual value is also overstated by considering the isolated removal of just one part of the system.

For this reason, a group of projects, when their benefits are assessed using TOOT, are quickly found to have benefits whose sum exceeds the total benefit of the group. Benefits are consistently over-counted in this way, as shown in Table 1.

We argue that the ISP should consistently, logically, and transparently decide which projects are considered together as a connected subsystem rather than individually (as is done with TOOT analyses). This approach ensures a proper understanding of how much transmission cost increases would make a project no longer viable.

The analysis already shows precedent for considering multiple projects together, as seen with SuperGrid South and Gladstone Reinforcement. It's logical to consider them as partially dependent on each other and optimize them as a subsystem. However, the inconsistent approach of conducting a separate TOOT for SuperGrid South, a combined analysis for both projects, and no separate TOOT for Gladstone Reinforcement misses an opportunity to demonstrate and quantify network effects and discrepancies between individual TOOTs and larger combined assessments in this instance.

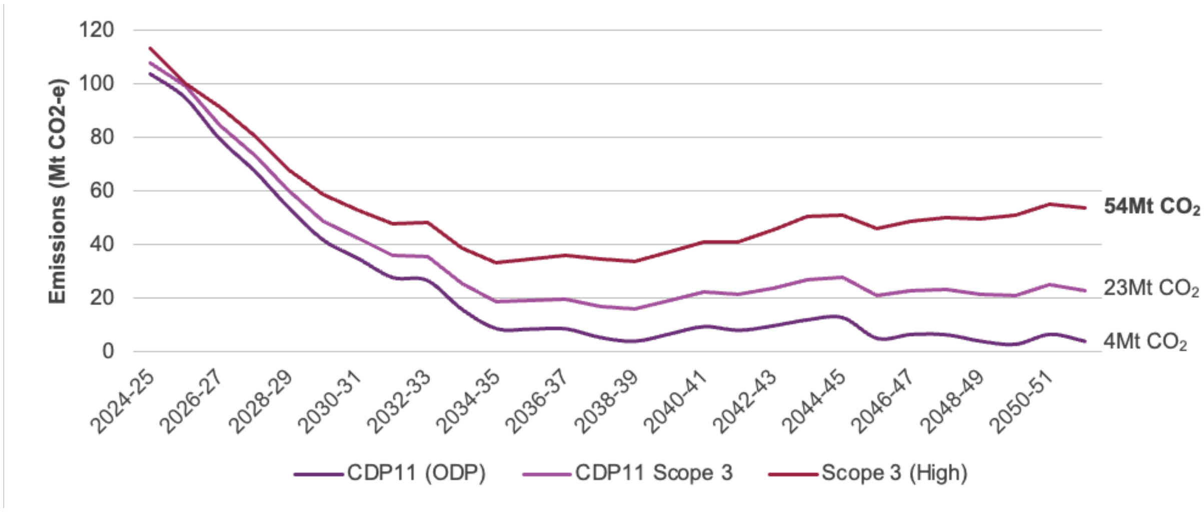
The most egregious abuse of this method centres on the consideration of HumeLink and VNI West, as well as potentially Sydney Ring, all via individual TOOT analyses. These systems combined massively increase the interconnection capacity between Australia's two largest load centres in Melbourne and Sydney, and also link vast projected renewable energy resources in Victoria and NSW to the largest energy storage system in the NEM at Snowy 2.0. The capacity for Victorian renewable energy to enhance the weather diversity available to support NSW requires both HumeLink and VNI West, and vice versa for NSW supporting Victoria. Removing just one of these projects alone will obviously leave an inefficient system remaining, which can't be considered a serious alternative.

The potential for either state to store energy in the Snowy Hydro 2.0 is also dependent on these interconnectors, and to the extent that stored energy can serve either state in its time of greatest need, the benefits associated would also be very strongly linked. The treatment of Snowy Hydro 2.0 as a sunk cost in all scenarios, as well as other vital REZ transmission investments (such as Central West Orana, Western Renewables Link) by virtue of them being committed to by state governments also massively distort the benefits that can be assessed via a TOOT analysis.

This has prevented the ISP from examining a significant alternative scenario where Snowy Hydro 2.0, HumeLink, and VNI West are all removed — saving billions of dollars — and states develop their own renewable energy zones, storage and gas firming with less interconnection. This failure to consider the alternative is a serious flaw in the ISP, potentially suggesting bias towards vested interests in flawed projects already underway, despite their economic case weakening. We propose the ISP should test this credible alternative scenario to rebuild trust in its integrity.

7. Emissions intensity

The exclusion of lifecycle emissions from the ISP report currently significantly understates the impact of Australia's energy transition on climate change. The emissions from firmed renewables are still uncertain, but excluding lifecycle emissions could lead to underestimating emissions by a large margin, potentially up to 54 megatons of CO2 emissions in 2050. (see Figure 9).



Note: The assumptions for this calculation are based on Wang[225] and modified to account for the capacity factor of rooftop PV (15%) and capacity of utility scale solar (29%). Scope 3 battery emissions are estimated using 72.9kg/kWh from Dai and co-authors[226] and assuming a lifespan of 20 years for utility-scale batteries and 15 for consumer batteries. Wind emissions intensity was taken from the UNECE.[227] CDP11 (ODP) emissions, graph itself, and other assumptions are from the 2024 Draft ISP results workbook, Summary sheet, "NEM Emissions Trajectory".

Figure 9. Projected emissions intensity including median and high estimates of lifecycle emissions for solar, wind, and batteries.

Accounting only for direct (scope 1) emissions, the ISP effectively 'exports' emissions to the point of manufacture, ignoring the lifecycle impact of selected energy sources. Such an approach is particularly problematic for renewables — which are largely manufactured in China where the grid remains highly reliant on coal, particularly for energy-intensive applications. This oversight is critical for renewables like solar, wind, and batteries which require highly energy-intensive manufacturing. Thus, the ISP likely underrepresents the true environmental cost of these technologies when evaluated solely on their direct emissions.

Alongside direct (scope 1) emissions, Australia's National Greenhouse Energy Reporting Scheme (NGER) allows companies to report scope 3 emissions which are "indirect greenhouse

[225] Seaver Wang, 2022. Sins of a Solar Empire. Breakthrough Institute.
[226] Qiang Dai et al, 2019. Life Cycle Analysis of Lithium-Ion Batteries for Automotive Applications. Batteries. Volume 5, no. 2, pp 101-111.
[227] UNECE, 2022. Carbon Neutrality in the UNECE Region.

gas emissions other than scope 2 emissions that are generated in the wider economy. They occur as a consequence of the activities of a facility, but from sources not owned or controlled by that facility's business."[228] As noted by Deloitte UK, "Scope 3 is nearly always the big one,"[229] and in the case of zero emissions energy sources, Scope 3 is the only source of greenhouse gas emissions associated with these technologies. It is therefore critical for AEMO to consider it.

Emissions for both residential and utility-scale solar and battery

The estimates for the lifecycle emissions of renewables vary wildly, with batteries emitting anywhere from 15–487 kg CO2e per kWh, and solar anywhere from 8–174 g CO2e per kWh. Both depend particularly on the energy mix of the grid where they are manufactured. While the literature is still settling on this, it is clear that both batteries and solar have the potential not only to significantly contribute to global emissions, but under some assumptions even jeopardise attempts to reach net zero.

The emissions intensity of a system with any variable energy source needing battery storage will be higher than that of one with a firm source of energy; if the ISP intends to model whole-of-system emissions, it needs to use reasonable estimates of the scope 3 emissions of each component of the system.

The UNECE estimates "8.0–83 g CO2e/kWh for photovoltaics".[230] This assumes a European (Spanish) capacity factor of 12.4%, consistent with AEC estimates for Australian rooftop solar. However, because the lifecycle emissions estimates for solar panels are sensitive to the energy mix of the grid where manufacture took place, and now that nearly 90% of cells and three quarters of modules on the market are produced in China, we argue that these estimates are low. Estimates accounting for Chinese grid intensity such as Mariutti (2023) found that the range for scope 3 emissions (excluding those related to transmission and firming) are 96–174 g CO2/kWh.[231]

And notably, even for solar power that is consumed onsite, a battery system under conservative (low) assumptions can add 9–28 g CO2-e per kWh to the emissions intensity. This is from the IEA (2020) who estimated that the "cumulative greenhouse gas emissions from 1 kWh of electricity generation for self-consumption via a PV-battery system are 80, 84, and 88 g CO2-eq/kWh, respectively."[232] meaning that passive CER also has lifecycle emissions that should be considered. Under similarly conservative assumptions, they also estimate that for utility-scale PV-battery systems "adding 4 hours of 60-MW storage to a conventional 100-MW PV system would increase GHG emissions from 62 to 71–90 g CO2 eq./kWh".[233]

[228] NGER, 2023. Greenhouse gases and energy.
[229] Deloitte, 2024. Scope 1, 2 and 3 emissions.
[230] UNECE, 2022. Carbon Neutrality in the UNECE Region.
[231] Enrico Mariutti, 2023. The Dirty Secret of the Solar Industry. p 20
[232] IEA, 2020. Environmental Life Cycle Assessment of Residential PV and Battery Storage Systems. p 9.
[233] UNECE, 2022. Carbon Neutrality in the UNECE Region. p 35.

