REVIEW

Australian Energy Market Commission

FINAL REPORT

COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT

21 DECEMBER 2018

INQUIRIES

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ABOUT THE AEMC

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

SUMMARY

1 The Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission (AEMC or the Commission) to undertake biennial reporting on when the transmission planning and investment decision-making frameworks will need to change, given the state of the power system. This reporting focusses on evaluating the transmission frameworks in light of current and future conditions to see if there is a case for change now to better coordinate investment between the transmission and generation sectors. The Commission is of the view that change is needed at the present time, so that our regulatory frameworks evolve to match the transition in the national electricity market (NEM).

Context

2 The transforming generation fleet has implications for investment in the transmission network. Generation investment and retirement decisions need to be coordinated with transmission investment so that reliable, secure outcomes in the long-term interests of consumers are delivered.

3 There is a significant amount of generation capacity that is seeking to connect to the network. Private sector investors are planning generation where transmission has limited or no capacity for the generation to connect, which limits these generators accessing the wholesale market and so creates congestion resulting in costs for consumers. In addition, interconnectors are sometimes constrained, meaning that consumers cannot always access lower cost energy from generation in neighbouring states. This creates congestion, meaning that consumers bear the cost of more expensive generation being dispatched to supply their demand. Conversely, given transmission infrastructure is expensive, it would not be efficient to build transmission to remove all of the congestion. This could result in underutilised or inefficient investments, which, given the long-life of transmission, consumers would pay for over decades.

4 The pattern of network flows in the transmission system is changing and forecasts of future needs are increasingly uncertain. The transmission framework needs to be fit for purpose and be able to deliver outcomes in a timely and flexible way to accommodate this change, and serve the long-term interests of consumers. The process for coordinating transmission and generation investment must be rigorous and transparent, in order for this to occur.

An Integrated System Plan

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

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

6 The ISP identifies a pathway for developing the transmission network based on modelling the entire market over possible future scenarios over the next twenty years. The inaugural ISP also identified transmission investments in three groups, in order of priority, that need to be addressed. AEMO identified that there are five group 1 projects that require immediate action; group 2 projects need to be developed in the medium term (mid 2020s) in order to enhance trade between regions, provide access to storage and support extensive development of renewable energy zones (REZs); while group 3 projects are longer-term developments to support REZs, reliability and security.

7 In August 2018, the COAG Energy Council asked that the Chair of the Energy Security Board (ESB) take the lead on the delivery of a work program to "convert the ISP" into an "actionable strategic plan" and report back to the Council's 2018 meeting. In addition, the COAG Energy Council requested the ESB report to the December 2018 meeting on "how the Group 1 projects identified in the ISP can be implemented and delivered as soon as practicable and with efficient outcomes for customers, and how the Group 2 projects will be reviewed and progressed."

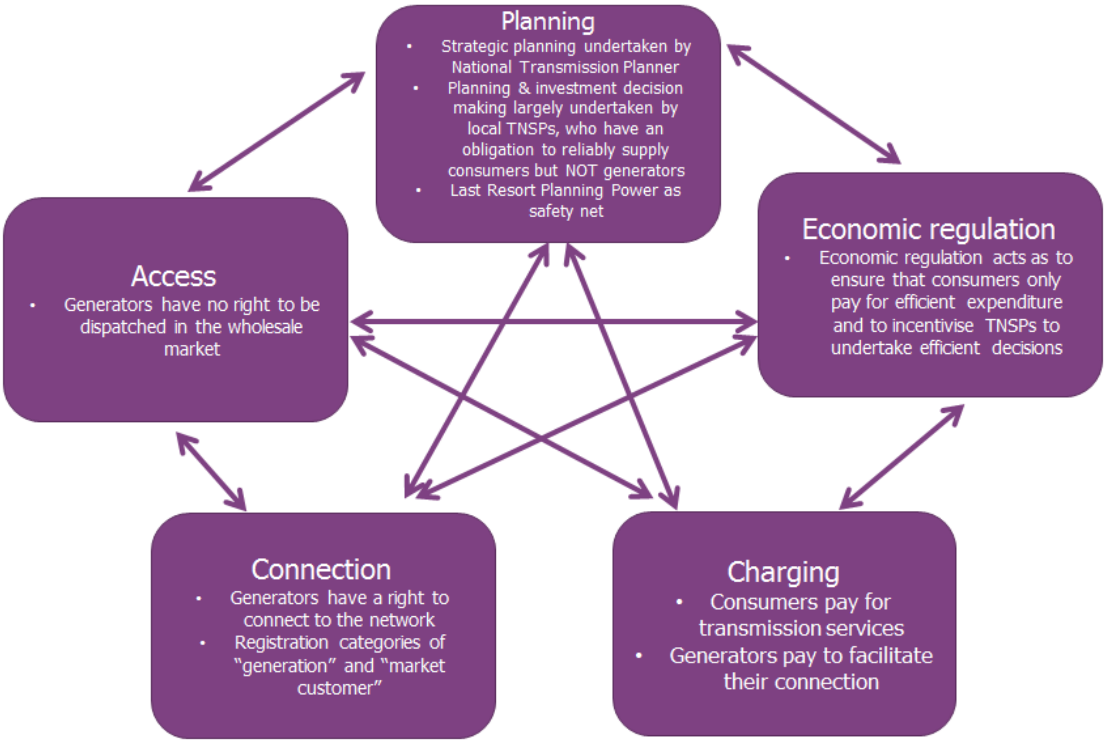
8 This report, in addition to addressing the COAG Energy Council's terms of reference for this review, forms an input into the Chair of the ESB's report. In particular: Chapter 3 of this report on actioning the ISP provides the detail for how the refinements to the transmission regulatory process recommended by the Chair of the ESB could be implemented (ESB recommendations 8 and 10); and Chapter 6 provides the detail for a path forward on addressing concerns with current access and congestion management arrangements outlined in the Chair of the ESB's report (ESB recommendations 11 and 12).

A cohesive package of recommendations to transform coordination of generation and transmission investment

9 The Commission has made a series of recommendations for how investment in generation and transmission should be better coordinated into the future. The outcomes that would be achieved through the actioning of the recommendations form part of a cohesive package to transform the way generation and transmission would be planned, invested in and operated in the NEM. The recommendations complement each other.

10 The review has undertaken a holistic examination of the existing transmission framework to reach these conclusions. There are five key aspects of the exiting framework: planning, access, charging, connection and economic regulation. Each feature of the framework has implications and impacts on the other aspects, with these being considered by the Commission in this review.

Figure 1: Current transmission framework



11 The needed reform delivered by our recommendations ultimately serves the interests of consumers by increasing the efficient operation of the wholesale energy market and assigning risks to those parties best able to manage them, and seeks to do so in an affordable manner. Investing progressively, while planning strategically and nationally, provides the agility necessary to avoid the risks of unnecessary investment or uneconomic levels of congestion.

12 Our recommendations create a reform work program to transform the coordination of generation and transmission investment.

Stage 1: Implement reforms that are necessary to advance ISP group 1 projects

13 In order to address the group 1 projects, Dr Kerry Schott AO will submit a rule change request to the Commission to allow the three post-regulatory investment test for transmission (RIT-T) regulatory processes to be undertaken concurrently for the group 1 projects. These processes are the Australian Energy Regulator's (AER's) assessment of: any dispute lodged, the preferred option assessment, and the contingent project revenue determination.

14 The AEMC will progress this rule change request on an expedited basis, with the rule change process completed by the end of quarter 1 2019. If implemented, the proposed rule changes would be in place in time to allow the AER to undertake the three processes in parallel, saving six to eight months off the post RIT-T time frames. However, the proposed rule

change for group 1 projects would also ensure that the checks and balances for a robust process, and assessment that the investments are efficient, remain. This will provide sufficient time for the group 1 projects to be operational in time frames consistent with the requirements identified by AEMO in the ISP. Streamlining the RIT-T processes for Group 2 projects is addressed as part of embedding the actioned ISP in current frameworks.

Stage 2: Embed an actioned ISP in the regulatory framework to progress projects going forward and integrate large-scale energy storage systems into the NEM

Embedding the ISP

15 Going forward, the progression of ISP group 2 and 3 projects (and subsequent projects identified in the ISP) will occur through the actioned ISP. Actioning the ISP is an important component to make sure that the transmission framework remains fit for purpose.

16 The actioned ISP requires clear links between the ISP and network investment decisions, and the ability for generation and network investment decisions to be coordinated by those best placed to meet them. Embedding the actioned ISP streamlines, removes duplication and de-risks the transmission planning and investment decision-making process to help TNSPs make the decisions that they need to be making to assist the transition of the power system.

17 Under the actioned ISP, AEMO will develop scenarios, inputs and assumptions, through public consultation. The COAG Energy Council Senior Committee of Officials (SCO) will provide information to AEMO on which jurisdictional policies should be included in the ISP modelling, to assist with this. Following the development of these aspects, AEMO will undertake NEM wide modelling to determine system wide needs, taking account inputs from transmission network service providers (TNSPs). This draft ISP will be published by AEMO for public consultation. The draft ISP will include credible options for transmission investment identified by AEMO for addressing system wide needs. Robust and transparent consultation will create confidence in the transmission investment process, and minimise the scope for disputes at the end of the cost-benefit assessment process.

18 AEMO will refine the ISP based on public consultation, and publish the final ISP which will provide a single recommended development pathway that outlines the priority projects needed across the NEM, and the time frames in which they need to be developed. The inclusion of credible options analysis in the ISP will mean that the project specification consultation report would be removed from the RIT-T for ISP projects, streamlining the regulatory process.

19 Following the publication of the final ISP, TNSPs will be required by the National Electricity Rules (NER) to conduct a streamlined and shortened assessment based on the needs identified in the ISP, and would be required to use the ISP inputs, assumptions and scenarios for its cost-benefit analysis of the ISP credible options. TNSPs will consider non-network options, and be required to confirm with AEMO whether the non-network options would meet the system wide need identified in the ISP. Under this process, TNSPs would move straight to publishing a draft report on the project for public consultation, and then refine the analysis for a final report based on feedback. This will enhance and harness the information provided in the ISP, linking it to the decisions TNSPs need to make to serve the strategic needs of the

NEM in a way that serves the long term interests of consumers.

20 Following the completion of the cost-benefit analysis, TNSPs would obtain AER revenue approval. However, there would be a change to current post RIT-T regulatory processes that would streamline, shorten and remove duplication for projects identified in the ISP. Clause 5.16.6 (where the AER makes a determination as to whether the preferred option for investment satisfies the regulatory investment test) would be removed from the NER, enabling the TNSP to progress to undertake the detailed, project specific costing and planning for the investment, including obtaining land easements and environmental approvals faster.

21 This approach therefore does not lose important safeguards to ensure that consumers are not paying more than they need to – either through uneconomic levels of congestion, or through transmission infrastructure. However, it does remove duplication and streamline the process.

22 By removing duplication and streamlining the process, actioning the ISP would **reduce the time** it currently takes for the RIT-T and post RIT processes to be completed **by** an estimated **18 months.**

23 The regulatory process for non-ISP projects can also be improved, to complement an actioned ISP. Reducing the time frame associated with completing the project assessment draft report of the RIT-T from 12 months to nine months will reduce the time it takes to complete transmission planning and investment decision-making processes.

24 Actioning the ISP is required for the changes to be put in place to allow the progression of the group 2 projects in a timely manner. While group 2 projects are needed in the medium-term, they also have a longer lead time than the (smaller) group 1 projects. Actioning the ISP will require both National Electricity Law (NEL) and NER changes.

25 In order to allow the regulatory framework to reflect the actioned ISP as soon as possible, the Commission will coordinate with the COAG Energy Council SCO, as well as the ESB, to develop the necessary NEL and NER changes required to embed the ISP into the regulatory framework. The Commission will also work with SCO and the ESB to identify the most timely and efficient process for progressing the NEL and NER changes. The NEL and NER changes will need to be in place by mid-2019 to enable the 2020 ISP to be published under the new arrangements.

