ABN 70 250 995 390
180 Thomas Street, Sydney
PO Box A1000 Sydney South
NSW 1235 Australia
T (02) 9284 3000
F (02) 9284 3456

Monday, 23 June 2025

Merryn York
Executive General Manager System Design
Australian Energy Market Operator

Dear Merryn,

AEMO's Draft 2025 ENOR Consultation

Transgrid welcomes the opportunity to provide feedback on the Australian Energy Market Operator's (**AEMO**) Draft 2025 Electricity Network Options Report (**ENOR**). The Draft 2025 ENOR is part of AEMO's two-yearly consultation on network inputs for the Integrated System Plan (**ISP**). The report identifies potential augmentation options in electricity networks within the National Electricity Market (**NEM**) which are an important input to the development of the 2026 ISP.

We recognise the critical role the ENOR consultation has in developing accurate and transparent project scope, cost and timing. The credibility of the ISP requires network project costings in the ENOR to be accurate and prepared on a consistent basis. We continue to support the use of the Transmission Cost Database (**TCD**) for early-stage project costing. It provides a valuable foundation for consistent and comparable estimates across the ISP. We believe:

- **Accurate and consistent project cost information –** The credibility of the ISP requires network project costings in the ENOR to be accurate and prepared on a consistent basis. This means projects should be based on the same principles such as real (vs nominal), base year dollars, treatment of escalation and treatment of contingency.
- **TCD** – We welcome the improvements made in the 2025 TCD however we have concerns that the 2025 TCD update (version 3.0) may not fully reflect the actual costs of delivering transmission infrastructure. Our internal benchmarking suggests that for some projects there are material gaps between estimates developed using the TCD and alternative bottom-up approaches. Transgrid remains committed to working collaboratively with AEMO and the broader industry to continue to improve the accuracy of project cost estimates. This will ensure that we collectively meet consumer and stakeholder expectations on cost transparency and the reliability of related analysis. We have outlined several of our observations in our attached submission.
- **Distribution network opportunities** - Transgrid supports the assessment of distribution network opportunities in the ISP. We note that cost estimates for these projects are likely to require further development to enable like-for-like cost comparison with transmission-connected projects, including additional augmentation required to relieve transmission-level constraints for generation to be transferred to other parts of the NEM.
- **Generation and storage connection costs** – There are inconsistencies between the cost trends for generation and storage connections. The 330 kV connection costs have increased by over 50%

since the 2023 publication while 500 kV connection costs have decreased by up to 29%. This contradicts the broader pattern of rising transmission costs.

- **Concessional finance treatment** - Concessional finance may be available for projects that would otherwise have higher funding costs than the regulated weighted average cost of capital (**WACC**). Concessional finance enables Network Service Providers (**NSP**) to achieve the regulated WACC (but not lower). Any further reduction in project costs is therefore not appropriate.
- **Social license and route selection** - The ability to invest in community benefits and social impacts for community can create and maintain social license when determining project options and cost estimates

Our attached submission provides further commentary on the above-mentioned points and our responses to AEMO's questions included in the Draft 2025 ENOR documentation.

Please do not hesitate to contact us should you require any further clarification or supporting information. For any questions, feel free to reach out to Jenna Connellan, Major Projects Planning Manager, jenna.connellan@transgrid.com.au.

Yours faithfully

Kasia Kulbacka
General Manager of Network Planning

1. Executive Summary

Transgrid welcomes the opportunity to provide feedback on the Draft 2025 Electricity Network Options Report (**ENOR**). The 2025 ENOR is a critical input to the Australian Energy Market Operator's (**AEMO**) 2026 Integrated System Plan (**ISP**). It sets out the scope, timing and costs of network project options that will be available to be economically optimised in the ISP. Projects that are assessed as part of the most efficient way to transition the National Electricity Market (**NEM**) will form the Optimal Development Pathway (**ODP**) of the 2026 ISP and become "actionable" under the National Electricity Rules (**NER, Rules**).

1.1. Importance of presenting accurate and consistent project cost information

The credibility of the ISP requires network project costings in the ENOR to be accurate and prepared on a consistent basis. This ensures a 'level playing field' and enables accurate trade-offs to be made on the genuine costs and benefits of different network expansion options and generation/storage, rather than on differences in estimation methodologies. It is essential that stakeholders have confidence that ISP input assumptions, including network project costs and timing, are reasonable.

Transgrid has invested $4 billion to date on our major transmission project development and delivery, and has learned from this experience that early development costs are often significantly underestimated. We have heard from consumer advocates and other stakeholders that the upward revision of project costs over time is frustrating and erodes trust in the energy transition. We consider that, to the extent possible, project options included in the ENOR should include allowances for issues and risks that are known to drive material cost increases during project development and delivery.

We believe we are best placed to provide cost, scope and timing estimates for projects that we are developing as the jurisdictional planning body for NSW.

We intend to submit the most accurate and up-to-date cost estimates available for our projects, reflecting our detailed assessments and extensive real-world delivery experience.

Project cost updates will be provided to AEMO as an addendum to this submission, by 4 July 2025 – including NSW scopes for VNI West, Sydney Ring South and QNI Connect, and also system strength infrastructure. We consider that it is important to be transparent with stakeholders about expected transmission project cost increases and delivery timeframes. For some early-stage projects these estimates will utilise the TCD, while for more mature projects we will instead use our own estimates which we consider to be more accurate.