We submit that AEMO should:

1. Include scope 3 emissions when modelling the energy transition and selecting appropriate low-emissions energy sources to hit emissions targets.
2. Indicate the range of potential scope 3 emissions of technologies in emissions trajectory reporting.
3. Ensure that lifecycle emissions account for the carbon intensity of the grid where goods are manufactured.

8. Why is HumeLink still actionable despite huge cost overrun?

The total cost for delivering HumeLink, as disclosed by Transgrid, escalated from $3.3 billion (in June 2020 dollars)[234] to $4.9 billion (in June 2023 dollars),[235] marking a steep 48% or $1.6 billion increase. Such a substantial escalation should have had an adverse impact on the project's economic feasibility. Yet, the Draft 2024 ISP still shows a net present value of total market benefits for HumeLink at $1 billion[236] — an *uptick* from the $977 million reported in the 2022 ISP.[237] The cost overrun appears to be neutralised by a $1.7 billion rise in projected market benefits. What explains this substantial increase in projected market benefits?

Class of market benefits	2022 ISP Original ($m)	2022 ISP Restated ($m)	Draft 2024 ISP ($m)	Change ($m)
Generator and storage capital deferral savings	2,485	1,862	3,249	+ 1,387
FOM cost savings	323	242	359	+ 117
Fuel cost savings	319	239	480	+ 241
VOM cost savings	20	15	27	+ 12
USE+DSP costs reduction	84	63	27	- 36
Other network investment (REZ augmentations)	100	75	39	- 36
Gross market benefits	3,330	2,496	4,180	+ 1,684
Network (actionable and future ISP projects)	(2,026)	(1,519)	(3,111)	- 1,592
Total market benefits	**1,303**	**977**	**1,069**	**+ 92**

Sources: 2022 ISP, Appendix 6; Draft 2024 ISP, Appendix 6

Table 2. Net present value of HumeLink market benefits relative to not building HumeLink.

During the recent Draft ISP Consumer Advocate pre-submission webinar, Eli Pack explained that that the additional benefits are due to "the cost of alternatives to HumeLink have also gone up"[238], allowing HumeLink to maintain a positive net present value. In other words, the substantial increase in relative market benefits for HumeLink is ostensibly due to inflationary pressures affecting the costs of constructing and operating alternative generator capacity in the absence of HumeLink.

The ISP's TOOT analysis indicates that HumeLink's main benefits come from delaying spending on generators and storage, and partly from saving on fuel costs due to less need for gas-generated power. Table 2 illustrates that both projected benefits have notably increased from the previous ISP update: delaying expenditures on generators and storage has risen by $1.4 billion, and fuel cost savings by $241 million. We will delve into these two components further below.

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[234] Transgrid, 2021. Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink): Project Assessment Conclusions Report.
[235] AEMO, 2023 Transmission Expansion Options Report, p 61. See also Transgrid, HumeLink Draft Contingent Project Application–Principal Application document, p 6.
[236] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 41.
[237] The present value figures for the 2022 ISP, which applied a discount rate of 5.5%, have been restated in 2023 dollars using the draft 2024 ISP's discount rate of 7% to allow consistent comparison.
[238] Eli Pack, 2024. Draft ISP Consumer Advocate pre-submission webinar. AEMO.

How much of the additional market benefits of HumeLink is attributable to escalated construction costs?

The Draft 2024 ISP's cost benefit analysis posits that implementing HumeLink would yield significant market benefits by deferring the capital expenditure needed to construct gas power plants, pumped hydro, and onshore wind as coal plants in New South Wales are aggressively decommissioned by 2037-38 to meet the cumulative carbon budget target. To quote the cost benefit analysis from Appendix 6:

> "Without HumeLink, 1.2 GW of GPG in the Sydney, Newcastle, and Wollongong subregion, approximately 500 MW of pumped hydro in Northern New South Wales, and 1.2 GW of onshore wind in Central New South Wales and Queensland are required from 2026-27 to replace the New South Wales coal fleet as it retires."[239]

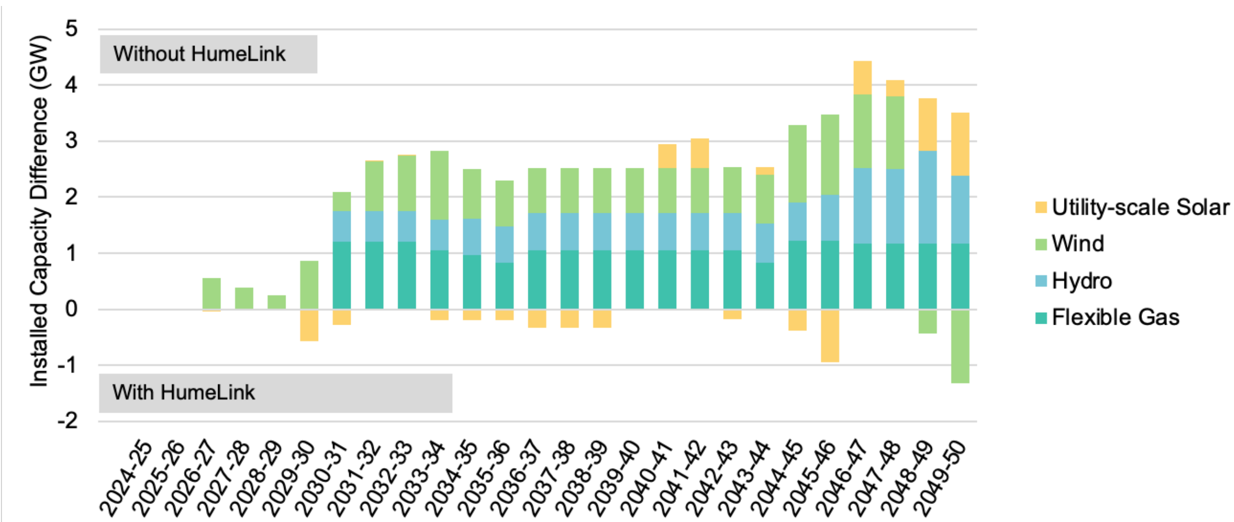

Figure 10. Comparison of capacity with HumeLink (2029-30) and without HumeLink in Step Change.[240]

As noted in the Draft 2024 ISP, the modelled installed generator capacity difference in the Draft 2024 ISP significantly diverges from the 2022 ISP results. In the Draft 2024 ISP, pumped hydro and peaking gas were deemed the next best alternative to an actionable HumeLink.

[239] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 42.
[240] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 43.

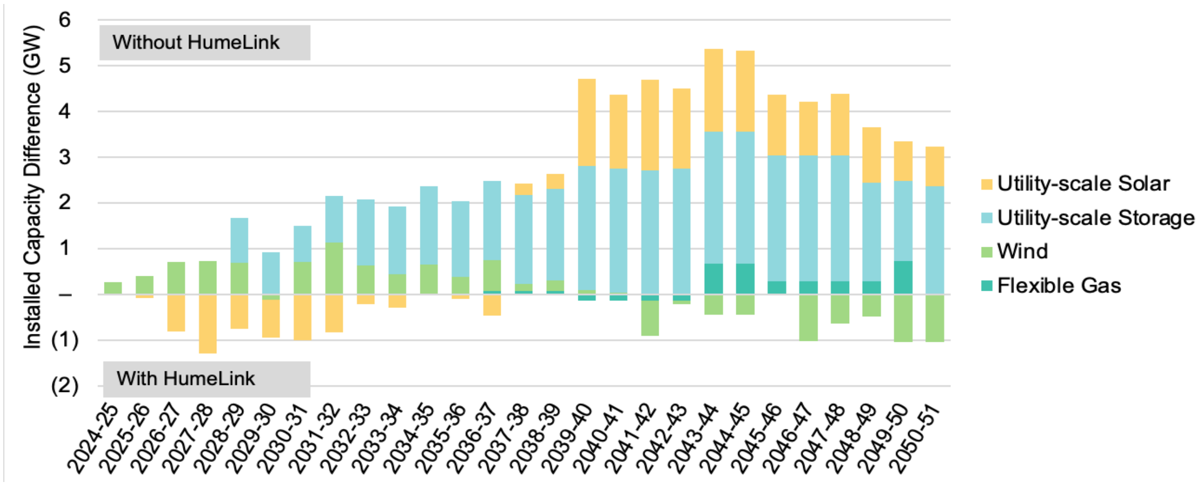

Figure 11. Comparison of capacity with HumeLink (in 2026-27) and without HumeLink in Step Change.[241]

Generator type	Average Additional Capacity Installed Without HumeLink		Average Capital Cost ($/kw, 2023 dollars)		
	2022 TOOT	2024 TOOT	2022 ISP	Draft 2024 ISP	%Ch
Utility-scale Solar	410 MW	2 MW	$ 769	$ 947	+23%
Hydro	–	606 MW	$ 2,720	$ 2,866	+5%
Utility-scale Storage	1,712 MW	–	$ 889	$ 1,386	+56%
Flexible Gas	110 MW	840 MW	$ 1,299	$ 1,163	-11%
Wind	108 MW	670 MW	$ 1,969	$ 2,052	+4%
Total	**2,340 MW**	**2,118 MW**	–	–	–

Table 3. Average installed capacity difference and average build cost from 2024-25 to 2049-50.

