5 October 2021

Rupert Doney
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Dear Mr Doney

RE: Transmission Planning and Investment Review Consultation Paper

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) Transmission Planning and Investment Review consultation paper, including the material change in network infrastructure project costs rule change ("the rule change").

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 gas, electricity, 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.

www.shellenergy.com.au

General comments

Shell Energy supports a robust and thorough regulatory process to govern major network investments given that currently all these investments are paid for by consumers and deliver long-term, low-risk guaranteed returns for the network businesses building and operating this infrastructure. That said, we hold concerns that the existing process lacks adequate governance and transparency structures. When proposing investments, transmission companies are essentially given free rein to define the problem, the technical solutions and the costs for these and how the benefits are modelled within the existing framework. Further, we consider the way the framework operates currently creates an environment that is biased against non-network options, does not adequately protect consumers from cost increases during both the project approval and construction stages and does not necessarily deliver the most efficient results for consumers.

We agree with the proposed framework's focus on the National Electricity Objective and the criteria in Table 1. We also agree with the Commission's assessment of the framework in relation to materiality and feasibility.

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[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.

In general, we have confidence that the existing ex ante framework, appropriately modified in a few areas as set out in this submission and by the approval of the proposed rule change on Material Change in Network Infrastructure Project Costs with regards to costs increases post the Regulatory Investment Test (RIT) cost benefit analysis, can remain 'fit for purpose'. We do not see a case for it being considered at all, let alone a priority under this review.

The submission that follows outlines our concerns with the existing process and includes our response to the material change in network infrastructure project costs rule change.

Regulatory Investment Test timeframes

Broadly speaking, Shell Energy sees that the RIT processes remain fit for purpose and that its timeframes are a feature of, rather than a problem with the framework. Over the past few years, we have seen various processes assert that the RIT process is too slow and onerous and that changes are needed to ensure transmission investments can be efficiently delivered. In our view, the process could certainly be sped up, but this is usually framed in such a way as to lessen the regulatory oversight.

The RIT is not a "hurdle to be overcome" in order to facilitate timely transmission investment, it is the fundamental process by which it is demonstrated to consumers, who ultimately incur the costs and risks of all network investment, that this network investment is in consumers' best interests. The argument accredited to the Energy Security Board cited in the consultation paper[3] that implies the RIT process is an unnecessary delay to building what the ISP says should be built, is in Shell Energy's view flawed logic. The ISP process is deliberately high level in its consultation and assessment process that it sets out projects that should be subject to further detailed analysis. It is not a satisfactory process to justify network investment. The RIT is the process that undertakes this detailed analysis and confirms that provision of the new regulated infrastructure is in consumers' best interests.

From our perspective, we see that the timeframes often extend unnecessarily in the time it takes network businesses to release their draft and final reports including provision of the proponent's modelling. Network businesses have 9 months (recently reduced from 12 months) from the close of submissions on the Project Specifications Conclusion Report (PSCR) to release the Project Assessment Draft Report (PADR), which identifies and seeks feedback on the preferred investment option. This timeframe is often subject to extension request by the proponent. In contrast, timeframes for consultation on the details set out in the PSCR and PADR are relatively short by comparison. This places interested stakeholders at a distinct disadvantage to project proponents in the RIT process.

Given the level of control network businesses have over the PSCR and PADR and the modelling associated with each of these, we are concerned that this 9-month timeframe could be used to finesse modelling to a degree that delivers the network business' preferred outcome rather than the most efficient outcome for the market. The timeframe between the PSCR and PADR could certainly be shortened without impacting regulatory oversight.

Alternatively, and preferably in Shell Energy's views, transmission projects should be subject to an independent modelling process with regards to the calculation of benefits rather than one managed by the TNSP. From a governance perspective, there seems to be a real conflict of interest in allowing the party which stands to benefit financially from building a project for which they will receive a guaranteed regulated return to control the modelling which helps determine whether it gets built.

An independent process administered by the Australian Energy Regulator (AER) using agreed sets of inputs, assumptions and scenarios, with input from both project proponents and stakeholders such as consumer groups undertaken by the AER via specialist service providers could allow for more robust and accurate discussions as well as 'buy-in' from consumers around the substance of the modelling. This approach would be more efficient by

[3] AEMC Transmission Planning and Investment Review Consultation Paper Page 24

allowing some of the existing consultation process to occur concurrently, with the release of the modelling outcomes to the project proponent(s) and stakeholders at the same time, and would facilitate improvements in submissions from stakeholders to the PADR and PACR process, with greater transparency and effectively reducing the time stakeholders are currently provided with to review and respond to the TNSP's modelling. Stakeholders would be able to raise questions on the modelling outcomes through the AER, with answers to questions also available to all parties. It could also form part of a shorter timeframe between the PSCR, PADR and PACR.

