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Australian Energy Market Operator - Draft 2020 Integrated System Plan

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500 MW of generation capacity.

AEMO's 2020 integrated system plan is an important scenario-based study that draws from the process and findings of the original 2018 version and it will be used to guide co-ordinated transmission and generation investment across the NEM through a complex range of plausible futures.

This is reflected in the materiality of the total system costs estimated by AEMO over the next two decades ranging from $57b to $91b.[1] We note however the ISP is not designed, or intended, to be a replacement for the more rigorous cost benefit analysis requirements of a RIT-T.

We consider that AEMO has undertaken a substantive amount of analysis in leading up to its draft ISP and we applaud its efforts in undertaking meaningful consultation with stakeholders. We are also appreciative of the amount of data AEMO has published to assist stakeholders in understanding AEMO's analysis and findings.

In undertaking our own market studies and investment analysis, we recognise the complexity and pitfalls in completing a study of this nature, the broad uncertainties involved in scenario based system planning, and the need to lock down the study at a reference point in time that will always be compromised by the dynamic nature of inputs, assumptions and new information. We are also cognisant of the limits to AEMO's capacity in addressing voluminous and varied stakeholder feedback.

[1] NPV, real June 2019 dollars - Table 4 of 2020 ISP - slow change and step change scenarios, respectively with transmission projects, recognising direct comparisons across scenarios are difficult given different assumptions and impacts outside of the energy sector.

The attached submission contains various detailed observations and suggestions for AEMO's consideration.

Our overarching views of the draft ISP and recommendations for AEMO in publishing the final 2020 ISP include:

- **recognising the inherent limitations of the ISP study** - there should be more recognition of the inherent limitations of the least cost modelling approach and the ISP's role in providing signals to a broad range of stakeholders, including to investors and policy-makers, regarding future transmission and generation investment.

- **the ISP outlook underestimates the need for dispatchable capacity, potentially overstating the role and benefits of transmission** – the findings conclude that only ~35 GW of dispatchable capacity is required longer-term, inclusive of demand side response. This is a significant reduction from the 2018 ISP which projected dispatchable capacity to be broadly maintained at around 40 GW[2]. We encourage AEMO to clearly outline why this has changed, as EnergyAustralia is particularly concerned that there is material deficit in dispatchable capacity.

- **moderating the transmission investment case as it does not appear compelling** – the study identifies marginal net benefits of $1.6b[3], or only 2% of total system costs, relative to the counterfactual cases. This seems within the bounds of modelling noise and suggests a degree of false precision, particularly when deviations from the efficient/optimal case are recommended based on hypothetical least regret costs. Customers will be faced with decades of payments for these decisions, whilst taking the full risk of benefits realisation.

  testing the reliability and dependence on interconnectors - the draft ISP places increased and significant reliance on transmission investment and associated resource sharing in all scenarios, in lieu of more localised dispatchable generation[4]. Power system and market operations should be further stress tested, including clearer insights into tail risks and exposure to unserved energy or market interventions arising from low probability, high impact events such as the extreme weather and fire events seen this summer[5].

- **recognising an overreliance on pumped hydro** – the central case assumes an additional 10 GW of deep pumped hydro storage, above and beyond the capacity of Snowy 2.0, is required by 2041/42. This represents investment in capacity twice the size of existing generation capacity in the Latrobe Valley. This seems ambitious, bordering on implausible, and represents a 'technology bet' that undermines the broader findings. Further, the lack of utility scale batteries appears to be clear disconnected from what is happening in the market today. Further, gas-fired generation is also missing from supply mix.

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[2]AEMO, *2018 Integrated System Plan,* Page 37
[3]AEMO, *2020 Draft Integrated System Plan,* Table 4, averaged across the five scenarios.
[4] As represented in Figure 16, 2020 ISP, where new interconnectors replace retired coal capacity
[5] For example refer to instances like 31 Jan 2020 where NEM-wide coincident operational peak demand was 36 GW, or 20 Dec 2019, where it is understood thermal derating of renewables resulted in the over-forecasting of hundreds of MW.

We trust this submission is constructive in nature, and if you would like to discuss it further, please contact Lawrence Irlam on 03 8628 1655 or Lawrence.irlam@energyaustralia.com.au.

Regards

Lawrence Irlam
Industry Regulation Lead

Recognising the inherent limitations of the ISP study

There should be more recognition of the inherent limitations of the least cost modelling approach and the ISP's role in providing signals to a broad range of stakeholders, including to investors and policy-makers, regarding future transmission and generation investment.