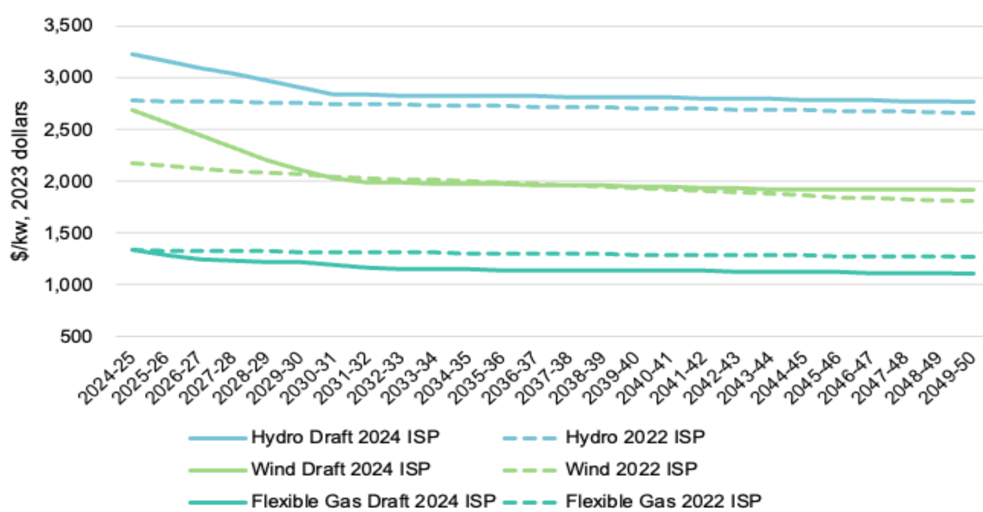

Figure 12. Comparison of capital costs — 2022 ISP versus the Draft 2024 ISP, Step Change scenario.[242]

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[241] 2022 ISP, Appendix 6: Cost Benefit Analysis, p 49.

[242] 2022 ISP Inputs, Assumptions and Scenarios Workbook, Build Cost tab; Draft 2024 ISP Inputs, Assumptions and Scenarios Workbook, Build Cost tab.

To evaluate the impact of the escalated construction costs on HumeLink's market benefits, we replaced the build cost assumptions from the Draft 2024 ISP with those used in the 2022 ISP. We found that the 2022 prices actually slightly increase the capital savings in the 2024 ISP (by $61 million), the reverse of the change that would be expected by generally increasing costs. This reflects that there are only minor changes in the assumed costs for capital across the different asset classes, and the capital costs assumptions for gas have actually decreased, which slightly eclipses the impact of minor increases in wind and hydro (per Figure 12 above).

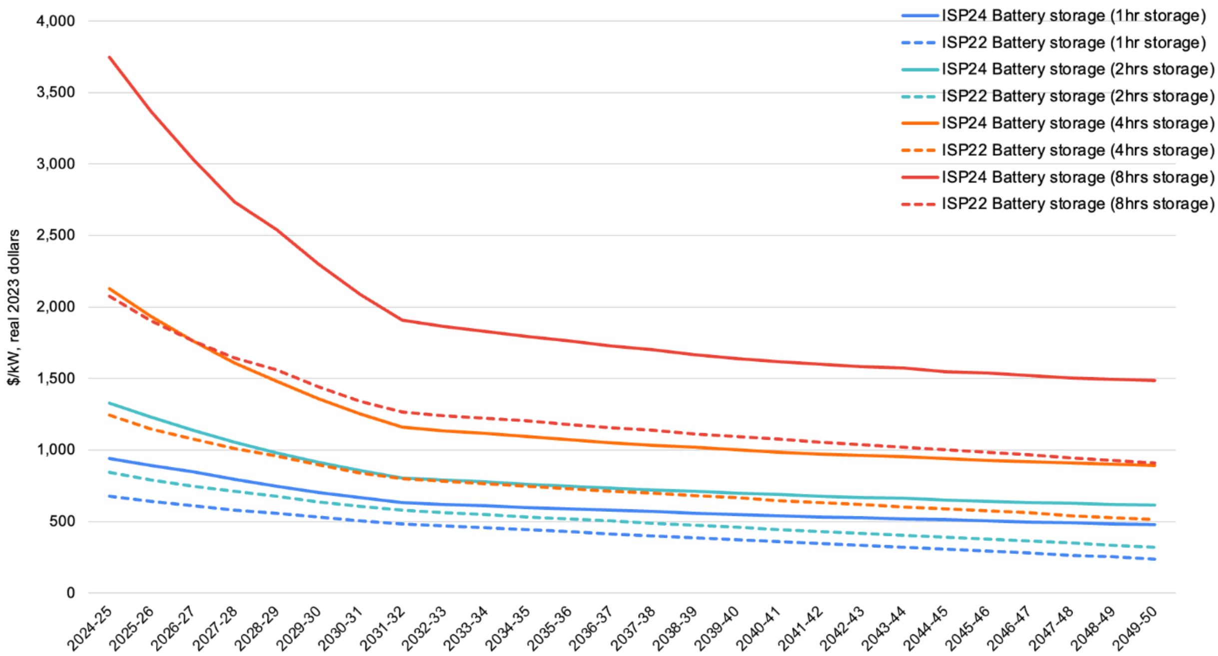

Figure 13. Projected capital cost of battery storage — 2022 ISP versus the Draft 2024 ISP, Step Change scenario.[243]

The prices of batteries have increased significantly more in the change between 2022 and 2024 assumptions. It is noted in the 2024 draft that the switch to pumped hydro storage was necessitated partly by an increase in battery costs and hence the increase in battery prices might place an upper-bound on the cost of the switch from batteries to hydro. However, even when replacing the hydro capacity of the 2024 ISP with batteries, taking the weighted mix of battery storage depths from the 2024 ISP, we find that battery changes only account for a slightly larger amount. In total, increases in capital costs even accepting this battery replacement can only explain approximately $328 million, or 10% of the increase in HumeLink's market benefits (see Figure 14 below).

We therefore conclude that increases in the capital savings are not due to price rises, but mostly due to increases in the volume of capacity in this particular model, which we will discuss later.

[243] 2022 ISP Inputs, Assumptions and Scenarios Workbook, Build Cost tab; Draft 2024 ISP Inputs, Assumptions and Scenarios Workbook, Build Cost tab.

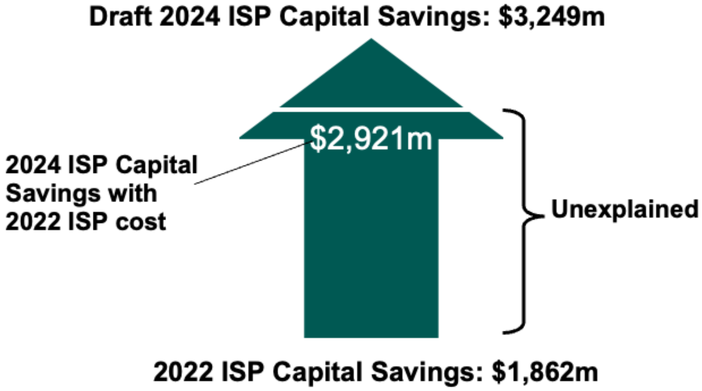

Figure 14. Rise in construction cost increase fails to explain $1,059 million of HumeLink's relative benefits in capital deferral savings.

It's important to note the sudden shift in the type of alternative generation capacity required between the 2022 and Draft 2024 models, which reveals excessive sensitivities and overfitting in the ISP's perfect foresight model. The significant increase in projected battery costs over two years isn't due to real-world changes, which have remained relatively stable. Instead, the main shift stems from switching the mapping for the Step Change from the 'High VRE' scenario in the 2022 ISP to the 'Net-Zero post 2050' scenario in the Draft 2024. This means that a modest real-world uptick has been greatly amplified by this change in assumptions. As a result, a solution relying on batteries has been largely replaced by pumped hydro, even in the near future.

This further underlines the fact that the model is inherently over-fit and assumes utterly unreasonable degrees of precision being possible in planning the energy transition. There will be no possibility for us to switch between a battery-based solution and a pumped-hydro solution every two years. We will have to plan and commit to things further in advance. Cost benefit analyses that reflect modelled energy mixes that swing so greatly in response to small assumption updates are fundamentally not fit for purpose.

But most crucially, it should be noted that Eli Pack's claim that HumeLink's benefits have been preserved because the cost of alternatives to HumeLink have risen is still very deceptive and untrue. Battery costs have only risen very modestly. AEMO's assumptions about them projected into the future have changed more dramatically. The previous ISP was underpinned by an *assumption* about battery costs into the future, which has been modified. If subtly shifted *assumptions* with very large impacts are claimed to justify very dramatic changes in value proposition, when the real world prices are actually evolving quite slowly, but failing to accord with earlier assumptions, the credibility ISP as a planning tool is greatly damaged.

