1 March 2021

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Australian Energy Market Operator – ISP methodology issues paper – February 2021

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 issues paper and have also appreciated the recent bilateral discussions with AEMO staff on input assumptions and specific methodology issues. The process map in Figure 1 of AEMO's issues paper illustrates the many (and mandatory) points for formal stakeholder input leading into the final ISP. It may be prudent for AEMO to manage stakeholder expectations on what improvements to inputs and methods it can realistically accommodate in time for the draft and final 2022 ISP, noting it will receive voluminous feedback on many detailed matters. AEMO should prioritise its effort on those suggestions that will deliver the biggest improvement to its analysis.

Our responses to AEMO's issues paper are listed in the attached and cover a range of matters that can be addressed through our ongoing engagement and discussions. Some issues we raise reflect areas where we recommend information to be published within the methodology paper itself. The key matters are:

- We encourage AEMO's methods, particularly design of counterfactual cases and treatment of anticipated projects, to appropriately explore the value of announced REZ developments, as well as other policies that are not yet certain.

- AEMO is proposing that Anticipated generation and transmission projects only require three out of the five defined committed criteria questions to be progressed for them to be treated as exogenous committed projects. We consider this is a relatively low hurdle and it should be increased so that at least four of the five criteria are met, with the Finance criteria being compulsory.

- AEMO needs to carefully treat how plant operation and closures are affected by factors that do not appear to be captured in its modelling, primarily economic/ commercial drivers such as non-energy revenue streams and contract markets.

- AEMO notes that its approach of using generic linearised REZ expansion costs introduces inaccuracy, but is adopted to avoid computational burden. AEMO should provide more details on the extent of this inaccuracy and the trade-off in terms of the effort in using engineering analysis to determine feasible exogenous projects on a REZ-by-REZ basis.

- AEMO should conduct 'deep dive' workshops to provide stakeholders greater transparency on its capacity modelling, including its variants, and their relationship with time sequential modelling and engineering assessments. Similarly, AEMO should provide more transparency of its gas supply modelling to enable focussed stakeholder feedback in subsequent consultation.

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

Regards

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Regulatory Affairs Leader (acting)

AEMO's methods should provide for transparent assessment of future policy

AEMO's draft IASR report notes that for a policy to be "included in all scenarios" it must be sufficiently developed to enable power system impacts to be identified and must also satisfy at least one of several criteria, including international commitment, legislation, material funding allocation or regulatory obligation.[1] Clause 5.22.3(b) of the National Electricity Rules states that AEMO may consider a jurisdictional policy as part of power system needs where it satisfies at least one of those criteria.

We raised the specific point about the relationship between the Tasmanian Renewable Energy Target (TRET) and Marinus Link in our feedback to the draft IASR, highlighting AEMO's intention to include the TRET in all scenarios given the target was legislated, even though there are some doubts about the funding of Marinus Link, which is necessary to meet the TRET.

We have further comments regarding AEMO's methods as it relates to the role of the ISP to identify optimal development paths and policy interventions in the form of announcements around REZ developments. In reflection of policy targets at the time, very few REZs were identified as Actionable or Future projects in the 2020 ISP. Jurisdictional (and national) frameworks are now being proposed around the development of REZs on the presumption that they would be necessary to deliver accelerated generation investment targets.[2] However, mechanisms to ensure targets are achieved at least cost, and how risk and costs will be allocated across market participants, customers and taxpayers is still unclear.

AEMO's issues paper notes the use of 'shadow' REZs in the 2020 ISP's counterfactual modelling[3], and we support the proposal to include these in the assessment of optimal development paths, in recognition of hosting capacity that will become available at brownfield sites once thermal plant retire and should be utilised where this is efficient. These matters go directly to the necessary costs of the transition and the overall efficiency of the network build. We request that AEMO provide more detail on how shadow REZs account for thermal plant closures, for example how they have been modelled for closures at Hazelwood, Northern, Munmorah, and the same for future closures such Liddell etc.

