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EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 33
385 Bourke Street
Melbourne Victoria 3000

Phone +61 3 8628 1000
Facsimile +61 3 8628 1050

enq@energyaustralia.com.au
energyaustralia.com.au

Nicola Falcon
GM Forecasting
Australian Energy Market Operator
GPO Box 2008
MELBOURNE VIC 3001

Submitted electronically: forecasting.planning@aemo.com.au

Dear Ms Falcon

Australian Energy Market Operator – Draft 2021 Inputs, Assumptions and Scenarios Report – December 2020

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 4,500MW of generation capacity.

We appreciate the opportunity to provide feedback on AEMO's Draft Inputs, Assumptions and Scenarios Report (IASR). Our main areas of feedback are:

- it is not clear how AEMO has incorporated findings from its recent Renewables Integration Study into the inputs and assumptions
- the Tasmanian Renewable Energy Target (TRET) and business case for Marinus Link are inextricably linked, and uncertainties around the funding of Marinus Link warrant a broader and more careful treatment than AEMO has presented
- in examining the risks around generator closures, AEMO's scenario modelling should allow for plant to close for economic reasons as a model output, rather than have closure dates set as modelling assumptions
- AEMO should continue to engage with participants regarding input assumptions for their generation plant
- we request that AEMO engage more closely with participants and transmission network service providers (TNSPs) to clearly explain inputs used for congestion modelling impacting interconnector transfers, REZ developments and new entrants, including the need for system strength remediation requirements. This applies particularly to the capacity expansion plan in each scenario. AEMO needs to validate how firm the current and augmented interconnector transfer capacities will be, as affected by system strength and other power system limitations in a world with very little synchronous generation after coal closures. It should squarely address whether the large number of high-cost transmission projects will actually deliver their claimed increases in transfer capability

- we further support AEMO closely engaging with the AER and TNSPs to improve the sector's understanding of transmission costs and how changes to these could affect the optimal development path and project timings.

If you would like to discuss this submission, please contact me on 03 8628 1655 or Lawrence.irlam@energyaustralia.com.au.

Regards

Lawrence Irlam
Regulatory Affairs Leader (acting)

General comments on scenarios, including "most likely" terminology

We consider that AEMO has conducted an appropriate consultation process and our observations of this has been that stakeholders have had solid opportunity to provide input. This also reflects a trend of continued improvement around scenario development over recent years.

AEMO has developed an appropriate set of scenarios, with generally sufficient breadth to test a range of plausible future outcomes.

Clause 5.22.5(e)(3) of the NER, via the AER's cost benefit analysis guidelines, effectively requires AEMO to develop a "most likely scenario" and an associated optimal development path that has a positive net present value under that scenario. The AER's guidelines contain further requirements around the most likely scenario, including that AEMO consider taking the "most probable" values for inputs (provided they together are internally consistent and plausible).[1] The language in the draft ISAR paper suggests that the central scenario will be populated with "best estimates".[2]

AEMO should consider how this construct and terminology will frame discussion of the subsequent analysis and potentially skew stakeholder views. While AEMO will be bound to use terms in the NER and AER guidelines, labelling the central scenario as the "most likely" may overplay the probability of it being realised. It could be the case that AEMO determines the central scenario to have a relatively low probability (e.g. 20%) of being realised, yet it will still be more probable or the "most likely" of scenarios under consideration. Outputs of the central scenario may also be more convenient to use for general presentational purposes, including in media and through subsequent commentary by policy-makers, whereas the optimal development path may depend on findings from less likely scenarios or in dealing with particular risks. We expect AEMO will appropriately qualify its findings and note the level of uncertainty in all its analysis when communicating with less specialised audiences.

Treatment of risks and sensitivities within scenarios

AEMO has also adequately canvassed key issues in identifying 'risk' scenarios, particularly in exploring the impacts of exiting coal plant.

In addition to modelling specific closure dates and allowing its modelling to optimise for transmission and generation investment, AEMO should explore situations where coal plant closes before 'optimal' transmission investment is able to be commissioned. AEMO has flagged this as a possibility in the case of Marinus Link, which we discuss further below.

Other restrictions to investment timing and delivery of transmission transfer capacity seem likely to arise. For example, we note the current voltage stability issues arising and constraining flows between Victoria and NSW, with associated price impacts. AEMO's modelling appears to assume that power flows will be constrained only by relatively firm thermal limits and this should be revisited, particularly as non-thermal network constraints will become more common and less predictable with more renewable generation investment. This is discussed in further detail in subsequent sections of this submission.

[1] AER, *Cost benefit analysis guidelines*, August 2020, p. 11.

[2] AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020, p. 22

We also question whether AEMO has suitably implemented the findings and risks from its more recent Renewable's Integration Study.