Integrating large-scale storage systems

26 The ISP also identified that storage will have a large role to play in the future NEM. Electricity storage technologies have the potential to provide benefits to both the operators of those assets and the electricity grid more broadly.

27 Several large-scale energy storage systems have recently connected to the grid, and AEMO is receiving an increasing number of enquiries and registration applications from storage proponents, and expect this growth to continue.

28 This has raised some questions about the applicability and appropriateness of the existing regulatory framework for large-scale energy storage technologies, including hybrid systems

(i.e. systems that include a combination of storage and generation or load). The appropriate NEM registration category that should apply to energy storage systems, and consequently how they should be treated within the regulatory framework, are issues that require long-term solutions.

29 AEMO is currently undertaking work on this issue, given its recent experiences with registering such systems. The Commission agrees with AEMO's proposal that to improve clarity for energy storage system proponents and remove operational inefficiencies for both registered participants and AEMO, a new NEM registration category should be created to accommodate energy storage systems.

30 AEMO will submit this rule change request to the Commission by March 2019. In this rule change request, it will consider what regulatory obligations should be placed on participants registered under the new category for energy storage systems, including whether or not it is appropriate for energy storage systems to pay for the use of the transmission system. An assessment of whether storage should pay transmission use of system (TUOS) charges should adopt a technology neutral approach, be based on the principles applied in the NEM, and should not seek to pick winners in determining a charging arrangement.

31 While the Commission has a number of rule changes relating to registration categories on foot, and has previously flagged that a more holistic look at registration is required, the pressing need to provide clarity for storage proponents, and to allow these proponents to be treated on an equal footing with generation, means that this rule change needs to be considered immediately.

Stage 3: Dynamic regional pricing to provide congestion signals to connecting parties, as well as implementing reforms to inter-regional TUOS pricing to ensure that the costs of interconnectors are aligned to those who benefit

32 Actioning the ISP needs to be paired with the mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion along it.

33 How generators access the transmission network, and how congestion of the transmission network is managed, underpin the transmission framework. The way that transmission and generation investment decision-making processes interact has been the subject of ongoing discussion before the establishment of the NEM in 1998. Since NEM start, there have been at least twelve major reports and reviews dealing with various aspects of congestion management and generator access – many of which have been undertaken by the Commission.

34 Generators currently have no right to be dispatched in the wholesale market. Therefore, there is no guarantee that the network will have the capacity to export the energy they generate to enable them to earn revenue in the wholesale market. In contrast, transmission businesses have an obligation to meet jurisdictionally-set reliability standards for their networks, and so are focussed on making investments to reliably supply *consumers.*

35 Under the current access regime,[1] there are limited congestion related locational signals for generators, and increasing congestion in the network is resulting in very unpredictable and volatile market outcomes. Transmission businesses do not plan to provide a particular generator with a specific amount of capacity across the transmission network. This is not sustainable for either generators or customers, given the amount of congestion that this is creating.

36 Currently, there is a significant amount of generation capacity that is seeking to connect to the network. Private sector investors are planning generation where transmission has limited or no capacity to connect it. This is not sustainable and is increasing costs in the sector. Given that a significant amount of this new capacity is seeking to locate at edges of the network, there is an increasing need to invest in and build transmission to reliably connect *generators*.

37 Therefore, the current access regime needs to evolve to allow the risk and cost of generation investment to complement planning and investment in transmission. Building transmission to benefit generators, means that generators should *pay* for this transmission investment.

38 Reform to the access regime should occur through a phased approach to address generator connection and access to the transmission network, and to make congestion management fit for purpose for the energy transformation. Reform is needed now in order to be put in place for the future; however this reform should be phased in overtime in a number of stages.

39 First, dynamic regional pricing should be implemented. Where congestion arises, and transmission constraints occur, pricing regions will be dynamically created through existing dispatch processes which will reflect transmission constraints that are actually occurring at that particular time. This will put a price on congestion and introduce a signal to generators that reflects the short-run costs of using the network, providing better information to generators.

40 In addition, an actioned ISP focusses attention on the development of interconnectors. Given this, concerns have been raised about whether the current inter-regional transmission charging regime adequately attributes the cost of interconnectors to their beneficiaries. The current inter-regional transmission charging arrangements provide a mechanism for TNSPs to monetise the benefits of interconnector investments that accrue to other regions.

41 Transmission pricing is always complicated and contentious, because it involves multiple objectives which are almost certain to conflict with each other. In considering charging arrangements, it is important to recognise that they will never be perfect, and therefore, there is likely to be a trade-off between improved accuracy and administrative complexity and costs.

42 Indeed, in relation to upgrading interconnectors, it is not immediately clear or simple to work out who benefits, given that interconnector flows in a meshed network like the NEM affect multiple regions, and reverse direction at different times of the day, and in different seasons.

1 In the NEM, generators have a right to negotiate a connection to the transmission network, but no right to be dispatched in the wholesale market and so earn revenue.

43 The Commission considers that there may be some elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment. These should be considered in more depth through re-examining the inter-regional TUOS (IR-TUOS) arrangements, and work will commence in March 2019. This would allow these changes to be implemented alongside dynamic regional pricing, and will assist in providing information about costs of congestion.

Stage 4: Information from dynamic pricing revealing congestion costs, with this being used as an input into the ISP's transmission planning

44 Next, the information that is revealed through the dynamic regional pricing, such as the patterns of congestion and the dynamic location of regions; as well as costs associated with congestion will be used in planning. This information will be available to AEMO and the wider market, enabling: AEMO to develop future ISPs with increased accuracy; TNSPs to make efficient transmission investments informed by an enhanced ISP; and the AER to assess the efficiency of transmission investments.

Stage 5: Enabling generators to fund transmission infrastructure, providing them with choice and control about how they access the wholesale market, as well as broader TUOS reform

45 Under the final stage, generators will use the ISP, along with other sources of information, as an important guide to their generation and transmission investment decision-making and be able to compel TNSPs to provide transmission services consistent with the level of firm access (that is, guaranteed access to the wholesale market) underwritten by generators. This final stage is a significant reform to the NEM, but is necessary in the face of the rapid transformation of the electricity sector.

46 Once all stages are completed, generators will be provided with a price signal about the costs associated with locating in a particular place of the grid. Generators will then be able to make a *choice* about whether or not to pay to receive firm access to the transmission network. This market driven approach aligns the disaggregated, commercial decisions of the generation sector, with that of the transmission sector. It provides the necessary tools for those who are best placed to bear the risk of resource investment to do so, facilitating the coordination of generation and transmission investment and avoid unnecessary risks being placed on consumers.

47 A phased approach strengthens the benefits that will be realised by actioning the ISP, as well as addressing the pressing issue of integrating large-scale storage into the NEM, while providing a pathway to address the remaining issues of the current open access regime. Coordinating investment in generation and transmission in this way will reduce the risk of both over-investment (stranded assets) and underinvestment (congestion) in transmission infrastructure. In order to progress this phased approach to access reform, the Commission will develop the necessary rule changes through our 2019 biennial review of the coordination of generation and transmission investment. We expect that the COAG Energy Council will submit the rule changes for all stages of the phased approach to the AEMC, by mid 2019. Our consideration of the phased reform through 2019, as well as through the subsequent

rule changes, with extensive stakeholder consultation, will allow consideration as to whether the proposed implementation dates, and sequencing of staging is appropriate.

48 Part of the access reforms involve generators paying for transmission. This raises broader questions about the rest of the TUOS framework. In order to allow a holistic consideration of TUOS issues, alongside the implementation of access reform, CoGATI 2019 should scope components of TUOS that need to be revisited, with the intention for rule changes on these aspects to be submitted by the COAG Energy Council by the end of 2019. These will be progressed alongside the implementation of the phased access reform, with reforms to TUOS being put in place at the same time as the final stage of access reform is delivered.

49 In addition, actioning the ISP and its complementary changes to access will facilitate REZs, through introducing more commercial drivers into transmission development. The changes to the access regime described above would enable better trade-offs to be made between the cost of transmission and the cost of generation in the development of REZs, and would align more of the risk of investment decisions with those who make them, and away from consumers. REZs forming through generators making a decision about the most efficient way to coordinate their investment in both generation and transmission infrastructure is likely to minimise total system costs since generators will be given more options and opportunities to fund transmission infrastructure, influencing transmission planning decisions. Under these changes, REZs will emerge as a consequence of generators' and prospective generators' commercial locational investment decisions.

Table 1: **Implementation work plan**

TIMING	PLANNING	ACCESS AND CONGESTION	CHARGING	CONNECTION (AND STORAGE)	ECONOMIC REGULATION
December 2018	Dr Kerry Schott AO submits rule change request to the AEMC to allow concurrent AER assessment of post RIT-T process for group 1 projects.				
March 2019	AEMC final determination on rule change request to allow concurrent AER assessment of post RIT-T processes for group 1 projects. AER to submit a rule change request to the AEMC to reduce the time frame associated with completing the project assessment draft report of the RIT-T from 12 months to nine months.			AEMO to submit rule change request to the AEMC to create a new NEM registration category to accommodate large-scale energy storage systems.	AER to submit a rule change request to the AEMC to remove clause 5.16.6 (where the AER makes a determination as to whether the preferred option satisfies the regulatory investment test) from the NER to streamline and reduce duplication.
January - June 2019	AEMC, ESB and SCO to work together to develop the necessary NEL and NER changes required to implement the ISP.	AEMC through CoGaTI 2019 to develop rule changes to progress the phased network			

TIMING	PLANNING	ACCESS AND CONGESTION	CHARGING	CONNECTION (AND STORAGE)	ECONOMIC REGULATION
		congestion and access reforms.			
August 2019	NEL and NER changes implementing the ISP to be in place. AEMO starts consultation on the 2020 ISP, under the new framework.				
June - December 2019		AEMC through CoGaTI 2019 to develop rule changes to progress the phased network congestion and access reforms.	AEMC to review IR-TUOS & TUOS arrangements and develop rule change requests on any changes.		
January 2020		COAG Energy Council to submit rule change requests on network congestion and access reforms to the AEMC.	COAG Energy Council to submit rule change requests on TUOS changes to the AEMC.	AEMC final determination on AEMO rule change request on new registration category for large-scale energy storage systems.	
July 2022	Information from dynamic regional pricing is being used	Dynamic regional pricing is	IR-TUOS reforms are		

TIMING	PLANNING	ACCESS AND CON-GESTION	CHARGING	CONNECTION (AND STORAGE)	ECONOMIC REGU-LATION
	to inform the ISP's transmission planning.	implemented.	implemented.		
July 2023	Generators are allowed to fund transmission infrastructure, influencing transmission planning decisions.	Generators are allowed to fund transmission infrastructure, and receive access rights in return, implementing firm transmission rights.	TUOS reforms are implemented.	REZs are enabled through funding transmission infrastructure.	Corresponding changes to the economic regulatory framework, reflecting that generators are funding transmission infrastructure are in place.

CONTENTS

1 TERMS OF REFERENCE

In 2016, the COAG Energy Council asked the AEMC to implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. The terms of reference for this reporting were received from the COAG Energy Council in February 2016 under section 41 of the NEL.[2]

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

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

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

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

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

2 INTRODUCTION

The COAG Energy Council has asked the AEMC to undertake biennial reporting on when the transmission planning and investment decision-making frameworks will need to change, given the state of the power system.

2.1 Purpose of the review

This reporting focusses on evaluating the transmission frameworks in light of current and future conditions to see when net benefits could be derived in adopting a transmission framework that would provide for better coordination of investment between the transmission and generation sectors.

