AEMC

REVIEW

Australian Energy Market Commission

OPTIONS PAPER

COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT

21 SEPTEMBER 2018

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission (AEMC or the Commission) to undertake biennial reporting on a set of drivers that could impact on future transmission and generation investment. This reporting focuses on evaluating the transmission frameworks, in light of current and future conditions. It also considers when net benefits could be derived in adopting a transmission framework that would provide for better coordination of investment between the transmission and generation sectors.

2 The Commission has sought to explore the key features of the transmission framework and how to improve the way investment in transmission infrastructure and generator connections is coordinated.

Context

3 The transforming generator fleet has implications for how to coordinate investment in transmission infrastructure with that of generators so that reliable, secure outcomes that are in the long-term interests of consumers are delivered by the National Electricity Market (NEM). Transmission assets can be very expensive, running into the billions of dollars. Once they are built, consumers pay for them for decades. The process for managing the risk that consumers pay for underutilised or inefficient investments must therefore be rigorous and transparent.

4 The pattern of network flows is changing in the transmission system and forecasts of future needs are increasingly uncertain. The transmission framework needs to be fit for purpose and deliver outcomes in a timely way to accommodate this change.

5 Since this review commenced, the Australian Energy Market Operator (AEMO) published its inaugural Integrated System Plan (ISP) in July 2018. The ISP was developed in response to a recommendation[1] from the *Future Security of the National Electricity Market: Blueprint for the Future* (Finkel Review) that:

> *"the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market."*

6 The ISP identifies a pathway for developing the transmission network based on modelling the entire market over a range of possible future scenarios over the next 20 years.

7 The Australian Energy Regulator (AER) published draft revisions to the regulatory investment test for transmission (RIT-T) and the regulatory investment test for distribution (RIT-D) application guidelines in July 2018.[2] The RITs are cost-benefit analyses that network

1 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p.24.

2 The COAG Energy Council undertook a review of the RIT-T that was concluded in February 2017. The AER's review is consistent wtih the recommendations from the COAG Energy Council.

businesses must perform and consult on before making major investments or replacements in their networks. The draft guidelines include guidance on how RIT-T proponents might incorporate aspects of the ISP into a RIT-T.

8 In August 2018, the COAG Energy Council asked that the Chair of the Energy Security Board (ESB) take the lead on the delivery of a work program to "convert the ISP into an actionable strategic plan" and report back to the Council's December 2018 meeting.

9 AEMO's work on the ISP and the AER's review of the regulatory investment test application guidelines have been incorporated into this paper where relevant.

Making the ISP actionable

10 The AEMC has articulated five potential options for making the ISP actionable. These options are intended to create stronger links between the ISP and actual investments in transmission to improve overall confidence in the regulatory investment process. While creating these stronger links, the options are intended to provide appropriate accountabilities and regulatory oversight to protect consumers who pay for transmission services, and in whose interests' transmission investments are undertaken. The options are intended to be indicative of a potential range of investment decision paths, rather than an exhaustive list.

11 The five options for how the ISP could be implemented are described in terms of who is responsible for undertaking the various stages in a transmission investment process, and the different ways in which the stages would be regulated. Each of these stages are needed so that investments, and their alternatives, are appropriately identified, tested, costed, consulted on and assessed against the various views of the future. These stages are not specific to transmission investments – they are steps that would be taken in any decision to make a significant infrastructure investment.

12 The spectrum of these five key options moves from an enhanced status quo, where transmission network businesses keep responsibility for the majority of steps in the transmission planning and investment decision making process, to an option where AEMO would take on the responsibility for all of the steps as part of the ISP. The options can be described as follows:

- option 1 - Transmission network service providers (TNSPs) decide on transmission investments but are required to consider ISP-identified investment needs in their transmission annual planning reports and regulatory proposals
- option 2 - TNSPs decide on transmission investments but are required to conduct RIT-Ts on ISP-identified investment needs and options
- option 3 - In addition to identifying investment needs and options in the ISP, AEMO determines the "best" option for transmission investment but the TNSPs are still able to determine how to most efficiently meet that option e.g. to take into account local conditions
- option 4 - AEMO determines the "best" option for transmission investment and directs a TNSP to proceed with the "best" option, although the TNSP can still choose the functional specification of that option

- option 5 - AEMO determines what transmission investment is necessary, including the functional specification, and directs a TNSP to implement the investment

13 The options have been developed based on the assumption that the existing open access arrangements in the NEM are retained. The effect of the current open access framework is that transmission infrastructure is built to serve consumers, to provide a reliable supply of energy, and is therefore paid for by consumers. The existing economic regulatory framework that applies to TNSPs is structured to reflect these transmission investment and charging arrangements. Changing the access arrangements in addition to revising the transmission frameworks to make the ISP "actionable" would impact on the timelines for implementing any of the options discussed in the options paper. While the nature of access arrangements may need to change in the future, options to make the ISP actionable, while leaving the access arrangements unchanged, minimises the complexity involved in the implementation of the options.

14 The key difference between each of the options is how many of the stages in a transmission investment process are undertaken by AEMO through the ISP, compared to individual TNSPs. The options start with an enhanced status quo where TNSPs would be required to explicitly consider the outcomes of the ISP in their planning processes. Moving across the options, AEMO undertakes more and more steps. This occurs until option 5, where AEMO is undertaking the majority of the steps in the transmission planning and investment decision making process, and the TNSP is only responsible for delivering the investment as specified by AEMO in the ISP. Option 5 would likely require both National Electricity Law and National Electricity Rules (NER) changes as well as changes to the AER's and AEMO's existing roles and responsibilities.

15 The AEMC's work on options for making the ISP actionable, implications for the economic assessment of investments and the regulation of TNSPs is an input into the ESB's work program and reporting on these issues at the December COAG Energy Council meeting. The written submissions that are provided to the AEMC on the above options will also be an input into the ESB process. The feedback will be considered by the Commission in order to refine the options ahead of the publication of the final report in this review, due at the end of 2018.

Implications for the Regulatory Investment Test for Transmission

16 For investments in new or replacement transmission assets, TNSPs are required to undertake a cost-benefit analysis of potential options where the cost of the investment will be recovered from consumers - known as the RIT-T. It is a key feature of the existing transmission planning and investment decision making framework. This transparent cost-benefit analysis is conducted to determine the most appropriate solution for addressing a need on the transmission network, and whether addressing the need provides a net positive benefit to the market.

17 The spectrum of options for how the ISP could be made "actionable" addresses key features of the current RIT-T that are designed to protect consumers. In addition, this paper also discusses the objectives of the RIT-T, the steps that are involved and how it fits within the broader economic regulatory framework. This is done with a view to considering how the

RIT-T process could be made faster, and how the process and test itself could be adapted given the current environment. Submissions on these issues will also be an input into the ESB coordinated process.

Renewable Energy Zones

18 In addition to recommending a national strategic approach to transmission planning, the Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment by focussing on the option of the development of renewable energy zones (REZs). The discussion paper published in April 2018 as part of this review sought to highlight the regulatory and framework implications for facilitating the development of transmission assets to facilitate specific zones for generators to connect in those regions that are rich in renewable energy resources.

19 This options paper discusses REZs in light of the publication of the inaugural ISP and stakeholder feedback. The Commission considers that the discussion of REZs and how they might be facilitated is dependent on the issue of how stronger links could be created between the ISP and transmission investment decisions. Depending on how the ISP is made actionable, the subsequent implications for the facilitation of any REZs in the NEM will be different.

Connection and access

20 Stakeholders, as well as AEMO's ISP, have expressed that there is likely to be significant congestion in the future due to the rapid growth in proposed new generation. As congestion increases, augmentations to the transmission network may be required to keep congestion at an efficient level. Given the proposed transmission pathways being put forward in the ISP, and the impacts of investments on those pathways for levels of congestion, this paper is focussed on the role of the ISP and how a link could be created between it and the transmission planning and investment decision making framework.

21 However, given these trends, access and congestion management issues are likely to need to be addressed in the near term, once the role of the ISP has been addressed.

Treatment of storage

22 Some of the proposed new generation capability entering the market includes large-scale capability storage. One notable example has already connected under the current regulatory framework – Tesla's battery at Hornsdale Wind Farm. Electricity storage technologies have the potential to provide benefits to both the operators of those assets and the electricity grid more broadly. The experience of a few storage connections that have occurred to date has revealed some potential areas of the transmission framework that may need to be clarified or adjusted to ensure large-scale storage connections do not face unnecessary regulatory barriers to market entry.

23 The recent and potential connection of utility-scale storage facilities to the grid has raised questions about the appropriate market participant category for energy storage facilities to be registered in. The Commission considers that a more holistic look at the registration framework in the NER may be needed so the participant categories sufficiently accommodate

and support the participation of existing and emerging technologies and business models into the future, and to reduce operational complexity and administrative burden for AEMO and participants. Such consideration may reduce barriers to entry for such storage facilities, and so would better facilitate a competitive wholesale market.

24 Whether storage should pay transmission use of system charges is also considered. Under the current transmission framework, TNSPs are required to invest in transmission infrastructure to meet the supply needs of customers, and customers meet the costs of these investments through the current economic regulatory arrangements by paying transmission use of system charges. TNSPs are not required to invest in transmission infrastructure to faciliate a generator's connection to the network. However, energy storage systems are *both* consumers and producers of energy. This options paper examines the issue of whether storage should pay transmission use of system charges. The Commission considered stakeholder feedback when undertaking its analysis of both of these large-scale storage regulatory issues.

Next steps

25 The Commission will produce a final report for this review by the end of 2018.

26 As noted above, the AEMC work is an input into the ESB's work program and reporting on these issues at the December COAG Energy Council meeting. The written submissions that are provided to the AEMC on the options paper will also be an input into the ESB coordinated process.

27 In order to assist in receiving feedback on these matters, the ESB will host two public forums on these matters:

- 1.30pm - 4.30pm on Tuesday 9 October in Sydney
- 9.30am - 12.30pm on Thursday 11 October in Melbourne

28 To register for these forums, please use the AEMC website.

29 In addition, submissions are due on 19 October 2018. Submissions will be shared with all members of the ESB. The Commission is seeking stakeholder feedback in response to a series of questions throughout the options paper. These questions are provided in Box 1 below:

BOX 1: QUESTIONS WE ARE SEEKING STAKEHOLDER ENGAGEMENT ON

Chapter 4 - Making the ISP an actionable strategic plan

Question 1: Questions arising from the ISP

The paper considers a number of questions about the role and regulatory implications of the

ISP, including the links between the ISP and transmission investment decisions.

A) Are there any questions about the role and regulatory implications of the ISP that are not set out in the options paper?

B) Is our approach to making the ISP actionable (i.e. strengthening the link between the ISP and investment decisions) appriopriate?

Question 2: Interaction between the ISP and government policies

A) *The ISP will necessarily have to take into account government environmental and industry policies in modelling ISP scenarios. Do stakeholders consider it would be helpful for the COAG Energy Council to provide formal advice to AEMO as to what government policies or scenarios should be modelled in the ISP?*

B) *Are there other ways in which government policies that impact on the NEM could be incorporated as modelled scenarios in the ISP?*

Question 3: "Strategic, national" investments and regional investments

A) *It is proposed that the ISP only focusses on "strategic, national" investments. Do stakeholders consider this is appropriate?*

B) *If so, how could this threshold be defined, or what criteria could be used to define it?*

Question 4: Risk allocation

A) *The paper canvasses a number of options for making the ISP actionable. How may the existing risk allocation for consumers, TNSPs and generators change under the proposed options?*

B) What other regulatory changes may be required in order to mitigate against changes in the risk allocation?

Question 5: Level of consultation required under each of the options for how the ISP could be made actionable

A) What do stakeholders think about the level of consultation that would be required under each of the options considered for how to make the ISP an actionable strategic plan?

B) Should there be more consultation for options that fall to the right-hand side of the table?

Questions 6-10. The Commission has articulated five possible options for how the ISP could be made actionable, and incorporated into the existing regulatory framework. For each option, the Commission asks:

A) *What are stakeholder views on each of the options proposed for how to make the ISP an actionable strategic plan?*

B) *Would the effective delivery of the different options have an impact on the speed with which "strategic, national" investments are made?*

C) *Are there any regulatory or other implications that are not raised in the discussion of these* *options?*

Question 11: Other options and considerations

A) *Are there other options to strengthen the link between the ISP and individual TNSP investments that are not raised here?*

B) *Are there any other matters that should be taken into account when considering options to strengthen the link between the ISP and TNSPs' individual investments?*

Chapter 5 - The regulatory investment test for transmission

Question 12: RIT-T benefits

A) *Are there any additional benefit categories that should be considered in the RIT-T?*

B) Why have no network businesses sought approval from the AER for additional benefits to be considered in RIT-T assessments as allowed for under the current NER?

Question 13: Potential concerns with the RIT-T process

A) *What are stakeholder views on current limitations with the RIT-T process?*

B) *Setting aside the ISP and how to make it more "actionable," what other issues warrant attention when considering the objective of the RIT-T?*

C) *What changes may make the existing RIT-T process "faster"?*

D) What is the role of a dispute process in the RIT-T? How could spurious disputes be minimised?

Chapter 6 - Renewable Energy Zones

Questions 14-18. The Commission discusses five potential options for developing REZs. For each option, the Commission asks:

A) *Do stakeholders agree with our conclusions for how REZs can occur under current regulatory arrangements?*

B) *Do stakeholders agree with our assessment of whether potential REZ models are consistent with the options discussed for making the ISP actionable? What other considerations should be taken into account?*

Question 19. REZs and access

Do stakeholders agree with our conclusion about the types of REZ models that are feasible under the current transmission access framework?

Chapter 7 - Congestion and access

Question 20: Conclusion on need to consider access issues

Do stakeholders agree with the Commission's conclusion in this Chapter that access and congestion management issues are likely to need to be addressed in the near term, once the role of the ISP has been addressed?

Chapter 8 - Treatment of storage

Question 21: Storage and TUOS

Do stakeholders agree with the way the Commission has framed the issue of whether or not storage should pay transmission use of system charges?

Question 22: Storage and TUOS - current arrangements

Do stakeholders have any comments on the Commission's initial views on storage and transmission charges? Are there any other arguments that are not discussed?

Question 23: Storage and TUOS - considering changing existing arrangements

Are there any matters the Commission hasn't discussed that should be addressed if a change to the existing arrangements for transmission charging for storage is considered?

Question 24: Storage and TUOS - additional considerations

When considering the approach to the recovery of transmission charges, are there any additional factors worthy of consideration that the Commission has not listed?

CONTENTS

1 TERMS OF REFERENCE

In 2016, the Council of Australian Governments (COAG) Energy Council asked the AEMC to implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. The terms of reference for this reporting were received from the COAG Energy Council in February 2016 under section 41 of the National Electricity Law (NEL).[3]

The intention was that the work would help governments and industry participants consider when future conditions might arise where net benefits would be derived from adopting a transmission framework that would provide for better coordination of investment between the transmission and generation sectors.

The task, as outlined in the terms of reference, is a two-stage approach to the reporting of conditions that influence transmission and generation investment. The stages, as outlined in the terms of reference, are:

- Stage 1 - In the first stage, analysis is to be undertaken on a set of drivers that influence the coordination of transmission and generation investment. The aim of the first stage is to determine whether there is substantial change in a factor(s) such that it suggests that there is an environment of major transmission and generation investment and that this investment is uncertain in its technology or location. If it is determined that such conditions are present, the reporting will progress to the second stage.
- Stage 2 - The second stage is to be a more in-depth assessment of whether the factors identified in Stage 1 have changed materially since mid 2015. At that time, a review of optional firm access design and testing concluded that in the environment of that time, the implementation of optional firm access would not contribute to the National Electricity Objective (NEO). The second stage would also assess whether the implementation of a model that would introduce more commercial drivers into transmission and generation development would meet the NEO.

The NEO, as stated in the NEL, is: "to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; the reliability, safety and security of the national electricity system".

3 The terms of reference are available from the AEMC website at https://www.aemc.gov.au/sites/default/files/content/97164a7b-09bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

2 INTRODUCTION

2.1 Key milestones and stakeholder consultation conducted to date

Stage 1 of the review concluded in July 2017. The Commission recommended that the review progress to stage 2. Three criteria were noted:

- the drivers of transmission and generation investment have significantly changed since July 2015[4]
- there is expected to be large investment in transmission and generation
- the expected future investment is uncertain in its location and technology.

The drivers of transmission and generation investment have changed significantly since the AEMC was issued with the terms of reference in February 2016. At that time, the AEMC noted that there was increased uncertainty regarding government emissions reduction policy, and that this was having ramifications for investor confidence. This is still the case.

There is an observed trend of thermal generation exiting the market and significant entry of variable, renewable generation. The take-up of distributed energy resources is also expected to continue, with new business models entering the market seeking to maximise the benefits from these resources.

It is expected that there will be significant transmission and generation investment in the future, which is evidenced by the large number of potential connection applications being made to network businesses. Renewable generators are likely to connect in areas with signficant renewable resources, which may be at the edges of the existing transmission network. Therefore, the shape of the transmission network may need to change in response, in order to reliably supply consumers.

The Commission commenced stage 2 of this review in August 2017 by publishing an approach paper. Written submissions to the approach paper are available on the AEMC website.

This was followed by a discussion paper in April 2018 which presented further information and asked questions about how coordination of generation and transmission investment in the National Electricity Market (NEM) could be improved. Specifically, the discussion paper focussed on three key developments which may necessitate changes to the current transmission framework:

- likely future congestion on transmission networks as more generators seek to connect to the grid in places where there is not substantial spare capacity
- new types of generation capability - such as large-scale battery storage - connecting directly to the transmission network

4 In 2015, a review of optional firm access design and testing concluded that the implementation of optional firm access would not contribute to the NEO at that time. However, it could be beneficial in a future environment where there is significant investment, but the patterns of that investment are uncertain. Accordingly, the Commission recommended regular reporting and assessment of a series of drivers of transmission and generation investment – the subject of the terms of reference for this review.

- more lower emissions generation such as wind and solar farms entering the market, which may need to locate in areas that are at the edges of the existing network, potentially in new renewable energy zones (REZs).

Written submissions to the discussion paper are also available on the AEMC website.

2.2 Purpose of this paper

This options paper incorporates stakeholder submissions to the discussion paper published in April 2018. It also addresses the publication of the inaugural Integrated System Plan (ISP) developed by the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator's (AER) draft regulatory investment test for transmission (RIT-T) application guidelines and explanatory statement. It seeks further input from stakeholders, building on the feedback already received, the progression of work being undertaken by the other market bodies, as well as the ESB's broader work program on these matters.

Specifically, this paper:

- explains the objective of transmission investment and the regulatory framework that exists to support it
- provides analysis of the regulatory implications of the ISP and explores options to strengthen the link between the ISP and the individual investment decisions of transmission network service providers (TNSPs), including how such a plan could be made actionable
- examines the RIT-T framework and how that may need to be changed in light of the ISP
- provides a further analysis of REZs in light of the publication of the ISP
- examines whether the scale of congestion that the NEM is facing may necessitate reconsidering the existing access arrangements, and
- considers further the treatment of large-scale storage units, specifically how they register in the NEM and whether or not they pay transmission charges.

2.3 Related work

2.3.1 Integrated System Plan

Currently, under the National Electricity Rules (NER), AEMO is required to publish a National Transmission Network Development Plan (NTNDP) by 31 December each year, the purpose of which is to provide an independent, strategic transmission planning assessment for the NEM, with a 20 year outlook. This serves as an input for TNSPs on transmission investment required for inclusion in their Transmission Annual Planning Reports (TAPRs). However, the final report of the Finkel Review recommended an alternative approach - the preparation of an integrated grid plan for the NEM. The Finkel Review identified the purpose of the integrated grid plan as being required to establish an optimal transmission network design so that networks connect the areas with the best renweable energy resources, at an efficient scale, which inculdes facilitating the efficient development and connection of REZs across the NEM.

In July 2018, AEMO published the inaugural ISP. An integrated system plan; rather than an integrated grid plan, reflects that over time, the ISP will by necessity consider a wide spectrum of interconnected infrastructure and energy developments including transmission, generation, gas pipelines and distributed energy resources.

AEMO described the ISP as "a cost-based engineering optimisation plan that forecasts the overall transmission system requirements for the NEM over the next 20 years."[5] The ISP presents specific transmission investments for the NEM that AEMO has assessed are necessary over the short, medium and long term.

As the ISP's purpose and scope encompass those which would normally be covered in AEMO's NTNDP, the AER permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the ISP.[6]

The ISP is discussed in more detail in Chapter 4.

2.3.2 Review of application guidelines for the regulatory investment tests

The COAG Energy Council undertook a review of the RIT-T that was concluded in February 2017. The AER is currently undertaking a large-scale review of the application guidelines for the regulatory investment tests (RITs) used by networks, consistent with the recommendations from the COAG Energy Council during its RIT-T review. The AER initiated the review in December 2017.

The RITs are cost-benefit analyses that network businesses must perform and consult on before making major investments or replacements in their networks.[7] The application guidelines for RITs provide guidance to networks on how to apply the RITs to potential investments that the NER states must be subject to these tests. When undertaking RITs, network businesses must give due consideration to all possible options before identifying the best way to meet the demands on their networks.[8]

The NEM currently has separate RITs for transmission and distribution networks – the 'RIT-T' and the regulatory investment test for distribution ('RIT-D'). Each RIT has its own application guidelines in order to guide network businesses on how to apply the RITs consistently and transparently.

As part of the review, in July 2018, the AER published draft revisions to the RIT-T and RIT-D application guidelines, and sought stakeholder views on these. The AER is exploring improvements that:

- the COAG Energy Council identified in its RIT–T review
- have arisen out of the replacement expenditure planning arrangements rule change[9]

5 AEMO, *Integrated System Plan*, July 2018, p.3.

6 AER, Quarterly Compliance Report: National Electricity and Gas Laws, 1 October – 31 December 2017, p. 21.

7 Clause 5.6.5C of the NER provides that a TNSP must apply the RIT-T to all proposed transmission investments unless the investment falls under defined circumstances. Clause 5.17.3 of the NER provides that a RIT-D proponent must apply the RIT-D to a RIT-D project unless the project falls under defined circumstances.

8 Clause 5.16 and clause 5.17 of the NER.

9 See: https://www.aemc.gov.au/rule-changes/replacement-expenditure-planning-arrangements

- have been identified from ongoing applications of the RITs
- stakeholders identify.

The draft revisions also include guidance on how RIT-T proponents might incorporate aspects of the ISP into a RIT-T, and the AER stated that it may be necessary to further update the RIT application guidenlines once the ISP framework is formalised.[10]

The AER plans to finalise this review in November 2018.

2.3.3 Energy Security Board work on transmission planning

On 20 April 2018, the COAG Energy Council provided the Energy Security Board (ESB) with responsibility for coordinating the work of the energy market bodies on planning and regulation of the transmission system and interconnection.[11]

The ESB provided an update on progress of this coordinated work, namely this review, the ISP process being undertaken by AEMO, and the AER's review of the RIT-T application guidelines, to the COAG Energy Council on 10 August 2018.

At that meeting, the COAG Energy Council requested that the ESB report to the December 2018 meeting on "how the Group 1 projects identified in the ISP can be implemented and delivered as soon as practicable and with efficient outcomes for customers, and how the Group 2 projects will be reviewed and progressed."[12]

Additionally, the Chair of the ESB was tasked with identifying a work program to convert the ISP to an actionable strategic plan. This paper seeks to explore options for how to do this, with this work informing the ESB's report to the COAG Energy Council in December 2018. The Commission continues to work with the ESB, AEMO and the AER as part of this process.

2.4 Consultation and next steps

The Commission is seeking input from stakeholders in response to a series of questions throughout this paper. The feedback will be incorporated ahead of a final report due at the end of 2018. The feedback will also be an input into the ESB process.

The Commission invites comments from interested parties by 19 October 2018. All submissions will be published on the Commission's website subject to any claims of confidentiality.

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0052".

10 AER, *Explanatory statement: draft revisions of the application guidelines for the regulatory investment tests*, July 2018, p.37.

11 COAG Energy Council, Meeting Communique, 20 April 2018.

12 See:http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/18th%20COAG%20Energy%20Council%20Communique.pdf

The ESB will also hold two public forums on the issues raised in this options paper, to assist in their reporting back to the COAG Energy Council in December on how to make the ISP an actionable strategic plan. These will be held:

- in Sydney on 9 October 2018
- in Melbourne on 11 October 2018

More information on how to register for these forums can be found on the AEMC website.

The final report for this review is due late 2018.

Timeline of milestones for the ESB report back to the COAG Energy Council on how to convert the ISP to an "actionable" strategic plan:

Table 2.1: Milestones

DATE	MILESTONE
21 September 2018	Publication of the AEMC's options paper in the Coordination of generation and transmission review Publication of the ESB's paper, "Converting the ISP into action"
9 October 2018	ESB stakeholder forum in Sydney
11 October 2018	ESB stakeholder forum in Melbourne
19 October 2018	Consultation closes on AEMC's options paper
November 2018	Publication of the AER's final RIT application guidelines
December 2018	Publication of the AEMC's final report in the Coordination of generation and transmission review
December 2018	ESB report back to the COAG Energy Council meeting

2.5 Structure of this paper

This paper is structured as follows:

- Chapter 3 outlines the current transmission framework in the NEM.
- Chapter 4 discusses the role of the ISP and its regulatory implications, and presents five options for how the link between the ISP (as the strategic national transmission plan) and the individual investment decisions of TNSPs could be strengthened.
- Chapter 5 outlines the current RIT-T.

- Chapter 6 presents the Commission's analysis of REZs in light of the ISP.
- Chapter 7 discusses congestion and access in the NEM.
- Chapter 8 discusses the treatment of electricity storage with respect to market participant registration and the payment of transmission use of system (TUOS) charges.

3 CONTEXT – CURRENT TRANSMISSION FRAMEWORK

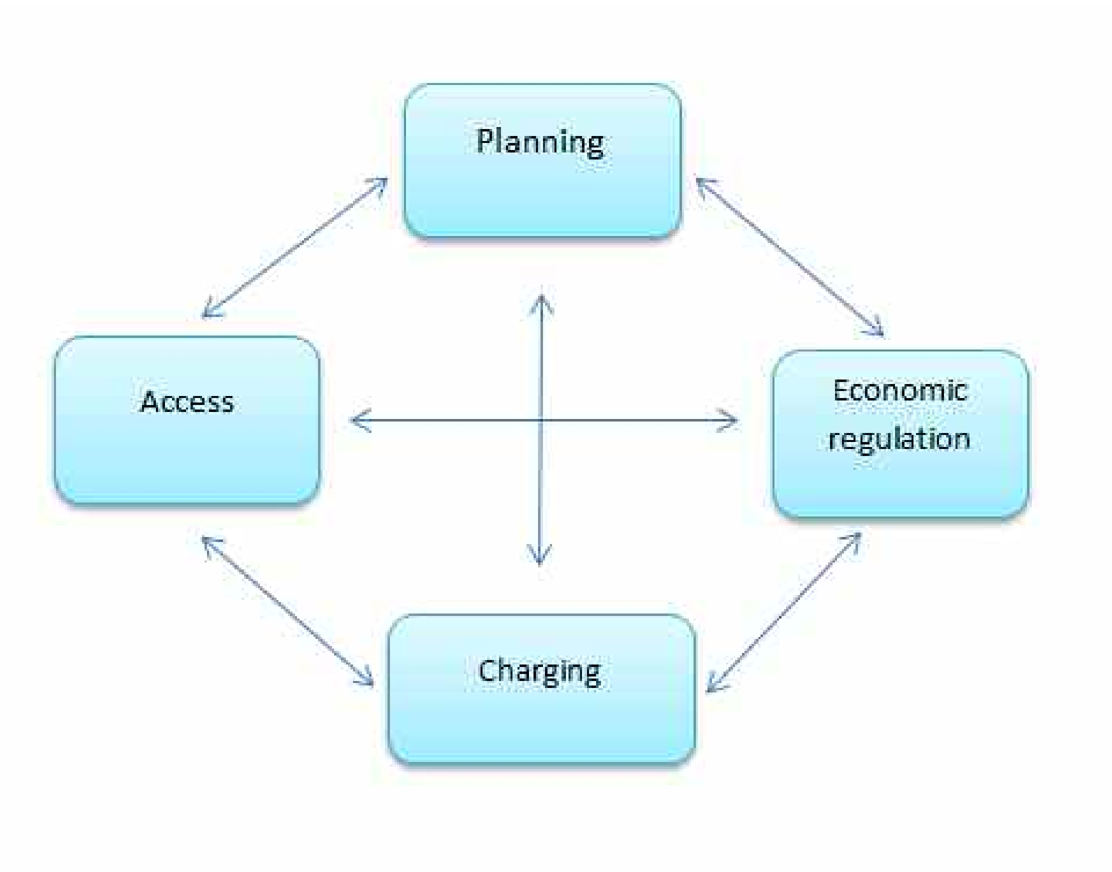
3.1 Overview of the current transmission framework

The current transmission framework is holistic. There are four key aspects:

- planning
- access
- charging
- economic regulation.

Each feature of the framework has implications and impacts on the other aspects. For example, under the current arrangements TNSPs are responsible for making investment decisions that are consistent with these features.

Figure 3.1: Current transmission framework



3.2 Planning

Transmission planning occurs over a number of time horizons

Transmission network planning aims to identify and plan for efficient network investment and retirements. Transmission planning also plays an important role in providing market participants with information on likely future developments in the transmission network in order to help market participants (i.e. generators and load) make investment, retirement and operational decisions. These planning processes are clearly defined to assist transmission businesses in identifying the solutions to network issues in a timely manner.

Currently there are several different forms of planning:

- Long-term planning focusses on long-term expected generation and demand, and so on long-term investment and replacement needs. This long-term planning is typically strategic in nature, and is undertaken by AEMO as National Transmission Planner through its prepartion of the NTNDP (replaced this year by the ISP), which projects out 20 years.
- Short-term planning has a focus on the near term and specific investment and replacement needs. It takes into account the results of the national planning undertaken by AEMO. This short-term planning is currently undertaken by the jurisdictional planning bodies and focusses on more regionally specific needs, with a more immediate focus - TAPRs typically focus on the next 5-10 years.
- Project specific planning relates to a particular investment need and culminates in an investment or replacement decision being made by the TNSP. These project specific plans consider the benefits to generators, consumers and network businesses of a particular investment. This is currently undertaken by the jurisdictional planning bodies[13] and focusses on what is the best way to achieve a particular identified need, e.g. in building this transmission line, what exact specifciations should it be built to, and what route should it take. In particular, this also includes considering whether a network investment should be made, or whether the identified need could be addressed through a non-network option, e.g. demand management. This approach assists in providing transparency on these planning activities to put forward non-network options as a credible alternative to network investment and assist network users to make decisions about where best to connect to the network.

The last resort planning power also acts as a safety net to ensure that new inter-regional transmission investments are being assessed

In addition to these types of planning, the AEMC also has a last resort planning power. This allows the Commission to direct registered participants to apply a project specific test (RIT-T) to potential transmission projects if they are likely to relieve projected constraints in respect of national transmission flowpaths connecting NEM regions.

A key transmission planning question is what standards apply, i.e. what is a business planning too. Identifying a standard is important since this is one way that the costs and benefits associated with the transmission network can be quantified, and so costs

13 Powerlink in Queensland; TransGrid in NSW; AEMO in Victoria; ElectraNet in South Australia; and TasNetworks in Tasmania.

constrained. The standard to which parties are planning the transmission framework also impacts on who pays for the transmission infrastructure, that is, the beneficiaries of the particular standard are the parties who bear the cost.

Transmission businesses have an obligation to reliably supply customers

Transmission businesses have an obligation to meet jurisdictionally-set reliability standards for their networks. Reliability standards relate to how transmission and distribution networks can withstand risks without consequences for consumers, and so guide the level of investment that network businesses undertake. The standards are set by state and territory governments and reflect a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers.

The reliability standards that networks are required to meet are defined in terms of reliably supplying customer load.

There is no reliability standard for generators

There is no set reliability standard for generators - they have no guarnteed right to use the transmission network to export electricity in the wholesale market in order to earn revenue. This translates through to the planning of the network - transmission businesses do not plan to provide a particular generator with a specific amount of capacity across the transmission network.

However, the existing framework does allow AEMO and TNSPs to plan investments that could be considered "net beneficial." That is, if by building transmission infrastructure to allow increased output for generators, outcomes in the wholesale market will be improved for the benefit of consumers.

3.3 Access

Generators have no right to be dispatched in the wholesale market

Currently in the NEM, generators have a right to negotiate a connection to the transmission network, but no right to be dispatched in the wholesale market and so earn revenue (this is otherwise known as "open access"). The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point, not the ongoing use of the shared transmission network to access the market.

Generators have no guarantee that they can export all of their output to the system at any given time. Instead, generators earn money by being dispatched through the wholesale market that is run by AEMO. AEMO's market dispatch engine seeks to maximise the value of trade given the physical limitations[14] of the power system. As a consequence, generators are not required to pay for the cost of transmitting the electricity they produce.

Each generator in a particular region receives revenue at the clearing price (known as the "regional reference price") for the electricity delivered - even when that clearing price is

14 Otherwise known as "constraints," which restrict how much electricity can flow over a particular piece of equipment while preserving its integrity.

above the price it offered into the market. In this way, the spot market coordinates the physical dispatch of generation and all generators earn at least their offer for each unit of electricity delivered. If a generator is not dispatched, then they cannot earn revenue from the spot market. Since generators have no rights to earn revenue in the wholesale market, they also do not have a right to be compensated for not being dispatched.

BOX 2: WHOLESALE MARKET AND NODAL PRICING

The NEM comprises five interconnected electrical regions: Queensland, New South Wales (including the ACT), Victoria, Tasmania and South Australia. There is a designated regional reference node in each region, where the regional spot price of electricity is set. The regional reference price is based on the marginal cost of energy for supplying a particular regional reference node. It is at this point that intra-regional and inter-regional generator bid prices are compared, and where the regional reference price is set. The regional reference node is typically at a major demand and / or generation centre.

Market participants' bids and offer prices are referred to the central reference node using transmission marginal loss factors and distribution loss factors to determine comparative prices for dispatch and pool settlement purposes.

Since the NEM has five regions in which a wholesale price is set, it is not considered to be a fully nodal system where *all* locations or nodes in the transmission network would have a price associated with them to reflect the local marginal value of supplying energy at that particular point.

Under a full nodal pricing model, generators would be settled by default at their locational marginal price, but depending on the design, could have the option to purchase fully financially firm access rights to another node. In this case, the concept of NEM regions and settlement against a regional reference price would no longer be applicable. Under this approach, differences in locational marginal prices would reflect the costs of network congestion.

In a nodal system, generators are paid the marginal cost of generation at their transmission node based on merit order dispatch. Nodal prices more accurately signal the value of electricity at each location, and do not impose the same perverse incentives on bidding that can be a feature of regional systems. They are therefore considered to deliver the best dispatch outcomes in the presence of transmission constraints.

Nodal pricing is common in international jurisdictions, including many US and European markets. When the NEM was developed, it was considered that while marginal pricing of delivered energy would provide the best support for economic efficiency objectives, complete implementation of this principle to a fully nodal arrangement would be too complex,* and so a modified, simplified framework was subsequently adopted.

The NEM represents a simplified nodal pricing framework - while participants settle on a regional price, the dispatch of generation, and so AEMO's optimisation, takes into account both energy losses as well as constraints on the transmission network.

Note: *Concerns about the complexity of implementing nodal pricing were centered on high costs in rural areas, the liquidity of financial contracts and localised market power issues.

3.4 Charging

Consumers pay for transmission services

Given that the current framework is set up around transmission businesses planning to provide transmission services that are for the benefit of consumers, it follows that end-use consumers pay for the costs (investment and operational) incurred by the TNSPs in providing these shared transmission services. Consumers therefore pay TUOS charges.

Generators pay to facilitate their connection

In contrast, generators only pay for the costs of the services provided to them by the transmission businesses to facilitate their connection to the transmission network since they have no right to the regional reference price. In other words, they do not pay for the broader costs of the transmission network.

The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point. A generator only pays the costs of the services provided to them by the TNSP to facilitate their connection, that is, a connection charge that relates to the cost of their immediate connection to the transmission network.[15]

3.5 Economic regulation

Economic regulation is a key component of the transmission framework to ensure that consumers only pay for efficient expenditure

The planning framework does not regulate or direct which plans or investment decisions should be made, nor does it determine what investment costs should be recoverable from the regulated revenues of transmission companies. Instead the planning framework accompanies an incentive-based economic regulatory framework, with it providing opportunities for the AER and other stakeholders to be more fully informed on the efficiency of network investment decisions.