How much of the additional market benefits of HumeLink is attributable to inflated gas fuel price?

We now turn to the $241 million additional fuel cost savings reported in the Draft 2024 ISP. As noted above, the ISP's TOOT analysis shows that delivering HumeLink would enable significant "fuel costs savings from avoided GPG over the outlook period" by facilitating "greater access to

Snowy 2.0 [and thereby avoid] more expensive GPG in Sydney, Newcastle, and Wollongong subregion, and in Victoria".[244]

This explanation is puzzling. The Draft 2024 ISP predicts lower gas prices for power generation compared to the forecasted prices used in the 2022 ISP for most of the outlook period. Therefore, to the extent that gas usage is considered as an alternative to HumeLink, this price change doesn't significantly boost the benefits of HumeLink.

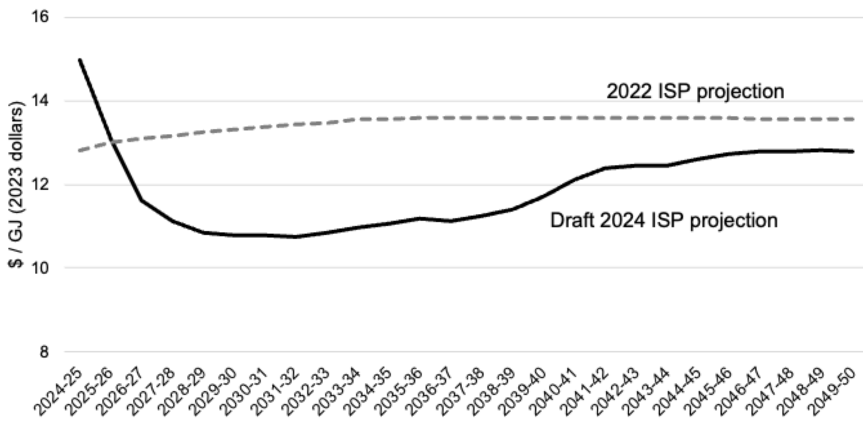

Figure 15. Median gas prices for new plants – the 2022 ISP versus the Draft 2024 ISP.[245]

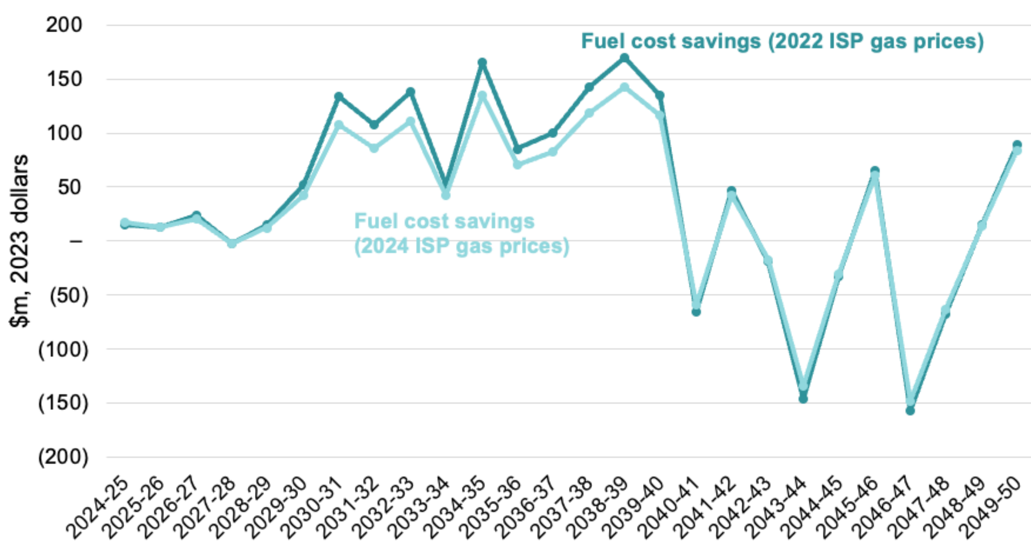

Figure 16. Adjusting fuel cost savings in 2024 HumeLink TOOT analysis for changes in gas price forecast since 2022 ISP.

[244] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 41.
[245] 2022 ISP Inputs, Assumptions and Scenarios Workbook, Fuel Price Summary tab; Draft 2024 ISP Inputs, Assumptions and Scenarios Workbook, Fuel Price Summary tab.

Net Market Benefits of HumeLink

We've shown that changes in alternative costs don't explain the increased benefits of HumeLink in the 2024 ISP. Now, we focus on how the amount and timing of alternative capacities to HumeLink provide a more likely explanation for the differences observed. We argue that there's evidence of significant experimental bias because key experiments that would objectively support HumeLink's inclusion in the Optimal Development Path, with its proposed timing in the Feedback Loop, have been either left out or misrepresented.

The 2022 ISP included HumeLink as a staged project, such that the option to construct HumeLink at the Earliest In Service Date (EISD) of 2026-27 would be retained. Table 51 of Appendix 6 in the 2022 ISP demonstrated that proceeding to full construction at the EISD (no staging) would actually result in approximately $190 million dollars lower net benefits than allowing the option to leave completion two years later, to 2028-29.[246] It also showed that leaving the project to complete even later (schedule slippage) to 2030-31 would have a smaller reduction in net benefits, of only $130 million.

Table 51 Assessing the benefits of HumeLink as a staged actionable project, including consideration of schedule slippage under updated inputs

Scenario	Net market benefits ($ billion)					
	No schedule slippage			Schedule slippage leading to 2-year delay		
	Staged actionable project for delivery in 2026-27 (CD12)	No action, delivery from 2028-29 (CDP10)	Full project progressed now, delivery in 2026-27 (CDP11)	Staged actionable project with delivery in 2028-29 (CD12)	No action, delivery from 2030-31 (CDP10)	Full project progressed now, with delivery in 2028-29 (CDP11)
Step Change	24.48	24.48	24.30	24.48	24.44	24.49
Progressive Change	15.10	15.23	14.79	15.10	15.23	15.02
Hydrogen Superpower	64.59	64.38	64.59	64.38	63.75	64.38
Slow Change	3.53	3.53	3.28	3.53	3.46	3.53
Weighted	27.74	27.74	27.55	27.70	27.61	27.68

Table 4. Net market benefits of HumeLink as a staged actionable project, including consideration of schedule slippage under updated inputs in 2022 ISP.[247]

The optimal timing of HumeLink is also shown in Table 8 of the 2022 ISP to be 2028-29 in *Step Change*, which was deemed the most likely scenario. Table 8 of Appendix 6 shows that bringing HumeLink forward from that optimal timing cost reduces net market benefits by $361 million.

Arguments favouring an earlier timing for HumeLink relied heavily on concepts of ‘insurance’ and ‘risk’, which were extensively discussed in the Consumer Panel report on the Draft ISP. However, the 2022 ISP lacked measurable evidence that advancing HumeLink's timing was truly in consumers' best interests. It assumed consumers would willingly pay more to mitigate

[246] 2022 ISP, Appendix 6: Cost Benefit Analysis, p 64.
[247] 2022 ISP, Appendix 6: Cost Benefit Analysis, p 64.

risks, without quantifying HumeLink's actual "insurance" value in reducing energy shortages. AEMO asserted its usefulness in this role without providing concrete evidence. There's strong reason to believe that increasing connections between weather zones in NSW and Victoria only marginally reduces the likelihood of shortages rather than reliably preventing them. As such, in the 2024 ISP, the obvious and most important question that should be asked, and that the ISP should answer, is whether the HumeLink should be progressed urgently, to meet the same EISD of 2026-27, or whether it would be best delayed two years (as optimal in the 2022 ISP), or perhaps even further.

Omission of a 2026-27 delivery analysis of net market benefits

The obvious way of answering such a question would be to compare alternative development paths where the only change was the in-service date of HumeLink, between 2026-27 which has already been approved in the Feedback Loop Notice issued 21 December 2023, and another alternative later date. The language of the Draft Contingent Project Application published by Transgrid on 8th of December 2023 indicates that HumeLink is being advanced in the greatest haste, in order to meet the 2026-27 EISD, specifically referencing the 2022 ISP.[248]
The same document makes clear that Transgrid had confidence that the Optimal Development Path to be published by AEMO in the 2024 Draft would confirm this timing in the Feedback Loop. The significance of this timing question should and would have been clear to AEMO, and the need for an objective and rigorous experiment in the ISP to support it.

Yet, the 2024 Draft ISP fails to explore any development path that includes any consideration of HumeLink actually being progressed at the EISD timing of 2026-27. Instead, the only timing contemplated in any of the development paths is 2029-30 and later. This oversight is particularly baffling, given that the TOOT analysis for HumeLink conducted in the 2022 ISP positioned the project's delivery in 2026-27.

