25 June 2021

Ms Nicola Falcon
General Manager Forecasting
Australian Energy Market Operator
GPO Box 2008
Melbourne VIC 3001

Lodged via email: ISP@aemo.com.au

Dear Ms Falcon

RE: Transmission costs for the 2022 Integrated System Plan

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Operator (AEMO) consultation on the Draft Transmission Cost Report (DTCR), which will inform the 2022 Integrated System Plan (ISP).

About Shell Energy in Australia

Shell Energy is Australia's largest dedicated supplier of business electricity. We deliver business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers. The second largest electricity provider to commercial and industrial businesses in Australia[1], we offer integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. We also operate 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and are currently developing the 120 megawatt Gangarri solar energy development in Queensland. Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy.

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General comments

Shell Energy welcomes AEMO's consultative approach to developing the 2022 Inputs, Assumptions and Scenarios Report (IASR). We consider the DTCR to be a critical part of this process. Without appropriate inputs for transmission costs and potential network augmentation options, the ISP and related processes could be greatly reduced in value. This would have flow-on impacts to the transmission network's design and the costs borne by consumers.

We would like to acknowledge the work by AEMO and GHD Advisory (GHD) to develop the Transmission Cost Database (TCD) as a central point of authority to inform transmission costs used in the ISP. We believe this is an excellent first step in what will undoubtedly be an evolutionary process. However, we are concerned that, despite its name, the DTCR does not focus solely on costs, and instead provides a high-level discussion of potential network augmentation options. In our view, a separate, more-detailed report should have been

[1] By load, based on Shell Energy analysis of publicly available data.
[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2020.

provided for the potential network options, including all options considered but not progressed and an explanation for why these options were discarded. Releasing two detailed reports would have allowed due process for feedback to AEMO on either or both sets of data.

Our primary objective is to reduce the risk of consumers bearing inefficiently high costs. In this context, our submission provides feedback on the three key areas of AEMO's consultation: the transmission cost estimation process, the flow path/renewable energy zone (REZ) options considered in the ISP, and generator connection costs.

Our overarching concern is that consumers may bear inefficiently high costs

To date, stakeholders have observed that transmission costs tend to be significantly underestimated in the ISP and regulated investment test for transmission (RIT-T) process, before sharply increasing when project proponents apply for contingent project application (CPA) funding. We also note that a project's actual costs (when reported separately after completion) tend to exceed the costs set out in its CPA funding request. This has several negative consequences.

- Firstly, it is unclear how a preferred transmission option can be accurately determined or reasonably compared to non-network options (NNOs) in the ISP (or RIT-T) if the cost estimates are grossly inaccurate. If transmission costs have a large margin of error, it is plausible that the ISP's 'optimal development path' is actually substantially suboptimal.
- Secondly, if cost estimates have a large margin of error, there can be uncertainty as to whether a project will deliver a net market benefit in the long run. Whilst cost recovery (including a profit margin) for transmission network service providers (TNSPs) is certain, the provision of benefits, particularly for consumers, is not assured.
- Some stakeholders may believe that the above concerns are largely mitigated by the 'feedback loop', provided by clause 5.16A.5(b) of the National Electricity Rules (NER). Under this clause, before a proponent can submit a CPA for an actionable ISP project, "the RIT-T proponent must obtain written confirmation from AEMO that... the cost of the preferred option does not change the status of the actionable ISP project as part of the optimal development path".

  Shell Energy considers that the feedback does not adequately protect consumers from cost increases.

  - At best, the feedback loop has the potential to ensure that the total cost of an actionable ISP project remains below the <u>maximum</u> cost at which meeting the AEMO-identified need remains on the optimal ISP pathway. However, in the event of a large cost increase between the finalised RIT-T and the CPA, the feedback loop does not provide any assurance that the specific project being progressed in the CPA remains the <u>most efficient</u> way to meet the AEMO-identified need or will deliver a net market benefit.
  - Additionally, if the costs used in the ISP and the feedback loop maintain a relatively high margin of error, then AEMO's feedback loop assessment may mistakenly judge a project to still be on the optimal development path.
  - Finally, if the feedback loop is applied diligently, then it has the potential to rule out projects that have progressed through the RIT-T process. While this is an appropriate outcome if it protects consumers from inefficient costs, it represents a significant delay that may have been avoided with more accurate ISP and RIT-T costs. Given that the optimal development path may change because of a project being ruled out, there could also be flow-on impacts to other projects proposed in the ISP.