It is also important to establish clear project scope boundaries and sequences between adjacent or intersecting transmission projects to ensure the prudent and efficient execution for both projects. This is particularly important where projects may be planned and delivered by different parties under different regulatory frameworks. For example, there is substantial overlap between VNI West and the South-West Renewable Energy Zone (**REZ**) enablement, and the scope, sequencing and costs of these should be rationalised. We note that cost estimates for other NSW transmission projects may also need to be updated, including backbone infrastructure augmentations for the Hunter Transmission Project and New England REZ transmission link. We welcome the opportunity to work collaboratively with the Infrastructure Planner and AEMO on these matters.

We recommend that all projects in the ENOR be presented on a consistent basis to readily enable like-for-like comparisons – for example, real (vs nominal), base year dollars, treatment of escalation and treatment of contingency.

1.2. Transmission Cost Database

We consider that projects presented in the ENOR should be prepared on an equally rigorous basis. While Transgrid supports in principle the development and use of a Transmission Cost Database (**TCD**) to develop transmission project cost estimates, **we are concerned that the 2025 TCD update (version 3.0) continues to underestimate costs for several projects.** The intent of the TCD is to provide a high-level desktop calculation tool and cost estimation framework for projects on a transparent and consistent basis, which is particularly useful for early project concepts for which detailed bottom-up project estimations are not yet available. However, if the TCD underestimates project costs, it may skew ISP outcomes towards early-stage projects and disincentivise proponents from updating cost estimates for projects as they mature. This limits transparency and will be detrimental to both stakeholder trust and the accuracy of ISP optimisation modelling.

This submission includes detailed commentary on the strengths and limitations of the TCD and proposes amendments that we consider would improve its accuracy. We look forward to continued engagement and collaboration with AEMO on refining the TCD.

1.3. Distribution network opportunities

Transgrid supports the assessment of distribution network opportunities in the ISP. This recognises that the scale and pace of the energy transition requires a 'whole of system' response, and that there may be opportunities to deliver renewable generation, storage and demand flexibility within distribution networks. These solutions can and should be pursued when they can be achieved at a lower cost for consumers.

We note that **Distribution Renewable Energy Zones (DREZ) in NSW are in early stages of project development**, and Transgrid is undertaking joint planning with AEMO, EnergyCo and NSW Distribution Network Service Providers (**DNSP**) to identify the infrastructure upgrades required to connect them to the broader network. Scope and cost estimates from these projects are likely to require further development to enable like-for-like cost comparison with transmission-connected projects, including additional augmentation required to relieve transmission-level constraints for generation to be transferred to other parts of the NEM.

Transgrid appreciates that distribution network augmentation costs for unlocking tranches of consumer energy resources (**CER**) and other distributed resources are complex and will vary significantly across and between networks reflecting local conditions and topographies. We note that the proposed approach of applying standard 'median' cost values for voltage management optimisation and network augmentation across most DNSPs does not reflect the wide range of underlying long-run marginal cost estimates they are calculated from. Two DNSPs have also provided their own cost estimates that are substantially lower than the industry median values. **We consider that distribution network cost estimates should have similar rigour and transparency as transmission projects**, and that this process could be strengthened for future ENOR publications with the development of a publicly available 'distribution cost database' (equivalent of the TCD) for transparent benchmarking. Results in the 2026 that are based on these estimates should be presented with **large uncertainty ranges**, reflecting the simplified factors being applied.

1.4. Generation and storage connection costs

Transgrid notes that the cost trends for generation and storage connections presented in the Draft ENOR are inconsistent. 330 kV connection costs have increased by over 50% since the 2023 publication while 500 kV connection costs have decreased by up to 29%—a trend that contradicts the broader pattern of rising transmission costs. Assumptions that Battery Energy Storage Systems (**BESS**) will have lower connection costs due to perceived flexibility to co-locate in hybrid facilities may not be reasonable in constrained subregions like Sydney Newcastle and Wollongong (**SNW**) and Melbourne, where hybrid options are limited and more costly solutions, such as undergrounding, may be required.

1.5. Concessional finance treatment

Transgrid considers that transmission project costs should be estimated using the regulated weighted average cost of capital (WACC) where this is a relevant calculation input. Our experience is that concessional finance is only available for projects that would otherwise have higher funding costs, to the extent that it enables them to achieve the regulated WACC. Any further reduction in project costs is therefore not appropriate.

1.6. Social license and route selection

Transgrid welcomes community input and feedback in the route selection process to gain community acceptance on route selection earlier in the project lifecycle. The ability to invest in community benefits and social impacts for community can create and maintain social license when determining project options and cost estimates (e.g. accounting for longer project routes to avoid sensitive geographies and reduce community social impacts).

2. Transgrid's response to AEMO's questions

Questions from the consultation for reference

1. Do stakeholders agree with the approach taken to reflect recently observed transmission market cost increases in the updated Transmission Cost Database? Do the updated Transmission Cost Database and subsequent cost estimate updates in this report reflect stakeholders' market observations in the NEM?

Transgrid appreciates AEMO's efforts and its collaboration with Transgrid and other Transmission Network Service Providers (**TNSP**s) in developing a common cost estimation tool in the form of the TCD for industry-wide use. The initiative is a positive step toward greater consistency and transparency in cost estimation during early stages of concept development for the energy network.