While recognising the rights of jurisdictional governments to set policy targets within their geographic borders, AEMO should, as part of its functions as the national system planner, publish analysis that demonstrates how appropriately coordinated state investment targets can be aggregated and optimised across the NEM. This could inform options around the timing or sequencing of state-based investment that minimises issues arising from interstate flows, system security issues, and the exit of coal plant. AEMO should generate analysis that can be used in jurisdictional planning discussions and potential derogations from the RIT-T framework that appear to be likely for at least two NEM jurisdictions. Specifically, if AEMO were to identify that certain REZs or their stages were not efficient, or were subject to considerable regret costs under its scenario analysis, this may usefully guide jurisdictional governments when setting incentives, targets, and other policy parameters that are in the long-term interest of consumers. Under the current RIT-T framework, where governments or other proponents are looking

[1] AEMO, Draft 2021 Inputs, Assumptions and Scenarios Report, December 2020, p. 42.

[2] This includes specific REZs recently announced in the NSW Electricity Infrastructure Roadmap; the Victorian Renewable Energy Zones Development Plan Directions Paper; and the general framework proposed by the ESB in its 'stage two' Renewable Energy Zones Consultation paper.

[3] AEMO, ISP Methodology Issues Paper, February 2021, p. 39.

to pursue projects with scope or timing that are suboptimal, funding contributions would be necessary, and AEMO's ISP analysis would presumably form a strong foundation for these considerations.

Further, and in the context of TRET and Marinus Link, AEMO's analysis of distributional impacts could also be instrumental in determining and allocation of government funding between jurisdictions, where this is an issue. Presenting information on key distributional effects of optimal development paths is identified in the AER's Cost Benefit Analysis (CBA) Guidelines as a requirement of the ISP.[4]

In publishing its 2022 ISP, AEMO may also be able to inform the discussion of the efficiency of policy announcements via reconciliation of optimal development paths, total system costs, regional pricing outcomes and other outputs of the 2020 ISP. Specifically, increased reliance on REZ developments and accelerated generation build within state boundaries seems likely to result in a system that is less reliant on interconnector flows and associated technology, weather and demand diversities. Such a future contrasts with the 2020 ISP, which saw significant reliance on interstate power flows. We note that different jurisdictional decarbonisation and other policy targets would need to be appropriately accounted for in making comparisons between different ISPs.

Committed and anticipated projects

We support AEMO's exploration of the role of government funding in relation to project commitment status, specifically how projects meet the criteria for being 'anticipated' and further filtering that would see projects included in the modelling of all scenarios and counterfactuals.[5]

The AER's CBA Guidelines define 'Anticipated' as one that is "in the process of meeting" at least three of the criteria for a committed project.[6] In line with this, AEMO is proposing that Anticipated generation and transmission projects only require three out of the five defined committed criteria questions to be progressed for them to be treated as exogenous committed projects. We consider this is a relatively low hurdle for such projects and the criteria should be increased so that four of the five criteria are met, and with the Finance criteria being compulsory.

Furthermore, we agree that the announcement of government funding for a particular project clearly signals progress towards achieving full financial commitment. We do not, however, consider that government funding is a sufficient condition to satisfy non-financial criteria, and that satisfaction of other criteria should still be independently considered. Such an evidence-based assessment would satisfy (or not) AEMO's suggestion that government funding commitments signify overall project viability, that is, we do not see any compelling reason to simply assume this is the case, particularly as other criteria appear to be easily verifiable. Otherwise, the revisiting of existing AEMO categories of 'advanced' and 'maturing' with respect to the 'Anticipated' category, which has a specific function in the AER's guidelines, seems prudent.

We would be interested in seeing further updates on AEMO's proposed treatment of Project Energy Connect which is highly advanced on all criteria except for securing financing, and also approval for its contingent project application by the AER, with the latest AER position raising questions around some elements of the project's forecast

[4] AER, Cost Benefit Analysis Guidelines, August 2020, pp. 27-35.
[5] AEMO, February 2021, p. 14.
[6] AER, p. 102.

capex allowance.[7] Were this project to be modelled endogenously by AEMO, alongside NSW Roadmap investment targets, our expectation is that it would no longer be an Actionable project.

As AEMO highlights, whether or not a project is "in the process of meeting" commitment criteria is an area worthy of closer scrutiny and potential refinement. Generally, we support the tightening of criteria which results in less projects being treated as Anticipated, and AEMO should err on the side of not including projects in its counterfactuals. Borderline generation and storage projects that are treated as 'sunk' may inadvertently justify Actionable transmission projects that have marginal business cases, which in turn could reinforce the apparent need for the uncertain generation and storage projects in question. In this way the ISP can be a useful tool in validating the prudence of project announcements and commitments of governments (including REZ developments as noted above).