Inherent limitations are predicated on a range of the sources, assumptions and methodologies applied, including:

- the draft ISP is established on a centrally planned least cost basis that excludes real world market dynamics and influences such as ancillary services, the retailer reliability obligation, portfolio bidding and risk management practices used by participants and the inability to effectively hedge with Settlement Residue Auctions (SRAs);
- simplifications of the integration across markets such as electricity and gas, and theoretical co-optimisation principles across dispatchable and intermittent generation, transmission, storage and gas;
- assumption of perfect competition based on short run marginal costs (SRMC) and perfect foresight for hydro and renewable modelling, including prior knowledge of hydrological and wind droughts;
- the ability to capture the increasingly multi-dimensional impacts of diurnal and seasonal weather;
- simplification of increasingly critical power system operation and performance considerations;
- the ISP is not designed or intended to be robust as an investment decision grade discounted cost benefit assessment such as the RIT-T;
- the ISP excludes impacts and costs/benefits both within and outside of the energy market, for example: relative considerations of ancillary services costs; distribution network expenditure influences or tariff design changes on Behind the Meter economics and distributed energy resources (DER) take up rates;
- the need to make simplified representations across (and when interfacing between) the multi-staged modelling time horizons, particularly regarding new entrants and retirements;
- point in time modelling every two years that struggles to capture new information and market dynamics or potential reforms.

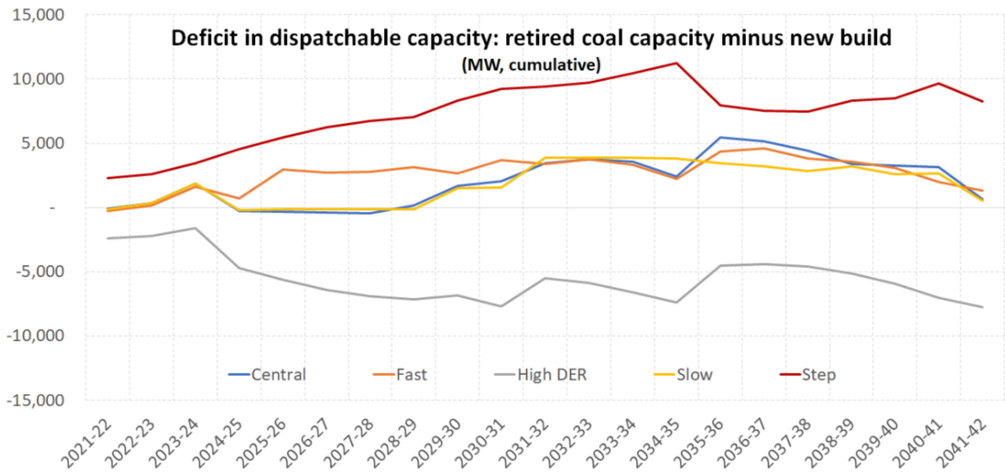
Calling out these inherent limitations is not a criticism of AEMO, or its efforts. It's simply recognising that while the modelling is scenario based and valuable, the ISP is an extraordinarily complex and a best endeavours model. It is a guide at a point in time, and its strategic value lies in understanding the signposts for future investment decisions and recognising the actual investment plan is highly dynamic in nature. Users of the ISP for policy and investment decision-making should be aware, and highly cognisant, of its limitations and the implications of these limitations in interpreting the results.

The ISP outlook underestimates the need for dispatchable capacity, potentially overstating the role and benefits of transmission

Magnitude of the deficit

The findings conclude that only ~35 GW of dispatchable capacity is required longer-term, inclusive of demand side response. This is a significant reduction from the 2018 ISP which projected dispatchable capacity to be broadly maintained at around 40 GW[6]. We encourage AEMO to clearly outline why this has changed, as EnergyAustralia is particularly concerned that there is material deficit in dispatchable capacity.

Headline findings in the draft ISP identify that only 5-21 GW of new dispatchable capacity is required, leaving between 28-37 GW of dispatchable capacity[7] once retirements are considered. he following chart shows the difference between retired coal capacity and new dispatchable capacity, highlighting in all but the High DER scenario, a significant decrease in dispatchable capacity.



We suggest it would be prudent for AEMO should to examine the resilience of its optimal development path economics to cases where higher levels of dispatchable generation have been driven by market outcomes.