This reporting has occurred in two stages:

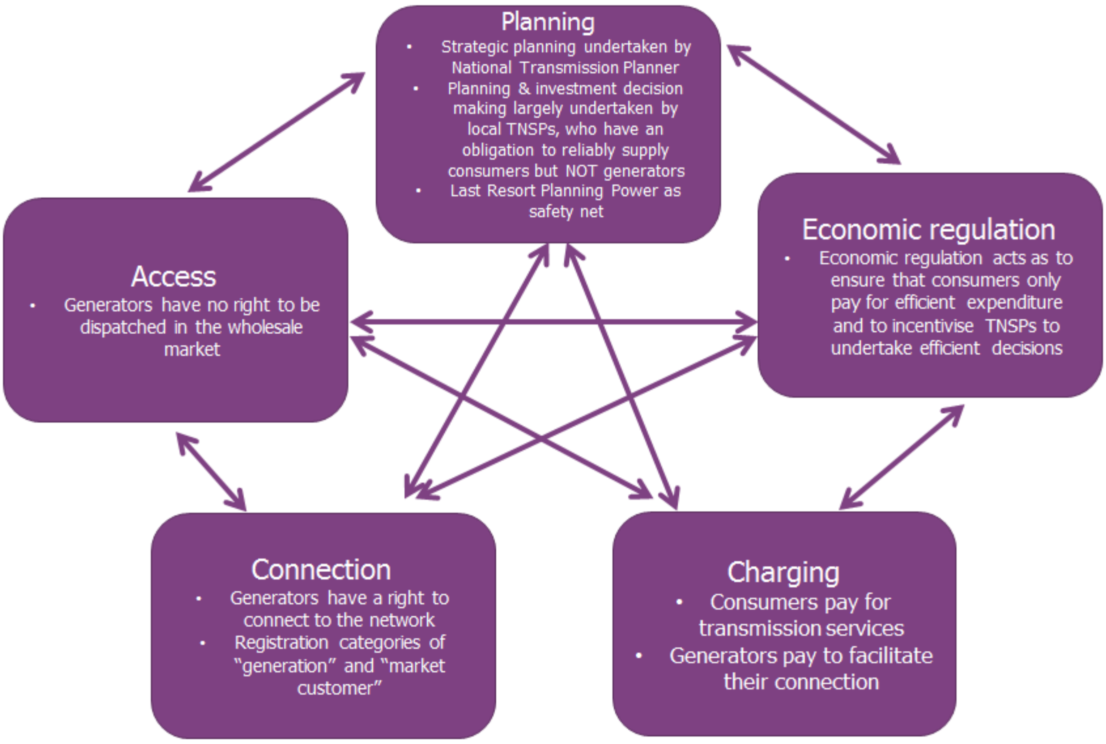
- Stage 1 concluded in July 2017, where the Commission recommended that the review progress to stage 2. This was because: the drivers of transmission and generation investment have significantly changed since July 2015;[3] there is expected to be large investment in transmission and generation; and the expected future investment is uncertain in its location and technology. The Commission also considered that there was increased uncertainty regarding government emissions reduction policy, and that this was having ramifications for investor confidence. This is still the case.
- The AEMC commenced stage 2 in August 2017, by publishing an approach paper. Stage 2 of the review involves considering in detail the transmission framework, in order to make a number of recommendations to the COAG Energy Council regarding the changes required to the regulatory and market frameworks to make sure that transmission and generation investment is sufficiently coordinated, as the electricity system transforms.

2.2 Project scope

This review has undertaken a holistic examination of the existing transmission framework. There are five key aspects: planning, access, charging, connection and economic regulation. Each feature of the framework has implications and impacts on the other aspects. The current transmission framework is further summarised in Appendix B.

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

Figure 2.1: Overview of current transmission framework



2.3 Purpose of the final report

This report concludes the work undertaken in this cycle of reporting, and sets out a number of intermediate and more long-term recommendations to the COAG Energy Council to make existing transmission frameworks fit for purpose and provide reliable and secure outcomes for consumers at the lowest cost.

The report makes recommendations with respect to the five key elements of the transmission framework in the NEM:

- **planning** - how to make the ISP actionable, and what associated changes are required to make the regulatory investment test for transmission fit for purpose in the transforming sector
- **access -** access and congestion underpins the transmission framework, and so changes to this are required as a necessary complement to making the ISP actionable
- **connection -** a REZ is a form of connection assets shared by multiple generators. We set out our conclusions on how REZs can be facilitated
- **charging -** underpinning the above aspects is who pays for transmission infrastructure, which should flow from who benefits

- **economic regulation -** transmission investment is made by monopolies, obliged by governments to meet government set reliability standards. Ensuring that the transmission investment is efficient is an important component of the existing framework which should be preserved.

The final report, and its recommendations, also sets out the Commission's conclusions on key matters raised in the Finkel Review. The Finkel Review concluded that:

> A more strategic approach is required for the coordination of generation and transmission investment in the NEM, and to ensure security and reliability are maintained - a view supported by current international practice. [...]
>
> The Panel concludes that there is a need for strengthened planning in the NEM to address these challenges, including:
>
> - A long-term, integrated plan for the grid that establishes the optimal transmission network design to enable connection of renewable energy resources, including through inter-regional connections.
> - Improved coordination of generation and transmission planning and investment.

Finkel Review recommendation 5.1 was that by mid-2018, AEMO, supported by TNSPs and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of REZs across the NEM.

AEMO published its inaugural ISP in July 2018. AEMO noted that it called this an ISP, rather than an integrated grid plan, to reflect that over time, the ISP will by necessity consider a wide spectrum of interconnected infrastructure and energy developments including transmission, generation, gas pipelines, and distributed energy resources.

In August 2018, the COAG Energy Council asked that the Chair of the ESB take the lead on the delivery of a work program "to convert the ISP into an actionable strategic plan" and report back to the Council's December 2018 meeting. This report's conclusions on how to make the ISP actionable is an input into the Chair of the ESB's advice.

In addition, the Finkel Review considered that there may be a future role for governments in facilitating considered and targeted investments in network infrastructure to enable the efficient development of renewable energy resources. This would be necessary if it becomes clear that it is not possible to resolve the coordination problem between generators and TNSPs under the current regulatory framework. It would likely require governments to make decisions on particular transmission investments.

Therefore, the Finkel Review recommended that AEMO, in consultation with TNSPs, should develop a list of potential projects, consistent with the proposed integrated grid plan. The AEMC should develop a rigorous framework to enable the evaluation of these projects, including guidance for governments regarding the circumstances that would warrant government intervention to facilitate specific transmission investments. This should minimise the risk of consumers bearing the cost of unnecessary transmission infrastructure.

2.4 Assessment framework

2.4.1 National Electricity Objective

The overarching objective guiding the Commission's approach to this review is the NEO. The NEO is set out in section 7 of the NEL, which states:

> "the objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (A) price, quality, safety, reliability, and security of supply of electricity; and
>
> (B) the reliability, safety and security of the national electricity system"

2.4.2 Coordination of transmission and generation

In order to assess options that may improve the coordination of transmission and generation investment, it is important to articulate what coordination means.

Generation and transmission are dependent on each other to achieve their individual objectives. Generators need the transmission network in order to access the wholesale market and earn the regional reference price for their generation output. TNSPs need sufficient generation to reliably supply their customers and to meet their individual reliability standards.

It is clear that TNSPs and generators have different incentives and priorities when making their respective investment decisions. The decision-making of generators and TNSPs occur separately and under different conditions. Generation decision-making is market-driven and seeks to maximise the profits for the generation business. Network investment is based on a regulatory process that is designed to meet TNSPs' statutory and regulatory obligations to reliably supply consumers, at least cost.

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

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

Market-based solutions generally provide more efficient, cheaper and innovative outcomes to centrally planned or mandated ones. Centrally-planned solutions rely on a centralised agency making a decision about the coordination of transmission and generation investment. This will likely foreclose the considerable potential benefits of a well-functioning market, and may result in trade-offs being made between different objectives by governments on behalf of consumers. It also means that consumers, not competitive businesses, bear the costs of investment risk.

On the other hand, markets generally provide incentives to innovate, which benefits consumers. This is because competitive pressures are thought to drive more cost-effective and efficient investment and consumption decisions, and because the iterative process of many participants transacting allows for greater responsiveness to changing information and circumstances.

2.4.3 Assessment criteria

In developing our recommendations the Commission has been guided by the below principles:

- **Efficient investment in transmission and generation:** TNSPs should be able to trade-off the cost of augmenting the network with the costs of managing congestion. Having congestion is not efficient since this could be constraining off lower-cost generation, however, building out all constraints is also unlikely to be efficient. The optimal level of congestion is therefore not zero. Similarly, generators should have incentives to invest in new plants where and when it is efficient to do so. Information and price signals should provide financial incentives for generators and load to make efficient location decisions by trading off the costs they impose on the shared transmission network with other relevant decision factors such as proximity to fuel source. However, there are costs associated with the provision of transmission and generation investment, which should be assessed against the value to consumers.
- **Efficient operation of the network and market dispatch:** TNSPs should face incentives to operate the network to provide an efficient level of capacity, maximising availability when the value of network capacity is at its highest (such times may arise when congestion occurs). Efficient operation decisions occur when parties have clear responsibility and accountability for operation. Similarly, generators should have incentives to offer their energy into the wholesale market at an efficient price, resulting in wholesale market outcomes being explained in terms of the underlying supply and demand conditions.
- **Appropriate allocation of risks to parties best placed to bear them:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a reliable supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement, risks are more likely to be borne by consumers. Solutions that are better able to allocate risks to market participants such as commercial businesses, who are better able to manage them are preferred, where practicable.
- **Maintaining a secure and reliable power system:** Regulatory and market design arrangements must take into account the need to support the safe, secure and reliable supply of electricity to consumers. Such outcomes are particularly important in the context of transmission and generation since the consequences potentially have greater effect. Regulation may be required to safeguard these outcomes.
- **Transparency through the provision of timely and accurate information:** Market and regulatory arrangements should promote transparency as well as be predictable, so

that market participants are informed about aspects that affect reliability, and so can make efficient investment and operational decisions.

The Commission has also considered the costs associated with the recommendations.

2.5 Review timeline

Table 2.1 provides a timeline for this review.

Table 2.1: Review timeline

ITEM	DATE	NUMBER OF SUBMISSIONS RECEIVED
Stage 1: Publication of draft report	11 April 2017	6
Stage 1: Publication of final report	18 July 2017	n/a
Stage 2: Publication of approach paper	22 August 2017	11
Stage 2: Publication of discussion paper	13 April 2018	31
Stage 2: Publication of options paper	21 September 2018	40
Stage 2: Publication of final report	21 December 2018	n/a

2.6 Related work

2.6.1 Energy Security Board work on transmission planning

On 20 April 2018, the COAG Energy Council provided the ESB with responsibility for coordinating the work of the energy market bodies on planning and regulation of the transmission system and interconnection.[4]

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

At that meeting, the COAG Energy Council requested that the ESB report to the December 2018 meeting on "how the Group 1 projects identified in the ISP can be implemented and delivered as soon as practicable and with efficient outcomes for customers, and how the Group 2 projects will be reviewed and progressed."[5]

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

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

In order to address the group 1 projects, Dr Kerry Schott AO will submit a rule change request to the Commission to allow the three post-regulatory investment test for transmission (RIT-T) regulatory processes (the AER's assessment of: any dispute lodged, the preferred option assessment, and contingent project revenue determination) to be undertaken concurrently for the group 1 projects only. The AEMC will progress this rule change request on an expedited basis, with the rule change process completed by the end of quarter 1 2019.[6]

The Commission considers that a pragmatic approach will be required over the next five years in order to build the Group 1 projects identified by AEMO in the ISP as being urgently required in the NEM.

Speeding up the Group 2 projects will be facilitated by the Commission's recommendations in this report.

