REVIEW

Australian Energy Market Commission

CONSULTATION PAPER

TRANSMISSION PLANNING AND INVESTMENT REVIEW

19 AUGUST 2021

INQUIRIES

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Reference: EPR0087

CITATION

AEMC, Transmission Planning and Investment Review, Consultation paper, 19 August 2021

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.

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1 INTRODUCTION

This chapter introduces the Review and details:

- the purpose and focus of the Review
- the reasons for the Review
- the Commission's approach to the Review
- how the remainder of the consultation paper is structured.

1.1 Purpose and focus of the Review

The National Electricity Market (NEM) is experiencing a significant transition away from reliance on thermal generation towards demand being principally met by geographically dispersed renewable generation. Substantial investment in transmission infrastructure is required to underpin the transition to clean energy and bring power from new renewable generation and storage to consumers. It is important that the regulatory framework can accommodate discrete investments of the size and scale required for the energy transition, and that it is sufficiently robust to effectively manage the uncertainty stemming from the pace of Australia's energy transition.

The Commission has therefore self-initiated this Review to:

- identify issues with the existing regulatory frameworks in relation to the timely and efficient delivery of major transmission projects
- explore options for reform of or improvements to the existing regulatory frameworks
- recommend possible changes to the National Electricity Rules (NER) and other regulatory instruments (if required) to support frameworks that are fit-for-purpose and promote the timely and efficient delivery of transmission services.

The Commission has prepared this consultation paper to facilitate public consultation and to seek stakeholder feedback on the identification and prioritisation of key issues and proposed solutions. The Commission has identified two overarching issues with the existing regulatory frameworks for consultation:

1. **The transmission planning framework**: Is the existing ex-ante incentive-based framework 'fit for purpose' to support the timely and efficient delivery of major transmission projects?
2. **The framework for transmission investment and delivery:** Is TNSPs' existing exclusive right to build and own transmission projects but no corresponding obligation to invest and deliver these projects leading to uncertainty regarding such major projects proceeding? The consultation paper will specifically consider:
   - the potential for financeability challenges in the delivery of major infrastructure projects, and
   - whether the delivery of major transmission projects should be made contestable.

More specifically, the consultation paper identifies the following questions and potential issues with the **regulatory framework for transmission planning**:

- Is the existing ex-ante incentive-based approach to regulation appropriate in light of the significant intrinsic uncertainty associated with the costs and benefits of major discrete transmission investments? (Section 3.1)
- Is the economic assessment process too complex and impacting the timely delivery of projects? (Section 3.2)
- Treatment of benefits in the transmission planning process (section 3.3), in terms of:
  - Are the benefits included in current planning processes (i.e., the ISP and RIT-T) sufficiently broad to capture the drivers of major transmission investment? (Section 3.3.1)
  - Is there a disconnect between what is required under the Rules and feasible in practice and does this disconnect warrant guidance on hard to monetise benefits? (Section 3.3.2)
  - Have changes occurred in the energy sector that warrant reconsidering the merits of a market versus consumer benefits test? (Section 3.3.3)
- Are there barriers that prevent the equal treatment of non-network options under the RIT-T? (Section 3.4)

With regard to the **regulatory framework and processes for transmission investment and delivery**, the consultation paper outlines the following potential issues and questions:

- Are changes to the exclusive right of TNSPs to provide regulated transmission assets required or what other options could be considered to ensure timely investment and delivery of major transmission projects? (Section 4.1)
- Issues that may impact on the project planning and delivery phase (section 4.2), more specifically:
  - Is clarification on the treatment of 'preparatory activities' and 'early works' required? (Section 4.2.1)
  - What is the impact of jurisdictional environmental and planning approval processes on the timely and efficient delivery of transmission investment and are any changes necessary? (Section 4.2.2)

Although the Commission identified these initial issues with the existing frameworks, the Review is not limited to these issues and therefore welcomes feedback from stakeholders on other issues that may impact the timely and efficient delivery of major projects.

1.2 Reasons for the Review

1.2.1 A pipeline of major transmission investments is required to support the energy transition

Major transmission investment is required to facilitate Australia's energy transition in line with the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) and beyond.[1] Further, jurisdictions are identifying and planning Renewable Energy Zones (REZs), with major transmission required to support and bring this energy to consumers.

1 AEMO, *2020 Integrated System Plan,* July 2020, p. 9.

The magnitude of anticipated investment brings into focus the need for the regulatory framework to accommodate the substantial investment and effectively manage the uncertainty of the transition, as such major discrete projects have a greater degree of uncertainty than business-as-usual (BAU) transmission investment.[2] For the purposes of this consultation paper, the Commission considers major transmission projects to be projects of a significant size, scale and scope such that they are associated with greater uncertainty relative to BAU investments. These can be ISP or non-ISP projects.

The objective of the Review is to ensure that the regulatory frameworks strike an appropriate balance between requiring rigorous assessment, to mitigate the risk of inefficient transmission investment, and the need to facilitate timely investments that deliver beneficial outcomes. Consumers will be paying for these projects for decades into the future and it is therefore important that they are in the long term interest of consumers. As such, it is imperative that the regulatory framework for assessing and approving them remains fit-for-purpose.

1.2.2 The Commission committed to a review to explore options to support the timely and efficient delivery of major transmission projects

The Commission considered that the *Participant derogation – Financeability of ISP projects (TransGrid and ElectraNet)* rule changes raised some significant issues, in particular in relation to the timely and efficient delivery of major transmission projects (including current and future ISP projects). These issues were considered to be broader in their scope than could be addressed by the Commission in the rule changes. For this reason, the Commission proposed that the AEMC should explore options to support the timely and efficient delivery of major transmission projects in a review outside of the rule change process.[3]

The rule changes brought to light a characteristic of the current regulatory framework that could lead to projects not being delivered - notably that currently TNSPs have an exclusive right, but no corresponding obligation, to deliver transmission projects under the national regulatory framework.[4]

The Commission considered that an advantage of initiating a review is that it creates an opportunity to first understand the cause of an issue, i.e. if the cause relates to matters that fall under the NER, NEL or within jurisdictional regulatory instruments.[5] On this basis, the Commission can then consider a suite of possible measures to address the identified issues within or outside of the Rules framework, if necessary and appropriate.[6]

2 I.e. each of these individual projects is by itself of a significant size, which is different to small projects within a significant investment portfolio which would allow for diversifying the risk within a portfolio.

3 AEMC, *Participant Derogation – Financeability of ISP Projects (TransGrid)* and *Participant Derogation – Financeability of ISP Projects (ElectraNet)*, Final determination, 8 April 2021, p.vii.

4 With the exception of Victoria, where transmission is contestable subject to specified criteria including that it must have a capital cost over $10M and must be deemed by AEMO to be separable.

5 AEMC, *Participant Derogation – Financeability of ISP Projects (TransGrid)* and *Participant Derogation – Financeability of ISP Projects (ElectraNet)*, Final determination, 8 April 2021, p.vi.

6 For example, under the NEL, determination of the rate of return is the responsibility of the AER. As part of this responsibility, the AER is required to publish a new rate of return instrument (RORI) every four years, and is currently consulting on the 2022 RORI which will bind all regulatory determinations in the subsequent four years. The Commission will continue to work closely with the AER to assess the relevance of any issues raised through the RORI Review in relation to regulatory framework level considerations explored through the Commission's Review.

1.3 Approach of the Review

The Commission is initiating this Review of the regulatory frameworks for transmission planning and investment under section 45 of the National Electricity Law (NEL).[7]

In completing the Review, the Commission will follow a two-staged process:

1. **Stage 1:** identify and test issues associated with the frameworks for planning, funding and delivering major transmission projects.
2. **Stage 2:** identify and develop solutions to address the issues identified in Stage 1.

In developing its advice, the Commission will work closely with the other market bodies and consult with a range of stakeholders through various public consultation processes. In particular, the Commission:

- has established a Market Bodies Advisory Group, which will draw on the expertise of the market bodies, and the significant relevant work already undertaken by them, to assist the Commission in meeting the Review's objectives
- has established a Jurisdictional Reference Group, which will be used to inform and consult with state and federal government representatives on the Commission's progress in the Review
- will draw on the Commission's existing Investor Reference Group to develop a thorough understanding of investor decision-making processes
- will engage with broader market participants and consumer groups, including but not limited to Energy Consumers Australia (ECA), through consultative forums.

1.3.1 Assessment framework

This section sets out the Commission's proposed assessment framework for the Review. It first discusses the overarching objectives that guide all of the Commission's work, including this Review. It then outlines the criteria that we propose to use in testing whether reforms to the regulatory framework promote these energy objectives.

National Electricity Objective

This Review is considering potential changes to the NER. As such, the national energy objective relevant to this Review is the National Electricity Objective (NEO):[8]

> 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:
>
> (a) price, quality, safety, reliability and security of supply of electricity and
>
> (b) the reliability, safety and security of the national electricity system.

Consistent with the terms of reference for the Review, the Commission considers that the relevant aspects of the NEO are the promotion of efficient investment in, and efficient

7 Part 4 of the NEL sets out the functions and powers of the AEMC. Under Division 5 of Part 4, the AEMC has the power to conduct a review into the operation and effectiveness of the National Electricity Rules (NER).

8 Section 7 of the NEL.

operation and use of electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, security and reliability.[9]

Assessment framework criteria

The assessment framework will use the criteria summarised in Table 1.1 to assess whether proposed recommendations are likely to promote the NEO.

Table 1.1: **Proposed assessment framework criteria**

CRITERIA	EXPLANATION
Effectiveness	• Assesses whether the regulatory arrangements promote the timely and efficient delivery of transmission projects.

Economic efficiency	• Assesses whether the solution promotes efficient investment in, and use of, electricity services in the long term interests of consumers with regard to:
	  • **Efficient risk allocation:** allocating risk (and costs) to parties best placed to manage them and who have the incentives to do so will support efficient decision making.
	  • **Effective price signals/incentives:** effective incentives are needed to support service providers in making efficient and timely investment decisions.
	  • **Information provision/transparency:** service providers require clear adequate information to inform decision making in an evolving market.
	  • **Clear, consistent, predictable rules:** a stable regulatory environment creates confidence in the market and will encourage investment and innovation through the transition and beyond.
	• Evaluates whether the solution provides service providers with a reasonable opportunity to recover at least their efficient costs.

Implementation	• Considers the complexity of implementing a solution, i.e. whether it will require law and rule changes or other jurisdictional legislative changes. • Assesses the costs of implementing a solution (practical implementation and compliance costs) • Evaluates the timing of costs and benefits.
Flexibility	• Assesses whether the solution is consistent with the long-term direction of energy market reform. • Evaluates whether the solution is flexible enough to accommodate uncertainty regarding unknown technological, policy and other changes

9 For a detailed discussion on the Commission's approach to applying these overarching objectives to rule making processes and reviews, such as this one refer to AEMC, *Applying the energy objectives: A guide to stakeholders*, 8 July 2019, available on the AEMC's website www.aemc.gov.au.

CRITERIA	EXPLANATION
	that may eventuate.

QUESTION 1: ASSESSMENT FRAMEWORK

1. Do you agree with the Commission's proposed assessment framework for this Review? Are there any additional criteria the Commission should consider as a part of its assessment framework?

1.3.2 Prioritisation framework

As noted above, the purpose of the first stage of the Review is to identify and test issues associated with the regulatory frameworks for planning, funding and delivering major transmission projects. The remainder of this consultation paper sets out the Commission's understanding of a number of issues identified with these frameworks. However, the Commission anticipates that stakeholders will raise additional issues. The Commission notes that the purpose of the Review is to examine critical issues to promote efficiency for consumers through reform for upcoming ISP and non-ISP projects. The Review may therefore be unable to consider all issues raised in consultation in order to ensure timely reform of the regulatory frameworks for efficient delivery of ISP projects.

The role of the prioritisation framework is to clearly explain the Commission's rationale for focusing on particular issues during the second stage of the Review. Prioritisation of issues is intended to enable the Commission (with the input of stakeholders) to identify the set of issues that the Review will consider and which will deliver the greatest prospective gains to consumers.

To give effect to the prioritisation framework, the Commission intends to assess issues in relation to:

- **materiality** by reference to the economic efficiency criteria of the assessment framework, the Commission will consistently evaluate issues to determine the prospective gains for consumers
- **feasibility** by reference to whether the issue is within the remit of the Commission, other market bodies or jurisdictions.

While the Commission outlines in the remainder of this consultation paper its preliminary view on the prioritisation of issues to date, it notes that the framework will be applied to all issues raised within the consultation. In this way, the purpose of the prioritisation framework is to determine the order of issues that will make up the second stage of the Review, as well as a rationale and plan for managing any outstanding issues.

1.3.3 Lodging a submission and next steps

As noted in section 1.2, the Commission has established formal forums for engagement with the market bodies, jurisdictional representatives and investors.

In developing its advice, the Commission will further consult with a range of stakeholders through a public consultation process following publication of the consultation paper and draft report. Public workshops and forums to gather feedback and discussion papers on issues raised by stakeholders may also be undertaken over the course of the Review.

The key project milestones are highlighted in Table 1.2 below:

Table 1.2: **Key milestones for the Review**

MILESTONE	DATE
Submissions on consultation paper due	30 September 2021
Complete Stage 1 of the Review	Q4 2021
AEMC to publish draft report	Q4 2021
Complete Stage 2 of the Review	Dependent on the scope of Stage 2 of the Review
AEMC to publish final report	Dependent on the scope of Stage 2 of the Review

Lodging a submission

Written submissions on this consultation paper must be lodged with the Commission by 30 September 2021 online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code EPR0087.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions.[10] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

Stakeholders are encouraged to use the stakeholder submissions template when providing feedback to the consultation paper.

All enquiries on this project should be addressed to Rupert Doney on (02) 8296 7800 or rupert.doney@aemc.gov.au.

1.4 How the consultation paper is structured

The remainder of the consultation paper is structured as follows:

- Chapter 2: provides an overview of the economic regulatory framework, as well as the planning and investment framework

10 See for further information here: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

- Chapter 3: sets out the Commission's understanding and prioritisation of issues already identified in relation to the regulatory frameworks and processes for transmission planning
- Chapter 4: sets out the Commission's understanding and prioritisation of issues identified in relation to the regulatory frameworks and processes for transmission investment, and delivery.
- Chapter 5: sets out the issue and consultation questions for the *Material change in network infrastructure project costs* rule change request, which will be considered concurrent to this Review given the focus on issues central to the transmission planning and investment process.

2 OVERVIEW OF EXISTING ARRANGEMENTS

The energy transition being experienced in the NEM has been the catalyst for significant changes to the planning and investment framework for transmission infrastructure. These changes have predominantly occurred at the planning stage to better coordinate and facilitate investment in electricity transmission networks. Most notably, there has been a move towards greater centralisation of planning. Examples of this shift towards centralisation include:

- AEMO's development of the ISP, supported by the introduction of the actionable ISP rules and guidelines
- the ongoing establishment of jurisdictional specific planning arrangements, particularly in relation to the development of REZs, to meet renewable energy targets.

The purpose of this chapter is to provide background relevant to understanding the issues set out in chapters three and four. Specifically, this chapter describes:

1. the operation of the economic regulatory framework that applies to transmission services
2. the planning and investment framework for major transmission infrastructure.

2.1 Economic regulation of transmission services

TNSPs are regulated by the Australian Energy Regulator (AER), consistent with the ex-ante incentive based framework set out in Chapter 6A of the NER.[11] Accordingly, major transmission projects fall under this regulatory framework.

The regulatory framework has been designed to provide incentives for TNSPs to run efficient businesses and promote consumers paying no more than necessary for safe and reliable service. Put simply, the framework by which the AER regulates the revenues and prices of TNSPs is intended to promote the long term interest of consumers by providing incentives for TNSPs to provide services at their efficient costs.[12] These revealed efficient costs are then used to inform the regulation of future prices.

The main features of the regulatory framework are:

- **Ex-ante incentive based regulation**: The AER sets allowances (such as capital expenditure allowances) over a regulatory control period. Incentive schemes encourage TNSPs to make efficient investment decisions. If a TNSP is able to outperform its allowance (such as actual capital expenditure being lower than the allowance), while still meeting other targets (e.g., reliability), it is permitted to keep a proportion of the underspend for a period of time, with the balance passed on to consumers through lower prices. However, TNSP may be required to spend more than its forecast capital expenditure during a regulatory control period due to circumstances outside of its control

11 The rate of return instrument is set outside of Chapter 6A, pursuant to Part 3, Division 1B of the NEL. The AER may make an instrument only if satisfied the instrument will, or is most likely to, contribute to the achievement of the national electricity objective to the greatest degree. In making an instrument, the AER must have regard to the revenue and pricing principles.

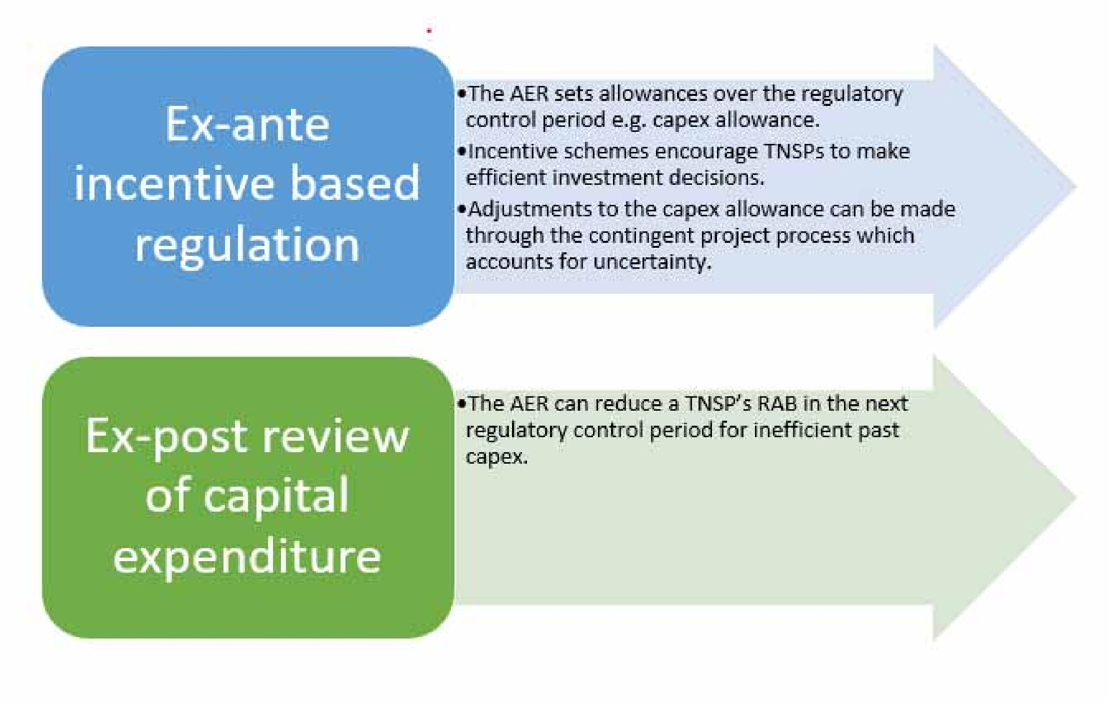
12 A detailed overview of the economic regulation of natural monopolies can be found in: AEMC, *Financeability of ISP projects,* Consultation Paper, 5 November 2020, p. 5.

or as a means of managing significant uncertainty. Specific arrangements, such as the contingent project process, account for such major capital expenditure projects where the timing or cost of the project is uncertain due to external factors.

- **The potential for ex-post review of capital expenditure**: The AER may exclude some or all of over-spending from the regulated asset base (RAB), where it determines that this expenditure is not prudent or efficient.

Figure 2.1 illustrates the main features of the economic regulatory framework and the remainder of this section discusses the key elements of the economic regulatory framework.

Figure 2.1: Features of the economic regulatory framework



Source: AEMC.

2.1.1 Ex-ante revenue cycle and contingent project process

TNSPs are regulated on an ex-ante basis, with the Rules requiring the use of a revenue cap form of price control for prescribed transmission services.[13] For each regulatory control period (which must be at least five years in length),[14] TNSPs must submit a revenue determination for approval by the AER. This regime is structured to provide each TNSP with a 'bucket' of forecast capital expenditure at the beginning of each regulatory control period, from which it is able to allocate to meet service reliability requirements and seek out opportunities for productive efficiency gains.

13 Clause 6A.4.2 of the NER.

14 Clause 6A.4.2(c) of the NER.

Determination of revenue cap

The revenue cap is derived using a building block assessment. The application of the building block model is designed to allow for a return commensurate with the regulatory and commercial risks involved in providing prescribed transmission services with reference to a hypothetical efficient firm. The framework does not consider actual businesses, including their capital structure, actual debt costs or profitability. The components of the model (i.e., the building blocks) are set out in clause 6A.5.4 of the NER, with subsequent rules detailing how the components should be measured, and include:[15]

- return on capital (to compensate investors for the opportunity cost of funds invested in the business)
- return of capital (depreciation, to return the initial investment to investors over time)
- operating expenditure (to cover the day-to-day costs of maintaining the network and running the business)
- costs of corporate taxation.

Incentives to encourage efficient investment

Incentive schemes encourage TNSPs to pursue efficiency improvements in capital and operating expenditure, whilst not lowering service quality for consumers. The capital expenditure sharing scheme (CESS) is an incentive mechanism that rewards TNSPs for efficient capital expenditure and shares the benefits with consumers. It operates by measuring efficiency gains and efficiency losses by reference to the difference between the approved capital expenditure forecast and actual capital expenditure.

As a result, it places some of the risk of over-performance and under-performance against expenditure forecasts on TNSPs as opposed to consumers. Efficiency gains and losses are shared between TNSPs and consumers, whereby TNSPs retain approximately 30 per cent of an under-spend or over-spend.

Adjustments to the revenue cap through the contingent project process

Although the revenue cap is determined at the start of the regulatory control period, there are a number of mechanisms incorporated into the regulatory framework that address the risk a TNSP may be required to spend more than its forecast capital expenditure during a regulatory control period due to circumstances outside of its control or as a means of managing significant uncertainty.[16]

15 Additional building blocks include revenue increments/decrements relating to incentive schemes.

16 If there is a cost overrun, the TNSP still has options to reprioritise and/or defer capital expenditure to remain with its allowance, even if this is more challenging for larger projects and/or larger cost overruns. While there are risks that increase project costs during delivery, there are also risks and efficiencies that decrease project costs.