Reasons for insufficient dispatchable capacity being forecast in the model

In our view AEMO's least-cost modelling does not adequately capture the economic drivers for storage and peaking generation. These drivers include, for example, retailer reliability obligations, access to firm capacity to hedge retail load or intermittent supplies in a retailer's position, ancillary services revenues and increased operational requirements for more localised synchronisation and system strength issues.

We recognise that it may be difficult to model contract market effects, and these are typically not assessed in RIT-Ts. However, in AEMO's case we consider this is a significant issue as its optimal development path involves a substantial reduction in the

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[6] AEMO, *2018 Integrated System Plan,* Page 37

[7] Excluding behind the meter DSP and orchestrated/aggregated VPP.

amount of dispatchable capacity, as discussed above, which may influence liquidity in forward markets.

Other factors restricting more dispatchable capacity installs include the use of perfect foresight, which supports PHES, and not recognising the practical reality that aggregated VPP and DSP are less effective at managing onerous conditions because they are energy limited to 1-3 hours duration.

Consequences of insufficient dispatchable capacity

A reduction in firm capacity could eventually lead to a critical scarcity in contracts required by retailers to manage their exposure to price risk, resulting in significant additional costs being incurred and passed onto consumers. Politically this would be precarious, and we note that there is a range of proposals being considered around wholesale market design and AEMO has correctly highlighted these reforms as critical for its optimal development path.[8] The corollary of the observation that these reforms will reward the "increasing value of flexibility and dispatchability" is that AEMO should consider how this might change the future generation mix, even though these reforms cannot be modelled at present.

The reduced reliance on firm generation, and therefore weaker signals to invest in this type of capacity, under AEMO's modelled scenarios is, on face value, also at odds with the current short-term focus on reliability of supply as thermal generators are reaching end of life and subject to higher forced outages. This includes AEMO's recent suggestions in the ESOO[9] around revising the reliability standard to better capture long tail risks and new RRO obligations.

The impact of a reduction in firm capacity is exacerbated by an 18 per cent increase in underlying energy consumption.[10]

Our other views on the generation mix is that gas generation is a strong complement for wind, especially as wind droughts can be broad across the NEM. We note AEMO's comments that flexible gas generators could play a bigger role if gas prices materially reduce.[11] However for low capacity factor plants, gas prices are not a strong driver of costs, so we do not see this as an inhibiting factor.

We expect all these factors contribute to a greater need for local dispatchable generation and storage than foreshadowed in the draft ISP's modelling outputs.

Suggested modelling improvements

In exploring whether these factors are significant from the perspective of AEMO's optimal development path, we recommend AEMO identify a threshold or tipping point where its modelled ISP projects, storage and optimal development path are affected by the presence of local firm generation or storage to better manage regional supply and demand balances under more extreme conditions.

[8] AEMO, *2020 Draft Integrated System Plan,* Page 13,
[9] AEMO, *2019 Electricity Statement of Opportunities,* Page 13
[10] NEM wide, Central case, underlying demand to 2041/42
[11] AEMO, *2020 Draft Integrated System Plan,* Page 10

Moderating the transmission investment case as it does not appear compelling

The study identifies marginal net benefits of $1.6b[12], or only 2% of total system costs, relative to the counterfactual cases. This seems within the bounds of modelling noise and suggests a degree of false precision, particularly when deviations from the efficient/optimal case are recommended based on hypothetical least regret costs. Customers will be faced with decades of payments for these decisions, whilst taking the full risk of benefits realisation.

To expand on this, EnergyAustralia has three primary concerns related to AEMO's recommended transmission investment path:

- the magnitude of net benefit estimates,
- the surprising consistency in investment needs and timing across the range of scenarios, and
- the deviation from the efficient/optimal path based on least regret costs.

The size of net market benefits and regret costs between counterfactual and 'with investment' situations appears to be modest in the context of overall system costs. Whilst we recognise the transmission development expenditure itself ranges from $2.2b to $5.8b[13], AEMO should reflect on the likely variance, potentially in the form of confidence intervals or standard errors, in costs and benefits as its current analysis implies a certain degree of precision and confidence in conclusions.

The optimal timing of QNI Minor, VNI Minor, EnergyConnect and Humelink does not change over the five scenarios or the sensitivities. This is surprising given the variance across the scenarios and we request further insights from AEMO on this consistency, particularly HumeLink and why it isn't later than 2025/26 in the slow change scenario, or the sensitivity with Snowy 2.0 delays or early load closure?