One option to mitigate some of these risks would be to require more accurate estimates for all options considered at the final Project Assessment Conclusions Report (PACR) stage of the RIT-T process[3]. Overall, Shell Energy considers AEMO's proposal to only require an AACE Class 4 or 3 cost estimate at the PACR stage[4] as unacceptable. In our view, a project's cost estimate should meet Class 2 standards at the PACR stage, and Class 1 standards when the project proponent seeks AER funding approval.

Another option would be to invest in more accurate cost estimates during the ISP development process – particularly for network upgrades with a material flow-on impact to the rest of the network. The next section of this submission considers a third option: for the ISP cost-benefit analysis to use a 'high-range' estimate rather than a mid-point estimate for transmission costs.

As a recent example of consumers being exposed to substantial cost increases consider Project EnergyConnect (PEC).

- AEMO's 2018 ISP modelling costed PEC (then RiverLink) at $1.27B, with ElectraNet providing an updated cost estimate of $1.5B prior to the ISP's July 2018 publication.[5]
- In February 2019, ElectraNet confirmed a cost estimate of $1.53B after completing its final RIT-T assessment. [6]
- In January 2020, when assessing (and subsequently approving) the PEC RIT-T, the Australian Energy Regulator (AER) found that the proponents had substantially overestimated the project's net benefit, revising it down from $924M to $269M based on a cost of $1.53B.[7]
- In May 2021, the AER approved capital expenditure of $2.28B as part of its CPA determination[8]. This is a 72% increase on what AEMO used in its 2018 modelling, or a 52% increase on ElectraNet's 2018/2019 estimates. Assuming the benefits remained the same, if the AER had used $2.28B as the cost in its 2020 assessment of the RIT-T, the AER would have found net disbenefit of $481M, and would not have given RIT-T approval. At a cost of $2.28B, PEC may not have even been the preferred option in the RIT-T process. However, the RIT-T was not reapplied because the project proponents deemed that the $750M cost increase did not represent a "material change in circumstances"[9].
- There remains a risk that the project experiences additional cost overruns during construction. Further, there is a risk that this cost is borne by consumers because of the following loophole in the regulatory framework.

  The AER only undertakes an ex-post expenditure review if a TNSP's actual total capex during a regulatory period exceeds its total capex allowance by a nominal threshold. This can be exploited, because TNSPs can manage actual capex during each regulatory period by cancelling or deferring capital projects for which a capex allowance has been included. TNSPs can then include the cancelled or deferred projects in their capex project lists for the subsequent regulatory period. This allows TNSPs to overspend on projects and/or claim incentive payments under the Capital Expenditure Sharing Scheme (CESS). If this occurs, consumers ultimately pay for the cost overruns, CESS incentive payments and the cancelled or deferred projects.

[3] The AEMC is currently considering a rule change request (ERC0325) to address this issue.
[4] AEMO, *Draft Transmission Cost Report*, May 2021, pp 15.
[5] AEMO, *2018 ISP appendices*, July 2018, pp 63.
[6] ElectraNet, *SA Energy Transformation RIT-T, Project Assessment Conclusions Report*, 13 February 2019, pp 124.
[7] AER, *Decision – South Australian Energy Transformation – Determination that the preferred option satisfies the regulatory investment test for transmission*, January 2020, pp 7.
[8] AER, *TransGrid and ElectraNet – Project EnergyConnect contingent project*, 31 May 2021.
[9] AER, *ElectraNet – SA Energy Transformation regulatory investment test for Transmission (RIT-T)*, accessed 25 June 2021.