This usefulness presumes there is appropriate alignment between value drivers for projects as assessed by project proponents versus those that are captured in AEMO's simplified least cost resource modelling. As we note below, there are areas of misalignment that should be corrected if possible.

Appropriate treatment of the economics of plant operation and investment

We have raised several issues stemming from modelling limitations as part of discussions on AEMO's 2020 ISP. These could systematically skew AEMO's modelling outputs as they relate to the assumed operation of storage, and of firm generation generally.

Our primary observation is that AEMO's modelling tends to bias investment in longer duration storage by relying on short-run marginal cost (SRMC) bidding assumptions and overlooking price separation and arbitrage opportunities. Instead, there is a focus on optimal investment based on minimising long run resources costs, particularly in terms of fuel savings. In reality, there is likely to be a greater role for batteries which can be optimally located and commissioned faster. This may result in lower system costs and reliability risks compared to the modelled reliance on pumped hydro energy storage (PHES) which is locational specific, has longer commissioning times and with larger capacity increments.

Some modelling imperfections giving rise to this bias and other potential distortions include:

- limited consideration of externalities such as the Retailer Reliability Obligation (RRO) or contract markets. For example, in ensuring there is enough firm capacity to ensure availability of hedge contracts, especially if the RRO is amended to be 'always on'
- no consideration of ancillary services requirements, which we consider will become more important over time
- questions around the treatment of potential revenues from new essential system services

[7] https://www.aer.gov.au/system/files/AER%20-%20Preliminary%20Position%20-%20TransGrid%20-%20Project%20EnergyConnect%20Contingent%20Project%20-%20December%202020_0.pdf

- risk management practices used by participants and the inability to effectively hedge with Settlement Residue Auctions (SRAs), and the signal for firm dispatchable capcity provided by the contract market via 'cap' contracts

- incorporation of spot price outcomes and contracting into economic decisions around coal closures

- generator and storage behaviour when viewed as part of a portfolio

- modelled behaviour of storage when it forms part of a REZ i.e. whether it will be operated to provide network support to the REZ

- assumption of perfect competition based on SRMC and perfect foresight for hydro and renewable modelling, including prior knowledge of hydrological and wind droughts. SRMC bidding also ignores the sunk cost of latent or existing PHES capacity.

It may be the case that some of these issues are immaterial and have already been explored through detailed time sequential modelling. Stakeholders may benefit from 'deep dives' of how AEMO's time sequential modelling accommodates the decisions of plant owners in terms of SRMC and other bidding approaches, unit commitments, intertemporal constraints and other complex validations. It would also be useful to explore examples of how AEMO performs iterations between its different models and its engineering assessments.

In our view, some of limitations listed above appear to explain why the 2020 ISP placed very heavy reliance on PHES, but also understated the need for dispatchable capacity. The materiality of any bias in AEMO's methods against short-term storage and firm capacity should be tested with respect to impacts on its optimal development paths. At least two elements of AEMO's methods could be explored in this respect:

- exploring the role of reserve margins and the sufficiency of localised capacity, including whether margins need to change in line with new interim reliability measure

- the firmness of new interconnectors from the perspective of sharing capacity. PLEXOS overlooks contract markets and how participants undertake hedging in real life, potentially understating drivers for investment in firm capacity. Closer attention should be paid to various issues and uncertainties around constraints affecting interconnector flows, for example the recent constraints limiting VNI exports. The impact of the RRO is a further complicating factor.

Flexible operation of coal plant

AEMO's issues paper raises issues around reliance on interconnectors to cope with high rates of change of renewable energy output, and refers to maximum variable renewable energy (VRE) ramp rates as determined in the recent Renewable Integration Study report.[8] The impacts on aging coal plant and how this is treated in AEMO's time sequential modelling is also an important issue.

Noting that participant data are commercially sensitive, we encourage AEMO to explore these issues transparently and via open engagement with all market participants. Some of these matters relate to using realistic assumptions around plant operation and the need to validate modelling outputs in relation to ramp rates and daily output profiles, outage assumptions, plant degradation and associated reliability risk.