In regard to deviations from the optimal development path, AEMO proposes to accelerate VNI West and Marinus Link planning ('shovel-ready') on the basis that this minimises the worst regret costs. However, this appears to directly contradict Table 14, where accelerated VNI West without shovel ready Marinus Link does minimise regret costs (viz. -$139m compared with -$155m).

Furthermore, it is EnergyAustralia's contention that the 'no accelerated action' candidate path minimises the *average* regret costs when all five scenarios are considered (viz. -$48m compared with -$79m in the accelerated VNI West option).

[12] AEMO, *2020 Draft Integrated System Plan,* Table 4, averaged across the five scenarios.
[13] Accounting for expenditure for new or augmented interconnectors and grid development directly associated with REZ expansions.

Suggested reporting improvements to improve confidence in ISP conclusions

Should a 'shovel ready' recommendation be carried into the final ISP, we recommend that AEMO seek and provide stakeholders further information on the various justifications offered in the draft ISP[14]:

- the expected $130 million cost associated with progressing Marinus Link, including who would pay for this;
- what feasibility work has already been conducted (outside of the current RIT-T assessment, noting it has not received any approvals by the AER) and why this would need to be redone if the project is delayed;
- whether the extent of customer benefits is limited to the $20 million associated with works already completed, and whether those associated with its RIT-T assessment will need to be redone at the time Marinus Link is identified as an "Actionable" project and market circumstances have changed;
- the likelihood of the project stalling for eight to ten years if not progressed now, particularly as AEMO is expected to be able to mandate the completion of a RIT-T assessment under the new "Actionable" rules framework.

Testing the reliability of, and dependence on, interconnectors

The draft ISP places increased and significant reliance on transmission investment and associated resource sharing in all scenarios, in lieu of more localised dispatchable generation.[15] Power system and market operations should be further stress tested, including clearer insights into tail risks and exposure to unserved energy or market interventions arising from low probability, high impact events such as the extreme weather and fire events seen this summer.[16]

Could a future with critical dependence on interconnectors actually lead to more market interventions or unserved energy given correlated intermittency of renewables and demand across regions?

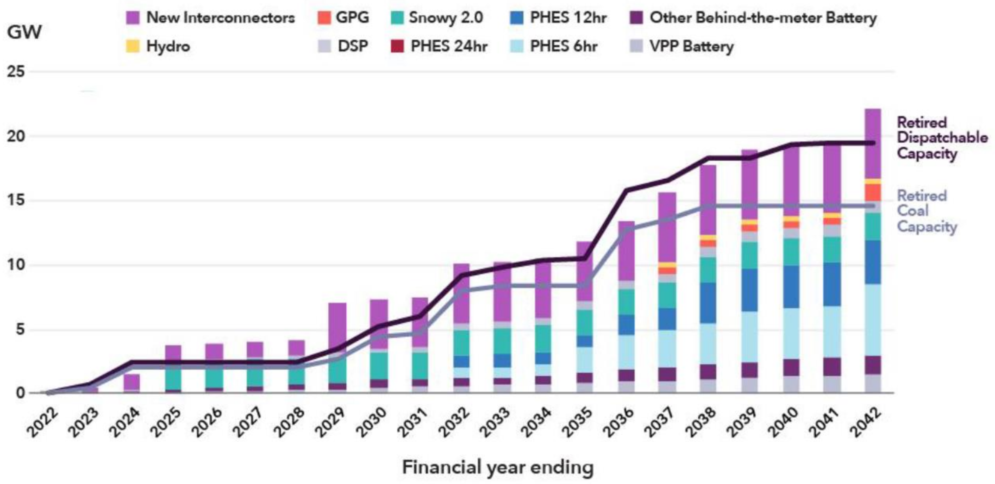
The draft ISP's presumed reliance on interconnectors is likely to affect stakeholder expectations of how large amounts of variable renewables will be accommodated into the system from a technical perspective. For example, Figure 16 of the draft ISP report includes installed interconnector capacity alongside new and retiring firm generation, which is potentially misleading; it may give a false sense of security as dispatchable capacity via interconnectors is a function of available capacity in exporting regions, which will not necessarily be available when required.