It is important to note that the PEC CPA was approved despite strong opposition from consumer groups, and AEMO applying a process similar to the feedback loop. This suggests that the existing process does not provide consumers with sufficient protection against actionable ISP transmission projects that ultimately force consumers to bear inefficiently high costs.

AEMO's transmission cost estimation process

Using the Transmission Cost Database

Shell Energy commends AEMO for commissioning GHD to develop the TCD. We consider that the TCD gives greatly improved rigour and transparency to the transmission costs AEMO applies to potential network augmentations in the ISP.

We acknowledge that, at the time the ISP is conducted, transmission options may be defined only at a high level, which makes it difficult to accurately estimate costs. We therefore understand why GHD has estimated the margin of error for a mid-point cost estimate to be ±30%[10]. However, given the TCD estimates are themselves based on estimated costs (not actual costs), rather than use a mid-point cost estimate with a symmetric error margin, we consider it would be more appropriate for the ISP cost-benefit analysis to use a high-range cost estimate, with an asymmetric error margin[11]. Our rationale is as follows.

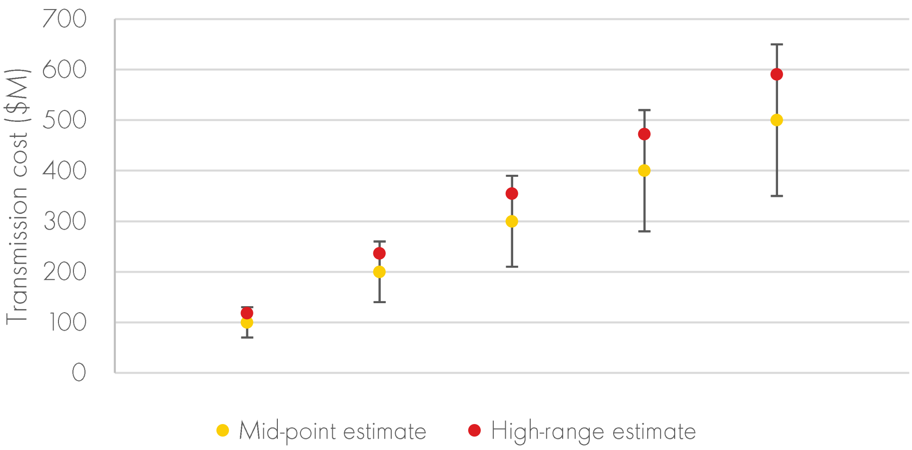
- The ISP uses PLEXOS to identify "the gas, electricity, storage and transmission investment that would minimise the total system cost while meeting reliability and emission expectations"[12]. In order for PLEXOS to make rational decisions (e.g. trading off between VRE overbuild, storage, the locations of these assets, and high-cost additional transmission between regions), it should compare options with similar upper error bounds. In our view, the ISP cost estimates for most non-transmission capital investment tend to have a much lower error margin than ±30%. For the key technologies considered in the ISP, due to the detailed process and AEMO's use of expert consultants, we think the error margin would likely be closer to ±10%. As a result, the transmission cost estimates should also have an upper error bound of ~10%.
- AEMO's assessment of transmission options determines whether they are declared as actionable ISP projects. This has a direct bearing on whether they are eventually approved and constructed. If the projects are approved, TNSPs receive a guaranteed return, funded by consumers' transmission use of service (TUOS) charges. The ISP has much less direct impact on non-transmission investment, where decisions and risks are shouldered by private investors. Given that transmission is regulated infrastructure with all risks held by consumers, there is merit in requiring a higher degree of rigour and/or a lower degree of risk, when generating transmission cost estimates for the ISP.
- As discussed in the previous section, transmission costs have historically risen dramatically from early-stage estimates. While we appreciate that the TCD aims to mitigate this risk, the TCD has only been calibrated against a relatively small number of projects, and these projects are only at the cost estimation stage (i.e. there has not yet been benchmarking to actual project costs). Additionally, the sample project costs may not be representative of the projects that will be built in the future (e.g. due to project size[13], complexity, stage of development and/or date of construction). This is somewhat unavoidable due to the lack of recently built, large-scale transmission infrastructure. However, this fact