We raised questions around AEMO's approach to modelling generator retirements in consultation on the 2020 ISP. Retirements should be modelled on an economic basis, with closure decisions also made where prices and revenues fall to unsustainable levels. It is not clear whether AEMO's modelling approach can accommodate this as it does not appear to produce market prices as an output. Modelling closures endogenously would also illustrate the impact of key policy announcements which are of high interest to stakeholders, in particular the interplay between the NSW Roadmap and Project EnergyConnect. Specifically, Project EnergyConnect obtained regulatory approval largely on the back of the assumed presence of black coal generation in NSW, which could now be forced out of the market by lower prices, on the back of a large government-mandated influx of renewable generation and storage. Modelling for the NSW Government's Roadmap also presumed certain black coal generators would remain in service, which should also be tested with appropriate modelling of retirements on an economic basis.

AEMO should also consider the role of scenarios versus sensitivities, with the AER guidelines generally contemplating variation to the values of continuous variables.[3] We generally support AEMO's comment that risk 'sensitivities' would be better characterised as 'scenarios', and note that AEMO intends to develop further sensitivities as its analysis progresses.[4]

AEMO's approach to Marinus Link warrants closer attention. AEMO has stated that it will examine a risk scenario where funding arrangements for Marinus Link are not resolved. It is not clear whether this means funding arrangements are delayed from optimal timing, or never resolved. Irrespective of this, such a scenario, combined with the TRET as a modelling constraint, is infeasible. This demonstrates that Marinus Link and the TRET are inextricably linked, and raises questions around AEMO's proposal to include the TRET as a policy input in all scenarios, noting this is consistent with other jurisdictional policies that have been legislated.

The effect of including the TRET as a modelling constraint will be to justify investment in Marinus Link. AEMO needs to be very clear how it will implement the TRET policy into its modelling – outlining whether the new renewable generation (15.8TWh by 2030 and 21TWh by 2040) will actually be 'forced in' as a hard deterministic exogenous input to future studies, or whether it will actually be included as a soft optimisation input where the target may not be met if the economic efficiencies aren't realised with these developments in Tasmania. We consider this runs counter to the intent of the ISP which is to identify the prudence of commissioning such large transmission projects. The NER criteria for recognising policy includes whether it has been legislated, or whether the jurisdictional government has allocated government funding.

However, the Tasmanian Government has expressed reservations about funding Marinus Link. For this reason we recommend AEMO treat the TRET as less certain than other state-based renewable energy targets. That is, recognition of TRET as a confirmed policy should be dependent on legislation as well as associated funding commitments, rather than just the legislative criterion in isolation. The element of funding uncertainty is likely

[3] AER, pp. 33-5.
[4] AEMO, p. 34.

to be present across many scenarios and should not be isolated as AEMO has proposed in a single 'risk' scenario.

Our other observation on scenario likelihoods is that Export Superpower is likely to have the lowest probability, however is still an important scenario and worth exploring. That said, we would be concerned if creating and assessing more speculative scenarios inadvertently affects the selection of optimal development paths and actionable projects, and gives rise to AEMO recommending certain outcomes and actionable projects on this basis.

Policy settings

Discussions in AEMO's recent working groups have noted that accommodating policy developments in the current environment is particularly challenging. Generally, the market is increasingly shaped by the cumulative effects of policy changes, increasing the relevance of even the smallest interventions. On top of this, we note substantial developments including the NSW Electricity Infrastructure Roadmap announced in November and ongoing consultations on national frameworks for generation and transmission investment under the ESB's post-2025 work program. The details of these and other policy measures will not be known by the time AEMO finalises its IASR by the middle of 2021, raising questions around an appropriate 'cut off' for policy inputs for the purposes of ISP and other modelling. We suggest that policies that meet the criteria for inclusion across all scenarios continue to be incorporated for the duration of 2021, and not halted as at May 2021 as AEMO suggests.

Aside from this general comment on process, we consider that AEMO's coverage of policy impacts to be well-researched and its scenario alignment is appropriate for IEA scenarios, SSPs and global temperature pathways. AEMO's updating of these inputs with AR6 updated climate assessments should be subject to Bureau of Meteorology guidance on the most representative models.

In the context of the NSW Roadmap:

- we disagree that the additional 2GW of long duration storage should be reflected as a single development constraint by 2030 and suggest instead that this be modelled as separate developments commissioned in increments. AEMO's optimisation modelling may also involve some long-term storage being made up of batteries in smaller increments

- the 'Energy Security Target' component of the Roadmap (i.e. N-2) appears likely to affect NSW reserve requirements and should be considered further by AEMO

- there could also be additional entry costs and ongoing revenue implications for generators connecting within REZs in terms of submitting bids for, and receiving, access rights.

In the same way that AEMO is allowing optimisation of generation and storage investment for NSW policy, we recommend that storage arising out of auctions proposed by the Victorian and Queensland Governments be modelled rather than taken as exogenous inputs. If not, AEMO should provide clarity on any assumptions around storage auctions.

As raised above in the context of AEMO's proposed risk scenarios, we consider that the ability to achieve targets set in the TRET is dependent on appropriate funding arrangements for Marinus Link. The TRET should be treated as a 'committed' policy at the point funding arrangements are resolved, rather than assuming this is the case across all scenarios. While governments have reached agreements on funding for design and project approvals[5], the Tasmanian Government does not appear to have changed its opposition towards Tasmanian taxpayers funding the actual project. Arrangements for funding transmission interconnectors generally is also being considered by the former COAG Energy Council. We expect policy discussion around the question of funding will be informed by analysis conducted by AEMO, including distributional impacts. For these reasons AEMO should ensure that Marinus Link is assessed on its merits and not essentially assumed to be an actionable project via imposing the TRET targets as modelling constraints.