Transgrid is keen to continue working with AEMO's TCD tool, particularly with projects that are at the early concept stage (ie class 5b, 5a). We note that the gap has closed considerably between estimates produced by the TCD tool and more rigorous bottom up estimations now that changes have been made to risk and cost data tables.

Whilst the efforts undertaken by AEMO with GHD's assistance has sought to address the market trends with construction costs, Transgrid has undertaken further benchmarking exercises with the most recent TCD and identified that distinct area impacts can be missed in the early concept estimating, hence producing estimates that haven't been able to capture these specific issues.

A project cost estimate is the outcome of highly intensive and detailed analysis including engineering, program scenarios, staging and constructability options, packaging assessments, interface management, safety in design and market assessment. Cost estimates are pulled together similarly to a scope that is matured from inception through to delivery to final commissioning. By virtue of this maturity process, a project's final costs estimate can only be confirmed once a risk assessment has been completed.

There are also several market forces that are outside the control of Transgrid and other proponents. These include market fluctuations, global events, and tight contracting markets. Through our past and current experiences delivering these large scale projects, we believe that we are best placed to inform and incorporate these market uncertainties into our project costing.

Current significant transmission projects in the ISP tend to be scheduled for a 5 year period from concept to delivery. However, our experience has demonstrated that timelines for large scale transmission projects are approximately 7 years considering the required planning and regulatory approval cycles. Transgrid establishes teams to plan out the project focusing on key items such as camps, laydown facilities, integration with regional towns, supply chain and logistics. For example, details such as the question of whether we can source water for the project's concrete or what impact the project will we have on local community. All these items become a crucial element of the project estimate rigour that then reflects on the schedule of activities and the intensive labour effort to achieve these milestones and therefore our ability to manage the project's risk. Whilst the TCD is solid tool for early project estimates, Transgrid prefers the bottom-up approach as soon as it is reasonable. We consider these estimates to be more accurate and de risk the project due to the ability to incorporate the time sensitive gates/milestones that major projects need to navigate.

2. What feedback do stakeholders have about any further work required to support finalising the updated Transmission Cost Database?

Transgrid has been working alongside industry experts and have gained substantial insights and improvement opportunities for the database. While the 2025 TCD provides a significantly improved baseline compared to the previous version, we note that the tool currently has limitations in capturing site-specific factors—such as construction camps and property-related costs—which can significantly influence overall estimates.

- Inconsistent application across industry: If some Network Service Providers (**NSP**s) include additional location-specific costs while others do not, the resulting estimates may not be directly comparable, undermining the goal of a like-for-like assessment.
- Underestimation in early stages of a project: The absence of detailed location-specific inputs may lead to systematically lower cost estimates in early project phases. This could skew ISP results towards early-stage projects and may disincentivise proponents from updating cost estimates for projects as they mature. This will also set unrealistic stakeholder expectations based on figures that do not reflect the full scope of expected costs, which will impact the accuracy and credibility of ISP modelling outcomes. We suggest that this limitation be acknowledged in the TCD, ENOR, and ISP documentation.
- Does not consider a holistic view: The process does not capture the impact of time taken to clear all approvals across multiple agencies and layers of government. As such timeframes usually are longer if community resistance is high and/or legal actions are undertaken
- Point-in-time nature of the TCD: It is inherently difficult to maintain an accurate database based on actual delivered costs (i.e. backwards looking) in an environment where project costs are experiencing significant escalation.

To support consistent and effective use of the TCD, we propose a collaborative session involving AEMO, GHD, and NSPs. This session would aim to align on: When and how the TCD should be applied; how outputs should be interpreted and integrated into the ENOR; How to address current gaps in location-specific detail. We believe the TCD is a valuable tool for generating consistent baseline estimates and look forward to working together to enhance its application across the industry.

Strengths of the Transmission Cost Database

The TCD has proven to be a valuable tool in improving the accuracy and consistency of early-stage transmission project cost estimates. The enhancements of version 3.0, particularly the adoption of revised rates and factors, have led to a clear uplift in estimate reliability, as evidenced in the GHD report. Its intuitive, top-down design allows for rapid data input and usability by non-specialist estimators, making it highly effective for early concept optioneering both within Network Service Providers and across broader stakeholder groups. The tool's flexibility in accommodating different voltage levels, risk profiles, and project attributes (e.g., station works, overhead/underground line works) enhances its applicability across a range of scenarios.

Importantly, the TCD serves as a common pricing reference point for TNSPs, DNSPs, jurisdictional bodies, and AEMO, fostering continuity and transparency in cost benchmarking. The involvement of an industryrecognised expert (GHD) in developing version 3.0, with feedback from TNSPs, further reinforces its credibility and relevance.

Development Areas and Limitations

Despite these strengths, Transgrid considers that the 2025 TCD update (version 3.0) underestimates transmission project costs for some transmission projects. It has the following limitations that constrain its effectiveness for detailed or site-specific project estimates:

- The tool does not adequately reflect the cost impacts of access tracks, benching, and bulk earthworks, which can vary significantly between projects.
- Site-specific conditions - such as foundation requirements in flood zones or hard rock areas, workforce accommodation logistics, and proximity to metropolitan centres—are not explicitly captured, leading to potential underestimation or overestimation.
- Biodiversity costs - while these costs estimates have improved through regional and land-use factors, there remains a shortfall in accounting for ecological variability and its associated financial implications.
- Indirect cost estimates for development and delivery phases do not align with actual resourcing demands observed from our experience in major projects, particularly in projects that require collaboration of multiple planning and execution parties.
- The tool's output structure lacks transparency, with cost items not clearly delineated, creating uncertainty around inclusions and exclusions.
- The TCD is sensitive to user interpretation, which can result in significant estimate variances. It remains a forecast tool based on other forecast inputs, lacking a robust library of completed project data for comparative validation.