This supports an outcome where consumers only pay for efficient expenditure. Given consumers pay for transmission, any proposed expenditure on the network must be shown to provide market benefits or be necessary to maintain a reliable supply of electricity to network customers. Consumers should not bear the risk of speculative investments or investments

15 The Commission recently made a rule that establishes a transparent and efficient framework for the management of power system fault levels, also known as 'system strength', in the NEM. As part of this framework a new requirement was introduced on new connecting generators to "do no harm" to the security of the power system. This relates to any adverse impact on the ability of the power system to maintain system stability or on a nearby generating system to maintain stable operation, in accordance with AEMO's system strength impact assessment guidelines. For example, this could involve them paying costs to remediate the network for the impact they cause. For further information see: AEMC, *National Electricity Amendment (Managing power system fault levels) Rule 2017.*

that are for the sole benefit of generators (if such an investment would, for example, relieve congestion for generators but not to the extent that it provides an overall market benefit through a reduction in wholesale electricity costs).

The regulatory framework contains a number of checks and balances on this expenditure:

- TNSPs are subject to economic regulatory oversight by the AER in relation to their augmentation, replacement, operating and maintenance costs for the provision of prescribed services.[16] TNSPs must have the AER assess their revenue requirements.
- Augmentation and replacement decisions relating to the network are subject to cost-benefit tests (RITs) to assess whether the investment or replacement will create a net market benefit for consumers. The RIT-T is an important part of the planning undertaken by TNSPs, influencing investment decisions and drawing on other planning outputs, such as their TAPRs. The role of the RIT-T is to seek cost effectiveness for the consumer by increasing the transparency of individual investment decisions. This transparency and accountability for investment decisions is what reconciles any differences between the economic interests of the TNSP conducting the RIT-T and what maximises the net economic benefits across the market.

Economic regulation is incentive based

The economic regulation in the NEM is incentive based regulation. The AER projects the revenue requirement of the TNSP to: cover its efficient costs of reliably supplying customers; and earn a return. Given it is a projection of potential costs, the transmission business is encouraged to be more efficient by reducing the costs of transmission projects so it can maximise the return it receives on the investments.

16 Aside from in Victoria, where AEMO procures augmentation investments through contracts. The costs associated with these are recovered on a cost-pass through basis from Victorian consumers, and are not subject to economic regulatory oversight. Network owners (AusNet Services and Murraylink) have the costs of replacement, operating and maintenance determined by the AER, and so are subject to economic regulation in this respect.

4 ROLE OF THE INTEGRATED SYSTEM PLAN

In June 2017 the Finkel Review Panel recommended[17] that:

> *"the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market."*

This recommendation recognised a need for a more strategic approach to transmission planning in the NEM. Given the changing generation mix this was needed to maintain a secure and reliable supply of electricity to consumers.[18] In July 2018 AEMO published its inaugural ISP, to meet this recommendation. The ISP identifies a pathway for developing the transmission network. It is based on modelling the entire market over a range of possible future scenarios.[19]

At the COAG Energy Council meeting on 10 August 2018, the Council asked that the ESB take the lead on the delivery of a work program to "convert the ISP into an actionable strategic plan" and report back to the December 2018 meeting.[20] As noted in the communique, the AEMC is closely involved in that work. This report forms part of the AEMC's contribution to that work program, with the AEMC's analysis in this Chapter helping to inform the ESB's conclusions on this matter.

This Chapter explores possible ways to make the ISP an actionable plan. Possible options to create stronger links between the ISP (as the strategic, "actionable" national transmission plan) and the investment decisions (which are currently made by TNSPs) are examined.

Each of these options assumes that the existing open access arrangements, as described in Chapter 3, are retained. There would be additional options if a decision was made to look at alternatives to the existing open access arrangements. While the nature of access arrangements may need to change in the future, only considering options that make the ISP actionable but leave the existing access arrangements unchanged, minimises the complexity involved in the implementation of the options.

The Commission welcomes stakeholder feedback on the options.

4.1 What is the role of the ISP?

4.1.1 What does the ISP do?

The ISP is a cost-based engineering optimisation plan by AEMO that forecasts the overall transmission system requirements for the NEM over the next 20 years. It identifies a potential plan of the transmission investments that will be necessary to support the long-term

17 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017, p.24.

18 Ibid, p121.

19 The ISP's purpose and scope encompass that which would normally be covered in AEMO's NTNDP. Given this, the AER permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the 2018 ISP.

20 COAG Energy Council, Meeting communique – Friday 10 August 2018.

interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures.

ISP modelling incorporates a range of plausible scenarios to identify future demand for power from the system and likely market response. For the latter, the modelling applied technology-neutral analysis to identify the required level and likely fuel type of supply investments required to meet future needs. The ISP model uses cost-based economic analysis, and integrates system security and reliability considerations, as well as current Commonwealth and State Government policies. A scenario-based approach is appropriate, given that the future is inherently uncertain, as it allows for a range of potential future outcomes to be incorporated in the modelling.

The ISP groups investments identified in the plan into three phases.[21]

The Group 1 investment projects are those that AEMO considers should be progressed as soon as possible because they provide immediate benefits. These projects are:

- Increase transfer capacity between Victoria, NSW and Queensland:
  - Increase Victorian transfer capacity to New South Wales by 170 MW.
  - Increase Queensland transfer capacity to New South Wales by 190 MW.
  - Increase New South Wales transfer capacity to Queensland by 460 MW.
- Access renewable energy in western and north-western Victoria.
- Remedy system strength in South Australia.

The estimated costs of the transmission investments in Group 1 are in the order of $450 million to $650 million. The progress of these projects is shown in figure 4.1 below.

21 This is based on the timing within which the identified network need is forecast to arise, and the time that may be needed to build infrastucture to address the need.

Figure 4.1: ISP Group 1 projects

ISP Group 1 projects (identified for immediate investment with completion as soon as is practicable)	Stage of the regulatory process						**Indicative project commencement timing suggested in ISP**
			RIT-T				
	TNSP includes in APR	**Accepted by AER as a contingent project**	**Project specification consultation report (PSCR)**	**Project assessment draft report (PADR)**	**Project assessment conclusions report**	**AER decision to amend revenue determination**	
Minor NSW to QLD upgrade	Powerlink: **2017** (again in 2018)[1] TransGrid: **2017** (again in 2018)	Powerlink: **April 2017** TransGrid: **May 2018**	**Q3 2018** (Powerlink TAPR, 2018; TransGrid TAPR 2018, although no date for the PSCR is provided)	**Q4 2019** (NER require PADR is published within 12 months after consultation period on PSCR closes)	**Q1 2020** (NER require it is published as soon as practicable after consultation period on PADR closes)		**2020**
Minor VIC to NSW upgrade[2]	AEMO **2018** (while discussed in previous APRs, benefits were not estimated to outweigh costs)		**Q3 2018** (in its VAPR, AEMO stated it will commence a RIT-T following the release of the ISP)	**Q4 2019** (NER require PADR is published within 12 months after consultation period on PSCR closes)	**Q1 2020** (NER require it is published as soon as practicable after consultation period on PADR closes)		**2020**
SA System strength remediation[3]	ElectraNet **2017**	April **2018**					**2020**
Transmission augmentation to access renewable energy in Western VIC	AEMO **2016** (again in 2017 and 2018)		Published **April 2017**	*Was due July 2018. AER granted extension to* ***December 2018.***	**Q1 2019** (NER require it is published as soon as practicable after consultation period on PADR closes)		ISP suggests timing in the neutral case of 2025 (or 2020 in the 'fast case'), and indicative timing in **2023**
Transmission augmentation to access renewable energy in North-Western VIC (Murray River REZ)	AEMO **2016** (again in 2017 and 2018)		Published **April 2017**	*Was due July 2018. AER granted extension to* ***December 2018.***	**Q1 2019** (NER require it is published as soon as practicable after consultation period on PADR closes)		ISP suggests network upgrade timing in all cases is **2024**

= completed   = not required or alternate process   = allows for maximum period of time (could be completed sooner)

[1] Powerlink and TransGrid have assessed whether an upgrade of QNI could be technically and economically justified on several occasions since the interconnector was commissioned in 2001, and as such been mentioned in multiple APRs.
[2] The regulatory process for AEMO in Victoria is different to other jurisdictions. Transmission determinations for AEMO in VIC do not include revenue determinations, and as such do not follow the same funding arrangements as other jurisdictions.
[3] This project is exempt from a RIT-T and has been fast tracked. ElectraNet's alternative economic evaluation is currently underway.

The second group of transmission investments outlined by AEMO include developments in the medium term (by the mid-2020s) to increase trade between NEM regions, provide access to storage and support the development of REZs. The REZs identified for development in the ISP "do not conform to the stereotype of long network extensions to remote locations," and the transmission augmentations identified in the ISP would encourage renewable generators to connect to the transmission network in areas with existing capacity.[22]

The identified REZs are largely located along the path of proposed new interconnectors. This implies that the future development of REZs will be biased towards generators connecting where there is existing transmission capacity, rather than the development of areas with good renewable resources with new, dedicated transmission infrastructure that is designed to facilitate the connection of new generation.

The Group 2 investment projects are:

- Establish new transfer capacity between NSW and South Australia of 750MW.
- Increase transfer capacity between Victoria and South Australia by 100 MW.
- Increase transfer capacity from Queensland to New South Wales by a further 378 MW.

22 AEMO, Integrated System Plan, July 2018, p.87.

- Efficiently connect renewable energy sources through maximising the use of the existing network and route selection of the above developments.
- Coordinated distributed energy resources in South Australia.

The third group of transmission investment identified by AEMO in the ISP is focused on the 2030s and is proposed to increase inter-regional and intra-regional transfer capacity across the NEM. AEMO noted in the ISP that there is "time to consult on, refine and finalise proposed initiatives in Group 3, including the selection of preferred REZs and their timing," along with the timing of transmission development.[23]

4.1.2 Regulatory implications of the ISP

All of the Group 1 projects identified by AEMO in the ISP have been identified and are being progressed by individual TNSPs under current arrangements. The projects are all either: currently the subject of RIT-T assessments; are exempt from a RIT-T assessment; or have been identified as contingent projects by TNSPs. Hence, the current regulatory framework has worked to identify immediate network needs and is in the process of assessing the value of the associated investments required. That said, there are other, non-regulatory risks to the implementation of transmission network investment, including development approvals, environmental approvals and the procurement of easements. These challenges are explored in more detail in Chapter 5.

Some of the Group 2 projects are also being considered and progressed under the current arrangements. These projects are listed in the table below.

Table 4.1: Group 2 projects being considered through the regulatory framework

ISP IDENTIFIED PROJECT	CORRESPONDING PROJECT/RIT-T
RiverLink (SA to NSW upgrade)	*South Australian Energy Transformation* RIT-T.
Medium NSW to QLD upgrade	We understand that TransGrid and Powerlink will shortly commence a RIT-T on this.
SnowyLink North	TransGrid's *Reinforcement of Southern Network in response to Snowy 2.0* contingent project.

Source: SA Energy Transformation RIT-T: https://www.electranet.com.au/projects/south-australian-energy-transformation/; QNI Upgrade: AER, TransGrid transmission determination 2018 to 2023, Final Decision, Attachment 6 – Capital expenditure, May 2018; Transgrid re-inforcement of southern netork: AER, TransGrid transmission determination 2018 to 2023, Final Decision, Attachment 6 – Capital expenditure, May 2018.

The AEMC acknowledges the concerns of some stakeholders that these arrangements are not facilitating the delivery of the transmission investments that may be needed to deliver the ISP within the timeframes identified in the ISP. There are a number of options for changes to the existing planning arrangements to achieve this goal - that is, to make the ISP an "actionable"

23 Ibid, p.89.

plan, and deliver such action in a timely manner. There may also be scope to identify improvements to the various stages in the investment decision process, including those parts that are regulated by the NEL/NER and those that aren't, to promote timeliness and process efficiency.

4.1.3 Questions arising from the ISP

While the AEMC's discussion paper on this review was published prior to the publication of the ISP, some stakeholders raised questions in relation to the role of ISP in their submissions. For example, Wirsol and Renew Estate stated in its submission that it "would like to see clarity from the ISP on how the costs of development in the networks will be distributed between network service providers (NSPs), generators and government."[24]

Two important questions arise from the ISP:

1. What is the relationship between the ISP and government policy objectives that are beyond the scope of the NEO?[25]
2. What should be the link between the ISP and investment decisions? How would this affect how TNSPs are regulated?

The remainder of this section addresses the first question.

The AEMC's views on question two are set out in this Chapter. We consider that this is consistent with making the ISP actionable, but welcome stakeholder views on this. We set out five options for how the ISP could be made an "actionable" plan, and the implications for other aspects of the transmission framework.

> QUESTION 1: QUESTIONS ARISING FROM THE ISP
>
> A) Are there any other questions about the role and regulatory implications of the ISP that are not set out here?
>
> B) Is our approach to making the ISP actionable (i.e. making the link between the ISP and investment decisions) made appropriate?

Interaction with government policies

AEMO, as the national transmission planner, must have regard to the NEO. The ISP should therefore be designed with the NEO in mind and identify the most efficient transmission path that is consistent with the NEO. However, there are broader policy objectives that may impact on the energy market, but that are not within scope of the NEO. Two common examples are industry and environmental policies.

24 Wirsol and Renew Estate, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2.

25 The NEO governs and guides the AEMC in their activities. It is defined in the National Electricity Law as follows: "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system."

A number of states and territories have implemented policies with the objective of boosting the renewable energy industry in their jurisdictions. These policies often take the form of reverse auctions where state governments purchase an amount of energy from renewable energy generators at an agreed price. These types of policies have industry and environmental objectives and TNSPs do not have regulatory obligations to consider such objectives. However, these policies have a direct impact on the energy market and may drive a need for transmission investment that is beyond a TNSP's regulatory obligations.

Similarly, the Commonwealth government is responsible for certain environmental policies, including emissions reductions in accordance with international commitments. These environmental policies may also affect the need for transmission investment as they are likely to change the mix of generation in the NEM.

The national transmission planner should have regard to these policies when preparing a long-term strategic plan for the transmission network. However, the national transmission planner does not have perfect foresight as to what these policies might be over the 20 year planning horizon.

One way of addressing this uncertainty would be for the COAG Energy Council to provide formal advice to AEMO as part of a regular annual process, in order to make sure that AEMO is able to effectively incorporate government policies into its ISP modelling. For example, if a current government policy includes multiple stages, the COAG Energy Council could specify what sensitivities or scenarios it wishes AEMO to model in relation to government politices. Such an approach would also assist governments to understand the costs and how government policies can shape the development of the transmission network.

QUESTION 2: INTERACTION BETWEEN THE ISP AND GOVERNMENT POLICIES

A) Do stakeholders consider it would be helpful for the COAG Energy Council to provide formal advice to AEMO as to what government policies or scenarios should be modelled in the ISP?

B) Are there other ways in which government policies that impact on the NEM could be incorporated as modelled scenarios into the ISP?

4.2 Options to strengthen the link between the ISP and investment decisions

4.2.1 "Strategic, national" investments and regional investments

Under the NEL, AEMO, as national transmission planner, is obliged to:

- to prepare, maintain and publish a plan for the development of the national transmission grid (the NTNDP) in accordance with the NER
- to keep the national transmission grid under review and provide advice on the development of the grid or projects that could affect the grid

- to provide a national strategic perspective for transmission planning and coordination.[26]

AEMO considers the NEM in its entirety and relies on information from TNSPs on the conditions in each of their networks to use in preparing the national plan.

The term *national transmission grid* is defined in the NEL as "the transmission systems that form part of the interconnected national electricity system". AEMO has produced the ISP to be a "strategic infrastructure development plan" for the national transmission grid, taking into account the efficient evolution of the supply mix across a range of plausible futures. It forecasts the overall transmission system requirements for the NEM over the next 20 years.[27]

TNSPs, on the other hand, are those registered participants who own, operate or control a transmission system that forms part of the interconnected national electricity system. Currently, TNSPs (including AEMO as TNSP in Victoria) have transmission planning responsibility for their respective systems.

There are likely to be limits to the level of detail about individual components that comprise the ISP that it can practically incorporate. For the purposes of this Chapter, it is assumed that it is not feasible for the ISP to attempt to plan for all of the needs for each TNSP i.e. including all replacement expenditure, as well as localised investments to meet jurisdictional reliability standards. Doing so would also likely be unrealistic, given the amount of specific network needs TNSPs must plan for.

This paper and the discussion of options in the following sections, assumes that in making the ISP "actionable", the focus is on those "strategic, national" investments. That is, AEMO plans for the interconnected national electricity system, and other investments within jurisdictions would be planned by TNSPs under existing arrangements. TNSPs would still be required to identify projects to meet identified network needs that are outside the ISP process, i.e. regional investments - projects that do not have a strategic element but are required to meet their individual reliability obligations.[28] The TNSP would have to manage the potential interactions between these two types of needs, and subsequent regulatory processes, to make sure that the development path of their network is efficient.

To clarify this distinction under the options considered in the next section, it may be appropriate to set a cost threshold or establish criteria by which AEMO would identify which network needs it should plan for, and which should be identified by the TNSPs through their annual planning reports. One option would be to establish a set of criteria to define needs or projects that are of "strategic importance" or have wider implications for the national transmission network. Or, the distinction could be tied to existing concepts in the NER, such as the concept of *national transmission flow path*, which is defined in the NER as "that portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres." Alternatively, the distinction could be drawn in accordance with who would benefit if the network need were to be addressed.

26 See section 49 of the NEL.

27 There is scope for AEMO to target specific projects on the national transmission flow path in more detail when they are reaching the point where an investment decision is required.

28 TNSPs' reliability obligations are explained in chapter 3.

This paper therefore assumes that some sort of threshold or criteria are established. There may also be a need to clarify how interactions between "localised" and "strategic, national" investment needs are managed.

QUESTION 3: "STRATEGIC, NATIONAL" INVESTMENTS AND REGIONAL INVESTMENTS

A) Is it appropriate that the ISP only focuses on "strategic, national" investments?

B) If so, how could this threshold be defined, or what criteria could be used to define it?

4.2.2 Overview of options

This section sets out five potential ways in which AEMO's role as national transmission planner could be linked more strongly to the individual investments undertaken by TNSPs, consistent with the COAG Energy Council request to make the ISP "actionable". These options are intended to create stronger links between the ISP and actual investments in transmission to improve overall confidence in the regulatory investment process, while at the same time providing appropriate checks and balances to protect consumers who fund transmission investment, and in whose interests' transmission investments are undertaken.[29]

The five options are described in terms of who is responsible for undertaking the various stages in a transmission investment process.

Each of these stages are needed so that investments (and alternatives to them) are appropriately identified, tested, costed, consulted on and assessed against the network need. These stages are not specific to transmission investments – they are steps that need to be taken by anyone who undertakes a significant investment. These steps are commonly accepted, and have been used in a range of literature on the subject.[30] Some of the steps are discussed in more detail in Chapter 5.

As such, the stages in the process do not refer explicitly to the existing processes (regulatory or otherwise) for transmission investment in the NEM, for example the RIT-T. The intention is to focus on the steps required in any investment decision making process, since the existing tools will likely need to change if any of these options are pursued.

Table 4.2 below summarises the potential allocation of responsibilities for each of these stages under the various options. The key difference between each of the options is how many of the stages in a transmission investment process are undertaken by AEMO through the ISP, compared to individual TNSPs. As you move towards the right-hand side of the table, AEMO undertakes more and more steps. This occurs until you reach option 5 where AEMO is undertaking the majority of the steps in the transmission planning and investment decision

29 Each option assumes that the COAG Energy Council has approved any policy scenarios subject to modelling and other relevant assessments as part of developing the ISP; and all projects meet the existing cost thershold for consideration under a RIT-T process.

30 For example, see: NERA and Allens Linklaters, Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-making, May 2012; and FTI-CL, Investment Tests for Transmission Networks, 6 September 2018.

making process, and the TNSP is only responsible for delivering the investment as specified by AEMO in the ISP.

A key consideration in deciding which option would best contribute to the NEO is whether it is more efficient for one party (or a collaboration of parties) to make the necessary investment decisions as part of one large national plan that accommodates the relevant 'localised' or regional detail, or as part of a two-stage process of taking the results of the national transmission plan (i.e. the ISP) and undertaking a project-specific assessment of individual investment options to meet that plan.

Given this transition, as you move towards the right-hand end of the table the following other areas also change:

- **The degree of control TNSPs have over the outcome, and the flexibility of that outcome to changing circumstances.** Under the options on the left side of the table, TNSPs retain a large degree of control over the investments that occur in their networks, but this control shifts to AEMO as you move to the options on the right side of the table.
- **The degree of certainty that the ISP will be "delivered".** As the outcomes of the ISP become more binding on TNSPs, there would be greater certainty that they will undertake investments to meet what is identified in the ISP. As you move to the right of the table, the requirement for how non-network investments are effectively considered as alternatives to network investments would need to be built into the regulatory process.
- **When the economic regulator needs to be involved in the process.** The AER plays an important role as the economic regulator in setting network revenues in order to make sure that expenditure by TNSPs is efficient and so in the long-term interests of consumers. As the outcomes of the ISP become more binding, there will need to be earlier AER engagement in any ISP/RIT process in order that investments identified contribute towards efficient expenditure. At the extreme, if investment decisions are being made as part of the ISP process, the AER will need to have a strong involvement in the ISP process, and potentially need to approve the ISP itself.
- **The extent of regulatory change required to implement the option.** Those options on the right side of the table represent greater changes to the existing regulatory arrangements than those on the left, particularly in relation to the economic regulation of TNSPs. Consequently, the time and cost required to implement these options is likely to be greater. In particular, while all options will require NER changes; options towards the right of the spectrum will also likely require NEL changes.

Table 4.2: Options to strengthen the link between the ISP transmission investment decisions

	STAGE IN INVESTMENT PROCESS	**RESPONSIBILITY UNDER EACH OPTION**				
		1. TNSPs must consider ISP-identified needs in their TAPRs	**2. TNSPs must conduct RIT-T on ISP-identified needs and options**	**3: AEMO determines "best" option**	**4: AEMO directs TNSP to proceed with the "best" option**	**5: AEMO directs TNSP to implement the investment**
1	**Identify need**	AEMO	AEMO	AEMO	AEMO	AEMO
2	**Identify credible options that address the need**	TNSP	AEMO	AEMO	AEMO	AEMO
3	**Assess costs and benefits of credible options**	TNSP	TNSP	AEMO	AEMO	AEMO
4	**Determine "best" option**	TNSP	TNSP	AEMO	AEMO	AEMO
5	**Make decision to implement "best" option**	TNSP	TNSP	TNSP	AEMO directs TNSP to do so	AEMO
6	**Undertake detailed costing and planning for the investment**	TNSP	TNSP	TNSP	TNSP	AEMO
7	**Implement the investment**	TNSP	TNSP	TNSP	TNSP	AEMO directs TNSP to do so
TNSP control over investment		Higher degree of control				Lower degree of control

4.2.3 Risk allocation

One of the main elements in choosing a market design or form of regulation is deciding who takes responsibility for the various risks that are present. In relation to transmission investment, there are risks associated with having too much, or too little, transmission capacity. Consumers will bear these risks through either:

- paying higher than necessary network charges, if the network is oversized; or
- reliability issues, or higher electricity prices if congestion occurs where the network is undersized.

TNSPs may bear some of the risk:

- depending on the extent to which the errors are reflected in the AER's projections that it bases the TNSP's revenue allowance on; and
- if it suffers any reputational risk through building the network differently to what should have been built.

Generators may also face some risks, depending on where they are located, and the level of congestion that results. The current transmission planning and investment decision making process seeks to minimises these risks, largely through having reliability standards that TNSPs must plan to; and the corresponding economic regulation by the AER.

Therefore, in considering changes to the transmission planning and investment decision making process, the Commission is conscious that the risks related to these processes may either:

- change in how they are shared between generators, TNSPs and consumers; or
- if the sharing of risks is not to change, require other regulatory changes to make sure that this is the case.

The placement of risk should lead to:

- mitigation of risk: the consequences of that risk should it materialise (that is, the potential for loss - either in a financial or a physical sense) being avoided or lessened
- incentives to improve risk management: incentives being created for the risk management to improve over time. That involves allocating risk to a party who can, relative to others, better manage the consequences of that risk.

This can occur if the party holding the party has:

- Incentives to manage the risk, because it stands to gain or lose from doing so, and there is a clear link between its actions and the outcomes of the risk.
- More information than other parties to manage the risk. It can use this information to better mitigate the impact of the associated loss.
- The ability to better manage risk than other parties, and so it can take actions to avoid or reduce the impact of the associated loss.
- The ability to improve risk management over time through experience. The party can learn and become more adept at risk management, meaning that it might make fewer errors in the future, or the likelihood of errors would become lower over time.

We are interested in stakeholder views on how risk allocation may need to change under the proposed options. Some of the Commission's preliminary views include:

- In relation to consumers, if some options have less scope for the investment decision to change in response to changing circumstances, then consumers may bear increased risks (and costs) associated with investments being undertaken that may no longer be required. To the extent that the change promotes the NEO, then consumers should benefit from having more efficient transmission infrastructure built.
- It is not clear what the impact of risks on TNSPs will be as we move towards the right-hand side of the spectrum. On the one hand, given that the investment decision has been made by another party, TNSPs may consider they have increased reputational risks or risks associated with needing to comply with localised license and safety requirements. On the other, TNSPs may consider that there may be reduced financial risks for their business given that the investment decision will no longer be undertaken by them.
- Given that the options do not seek to change access arrangements, it is unlikely that there will be a substantial change of risk allocation for generators.
- In relation to incentives, financial incentives are typically considered to provide the most robust and transparent driver for efficient decision making since they provide an understandable and transparent approach to influence behaviour. However, there are other incentives, such as reputational incentives or incentives to make another function that the party undertakes easier. In comparing the options the different incentives placed on parties need to be considered - and how this flows through to the risk allocation.

QUESTION 4: RISK ALLOCATION

A) How may the existing risk allocation for consumers, TNSPs and generators change under the proposed options?

B) What other regulatory changes may be required in order to mitigate against changes in the risk allocation?

4.2.4 Level of consultation required under each of the options

There is a need for robust stakeholder consultation throughout the investment process under all of the five options discussed in this Chapter.

Effective consultation means that stakeholders:

- are heard in the development of the inputs and assumptions that inform the identification of needs and options to address those needs
- are part of the process when decisions are made
- have the ability to challenge these inputs, assumptions and decisions, and that their feedback is taken into account.

A robust consultation process supports confidence in the planning process and in its outcomes. Meaningful consultation with stakeholders throughout all stages of an investment process may help to mitigate the risk of the outcome being disputed. It may also speed up the overall investment process if stakeholders are able to raise questions and concerns earlier on, for example, by reducing the amount of consultation that occurs at later stages of the process.

Confidence in the planning process will likely become more important if the ISP is to be "actionable". In the AEMC's view, the options to the right side of the table, under which AEMO has greater responsibility for the stages in the investment process, would require a more robust and prescriptive consultation process through the ISP than is currently the case.[31] The more binding AEMO's input is on TNSPs' individual investments, and thus the 'closer' the relationship between TNSPs' and AEMO's decisions (impacting directly on the costs of transmission investment that are paid for by consumers), the greater the need for confidence that the methodology and modelling used to arrive at particular decisions used accurate and complete information. It would also require the ISP to take account of a number of local, project specific factors that are relevant to each investment that are currently considered as part of the 'localised', individual network planning of TNSPs.

Other international jurisdictions where the system operator has a more direct role in making transmission investment decisions have recognised the importance of providing confidence in the planning process and outcomes. These jurisdictions have put processes in place that provide for high levels of stakeholder engagement with the transmission planning process.

> **QUESTION 5:** LEVEL OF CONSULTATION REQUIRED UNDER EACH OF THE OPTIONS
>
> A) What do stakeholders think about the level of consultation that would be required under each of the ISP options considered in this Chapter?
>
> B) Should there be more consultation for options at the right-hand side of the table?

4.3 Option 1: Requirement for TNSPs to consider ISP-identified needs in their TAPRs

Currently the NER require that a TNSP has regard to the NTNDP when undertaking its annual planning review but is under no obligation to use the outputs of the NTNDP in its own planning activities. This option reflects an enhanced status quo,[32] and would strengthen the links between the ISP and TNSP planning and investment decision making processes by:

31 Building this robust and transparent consultation into the ISP development process could mean that the early stages of the RIT-T are streamlined, as discussed later in this chapter.

32 This option most closely resembles the existing allocation of responsibility between the national transmission planner and individual TNSPs. That is, AEMO sets out a high level plan for the long term development of the national transmission grid and individual TNSPs conduct the detailed cost/benefit analyses and localised planning processes to meet their network needs, having regard to AEMO's long term strategic vision.

- imposing a regulatory obligation on AEMO to consult with TNSPs to get sufficient information on conditions in individual transmission networks to identify the needs of the national transmission grid in the ISP
- placing a regulatory obligation on TNSPs to consider those needs identified in the ISP in the TNSPs individual planning exercises, such as the transmission annual planning reports and RIT-Ts. TNSPs could also use the assumptions and inputs that were used in the ISP as a starting position in their planning activities. This may shorten the time associated with the RIT-T process. It is also likely that most of the needs identified in the ISP would become the subject of the RIT-Ts.[33]

The allocation of responsibilities would be as set out in Table 4.3.

Table 4.3: Allocation of responsibilities under Option 1

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
1	**Identify need**	AEMO identifies network needs through its modelling in the ISP, with TNSPs providing inputs into this process.
2	**Identify credible options that address the need**	TNSPs identify the various credible options that could meet the need that has been identified by AEMO through their TAPRs and RIT-Ts. TNSPs could use the assumptions and inputs that were used in the ISP as a starting point in their planning activities.
3	**Assess costs and benefits of credible options**	TNSPs undertake a robust and transparent cost/benefit assessment of the various credible options, including non-network options.
4	**Determine "best" option**	TNSPs determine which of the credible options provides the best net market benefit.
5	**Make decision to implement "best" option**	TNSPs make the decision as to how the "best" option will be implemented, including such decisions if a network option is chosen: preferred route; technical specifications of the assets; interfaces with the existing transmission network. (This step may involve a feedback loop with the TNSP checking with AEMO that the "best" option will address the identified need included in the ISP.)

33 Note that the TNSP would still be responsible for conducting RIT-Ts on investments that do not meet the threshold or criteria discussed in chapter 4.

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
6	**Undertake detailed costing and planning for the investment**	TNSPs undertake the detailed, project specific costing and planning for the investment. For a network investment, this will include obtaining land easements and environmental approvals; developing functional specfications for the assets and ordering / procuring the equipment. (It is typically at this stage that AER involvement in the economic regulation will begin, as under current incentive-based regulation arrangements)
7	**Implement the investment**	TNSPs implement the investment - either building and commissioning the transmission invesment; or finalising contracts with the non-network provider

4.3.1 Implications for the existing regulatory framework

This section outlines the regulatory implications of this option - that is, what would need to change to give effect to this option, and what impacts it might have on the long term interests of consumers.

Process for transmission planning and investment

Stage 1

Responsibility for identifying network needs would lie with AEMO who would set these needs out in the ISP. AEMO would have to consult with TNSPs in order to gather sufficient information on conditions in individual networks to prepare the ISP. TNSPs would also need to be quite closely involved in the development of the needs, to provide the appropriate level of 'localised' detail that is relevant to AEMO's assessment.

As a consequence of their different functions and responsibilities, AEMO might define network needs differently to how an individual TNSP might. It would need to be considered whether TNSPs should be able to re-define the identified need/s in their TAPRs, or be required to include consideration of the need exactly as it is specified by AEMO in the ISP. If TNSPs were able to re-define the need, a process could be established to provide the TNSP with "guided discretion" that would describe the circumstances under which this could occur. TNSPs could be required to seek the AER or AEMO's approval to conduct a RIT-T on that need, and then to explain that to AEMO to make sure that the options considered under the RIT-T can be taken into account in the next ISP. The risk of such an approach is that the sense of "national", "strategic" planning is lost because AEMO's ability to encourage investments that meet the needs of the national transmission grid is diminished.

Another matter that would need to be considered is the timing of TAPRs relative to the ISP.[34] Specifically, there would need to be enough time between the release of the ISP and the required underlying data for TNSPs to incorporate this information into their planning processes.

Stages 2-7

TNSPs would then be responsible for:

- using the inputs, assumptions and development paths in the ISP as a starting point for identifying credible options - including non-network options - to meet those needs, which should mean that the identification of options by TNSPs would be more closely aligned wtih the needs identified in the ISP
- completing a benefit / cost assessment of those options through the RIT-T and selecting the option that best meets the identified need
- making any investments that pass the RIT-T by building new or replacing existing network infrastructure, or implementing a non-network solution (at their discretion).

These processes would occur under the exisitng RIT-T arrangements, so little change would be required to implement this. One aspect of the existing RIT-T process that can take time is the decision on which inputs and assumptions to use, so using the ISP inputs and assumptions as a starting point could speed up this part of the RIT-T process. The process and timing of the current RIT-T process is discussed in detail in Chapter 5.

TNSPs could be required to provide information to AEMO as it conducts these activities. For example, if a TNSP completes a RIT-T to meet a need identified in the ISP and the result is that the need is not material or a 'do nothing' option is proven to provide greater benefits, the TNSP could be required to provide this information to AEMO so it can be taken into account in the next ISP. In practice, the identification of needs in the ISP and the TNSPs' planning activities are likely to be iterative processes, constantly informing each other.

One potential downside of this option is that the TNSP would not be *required* to undertake investments to meet the needs identified by AEMO in the ISP. While this approach largely retains the existing amount of control TNSPs have over the investments they make in their networks, there is the possibility that the combined actions of TNSPs do not achieve the overall NEM-wide objectives identified by AEMO in the ISP. This could be partially mitigated by introducting a "feedback loop" with AEMO and/or the AER at stage 5 of the investment process - "make decision to implement 'best' option" - to check that the chosen option is consistent with the identified need.

Last resort planning power

This option may also raise questions regarding the last resort planning power (LRPP).[35]

34 Currently under the NER, AEMO must publish the NTNDP by no later than 31 December each year. TNSPs must publish their APRs by 30 June each year.

35 Currently under the NER, AEMO must publish the NTNDP by no later than 31 December. TNSPs must publish their APR by 30June each year.

The LRPP allows the AEMC to direct one or more NSPs to apply the RIT-T to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path, including interconnectors.[36]

The purpose of the LRPP is to ensure timely and efficient inter-regional transmission investment for the long-term interests of consumers of electricity when other mechanisms for the planning of this investment appear to have failed. Being a last resort mechanism, it is designed to only be utilised where there is a clear indication that regular planning processes have resulted in a planning gap regarding inter-regional transmission infrastructure. The Commission must decide whether, and if so how, to exercise the LRPP in accordance with requirements in the NER and with the LRPP guidelines. The NER also require the Commission to report annually on the matters it has considered in deciding whether to exercise the LRPP during that year.

Under this option there is no regulatory *requirement* for TNSPs to conduct RIT-Ts on needs identified in the ISP. To make sure that all needs identified in the ISP are properly considered, either:

- TNSPs could be required to conduct RIT-Ts on needs identified in the ISP
- a process could be established for AEMO to provide advice to the AEMC on which ISP-identified needs should be subject to the RIT-T, via the LRPP.[37]

Regulatory oversight and the role of the AER

There are limited implications for the role of the AER under this option, given the current framework for making investment decisions would remain largely unchanged. Currently, the role of the AER in the RIT-T process is not to approve the outcome but to enforce the TNSP's compliance with the regulatory framework for undertaking the RIT-T. This role would be retained for the purposes of approving any RIT-Ts that are conducted as a result of the needs identified in the ISP.

However, there are three areas where the AER may need an expanded role to give effect to this option. These are:

- If the outcomes of the ISP were used to inform RIT-Ts, it would follow that the AER should also have a role in approving the process for preparing the ISP and the needs that are identified through that process.
- Additional scrutiny may be required of both the ISP and APRs to make sure that the information from both of these publications are consistent with each other.
- The AER may have a role in providing ex-ante approval of the RIT-Ts relating to strategic, national investments in the event that the need being tested in the RIT-T is different to that identified in the ISP. This would occur in the case described above where the TNSP

36 Clause 5.10.2 of the NER defines a potential transmission project as an investment in a transmission asset of a TNSP which is: an augmentation; has an estimated capital cost in excess of $5million, as varied in accordance with a cost threshold determination; and the person who identifies the project considers is likely, if constructed, to relieve forecast constraints in respect of national transmission flow paths between regional reference nodes.