Additionally, the Chair of the ESB was tasked with identifying a work program to convert the ISP to an actionable strategic plan. This paper is an input to that work program. The Commission continues to work with the ESB, AEMO and the AER as part of this process.

2.6.2 Integrated System Plan

Currently, under the NER, AEMO is required to publish a National Transmission Network Development Plan (NTNDP) by 31 December each year, the purpose of which is to provide an independent, strategic transmission planning assessment for the NEM, with a 20 year outlook. This serves as an input for TNSPs on transmission investment required for inclusion in their Transmission Annual Planning Reports (TAPRs). However, as noted above, following the Finkel Review, in July 2018, AEMO published the inaugural ISP.

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

Our recommendation on how to make the ISP actionable is discussed in Chapter 3.

2.6.3 Review of application guidelines for the regulatory investment tests

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

The RITs are cost-benefit analyses that network businesses must perform and consult on before making major investments or replacements in their networks.[7] The application

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6 This addresses the South Australian Government concern that Energy Ministers in December should be presented with options to immediately implement projects identified din the ISP as group 1 projects. See: SA Government, submission to the options paper, *Coordination of generation and transmission investment*, 4 December 2018, p. 1.

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

guidelines for RITs provide guidance to networks on how to apply the RITs to potential investments that the NER states must be subject to these tests. When undertaking RITs, network businesses must give due consideration to all possible options before identifying the best way to meet the demands on their networks.[8]

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

As part of the review, in July 2018, the AER published draft revisions to the RIT-T and RIT-D application guidelines, and sought stakeholder views on these. The draft revisions also include guidance on how RIT-T proponents might incorporate aspects of the ISP into a RIT-T, and the AER stated that it may be necessary to further update the RIT application guidelines once the ISP framework is formalised.[9]

The review was finalised in December 2018.

2.7 Structure of the report

This paper is structured as follows:

- Chapter 3 sets out recommendations on how to action the ISP
- Chapter 4 sets out recommendations to improve the RIT-T
- Chapter 5 sets out our views on renewable energy zones
- Chapter 6 sets out recommendations on network congestion and access
- Chapter 7 discusses charging for use of transmission infrastructure
- Chapter 8 sets out our views on the treatment of large-scale energy storage facilities
- Appendix A provides a summary of stakeholder views that are not raised or addressed elsewhere in the final report
- Appendix B provides an overview of the current transmission framework.

8 Clause 5.16 and clause 5.17 of the NER.

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

3 PLANNING: ACTIONING THE INTEGRATED SYSTEM PLAN

RECOMMENDATION 1: IMPROVE PLANNING OUTCOMES IN THE NEM BY ACTIONING THE ISP

To remain fit-for-purpose, the transmission framework needs to reform to provide for actionable change. We therefore need an integrated system-wide approach to planning - the ISP. Actioning the ISP requires a holistic approach to coordinating generation and transmission investment that will provide the flexibility and agility to achieve lowest cost outcomes for consumers during the uncertainty of the changing NEM. This requires:

- clear links between the ISP and network investment decisions
- the ability for generation and network investment decisions to be coordinated.

An actioned ISP streamlines, removes duplication and de-risks the transmission planning and investment decision-making process to help TNSPs make the decisions that they need to be making to assist the transition of the power system. An actioned ISP also promotes flexibility in the investment decision-making process, meaning that the outcomes are most likely to be affordable for consumers.

There is uncertainty in the energy sector at the moment, driven largely by a lack of clear policy guidance about what emissions reduction mechanism will be introduced and a large amount of government intervention in the sector. An actioned ISP addresses this uncertainty, by creating confidence in a strategic, holistic plan that can test the uncertainties, with the plan then being implemented by the TNSPs.

The Commission has heard from renewable providers that the current arrangements for generator access and congestion management are no longer sustainable. In the absence of any arrangements that deal with this in the NEM, parties are looking to the ISP to address and resolve these issues. However, given the ISP is a centralised plan, it will be unable to address these concerns, given that the generation, load and retail sectors of the industry are disaggregated and it will be nearly impossible for one party to correctly predict and guide decisions of such a sector. Markets, and decentralised decisions, have been shown to be more efficient and more innovative - delivering lower and cheaper outcomes for consumers.

An actioned ISP needs to be paired with the mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion occurring. This is delivered by evolving our current access regime in a way that allows the risk and cost of generation investment to complement planning and investment in transmission. This is the necessary complement to making the ISP actionable. An actioned ISP will be strengthened by the Commission's recommendations for the access framework in the NEM.

Evolving the access regime improves the information that is provided to the market about constraints in the network, while also providing this information to AEMO to more accurately plan the grid through the ISP. This enhanced information on alleviating constraints will lead to increased confidence in the transmission planning and investment decision-making process.

The Commission recommends that:

- The Commission coordinate with the COAG Energy Council's SCO to develop the necessary NEL and NER changes required to action the ISP. The Commission would work with SCO and the ESB to identify the most timely and efficient process for progressing the NER changes.
- As part of these changes, the NER be amended to include a clear definition of the scope of the ISP, i.e. strategic projects. This definition should incorporate that the ISP covers projects on transmission networks used to transport significant amounts of electricity between generation centres and load centres that result in benefits across multiple NEM regions.
- Necessary NEL and NER changes be in place by mid-2019, enabling the next ISP to be commenced in August 2019, ahead of the final ISP being published in mid 2020.

3.1 Background

Currently under the NER, AEMO is required to publish a NTNDP by 31 December each year, the purpose of which is to provide an independent, strategic transmission planning assessment for the NEM, with a 20 year outlook. This serves as an input for TNSPs on transmission investment required for inclusion in their TAPRs. For reliability and security needs identified on their networks, TNSPs conduct RIT-Ts to identify options that deliver the best net-market benefit outcomes and meet the needs that they have identified. TNSPs then decide whether or not they want to invest in the preferred options identified through the RIT-T process. This can be considered an incremental approach to transmission augmentation that is focussed on the jurisdictional needs of each TNSP.

In June 2017, the Finkel Review recommended that:[10]

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

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment. One of the three enabling pillars to achieve the blueprint outcomes in the Finkel Review was "System Planning: enhanced system planning will ensure that security is preserved, and costs managed, in each region as the

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

generation mix evolves. Network planning will ensure that renewable energy resource regions can be economically accessed."[11] Identifying the limited existence of detailed guidance to facilitate the connection of solar, wind or pumped hydro generators to load, the Finkel Review made a number of recommendations for the NEM transmission network, including the efficient development and connection of REZs to be facilitated by an integrated grid plan. This recommendation recognised a need for a more strategic approach to transmission planning in the NEM. Given the changing generation mix, this is needed to maintain a secure and reliable supply of electricity to consumers.[12]

In July 2018, AEMO published its inaugural ISP, to meet this recommendation. The ISP identifies a pathway for developing the transmission network. It is based on modelling the NEM over a range of possible future scenarios.[13] AEMO noted that they called this an integrated *system p*lan, rather than an integrated grid plan, to reflect that over time, the ISP will by necessity consider a wide spectrum of interconnected infrastructure and energy developments including transmission, generation, gas pipelines, and distributed energy resources.

At the COAG Energy Council meeting on 10 August 2018, the Council asked that the Chair of the ESB report back on a work program to "convert the ISP into an actionable strategic plan" at the December 2018 meeting. This chapter forms the AEMC's input to this process.

The pattern of network flows is changing in the transmission system and forecasts of future needs are increasingly uncertain. The transmission framework needs to be fit for purpose and deliver outcomes in a timely way to accommodate this change. An actioned ISP should involve the implementation of a streamlined regulatory process that is designed to result in ISP identified needs being met as quickly as possible, while managing the risks of higher prices that could result from unnecessary or underutilised investment. An actioned ISP ensures AEMO strategically plans the national transmission network, and reduces risk in the investment decision-making process to help TNSPs make efficient decisions that meet the needs of the NEM. An actioned ISP is complemented by an evolution of the access regime that allows the risk and cost of generation investment to be better coordinated with transmission planning and investment.

3.2 Summary of options articulated by the Commission in the options paper

In the options paper, the Commission considered how to make the ISP actionable. When considering how the ISP could be made actionable - or more precisely, what its role in the NEM should be - it is necessary to think through the fundamentals that must be addressed when designing a framework starting with a blank page:

11 Ibid, p.9.

12 Ibid, p.121.

13 The ISP's purpose and scope encompass that which would normally be covered in AEMO's national transmission network development plan (NTNDP). Given this, the AER permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the 2018 ISP.

- **what** - what assumptions should be taken into account for the planning necessary for the ISP; what government policies should be taken into account when completing this planning; what should the ISP focus on - strategic investments; if so, what defines strategic investments?
- **when -** when will the planning be done - annually, every second year, every five years; when will the planning be updated; how frequently should an ISP be done; what is the forecast window - 10 years, 20 years?
- **how** - how will an actionable ISP fit in with the existing regulatory framework; how will non-network options be taken into account; how will local and regional requirements be taken into account?
- **who** - who should be doing the planning; who should be making decisions on what investments to make; who decides what investments are in the long-term interests of consumers?

The above are all questions that need to be answered when considering the role of the ISP, noting that the overarching objective will lead to particular trade-offs being considered. The options paper set out five ways to make the ISP actionable by linking AEMO's role of national transmission planner more strongly to the individual investments made by network businesses - these are summarised in Table 3.1. The five options are described in terms of *who* is responsible for undertaking the various stages in a transmission planning and investment process.

The stages are not specific to transmission investments - they are steps that would be taken in any decisions to make a significant public infrastructure investment, e.g. rail or roads. Each of these stages are needed so that investments, and their alternatives, are appropriately identified, tested, costed, consulted on and assessed against the various views of the future. Without this, the risk of higher prices for electricity, arising from investment that is no longer needed or able to be fully utilised because circumstances change, increases.

The spectrum of options moved from an enhanced status quo, where transmission network businesses keep responsibility for the majority of steps in the transmission planning and investment process, to an option where AEMO would take on the responsibility for all of the steps as part of the ISP.

Table 3.1: Options to strengthen the link between the ISP transmission investment decisions

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

Note: AEMC, options paper, *Coordination of generation and transmission investment*, 21 September 2018, p.23.

The options can be described as follows:

- Option 1 - TNSP decides on transmission investments but is required to consider ISP identified investment needs in their transmission annual planning reports and regulatory proposals
- Option 2 - TNSP decides on transmission investment but is required to conduct RIT-Ts on its ISP-identified investment needs and options
- Option 3 - in addition to the ISP identifying investment needs and options, AEMO determines the "best" option for transmission investment, but the TNSP is still able to determine how to most efficiently meet that option, e.g. to take into account local conditions
- Option 4 - AEMO determines the "best" option for transmission investment and directs a TNSP to proceed with the "best" option, although the TNSP can still choose the functional specification of that option
- Option 5 - AEMO determines what transmission investment is necessary, including the functional specification, and directs a TNSP to implement the investment.

The Commission also recognised that these options represent a potential range of investment decision paths, rather than an exhaustive list, and welcomed stakeholders to develop alternatives.

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

What is common to all options is that AEMO undertakes system-wide, long-term planning of transmission needs, as it always has.

3.3 Overview of stakeholder submissions to the options paper

3.3.1 Views on the options

Stakeholders broadly supported AEMO using its expertise as the independent national planner to identify national, strategic transmission projects through the ISP.

Stakeholders recognised that the risks (to both consumers and generators) of over or under-investment in transmission increased as the options progressively remove decision-making from those exposed to financial incentives. Maintaining a strong link between financial incentives and investment decision-making is the best way to ensure that rigorous examination of the options is undertaken. AEMO has incentives in terms of market operation, but these may not explicitly apply to identifying the most efficient transmission investment outcomes.