Proposed Amendments to Enhance the TCD

To address these limitations and improve the TCD's utility, we propose several targeted amendments.

- The tool should incorporate additional user input fields for lump sum amounts (e.g., biodiversity offsets, property acquisition) and construction-specific variances (e.g., geotechnical conditions, access constraints, non-standard commercial arrangements).
- Bug fixes are essential, particularly in areas where cost multipliers (e.g., Contractor Preliminaries, Risk factors) were not correctly applied.
- Output costs should be realigned to reflect pricing responsibilities more accurately—for example, biodiversity and property costs should be housed within indirect costs, and risk should be presented as a distinct line item rather than being distributed across cost categories.
- The inclusion of the ITC commercial mechanism in the input options is recommended, given its relevance to transmission line projects.
- In addition to the above, we encourage AEMO to consider larger uncertainty ranges to reflect early stage nature of cost estimates using the TCD.

These changes will enhance the tool's precision, transparency, and alignment with real-world project delivery practices.

Transgrid encourages further collaborative engagement on improvements and future development of the TCD, and we propose a collaborative workshop session with AEMO and other network service providers on these topics. This session would aim to explore practical improvements to the tool, share insights from our deep dive, and collectively identify enhancements that reflect evolving industry methodologies and innovations.

3. Do you agree with AEMO's proposal for considering the inclusion of concessional finance for transmission projects in the ISP cost benefit analysis? Should AEMO align the treatment of concessional finance in the ISP with that in a RIT-T assessment? Should projects progressed via jurisdictional frameworks be treated in the same way?

Transgrid agrees that AEMO should treat concessional financing in the ISP using the same approach as when applying the Regulated Investment Test for Transmission (**RIT-T**). However, we consider that this will rarely (if ever) be a relevant consideration.

Concessional finance is only considered in a RIT-T process in the event that the benefits are likely to be shared with consumers. This is consistent with the AER's advice in their Cost Benefit Analysis guidelines.[1]

Our experience is that concessional finance for transmission projects is only ever considered by the Federal Government (i.e. CEFC through the Rewire the Nation program) in the event a NSP can demonstrate that the cost of funding for the ISP project is higher than that prescribed by the regulatory framework (i.e. a WACC cost). In that particular situation, the concessional funding package terms will be set such that the NSP is able to fund the ISP project at the WACC, allowing the project to go ahead.

Transgrid considers that transmission project costs should be estimated using the regulated WACC where this is a relevant calculation input. Any further reduction in project costs is therefore not appropriate.

In the context of contestable projects, we generally expect that proponent financing costs will be incorporated into contestable bid prices, with any concessional financing arrangements providing for lower bids than would otherwise be possible. In such cases it would be inappropriate to discount these prices further (but project costing included in the ENOR should reflect contestable market responses, adjusted for scope/risk exclusions).

4. What feedback do stakeholders have about AEMO's proposed forecasting approach for transmission costs over the ISP horizon?

Transgrid considers that it is appropriate to consider the escalation in real terms of transmission project costs over the ISP horizon. The GHD 2025 TCD Price Forecasting Methodology Report uses an 'asset building block' approach based on forecast costs of primary inputs such as commodities, labour and land, as well as broader economic factors and level of expected construction activity to produce transmission price forecasts. Transgrid considers similar factors when developing our own forecasts of project cost escalation over both the long and short terms (although our view will not necessarily align with that prepared by GHD).

We note that there is significant uncertainty, and a degree of subjectivity, in forecasting escalation over the ISP horizon (to 2050 and beyond), including assumptions made about global and domestic market

[1] See AER CBA Guidelines - [AER - Cost Benefit Analysis guidelines - 2024 - Version 3.pdf]

constraints, supply/demand and world affairs. GHD analysis suggests that many categories of transmission equipment may remain stable or decline in real-terms over the next decade (and beyond) while property and labour-related costs will increase. While these trends seem broadly reasonable over the long-term, we note that the assumption that transmission projects will experience a total of only 5% real cost inflation over the next five years may be low, given much higher escalation experienced is in recent years and current market conditions. Our experience is that global supply chains for key equipment continue to be significantly constrained because of the Covid pandemic, global energy transition and other geopolitical factors. These factors have been a material driver of project cost increases in recent years (compounding underlying commodity price movements), and it is not clear when these pressures will moderate and global supply and demand conditions will become more balanced.

Over the outlook period there are likely to be upward and downward variances rather than a 'straight line' decline.

5. What feedback do stakeholders have about AEMO's proposal to apply different forecasts for transmission project costs across each scenario?

Transgrid considers that it is reasonable to apply different rates of transmission cost escalation over the ISP horizon for the different scenarios. We note that transmission costs are strongly influenced by macroeconomic conditions and the pace of local and global energy transition efforts. We expect that these factors, along with the higher/lower coincident requirement for transmission project development in each scenario, would impact supply chain pressures and the available skills and labour market capacity to deliver projects, which would, in turn materially impact project costs.