If a general overspend occurs then no adjustment of the revenue cap occurs. However, where the timing or cost of the project is uncertain due to external factors, in particular, the contingent project process addresses the issue of major capital expenditure projects.[17]

Contingent projects are incorporated into the revenue allowance through the contingent project application (CPA) process. As noted above, contingent projects are significant network augmentation projects that may arise during a regulatory control period, but the need, timing and/or cost of the project is uncertain. As such, project costs are not provided for in expenditure forecasts for a regulatory control period. Rather, contingent projects are linked to unique investment drivers, which are defined by a 'trigger event'. When a trigger event occurs, the proponent is able to submit a CPA to seek an increase to the revenue allowance to fund the project.

The precise trigger event depends on whether the investment is an actionable ISP project or not. For actionable ISP projects, the contingent project trigger is set out in clause 5.16A.5 of the NER and involves the following criteria:

- publication of a project assessment conclusion report (PACR) that meets the RIT-T procedures for actionable ISP projects
- written confirmation from AEMO that (the AEMO feedback loop):
  - the preferred option addresses the identified need specified in the most recent ISP and aligns with the optimal development path referred to in the most recent ISP
  - the cost of the preferred option does not change the status of the actionable ISP project as part of the optimal development path
- no dispute has been raised with respect to the RIT-T (or any dispute has been resolved)
- the cost of the preferred option must not exceed the costs considered in the AEMO feedback loop.

For non-ISP projects, the contingent project trigger is set by the AER when it determines to accept a proposed contingent project in a revenue proposal.[18]

The purpose of the CPA process is for the AER to assess the proposed expenditure by reference to the capital expenditure and operating expenditure criteria and factors.

2.1.2 Ex-post review of capital expenditure

Clause S6A.2.2A of the NER provides the AER with the ability to make reductions to a TNSP's RAB for inefficient past capital expenditure through the ex-post review mechanism. Although a reduction may be made by reference to a number of factors,[19] the most relevant for this Review is the overspending requirement, which is satisfied when the sum of all capital expenditure incurred during the review period exceeds forecast capital expenditure, taking

17 Clause 6A.8 of the NER. Other arrangements to account for additional costs exist in the form of 1) cost pass-through provisions, addressing additional costs (or cost reductions that occur during the regulatory control period, due to specific factors, such as any change in an externally imposed service standard obligation, where these exceed the materiality threshold, see clause 6A.7.3 of the NER, and 2) capital expenditure reopener provisions, where the NSP faces a major increase in capital expenditure requirements due to factors that could not have been foreseen at the time of the determination, see clause 6.A.7.1 of the NER.

18 Clause 6A.8.1(c) of the NER.

19 Clauses S6A.2.2A(b)-S6A.2.2A(e) of the NER.

into account adjustments such as contingent projects. In conducting an ex-post review based on the overspending requirement, the AER may only make a reduction determination by reference to the capital expenditure factors, and the information and analysis that the TNSP could reasonably be expected to have considered or undertaken at the time.[20]

2.2 The planning and investment framework under the NER

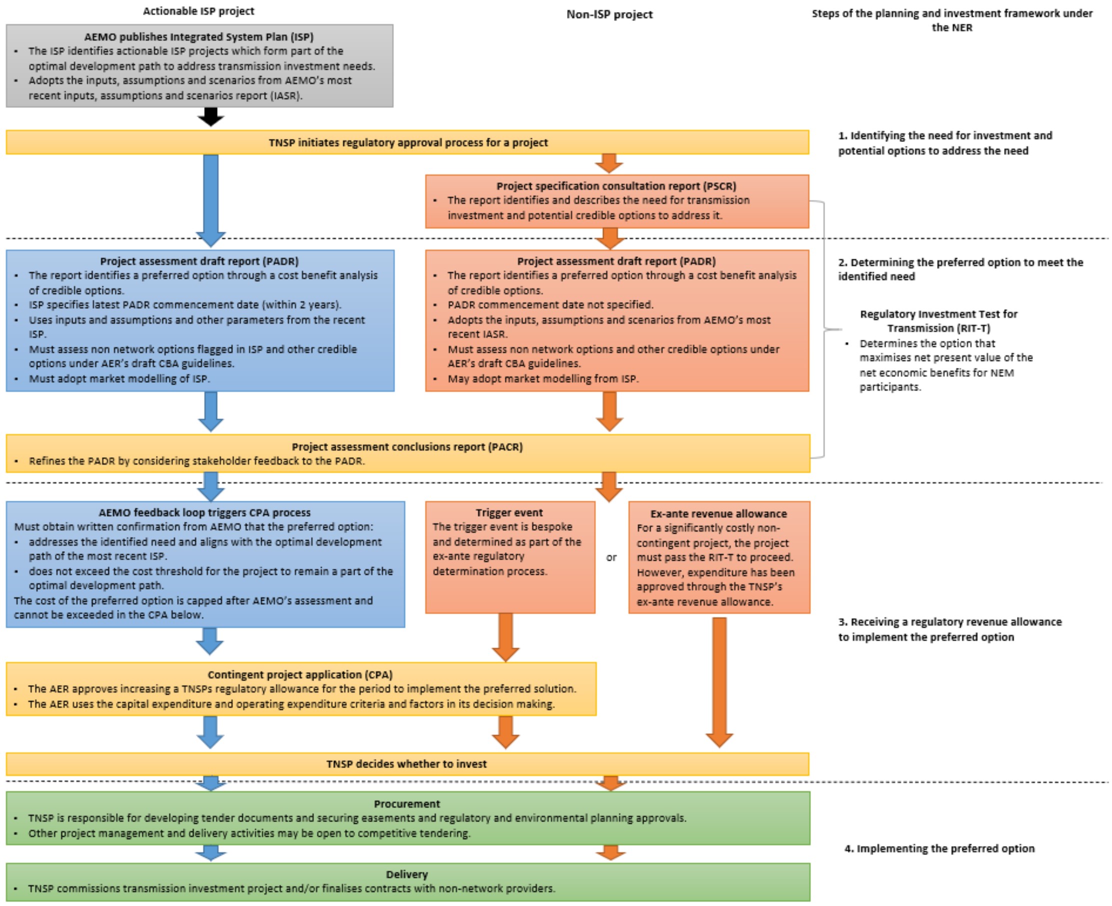
Broadly speaking, the planning and investment framework for major transmission projects under the NER comprises four steps. These are:

1. Identifying the need for investment and potential options to address the need
2. Determining the preferred option to meet the identified need
3. Receiving a regulatory revenue allowance to implement the preferred option
4. Implementing the preferred option.

Although the steps of the planning and investment framework broadly align between actionable ISP projects and non-ISP projects, the precise nature of how an investment proceeds through each step differs. The remainder of this section provides a detailed overview of these steps which are outlined in figure 2.1, highlighting the differences between actionable ISP and non-ISP projects where relevant.

20 Clause S6A.2.2A(h) of the NER.

Figure 2.2: Overview of key steps in the planning and investment framework



Source: AEMC.

2.2.1 Identifying the need for investment and potential options to address the need

The first step in the planning and investment framework for major transmission projects is identifying the need for investment. The identified need is defined in the NER as:[21]

> The objective a Network Service Provider or a group of Network Services Providers seeks to achieve by investing in the network in accordance with the Rules or an Integrated System Plan.

21 See definition of 'identified need' in chapter 10 of the NER.

The definition of identified need also highlights that the identified need stems from either the Rules or AEMO's ISP.[22] This reflects a key difference between actionable ISP and non-ISP projects with respect to the identified need, namely:

- for actionable ISP projects, AEMO canvasses the identified need and potential options in its ISP, whereas
- for non-ISP projects, the TNSP canvasses the identified need and potential options in the project specification consultation report (PSCR) of the regulatory investment test for transmission (RIT-T) in accordance with the Rules.

These two processes are summarised below.

Identifying the need for investment through the ISP

The first ISP was prepared by AEMO and endorsed by the former Council of Australian Government (COAG) Energy Council in 2018.[23] It has since guided governments, industry and consumers on investments needed for an affordable, secure and reliable energy future while meeting prescribed emissions trajectories, and triggered the processes for actionable ISP projects. The ISP is updated every two years and the latest version, the 2020 ISP, was released on 30 July 2020.[24]

The purpose of the ISP is to:[25]

> ...establish a whole of system plan for the efficient development of the power system that achieves power system needs for a planning horizon of at least 20 years for the long term interests of the consumers of electricity.

Power system needs are in turn defined in clause 5.22.3(a) of the Rules and are:

- the reliability standard
- power system security
- system standards
- standards or technical limitations in Schedule 5.1 of the NER or in an applicable regulatory instrument.

22 In this context it should be noted that under NER clause 5.12.1, TNSPs are required to undertake an annual planning review and publish a transmission annual planning report (TAPR). The purpose of the TAPR is to identify an optimum level of transmission investment, taking into account the most recent forecasts of new load and generation (and retirement), demand and condition and ratings of existing network assets. The TAPR provides information on the short-term to medium-term planning activities of TNSPs, i.e. the planning timeframe is 10 years, whereas the focus of the ISP is more long-term planning.

23 On 29 May 2021, the Prime Minister announced the establishment of the National Federation Reform Council and the disbanding of COAG. New arrangements for the former COAG Energy Council will be finalised following the National Cabinet Review of COAG Councils and Ministerial forums, which will provide recommendations to National Cabinet. The Prime Minister has advised that, while this change is being implemented, former Councils may continue meeting as a Ministerial Forum to progress critical and/or well-developed work.

24 AEMO, *2020 Integrated system plan,* July 2020, pp. 14-15.

25 Clause 5.22.2 of the NER.

In determining power system needs, AEMO may also consider a current environmental or energy policy of a participating jurisdiction where the policy has been sufficiently developed to enable AEMO to identify its impacts on the power system.[26]

In preparing the ISP, AEMO develops scenarios, inputs and assumptions,[27] which form the basis of its assessment of the transmission network's needs, i.e., the identified needs. These identified needs in turn shape the optimal development path — the set of candidate options for transmission investments and other electricity supply chain investments (e.g., non-network options) that AEMO determines best meets the power system needs over a 20-year horizon.

In preparing the ISP, AEMO must further consider the costs and certain classes of market benefits, i.e., costs and benefits relating to those that produce, consume or transport electricity in the market.[28] This consideration of market benefits is consistent with the benefits to be considered in the RIT-T. The market benefits to be considered in preparing the ISP include, for example, changes in fuel consumption arising through different patterns of generation dispatch, changes in voluntary load curtailment, changes in involuntary load shedding, and changes in the costs for parties due to differences in the timing of new plant, capital costs, and operating and maintenance costs.

Only the market benefits deemed to be material to the optimal development path in AEMO's reasonable opinion are required to be quantified.[29] However, all classes of market benefits must be considered to be material unless reasons can be provided as to why the class of market benefit is not material, or why the estimated cost of undertaking the analysis is disproportionate.[30] In addition to the market benefits specified in the Rules, AEMO (as well as RIT-T proponents of non-ISP projects) can propose other market benefits subject to approval by the AER.[31]

Identifying the need for investment through the RIT-T - the PSCR

The PSCR is the first stage in the RIT-T process for non-ISP projects. More broadly, the purpose of the RIT-T is to "identify the credible option that maximises the net present value of the net economic benefit to all those who produce, consume or transport electricity in the NEM (the preferred option)".[32]

More specifically, the purpose of the PSCR is to set out information regarding the identified need and the credible options to address the need. A PSCR must include:[33]

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26 Under clause 5.22.3(b) of the NER, for AEMO to consider the policy, it must be that: a commitment has been made in an international agreement to implement that policy, that policy has been enacted in legislation, there is a regulatory obligation in relation to that policy, there is a material funding allocated to that policy in a budget of the relevant participating jurisdictions and the MCE has advised AEMO to incorporate the policy.

27 This process is consultative and the NER requires both the AER and ISP Consumer Panel to review the scenarios, inputs and assumptions report. See clauses 5.22.7(d) and 5.22.9 of the NER.

28 Clause 5.22.10(c)(1) of the NER.

29 Clause 5.22.10(c)(2) of the NER.

30 Clause 5.22.10(c)(3) of the NER.

31 Clauses 5.22.10(c)(1)(x) and 5.15A.2(b)(4)(x) of the NER.

32 Clause 5.15A.1(c) of the NER.

33 Clause 5.16.4(b) of the NER.

- a description of the identified need and the assumptions used in identifying the identified need
- the technical characteristics of the identified need that a non-network option would need to deliver
- a description, and technical characteristics of, credible options that address the identified need.

Prior to the establishment of the ISP, RIT-T proponents would typically have regard to publications such as the National Transmission Network Development Plan (NTNDP). However, the NTNDP has been replaced by the ISP. As such, RIT-T proponents are now required to reference any discussion of the identified need or credible options in the most recent ISP (if applicable).[34] These linkages are described in greater detail below.

2.2.2 Determining the preferred option to meet the identified need

Regardless of whether the project is an ISP or non-ISP project, the second step in the planning and investment framework for major transmission projects under the national framework is determining the preferred option to meet the identified need.

The RIT-T is based on a cost benefit assessment that evaluates the resource cost and market benefits of transmission investments. Its core features include:

- consideration of NEM-wide costs and market benefits
- exclusion of benefits and costs outside of the NEM (otherwise known as externalities – making the RIT-T a market benefits test)
- assessment of market benefits that reflect resource savings or efficiency gains, as opposed to separating out financial benefits to customers, networks and generators, or between jurisdictions, associated with impacts on wholesale electricity prices.

Consistent with this purpose, RIT-T proponents are required to reapply the RIT-T if there has been a material change in circumstances which, in its reasonable opinion, means that the previously identified preferred option is no longer the preferred option.[35] This element of the NER is currently the subject of a rule change request (described in Chapter 5).

However, the application of the RIT-T differs across ISP and non-ISP investments — reflecting the central role of the ISP for actionable ISP projects, as set out in further detail below.

Application of the RIT-T to actionable ISP projects

The development of the actionable ISP framework led to significant changes to the application of the RIT-T to ISP projects. In particular, the actionable ISP framework strongly links the ISP to the subsequent application of the RIT-T. Whereas the ISP identifies candidate options at a high level, the RIT-T provides a subsequent, more detailed, technical analysis of the credible options — drawing on the local knowledge of RIT-T proponents (typically the relevant TNSP). This more granular analysis is particularly important to refining the cost estimates of each option that is being considered under the RIT-T.

34 Clause 5.16.4(b)(4) of the NER.

35 Clause 5.16.4(z3) and clause 5.16A.4(n) for non-ISP project and actionable ISP projects, respectively.

One key change is that the ISP replaces the PSCR for actionable ISP projects, reflecting the fact that the ISP contains the identified need and call for non-network options (i.e., a request for non-network option proponents to submit solutions that they consider address the identified need). As a result, RIT-Ts relating to actionable ISP projects comprise only two reports:

- the project assessment draft report (PADR), which presents an economic net present value assessment of each credible option against a base case that quantifies the costs and benefits under a set of reasonable individual and weighted scenarios
- the project assessment conclusion report (PACR), which builds upon the PADR by refining all matters presented in the PADR and responding to any submissions to the PADR.

The actionable ISP framework requires RIT-T proponents to:[36]

- quantify all classes of market benefits identified in the relevant ISP, though is permitted to consider other classes of market benefits
- adopt the identified need set out in the relevant ISP
- consider the ISP candidate option, non-network options identified in the ISP and any new credible options that were not previously considered in the ISP
- adopt the most recent ISP parameters (unless there is a demonstrable reason to vary from those parameters)
- adopt the market modelling of the ISP to the extent possible.

These linkages between the ISP and subsequent application of the RIT-T are designed to streamline the RIT-T process. One way in which this is achieved is by limiting the scope for disputes, since disputes cannot be raised to the PACR on matters that use or rely on the most recent ISP.[37] Disputes can be raised in respect of the ISP, but they are limited to matters of process.[38]

Application of the RIT-T to non-ISP projects

Non-ISP projects continue to be subject to the complete RIT-T process. This process requires the publication of three reports, i.e.:

- the PSCR, which identifies and describes the need for transmission investment and potential credible options to address it
- the PADR, which identifies a preferred option through a cost-benefit analysis of credible options
- the PACR, which refines the PADR by considering stakeholder feedback to the PADR.

The content of these reports is largely similar to that described with respect to actionable ISP projects. In particular, the RIT-T proponent:[39]

36 Clause 5.15A.3 of the NER.

37 Clause 5.16B(b)(3) of the NER.

38 Clause 5.23 of the NER.

39 AER, *Regulatory investment test for transmission,* Melbourne, August 2020, pp. 5-6.

- must adopt the inputs and assumptions from the most recent inputs, assumptions and scenarios report (unless there is a demonstrable reason to depart)
- must base its cost-benefit analysis on an assessment of reasonable scenarios for future supply and demand if each credible option were implemented compared to the situation where no option is implemented
- may, in so far as practicable, adopt the market modelling from the ISP.

2.2.3 Receiving a regulatory revenue allowance to implement the preferred option

The third step in the planning and investment framework for major transmission projects under the national framework is securing a regulatory revenue allowance to implement the preferred option. Given the size and uncertain nature of major transmission projects, funding is typically sought through the CPA process.

The AER's regulatory assessment is guided by the expenditure criteria[40] in the NER — being, the efficient costs that a prudent operator would require to achieve the expenditure objectives,[41] as well as a realistic expectation of the demand forecast and cost inputs required to achieve those objectives.

As described in section 2.1.1, the trigger for a CPA differs between actionable ISP and non-ISP projects. In particular, the contingent project trigger for an actionable ISP project is successful completion of the RIT-T and passing the AEMO feedback loop. This process involves seeking written confirmation from AEMO that:[42]

- the preferred option addresses the identified need specified in the most recent ISP and aligns with the optimal development path referred to in the most recent ISP
- the cost of the preferred option does not change the status of the actionable ISP project as part of the optimal development path.

The AEMO feedback loop also interacts with the contingent project process by capping the costs (and therefore revenue) that the TNSP can seek – the cost of the preferred option set out in the CPA must be no greater than the cost considered in AEMO’s assessment.[43]

For non-ISP projects, the contingent project trigger is set by the AER when it determines to accept a proposed contingent project in a revenue proposal.[44]

2.2.4 Implementing the preferred option

The fourth step of the planning and investment framework under the national framework is the implementation of the preferred solution, with this process being common across all major transmission projects (i.e., ISP and non-ISP).

40 That is, the capital expenditure criteria and the operating expenditure criteria. See clauses 6A.6.6(c) and 6A.6.7(c) of the NER.

41 Expenditure objectives refer to capital expenditure and operating expenditure objectives. These are set out in clauses 6A.6.6(a) and 6A.6.7(a) of the NER.

42 Clause 5.16A.5(b) of the NER.

43 Clause 5.16A.5(d) of the NER.

44 Clause 6A.8.1(c) of the NER.

With the exception of Victoria which uses a contestable model when certain pre-conditions are met, the allocation of the right to build, own and operate transmission solutions in the NEM is based on an exclusive right of the TNSP to provide these services. Specifically, the geographic location of the preferred option dictates which incumbent TNSP implements the option. In the case of interconnectors, the respective TNSPs will build, own and operate the relevant assets located in their geographic area.

An important feature of the existing framework is that, although TNSPs are required to undertake the RIT-T, there is no corresponding obligation to invest in a project following a successful RIT-T and CPA.[45]

In the event that the TNSP proceeds with an investment (or in the case of Victoria, wins the tender), it is responsible for the project management and delivery of the investment through the entire implementation process. This includes securing the easements or land for the transmission line, as well as the regulatory and environmental planning approvals. However, some responsibilities may be transferred to third parties through contracting arrangements (e.g. construction, since TNSPs do not typically have in-house construction capability). There is no active role for the regulator in this step. Rather, the incentive mechanisms described above are intended to encourage the TNSP to make efficient decisions throughout project delivery and manage expenditure within its total capital expenditure allowance.

45 The Commission understands that the AER typically seeks TNSP Board commitment to proceed with a project as part of the trigger event for non-ISP projects.

3 ISSUES IN THE REGULATORY FRAMEWORK AND PROCESSES FOR PLANNING OF MAJOR TRANSMISSION PROJECTS

The planning component of the planning and investment framework for major transmission projects has undergone significant reform in recent years. The intent of recent reforms was to streamline the regulatory processes for key projects identified in the ISP whilst retaining a rigorous cost benefit assessment.[46] These reforms, which came into effect in July 2020, have only had the opportunity to be applied to a single project in full.[47] However, the Commission considers several issues around the timely and efficient delivery of major transmission investment remain.

This chapter sets out the Commission's understanding of these issues and its preliminary assessment of how each issue will be taken forward in stage two of the Review, for stakeholders' consideration. Specifically, the Commission is seeking feedback from stakeholders on the following issues, each of which the Commission intends to take forward as priority issues in stage two of the Review:

- whether the existing ex-ante incentive-based approach to regulation remains appropriate in light of the significant intrinsic uncertainty associated with the costs and benefits of major discrete transmission investments
- opportunities to streamline the economic assessment of major transmission projects
- the treatment of benefits in transmission planning
- the unequal treatment of non-network options under the RIT-T.

3.1 The intrinsic uncertainty of the costs and benefits of major discrete projects represents a challenge for the regulatory framework

The design of the planning framework for ISP projects builds on the ISP canvassing options at a relatively high-level, which are then further refined through the RIT-T and subject to a single revenue determination process through the CPA.[48]

Embedded within this approach to planning and approving transmission investments is the assumption that uncertainty regarding project benefits and costs reduces as the project progresses through the regulatory process. However, this reduction of uncertainty may not be occurring in relation to major discrete transmission projects.

Further, stakeholders appear to agree that actionable ISP projects are more uncertain than BAU transmission projects.[49] This is because the unique size and scale of these projects,

46 ESB, *Actionable ISP Final Rule Recommendation,* 27 March 2020, ESB, viewed 15 July 2021, https://energyministers.gov.au/publications/actionable-isp-final-rule-recommendation.

47 The AER made a contingent project determination for the Victoria New South Wales interconnector minor upgrade in April 2021. See: https://www.aer.gov.au/news-release/aer-approves-costs-for-victoria-to-new-south-wales-interconnector.