In addition, when considering the time taken for a network project to be delivered, very little time is actually taken by the RIT process. Current delays in the provision of network projects are more as a result of delays to project proponents obtaining a "social license" and development approval for the provision of the network infrastructure with significantly more time taken in route selection and acquiring the required easements. Stakeholders are more adequately informed today and likely to engage in joint action in opposing projects and delays may result from TNSPs' inexperience in dealing with a focussed stakeholder group given the infrequency of large transmission network developments. The time taken to obtain this "social license" and the costs associated with this should not be confused with the short time period required to undertake an "adequate" RIT process.

Finally, with regards to calls for change in the approval process for the provision of regulated transmission network investment, we believe the Commission must consider the recent Connection to Dedicated Network Assets rule change as well as the scale efficient network extension framework within the rules. Failure to consider these alternative funding arrangements for the provision of large transmission network assets would simply reward those parties who have actively engaged against the use of these provisions. Real alternatives to the RIT do exist. The key difference is that parties other than consumers bear the costs and risks. The effective use of the frameworks would also provide a strong locational signal for new supply side and consumer load investment.

The RIT process should not be considered to be failing just because in some parties view it fails to provide free transmission network infrastructure to their project(s) in what they consider to be a timely manner.

Treatment of non-network options

While Shell Energy does not believe that the regulatory framework itself has a systematic bias towards capital infrastructure, we do consider that in practice there is a bias against non-network options (NNOs).

One way in which we consider that there is a bias is that proponents of NNOs must provide very detailed and accurate cost estimates, in excess of what TNSPs must provide for their own capital-based network proposals (see discussion on cost estimates). While we accept that there is a strong rationale tor requiring detailed cost estimates, the fact that NNOs provide more detailed and accurate estimates than for the capital-based network proposal means that NNOs are not compared on a like-for-like basis. This disadvantages NNOs relative to network alternatives.

Based on AEMO's Transmission Cost Database (TC), AEMO uses the mid-point of the Class 5/4 capex estimates in ISP modelling. Yet the CSIRO approach to measuring the generation and storage capex is quite different to the TCD. CSIRO describe their approach as[4]:

> "Our preferred definition of current costs are the costs that have been demonstrated to have been incurred for projects completed in the current financial year (or within a reasonable period before). We do not wish to include in our definition of current costs, costs that represent quotes for delivery of projects in future financial years or project announcements."

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[4] See CSIRO "Gen Cost 2020-21" Final Report June 2021 p.16 https://www.csiro.au/en/news/News-releases/2021/CSIRO-report-confirms-renewables-still-cheapest-new-build-power-in-Australia

This approach suggests a Class 1 estimate or perhaps a Class 2. For NNOs it heavily implies an unequal playing field for AEMO modelling to be comparing midpoints of Class 5/4 estimates for network projects vs Class 1/2 estimates for NNOs such as using battery energy storage systems (BESS). As an example, an NNO with a firm estimate of $1 billion will generally not be favoured against a capex-based network solution with costs of $975 million ±50% based on the RIT-T and ISP frameworks if they were to provide the same benefits. To Shell Energy, this seems illogical as the uncertainty of the costs of the capex network solution contains a substantial risk of higher costs compared to the NNO.

Further, we consider there are weaknesses in how options such as battery energy storage systems (BESS) are considered. Firstly, we accept 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 in any cost benefit analysis. 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 full costs and all risks regardless of whether the asset provides benefits in the long term. Network providers bear no cost or risks in the event their network project is ultimately found to be less than effective or simply not required. 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 and/or network service providers expects. In the case of many NNOs, the facility may be relocated if the defined need changes. This flexibility and optionality provided by NNOs should also 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 current network support schemes currently being underpinned by BESS or other NNOs. AEMO could source this information from TNSPs on a confidential basis.