Our further observations on other specific policies and questions posed by AEMO are:

- as AEMO has flagged, updates will be required to accommodate actions provided for under the most recent Victorian Government budget such as to the VEU upgrade scheme, that will be of relevance to modelled outcomes

- The announcement around a 'safeguard' for Portland aluminium smelter also post-dates the draft IASR and will need to be accommodated.[6]

- AEMO's ISP Demand Forecasting Methodology Information Paper does not reflect updated levels of Victorian Government support for household PV and batteries. The draft ISAR refers to this paper and we assume that these policies will be updated as appropriate.

- We suggest that a price per tonne of negative emissions / offsets be applied if LULUCF or other contributions are to be credited to electricity generation sector emissions.

- Legislated state-level interim emissions reduction targets should be integrated once announced, and we underscore the need to continue to update the modelling with legislated and defined measures as they are confirmed throughout 2021.

Consumption and demand

Our general comment on these various inputs is that they reflect values from AEMO's recent ESOO and GSOO and that material changes (including from updated or new consultation reports) should be appropriately explained. AEMO should consider giving stakeholders appropriate opportunity to provide input (e.g. at working group level) prior to finalising its IASR.

Trajectories for distributed energy uptake are likely to be particularly affected by using the most recent historical data and policy announcements, and our expectation is that forecast uptakes would be higher overall as a result. The High DER scenario also had highest EV and PV uptake. Further policy developments affecting EV are likely as governments start looking to decarbonise the transport sector. For example, a recent SA

[5] https://www.marinuslink.com.au/2020/12/state-and-federal-agreement-delivers-for-project-marinus/

[6] https://www.minister.industry.gov.au/ministers/taylor/media-releases/securing-victorias-energy-system

Government policy statement has indicated a desire for new passenger vehicles sold in that state to be fully electric by 2035.[7]

In scenarios where a blend of multiple consultant inputs is being taken into consideration, it would be helpful to get more detail as to which specific elements or weighting of the consultant results are being used. AEMO should also ensure that forecasts for DER technologies and services produced by different consultants are appropriately integrated and internally consistent when adopted as a set by AEMO.

We are comfortable with AEMO's long-term projections of demand-side participation, noting incentives for participation are driven by price outcomes and so can be cyclical.

We recommend AEMO give further and specific attention around the growing system challenges of minimum demand and how management of DER from a policy and technical perspective may feedback into consumption and demand forecasts. For example, it is not clear that the projected uptake of rooftop PV and demand traces reflect various policy and system operator interventions, including emergency curtailment powers and related changes to customer incentives like declining feed-in tariffs and potentially different pricing/ access models for mass market customers. Some of these impacts will likely be mitigated by the take up of small-scale batteries.

Uptake and charging profiles for EVs are also subject to considerable uncertainty and materiality to the extent of justifying sensitivity analyses. For example, AEMO may wish to model situations where there is significant lag in developing time of use pricing signals and insufficient policy or customer behavioural response to discourage EV charging at times of system peak demand, which would have commensurate impacts on system costs.

AEMO notes it will take a "systematic approach to industrial load closures".[8] The impact of any assumptions taken as a result of interviews with specific consumers will likely have substantial impacts on scenario outcomes. If any reduction assumptions are assumed, AEMO should test closures with respect to optimal development paths as specific sensitivities.

Existing generator and storage assumptions

We have appreciated engagement to date with AEMO regarding various parameters on EnergyAustralia's generation portfolio and welcome the opportunity to provide further bilateral feedback to AEMO in completing its final IASR, and also in the development of the 2022 ISP. We similarly encourage AEMO to reach out directly to other market participants regarding their assets.

AEMO should be clear and provide a cohesive narrative on how its sets of assumptions have been or should be changed to reflect generator operations in a system with higher amounts of renewable sources. This also relates to the flexibility of coal units to cope with changes to demand with rising DER technologies and services.

Our observations on specific inputs, and use of inputs, for existing generation and storage are:

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[7] https://energymining.sa.gov.au/__data/assets/pdf_file/0020/376130/201216_Electric_Vehicle_Action_Plan.pdf

[8] AEMO, p. 73.

- **Fixed O&M Costs —** generators have a combination of fixed opex plus stay in business capex for outages etc. The definition of fixed operating costs should be made clearer, namely whether this is purely relating to operating costs (as per standard P&L approaches), or whether it also includes stay in business capex, which aims to maintain or upgrade both reliability and capacity. AEMO’s assumptions for QLD black coal generators do not appear to differentiate mine-mouth and non mine-mouth power stations and it is therefore not clear whether the associated cost differences are reflected in AEMO’s cost inputs e.g. fixed costs appear to be the same across all QLD black coal generators

- **Refurbishment costs —** these are based on an assumed 10-year refurbishment cycle, which appear inconsistent with industry practice of major outage cycles of 4 to 6 years.