48 Actionable ISP projects can proceed through a staged CPA process.

49 AER, *Final guidance note covering letter — Regulation of large transmission projects,* 31 March 2021, p. 10.

coupled with the pace of the energy transition, results in intrinsic uncertainty associated with both the benefits and costs of many major transmission projects. This uncertainty stems from:

- in relation to **project benefits**, their dependence on assumptions relating to the energy transition, e.g., the:
  - evolution of demand for electricity
  - future costs of generation and storage technologies
  - operation and retirement of the existing thermal generation fleet
  - policy direction of federal and state governments
- in relation to **project costs**, the scale and size of the investments because:
  - there has not been recent experience of projects of the scale and size contemplated, meaning there are few best practice examples off which to benchmark
  - the specific route design of a transmission line can substantially affect its costs, but this process is dependent on external environmental approval and planning processes — the timing and cost of which may not be controllable by TNSPs.

This greater degree of uncertainty represents a challenge for the regulatory framework, with stakeholders noting that the framework was designed around a mature network characterised by incremental investments.[50] Progressing projects with significant intrinsic uncertainty through a regulatory framework that presupposes reducing uncertainty may result in suboptimal outcomes for consumers and TNSPs. By way of example, the existing ex-ante arrangements require a detailed forecast of costs against a backdrop of intrinsic uncertainty. Not all costs are within the control of the TNSP and some costs that may be substantial cannot be accurately forecast (e.g., biodiversity costs), leading to TNSPs potentially making an investment decision (i.e., 'go or no go') on uncertain cost estimates. This uncertainty can lead to significant escalation in costs between the various stages of the planning and approval process (e.g., from the RIT-T to the CPA).[51]

Further, the risk-assessed capital expenditure forecast of TNSPs may lead to a difference between its forecast cost and best estimate of project costs in response to the intrinsic uncertainty. The uncertainty associated with these projects increases the prospect of cost overruns and therefore penalties under the CESS and the risk of ex-post review. Such a difference is a rational response to the uncertainty associated with these projects, but is likely to result in consumers paying more than is necessary or these projects not proceeding.

The Commission notes that an incentive to over-forecast costs is inherent in an ex-ante incentive based approach to regulation (irrespective of project size). Incentive arrangements strive to strike a balance between the efficiency benefits of exposing the service provider to

50 See, for example: NSW Government, *NSW transmission infrastructure strategy,* November 2018, p. 14; PIAC, *Submission to ENERF 2020 approach paper,* July 2020, p. 1; TransGrid, *Submission to consultation on the electricity economic* regulatory framework review 2020 approach paper, July 2020, p. 1; and ENA, *Rules to make ISP investment add up,* October 2020, viewed 4 August 2021, https://www.energynetworks.com.au/news/energy-insider/2020-energy-insider/rules-to-make-isp-investment-add-up/.

51 Stakeholders have raised concerns about cost escalations following the RIT-T. Consultation on a rule change relating to this matter is set out in Chapter 5.

risk against the compensation that may need to be paid when they are exposed to risk. This trade-off may differ between BAU projects and major discrete projects. In particular, the increased uncertainty associated with major projects warrants an examination of whether ex-ante incentive-based regulation is appropriate for these projects, or whether an alternative approach is more suitable for managing the uncertainty of major projects.

Improvements have already been made in relation to the uncertainty around how elements of the regulatory framework will be applied to large transmission projects. For example, the AER's recent guidance note on the regulation of actionable ISP projects[52] sets out detailed guidance on how proponents can stage CPAs and how the ex-post review process will be applied to major transmission investments. This guidance provides certainty for TNSPS in relation to how the AER will assess a project under the existing arrangements.

However, the Commission notes that the significant intrinsic uncertainty associated with major transmission projects raises the threshold question of whether the existing ex-ante incentive-based regulation approach is appropriate for major discrete transmission projects. The Commission therefore intends to consider this issue as a priority for the Review. More broadly, the Commission considers that intrinsic uncertainty underpins many of the issues identified in this consultation paper. The treatment of these issues likely depends on the answer to this threshold question. In particular, they may be addressed:

- as part of significant changes to the regulatory framework (such as introducing contestability) if the existing regulatory approach is not appropriate for major discrete projects, or
- through incremental reforms to the existing framework if it is found to be appropriate.

QUESTION 2: IMPLICATIONS OF INCREASED UNCERTAINTY FOR THE EX-ANTE INCENTIVE-BASED REGULATORY FRAMEWORK

1. Do you agree with that the identified factors contribute to an increase to the uncertainty surrounding major transmission projects, relative to BAU projects? Are there other factors that should be taken into account?
2. Do you consider that the current ex-ante incentive-based approach to regulation is appropriate for major transmission projects? Why? Are there opportunities to drive more efficient expenditure and operational outcomes?
3. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

52 AER, *Regulation of actionable ISP projects,* Guidance note, March 2021.

3.2 Opportunities to streamline the economic assessment of major transmission projects

Section 2.2 describes how both the ISP and the RIT-T are used to assess the economic merit of actionable ISP projects. The key difference between the ISP and the RIT-T is the level of granularity of the analysis. Whereas the ISP initially identifies candidate options at a relatively high-level, the subsequent RIT-T analysis is more refined with respect to scope — assessing alternative options and identifying the preferred option (including route design). The outcome of this more granular assessment is subsequently subject to the AEMO feedback loop to confirm that the preferred option aligns with the optimal development path referred to in the most recent ISP.

3.2.1 Issues with the existing economic assessment process for major transmission projects

Each component — the ISP, RIT-T and AEMO feedback loop — play an important and distinct role in the economic assessment of actionable ISP projects. However, their interrelated nature raises questions around whether the economic assessment process for actionable ISP projects is appropriately designed. In particular, there may be a degree of duplication or redundancy in the process and, as such, there may be opportunities to streamline the process.

One example is the nature of the inputs used in the analysis. RIT-T proponents of actionable ISP projects are required to use the most recent ISP parameters, i.e., the inputs, scenarios and assumptions. These parameters principally relate to the calculation of benefits (e.g., the categories of market benefits that must be quantified). In relation to costs, RIT-T proponents typically use cost estimates that are more refined than those used in the ISP analysis.[53] Subsequently, project cost estimates are subject to further refinement in the development of the CPA, with these costs assessed in the AEMO feedback loop. This interplay has led to stakeholders calling into question the value-add of the RIT-T. For instance, the ESB stated in its post-2025 market design options paper that:[54]

> As the Regulatory Investment Test for Transmission is principally a net economic benefit test that relies on the assumptions and scenarios for the ISP and uses less developed costs than the CPA [contingent project application], it is unclear what additional benefits the RIT-T delivers for actionable ISP projects however it does significantly add to the time taken to get these projects approved.

A further issue that adds to the complexity of the economic assessment process is the pace of change in market conditions. The rapidly changing environment potentially necessitates updating of inputs and assumptions, creating uncertainty and delay of the assessment process. By way of example, the PADR for the VNI West RIT-T has received a nine month extension to facilitate alignment with the 2022 ISP.[55] The pace of change also raises issues

53 The Commission notes that AEMO has developed a new transmission cost database as part of its development of the 2022 ISP.

54 ESB, *Post 2025 market design options - a paper for consultation | Part A,* Sydney, 30 April 2021, p. 78.

55 AEMO and TransGrid, *Victoria to New South Wales Interconnector West (VNI West) Regulatory Investment Test for Transmission,* Progress update, March 2021, p. 3.

with respect to the alignment between the ISP and RIT-T, since some RIT-T proponents have adopted the draft inputs and assumptions in their analysis.[56] This issue of alignment raises further questions regarding how the AEMO feedback loop, which is intended to provide consistency between the ISP and the RIT-T, will be applied in practice. It is unclear whether an ISP update would be suitable to address alignment issues in light of the effort and complexity in updating the ISP, or whether the present two-year cycle of the ISP is appropriate given the pace of the transition.[57]

The Commission notes the importance of distinguishing the role of the RIT-T in relation to actionable ISP projects and non-ISP projects. For non-ISP projects, the RIT-T is the core cost benefit assessment and, as such, any changes to the assessment process should be considered in this context.

3.2.2 Possibilities for improving the economic assessment process of major transmission projects

The Commission notes that stakeholder submissions to the ESB's options paper (summarised in Appendix A) expressed broad support for examining whether improvements can be made to the assessment process. Stakeholders also expressed that any contemplated changes should not lead to an overall weakening of the economic assessment of major projects.

The Commission agrees with stakeholders that any reforms to the economic assessment process must balance streamlining the process while maintaining its rigour. Detailed economic assessment of major transmission projects is an important safeguard in the regulatory framework since it helps to ensure that consumers only pay for investments that are in their long-term interests (i.e., they are net beneficial projects). Further, the existing economic assessment processes provide a transparent means for stakeholders to engage in the planning process. However, they are a resource-intensive exercise and can account for a significant proportion of the time taken to secure regulatory approval for a project (and therefore time taken to deliver the investment).[58] The assessment process is resource-intensive at both the ISP and RIT-T stage, i.e.:

- the actionable ISP rules and associated AER guidelines introduced a number of transparency mechanisms and reporting requirements that AEMO must comply with in its development of the ISP
- RIT-T proponents require time to develop each publication, invite submissions for a minimum period,[59] review submissions and potentially undertake additional market modelling.

A fit-for-purpose assessment process should provide a robust safeguard for consumers, while not unduly delaying net beneficial projects — potentially leading to benefits being deferred or

56 See, for example, the Marinuslink PACR. Tasnetworks, *Marinuslink RIT-T Project Assessment Conclusions Report,* June 2021, p. 32.

57 In this context, moving to an annual ISP cycle would need to be considered alongside the extent of the regulatory obligations and reporting requirements necessary to balance streamlining with rigour and transparency with resource-intensiveness. Under clause 11.126.10 of the NER, the AEMC is required to complete a review of the ISP framework by 1 July 2025.

58 Examples of the time taken for projects to complete the RIT-T process can be found in: AEMC, *Coordination of generation and transmission investment,* Final Report, 21 December 2018, p 46.

59 Proponents must invite submissions on the PADR for a minimum of six weeks under clause 5.16A.4(g) of the NER.

lost. Ensuring the assessment framework appropriately balances the rigour and time taken to comply may facilitate making robust investment decisions that can be delivered in a timely manner. The Commission therefore intends to consider this issue as a priority for the Review.

QUESTION 3: ECONOMIC ASSESSMENT OF MAJOR TRANSMISSION PROJECTS

1. Streamlining the economic assessment of ISP and non-ISP projects has implications for the rigour of the analysis. What level of compromise between streamlining and rigour is acceptable? Are there opportunities to streamline the economic assessments of ISP and non-ISP projects consistent with this acceptable level of compromise? If so, how could the framework be streamlined?
2. Do you agree that any changes to the assessment process needs to consider the role of the RIT-T in the context of ISP and non-ISP projects? If not, why?
3. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

3.3 Treatment of benefits in transmission planning

Section 2.2.1 explains that the economic analyses underpinning transmission planning activities build on an assessment of the costs and benefits of transmission investments. These costs and benefits relate to those that produce, consume or transport electricity in the market. The focus on market benefits has been a feature of transmission planning since reforms were made to the RIT in the late 1990s. However, there has been ongoing debate on whether the:

- benefits included in current planning processes (i.e., the ISP and RIT-T) are sufficiently broad to capture the drivers of major transmission investment
- disconnect between what is required under the Rules and feasible in practice warrants guidance on hard to monetise benefits
- market benefits test is appropriate, or if a customer benefits test should be used.

The scale and pace of the energy transition is once again bringing these questions into focus. The remainder of this section provides an overview of these issues relating to the treatment of benefits in transmission planning.

3.3.1 Benefits included in current planning processes

Broader economic impacts

Individual governments may value a range of benefits that are not currently captured under the ISP or RIT-T. These benefits may include boosting local economies or delivering additional employment opportunities to rural communities. Reflecting these broader drivers of investment, governments may see benefits in investments (such as REZs) that are bigger, earlier, or in a different location compared to an investment that would proceed under the

NEO focus of the existing regulatory framework. By way of example, the Victorian REZ Development Plan states that:[60]

> By supporting these investments sooner than the long timeframes of regulatory investments, such as the RIT-T, means more lower cost renewable generation can enter the market for the benefit of consumers, as well as providing non-market benefits such as local economic activity and jobs.

The inclusion of wider economic benefits in the RIT-T has been assessed in multiple reviews, including the Productivity Commission's *Electricity Network Regulation Inquiry* in 2013 and the former COAG Energy Council's review of the RIT-T. In each of these reviews, it was concluded that wider economic benefits should not be included within the RIT-T assessment. The former COAG Energy Council reiterated the Productivity Commission's conclusion that incorporating wider benefits would not enhance decision making because:[61]

- firms in other industries cannot capture the indirect benefits of their actions and therefore they do not consider them in investment decisions, meaning including indirect effects in the RIT-T may distort efficient investment
- accurately measuring the benefits of investment would require judgement regarding the distortions it may create in the broader economy.

Most recently, as part of its work on transmission access reform the Commission likewise concluded that excluding wider economic benefits from the RIT-T is appropriate because:[62]

- it better promotes the long-term interest of electricity consumers by ensuring they only fund projects that are efficient from a NEM perspective
- it does not hinder governments from achieving their objective to maximise social (rather than market) net economic benefits, since governments can provide capital contributions consistent with those benefits towards projects to increase their net economic benefits
- it avoids the measurement problems associated with casting the benefit too widely, including with the need to identify and estimate indirect benefits.

Incorporating wider economic benefits in the RIT-T would also increase computational complexity (due to the need for general equilibrium modelling), which may raise issues regarding transparency and therefore increase the likelihood of delays and disputes.

The Commission welcomes stakeholder views regarding whether recent developments in the energy sector warrant further examination of including wider economic benefits in the assessment process for major transmission projects. The Commission intends to consider this issue as a priority for the Review in order to ensure the timely and efficient delivery of major transmission projects.

Carbon

60 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development path,* Directions Paper, Melbourne, February 2021, p. 8.

61 COAG Energy Council, *Review of the Regulatory Investment Test for Transmission | RIT-T Review,* Canberra, 6 February 2017, pp. 34-45.

62 AEMC, *Coordination of generation and transmission investment,* Final Report, 21 December 2018, p. 43.

In contrast to these wider economic benefits, as part of its work on transmission access reform, the Commission previously stated that the approach to the treatment of carbon in the assessment process is different. Acknowledging stakeholder calls for the RIT-T process to facilitate a reduction in carbon emissions, the Commission noted that "the RIT-T already captures the economic value of environmental policy".[63] In particular, the Commission referred to the Commonwealth's Paris emission reduction target and to state based renewable energy targets, stating that these policies can be incorporated into the RIT-T analysis.[64] The Commission concluded that, "given the current uncertainty about mechanisms to reduce emissions of the electricity sector, the Commission considers this is an area where further clarification on how this can be considered would be useful".[65]

In mid-2020, policies such as those outlined above were formally incorporated into the development of the ISP, and thus the RIT-T analysis which draws on the ISP. As noted in section 2.2.1, AEMO may consider environmental or energy policies that impact the power system when it determines the "power system needs" that the ISP is seeking to achieve.[66] Consistent with this, the ISP models a range of different scenarios to explore how power system needs might evolve over the next 20 years. Further information on how the 2020 ISP incorporates current and potential future carbon emission reduction objectives is set out in Appendix B, together with information about how ISP scenarios inform analysis undertaken in RIT-Ts.

Notwithstanding these developments, stakeholders continue to raise concerns regarding the treatment of carbon emissions in the planning process.[67] The Commission therefore intends to consider this issue as a priority of the Review and welcomes stakeholder views on the issue of including carbon emissions in transmission planning and regulatory processes.

QUESTION 4: BENEFITS INCLUDED IN PLANNING PROCESSES

1. Are the benefits included in current planning processes sufficiently broad to capture the drivers of major transmission investment? Does the scale and pace of the NEM's energy transition necessitate inclusion of other classes of market benefits or wider economic benefits? If so, what kind of other classes of market benefits or wider economic benefits should be included?
2. Are major transmission projects failing to satisfy economic assessments because certain benefits (market or non-market) are not permitted to be quantified?
3. Are changes warranted to the manner in which carbon emissions inform transmission planning and regulatory processes?

63 AEMC, *Coordination of generation and transmission investment,* Final Report, 21 December 2018, p. 42.

64 AEMC, *Coordination of generation and transmission investment,* Final Report, 21 December 2018, p. 42.

65 AEMC, *Coordination of generation and transmission investment,* Final Report, 21 December 2018, pp. 42-43.

66 Clause 5.22.3(b) of the NER.

67 For instance, Spark Infrastructure Notes that "including broader economic benefits (valued by government and taxpayers such as emission reduction) in the RIT-T can reduce the likelihood that projects that are valuable to Australians are held up in NEM regulatory processes". See: Spark Infrastructure, *Submission to ESB P2025 Market Design consultation paper,* 9 June 2021, p. 5.

4. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

3.3.2 Guidance on hard to monetise benefits

Section 2.2.2 explains that both AEMO (in its development of the ISP) and RIT-T proponents (in applying the RIT-T) are required to consider all classes of market benefits as being material prior to undertaking the analysis. However, there may be a disconnect between what is required under the Rules and what is feasible in practice.

In particular, the complexity of quantifying particular market benefits that can be used to justify investment under the NER often leads to their exclusion from the analysis. This exclusion is typically a result of the estimated cost of undertaking the analysis to quantify the market benefit being disproportionate to the scale, size and potential benefits of each credible option being considered (or development path in the case of the ISP).[68] In other words, some categories of benefits (such as changes in ancillary costs and competition benefits) are not often estimated due to the complexity and cost of the modelling task.

The combination of excluding difficult to quantify market benefits coupled with a desire to complete the regulatory process as quickly as possible may create an incentive for RIT-T proponents to quantify the minimum benefits possible to pass the RIT-T. However, due to the intrinsic uncertainty associated with the capital costs of major projects there are likely to be cost increases, meaning proponents may later in the assessment process need to quantify new benefits (including those that are difficult to quantify) to justify the investment. Quantification of new market benefits inherently leads to delays in the completion of the RIT-T and therefore the delivery of the project.

The Commission therefore intends to consider this issue as part of the Review.

QUESTION 5: GUIDANCE ON HARD TO MONETISE BENEFITS

1. What classes of market benefits are hard to monetise? Is there a way that these benefits could be made easier to quantify?
2. Would guidance on hard to monetise benefits improve the timeliness at which projects proceed through the regulatory process?
3. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

68 Clauses 5.15A.2(b)(6) and 5.22.10(c)(3) of the NER. Note that RIT-T proponents of actionable ISP projects are required to quantify all classes of market benefits considered material by AEMO in the ISP.

3.3.3 Market benefits versus a customer benefits test

Prior to the commencement of the NEM, the National Electricity Code described a customer benefits test for transmission investment. Under this test, investments were justified on the basis that the benefits received by 'customers' should exceed the cost of the project. However, due to concerns of the Australian Competition and Consumer Commission (ACCC) that such a test was unclear, inefficient and unworkable, the test was replaced by a regulatory test based on an assessment of costs and market benefits from which the current RIT-T has evolved.[69] The difference between these tests is that generator sector benefits and costs are excluded from the customer benefits test, but included in the market benefits test.

The rationale for adopting a market benefits test in favour of a consumer benefits test was that:

- A market-wide cost-benefit test promotes the NEO because it attempts to limit or prevent the possibility of inefficient transmission.
- Market-wide cost-benefit tests face less measurement problems than consumer benefits tests, which need to estimate what proportion of wholesale market price changes will get passed on to consumers, i.e. retail customers. In competitive markets, savings or benefits that accrue to the generation sector should flow through to consumers. Allowing these benefits to be captured in a market-wide test recognises this.

The Commission welcomes stakeholder views on whether recent developments in the energy sector warrant further examination of the appropriateness of a market or customer benefits test. Given the extensive work done to date on this topic and the compelling arguments in favour of the market benefits test, the Commission's view is that a market benefits test remains fit-for-purpose. As such, the Commission does not intend to consider this issue as a priority for the Review.

QUESTION 6: MARKET VERSUS CONSUMER BENEFITS TEST

1. Do you consider that there are changes that have occurred in the energy sector that warrant reconsidering the merits of a market versus consumer benefits test? If yes, what are these changes and why do they require revisiting this issue?
2. Should the Review take forward this issue as a priority issue? Why?

3.4 Unequal treatment of non-network options under the RIT-T

Section 2.2 explains that the purpose of the RIT-T is to identify the preferred option for meeting an identified need. The RIT-T is technologically neutral, i.e. the preferred option may be either a network or non-network solution. However, an issue frequently raised in the context of the RIT-T is the perceived unequal treatment of non-network options relative to

69 Ernst & Young, Review of the Assessment Criterion for New Interconnectors and Network Augmentation Final Report to Australian Competition and Consumer Commission, March, 1999.

network options. In particular, there is a perception that there are a number of barriers for non-network options.[70]

The most significant of these barriers is the perception that TNSPs' have an intrinsic preference for network focused solutions. This preference results from three key factors:

- the fundamental purpose of TNSPs is to own and operate the transmission network. It follows that their knowledge and expertise centres around network-based solutions, as opposed to being providers of substitutes for transmission infrastructure.
- the structure of the regulatory framework as it relates to the profit-based compensation for additional capital expenditure but not operating expenditure. Such an outcome arises if the regulated weighted average cost of capital that the TNSP receives on any additional expenditure exceeds the actual (but unknown) cost of capital of the investment.
- network and non-network options are not like-for-like (such as their implications for reliability and the TNSP's risk profile), and the differences may shape how they are considered in the assessment process.

The Commission has previously considered whether there is a bias among network service providers for capital expenditure over operating expenditure in both the 2018 and 2019 Electricity Network Economic Regulatory Framework Review (ENERF).[71] The Commission's analysis illustrated that the regulatory framework does not necessarily create a clear, systematic bias towards either capital expenditure or operating expenditure. However, where the expected cost of capital is lower than the regulated cost of capital, the framework does create a bias towards capital investments.[72] The Commission also noted that the risk of expenditure bias were less in the current environment of historically low interest rates.[73]

In principle, a preference for network options may lead to TNSPs taking a relatively optimistic view of the net market benefits of network options, as a means of positioning these solutions as the preferred option. In contrast, the technical capability of non-network options to meet an identified need cost-effectively may attract a less optimistic assessment from TNSPs — disadvantaging non-network solutions. This could lead to a wholly network solution being implemented where a non-network option, or a combination of network and non-network options, may be efficient.[74] Preserving neutrality between network and non-network options is central to the regulatory framework facilitating identification of the most efficient solution to an identified need (which may be network, non-network or a combination of network and non-network solutions). The Commission therefore intends to consider this issue as a priority for the Review.