In terms of how stakeholders viewed the various options, there was no one favoured option.[14] A summary of stakeholders' support for each of the options is provided in Appendix A.1. Stakeholders were supportive of the articulation of the spectrum that was put forward by the Commission, and found it useful to think about all the components of a future planning and investment decision-making framework.

Many stakeholders - most notably, all of the TNSPs - put forward variations on the options.

In large part, themes can be deduced from the submissions made on the options:

- Stakeholders supportive of options on the left of the spectrum identified the following reasons:
  - They preferred market-based approaches and decentralised transmission investment decision-making. Although these stakeholders did not support a central planning type of model, they did consider that providing additional information to stakeholders through the ISP to better understand transmission investment decisions was imperative.[15]
  - The ISP should not be considered a replacement for the current RIT-T process. These stakeholders considered that the RIT-T should remain the vehicle through which the efficiency of investments is tested, characterised by a robust cost-benefit analysis that seeks to determine the net market benefit of potential options identified to address a need on the network. [16]
  - The options to the left of the spectrum presented solutions that could be implemented quickly but still achieve streamlined benefits. For example, these options would support TNSPs being able to use ISP scenarios, inputs and assumptions, which would reduce TNSP operational costs through removing duplication between the ISP and RIT-Ts, and help ensure a system-wide focus through the RIT-T process.[17]
  - Current risk allocation in the transmission planning and investment framework should remain largely unchanged.[18] The criticism of the options on the right-hand side of the spectrum is that they mean that consumers bear the risk of a future envisaged by a central planning approach to the grid not eventuating.
  - They thought these options provided the flexibility needed in the transmission planning and investment process given the uncertainty that exists in the market now. The cost-benefit analysis would be undertaken by TNSPs who could utilise their local expertise, and the options would provide flexibility to respond to changes in market

14 Although we would note that no one aside from the Victorian Government supported option 5. Option 5 is similar to the current transmission planning arrangements in Victoria.

15 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: ENGIE pp.1-3; ERM Power, pp.2-3.

16 Ibid; EUAA, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.13.

17 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: RES Australia p.4-5; Infigen p.2.

18 Delta Electricity, submission to the options paper, *Coordination of generation and transmission investment,* Delta Electricity, 22 October 2018, p.3.

conditions. Stakeholders viewed that these options would guide TNSPs towards the preferred options that deliver the best net market benefits across the NEM and streamline the RIT-T process.[19]

- These options would be less costly to implement than the others as they would require fewer changes to the NEL and the NER, and could be introduced in less time.[20]
- These options also avoid the risk that those on the right side of the spectrum are exposed to in that they would 'lock in' investments that may not be needed if they were considered as 'late as possible' in the planning process. By separating the processes undertaken by AEMO in planning the network, and TNSPs in assessing the net market benefit of credible options for addressing a system-wide need, there are multiple opportunities for flexibility to be incorporated into the process, and inputs and assumptions to be revisited and adjusted as necessary.[21]

- Stakeholders supportive of options from the middle to the right of the spectrum identified the following reasons:
  - More change to the existing regulatory framework is necessary to give effect to system wide planning, without which there would be more costs to the market due to a lack of national coordination. That is, in the absence of a mechanism which allows all parties in the NEM to enhance the shared transmission network and manage congestion, or respond to the costs of congestion, the ISP should fulfil this important coordination role.[22]
  - There should be more pressure placed on TNSPs to pursue options that are considered in the ISP to be in the best interests of consumers. Stakeholders preferred these options as TNSPs would be required to implement the preferred options for network development identified by AEMO through the ISP.[23] This view was expressed by stakeholders due to a concern that TNSPs are not incentivised to undertake investment in the current environment.
  - The planning and investment process under these options could be completed faster than the processes articulated under the options on the left-hand side of the spectrum, partly through the removal of duplicated effort on the part of AEMO and TNSPs. The ISP could replace the cost-benefit analysis in the RIT-T, and rather than only identifying the potential options for investment, the ISP would also be directing investment decisions.[24]

19 AER, submission to the options paper, *Coordination of generation and transmission investment*, 24 October 2018, p.3.
20 PIAC, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.23.
21 Origin Energy, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.3
22 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: CEC pp.1-3; AEMO pp1-10.
23 MEU, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.3-4.
24 S&C Electric Company, submission to the options paper, *Coordination of generation and transmission investment*, 18 October 2018, p.6.

- The options could drive more efficient network planning through AEMO assessing the strategic needs of the NEM and directing investment to meet them.[25]

3.3.2 Common general principles that should guide making an ISP actionable

Despite the range of views expressed, as summarised above, nearly all stakeholders agreed the following principles are essential for achieving the best outcomes for consumers when implementing the ISP:

- **Robust cost benefit analysis**: Stakeholders strongly supported robust cost-benefit analysis of proposed new transmission assets, regardless of whether the need for more transmission is identified in the ISP, or by a transmission business.
- **Effective and meaningful consultation**: Stakeholders broadly agreed there needs to be confidence in the planning process if the ISP is to be made actionable. This requires rigorous and transparent consultation that is effective in assisting all parties to make informed decisions, and meaningful in the sense that the input is genuinely considered throughout the preparation and implementation of the ISP.
- **Placing risks with the party best able to manage them**: Under the current framework, there are processes to mitigate the risk of consumers paying for inefficient transmission. In considering any changes to the framework, stakeholders agreed that the allocation of risk in any model adopted to implement the ISP should not increase risks for consumers. There was wide agreement from stakeholders that risks should be placed with those parties that are best able to manage them, and consumers should not be unduly exposed to risks associated with inefficient investment in transmission infrastructure. Stakeholders also noted that risks are created by locking in investment decisions based on modelling that is conducted in an inherently uncertain environment.
- **Balance between strategic versus local perspectives:** Stakeholders broadly supported the view that the ISP should be focused on "strategic, national" investments, and TNSPs should remain responsible for local jurisdictional planning. TNSPs should have the opportunity to provide input into the ISP. Stakeholders also thought that there needed to be clarity around what investments should be included in the ISP, and what investments should not.
- **Incorporate public policy -** Stakeholders largely thought that the ISP should incorporate federal and state policies, with some suggesting it was appropriate for governments or the COAG Energy Council to provide formal advice to AEMO as to what policies should be modelled.[26]

The extensive input provided by stakeholders has informed the development of the actioned ISP.[27]

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25 Victorian Government, submission to the options paper, *Coordination of generation and transmission investment*, 29 October 2018, p.1.

26 Some stakeholders noted that the COAG Energy Council may not be best placed to provide this advice, and perhaps this could be developed through industry consultation.

27 Views raised by stakeholders that have not been addressed in this Chapter are detailed in Appendix A.2.

3.4 Commission's conclusions and recommendations

3.4.1 There is a need for an actionable ISP

In order to keep pace with the changing generation mix, there needs to be an enhanced, integrated, system-wide approach to planning, which does not consider transmission investments on a project by project basis. AEMO has created this through its development of the ISP, which delivers a strategic infrastructure development plan that can facilitate an orderly energy system transition under a range of scenarios. The ISP therefore provides the planning arrangements through which the regulatory frameworks for transmission planning and investment can be reformed to meet the needs of the changing energy market.[28]

Pro-actively planning key elements of the network now in order to create the flexibility for changing technologies and preferences has the potential to reduce the cost of the system over the long-term. An ISP will also ensure that planning is occurring on a nationally coordinated basis, in order to maximise the net benefit to the NEM. This is particularly important in the current transformation - a nationally coordinated approach is important since the solution to an identified need could easily be one in another region, or an investment that involves assets in multiple jurisdictions, or indeed the most efficient solution could result in another identified need not eventuating.

The ISP therefore provides a long-term vision for the network, allowing planning to be considered from the perspective of the network as a whole. This holistic approach considers synergies that may be captured across time and space, and allows decisions to invest in any one option to be made in the context of the broader portfolio.

What should the ISP's focus be?

Therefore, the ISP should be primarily focussed on those strategic projects, ensuring coordination for those investments that affect flows across regions. This was supported by stakeholders. The Commission considers that PIAC's definition of strategic projects should be adopted in order to guide this distinction: "those where significant benefits accrue across multiple NEM regions, such as those involving major upgrades to interconnectors or national transmission flow paths".[29]

Importantly, there is no bright-line between what projects are strategic, and what are not - separating local from strategic projects will be challenging. A replacement of a transformer on the border of Queensland (QLD) - New South Wales (NSW) could be an important prerequisite to the consideration of the QNI upgrade.

However, there are likely to be limits to the level of detail about individual components that could comprise the ISP that it can practically incorporate. As recognised by stakeholders,[30] it is not practical for the ISP to attempt to plan for all of the needs for each TNSP, i.e. including

28 The Commission considers that this reform needs to be paired with changes to current access arrangements to allow the risk and cost of generation investment to be better coordinated with transmission planning and investment.

29 PIAC, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.9.

30 Several stakeholders stated that AEMO is not best placed to be able to assess the more detailed aspects of physical transmission planning, the costs and constraints of real power projects, or have the time and resources to fully consider all network and non-network options. Australian Energy Market Commission, *Coordination of generation and transmission investment*, submissions to the options paper: Infigen p.2; RES Australia p.6; Delta Electricity pp.1&5.

all replacement expenditure, as well as localised investments to meet jurisdictional reliability standards. Doing so would also likely be unrealistic and ignore the importance of local input. Network topography and local conditions vary substantially across the NEM. It is therefore important to allow for that specialised, local input. TNSPs should therefore remain responsible for local jurisdictional planning, and feed up information from this as an input into the ISP.

The inputs, assumptions and scenarios developed by AEMO, which would be subject to input from stakeholders and the AER, along with information on system reliability and security needs that would be included in the modelling to identify system-wide needs, would determine which projects belong in the ISP and which do not.[31] If the ISP process identifies that a particular system need exists, then that need belongs in the ISP.

3.4.2 Recommendation as to how the ISP can be actioned

Making the ISP actionable requires a holistic approach to coordinating generation and transmission investment that will provide the flexibility and agility to achieve lowest cost outcomes for consumers during the uncertainty of the transforming NEM. The Commission considers that actioning the ISP requires:

- clear links between the ISP and network investment decisions
- the ability for generation and network investment decisions to be coordinated.

Drawing on our assessment framework set out in Chapter 2, as well as the common principles articulated by stakeholders, the actioned ISP has been developed by reference to the following principles:

- be clear and transparent in the approach taken to planning and investment decisions, including providing transparent and comprehensive analysis, as well as undertaking a robust consultation process including engaging with all stakeholders in developing the plan, scenarios, inputs, assumptions and draft outcomes
- promote investment decision-making on a nationally coordinated basis to maximise net benefit (defined as the benefit to all those who produce, consume and transport electricity in the NEM)
- allow for both a local and strategic perspective as part of the planning process, which will ensure that there is sufficient 'local knowledge' as part of any planning framework, noting that both of these perspectives need to be integrated
- to the extent possible, minimise conflicts of interest between the party planning the network, parties making decisions to invest in the network, and the party responsible for exercising a last resort planning power (LRPP)
- allow for flexibility to deal with the transforming market
- allocate risk to the party best able to manage risk, and
- provide a streamlined process, and minimise duplication of analysis and decision-making.

31 The model for making the ISP actionable is detailed in Section 3.4.2 below.

Integrating the ISP into the transmission framework streamlines existing processes, removes unnecessary duplication and reduces risk in the transmission planning and investment decision-making process to help TNSPs make the decisions that they need to be making to assist the transformation of the power system. This is summarised in Table 3.2.