The three ISP scenarios represent a wide range of trajectories across these factors and should therefore reflect the plausible range and uncertainty in transmission cost escalation over the long-term ISP horizon.

6. Do you have any feedback on AEMO's land use mapping approach, or other aspects AEMO could consider for future improvements?

Transgrid welcomes consideration of community and social license issues when determining project options and cost estimates. Whilst adopting cost considerations for different geographical areas makes sense, there are still opportunities to capture impacts that are measurable when considering options and comparative analysis activities.

Transgrid would like to further engage with AEMO and other stakeholders in determining the most appropriate methods to capture specific community needs and concerns when looking at early concept development of Network projects. Through Transgrid's extensive community engagement activities in NSW there has been a wealth of understanding and knowledge acquired that would be useful to guide future TCD tool updates.

Whilst the land mapping also seeks to distinguish between different communities from a property and biodiversity offset point of view, there are specific areas where there could be additional lump sum considerations that closes the gap between the generic allowances as developed and the real world impacts.

7. Is the planned approach for calculating opportunities for CER and associated distribution network costs reasonable? Noting time and data constraints, are there other factors AEMO and DNSPs could reasonably consider?

Transgrid appreciates that distribution network augmentation costs for unlocking tranches of CER and other distributed resources are complex and will vary significantly across and between networks reflecting local conditions and topographies. The proposed approach of applying broad assumptions and simplifications, and average cost values for voltage management optimisation and network augmentation across multiple networks will provide only indicative results and will (by definition) significantly overestimate and underestimate opportunities in different DNSP network regions. Results in the 2026 that are based on these estimates should be presented with large uncertainty ranges, reflecting the simplified factors being applied.

For example, the cost assumed for voltage management optimisation across most DNSP networks of $0.4m per MW approximates the median of available underlying long-run marginal cost values with wide-ranging values from $0.1-$0.9 m per MW. Two DNSPs have also provided their own cost estimates that are 37% and 78% lower than the industry median values, respectively. There is limited visibility of how these costs have been developed and verified.

It might be more suitable to apply a ‘cost curve’ methodology rather than a single value for each network which would better reflect the range of likely costs associated with unlocking capacity in each network (and the benefits of capturing low-cost opportunities in the first instance).

It is also important to present realistic lead times for implementing different opportunities identified within DNSP networks. While some options may be relatively fast to implement and can be delivered using existing regulatory funding, others are likely to take several years, including: time to complete detailed (investment-grade) technical analysis based on actual network conditions and augmentation requirements rather than simplified averages; securing regulated revenue allowances; and/or resolving any required policy or regulatory reforms to enable projects like community batteries to proceed at scale. The lack of “actionable” delivery pathways for distribution level opportunities may prove to be a barrier to their delivery on a timely or certain basis, while momentum may also be lost on the development and delivery of complimentary (or alternative) utility-scale infrastructure.

Transgrid notes that the differentiated methodologies applied in the ISP for distributed and utility-scale opportunities will make it difficult to compare ISP results across these categories on a consistent basis. The treatment of prospective CER investments by energy consumers as a fixed exogenous input effectively makes them a free resource to the power system, so models will prioritise them over utility-scale generation and storage projects for which capital costs are accounted for and co-optimised with other infrastructure investments. While ISP results will indicate the value of DNSP investments to unlock CER capacity, they will not provide insights about the relative economic merits of encouraging CER uptake supported by DNSP augmentation, and/or utility-scale generation and storage supported by transmission. This is further compounded by the simplified assessment of distribution network opportunities when compared to the detailed project-specific transmission project options outlined in the ENOR.

8. Is the planned modelling approach reasonable for the uptake of other distributed resources? Noting time and data constraints, are there other factors AEMO and DNSPs could reasonably consider?

Transgrid supports the assessment of distribution network opportunities in the ISP. This recognises that the scale and pace of the energy transition requires a 'whole of system' response, and that there may be opportunities to deliver renewable generation, storage and demand flexibility within distribution networks. These solutions can and should be pursued when they can be achieved at a lower cost for consumers.

Several of the underlying factors that have contributed towards transmission cost inflation and delivery delays in recent years are likely to also apply to other classes of energy infrastructure, including distribution (and storage/generation). Examples include:

- supply chain constraints impacting cost, availability and lead-times for equipment and materials following the covid pandemic and war in Ukraine.
- limited availability of skilled labour and strong competition for resourcing between new and existing players.
- increased land costs, particularly in metropolitan areas; and
- greater social license and community consultation processes and considerations adding time and cost to projects and impacting where infrastructure can be developed.

While the impact of these issues is clear for transmission projects currently in development, they may not be fully reflected in cost estimates for other project types where there are fewer current case studies, projects are in an earlier stage of development, and/or there is lower transparency of delivered project costs.

We consider that distribution network cost estimates should have similar rigour and transparency as transmission projects, and that this process could be strengthened for future ENOR publications with the development of a publicly available 'distribution cost database' (equivalent of the TCD) for transparent benchmarking. This will ensure the ISP results are practically and commercially sound and help to prevent future reliability gaps emerging because of project delays or unrealistic assumptions.

3. Flow paths and Renewable Energy Zone augmentation

9. Do stakeholders have any feedback on the proposed augmentation options for the flow paths in the NEM?

Please see response to Question 10.

10. Do stakeholders have any proposed additional or alternative network options for the flow paths in the NEM, that should be considered for the final 2025 Electricity Network Options Report?