- **Outage cycles capex and opex —** it is not clear whether the costs associated with lumpy outage cycles are being captured in the AEMO cost assumptions. AEMO should engage generally with market participants regarding outage cycles for their plant and to understand whether there is a degree of consistency in approach across the industry that warrants a uniform set of input assumptions (e.g. 4-year outage cycles for coal units).

- **Ramp rates —** AEMO’s assumptions appear to be maximum ramp rates, which in practice might not be achievable when deep cycling between min-gen and full output due to issues such as switching coal mills in and out of service. For this reason, AEMO should use conservatism in its modelling rather than assuming maximum ramping rates are achieved all the time, and outline where and how it has captured findings from its Renewable Integration Study into inputs and assumptions

- **Coal unit flexibility and operations under accelerated market transition —** the continued influx of renewable generation and supporting forms of storage will significantly change the operating regime of coal generators remaining in the system, which were originally designed and operated for a baseload role. We note that the pace of change is accelerating, with the investment targets in the recently announced NSW Electricity Industry Infrastructure Roadmap being higher than those modelled under the 2020 ISP’s Fast Change scenario. The growing pace of change warrants a general review of the suitability of key operational parameters such as ramping rates, min up and down times, and future maintenance and reliability. We also note AEMO’s assumptions do not appear to include start costs for coal generators.

- **Coal Life Extensions —** under the current market and policy outlook it is difficult to imagine coal life extensions without these being supported by government policies. We would suggest that the question of coal life extensions be aligned to the policy assumptions inputs, which could then vary by scenario.

- **Solar and Wind outage assumptions —** AEMO’s workbook does not list outage rates for renewable plant and notes these have been included implicitly in the relevant generation profiles. We would like to see additional transparency regarding both the assumptions and methodologies used, and insights into why taking forward historical observations is the best approach when considering aging maintenance influenced plant and equipment.

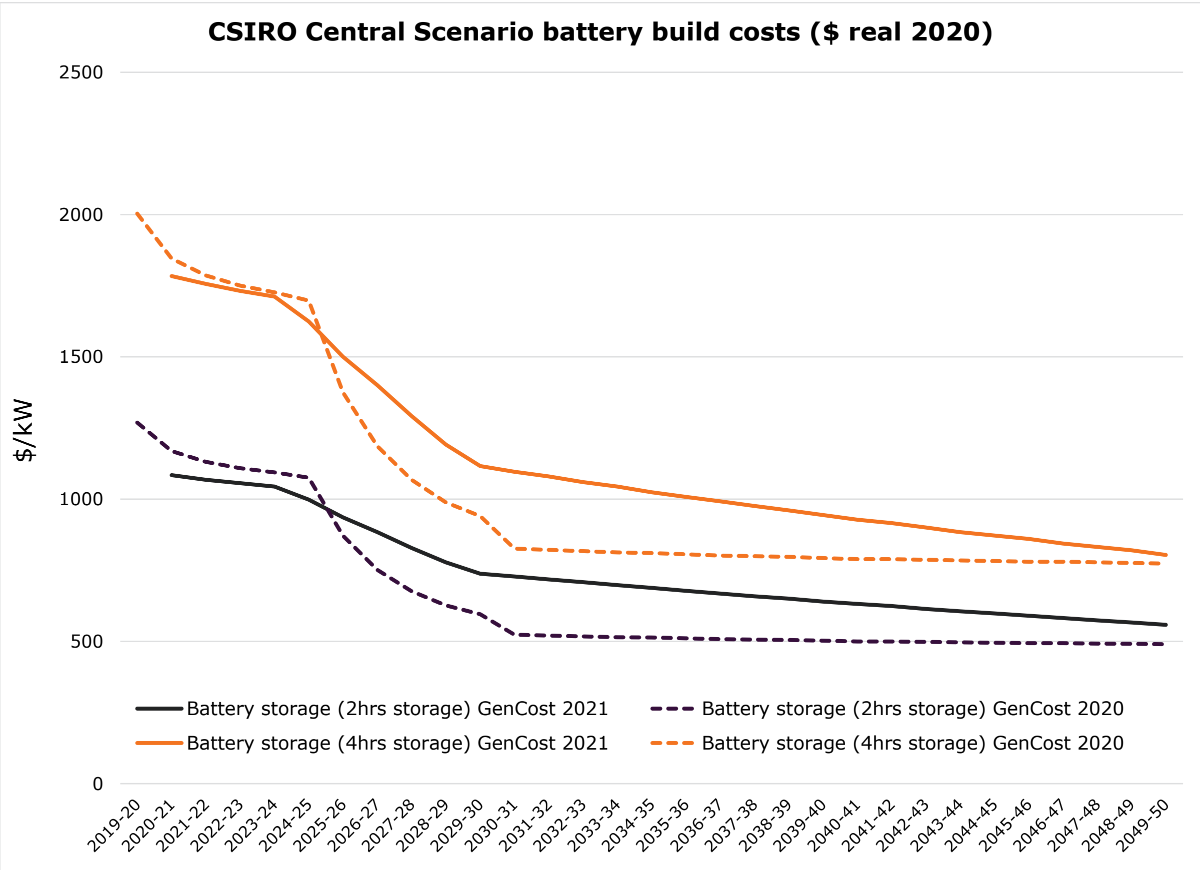
- **Wind modelling —** although this is more of a methodology issue, we have appreciated the transparency AEMO has provided regarding potential over-forecasting bias with the existing wind forecasts, and support AEMO's initiatives to improve the accuracy of wind forecasting during both high temperatures and high wind speeds, which are seen to have the effect of materially reducing dispatch capacities at times when it is highly valued.