Delaying HumeLink's delivery from 2026-27 to 2029-30, as projected in the 2024 TOOT analysis, has a critical impact. Pushing back HumeLink's costs by three years significantly lowers discounted network expenses, increasing its net market benefits. Our calculations indicate that reverting HumeLink's delivery timing to 2026-27 would greatly reduce its net market benefits, from $1 billion to just $185 million. Combined with other factors discussed, this would likely make HumeLink's net present value negative, endangering its business case.

[248] Transgrid Draft Contingent Project Application for HumeLink, Executive Summary, p 5.

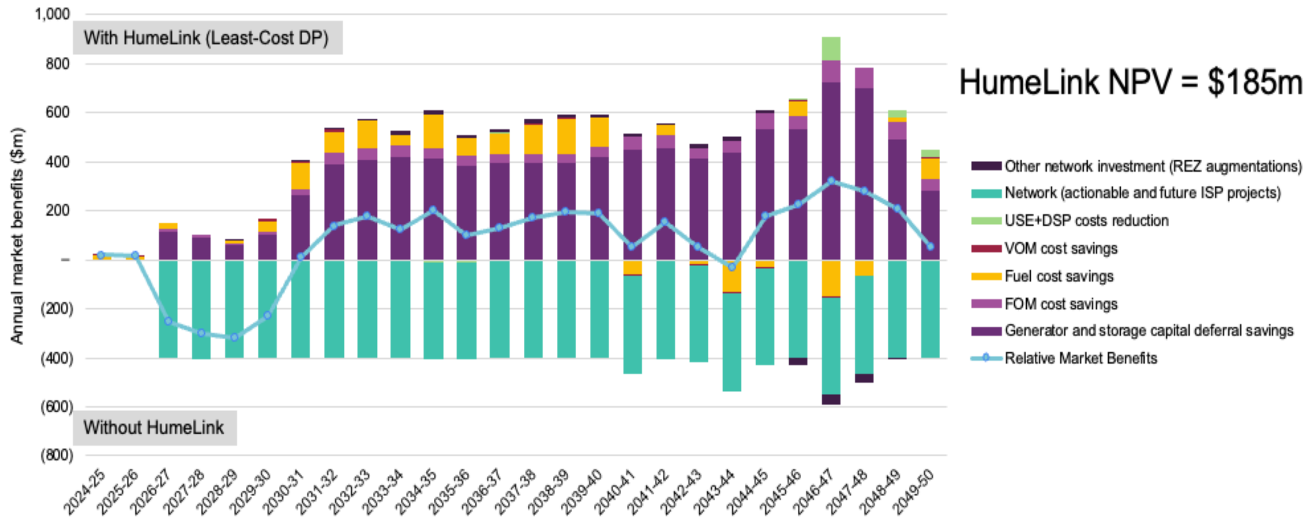

Figure 17. Recalculated NPV of HumeLink delivered at planned in-service date.

Flow path augmentation timings by CDP

Project	CDP1	CDP2	CDP3	CDP4	CDP5	CDP6	CDP7	CDP8	CDP9	CDP10	CDP11 (ODP)	CDP12	CDP13	CDP14	CDP15	CDP16	CDP17	Least-cost DP	Counterfactual
New England REZ Transmission Link 1	2028-29	2032-33	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2032-33	2028-29	-
New England REZ Transmission Link 2	2031-32	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	2034-35	-
Sydney Ring Option 1	2028-29	2028-29	2028-29	2031-32	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2028-29	2031-32	2028-29	-
Sydney Ring Option 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gladstone Grid Reinforcement	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2032-33	2032-33	2030-31	-
Queensland SuperGrid North Option 1	2031-32	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2031-32	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	-
Queensland SuperGrid North Option 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HumeLink	2029-30	2029-30	2029-30	2029-30	2032-33	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2032-33	2029-30	-
Project Marinus Stage 1	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2035-36	2029-30	2029-30	2029-30	2029-30	2035-36	2029-30	-
Project Marinus Stage 2	2036-37	2036-37	2047-48	2047-48	2047-48	2047-48	2047-48	2047-48	2047-48	2047-48	2036-37	2047-48	2036-37	2036-37	2047-48	2047-48	2047-48	2047-48	-
QNI Connect Option 2	2031-32	2033-34	2033-34	2033-34	2033-34	2033-34	2031-32	2033-34	2033-34	2033-34	2033-34	2033-34	2033-34	2031-32	2033-34	2033-34	2033-34	2033-34	-
QNI Connect Option 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Queensland SuperGrid South Option 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Queensland SuperGrid South Option 5	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2032-33	2032-33	2032-33	2030-31	-
VNI West	2029-30	2029-30	2029-30	2029-30	2034-35	2035-36	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2035-36	2029-30	-
Mid-North South Australia Upgrade	2028-29	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2045-46	2028-29	2045-46	2045-46	2028-29	2045-46	2045-46	2045-46	2045-46	2045-46	-
New England REZ Extension	2030-31	2032-33	2030-31	2030-31	2030-31	2030-31	2030-31	2032-33	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2030-31	2032-33	2030-31	-
Tasmanian Central Highlands REZ Upgrade	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2029-30	2035-36	2029-30	-

Figure 18. Flow path augmentation timings by CDP in Step Change.[249]

Further, the absence of information on the best timing for HumeLink in the 2024 Draft ISP, similar to Table 8 in the 2022 ISP could be seen as an intentional avoidance of this crucial question. Table 7 in the Draft 2024 ISP lists optimal timings for Future ISP projects but omits HumeLink and other actionable projects, resulting in a significant loss of transparency.

The lack of transparency is further compounded by how relative market benefits for HumeLink are presented in Appendix 6. The benefits are shown for a scenario where HumeLink is completed in 2029-30, a year later than the optimal year in the 2022 ISP and three years later than the earliest expected service date, contrary to AEMO's claim in the Feedback Loop notice. This discrepancy in timing for evaluating market benefits is undeniable for several reasons:

1. In the paragraph above the Draft 2024 ISP's Table 21, the 2029-30 date is mentioned explicitly in association with the cost.
2. The label of the Draft 2024 ISP's Figure 8 also includes 2029-30 in brackets.
3. This figure shows costs for the Network commencing in 2029-30.
4. There is no CDP that contemplates any earlier starting date.

[249] Draft 2024 ISP Generation Outlook - Step Change.

The language and labels used in Appendix 6 make it difficult to see the difference between the timing modelled in the analysis and the timing AEMO says is consistent with the ISP in the Feedback Loop. On page 41, when discussing Table 2 of the ISP, the situation is described as the "least cost DP's timing," which hides the fact that this timing isn't what HumeLink or AEMO has planned. The terms "actionable window," "actionable HumeLink," and "not actioning the project" on page 43 and Table 22 of the ISP further obscure this difference because there's no mention in the section that the actionable window declared for HumeLink is actually six years. As it's currently written, any timing between 2026-27 and 2032-33 could be chosen and modelled, still supporting the claim that HumeLink should be actionable.

We submit that the omission of experimental evidence supporting the 2026-27 timing, as claimed by the Feedback Loop to be consistent with the Draft 2024 ISP, is a significant flaw in the draft ISP. As we've discussed before, advancing the costs of HumeLink by three years could erase most of the net benefits claimed by the ISP, primarily by increasing the net present value of the costs. Conducting a cost benefit analysis for just one year in a wide window to justify immediate delivery at the earliest service date lacks credibility and suggests that the timing may have been deliberately selected and manipulated to achieve a predetermined outcome for HumeLink.

Distortion of CDP5 vs CDP3 comparison

Further support for HumeLink being actionable is advanced in the ISP's Table 22. The paragraph above this claims "Table 22 compares the net market benefits of CDP3 and CDP5, which differ only on whether HumeLink is delivered within its actionable window or not, for each scenario. Overall, an actionable HumeLink results in an increase in weighted net market benefits of $953 million."

However, this statement is misleading because the timing of VNI West is also changed in CDP 5, delayed by five years from 2029-30 to 2034-35. On page 44, it is claimed that "Delivering HumeLink at an actionable timing is also necessary to ensure that VNI West can deliver its full range of assessed benefits. If HumeLink is not developed within its actionable window, the effectiveness of VNI West is reduced, leading to a commensurate deferral, which results in further benefits being accrued in CDP3 compared to CDP5 due to further deferral of generation capital costs." However, this is also misleading because the purpose of these analyses is to compare development paths, where specific timing changes are tested by altering them as an input. Implying that the deferral of HumeLink necessitated the deferral of VNI West is confusing and misleading, as AEMO has control over which dates the transmission projects are modelled at, as their earlier statement also suggests.

Consequently, there is no value in the comparison between CDP5 and CDP3 in terms of justifying keeping HumeLink actionable, as there is no way of attributing how much of the change is due to HumeLink's timing shifting by 3 years, or VNI West's shifting by 5 years.

There are important and straightforward experiments that could have been conducted to validate the timing proposed by AEMO for HumeLink. Specifically, modelling the proposed timing (2026-27) is crucial, yet it's inexplicably omitted. This experiment could compare the benefits of the 2026-27 delivery with alternative timings for HumeLink alone, keeping other project timings constant. If the benefits of delivering in 2026-27 were similar to or better than later timings (such as 2029-30 or 2032-33), then Transgrid's proposal for HumeLink could be seen as consistent with the ISP. However, these experiments weren't carried out, raising doubts about the objectivity of the ISP process. Weather event timing impacts on cost benefit analyses.