37 A variation on this option could involve the LRPP moving to the AER, and the AER directing TNSPs to undertake a RIT-T for investments to address ISP-identified needs that they have not included in their planning or revenue proposals.

intends to conduct a RIT-T on an identified need that is different to that identified in the ISP (unless TNSPs are not able to deviate from the ISP-identified need).

Summary

This option builds on the existing planning arrangments but largely retains the degree of discretion TNSPs have to identify and undertake investments in their networks, and their control over those investments. As noted above, there will not be much certainty that TNSPs will undertake investments to meet the needs that AEMO identified through the ISP. This option could therefore be considered a light version of "actionable".

Few regulatory amendments would be required to give effect to this option. Importantly, no changes to the way in which TNSPs are economically regulated would be required. TNSPs would still be subject to the incentive-based regulation regime when determining the investments that they undertake.

Consideration would need to be given as to whether there are aspects of the existing RIT-T process that could be incorporated into the development of the ISP in order to reduce duplication and streamline the RIT-T process.

QUESTION 6: OPTION 1 -REQUIREMENT FOR TNSPS TO CONSIDER ISP-IDENTIFIED NEEDS IN THEIR TAPRS

A) What are stakeholder views on this option?

B) Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?

C) Are there any regulatory or other implications that are not raised here?

4.4 Option 2: Requirement for TNSPs to conduct RIT-T on ISP-identified needs and options

This builds on the option described above and imposes a regulatory *requirement* for TNSPs to consider ISP-identified needs and credible options in their individual planning exercises. The assumptions and outputs of the ISP would be directly included in TNSPs' planning exercises, and all of the investments identified in the ISP would become the subject of RIT-Ts.

The AEMC understands that one aspect of the existing RIT-T process that can take time is the narrowing down of credible options to meet the identified need.[38] Therefore, this option could speed up this part of the RIT-T process since the options the TNSPs consider would be identiifed by AEMO in the ISP.[39]

38 Stakeholder feedback on the current RIT-T process is discussed in Chapter 5.

39 This could be considered similar to a proposal put forward by TransGrid in its submission to the discussion paper. TransGrid proposed that AEMO recommend a single development pathway in the ISP that outlines priority projects, including REZs, required across the NEM, and the timeframes in which they should be developed. TNSPs would then apply the RIT-T to individual projects using AEMO's single recommended development pathway as the "base case" for assessment. TransGrid's proposal is further detailed in Appendix A.5.

The other amendments to the existing process discussed above would all apply to this option as well.

The allocation of responsibilities would be as set out in Table 4.4. Italicised elements are what is different to the previous option.

Table 4.4: Allocation of responsibilities under Option 2

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
1	**Identify need**	AEMO identifies network needs through its modelling in the ISP, with TNSPs providing inputs into this process.
2	**Identify credible options that address the need**	***AEMO identifies the credible options that could meet the identified need through the ISP process, with TNSPs providing inputs into this process. It is unlikely at this stage that non-network options could be identified.***
3	**Assess costs and benefits of credible options**	TNSPs undertake a robust and transparent cost/benefit assessment of the various credible options, including seeking out non-network options.
4	**Determine "best" option**	TNSPs determine which of the credible options provides the best net market benefit.
5	**Make decision to implement "best" option**	TNSPs decide that the "best" option will be implemented, including such decisions if a network option is chosen: preferred route; technical specifications of the assets; interfaces with the existing transmisison network. (this step may involve a feedback loop with the TNSP checking with AEMO that the "best" option will address the identified need and ***its assessment includes consideration of the credible options included in the ISP***).
6	**Undertake detailed costing and planning for the investment**	TNSPs undertake the detailed, project specific costing and planning for the investment. For a network investment this will include obtaining land easemenets and environmental approvals; developing functional specifications for the assets and ordering / procuring the equipment. (It is typical at this stage that AER involvement in the economic regulation will begin, as under current incentive-based regulation arrangements)

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
7	**Implement the investment**	TNSPs implement the investment - either building and commissioning the transmission investment; or finalising contracts with the non-network provider.

4.4.1 Implications for the existing regulatory framework

This section outlines the regulatory implications of this option - that is, what would need to change to give effect to this option, and what impacts it might have on the long term interests of consumers.

Process for transmission planning and investment

Stages 1-2

AEMO would go one step further in the investment process under this option and would also identify credible options (i.e. actual projects / investments) to meet those needs. It is likely that AEMO's consultation process would need to be more rigorous than that under option 1, given AEMO would be taking on essentially the first stage of the RIT-T process: the identification of credible options. TNSPs would need to provide input into AEMO's development of needs and credible options. It is likely that AEMO will be unable to identify non-network options; and that this will still have to be undertaken by the TNSP in stage 3.

AEMO may define network needs and credible options, differently to how an individual TNSP might, which raises questions such as:

- whether TNSPs should be able to re-define the identified need/s in their TAPRs, or be required to include consideration of the need exactly as it is specified by AEMO in the ISP
- whether TNSPs should be able to reject consideration of particular credible options, or consider alternative options, in its RIT-T process

As with option 1, if TNSPs were able to do both of the above, a process could be established to provide the TNSP with "guided discretion" that would describe the circumstances under which this could occur. Further, the timing of TAPRs relative to the ISP would need to be considered.[40] Specifically, there would need to be enough time following the release of the ISP for TNSPs to incorporate this information into their planning processes.[41]

As under option 1, the timing of TAPRs, relative to the ISP, would need to be considered.[42] Specifically, there would need to be enough time following the release of the ISP for TNSPs to incorporate this information into their planning processes.[43]

40 Currently under the NER, AEMO must publish the NTNDP by no later than 31 December each year. TNSPs must publish their APRs by 30 June each year.

41 The joint transmission planning process means that the TNSPs are well informed about the content of the ISP as we prepare it.

42 Currently under the NER, AEMO must publish the NTNDP by no later than 31 December each year. TNSPs must publish their TAPRs by 30 June each year.

43 The joint transmission planning process means that the TNSPs are well informed about the content of the ISP as it is prepared.

Stages 3-7

TNSPs would be required to conduct RIT-Ts using the needs and credible options put forward by AEMO in the ISP. They would be responsible for assessing the costs and benefits of those options, selecting the option that best meets the identified need, making the investment decision and implementing that option. These processes would occur under the existing RIT-T arrangements, and thus little regulatory change would be needed to give effect to these stages of the investment process under this option.

However, the RIT-T process would likely need to be amended to recognise that AEMO has undertaken stages 1 and 2 of the investment process for ISP-identified needs and options. This may or may not change the length of the investment decision making process.

This option narrows the scope of the TNSP's consideration of options, whilst retaining the TNSP's discretion to select the "best" option to meet those needs. Similar to option 1 a "feedback loop" with AEMO or the AER could be introduced at stage 5 of the investment process - "make decision to implement 'best' option" - to check that the TNSP's chosen option is consistent with the need and the credible options determined by AEMO through the ISP.

Regulatory oversight and the role of the AER

There are some implications for the role of the AER under this option:

- If the options set out in the ISP will subsequently be considered through RIT-Ts, it would follow that the AER should have a role in approving the process for preparing the ISP and the needs and options that are identified through that process. Similarly, the RIT-T process would need to be amended so that stages 1-2 of the investment process are not "re-tested" through the RIT-T.
- Additional scrutiny may be required of both the ISP and APRs to make sure that the information from both of these publications are consistent with each other. For example, it is likely that the AER would need to be more involved in the development of credible options in order to enforce compliance and economically regulate the TNSPs' investment more effectively during the later stages of the investment process.
- The AER may have a role in providing ex-ante approval of RIT-Ts that relate to the strategic, national flowpath projects in the event that a need or option being tested in the RIT-T is different to that identified in the ISP. This would occur in the case described above where the TNSP intends to conduct a RIT-T on an identified need that is different to that identified in the ISP, to rule out consideration of a particular option or to include consideration of an option that was not identified in the ISP. These issues would not arise if TNSPs were not permitted to deviate from the ISP-identified needs and options.

Once the network need and credible options are identified, the existing framework for making investment decisions and associated economic regulation would remain largely unchanged. The AER would continue to enforce the TNSP's compliance with the regulatory framework for undertaking the RIT-T and have regulatory oversight of the TNSP's revenue.

Summary

This option builds on the existing planning arrangments but largely retains the degree of discretion TNSPs have to identify and undertake investments in their networks, and their control over those investments. This has a greater certainty than option 1 that TNSPs will consider the needs and options that AEMO identified through the ISP, whilst the TNSP retains a degree of control over which investments, if any, to undertake.

Some regulatory amendments would be required to give effect to this option. Importantly, no changes to the way in which TNSPs are economically regulated would be required. TNSPs would still be subject to the incentive-based regulation regime when determining the investments that they undertake.

Consideration would need to be given as to which aspects of the existing RIT-T process could be incorporated into the development of the ISP in order to reduce duplication and streamline the RIT-T process.

QUESTION 7: OPTION 2 - REQUIREMENT FOR TNSPS TO CONDUCT RIT-TS ON ISP-IDENTIFIED NEEDS AND OPTIONS

A) What are stakeholder views on this option?

B) Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?

C) Are there any regulatory or other implications that are not raised here?

4.5 Option 3: AEMO determines "best" option

Under this option, AEMO, in addition to identifying network needs and credible options, would also conduct cost/benefit analyses to determine the investment option that best meets the needs identified in the ISP. This will mean AEMO will have to consider both network and non-network options through the ISP. This would then be communicated to the individual TNSP/s, who would have discretion to decide whether to implement that option or whether circumstances have changed such that it would no longer be efficient to do so.

There will be no regulatory obligation for TNSPs to undertake the investments identified in the ISP, recognising that TNSPs may, as commercial businesses, wish to retain control over the investments that take place in their networks. For example, the TNSP could consider an option identiifed by AEMO and decide that since a large industrial facility has closed it is preferable to proceed with a different credible option to meet the same identified need. Consideration would have to be given so that the process is iterative, rather than duplicative; but will make the option robust to changing circumstances.

The links between the ISP and TNSP would strengthen planning outcomes for several reasons:

- The ISP would identify network needs, and options to address those needs, consistent with the least-cost development pathway for the transmission framework in the NEM.
- The ISP would include the project-specific planning for each of the components of this development pathway.
- TNSPs would be responsible for undertaking those investments if they make the commercial decision to do so.

The allocation of responsibilities would be as set out in Table 4.5. Italicised elements are what is different to the previous option.

Table 4.5: **Allocation of responsibilities under Option 3**

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
1	**Identify need**	AEMO identifies the network needs through its modelling in the ISP, with TNSPs providing inputs into this process.
2	**Identify credible options that address the need**	AEMO identifies the credible options that could meet the identified need through the ISP process, with TNSPs providing inputs into this process. It is likely at this stage that non-network options could be identified, ***and so will require AEMO to undertake robust consultation in order to identify these options.***
3	**Assess costs and benefits of credible options**	<u>***AEMO undertakes robust and transparent cost/benefit assessment of the various credible options, including seeking out non-network options, through the ISP.***</u>
4	**Determine "best" option**	<u>***AEMO determines which of the credible options provides the best net market benefit through the ISP.***</u> <u>***(The AER's involvement in the economic regulation may need to begin from this stage given investment decisions are starting to be made)***</u>
5	**Make decision to implement "best" option**	TNSPs decide that the "best" option will be implemented ***and undertakes a "check" to make sure that the option is still the "best" given the TNSP's knowledge of local conditions.*** This will include making such decisions such as how things may have changed; and, if a network option is chosen what the preferred route;

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
		technical specifications of the assets; interfaces with the existing transmission network.
6	**Undertake detailed costing and planning for the investment**	TNSPs undertake the detailed, project specific costing and planning for the investment. For a network investment this will include obtaining land easements and environmental approvals; developing functional specifications for the assets and ordering / procuring the equipment.
7	**Implement the investment**	TNSPs implement the investment - either building and commissioning the transmission investment; or finalising contracts with the non-network provider.

4.5.1 Implications for the existing regulatory framework

This section outlines the regulatory implications of this option - that is, what would need to change to give effect to this option, and what impacts it might have on the long term interests of consumers.

Process for transmission planning and investment

Stages 1-4

AEMO would take on assessing the costs and benefits of those options, and selecting the option that best meets the identified need would also lie with AEMO. AEMO would therefore need to make sure there was sufficient consultation with non-network providers through the development of the ISP. Stages 1-4 of the investment process that are currently contained within the RIT-T that TNSPs undertake, would now be contained within the ISP under this option.

This option would involve a large transfer of responsibility for transmission planning from individual TNSPs to AEMO requiring changes to how the process of planning the future needs of the transmission framework is conducted. The majority of the residual transmission planning undertaken by TNSPs would now be to meet those needs that are specific to its network alone, rather than to meet those needs that fit the "strategic, national" criteria. This would narrow the current role of TNSPs and would likely require changes to TNSPs' licence conditions. The appropriate role of APRs and individual TNSP planning in light of the expanded role of the ISP under this option would require consideration.

AEMO would be required to consult widely more widely with TNSPs and market participants in preparing the ISP under this option compared to earlier options as the complexity of the necessary modelling will increase, along with the responsibilities assigned to AEMO. Given that the scope of the ISP would be much broader under this option, a comprehensive and formalised consultation process would be appropriate, with this included in the NER. AEMO would also need to expand the ISP process to incorporate the consultation associated with the identification of network needs and credible options, and the selection of the best option (which currently occurs through the RIT-T). The rigour of consultation required would likely add to the complexity of the ISP, but could possibly mean that the RIT-T process is shorter as aspects of the current RIT-T could be incorporated into the ISP process. Consideration of whether it is feasible for AEMO to conduct such a comprehensive consultation and planning exercise on an annual basis would be required if this option is pursued.

In order to undertake these functions AEMO would need to have access to a lot of information from a variety of sources. In particular, AEMO would need sufficient information from TNSPs to identify all TNSPs' network needs, determine the various options to meet those needs, and conduct benefit/cost assessments of those individual options. The information required to complete a benefit/cost assessment is much more local and granular in nature than that required to complete the existing NTNDP. Cooperation between AEMO and the TNSPs would therefore be very important under this option. There would need to a rigorous process for cooperation and information exchange between individual TNSPs and AEMO. For example, for AEMO to undertake a cost-benefit assessments, details of the specific nature of the project, for example the route selection, land use issues and community engagement would be required. Without these details it would not be possible to estimate the timing or cost of the project, or indeed if the project is possible given specific local conditions.This process would most likely need to be included in the NER.[44] In addition, they would also need information from potential non-network providers.

There could be a difference between the objectives of a strategic national plan and of individual investment tests. Under this option both of these objectives would need to be delivered in the ISP. Identifying the least cost pathway <u>and</u> conducting project specific assessments would likely need to be an iterative process. This is because projects are interdependent and the result of one project assessment may have implications for the plan as a whole. The least cost path may change depending on project specification. In other words, the project-specific assessment of individual components of the national plan may change the plan itself.[45]

The implication of this is that even if all planning is conducted as part of the ISP it would likely remain a two-stage or iterative process of identifying the national pathway and then assessing individual components of that pathway. The national plan would inform the individual projects to be assessed and the results of the project-specific assessments would inform the national plan. The need to incorporate this level of detail in the ISP could greatly increase the complexity of the modelling required for the ISP, and would require input from TNSPs and other stakeholders. Significant input from TNSPs would be required as they have

44 One option is for TNSPs to submit binding cost estimates to AEMO as the project reached final investment decision stage. This approach would help the regulatory framework to emulate the rigour of a competitive market, since the ISP modelling would compare the cost of the solution submitted by the TNSP against other options (such as alternative transmission options, more local generation, or demand response) and select the most efficient solution. Given the project pipeline described above, TNSPs would have sufficient time to prepare their cost estimates.

45 To address this issue, TNSP could have an obligation to undertake project specific assessments as the project gets closer to final investment stage, with their findings being rolled into the ISP.

much of the information and knowledge regarding the specific conditions associated with an investment on their network.

Stages 5-7

Under this option, AEMO would identify the option/s that best meets the need/s it had identified, but TNSPs would ultimately decide whether to proceed with that option. This would allow the TNSP to consider local conditions or material changes in assumptions and inputs that would suggest that circumstances have changed.

Such an approach would mean that TNSPs retain control over the specific investments they commit to (and that their customers pay for). This enables TNSPs to undertake more detailed costing, stakeholder engagement or other analysis to determine whether it is willing to take on the risks associated with the project. This is consistent with the existing framework for economic regulation of TNSPs. A variation on this option is for the output from the TNSPs to feedback into the ISP.

The TNSP would not be required to undertake detailed analysis of other credible options to meet the identified need if it did decide to proceed with an AEMO-identified option, because this has all occurred through the ISP. In this way, the RIT-T process for 'strategic', national investments would be shortened. However, there is no guarantee that the overall investment process would be shorter because the detailed analysis of needs and options would still need to be undertaken by AEMO through the ISP, although it could become more efficient over time.

Consideration may also need to be given as to what would/should happen if a TNSP decided not to undertake an investment option that was identified by AEMO in the ISP e.g. if circumstances have changed such that the TNSP no longer considers that the investment would be beneficial. That is, should TNSPs be required to take on some sort of risk for not proceeding with an option that was put forward in the ISP? This risk may be addressed through the incentive-based regulation arrangements that TNSPs are subject to.

Regulatory oversight and the role of the AER

As the ISP would become both the national strategic plan and the assessment of individual, strategic investment options, the ISP process may need to be approved or overseen by the AER since much of the project-specific detail that is currently considered through the RIT-T would now be incorporated into the ISP.

AER approval of the projects would be needed to make sure that there is still a sufficient degree of regulatory oversight to protect consumers from inefficient network investment. However, it would seem more time efficient for the AER to be involved throughout the development of the ISP. Either way, the AER would need to be satisfied that the information used to inform the development of options and the actual investment decision was adequate in order for it to determine whether the cost of the project is likely to represent an efficient outcome.

Regulatory change would also likely be required so that the outcomes of AEMO's work in the ISP binds the AER. This would mean that stages 1-4 of the investment process would not need to be re-tested by the AER through a subsequent process. However, this option raises the question of whether the amount of money the TNSP is able to recover for the investment would be based on AEMO's conclusions in the ISP or whether it would be through the existing revenue determination process. If so, the TNSP is likely to need to be comfortable that it can carry out the option for the amount (or less) than AEMO identified.

Finally, the AER would need to approve the efficient expenditure undertaken by the TNSP in making the investments identified through the ISP. This would be to make sure that the investments were carried out in an efficient way and at lowest cost.[46]

Summary

This option shifts a significant proportion of the responsibility to conduct due diligence on investment decisions to AEMO through the ISP. As such, it relieves TNSPs of some of this responsibility in relation to strategic, national projects, but also potentially reduces TNSPs' control over decisions which influence reliability, safety and security on their networks, as well as price risks for the TNSPs.

However, as noted above, this option may not achieve the national network development plan identified by AEMO through the ISP, as ultimately TNSPs would have the ability to decide whether or not to undertake these investments.

The regulatory changes required to implement this option would comprise a transfer of many aspects of the RIT-T process to AEMO, and a review of how the AER assesses the decisions of AEMO and the actual investment decisions of TNSPs. The development and implementation of this option may therefore take some time, including potentially NEL changes.

QUESTION 8: OPTION 3 - AEMO DETERMINES "BEST" OPTION

A) What are stakeholder views on this option?

B) Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?

C) Are there any regulatory or other implications that are not raised here?

4.6 Option 4: AEMO directs TNSP to proceed with the "best" option

This option builds on the above option and requires AEMO to conduct detailed cost/benefit analyses to determine the investment option that best meets the needs identified in the ISP, as well as to instruct the relevant TNSP/s on what investment must be undertaken, removing the discretion that existed for TNSPs in the above option TNSPs would then proceed with implementing that option.

46 This could involve a requirement on TNSPs to undertake an open book tender for the works.

TNSPs would only be responsible for undertaking detailed costing and planning for the investment (including obtaining development approvals and conducting localised stakeholder engagement), and implementing that investment (including by selecting line routes, equipment brands and specifications).[47]

This option would strengthen the links between the ISP and TNSP planning outcomes for several reasons:

- The ISP would identify network needs, and options to address those needs, consistent with the least-cost development pathway for the transmission framework in the NEM.
- The ISP would include the project-specific planning for each of the components of this development pathway.
- TNSPs would be under a regulatory obligation to implement the option/s identified by AEMO in the ISP.

The allocation of responsibilities would be as set out in table 4.6. Italicised elements are what is different to the previous option.

Table 4.6: Allocation of responsibilities under Option 4

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
1	**Identify need**	AEMO identifies the network need through its modelling in the ISP, with TNSPs providing inputs into this process.
2	**Identify credible options that address the need**	AEMO identifies the credible options that could meet the identified need through the ISP process, with TNSPs providing inputs into this process. It is likely at this stage that non-network options could be identified, and so will require AEMO to undertake robsut consultation in odrer to identify these options.
3	**Assess costs and benefits of credible options**	AEMO undertakes robust and transparent cost/benefit assessment of the various credible options, including seeking out non-network options through the ISP
4	**Determine "best" option**	AEMO determines which of the credible options provides the best net market benefit through the ISP (The AER's involvement in the economic regulation may need to begin from this stage

47 The findings of this work can be fed back into the next ISP.

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
		given investment decisions are starting to be made)
5	**Make decision to implement "best" option**	***AEMO directs TNSPs to invest in the "best" option. This includes directing the TNSP whether the option is a network option (and if so, the preferred route and technical specifications of the assets) or a non-network option (and if so, the preferred supplier).***
6	**Undertake detailed costing and planning for the investment**	TNSPs undertake the detailed, project specific costing and planning for the investment. For a network investment this will include obtaining land easements and environmental approvals; developing functional specifications for the assets and ordering / procuring the equipment.
7	**Implement the investment**	TNSPs implement the investment - either building and commissioning the transmission investment; or finalising contracts with the non-network provider

4.6.1 Implications for the existing regulatory framework

This section outlines the regulatory implications of this option - that is, what would need to change to give effect to this option, and what impacts it might have on the long term interests of consumers.

Process for transmission planning and investment

The regulatory implications of stages 1-4 of the investment process are the same as those for option 3.

Stages 5-7

This option would involve AEMO instructing the relevant TNSP/s to proceed with the option that best meets the identified need, and TNSPs would be under a regulatory obligation to do so. Some form of contractual arrangement may be required between AEMO and the TNSP to tie the TNSP to that obligation and allocate risk in addition to a regulatory obligation. Such an approach would mean that TNSPs would not retain control over the specific investments they commit to (and that consumers pay for). To implement this option, TNSPs would need to be comfortable with this lack of control and the associated risks.

TNSPs would be required to undertake the more detailed costing, stakeholder engagement and other analysis that would be needed to undertake the project. However, given it has a direction from AEMO to undertake the project, the TNSP has no ability to re-assess the project as a whole, should unforeseen costs or risks emerge. However, they would still manage localised risks, for example those associated with obtaining development approvals, procuring easements and complying with jurisdictional safety requirements. If a non-network option was chosen, the TNSP would be required to enter into a contract with the chosen provider. Similar to option 3, information from this stage could feedback into the ISP.

Nevertheless, the costs associated with the actual investment would still be subject to the existing incentive-based regulation regime (explained in Box 3 in the next section), which should provide an incentive for the TNSP to minimise these costs. The TNSP would be allowed to adapt any network investments to the local conditions and requirements e.g. it will have a choice about what brand of transformer to install or how exactly to interface the equipment with its existing network. Specifically, the AER would forecast and lock in the total operating expenditure and capital expenditure a TNSP will require to meet its pre-defined service and reliability targets at the start of each regulatory period (as it does under the current arrangements),[48] but if the business spends less than the forecast it will still earn revenue to cover the total forecast amount.

Regulatory oversight and the role of the AER

Under this option, the TNSP is not responsible for assessing the relative costs and benefits of the identified need, or deciding to proceed with the investment. These responsibilities would lie with AEMO. This changes incentives away from TNSPs who are subject to financial incentives; to AEMO who are not.

The AER would need a regulatory framework by which it could approve the process of identifying options by AEMO, and its direction to the TNSP, to make sure that there is still a sufficient degree of regulatory oversight to protect consumers from inefficient network investment. Regulatory change would likely be required so that the AER has an approval role of the ISP, and be able to test the investment against its usual efficiency objectives, with the outcomes of this then binding the TNSP. Ideally, the AER would be involved enough through the process of coming up with this option that there should be no surprises.

Thus an alternative means may be needed for the AER to assess the inputs and conclusions of AEMO's ISP, as is the case currently for TNSPs under the RIT-T process. AER approval would be needed to make sure that there is still a sufficient degree of regulatory oversight to protect consumers from inefficient network investment.

The AER would also need to be satisfied that the information used to inform the development of options and the actual investment decision was adequate in order for it to determine whether the cost of the project represents an efficient outcome. This would mean that the outcomes would not need to be re-tested through a subsequent process. These investments would not be re-evaluated through the revenue determination processes; although the

48 Or through contingent projects during the regulatory period which have the same ex-ante incentive arrangements.

regulatory framework would still be based on incentive regulation so the AER has a decision to make on the revenues within the confines of the investment that AEMO selects, but would likely be based on reviewing whether the project has been implemented at least cost.

Summary

This option shifts the majority of the responsibility to conduct due diligence on investments to AEMO through the ISP, as well as the decision making power associated with those decisions. As such, it relieves TNSPs of most of this responsibility in relation to strategic, national projects, but also reduces their control over decisions for how their networks develop and the revenue they can seek AER approval to recover.

This option is more likely to achieve the national network development plan as identified by AEMO through the ISP. This is because AEMO would have the power to direct investment in accordance with what it had identified in the ISP.

The regulatory changes required to implement this option would comprise a transfer of many aspects of the RIT-T process to AEMO, changes to TNSP licence conditions, and the introduction of some sort of ability for the AER to assess the efficiency of AEMO's decisions. The development and implementation of this option may therefore take some time. There would also need to be the creation of regulatory and contractual obligations to invest as directed by AEMO.

QUESTION 9: OPTION 4 - AEMO DIRECTS TNSP TO PROCEED WITH THE "BEST" OPTION

A) What are stakeholder views on this option?

B) Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?

C) Are there any regulatory or other implications that are not raised here?

4.7 Option 5: AEMO directs TNSP to implement the investment

This option would require AEMO to conduct all stages of the investment process, with the exception of actually implementing the investment. In order for AEMO to do this, they would develop detailed specifications for the investment. The incumbent TNSP could then be directed to undertake the investment. The alternative would be for AEMO to run a competitive tender process to elicit bids from registered and licensed TNSPs to undertake the investment. This could be considered similar either to the model that currently exists in Victoria; or to arrangements that apply in the US.

The TNSPs (either being directed or being chosen through a tender process) would be responsible for implementing the investment at the cost and within the timing determined by AEMO. As such the TNSPs would be contractually liable for delivering the network need as specified and in a timely fashion.

This option would strengthen the links between the ISP and TNSP planning outcomes for several reasons, outlined below.

- The ISP would identify network needs, and options to address those needs, consistent with the least-cost development pathway for the transmission framework in the NEM.
- The ISP would include the project-specific planning for each of the components of this development pathway.
- The network needs identified as part of the ISP, and the investments to address them, would be assessed in detail by AEMO as part of the ISP.
- The detailed assessment of project-specific factors that impact on the cost and timing of an investment, for example community consultation and planning approval processes, would be done by AEMO as part of the ISP, rather than by the TNSP as part of a RIT-T.

The allocation of responsibilities would be as set out in Table 4.7. Italicised elements are what is different to the previous option.

Table 4.7: **Allocation of responsibilities under Option 5**

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
1	**Identify need**	AEMO identifies the network need through its modelling in the ISP, with TNSPs providing inputs into this process.
2	**Identify credible options that address the need**	AEMO identifies the credible options that could meet the identified need through the ISP process, with TNSPs providing inputs into this process. Non-network options will be identified at this stage, and so will require AEMO to undertake robust consultation in order to identify these options.
3	**Assess costs and benefits of credible options**	AEMO undertakes robust and transparent cost/benefit assessment of the various credible options, including seeking out non-network options through the ISP.
4	**Determine "best" option**	AEMO determines which of the credible options provides the best net market benefit through the ISP. (The AER's involvement in the economic regulation may need to begin from this stage given investment decisions are starting to be made).
5	**Make decision to implement**	AEMO directs TNSP to invest in the "best"

	STAGE IN INVESTMENT PROCESS	RESPONSIBILITY
	"best" option	option.
6	**Undertake detailed costing and planning for the investment**	***AEMO undertakes the detailed, project specific costing and planning through the ISP. This involves developing a specification of the investment requirement, including a functional specification if it is a network investment.*** (limited AER involvement in economic regulation)
7	**Implement the investment**	***AEMO directs TNSP to build the transmission infrastructure. The TNSP could potentially be chosen through a contestable process. The TNSP would be required to comply with AEMO's functional specification when building the investment.***

4.7.1 Implications for the existing regulatory framework

This section outlines the regulatory implications of this option - that is, what would need to change to give effect to this option, and what impacts it might have on the long term interests of consumers.

Process for transmission planning and investment

The implications for the current process for transmission planning and investment under this option are largely the same as those set out for option 4.

The key distinction is that this option would require AEMO to conduct the detailed project-specific planning and processes through the ISP, or some other process, such that the TNSP receives a complete plan for which investment to undertake and how to undertake it. This raises questions about whether AEMO would have sufficient knowledge to undertake this task. In essence this would implement the Victorian planning regime at a national level. This option is also most likely to raise questions about whether the investments should be subject to competitive processes - a question that is raised in the next section.

Given it has a direction from AEMO to undertake the project, the TNSP would have no ability to re-assess any aspect of the project should unforeseen costs or risks emerge. (Although you could have a material change in circumstances element where if such things changed in a material manner, then the invesment could be reassessed). Some form of contractual arrangement in addition to a regulatory obligation would likely be required between AEMO and the TNSP to facilitate the delivery of the project and manage any risks between the two parties.

An alternative would be to implement some type of contestability arrangement, where AEMO ran a tender for parties to compete to build the specified transmission assets.

Because of this, AEMO would likely need to be closely involved in the implementation phase of the project.

Regulatory oversight and the role of the AER

The NEM currently uses incentive-based regulation[49], described in Box 3, to regulate monopoly network businesses.

BOX 3: INCENTIVE BASED REGULATION

Incentive-based regulation is a form of regulation where the regulator, in this case the AER, forecasts and locks in the total operating expenditure and capital expenditure a business will require to meet its pre-defined service and reliability targets at the start of each regulatory period.

Businesses are given financial rewards where they improve their efficiency and spend less than the forecast during the regulatory period. Put simply, if the business spends less than the forecast it will still earn revenue to cover the total forecast amount. Hence it can 'keep the difference' between the forecast and its actual expenditure until the end of the regulatory control period. Conversely, if its spending exceeds the forecast, it must carry the difference itself until the end of the period. Similarly, businesses are rewarded where they improve service quality that is valued by customers and penalises them where service quality falls. Consumers benefit from efficiency improvements, that are not at the expense of service quality, through lower regulated prices.

Incentive-based regulation relies on NSPs making decisions on capital and operating expenditure in a way that minimises costs to consumers.

Source: AER, Overview of the Better Regulation reform package, April 2014, p.5.

Depending on how the regulatory arrangements were designed, Option 5 could be viewed as a move away from incentive-based regulation as it would remove TNSP discretion to undertake an investment and would require them to undertake an investment subject to the detailed costing and planning of another party (i.e. AEMO). If the TNSP has a guarantee that the costs of the project will be passed through directly to consumers, the TNSP has no incentive to minimise these costs. An alternative would be to still have incentive based

49 The other type of regulatory approach that can be applied to natural monopolies is cost of service regulation. Under this model, prices are set to cover the business's actual expenditures, including a return on investment. Cost of service regulation is used by some energy networks in the United States. It is relatively simple to regulate in this way - businesses provide cost information, and the regulator only needs to determine a "fair" rate of return. However, there is little incentive for the businesses to minimise costs as all costs are passed on, and further there is an incentive to "gold plate" (over-invest in its assets) since the profit is set according to the return on the asset base.

regulation, with the AER determining the ex ante costs and the TNSP having an incentive to implement the option at a lower cost.

Careful consideration would be required to determine how these investments could be accommodated in an incentive-based economic regulation model, if this option is pursued.

Summary

This option shifts all of the responsibility to conduct due diligence on investments to AEMO through the ISP, as well as the decision-making power associated with those decisions. As such, it relieves TNSPs of most of this responsibility in relation to strategic, national projects, but also, as mentioned under option 3, significantly reduces their control over decisions for how their networks develop, what they can spend money on, and how much revenue they can seek AER approval to recover.

This option is more likely to achieve the national network development plan as identified by AEMO through the ISP. This is because AEMO would have the power to direct investment exactly in accordance with what it had identified in the ISP.

The regulatory changes required to implement this option would comprise a transfer of all aspects of the RIT-T process to AEMO for these types of investments, changes to TNSP licence conditions, and the introduction of some sort of ability for the AER to assess the efficiency of AEMO's decisions. It would also require consideration of how to treat the costs associated with the investments, given that this option is not consistent with the existing incentive-based framework for economic regulation of TNSPs. The development and implementation of this option may therefore take some time.

> QUESTION 10: OPTION 5 - AEMO DIRECTS TNSP TO IMPLEMENT THE INVESTMENT
>
> A) What are stakeholder views on this option?
>
> B) Would the effective delivery of this option have an impact on the speed with which "strategic, national" investments are made?
>
> C) Are there any regulatory or other implications that are not raised here?

4.8 Other options and considerations

The five options set out above present a spectrum of possible approaches. They by no means represent all potential options. The AEMC welcomes stakeholder views on these options, and any others that are not set out here.

In determining which of the above options, if any, is preferred, the AEMC is of the view that consideration would also need to be given to:

- whether investments undertaken should be subject to competitive processes (i.e. contestability arrangements where TNSPs could "compete" to build the investements required) and, if so, whether the options above would support a level playing field for those investments

- any impact on TUOS charges.

QUESTION 11: OTHER OPTIONS AND CONSIDERATIONS

A) Are there other options to strengthen the link between the ISP and individual TNSP investments that are not raised here?

B) Are there any other matters that should be taken into account when considering options to strengthen the link between the ISP and TNSPs' individual investments?

5 REGULATORY INVESTMENT TEST FOR TRANSMISSION

Transmission assets can be very expensive, running into the billions of dollars. Once they are built, consumers pay for them for decades. The process to minimise the risk that consumers pay for inefficient investments must therefore be rigorous and transparent.

A key feature of the existing transmission planning and investment decision making framework is that for investments in new or replacement transmission assets, TNSPs are required to undertake a cost-benefit analysis of potential options. This cost-benefit analysis is conducted to determine the most appropriate solution for addressing a need (e.g. a forthcoming network constraint or limitation) on the transmission network, and whether addressing the need provides a net positive benefit to consumers – the RIT-T. The transmission business must consult with stakeholders when undertaking a RIT-T.

This Chapter seeks to explain what the RIT-T was designed to achieve, the key steps in the process, how it fits within the economic regulatory framework, and what the implications might be for the current RIT-T given the potential options discussed in Chapter 4 for making the ISP an 'actionable' strategic plan.

5.1 Where does the RIT fit into the broader regulatory framework?

The context for this test in the broader network investment regulatory instruments is set out in table 5.1.

Table 5.1: Network investment regulatory instruments

INSTRUMENT	FREQUENCY	OBJECTIVE
Transmission Annual Planning Report	Annual with forward planning period of ten years	Report on expected future operation of networks over an appropriate planning period
Regulatory Investment Test	As required	Identify an efficient option for new and replacement infrastructure, and protect consumers from inefficient investments
Regulatory information instruments	As required	AER sets out objectives – either a regulatory information order or regulatory information notice
Revenue proposal	For each regulatory control period: normally five years	Allow AER to make a revenue determination that sets

INSTRUMENT	FREQUENCY	OBJECTIVE
		maximum allowable revenue for a network service provider over a regulatory control period

The NER governing the economic regulation frameworks for the electricity sector enable the AER to set the maximum revenues that electricity transmission network businesses can charge for the transmission services they provide. TNSPs submit a revenue proposal to the AER covering what is typically a five year period, and the AER determines how much each TNSP is able to recover from consumers for these services. These revenues are based on, among other things, a return on, and return of, any capital expenditure a network business forecasts it will make over that period.