Transparency of capacity expansion modelling

Generally we consider that AEMO should provide further information on its capacity expansion modelling, as outlined in section 2.2 of the Issues paper and referred to in previous methodology publications. As above, some of these details could be covered in 'deep dive' sessions with stakeholders, in reflection of AEMO's proposed improvements to accommodate policy directions and more granular modelling e.g. of REZs.

We would be interested in understanding the following details, which should guide the level of AEMO's modelling transparency:

- clearer prescription of the settings in the three variants of the capacity outlook model (i.e. single stage optimisation and two multi-step optimisations) and what gets passed between them
- how these three variants reconcile with the two separate IM and DLT models described in AEMO's previous modelling methodology paper
- load chronology assumptions – sampling vs fitted – details such as step sizes, overlap periods, load block types and numbers, whether the top and bottom demands are pinned in any fitted chronology assumptions, and how any of these may change over the forecast period
- VRE generation and DER participation profiles and chronology assumptions and how they represented and simplified, and whether any correlation to demand is maintained
- what the specific objective function is when aiming to determine 'the most cost effective' trajectory for generation, storage, network investments and retirements
- clarification of what a linearised transmission augmentation is and how it is defined and reported on
- whether the look ahead periods vary from the step sizes
- full specification of any operational limits to reflect technical constraints
- improved transparency around the use of seasonal ratings – notably what the difference between 10% PoE summer derating are versus typical summer rating by unit, and whether a more conservative 50% PoE temperature threshold should

[8] AEMO, p. 34.

be used, as well as clear presentation of what the temperature or demand thresholds are that switch between the ratings

- explanation of how the capacity expansion firm capacities for plant are adjusted for effective full forced outage rate, noting this is used as a proxy for the impact of full and partial outages which are modelled stochastically in reliability assessments

AEMO plans to improve the representation of network transfer limits at times of peak demand between sub-regions. We agree these improvements are warranted and we support an approach that looks at how these transfers vary both across seasons and intra-day and also encourage AEMO could consider quarters as an interval as this is typically how energy is traded in the forward contract markets.

Interconnector loss representation is important and should reflect the existing regional FLLF methodology to the extent possible based on power system modelling of the new transmission projects. We suggest AEMO avoid doing this based on sub-regions though as this will not reflect the current market design.

Additional information that can be used to aid AEMO in selecting new entrant candidates for inclusion in the capacity expansion plan inputs includes the number and type of connection enquires and applications by sub-region.

More broadly, EnergyAustralia supports the adoption of a sub-regional topology, however AEMO should check whether this interacts with necessary changes to the load/VRE/DER chronology assumptions and compromises on computational complexity and accuracy. We would encourage AEMO to discuss and provide evidence and statistics on the results of its simulations, such as duration of simulations, and percent of data points within the ST time series inputs that have been captured.

Accommodating market redesign

The NSW Roadmap and potentially VIC arrangements suggest a policy-driven focus on ensuring appropriate combinations of variable renewables and co-located storage to optimise local network augmentations and REZ hosting capacity. We note AEMO’s proposed treatment of hybrid battery-wind/ solar projects, specifically that it would use time sequential modelling to inform specific REZ augmentation costs, with further TOOT analysis for actionable REZ projects. We will continue to engage with AEMO on these and other potential methodology changes once government contracting and other incentives around REZ developments become clearer.

The integrating energy storage rule change[9] also has implications for the location of storage within distribution networks rather than in transmission networks, which could materially alter network augmentation needs, both inside and outside of REZ developments.

As it relates to economic drivers of storage utilisation, we are unclear whether AEMO’s modelling appropriately reflects different incentives on storage operators to maximise revenue from arbitrage or whether (including through policy or contractual incentives) storage will be optimised to suit the needs of local networks, REZs etc.

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[9] https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

As noted briefly above, new revenue streams arising from reforms to essential system services and those around flexible demand/ DER integration could materially alter plant economics, affecting new investment as well as closure decisions.

We do not consider that REZ access options being explored by the ESB should be modelled on the basis of reflecting firm policy developments. In any case, options that involve generators paying for some form of access rights, which could be reflected in penalty prices or connection costs, are likely to be offset via revenue streams or reduced congestion risk (which would be extremely difficult to model).