Transgrid has engaged with AEMO via joint planning forums to define augmentation options to include in the ENOR for the flow paths in NSW.

We recommend that all projects in the ENOR be presented on a consistent basis to readily enable like-for-like comparisons – for example, real (vs nominal), base year dollars, treatment of escalation and treatment of contingency.

We consider that it is important to establish clear project scope boundaries and sequences between adjacent or intersecting transmission projects to ensure the prudent and efficient execution for both projects. This is particularly important where projects may be planned and delivered by different parties under different regulatory frameworks (see commentary below on VNI West and the South-West REZ overlap below).

Transgrid will provide project cost updates to AEMO as an addendum to this submission, by 4 July 2025 – including NSW scopes for VNI West, Sydney Ring South and QNI Connect, and system strength infrastructure. We intend to submit the most accurate and up-to-date cost estimates available for our projects, reflecting our detailed assessments and extensive real-world delivery experience. Other commentary on these projects is provided below.

We note that cost estimates for other NSW transmission projects may also need to be updated, including backbone infrastructure augmentations for the Hunter Transmission Project and New England REZ transmission link. We welcome the opportunity to work collaboratively with the Infrastructure Planner and AEMO on these matters.

HumeLink

HumeLink is expected to achieve committed status ahead of the finalization of the 2025 ENOR.

VNI West and South-West REZ

Commentary in the Draft 2025 ENOR appears to imply that Transgrid continues to support outdated cost estimates for VNI West, which is not the case. Transgrid has sent separate correspondence to AEMO on this matter. Commentary in the final 2025 ENOR should accurately reflect how project costs have been estimated (including when, and by whom) to provide stakeholder clarity.

We note that there is substantial overlap between the scopes in the Draft ENOR for VNI West and the South-West REZ in NSW, including existing committed upgrades to Project EnergyConnect and HumeLink, and substation upgrades at Dinawan and Gugga. We recommend that the scope, sequencing and costs of these options should be rationalised in the ENOR.

Sydney Ring South

Transgrid considers that following detailed commercial and technical assessments, Option 2d (the 2024 ISP candidate option) which includes power flow control devices is no longer a credible option. We propose that it should be deleted from the 2025 ENOR.

We are continuing to assess options using alternative technologies (such as series reactors) to achieve equivalent network outcomes. We have not yet finalised the scope or cost of this option, but we intend to include and assess it as a credible option in the Sydney Ring South RIT-T PADR, which will be published by April 2026.

11. Please feel welcome to provide any non-network options as alternatives to the proposed transmission network augmentation options for the flow paths.

Refer to response to question 16 about the use of grid-forming BESS as a non-network option alternative to synchronous condensers for providing the efficient level of system strength to support the connection of inverter-based resources to the grid.

Transgrid welcomes consideration of non-network options in the ISP, including existing projects like the Waratah Super Battery SIPS, as well as the economic optimisation of innovative and technical alternative and complementary solutions to transmission projects, including demand side participation, coordinated CER, utility-scale storage, etc. We further seek and assess non-network options during the RIT-T process for ISP actionable projects.

12. Do stakeholders have any feedback on the proposed augmentation options for the candidate REZs in the NEM?

Transgrid recognises the strategic importance of extending the ISP scope to include distribution opportunities. We welcome the refinement of scope, cost and planning studies to develop the concepts as part of joint planning.

Transgrid is actively supporting joint planning with EnergyCo, AEMO and the NSW DNSPs, for the development of distribution renewable energy zones (DREZ) as part of the portfolio of options to facilitate the energy transition. It is critical that all options are considered to identify the most cost effective pathway for the connection of new renewable generation and storage.

Transgrid has submitted joint proposals with EnergyCo, Ausgrid and Essential Energy outlining five new network options in the distribution network (Hunter Central Coast, Dubbo, Albury, Marulan and Yass). Transgrid has been collaborating to develop the concept plans included in the proposals.

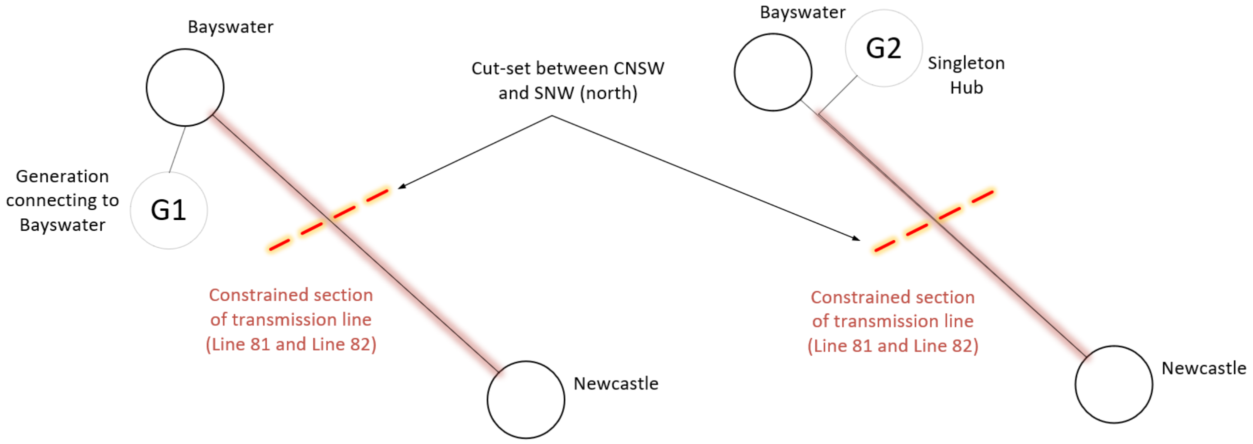
To realise benefits for consumers and achieve best outcomes, it is important to consider overall scope and cost. In the context of DREZ, this needs to include the cost of any required transmission augmentations, or alternatively to recognise that appropriate constraints will need to be applied to reflect existing network limitations.