70 The issue of whether non-network options have equal treatment in the transmission planning and regulatory process was recently raised in the context in the AER's review of the regulation of large transmission projects. See: AER, *Final guidance note covering letter — Regulation of large transmission projects,* 31 March 2021, pp. 8-10.

71 This assessment was undertaken in the context of an anticipated increase in DER in the electricity grid.

72 AEMC, *Economic regulatory framework review | Integrating distributed energy resources for the grid of the future,* 26 September 2019, p. 64.

73 AEMC, *Economic regulatory framework review | Integrating distributed energy resources for the grid of the future*, 26 September 2019, p.64.

74 Non-network options are unlikely to be substitutes for major transmission investments. Rather, they are more likely to contribute to lowering the overall cost of the investment.

QUESTION 7: TREATMENT OF NON-NETWORK OPTIONS

1. Do you agree that there are barriers for non-network options in economic assessments? If so, do you agree with the barriers identified? Are there any further barriers? How should these barriers be addressed?
2. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

4 ISSUES IN THE REGULATORY FRAMEWORK AND PROCESSES FOR TRANSMISSION INVESTMENT AND DELIVERY

The investment component of the planning and investment framework has not been subject to the same degree of reform as the processes underpinning the planning framework. However, recent developments have brought into focus characteristics of the regulatory framework regarding the investment decision which may affect the timely and efficient delivery of major transmission investments.

This chapter sets out the Commission's understanding of issues regarding the investment framework and how they may affect the timely and efficient delivery of major transmission projects. Specifically, the Commission is seeking feedback from stakeholders on:

- the risk that the TNSP's exclusive right to build and own transmission projects may lead to major projects not proceeding due to misalignment between the long-term interests of consumers and the commercial considerations of investors
- the potential impacts of different factors during the project planning and delivery stages of major transmission projects that can impact their efficient and timely delivery.

4.1 Potential impacts of TNSPs' exclusive right to build and own transmission projects

The allocation of the right to build, own and operate transmission solutions in the NEM is based on an exclusive right — the geographic location of the preferred option dictates which incumbent TNSP is responsible for its implementation. Despite this exclusive right, there is no corresponding obligation on TNSPs to deliver (i.e. invest in) transmission projects under the national regulatory framework.

An implication of this exclusive right with no corresponding obligation is the risk that major strategic projects that present net market benefits may not proceed in a timely way due to commercial considerations. In other words, there is the potential for misalignment between the long-term interests of consumers and the commercial considerations of investors. Incumbent TNSPs have raised a number of commercial concerns that may lead to these projects not proceeding. These include:

- the financeability of the investments
- the level of compensation relative to the risk profile of these investments given their scale.

This section describes these commercial considerations in further detail. It provides context with regard to approaches to financing public infrastructure, how financeability and risk compensation sit within the existing regulatory framework, as well as how these considerations intersect with the AER's regulatory functions and current consultation on the development of the 2022 Rate of Return Instrument (RoRI).[75] While it is the Commission's view that these commercial concerns may warrant consideration, it notes that the AER is best placed to explore detailed concerns regarding financeability and risk compensation given its statutory function in setting the rate of return and its role as the economic regulator under the Australian Energy Market Agreement (AEMA).[76] Further, the Commission indicated in the *Financeability of ISP projects* rule change that the scope of the Review would include financing, regulatory and governance issues in the context of the overall regulatory framework for network businesses. The Commission noted that it did not intend for the Review to consider future arrangements to support project specific ISP financeability under the existing framework. As such, the focus of feedback sought as part of this Review is with regard to TNSPs' exclusive right to build and own major transmission projects but with no corresponding obligation to invest.

4.1.1 Approaches to financing public infrastructure: financeability of "lumpy" investments

The potential for financeability challenges in the delivery of major infrastructure projects is not unique to the energy sector. The investment needed for large, complex infrastructure projects is typically 'lumpy'. As such, infrastructure projects that require the financing of long-lived and capital assets can present particular challenges owing to the capital intensity, high-upfront costs and lack of liquidity generating substantial financing requirements.[77] Infrastructure projects may not generate positive cash flows in the early phases, yet often produce stable cash flows once the infrastructure has been commissioned.

Financing options in other sectors

Financing of the high initial cost of constructing infrastructure and the subsequent revenue recovery can take a number of forms. Governments have adopted various project finance techniques to fund public infrastructure, including toll roads, bridges, tunnels, stadiums, and airports. In some instances, such projects are backed by government sponsors (where government finances their own assets). More recently, there has been greater involvement of the private-sector in constructing and operating large-scale public service projects (where the private sector finances and owns the assets).

Alternative funding and financing models, including Public Private Partnerships, involve arrangements in which risk is transferred to varying degrees between the public and private parties. For example, payments for infrastructure services, used to repay private financing costs over the life of the asset, can either come from the government via budget transfers, or from users of the infrastructure through user charges, such as tolls.

There are a wide range of financing channels available for infrastructure investment – each with its own set of characteristics and implications for lending or investment portfolios.[78] The

75 https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/consultation.

76 See clause 9.1 of the AEMA (https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/Australian%20Energy%20Market%20Agreement%20-%20Dec%202013.pdf).

77 Reserve Bank of Australia (2013), Financing Infrastructure: A spectrum of Country Approaches, RBA Bulletin, September, pp. 65–76.

78 See OECD (2015), Infrastructure Financing Instruments and Incentives, pp.13-15.

types of financial instrument used (for example, bonds or hybrids) can further define the level of control in an investment, liquidity and the types of contractual claims on cash flows.

These features of financing infrastructure projects should be considered in the context of the efficient and timely delivery of major transmission projects.

4.1.2 Financeability and risk compensation of major transmission investments

The benchmark efficient firm

The economic regulatory framework set out in Chapter 6A of the NER is designed to (among other things) provide TNSPs with the opportunity to recover returns commensurate with the regulatory and commercial risks involved in providing prescribed transmission services.[79]

Importantly, in setting rates of return, the AER does not consider the details of individual businesses or projects. Rather, it considers the market cost of capital (or the weighted average cost of capital (WACC)) commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to a service provider in respect of the provision of regulated services.[80] In other words, the economic regulatory framework is designed to regulate the benchmark efficient entity as distinct from individual businesses and projects (see box 1 below). The framework does not consider actual businesses, including their capital structure, actual debt costs or profitability. Similarly, the determination of the maximum allowed revenue does not consider individual investments in isolation but is concerned with the total asset base — that is, the regulatory asset base (RAB). As such, issues of financeability in relation to major transmission projects ought to be considered in terms of the TNSP's financeability as an entity within the context of it's overall RAB.

Generally, financeability refers to the willingness of investors to extend equity or debt to a business to finance its activities. In practice, it relates to generating sufficient cash flows to cover operating costs, debt repayments and a level of retained profit attractive to equity investors. Within regulatory settings, it is often interpreted as the ability of the service provider to achieve and maintain the benchmark credit rating applied in the estimation of the rate of return.[81] This is typically assessed through examining the key financial ratios used by credit rating agencies and testing if these ratios support the benchmark credit rating, based on a service provider's allowed cash flows.[82]

BOX 1: THE EFFICIENT BENCHMARK AND ACTUAL FINANCING PRACTICES

Economic regulation of energy network assets is based on a hypothetical benchmark efficient firm. This approach ensures that network businesses have incentives to finance their business

79 NEL, sections 2B and 7A(5) and 18I(5), NER s.6A.1.1, Chapter 10.

80 AER, *Rate of return instrument*, Explanatory Statement, December 2018, p. 33.

81 AER, *Rate of return- Overall rate of return*, Draft working paper, July 2020, p. 54.

82 See AER, *Rate of return and cashflows in a low interest rate environment,* Draft working paper, May 2021, p. 35-36 for an overview of the various measures of financeability used by credit rating agencies and regulators.

as efficiently as possible. This is important in the context of the revenue and pricing principles set out in the NEL. Under these principles, network businesses should, among other things, be afforded a reasonable opportunity to recover at least efficient costs - this is over the long term, not necessarily within a single regulatory period. In addition, businesses should be provided with effective incentives in order to promote economic efficiency. Businesses are incentivised to seek out economic efficiencies by being rewarded if they can achieve lower costs of equity and debt than assumed for the benchmark efficient entity and penalised if their cost of financing is higher than the regulated rate of return. This also applies to the financing of assets. In particular, transmission network service providers are not required to use the efficient benchmark assumptions the AER uses to derive the regulated WACC. Indeed, they are incentivised to outperform the regulated WACC by being able to keep any efficiency gains they realise.

Source: AER, *Rate of return instrument*, 2018.

Financeability in the construction phase

In principle, the existing revenue model (the Post Tax Revenue Model or PTRM) allows efficient costs to be recovered over the life of an asset.[83] However, in relation to the financeability and delivery of individual ISP projects there may be short-term cash flow variability or a mismatch in the timing of investment and revenue recovery. For example, the construction period of an asset (which may take between five and seven years) involves significant costs, while recovery of those costs does not occur until the asset is commissioned and in service.

Once revenues begin to accrue, they are smoothed over the life of the asset (potentially as long as, for example, seventy years) and so the revenues from that specific project may not be sufficient to support the financing of the investment. This allows for alignment between the profile of revenue received by regulated network service providers with the timing benefits to consumers in respect of these projects. Even for projects in competitive sectors of the economy, revenue is normally generated only after benefits start being delivered.[84]

The Commission recently published two rule change determinations that examined the financeability of ISP projects, particularly in relation to deferred revenue recovery.[85] The final determinations on *Participant derogation - Financeability of ISP projects* stated that the regulatory framework does not create a barrier to the proponent TNSPs financing their respective shares of current ISP projects in the context of their overall RABs.[86] In addition, the Commission noted that the proposed rules would not provide the right incentives for TNSPs to invest in ISP projects now and in the future.[87]

83 See section 2.1 for an overview of the ex ante revenue cycle.

84 For example, tolls can not be recovered from a road until it is operational.

85 The Commission received separate rule change requests in the form of participant derogation from TransGrid and ElectraNet, which were considered in parallel.

86 AEMC, *Participant Derogation – Financeability of ISP Projects (TransGrid)* and *Participant Derogation – Financeability of ISP Projects (ElectraNet)*, Final determination, 8 April 2021.

87 AEMC, *Participant Derogation – Financeability of ISP Projects (Transgrid)* and *Participant Derogation – Financeability of ISP*

However, the Commission considered that the rule changes raised some significant issues in relation to the timely and efficient delivery of major transmission projects (including current ISP projects). In particular, while there are options available to TNSPs under and outside of the current regulatory framework to help manage financeability, the ultimate decision on whether to invest in a transmission project rests with TNSPs, which have a duty to act in the best interests of their shareholders. To this end, the Commission noted that a business, behaving rationally, would only undertake those projects that it believes will add value to its shareholders. However, under the existing regulatory framework it is possible for TNSPs to choose not to proceed with projects where those projects are not attractive, even where the entirety of the RAB, inclusive of those projects, is providing the TNSP with an opportunity to recover at least their efficient costs.[88] As outlined further in section 4.1.3, this has potential implications for the timely delivery of transmission projects and the long-term interests of consumers.

Compensation relative to risk profile of major investments

The major, discrete transmission investments comprising the ISP's optimal development path represent a transformational scale of transmission investment in the NEM. Incumbent TNSPs have raised concerns that their investors face higher risks associated with these projects relative to BAU activities. TNSPs suggest that this greater risk profile reflects the greater potential for 'unknown unknowns' in the context of large investments because:

- TNSPs do not have recent experience in projects of the scale and size identified, meaning there are few best practice examples against which to benchmark
- final route design will ultimately be shaped by environmental and planning approvals, both of which fall outside of a TNSP's direct control.

This heightened risk profile may mean investors may not view the current rate of return as sufficient compensation, and so may not be willing to invest in the asset. According to TNSPs, this has implications for their ability to attract capital to finance major projects.

It is noted that TNSPs have opportunities to manage many project risks (discussed in section 3.1), and there are existing mechanisms in the regulatory framework that provide an efficient allowance for TNSPs to manage risks and allow TNSPs to pass through risks in certain circumstances that are beyond their reasonable control.

TNSPs often transfer project risk to contractors through fixed price contracts. This provides greater cost certainty and potentially reduces delivery risk for both TNSPs and consumers. However, it may also increase contracted costs due to the contractor bearing procurement and construction risk. Such additional costs would be passed on to consumers.

Alternative contracting approaches may have lower tendered costs but could potentially increase a TNSP's own costs (including overheads and contract management) and risk. This may be reasonable where it efficiently balances risk such that the party most able to bear a specific risk should incur the costs. However, it is important that the AER and consumers

Projects (ElectraNet), Final determination, 8 April 2021, p. ii.

88 AEMC, *Participant Derogation – Financeability of ISP Projects (TransGrid)* and *Participant Derogation – Financeability of ISP Projects (ElectraNet)*, Final determination, 8 April 2021, p. 27.

have transparency over the types of risks that are being passed to contractors and how much it costs, so that consumers have confidence that risk is being efficiently shared between consumers and contractors. In this context, information asymmetry is a key challenge.

4.1.3 Financeability and risk compensation are related to the rate of return

The previous section outlined that financeability and risk compensation are key commercial considerations shaping the investment decision of TNSPs in relation to major transmission projects. An important feature of these two commercial considerations is that they are related to the rate of return. In particular:

- financeability in regulatory contexts is often interpreted as the ability of the service provider to maintain the benchmark credit rating, which is set as part of the rate of return process
- the intent of the rate of return is to provide for a return that is commensurate with the commercial and regulatory risks of providing the relevant service.

However, while the regulated rate of return may directly impact financeability, financeability is broader than the rate of return. Financeability is dependent on all cash flows and actions of the regulated firm who has primarily responsibility for managing financeability. Key factors influencing the financeability of projects include:

- regulatory cash flows including the allowed rate of return, depreciation, tax and operating cost revenue allowances;
- the timing and size of capital expenditure and nominal debt costs; and
- the decisions of the regulated firm in managing its operations and financing arrangements.

The final determinations for the *Participant derogation - Financeability of ISP projects* examined financeability in the context of ISP investment required by TransGrid and ElectraNet. The final determinations did not find the participant derogations these businesses requested to be needed. The Commission considered the current rules would support efficient investment.[89]

Nevertheless, financeability problems may arise because the rate of return is set incorrectly. They may also occur for standalone projects under a contestability framework depending on framework design. The interaction with the AER RORI review process is considered directly below, while considerations for standalone projects under a contestability framework are covered in section 4.1.3.

As part of its process for preparing the 2022 RORI, the AER will also be considering financeability related issues if they intersect with considerations relevant to the rate of return.[90]

89 AEMC, *Participant Derogation – Financeability of ISP Projects (TransGrid)* and *Participant Derogation – Financeability of ISP Projects (ElectraNet)*, Final determination, 8 April 2021.

90 AER, *Rate of return- Overall rate of return*, Draft working paper, July 2020.

Under the NEL, determination of the rate of return is the responsibility of the AER.[91]As part of this responsibility, the AER is required to publish a new RORI every four years, and is currently consulting on the 2022 RORI which will bind all regulatory determinations in the subsequent four years.[92]In making the instrument, the AER must have regard to the revenue and pricing principles (set out in the NEL and the NGL), any submissions received in relation to the making of the instrument, any advice or recommendations of the consumer reference group, the outcomes from seeking concurrent expert evidence, the independent panel's report, as well as any other information it considers relevant.

The consideration of financeability as part of the RORI review process was foreshadowed in the AER's recently released *Rate of return and cashflows in a low interest rate environment* paper, which noted the range of issues that intersect with financeability to be considered by the AER, including:[93]

- gearing
- credit rating
- the 10 year-trailing average cost of debt methodology and whether this could be adjusted to more accurately reflect large, lumpy investment.

The paper outlined the preliminary view that measures of financeability should not be used directly when setting the rate of return.[94] While the paper noted that bringing forward cash flows may address financeability issues early in an asset's life, the AER considered this would result in current consumers paying for more of the regulatory asset than they consume in a present value sense, while future consumers will pay less.[95] This raises inter-generational equity considerations.[96]

In the most recent draft paper on the *Overall rate of return,* the AER noted that its preliminary view is to explore the possibility of using financeability tests as an overall cross-check on the rate of return.[97] As such, the AER is consulting on how financeability metrics can be used in this way.[98] However, AER staff have indicated that consideration of financeability in the RORI review process may be limited to considering what, if anything, it may imply about the rate of return.

This Review will focus on whether the existing incentives within the regulatory framework may lead to misalignment between the long-term interest of consumers and commercial considerations of investors that risks net beneficial projects not proceeding. The Commission is satisfied that issues relating to TNSPs' financeability will be adequately dealt with in the AER's 2022 RORI Review. The Commission will continue to work closely with the AER to

91 Division 1B of the NEL states that the application of a rate of return instrument is an AER economic regulatory function or power.

92 See under: https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022.

93 AER, *Rate of return and cashflows in a low interest rate environment*, Draft working paper, May 2021, p. 48

94 See AER, *Rate of return and cashflows in a low interest rate environment,* Draft working paper, May 2021, p. 36-47.

95 AER, *Rate of return and cashflows in a low interest rate environment*, Draft working paper, May 2021, p. 48

96 The Commission raised similar concerns regarding intergenerational wealth transfer in the final determination for the *Participant Derogation – Financeability of ISP Projects (TransGrid)* and *Participant Derogation – Financeability of ISP Projects (ElectraNet)* rule changes, 8 April 2021, p.63.

97 AER, *Rate of return - Overall rate of return*, Draft working paper, July 2020.

98 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-omnibus-papers.

assess the relevance of any issues raised through the RORI Review in relation to framework level considerations explored through the Commission's Review.

4.1.4 Options to deal with the non-delivery of major transmission projects

As noted above, the Commission's *Participant derogation- Financeability of ISP projects* final determinations have brought to light characteristics of the current regulatory framework which could lead to projects not being delivered or being delayed.

The fact that TNSPs have an exclusive right, but no obligation to deliver transmission projects under the national regulatory framework creates an environment of uncertainty around the timely delivery of future transmission projects.[99] TNSPs might not go ahead with projects. This could result in net market benefits not being realised for major transmission projects that are in the long-term interests of consumers. There are currently no alternatives if a TNSP decides not to deliver a project and there are also no regulatory consequences for the TNSP should it choose this course of action.[100] The Commission therefore intends to consider this issue as a priority for the Review.

As outlined in section 2.1, the increased uncertainty associated with major projects warrants an examination of whether ex ante incentive-based regulation is appropriate for these projects, or whether an alternative approach is more suitable. A broader framework issue for consideration is therefore whether parties other than incumbent TNSPs should be permitted to invest in regulated infrastructure. A number of stakeholders including the MEU, ERM Power, the Clean Energy Investor Group (CEIG) and ENGIE have previously suggested that transmission projects could be made contestable, particularly where the TNSP refuses to fund them.[101] The ESB P2025 market design options paper raised several issues relevant to contestability in transmission investment.[102] CEPA have also explored contestable service provision, citing examples of where it has been successfully used overseas.[103] Finally, the AER engaged Houston Kemp to provide a report on the *Regulatory treatment of large, discrete electricity transmission investments*, which examined different models of competitive service provision in the planning and delivery of transmission.[104]

The Commission also recognises that some individual ISP projects will be attractive to a TNSP and others will not, given some projects may face greater or lesser project specific risk. In circumstances where projects are put out to competitive tender they will not be funded in the context of an existing RAB or under existing regulatory arrangements. Such projects are standalone and need to be considered in the context of the efficient standalone project financing. Financeability may therefore be a relevant consideration for bidding parties in

99 Noting that there are potential options available to the NSW Government through the *Electricity Infrastructure Investment Act 2020*, but these are outside of the national regulatory framework.

100 With the exception of Victoria, where transmission is contestable subject to specified criteria including that it must have a capital cost over $10 million and must be deemed by AEMO to be separable.

101 Submissions to the consultation paper for the *Participant derogation- Financeability of ISP projects* rule change request: MEU, p. 10; ERM Power, p. 3; CEIG, p. 2; ENGIE, p. 4.

102 ESB, P2025 market design options paper, April 2021. A summary of submissions relevant to contestability is located in Appendix A.

103 CEPA, *Financeability of ISP Projects*, Report for the AEMC, 8 January 2020, section 3.2.

104 Houston Kemp, *Regulatory treatment of large, discrete electricity transmission investments - A report for the Australian Energy Regulator*, 19 August 2020, Chapter 5.

setting the proposed funding arrangements for what they tender. On this basis, the Commission considers there may be scope to consider aspects of financeability in the context of the competitive provision of transmission projects. It notes that this is a different issue to the financeability of a benchmark efficient TNSP.

QUESTION 8: BALANCING TNSPS' EXCLUSIVE RIGHT TO BUILD AND OWN TRANSMISSION PROJECTS

1. Are there features of financing infrastructure projects used in other sectors that should be considered in the context of the efficient and timely delivery of major transmission projects?
2. Should the delivery of major transmission projects be made contestable? If not, why?
3. What options, other than changes to the exclusive right of TNSPs to provide regulated transmission assets, could be considered to ensure timely investment and delivery of major transmission projects?
4. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

4.2 Project planning and delivery

If a decision is made to proceed with an identified transmission investment, then there are a number of subsequent factors that may impact on the timely and efficient delivery of major projects. This section focuses on two key processes following the investment decision and the factors that may impact on the timely and efficient delivery of transmission projects. These are:

- the treatment of preparatory activities and cost recovery arrangements for early works in the development and implementation of major projects
- sources of delay in progressing the delivery of transmission projects related to meeting jurisdictional requirements.

4.2.1 Treatment of preparatory activities and cost recovery arrangements for early works in the development and implementation of major projects

Cost recovery of ‘early works’ continues to be an issue for stakeholders, including jurisdictions, when discussing the timely delivery of major projects. In initial discussions with the Commission, various stakeholders have indicated that the treatment of ‘preparatory activities’ and ‘early works’ in the development and implementation of transmission projects should be clarified, particularly around cost recovery for early works.

What are preparatory activities?

Under the NER, TNSPs have an obligation to undertake preparatory activities for all actionable ISP projects, as well as for future ISP projects where specified in the ISP.[105] In general, preparatory activities are required to investigate the costs and benefits of actionable ISP projects and, if applicable, future ISP projects to support ongoing improvements to the ISP through the TNSP and AEMO joint planning process.[106] Preparatory activities are defined in NER clause 5.10.2 as follows:

> **preparatory activities** means activities to design and to investigate the costs and benefits of *actionable ISP projects*, future ISP projects and REZ stages (as applicable), including:
>
> (a) detailed engineering design;
>
> (b) route selection and easement assessment work;
>
> (c) cost estimation based on engineering design and route selection;
>
> (d) preliminary assessment of environmental and planning approvals; and
>
> (e) council and stakeholder engagement.