[14] AEMO, *Draft 2020 Integrated System Plan,* Page 61

[15] As represented in Figure 16, 2020 ISP, where new interconnectors replace retired coal capacity

[16] For example, refer to instances like 31 Jan 2020 where NEM-wide coincident operational peak demand was 36 GW, or 20 Dec 2019, where it is understood thermal derating of renewables resulted in the over-forecasting of hundreds of MW.

Figure 16 Announced retirements and corresponding builds in Central scenario to help firm VRE



While AEMO has obviously spent considerable effort in testing the technical feasibility of its outputs, its modelled mix of generation and transmission investment is ultimately determined by an economic, or total resource, perspective first and foremost.

In our view, AEMO is aggressive in its projections that place heavy reliance on transmission interconnection to make up for a loss of dispatchable generation capacity. It represents a relatively extreme risk position from a reliability perspective that is at odds with the increased political and societal focus on reliability. We are concerned practically it may lead to state of increased market intervention.

AEMO states the proposed supply and transmission developments maintain the overall reliability of the power system (Page 65 of appendices). We don't feel as confident as AEMO of this based on the data and information provided to date. We would like to see more details around tails risks and deterministic outcomes, so our understanding can be improved.

Suggested reporting improvements

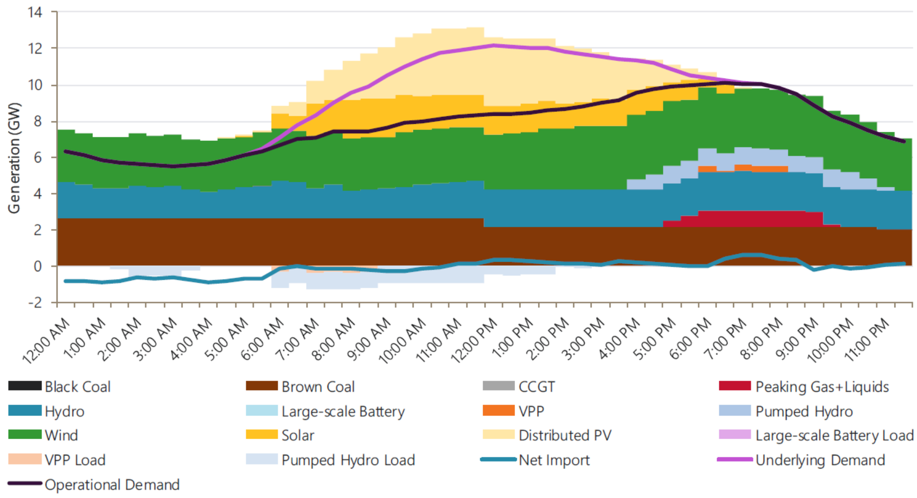
We encourage AEMO to release more modelling details that affirm how its optimal development path and associated generation mix will deliver against peak demand conditions and coincident high demand across regions, including allowance for thermal de-rates of variable renewables.

Below we recommend four further areas of analysis to stress test the interconnector dependence conclusions of the ISP.

Stress testing the interconnected power system

While we appreciate the detailed intra-day regional maximum demand charts in section 4.5 of the ISP Appendix, they do not address our concerns regarding future system reliability as they don't represent expected conditions of low wind at times of peak demand.

Figure 70 Victoria – forecast maximum operational demand 19/01/2040, Central scenario



The variable renewable output on these charts appears much higher than AEMO's published firmness assumptions for renewables. AEMO should explain these deterministic outcomes in the context of the firmness assumptions and release details of modelling that considers system operation under tight supply conditions created by limited firm generation as well as time periods associated with high demand.

Furthermore we would also appreciate examples of co-incident multi-state demand events given the draft ISP has a strong reliance on capacity sharing across neighbouring regions.

System security and resilience in a predominantly VRE future

Since its 2018 ISP, AEMO states it has improved its assessment of system security and dispatchability in a system with large amounts of VRE, including the cost of services such as system strength.[17] Large amounts of inverter-based resources (IBR) are projected from the mid 2020's, with a need for coordinated or optimised solutions to address inertia and fault level shortfalls.[18] AEMO states that the final ISP will highlight key security needs out to 2030.[19] This time horizon is shorter than the ISP's forecast periods, therefore these considerations may still have a bearing on AEMO's optimal development path and we remain concerned that system security considerations may jeopardise the modelled investment benefits.

It is not clear to us whether any findings of AEMO's forthcoming Renewable Integration Study will be accommodated in the final 2020 ISP. As this study will be constrained to examine the power system expected in 2025, its relevance to the ISP planning horizons may be minimal.