Importantly, while the AER takes into account the business's proposed capital investment program in setting the allowed revenues, once set by the AER these revenues are not tied to any particular project. That is, the actual capital expenditure undertaken is within the business's discretion, noting that, among other things, the business must comply with the jurisdictional reliability standards.

The approach to network regulation creates incentives on the network business. As the allowed revenue is fixed, the business has an incentive to deliver its capital expenditure program at a lower cost than the allowed forecast because it keeps any difference for the remainder of the period. This distinguishes the current approach from cost of service regulation, where the business just recovers its actual costs.

RITs are undertaken by the network business separately from the AER's determination of network revenues. If a project that a TNSP has accounted for in its revenue proposal is estimated to have a capital cost over $6 million,[50] the TNSP is required to conduct a RIT-T to identify the most efficient way to deliver the project. Even though the AER determines how much TNSPs are able to recover from consumers within a revenue determination period, the RIT-T process protects consumers from inefficient expenditure on more significant projects.

TNSP revenue proposals can also include significant network projects that may be reasonably required to be undertaken, but which are excluded from the ex-ante capital expenditure allowance in a revenue determination because of uncertainty about their requirement, timing or costs.[51] These have the effect of enabling network revenue to be adjusted within a businesses' regulatory determination period. These are known as contingent projects. Contingent projects are large discrete projects that are somewhat uncertain in terms of their need or timing at the start of the regulatory period.

In TNSPs' revenue determinations, the AER can approve proposed contingent projects and associated trigger events that would satisfy a contingent project application to the AER.

50 As varied under NER clause 5.15.3(b)(2),(4).

51 NER clause 6A.8.1(b).

Should the trigger event occur, a TNSP may apply to the AER during the regulatory period to amend the revenue determination and so the businesses's allowed revenue to include forecast capital expenditure and incremental operating expenditure for the project.

The successful completion of a RIT-T is often used as a trigger event for contingent projects. While a RIT-T might be completed by a TNSP for a particular contingent project, the TNSP must still apply to the AER to amend its revenue determination to include the new project. The AER must then decide whether or not the appropriate trigger events have occurred to allow the revenue determination to be amended, and the costs of the project recovered from consumers.

The revenue determination process is important because successful completion of a RIT-T by itself does not provide for the revenues that the TNSP will be able to recover from consumers. Until this process is complete, the TNSP is unlikely to commit to any investment. RITs therefore complement the ex ante incentive framework in respect of TNSPs only recovering revenue from consumers where the expenditure on its network is prudent and efficient.

In addition, the AEMC's last resort planning power allows it to direct one or more network businesses to apply the RIT-T to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path. The purpose of the power is to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity. The power can be exercised by the AEMC when other mechanisms to provide for the planning of this investment appear to have failed, for example where AEMO has identified a material constraint in the NTNDP but the relevant transmission network business has not addressed that constraint in its TAPR. The AEMC must exercise its power in accordance with requirements in the NER and the last resort planning power guidelines. To date, there have been no circumstances in which the AEMC has identified a need to invoke this power.

This framework for transmission network planning and investment was set up to:

- protect consumers from inefficient investments
- create incentives for TNSPs to consider potential non-network solutions to network constraints or limitations
- establish clearly defined planning and decision-making processes to assist network service providers in identifying the solutions to network issues in a timely manner
- provide transparency on network planning activities to assist non-network providers to put forward non-network options as credible alternatives to network investment and assist network users to make decisions about where best to connect to the network.

The purpose of the planning framework is not to regulate or direct which plans or decisions should be made, nor to determine what investment costs should be recoverable from regulated prices and revenues.

Instead, it accompanies an incentive-based economic regulatory framework. In this context, the planning information and investment decision-making process may also provide opportunities for the AER and other stakeholders to be more fully informed on the efficiency of network investment decisions. This in turn would be likely to support an outcome where consumers only pay for efficient investments.

The NER detail requirements for when the RIT-T must be applied, and what it must consider. In general, TNSPs are only required to undertake a RIT-T where:[52]

- investments will be recovered from electricity consumers via regulated revenues
- the most expensive potential credible option to address a need is more than the specified cost threshold (currently $6 million for transmission network investments)
- the investment is not addressing an unforeseen and urgent network issue that would have an effect on reliability
- the investment does not relate to the maintenance of existing assets.

If an investment is required to address an unforeseen and urgent issue that would put at risk the reliability of the transmission network,[53] then the RIT-T does not have to be undertaken.

5.2 What is the RIT-T designed to achieve?

The RIT-T is designed to identify the most efficient regulated investment in transmission infrastructure. The goal of the RIT-T is ultimately to protect consumers from paying more than necessary for the transmission required to deliver them with a reliable supply of electricity.[54]

The NER states that the purpose of the RIT-T is to:

> *...identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is a net economic cost) where the identified need is for a reliability correction action.*

The current access arrangements in the NEM mean that the cost of investment in shared transmission assets is recovered from consumers. The significant cost of extensive, capital intensive networks means that network services in a particular region can be most efficiently provided by a single monopoly supplier. Given that electricity networks are a natural monopoly, their services are regulated by the AER to protect consumers from monopoly pricing, and potentially paying for transmission infrastructure that does not serve their long-term interests.

In the absence of competition driving efficient investment options, the RIT-T was therefore designed to replicate the type of investment decision process that would be undertaken in a competitive market environment.[55] A RIT-T is a cost–benefit analysis framework that network

52 NER clauses 5.16.3 and 5.17.3.

53 The NER (clause 5.16.3(b)) sets out the conditions that must be met for investments to be exempt from the RIT-T because of urgent action required to address reliability issues.

54 COAG Energy Council, Review of the regulatory investment test for transmission, 6 February 2017, p.4.

55 COAG Energy Council, Review of the regulatory investment test for transmission, 6 February 2017, p.9. The Commission notes that a competitive business would seek to maximise its own net economic benefits, however the RIT-T seeks to maximise market-wide net economic benefits.

businesses must apply and consult on before making major investments in shared transmission assets in their networks to address an identified need. When undertaking RIT-Ts, network businesses must give due consideration to what credible options[56] are out there to meet the identified need, before identifying the best way to address needs on their networks. The NER refers to this optimal infrastructure investment as the 'preferred option.'[57] The preferred option is the credible option which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the relevant market.[58]

Some form of cost-benefit test to be applied by transmission businesses has been around since NEM start. However, the most recent incarnation of the test – the RIT-T – was introduced in 2009. Part of the creation of the RIT-T was amalgamating the previous separate reliability and market benefit limbs, with this occurring so that the decision making process in relation to transmission planning would be optimised. This provides the flexibility for proposed transmission projects to be assessed against both local reliability standards as well as their ability to maximise benefits to the national market. TNSPs would be required to investigate whether an enhancement to a reliability project, or a different project that met the same reliability standard, would provide additional market benefits that justified a higher cost, and select such a project if one is found.

In the interest of ensuring a thorough assessment of costs and benefits for the market, the RIT-T requires that any relevant costs or benefits (described in further detail below) that would flow from a particular investment be included as part of the RIT-T analysis.

The purpose of the RIT-T is directly related to the NEO.[59] The relevant element of the NEO when thinking about the RIT-T is the promotion of "efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers."[60] As explained by the AER in its draft amendments to the RIT application guidelines, by requiring TNSPs to consider all credible options to meet an identified need before selecting the option that maximises the net economic benefit in the market, the RIT-T promotes the NEO.[61]

More recently the AEMC amended the RIT-T process by extending the test to apply to network replacement expenditure decisions, as well as augmentation decisions.

It is also worth noting that in 2016, the COAG Energy Council tasked officials to undertake a review of the RIT-T. The review was to assess whether it remains appropriate in the changing energy market, with a particular focus on its application to interconnectors given their importance to all regions of the NEM. The findings are summarised in Box 4 below. Broadly, the review found that the RIT-T in its current form remains the appropriate mechanism to

56 Credible options are options to address the identified need that are commercially or technically feasible and can be implemented in sufficient time to meet the identified need.

57 AER, Draft regulatory investment test for transmission application guidelines, July 2018, p.8.

58 Ibid, p.8.

59 Ibid, p.17.

60 NEL, Section 7.

61 AER, Draft regulatory investment test for transmission application guidelines, July 2018, p.17.

ensure that new transmission infrastructure in the NEM is built in the long-term interests of consumers.

BOX 4: SUMMARY OF COAG ENERGY COUNCIL REVIEW ON RIT-T

In line with the terms of reference agreed by the Senior Committee of Officials, the review considered the appropriateness, effectiveness and efficiency of the test with a focus on the following areas: the balance between timeliness and rigour; the extent to which the RIT-T's current design is able to capture the full costs and benefits associated with transmission projects; whether the RIT-T is being applied appropriately; whether the RIT-T is appropriate to facilitate strategic interconnection investment decisions and the effectiveness of current governance arrangements.

Broadly, the review found that the RIT-T in its current form remains the appropriate mechanism to ensure that new transmission infrastructure in the NEM is built in the long term interests of consumers. Further, it remains an appropriate mechanism for the assessment of interconnection investments.

Officials identified a number of potential areas for improvement in both the test and wider transmission planning arrangements. These included:

- Review of the AER's RIT-T application guidelines, with a view to better reflect the net system benefits of options, including those relating to system security and renewable energy and climate goals (The AER is currently reviewing these guidelines in response to this recommendation).
- Improvements to the level and accessibility of information relating to transmission networks (the AER's Transmission Annual Planning Report Guideline will assist in this regard).
- Further explore the merits of increasing the AER's level of oversight for the RIT-T process (which was considered as part of the AEMC's replacement expenditure planning arrangements rule change).

The review considered, but found no evidence to warrant, options to streamline the test by shortening consultation and/or lessening requirements around the cost-benefit analysis in certain circumstances. The underlying issues which led to protracted processes, in some cases, appear to stem from contention between project proponents, interested stakeholders and proponents of competing options rather than the design of the test or its governance. Any paring back of current timeframes would compromise the ability of the test to effectively identify and assess all credible options. However, to the extent that delays relate to the complex task of assessing the relative costs and benefits of options, clearer guidelines and improved information should lead to a more efficient and streamlined RIT-T process.

The review further considered, but found no evidence to warrant, changes to the categories of costs and benefits which are captured in the RIT-T or to its current confinement to a partial equilibrium analysis focused on costs and benefits to those producing, transporting and consuming electricity in the NEM. What is needed are enhancements to modelling tools and processes to better capture system security benefits, such as changes in the costs of procuring ancillary services and the implications of high impact, low probability events such as that experienced recently in South Australia, as the proportion of renewables in the NEM progressively increases.

While outside the terms of reference for the review, the Energy Project Team noted it would be open to jurisdictions and/or the Energy Council to bring forward and cover the cost of interconnector investment outside the regulated framework, taking account of considerations broader than those under the RIT-T.

Source: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/RIT-T%20Review%20report%20%28final%206%20February%202017%29.pdf

5.3 Stages and timing of the RIT-T

5.3.1 RIT-T steps

There are a number of steps that the NER require a TNSP to follow when applying the RIT-T to a proposed project. The AER's draft RIT-T application guidelines provide an overview of these steps, which are summarised below.[62]

Identify a need for the investment, known as the identified need.

Chapter 10 of the NER defines an identified need as the objective a network business seeks (or network businesses seek) to achieve by investing in the network. Either a network or a non-network option may address an identified need. RIT–T proponents should express an identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. The identified need should be explicitly stated and explained clearly so as not to bias the development of options towards a particular solution.

Identiifed needs typically fall into one of two areas:

1. A common identified need expressed by transmission businesses is the need to meet minimum reliability standards to connection points in its jurisdiction. For example, Powerlink is currently undertaking a RIT-T focussed on maintaining a reliability of supply to Ingham, where the identified need is driven by the need to meet minimum reliability standards, specifically, that Powerlink must plan and operate its network such that it can meet forecast peak electricity demand during an outage of the most critical single network element. Such needs can be considered relatively "technical" requirement since it is an obligation that must be met.

2. The second area of identified need is where net market benefits have been identified e.g. alleviating congestion on part of a network in order to allow generators with lower marginal costs to access the market. Such identified needs are rarer than the above to be identified. RIT-Ts assessing interconnector upgrades would include this type of investment need. For

62 AER, Draft regulatory investment test for transmission application guidelines, July 2018.

example, ElectraNet's current RIT-T on the South Australian Energy Transformation is looking at new interconnector options that could create net market benefits to consumers, through allowing increased export of lower cost renewable generation.

Identify a set of credible options to address the identified need, and characterise the base case under which to compare credible options.

A credible option is an option (or group of options) that:

- achieves the objective the RIT–T proponent seeks to achieve by investing in the network;
- is (or are) commercially and technically feasible; and
- can be implemented to meet any specific timing imperatives of the RIT–T proponent's objective.

Credible options can be either network investment (e.g. investing in two transformers, such as in the Powerlink example above); or it can be a non-network option (e.g. entering into a contract with a demand management provider).

The base case for augmentation projects is a 'do nothing' scenario where the RIT-T proponent does not implement a credible option to meet the identified need. The base case for replacement projects refers to a scenario where the RIT-T proponent does not retire the infrastructure in poor condition nor implement a credible option to meet the identified need.[63]

Identify reasonable inputs to include in the cost–benefit analysis, and quantify costs and market benefits.

RIT–T proponents should use:

- inputs based on market data where this is available and applicable;
- assumptions and forecasts that are transparent and from a reputable and independent source; and
- up-to-date and relevant information most appropriate to the circumstances under consideration.

A RIT-T must provide the present value of a credible option's direct costs, including:

- costs incurred in constructing or providing the credible option, including the market value of land;
- operating and maintenance costs over the credible option's operating life; and
- costs of complying with relevant laws, regulations and administrative requirements

The NER require the RIT-T proponent to consider specific classes of market benefits that could be delivered by the credible option. The RIT-T also allows for the consideration of any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing that credible option with respect to the likely future investment needs of the market. Market benefits are quantified by identifying a set of reasonable scenarios under which to derive states of the world to

63 The base case for replacement projects must incorporate the operational and maintenance expenditure required to allow the ageing infrastructure to remain in service as effectively as possible for as long as possible, as well as the management of safety risk, environmental risk and equipment protection.

compare the market benefits of that credible option relative to the base case. The expected market benefit of that credible option is calculated over a probability weighted range of reasonable scenarios.

Quantify the expected net economic benefit of each credible option and identify the preferred option as the credible option with the highest expected net economic benefit.

The preferred option is the credible option that maximises the net economic benefit across the market, compared to all other credible options. The net economic benefit of a credible option is simply the market benefit less the costs of the credible option.

The NER[64] outlines costs and benefits considered to be relevant to this objective, including costs of construction, operating and maintenance costs, costs of complying with laws and regulations (including the impact of environmental policies such the Renewable Energy Target on the costs and benefits of different options), reductions in generation dispatch costs, reductions in voluntary and involuntary load curtailment/shedding requirements, reductions in transmission losses, deferral of new plant requirements and competition benefits (capturing for example, the efficiency benefits of increased competition between generators), among others.

Although classes of market benefits are defined in the RIT-T, the NER also allow for new categories of market benefits to be considered. Network businesses are required to obtain approval from the AER prior to considering such benefits as part of the RIT-T. To date, this has not occured.

To assist TNSPs in completing a RIT-T, regulatory investment test application guidelines are required to be developed, published and reviewed by the AER. These guidelines provide guidance and worked examples on the use of the regulatory investment tests. The AER is currently reviewing these guidelines to ensure they are useful to TNSPs and other stakeholders in understanding how to apply the RIT-T.

Price outcomes or wealth transfers between different groups (resulting from price separation in the NEM due to constraints which impact on interconnector flows for example) were deliberately excluded from the test as inconsistent with the principle of cost/benefit analysis. Similarly, wider economic impacts such as increases/decreases in industry costs, labour market outcomes and the like were excluded from consideration, reflective of the focused role of the test in promoting economic efficiency within the NEM and the long-term interests of electricity consumers (noting that the costs of investments that are subject to the RIT-T will be paid for by electricity consumers) and the significant additional regulatory burden more expansive modelling would impose. Since the introduction of the RIT-T, concerns have been raised by some stakeholders that it does not adequately capture certain classes of benefits which are increasingly important in the transitioning energy market; in particular, high impact, low probability events.

64 NER clause 5.16.1.

However, in principle, these types of benefits can already be included in a RIT-T assessment. The AER has spent time articulating case studies and examples of such events in its current review of the application of RIT guidelines.

The RIT-T is set up in a way to promote flexible outcomes. For example, while there are a set of benefits that must be quantified in the RIT-T set out in the NER, the AER can sign off on other benefits being taken into account provided they relate to the benefits for those who consume, produce and transport electricity in the NEM. If investments are being considered that affect multiple regions (e.g. an interconnector), then TNSPs can undertake the test jointly. The recent *Transmission Conection and Planning Arrangements* (TCAPA) Rule made by the Commission further enhances the planning framework by requiring TNSPs to undertake joint planning with other TNSPs where there is the potential for investments in other transmission networks to deliver market and reliability benefits in their own network – supplementing the RIT-T as a system wide test.

> **QUESTION 12:** RIT-T BENEFITS
>
> A) Are there any additional benefit categories that should be considered in the RIT-T?
>
> B) Why have no network businesses sought approval from the AER for additional benefits to be considered in RIT-T assessments as allowed for under the NER?

5.3.2 Consultation

The RIT-T process is centred on stakeholder engagement and consultation, providing multiple opportunities for stakeholders to be involved and provide input. The consultation aspect is a key component of the RIT-T process. The NER detail a stakeholder engagement process that a RIT-T proponent must follow to consult with registered participants, AEMO and interested parties on the project.[65] The three stage consultation process involves:[66]

1. **A project specification consultation report:** the RIT–T proponent must make the consultation report available to all registered participants, AEMO and interested parties and invite submissions.
2. **A project assessment draft report:** if a RIT–T proponent decides to proceed with the proposed transmission investment, it must prepare a draft report ***within 12 months*** after the consultation period on the consultation report (or a longer period agreed to by the AER writing).[67] This draft report can be included as part of a TNSP's annual planning report. As with the consultation report, the RIT–T proponent must make the project assessment draft report available to all registered participants, AEMO and interested parties and invite submissions. While the NER provides a timeframe within which the

65 NER clause 5.16.4.

66 AER, Draft regulatory investment test for transmission application guidelines, July 2018, Chapter 4.

67 A RIT-T proponent can skip this consultation step if the capital cost of the project is less $38 million (as varied under NER clause 5.15.3(b)(5).

project assessment draft report must be published, TNSPs can complete this stage in less time if they wish to.

3. **A project assessment conclusions report:** the conclusions report must be publishedas soon as practicable after the consultation period for the draft report. The RIT–T proponent must make available its conclusions report to all registered participants, AEMO and interested parties. A RIT-T proponent can include the conclusions report as part of its annual planning report.

A number of parties, including registered participants, the AEMC, AEMO and connection applicants, are able to raise a dispute in regard to defined components of the conclusions set out in the project assessment final report published at the conclusion of a regulatory investment test process.[68] The dispute has to occur within 30 days of publishing the conclusions report. The AER has to make a determination either rejecting the dispute or publishing a determination setting out whether the network business will be required to amend the conclusions report within 40 days of the receipt of the notice.[69] The AER may only require amendment where it finds that the RIT-T proponent has:

- Not correctly applied the RIT-T in accordance with the NER
- Erroneously classified the preferred option as being for reliability corrective action
- Not correctly assessed whether the preferred option will have a material inter-network impact
- Made a manifest error in calculations.

There have only been two disputes to the RIT (distibution rather than transmission) process so far. One of these disputes is still ongoing, and in the other the AER determined no amendment was necessary.

While the AER is not required to approve the outcome of a particular RIT-T, it can review whether the appropriate process was followed by the TNSP in identifying the preferred option for investment, including whether a manifest calculation error occurred.

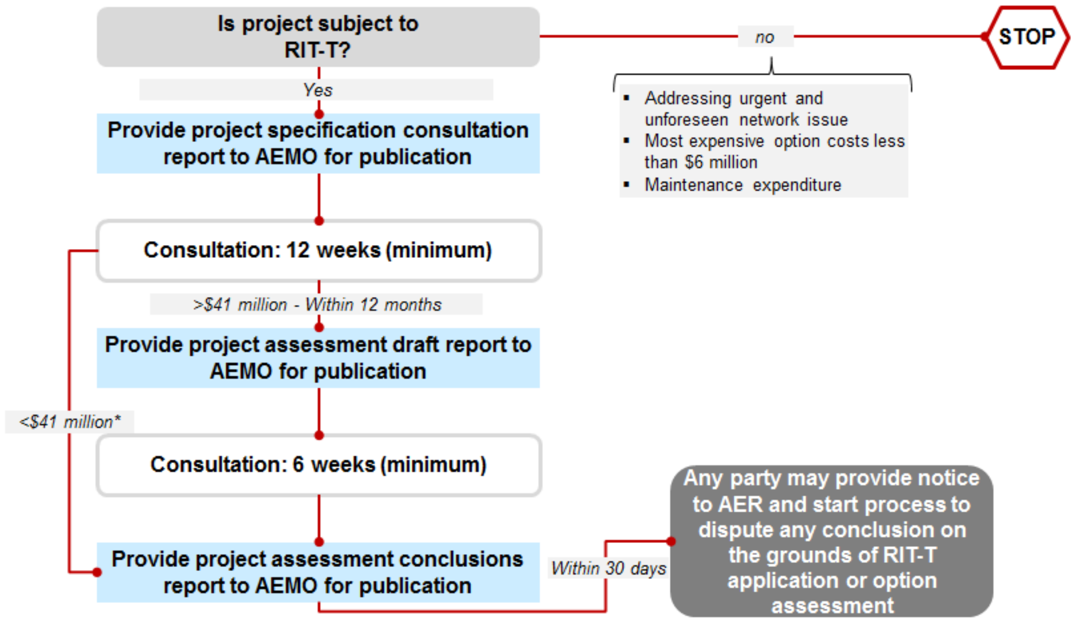
In the broader context of the economic regulatory framework, the RIT-T, including how it was applied by the TNSP, informs the AER about the merits of proposed capital expenditure projects and the efficiency of the proposed capital expenditure.

Figure 5.1 summarises the RIT-T consultation process, and table 5.2 provides an overview of the RIT-T steps that must be included at each stage of the consultation process.

68 The defined components that can be disputed our set out in NER clause 5.16.5(a).

69 Although the timeframe for the AER to consider a dispute can be extended by an additional period of up to 60 days.

Figure 5.1: The RIT-T process



Source: AEMC, rule determination, *National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 65.
Note: Other requirements are: no material market benefit, the TNSP has identified its preferred option in the consultation report, and submissions on the consultation report did not identify any additional credible options which could deliver a market benefit.

Table 5.2: Steps involved at each stage of the RIT-T process

PROJECT SPECIFICATION CONSULTATION REPORT	PROJECT ASSESSMENT DRAFT REPORT	PROJECT ASSESSMENT CONCLUSIONS REPORT
Description of **identified need** and underlying assumptions	Description of each assessed **credible option**	Set out the matters detailed in the project assessment draft report, and make necessary revisions
Technical characteristics of **identified need**	Summary of **submissions to the project specification consultation report**	Summary of, and RIT-T proponent's response to, **submissions to the project assessment draft report**
Description of all **credible options**	Breakdown of operating and capital expenditure, and material market benefit for each **credible option**	

PROJECT SPECIFICATION CONSULTATION REPORT	PROJECT ASSESSMENT DRAFT REPORT	PROJECT ASSESSMENT CONCLUSIONS REPORT
Technical characteristics of each **credible option**	Description of methodologies used in quantifying each class of material **market benefit and cost**	
Whether each **credible option** has a material inter-network impact	Net present value analysis of each **credible option**	
Classes of immaterial network options and justification for each **credible option**	Identification and technical characteristics of **preferred option**	
Construction timetable and commissioning date for each **credible option**	Construction timetable and commissioning date for **preferred option**	
Indicative capital and operating and maintenance costs for each **credible option**		

Source: NER clause 5.16.

5.3.3 Determining network revenues

Following the conclusion of the RIT-T process, the TNSP would then seek revenues to recover its expected costs of the preferred RIT-T option, which in most cases would have positive net economic benefits. These revenues must be approved by the AER (see discussion in the next section). The AER would only permit the TNSP to recover revenues which it considers to be prudent and efficient. Until these revenues are approved the TNSP would not usually commence work on the preferred option.

In the case of the Powering Sydney's Future project, the revenues were included as part of the TransGrid regulatory proposal submitted in January 2017 for the regulatory period 2018-23. An AER decision on this proposal was made in May 2018. In the case of the Heywood interconnector upgrade this occurred as part of a contingent project process part way through a regulatory period, which had the effect of adjusting ElectraNet's revenue allowance for that period.

Steps for the AER to approve network revenues

The time for the AER to approve network revenues depends on whether the timing of the regulatory process aligns with a revenue determination for the relevant business.

Flow diagrams that illustrate the two processes below are included in Appendix A.

Steps where Process DOES align with Revenue Determination ("Standard process")

In this case the business includes the relevant project in its general revenue proposal in respect of the relevant five year regulatory period. The revenue proposal is submitted approximately 18 months before the start of the period and the AER's final revenue determination is made two months before the start of the regulatory period. Where a RIT has been undertaken or is in the process of completion, the AER will assess the analysis undertaken in the RIT process to inform its final revenue determination.[70]

In some cases the RIT-T will be completed during the revenue proposal process. In this case the AER will still endeavour to take the RIT outcomes into account in its final determination. While this is not the ideal process, having the RIT submitted after the start of the process will have the effect of shortening the time between completion of the RIT and approval of the related network revenues.

Steps where Process DOES NOT align with Revenue Determination ("Contingent project")

A contingent project is a project which is identified at the start of the relevant regulatory period as likely to be subject to a RIT during the regulatory period. Where the RIT is completed during the period and the relevant project is the preferred option under the RIT, the AER usually requires that it (the AER) is satisfied that the RIT has been successfully completed, including the relevant project is the preferred option under the RIT. If this occurs, and where relevant other aspects of the trigger event have been satisfied (e.g, committed generation connection on relevant parts of the network), the AER then commences a contingent project determination. This determination sets the capital expenditure that is to be added to the existing revenue determination, and adjusts the business's revenues accordingly.

For the contingent project trigger event to be satisfied for most contingent projects that the AER has approved in recent revenue determinations, the AER will need to be satisfied that the RIT-T has been successfully completed before a TNSP submits a contingent project application.

After that, the AER has 40 business days from when it receives a contingent project application under the NER to make a contingent project determination on the network revenues. This can be extended by an additional 60 business days in complex cases. As part of this process the AER is required to invite submissions from interested parties.

5.3.4 RIT-T timing

As described above, RIT-Ts are undertaken by a network business in a separate process from the AER's approval of network revenues. In general, the transmission business will not commence work on a project until the AER approves the relevant network revenues. The regulatory process for obtaining approval of a transmission investment under the NER therefore comprises:

1. those steps that form part of the RIT-T; and

70 It is not always the case that a RIT has been completed before a revenue proposal is submitted to the AER.

2. those steps that are needed for the AER to approve the relevant network revenues.

RIT-Ts are driven by TNSPs, and the time taken to complete the RIT-T process is a function of the analysis that is undertaken. Working up options for investment – including non-network options – to meet the identified need takes some time. In addition, market modeling must be undertaken to compare the market benefits of each option by looking at market outcomes. Assumptions must be finalised, and the options worked through.

A key function of the RIT-T is that it creates transparency and confidence in the regulatory process by seeking stakeholder input. The RIT-Ts can be technically complex and require specialist engineering, energy market and modelling expertise to provide informed feedback. Stakeholders may need to work with consultants to do this.

Appendix A details the timeframes of seven RIT-Ts that have been completed to date, the breakdown of time between consultation and preparation of reports in completed RIT-T processes, and examples of timelines for AER revenue determinations after RIT-Ts have been completed.

Decisions about policy settings must also be made in order to generate accurate models. The more these policy settings shift around, the more difficult this is. ElectraNet identified policy uncertainty, including the development of the ISP and South Australian government policy changes, as the main driver of the time it took to go from publishing its consultation paper to publishing its draft report for the South Australian Energy Transformation project.

The Heywood interconnector process took over two years from consultation report to approval of the contingent project revenues. For the RIT-T process itself, the longest stages were the preparation of the draft and final reports. In addition, there was 14 months following the RIT process being finalised before the network revenues were approved which involved the AER coming to a view on the preferred option and the appropriate level of network revenue.

In terms of the time it takes for the AER to set revenues that relate to the project, where the standard process is followed there is a set time frame which applies regardless of the projects being considered. However, in the case of contingent projects such as the Heywood upgrade, the AER may be more comfortable with the RIT-T outcomes if it was fully involved during the RIT-T process and the outcomes reflect any AER feedback, however in most cases the TNSP does not facilitate this occurring.

5.4 RIT-T process and the ISP

As noted in the previous Chapter, depending on how the ISP is made ‘actionable,’ there will be consequences for the RIT-T process e.g. it could change the nature of the RIT-T test. The options for strengthening the links between the ISP and the transmission investment decision process discussed in Chapter 4 have varying implications for the way the current RIT-T operates. At a minimum, some of the initial RIT-T steps, such as those listed at the beginning of the left-hand column in table 5.2, could be completed as part of the ISP process. Moving along the spectrum of how to make the ISP ‘actionable’ to the process described for option 5 in Chapter 4, the RIT-T could be replaced by a comprehensive consultation and cost-benefit analysis as part of the ISP to identify the most efficient option for investment. This end of the spectrum would result in the ISP development process being significantly expanded to include the market benefit assessment that the RIT-T currently provides.

The current objective of the ISP is to identify investments in the transmission network that can best unlock the value of existing and new energy resources at the lowest cost, while also delivering reliability to consumers. The objectives of the RIT-T in the current framework, as outlined in table 5.3, are centred on avoiding inefficient regulated investment, paid for by consumers, in new transmission assets in the NEM. The modelling undertaken for the inaugural ISP sought to find the optimal mix of gas and electricity infrastructure investment and operation which meets the future needs of the NEM at lowest cost for consumers – an engineering optimisation at lowest cost exercise. Analysis undertaken for a RIT-T seeks to identify the credible transmission investment option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the relevant market – a process that weighs the benefits of a particular investment against the costs.

These processes have been designed to achieve different things - the ISP is a strategic infrastructure development plan, while the RIT-T replicates investment outcomes for defined projects in a competitive market environment. The objectives of the RIT-T, and how they are achieved, are set out in table 5.3.

Table 5.3: **RIT-T objectives**

RIT-T OBJECTIVE	WAY IN WHICH RIT-T ACHIEVES OBJECTIVE
Reduce the risk that consumers will pay for inefficient investments (i.e. address the harm of TNSPs overinvesting).	• Getting TNSPs to perform a cost-benefit analysis before making major investment decisions. • Public consultation with the potential for AER to resolve disputes.
Promote competitive neutrality (i.e. address the harm of TNSPs using their monopoly position to take solutions in-house, thereby limiting the ability for the contestable market to deliver competing solutions to network needs).	• TNSPs consider all credible options to meet the investment need before making a major investment decision. • Public consultation that includes requesting third party solutions, as well as potential for AER to resolve disputes.
Reduce investment uncertainty in contestable markets caused by inefficient investments undermining existing generation and thereby harming future wholesale market development (i.e. address the harm caused by relatively unpredictable uneconomic investments).	• Reducing potential for inefficient investments.

Under any of the options for making the ISP actionable described in Chapter 4, the Commission considers that the role the RIT-T fulfils in protecting consumers from inefficient investment should not be diminished. Under any of these options, the principles of considering multiple potential options and weighing the market benefits against the costs for each of them, to ultimately protect consumers from inefficient investment, need to be present. Along with these principles, extensive and meaningful consultation throughout the planning and investment decision process, needs to be a key feature of a framework that makes the ISP 'actionable.' The Commission considers that this comprehensive consultation, especially in the early stages, will assist in streamlining the whole process, achieving buy-in from key stakeholders and reducing the likelihood of disputes being made against an identified 'preferred option.' As discussed in Chapter 4, changes to the way the current RIT-T operates would require amending the NER.

However, even in the absence of these considerations, stakeholders have expressed concerns with the speed and scope of the existing RIT-T process. Specific issues that have been highlighted are that it takes too long, it is not able to consider the benefits that strategic projects provide to the NEM as a whole, and that it requires too many credible options to be considered. The Commission considers that the outcomes that have led to these types of concerns may have more to do with the way the RIT-T has been applied, rather than problems with the RIT-T itself. However, given that we are working through how to strengthen the links between the ISP and the transmission investment decision process, the opportunity to consider whether there may or may not be ways to improve the current RIT-T process has been created.

The section below explores feedback that has been received on potential limitations with the RIT-T's operation in the current regulatory framework. The feedback focusses on issues with the RIT-T that may require rule changes; other issues with the current RIT-T process are being considered through the AER's review of the application of the RIT guidelines.

5.5 Potential concerns with the RIT-T

We have received feedback on the application of the RIT-T, both in stakeholder submissions, but also in informal consultation with stakeholders. These are summarised below:

- Several submissions stated that the RIT-T in its current form and application is not suitable for the type of "strategic investment" that a REZ is likely to present.[71]
- We have heard from some stakeholders that it is difficult to narrow down an appropriate amount of credible options and some more guidance may assist in determining what an appropriate number of credible options are.
- Similarly, we have heard from some stakeholders that while in theory, the RIT-T should consider system wide benefits, in practice, given the high amount of uncertainty and change in the electricity sector, this is difficult to achieve. This concern appears to be driven by the fact that typically RITs are undertaken by a single transmission business. However, for consideration of interconnectors, RIT-Ts have typically been conducted

71 Submissions to discussion paper from ENA, TransGrid, UPC Renewables, Powerlink, CEC and Snowy Hydro.

jointly by neighbouring TNSPs. Further, the recent TCAPA Rule put in place joint planning arrangements for neighbouring TNSPs and established requirements for transmission businesses to consult with each other. It would be useful to understand whether these changes mitigate these concerns, or whether it is unlikely that a TNSP would be able to generate and compare options across the NEM.

- Some stakeholders consider that transmission businesses have a potential bias against non-network options. The AEMC investigated the potential for a capex bias in its *Economic Regulatory Framework Review* 2018. The AEMC did not find "conclusive empirical evidence" of a capex bias, but its financial modelling showed the "incentives between capex and opex are not aligned as they vary depending on individual circumstances". The AEMC expects to work on rule changes that better align capex and opex incentives. The AER's TAPR Guideline, which was implemented in the TCAPA Rule, should also promote consistency on information provided on non-network options between TNSPs and so may assist in this regard.
- Some stakeholders have raised concerns about the scope of market benefits that may be taken into account, specifically that it doesn't include benefits that might be experienced outside the NEM. As noted above, while there are a narrow set of benefits defined in the NER, the AER can sign off on other benefits being taken into account provided they relate to the benefits for those who consume, produce and transport electricity in the NEM.
- Others have raised concerns about the length of the process, and the potential for disputes to elongate the time associated with a RIT. However, it is worth noting that most of the time delays associated with infrastructure build are associated with planning and environmental approvals which are clearly outside the scope of the regulatory framework. Further, the chance of a dispute can be minimised the more involved stakeholders are earlier in the process.

It is also worth noting that some stakeholders were in favour of the existing RIT, for example, AGL noted in its submission that, while it needs improvement, the RIT-T "remains, in its current form, the best mechanism to protect consumers and balance out investment risks."[72] Building on this view, the Australian Energy Council (AEC) stated in its submission that market forces should determine the most efficient means by which generation can connect and supply demand, and that the economic principles underpinning the RIT-T should continue to be followed.[73]

QUESTION 13: POTENTIAL CONCERNS WITH THE RIT-T PROCESS

A) What are stakeholder views on current limitations with the RIT-T process?

B) Setting aside the ISP and how to make it more "actionable," what other issues warrant

72 AGL, submission to discussion paper, Coordination of generation and transmission investment, 22 May 2018, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

73 Australian Energy Council, submission to discussion paper, Coordination of generation and transmission investment, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

attention when considering the objective of the RIT-T?

C) What changes may make the existing RIT-T process "faster"?