Cost associated with preparatory activities are typically accommodated within TNSPs' capital and operating expenditure allowances via the revenue determination process.[107] This requires TNSPs to demonstrate that expenditure on preparatory activities is prudent and efficient in the regulatory proposals they lodge as part of the regulatory determination process. TNSPs also typically incur some costs in preparing a CPA for lodgement with the AER that contains the TNSP's forecast expenditure for the project. The AER will assess the efficiency and prudency of that expenditure in its assessment of the contingent project application.

What are early works?

Early works are not defined or referred to in the Rules for the ISP. The term early works is used in the 2020 ISP in relation to actionable ISP projects such as VNI West and Marinus Link.[108] However, the description of early works in relation to these projects is not clearly distinguishable from the definition of preparatory activities. The term is also used in the AER *Cost Benefit Analysis Guideline* and the AER *Guidance Note - Regulation of Actionable ISP Projects*.[109] Across these documents, the term is used in relation to processes of ISP planning, RIT-T investment and CPA funding.

At the RIT-T investment stage, early works are often treated as substantive project delivery activities/expenditure that occur before a preferred option has been identified. TNSPs have no certainty of recovering revenue from a project until it has passed all the stages. To avoid delays in the delivery of a project, this has led to underwriting arrangements where State and Federal governments pay the network owner for the reasonable cost of early works if the

105 Clauses 5.10.2 and 5.22.6 of the NER.

106 Clause 5.14.4 of the NER.

107 Note that it is not clear that preparatory works will always be in the revenue determination allowance as the development of the ISP and revenue determination cycles will not always be aligned.

108 AEMO, *2020 Integrated System Plan*, p. 15.

109 AER, *Cost benefit analysis guidelines*, August 2020 and AER, *Guidance note - Regulation of actionable ISP projects*, March 2021.

project is not approved, or if the recovery of those costs is not ultimately approved by the AER. This is on the basis that TNSPs do not want to spend money getting started on a project without it first having been approved to proceed under the RIT-T. In instances where jurisdictions may want early works to commence to accelerate delivery timing of a project prior approval to proceed under the RIT-T, clarification of the cost recovery arrangements for early works is an issue that has been raised by several stakeholders.

At the CPA funding stage, the AER's *Guidance Note - Regulation of actionable ISP Projects* outlines that lodging an early works CPA before lodging a CPA for a particularly large or uncertain actionable ISP project allows a separate process for approving efficient and prudent planning and design costs ex-ante.[110] In this way, TNSPs can stage the regulatory process for actionable ISP projects by lodging multiple CPAs with the AER to help reduce uncertainty associated with a project's costs and benefits, and to improve expenditure forecasts.[111] This is intended to provide TNSPs with more revenue certainty, and stakeholders and the AER with more information about the project before receiving the full project CPA.[112] Under a staged CPA approach for early works, how the costs of early works are assessed by AEMO in the feedback loop (which must be passed before lodging a CPA) will depend on the project staging. The costs of each staged CPA need be considered as an element of a larger overall project, so that cost assessed in the feedback loop can be considered in relation to the total cost of the ISP project chosen through the RIT-T.

Clarification and transparency around the meaning and cost recovery arrangements for early works is proposed as a key area of focus for the Review. There are multiple processes (such as ISP planning, RIT and CPA) which intersect with the treatment of early works under the regulatory framework. The treatment of these activities, and whether the lack of clarity around the defined purpose of each activity is impacting the timely and efficient delivery of projects requires consideration. The Commission seeks to understand if clarification regarding the definitions or treatment of preparatory activities or early works would assist stakeholders in understanding the issue around cost recovery for early works. In particular, the Commission is interested in stakeholder views in relation to how cost recovery for preparatory activities or early works might be clarified and whether cost recovery for early works is an issue that the Commission should consider.

QUESTION 9: TREATMENT OF 'EARLY WORKS'

1. Do stakeholders seek further clarity on the meaning of preparatory activities and early works?
2. Should the Commission consider how the costs of early works can be recovered?
3. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

110 AER, *Guidance note - Regulation of actionable ISP projects,* March 2021, p. 26.

111 AER, *Cost benefit analysis guidelines*, August 2020, p. 25.

112 Ibid.

4.2.2 Jurisdictional environmental and planning processes may affect the delivery of transmission projects

The length of the planning and construction processes involved in the delivery of regulated transmission infrastructure has been raised by various stakeholders. The current transmission development process can take six to seven years end-to-end.[113] Separate from the planning processes under the national transmission framework, prospective transmission investments are also required to meet subsequent jurisdictional requirements, including:

- procurement of easements/property rights for transmission lines; and
- environmental planning approvals.

With regard to easements, TNSPs require physical spaces for their transmission assets in order to provide electricity transmission services. To do this, TNSPs are required to acquire appropriate property rights for their networks. Typically, TNSPs enter into negotiations to procure land or easements. If an agreement to acquire land cannot be reached through negotiation, jurisdictional statutory powers of compulsory acquisition can be drawn on. The compulsory acquisition of land would require additional time and outcomes are not necessarily certain. It is also important to note that TNSPs often have time constraints on their ability to negotiate land access agreements where the TNSP has contracted with parties involved in the construction of the transmission line. Delays in land acquisition therefore present cost overrun risks for TNSPs.

In terms of environmental approvals, jurisdictional-based legislation and regulation govern the approvals that are required for project construction to commence.[114] While the specific requirements vary across jurisdictions, the general processes for environmental approval are broadly consistent. This involves a comprehensive assessment process, which includes the development of an environmental impact statement. The environmental impact statement is informed by a number of studies on specific environmental, economic and social considerations. These studies identify potential impacts to the environment and communities, and propose management measures to avoid or minimise these impacts. These studies and project plans are typically exhibited for public feedback before a recommendation is made by the planning agency to the relevant Minister. Given the detailed nature of the environmental studies required and processes of consultation, there is often little scope to streamline the process.

TNSPs may also require Commonwealth environmental planning approvals where relevant.[115] It is understood that the environmental assessment is undertaken by the jurisdictional authority based on a bilateral agreement with the Commonwealth.[116] The Commonwealth then reviews the assessment to confirm and make the determination.

113 This requires approximately: two years for the RIT-T process to ensure the project is justified, followed by regulatory approval as a contingent project by the AER; two years for jurisdictional planning development, environmental approvals for transmission corridors and associated infrastructure, along with engineering and design; and, two years for construction.

114 For example, in NSW the Environmental Planning and Assessment Act 1979 (EP&A Act), the State Environmental Planning Policy (State and Regional Development) 2011 (SRD SEPP) and the Infrastructure SEPP define a tiered planning approval regime for electricity infrastructure.

115 For example, in relation to matters of national environmental significance under the Environmental Protection and Biodiversity Conservation Act 1999.

116 https://www.environment.gov.au/epbc/publications/coag-agreement.

These processes are linked to the national framework through the investment approvals that TNSPs have to achieve to access funding to undertake activities like environmental approvals. Such activities are considered by AEMO and the AER in the assessment of CPAs and the RIT-T when considering whether the TNSP has conducted efficient preparatory and early works activities to better identify and manage project risks. However, TNSPs do not often undertake these activities until there is certainty of the preferred option and the costs of the project are accepted by the AER as part of the RIT-T and CPA process. This may lead to a potential source of delay in progressing the delivery of transmission projects related to the lack of clarity regarding cost recovery arrangements discussed in section 4.2.1.

Given this cross-over between national and jurisdictional frameworks, the Commission proposes that the Review explores issues in relation to whether the current cost recovery arrangements impact TNSPs' ability to meet jurisdictional requirements in a timely manner. Consideration may also be given to issues identified that may sit outside the scope of the national regulatory framework and which may be more appropriately addressed via reforms to jurisdictional policies. For example, for numerous ISP projects multiple jurisdictional planning and environmental approvals are required for cross-border projects. Given the regulatory time frames and uncertainty involved in transmission investment, it is important that the requirements on TNSPs to engage with multiple jurisdictional bodies can be aligned as early as possible in the process so that local permissions and potential challenges can be understood earlier in the planning process.

QUESTION 10: PROCESSES FOR JURISDICTIONAL ENVIRONMENTAL AND PLANNING APPROVAL

1. Would additional clarity on cost recovery arrangements for early works improve a TNSP’s ability to meet jurisdictional requirements in a timely manner?
2. Do jurisdictional planning and environmental requirements intersect with the national transmission planning and investment frameworks in ways that are not discussed above and may require further consideration?
3. Do you agree that the Review should take forward this issue as a priority issue? If not, why?

5 MATERIAL CHANGE IN NETWORK INFRASTRUCTURE PROJECT COSTS RULE CHANGE REQUEST

On 15 February 2021, the Energy Users Association of Australia (EUAA), Delta Electricity, Major Energy Users, ERM Power Limited and AGL Energy submitted a rule change request to the Commission on material changes in network infrastructure project costs.

This chapter has been prepared to facilitate public consultation on the rule change request and to seek stakeholder feedback on the key issues raised by the proposal.

This chapter sets out the:

- rule change request
- current provisions in the NER
- proposed changes
- issues arising from the proposed changes.

5.1 The rule change request

The rule change request seeks to amend the NER to require a RIT proponent to reapply the RIT process if, following completion of the RIT, its project's costs have increased by 10 per cent (for larger transmission and distribution projects) or 15 per cent (for smaller transmission and distribution projects), unless an exemption is granted by the AER.

Under the existing arrangements the RIT must only be reapplied where, in the reasonable opinion of the proponent, there has been a material change in circumstances which means that the preferred option identified in the final report is no longer the preferred option.[117]

The proponents consider that "allowing capital costs to significantly increase after the application of the RIT is a poor outcome from a governance perspective and negatively impacts consumer and stakeholder confidence that the RIT framework is achieving its stated purpose".[118] They seek to "restore confidence in the RIT process by ensuring that the AER and not the project proponent is the determining authority and that a RIT must be reapplied when a significant increase in network project costs occurs post completion of the RIT unless otherwise determined by the AER".[119]

The rule change proponents acknowledge that there have been a number of recent initiatives to improve cost estimation accuracy for transmission projects, including AEMO's development of a transmission cost database, the introduction of the "feedback loop" (whereby AEMO

117 Clauses 5.16.4(z3), 5.16A.4(n) and 5.17.4(t) all include the same reference to material change in circumstances. These provisions apply to non-ISP projects, ISP projects and RIT-D projects respectively. In each case, the AER has discretion to determine that the proponent is not required to reapply the RIT, or is only required to repeat part of the RIT process. For ISP projects only, the requirement to reapply the RIT may also be triggered by AEMO updating the ISP in a way that changes the identified need which is addressed by the RIT: see clause 5.16A.4(n)(2)(ii).

118 ERM et al, *Rule change request*, 15 February 2021, p. 2.

119 ibid.

confirms that an actionable ISP project remains part of the optimal development path) and development of the AER's *Guidance note for actionable ISP projects*.[120]

Notwithstanding these developments, the proponents consider that NSPs should use more robust cost estimates in the RIT to identify the "preferred option". They consider that the threat of the RIT being reopened due to subsequent material cost increases would encourage increased rigour in the RIT cost estimation process, and suggest this could also be supported by changes to the AER RIT-T and RIT-D guidelines.[121] In particular, they suggest that the AER should require a level of detail in RIT cost estimates equivalent to a Front End Engineering Design (FEED) so that decisions regarding preferred options are not based on preliminary estimates.[122]

Finally, in response to concern about the increased cost of Project EnergyConnect (PEC), the proponents request a transitional rule requiring reassessment of PEC via a requirement to update the PACR (the final RIT-T report). In addition to concern about increased costs, the proponents note that there is a need to reassess the estimated benefits of PEC in light of the NSW Electricity infrastructure roadmap which was released in November 2020 and which includes a legislated amount of 12GW entering the system before 2030. They suggest that reassessing PEC will cause minimal delay and will help restore confidence in the RIT process.[123]

The rule change request includes proposed drafting but does not include transitional provisions. Copies of the rule change request can be found on the AEMC website.[124]

5.2 The current provisions in the NER

5.2.1 Purpose of the RIT – identify the preferred option to meet an identified need

For both transmission and distribution projects, a proponent is required to apply the RIT-T or RIT-D (as applicable). There are a number of exceptions to this requirement, including where the estimated capital cost of the most expensive option to address the identified need which is technically and economically feasible is less than $6 million,[125] or where the project is to address an urgent or unforeseen network issue, involves maintenance work that is not intended to augment the network, or is needed to address inadequate levels of inertia or system strength (and there is less than 18 months in which to complete the work).[126]

120 AER, *Regulation of actionable ISP projects,* Guidance note, March 2021.

121 The AER is required to develop guidelines for the application of the RIT-T to non-ISP projects under clause 5.16.2, for application of the RIT-T to actionable ISP projects under clause 5.22.5, and for application of the RIT-D under clause 5.17.2 of the NER.

122 A FEED is a detailed feasibility study which is typically undertaken once a preferred approach to a project has been identified.

123 On 31 May 2021 the AER approved the final costs for PEC following CPA applications from ElectraNet and TransGrid. The AER's final decision and assessment of the forecast project cost can be viewed at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet-%E2%80%93-project-energyconnect-contingent-project.

124 See the project page for this rule change request at: https://www.aemc.gov.au/rule-changes/material-change-network-infrastructure-project-costs.

125 See clause 5.16.3(a)(2) of the NER for RIT-Ts and clause 5.17.3(a)(2) for RIT-Ds. While both provisions refer to $5 million, this value is subject to variation in accordance with a cost threshold determination. Under the AER's most recent cost threshold determination (published in November 2018), the value of this threshold is now set at $6 million. See AER, *Final Determination - Cost thresholds determination*, November 2018.

126 ibid.

As noted in section 2.2.2, the purpose of the RIT is to identify the credible option that maximises the present value of net economic benefits in the market. Before investing in a significant transmission or distribution project to meet an identified need on the network, a proponent must consider all credible options to meet that need, before selecting the option that maximises the net economic benefit across the market. This reduces the risk that consumers will pay for inefficient investments and promotes efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity.

5.2.2 Need to re-apply the RIT if there has been a material change in circumstances

Where a proponent has published a final RIT report and still wishes to undertake the project, the NER stipulate that the proponent – unless otherwise determined by the AER – must "reapply" the RIT to the project if "there has been a material change in circumstances which, in the reasonable opinion of the RIT-T [or D] proponent means that the preferred option in the project assessment conclusions report [or final project assessment report] is no longer the preferred option".[127]

It is worth noting that the focus of this provision is on the outcome that flows from the change in circumstances: namely, that the material change in circumstances has resulted in the preferred option no longer being the preferred option.

The NER provide that the AER may determine that the RIT proponent is not required to reapply the RIT, even when there has been a material change in circumstances. No detail is provided as to how such a determination would come about: for example, there is no requirement for the proponent to notify the AER of the change in circumstances and request a determination to waive the reapplication requirement. Unlike other provisions requiring the AER to make a determination, there is also no guidance as to whether the AER is to invite and consider stakeholder submissions, or the timeframe in which a determination is to be made.

However, the NER do set out factors that the AER must have regard to in the event that it makes such a determination. In particular, the AER must have regard to the credible options (other than the preferred option) identified in the final report, the change in circumstances identified by the RIT proponent, and whether a failure to promptly undertake the project is likely to materially affect the reliability and secure operating state of the transmission or distribution network (as applicable), or a significant part of that network.[128] This is not an exhaustive list and the AER could consider other factors in making its determination.

The NER give examples of what may constitute a material change in circumstances. They may include, but are not limited to, a change to the key assumptions used in identifying the need described in the final RIT report, or the credible options assessed in the final report.[129]

127 Clauses 5.16.4(z3), 5.16A.4(n) and 5.17.4(t) of the NER. The PACR is the final report in the RIT-T while the final project assessment report (FPAR) is the final report in the RIT-D.

128 Clauses 5.16.4(z5), 5.16A.4(p) and 5.17.4(v) of the NER.

129 See clauses 5.16.4(z4), 5.16A.4(o) and 5.17.4(u) of the NER.

The NER do not provide any detail as to what it means to reapply the RIT (which is defined as the test developed and published by the AER, and amended from time to time).[130] The RIT for both transmission and distribution comprises a number of steps and, importantly, includes consultation with stakeholders.[131] Thus, a requirement to "reapply the RIT" means the proponent is required to go back to the start of the process and complete all the steps again.

However, the AER may determine that a proponent is only required to repeat some steps in the process. While this is not explicitly set out in the NER, the Commission's 2017 determination regarding replacement expenditure planning arrangements referred to this discretion saying "the AER may conclude that all of the RIT-T process should be carried out, certain elements of the RIT-T [should] be re-run or, the RIT process is not required [to be re-run]".[132]

5.3 Proposed rule changes

The rule change request proposes that, unless otherwise determined by the AER, RIT-T proponents be required to reapply the RIT if, following completion of the RIT, a project's total assessed project cost was found to have increased by:

- 15 per cent or more for projects that cost less than $500 million in total
- 10 per cent or more for projects that cost more than $500 million in total.

This proposed change would apply for both actionable ISP projects and non-ISP projects. The proponents propose similar changes for distribution projects: i.e. requiring proponents to reapply the RIT if, following completion of the RIT-D, a project's total assessed project costs had increased by:

- 15 per cent or more for projects that cost less than $200 million in total
- 10 per cent or more for projects that cost more than $200 million in total.

Under the proposed approach, if a material cost increase occurs, a proponent would need to reapply the RIT, or apply to the AER to waive the reapplication requirement, even if the ranking of the preferred option had not changed.

The rule change proponents consider that reapplication of the RIT following material cost increases is less essential for lower cost projects. They state "the intent is not to require reapplication of the relevant RIT for lower cost projects".[133] However, rather than exempt lower cost projects altogether from the requirement to reapply the RIT, the proponents suggest that the AER should have discretion to waive the requirement to reapply the RIT, including where projects are below the threshold of:

- $150 million for transmission network projects and

130 See chapter 10 of the NER for definitions of regulatory investment test for distribution and regulatory investment test for transmission.

131 As noted earlier, the number of steps in the RIT-T varies depending on whether the RIT is applied to an ISP project or non-ISP project – however both processes are informed by consultation with stakeholders. For actionable ISP projects, this includes the PADR and PACR. For large transmission projects which are not actionable ISP projects, this includes the PSCR, PADR and PACR.

132 AEMC, *Replacement expenditure planning arrangements, Rule determination*, 18 July 2017, p. 76.

133 ERM et al., Rule change request, p. 12.

- $50 million for distribution network projects.[134]

The rule change request proposes that the AER has 30 days, following publication of the materially increased project cost, to make and publish a determination exempting a RIT proponent from the requirement to reapply the RIT.

The proponents suggest that the proposed rule change should apply to all RIT-Ts and RIT-Ds that are “yet to be finalised and approved by the AER” and request the Commission to consider transitional provisions to deal with any RIT-Ts and RIT-Ds that are currently in progress.[135]

5.4 Issues arising from the proposed changes

5.4.1 Is the current approach suitable?

The Commission is not aware of any instance in which a proponent has reapplied the RIT in response to a material change in circumstances, nor any determination by the AER to waive the requirement to reapply the RIT. That this provision has not been used raises a threshold question as to whether the current approach is suitable.

Under the current provisions, the requirement to reapply the RIT is only triggered if the project proponent forms the view that circumstances have changed to the point where the preferred option is no longer the preferred option. It is reasonable to assume that a proponent would be reluctant to form this opinion and trigger the reapplication requirement because doing so may involve repeating a lengthy and resource-intensive process. This has important implications for the robustness of this part of the regulatory framework.

While the AER could waive the requirement to repeat the whole RIT or require only part of the process to be repeated, the default position in the NER is that the proponent "must reapply the regulatory investment test". As such, a proponent will have no certainty as to how the AER will respond to a request for a determination to waive part or all of the reapplication requirement.

If a proponent does not consider that circumstances have materially changed, there is no recourse available if stakeholders have a different view.[136] The dispute resolution provisions that relate to the RIT are only available for a 30 day period following publication of the PACR and only apply to matters in the RIT-T. As such, they do not deal with matters relating to the CPA (for example, if the costs outlined in the CPA are significantly higher than those in the RIT).[137]

134 The wording of the rule change request refers to the requirement to reapply the RIT being “automatic” when higher cost projects (those exceeding the thresholds listed here) are subject to material cost increases. However, the drafting appended to the rule change request retains the existing discretion conferred on the AER whereby a proponent is required to reapply the RIT in the event of a material change in circumstances, “unless otherwise determined by the AER”. Thus, under the proposed drafting, the requirement to reapply the RIT would not be “automatic”, since it could still be waived by the AER (regardless of project size).

135 ERM et al., *Rule change request*, p. 12.

136 This is different to the situation where a statutory authority forms a view with which stakeholders disagree. In such cases, the authority's decision may be open to challenge on the ground that it is manifestly unreasonable, or through a dispute resolution process.

137 See clause 5.16B(c) of the NER.

The rule change request has sought to address this issue by including objective metrics that do not rely on the proponent's reasonable opinion. However, a broader issue that arises is who should be responsible for ensuring that, when circumstances require it, the RIT is reapplied.

While the proponent will be most familiar with the project's costs and benefits and thus may be best placed to identify if the ranking of the preferred option has changed, it may naturally be reluctant to reapply the RIT or even be seen to have a conflict of interest. By contrast, the AER is impartial and focussed on consumer protection. As such, it may be considered the more objective judge of whether reapplication of the RIT, in some form, is warranted.

In view of this, there may be a case to revisit the broader basis of the provision – rather than, or in addition to, the proponent's proposal to introduce a requirement to establish a cost threshold as a means of triggering the reapplication of the RIT. For example, the proposed approach would not address a situation where a project's estimated benefits have materially reduced and yet the proponent is unwilling to reapply the RIT. This raises the question of whether the AER should have some recourse in such circumstances – e.g. requiring the proponent to justify why the preferred option remains preferred – rather than the proponent's reasonable opinion being the determining factor.

QUESTION 11: WHO SHOULD DECIDE WHETHER THE RIT MUST BE REAPPLIED?

1. Should this decision remain the responsibility of the proponent or should it be a matter for the AER? Why?
2. If the decision remains with the proponent, should the AER have the right to test that opinion?