Benefits included in the RIT and planning processes

We consider the current range of benefits allowed under the rules for the RIT processes are sufficiently broad to capture the drivers of major transmission investment. While Governments will have legitimate objectives outside the current framework, we agree with the conclusions of reviews undertaken by the Productivity Commission and the AEMC that these wider benefits should not be included in the RITs. We see no reason to change this view given recent developments in the NEM. Including them will simply distort efficient decision making and add unnecessary complexity and confusion as different stakeholders seek to push their particular valuation of a particular benefit.

With regards to what are described as 'hard to monetise' benefits, we consider these are well named for a reason. They are hard to monetise and hence very difficult, if not impossible, to get consensus on how they should be valued. Pages of guidance are not going to facilitate the inclusion of benefits that in our view are not in the long-term interests of consumers. It risks being used to justify more network investment than would otherwise be needed, increasing the probability of inefficient investment over the long term.

We support the continuation of the market benefits test as the determination methodology for network investment. We consider it would be very difficult to develop a consumer benefits test that is clear, robust, efficient and workable. This is for the same reasons the Australian Competition and Consumer Commission (ACCC) rejected the use of a consumer benefits test to justify network investment over 20 years ago. It is unclear to Shell Energy that a change in spot price outcomes which is currently considered a wealth transfer, neatly transfers to consumers as a benefit. Very little consumer load is contracted on a "spot pass through" basis and future contract pricing is being driven more by the costs for provision of variable renewable energy generation supply and the cost of firming this intermittent supply side resource. Coupled to this is the cost of ever increasing uncertain regulatory risk impacting both wholesale and retail markets.

Taking all these facts into consideration, we support the current rules definition of benefits able to be considered as part of the RITs. In our view, no changes are warranted.

We are also concerned by the recent trend to include benefits which are calculated to accrue well into the future such that there is a strong probability that these forecast benefits might never be delivered due to change in the market that has not been foreseen. These benefits often align with input assumptions that could be perceived as a "distant bookend" with very low probability of ever being realised. We recommend that the Commission consider increased detail in the Rules in this area so as to provide improved clarity as to how far into the future benefits in the PADR and PACR cost benefit analysis may be claimed. This is critical given the use of very low discount rates by project proponents in assessing future and highly uncertain benefits.

From a consumer's perspective, only the costs are certain, while historically the benefits claimed in the RIT process have been elusive.

TNSPs' exclusive right to build

We are pleased that the AEMC has included discussion on the TNSPs' exclusive right to build and own transmission projects. This is an issue we raised in our submission on the Financeability of ISP Projects rule change.[5] In our submission we argued that if the TNSPs were unwilling or unable to secure financing to deliver Project EnergyConnect then there was no reason that other companies could bid to deliver the project under an open tender. We maintain that allowing more competition to build and operate transmission projects could deliver greater benefits to consumers over the longer term. Indeed, the AEMC's Transmission Connection and Planning Arrangements rule change in 2017 and the recent Connection to Dedicated Connect Assets rule change (July 2021) opened up some aspects of transmission services to competition.

There is evidence from a range of jurisdictions that competition in building transmission infrastructure can deliver delivered benefits to consumers through lower costs. In the United States, the Federal Energy Regulation Commission's (FERC) Order 1000 opened up the right to build and operate transmission infrastructure to non-incumbent parties, amongst a range of other changes. While there are a range of complexities surrounding the broader application of Order 1000, where it has been used, there is evidence it has resulted in lower cost network projects compared to those proposed by an incumbent transmission business.

Research from the Brattle Group has found that competition in building transmission infrastructure has delivered savings of 22 per cent in the New York Independent System Operator (NYISO), 21 per cent in Alberta, 16 per cent in Ontario, 23-34 per cent in the United Kingdom and around 25 per cent in Brazil.[6] Brattle found that lower costs could be delivered not only through the use of new technologies for conductors, tower type, materials, and foundations, or optimised routes, but also measures that protected consumers from cost increases as the projects are developed and constructed such as cost caps. In this case, the project proponent takes the risk of cost overruns, not consumers as is currently the case in the NEM.

Shell Energy therefore considers it would largely be a no regrets option for the construction and operation of large transmission projects to be opened up to competition. Given the scale of transmission build set out in the

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[5] ERM Power, Submission to Financeability of ISP Project rule change, 3 December 2020

[6] Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, April 2019, p 8.

2020 Integrated System Plan, consumers would stand to benefit significantly from competition if the kinds of savings achieved internationally can be reflected in the NEM.