D) What is the role of a dispute process in the RIT-T? How could spurious disputes be minimised?

6 RENEWABLE ENERGY ZONES

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment by focussing on the option of the development of REZs. It was envisaged that these REZs would facilitate the connection of new renewable generators to the transmission network. The discussion paper published as part of this review sought to highlight what the regulatory and framework implications might be for facilitating the development of transmission assets to facilitate specific zones for generators to connect to in those regions that are rich in renewable energy resources.

The Commission sought feedback from stakeholders on the definition of a REZ and potential options for connecting more renewable generators to the transmission network in a way that protects consumers from inefficient investment in transmission infrastructure. The Commission also sought stakeholder input on what other options or changes to the regulatory framework would help to coordinate the connection of renewable energy generators to the transmission network in a way that protects consumers from inefficient investment.

Since publication of the discussion paper in April 2018, AEMO published the inaugural ISP. As outlined in Chapter 4, the ISP identified a pathway for developing the transmission network, detailing three groups of projects with the groupings based on the timing of the need and the scale and time it would take to construct these identified projects. Broadly, AEMO set out that the existing transmission network provides the capability to efficiently connect considerable renewable generation.

The second group of transmission investment projects outlined in the ISP includes developments in the medium-term to increase trade between NEM regions, provide access to storage and support the development of REZs. The REZs identified for development in the ISP "do not conform to the stereotype of long network extensions to remote locations," and the transmission augmentations identified in the ISP would encourage renewable generators to connect to the transmission network in areas with existing capacity.[74] The identified REZs are largely located along the path of proposed new interconnectors, which is consistent with the current transmission framework where generators only pay for the direct costs of connecting them to the network.[75]

However, AEMO also noted that to connect renewable projects beyond the current transmission capacity, further action will be needed.

The Commission considers that the publication of the ISP allows for consideration of REZs in a more tangible light. In addition, given Chapter 4 considers how to convert the ISP into an actionable strategic plan, consideration of REZs must be undertaken in that context. The ISP has shown that some of the REZs identified are on interconnector flowpaths, and so will be assessed through any RIT-Ts that are undertaken on those investments.

74 AEMO, *Integrated System Plan*, July 2018, p.87.

75 Aside from those costs associated with mitigating system strength issues, as detailed in Chapter 2.

Therefore, the discussion in this chapter focusses on considering REZs that are not either: a) nationally strategic transmission flow path projects (and so identified in the ISP) or b) other shared tranmission projects that would be justifiable under the RIT-T and so are projects consumers would pay for.

In other words, the concept of REZs considered here focus only on different models for how, in an open access framework, generators can get scale efficiencies from connection assets.

In this context, the Commission considers that the discussion of REZs and how they might be facilitated is secondary to the issue of how stronger links could be created between the ISP and transmission investment decisions. Depending on how the ISP is made actionable, the subsequent implications for the facilitation of any REZs in the NEM will be different.

This chapter discusses the spectrum of options for REZ facilitation presented in the discussion paper, whether they could be implemented under the current rules and existing open access framework, and how they align with options for the role of the ISP and how it could fit into the regulatory framework for transmission investment decisions discussed in Chapter 4. Given the above framing of REZs, the Commission notes that the majority of REZ models proposed by stakeholders are based on the assumption that a fully utilised transmission asset that connects generation should be paid for by customers. However, full utilisation by generation is not sufficient to make the argument for customers paying for this investment. This illustrates the challenges of considering REZs given that the REZ concept itself blurs the boundaries of what are shared transmission and what are dedicated connection assets.

6.1 What is a REZ?

In the ISP consultation paper, AEMO defined REZs as "areas in the NEM where clusters of large-scale renewable energy can be developed to promote economies of scale in high-resource areas and capture geographic and technological diversity in renewable resources." AEMO went on to note that an efficiently located REZ can be identified by considering a range of factors, primarily: the quality of its renewable resources (wind or sun) and the cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers.

The large majority of stakeholder submissions to the discussion paper commented on REZs and the role they could play in coordinating transmission network planning and renewable generation investment.

Overall, submissions to the discussion paper were supportive of the broad concept of REZs as a way to connect more renewable energy generators to the existing transmission network in a cost-efficient way that benefits consumers. The Clean Energy Council (CEC)[76] stated that:

> *"...the concept of REZs...has the potential to support the investment in energy generation required to achieve a future NEM that is reliable, secure, low emissions and affordable. REZs could benefit the market by increasing economies of scale and*

76 Clean Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

> *improving efficiencies in generation output. If REZs are well-planned, communities could benefit from development and investment that is strategically located in respect to towns and communities."*

In its submission, AGL also in-principally supported "the concept of clustered intermittent generation within designated REZs as an integral way of unlocking the value of these assets and meeting Australia's international climate change obligations."[77] AGL did note, however, that "further consideration and a cautious approach is necessary to ensure the design, development and regulatory frameworks governing REZs deliver net benefit to consumers, whilst appropriately supporting the REZ investments."[78]

In its submission, TransGrid supported "the strategically planned connection of large scale energy zones, supported by greater interconnection, to provide consumers with the lowest priced energy and system security as ageing coal power stations retire from the market."[79] However, TransGrid contended that "relying on the existing market-led approach to generation and transmission planning will not deliver a reliable or low cost outcome for consumers in the timeframes in which existing thermal generation will retire."[80]

In contrast to the views expressed in submissions that were supportive of REZ development, the AEC questioned the need for REZs, stating that "current arrangements must be satisfactory as almost 40,000MW of renewable generation is proposed for connection to the existing grid." The AEC further stated that if material congestion develops after these connections, "the existing RIT-Ts will remove the congestion where it is efficient to do so."[81]

Across submissions, the view was expressed that consumers should not bear undue risk in whatever model might be adopted in the development of REZs. In its submission, the Public Interest Advocacy Centre (PIAC) stated that "checks and balances are required to ensure that the risk of under- or over-investment is not put unfairly onto consumers."[82] Aurizon stated there should be "thorough understanding of the true cost of energy paid by energy consumers that is reconciled with its consistency with the NEO before major investment occurs."[83] ERM Power noted in its submission that "unnecessary network infrastructure has at times been constructed with costs passed through to consumers where the assumptions used to justify the investment have proved to be inaccurate…this risk would be best borne by the party responsible for the accuracy of the original assumptions".[84]

77 AGL, submission to discussion paper, *Coordination of generation and transmission investment*, 22 May 2018, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

78 Ibid.

79 TransGrid, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.4. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

80 Ibid.

81 Australian Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

82 Public Interest Advocacy Centre, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.6. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

83 Aurizon, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

84 ERM Power, submission to discussion paper, *Coordination of generation and transmission investment*, 17 May 2018, p.5. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

Offering an alternate approach to coordinating the connection of an increasing number of renewable generators, a number of network businesses suggested that distribution should be considered as a cost-effective way of increasing the capacity of renewables in the NEM.[85] Highlighting a key consideration in the connection of intermittent generation to the network, the CEC stated that the AEMC should outline how system strength requirements will impact the success of REZs and provide assurances for their viability.[86]

In the discussion paper, the Commission sought feedback from stakeholders on the definition of a REZ. A number of submissions addressed this question, with the key characteristics of a REZ identified by stakeholders being that they feature high quality renewable resources where economies of scale can be achieved with transmission infrastructure investment.[87] The Chamber of Commerce and Industry South Australia (Business SA) endorsed the use of ElectraNet's transmission investment on the Eyre Peninsula as an example of a REZ, noting that it takes into account the potential future benefit of increased generation capacity.[88] In its submission, the University of New South Wales supported the definition of a REZ outlined by AEMO in its ISP consultation paper, and suggested that the AEMC consider the technical aspects of transmission expansion and how these impact on available options, as well as the economic factors.[89]

6.2 REZ options

Given the broad definition of REZs, variations of each of the above options for REZs can be delivered under the current framework, depending on whether the services provided by the REZ are classified as connection services or prescribed transmission services. We set out our views on this below.

In the discussion paper, the Commission presented four examples which we considered were indicative of a range of REZ models or definitions. These are outlined in Table 6.1.

These have been refined and developed following stakeholder consultation on the discussion paper, with each discussed in turn below. We have also considered these options in light of the ISP published by AEMO; and the consistency with the various ISP options identified in the previous chapter.

85 CitiPower, Powercor and United Energy, submission to discussion paper, *Coordination of generation and transmission investment*, 17 May 2018, p.1. TransGrid, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.4. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

86 Clean Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

87 Australian Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2. TransGrid, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.4. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

88 Business SA, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

89 University of New South Wales, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.1. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

Table 6.1: **Summary of the range of options for REZs**

OPTION	OPTION 1: ENHANCED INFORMATION PROVISION	OPTION 2: GENERATOR COORDINATION	OPTION 3: TNSP SPECULATION	OPTION 4: TNSP PRESCRIBED SERVICE
Features	Enhanced AEMO and TNSP coordinated planning to signal REZs for development by the market	Generators connecting in the same area coordinate connections	TNSPs undertake speculative investment to build the REZ	TNSPs invest to deliver a prescribed service in anticipation of generators connecting
Who pays?	Same as now	Generators	TNSPs - but if generators connect in the future, costs would be recovered from consumers	Consumers
Who bears the risk?	Same as now	Generators	TNSPs - they would be rewarded if generators connect in future	Consumers - including facing the stranded asset risk
Changes to the existing framework	Minimal	Minimal - but larger coordination issues exist	Moderate	Substantial

While stakeholders expressed support for the concept of REZs, submissions to the discussion paper included differing views on how their development might occur. Although the potential options for REZs presented by the Commission were not designed to be final models or solutions to an evolving challenge, they did serve to highlight regulatory and framework issues that would likely arise and need to be considered and addressed depending on the circumstances of a particular REZ.

6.2.1 Enhanced information provision

The first option presented in the discussion paper was characterised by enhanced AEMO and TNSP coordinated planning to provide information to market participants on potential REZs for development by the market. The release of AEMO's ISP is consistent with our finding in the discussion paper that this option can already be accommodated under the current regulatory framework.

Stakeholders expressed support for this enhanced information provision option for defining a REZ. The value of additional information in assisting with the coordination and facilitation of investments, and the ability of relevant parties to make informed investment decisions was noted as the strength of this option. While viewed as valuable, stakeholders also noted that enhanced information provision to the market may not be enough to incentivise the coordinated investment necessary to develop REZs. A more detailed outline of stakeholder comments on this option is provided at Appendix B.1.

Under current arrangements

There are already a number of existing processes underway to provide better information to generators about where to connect:

- The ISP has provided information on optimal REZ development areas, which are supported by existing transmission capacity and system strength. The ISP sets out more information to prospective connecting parties about where a good location to connect is (i.e. favourable resources, avaliable land, and spare network capacity)
- This will be supported by the AER's TAPR Guideline, that the AER is currently developing, which aims to support the consistent provision of information by transmission businesses across the NEM. The TAPR Guideline will provide generators and large transmission customers useable and consistent information that they need to make informed connection decisions
- AREMI is a spatial data platform for the Australian energy industry that provides information to generators about capacity on transmission networks.

Therefore, the Commission views that the provision of strategically coordinated information on where and when transmission infrastructure investment will be required to facilitate the entry of new renewable generation is already provided.

This view was supported by several stakeholder submissions to the discussion paper. Submissions supporting REZs acknowledged that some degree of coordinated planning or information provision will be required in order to facilitate them, identifying the ISP as a suitable tool in this process. Snowy Hydro expressed support for "an ISP for the NEM transmission network which identifies REZs across all NEM regions and identifies transmission network routes to efficiently connect the REZs to the existing transmission infrastructure."[90] Snowy Hydro also stated that "AEMO and TNSP's should continue to coordinate and provide information to market participants about where (are) good places to connect, preferably through AEMO's ISP."[91] In its submission, AGL stated that it values the ISP "as a guidance document that examines the interconnected NEM and, to the extent that new investment is required, ways to improve the efficient development and connection of REZs."[92]

90 Snowy Hydro, submission to discussion paper, Coordination of Generation and Transmission Investment, 18 May 2018, p.1. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

91 Ibid.

92 AGL, submission to discussion paper, Coordination of Generation and Transmission Investment, 22 May 2018, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

Consistency with ISP options

This option for enhanced information provision could occur under any of the options discussed in Chapter 4 for making the ISP "actionable". Facilitating REZs through enhanced information provision to the market would be consistent with each of the options for the role of the ISP as they have been described. The identification of potential REZs in the ISP, along with the recommended transmission pathways for development, provide the market with information about where AEMO recommends REZs should ideally be developed.

Regardless of what option is pursued, more information would be provided to the market to inform the development of REZs. The key difference for making further changes to allow for this option would be based around making the various planning processes consistent about how information about potential REZs is provided to the market. As planning progresses from longer-term, to shorter-term planning, the granularity of the information that can be provided to prospective connecting parties about where a good location to connect would be (i.e. favourable resources, avaliable land, and spare network capacity) changes.

> QUESTION 14: ENHANCED INFORMATION PROVISION
>
> A) Do stakeholders agree with our conclusions for how this can occur under current arrangements?
>
> B) Do stakeholders agree that this option is consistent with the ISP options? What other considerations should be taken into account?

6.2.2 Option 2: Generator coordination

The second option for developing REZs presented by the Commission in the discussion paper involved generators coordinating to construct and build REZs. The development of REZs under this option is possible under the current NER.

Under current arrangements

The *Scale Efficient Network Extensions* (SENE) Rule made by the AEMC in 2011 requires transmission businesses to undertake and publish, on request, specific locational studies to reveal to the market potential opportunities for efficiency gains from the coordinated connection of expected new generators in a particular area. The study is designed to help potential investors make informed, commercial decisions to fund a SENE, having weighed the potential gains from coordinated, efficient generator connection arrangements against the potential costs of assets not being fully used. Decisions to fund, construct, operate and connect to a SENE would then be made by market participants and investors within the existing framework for connections in the NER.

In addition, the recent TCAPA Rule further facilitates this option. The TCAPA Rule made in 2017 introduced greater contestability for the design, construction and ownership of assets on the transmission network used for connection. Allowing parties other than the TNSP to construct connection assets would more easily allow generators to coordinate through either themselves, or a third party.

In its submission to the discussion paper, Ausgrid suggested a 'Pioneer Scheme' whereby renewable generators at REZ locations fund the cost of network augmentations.[93] Renewable generators seeking to connect to part of the network funded by another generator within a certain period of time would make a 'Pioneer Scheme' payment that would be passed on to that generator. Ausgrid, along with some other distributors in the NEM, currently operate this type of scheme for new load connections.[94] Ausgrid stated that this approach may lead to more efficient procurement of network infrastructure because the opportunity to recover a 'Pioneer Scheme' payment may incentivise generators to fund an augmentation that is sized to meet the capacity of future generation, unlocking the economies of scale required for efficient network investments.[95] This type of framework is possible under the changes introduced by the TCAPA Rule.

Although the current NER allow the development of REZs by generators coordinating, this will only occur if generators actually cooperate by sharing information in order to enable coordination of connections and investment in connection assets. While noting that there would be considerable efficiencies achieved if generators coordinated their connections, stakeholders overwhelmingly concluded that competitive tensions and commercial challenges act as a disincentive for generators to facilitate coordinated connections to the transmission network. Such issues were evidenced in TransGrid's consideration of the New England renewable energy hub. More importantly, these issues can not be addressed by the regulatory framework.

A more detailed outline of stakeholder comments on this option is provided at Appendix B.2.

Consistency with ISP options

Similar to the enhanced information provision, this option could work with all ISP options discussed in chapter 4.

However, while this option is not inconsistent with any of these options for strengthening the link between the ISP and transmission investment decisions, we do not consider that the commercial hurdles would necessarily be overcome in order for REZs to be developed through generator coordinated connections and so propose not to consider this option further.

QUESTION 15: GENERATOR COORDINATION

A) Do stakeholders agree with our conclusions for how this can occur under current arrangements?

93 Ausgrid, submission to discussion paper, Coordination of generation and transmission investment, 23 May 2018.

94 Ibid.

95 Ibid.

B) Do stakeholders agree that this option is consistent with the ISP options? What other considerations should be taken into account?

6.2.3 Option 3: TNSP speculative investment

The third option for developing REZs presented by the Commission in the discussion paper suggested that TNSPs make speculative investments using their own profits, not regulated revenue, to facilitate a REZ. That is, shareholders of TNSPs would bear the risks associated with a REZ.

Under current arrangements

Under current arrangements TNSPs could make speculative investments; however, they would be exposed to the risks associated with this. Therefore, it is unlikely that TNSPs would make such an investment. These issues were explored by TransGrid in their assessment of a renewable energy zone for New England.[96]

Potential change to the framework

As noted in the discussion paper, the existing arrangements could be changed to allow TNSPs to recieve a regulatory allowance to the extent that such assets are being used to provide prescribed transmission services.

This would be similar to the mechanism for speculative investment set out in the National Gas Rules (NGR). In the NGR, there is a mechanism that allows full regulation pipelines to undertake speculative investments and to include this expenditure in the capital base when circumstances change. The NGR allow full regulation gas pipelines to create speculative capital expenditure accounts.[97] This speculative expenditure is expenditure that does not conform to the regulator's assessment of what is appropriate at a given point in time but that can subsequently be approved due to changes in volumes or service charges.

As part of the assessment of a gas access arrangement, this non-conforming speculative capital investment can be allocated to a speculative capital expenditure account. If, as a result of changes to volumes or service charges, the expenditure would become approved, the relevant portion of the speculative capital expenditure account (including a return that is approved by the regulator) can be rolled into the capital base at the commencement of the next access arrangement period. This would then allow the capital cost to be recovered through reference tariffs in the future.

In the Commission's recent *Review into the scope of economic regulation applied to covered pipelines*,[98] the Commission considered that these existing arrangements could be modified to provide greater certainty on the rate of return that can be set by a regulator for speculative

96 TransGrid, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018.

97 Rule 84 of the NGR.

98 See: https://www.aemc.gov.au/markets-reviews-advice/review-into-the-scope-of-economic-regulation-appli

capital expenditure while still providing the regulator with the flexibility to take into account, where appropriate, the specific circumstances of speculative investment.[99]

Stakeholder submissions to the discussion paper noted that there is merit in TNSPs bearing some of the risk associated with REZ development as they are in a position to promote efficiencies in investment decisions, and should be able to enjoy the benefits of such efficient investments. The Commission considers that, under the current regulatory framework, TNSPs are able to undertake the type of speculative investment described in this option, although without the increased rate of return. Setting a higher rate of return for speculative investments would require a change to the current regulatory framework.

Concerns raised by stakeholders centred on exactly how decisions deemend to be efficient would be recovered from consumers, including how a higher rate of return for the investing TNSP would be set. Whether the regulatory settings could be accurately determined to incentivise TNSPs to take on the risk associated with such an investment was also raised in stakeholder feedback as a significant issue that would require detailed assessment. Stakeholder feedback on this option is detailed in Appendix B.3.

The Commission agrees with stakeholders that the benefits to consumers of a TNSP speculative investment type of model would have to be demonstrated. Efficiencies achieved through the oversizing of infrastructure would have to be weighed against the higher rate of return delivered to TNSPs to incentivise the anticipatory network augmentation. Whether the appropriate balance could be achieved has not yet been further considered by the Commission at this stage.

One way of managing this risk would be to incorporate ENGIE's suggestion to the discussion paper, whereby a TNSP would issue transmission bonds of sufficient value to underwrite a transmission infrastructure project, based on the estimated costs.[100] Generator project proponents could choose which transmission projects they would like to underwrite through purchasing bonds. ENGIE explained that this choice would allow them to optimise their investment decisions by weighing up the relative costs and opportunities associated with different REZs.[101] ENGIE's model proposed that when generator project proponents have chosen a particular REZ that they wish to locate at they can underwrite the required transmission investment that is needed to develop this REZ through the purchase of a transmission bond.[102] The use of bonds that are available to generator proponents is a market-based means of gauging if there is sufficient interest in a given transmission investment to justify it going ahead. Crucially, it does not depend on generators, who are in competition with one another, coordinating their actions. Rather, the decision to secure bonds for a given investment is made by each generator individually.[103]

99 Recommendation 15 was to clarify in the NGR that "the rate of return to be applied to a speculative capital expenditure is, at a minimum, the return implicit in the reference tariff but that this could be adjusted upwards if the regulator deemed it was appropriate having regard to the circumstances of the particular investment." Final report of the *Review into the scope of economic regulation applied to covered pipelines*, 3 July 2018, p.141. See: https://www.aemc.gov.au/sites/default/files/2018-07/Final%20Report.PDF

100 ENGIE, submission to discussion paper, Coordination of generation and transmission investment, 18 May 2018.

101 Ibid.

102 Ibid.

103 Ibid.

The Commission considered whether ENGIE's transmission bonds model could currently be implemented by interested TNSPs and generators in order to fund transmission investment required for the development of a REZ.[104] While the TCAPA Rule introduced contestability into the construction of connection assets, this would not stop an incumbent TNSP or indeed a contestable provider of connection assets from issuing bonds for a shared transmission asset being built to deliver a prescribed transmission service. If the TNSP issued enough bonds to justify investment in the project, it is assumed that it would seek to role the infrastructure into its regulated asset base, and recover the investment from consumers. If an incumbent TNSP issued bonds and was hoping to have the infrastructure providing prescribed transmission services at a later date, the TNSP would need to have the confidence that it could satisfy the AER that the investment should be classified as a prescribed service before issuing the transmission bonds.

Consistency with ISP options

The Commission considers that such an option could be consistent with all the options for the ISP. In particular, while the ISP seeks to identify investments that have overall market benefits for the shared transmission services (i.e for major transmission flow paths); such a model where TNSPs are rewarded for making speculative investment to facilitate generator connections could help to provide opportunities with issues of having more efficient generator connections. The Commission therefore proposes to consider this option further as a potential enhancement to existing arrangements.

QUESTION 16: TNSP SPECULATIVE INVESTMENT

A) Do stakeholders agree with our conclusions for how this can occur under current arrangements?

B) Do stakeholders agree that this option is consistent with the ISP options? What other considerations should be taken into account?

6.2.4 Option 4: TNSP prescribed service

The fourth option for developing REZs presented by the Commission in the discussion paper suggested that the REZs are treated as prescribed transmission services and so TNSPs make these investments on the behalf of consumers to facilitate a REZ. Accordingly, consumers would pay the costs for these investments. Regardless of whether generators do or do not end up connecting to these zones, the assets would be rolled into the TNSP's asset base, and they would receive a regulatory allowance for these assets, paid for by consumers. The Commission considered that under this option, if all REZs were to be funded in this way, amendments to the NER would need to be made to make it clear that certain assets built for the REZ provide prescribed transmission services, and so would form part of the shared transmission network and be paid for by consumers.

104 ENGIE's transmission bond idea is further detailed in Appendix A.5.

Under current arrangements

Under certain circumstances, you could envisage that this could occur under the current arrangements.

The existing RIT-T process does not exclude REZs if the criteria for investment can be met through demonstrating the benefits that would be provided to consumers through a coordinated investment process. An assessment of such an investment should balance both the potential for efficiency to be maximised against the appropriate allocation of the costs and risks of network investments. The purpose of the RIT-T is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the NEM.[105] Therefore, if a TNSP could show that building a spur line out to a collection of new generators would best improve reliability outcomes or provide net benefits, then such an investment could pass the RIT-T and so be built as providing prescribed transmission services. An example of such a test is the recent ElectraNet RIT-T on upgrading the Eyre Pensinsula.

BOX 5: ELECTRANET: EYRE PENINSULA ELECTRICITY SUPPLY OPTIONS

ElectraNet has been actively exploring options to improve the reliability of supply to Port Lincoln, including options to replace or upgrade the transmission lines serving the lower Eyre Peninsula.

ElectraNet's most recent assessment of the line condition indicates that components of the line are nearing the end of their functional life and will require replacement in the next few years. To enable this work, the TNSP has included the replacement of major transmission line components on the Eyre Peninsula as a contingent project in its 2018-19 to 2022-23 revenue proposal to the AER . Alternatively, the full replacement of the line (for example as a double circuit line) may be more cost effective and deliver greater benefits to Eyre Peninsula customers through potentially improving supply reliability and capturing other market benefits.

To take this forward, ElectraNet is undertaking a RIT-T, which is assessing the costs and benefits of alternative network and non-network solutions. In April 2017, five credible options to upgrade the power supply were released publically and since then ElectraNet has undertaken detailed investigations into which will best meet the needs of the Eyre Peninsula and South Australian electricity customers. Following these investigations and assistance from various project stakeholders, ElectraNet argued that the option that delivers the greatest benefits to the community has been identified. The option includes the construction of a new double-circuit 275 kV power line between Cultana and Yadnarie and a new 132 kV double-circuit power line between Yadnarie and Port Lincoln.

ElectraNet stated that this option will provide the Eyre Peninsula with a reliable power supply and the ability to meet future electricity demands and generation capacity from proposed

105 Rule 5.16.1 of the NER.

mining ventures and wind farms respectively. The Project Assessment Draft Report published as part of the RIT-T recognised that while the Eyre Peninsula has strong mining and renewable generation potential, there is inherent uncertainty in relation to when these resources will be developed. In particular, renewable energy developments on the Eyre Peninsula are heavily influenced by both Federal and State-based carbon emission policies and the quality of renewable generation resources in the region. ElectraNet stated that it applied a combination of both wholesale market modelling and 'real option analysis' to address the various uncertainties surrounding future development on the Eyre Peninsula. The Eyre Peninsula RIT-T is the first RIT-T in the NEM to formally estimate 'option value' in relation to options which, for additional upfront cost, provide the flexibility to upgrade network capacity in the future if it is efficient to do so.

A final ruling by the AER on the outcome of the RIT-T process is expected in 2018. If the option is approved, ElectraNet states that it is expected to cost approximately $300 million and would be operational by the end of 2020.

Source: ElectraNet, Eyre Peninsula electricity supply options. See:https://www.electranet.com.au/projects/eyre-peninsula-electricity-supply-options; ElectraNet, submission to the discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3.

In its submission to the discussion paper, ElectraNet provided feedback on its experience of using the RIT-T for strategic transmission investments, including coordination with the ISP, and suggested regulatory improvements to better facilitate these:[106]

> *"The Eyre Peninsula and South Australian Energy Transformation investigations are live examples of how ElectraNet is currently addressing the development of prospective REZs within a RIT-T assessment and progressing priority transmission development options identified in the ISP consultation process.*
>
> *This experience is demonstrating that the current regulatory framework can accommodate the economic assessment of strategic transmission investments, while accounting for the uncertainty of priority REZ locations and allowing for effective coordination with AEMO as it develops its inaugural ISP. This provides for integrated system planning by AEMO, and retains commercial responsibility for network investment and accountability for shared network outcomes with TNSPs.*
>
> *This approach can be further improved under the current framework by allowing the inputs and assumptions considered by AEMO in respect of an ISP identified project to provide a clearer foundation for the purposes of the corresponding RIT-T assessment to be undertaken by the relevant TNSPs. Enhancements to the AER's RIT-T Application Guidelines as a result of its current review can also assist in this regard."*

106 ElectraNet, submission to the discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.4.

Potential future changes

What was envisaged in the discussion paper was that the existing prescribed service model would be applied in all instances of a REZ being developed. While there was some support provided for the TNSP prescribed service option in stakeholder submissions, the majority of feedback cautioned against using this model for REZ development due to the significant risk that consumers would be exposed to from the potential for underutilised transmission assets. In implementing an option that involved TNSPs undertaking speculative investment on behalf of consumers, stakeholders warned that significant mitigation measures would be required to protect consumers from inefficient investment and stranded assets. Stakeholder feedback on this option is detailed in Appendix B.4.

To the extent that speculative investment might be necessary in association with treating REZs as a prescribed transmission service, in its submission to the discussion paper, Ausgrid proposed a prescribed transmission service funding model that would involve network investment risk being shared between customers and the network service provider.[107] For network augmentation to a location rich in renewable energy resources but which may not necessarily have any generation capacity committed to the area, or a designation as a REZ site in the ISP, 70 percent of network investment would be rolled into the network service provider's regulated asset base, which is paid for by consumers.[108] Ausgrid suggested that an ex post review would be conducted into the efficiency of the network investment to determine whether the remaining 30 percent should be rolled into the regulated asset base and recovered from consumers.[109] Ausgrid viewed this risk sharing ratio may strike the right balance between encouraging efficient investment and protecting consumers. It provides certainty to NSPs that they will be able to recover at least 70 percent of the capital expenditure they incur, while not providing an incentive to overinvest given the risk that shareholders could be forced to cover 30 percent of the costs of an inefficient investment.[110]

As the Commission outlined in the discussion paper for this review, a REZ approach that involves the development of the transmission network to influence where new generators should locate is significantly different to the current practice where a new generator connection request drives incremental augmentation of the transmission network. If a transmission investment that will deliver a prescribed transmission service is made on the basis of an expectation that new generation will locate in a particular area of the NEM, consumers will bear the risk that this expectation is wrong and the asset becomes stranded. To facilitate this, including introducing additional protections for consumers such as a generator commitment threshold, would require changes to the existing regulatory framework.

Given this, the Commission does not propose to consider this model further at this stage of the review. It is also worth noting that contemplating a new prescribed transmission services

107 Ausgrid's idea is outlined in more detail in Appendix A.5.

108 Ibid.

109 Ibid.

110 Ibid.

to faciltiate REZs would represent a change to existing transmission access arrangements (discussed further in section 6.3 and Chapter 7).

> QUESTION 17: TNSP PRESCRIBED SERVICES
>
> A) Do stakeholders agree with our conclusions for how this can occur under current arrangements?
>
> B) Do stakeholders agree that this option is consistent with the ISP options? What other considerations should be taken into account?

6.2.5 The clustering approach

The discussion paper also put forward an additional option – the "clustering approach" – whereby TNSPs would establish a 'season' during which connection applications would be accepted, and then would process those connections based on what delivers the most efficient outcome.

There were very few specific comments on this option in submissions to the discussion paper. The remainder of this section sets out the main comments on the option, and the Commission's further analysis of the issues it raises.

Can a clustering approach and transmission connection contestability co-exist?

In its submission to the discussion paper, PIAC saw some value in the clustering option but questioned whether it would be appropriate for the incumbent TNSP to run such a process in light of the recent introduction of contestability for some transmission connection services.[111]

As a result of the TCAPA Rule, from 1 July 2018 the detailed design, construction and ownership of certain transmission connection assets are (subject to certain criteria) services that are open to competition.[112] This means that parties other than the incumbent TNSP are able to bid to provide some services for assets that form part of the shared transmission network, and the costs of those services are recovered from the connection proponent on a purely commercial basis. Previously, these were services that were provided by the incumbent TNSP as negotiated transmission services.

The concern raised by PIAC in its submission was that, under a clustering approach, the TNSP would need to be given discretion to delay or refuse a connection, and that this may provide (or appear to provide) an unfair advantage to the incumbent TNSP over other potential providers of the contestable services. This is because the TNSP (in its regulated capacity) would be making decisions about which connection applications should proceed to development, whilst also potentially having an interest in providing contestable services to those connections.

111 PIAC, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.9.

112 See: https://www.aemc.gov.au/rule-changes/transmission-connection-and-planning-arrangements

To provide contestable services, TNSPs are required to comply with the requirements of their cost allocation methodologies and the transmission ring-fencing guideline. The existing transmission ring-fencing guidelines were developed by the Australian Competition and Consumer Commission in 2002 and are now administered by the AER.[113] These guidelines do not impose any restrictions on a TNSP that provides prescribed transmission services from also providing other (e.g. non-regulated) transmission services. The only restriction is on TNSPs carrying out generation, distribution or retail activities that attract revenue of more than five per cent of the TNSP's total annual revenue.[114] A clustering approach may therefore pose a conflict of interest for TNSPs under the current transmission ring-fencing guidelines, in the absence of stronger separation between the regulated and non-regulated parts of the business.[115]

If ring-fencing is not sufficient to address this potential conflict of interest, it could be addressed by:

- specific regulation of how the TNSP is to conduct its assessment of which projects should proceed to connection in a cluster
- involving a third party in the decision-making process, for example AEMO, the AER or the relevant state/territory government.

However, the materiality of the potential conflict (or perceived conflict) of interest is unknown to the AEMC at this stage. It is not clear whether it would materially affect the competitiveness of the pool of contestable transmission service providers or the price paid by the connecting generator/s for contestable services. The Commission welcomes stakeholder views on this.

Broader issues with the clustering approach

The intended objective of a REZ is to enable the coordination of the development of transmission and generation at the lowest cost. A clustering approach aims to achieve this objective by requiring the incumbent TNSP to assess the transmission augmentations needed, to connect generation projects and coordinate these based on what is most efficient.

The main benefits of a clustering approach appear to be that the risk of not being selected by the TNSP to connect as part of a cluster, and presumably be charged lower connection costs than they would be subject to if they were to connect separately, would incentivise proponents to:

- offer the most efficient solutions, including locating close to other potential connection proponents
- work constructively with the TNSP
- share information and work constructively with other project proponents.

113 See: https://www.aer.gov.au/system/files/Ring-fencing%20guidelines%20only%20-%2015%20August %202002_1.pdf

114 See clause 7.1(a)(ii) of the transmission ring-fencing guidelines.

115 The AER has signalled its intention to revise the transmission ring-fencing guidelines at some stage, but the exact timing of this review is unknown.

However, this approach raises some potential conflicts with the existing transmission connection framework, and other issues that would need to be worked through if it were to be considered further.

Fundamentally, such an approach may be inconsistent with an element of the open access framework that underpins the NEM. Under the existing arrangements, generators have a right to negotiate a connection to the transmission network, and they are able to connect to the network provided that they meet the various regulatory and technical requirements (such as performance standards) set out in the NER. Under the current arrangements, consideration of whether the connection is cost efficient lies entirely with the connecting generator.

It is important to clarify that a clustering approach does not have to mean that a generator is refused the ability to negotiate access to the transmission network altogether because the TNSP determined that the proposed connection was not part of the group of connection projects that would deliver the most efficient augmentation outcome. The clustering approach just means that the TNSP would not connect the generator as part of a cluster, but would negotiate it outside the cluster, as is the current process. The clustering model does however afford TNSPs increased power to influence generator project development timing, and potentially where potential generators propose to connect to the transmission network. The outcome of a TNSP cluster assessment could also be expected to influence a developer's decision about whether or not to proceed with a generation project.

Important issues to consider in further exploring a clustering approach therefore include:

What is "an efficient outcome"? The approach set out in the discussion paper was that the incumbent TNSP would coordinate generator connections based on what delivers the most efficient outcome. This assessment is likely to be subjective. The generator's views on what is efficient are likely to be different to the TNSP's views on what is efficient, and different again to what AEMO, the jurisdictional government or consumers themselves would consider is efficient. Further consideration would therefore need to be given as to what an efficient outcome is, how it is defined and who defines it. Regulatory prescription would likely be needed to make sure that TNSPs' decisions on which projects proceed to development reflect this.

The size of the geographical area in the 'cluster'. Consideration would need to be given as to the size of the geographical area for the cluster, who determines this, and how it is determined. In its submission to the discussion paper, Energy Networks Australia noted that non-synchronous generation connections, even in geographically diverse areas, can have system-wide effects.[116] The TNSP's decision on which project/s proceeds to development will therefore be affected by the size of the cluster area.

The length and frequency of the 'seasons', and their alignment with other commercial processes. The connection of a generator to the network is not a straightforward process. It involves the negotiation and agreement of finance, development

116 Energy Networks Australia, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p. 9.

and environmental approvals, asset procurement, registration and licensing, among many other things. Many of these matters are not regulated by the NER. As noted by Reach Solar in its submission to the discussion paper, project transactions have a finite validity.[117] A clustering approach would therefore need to recognise, or accommodate, the fact that generation project processes are not sequential and may not fall neatly into a TNSP's 'season'. This fact may drive decisions on the length of the season and how frequently they are held.

Additional issues with the clustering option that the Commission has not considered above include the implications for committed generators if not enough connection applications are received to justify investment, and what information the TNSP would need from proponents to determine whether the project/s is efficient.

While the issues discussed above deserve further consideration, the Commission considers that a generator connection clustering model coordinated by TNSPs is not necessarily inconsistent with the five options for the role of the ISP outlined in Chapter 4. While transmission investment decisions may not necessarily sit with TNSPs as they currently do, TNSPs would still need to negotiate the connection of generators to the transmission network, and could do this in such a way as to achieve efficiencies where possible. Concern was also raised by stakeholders about whether a clustering approach could increase the timeframes taken to connect generators, which would be clearly inefficient. This suggests that it may not be an effective option to consider going forward.