5.4.2 Cost thresholds

If the Rules were to be changed in the manner proposed by the rule change request, consideration needs to be given to what projects should be covered by the new requirements, and what percentage cost increase would trigger the reapplication requirement.

Projects covered by the proposed new requirements

The rule change request suggests that all transmission and distribution projects which require a RIT should be covered and that the AER should have discretion to waive the requirement for smaller projects (<$150 million for transmission and <$50 million for distribution).

In considering what – if any – projects should be captured by the proposed rule change, it is relevant to weigh up the impact on consumers of small projects experiencing cost increases and the administrative cost and delay associated with reopening the process (or seeking a determination to waive the reapplication requirement). For small projects, there is also very limited visibility about project cost data following completion of the RIT.[138]

It may be more appropriate to focus attention on major projects since cost increases associated with such projects will have a greater impact on consumers.

Any decision as to which projects should be covered by the proposed amendment would need to have regard for the number of projects that would be expected to meet various thresholds, and the impact on consumers of cost increases for projects of various sizes.

One option may be to use the same threshold as for contingent projects ($30 million)[139] or some other figure that more appropriately reflects the cost of a major investment – such as $50 million, $150 million, $200 million or $500 million (noting that these thresholds are included in the rule change request).[140]

Another option would be to align with the threshold in clause 5.16.4(z1) of the NER. That provision enables a RIT-T proponent to skip preparation of the PADR if the estimated capital cost of the preferred option is $35 million (adjusted to $43 million by the AER's latest cost threshold determination) and other criteria are met. An alternate approach could be to adopt an appropriate figure and then make it subject to some form of indexation or cost threshold review by the AER. A potential advantage of this approach is that the value of the threshold is dynamic rather than static and thus can keep pace with rising input costs.

More information on the cost of recent RIT projects is set out in Appendix C.

Percentage cost increase

Having considered which projects could be subject to the proposed amendment, a further consideration is what percentage cost increase should trigger the reapplication requirement.[141] While the rule change request suggested cost increases of 10 per cent (for

138 As discussed in the following section, this raises questions about how the proposed rule would operate in such cases.

139 Clause 6A.8.1(b)(2)(iii) of the NER provides that contingent projects have a value that exceeds either $30 million or 5 per cent of the value of the maximum allowed revenue for the relevant TNSP for the first year of the relevant regulatory control period, whichever is the larger amount.

140 For example, under the approach set out in the rule change request, a transmission project costing less than $500 million would trigger the RIT reapplication requirement if its costs were to increase by 15 per cent, while a transmission project costing more than $500 million would trigger the reapplication requirement if its costs were to increase by 10 per cent. The AER would have discretion to waive the reapplication requirement for transmission projects costing less than $150 million. The equivalent thresholds for distribution projects are $200 million and $50 million.

141 It is noted that increased costs are only part of the equation: what matters in considering the ranking of credible options is their net market benefit, having regard for both costs and benefits. Nonetheless, cost is an objective metric that is readily discernible compared with harder to quantify benefits. As such, the use of a percentage cost increase trigger could be an appropriate approach, noting that the AER would have discretion to determine whether further analysis by the proponent is required in the circumstances. For example, if costs and benefits both rise, there may be no need for further analysis.

larger projects) and 15 per cent (for smaller projects), these thresholds may be considered too low in light of the wide error margins typically associated with cost estimates for complex projects at the RIT stage.

As part of its efforts to improve transmission cost estimation for the ISP, AEMO has set out what it considers an appropriate approach to estimating project costs for the purposes of the ISP, the RIT and the CPA. This uses the same classification system (developed by the Association for the Advancement of Cost Engineering (AACE)) as suggested by the rule change proponents but takes a different view as to the level of rigour that is appropriate to require at the RIT stage.[142]

In particular, the proponents suggest that the RIT cost estimate should be based on a class 2 AACE estimate (i.e. a detailed feasibility study). The cost of preparing such an estimate is generally said to be 1-3 per cent of the total cost of the project.[143] For a $1 billion project, the estimate would therefore cost $10-$30 million.

By contrast, AEMO considers that a class 4 or 3 AACE estimate is adequate for use at the RIT stage (the RIT-T for PEC was based on a class 4 estimate) while a CPA should be based on a class 3 estimate or better.[144] For a major or complex project, a class 4 estimate has an error margin of -30% to +50% while a class 3 estimate has an error margin of -20% to +30%.[145] The percentage cost increases suggested in the rule change request (10 per cent for larger projects and 15 per cent for smaller projects) are well within these error margins and hence may be considered too low. A proponent could prepare a cost estimate in accordance with AEMO's guidance and still experience a material cost increase as defined in the rule change request.

An alternate approach to adopting a "one size fits all" cost increase reapplication trigger could be to require proponents to include in their PACR or FPAR bespoke "decision rules", similar to those developed by AEMO for ISP projects. Such rules could enable proponents to test, once market costs are revealed, whether the preferred option remains preferred, or whether another credible option should be re-examined. For example, the PACR could specify that, if the cost of the preferred option were to increase by X% (following market testing) and/or the cost of the second option reduce by Y% (e.g. based on producer price indexes or market data), then the outcome of the RIT should be revisited.

This could build on existing practice whereby TNSPs and DNSPs often include cost sensitivities in their RIT analysis, and may also identify the percentage cost increase that would change the preferred option. This practice could be formalised by requiring all proponents to include such metrics in their final RIT report. Such an approach may be more efficient and less duplicative than requiring the RIT proponent to reapply the RIT following a

142 This system defines a series of "classes" of estimates, ranging from Class 5 (least accurate) to Class 1 (most accurate). AEMO's 2021 Transmission cost report notes (p. 11) that "AER guidelines outline the expectations for each stage of the RIT-T, however they do not currently stipulate a specific class level for cost estimates, as estimate accuracy achieved at each stage will depend on the nature of the project."

143 See: http://www.processindustryinformer.com/short-cutting-front-end-engineering-design-feed.

144 AEMO, *2021 Transmission cost report*, Final report, July 2021, p. 12.

145 For small or straightforward projects, the class 4 estimate has an upper error range of +30% while the class 3 estimate has an upper error range of +20%.

"one size fits all" cost increase (or seek a determination from the AER to waive the reapplication requirement), even when the proponent already knows the change in cost that would affect the ranking of options.

More nuanced sensitivity analysis, and potentially bespoke "decision rules", will be particularly important where credible options considered in a RIT-T are heterogenous (e.g. network and non-network options). Where this is the case, each type of option may be subject to different cost pressures or movements. For example, AEMO notes in the 2020 ISP that, while transmission costs have risen by 30%, grid-scale battery costs have fallen by 30-40%.[146] Whereas, if all credible options are network options, then cost pressures may be similar across all options.

This "decision rule" approach would align with the rule change request which states:[147]

> "In cases where significant changes in the costs and benefits of major transmission projects occur, following completion of a RIT, it is appropriate that detailed sensitivity analysis of key assumptions be undertaken to assure stakeholders that the economics of the project remain robust."

Such rules could identify not only changes in costs but also changes in benefits or other factors that may impact the ranking of options. If the decision rules in a PACR or FPAR were triggered, the proponent could be required to update its analysis and provide a copy of its findings and underpinning modelling to the AER. Requiring publication of such modelling (both high level findings and underpinning data) would help restore confidence in the RIT process and ensure that RIT-T modelling appropriately incorporates and aligns with ISP parameters.

Engagement with stakeholders could also occur at this time. This would allow interested stakeholders, potentially including proponents of other credible options, to engage with the NSP and the AER and ensure that the process is appropriately robust and the RIT-T's conclusion sound.

Proponents could also be required to provide revised cost estimates to AEMO so that the accuracy of ISP cost estimates can improve over time.[148]

146 AEMO, *2020 Integrated system plan*, p. 31.

147 ERM et al., *Rule change request*, p. 4.

148 A similar idea was supported by the MEU in its submission to the AER's guidance note development process: MEU, *Submission to AER draft guidance note on regulation of actionable ISP projects*, 5 February 2021, p. 4.

QUESTION 12: COST THRESHOLDS

1. Should the NER include a requirement to reapply the RIT, or update analysis, when costs increase above specified percentage thresholds? If so, do you have a view as to what those percentage thresholds should be?
2. Do you consider this requirement should apply to all RIT projects or only those above a particular cost threshold/thresholds? If so, do you have a view as to what the cost threshold/s should be?
3. Do you have any views regarding the suggested alternative "decision rule" approach?
4. Should updated project cost data be provided to AEMO to help improve the accuracy of the ISP?
5. Do you have any other suggestions regarding alternative ways to manage cost increases?

5.4.3 Requirements when reapplying the RIT

Completing the RIT can take several years. For example, the PEC PSCR was published in November 2016, the PADR followed in June 2018 and the PACR in February 2019 (see the PEC case study in Appendix C.1).

In response to the consultation paper for the Commission's 2017 determination on replacement expenditure planning arrangements, AEMO submitted that a TNSP should not be required to repeat the whole RIT-T process in the event of a material change in circumstances. Instead it suggested that a TNSP only be required to repeat those elements of the RIT-T process which are materially affected by the change in circumstances. AEMO noted that it may otherwise become difficult for a TNSP to finalise its decision.[149]

Indeed, repeating the whole RIT may not prevent project costs rising again when the proponent performs market testing for a second time. The purpose of the RIT is to identify credible options, estimate their costs and benefits to ascertain whether they have a net market benefit, and rank them.[150] By contrast, the CPA process entails estimating project costs more accurately in order to calculate how much revenue needs to be recovered from consumers. The fundamental difference between these two processes is a key driver of the cost increases observed post completion of the RIT.[151] As such, repeating the RIT may not prevent costs increasing again at the market testing or CPA stage.

149 AEMC, *Replacement expenditure planning arrangements*, Rule determination, 2017, p. 75.

150 Where no credible option has a net market benefit, the preferred option is to do nothing.

151 This point was acknowledged by the AER in connection with PEC when it said, "We also understand that there is the potential for updated proposed costs in a contingent project application to diverge from the estimated costs in the SAET RIT-T." AER, *Decision: South Australia Energy Transformation*, Determination that the preferred option satisfies the regulatory investment test, January 2020, pp. 10-11.

Input costs could also rise during the reapplication process so that cost estimates in the second PACR may be higher than those in the first. Adding a significant delay to the planning process by requiring the RIT to be reapplied could also increase costs to consumers (for example, ongoing congestion in the transmission system may put upward pressure on wholesale energy prices).[152] Even if these risks do not materialise, consumers are likely to bear the cost of the planning process being undertaken twice. As such, repeating the whole RIT may only be warranted in rare cases.

Despite this, the default position set out in the NER is that the proponent must – in the event of a material change in circumstances – "reapply the regulatory investment test". While the AER has discretion to require the proponent only to repeat some parts of the RIT, the nature of this provision means that a proponent has no certainty as to whether the AER will waive the requirement to reapply the RIT, either in part or in full.

This raises a question as to whether it would be preferable to adopt an approach which is more targeted and does not require an AER determination as to how much of the RIT must be repeated. For example, it may be more efficient to require the proponent to update its cost benefit analysis (CBA) and engage with stakeholders on the updated analysis.[153] Such an approach may also increase the likelihood of a proponent being willing to trigger the reapplication requirement by forming the requisite reasonable opinion.

QUESTION 13: REQUIREMENTS WHEN REAPPLYING THE RIT

1. Should the requirement to reapply the RIT be more targeted?
2. Should any additional analysis and modelling that is required to be undertaken be published and subject to public consultation?

5.4.4 Trigger to reapply the RIT-T

The rule change request proposes that the AER would have 30 days, from the date of publication of the revised total project cost forecast, to make and publish a determination as to whether the RIT needs to be reapplied in full or in part. This requirement would rely on

152 TUOS charges account for a smaller portion of consumer bills than do wholesale energy costs. In 2020/2021 for example, TUOS accounted for 7.5 per cent of residential consumer bills (NEM wide average) compared with 33.7 per cent for wholesale energy costs. AEMC, *Residential electricity price trends 2020,* Final report, December 2020. Data is drawn from figure 2.1 on p. 4. Distribution use of system (DUOS) charges accounted for 34.9 per cent of residential bills.

153 This would be in line with the rule change request which suggested a more targeted approach of reapplying the PADR and/or PACR, and "allow[ing] stakeholders to review this material change through a transparent process which will result in a more rigorous updating of the project's Cost Benefit Analysis". ERM et al., *Rule change request*, pp. 4-5.

the proponent publishing revised cost estimates and this is only likely to occur if the project is contingent (meaning that the proponent has to submit a CPA to the AER, at which point the revised cost estimate would be published). There is no requirement in other cases for such revised estimates to be published, and a proponent would have no incentive to do so if publication could lead to the need to reapply the RIT.

This raises the question as to whether the proposed approach is suitable for non-contingent projects, and a more fundamental question about the amount of data that is publicly available for projects that do not involve a CPA. As discussed in Appendix C, the Commission sought to examine how often material project cost increases occur. The Commission's analysis revealed that, except for contingent projects, there is very little data available about revised project cost estimates, post completion of the RIT.

Therefore, under the approach proposed in the rule change request, the process that would lead to the reapplication of the RIT may not be suitable for non-contingent projects given limited data availability. However, it may still be appropriate to require non-contingent projects above a certain size to notify the AER in the event of material cost increases. Given that the level of scrutiny of non-contingent projects is typically less than for contingent projects, it may be important to include major non-contingent projects in any reapplication requirements so as to protect consumer interests.[154]

It will also be important, if the NER are amended as proposed, to provide clarity about the latest point in time at which a requirement to reapply the RIT could be triggered, and whether this process can be triggered more than once. Managing the degree of uncertainty in the planning process that may result from the proposed changes could help limit the potential for unintended adverse outcomes.

QUESTION 14: TRIGGER TO REAPPLY THE RIT

1. Do you have any views as to how the requirement to reapply the RIT should be given effect, including for contingent and non-contingent projects?
2. Should there be a cut-off point (e.g. once the AER approves the CPA, or once construction commences) beyond which any requirement to update analysis cannot be triggered? If so, what would be an appropriate cut-off point?
3. Should there be a limit on how many times RIT analysis must be updated?

154 Note that non-contingent projects form part of the broader revenue determination process and therefore the costs of these projects are not subject to direct scrutiny outside of the ex-ante revenue determination process, unless the AER considers it appropriate to consider a particular project in greater detail.

5.4.5 What level of rigour is appropriate for RIT cost estimates?

The rule change request proposes that the AER guidelines be amended to require proponents to develop more rigorous (and expensive) cost estimates for the PACR or FPAR. The proponents suggest this should be based on an AACE class 2 estimate or detailed feasibility study. This is at odds with the approach adopted by AEMO in its 2021 *Transmission cost report* (which recommends a class 4 or 3 estimate at the RIT stage, and a class 3 estimate or better at the CPA stage) and by other organisations such as CSIRO.[155]

Even a feasibility study for a small transmission project can be a resource intensive exercise.[156] As such, consideration would need to be given to whether the cost of undertaking detailed feasibility studies for each option (which cost will likely be passed through to consumers) is warranted at the RIT stage, and whether requiring such detailed analysis could have unintended outcomes (e.g. inefficiently limiting the number of options considered). It will also be important to consider whether more detailed analysis is required for all RIT projects, or whether such requirements should be limited to larger projects which have greater impacts on consumers.

QUESTION 15: SHOULD RIT COST ESTIMATES BE MORE RIGOROUS?

1. Do you consider that the current level of rigour used for RIT cost estimates is suitable? If not, what level of rigour is appropriate? In particular, would it be appropriate to require an AACE 2 estimate (i.e. a detailed feasibility study) for each credible option?
2. If more detailed cost estimates are required at the RIT stage, should this apply to all RIT projects, or only to larger projects? If so, which projects should be subject to this requirement?
3. Do you have any other suggestions to address the issues raised in the rule change request?

5.5 Lodging a submission and next steps

In considering this rule change request, the Commission will seek stakeholder views through a public consultation process following publication of the consultation paper and draft

155 CSIRO adopts a similar approach to AEMO, only using FEEDs once a preferred option has been identified. See: http:// https://research.csiro.au/hyresource/project-status/.

156 For example, TransGrid is undertaking a $3.45 million study to develop, test and deliver a technical design and commercial process for the development of the New England Transmission Infrastructure. ARENA has contributed $1 million to help cover the cost of this feasibility study. See: https://infrastructuremagazine.com.au/2020/07/21/arena-invests-1-million-in-transmission-infrastructure-study/.

determination. The key project milestones are set out in Table 5.1 below, however consideration will be given to the need to adjust these timeframes to align with the timetable for the review.

Table 5.1: **Key milestones for the rule change request**

MILESTONE	DATE
Submissions on consultation paper due	30 September 2021
AEMC to publish draft determination	09 December 2021
Submissions on draft determination due	20 January 2022
AEMC to publish final determination	03 March 2022

Lodging a submission

The Commission has published a notice under s. 95 of the NEL for this rule change proposal inviting written submissions.

Written submissions on this consultation paper must be lodged with the Commission by 30 September 2021 online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0325.

Stakeholders are encouraged to use the stakeholder submissions template when providing feedback to the consultation paper. No separate submission is required if stakeholders are also making comments on matters relating to the review more broadly.

All enquiries on this project should be addressed to Katy Brady on (02) 8296 0634 or katy.brady@aemc.gov.au.

ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
AEMA	Australia Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BAU	Business-as-usual
Capex	Capital expenditure
CBA	Cost benefit analysis
CESS	Capital Expenditure Sharing Scheme
Commission	See AEMC
CPA	Contingent project application
DCA	Dedicated connection asset
DER	Distributed energy resources
DNA	Dedicated network asset
DNSP	Distributed network service provider
DPAR	Draft project assessment report
ESB	Energy Security Board
EUAA	Energy Users Association of Australia
FEED	Front end engineering design
FPAR	Final project assessment report
ISP	Integrated System plan
LTESA	Long term energy service agreement
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NGL	National Gas Law
NSP	Network service provider
NTNDP	National Transmission Network Development Plan
ODP	Optimal development path
Opex	Operating expenditure
PACR	Project assessment conclusion report
PADR	Project assessment draft report
PAFR	Project assessment final report
PEC	Project Energy Connect

PSCR	Project specification consultation report
PTRM	Post-tax revenue model
RAB	Regulated asset base
REZ	Renewable energy zone
RFM	Roll forward model
RORI	Rate of return instrument
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
TNSP	Transmission network service provider
WACC	Weighted average cost of capital

A SUMMARY OF STAKEHOLDER SUBMISSIONS TO THE ESB OPTIONS PAPER

The ESB P2025 market design options paper raised several issues relevant to the transmission review. Table A.1 summarises submissions from stakeholders responding to the options paper in relation to these issues. These comments were taken into account when preparing this paper.

Table A.1: **Summary of stakeholder submissions**

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
Streamlining the assessment process of actionable ISP projects.	Open to improving/bypassing the RIT-T	Stakeholders acknowledge that the RIT-T is not meeting their expectations. They are unclear about the additional value of the RIT-T as the ISP includes a cost-benefit analysis and they agree that timeliness and efficiency can be improved. Stakeholders are open to improving or bypassing the RIT-T process, if it can be achieved without compromising delivery of the optimal project on behalf of customers. This requires careful further assessment of whether key features of the RIT-T are adequately captured in the ISP and the CPA such as: a robust cost-benefit analysis, requirements to consider non-network options and appropriate engagement with communities. Speeding up the process for new transmission may carry some risk of early expenditure where a project fails, however the risk is likely to be relatively small against the consequences of delay.	AEC submission to the ESB P2025 options paper: p. 10. CEFC submission to the ESB P2025 options paper: p. 9. CEIG submission to the ESB P2025 options paper: p. 3. Finncorn submission to the ESB P2025 options paper: p. 34. ENA submission to the ESB P2025 options paper: p. 20. APA submission to the ESB P2025 options paper: p. 6. Transgrid submission to the ESB P2025 options paper: p. 5. Grattan Institute submission to the ESB P2025 options paper: p. 9.

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
	Opposed to weakening the RIT-T	Stakeholders oppose weakening the RIT-T process as it supports a robust cost-benefit analysis of actionable ISP projects which safeguards against overbuild by ensuring that projects provide net benefits. The length of the RIT-T process may be necessary to deliver optimal projects and maintain customer confidence in the process. Delays may also be attributed to accounting for uncertainty rather than the process itself. Stakeholders are concerned that weakening the RIT-T would lead to inefficient investments and push the risk of marginally beneficial investment onto unwilling consumers. However, stakeholders agree that further analysis is required on this issue.	Aluminium council submission to the ESB P2025 options paper: p. 7. Origin Energy submission to the ESB P2025 options paper: p. 15. EDL submission to the ESB P2025 options paper: p. 4. EUAA submission to the ESB P2025 options paper: p. 15. Ausnet submission to the ESB P2025 options paper: p. 8. Energy Australia submission to the ESB P2025 options paper: p. 22. Stanwell submission to the ESB P2025 options paper: p. 12.
Assessment of benefits during the RIT-T	Supports broadening the scope of the RIT-T benefits test	Some stakeholders find the RIT-T benefits test too narrow and does not fully capture the long term value of actionable ISP projects to the wider economy and society. This may lead to projects, which are valuable to Australians and potentially better for the wider economy and society, being under valued and held up by NEM regulatory processes, in favour of	Transgrid submission to the ESB P2025 options paper: p. 6. Snowy Hydro submission to the ESB P2025 options paper: p. 10. CEIG submission to the ESB P2025 options paper: pp. 3-4. CEFC submission to the ESB

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
		projects that may be to the detriment of the wider economy and society. Stakeholders support broadening the scope of the benefits at varying degrees. From adopting a "whole-of-system" benefit approach to including relevant quantifiable benefits consistent with government policy objectives. A further improvement would be to include any consequential network price increases alongside the expected total cost reductions to highlight the savings forgone if network projects are delayed or abandoned.	P2025 options paper: p. 9. RWE submission to the ESB P2025 options paper: p. 3. Spark infrastructure submission to the ESB P2025 options paper: p. 5.
	Opposed to broadening the scope of the RIT-T benefits test	Stakeholders oppose broadening the benefits test because they find that it would be inconsistent with the NEO. They are concerned that it may lead to an inefficient allocation of costs to consumers and the politicisation of transmission investment decision-making. Factoring additional benefits may further increase the time of the assessment process which is potentially unnecessary as it may not materially alter the conclusions regarding the national view of project priorities. Stakeholders are also concerned that equal attention will not be given to broader costs of projects should	AEC submission to the ESB P2025 options paper: p. 10. AGL submission to the ESB P2025 options paper: p. 26. Ausnet submission to the ESB P2025 options paper: p. 7. Delta energy submission to the ESB P2025 options paper: p. 5. ENA submission to the ESB P2025 options paper: pp. 20-21. Energy Australia submission to the ESB P2025 options paper: p.