Cost recovery of early works

We support the Commission's consideration of providing additional clarity on cost recovery arrangements for "early works" and "preparatory activities." We believe consumers and potentially other parties who would derive tangible benefit from "early works" and "preparatory activities" would accept new arrangements for cost recovery if this resulted in improvements in the cost estimates for projects.

As discussed later in our submission, the impact of increasing jurisdictional requirements and their costs was a key factor in the Material Change in Network Infrastructure Project Costs rule change to which Shell Energy is a co-signatory. The costs of land acquisition and environmental approvals as well as the requirement to obtain a "social license" from the community need to be better estimated for all transmission network projects. These costs are proving to be well above the costs considered under the Integrated System Plan and recent RIT-T processes. In our view a RIT process needs to ensure these costs are considered in some detail to ensure consumers are fully informed when being asked to support particular projects. While there are provisions for compulsory acquisition, we consider that resorting to this is an indication of a failed stakeholder engagement plan.

We agree with this review taking this issue forward as a priority issue.

Material change in network infrastructure project costs rule change

As one of the proponents of the rule change request, Shell Energy is in favour of the rule change being made. As detailed in the rule change request, we consider there are substantial weaknesses in the RIT and project funding process that lead to consumers facing higher costs for network infrastructure projects. Further, the structure of the RIT process may even incentivise inaccurate cost estimates for projects to facilitate the approval of the RIT by the AER. As we have seen with Project EnergyConnect and Humelink, initial cost estimates used in the RIT cost benefit analysis have fallen well short of cost estimates coming later in the regulatory process. Final costs to consumers are well above cost values used in the RIT cost benefit process and having gained RIT approval, the project proponent is well aware that they can increase their costs when applying for project funding approval without facing review of their cost benefit analysis.

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 an application for project funding approval, e.g. contingent project application (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 loop does not adequately protect consumers from inefficient and unnecessary cost increases. If the intent was that the rule should do so, it was very poorly specified.

At best, the feedback loop has the potential to ensure that the total cost of an actionable ISP project remains below the maximum 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 project funding approval application, the feedback loop does not provide any assurance that the specific project being progressed remains the most efficient way to meet the AEMO-identified need or will deliver a net market benefit.

Additionally, if the cost estimates used in the ISP and the feedback loop maintain a relatively high margin of error, as is currently being proposed, 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 project cost estimates and a more accurate, or alternatively a more reasonable level of costs based on the level of uncertainty in the cost estimate being used in the RIT-T PACR cost benefit analysis. 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.

Shell Energy considers that change to the regulatory treatment of network infrastructure projects is necessary. Lumping consumers with higher costs and expecting consumers to bear all cost increase risks undermines confidence in the regulatory process, and raises the real prospect that consumers will be paying for projects that may deliver no net benefits. Consumers may therefore be paying higher energy costs than they otherwise should.

Our responses below should be considered alongside the arguments made as part of the rule change request and the joint submission made by the rule change proponents to the questions in Section 5 of the consultation paper.

Reapplying the RIT

Shell Energy argues that the AER be the party required to determine whether the RIT must be re-applied where a significant increase in costs occurs between the PACR cost benefit analysis on which the RIT approval was based and the submission of the project funding approval application. From a governance perspective, it is unreasonable for the proponent to decide whether a "material change" has occurred under the clauses set out in the rule change request and if the RIT must be re-applied or not. They are currently able to do so, but in practice have not, despite increases in project costs post RIT approval of between 20 to 60%. This is because proponents stand to benefit substantially from a project going ahead – they receive a regulated return for decades. We are sure that for a project that had not initially passed the RIT process, the proponent would be quick to claim a "material change" for a decrease in costs or a claimed increase in benefits.

We agree with the point the AEMC raises in the consultation paper that there may be a case to review and potentially reapply the RIT if the benefits of a project have materially decreased. In terms of whether the preferred option remains the preferred option, a decrease in benefits has much the same effect as an increase in costs in determining the project delivers a net benefit and as such, the impact of both should be considered if they materially change over the course of the RIT process.

However, it is unclear how a decrease in benefits could be identified when the proponents hold all the information necessary to identify such a change. Such a requirement would need strong and specific rules obligations and impose a large civil penalty on project proponents for failing to disclose such information. We believe proving that a project proponent was in breach of the National Electricity Rules in this area would be challenging. Using Project EnergyConnect as an example, the cost benefit analysis excluded significant new generation supply in southwest New South Wales and northwest Victoria[7] from the RIT-T cost benefit analysis which resulted in increased claimed benefits for capital deferment and dispatch costs and claimed significant benefits for the forgone need to duplicate the 330 kV transmission line between Darlington Point and Wagga Wagga in NSW which TransGrid has now moved to facilitate construction of through a RIT-T process[8]. Perhaps the Commission could consider these examples as a test case for how the proposed "decrease in benefits" material change rule could work.