The Commission considers that there could be a variation on the clustering model that incorporates principles from the TNSP speculative investment model outlined above. TNSPs could undertake speculative investment in connection assets, scaled to meet the capacity of the REZ, and therefore achieve economies of scale benefits. This would likely result in a better risk balance, with generators not exposed to the risk that a particular connection cluster does not go ahead, or that they will have to wait for other generators to express interest before connections can commence. As the TNSP would not be using regulated revenue to undertake the investment, consumers would not be exposed to the risk of inefficient investment. Once connections were built, generators could connect one by one and reimburse the TNSP for the generator's connection costs.

One issue with these arrangements is that they could be inconsistent with the TCAPA Rule changes that took effect in July 2018 which sought to introduce contestability into the construction of transmission connection assets. By building all of the connection assets in a particular REZ, the incumbent TNSP would be removing the opportunity for these services to be contestable. The TNSP undertaking the speculative investment would be exposed to the risk that not all of the connection assets it builds end up being utilised by generators, although it is not clear how material this risk is.

Consistency with ISP options

Depending on the level of control TNSPs have over planning, clustering may or may not be consistent with those options.

117 Reach Solar, submission to discussion paper, *Coordination of generation and transmission investment*, 1 May 2018, p. 1.

QUESTION 18: CLUSTERING

A) Do stakeholders agree with our conclusions for how this can occur under current arrangements?

B) Do stakeholders agree that this option is consistent with the ISP options? What other considerations should be taken into account?

In submissions to the discussion paper, stakeholders suggested a number of additional options for facilitating the development of REZs. These are detailed in Appendix B.5.

6.3 REZs and access

As described in chapter 3 of this paper, under the transmission framework in the NEM generators have no right to receive revenue in the wholesale market - but they do have a right to negotiate a connection to the transmission network. As such, generators only pay to connect to the transmission network. They do not pay for ongoing use of the shared transmission network.

Transmission businesses must make investments or procure services to meet the relevant jurisdictional reliability standard. Reliability standards relate to how transmission and distribution networks can withstand risks without consequences for consumers and guide the level of investment that network businesses undertake. These standards are set by state and territory governments and reflect a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers, which is defined in terms of serving customer load. The reliability standards that networks are required to meet are therefore defined in terms of reliably supplying customer load. As such, the focus of TNSPs, including their operation and investment decisions, is to deliver a reliable supply of electricity to consumers. Their focus is also to make offers to connect generators and loads that wish to connect to the network consistent with the open access regime described above. Since the network reliability standard relates to consumers, it can be considered that consumers have an implied access right to the transmission network. Consequently, consumers pay for use of the shared transmission network, that is, they fund investment in transmission assets that provide prescribed transmission services.

The implication of the current access regime in the NEM is that paying for shared transmission infrastructure would imply some degree of guaranteed access to the network. Conclusions on the approriateness of the existing access arrangements are set out in Chapter 7.

Therefore, models for the facilitation of REZs that involve generators paying for transmission infrastructure beyond that required to connect them to the transmission network are not consistent with this framework. If generators are required to pay for shared transmission assets, they would expect some degree of guaranteed access to the transmission network to export the electricity they produce. In particular, questions are raised in a model where generators coordinate in REZs - given the current access regime such generators do not have a gurantee to revenue in the wholesale market. Having generators coordinate for a REZ starts to raise questions about whether or not this remains the case.

Some stakeholders have suggested having narrowly targeted "access" i.e. generators get a right to be dispatched in a particular zone. However, it is not clear under the current framework that even such a narrow approach would be feasible. How would such a zone be defined? Generators could also choose to come in and connect next to that zone and constrain off the generators within that zone. If generators are paying for the services provided by the zone, then they may not want to pay anything beyond a shallow connection charge if they are not guaranteed access to the broader wholesale market. Therefore, it is likely that any changes to facilitate access to a REZ only (as opposed to changing the broader access framework) are unlikely to be achievable.

QUESTION 19: ACCESS

Do stakeholders agree with our conclusions on access?

7 CONGESTION AND ACCESS IN THE NEM

As detailed in Chapter 3, a foundational principle of the NEM is that decisions to invest in generation capacity are made by businesses operating in a competitive environment, rather than by vertically integrated monopolies. Investment in generation assets is market-driven and takes account expectations of future demand, the location of energy sources, access to land and water and access to transmission. The result is that risks associated with generation investment rest with those businesses.

The way that transmission and generation investment decision making processes interact, and in particular, their operational consequences, have been the subject of ongoing discussion since the establishment of the NEM in 1998. Since NEM start, there have been twelve major reports and reviews dealing with various aspects of congestion management and generator access. Generation and transmission are both complements and substitutes. This implies that investment and operational decisions by generators and TNSPs should work together to achieve overall efficient outcomes.

Such matters are the subject of this review, where the COAG Energy Council requested that the AEMC implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. The intent is to consider when future conditions might arise where net benefits would be derived from adopting a transmission framework, which would provide for better co-ordination of investment between the transmission and generation sectors. One way in which this could be achieved would be through the optional firm access model.[118]

In stage 1 of this review, the Commission concluded that:

- the drivers of change that impact transmission and generation investment have changed since October 2015[119]
- there is likely to be large amounts of transmission and generation investment in the near to medium term
- future expected investment is uncertain in its location or technology.

In stage 2 of this review, the Commission engaged Ernst & Young (EY) to assess patterns and costs of congestion in the NEM. Summarising the results detailed in the discussion paper, EY found that there is limited congestion at the moment within the NEM. Submissions in response to this analysis noted that:

- at the moment there is limited congestion in the NEM

118 This would allow generators to purchase a partially firm financial access right to the regional reference node, at a regulated price in order to manage the financial impacts of network congestion. Generators would be entitled to compensation if constrained below their level of firm access. This would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some transmission investment. In effect this would introduce firm transmission rights, while providing locational (nodal) pricing signals to generators.

119 July 2015 being when the Commission’s 2015 review of optional firm access concluded. At this time, the Commission considered the optional firm access model would not contribute to the NEO at that time, but recommended biennial reporting of changes in drivers of generation and transmission investment (the subject of this review).

- to the extent that congestion occurs, it is largely limited to between regions, or is congestion occurring at the ends of the regions which is translating to congestion being observed on interconnectors.

Since that time, AEMO's ISP was published which noted that there is a need to increase the capability of the transmission system to reduce congestion and provide generators, existing and new, with cost-effective access to market. It highlighted the importance of coordinating generation and transmission investment.

Stakeholders that expressed their views on congestion in response to our discussion paper also noted that there could be expected significant congestion in the future due to the rapid growth in proposed new generation. TransGrid stated that "...the current state of constraints binding in the network is not a good measure of the current scale of the problem being considered by the AEMC...In some regions of New South Wales with high quality renewable resources, TransGrid's network is already 'full' with no spare capacity to connect additional generators. This is resulting in new generation projects not being progressed."[120]

Supporting this point, in its submission, Aurizon provided arguments from Powerlink's 2017 TAPR, stating that "additional generating capacity above committed levels in north or central Queensland is expected to lead to a rise in congestion on the Gladstone or Central Queensland – Southern Queensland sections...result[ing] in material constraint durations."[121]

Further, AusNet Services stated in its submission that "generation connections processes show that significant new renewable generation could not be dispatched to capacity in the north western Victorian REZ [because of congestion]."[122]

Submissions clearly showed that stakeholders are interested in further network congestion analysis. AGL viewed that:[123]

> *"... the scope should include a more detailed assessment of the options identified as viable by the AEMC, including a re-examination of optional firm access arrangements. The review should also consider how investment decisions are made, whether greater nodal pricing is necessary to facilitate regional expansion, and the role of regional reliability standards on transmission service providers."*

TransGrid considered that future analysis should "...include forecasts of future network congestion, including committed and likely generation developments."[124]

120 TransGrid, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi. Snowy Hydro also referenced this issue raised by TransGrid, Snowy Hydro submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

121 Aurizon, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

122 Ausnet Services, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.7. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

123 AGL, submission to discussion paper, Coordination of Generation and Transmission Investment, 22 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

124 TransGrid, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

In its submission, ERM Power highlighted that there is a lack of relevant and transparent information available to the market on the impacts of network congestion. ERM Power stated that:[125]

> *"...whilst network service providers are starting to publish connection capability information in Annual Planning Reports, this data fails to include critical information such as uncongested headroom and congestion ratios. Lack of this data…is resulting in a general misunderstanding by potential connection applicants who are then ill-advised as to the true capability of the existing network. The resulting increase in congestion experienced from the connection impacts the new generation facility, existing generators and ultimately the future of reliable supply to consumers."*

S&C Electric Co explained congestion as the "natural consequence" of generators not paying for the use of the system.[126] S&C Electric Co considered that:[127]

> *"if generation wants a guarantee to export full or near full capacity, then that is a paid for service that could be delivered by the NSP, a 'use of system' charge would cover carriage of the generated electricity and failure to carry that electricity may result in a penalty on the NSP…The notion that all connecting generation is "good" because it meets demand and so should be facilitated by removing use of system costs is outdated…Generators can't complain about insufficient network and then say they can't share information due to competitive reasons when working together with other generators and/or the TNSP would result in lower cost connections and lower costs to the end consumer."*

Similarly, the South Australian Government highlighted that "the locational decisions made by generators in the past have led to historically high levels of congestion in South Australia" and that "despite the south-east and mid-north regions of South Australia historically suffering from constraint issues, there is an ongoing possibility that a new renewable generator may connect to these regions due to the optimal conditions that exist in these areas."[128] It goes on to note that the "existing NEM design does not adequately deal with the impacts of congestion on market participants" and it believes "there is a need to develop regulatory frameworks to support a sustainable congestion management regime".

In the current environment, given the different risks they are expected to bear, TNSPs and generators have different incentives and priorities when making their respective investment decisions. Generator decision-making is market-driven and seeks to maximise the profits for the generation business. Network investment is based on a regulatory process that is designed to allow TNSPs sufficient revenue to meet their statutory and regulatory obligations to reliably supply consumers.

125 ERM Power, submission to discussion paper, Coordination of Generation and Transmission Investment, 17 May 2018, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

126 S&C Electric Co, submission to discussion paper, *Coordination of Generation and Transmission Investment,* 18 May 2018, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

127 Ibid.

128 South Australian Government, submission to the discussion paper, *Coordination of generation and transmission investment*, 14 August 2018, p. 2.

Increasing the efficiency of coordinating generation and transmission investment would contribute to efficient investment in both networks and generation. This is most likely to occur when:

- the combined costs of generation and transmission are taken into account in investment and operational decisions by generators and TNSPs, leading to lower costs overall
- parties that make investment decisions have a direct financial stake in the efficiency of outcomes resulting from these decisions.

As the ISP demonstrates, congestion is projected to increase with the connection of more renewable generators to the transmission network, and augmentation will be required to keep congestion at an efficient level. Given the proposed transmission pathways being put forward in the ISP, and the impacts of investments on those pathways for levels of congestion, this stage of the review is focussed on the role of the ISP and how a link could be created between it and the transmission investment decision framework.

However, given these trends, access and congestion management issues are likely to need to be addressed in the near term, once the role of the ISP has been addressed.

QUESTION 20: CONCLUSION ON NEED TO CONSIDER ACCESS ISSUES

Do stakeholders agree with the Commission's conclusion in this Chapter that access and congestion management issues are likely to need to be addressed in the near term, once the role of the ISP has been addressed?

8 TREATMENT OF ELECTRICITY STORAGE

As set out in the discussion paper for this review, electricity storage technologies have the potential to provide benefits to both the operators of those assets and the electricity grid more broadly.

Two large-scale energy storage facilities have connected to the NEM in the past 12 months:

- A 100 MW, 129 MWh lithium-ion battery storage system at Neoen's Hornsdale wind farm near Jamestown in South Australia. The Hornsdale Power Reserve utilises Tesla's technology and commenced operation in December 2017.
- A 30 MW, 8 MWh lithium-ion battery storage system at the Dalrymple substation on the Yorke Peninsula in South Australia. The Energy Storage for Commercial Renewable Integration, South Australia (ESCRI-SA) project is owned by ElectraNet and will be operated by AGL, and is due to be commissioned in the coming months.

The connection of these facilities has raised some questions about the applicability and appropriateness of the existing regulatory framework to energy storage technologies. These questions have also been raised by a number of potential storage providers as they look to understand the existing regulatory framework, including AEMO's approach to registering energy storage technologies, and how their business case might stack up. Specifically, since storage facilities both "generate" and "consume", these lead to questions of:

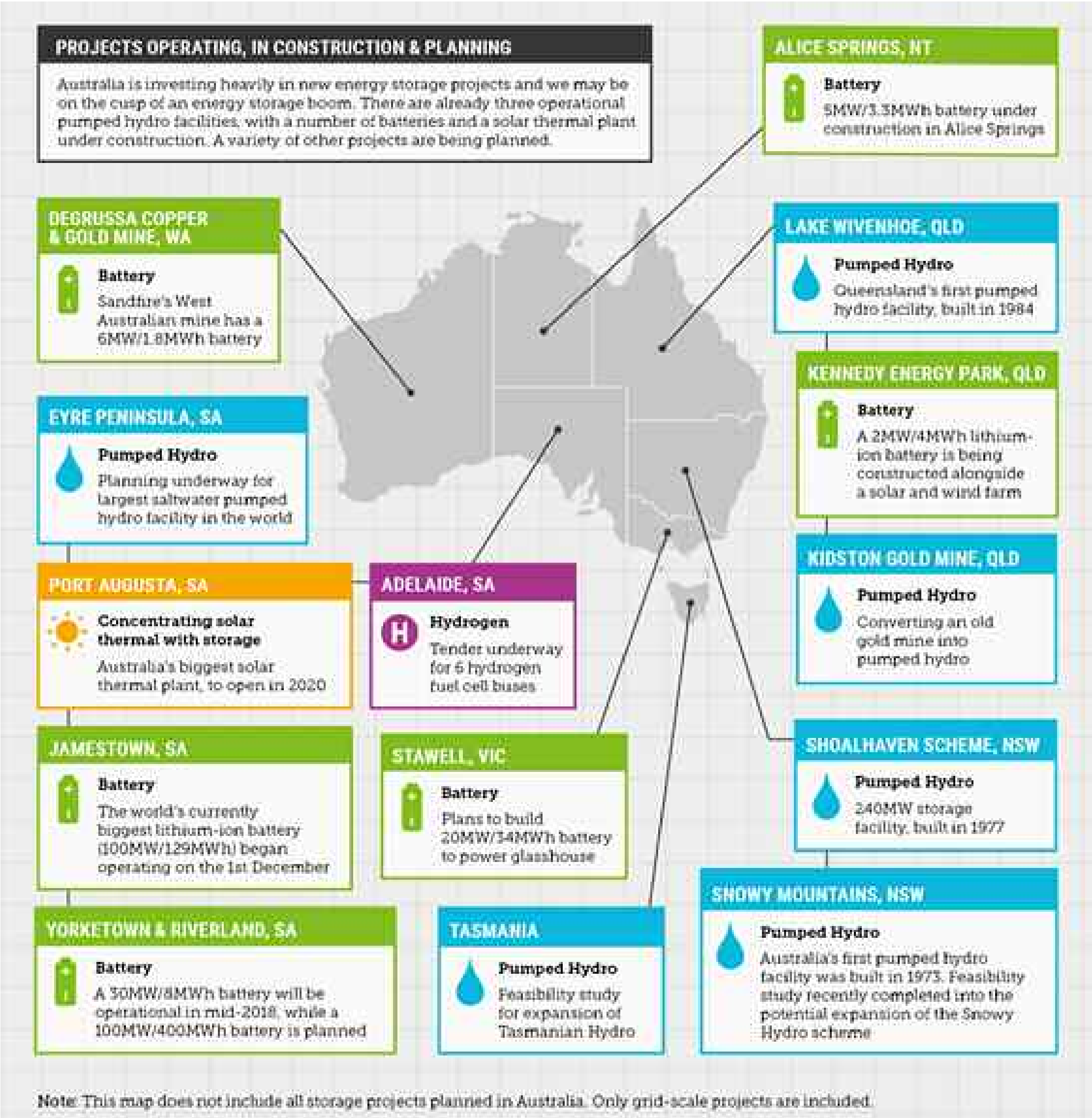
1. Under what participant category (or categories) energy storage technologies should be registered. This includes consideration of the appropriate registration category for hybrid facilities (i.e. those that combine storage with another generation source).
2. Whether transmission-connected energy storage technologies should pay TUOS charges.

AEMO and the AER have put in place interim arrangements, and agreed certain arrangements with the proponents of the two projects above, to get them connected. In 2017 AEMO published its views on how to apply the existing NER to the connection of utility-scale battery storage facilities.[129] The document explains that, under the existing NER, such facilities should be required to register as both Market Generators and Market Customers (if they have an aggregate nameplate rating over 5MW), and should discuss the process for negotiating TUOS charges with the relevant TNSP consistent with principles set out in the NER. Nevertheless, AEMO concluded that there may be scope to improve the NER as they apply to batteries and other forms of storage to develop "comprehensive and robust long term arrangements."

As shown in Figure 8.1, more energy storage facilities are expected to connect to the transmission network in future. The AEMC agrees with AEMO that a more transparent and durable approach to addressing the two questions above is likely to be required.

129 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Interim-arrangements-Utility-Scale-Battery-Technology

Figure 8.1: Energy storage projects



Source: Climate Council, March 2018. Note: The figure does not include Alinta's 30MW battery in the Pilbara region of Western Australia, launched in April 2018. See: https://www.alintaenergy.com.au/about-us/news/alinta-energy-switches-on-big-pilbara-battery

The sections below set out both of these issues, including stakeholder views as expressed in submissions to the approach paper and discussion paper, and the AEMC's preliminary analysis and conclusions.

It is important to remember that there are many forms of storage, not just batteries, including:

- electricity drawn from the grid to run pump actions by pumped-hydro

- electricity drawn from the grid to compress air and pump it into underground caverns (compressed air energy storage)
- electricity drawn from the grid to compress and liquefy air that is pumped into above-ground cryogenic storage tanks (liquid air energy storage)
- electricity drawn from the grid to charge utility-scale battery systems.

This chapter uses the term energy storage system to refer to all of these technologies.

8.1 Registration of energy storage and hybrid systems

Background

The recent and potential connection of utility-scale storage facilities to the grid has raised questions about the appropriate market participant category for energy storage facilities to be registered in.

In 2017 AEMO published interim arrangements for utility-scale battery storage facilities to "expedite the entry of utility scale battery projects to the NEM in the short term".[130] The document sets out AEMO's views on how to apply the existing NER to battery projects, including in relation to participant registration, recognising that there may be scope to improve the NER framework going forward.

Under the interim arrangements, AEMO requires utility-scale battery storage technologies with an aggregate nameplate rating greater than or equal to 5MW, whether directly connected to the network or integrated behind the meter with new or existing generation, to be registered as both generators and market customers. In addition, these parties must be registered as both scheduled generators and scheduled loads, meaning their charge and discharge will be set through AEMO's dispatch system. AEMO and stakeholders have raised some concerns about the ongoing suitability of these arrangements.

Hybrid generation facilities – that is, those that combine an energy storage system with a form of generation, such as wind or solar – are also becoming more common. These facilities again raise questions about the appropriate way to register them for participation in the NEM.

The remainder of this section sets out stakeholder views on these matters, and the AEMC's preliminary analysis and conclusions.

Stakeholder views

<u>Registration of energy storage</u>

Several stakeholders were of the view that the NER should be amended to include a specific market participant category for storage technologies.

In line with its views on the differentiation of TUOS charging arrangements, Genex Power considered that a separate or sub-class of registration for large-scale storage could be established. It argued that such a framework could require generators to demonstrate their

130 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Interim-arrangements-Utility-Scale-Battery-Technology

technical capability and economic business case to use load primarily to support the future dispatch of this energy into the NEM, in order to qualify for this exemption.

The AEC expressed support for establishing a separate registration category for storage, and specific consideration of the TUOS charging arrangements for such participants, which reflect the purpose of the storage: to increase the reliable supply to the grid.[131]

TransGrid was of the view that a separate registration category for grid scale storage should be provided for in the NER in order to recognise the range of benefits that storage can provide. Particularly, it saw a benefit in TNSPs being able to register in this new category and provide the full range of services offered by energy storage, which would, in its view, promote efficient investment in grid scale storage resulting in a lower cost, reliable and secure electricity supply. It argued that any concerns about allowing TNSPs to efficiently provide the range of services offered by batteries can be addressed through the application of the AER's cost allocation and shared asset guidelines.[132]

Tesla was of the view that the current requirement to register a single storage asset as both a generator and a customer has resulted in unintended administrative and cost implications for the financially responsible market participant and/or operators of the storage systems. Specifically, it noted that:

- The current approach requires raise and lower Frequency Control Ancillary Serices (FCAS) to be registered to the battery operating either as a load or a generator. The Hornsdale Power Reserve is registered to provide 63MW as a Scheduled Generator for contingency FCAS (6 second raise) and 63MW as a Market Customer for contingency FCAS (6 second lower). If the Hornsdale Power Reserve was registered as a single asset then it would be able to register to potentially provide >180MW in both the contingency FCAS raise and lower markets. This accounts for the ability of a storage asset to swing from full charge to full discharge within a single dispatch period.
- Managing a single physical asset as two separate assets for the purpose of AEMO dispatch presents dual clearing risks. The operator of a market energy storage asset will need to manage dispatch bids conservatively to ensure that it is not inadvertently cleared as both a generator and a load in a single dispatch period.

Tesla argued that the combination of these factors has led to a reduction in revenue when considered against how the system would operate as a single asset.[133]

S&C Electric Company noted that other jurisdictions have not necessarily defined electricity storage as generation, for example in the UK. It was of the view that, if electricity storage is generation, then it should be treated as generation for all other purposes, and that if electricity storage cannot be treated as generation because it sometimes acts as load, then it should not be defined as generation and should be defined as a separate asset class.[134]

131 Australian Energy Council, submission to discussion paper, p. 2.
132 TransGrid, submission to discussion paper, p. 5.
133 Tesla, submission to discussion paper, p. 4.
134 S&C Electric, submission to discussion paper, p. 5.

Tesla raised similar points, noting also that the US Federal Energy Regulatory Commission has separately defined energy storage, and that the Californian system operator has put in place specific arrangements to manage the operation of electricity storage assets.[135]

Hybrid facilities

Tesla was of the view that the requirement for a storage asset to be registered as both a scheduled generator and a market customer, and for wind and solar assets to be registered separately as semi-scheduled generators, does not allow the entity to use the storage asset to smooth out the co-located wind or solar generation. It argued that improvements to the conditions for firming could be done prior to introducing a new market classification for battery storage.[136] Tesla was of the view that there should be no reason that the co-located renewable asset could not combine with the energy storage system to provide scheduled output if operated by a single FRMP or system operator. It argued that installing a storage asset downstream of an existing generating asset connection point should not require the existing asset to register as a scheduled generator. Tesla noted that the fear of adding onerous requirements to existing generators if an energy storage system is installed and shares their connection point is driving layouts that are economically inefficient and which may be sub-optimal from a power system security perspective.[137]

Tesla argued that hybrid plants should be able to allow for renewable firming under the existing NER arrangements under a number of potential configurations if the following principles are followed:

- Both/ all assets (wind or solar and storage) are installed behind a single connection point.
- Each asset can respond to separate signals from AEMO, with the appropriate control metering for each asset.
- A single generator performance standard could apply to the entire hybrid site, with some different performance standards for the electricity storage portion.[138]

AGL encouraged the AEMC to examine whether sufficient merits exist to warrant the creation of an additional or sub-category of registration for hybrid facilities to allow market participants to utilise their entire facility as a scheduled generator. It argued that this would enable generators to provide the benefits of storage to address network issues, whilst offsetting any applicable TUOS charge when absorbing excess load.[139]

AusNet Services supported a rule change request being submitted on the matter to clarify the framework for registration of storage, and argued that this framework should be applicable equally for standalone storage assets and assets built in conjunction with an intermittent generation project.[140]

135 Tesla, submission to discussion paper, p. 4.
136 Tesla, submission to discussion paper, p. 3.
137 Ibid, p. 5.
138 Ibid.
139 AGL, submission to discussion paper, p. 4.
140 AusNet Services, submission to discussion paper, p. 7.

S&C Electric Company noted that there may be issues with the definition of a renewable site, and that connecting and retro-fitting electricity storage to such a site may cause complications in the application of renewable energy incentives or modifications to connection agreements. It argued that this issue needs to be resolved quickly to ensure projects are not delayed by uncertainty.[141]

BOX 6: TREATMENT OF ELECTRICITY IMPORTS AS AUXILIARY LOAD

One question that has been raised in conversations with the AEMC is whether it is appropriate to treat the electricity drawn from the grid by an energy storage system as 'auxiliary load'. Such an approach would mean that the energy storage system would not be required to register as a Customer in relation to its demand.

Auxiliary plant is not a defined term in the NER, but it is used in the NER definitions of generating system and continuous uninterrupted operation. In both instances it is used in connection with the defined term, reactive plant. In general, auxiliary is a term used to describe things that give support to, aid or otherwise assist.

Market generators can buy electricity through the spot market to support the operation of their generating system, e.g. to supply on-site offices, mines owned by the generator, conveyor belts or power station auxiliaries. The generator must satisfy AEMO that the electricity is used for that purpose and that all power station connection points are part of the overall connection of the generator to the network.

Auxiliary can also be used to mean 'used as a reserve'. It is therefore possible that an energy storage system, fitted to an existing generating system, may be captured by the definition of 'auxiliary plant', but only to the extent that it is necessary for the generating system to meet its performance standards. Standalone energy storage systems would not fall within any understanding of 'auxiliary plant'.

Under AEMO's interim requirements for utility-scale storage, all batteries above 5 MW (whether standalone or behind the same connection point as a wind/solar farm, for example) are required to be registered and classified as scheduled generators. The arrangements note that if the battery is less than 5MW it may be considered to be an auxiliary load.

In the discussion paper on the *Integration of storage* project, the Commission concluded that the electricity a storage system draws from the grid to charge for purposes of discharging later is not 'auxiliary'. This is because the proportion of load an electricity storage facility uses to charge and discharge for participation in the NEM is likely to be greater than that used to supply the auxiliary needs of the facility. Electricity used for the purposes of charging is not electricity it needs to run the battery system. Rather, it is the fuel source for a generator. It was for this reason that the AEMC concluded that energy storage systems that withdraw electricity from the grid for the purposes of charging and discharging back into the grid should register as a Customer.

141 S&C Electric Company, submission to discussion paper, p. 6.

AEMC analysis and preliminary views

Incorporating energy storage and hybrid facilities

The AEMC agrees with stakeholders that certainty on a long-term approach to registering electricity storage is needed. AEMO shared this view in its submission to the discussion paper.[142] AEMO has been conducting analysis and consultation on the registration of emerging generation and energy storage, including hybrid facilities, in recognition that its interim arrangements are only intended to be in place until a more permanent approach is settled on. The AEMC and AEMO are working collaboratively to identify the challenges of the existing arrangements and potential solutions. The outcomes and experiences of participants registering under AEMO's interim arrangements will likely inform any future consideration of these matters, including through changes to the rules.

The existing NER sets out all of the rules and obligations that apply to the existing registered participant categories. Any change to more explicitly accommodate energy storage technologies and hybrid facilities, for example the introduction of a new registration category, would need to carefully consider which of these existing obligations should apply.

Section 8.2 sets out the AEMC's preliminary views on only one of these obligations – TUOS charging. The AEMC has focused on this because it relates closely to the fundamental aspects of the transmission framework, and the recovery of costs associated with the transmission framework, that form the context of this review. Under the current arrangements, energy storage systems that are registered as Customers (or are Non-Registered Customers) are subject to TUOS charges. Thus the creation of a new registration category would need to address this question. The next section sets out the AEMC's preliminary views on matters that would need to be considered to help answer this question if there were a proposed change to the way in which energy storage and hybrid systems are registered.

However, as noted above, any change to the approach to registering energy storage and hybrid facilities would need to include consideration of many issues, not just TUOS charging. For example, the introduction of a registration category specifically for storage would need to consider, among other things:

- What technical obligations the provider should be subject to. Should these technical obligations be the same or different to those currently imposed on generators and loads?
- Which markets the provider should be able to participate in, e.g. energy and FCAS?
- How they should participate in those markets, (e.g. scheduled, non-scheduled), and how they should be settled.

The appropriateness of the existing registration categories is also being considered in light of a range of broader issues than just energy storage. A range of new technologies and business models are emerging in the NEM, some of which are challenging the assumptions that guided the development of the existing participant categories.

142 AEMO, submission to discussion paper, p. 12.

This includes virtual power plants. Through a joint program of work, the AEMC, AEMO and the AER are exploring the broader technical and regulatory challenges associated with virtual power plants through a NEM trial program. This will include consideration of whether virtual power plants are accurately captured by the NER's existing registration categories, and the MW threshold at which they should be scheduled.

The AEMC also recently recommended changes to the existing market participant categories of Small Generation Aggregator and Market Ancillary Service Provider in the final report of the *Frequency control frameworks review*.[143] These proposed changes would allow Small Generation Aggregators to aggregate small generating units for participation in FCAS markets, and would clarify that Market Ancillary Service Providers are able to do the same. However, if made, these changes would result in registration categories that look more and more alike – that is, they would increasingly overlap in the services each category can provide. This may also be the case for any future registration category that accommodates virtual power plants or aggregation for the purposes of providing wholesale demand response, as was recommended in the Commission's *Reliability frameworks review*.[144]

The current market participant categories that are able to buy or sell energy and ancillary services in the NEM are set out below.

Service	Buy	Sell
Energy	Market customer	Market generator, market small generation aggregator
Demand response	- (in future?)	- (in future?)
Market ancillary services	(AEMO)	Market customer, market generator, market ancillary service provider

Incremental changes to the rules may address the immediate concerns of new technologies and business models registering in the NEM. However, the Commission is of the view that a more holistic look at the registration framework in the NER may be needed to make sure that the participant categories sufficiently accommodate and support the participation of existing and emerging technologies and business models into the future, and to reduce operational complexity and administrative burden for AEMO and participants.

Such a review could consider whether the existing approach to registering participants is appropriate, or should move to an alternative approach. For example, the framework could be amended to categorise participants based on:

1. whether the participant is buying or selling from the market (regardless of what service they are providing), or

143 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Frequency-control-frameworks-review

144 See: https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

2. the specific service/s that the participant intends to provide, regardless of whether they are buying or selling it (e.g. energy participant, demand response participant, ancillary service participant).

Alternatively, the framework could define each service individually, and participants could choose which service they wish to buy/sell and not be constrained by the requirements of a particular registration category. Under this approach, participants could choose whether they only provide one service, or provide all. The rules would then apply to the specific service that participant is providing, not what registration category they are in. Such an approach would likely support a more efficient means of registering hybrid facilities, as the framework would focus more on the services that are being provided at the connection point rather than the assets that are used to provide them.

Any significant change to the registration framework in the NER would need to be reflected throughout the rest of the NER framework. The many and varied NER obligations (for example technical performance standards) are tied to the existing registration categories. A completely new approach to registering participants would need to re-map these obligations to the appropriate parties. Careful consideration would therefore need to be given through any such review to determine that the benefits of changing these arrangements outweigh the potential costs of implementation.

8.2 TUOS charging

Application of the existing NER to transmission-connected energy storage facilities

This section provides an overview of the existing NER arrangements and their applicability to transmission-connected energy storage facilities, specifically:

- what TUOS charges are
- how TUOS charges are calculated
- who pays TUOS charges
- how energy storage technologies fit under these arrangements
- the implications of these arrangements.

A more detailed description of the first three dot points above is set out in Appendix C.

<u>What are TUOS charges?</u>

The NER define four categories of prescribed transmission services provided by TNSPs for the purposes of pricing:

1. Prescribed entry services.
2. Prescribed exit services.
3. Prescribed common transmission services.
4. Prescribed TUOS services.

While not explicit in the NER, TUOS charges (not a defined term) are used by TNSPs to recover the costs associated with their provision of prescribed TUOS services.

How are TUOS charges calculated?

Chapter 6A of the NER, among other things:

- regulates the revenues that may be earned by TNSPs from the provision of transmission services
- regulates the prices that may be charged by TNSPs for the provision of prescribed transmission services
- establishes principles to be applied by TNSPs in setting prices that allow them to earn the whole of the aggregate annual revenue requirement.[145]

The NER require a TNSP to submit to the AER a revenue proposal and a proposed pricing methodology relating to the prescribed transmission services that are provided by means of, or in connection with, a transmission system that is owned, controlled or operated by that TNSP.[146]

The NER requires that:

- prices for recovering the adjusted locational component of prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for which network investment is most likely to be contemplated
- prices for recovering the adjusted non-locational component of prescribed TUOS services must be on a postage stamp basis.

Who currently pays TUOS charges?

It is not explicitly stated in the NER that a TNSP must recover the costs of prescribed TUOS services from Transmission Customers and other TNSPs (i.e. those that, by definition, receive the services). Rather, it is the definition of prescribed transmission service, the definitions of the categories of prescribed transmission services, the pricing principles and TNSPs' pricing methodologies that establish a basis by which the costs of prescribed TUOS services are recovered from those parties.

So, in practice, the costs of prescribed TUOS services are recovered from Transmission Customers and other TNSPs through TUOS charges. As stated above, Transmission Customers include Customers, Non-Registered Customers and distribution network service providers (DNSPs) that have a connection point with the transmission network.

TUOS charges are therefore not currently recovered from generators. The remainder of the analysis in this chapter assumes that this will continue to be the case.

How do energy storage technologies fit into these arrangements?

145 The aggregate annual revenue requirement (AARR) is the calculated total annual revenue to be earned by an entity for a defined class or classes of service. The AARR for prescribed transmission services is the maximum allowed revenue that a TNSP may earn in any regulatory year of a regulatory control period from the provision of prescribed transmission services. See clause 6A.3.1 of the NER.

146 See clause 6A.10.1(a) of the NER.

As required by AEMO's interim arrangements for the registration of utility-scale storage,[147] the project proponents of energy storage systems greater than 5MW are required to register as both a Market Generator and a Market Customer in relation to their connection points. Under the current arrangements, Transmission Customers (which includes Market Customers) pay TUOS charges.

ElectraNet sought an exemption from the AER from TUOS charges being payable for the ESCRI-SA battery on the basis that the transmission services being provided under the terms of the connection agreement between AGL and ElectraNet will comprise negotiated transmission services, not prescribed transmission services. The AER accepted this conclusion and agreed that TUOS charges would not be payable at the connection point under the NER. However, the AER did not consider that this approach should set a precedent for all future projects.[148]

Thus, it appears as if in the absence of any regulatory change, or bespoke arrangements agreed to by the AER, transmission-connected energy storage systems are liable to pay TUOS charges if they are a Customer or a Non-Registered Customer.

<u>Implications of the current arrangements</u>

Energy storage systems are both consumers and producers of energy. As explained above, AEMO has put in place interim arrangements requiring utility-scale storage facilities to register as both Market Generators and Market Customers to reflect this dual capability.

AEMO flagged that it would review its experience under the interim arrangements to assess whether there is scope for improvement, including in relation to registration. Any changes to the existing approach, for example the creation of a new registration category specifically for energy storage systems, would require changes to the NER. Given the link between registration and TUOS charging, any such change would also require consideration of whether TUOS charges should by payable by transmission-connected energy storage facilities. The remainder of this section sets out the AEMC's preliminary views on matters that would need to be considered regarding the payment of TUOS charges by energy storage facilities, should there be a change to the existing regulatory arrangements that causes this question to be revisited.

The broader question of whether Market Customer (and/or Market Generator) is the appropriate registration category for energy storage systems is set out in section 8.1.