Resilience of the transmission network assets is also an issue, as well as required outages

We acknowledge that transmission assets are inherently highly reliable in terms of forced outage rates and mean time to repair. However, we are concerned that with a highly interconnected system reliant upon sharing of capacity from neighbouring regions via

[17] AEMO, *2020 Draft Integrated System Plan,* Page 27
[18] AEMO, *2020 Draft Integrated System Plan,* Page 49
[19] ibid

long transmission lines, the consequences of low probability, high impact transmission interruptions may be significant. We would encourage AEMO to consider reviewing the system resilience to extreme events for a highly interconnected system, versus a system with higher distributed and local dispatchable capacity.

A further issue relating to transmission outages is the market costs of network outages that are required to integrate new transmission projects. Costs of extended outages can be very high and are usually materially understated based on least cost planning and SRMC pricing assumptions. Experience with the Heywood upgrade, and proposed outages during QNI minor and VNI minor augmentation are examples of these concerns. TransGrid estimated the impact of outages on QNI upgrade to be approximately $12 million or 6 per cent of expected net benefits[20], and in our view this was likely to be understated given the SRMC nature of the forecast methodology. These issues should be considered, and estimates of costs included as part of reviewing the deliverability of the ISP's optimal development path.

Further information to promote understanding and confidence of the benefits of interconnectors

In providing guidance to AEMO in prioritising further work to conduct as part of its final ISP, we have identified the following critical issues to validate the reliability and dependence on interconnectors:

- The potential implications of breakdown in assumptions around weather correlations and coincidence. Specifically, the ISP places a much stronger reliance on inter-regional capacity sharing, and so assumptions regarding correlation of renewable resources and co-incident demand events become critical. Low probability high impact events such as the high co-incident NEM-wide demand witnessed on Friday 31 January 2020 would, in our view, risk significant load shedding and/or market intervention.
- The 2019 ESOO included an AEMO recommendation to refine the reliability standard to better reflect tail risk. AEMO's ISP analysis suggests the proposed supply and transmission developments maintain the overall reliability of the power system (Page 65 of appendices). We would like to see more details around tails risks including commentary around whether AEMO's proposed refined reliability standard would be met (i.e move to likelihood of USE rather than expected USE being less than .002% to deal with long tail risks)
- AEMO has highlighted that weather events are becoming more extreme, and we have recently witnessed a succession of record maximum temperatures. We are interested to determine whether AEMO's maximum demand forecasts remain robust given the increased likelihood of extreme temperatures.
- We are also seeing increasing instances of thermal de-rates of inverter-connected generation, both utility scale and distributed. We suggest AEMO review their firmness assumptions for inverter related technologies.
- As a 'headline' issue to communicate to stakeholders, AEMO should identify the key changes, either in methods, inputs or market circumstances, that have allowed the

[20] TransGrid, *Expanding NSW-QLD transmission transfer capacity - Project Assessment Draft Report*, 30 September 2019, p. 61.

reduction in minimum dispatchable capacity from 40 GW in the 2018 ISP to 35 GW in the draft 2020 ISP.

- Publishing some stochastic results or distributions of the Monte Carlo simulations, showing the relative change in tails risks between the counterfactual and optimal development path cases would be valuable in helping to explain how interconnection builds resilience.

Recognising an overreliance on pumped hydro

The central case assumes an additional 10 GW of deep pumped hydro storage, above and beyond the capacity of Snowy 2.0, is required by 2041/42. This represents investment in capacity twice the size of existing generation capacity in the Latrobe Valley. This seems ambitious, bordering on implausible, and represents a 'technology bet' that undermines the broader findings. Further, the lack of utility scale batteries appears to be clear disconnected from what is happening in the market today. Further, gas-fired generation is also missing from supply mix.

We question AEMO's modelling where it relies so heavily on PHES, given the high development risk and continued uncertainty regarding resource availability, construction costs and the economic threat of competing storage technologies. For these reasons we consider AEMO should produce a sensitivity that genuinely challenges the presumption of PHES playing a critical role in the transition of the electricity system.

Such heavy reliance on a particular technology (noting it is traditional synchronous generation that will support power system operations) has parallels to earlier modelling of the Government's LRET target which assumed large amounts of geothermal generation to support large scale deployment of variable renewables. While not a criticism of this work, it illustrates the inherent risk in relying on least cost optimisation modelling and the prudence of testing any strong presumptions regarding an individual technology.