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
		the benefits test be widened. Further, stakeholders find it more appropriate for government jurisdictions to contribute to costs which deliver benefits they value consistent with their policy objectives and not offload the cost of their policy via a regulatory process.	22. EUAA submission to the ESB P2025 options paper: p. 15. Finncorn submission to the ESB P2025 options paper: p. 34. St Baker submission to the ESB P2025 options paper: p. 8.
Managing uncertainty	Support implementing solutions to deal with greater uncertainty	Stakeholders have identified a timing mismatch between investment and the ramp up of utilisation of investment. This problem reflects uncertainty in the ISP process. Stakeholders agree that the regulatory process should account for uncertainty. They suggest creating a pathway to account for new information and changes in the market, for example: cost revisions.	Finncorn submission to the ESB P2025 options paper: p. 34. Origin submission to the ESB P2025 options paper: p. 15.
Difficulty in financing ISP investments	Agree that financing ISP investment can be difficult	TNSPs expressed concerns regarding their ability to finance ISP investments under the current regulatory framework. Transgrid noted that their recent decision to proceed with PEC was only possible with the financial support from the CEFC. They expressed concern over whether similar support would be available for future projects. Hence, there investment commitments are	ENGIE submission to the ESB P2025 options paper: p. 9. Transgrid submission to the ESB P2025 options paper: p. 4.

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
		subject to the financeability of future projects.	
Contestability in transmission investment	Supports increase in contestability	Stakeholders support increased contestablilty if it leads to: • lower cost to consumers • greater innovation • a reduction in the barriers to delivering transmission infrastructure and • improved timeliness and efficiency. However, exploration into potential increased contestability should include an examination of general expenditure incentives administered by the AER and other cost drivers.	ATCO submission to the ESB P2025 options paper: p. 3. CEFC submission to the ESB P2025 options paper: p. 9. CEIG submission to the ESB P2025 options paper: p. 4. Energy Australia submission to the ESB P2025 options paper: p. 22.
	Reservations regarding increased contestability	Stakeholders are concerned that increased contestability may increase administrative burden and deliver limited cost savings. Additionally, Further fragmentation of transmission ownership might make cost recovery more complex and inefficient. TNSPs already exploit competition in their procurement approaches. Some stakeholders find that contestability will only resolve funding challenges where it is accompanied by flexibility in returns and revenue recovery over and above the regulatory framework. Alternatively, increasing the strength of incentives for	Spark infrastructure submission to the ESB P2025 options paper: p. 3. Network of Illawara consumers of energy submission to the ESB P2025 options paper: p. 45. Energy Australia submission to the ESB P2025 options paper: p. 22.

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
		cost minimisation should be considered.	
Allocation of risk of transmission investment	Neither customers nor TNSPs should bear all the risk of transmission investment	Stakeholders expressed that customers and TNSPs should not bear all the risks of uncertainty and stranded assets or under-utilised investment. They suggest that some risk should be borne by project proponents, though allocating some costs (and risk) to generators does not in itself address this issue. Stakeholders suggest that jurisdictions may bridge the gap. This could be either via short-term financing to TNSPs or underwriting regulated asset revenues to the extent they are not justified by asset utilisation in the ramp-up period. Methods to minimising risk should also be considered such as delaying capital expenditure where assumptions like costs of non-network solutions have been updated. An approach that promotes greater scrutiny on larger ISP projects where consumers bear greater risk, and less scrutiny on smaller ISP projects where consumers bear less risk may be sensible. Ultimately stakeholders support a review of the sequencing and risk borne by parties across all elements of the planning and investment process.	ENGIE submission to the ESB P2025 options paper: p. 9. Finncorn submission to the ESB P2025 options paper: p. 34-35. Bright Sparks submission to the ESB P2025 options paper: p. 3. Ausnet submission to the ESB P2025 options paper: p. 8.

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
Regulated rate of return (RORI)	Supports changes to the RORI	Spark infrastructure noted that it is deemed good practice internationally to incorporate financeability assessments in the process for determining regulated returns, which the AER sees no need for. Spark infrastructure does not agree with the AER's conclusion that investors find the RORI sufficient to attract investment. Spark infrastructure suggested including a transparent test supported by all stakeholders that assesses whether the AER's estimate of the efficient cost of capital is the best estimate and, in turn, will provide compensation sufficient to support the credit rating metrics adopted in the estimate. Further, Spark finds that the current regulatory settings deliver returns on network investment that are too low and regulatory risk that is higher for major projects. It noted that the equity returns in the 2018 RORI are globally uncompetitive. To ensure that the returns on regulated network infrastructure are sufficient to attract capital and commensurate with risk, Spark suggests that consideration should be given to enabling variations to regulated returns for higher risk projects, flexibility in revenue profile over the life of investment and mitigating cost recovery risk and penalties on	Spark infrastructure submission to the ESB P2025 options paper: pp. 3-7.

ISSUE	STANCE	COMMENTS	STAKEHOLDERS
		efficient investment for ISP projects, and transparent financeability assessments.	
Investment timing trade-offs	Further work needs to be done	Investing late increases the risk of power system reliability whereas investing to early increases the risk that consumers pay higher prices. The ECA considers it critical that further work be undertaken to identify the trade-offs between investment in distribution and transmission capacity, as well as the least regrets timing of additional transmission capacity.	ECA submission to the ESB P2025 options paper: p. 10

B RELATED WORK, JURISDICTIONAL INITIATIVES AND CARBON

This chapter provides background relevant to:

1. the interrelationship of the Review with other rule change requests
2. the jurisdictional arrangements that have been developed to progress major transmission projects
3. the treatment of carbon in transmission planning.

B.1 Current work related to the planning and investment framework

There are several pieces of work that are related to the planning and investment framework for major transmission projects. These include the:

- connection to dedicated connection assets rule change
- coordination of generation and transmission investment reforms, being progressed through the Energy Security Board's (ESB's) post-2025 market design workstream
- AER Transmission investment review
- AER Review of the 2022 Rate of Return Instrument

The remainder of this section provides a summary of these processes and highlights their interactions with the planning and investment framework.

B.1.1 Connection to dedicated connection assets final rule

Changes in contestability arrangements for certain transmission assets

The final rule on the *Connection to dedicated connection assets* rule change[157] amended the regulatory framework for transmission assets built to connect generation to the 'shared' network, e.g. the power line that connects a generator to the existing network. Under the new arrangements material assets with a total route length of 30km or more form part of the transmission network operated by a Primary TNSP and are defined as 'designated network assets' (DNAs). Under the previous arrangements, these assets were classified as large dedicated connection assets (DCAs). Importantly, DNAs are limited to radial extensions of the existing network and cannot be looped or meshed.[158]

The different regulatory treatment of these assets has implications on the contestatability arrangements applying to these assets.[159] Large DCAs were separate from the network and fully contestable, i.e. any party could own, control or operate them. In contrast, DNAs form part of the network and the Primary TNSP is responsible for operation, maintenance and setting the functional specifications, but they can be contestably designed, constructed and owned. The Commission considered this reduction in contestability to be necessary in order

157 AEMC, *Connection to dedicated connection assets*, Final determination, July 2021.

158 AEMC, *Connection to dedicated connection assets*, Final determination, July 2021, p. 12

159 See AEMC, *Connection to dedicated connection assets*, Final determination, July 2021, Appendix E.

to treat such material assets as part of the transmission network. The greatest benefits from allowing for competition in the provision of transmission services are likely to arise during construction, which remains contestable.

Interactions with the existing transmission planning and investment framework

The final rule on the *Connection to dedicated connection assets* rule change does not directly address the interaction between the new DNA framework and the NER's broader transmission planning and investment framework. However, the Commission emphasised in its final determination that the new framework for DNAs is not intended, and is unlikely, to impact the existing transmission planning and investment framework.[160]

The core focus of the existing transmission framework is to facilitate efficient investment in shared network infrastructure to meet consumer demand for safe, reliable, and secure power supply. Such infrastructure remains funded by consumers through regulated charges. By contrast, the new framework for DNAs seeks to facilitate third party investment in transmission infrastructure, limited to radial network assets. Accordingly, the cost of DNAs is not recovered from consumers through regulated charges. Where DNA projects could be more efficiently delivered as shared network infrastructure, the Primary TNSP remains able to propose the project through the RIT-T process for new transmission network investment. Accordingly, the transmission planning and investment framework remains the prime mechanism for investing in shared network infrastructure to meet consumer demand. Nothing in the final rule on *Connection to dedicated connection assets* undermines these arrangements.

B.1.2 ESB Post - 2025 market design

The ESB was tasked by the former COAG Energy Council to develop advice on reforms to the NEM to meet the needs of the energy transition and beyond 2025.[161] In April of this year, the ESB published an options paper that set out reform options across the following four reform areas:[162]

- resource adequacy and ageing thermal generation retirement
- essential system services and scheduling and ahead mechanisms
- distributed energy resources (DER) and demand side participation
- transmission and access.

Final recommendations will be delivered to the Energy Ministers in the middle of this year.[163]

Of relevance to this Review is the transmission and access reform area. However, it is only relevant to the extent that it pertains to the planning and investment framework. By way of example, the design of access models is not within the scope of this Review. Accordingly, this Review will focus on the issues regarding the timely and efficient delivery of transmission

160 AEMC, *Connection to dedicated connection assets*, Final determination, July 2021, p. 184.
161 ESB, *Post 2025 market design options – a paper for consultation | Part A,* Sydney, April 2021, p 13.
162 ESB, *Post 2025 market design options – a paper for consultation | Part A,* Sydney, April 2021, pp 17-18.
163 ESB, *Post 2025 market design options – a paper for consultation | Part A,* Sydney, April 2021, p 7.

investment identified by the ESB through its post 2025 market design work. Of note is that the ESB has explained in its post 2025 market design work that:[164]

> ...challenges are emerging in getting the new [transmission network] built. These include planning issues, community concerns, biodiversity, indigenous heritage, difficulties getting access to land and reluctance by networks to take risk and cope with financing very large projects. Unaddressed, these issues have the potential to result in delays and increased costs.

Of these issues, the ESB has signalled its intention to consider issues relevant to the role of the RIT-T, the nature of the test and issues regarding the allocation of costs between jurisdictions.

B.1.3 AER transmission investment regulation review

The AER commenced a program of work in November 2020 that sought to support the efficient and timely delivery of large actionable ISP projects. As part of this program, the AER has developed a guidance note designed to improve the predictability and transparency of how it will assess the costs of large transmission projects. In particular, the guidance note covers:[165]

- the contingent project application assessment process, clarifying the AER's expectations in terms of what a TNSP is required to demonstrate to increase confidence in the quality of its cost forecasts, as well as how it has assessed and managed risk
- contingent project application staging, clarifying how the AER will approach and consider sequencing actionable ISP projects through staged contingent project applications — assisting TNSPs to understand and manage project risks better and reduce uncertainty regarding cost forecasts
- the ex-post measures that may apply to the capital expenditure of ISP projects, increasing predictability regarding how an ex-post review will be undertaken.

The AER's initial work program also identified longer term areas of reform relating to the RIT-T, changes to the incentive regulation framework and introduction of contestability. These issues will be canvassed in the current Review process.

B.1.4 AER's development of 2022 rate of return instrument

The AER is currently consulting on the development of its 2022 rate of return instrument (RORI). The AER is required to make a RORI under the NEL,[166] and it sets how the AER will calculate the:

- allowed return on debt
- return on equity
- value of imputation credits.

164 ESB, *Post 2025 market design options - a paper for consultation | Part A,* Sydney, April 2021, p 78.
165 AER, *AER guidance note to support efficient delivery of actionable ISP projects,* Covering letter, Sydney, 31 March 2021, pp 1-2.
166 The AER is also required to make a RORI under the National Gas Law.

These elements are used to calculate the allowed rate of return on capital in electricity network determinations for the four-year duration of the relevant RORI. The rate of return of a material component of regulated revenues, and an unbiased estimate that reflects the market cost of capital is important to incentivising efficient investment.

B.2 Jurisdictional arrangements to progress major transmission projects

The nature of the energy transition is such that a significant volume of existing generation capacity in the NEM is expected to reach the end of its technical life in the next two decades. Replacing these resources, coupled with state-based renewable energy targets, had led to the emergence of jurisdictional specific planning arrangements that sit outside the national framework. This section provides a summary of these jurisdictional initiatives. Specifically:

- the New South Wales Transmission Infrastructure Strategy
- the New South Wales Electricity Infrastructure Roadmap
- the Victorian REZ Development Plan.

B.2.1 The New South Wales Transmission Infrastructure Strategy

The New South Wales government published its Transmission Infrastructure Strategy in 2018. The strategy is designed around three key objectives:[167]

- boosting New South Wales' interconnection with Victoria, South Australia and Queensland, and unlock more power from the Snowy Hydro Scheme
- increasing New South Wales' energy capacity by prioritising REZs in the Central-West, South West and New England regions
- working with other states and regulators to streamline regulation and improve conditions for investment.

These three objectives are described in greater detail below.

Boosting New South Wales' interconnection

The New South Wales government is intending to accelerate the development of priority transmission projects to boost interconnection with other NEM jurisdictions. In particular, the New South Wales government has identified four priority transmission projects, i.e.:[168]

- upgrading the existing Victoria-New South Wales interconnector
- upgrading the Queensland-New South Wales interconnector
- developing a new South Australia-New South Wales interconnector
- developing new transmission from Snowy Hydro to Bannaby.

To accelerate these projects, the New South Wales government is providing funding guarantee that will enable TransGrid (the incumbent TNSP) to expedite preliminary planning work.[169]

167 NSW government, *NSW transmission infrastructure strategy,* Sydney, November 2018, p 5.

168 NSW government, *NSW transmission infrastructure strategy,* Sydney, November 2018, p 8.

169 NSW government, *NSW transmission infrastructure strategy,* Sydney, November 2018, p 10.

Increasing New South Wales' energy capacity

The New South Wales government is prioritising the development of three REZs in the state's New England, Central-West and South-West regions. These REZs are being progressed through the New South Wales Electricity Infrastructure Roadmap, which is discussed in section B.2.2.

Streamlining regulation and improving conditions for investment

The New South Wales government is concerned that there are separate planning and economic approvals required for regulated transmission infrastructure, which can be a barrier to timely and efficient new generation and storage connecting to the grid.[170] It intends to continue to take a leadership role through the (former) COAG Energy Council to ensure the processes are fit-for-purpose during the energy transition.[171]

B.2.2 The New South Wales Electricity Infrastructure Roadmap

The New South Wales government's electricity infrastructure roadmap (the Roadmap) builds upon its 2019 New South Wales electricity strategy and 2018 transmission infrastructure strategy. In particular, it is designed to set out a plan that transitions the New South Wales electricity sector into one that is cheaper, cleaner and more reliable.[172] The Department of Planning, Industry and Environment further explains that:[173]

> The Roadmap will drive integrated and coordinated investment in large-scale electricity infrastructure, specifically generation, transmission, and firming of variable renewable electricity to maintain an affordable, reliable and secure supply.

The Roadmap is given effect through its enabling legislation — the *Electricity Infrastructure Investment Act 2020 (NSW)* — which passed the New South Wales parliament in December 2020. This legislation commits the New South Wales government to:[174]

- declaring five REZs in the Central West Orana, Illawarra, New England, South West and Hunter-Central Coast regions, which together are intended to delivery network capacity of 12 gigawatts
- establishing an Electricity Infrastructure Investment Safeguard to deliver new generation, long duration storage and firming capacity through Long Term Energy Service Agreements (LTESAs)
- establishing an Electricity Infrastructure Jobs Advocate and New South Wales Renewable Energy Sector Board to ensure the use of locally manufactured and supplied goods and services

170 NSW government, *NSW transmission infrastructure strategy,* Sydney, November 2018, p 14.

171 NSW government, *NSW transmission infrastructure strategy,* Sydney, November 2018, p 14.

172 NSW government 2020, New South Wales government, Sydney, viewed 3 June 2021, https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap.

173 NSW Department of Planning, Industry and Environment, *NSW Electricity infrastructure roadmap | Building an energy superpower detailed report,* Sydney, November 2021, p 26.

174 NSW government 2020, New South Wales government, Sydney, viewed 3 June 2021, https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap.

- establishing a Transmission Development Scheme that will de-risk REZ investment.

At the centre of the Roadmap is the Consumer Trustee, which is responsible for setting out the development pathway for generation (and associated network infrastructure) to meet the intended network capacity of each REZ.[175] The Consumer Trustee will also be responsible for administering competitive tenders to offer LTESAs for generation, long duration storage and firming. LTESAs are option contracts that give the control holder the option to access a minimum price for their energy service.[176]

B.2.3 The Victorian REZ Development Plan

The Victorian REZ Development Plan is still in the early stages of development, with a directions paper published in February 2021.[177] The directions paper outlines three initiatives being undertaken by the Victorian government to develop REZs in Victoria, i.e.:[178]

- preparation of an initial REZ development plan that includes investments that could be delivered immediately
- establishing an organisation — VicGrid — to plan and develop Victorian REZs
- publishing an implementation plan that outlines how REZs in Victoria will be planned, developed and invested in.

The remainder of this section provides a brief overview of these initiatives.

Initial REZ development plan

The initial REZ development plan is a collaboration between the Victorian government and AEMO (in its role as jurisdictional planner for Victoria) to identify network investments that support the timely and efficient development of REZs. The plan is divided into two stages:[179]

- stage one projects — investments that be immediately progressed by the Victorian government to alleviate network limitations on renewable energy projects
- stage two projects — investments in REZ infrastructure over the medium-term that require further assessment and consultation.

Stage one projects are further divided into two categories, with different funding options being considered for each. The first category relates to projects targeted at immediate grid operation, system strength or curtailment issues, with the Victorian government considering financing these projects through its $540 million REZ fund.[180] The second category relates to upgrades that facilitate additional renewable capacity in the West and South West REZs. The

175 NSW Department of Planning, Industry and Environment, *NSW Electricity infrastructure roadmap | Building an energy superpower detailed report,* Sydney, November 2021, p 29.

176 NSW Department of Planning, Industry and Environment, *NSW Electricity infrastructure roadmap | Building an energy superpower detailed report,* Sydney, November 2021, p 29.

177 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021.

178 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 2.

179 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 7.

180 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 8.

Victorian government is considering whether these projects could be progressed through the existing national framework but will explore alternative options if it deems necessary.[181]

These investments have the potential to enable 10 gigawatts of additional renewable generation in Victorian REZs. The initial plan will be further developed through consultation, while the REZ development plan more broadly will be maintained and updated by VicGrid upon its establishment.[182]

Establishment of VicGrid and funding pathways

VicGrid is intended to be established in the middle of 2021 and will be tasked with the planning and development of Victorian REZs.[183] The precise form and functions of VicGrid are still under development, but may include:[184]

- planning, developing and delivering timely and coordinated transmission, generation, storage and network firming projects in REZ areas
- facilitating delivery of renewable energy projects in REZ areas
- leading community engagement and benefit sharing from REZ development
- supporting state and regional economic development opportunities through REZ development
- identifying and applying appropriate procurement, cost recovery and co-funding approaches
- financial support for REZ development projects.

Publication of implementation plan

The Victorian government intends to release its REZ implementation plan in July 2021, which will set out:[185]

- the finalised REZ development plan
- formal establishment of VicGrid and its ongoing work agenda
- the framework for investment in and funding of REZ development plan projects.

B.3 Treatment of carbon in transmission planning

B.3.1 Approach to carbon in the 2020 ISP

The 2020 ISP already includes a number of policies relevant to emission reduction objectives in its inputs, assumptions and scenarios. As noted in section 2.2.1, the ISP is to achieve

181 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 10.

182 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 7.

183 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 15.

184 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 15.

185 Victorian Department of Environment, Land, Water and Planning, *Victorian renewable energy zones development plan,* Directions Paper, Melbourne, February 2021, p 17.

"power system needs" over a planning horizon of at least 20 years for the long term interests of the consumers of electricity.[186]

In determining power system needs, AEMO may consider a current environmental or energy policy where that policy has been sufficiently developed to enable AEMO to identify the impacts of it on the power system and at least one of the following is satisfied:

- a commitment has been made in an international agreement to implement that policy;
- that policy has been enacted in legislation;
- there is a regulatory obligation in relation to that policy;
- there is material funding allocated to that policy in a budget of the relevant participating jurisdiction; or
- the Ministerial Council of Energy (MCE) has advised AEMO to incorporate the policy.[187]

AEMO is required to develop the ISP in accordance with guidelines developed by the AER. These guidelines require AEMO to test the robustness of alternative development paths to future uncertainties through the use of scenarios and sensitivities.[188]

Consistent with these guidelines, the 2020 ISP explored five scenarios and six sensitivities. The five scenarios include:

- Central
- Slow change
- High DER
- Fast change, and
- Step change

The central scenario is determined by market forces under current federal and state government policies, including:

- the NEM's share of the federal Government's objective to reduce emissions by at least 26% by 2030
- renewable energy targets in Victoria (VRET, 50% by 2030), Queensland (QRET, 50% by 2030) and Tasmania (first phase of TRET, 100% by 2022)
- the New South Wales Electricity Strategy (Central-West Orana REZ Transmission Link)
- Snowy 2.0 energy storage project
- state and federal policies which impact DER and energy efficiency (EE) policies at the time.[189]

Under the NER, the AER guidelines must "require the optimal development path to have a positive net benefit in the most likely scenario", and "have regard to the need for alignment between the ISP and the RIT-T as it applies to actionable ISP projects".[190]

186 Clause 5.22.2 of the NER.

187 Clause 5.22.3(b) of the NER.

188 AEMO, *2020 Integrated System Plan,*p. 33.

189 AEMO, *2020 Integrated System Plan,* p. 33.

190 Clause 5.22.5(e)(3) and (4) of the NER.

To determine the net benefit of a development path, AEMO is to consider the classes of benefits (e.g. changes in fuel costs, load curtailment, deferred transmission and generation capex and opex) and costs (e.g. the specific capex and opex relating to the option, and regulatory compliance costs) set out in clause 5.22.10(c) and (d) of the NER. In addition to the specified classes, the AER may agree to the inclusion of other classes of benefits or costs that are considered to be relevant by AEMO.[191] To date this has not occurred.[192] A candidate development path is only considered justified when it is assessed as likely to deliver net market benefits under the central scenario.