Stakeholder views

The question that the AEMC posed in its discussion paper was whether it is appropriate for energy storage systems to pay TUOS charges. Submissions to the discussion paper indicated that stakeholders were largely divided in their views on this question. Several expressed concern at the level of uncertainty regarding the payment of TUOS charges by storage

147 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Interim-arrangements-Utility-Scale-Battery-Technology

148 See: https://escri-sa.com.au/globalassets/reports/escri—-sa—-project-summary-report—-the-journey-to-financial-close—-may-2018.pdf

facilities, and recommended that the policy framework provide clear guidance on this as soon as possible to support investment.[149]

ENGIE noted that storage has the property of demand when charging and generator when discharging. It was therefore of the view that storage systems should pay cost reflective transmission charges for any electricity imports, and be treated the same as generators (i.e. not pay TUOS charges) on the exports. It considered that such an approach would be equitable when compared to other loads. However, ENGIE was also of the view that network charges would need to be more granular than they are currently (either dynamic or conditional on system conditions) or storage systems would potentially increase system costs by not seeing economically efficient price signals and therefore not being able to respond. It noted the key challenge of exposing storage operators (at both the distribution and transmission levels) to efficient price signals so that the mix of services they are capable of providing (energy, FCAS, network support, etc) can be optimised.[150]

AGL expressed a similar view, submitting that all forms of connected energy storage should be treated in the same way to maintain simplicity in application. It supported loads continuing to be the vehicle through which TUOS charges are recovered, but considered that any TUOS charges applicable to a storage device when used as a load should reflect the value that the device provides to the network. It also considered that the approval of all TUOS charges should be conducted by the AER via the regulatory determination process.[151]

Reach Solar also considered that a storage facility should pay TUOS charges if it "intends to behave as demand" and imports electricity from the grid for arbitrage purposes, but not where its main focus is generation and the provision of ancillary services.[152]

Genex Power strongly opposed the payment of TUOS charges by storage facilities on the basis that:

- a storage asset's business is to serve customers, as is the case for other generators
- large-scale storage provides benefits to the NEM
- large-scale storage load is different to other types of energy consumers
- there is a need to promote the uptake of storage in the NEM
- a requirement to pay TUOS charges would provide a direct disincentive to invest in storage and potentially render projects commercially unviable.[153]

Nevertheless, Genex Power supported a differentiation of the treatment for TUOS charges on the basis of the benefits they provide to customers. It argued that large-scale storage that exists largely to dispatch energy to the NEM should be exempt from TUOS charges, while behind the meter storage that exists to supplement existing storage should not.[154]

149 See for example: Genex Power, submission to discussion paper, p. 3; Tesla, submission to discussion paper, p. 1.
150 Engie, submission to discussion paper, p. 5.
151 AGL, submission to discussion paper, p. 4.
152 Reach Solar, submission to discussion paper, p. 2.
153 Genex Power, submission to discussion paper, p. 2.
154 Ibid., p. 3.

Snowy Hydro argued that large-scale storage, specifically pumped hydro technologies, should not be liable for TUOS charges on the basis that they provide essential system services such as energy, inertia, system strength and voltage support – services that are not provided by loads but rather by synchronous generation.[155]

AusNet Services also noted that storage systems can provide frequency regulation, reserve capacity, load levelling and peak shaving, and that these services will become increasingly important as the percentage of intermittent generation in the power system grows. It argued that storage should not be liable for TUOS charges when performing these functions on the power system. It also argued that storage connections can be distinguished from other loads, including scheduled loads, because:

- they are negotiated transmission services, and the pricing arrangements under Part J of Chapter 6A of the NER would not apply
- their services are primarily energy supply chain services provided for the benefit of energy consumers, and are subject to AEMO dispatch control.

AusNet Services also noted that batteries located in the distribution system are currently typically treated as loads, even if they are primarily providing a supply chain function.[156]

Tesla also raised the point that battery energy storage is capable of providing critical system services, and therefore argued that applying TUOS charges for an AEMO-instructed dispatch to charge may result in a counter incentive to provide critical system services such as frequency control. It was of the view that the basis for charging TUOS to market customers is to ensure that TNSPs are adequately compensated for maintaining existing transmission infrastructure to ensure ongoing reliable and efficient supply of energy at all times, and for investing in new infrastructure to meet projected increases in peak demand. Tesla argued that battery charging most often occurs during low price periods, which equates with periods of high generation, and therefore that storage assets will not contribute to peak network congestion, and do not result in the same requirement for future network expenditure.[157]

ElectraNet shared a similar view, noting that energy storage is playing an increasing role in delivering market and system security benefits, and arguing that transmission-connected batteries that are centrally dispatched and cannot drive transmission augmentation should not be liable for TUOS charges.[158]

AEMO supported a technology-neutral approach to the payment of TUOS charges by energy storage systems when they are performing functions that "make it part of the electricity supply chain", including the provision of FCAS and renewables firming. It noted that, the same as a generator, it would not have firm transmission access and could be constrained off in the event of network congestion. However, it noted that battery storage can be flexibly located and could provide valuable services to the network. AEMO argued that the

155 Snowy Hydro, submission to discussion paper, p. 5.
156 AusNet Services, submission to discussion paper, p. 7.
157 Tesla, submission to discussion paper, pp. 2-5.
158 ElectraNet, submission to discussion paper, p. 5.

transmission pricing regime and payments for services should provide incentives for batteries to locate in "advantageous locations".[159]

S&C Electric Company noted work undertaken by Ofgem in the UK regarding charging, and rule changes submitted by Scottish Power to exempt electricity storage from balancing use of system charges.[160]

Several stakeholders saw that any decision on TUOS charging arrangements should be contingent on a decision regarding the most appropriate registration category for storage. These views are set out in section 8.1.

Issue definition

In the AEMC's view, the issue of whether energy storage systems should pay TUOS charges under any future regulatory arrangements, including a new approach to registration, should be addressed in three parts:

1. Should energy storage systems that do not withdraw electricity from the grid pay TUOS charges?
2. Should energy storage systems that *only* withdraw electricity from the grid (i.e. do not export) pay TUOS charges?
3. Should energy storage systems that withdraw electricity from the grid for the purposes of storage and then export electricity back into the grid at a later time/date pay TUOS charges?

The first question relates to configurations where the energy storage system is co-located with a generating system for the purposes of maximising the output of that generating system. For example, a wind generator might use an energy storage system to store excess electricity produced by the wind farm during the night-time to export into the grid during peak periods in the daytime. The energy storage system is not being charged from the grid. So, from the grid's perspective, the connection point is only ever exporting electricity.[161] As such, the party who owns/operates/controls the generating system at that connection point should only be required to register as a generator. This is consistent with the conclusion the AEMC put forward in its Integration of Storage report – that is, an energy storage system should be treated as a generator (only) if, from the grid's perspective, it only ever exports electricity to the grid. Under the current arrangements, generators do not pay TUOS charges.

The second question relates to configurations where the energy storage system only charges from the grid, presumably to supply its own energy needs or on-supply someone else. In this case, from the grid's perspective, the connection point is only ever importing electricity. As such, the party who owns/operates/controls the energy storage system should only be required to register as a Customer (assuming it meets AEMO's threshold for registration). This is also consistent with the conclusion the AEMC put forward in the *Integration of Storage* report – that is, an energy storage system should be treated as a customer (only) if, from the

159 AEMO, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.13.

160 S&C Electric Company, submission to discussion paper, p. 5.

161 This conclusion ignores the concept of 'auxiliary supply', which is discussed further below.

grid's perspective, it is only ever importing electricity from the grid. In this case, the AEMC is of the view that it is clear that the energy storage system should be allocated TUOS charges if it is registered as a Customer (or is a Non-Registered Customer).

Thus, in the AEMC's view, the main policy question that would need to be addressed is the third question above – where an energy storage system withdraws electricity from the grid for the purposes of storage, and then exports electricity back into the grid at a later time/date. This question relates to two possible storage configurations:

- A standalone, grid-connected storage system whose business case is based on energy price arbitrage (for example, like existing pumped hydro) or FCAS provision.
- A storage system co-located with a grid-connected generator that charges from the grid on occasion (in addition to any auxiliary supply), for example to participate in energy/FCAS markets as a supplement to the generating system's participation.

QUESTION 21: STORAGE AND TUOS

Do stakeholders agree with the AEMC's definition of the issue?

In both cases, the storage system will (at times) be withdrawing electricity from the grid for re-export. In its submission to the discussion paper, S&C Electric Company defined this as *electricity storage* – "where electricity is temporarily converted to another energy (chemical for a battery, potential energy for pumped hydro), before being reconverted to electricity."[162]

In the *Integration of storage* report the AEMC concluded that an energy storage system should be treated as both a generator and a customer if (from the grid's perspective) it is both exporting and importing electricity to and from the grid. This is consistent with the approach that AEMO has taken in its interim arrangements for utility-scale battery technology. The operators of the Hornsdale and ESCRI-SA batteries are registered as both Market Generators and Market Customers.

As noted above, under the current arrangements it is clear that Market Customers are subject to TUOS charges. However, stakeholders have raised questions about whether this approach should change and instead of treating storage as both generation and customers, they should be registered as a separate, standalone storage category. This is a question that requires further thought and consideration. In order to inform others on these matters the analysis provided below sets out the AEMC's initial considerations on TUOS charging should there be a change to the existing regulatory treatment of energy storage systems, for example to establish a single, bespoke category of registration for them. The remainder of this section sets out:

- the AEMC's initial views on the arguments put forward by stakeholders to change the existing arrangements, i.e. to exempt energy storage systems from TUOS charges

162 S&C Electric Company, submission to discussion paper, p. 4.

- a summary of the implications of such a change, and things that would need to be considered in making such a change.

AEMC's preliminary views on stakeholder views against payment of TUOS charges by energy storage systems

Stakeholders have raised a number of reasons why energy storage systems should not be liable for TUOS charges in their submissions to the discussion paper and in conversations with the AEMC. These, and the AEMC's preliminary views on them, are set out below.

1. *It would disincentivise investments in storage and potentially render projects commercially unviable, and there is a need to promote the uptake of energy storage in the NEM.*

This view is that requiring storage systems to pay TUOS charges would represent an additional cost among a range of other costs and uncertainties that affect the commercial viability of storage projects. While this may be the case, putting in place an exemption for energy storage providers would not be technology neutral.

Moving to this approach would require a re-definition of the purpose and allocation of TUOS charging from "those who are supplied electricity via the transmission network" to "those who do not need financial assistance to use the transmission network."

It is not the AEMC's role to "pick winners" through the regulatory framework. Any incentives for the uptake of particular technologies are best determined by governments as an overlay to the technology-neutral framework that the NER seeks to provide. This is consistent with the AEMC's remit under the NEO - social and industry policies, such as the promotion of particular technologies, is a matter for governments.

Such an approach also raises questions about the treatment of other loads. If energy storage systems are exempt from TUOS charges, should other loads also be exempt?

Further, as we have learnt from the connection of the Hornsdale and ESCRI-SA batteries, there are many factors that make the business case for a large-scale energy storage system difficult to stack up at the current time. While this is not a reason to not take action to address these difficulties, an exemption from paying TUOS charges is unlikely to address all of the challenges associated with financing a large-scale energy storage system. As noted above, any decision to financially support the uptake of particular technologies is better made by governments than the AEMC, whose remit is to promote economic efficiency in the long-term interests of consumers.

2. *Energy storage systems provide valuable system services. Payment of TUOS charges would disincentivise storage providers to provide these services.*

In their submissions to the discussion paper AusNet Services and Snowy Hydro commented that large-scale storage should not be liable for TUOS charges because they provide essential system services such as frequency regulation, system strength, voltage support, reserve capacity and peak shaving.

Tesla raised the concern that an AEMO-instructed dispatch to charge may result in a counter incentive to provide critical system services, such as frequency control, if energy storage systems are required to pay TUOS charges.

As above, while this may be the case, putting in place an exemption for energy storage providers would not be a technology neutral approach to allocating the costs of the transmission network. Further, there is no requirement for energy storage systems to provide system services – this is a commercial decision for the project proponents. The AEMC acknowledges that exempting energy storage systems from TUOS charges may provide an incentive for them to provide system services, if that is the policy objective. However, the AEMC's initial view is that the provision of these services should be rewarded separately to the allocation of TUOS charges.

As noted above, moving to this approach would require a re-definition of the purpose and allocation of TUOS charging from "those who are supplied electricity via the transmission network" to "those who do not need financial assistance to use the transmission network." This is a distinction that is not currently made in the NER. Any re-definition of the purpose and allocation of TUOS charges to reflect such an approach would need to consider the treatment of energy storage systems that do not provide system services, and indeed the treatment of any other loads.

3. Energy storage systems are not 'customers' in the way that residential or business consumers are.

This view is that energy storage systems withdraw electricity from the grid for the purposes of storage and re-injection into the grid – the energy is not 'end-consumed' by them, but rather converted and stored and converted again for use by end-consumers (although some energy is lost in the process). In this way, it may be considered that energy storage systems facilitate the efficient delivery of electricity to consumers (storing excess when it is not needed, and making it available when it is).

By contrast, residential and business customers are connected to the grid for the purpose of 'end-consuming' the electricity it conveys. This may therefore be the basis of an argument to suggest that the purpose of the grid is to supply electricity to end consumers, and therefore that those consumers should pay for the services the grid provides. Much of the existing regulatory framework, including reliability standards and the concept of Customer, appears to be built on this assumption.

Changing this approach would therefore require a re-definition of the purpose and allocation of TUOS charges from "those who are supplied electricity by means of the grid" to "those who end-consume the electricity provided by the grid." This is a distinction not currently made in any other aspect of the NER.

However, storage systems are still consuming electricity in that they are taking available capacity from the network that cannot be used by another consumer at that time.

4. Energy storage systems do not drive transmission investment.

Several stakeholders, including TNSPs, consider that energy storage systems should not be required to pay TUOS charges because they import electricity during periods of high generation and so do not drive transmission investment.

Whether or not an energy storage system drives transmission investment likely depends on a number of factors, including:

- what the jurisdictional reliability standards say about the reliability standard required at the energy storage system's connection point
- the time of day the system imports electricity from the grid
- where on the network the system is located.

These three factors are discussed further below.

<u>Application of jurisdictional reliability standards</u>

Under the current arrangements, TNSPs are required to meet network reliability standards. These standards are set by jurisdictions and are generally phrased in terms of meeting the supply needs of customers, which include DNSPs and direct-connected customers. To the extent that they are considered direct-connected customers, energy storage systems would be covered by these network reliability standards. That is, TNSPs would be required to plan and operate their networks to meet the supply needs of electricity storage systems, consistent with their network reliability standards. TUOS charges are a means of recovering a TNSP's provision of prescribed transmission services to meet its network reliability standards.

If energy storage systems are not considered 'customers' and not required to pay TUOS charges, consideration would need to be given as to whether there should be any obligation for TNSPs to plan and operate their networks to meet the network reliability needs of energy storage systems.

For example, the Essential Services Commission of South Australia (ESCOSA) recently revised the transmission network planning and reliability standards to clarify a number of issues, including the application of reliability standards to customers (including utility-scale battery storage systems) that receive negotiated transmission services. In its draft decision, ESCOSA proposed to insert a new clause into the Electricity Transmission Code (which provides reliability standards for ElectraNet to follow) to clarify that the reliability standards in the Code apply only to those exit points that receive prescribed transmission services, as defined under the NER.[163] In practice, this clarifies that any connection point that receives a negotiated transmission service, such as a utility-scale storage system, is not subject to those reliability standards.

<u>Where the system is located and when it operates</u>

Decisions about whether and when to import and export electricity will be driven by the commercial incentives and other needs of the party operating the energy storage system – that is, there is no guarantee that the system will only charge when network generation is high.

As explained in detail in Appendix C.2, the NER requires that prices for recovering the adjusted locational component of prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for

163 See: https://www.escosa.sa.gov.au/ArticleDocuments/1212/20180424-E-ElectricityTransmissionCode-DraftDecision.pdf.aspx?Embed=Y

which network investment is most likely to be contemplated. Powerlink's approach to calculating and charging the costs of prescribed transmission services was provided as an example, which showed that Powerlink allocates costs based on the Transmission Customer's demand (for example historical demand or maximum contract demand). AEMO, as the party responsible for the provision of prescribed shared transmission services in Victoria, explains that "locational charges are designed to encourage the most efficient use of the transmission network and are based on average maximum demand. They reflect the long run marginal cost of transmission at each connection point."

The NER intention is that the adjusted locational component of prescribed TUOS services is cost-reflective. So, in theory, the magnitude of this component should depend on how much the energy storage system drives transmission investment – if it does not, this proportion will be minimised. However, it is unclear to the AEMC the degree to which these charges are truly cost reflective. Thus the ability for an energy storage system to avoid TUOS charges that recover new network investment for which it was not responsible may be limited. In their submissions to the discussion paper, some stakeholders argued that TUOS charges should be more granular and dynamic to reflect the efficient costs and benefits the device provides to the network.

It is possible that an energy storage facility that withdraws electricity from the network at times of excess generation could have a negligible impact on transmission investment needs, or indeed have a benefit. However, while this activity may not drive transmission investment, energy storage providers that charge from the grid are able to do so because of the investments and operations undertaken by the TNSP, which are currently paid for by Transmission Customers. TUOS charges cover not just new investments in the network, but also the day to day maintenance and operation of the network that is needed to ensure a reliable and safe supply of electricity to consumers.

In an era of flat demand growth, network expenditure is shifting from new investment to replacement expenditure. That is, servicing the needs of customers is no longer primarily met by making new investments in the network, but by maintaining and replacing the existing infrastructure to ensure its continued operation.

It is also worth considering the treatment of other energy consumers who do not drive transmission investment. Consideration would also need to be given as to the treatment of energy storage systems that do drive investment in the network, as it may not always be the case that the system operates in a way that has no negative impact on the network.

5. If the storage system is registered as a scheduled load, it can be constrained off if there is congestion – it is unfair to make it pay TUOS charges when this can occur.

The argument here is that an energy storage system should not have to pay for the grid service when it can, without compensation, be refused access to the grid for the purposes of importing electricity, e.g. due to constraints. As above, this is part of the rationale for why generators do not pay TUOS charges – under an open access framework there is no guaranteed dispatch. It may be fair to suggest that an energy storage system should not be required to pay TUOS charges if it has no guarantee that it will be able to import electricity when it wants to. Similarly, scheduled loads are often the first categories of load to be shed in the event that load shedding is required to maintain power system security.

However, this also raises the question of how other scheduled loads should be treated, or whether there is an incentive to become a scheduled load in order to avoid paying TUOS.

6. A generator will pay connection costs. If the generator is also registered as a customer, it will pay TUOS charges as well, which means it is paying twice for the same thing.

Historically, load connections were provided by TNSPs as prescribed transmission services. Over time, it is the AEMC's understanding that most TNSPs treated new load connections as negotiated transmission services,[164] and therefore that the costs of establishing or amending a connection were paid for entirely by the load.

As of 1 July 2018, any new loads connecting to the transmission network pay connection costs in the same way that generators do – some of these services will be contestable and some must be provided by the connecting TNSP as negotiated transmission services.[165]

As explained above, the AER's transmission pricing methodology guidelines set out the types of transmission system assets that are directly attributable to prescribed TUOS services, which includes assets such as substation buildings, substation land and associated infrastructure (such as fences, earthing equipment etc), transmission lines, switchgear and auto-transformers.

This guideline may therefore be inconsistent with some existing load connections, and new connections from 1 July 2018, under which some (if not all) of these assets should be provided either as negotiated transmission services or on a contestable basis. While a TNSP's cost allocation methodology should address any double counting of the costs of these assets, conceptually it would seem possible that an energy storage system that is required to register as both a generator and a customer might pay twice for the same assets – that is, once through the costs associated with its connection (as either negotiated or unregulated transmission services) and once through TUOS charges (in its capacity as a customer).

QUESTION 22: STORAGE AND TUOS - CURRENT ARRANGEMENTS

Do stakeholders have any comments on the AEMC's initial views in this section? Are there any other arguments that are not discussed here?

Questions to consider if changing the current allocation of TUOS charges

Below are a set of questions that would need to be addressed under any future proposal to change the payment of TUOS charges by energy storage systems, including as a consequence of changing the market participant category in which they are required to be registered. In order to meet the long-term interests of consumers (that is, further the NEO) it would have to be demonstrated that the benefits of the chosen approach outweigh the costs.

164 With the exception of those that are grandfathered as prescribed transmission services under rule 11.6.11.

165 As a consequence of the *Transmission connection and planning arrangements* rule change.

1. Does the approach align with the principles that underpin the transmission framework?

As explained earlier in this section and in Chapter 3, the fundamental principles that underpin the existing transmission framework are that the purpose of the network is to supply electricity to consumers, and that consumers of electricity pay for the costs incurred by the TNSP in providing the shared transmission services from which they benefit. Because energy storage systems withdraw electricity from the grid like other consumers, careful consideration would need to be given to the implications for other participants if energy storage systems were to be exempt from TUOS charges.

Such an approach may require a change to these fundamental principles. As explained in Chapter 3, any change to these fundamental principles would have broader impacts across the regulatory framework than just the consideration of TUOS charging.

However, as set out previously, several aspects of the existing regulatory framework (including reliability standards) appear to be based on the assumption that Transmission Customers 'end consume' the electricity supplied by means of the transmission network, or represent consumers who 'end consume'. A re-definition of what it means to 'consume' energy could be explored to create a distinction between 'end-consumers' and energy storage systems who consume for the purposes of generating later.[166]

2. What is the policy objective? Is that objective technology / participant neutral?

Several of the reasons put forward by stakeholders for not allocating TUOS charges to energy storage systems seek to achieve particular policy objectives – for example to support the uptake of energy storage or incentivise the provision of system services. It will be important to clearly define the policy objective and determine whether the NER is the appropriate means to achieve that objective.

Consideration of technology neutrality is also important when defining this policy objective. For example, arguments that suggest energy storage systems shouldn't pay TUOS charges on the basis that they provide ancillary services do not recognise that other non-energy storage Customers are also able to provide ancillary services. This therefore raises the question of whether these parties should be exempt as well.

The current arrangements treat all transmission customers the same, regardless of what services they provide to the grid or how much it otherwise costs them to be financially viable. Exempting energy storage providers from TUOS charges raises questions about the implications for other parties that withdraw electricity from the network. There are 74 registered Customers in the NEM and an unknown number of non-registered Customers, all of whom are liable for TUOS charges.[167] Clear justification would need to be found for exempting energy storage systems from TUOS charges if these other parties are to continue to pay them.

166 This raises the issue of whether storage should only pay TUOS on the net consumption, that is, total consumption less the amount that is exported.

167 All consumers pay TUOS via their distribution use of system charges.

As noted earlier in this section, it is not the AEMC's role to "pick winners" through the regulatory framework. Rather, the AEMC seeks to maximise economic efficiency in the long-term interests of all consumers. In the AEMC's view, any incentives for the uptake of particular technologies or the provision of particular services are best determined by governments as an overlay to the technology-neutral framework that the NER seeks to provide.

3. <u>What impact would the approach have on the allocation of TUOS charges to other parties?</u>

Continuing to allocate the costs of the transmission network to those parties who benefit from the prescribed shared transmission services that it provides (i.e. Transmission Customers) means that other parties would not be taking on these costs.

If you assume that the total cost of prescribed TUOS services remains constant and has to be recovered, then reducing the pool of parties from whom it can be recovered means that the remaining pool must pay more.

For example, if all Customers were exempted from paying TUOS charges, these costs would be entirely allocated to DNSPs (and passed on to consumers) and other TNSPs (if applicable, who would then pass those costs on to DNSPs in their region). The network component of retail customers' bills would therefore likely increase.

Careful consideration would need to be given to whether the benefits of the chosen policy objective being achieved outweigh any negative impacts on other consumers.

QUESTION 23: STORAGE AND TUOS - CONSIDERING CHANGING EXISTING ARRANGEMENTS

Are there any other matters that should be addressed if a change to the existing arrangements is considered?

Additional considerations

There are a number of other matters that would need to be taken into account when considering the approach to the recovery of TUOS charges.

- *Magnitude of TUOS charges*

It is not clear to the AEMC how much TUOS charges are as a proportion of a market customer's costs.[168] The magnitude of these costs would support an understanding of the potential impact of changing the allocation of TUOS charges. If transmission prices were truly cost reflective, TUOS charges would be based on the contribution of load that a customer imposed on the network at times of peak; then TUOS charges for energy storage systems would be low, given it would be expected that they are exporting at peak, not consuming.

168 The AEMC's 2017 residential electricity price trends report stated that transmission and distribution costs account for around 40-55 percent of bills. See: https://www.aemc.gov.au/sites/default/files/content/bf56a5d5-e2b2-4c21-90ed-79dda97eb8a4/2017-Residential-Electricity-Price-Trends.pdf

- *Recovery of prescribed common transmission charges*

Any change to the way in which TUOS charges are recovered may necessitate consideration of the way prescribed common transmission services are recovered more broadly.

As set out above, prescribed common transmission services are those that provide equivalent benefits to all Transmission Customers (and other TNSPs) who have a connection point with the relevant transmission network without any differentiation based on their location. They are recovered on a postage stamp basis.

If it were to be determined that energy storage systems should not pay cost reflective TUOS charges, it would also be prudent to consider whether they should also be exempt from paying prescribed common transmission services.

- *DUOS charges*

Any change to the arrangements by which TUOS charges are allocated may require similar changes in approach to DUOS charges, to ensure consistency across the transmission and distribution frameworks.

- *Approaches being taken in other jurisdictions*

Australia is not alone in grappling with the regulatory challenges associated with new technologies such as energy storage. Other jurisdictions, such as the UK and the USA are also seeking to address the questions set out in this chapter. While many aspects of those markets are different to the NEM, the analysis and decisions made in those jurisdictions would be useful for the AEMC and stakeholders if considering any regulatory change.

QUESTION 24: STORAGE AND TUOS - ADDITIONAL CONSIDERATIONS

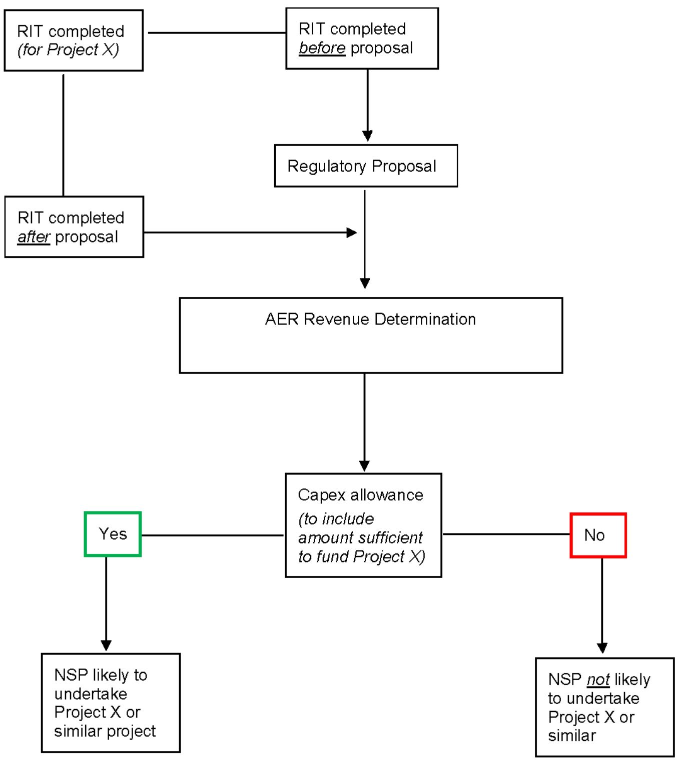
Are there any other considerations that are not covered here?

9 ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AREMI	Australian Renewable Energy Mapping Infrastructure
COAG	Council of Australian Governments
Commisison	See AEMC
DNSP	Distribution Network Service Provider
ESCRI-SA	Energy Storage for Commercial Renewable Integration, South Australia
ESB	Energy Security Board
FCAS	Frequency Control Ancillary Services
ISP	Integrated System Plan
LRPP	Last Resort Planning Power
MLF	Marginal loss factor
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National electricity objective
NER	National Electricity Rules
NGR	National Gas Rules
NTNDP	National Transmission Network Development Plan
RCP	Regulatory control period
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SENE	Scale Efficient Network Extensions Rule
TAPR	Transmission Annual Planning Report
TCAPA	Transmission Connection and Planning Arrangements Rule
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System Charges

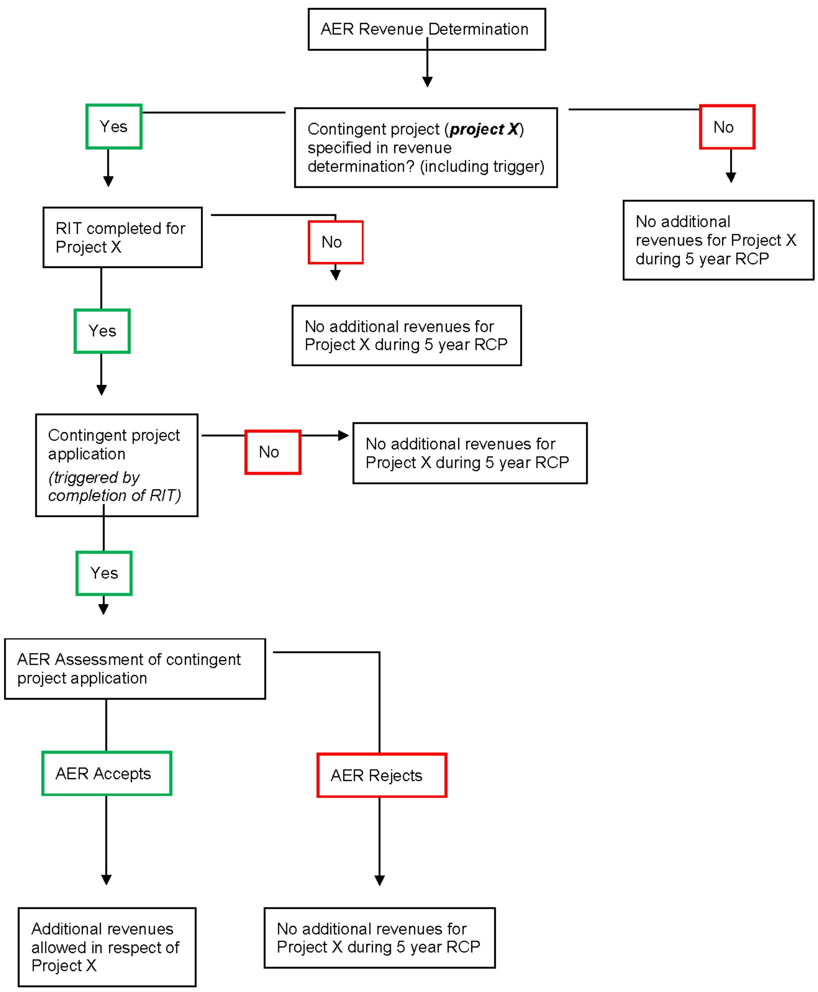
A RIT-T RELATED PROCESSES

Figure A.1: Process for AER approval of revenues - standard process



Source: AER

Figure A.2: Process for AER approval of revenues - contingent project



Source: AER

Figure A.3: Time taken to complete RIT-Ts to date (weeks)

RIT-T	Submission period on consultation report	Time between close of submissions and draft report	Submission period on draft report	Time between close of submissions and final report	Total Time between consultation report and final report
Completed projects where capital costs are more than $41m					
Minimum under the NER	12	N/a	6	N/a	**N/a**
AEMO - Regional Victoria Thermal Capacity – Ballarat and Bendigo	12	18	7	25	**62**
AEMO, ElectraNet - Heywood interconnector	17	48	8	18	**66**
Powerlink, TransGrid - Qld to NSW interconnector	23	69	9	23	**125**
TransGrid - Powering Sydney's Future	13	16	7	19	**55**
Completed projects where capital costs are less than $41m					
Minimum under the NER	12	0	0	0	**12**
Powerlink - Maintaining a reliable electricity supply to the Bowen Basin	13	26	6	17	**62**
AEMO - Victorian Reliability Support (deferred after final report)	13	0	0	6	**19**
ElectraNet: Dalrymple substation upgrade	13	0	0	7	**30**

Source: AER

B SUMMARY OF STAKEHOLDER SUBMISSIONS ON REZ OPTIONS

B.1 REZ option 1: Enhanced information provision

Stakeholders expressed support for this enhanced information provision option for defining a REZ. Reach Solar suggested in its submission that a review of this type of approach would be warranted shortly after it was implemented to determine whether it was achieving the desired results.[169]

In its submission, Snowy Hydro supported this option as it could be facilitated through the existing framework, with the recently commenced TCAPA Rule likely to enable generators to connect to the transmission network faster than under the previous arrangements.[170] The TCAPA Rule amendments to the framework that took effect on 1 July 2018 improve transparency, contestability and clarity in the connection framework with the aim of making it easier and cheaper for generators to connect to the network - and so to develop REZs.[171] Similarly, the AEC stated this option may act to facilitate investment.[172]

The ability of the current regulatory framework and process for coordinating transmission and renewable energy investment, supplemented by more effective coordination and information from AEMO and TNSPs, was endorsed by UPC Renewables in its submission.[173] Similarly, in its submission, PIAC supported this option and viewed that there is a strong opportunity for AEMO to strategically coordinate information related to transmission planning and provide this to the market in its role as the national transmission planner and developer of the ISP.[174] PIAC also noted that industry and stakeholders have already taken steps to proactively make this information available through other avenues such as the Network Opportunity Maps developed by the Institute for Sustainable Futures and Energy Networks Australia.[175] Qualifying its support for option 1, PIAC stated that while enhanced information provision alone is unlikely to fully unlock the benefits of new generation connection, it is an important enabler and should be examined further and implemented in addition to other regulatory arrangements for REZs.[176]

The CEC shared the view that the enhanced information provision option may not be enough to drive coordinated investment in REZs in its submission. The CEC suggested that while additional information being provided to the market is valuable, it is unlikely to provide the

169 Reach Solar, submission to discussion paper, *Coordination of generation and transmission investment*, 1 May 2018, p.2.

170 Snowy Hydro, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.5.

171 For further information on the changes to the transmission connection framework introduced by the TCAPA Rule, see Box 5.2 in the *Coordination of generation and transmission investment*, Discussion Paper, 13 April, p.55. See: https://www.aemc.gov.au/sites/default/files/2018-04/EPR0052%20-%20Discussion%20Paper%20for%20publication%20180413.pdf

172 Australian Energy Council, submission to discussion paper, Coordination of generation and transmission investment, 18 May 2018, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

173 UPC Renewables, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.1.

174 PIAC, submission to the discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.6.

175 Ibid.

176 Ibid.

change required to incentivise coordinated transmission and generation planning in the NEM as it represents an enhanced business-as-usual approach.[177]

Building on the last point made by the CEC, the submission from Renew Estate and Wirsol suggested that the necessary streamlining and alignment of infrastructure development timelines for transmission and generation would require consultation and engagement that goes beyond what option 1 proposed for facilitating REZs.[178]

B.2 REZ option 2: Generator coordination

In its submission to the discussion paper, PIAC stated that there are significant efficiencies possible if prospective generators coordinate their connections.[179]

As noted by TransGrid in its submission to the discussion paper, this option can occur under the existing regulatory framework via the SENE framework.[180] The SENE Rule made by the AEMC in 2011 requires transmission businesses to undertake and publish, on request, specific locational studies to reveal to the market potential opportunities for efficiency gains from the coordinated connection of expected new generators in a particular area. The study is designed to help potential investors make informed, commercial decisions to fund a SENE, having weighed the potential gains from coordinated, efficient generator connection arrangements against the potential costs of assets not being fully used. Decisions to fund, construct, operate and connect to a SENE would then be made by market participants and investors within the existing framework for connections in the NER.

Submissions from stakeholders raised a number of problems with the generator coordination option that suggest that it would not be effective in facilitating REZs. Reach Solar, the CEC and Renew Estate and Wirsol noted in their submissions that it would be difficult to get generators to coordinate connection processes in a commercial and competitive environment.[181] Without substantial changes to the current regulatory framework, PIAC's submission stated that it does not consider generator coordination a viable option for delivering efficient or timely coordinated generation connections.[182]

Energy Networks Australia, Powerlink and Snowy Hydro raised in their submissions that current confidentiality provisions which prevent the sharing of information with multiple proponents seeking connection to the transmission network within a region or zone are too limiting for TNSPs to initiate and drive coordination.[183] Powerlink encouraged the AEMC to

177 CEC, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3.

178 Renew Estate and Wirsol, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.1

179 PIAC, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.6.

180 TransGrid, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.5.

181 Reach Solar, submission to discussion paper, *Coordination of generation and transmission investment*, 1 May 2018, p.2, Clean Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3, Renew Estate and Wirsol, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.1.