Table 3.2: **Summary of the actioned ISP**

	STAGE IN PLANNING AND INVESTMENT PROCESS	RESPONSIBILITY
1	ISP input, assumption and scenario development	**- AEMO** develops basic scenarios, inputs and assumptions, and consults publicly on this detail, with AER oversight and consumer involvement. - COAG Energy Council SCO provides information to AEMO on which jurisdictional policies should be included in the ISP modelling, or AEMO provides draft information to SCO for their amendment/endorsement.
2	Identify system-wide needs	**- AEMO** undertakes NEM wide modelling to determine system wide needs, which takes into account inputs from TNSPs. - A draft ISP is published for public consultation that details system-wide needs and credible options identified by AEMO (see stage 3 below). The AER is involved in the development of the draft report.
3	Identify credible options that address the system-wide needs	**- AEMO** identifies credible options for addressing system wide needs, with direct input from TNSPs. The credible options would not include non-network options in detail at this stage. - The credible options are also published as part of the draft ISP for public consultation. *The draft ISP would replace the current RIT-T project specification consultation report.*
4	Publication of the final ISP	**- AEMO** refines the ISP based on public consultation and publishes the final ISP. It provides a single recommended development pathway that outlines the priority projects needed across the NEM and the timeframes in which they should be developed.
5	Assess costs and benefits of credible options	**- TNSPs** are *required* by the NER to conduct a streamlined RIT-T for needs identified in the ISP, using the ISP scenarios, inputs and assumptions

	STAGE IN PLANNING AND INVESTMENT PROCESS	RESPONSIBILITY
		for the cost-benefit analysis of the ISP credible options. - **TNSPs** are required to consider non-network options, and to check with AEMO whether they would also meet the system-wide need identified in the ISP. - **TNSPs** publish a RIT-T project assessment draft report for public consultation.
6	Determine the “best” option	**- TNSPs** publish a RIT-T project assessment conclusion report that details what the TNSP has concluded is the “best” option. - **TNSPs** are required to check with AEMO that the preferred option addresses the system-wide need identified through the ISP. - The RIT-T dispute mechanism would remain the same as it is now.
7	Make decision on implementation of the best option	**- TNSPs** decide on implementation of the preferred option.
8	Undertake detailed costing and planning for the investment	**- TNSPs** undertake the detailed, project specific costing and planning for the investment, including obtaining land easements and environmental approvals, developing functional specifications for the assets and ordering/procuring the equipment. - **TNSPs** could commence the AER revenue determination process before this stage is complete (see stage 9).
9	AER revenue approval	**- TNSPs** would continue to use the existing contingent project mechanism. If the project is not a contingent project, TNSPs may wish to delay it to the next regulatory control period.
10	Implement the investment	**- TNSPs** implement the investment – either commissioning and building the transmission investment, and/or finalising contracts with the non-network provider. - **TNSPs** could commence this process before the AER revenue determination is finalised.
11	Safety net	The LRPP would reside with the **AEMC** as a

	STAGE IN PLANNING AND INVESTMENT PROCESS	RESPONSIBILITY
		"safety net" for the transmission planning and investment decision framework. If the responsible TNSP does not undertake a RIT-T for the ISP-identified need, or if AEMO does not agree that the preferred option identified by the TNSP is consistent with the overall strategic plan, the AEMC could direct a TNSP to consider a particular investment in detail through a streamlined RIT-T process.

The actioned ISP demonstrates the principles articulated above, and builds on the model proposed by AEMO in its submission to the options paper.[32] Each of the stages are further outlined below.

Stage 1: ISP input, assumption and scenario development[33]

AEMO would prepare basic scenarios, inputs (including demand forecasts and generation technology costs) and assumptions for the ISP. This would be tested with its forecasting reference group (an industry stakeholder group comprised of modellers), with the AER attending and observing any forecasting reference group meetings.

AEMO would then work up this detail into a consultation paper for public consultation, and seek written submissions. AEMO could consider holding public forums or workshops on the consultation paper, with a public invitation. The AER would also attend and observe any forums that were held. It is recommended that resourcing be allocated for consumer representatives to provide expert input into this process, which could take the form of attending the forecasting reference group meetings, attending public forums, or preparing submissions to the consultation paper. The provision of a Consumer Challenge Panel similar to the AER's model may be beneficial.[34] Alternatively, the Commission considers that Energy Consumers Australia could play an important role in facilitating this.

Following receipt of submissions to the consultation paper, AEMO would consider the submissions and refine its scenarios, inputs and assumptions. A summary of submissions and AEMO's responses to the suggestions by stakeholders would be published on AEMO's website.

AEMO would model the ISP with and without consideration of jurisdictional policies to reflect the impact they would have on the network. The COAG Energy Council SCO would facilitate a process whereby the jurisdictional policies that should be included in the former version of the ISP are provided to AEMO. This would confirm what jurisdictional policies will be in place

32 AEMO, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.11-15.

33 This process builds on some of the scenario development steps and corresponding consultation process outlined in AEMO's proposal for making the ISP actionable. Ibid.

34 See: https://www.aer.gov.au/about-us/consumer-challenge-panel

in order to enable a forecasting of, say, changes to demand or likely costs of new generation, as a result of these policies. Many stakeholders agreed that it would be helpful for the COAG Energy Council to provide policy guidance to AEMO as to what jurisdictional policies should be modelled, including what sensitivities. We suggest the SCO may be more appropriate than the COAG Energy Council as they meet more frequently. An alternative to this process would be for AEMO to draft this information and provide it to the SCO for their amendment and endorsement. If AEMO did not receive a response to what it proposed, it would be assumed that SCO did not have any objections.

The planning process will also have to consider transmission needs driven by public policy requirements established by state and federal laws or regulation, as suggested by Snowy Hydro.[35] This should be included into the plan as a particular scenario.

The rationale for these steps has been based on stakeholder feedback on the need for AEMO's input, assumption and scenario development for the ISP to be more robust and open for consultation, including the need for the AER and consumers to have their views incorporated. In particular, stakeholders recognise that there needs to be confidence and trust that the preparation of the ISP will occur with a robust consultation process.

A robust consultation process involves public, transparent consultation as well as public, transparent documentation of the feedback from the stakeholders themselves, as well as an explanation of how the feedback has been taken into account. Establishing a robust consultation process upfront, with involvement from multiple parties will assist with streamlining later parts of the process, as well as minimising the potential for disputes.

Similarly, having the AER involved through the process should provide it with information on investments that streamline its later regulatory processes for assessing the efficiency of investments. However, the AER's role in the planning process is different from the AER's role in the investment decision process. The AER could approve ISP methodology and consultation processes that were used, but not the technical decision itself. This would provide confidence to stakeholders about the information and processes informing any decisions.

Stages 2-3: Identify system-wide needs and credible options that address them

AEMO would use the finalised inputs, assumptions and scenarios to undertake NEM wide modelling. This modelling would take into account system-wide reliability (driven by the jurisdictional reliability standards for transmission infrastructure, as well as the reliability standard for generation), system security considerations, and risk resilience needs.[36]

AEMO's modelling would take into account inputs from the TNSPs on intra-regional reliability needs that will be identified through their annual planning reports (which will be separately consulted on), and any RIT-Ts that they currently have underway. TNSPs and AEMO would collaborate on the preparation of this modelling and effectively negotiate around system needs through a joint planning group.

35 Snowy Hydro, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.5.

36 AEMO, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.11-15.

AEMO will use the data that will be provided to it through the reforms recommended in Chapter 6 to develop projected future costs of congestion and identify system bottlenecks. As recognised by AEMO, when the final stage of the complementary reforms to access are implemented, which will promote market based signals to co-ordinate transmission and generation investment, these signals will also be incorporated into the ISP modelling. The Commission's recommendations for reform to the access regime in the NEM will improve the information that is provided to the market about constraints on the network, while also providing this information to AEMO to more accurately plan the grid through the ISP.

AEMO will undertake NEM wide modelling and analysis to determine the development needs for more detailed investigation by TNSPs.

AEMO would also identify credible options for addressing the system-wide identified needs with direct input from TNSPs. These credible options should all meet the system-wide needs that have been identified. TNSPs would have direct input into this process. The identification of options would not include consideration of non-network options in detail, although it could include criteria for the needs that are identified such that non-network providers could start to consider whether their project may potentially meet the identified need. Developing non-network options requires detailed localised knowledge that TNSPs are in the best position to provide. Incorporating non-network options into the ISP would increase its complexity, and given non-network options are largely driven by local knowledge, it does not appear that the ISP would be the best place to consider these options.

The system-wide needs and credible options to meet them would be documented by AEMO in a draft ISP, which would be published for public consultation.[37] Stages 2 and 3 replace the RIT-T project specification consultation report – the draft ISP would detail technical characteristics, construction timetables and indicative costs of each credible option.[38] Therefore, projects that are being considered through this process could move straight to the draft report stage of the RIT-T following the consultation on the draft ISP. AEMO could consider holding public forums or workshops on the draft ISP. The AER would be involved in the development of the draft ISP, and observe any workshops that may occur. Having the AER involved through the draft ISP should provide it with information about investments that will streamline its later regulatory processes for assessing the efficiency of investments.

These stages reflect that there is value in AEMO, as national transmission planner, modelling a national plan, which would identify system-wide needs across the network. The inputs from the TNSPs are important in order to make sure that local considerations are taken into account, to plan an efficient overall network. This will guide TNSPs to options that deliver the best net economic benefits across the NEM, rather than just in their jurisdiction, effectively facilitating TNSPs being able to plan cross-jurisdictionally. It addresses the concern that two transmission infrastructure projects may compete with each other, but the outcome would be influenced by which TNSP pursues the option first. This approach allows AEMO to outline what is an overall efficient path or plan for the NEM through the ISP.

37 Non-network options would be added to the list of credible options by TNSPs, see Stage 5.

38 With this information included in the ISP, the Commission recommends removing the project specification consultation report from the RIT-T for ISP projects.

These stages also seek to streamline the regulatory process by replacing the consultation paper stage of the RIT-T with a draft ISP. They allow AEMO to identify a strategic plan, but without needing to have all the local information that TNSPs have access to. As detailed in stage 1, a robust consultation process would be expected to establish confidence in the process and outcomes.

Stage 4: Publication of the final ISP

AEMO would incorporate stakeholder comments on the draft ISP, and refine the ISP in order to develop the final ISP, which would detail system-wide needs and credible options to address them. AEMO would include a section in the final ISP that sets out stakeholder comments on the draft, and provides a response as to how they were taken into account. The final ISP would essentially form a single recommended development pathway that is an aggregate of multiple scenarios, and outlines the priority projects required across the NEM and the time-frames in which they should be developed.

The final ISP would include all of the information that is required to be provided in the NTNDP, and the information required to inform the LRPP process. The LRPP provides an important safety-net to ensure that necessary transmission infrastructure projects commence the regulatory process.[39]

This stage seeks again to establish a robust consultation process by requiring AEMO to respond to comments made on the draft ISP.

Stage 5: Assess costs and benefits of credible options

For needs that were identified in the ISP, the TNSP would be *required under the NER* to conduct a streamlined RIT-T (the RIT-T would not include a project specification consultation report, which would be covered off by the ISP process) using the needs and credible options put forward by AEMO in the ISP as a starting point. The streamlined RIT-T could assume the ISP plan as the base case in these assessments.

TNSPs would adopt the ISP development needs, scenarios, inputs and assumptions for the cost-benefit analysis since these will have been tested through the ISP consultation process. TNSPs would be allowed to replace these if necessary with updated information that becomes available to the market, or where their local perspective may consider that these assumptions may be different.[40]

Potentially, TNSPs could only take into account the credible options identified by the ISP, as well as any non-network alternatives that they consider are valid. On the one hand, limiting credible options would streamline the current RIT-T. If TNSPs wish to consider an alternative credible option or options, they could be required to "check" with AEMO that the additional credible option/s addresses the system-wide need identified through the ISP. This will also

39 The 2018 ISP contained less detailed information on expected inter-regional transmission network constraints than previous NTNDPs. In undertaking the 2018 LRRP the Commission identified, which AEMO staff confirmed, that the ISP does not specify the features of each expected inter-regional constraints. This lack of information has impacted on the AEMC's ability to identify, based on the key transmission planning documents, which specific inter-regional constraints need to be addressed by TNSPs in the coming years and the projects that TNSPs plan to pursue to address them. There would need to be consideration given to whether all of the information currently included in the NTNDP would need to be included in the ISP going forward.