- **Reserve margin assumptions —** the regional reserve margin for South Australia is 273 MW which appears to be the capacity of the Northern unit which closed in 2016. This seems outdated and is no longer the largest unit in South Australia.

New entrant generator assumptions

We note AEMO is developing inputs for two sizes of OCGT plant and support this additional flexibility in the mix of new entrant generation plant.

CSIRO's latest cost trajectories for battery storage reflect a slower rate of decline from the mid-2020s in its Central Scenario and we request further information on what has driven this change from its previous deployment projections and scenario definition.



Source: AEMO ISP input assumptions workbooks

Fuel assumptions and gas market modelling

We note that AEMO has assumed a brown coal fuel price of $0.6/GJ for all Victorian generators for some time now and request further information on the basis of this assumption. We also question the assumption that coal prices for Bayswater significantly increase in the late 2020s, from being the cheapest of NSW coal generators to the most expensive, which does not appear to accord with its particular location and access to fuel. These assumptions may be worth refreshing or applying closer scrutiny given our suggestion to focus more on revenue sufficiency calculations and drivers for generator closures than AEMO has done in the past.

In addition to accounting for coal costs, AEMO should be aware that contractual coal volume constraints have a profound impact on both minimum and maximum coal generation volumes. The AEMO assumptions do not appear to consider volume constraints, which is potentially a material omission from its suite of assumptions and methodology.

On gas, we note there is a material difference in fuel prices underlying the 2020 ISP produced by CORE and those now presented by LGA, with limited apparent change in drivers over this time. As was the case with CORE, the LGA report provided minimal detail on how forecasts are developed which can undermine confidence in how they have been prepared. Given the materiality of gas price forecasts to the ISP (and RIT-Ts) AEMO should endeavour to address any concerns about a lack of transparency. Given the inherent difficulties in producing "accurate" long term forecasts, it may be best to explore these concerns via sensitivity analyses rather than spending effort on methodological issues.

That said, our view is that the longer-term gas price forecasts produced by LGA are consistent with our price expectations. This includes the presumption of a divergence in costs between QLD and southern states, with marginal supply sources coming from QLD which incur a transport premium when shipped southwards. The relatively lower prices produced by LGA for scenarios with more ambitious climate targets also contrasts to the forecasts produced previously by CORE, and in our view this is more plausible.

As we have raised in the past, AEMO appears to model gas transmission costs on the basis of a 'flat' $/GJ whereas tariffs are charged with a capacity element (typically $/GJ/day). This would introduce an error where declining pipeline utilisation drives up per GJ unit cost of transport for gas generators, and we recommend AEMO test whether using a simplified tariff approach introduces a material downward bias in gas fuel cost estimates. We note there are several other factors affecting gas transport cost estimates that may be worth exploring further, although their materiality or directional bias is less certain, and may be too difficult to resolve in any case:

- Pipelines that are highly contracted may also involve paying a premium to run peaking gas generation which can require a higher maximum hourly quantity, affecting pipeline compression.
- Conversely, pipelines that are not fully contracted may be accessed at a discount to published tariffs.

- Gas fuel costs can also be affected by contracting across multiple pipelines with the same owner, who may offer discounts

- vertically integrated entities manage their pipeline usage (and total cost) across generation and retail loads.

On specific gas production costs, our view is that Gippsland pricing (based on EnergyQuest) is likely to be in the 2C range instead of the 2P range due to the high costs of removing CO_2.

In terms of AEMO's modelling of gas expansion candidates, we consider that it will be challenging for the QLD/NSW interconnector and Hunter pipeline to be available from 2022-23. Similarly, the assumed start dates for the Narrabri field (2024) and Beetaloo basin (2025) are optimistic. On import terminals - Port Kembla and Crib Point are the only two credible projects to start by 2023, Newcastle and Adelaide are less likely to be starting by then based on their status.

Financial Parameters

We note that the AER's cost benefit analysis guidelines suggest that AEMO, in exercising its discretion, should use the AER's most recent rate of return determination as a lower bound discount rate.[9] AEMO has also stated that it wishes to remain technology agnostic in dealing with discount rates[10], which is in line with a desire to maintain competitive neutrality between network and non-network options.

However, we consider that network determinations for regulated monopolies in the current economic environment are likely to materially understate risk adjusted return expectations for market based competitive generation investments, particularly over the longer-term modelling horizon of the ISP, noting risk free rates are at historical lows.