Reference years and modelling of distributed energy resources

Discussions at the working group level have suggested potential alternations to or omission of values for 2020 due to COVID-19 impacts. We would caution against treating 2020 as an anomaly in this context as the choice of reference years should reflect the full range of extremes in demand, weather etc.

We support AEMO's utilisation of multiple reference years, however we do have some concerns regarding the current approach to using rolling refence years. EnergyAustralia's internal market modelling has found that the sequence of reference years can have a material impact on both the timing and location of new capacity, and we would encourage AEMO to explore this topic in more detail to understand if this is a material input assumption that impacts on the robustness of outcomes.

We also note AEMO has previously presented analysis at the Forecasting Reference Group that indicates its wind forecasting may systemically over forecast wind output during period of both high wind and extreme temperatures. We would encourage AEMO to continue to enhance its modelling to provide more realistic wind outputs given the previous ISP has heavily relied upon sharing renewable resources and capacity across regions, and over forecasting wind output may lead to over reliance on interconnection for firm capacity.

We note that latest AEMO's forecasts for rooftop PV update are more aggressive than in the prior ISP and appear to be more consistent with actual take-up rates. However, we note that AEMO has publicly expressed concerns around the impact of low minimum demands and has spoken to the need for controllability or curtailment of rooftop PV output. At this stage it is not clear whether AEMO's rooftop PV forecasts and traces include any allowance for interventions by AEMO, and we ask AEMO to provide greater transparency around any such assumptions and the potential impact on minimum demands.

We also recommend AEMO give detailed attention to forecasting consumption and demand impacts of electric vehicles (EVs), as assumptions around active or passive behaviour will significantly alter system impacts and cost analyses. Our understanding from recent discussions at AEMO's Forecasting Reference Group is that recent analysis of observed EV behaviour is leading to the adoption of longer-term assumptions that customers will charge EVs at times of their convenience (i.e. at evening peak). Given the inherent uncertainty and materially around both the projected uptake of EVs and their charging pattern, we feel this topic requires careful consideration, and a range of sensitivities around these assumptions may be warranted. We would also encourage AEMO to provide some commentary regarding additional network infrastructure that may be required to support the different assumptions around EV uptake and charging.

It may be appropriate to retain assumptions that households use technology to minimise their own cost of electricity supply. However, the case of distributed solar PV illustrates that there are likely to be overrides to customer technology where penetration rates and geographic concentration results in reliability issues, and the general policy trend is towards encouraging more active DER specifically to manage costs to the system. AEMO should seek governments' input on this.

We support AEMO's proposal to moderate the firm contribution factor to peak demand to be used for VRE and storage[10], particularly the firmness associated with limited duration storage assets however note that this should also really be considered as equally critical for behind-the-meter storage and virtual power plants.

Modelling of hydrogen

We note AEMO's approach to integrating hydrogen into its energy systems models reflects the treatment of electrolysers, in terms of investment locations and operational behaviour, subject to meeting exogenously determined domestic and international hydrogen demand. Storage needs are essentially assumed to be satisfied by existing infrastructure or at least not treated, alongside many other complex relationships and uncertainties.

These considerations largely impact modelling of the Export Superpower scenario. As we have submitted recently, because of the reliance on hydrogen we consider this scenario is of interest but should be given a very low probability and should not drive AEMO's assessment of optimal development paths. Given the deployment of electrolysers already underway for domestic consumption (albeit at a small scale), AEMO should consider the role of Hydrogen in other scenarios. In doing so, the ISP will be able to test assumptions around existing infrastructure and access to domestic markets.

We cannot provide much guidance on potential improvements to AEMO's proposed methods for the 2022 ISP. Many uncertainties remain on how best to accommodate hydrogen into modelling of the electricity system, particularly its role in blending with natural gas fuel for heating or power generation, in substitution of transport/ EV load via fuel cells or as a means of energy storage. However, we are supportive of this first attempt at including hydrogen into the ISP and will provide feedback as the details of the approach and key assumptions become available.