40 The RIT-T Application Guidelines would need to change to take this into account.

allow this information to be incorporated into the next iteration of the ISP. If AEMO does not consider that the option is consistent with the ISP, then this feedback could be provided in a submission to the RIT-T process.

However, on the other hand, restricting the credible options that TNSPs could consider may actually eliminate some more efficient investments that could take place. For example, this was a deliberate consideration in amalgamating the previous separate reliability and market benefits limbs, with this occurring so that the decision-making process in relation to transmission planning would be optimised. A project that could be required to meet a reliability standard, may provide additional market benefits that justify a higher cost. If only the credible options assessed by AEMO were allowed, this could preclude such investments.

It is also worth noting that the 2018 ISP identified the minor QNI upgrade as being an upgrade of the Liddell-Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines; and static VAR compensators at Dumaresq and Tamworth substations and shunt capacitor banks at Tamworth, Armidale and Dumaresq. In the TransGrid/Powerlink project specification consultation report for this project, this is expected to cost $142m and take two to three years. The report also includes another option that involves a Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek, which can be completed in one to two years and at only $45m. While these options - along with the others raised in the report - need to be considered through the RIT-T process, it is a useful example of how restricting the credible options could preclude more flexible or innovative solutions being developed at a later date.

TNSPs would also be required to consider and document the rationale for whether there are non-network options that could also be assessed. TNSPs could draw on a demand management register, as well as their understanding of generation in an area to flesh out these opportunities. This process would allow TNSPs to take into account local conditions when assessing whether non-network options could meet the needs identified in the ISP. In assessing this, TNSPs could evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis.

The cost-benefit analysis undertaken in the RIT-T would still be informed by the AER's RIT-T guidelines, and would be designed to identify the net market benefits associated with each credible option (including the 'system-wide' benefits). TNSPs would publish a RIT-T project assessment draft report – as they do now – for public consultation. This would include input from the Consumer Challenge Panel, in order to provide consumers' perspective. The Commission considers that robust consultation and involvement of a wide range of stakeholders will minimise the chance of disputes. The AER would be involved throughout this process. The involvement of the AER will assist it in making its assessments at the end of the process quicker than under current arrangements.

Stage 5 reflects that, as the party who will ultimately make the investment decision (and take the risk that the AER may not allow the recovery of revenue to cover project costs), the TNSP should undertake the cost-benefit analysis. Through the economic regulatory framework, a TNSP currently has an incentive to identify the most efficient outcome. TNSPs would be required to undertake a streamlined RIT-T for a need identified in the ISP to ensure there is an assessment of whether the project should proceed based on the costs and benefits of the project given the circumstances at the time.

The modelling undertaken for the inaugural ISP sought to find the optimal mix of gas and electricity infrastructure investment and operation which meets the future needs of the NEM at lowest cost for consumers – an engineering optimisation at lowest cost exercise. Analysis undertaken for a RIT-T seeks to identify the credible transmission investment option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the relevant market – a process that weighs the benefits of a particular investment against the costs.

Stages 6-7: Determine the "best" option and make the decision to implement it

TNSPs would respond to and incorporate any stakeholder feedback received on the RIT-T project assessment draft report. They would then publish a RIT-T project assessment conclusions report which would set out what the TNSP considers is the "best" option. The TNSP would be required to cover off in the final report whether or not AEMO considers that the preferred option still addresses the system-wide need identified through the ISP. The chance that it does not should be relatively low given that the TNSP used the ISP scenarios, inputs, assumptions and credible options, and the TNSP consulted with AEMO if alternate credible options were identified.

The RIT-T dispute mechanism would remain the same. With the level of consultation throughout the planning and investment process, the risk of a dispute would likely be reduced. It is important to have a dispute mechanism as part of an effective regulatory framework. Indeed, the prospect of a dispute mechanism provides an incentive for parties to undertake the process in a robust and consultative manner in order to avoid the dispute mechanism being triggered.

TheTNSP would decide that the preferred option will be implemented, including such decisions if a network option is chosen, such as the preferred route, technical specifications of the assets and interfaces with the existing transmission network.[41]

This stage is designed to reflect that the preferred options identified by TNSPs need to address the identified needs published in the ISP. It is also designed to reflect the Commission's view that decisions to invest in what can be significant cost projects, recovered from consumers, should rest with the parties that are best able to manage the risk that the project is selected and implemented inefficiently. In making a decision to invest, TNSPs take the risk that the AER may not allow the recovery of revenue to cover project costs - TNSPs are incentivised to identify the most efficient outcome through the cost-benefit analysis process.

Stage 8: Undertake detailed costing and planning for the investment

TNSPs undertake the detailed, project specific costing and planning for the investment. For a network investment this would include obtaining land easements and environmental

41 The decision to invest would practically involve conditional board approval subject to the AER's decision on revenue recovery, detailed in Stage 9.

approvals, developing functional specifications for the assets and ordering/procuring the equipment.

This stage recognises that there are significant non-electricity industry regulations to deal with after the finalisation of the RIT-T. Having the AER involved in the process throughout the preparation of the investment decision should allow the TNSP to (theoretically) be more comfortable starting to undertake some of these processes, prior to this stage.

Stage 9: AER revenue approval

The AER would continue to enforce TNSPs' compliance with the regulatory framework for undertaking the (streamlined) RIT-T and have regulatory oversight of TNSPs' revenue. Once a decision is made to implement the preferred option, and AEMO has confirmed it meets the system-wide need identified in the ISP, TNSPs would continue to use the existing contingent project mechanism. This assumes that the projects have been identified as contingent projects in the regulatory determination for the current regulatory control period. If this is not the case, TNSPs would have a strong incentive to delay the project to the next regulatory control period.

However, there is also the possibility for TNSPs to recover revenue prior to the next regulatory period. Projects could be classified as "pass through events", which is a mechanism that can be used if a specified event (each with their own definition in the NER) occurs during the regulatory control period e.g. regulatory change events. All events specified as pass through events are events that cannot be foreseen at the start of the regulatory control period and are therefore not factored into the TNSP's revenue allowance (as per Clause 6A.7.1). In addition, there are provisions for a "capex reopener mechanism" under Clause 6A.7.3 of the NER where the necessary criteria for each of these are met. This can be used where an event that is beyond the reasonable control of the TNSP occurs during the regulatory control period and the occurrence of that event (or an event of a similar kind) could not reasonably have been foreseen at the time the revenue determination was made (as well as other criteria being met).

However, there would be a change to the post RIT-T regulatory processes that would streamline, shorten and remove duplication for projects identified in the ISP. Clause 5.16.6 (where the AER makes a determination as to whether the preferred option for investment satisfies the regulatory investment test) would be removed from the NER, enabling the TNSP to progress to undertaking the detailed, project specific costing and planning for the investment, including obtaining land easements and environmental approvals faster. This is discussed further in Chapter 4.

Given the AER has been involved throughout the planning and investment decision process, this stage should be completed faster than under current arrangements, and potentially in parallel with stages 8 and 10.

Stage 10: Implement the investment

TNSPs would implement the investment, either building and commissioning the transmission investment, and/or finalising contracts with the non-network provider. Depending on the risk appetite of TNSPs, they could commence this process before the AER revenue determination is finalised.

Stage 11: Safety net

If a need is identified in the ISP, but then the relevant TNSP does not undertake a RIT-T, or if AEMO does not agree that the final need identified by a TNSP is consistent with the overall strategic plan, then there is a role for the LRPP. It would be operated as it currently is by the AEMC, and would allow the AEMC to direct a TNSP to consider an ISP identified investment project in detail through the streamlined RIT-T process outlined above.

It is important to have this safety net in case there is something that necessitates its use. If AEMO has identified through the ISP that a particular transmission project needs to be built, but the TNSP does not pursue this, then there should be testing of both of these points of view. This will only occur if the safety net is operated by a third independent party that can assess both the local and strategic perspectives.

3.4.3 Benefits of the actioned ISP

There are several key features of the actioned ISP described in section 3.4.2 that will improve the current regulatory process for transmission planning and investment decision-making:

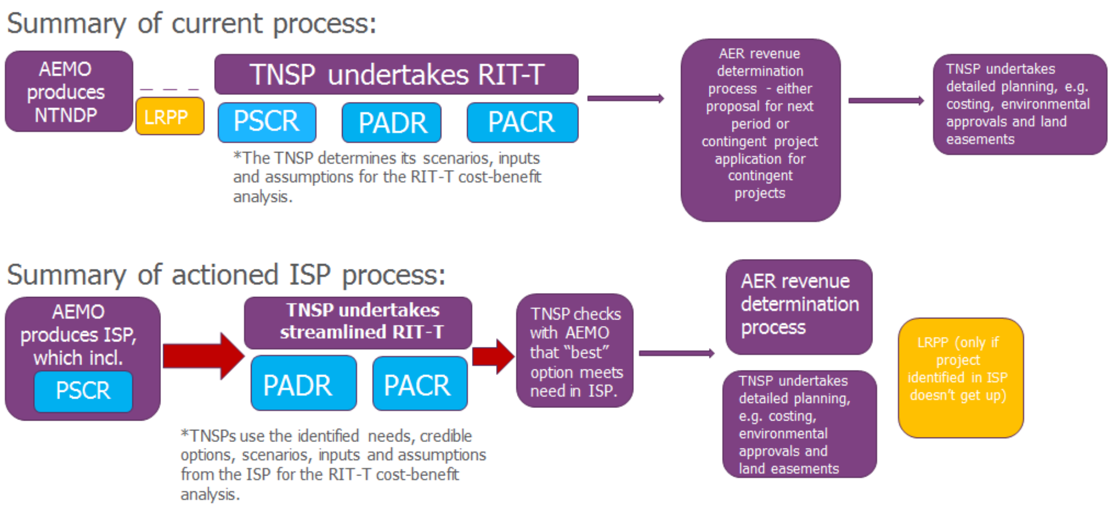
Transmission is built to address strategic needs identified in the ISP - The involvement of TNSPs in the ISP planning process, the inclusion of ISP credible options, scenarios, inputs and assumptions in the RIT-T, and the requirement that TNSPs check that the preferred option meets the ISP-identified need, all contribute to an outcome where TNSPs build transmission infrastructure to meet the system-wide needs identified in the ISP. The LRPP at the end of the process provides a "safety net" to ensure ISP-identified needs are considered for investment.

Establishes credibility and reduces likelihood of a dispute - Robust and transparent consultation is conducted at every planning and investment decision step. This can be expected to increase confidence in the transmission investment decisions, and minimise the chances of a dispute at the end of the process.

Streamlined cost-benefit assessment and revenue determination processes - The incorporation of the identification of credible options (currently done through the RIT-T project specification consultation report) into the ISP results in a streamlined RIT-T process. Allowing TNSPs to use ISP scenarios, inputs, assumptions and credible options for the streamlined RIT-T removes duplication from TNSPs having to formulate all of these again. The inclusion of the AER in an observatory role at every step of the planning and investment decision process means that it is not starting from scratch for the revenue determination. This process will be streamlined as the AER will already have a lot of information about the project.

Figure 3.1 provides a comparison of the current regulatory process for transmission planning and investment and the actioned ISP process.

Figure 3.1: Comparison of the current regulatory process for transmission planning and transmission investment, and the actioned ISP process



Note: PSCR=project specification consultation report; PADR=project assessment draft report; PACR=project assessment conclusions report

By removing duplication and streamlining the transmission planning and investment decision process, the actioned ISP would reduce the time it currently takes for the regulatory process to be completed. Table 3.3 outlines the current timing of the regulatory process based on the stages that have been articulated above, and how long the actioned ISP would take. This shows that we expect savings of approximately **18 months** by actioning the ISP.