As discussed earlier, an examination of the capacity factors for solar across all of the REZs demonstrates some conspicuous years, almost certainly corresponding to La Niña events, when solar output is generally lower. In the 2024 Draft ISP the most severe of these occur in 2030-31 and 2044-45, as can be seen from the consistent depression of capacity factor in these years.

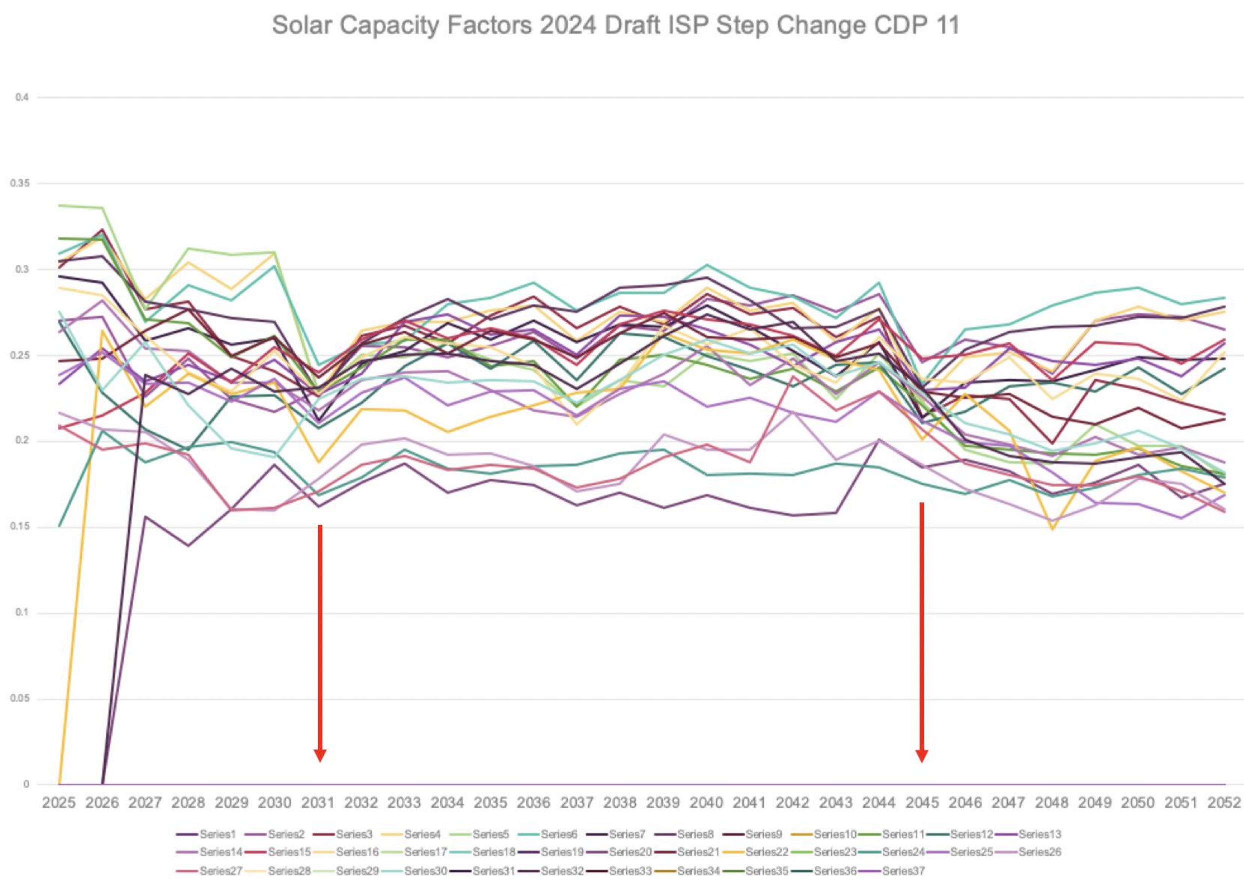

Figure 19. Capacity factors for solar in REZs in Draft 2024 ISP ODP, with years of low solar output marked.[250]

In the 2022 ISP, a similar examination reveals that those conspicuous years of depressed output fall in 2032-33 and 2043-44.

[250] Draft 2024 ISP Generation Outlook - Step Change.

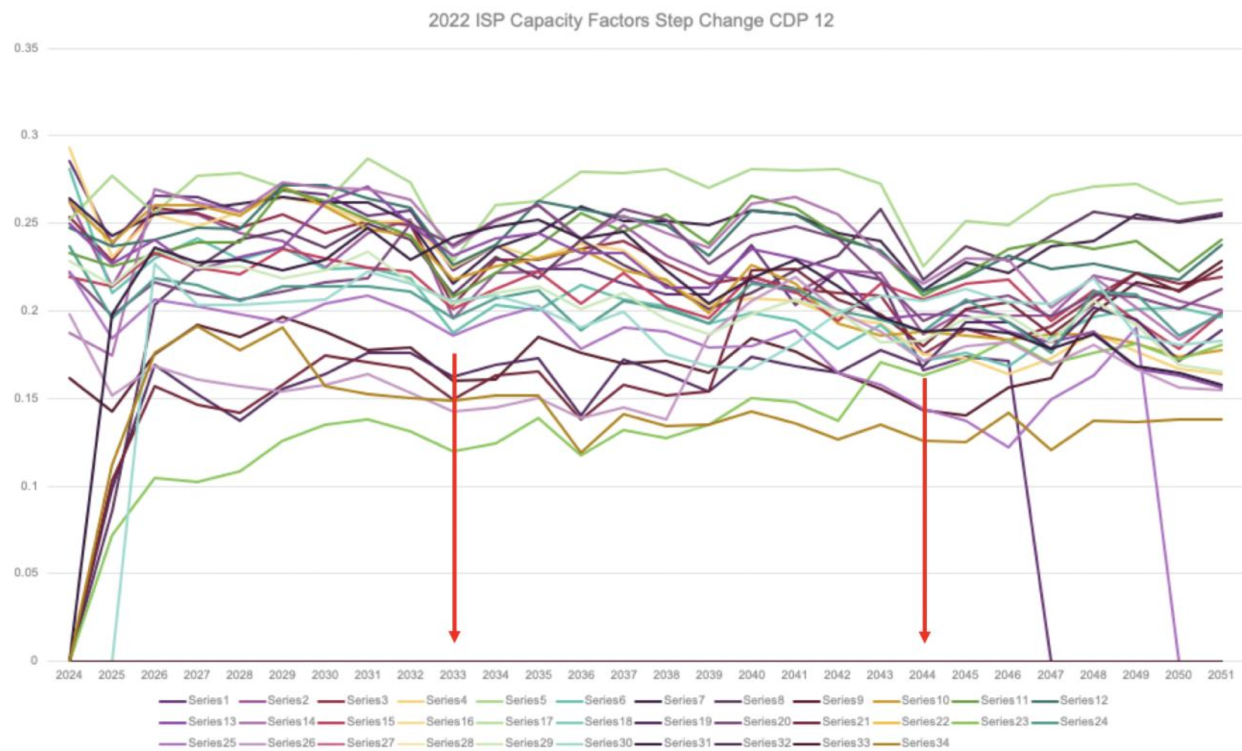

Figure 20. Capacity factors for solar in REZs in 2022 ISP ODP.[251]

This outcome doesn't match a repetition of the same weather years between ISPs or a straightforward shift. Instead, one weather event is moved earlier, and the other is pushed further back. Clearly, the sequence of weather years has been adjusted in a more customized manner.

As has already been discussed, the event in 2044-45 in the Draft 2024 ISP has a very significant impact on installed gas peaking capacity, and coincides with significant battery capacity retirement the following year. So we can expect that events such as these can and will be key drivers of installed capacities, and hence averted costs in transmission cost benefit analyses.

Moving a major weather event forward by two years, as seen in the shift from 2033-34 to 2030-31, is likely to significantly affect the benefits of HumeLink. Figure 8 in Appendix 6 of the draft ISP shows a high demand for hydro and flexible gas in that year, with little additional capacity needed for over a decade until the second weather event in 2044-45. Given that the 7% discount rate reduces the impact of later changes, advancing the main benefits of HumeLink by two years due to this weather adjustment would likely have a major impact on HumeLink's net market benefits.

[251] Draft 2024 ISP Generation Outlook - Step Change.