[10] Although as discussed in the next subsection, we are concerned that what has been communicated as a ±30% range could be a -15%/+45% range.
[11] Such that the error bounds are the same as for the mid-point estimate. See Figure 1 for an illustration.
[12] AEMO, *2020 Integrated System Plan*, July 2020, pp 35.
[13] The risk of substantive cost blowouts may be higher for projects that are larger than those considered during the calibration exercise.

does not ameliorate the risk that the current TCD calibration may systematically underestimate the cost of future transmission projects. The TCD calibration process is discussed further in the next subsection.

It would be relatively easy to implement a high-range cost estimate with an asymmetric error margin such that the error bounds remained the same. The simplest method would be to linearly rescale the final TCD output for any given network option. As an example, if a cost estimate is $x \pm 30\%$ (or equivalently $0.7x < \text{cost} < 1.3x$, with a mid-point estimate of x), then a high-range estimate, y, with an upper uncertainty of $+10\%$ would be calculated as $\left(1 - \frac{53}{130}\right) y < \text{cost} < \frac{11}{10} y$, where $y = \frac{13}{11} x$. Figure 1 illustrates how this would impact the cost estimates for different-sized projects.

Figure 1: Comparison of mid-point and high-range cost estimates



We acknowledge that a mid-point estimate may be appropriate for Class 2 or Class 1 cost estimates, which we believe should be used for a project's PACR and CPA (as suggested above). However, at the earlier RIT-T and ISP stages where only less-accurate estimates are available, we believe use of high-range estimate in the cost-benefit analysis is appropriate given the level of remaining uncertainty. This would provide increased confidence to stakeholders, including consumers, that the cost-benefit analysis uses an appropriate 'base' cost from which the potential for large cost increases may be minimised and that net benefits associated with each project will reflect close to final approval values. This aligns with the fact that the ISP assessment is only the first step of any transmission augmentation approvals process, and should be used to cull any projects with limited net benefit.

Calibrating the Transmission Cost Database

Increasing transparency

The DTCR states that 16 "network elements from large-scale transmission and substation projects in the advanced stages of design [were] used as a set of benchmarks against which to calibrate the cost and risk data in the [TCD]"[14]. The DTCR asserts confidence that the calibration was effective because the input costs of 14 of these 16 elements were within 15% of the TCD outputs estimating those same projects. However, for several reasons, it is difficult to share this confidence based on GHD's TCD report.

- Assuming that the 16 network elements (from only four projects) used for benchmarking (Section 9.2 of the report) are a subset of the elements described in Section 8.4, the benchmarking costs were

[14] AEMO, *Draft Transmission Cost Report*, May 2021, pp 19.

estimates with uncertainties of their own, not actual costs. Additionally, when considering only the network elements of material size, it appears that the average cost increase is closer to ~30%. [15]

- In both Sections 8.4 and 9.2 of the report, there is little detail regarding the actual changes that resulted in the increase or decrease in project costs. This makes it difficult to determine if the benchmarking provides an 'apples to apples' comparison for different network elements.

In order to improve transparency (and therefore stakeholder confidence in the TCD), we consider it would be useful if AEMO published:

- a list of the 16 network elements used for calibration in Section 9.2, including the stage of project development for each element and/or the date of construction
- the specific network elements included for each of the projects in Section 8.4, at both stages of project costing
- the TCD output cost compared with the input cost for each network element in Section 8.4 and 9.2.

Clarifying uncertainty

In the 10 June 2021 webinar, the GHD representative made a comment suggesting that the TCD cost estimates had an uncertainty range of -15%/+45% rather than ±30%, as outlined in the DTCR. We recommend that AEMO clarifies this point.