AEMO should also consider that private sector investment in NSW generation will likely be brought on through some form of government involvement, with commensurate reductions in risk.[11]

Climate change factors

AEMO briefly notes factors affecting network resilience including line ratings, however extreme maximum temperatures also bring about thermal de-rates on inverter connected equipment, both utility and behind the meter. We recommend AEMO review the firmness assumptions for inverter connected equipment, as well as the performance of underlying wind resources during these previously unprecedented temperatures.

We also note thermal derating is not only a matter of gradual adjustment in line with temperature trends but presents modelling, system planning and operational issues around islanding (e.g. for networks, via bushfires) and cut-offs of large PV and wind capacity.

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[9] AER, p. 10.
[10] AEMO, p. 105.
[11] https://energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20WACC%20Report.pdf

Renewable Energy Zones

AEMO's removal of the N4 REZ (Southern NSW Tablelands) seems inconsistent with the number of operational wind farm developments in this REZ and the earlier description of the high quality of the wind resource by AEMO.

We consider AEMO should adopt a pragmatic approach to REZ transmission expansions, system strength remediation and other connection costs sensitivities (i.e. apply for example an additional +30%) given the simplistic approach currently adopted. AEMO should also outline the basis of the expansion cost component more clearly. This is particularly the case for geographically remote REZs where, for example, a locational uplift is warranted. The use of a low regional cost profile for Q1, Q2, Q3 and even Q4 seems unusual and understated.

The adoption of REZ group transmission constraints seems suitable and appropriate.

AEMO has presented the results of how various network augmentations will impact on REZ transmission capacity through the calculation of limit modifiers. It is not clear what methodology was used to arrive at these, which makes it difficult to inform a view of whether they are reasonable or not. Further, it is not clear whether the expansion will impact on the need for increased system strength remediation. There has been a clear and increasing trend of issues associated with system strength and voltage control that have detrimentally impacted interconnection transfers due to large intermittent power stations locating close to interconnectors. AEMO needs to better reflect these and how they impact the market when considering REZ developments interactions with interconnectors.

ISP zonal model

The proposed zonal representation and associated Zonal Reference loads appear to be a reasonable and warranted improvement in the representation of the network that will provide increased insights into network limitations. We also think the zonal approach will make the impact of augmentation options much clearer.

However, we are keen for AEMO to be mindful of the following matters as it progresses its analysis of the topology proposed or feasibility of the increased resolution studies:

- being very clear as to when the zonal vs regional model is being applied
- what it means in terms of the increased number of input load traces across the scenarios and how inter-zonal demand diversity will be maintained across all the refence years, and whether AEMO will need zonal load growth forecasts (energy and peak summer/winter demands)
- whether the cut-set between Central NSW (CNSW) and Sydney-Newcastle-Wollongong (SNW) zones will allow for sufficient insight to differentiate between the anticipated Newcastle and Bannaby constraints and therefore the selection of the Northern loop or Southern loop network development options.

We question whether the inter-zonal cut-set between CNSW and SNW should include Bannaby-Sydney West, Marulan-Avon, Marulan Dapto and Kangaroos Valley Dapto 330kV lines as currently defined, or whether it should probably include Bannaby-Sydney West, Dapto-Sydney South and Avon-Macarthur 330kV lines, noting that Tallawarra and all load and generation at Dapto is defined to be in CNSW not SNW. Specifically, we wish to confirm to what extent Tallawarra generation and Dapto load will influence the defined power flow on this 5,600MW cut set as the zonal representation diagram shows Dapto and Tallawarra to be in SNW.

Network transfer capability

We have some concerns with the deterministic representation of interconnector transfer capability adopted for the regional capacity expansion model. This matter is less about the transfer capacities at different demand levels, and more about the prevailing power system conditions, and particularly how intermittent renewables and dispatch conditions that impact transfers.

As a starting point and to provide transparency, AEMO should explain which constraints define the notional limits used to represent the worst-case approximation transfers. For example, the forward direction capability approximation from CNQ to GG is 615MW – what is this limit defined by and does AEMO place any additional firmness factor on these limits as part of the capacity expansion planning process?

Whilst the proposed static limits are consistent with the approach adopted for the 2020 ISP (and are based on thermal ratings and reflect worst case transfer limits at time of peak demand) there is increasing evidence they are overstated. For example, flows from VIC to NSW can be constrained well below the nominal value of 700MW and this can be for several factors – such as volatile and recently observed voltage stability limits, but most materially intermittent renewables and dispatch outcomes in the Snowy area and south west NSW.

AEMO should consider the inclusion of a select set of system normal constraint equations to be applied in the capacity expansion planning to better reflect a wider range of interconnector transfer limits at times of peak demand as affected by semi scheduled plant. Examples include how Lake Bonney can impact VIC to SA transfer, how Sapphire impacts QNI limits, and how Murray dispatch impacts VNI. A select use of constraint equations to be included in the capacity expansion process will likely result in a more accurate representation of inter-regional transfers under the diverse conditions in the various reference years used by AEMO, and aid in avoiding any potentially overstated transfer levels using the current static limit assumptions.

AEMO presented a reasonably comprehensive list of typical system normal constraints per interconnector in the 2019 input and assumptions workbook (see extract below), and this could be updated and applied in the 2021 inputs and used in the capacity expansion simulations.