We note that further development is required to confirm and refine the scope of our DREZ proposals. In particular, system strength requirements will need to be re-assessed once there is greater certainty in ISP candidate options. Whilst the proposals will provide an uplift in transmission capacity, downstream constraints may limit generator access in the DREZ. Transgrid encourages AEMO to ensure Group Constraints are tailored for the DREZ proposals. We continue to work with AEMO to develop new Group Constraints for the purpose of ISP modelling. Detailed congestion modelling will need to be undertaken in future.

Transgrid identifies that the connection of DREZ hubs onto the transmission network at a cut-set location between two existing transmission substations (such as Bayswater and Newcastle) will contribute towards the cut-set constraint. This must be reflected in the modelling so that it is modelled upstream of the constraint, not downstream. If modelling the generation downstream of the constraint, the generator would simply offset load at the load centre, and its contributing flows would not be accurately represented on the constraint.

For the proposed Hunter-Central Coast REZ expansion generation hubs connecting around Bayswater (including those connecting on Lines 31, 32, 81, 82), their output will contribute to line flows and constraints on those lines.

In this instance, that would involve considering this generation as being in the Central New South Wales (CNSW) sub-region, with high generation coefficients for the northern flow path into Sydney, Newcastle & Wollongong (SNW).



ISP modelling will consider G1 as contributing to the CNSW-SNW (north) constraint.

ISP modelling must consider G2 as also contributing to the CNSW-SNW (north) constraint, it is not simply 'netting off load' against Newcastle load in the SNW node.

Additionally, Muswellbrook substation is defined as being within the CNSW sub-region, and therefore the proposed HCC REZ generation hub connecting into Muswellbrook should also be located within CNSW.

We recognise significant effort has gone into the development of the Transmission Cost Database. While there are still opportunities for further improvement (as noted in question 2 and 15), we consider that this is the most useful tool for transparent comparison of options. It is strongly recommended that similar rigour needs to be applied to distribution network options to enable valid comparisons and selection of the highest net benefit solution.

13. Do stakeholders have any proposed additional or alternative network options for the candidate REZs in the NEM, that should be considered for the final 2025 Electricity Network Options Report?

Potential for South-West REZ expansion

Based on Transgrid's engagement with wind farm proponents in the South-West region of NSW, we consider that the wind resource is likely to be stronger than has been previously assessed by AEMO.

1. Our understanding, based on proponent's on-site wind sampling data records, is that the capacity factors are within the 35% to 40% range for this area. This is notably higher than the assessments currently used in AEMO's Integrated System Plan (ISP), which cite capacity factors at around 29% to 30%.
2. Location of the South-West REZ relative to the central-north and north of the NSW state – the South-West REZ geographical disparity from that region.

Given the above observations, we encourage AEMO to review wind capacity factors in the South West REZ area and apply them in the 2026 ISP. We believe higher capacity factors may support the development of a larger South-West REZ in the ISP, which would align with the NSW Electricity Infrastructure Roadmap and recent award of access rights for the REZ.

These observations will likely yield a need for consideration of future network and non-network options to enable the increased output from the REZ. Transgrid is committed to supporting this growth and is willing to collaborate with AEMO and other stakeholders to develop network capacity expansion options beyond 2.5GW of transfer capacity.

Consideration of Remote Inland REZ's in NSW

Transgrid recognises that over the long-term ISP horizon electricity demand in NSW and across the NEM is forecast to significantly increase due to population growth, industry and transport electrification and the development of emerging industries. Most of the new capacity to support this growth is expected to be provided by renewables supported by transmission and storage infrastructure.

Transgrid has explored several potential Remote Inland REZs, including Broken Hill, Noona, and Northwest Horizon and found them to have high quality wind and solar resources (with generation diversity relative to Central-West Orana, New England and Hunter-Central Coast REZs) as well as low population density and few competing land uses (and related social license considerations). Transgrid supports the representation of remote inland REZ in the ISP and the inclusion of transmission options to support them in the ENOR (including Broken Hill (N4) and South Cobar (N13)). In addition, Transgrid encourages AEMO to consider the Western NSW REZ (south of Broken Hill) for inclusion in the ENOR, given its potential to contribute meaningfully to the energy transition.

14. Please feel welcome to provide any non-network options as alternatives to the proposed transmission network augmentation options for the candidate REZs.

Refer to response to question 11 about non-network options, including the use of grid-forming BESS as an alternative non-network option to synchronous condensers to provide system strength services to inverter-based renewable generators connecting to the grid, including in REZs.

4. Distribution network opportunities

15. Do you agree with the proposed DNSP cost tranches and the methodology AEMO has used to identify these? If not, do you have recommendations for how the methodology can be enhanced?

Refer to responses to questions 7 and 8.

5. Generator and storage connection costs

16. What feedback do stakeholders have about the proposed treatment of generation and storage connection costs, including treatment of system strength costs?