Comparing transmission projects with non-network options

In the 10 June 2021 webinar, AEMO explained that it is difficult for the ISP to consider NNOs like battery energy storage systems (BESS). We understand AEMO's rationale is that:

- BESS projects typically have multiple revenue streams (that vary between projects), so there is uncertainty around the cost of providing the transmission-related services.
- To account for this uncertainty, AEMO typically compares the full cost of the BESS (sourced from the CSIRO GenCost) to the network options.

We agree there is uncertainty around the proportion of BESS costs that would need to be recovered from providing network services. However, using the full BESS cost in the cost-benefit analysis is the worst possible edge case because it unrealistically implies the BESS generates zero revenue from other sources. This is inconsistent with then using mid-point estimates for network options, rather than worst-case estimates. The inconsistent approach is of particular concern because a transmission asset (which is assessed less conservatively) will typically have a high, fixed capital cost for which consumers pay over the asset's long (e.g. 50 year) life. Consumers bear the cost regardless of whether the asset provides benefits in the long term. Conversely, a BESS with a lower cost and a relatively shorter period for network support (e.g. a 10-15 year contract) reduces the risk of consumers paying for a stranded asset if the market develops differently to how AEMO expects. The flexibility and optionality provided by NNOs should be valued.

These arguments extend to non-BESS NNO technologies (e.g. it would be excessively conservative to use the full cost of an open cycle gas turbine project with the capability to operate in synchronous condenser or inertia-enhanced synchronous condenser mode). We consider that a better approach would be to apply a static percentage discount to NNOs. The discount could be informed by the cost of network support schemes currently being underpinned by BESS or other NNOs. AEMO could source this information from TNSPs on a confidential basis.

[15] GHD, *Transmission Cost Database*, 7 May 2021, pp 27-28, particularly Figures 10 and 11.

Flow path augmentation and REZ development options

In reviewing the proposed flow path augmentation options (Section 3 of the DTCR), we note the following.

- All transmission projects in the DTCR fail to refer to an identified need. A clearly identified need is required for the initial Project Specification Consultation Report (PSCR), which forms the first stage of the RIT-T process. As the ISP replaces the PSCR, in our view it is critical that each proposed ISP transmission project is matched with a clearly identified and quantifiable need that the proposed project is intended to meet. In the absence of a clearly identifiable need, we question the need for any transmission project at all.
- The network flow path options concentrate on large network options and fail to consider targeted options that could provide additional network capacity at lower costs. By way of example, the addition of a double circuit 220 kV transmission line between Bendigo and Shepparton in Victoria and a flow control device on the Dederang to Wagga 330 kV loop could defer the need for the expensive VNI West major project for a number of years. This could be further improved at a later date by a single circuit 330 kV transmission line between Murray and Dederang and an additional 220/330 kV transformer at Dederang, which would further defer the need for the high-cost VNI West projects. Similarly, it is unclear why Option 3 in the Victoria to Southern NSW projects[16] needs to be a double circuit 330 kV construction when a single circuit 330 kV transmission line would deliver close to the stated transfer capacity, and why either VNI West project is a pre-requisite for this option. This option should be considered as a standalone project as an alternative to VNI West. We request that AEMO include the above options in the final transmission augmentation list as alternatives to the larger and more expensive VNI West projects.
- We also note that transfer capability from Central to Northern NSW and to Southern Queensland could be improved by the completion of a relatively short length (approximately 25 km) of 330 kV transmission line between Bayswater and Muswellbrook. This would also remove the need to increase transfer capacity between Bayswater and Liddell following the retirement of the Liddell generating units.
- The REZ and flow path options are clearly delineated into two areas and treated separately. It should be noted that electrons do not respect notional boundaries and will flow according to the physics of the system. The delineation of REZ and flow path augmentation categories is artificial and risks non-optimum planning outcomes. The development of a REZ will require reinforcement of flow paths, whereas the reinforcement of a flow path will encourage generation to connect at specific locations on the grid. It risks being ineffective to attempt to consider the developments separately as if they are unrelated to each other.
- Many of the options have not yet been costed by the relevant NSP or interested parties (for non-network solutions).
- The degree to which a specific option increases the network capacity or provides reliability benefits does not appear to have been quantified in all cases.