182 PIAC, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.6.

183 Energy Networks Australia, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.8, PowerLink, submission to discussion paper, *Coordination of generation and transmission investment*, 21 May 2018, p.3, Snowy Hydro, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.5.

further consider how alternative arrangements to manage commercially confidential information may assist in promoting scale efficient transmission development through market-led solutions.[184]

In its submission, TransGrid highlighted its experience of the Renewable Energy Hub in New England to demonstrate the issues that arise when attempting to encourage generators to coordinate with each other. As part of this project, TransGrid conducted a feasibility study for establishing a shared connection hub to facilitate the connection of three existing generators and attract further energy projects in future.[185] Developing the connection infrastructure to be shared among multiple generators was estimated to cost less that stand-alone connections for individual generators.[186]

The commercial challenges encountered by TransGrid through this process included the potential for stranded assets if the connection infrastructure is underutilised, coordinating generator and TNSP construction timelines to ensure a return on investment is achieved as soon as possible, and incentivising competing generators to coordinate and facilitate cost savings for each other.[187] A further challenge identified by TransGrid was whether regulatory frameworks would enable a reasonable rate of return to be earned on the Renewable Energy Hub investment, commensurate with the risks, if upgrades to the shared transmission network were required to accommodate the Renewable Energy Hub and relieve congestion.[188] Ultimately, no investor was willing to fund the connection hub and accept the risks involved.

B.3 REZ option 3: TNSP speculative investment

In its submission, PIAC supported the concept presented in this option on the basis that networks are better placed to bear the risk of speculative investment and are entitled to enjoy the benefits of successful speculation. PIAC did, however, outline issues regarding the shift in cost-recovery for connection assets from the connection proponents themselves to consumers. PIAC's primary concerns included whether the speculative investment framework that exists for gas pipeline investments is appropriate for a REZ scenario given that anticipatory TNSP investment in the latter would reduce connection costs for generators.[189] The Commission notes that the direct costs savings from speculative investment in transmission infrastructure to facilitate a REZ would indeed be experienced by connecting generators, rather than consumers. While not a cost saving passed directly on to consumers, the effect of cheaper connection costs for potential generators on promoting increased competition in the wholesale market would arguably benefit consumers over the longer term.

184 PowerLink, submission to discussion paper, *Coordination of generation and transmission investment*, 21 May 2018, p.3

185 TransGrid, submission to the discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.5.

186 Ibid.

187 Ibid.

188 Ibid.

189 PIAC noted that "the speculative investment mechanism for gas pipelines was designed to allow network operators, while expanding their core regulated network to meet load growth, to build additional capacity in expectation of further load in the future. The return allowed on the original assets and the higher return allowed on the speculative portion of the assets would both be recovered from consumers. In the absence of the speculative investment, should the further load growth eventuate, additional assets would need to be constructed alongside the original which would be recovered from consumers." PIAC, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.7.

The other key issue raised by PIAC in its submission concerned how the higher rate of return for a TNSP speculative investment would be applied. Specific questions raised concern:

- how to determine when a speculative investment had been undertaken and when it should reasonably begin earning a return
- whether in fact a TNSP had taken on additional risk with such an investment
- what the higher rate's interaction is with the regulated base rate of return
- the period of time for which an asset should earn a higher rate of return.[190]

The Clean Energy Council noted in its submission that while the TNSP speculative investment option may be viable, TNSPs are not currently willing to take on the risk and this approach would require a significant change to their business models.[191] Building on this point, TransGrid stated in its submission that "TNSPs would need to be appropriately remunerated for the additional risk they would be exposed to…in the same way that other non-regulated businesses receive a return commensurate with the increased commercial risk."[192] More fundamentally, TransGrid assessed that "it remains unclear that the scale of investment required for system transformation would be delivered under this model, and the higher risk-rated financing costs would ultimately be recovered from consumers."[193]

B.4 Option 4: TNSP prescribed service

Submissions to the discussion paper raised a number of issues with this option. Of the four options presented by the Commission, Reach Solar favoured the TNSP prescribed service option for designated REZs in the medium-term. To facilitate it, Reach Solar suggested in its submission that "the optional firm access model may warrant further investigation in the future when there is less coincident regulation ongoing and be designed in a way that reduces the risk of (asset) stranding."[194] Business SA endorsed the suggestion made by the Commission in the discussion paper that a degree of generator commitment to a particular REZ be achieved before the transmission investment went ahead in order to reduce the exposure of consumers to the risk of stranded assets.[195]

While there was some support provided for the TNSP prescribed service option in stakeholder submissions, the majority of feedback cautioned against using this model for REZ development due to the significant risk that consumers would be exposed to from the potential for underutilised transmission assets. The AEC and CEC stated that this model poses

190 Ibid, p.8.

191 Clean Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3.

192 TransGrid, submission to the discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.9.

193 TransGrid, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.9. The Australian Energy Council made the point in its submission that the TNSP speculative investment option is not in the interests of consumers. AEC, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3

194 Reach Solar, submission to discussion paper, *Coordination of generation and transmission investment*, 1 May 2018, p.6.

195 Business SA noted that this point was conditional on the basis that transmission pricing structures appropriately distribute costs to consumers. Business SA noted that "in the case of ElectraNet's proposed Eyre Peninsula upgrades, without any public commitments from wind generation companies, South Australian business consumers more broadly feel too exposed to future costs they may bear through existing transmission pricing structures." Business SA, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.5.

a significant cost to consumers and is ultimately not in their interest.[196] The CEC also made the point in its submission that this type of framework would present a significant change to the current network business models.[197]

While noting that in certain instances it can be in the long-term interests of consumers to socialise some of the costs of enabling new generation connection, PIAC expressed reservations regarding this option in its submission. This concern was based on "the affordability crisis currently facing many energy consumers and the role that growth in the regulated asset base of many network businesses has played in driving this affordability crisis."[198] PIAC suggested that to mitigate against consumers being exposed to the risk of underutilised assets, powerful independent "oversight is required to ensure that such a model does not provide a windfall gain to TNSPs and that the benefits of unlocking new low-emissions and low-cost generation is passed through to consumers."[199]

B.5 Ideas suggested by stakeholders for how to implement REZs

Stakeholder submissions to the discussion paper suggested a number of new options to facilitate the connection of renewable generators to the transmission network. The Commission understands that these proposals are focussed on addressing two key issues that arise when anticipatory investment in transmission infrastructure is required to connect new renewable generators: how best to manage the allocation of risk to protect consumers; and how to promote the most efficient cost outcome and achieve economies of scale. These options are outlined in this section.

ENGIE's transmission bond idea[200]

- Potential REZs are identified through a process, for example the ISP or through the TNSPs own planning process.
- The relevant TNSP would estimate the cost of the project to augment the network to facilitate the development of a new REZ.
- The TNSP would issue transmission bonds of sufficient value to underwrite the project, based on the estimated costs. ENGIE's proposal notes that the bonds should be denominated as $/MW (notional capacity not firm capacity).
- Generator project proponents could choose which transmission projects they would like to underwrite through purchasing bonds. This choice would allow them to optimise their investment decisions by weighing up the relative costs and opportunities associated with different REZs.

196 AEC, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3, Clean Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3.

197 Clean Energy Council, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.3.

198 PIAC, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018, p.8.

199 PIAC also noted that oversight will be required for the sizing, timing and cost of transmission investment, and a threshold would likely need to be determined that identifies the required level of generator connection commitment before a REZ is developed. Ibid.

200 ENGIE, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018.

- When generator project proponents have chosen a particular REZ that they wish to locate at they can underwrite the required transmission investment that is needed to develop this REZ through the purchase of a transmission bond.
  - The transmission bond could be secured by cash or bank guarantee.
- The use of bonds that are available to generator proponents is a market-based means of gauging if there is sufficient interest in a given transmission investment to justify it going ahead. Crucially, it does not depend on generators, who are in competition with one another, coordinating their actions. Rather the decision to secure bonds for a given investment is made by each generator individually.
  - If generator project proponents do not secure a sufficient amount of bonds to fund the transmission investment, the project will not go ahead.
  - If a sufficient number of bonds are secured by generator project proponents, the investment will go ahead.
  - If the bonds are over-subscribed the TNSP:
    - may examine the potential to expand the project, based on the large amount of interest in this particular location and provide additional bonds to the value of the expanded project; or
    - allocate the available bonds using an agreed methodology, for example, first-come-first-served.
- A secondary market could be established where generator projects could trade the bonds between themselves. This would help to make sure that only the most cost-effective projects go ahead.
- To avoid a potential "free-rider" problem, it may be necessary to require that a generator holds transmission bonds related to that project in order for them to connect to a REZ. This requirement would need to be time-limited. This requirement would also incentivise secondary trading on bonds.
- If a generation project that holds transmission bonds proceeds the bondholder is eligible for a refund of the bond valued at the time of purchase from the TNSP. In this way new generators connecting to the transmission network are treated the same as incumbent generators, in that they are not paying for transmission investment above what is needed to facilitate their direct connection.
- If a generation project that holds transmission bonds does not proceed, the bondholder can:
  - Attempt to sell the bond to another project
  - Would forfeit the cost of the bond, therefore consumers do not bear the risk associated with this project.
- This model would allow for governments to fund transmission investment, if they so wished. This would be done by the government buying any shortfall in bonds associated with a particular transmission investment. The government could sell the bonds to project proponents or use the bonds to fund the investment outright. In this case the

government would not be refunded by the TNSP for the amount of bonds that were purchased.

There are several potential benefits of this option. It protects consumers from bearing the risk of underutilised assets, placing the risks of transmission infrastructure investment with those parties best placed to manage them. This option also overcomes the issue of requiring generators to coordinate with each other in order to facilitate the investment as each individual generator makes its own decision about whether to secure bonds for a particular investment. Additionally, this model provides a vehicle through which to implement the idea that anticipatory transmission investments only proceed when a certain threshold of generator connection commitment is reached.

Issues that would require further consideration regarding this option include how the prices of bonds would be determined by TNSPs, the process that TNSPs would go through and whether these decisions would be open to review. It is possible that small renewable developers would not be able to afford transmission bonds under this model, pricing them out of the market and reducing competition designed to put downward pressure on electricity prices for consumers. A further issue concerns the timing of generator development versus that of the transmission infrastructure if the TNSP is waiting to sell a certain number of bonds before commencing construction. It may not be commercially viable for generators to wait for others to purchase bonds, let alone for the transmission infrastructure to be built.

TransGrid's proposed regulatory arrangements to facilitate REZs[201]

- The following steps be taken to expand of the capacity of, and extension of, the existing shared network to strengthen electricity flow pathways between population centres and from priority large scale REZs:
    - AEMO provide a single recommended development pathway in the ISP that outlines priority projects, including REZs, required across the NEM and the timeframes in which they should be developed.
    - TNSPs apply the RIT-T to individual projects using AEMO's single recommended development pathway as the "base case" for assessment.
    - The AER ensures that the proposed TNSP investment is efficient in meeting the requirements of the ISP as part of its regulatory determination processes.
    - TNSPs incorporate ISP projects into existing jurisdictional and joint planning processes (such as TAPRs).
    - This process is dependent on AEMO providing precise and actionable recommendations in the ISP based on a clearly defined set of scenarios and assumptions, and the AER clarifying how the ISP scenarios and assumption values should be treated in a RIT-T in its RIT-T application guidelines.
- To facilitate the optimisation of generator connection assets and potentially overcome some of the commercial barriers to generator coordination discussed in section 6.2.2,

201 TransGrid, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.4.

connection assets could initially be funded as a prescribed service until generators pay to connect.

The benefits and potential issues with the regulatory changes that TransGrid has proposed to integrate the ISP into the RIT-T process are discussed in the context of the role of the ISP in Chapter 4. With regard to the proposal that anticipatory investment in connection assets be funded as a prescribed service until generators pay to connect, this would place the risk of stranded assets on consumers, who are not in the best position to manage these risks.

Ausgrid's submission to the discussion paper suggested three separate options for improving the existing arrangements for the coordination of transmission infrastructure investment and the connection of renewable generation. These are described at a high level below: the first seeks to promote competition in the construction and ownership of network assets; the second would enable network service providers and their customers to share in the risks associated with proactively investing in REZs; and the third option put forward by Ausgrid considers a 'Pioneer Scheme' to reimburse renewable generators who first connect to a REZ.

Ausgrid's contestable augmentations idea[202]

- This option suggests applying elements of the transmission planning arrangements in Victoria to the REZ locations throughout the NEM. It shares some of the key features of option 5 discussed in Chapter 4.
- In Victoria, the planning and ownership of the declared shared network is split between AEMO and TNSPs. AEMO is responsible for planning and directing augmentations to the network, and plans and procures services from third parties to achieve this. Where AEMO assesses that network or non-network development is needed based on a cost-benefit analysis of the market impact of network limitations, augmentation projects may be competitively tendered.
- Step one would involve a robust, comprehensive and transparent consultation process through which stakeholders can suggest potential REZ locations. This consultation could be triggered based on requests that a particular site be developed as a REZ, or AEMO could periodically invite stakeholders to suggest REZ locations.
- This step would enable coordination in the investment process that Ausgrid suggests would not be possible if left to the market alone.
- Step two would involve AEMO making a declaration that a particular site has REZ status, initiating a process for the contestable delivery of network augmentations. Ausgrid argued that the declaration process that is supported by substantial consultation is likely to give generation investors confidence in where to invest.
- Any party, including the incumbent TNSP, should be able to bid in the competitive tender process for the construction of the network infrastructure. Ausgrid noted that the competitive tension between applicants would be likely to incentivise them to bid at their efficient costs.

202 Ausgrid, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018; AEMO, Victorian Electricity Planning Approach, June 2016.

- Ausgrid viewed that the level of capacity for the augmentation should be based on the long term potential of the site given the renewable energy resources available as this would:
    - unlock the economies of scale needed for it to be efficiently sized over its technical life; and
    - allow for the immediate connection of renewable generators as and when they arrive, rather than having to wait for the augmentation to be further reinforced each time a new generator connects.
- Given that anticipatory investment in transmission infrastructure is a feature of this option, Ausgrid considered the ideal model for recovery of the costs of the investment:
    - Ideally it would be possible to operate within a fully unregulated model, where a third party asset owner bids to build, own and operate the augmentation, underwritten by a group of 'foundation' generators (who would likely enter into take-or-pay arrangements with the asset owner and seek to recover the costs through their wholesale market participation).
    - In this scenario the third party asset owner would then take on the risk, and potential upside, of revenue associated with later generators connecting. Ausgrid noted that this model may have issues both from a financing perspective and from a market power perspective for the generators that connect later.
    - Ausgrid subsequently noted that these could be mitigated through risk sharing with NSP customers (the amount and duration of which would be part of the competitive tender process), and/or through a 'light regulation' model as is used for some gas transmission pipelines.

ERM Power also highlighted this type of infrastructure investment model in its submission. ERM Power suggested that AEMO could identify the most efficient outcomes for the market and call for expressions of interest to fund or fund, build, own and operate unregulated infrastructure.[203] Funding would not be limited to the incumbent TNSP, and would be open to contestable parties interested in funding this type of investment including government agencies such as the Clean Energy Finance Corporation.[204]

Ausgrid concluded that the primary benefit of this option is that it combines central planning with market based implementation. The Commission agrees that the role of consultation in the identification of REZs is integral to ensuring that the best outcomes for consumers are achieved. Introducing competitive tensions into the network augmentation process to achieve the most efficient cost outcome is a key benefit of this option.[205]

203 ERM Power, submission to discussion paper, *Coordination of generation and transmission investment*, 17 May 2018, p.4.

204 Ibid.

205 In Victoria, transmission projects are considered to be contestable if the capital cost of the augmentation is reasonably expected to exceed the relevant limit ($10 million), the augmentation is distinct and definable, and it will not have a material adverse effect on the incumbent declared transmission operator's ability to provide services to AEMO under any relevant network agreement. See: Clause 8.11.3, and 8.11.6(a)(1) and (2) of the NER.

One issue that would require further consideration is whether the AEMO planning and REZ designation function described by Ausgrid and also highlighted by ERM Power could be fulfilled through the ISP process. The role of the ISP is explored in Chapter 4.

Ausgrid's 70:30 stranded asset risk sharing mechanism idea[206]

- Network investment risk is shared between the customer and the NSP, using the same formula administered by the AER for efficiency gains and losses through the Efficiency Benefit Sharing Scheme and the Capital Expenditure Sharing Scheme.
- For network augmentation to a location rich in renewable energy resources but which may not necessarily have any generation capacity committed to the area, or a designation as a REZ site from an independent authority:
  - 70 percent of network investment would be rolled into the NSP's regulated asset base
  - an ex post review would be conducted into the efficiency of the network investment to determine whether the remaining 30 percent should be rolled into the regulated asset base and recovered from customers
- Ausgrid views this risk sharing ratio may strike the right balance between encouraging efficient investment and protecting consumers. It provides certainty to NSPs that they will be able to recover at least 70 percent of the capital expenditure they incur, while not providing incentive to overinvest given the risk that shareholders could be forced to cover 30 percent of the costs of an inefficient investment.
- Ausgrid explained that the establishment of an ex post review to consider if the full costs of a proactive investment should be rolled into the regulated asset base is a necessary second step - NSPs are unlikely to make an investment of a proactive nature if they do not at least have an opportunity to recover their full costs.[207]
- Ausgrid suggested that the ex post review should include consideration of the following:
  - whether a prudent NSP in the same circumstances would have made the investment.
  - whether an economic level of generation capacity has been reached in relation to the investment at a subsequent AER determination where the NSP's regulated asset base roll-forward is under consideration.

The benefit of this option for anticipatory investment in transmission infrastructure is that some of the risk is placed with the entity making the investment decision. The Commission agrees with the point made by Ausgrid in its submission that NSPs are likely to be in a position to manage the risks associated with a network asset becoming stranded, and therefore should have some of that risk placed on them.[208] The Commission also acknowledges that if a network business faces an artificially high risk they may not choose to undertake an investment, even if it is efficiency enhancing and would provide a benefit to market participants and customers.

206 Ausgrid, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018.

207 Ausgrid noted that the opportunity to recover the full cost of proactive investments is also consistent with the Revenue and Pricing principles in the NEL. Section 7A(2) requires that a 'regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs.'

208 Ausgrid, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018.

One issue that would require further consideration is the type of network augmentation that the risk sharing mechanism should apply to. Would the mechanism only be required for the portion of a prescribed transmission service project that involves anticipatory investment, that is, the infrastructure being built to accommodate potential future generator connections, or would it apply to the whole project, or indeed all REZ-related transmission investments?

Ausgrid's Pioneer Scheme idea[209]

- This idea would apply to situations where renewable generators at REZ locations are required to fund the cost of network augmentations.
- Renewable generators seeking to connect to part of the network funded by another generator within a certain period of time would make a 'Pioneer Scheme' payment that would be passed on to that generator.
- Ausgrid, along with some other distributors in the NEM, currently operate this type of scheme for new load connections.
- Ausgrid stated that this approach may lead to more efficient procurement of network infrastructure because the opportunity to recover a 'Pioneer Scheme' payment may incentivise generators to fund an augmentation that is sized to meet the capacity of future generation, unlocking the economies of scale required for efficient network investments.

Issues arising from Ausgrid's Pioneer Scheme idea that would require further consideration concern the level of incentive placed on generators to fund augmentations. Ausgrid highlighted that the risk adjusted cost to a generator that factors in a future Pioneer Scheme payment and contracts to build a higher capacity than they strictly require must be lower than the cost they would incur if they funded a smaller connection that meets their capacity requirements alone. As noted by Ausgrid, the level of risk – given the size of the connections at the transmission level – may also be too great for renewable generators to want to participate in such a scheme. Further to this point, as stakeholders raised in submissions to the discussion paper for this review, generators may not wish to participate in activities that benefit other generators due to commercial competitive tensions. One generator building transmission infrastructure that is large enough to accommodate the connection of future generators could be viewed as assisting those generators to reach the market in which they will be competitors.

The issue of applying a time limit for when the original generator that made the transmission infrastructure investment can recover payments from subsequent generators connecting to the network also requires further consideration. In its submission to the discussion paper, Renew Estate and Wirsol highlighted an issue identified with the consideration of a SENE development in Victoria that is also relevant to Ausgrid's Pioneer Scheme idea.[210] The SENE design allowed generator projects to share connection costs which were initially paid by the first connecting party with costs then recovered by subsequent connecting parties. However,

209 Ausgrid, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018.

210 Renew Estate and Wirsol, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2.

by applying a cut-off time for cost recovery, generators would be incentivised to sit on the sidelines and wait for the time limit to expire prior to connecting.[211]

In its submission, Ausgrid noted that its three ideas outlined above do not need to be considered on a mutually exclusive basis.

ERM Power's idea to share costs among multiple parties based on the reliability rating of generators[212]

In its submission to the discussion paper, ERM Power described another option for allocating the costs of new transmission infrastructure based on a generator's ability to reliably supply consumers at times when they value this the most.

- This option suggests sharing the costs associated with transmission infrastructure between generators, consumers and TNSPs.
- The value that a particular type of generation provides to consumers at high demand times based on how "firm" it is – how quickly and easily it can be dispatched at any given time – would be determined.
- AEMO could be tasked to align the calculation of a generator's contribution to reliability. ERM Power suggested that this could be done through a similar process as the calculation of a generator's contribution to reliability in the Projected Assessment of System Adequacy or Energy Adequacy Assessment Projection.
- The costs of the regulated portion of transmission infrastructure investment would be recovered from consumers based on generators' reliability value scores. For example, if consumers are receiving electricity from "firmer" sources, they would pay for a higher percentage of the necessary transmission infrastructure than they would pay if the electricity was coming from less "firm" sources.
- After subsequent changes were made to "firm up" a particular generator, such as the addition of a battery to a wind or solar farm, the costs could be incorporated into future regulatory reset reviews.

ERM Power stated that this approach will incentivise generators to secure "firmer" generation output when most needed by consumers.[213] There are a number of issues for consideration in reviewing this option. Providing a "firmness" rating to generators for the purpose of determining TUOS charges could bias investment towards a certain type of generation technology, and potentially lead to overinvestment in transmission infrastructure in certain areas, the cost of which is passed on to consumers. The current transmission framework is technology neutral and does not speak to types or specific attributes of generation. Incorporating determinations of a generator's "firmness" into regulated transmission service cost recovery would incentivise investment in particular types of technology, the value to consumers of which would need to be considered further.

211 Renew Estate and Wirsol, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2.

212 ERM Power, submission to discussion paper, *Coordination of generation and transmission investment*, 17 May 2018.

213 Ibid.

As outlined in section 6.3, models for the facilitation of REZs that involve generators paying for transmission infrastructure beyond that required to connect them to the transmission network are not consistent with the current open access framework in the NEM. An assessment of an option that might facilitate REZs needs to include consideration of this point.

Marginal Loss Factors

While not an idea for how to implement a REZ, stakeholders did identify managing marginal loss factors (MLFs) as a challenge for the NEM that will grow in importance as more renewable generators connect to the transmission network, and suggested a solution. In the ISP, AEMO provided a comprehensive summary of what a MLF is and why it is important when thinking about REZs, provided in Box 7.

BOX 7: AEMO'S EXPLANATION OF MLFS AND REZS

Energy is lost as it travels through the transmission network, and these losses increase as more generation connects in locations that are distant from load centres. In the NEM, MLFs are applied to market settlements, adjusting payments to reflect the impact of incremental energy transfer losses.

MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node, in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers. In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator's revenue is directly scaled by its MLF, through both electricity market transactions and any revenue derived from large-scale generation certificates created if accredited under the federal Large-scale Renewable Energy Target.

Increasing generation within a REZ is likely to increase losses between the REZ and the regional reference node, decreasing the MLFs for the REZ. The MLFs attributable to generators located in some REZs will be more sensitive to change as a result of new connecting generators than other REZs, particularly where they are distant from major load centres and interconnection is relatively weak.

Investors in new generation are concerned about the effect of decreased MLFs on their potential returns, and the uncertainty of how MLFs can vary from one year to the next. Generators in locations that are strongly connected to major load centres have MLFs that are less likely to change over time.

For a generator, an MLF represents the amount of electricity delivered to the regional reference node for a marginal (next MW) increase in generation; for a load, the MLF represents the amount of power that would need to be generated at the regional reference node for a marginal (next MW) increase in demand. In simple terms, a higher MLF is good for a generator's revenue, while a lower MLF is good for a load (as it means it is not paying for energy lost before it reaches the load). Marginal loss factors will change over time, most often

> decreasing as additional generation connects in an area."

Source: AEMO, *Integrated System Plan*, July 2018, pp.52-53.

In its submission to the discussion paper, PIAC said that MLFs are changing at a faster rate than earlier in the NEM, noting that an existing generator's MLF can change due to the subsequent connection of another generator.[214] As the MLF is calculated for each connection point in the transmission network and not apportioned according to a causer-pays principle, there is limited incentive (or signal) for connecting parties to reduce their impact on the MLF of other participants.[215] PIAC stated that the volatility in MLFs will likely increase as more generators connect to the network in more remote locations.[216]

PIAC suggested addressing this issue by introducing a system which better signals the impact that a single connecting party has on loss factors, outlined below.[217]

PIAC's marginal loss factor idea[218]

- Connecting parties could have their MLF 'locked in' by AEMO for a standard period of time – allowing the party greater certainty of its future revenue.
- If a new party were to connect nearby and affect the local MLF, this change would be borne by the second party alone rather than being spread across both parties.
- This provides a much stronger signal to minimise the impact on loss factors, such as by incorporating storage.
- Once the determined period of time has elapsed, the MLFs are no longer 'locked in' and the revised loss factor at the connection point is applied to both parties.

Renew Estate and Wirsol noted in its submission that loss factors have a relatively large impact on determining the success of a renewable energy project.[219] Renew Estate and Wirsol stated that the current forecast of loss factors are highly variable from year to year and become almost unreliable within months, and that the NEM could be changed from the existing regional model to a nodal model. The argument in favour of such a change is that it would provide an incentive to renewable generator developers to locate in certain areas of the network, and likely aid the successful development of a REZ.[220]

214 This can materially affect the future revenue, and hence value proposition, of the generator.

215 PIAC, submission to discussion paper, *Coordination of generation and transmision investment*, 23 May 2018, p.10.

216 Ibid.

217 Ibid.

218 PIAC, submission to discussion paper, *Coordination of generation and transmision investment*, 23 May 2018, p.10.

219 Renew estate and Wirsol, submission to discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, p.2.

220 Ibid.

C DESCRIPTION OF CURRENT TUOS CHARGING ARRANGEMENTS

C.1 What are TUOS charges?

The NER define four categories of prescribed transmission services provided by TNSPs for the purposes of pricing:

1. Prescribed entry services.
2. Prescribed exit services.
3. Prescribed common transmission services.
4. Prescribed TUOS services.

Prescribed entry services and prescribed exit services relate to connection services provided by means of the transmission network and are not discussed any further in this section.

Under the NER, prescribed common transmission services are defined as those that "provide equivalent benefits to:

1. all Transmission Customers who have a connection point with the relevant transmission network without any differentiation based on their location within the transmission system; and
2. TNSPs in interconnected regions, without any differentiation based on the location of their direct or indirect connection or interconnection with the relevant transmission system".

The NER requires that the recovery of the costs of prescribed common transmission services be done on a postage-stamp basis – that is, have a common value across all locations.

Under the NER, prescribed TUOS services are defined as those that "provide specific benefits to:

1. Transmission Customers who have a connection point with the relevant transmission network, based on the location of that connection point within the transmission system; and
2. Transmission Network Service Providers who have a direct or indirect connection or an interconnection with the relevant transmission network, based on the location of that connection or interconnection within the relevant transmission system."

Collectively, prescribed common transmission services and prescribed TUOS services are referred to in the NER as prescribed shared transmission services.[221] As evident in the definitions above, the difference between prescribed common transmission services and prescribed TUOS services relates to whether the services provide <u>equivalent</u> or <u>specific</u> benefits to Transmission Customers and other TNSPs.

221 Shared transmission service is defined in Chapter 10 of the NER as "a service provided to a Transmission Network User for use of a transmission network for the conveyance of electricity (including a service that ensures the integrity of the related transmission system)."

Transmission Customer is defined in the NER as "a Customer, Non-Registered Customer or Distribution Network Service Provider having a connection point with a transmission network." So, prescribed TUOS services are, by definition, only provided to loads and DNSPs (or another TNSP), not generators. The test for determining whether something is a prescribed TUOS service is therefore that it provides a specific benefit to a Transmission Customer (or another TNSP) based on the location of its connection point (or interconnection).

Under the NER, the AER is required to produce pricing methodology guidelines, which must be consistent with, and give effect to, the pricing principles for prescribed transmission services that are set out in the NER. The TNSP's pricing methodology must comply with the requirements of the guidelines and must also give effect to, and be consistent with, the pricing principles.

The AER's transmission pricing methodology guidelines state that the types of transmission system assets that are directly attributable to prescribed common transmission services are limited to:

- substation buildings, substation land and associated infrastructure (such as fences, earthing equipment etc)
- power system communications networks
- control systems
- network switching centres (excluding generation and system control functions)
- static and dynamic reactive control plant and associated switchgear
- spare plant and equipment including that installed at substations
- fixed assets such as buildings and land that are not associated with substation or line easements, (head office buildings, land for future substations etc.)
- motor vehicles and construction equipment.[222]

The guidelines state that the types of transmission system assets that are directly attributable to prescribed TUOS services are limited to:

- substation buildings, substation land and associated infrastructure (such as fences, earthing equipment etc)
- transmission lines and associated easements
- switchgear on transmission lines and auto-transformers which are part of the transmission network and are switched at the substation including associated bus work and control and protection schemes
- auto-transformers which transform voltage between transmission levels
- static and dynamic reactive plant and associated switchgear and transformation regardless of the voltage level
- all system controls required for monitoring and control of the integrated transmission system including remote monitoring and associated communications, load shedding and

222 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/pricing-methodology-guidelines-2014

special control schemes and voltage regulating plant required for operation of the integrated transmission system."

While not explicit in the NER, TUOS charges (not a defined term) are used by TNSPs to recover the costs associated with their provision of prescribed TUOS services.

C.2 How are TUOS charges calculated?

Chapter 6A of the NER, among other things:

- regulates the revenues that may be earned by TNSPs from the provision of transmission services
- regulates the prices that may be charged by TNSPs for the provision of prescribed transmission services
- establishes principles to be applied by TNSPs in setting prices that allow them to earn the whole of the aggregate annual revenue requirement.[223]

The NER require a TNSP to submit to the AER a revenue proposal and a proposed pricing methodology relating to the prescribed transmission services that are provided by means of, or in connection with, a transmission system that is owned, controlled or operated by that TNSP.[224]

The NER explain that a pricing methodology is a methodology, formula, process or approach that, when applied by a TNSP:

- allocates the aggregate annual revenue requirement for prescribed transmission services provided by the TNSP to each category of prescribed transmission services
- provides for the manner and sequence of adjustments to the annual service revenue requirement
- allocates the annual service revenue requirement to transmission network connection points (other than connection points of any Market Network Service Provider)
- determines the structure and recovery of prices for each category of prescribed transmission services.[225]

Rule 6A.23 of the NER sets out the pricing principles for prescribed transmission services. As above, a TNSP's pricing methodology is required to be consistent with these principles and set out how the TNSP will give effect to them through its pricing of prescribed transmission services.

Specifically, clause 6A.23.3 of the NER sets out the principles for the allocation of the annual service revenue requirement to transmission network connection points. One of these principles is that the annual service revenue requirement for prescribed TUOS services is to be allocated 50/50 (or an alternative allocation if it provides more efficient locational signals)

223 The aggregate annual revenue requirement (AARR) is the calculated total annual revenue to be earned by an entity for a defined class or classes of service. The AARR for prescribed transmission services is the maximum allowed revenue that a TNSP may earn in any regulatory year of a regulatory control period from the provision of prescribed transmission services. See clause 6A.3.1 of the NER.

224 See clause 6A.10.1(a) of the NER.

225 See clause 6A.24.1(b) of the NER.

between a locational component and a non-locational component. These components are then required to be adjusted to account for a range of factors, including applicable settlements residue and modified load export charges.

The NER requires that:

- prices for recovering the adjusted locational component of prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network by Transmission Customers and for which network investment is most likely to be contemplated
- prices for recovering the adjusted non-locational component of prescribed TUOS services must be on a postage stamp basis.

Therefore, transmission pricing may be considered somewhat cost reflective, but not fully. It is important to remember that it is highly unlikely that transmission pricing could ever be completely cost reflective given the complexities associated with it.

The AER's transmission pricing methodology guidelines specify permitted pricing structures for the recovery of the adjusted locational component of providing prescribed TUOS services, and permitted postage stamp pricing structures for the recovery of the adjusted non-locational component of providing prescribed TUOS services.

AEMO, as the party responsible for the provision of prescribed shared transmission services in Victoria, explains that:[226]

- Locational charges reflect the cost of utilising the network at various locations. They are designed to encourage the most efficient use of the transmission network and are based on average maximum demand. They reflect the long run marginal cost of transmission at each connection point.
- Non-locational charges recover the balance of the TNSP's annual revenue for providing the shared transmission network, and mainly relate to overhead and financing costs. The non-locational price is either an energy or capacity price, each of which has a common value across all locations.

A summary of how Powerlink calculates these components is set out in Table C.1.[227] This can be considered an example of how TUOS charges are calculated by one TNSP in the NEM.

Table C.1: **Summary of transmission charges, prices, conversion factors and invoice quantities**

TRANSMISSION CHARGES	TRANSMISSION PRICES	CONVERSIO N FACTORS	INVOICE QUANTITIES
Prescribed TUOS (non-locational)	**Prescribed TUOS (non-locational)**	Historical energy and	Either Historical energy or

226 See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Fees/2018/Electriciy-Transmission-Use-of-System-Prices-1-July-2018—-30-June-2019.pdf

227 This can be considered an example of how TUOS charges are calculated by one TNSP in the NEM.

TRANSMISSION CHARGES	TRANSMISSION PRICES	CONVERSION FACTORS	INVOICE QUANTITIES
(adjusted for settlement residue and any over or under collection from previous years)	Energy based (c/kWh) or demand based ($/kW/month)	maximum contract demand	maximum contract demand
Prescribed TUOS (locational)	**Prescribed TUOS (locational)** Demand based ($/kW/month)	Sum of average historical half-hourly demand, and either historical demand or maximum contract demand	Sum of measured average half-hourly demand, and either nominated demand or maximum contract demand

Source: Powerlink Queensland, Regulated transmission pricing, Version 225.12, p.4.

C.3 Who currently pays TUOS charges?

It is not explicitly stated in the NER that a TNSP must recover the costs of prescribed TUOS services from Transmission Customers and other TNSPs (i.e. those that, by definition, receive the services). Rather, it is the definition of prescribed transmission service, the definitions of the categories of prescribed transmission services, the pricing principles and TNSPs' pricing methodologies that establish a basis by which the costs of prescribed TUOS services are recovered from those parties.

So, in practice, the costs of prescribed TUOS services are recovered from Transmission Customers and other TNSPs through TUOS charges. As stated above, Transmission Customers include Customers, Non-Registered Customers and DNSPs that have a connection point with the transmission network.

TUOS charges are therefore not currently recovered from generators. The remainder of the analysis in this chapter assumes that this will continue to be the case.

TUOS charges are passed on to individual consumers via DNSPs – that is, through the network component of a retail bill. These requirements are set out in the distribution pricing rules. Rule 6.18 of the NER sets out the distribution pricing principles. Clause 6.18.7(a) requires a DNSP's tariffs to be designed to pass on to retail customers[228] the "designated pricing proposal charges" that are to be incurred by the DNSP. The "designated pricing proposal charges" are the charges for "designated pricing proposal services", which are

228 A retail customer is defined in Chapter 10 of the NER as "A small customer or a large customer". A small customer is defined in section 5 of the National Energy Retail Law and includes residential customers and certain business customers.

defined to include prescribed TUOS services. Therefore, the charges for prescribed TUOS services are ultimately passed on to end-users.

Neither the NER nor the AER's transmission pricing methodology guidelines appear to contemplate that prescribed common transmission services and prescribed TUOS services might also provide benefits to parties other than Transmission Customers and other TNSPs, i.e. generators. The current arrangements (i.e. that generators do not pay TUOS charges) reflect the overarching objective of the design of the current transmission framework that is set out in Chapter 3.

This principle that networks exist to supply electricity to customers is reflected throughout the NER, including:

S5.1.2.1 Network Service Providers must plan, design, maintain and operate their transmission networks and distribution networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service….