It is worth noting that the only network projects subject to independent review of benefits claimed in a RIT-T were a review undertaken in 2013 by Frontier Economics for the Heywood Interconnector Upgrade then clause 5.16.6 review and approval process. This independent report indicated that the proposed upgrade would not deliver the

[7] Section 9.8 South Australian Energy Transformation RIT-T PACR Market Modelling Report page 33

[8] https://www.transgrid.com.au/projects-innovation/improving-stability-in-south-west-nsw

level of benefits claimed in the PACR and unfortunately for consumers, this has proven to be the case. Similarly, the then 5.16.6 review of benefits claimed for PEC undertaken by the AER in 2020 resulted in a reduction in the benefits claimed in the PACR cost benefit analysis of close to 70%.

It is unfortunate this AER review process under clause 5.16.6 was removed from the Rules as part of the Converting the Integrated System Plan into Action rule change facilitated by the ESB. It was the key part in the RIT approval process that provided confidence to consumers that the network investment was in their best interest. We strongly recommend the Commission consider reinstating the rule as part of this review process. We consider the original rule 5.16.6 process applied to all RIT-T processes, both for ISP actionable projects and non-ISP projects would result in greater benefits to consumers than any suggested change with regards to reduced benefits under the material change provisions of the RIT's frameworks.

In addition, we reiterate that for consumers, the impact of higher costs is far more certain than the impact of reduced benefits as these costs will definitely be passed through, while benefits <u>may</u> be delivered. Over the course of the life of a major network project, consumers will rarely if ever know whether a project has delivered the purported benefits. Costs are far more certain for consumers and as such, the impact of higher costs is of greater interest.

Nonetheless, Shell Energy considers there is a gap in the regulatory process in that benefits are not examined on an ex-post basis. No ex-implementation review has ever been undertaken on any network investment to demonstrate that benefits claimed during a RIT process has actually been delivered. While there is an ex-post review of capital expenditure to allow the AER to potentially exclude some over-spending if it not deemed prudent or efficient, this tells only half the story. As Shell Energy has advocated for previously, there is a need for an ex-post review of benefits for major projects.[9]

The purpose of such a review would be to provide learnings that could feed into assumptions used in future processes such as the Integrated System Plan (ISP) or other RIT-Ts. This would ensure that forecasting assumptions more accurately reflect actual outcomes (as opposed to the theoretical assumptions currently used). This in turn would promote consumer confidence that ISP and RIT-T processes are acting in consumers' best interests.

Shell Energy acknowledges that some network project benefits are only expected to accrue in future years. However, this should not prevent the AER from undertaking ex-post benefit reviews of major transmission projects at every regulatory reset period – particularly given the small number of projects that would be subject to such review. The Commission could consider an ex-post review of the benefits claimed under the Heywood Interconnector Upgrade cost benefit analysis as a test case for how such a review could be undertaken as part of this review process. This would allow learnings from this RIT-T process to be implemented in time for the 2024 ISP process and any as yet uncompleted RITs.

Cost thresholds and cost estimates

Shell Energy stands by the cost thresholds stated in the rule change request. Our focus in the rule change was on large network projects that go through the contingent project application or other project funding cost approval process and where highly inaccurate cost estimates and lowballing of costs used in the cost benefit analysis can have the largest impact on consumers. That is why we proposed AER discretion below the $150m/$50m threshold. We support having a cut-off point based on capital costs and the AEMC's suggestion to use the threshold for contingent projects is reasonable. There are only a relatively small number of ISP projects above $150m capex.

[9] ERM Power, Submission to AER Regulation of Large Transmission Projects Review. 5 February 2021.

For projects that are above the $150/$50m thresholds, our proposal is for an automatic or mandated re-opening of the RIT when the cost increase thresholds are exceeded, but it will be at the discretion of the AER under the rules to determine the level and complexity of the re-opening.

The intent of the rule change request is not to force the AER to undertake a review of every project given the administrative costs. The proposal is specifically directed at only a small number of large projects where the risk of cost increases has the largest impact on consumers. There may be a case to apply some form of indexation on these trigger points to preserve their real value.