We appreciate AEMO's modelling already contains a sensitivity with lower PHES resource availability by region, and would like the outputs of this sensitivity to be published as per the other sensitivity results. However, the discussion provided by AEMO for this study shows this sensitivity is simplistic in nature and only installs more PHES in NSW and less in QLD, without a significant change in the total amount installed.

As identified in our submission on AEMO's Forecasting inputs[21], we encourage AEMO to undertake a further sensitivity with significantly higher PHES capex as we consider Entura's estimates to be untested against EPC outcomes or delivered projects.

AEMO's key justification for PHES is its ability to provide for 'deeper' storage operations to accommodate demand and weather conditions, with examples provided for up to 1 week or over seasonal timeframes.[22] We are concerned this modelling overstates the efficiency of PHES operations from a system-wide perspective because of modelling

[21] EnergyAustralia, 07Feb20 Australian Energy Market Operator - Consultation Paper on key Forecasting inputs in 2020 – December 2019
[22] AEMO, *2020 Draft Integrated System Plan* Appendices Pages 66-68

perfect foresight. We also note that bidding assumptions tied to SRMC, and that these ignore the sunk cost of existing or latent PHES capacity.

The combination of these factors is likely to understate the true cost of PHES in AEMO's modelling, while overstating their value and through reliance on their provision of synchronisation services.

AEMO should be clearer in its modelling and selection of Yallourn closure dates

We note that AEMO did not engage with EnergyAustralia regarding the sensitivity analysis focussed on a potential early closure of Yallourn. We request AEMO to provide a clear justification for examining this sensitivity, and in particular why advanced closure of QLD or NSW coal plants were not similarly explored.

Our view is that 2027 is arbitrary and not based any information or analysis of revenue sufficiency, and may simply be the earliest year in which VNI west can be commissioned.

We note the draft ISP's least regrets analysis shows VNI West should be accelerated where the probability of Yallourn's closure is greater than 36%, whereas AEMO's earlier "Insights" publication calculated this as 20%.[23] AEMO should clarify whether this change reflects latest market circumstances or a change in its method.

Modelled outcomes for plant operation appear unrealistic in some cases

Our experience with power stations and associated Plexos modelling is that generators will not always meet targets as the model assumes, especially if units are ramping up from a very low minimum load. The relationship is not linear over the full operating range and is sensitive to engineering and plant characteristics such as mill changes.

We request AEMO provide more details regarding their assumed daily operational profiles of incumbent generators so that operators can provide guidance regarding the validity of the modelling outcomes. We also suggest that AEMO test the sensitivity to the underlying assumptions – what happens if ramp rates increase or decrease over time?

Beyond the modelling of ramp rates, the following matters are relevant to plant operations and dispatch and warrant further discussion on how they could affect the speed of the transition under the ISP scenarios:

- How much is output from individual stations fluctuating year-on-year? Can annual capacity factors by station for each scenario be provided?
- Can AEMO provide number of starts per station per year?
- Does the model include unit 2-shifting, de-commitments or mothballing?
- Specifically in South Australia and with EnergyConnect – are any dependencies on local synchronous generation operation assumed around Adelaide?

[23] Page 16, Building power system resilience with pumped hydro energy storage July 2019

Noting that individual plant data is commercially sensitive, we observe there is insufficient transparency on how AEMO has assessed revenue sufficiency and what this means for generator closures in the modelling.

We note that the capacity factors of gas-fired generation decline significantly across AEMO's scenarios and question whether remaining operational, to meet system reliability and security and support VRE, would be a commercially viable prospect.[24] Similarly, AEMO notes that increasing flexibility requirements for coal generation will result in higher rates of degradation and operating costs.[25] It is not clear whether these costs or performance impacts would be acceptable to plant owners or result in earlier retirement decisions.