Connection costs

The Draft ENOR presents updated cost estimates for generator and storage connections which will translate into the connection cost assumptions ($/kW) presented in the final 2025 IASR workbooks. These costs have been calculated using rates from the revised TCD.

The tables below compare the connection costs between the final 2023 TEOR and the Draft 2025 ENOR. We observe that:

- 330kV connection costs have increased 60% for non-BESS connections, and 51% for BESS connections, which is consistent with other trends discussed in the ENOR.
- 500kV connection costs have decreased 19% for non-BESS connections and 29% for BESS connections. It is not clear why these costs would not be consistent with the broader transmission cost escalation trends, and we encourage AEMO to provide clarification.

Table 1: Connection costs for generation technologies (excluding BESS)

Connection Voltage (kV)	Final 2023 TEOR	Draft 2025 ENOR	Change
500	95	77	-19%
330	62.5	100	60%
275	80	117	46%
220	92	104	13%

Table 2: Connection costs for BESS

Connection Voltage (kV)	Final 2023 TEOR	Draft 2025 ENOR	Change
500	85	60	-29%
330	55	83	51%
275	70	97	39%
220	80	104	30%

For non-REZ connections, the Draft ENOR lists costs by connection voltage, which we understand is then translated into a region-specific connection cost based on assumptions about which connection voltages are most likely for different technologies in each NEM jurisdiction. We recommend that an additional table be included in the final IASR mapping the connection voltage assumptions to generation types in each region to provide clarity for stakeholders.

The Draft 2025 ENOR upholds assumption that BESS connection costs are lower than other types of generation due to more flexibility in siting and the ability to leverage connection assets of other variable renewable energy (**VRE**) generation in the form of a hybrid facilities. While this may be generally true, it may not hold in urban sub-regions like Greater Melbourne and Geelong (MEL) and Sydney, Newcastle and Wollongong (SNW) which may not have this flexibility or opportunity for co-location, and instead, the complexities of urban or urban-fringe developments are likely to increase connections costs due to constraints on land use or congestion around existing substations. For example, the Melbourne Renewable Energy Hub BESS required a high-cost 500kV underground cable connection due to constraints in its semi-urban setting. We consider that connection costs for BESS in urban subregions should not be discounted, and instead that higher connection cost assumptions may be warranted due to development complexities.

It is unclear whether the Locational Cost Factors described in the draft IASR also apply to the connection component of non-REZ generation costs, which are only estimated at the regional level. If not, this may further mask the higher relative costs of connections in urban sub-regions due to the factors addressed above. We recommend that this be clarified in the Final 2025 ENOR.

System Strength costs

Transgrid has engaged with the suppliers of synchronous condensers to refine cost estimates for use in the PACR for our *Meeting system strength requirements in NSW* project (cost estimates used non-binding estimations from suppliers). These cost estimates used in the PACR are lower than those presented in the Draft ENOR. However, Transgrid is also progressing procurement activities and expects to receive updated market information shortly, and we aim to provide AEMO with updated synchronous condenser costs in our submission addendum on 4 July 2025.

Transgrid also considers that AEMO should include in the ISP the specific synchronous condenser portfolio expected to be progressed following the publication of system strength PACRs for each jurisdiction over the coming months. This will be a more accurate basis to estimate system strength costs in each region, rather than undertaking an independent bottom-up estimate that approximates the detailed planning work undertaken by jurisdictional System Strength Service Providers.

Transgrid also notes that batteries with grid-forming capability can be a very cost effective solution to provide significant stable voltage waveform support. Where batteries are expected to be deployed for energy market purposes (including those within AEMO's Step Change forecast which Transgrid refers to as 'ISP-modelled' projects), only the marginal cost of increasing to grid-forming capability (compared to grid following mode) should be attributed to system strength. This is likely to be significantly lower than the costs of synchronous condensers and will be a much more accurate reflection of additional system strength costs for IBR build out, related to both BESS and hybrid projects self-remediation and central remediation of other IBR. Transgrid recommends that AEMO consider a reasonable combination of synchronous condensers and grid-forming batteries when determining system security costs in the 2026 ISP.

Gas infrastructure expansion

Transgrid has separately made a submission in response to the Draft 2025 Gas Infrastructure Options Report (GIOR) which outlines the need for consistent treatment between gas and electricity infrastructure options in the 2026 ISP. Some key themes from our response to the draft GIOR as they relate to the draft ENOR include:

- Gas and electricity infrastructure options should be presented with a comparable level of detail, including at a minimum, information about project lead times and total costs as calculated by AEMO using GHD’s 2025 Gas Master Cost database.
- Future ENOR and GIOR documents should be consistent in their description and treatment of social license themes, recognising that new gas and electricity infrastructure may have common social licence considerations. For example, methods used to escalate costs of electricity infrastructure options to reflect uncertain route assumptions could also be applied to gas pipeline options. Social licence matters unique to gas infrastructure, such as unique environmental concerns, should also be considered.

Engagement between key stakeholders

The consultation period between the draft and final ENOR presents an opportunity for NSPs and stakeholders alike to review and refine the cost outputs from the tool. To further support consistent and informed application of the TCD, we have also recommended that AEMO host an industry-wide training session focused on educating potential users on the intricacies of the tool. This initiative would help reduce variability in user interpretation and strengthen the reliability of outputs across the sector.