As noted by the AEMC, AEMO analysis of RIT-T proponents current cost estimating analysis considers that a Class 3 or 4 Association for the Advancement of Cost Engineering (AACE) estimate has generally been achieved at the PACR stage. For a major or complex project, a class 4 estimate has an error margin of -30% to +50% while a class 3 estimate has an error margin of -20% to +30%. AEMO's analysis made no recommendation that a class 4 estimate was what should be reasonably required, it was simply what was achieved by the RIT-T proponents. We acknowledge that the thresholds for triggering the reapplication requirement are within these bounds. However, we consider this is more relevant to the low accuracy of cost estimates used currently than the thresholds for reapplication suggested.

We, as a rule change proponent, have argued that a class 2 estimate is more appropriate. This is quite simply because Shell Energy sees that a network business expecting a multi-decadal, guaranteed regulated return on an investment should be required to provide cost estimates that are similar to what a normal commercial entity would do when considering a major investment. It is highly unlikely that any board of any company would agree to a major investment based on cost estimates with an error margin of -30% to +50%.

Shell Energy understands that more rigorous cost estimates would entail higher costs for the proponent – costs that would be recovered under the regulatory process in any case. However, the benefits delivered by this, both through improved cost certainty and transparency in the PACR cost benefit analysis process, warrants such an outcome. This would reduce the possibility that a project that delivers a negative benefit is unlikely to receive regulated funding approval.

Alternatively, the RIT frameworks in the Rules could require the project proponent to "use a value in the cost benefit analysis that adequately reflects the level of uncertainty in the costs estimates applied at the time of preparation and issue of the PACR so as to ensure any increases in cost post the cost benefit analysis, (on which the RIT approval is based), at the time of application to the AER for project funding approval is limited to a maximum of 10%". Project proponents are not required to use the mid-point of any costs estimate in their cost benefit analysis, they chose to do so to maximise the potential for a project, from which they will receive a guaranteed regulated return, to pass through the RIT process. While the collective of project proponents may argue that the proposed rule change could lead to feasible projects being overlooked because of the inaccurate cost estimating process, we believe this is less likely to be the case as project proponents will quickly refine their costs estimating process to ensure their preferred options receive priority consideration.

The AEMC's consultation paper cites an estimate by network service providers of 1-3 per cent of total project costs for a detailed feasibility study. We suspect however these costs may have been somewhat overstated to act as a barrier against the implementation of the proposed rule change. Notwithstanding, based on the PADR cost for Humelink of $1.35 billion, it would have cost $13-40 million. Yet, with the PACR calculating a $3.32 billion capex for the preferred option, with the strong probability of further increases of up to 50% by the project funding approval stage, we strongly believe consumers would prefer to see decisions based on more robust capex estimates. In the scheme of things, a few extra million dollars for improved cost estimates is insignificant compared to cost increases of hundreds of millions of dollars post RIT-T approval, that were observed in the case of Project EnergyConnect where in our view the prospect of a demonstrable net market benefit ever being delivered is remote.

In addition, we add that proponents of non-network options are required to have more detailed and accurate cost estimates and plans for their proposals than what the RIT process affords to network project proponents. It would be reasonable for network project proponents to deliver similar cost estimates, or as indicated above, use a value in the RIT coast benefit analysis that limits cost increases to similar cost increases under a class 2/1 estimate, to ensure non-network options can be compared on a more like-for-like basis than is currently the case.

Requirements and triggers to reapply the RIT

The AEMC's analysis on the requirements to reapply the RIT appear to imply that the rule change request calls for a complete re-application of the RIT process. This is not the intent. Shell Energy supports a targeted approach to re-applying the RIT. Our default position is that the proposing network would simply redo the PACR with the higher capex and undertake a range of stakeholder engagement if the option still has net benefits and is still the preferred option. The time involved in this option would be brief and the cost relatively minor. If it was no longer the preferred option, then greater scrutiny would be required.

We also proposed a deterministic decision rule (and the 30-day window for an AER decision) so there is no protracted debate on whether a review should take place. All parties want the issue to be dealt with promptly so that good investment decisions are not delayed.

The question is whether this more targeted approach should be prescribed in the Rules or left to the AER's discretion under the existing Rules. Shell Energy tends to favour giving the AER discretion. There are a wide range of potential outcomes and defining all possible eventualities in the NER would be extremely challenging.