AEMO's summary of system normal constraints affecting interconnector transfers as summarised in the 2019 IASR inputs

		Constraints which typically limit transfer in the NEM	
Interconnector	Forward Direction	Typical Forward Limiting Constraints	Typical Reverse Limiting Constraints
QNI (Note 3)	NSW to QLD	N>>N-NIL__3_OPENED N^^Q_NIL_B N^^Q_NIL_A N^^Q_NIL_B1, 2, 3, 4, 5, 6	Q^^NIL_QNI_SRAR Q::N_NIL_AR_2L-G N>N-NIL_DC
Terranora	NSW to QLD	NQTE_ROC N>N-NIL_LSDU	QNTE_ROC N>N-NIL_MBDU Q>NIL_MUTE_757 N_NIL_TE_B
VIC-NSW	VIC to NSW	V>>V_NIL_2A_R, V>>V_NIL_2B_R V>>V_NIL1A_R V>>V_NIL_5 V>>N-NIL_HA V^^N_NIL_1 V>>N-NIL_HG N^^N_NIL_1 V::N_NIL_xxx	N^^V_NIL_1 V>>V_NIL_1A V>>V_NIL_1B V>>V_NIL_3 N>>V-NIL_O
Heywood (Note 6)	VIC to SA	V::S_NIL_MAXG_xxx, V::S_NIL_TBSE_xxx V::N_NIL_xxx V^^S_NIL_MAXG_xxx	V>>V_NIL_2A_R V>>V_NIL_2B_R
Murraylink (Note 7)	VIC to SA	V>>V_NIL_2A_R V>>V_NIL_2B_R V>>V_NIL1A_R V>>V_NIL_5 V::N_NIL_xxx V^SML_NIL_3 V^^N_NIL_1 S>>NIL_RBTU_WEWT V^SML_NSWRB_2 V>SML_NSWRB_10	S>V_NIL_NIL_RBNW S>NIL_NIL_NWMH2 V>>V_NIL_3
Basslink	TAS to VIC	T_V_NIL_FCSPS V>>V_NIL_2A_R V>>V_NIL_2B_R	V::N_NIL_xxx V_T_NIL_FCSPS V:T_NIL_BL_1 T>>T_NIL_BL_EXP_5F T::T_NIL_3 T::T_NIL_4 T::T_NIL_2 T>>T_NIL_BL_EXP_7C

Source: AEMO

We also note AEMO suggests dynamic constraint equations used in time sequential modelling can invalidate the single nominal transfer limit representing the limit ranges for each of the augmentation options used in the capacity outlook models. We would encourage AEMO to transparently report changes it makes to the simplified representations if this approach is maintained.

AEMO needs to validate how firm the current interconnector transfer capacities are, as affected by system strength and other power system limitations.

Anticipated transmission projects

TNSP Network Capability Incentive Parameter Action Plan (NCIPAP) projects are intended to improve capability of those elements of the transmission system most important to determining spot prices; or improve capability of the transmission system at times when users place greatest value on the reliability of the transmission system. On this basis, we consider that AEMO should systematically review, summarise and include the impacts of all NCIPAP projects in the input assumptions as they impact on improving interconnector transfer levels and treat these as anticipated projects, and consider ways conceptual future NCIPAP projects are likely to impact interconnectors over the modelling outlook

Interzonal augmentation options

We consider the augmentation options for the inter-zonal model capture a good spread of credible options and that the evolution into inter-zonal augmentation options from inter-regional options are appropriately defined.

However, AEMO should explain what the new limits are that define the upgraded notional transfer limits, and how it has arrived at these upgraded transfer levels. For example, GG Option 1 increases notional transfer limit from CNQ to GG by 700MW from 615MW to 1315MW – what is this 1315MW limit defined by?

Generally, AEMO needs to validate how firm the augmented interconnector transfer capacities will be, as affected by system strength and other power system limitations in a world with very little synchronous generation after coal closures. Will the large number of expensive transmission projects actually deliver their claimed increases in transfer capability?

We also request AEMO to explain what appears to be an excessive cost for SQ-CNQ Option 1, along with an overly long build time, and what the next most critical constraint is once the mid-point switching station has been developed.

AEMO should also clearly articulate what the notional transfer limit increase is for CNSW-SNW Option 1 (Northern loop) and Option 2 (Northern loop) separately.

Transmission cost estimates

The RIT-T principles and therefore the ISP should be looking to promote interconnector upgrades that are robust across a wide range of input assumptions and scenarios. We strongly encourage AEMO to undertake and discuss transmission cost input sensitivity analysis to see how this may affect the optimal timing or need for upgrades.

In regard to the costing database work, EnergyAustralia believes AEMO should engage closely with other TNSPs and particularly the AER, and share information about what it believes to be prudent and efficient transmission capital costs. The AER has privileged insights into TNSP project cost estimating processes and assumptions, as well as actual out-turn costs. Recent experience as to why projects have come in or over budget will also be of high value to AEMO's work.