Figure 8 Comparison of capacity with and without HumeLink in *Step Change* (2029-30)

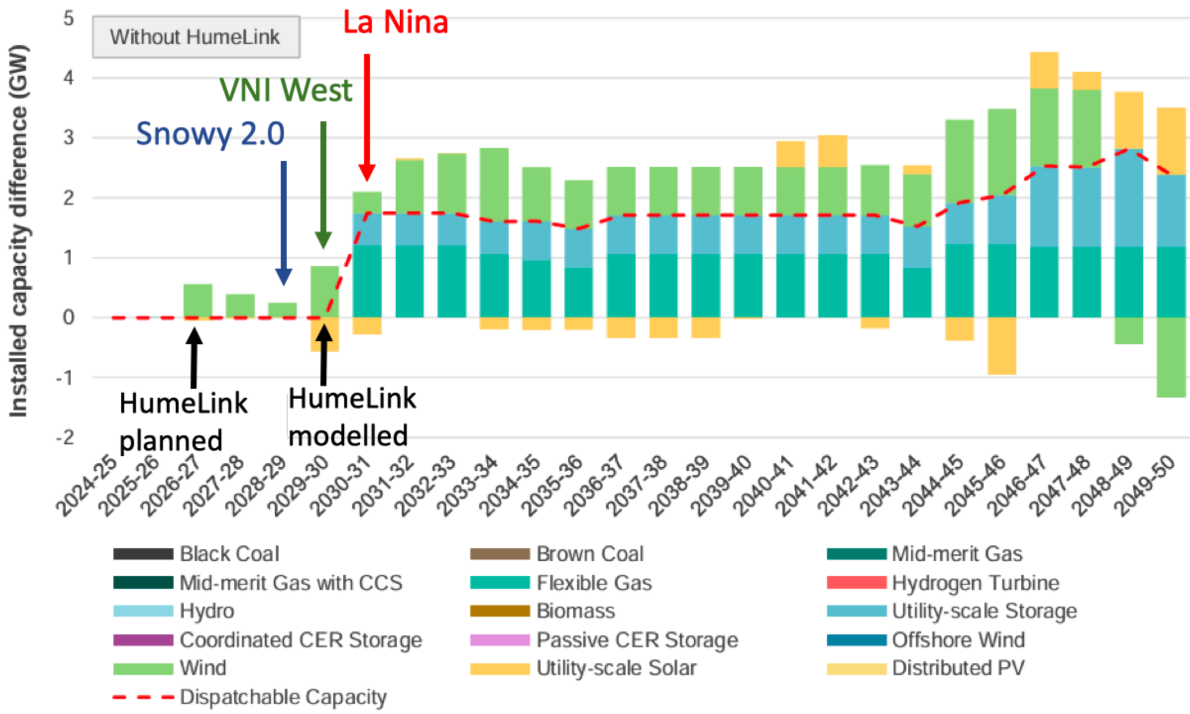

Figure 21. Timing comparisons for key events around HumeLink in 2024 Draft ISP ODP.[252]

This demonstrates an idealised timing for HumeLink, falling directly between the anticipated completion of Snowy 2.0, and the La Niña event which imposes the strongest demands for alternative capacities without HumeLink.

If the costs of HumeLink were modelled to commence at 2026-27, as planned and approved in the Feedback Loop, one would expect dramatically increased net present values of the costs for transmission (approximately $0.9 billion), and very little advancement of benefits, since those two of those would be prior to Snowy 2.0, and all three prior to VNI West, both of which would be expected to be crucial for unlocking the benefits of VNI West.

The comparison between CDP3 and CDP5, used in Appendix 6 to argue for HumeLink's actionability, reveals a reduction in benefits of $0.74 billion. This decrease could be due to various factors beyond HumeLink's timing shift. HumeLink is not aligned with VNI West or Snowy 2.0, and both projects now fall after the La Niña event, affecting alternative investment costs. While this naturally leads to lower net benefits, similar changes could result from any random shift in the La Niña event.

[252] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 43.

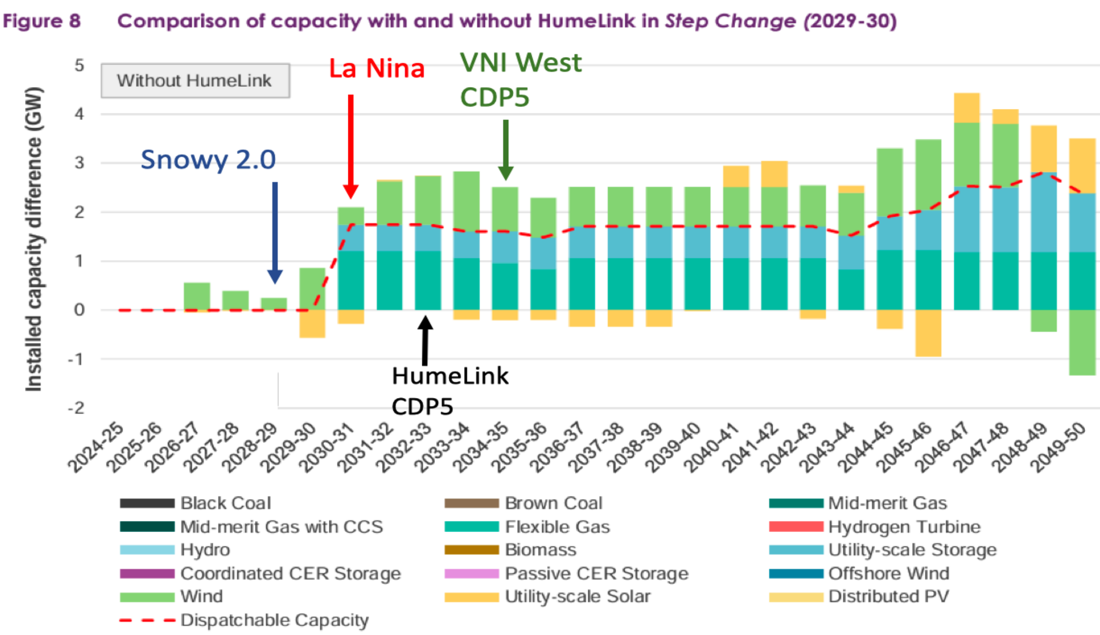

Figure 22. Timing comparisons for key events around HumeLink in Draft 2024 ISP CDP 5.[253]

In contrast, the timings around the 2022 ISP contrast significantly. VNI West's optimal timing, which is adopted in the ODP of the 2022 ISP, is one year prior to the La Niña event, which also suggests that this type of weather event has a material impact on the optimal development path. It would be ideal to contrast this with the optimal timing in the 2024 Draft, were they published.

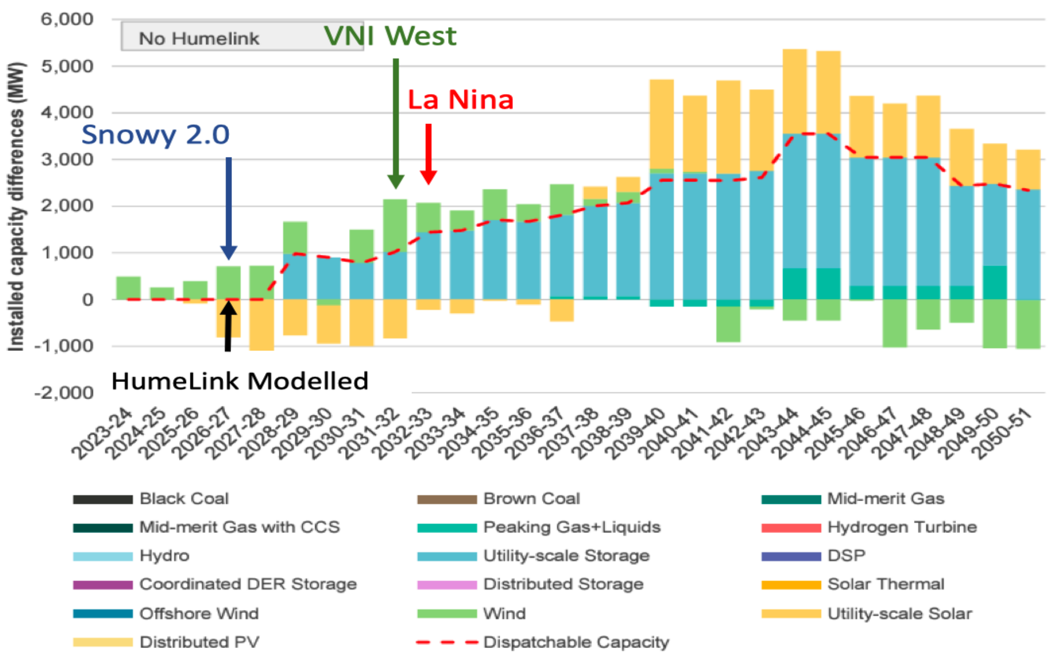

Figure 23. Timing comparisons for key events around HumeLink 2022 ISP ODP.[254]

[253] Draft 2024 ISP, Appendix 6: Cost Benefit Analysis, p 43.
[254] 2022 ISP, Appendix 6: Cost Benefit Analysis, p 49.

Increase in complementary sunk costs

A further means by which the scale of benefits associated with HumeLink may have been increased between the 2022 ISP and 2024 Draft is by the very substantial increase in the planned capacity of the Central West Orana REZ, which is treated as an anticipated project, and hence a sunk cost.