The focus of the rule change was on large network projects that may require a contingent project application or alternatively be approved under a TNSP regulatory reset process. That said, we understand that a case could be made to exclude non-contingent projects from the rule change given they are considered as part of the ex ante capex approval process. However, if a particular project increases in cost following the end of the RIT then the network simply increases its capex allowance request as part of its regulatory reset application or has less capex available for other projects given the fixed capital approval amount. However, we consider that 'major' (e.g. greater than $150/50 million) non-contingent projects should be included within the scope of the rule change to improve project transparency and help inform other capex estimates. On balance, the latter approach, to include 'major' non-contingent projects would be preferable.

The rule change proposal intended to allow the trigger at any time prior to the submission of the project funding approval application and should occur before the application of any "feedback loop" process. The project proponent would be required under the rules to notify the AER if capex were to increase above the relevant percentage. It would be at the network's discretion whether it immediately sought the AER's review or waited to see if costs were to rise further. The intention is that the revised capex cost subject to the AER review is the cost that will go into the feedback loop and be the subject of the application for project funding approval.

If a proposing network sought to trigger the review where the risk of further cost increases remains, this could potentially require a second review. That is why we recommend that the proposing TNSP have discretion on when to notify the AER of the triggering increase, to avoid multiple reapplication processes. However, we add that the risk of multiple triggers would likely be much lower were higher quality cost estimates used such as Class 2/3 instead of Class 4 estimates, or the value used in the PACR cost benefit analysis adequately reflect the current accuracy of the cost estimate and the potential for further cost increases.

Conclusion

Shell Energy considers a series of reforms is required to improve the regulatory process surrounding network investments broadly, and more specifically, around major transmission projects. Firstly, we recommend the AEMC implement the material change in network infrastructure project costs rule change to ensure that consumers do not continue to face a situation where major projects are approved by the RIT on the basis of "lowballed" cost estimates in the cost benefit analysis following which the project proponent supplies significantly increased costs in its application for project funding approval. We also recommend that the AEMC consider improvements to what is a relatively weak governance framework for the RIT processes. Both of the above allocate unreasonable risks and costs to be borne by consumers.

Improved cost estimates – using Class 1 or 2 AACE estimates – for the preparation of the PACR cost benefit analysis would be one way to both improve consumer confidence in the RIT process and reduce the likelihood of network businesses having to reapply the RIT. Alternatively, the proponent could use a value in the PACR cost benefit analysis that adequately reflects the current accuracy of the cost estimate and the potential for further cost increases. Both outcomes would also be in keeping with the treatment of how non-network options which are expected to have high accuracy cost estimates are treated when participating in the RIT process or as assumptions in AEMO's Integrated System Plan analysis. In turn, this may mean that more NNOs are considered, potentially delivering benefits to consumers at far lower costs and with greater optionality than capital network expenditure. In considering NNOs, it should be only the cost of the provision of network services that are allocated against the NNO, currently the full cost of the NNO is used in the cost benefit analysis which overstates the cost of the NNO.

In considering the vexed question often thrown about that "a RIT process takes too long", we suggest the Commission must concentrate only on the time taken for the RIT itself and should seriously question why it take so long for the project proponent to process its RIT requirements. In our view, the Commission must consider improvement to the governance and transparency of the RIT process which in our view also has the ability to reduce the time taken for completion of the RIT process. The Commission should also consider that viable alternatives to the RIT process do exist in the Rules if parties believe the provision of transmission network services should be "sped up."

We strongly recommend the Commission consider reinstating the original rule 5.16.6 process applied to all RIT-T processes, both for ISP actionable projects and non-ISP projects. The current framework in our view does not provide confidence to consumers that the network investment is in their best interests. We can only conceive that the ESB removed the requirements based on the views as set in the consultation paper. Again, we reject the notion that the RIT is a "hurdle to be overcome" in order to facilitate timely transmission investment. Similarly, we restate our view that the Integrated System Plan is merely a high-level view of potential network options for the future and should not be used as the approval process for network investment.

Finally, Shell Energy argues there is a strong case to allow for competition in the construction and operation of transmission projects. International experience has shown that there may be savings of around 20-30 per cent for consumers from allowing competition in transmission investment. This would also solve the current anomaly whereby TNSPs can be granted the right to build a project but choose not to if they believe the returns are not sufficient. TNSPs implied that this may have been an option for Project EnergyConnect in the Financeability of ISP Project rule change request.

Yours sincerely

[signed]

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