Gas supply modelling

AEMO should aim to release more information and be more transparent regarding its gas supply modelling. In prior discussions, AEMO has indicated that it considers there to be practical limitations, as well as confidentiality concerns, in publishing a redacted version of its model with the GSOO. However, AEMO is still able to release redacted information with its ESOO, which is presumably as complex and commercially sensitive in its full form. Ideally AEMO would share the entire PLEXOS model at the time it publishes its GSOO, similar to what is done for electricity.

It is difficult to comment on AEMO's gas supply model without seeing a higher resolution of its assumptions (daily level vs annual level). Currently AEMO only publish gross

[10] AEMO, pp. 18-19, for example where the duration of storage is compared to duration of peak demand events to determine a firm contribution factor.

annual demand and peak day forecasts. We would specifically like to access the daily demand traces for Tariff D & V by region.

Transmission costs and deliverability

We note AEMO's comments that a simplified incremental cost expansion model, based on generic projects, risks materially over or underestimating the true cost of expansion. Our view is that REZ transmission network limits and expansion costs should be based on TNSP engineering analysis of feasible exogenous projects, on a REZ-by-REZ basis. Unless a network planning body has validated the base limit and the expansion options, AEMO's approach could create a range of infeasible expansion options that do not reflect the ability of the power system to be expanded. We request that AEMO explore the amount of effort or computational burden associated with engineering analysis, as inaccuracy arising from a generic linearized expansion option, in line with the total value of network expansion costs, is likely to be high.

Furthermore, AEMO should consider the prospect of increasing project costs associated with project size in terms of community engagement and litigation potential. We refer to various recent instances where local communities have protested over land use and route selection. That said, government funding and community engagement efforts are likely to escalate through REZ development frameworks which could mitigate costs incurred by specific project developers.

AEMO should also look at the feasibility of grid connection processes and determine whether there will be bottlenecks in terms of the new network and REZ augmentation projects, plus all the regional new entrants, to provide some form of 'industry effort index'. This could highlight the annual profile of connections needed to be processed over the various scenarios to determine if this is feasible. This bottleneck may lead to material and prolonged capacity release and hold points for both interconnector upgrades and generation projects.

A further issue around project costs and deliverability relates to Australia's limited pool of skilled labour to accommodate large infrastructure investment across multiple areas of the economy. This needs to be factored especially in the near term where COVID restrictions and their aftermath will limit migration flows that could otherwise mitigate this. Finally, we think AEMO should also allow for delays and planning complexities and ensure allow realistic timeframes for transmission build.

Power system security costs

Regarding the System Security assessment, AEMO's methodologies and proposed approach seem reasonable but what is required is a clear view of the system strength and inertia needs, and the resulting install requirements and costs across all scenarios, especially in the counterfactual cases. Once these factors are considered, alternative solutions can be evaluated which cover other non-network options or those that involve contracting with existing generators, etc.

Selection and testing of optimal development paths

We do not have any in-principle preference for the mandated scenario weighted approach or least worst regret approaches outlined by AEMO, and support it retaining flexibility on its selected approach. Customer representatives may reflect preferences for a certain risk appetite during consultation on the ISP which could be a relevant consideration in adopting one approach or the other. Where probability weightings are used, AEMO should provide a clear and detailed explanation of the source of weightings and how these are tested and validated, and whether there are any threshold limits identified that unduly influence outcomes.

We support AEMO considering the inclusion of the terminal value of transmission costs and the ongoing benefits of those projects in the CBA. This reflects costs that may need to be recovered from a reducing customer base as scheduled demand supplied from the grid becomes increasingly negative and continues to reduce under some scenarios. Consideration should be given to how these treatments vary across scenarios.

The issues paper briefly mentions the role of sensitivity testing, cross checks and TOOT analysis.[11] AEMO should also consult on metrics of stakeholder interest in terms of key distributional impacts, as required under the AER's CBA Guidelines. Obvious candidates are spot price impacts across NEM regions, in addition to 'resource' costs and benefits. Distributional impacts in terms of when costs and benefits accrue over time i.e. intergenerational impacts, are also of interest and have been highlighted recently by the AEMC in its consideration of Project Energy Connect.[12]

[11] AEMO, p. 43.
[12] https://www.aemc.gov.au/news-centre/media-releases/request-change-rules-energy-financing-unnecessary-and-would-cost