Central West Orana REZ

When comparing the installed capacities of wind and solar in the Central West Orana (CWO) and New England REZs between the 2022 and 2024 ISPs, we see that the capacity in the CWO REZ has roughly doubled around the time HumeLink is expected to come online, in line with the NSW Infrastructure plan's doubling target. In 2029-30, when HumeLink starts operating, CWO has actually replaced capacity from the New England REZ, which has less installed solar capacity in the 2024 Draft ISP compared to the 2022 ISP. This is a foreseeable outcome when the assumed transmission capacity in the CWO zone increases significantly from 3 GW to 6 GW.

Such a substantial increase in installed capacity in one of NSW's largest REZs, especially the first to be fully developed by the time HumeLink begins in 2029-30, would naturally boost the benefits of HumeLink. However, by 2026-27, the planned date for HumeLink, the CWO REZ is projected to have much less installed wind and solar capacity—approximately one sixth and one third respectively. This suggests that constructing HumeLink so early, with significantly less renewable capacity installed in NSW and the largest REZ not yet completed, would likely result in significant differences in the benefits of HumeLink.

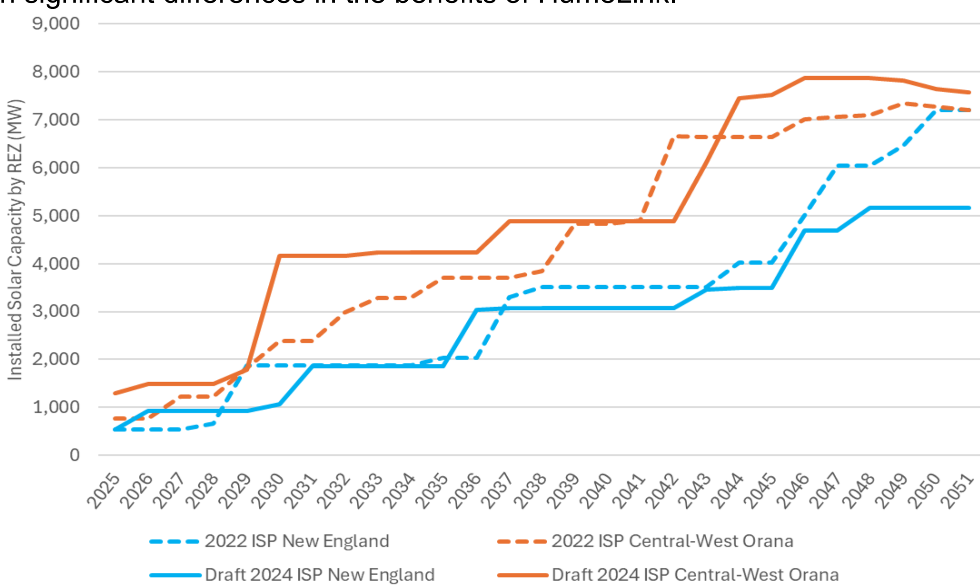

Figure 24. Installed solar capacity in the New England and Central-West Orana REZs under the ODP in Step Change for the 2022 ISP and Draft 2024 ISP.[255]

[255] 2022 Final ISP results workbook - Step Change - Updated Inputs; 2024 Draft ISP results workbook - Step Change.

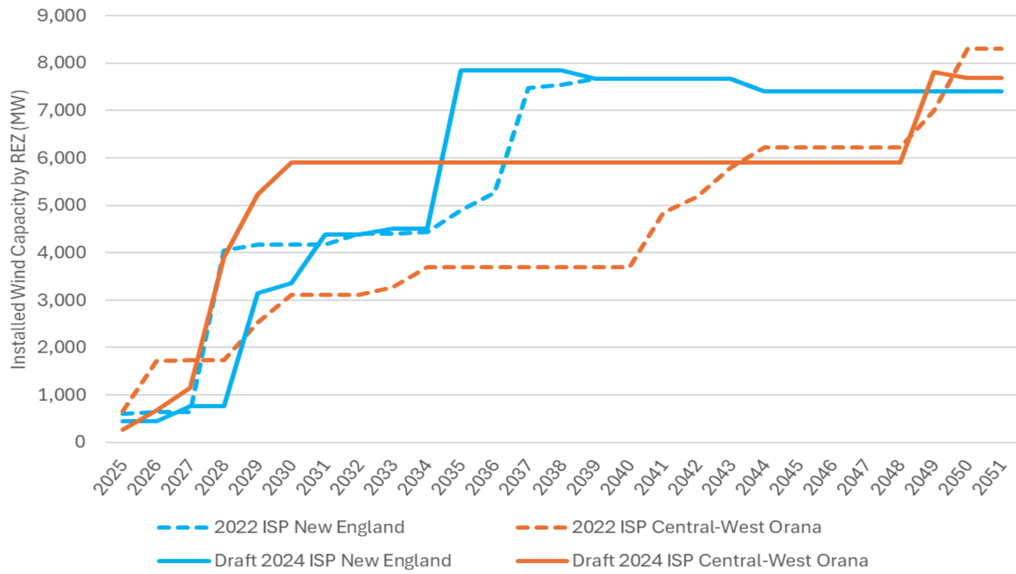

Figure 25. Installed wind capacity in the New England and Central-West Orana REZs under the ODP in Step Change for the 2022 ISP and Draft 2024 ISP.[256]

The exact timing and capacities of the CWO transmission included in 2024 Draft modelling remain unclear, since it is not specified as to which options will be undertaken at what time. This is a significant transparency shortfall, given the significance to those sunk costs and their bearing on the benefits of HumeLink.

Snowy Hydro 2.0 Uprating

The difference in HumeLink benefits between the 2022 ISP and 2024 Draft may also be linked to the Snowy 2.0 Hydro scheme being upgraded to 2200 MW. This upgrade increases the speed at which energy from NSW renewables, like the CWO REZ, can be stored and dispatched to major loads such as Sydney. It also aligns Snowy 2.0's capacity exactly with HumeLink's 2200 MW capacity, boosting HumeLink's benefits. However, since Snowy 2.0 is already accounted for in all scenarios, these benefits could be seen as inflated by investments beyond the ISP's scope.

The uprating of Snowy 2.0 was not included in the 2023 IASR, so it shouldn't be part of the ISP analysis. During a Senate Estimates session on February 12, 2024, Dennis Barnes, CEO of Snowy Hydro, suggested that the upgrade incurred no costs to the Commonwealth and required minimal changes. He indicated that it was merely a confirmation that additional capacity could be delivered within the existing machinery. If this is true, there's no reason why such an increase couldn't have been achieved in earlier ISPs. Including it in the 2024 draft after consultations on the IASR closed raises doubts about the objectivity and rigor of the process, leading to expanded benefits for HumeLink.

[256] 2022 Final ISP results workbook - Step Change - Updated Inputs; 2024 Draft ISP results workbook - Step Change.

Furthermore, in the initial release of the Generation Outlook files, Snowy 2.0's storage depth was listed as 376 GWh, higher than the published value. This represents a 7% increase, matching the capacity uprate from 2040 MW to 2220 MW. AEMO should clarify why capacities different from what was consulted and modelled were initially included in the Generation Outlook files and why they were swiftly updated.

VNI West acceleration

As discussed previously, the joint role of VNI West and HumeLink in enhancing weather diversity suggests their benefits are closely linked. Aligning VNI West with HumeLink in the 2024 Draft ISP could lead to significant cost savings, especially in the early years of HumeLink's operation when it will have more export capacity to Victoria. In the 2022 ISP, the earliest in service date for VNI West as advised by Transgrid was 2031-32.[257] In the Draft 2024 ISP that has now been brought forward to 2029-30.[258] This advancement of this project to bring it into alignment with HumeLink could be a substantial source of benefits, but it is not clear how or whether there is a cost or risk associated with this change, and how this would be reflected in VNI West's change. Given that the same proponent is building and benefiting from both projects going ahead, this demands an explanation of why an earlier in service date was not previously contemplated.

In summary, Eli Pack's explanations regarding why HumeLink's benefits have supposedly risen enough to balance out its increased costs can be proven inaccurate. Prices of alternative capacities haven't significantly risen, except for batteries, which weren't considered due to a switch to pumped hydro. If assumptions about price changes were updated, it would likely reduce the benefits rather than increase them. However, there are more convincing and quantitatively reliable reasons why the benefits are still anticipated to exceed the costs in the 2024 Draft ISP:

1. The TOOT analysis delays construction three years from what is actually planned
2. A significant weather event is brought forward two years bringing forward capacity demands
3. Massively increased capacity in the Central West Orana REZ increases renewable potential
4. VNI West is brought into exact alignment by bringing forward the in-service date
5. The Snowy Hydro 2.0 scheme is uprated to 2200 MW

Based on this, we believe that HumeLink's actual net benefits are very likely to be negative when properly evaluated with the planned start date and full inclusion of all system costs, and considering the reliability response to unpredictable weather. The lack of necessary experiments to determine HumeLink's true value as planned raises serious doubts about the objectivity and rigor of the ISP. This doubt is further increased by unexplained changes in data features like weather year sequences.

[257] 2022 ISP, p 67.
[258] Draft 2024 ISP, p 53.