[24] AEMO, *2020 Draft Integrated System Plan* Appendices, page 69
[25] ibid

The Final ISP should be accompanied by additional modelling data and insights

To build understanding and confidence in the study, there are several outputs that we would like to see, including:

- We encourage AEMO provide a short analysis of changes from its 2018 ISP. A headline finding from this earlier report was that AEMO's modelling showed the total investment required to replace the retiring generation capacity and meet consumer demand had a NPV cost of between $8 billion and $27 billion. We are interested in understanding how this headline finding has changed for the 2020 ISP, and why.
- Modelled price outcomes, including duration curves and intraday price shape. These are key drivers for economic build of storage and peaking generation and consumer costs, and we would like to review these to better understand the capacity planning outcomes, and the relative impacts of interconnector investment.
- Intraday examples of thermal unit generation over time. Appendix 4 on intra-day operability contains some sample intraday regional charts. We would like more detailed information on how thermal generation units are being dispatched in the ISP model, so we can provide more relevant feedback to AEMO on whether we think the profiles are credible. Currently we cannot assess whether the assumptions around ramp rates, unit commitment and de-commitment etc are credible.
- AEMO should consider conducting a deliverability review of the coincident transmission projects in the optimal plan to confirm the likelihood of any supply side constraints, which might result in higher out-turn costs.
- Charts of forecasts, including several years of historical observations, to help visualise and assess the reasonableness of trends, including annual energy consumption and rooftop PV deployment
- Publication of annual generation capacity factors
- Average intraday interconnector flows over time, and utilisation and flow duration curves – showing clearly how they change with the investments
- Transparency about the economic life of transmission assets and how they are converted to annual costs
- Insights into the impact of changing WACC, not just on the discounted cash flow, but also on the annualised costs of generation and interconnector projects
- Further analysis to test reliability and unserved energy implications associated with a delay in Snowy 2.0
- Explain further how the $118 million regret cost varies with different assumed retirement dates for Yallourn[26]
- Whether AEMO has undertaken a sensitivity of +30% to transmission costs, and how this may impact on ideal timing.[27] Specifically, detail the estimated capital cost used

[26] AEMO, *Draft 2020 Integrated System Plan Appendices,* Page 109
[27] AEMO, *Draft 2020 Integrated System Plan Appendices,* Page 143

to determine annualised costs for the transmission projects for cases where a range is given, and basis for that decision.[28]

- The optimal timing of Humelink if snowy 2.0 is delayed four years. AEMO has assumed it is not delayed along with the power station – are there regret costs with Humelink four years early?[29]
- Given the significance of the number in informing AEMO's decision to adapt the optimal development plan, more clarity is required around the regret costs of $240m with the 'no acceleration' candidate option in the Step Change scenario. Our expectation is that this is largely driven by the assumption that VNI West is built in 2031-32, rather than in 2027-28 in the optimal development path.

[28] For example, AEMO, *Draft 2020 Integrated System Plan Appendices,* Page 156,
[29] AEMO, *Draft 2020 Integrated System Plan Appendices,* Page 107,

Some inputs and assumptions should be updated

We refer AEMO to our prior submission on its 2019 Forecasting Inputs consultation paper, noting that there is some ambiguity as to whether, or which, inputs would be updated and incorporated in the final ISP. In any case, the summary observations and recommendations from our separate submission are:

- battery usage and cost assumptions — modelling should accommodate mid-life extensions for utility scale plant, including a possible 'brownfield' investment option with lower capex and consider the impact of longer economic lives
- pumped hydro cost assumptions — there should be a sensitivity with a 40 per cent increase PHES capex
- rooftop PV costs and deployment – we consider there is likely to be a higher rate of deployment, in line with recent trends and policy impacts
- open cycle gas turbine (OCGT) assumptions — AEMO's modelling should accommodate two sizes of OCGT plant, and consider the impact of longer economic lives
- firm capacity and thermal de-rates — we expect AEMO has overstated firmness assumptions for inverter connected equipment, and should also examine the performance of underlying wind resources during higher ambient temperatures.
- maximum Demand Forecasts — AEMO should clarity the effect and adequacy of its climate adjustment
- use of Reference Years and stochastic results — various elements of AEMO's forecasts are unclear, including use of reference years, application of 10 and 50 PoE demands, random forced outages, and how planned outages are scheduled
- regional demand traces — AEMO should publish relevant loss factors to allow stakeholders to reconcile demand traces
- renewable energy traces — AEMO should outline how the annual PV energy projections in the 2019 Input and Assumptions workbook are applied to create the PV traces for the various reference years
- inter-regional loss factor equations — it is not clear what inter-regional loss factor equations have been applied over the ISP outlook period
- costs of transmission projects — AEMO's assumptions about the annualisation of transmission costs are not fully transparent
- demand side participation — AEMO should clarify if any duration or frequency limits are assumed for the voluntary demand side participation volumes included
- gas price forecasts — CORE's gas price assumptions are below what we would regard as realistic forecasts in the short term.