That said, we question whether there is a risk that having full transparency on cost estimates will encourage contractors to shadow price these estimates, bringing into question the incentive arrangements on TNSPs in delivering actionable projects, and the circularity in informing any AEMO cost database.

AEMO should also:

- validate its adoption of only 1% of capital cost per annum for operation and maintenance costs of new transmission assets
- explain why it uses an economic life for new power stations that is much shorter than their technical lives, but does not appear to apply this concept for transmission project asset lives
- clearly state the methodology of how very large investment costs are annuitized into smaller amounts and how the costs and benefits of assets that extend beyond AEMO's modelling horizon are treated, particularly noting the long lives of transmission assets.

Preparatory activities

For the New England REZ network expansion, the 2020 ISP discussed an option that facilitated an extra 6,000MW of renewables. Notwithstanding that, the NSW Roadmap refers to a 9,000MW capacity objective. As part of the preparatory activities, TransGrid and AEMO should advise more specifically whether the network expansion option will be able to accommodate a notional extra 6,000 or 9,000MW of capacity.

Loss factor equations and marginal loss factors

We encourage AEMO to continue with its intentions to consult further on the approach to modelling changing loss factor equations. This will be valuable in understanding the full costs and benefits of interconnector projects over the outlook period, and on dispatch outcomes and critical locational signals for investment, particularly given the significant new lines being considered and how these will materially alter active power losses.

We also encourage AEMO to consider full network modelling of forward-looking loss factors at some intervals over the outlook period to update and better reflect the likely loss factors that will apply to locational generation and load under some of the modelled scenarios.

We understand this would all be quite feasible to do with preparation of network load models as part of the ISP.

Transmission line failure rates

Whilst AEMO confirms this matter is not subject to consultation a part of this IASR (as consultation is occurring though the Forecast Accuracy Report improvement plan) we seek further information from AEMO to help understand the proposal and the background to the suggested outage rates and mean time to repair figures.

AEMO indicates it will implement time varying outage rates based on meteorological parameters such as wind gusts and bushfire weather forecast and observations from within the applicable reference years.[12] It is proposing an unplanned outage rate and MTTR of 2.64% and 80.87 hours for the Heywood interconnector. This seems to imply that Heywood will be randomly forced out of service for approximately 230 hours per annum (or roughly three events per annum of 81 hours duration each). This seems quite significant and not reflective of the forward-looking reliability of the assets that form this interconnector. AEMO needs to explain how this methodology will work, and ensure that actions that have been put in place to prevent such unplanned outages or minimise repair times in the future are accounted for and justify the model parameters to be used based on sharing the data used to inform the model.

Other power system security inputs

AEMO appears to be taking a simplistic regional view of current and future power system requirements that is common across all scenarios. Essentially as new interconnectors are built and an unspecified number of synchronous condensers are installed, the need for a minimum requirement of synchronous units to always remain online is removed (except in Tasmania). This occurs based on a prescribed date in each region, which happens to be 2025-26 in all regions.

We request AEMO to provide further information on the basis of the input assumptions, namely:

- how the number of large synchronous units always online has been determined for the current power system
- how the threshold dates have been determined and justification of why they are appropriate across the wide range of scenarios (which each are likely to have different optimal dates for interconnection upgrades)
- what the implied requirements are on the number and locations of synchronous condensers that will resolve the system strength issues that have yet to be studied and identified
- how AEMO has accounted for findings from its Renewable Integration Study as they impact in inputs and methodologies under consultation.

Regarding system strength, we request AEMO to confirm that it will calculate and report on any fault level shortfalls measured against the locational 2020 minimum three phase pre- and post-contingency fault levels across the outlook period in each of the scenario and in the case where a shortfall is not identified, what the absolute fault levels are.

Further, regarding inertia, AEMO should confirm that it will calculate and report on any inertia shortfalls measured against the 2020 Secure and Minimum requirements in each region across the outlook period in each of the scenarios, and in the case where a shortfall is not identified, what the inertia trend is.

[12] AEMO, p. 157.

The 2020 ISP only undertook this analysis for a select sets of cases and pre-dated the RIS, we expect a much more detailed investigation into these maters going forward given how material they are likely to be with the coal closure profiles adopted.

Hydrogen

Aurecon states that Aero Derivative and Industrial (F-Class) Turbines are hydrogen ready (up to 85% and 65% blended hydrogen in natural gas respectively), and also considers that there is no material cost impact (capex or opex) in operating these assets with hydrogen. We do not agree with these statements:

- our understanding is that the flame behaviour of hydrogen is very different to the fuels that gas turbines have been designed to operate on, particularly the existing fleet of Australian turbines. Higher hydrogen mixes may involve a significantly higher risk of combustion oscillation and “flashback” (backfire)

- we are also aware of studies illustrating issues with NOx production from hydrogen combustion which again point to the need for redesign from existing plant

- some manufacturers have claimed that more modern designs can accommodate a modest mix of hydrogen and natural gas (perhaps up to 20%) however we are not aware of evidence to support this.

We are aware of new plant designs still in development that could accommodate higher concentrations of hydrogen and even those that are most advanced have not yet reached commercial readiness (aside from some smaller, modular designs).