RIT-T proponents for actionable ISP projects are also required to quantify the benefits and costs of each credible option considered.[193] With approval from the AER, RIT-T proponents may seek to include additional classes of benefits and costs.[194]

B.3.2 Proposed approach to carbon in the 2022 ISP

The next ISP is scheduled to be published in mid-2022 and work has recently been completed to develop the inputs, assumptions and scenarios that will underpin it. AEMO's 2021 Inputs, assumptions and scenarios report (IASR) sets out five scenarios for inclusion in the next ISP. The scenarios are differentiated not only by the rate of decarbonisation, but also by variations in the level of electricity consumed in the future and extent of electricity supply decentralisation.[195]

The "steady progress" scenario reflects current trends in consumer energy investments, technology costs, and includes all current environmental and energy policies (provided the policy has been sufficiently developed to enable AEMO to identify its impacts on the power system). It is conceptually similar to the 2020 ISP central scenario but its updated policy and uptake settings will lead to hastened transformation relative to the 2020 ISP.[196]

The "net zero 2050" scenario is similar conceptually to the 2020 central scenario in the first decade to 2030, updated to include the same growth considerations affecting DER and VRE as apply to the steady progress scenario. In the following decades, however, the pace of transition progressively increases, driven by a commitment to achieve economy-wide net zero emissions by 2050. This targeted decline in carbon intensity and resulting electrification of other sectors was not explicitly included in any of the 2020 scenarios.[197]

In addition to these scenarios, three other scenarios will be modelled to examine plausible variations in the pace of the transition: slow change (similar to the 2020 slow change scenario), step change (similar to the 2020 step change scenario) and hydrogen superpower (a new scenario reflecting strong global action towards emissions reduction). A Delphi

191 Clause 5.22.10 of the NER subparagraphs (c)(1)(x) and (d)(4).

192 AEMC, *Coordination of generation and transmission investment,* Final Report, 21 December 2018, p. 41.

193 Clause 5.15A.3(b)(4) and (b)(6) of the NER.

194 Clause 5.15A.3(b)(4) and (b)(6) of the NER.

195 AEMO, *2021 Inputs, assumptions and scenario report,* July 2021, p. 12.

196 Ibid, p. 20.

197 Ibid, p. 21.

methodology (based on advice from a panel of experts) will be used to determine the likelihood of the different scenarios presented in the 2021 IASR.

B.3.3 How carbon is treated within the RIT

RIT-T proponents are required to undertake a cost-benefit analysis that considers reasonable scenarios of future supply and demand under conditions where each credible option is implemented, and compared against conditions where no option is implemented.[198]

Proponents (for both ISP and non-ISP projects) use ISP scenarios and modelling to estimate the net market benefit of each credible option based on classes of benefit and costs that are set out in the ISP and NER.[199]

Under the AER guidelines, all relevant costs and benefits are to be quantified and qualitative considerations are not to be included. The AER is able to agree to the inclusion of other classes of market benefit and cost if determined to be relevant by the RIT-T proponent and agreed to by the AER or included in accordance with the cost benefit analysis guidelines.[200] Analysis is not to include any cost or benefit which cannot be measured as a cost or benefit to generators, distribution network service providers (DNSPs), TNSPs and consumers of electricity.[201] In considering whether to agree to additional classes of cost, the AER guidelines state that "when determining whether to approve a new class of cost, we will likely consider, at minimum, whether the proposed cost … falls outside the scope of the market, in which case it should not be included in the CBA".[202]

Under the AER guidelines, AEMO and RIT-T proponents are not permitted to include externalities in calculating costs and market benefits. Externalities are described as "economic impacts (costs or benefits) that accrue to parties other than those who produce, consume and transport electricity in the market."[203] The AER guidelines include examples of positive and negative externalities: namely, the positive benefit to a local restaurant of additional workers residing in the area during construction of a transmission line; and the negative impact of a new power station on the amenity and hence earnings of a nearby hotel.[204]

198 For ISP projects, this is to be done in accordance with guidelines developed by the AER under clause 5.22.5 of the NER. For non-ISP projects, proponents are required to comply with different (but similar) guidelines, developed by the AER under clause 5.16.2.

199 The classes of market benefit and cost are consistent across ISP and non-ISP projects. For non-ISP projects, classes of market benefit and costs are set out in clause 5.15A.2 of the NER. For actionable ISP projects, the classes of market benefit are to be those identified in the ISP (per clause 5.15A.3(b)(4)) while classes of costs for actionable ISP projects are set out in clause 5.15A.3(b)(6).

200 Clause 5.15A.2 for non-ISP projects and 5.15A.3 for ISP projects.

201 AER, *Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable*, August 2020, p. 18 (in relation to costs) and p. 21 (in relation to benefits).

202 AER, Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable, August 2020, p. 20.

203 AER, Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable, August 2020, p.35. Note that 'externality' is not defined in the NER but, under clause 5.16.2(c)(3), the AER's guidelines are to provide guidance and worked examples as what may constitute an externality under the RIT-T.

204 AER, Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable, August 2020, pp. 36-37.

C BACKGROUND: MATERIAL CHANGE IN NETWORK INFRASTRUCTURE PROJECT COST

This appendix provides additional information relating to the rule change request discussed in chapter 5.

C.1 The challenge of managing uncertainty in preparing cost estimates

Given the scale and pace of the current energy market transition, ongoing changes in cost inputs and estimated benefits are to be expected. The level of investment required will create competition for resources (e.g. skilled labour, bespoke construction equipment) and may push up some costs. At the same time, other costs will fall as deployment of new technologies (e.g. large-scale batteries) ramps up. The process of estimating project benefits will also need to navigate a dynamic policy environment in which government policies impacting the energy sector are evolving quickly.

In light of the scale and pace of the energy transition, any changes to regulatory frameworks – such as those proposed in the rule change request – will need to strike a balance between:

- requiring appropriately rigorous[205] and up to date cost estimation and analysis of net benefits, so as to mitigate the risk of inefficient investment, and
- the need to facilitate timely investments that deliver beneficial outcomes to consumers.

Recent reforms have sought to streamline regulatory approval processes and reduce the time required to obtain approval for and construct new transmission infrastructure. The rule change request may have implications for this objective.

Further, if changes to the regulatory framework result in additional costs, uncertainty and delays, there is an increased potential for participating jurisdictions to opt out of the process and develop their own state-based frameworks. If this were to occur, the rule change request may not achieve its desired objective of protecting consumers from inefficient outcomes. Instead, the regulatory framework could become more fragmented and inconsistent.

The following case study shows the length of time taken to complete the RIT for PEC and is relevant in considering whether reapplication of the RIT is the best way to protect consumer interests or whether other options warrant consideration.

BOX 2: **PROJECT ENERGYCONNECT (PEC) – CASE STUDY**

The challenge of decision-making in the context of uncertainty is illustrated by the number of policy developments that have occurred as PEC progressed through the RIT-T and CPA approval process. PEC (formerly known as RiverLink) is a new 860km 330kV double-circuit

205 The issue of what level of rigour is appropriate to require at the RIT stage is discussed in section 5.4.5. Requiring a very high level of rigour at the RIT stage could be inefficient and may have unintended outcomes such as discouraging fulsome consideration of alternative options.

interconnector between South Australia (SA) and NSW which has completed the regulatory approval processes under the NER. Environmental and planning approvals are currently being sought. Project completion is now expected by March 2023.

Outlined below are the key steps in the regulatory approval process under the NER, as well as intermediate steps where additional information has been provided in response to policy developments, revised cost inputs (for example between publication of the PACR in 2019 and preparation of the CPA in 2020) etc.

- **November 2016 – Publication of PSCR**
- **June 2018 – Publication of PADR**
- **February 2019 - Publication of PACR**: PEC was preferred option with estimated cost of **$1.53b** and net benefits of **$900m** (weighted average benefits across multiple scenarios)
- **April 2019 – ElectraNet requests AER 5.16.6 determination** that the RIT is satisfied
- **January 2020 – AER issues 5.16.6 determination** that RIT is satisfied. With a cost of **$1.53b** and revised net benefits of **$269m**, the AER determined that PEC satisfied the RIT-T but noted: "if updated costs and benefits of the project differ materially from the analysis in the RIT-T, ElectraNet should consider whether there has been a material change in circumstances such that the preferred option may no longer maximise the positive net economic benefits".
- **30 September 2020 – ElectraNet submits CPA to AER**: PEC cost up from $1.53bn to **$2.43b**. Net benefits now estimated at **$148m**.
- **31 March 2021 - ElectraNet publishes "PEC Review of economic assessment"**: Examines impact of policies announced post submission of CPA (e.g. NSW Government Roadmap, TRET). Concludes that changes are likely to have a positive impact on modelled benefits of PEC and that "it is not reasonably likely that there has been a material change of circumstances that could lead to the PEC no longer being the preferred option, thereby requiring a reapplication of the RIT"
- **31 May 2021 - AER issues final CPA determination**: AER approves capital expenditure of **$2.28b**, slightly lower than the **$2.36b** ($2017-18) sought by ElectraNet and TransGrid.

C.2 Adequacy of the current framework to manage the risk of material cost increases

To determine whether changes to the rules are warranted, it is relevant to consider whether existing frameworks under the NER adequately mitigate the risk to consumers of material cost increases. The degree to which material cost increases are visible and scrutinised differs depending on whether or not the project is a contingent project. This is also relevant in considering how the proposed rule change would work in practice.

It is important to note that one of the steps shown in the case study above, the clause 5.16.6 determination, no longer forms part of the regulatory framework. Under clause 5.16.6, the AER was required to make a determination as to "whether the preferred option satisfies the regulatory investment test for transmission". This clause was removed when the "Actioning the ISP" rules came into effect and introduced the new AEMO feedback loop set out in clause 5.16A.5(b).

The feedback loop is designed to check that the preferred option remains part of the optimal development path (ODP) identified by AEMO in the ISP. In addition, under clause 5.16A.5(d), the cost of the preferred option set out in a proponent's CPA may not exceed the cost considered by AEMO in its feedback loop assessment.

While this is an important safety net, the feedback loop does not seek to answer the same question as the RIT-T: namely, what is the option that achieves the identified need in the most efficient way (or "maximises the present value of net economic benefit")? Rather, the feedback loop focuses on the upper bound of acceptable costs, while the RIT-T seeks to identify the lower bound or least cost option that will meet the identified need. As such, both have a role to play in protecting consumer interests.[206]

While the NER no longer require the AER to determine whether a proponent's preferred option satisfies the RIT, they do require actionable ISP project proponents to complete the RIT prior to submitting a contingent project application.[207]

This means that the robustness of the transmission planning process (in terms of identifying the most efficient way to meet an identified need, as opposed to the upper bound of costs that will stay within the ODP) depends in large part on the quality of the analysis undertaken by NSPs and the process for dealing with material changes in circumstances. This is relevant in considering whether the current arrangements are adequate to protect consumer interests, and whether changes should be made such as those proposed in the rule change request.

C.2.1 Projects that involve a CPA

Contingent projects are subject to AER scrutiny as to whether the estimated cost of a proposed project is reasonably required for the purpose of undertaking the project.[208] The CPA means that there is publicly available data about post-RIT cost increases and hence a data point which could trigger the proposed RIT reapplication requirement.

206 Consider for example a preferred option with an estimated cost at the RIT stage of $1b. The cost of the next best option identified in the RIT was $1.2b. The revised cost of the preferred option at the CPA stage is $1.4b. This is still below the level at which the preferred option would fall outside the ODP but is $200m more costly than the second best option. The feedback loop does not assist in realising such savings. Instead, it falls to the change in material circumstances provision to realise such savings.

207 Under clause 5.16A.5(a), the RIT-T proponent must issue a project assessment conclusions report that meets the requirements of clause 5.16A.4 and which identifies a project as the preferred option. This provision applies only to ISP projects. For non-ISP projects that involve a CPA, the AER can include a requirement that the RIT-T be complete and satisfied in the trigger event for that project's CPA.

208 Clause 6A.8.2(e)(1)(i) of the NER. The CPA process is designed to assess what cost is reasonably required to build a specific project. It does not answer the question (which is the focus of the RIT) as to what is the most efficient project to address an identified need. Both processes are important to protect consumer interests.

In addition to the RIT and CPA process, there is also the potential for the AER to determine that some portion of a new asset should not be included in the proponent's RAB in the event that the AER determines that the investment was not prudent and efficient.[209]

C.2.2 Projects that do not involve a CPA

Data about post-RIT cost increases is not readily available for projects that are subject to a RIT but do not involve a CPA. As such, it is not clear how the rule change request would operate with respect to such projects, including transmission projects undertaken in Victoria and the majority of RIT-D projects across the NEM. Where information is made publicly available (e.g. in response to the AER's regulatory information notices), this would normally occur at a point (e.g. post project commissioning) when it is too late to query the choice of preferred option.

The situation in Victoria

In Victoria, unlike elsewhere in the NEM, AEMO is responsible for the planning of the transmission network and AEMO is required to conduct a competitive tender to determine who will carry out an augmentation to a declared shared network.[210] In such cases, AEMO will run the tender process and then enter into a commercial agreement with the successful tenderer. Procurement and construction costs are then recovered by AEMO through transmission charges in accordance with its pricing methodology. This differs from other NEM jurisdictions where the relevant TNSP will submit a CPA to the AER to adjust its maximum allowed revenue to take into account the capital expenditure required for the contingent project.

RIT-D projects

Most distribution projects which are the subject of a RIT-D do not require a CPA. Instead, DNSPs will include the capital and operating expenditure required for such projects as part of their revenue proposal submitted to the AER as part of the five-yearly revenue reset process. Compared with the situation for projects that involve a CPA, there is thus less visibility as to whether RIT-D projects experience material cost increases.[211] At the same time, the cost of such projects is typically low and hence "material" cost increases (in percentage terms) may not impact consumers. Accordingly, the approach proposed in the rule change request may not be warranted in relation to most RIT-D projects.

C.3 Frequency of material cost increases

While the bulk of the discussion in the rule change request relates to ISP projects such as Project Energy Connect, the rule change request covers the regulatory investment test for transmission (both ISP and non-ISP projects) and distribution. To determine the scale of the

209 See Clause S6A.2.2A of the NER.

210 Section 50F(3) of the NEL. Transmission is contestable subject to specified criteria, including that it must have a capital cost over $10 million and must be deemed by AEMO to be separable.

211 Nonetheless, the AER is able to scrutinise cost estimates that are submitted as part of the revenue reset process, as well as through their compliance monitoring role.

issue raised by the rule change request, and what response is appropriate, the Commission has sought to determine whether material cost increases occur across all project types, or whether material cost increases are more common in connection with larger, greenfield projects such as those outlined in the ISP.

C.3.1 ISP projects

The rule change request is concerned that – following completion of the RIT – project costs included in CPAs can be significantly higher than those used to identify the preferred option during the RIT process.

Only a small number of ISP projects have completed both the RIT-T and the CPA process. These are set out below:

Table C.1: **ISP project cost estimates**

PROJECT NAME	PACR COST ESTIMATE	CPA COST ESTIMATE	AER DETERMINATION ON CPA	% INCREASE BETWEEN PACR AND CPA
QNI Minor	$230m	$223m	$218	-3%
Western Victoria Transmission network project	$370m	N/A ($550m estimated)*	N/A ($550 estimated)	49%
VNI Minor	$87m	$140m total**	$45m***	61%
Project EnergyConnect	$1.536	$2.36b	$2.28b	54%

Source: AEMC
Note: *Note that there is no CPA for this project but a recent article cited an estimated cost of $550m. See Angela MacDonald-Smith, Vic power transmission project to unlock renewables, AFR, 1 March 2021.
Note: **The TransGrid component of this total was $45m; AEMO did not need to lodge a CPA.
Note: ***TransGrid component of capex only.

Three of the four projects have cost increases in excess of 10 per cent and would thus meet the criteria for a material cost increase, as proposed in the rule change request, thereby triggering the RIT reapplication requirement.[212] However, one project (VNI Minor) falls below the project cost threshold at which the rule change request proponents suggest AER would have discretion to waive the requirement to reapply the RIT.

In two cases (QNI minor and PEC), the cost increase was subject to scrutiny by the AER as part of the CPA process. For VNI Minor, the AER was able to scrutinise the cost of the NSW

212 For projects with a cost of less than $500m, the rule change request suggests that cost increases of 15 per cent are considered material. For projects with a cost of more than $500m, cost increases of 10 per cent are considered material. Of the projects in table C.1, only PEC has a project cost greater than $500m. With the exception of QNI Minor, all projects have a cost increase of well over 10 or even 15 per cent.

component of the project only (but not the Victorian component). No CPA process applied to the Western Victoria transmission network project.

C.3.2 Non-ISP contigent projects

ElectraNet is currently progressing a project to construct a new high-voltage power line and upgrading five substations to replace the existing transmission line servicing the Eyre Peninsula*.* This project was subject to both a RIT-T and CPA. While the PACR initially estimated a cost of $240m for the project, this was revised to $290m at the CPA stage (an increase of 21 per cent). This was subsequently reduced to $280m by the AER's CPA determination.

This project also meets the criteria for a material cost increase, as proposed in the rule change request, and hence would trigger the proposed RIT reapplication requirement. As with some of the ISP projects, this project was also subject to AER scrutiny via the CPA process. The Commission is not aware of any other major non-ISP projects involving a CPA.

C.3.3 RIT-T projects that do not involve a CPA

Most non-ISP transmission projects do not involve a CPA and hence cost increase data is far less visible.

In seeking to understand whether such projects experience material cost increases, the Commission examined 20 transmission projects that were subject to a RIT-T but did not involve a CPA. These covered projects in Queensland, NSW and South Australia. The Commission was able to compare cost estimates set out in the first and final RIT-T reports[213] but was not able to find information regarding post-RIT cost estimates. This exercise highlighted that there is little or no publicly available data about any refinements in cost estimates post completion of the RIT (e.g. at the point when the project goes to tender, or once construction is complete).

The analysis also highlighted that the majority of RIT-T projects do not entail large project costs: 12 of the 20 projects had an estimated cost of less than $10m; 7 had estimated costs below $25m and one had an estimated cost of just over $30m. As such, they all fall below the project cost thresholds below which the rule change request suggested that the AER should have discretion to waive the requirement to reapply the RIT. (The levels suggested by the rule change request were $150m for transmission projects and $50m for distribution projects. All the transmission projects examined by the Commission fell below the latter threshold, being that applicable to distribution projects.)

This is important when considering the potential impact on consumers of such projects experiencing cost increases that may be "material" in percentage terms but not material in monetary terms.

213 This was because 19 of the 20 projects did not involve a second report (the PADR) given that such reports are not required where the estimated cost of the proposed preferred option is less than $43 million: see clause 5.16.4(z1)(1) of the NER. That provision refers to a cost of $35 million but this is subject to variation by an AER cost threshold determination. The most recent AER determination, published in November 2018, sets the value of this threshold at $43 million.

C.3.4 RIT-D projects

The Commission undertook a similar exercise to examine whether RIT-D projects experience material cost increases post completion of the RIT. Again, the Commission was able to review RIT-D reports (draft and final project assessment reports – DPAR and FPAR) but was not able to discern if the cost estimates in these reports proved accurate once the projects moved into the subsequent stages of market testing and construction. As such, it is not clear how the rule change request would operate with respect to such projects.

All but two of the projects examined had an estimated project cost of less than $30m; one had an estimated cost of $40m and one of $87m. Having regard for the thresholds suggested in the rule change request, only one project falls above the $50m threshold below which the proponents suggest the AER should have discretion to waive the requirement to reapply the RIT. As with the transmission projects discussed above, this is important when considering the impact on consumers of such projects experiencing "material" cost increases, and whether any new RIT reapplication requirements should apply to such projects.

Finally, the analysis process highlighted that data on project costs is difficult to track through the planning and revenue determination process. To help improve visibility of project data, there may be benefit in requiring proponents to use project names that remain consistent throughout the process.

C.4 Improving the accuracy of cost estimates

In addition to considering whether and how the rules should be amended in response to the rule change request, consideration can also be given – as part of the review – to what steps could be taken to help reduce the likelihood and scale of project cost increases. This will help promote a robust planning process and reduce the need to trigger requirements to reapply the RIT.

Portfolio level risks

The ISP could play a role in improving the accuracy of cost estimates used in RIT-Ts. In particular, it could be useful for the ISP to consider market constraints and implementation risks that can be expected to arise at the portfolio level (i.e. across all ISP projects) and identify how these may impact individual RIT-T project costs at the CPA stage.

For example, the unprecedented scale of investment that makes up the optimal development path means that there will be competition for scarce resources such as skilled labour, inputs such as steel and the bespoke equipment needed to build transmission lines (cranes, cement trucks etc).[214] This is likely to result in market prices at the tendering stage of the project (i.e. the CPA stage) which are higher than would be the case if the project was being progressed in isolation. As such, these higher costs are unlikely to be accurately anticipated at the RIT-T

214 For example, the AER's 2018 Cost thresholds review final determination found that the produce price index (PPI) for primary metal and metal product manufacturing had risen 15.3% since June 2015 while the PPI for fabricated metal product manufacturing had risen 11.9% in the same period. These far outstrip the movement in economy-wide indexes and other inputs. See Table 2 on p. 11.

stage unless they are first identified through the ISP process. Such portfolio level analysis could then inform the use of appropriately targeted sensitivity analysis by RIT-T proponents.

As noted earlier, more nuanced sensitivity analysis will be particularly important where credible options considered in a RIT-T are heterogenous (e.g. network and non-network options).

Capacity building

Looking beyond the RIT-T framework, consideration could also be given to increasing NSPs' capacity to undertake robust planning activities. As noted earlier, ARENA has provided $1m funding to Transgrid to support it undertaking a feasibility study for a transmission project in the New England region. It may be efficient, as part of the revenue determination process, to ensure that NSPs have adequate resources to support appropriately robust planning processes. While this would not involve any changes to the rules, it could mitigate the risk of inefficient investments and thus promote the long-term interests of consumers. Enhancing planning capacity would also be consistent with the ISP's focus on undertaking preparatory activities to inform future decisions, and the AER's guidance regarding project staging.

More broadly still, and looking beyond the reach of the NER, it will also be important for jurisdictions to consider what complementary measures are required to mitigate the risk of material cost increases. For example, capacity building will be an important means to address the risk posed by potential skill shortages when multiple large transmission projects are being built at the same time. There will also need to be sufficient regulatory capacity to deal with the number of planning and environmental approvals required for larger projects.