The last point is pertinent to the exercise, because without knowing the benefit of a specific proposal (as well as its cost) it is not possible to make comparisons with competing projects. Furthermore, the additional network capacity figures quoted at project inception often fail to be realised at project completion. The benefit side of any cost-benefit analysis is just as important as the cost side of the equation. Therefore, the proposed methodology would be improved by making available the detailed benefit assessment of the proposed projects.

[16] AEMO, *Draft Transmission Cost Report*, May 2021, Section 3.9, pp 37.

When considering the costs of each project, it is also critical that they are based on the costs that will be paid by consumers over time, and not just the headline costs. Shell Energy is aware of work undertaken in this regard by the Major Energy User Incorporated and the ISP Consumer Panel. We recommend that AEMO considers this work for inclusion in the respective cost-benefit analysis.

Generator connection costs

We have the following comments with respect to Section 5 of the DTCR, which discusses connection costs for generators.

- We query the transfer capability listed in Tables 9 and 10 at the various nominated voltages based on the designated feeder numbers. Typical 275 and 330 kV transmission lines have constructed capabilities of 1,000 to 1,400 MVA, with 220 kV having known capability to 600 MVA. The 300 to 400 MVA capability assigned to 275 and 330 kV transmission lines are being achieved currently with 132 kV transmission lines.
- Table 9 lists connection costs for solar and wind technologies, assuming new generators are located 5 to 10 km from the existing network. To avoid this arbitrary assumption, it may be preferable to use a cost per km figure rather than assume a possibly inaccurate summation. Similar remarks apply to the number of assumed feeders.
- Table 10 lists connection costs for non-renewable generation. It is not clear why this would be significantly different to the costs listed in Table 9 for wind, solar PV and solar thermal. The methodology would be improved by not assuming cost differentials of network connection between similarly rated plant regardless of technology. It is unclear why Table 9 includes costs for a large number of REZ locales, whereas Table 10 ignores location of the generation. Similar remarks apply for Table 11 (which concerns BESS connections), although it is noted that BESS locations are not dependent on local resources in the same way that generation plant is.
- Section 5.2 discusses system strength remediation measures, and prematurely assumes that synchronous condensers will be required. This ignores recent advances in inverter technology that allows grid-forming inverters to provide many of the network support services (often in a superior way). Exclusively using synchronous condensers will lead to excessive costs, that will ultimately be passed on to consumers.

Conclusion

Reiterating our opening remarks, we believe that the TCD is an excellent first step in what will undoubtedly be an evolutionary process. We have made several suggestions to further improve the transparency and use of the TCD.

Although we commend AEMO's work on the TCD, we are concerned that, despite its name, the DTCR is not solely focussed on costs, but rather includes a high-level discussion of potential network augmentation options. In our view a separate, more-detailed report should have been provided for the potential network options, including all options considered but not progressed and an explanation for why these options were discarded. This would have allowed due process for feedback to AEMO on either or both sets of data.

Nonetheless, we have provided feedback on technical aspects of the DTCR's treatment of network augmentation options. The separation of transmission options into 'flow paths' and REZs is artificial and risks leading to sub-optimal planning. A similar issue is also apparent in the way that renewable generation, non-renewable generation and batteries have been treated with respect to cost estimates for network connection. It is not necessary to split the planning and cost estimation into separate categories because the network connection technology is identical in each case. Splitting into categories risks introducing unintentional bias which may lead to non-optimum comparisons. Finally, the tacit assumption that synchronous condensers are the only means of addressing system strength issues is incorrect, and if adopted in all cases will lead to a sub-optimal outcome for consumers.

If you would like to discuss this submission further, please contact Ron Logan, Senior Markets Adviser at ron.logan@shellenergy.com.au or on 0427 002 956.

Yours sincerely

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