Table 3.3: Timing of the actioned ISP

STAGE	TIMING OF CURRENT PROCESS	TIMING OF ACTIONED ISP
1. ISP input, assumption and scenario development	4 months	4 months (incl. consultation)
2. Identify system-wide needs	See stage 4	See stage 3
3. Identify credible options that address the system-wide needs	See stage 5	6 months (stages 2&3, incl. consultation on draft ISP)
4. Publication of the final ISP	8 months (current NTNDP process)	3 months (incorporate stakeholder feedback and publish final ISP)
5. Assess costs and benefits of credible options	Up to 28.5 months (PSCR & PADR incl. consultation), but more realistically 16 months (Heywood took 16 months)	5.5 months (incl. 6 weeks consultation) PADR must be published 4 months after final ISP is published – TNSPs

STAGE	TIMING OF CURRENT PROCESS	TIMING OF ACTIONED ISP
		would already be aware of what is going to be in the ISP
6. Determine the "best" option	6 months	3 months
7. Make decision to implement the best option	3 months	2 months
8. Undertake detailed costing and planning for the investment	Up to 24 months (non-regulatory processes)	Up to 24 months (non-regulatory processes)
9. AER revenue approval	10 months (incl Clause 5.16.6 assessment + contingent project assessment)	4 months (contingent projects) AER should already have a lot of information about the project
10. Implement the investment	Depends on size of the project	Depends on size of the project (TNSP could commence this process in parallel with Stage 9)
11. Safety net	Process would start from Stage 5	Process would start from Stage 5
Total	**47 months/3.9 years** (not including non-energy regulatory processes and building assets)	**27.5 months/2.3 years** (not including non-energy regulatory processes and building assets)

Source: Timing for the current process is based on requirements under the NER.
Note: Timing for the actioned ISP has been estimated based on the efficiencies that will be achieved throughout the process.

3.4.4 Central features of potential models linking the ISP and transmission investment decisions not pursued by the Commission

There are a number of features of the options proposed by the Commission in the options paper, and put forward by stakeholders in their suggested variations to those options, that were not included in the actioned ISP process.

Weaker link between the ISP and the TNSP investment decision process

The Commission considers that the link between the ISP and transmission investment decisions needs to be stronger than it is now, and indeed stronger than that proposed in option 1, detailed in Section 3.2. Simply requiring TNSPs to consider ISP-identified investments in their TAPRs would not necessarily ensure that the regulatory process would be commenced for ISP-identified needs. Option 1 also does not achieve some of the streamlined benefits described in Section 3.4.2 that the Commission considers improve the current transmission planning and investment process.

Cost-benefit analysis undertaken as part of the ISP, or a test that does not identify the net market benefit of projects

The Commission's view is that TNSPs are best placed to undertake the detailed, cost-benefit analysis of credible options designed to meet an identified need in the ISP. Option 3 articulated by the Commission in the options paper, as well as some suggested models from stakeholders, propose that the cost-benefit analysis of credible options be undertaken as part of the ISP. The Commission considers that this part of the process should be undertaken by TNSPs as part of their investment decision process. TNSPs have local knowledge that will inform how strategic projects can be carried out, and they can incorporate more up to date inputs, which retains flexibility in the process to respond to the changing market.

Similarly, TNSPs undertaking the cost-benefit analysis, while incorporating inputs and credible options identified by AEMO, maintains a level of separation between the planning and investment decision process that the Commission considers is important. As the parties who will ultimately make investment decisions and implement these projects, TNSPs should undertake the cost-benefit analysis to ensure they have confidence that the investments are efficient for their networks, which ultimately serve consumers.[42]

The Commission considers that a cost-benefit test that simply seeks to identify a least cost solution to address an identified need does not necessarily result in an efficient outcome for consumers. While a least cost option might be identified, it does not mean it is an efficient investment that provides a net market benefit - it may still result in a net cost to consumers. Our view is that the current RIT-T cost-benefit analysis that seeks to identify the option that provides the best net market benefit should be retained in the streamlined RIT-T detailed in Section 3.4.2.

AEMO makes the investment decision for a project

The Commission considers that the decision to invest in a transmission project should be made by the entity (i.e. the TNSP) that is required to implement it. Options 4 and 5 articulated in the options paper, as well as several submissions received from stakeholders, including AEMO, propose that AEMO direct transmission investment decisions. The Commission considers that it is not appropriate for AEMO to direct a TNSP to either make a decision to implement a preferred option, or to actually build a project that AEMO has determined must proceed through the ISP process. Under such a provision, it is possible that AEMO would require a network business to implement actions that it does not consider are in its own best interest. Limiting the incentive for TNSPs to minimise costs is not in the long-term interests of consumers as it would decrease capital and operational efficiency by further separating transmission system planning from ownership and operations.[43] Taking the decision-making power away from TNSPs would be inconsistent with the incentive based regulation framework and increase the risk that consumers would be required to pay for inefficient investments. Compelling TNSPs to invest in ISP projects could conceivably make

42 The actioned ISP requires that TNSPs "check" with AEMO that any additional credible option/s, as well as the preferred option, address the system-wide needs identified through the ISP.

43 AEC, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.2.

them more reluctant to invest in non-ISP projects, such as local projects, if they are not willing to take on any more risk.

In its submission to the options paper, AEMO proposed a model for implementing the ISP that would involve AEMO running a contestable process to build a particular project if the incumbent TNSP in the region declined to invest in it.[44] This is addressed below.

Need for contestability

Some stakeholders raised the idea of incorporating contestability into the framework, suggesting that it will increase innovation and decrease costs. The Commission has recently introduced contestability in the framework allowing third parties to build and own connection assets, even where these form part of the shared network. However, the Commission made sure that the operation and control of these assets is still undertaken by the TNSP, maintaining that there is one party that remains accountable for outcomes on its network.

Therefore, in the NEM currently, there exist frameworks for contestability:

- Anyone can build and construct transmission infrastructure. Indeed, as recognised by several TNSPs, including TransGrid, TNSPs typically competitively tender out construction of all of their assets. As noted above, there is contestability in the connections framework.
- Merchant TNSPs - Market Network Service Providers - can be constructed between regions, if the owner and operator of these considers that they can make a business model of the inter-regional price differentials that exist. At the moment there is only one Market Network Service Provider in the NEM, although there has been increasing talk of merchant interconnection.

Introducing broader contestability would blur the incumbent TNSP's accountability for the operation of the shared network, potentially affecting end-user consumers. Given the criticality of system safety, reliability and security, accountability for outcomes on the shared transmission network should be clearly defined - clear, singular accountability means that there is no question as to who:

- is ultimately responsible for the safety, reliability and security of the shared transmission network, including who is responsible for resolving any issues
- to contact in the event that there is an issue identified with certain assets, including who AEMO should direct if it needs to do so to support power system security
- is responsible for mitigating particular risks, for example, performance risks and any incentives or penalties that are applied through regulation or contracts.

The above examples of contestability preserve these principles. For example, Market Network Service Providers are separated by a connection point. In contrast, shared network assets are embedded within, and operate in concert with, the overall shared transmission system.

Further, in the Commission's recent determination on transmission connection and planning arrangements, the Commission undertook a survey to better understand the scope for

44 AEMO, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.14.

contestability in each of the services. The survey found that construction costs were most significant, and also had the most scope for contestability, including in innovation.

If contestability was to be considered further, it would be important to make sure the above principle is not compromised. The extent to which the market would be contestable would also need to be considered. Contestability is only a substitute for economic regulation where the market is sufficiently competitive. With limited competition, a contestable process would not necessarily lead to a lower cost outcome, and may indeed create a perverse incentive for the incumbent TNSP to decline to invest and then enter the contestable process with the understanding that it may receive a greater return by having all of its costs recovered via a direct cost pass through to consumers.

4 PLANNING: IMPROVING THE COST-BENEFIT TEST FOR TRANSMISSION

RECOMMENDATION 2: STREAMLINING AND IMPROVING UNDERSTANDING OF THE COST-BENEFIT TEST

Actioning the ISP will necessarily change the current cost-benefit test in the NEM for transmission - the RIT-T. For example, the steps that are currently undertaken through the current project specification consultation report of the RIT-T will now be undertaken through the ISP. Further, the RIT-T will use the inputs, assumptions and scenarios developed in the ISP as a starting point. And, the credible options that will be considered under a RIT-T will be limited.

However, in addition to these changes, the Commission also considers there are a number of other changes that should occur that focus on streamlining and removing duplication from the cost-benefit process for transmission.

The Commission recommends that:

- The recommended model to make the ISP actionable is adopted, since this will speed up and streamline the cost-benefit test process for ISP projects.
- The AER submit a rule change request to the Commission to remove clause 5.16.6 (where the AER makes a determination as to whether the preferred option satisfies the regulatory investment test) from the NER. This will streamline and reduce the time it takes to complete the transmission planning and investment decision-making process.
- The AER submit a rule change request to the Commission to reduce the time-frame associated with completing the project assessment draft report of the RIT-T from 12 months to nine months, which will further reduce the time associated with the transmission planning and investment decision-making process.

4.1 Background

Transmission assets can be very expensive, and, once built, consumers pay for them over the life of the asset, which may be decades. The process to minimise the risk that consumers pay for inefficient investments must therefore be rigorous and transparent.

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

the RIT-T. The transmission business must consult with stakeholders when undertaking a RIT-T.

4.1.1 What is the RIT-T designed to achieve?

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

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

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

The above isn't really a purpose, but more a description of how the RIT-T operates. The current access arrangements in the NEM mean that the cost of investment in assets that provide shared transmission services is recovered from consumers. Since transmission is an extensive, capital intensive business, network services in a particular region can be most efficiently provided by a single monopoly supplier. Given that electricity networks are a natural monopoly, the revenue for providing those services is regulated by the AER to ensure that expenditure is efficient.

The RIT-T is a cost–benefit analysis framework that network businesses must apply and consult on before making major investments in shared transmission assets in their networks to address an identified need. When undertaking RIT-Ts, network businesses must give due consideration to what credible options are out there to meet the identified need, before identifying the best way to address needs on their networks. The NER refers to this optimal infrastructure investment as the 'preferred option.' The preferred option is the credible option which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the relevant market.

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

BOX 1: WHY DOES THE RIT-T TAKE A MARKET BENEFITS APPROACH?

Prior to NEM commencement, the National Electricity Code described a customer benefits test for transmission investment. This test required that, before developing a new transmission project, a TNSP demonstrated that the consequential benefits received by "customers" should exceed the project cost. However, in light of Australian Competition and Consumer Commission concerns that such a test was unclear, inefficient and unworkable, the test was replaced by a regulatory test based on a conventional cost-benefit analysis, from which the current RIT-T has evolved. The difference between the two types of tests is that generator sector benefits and costs are excluded from the customer benefit tests, but included in the market-benefits test.

A market benefits test was deemed more appropriate since:

- A market-wide cost-benefit test promotes the NEO because it attempts to limit or prevent the possibility of inefficient transmission investment decisions to ensure efficient development of commercial generation investment with efficient transmission investment. In competitive markets, savings or benefits that accrue to the generation sector should flow through to consumers. Therefore, allowing these benefits to be captured in the market-wide test recognises this.
- Market-wide cost-benefit tests face less measurement problems than customer benefits tests because these rely on a cost-benefit analysis framework rather than needing to estimate what proportion of wholesale market price changes will get passed on to retail customers. Relying on market prices is problematic if these prices do not reflect competitive market behaviour and may include distortions due to the use of market power. In any case, if there was sufficient competition in generation for benefits to be passed onto consumers through prices, then customer and market benefits tests should yield equivalent estimates.
- A market-wide cost-benefit analysis is better for promoting competitive neutrality. A customer benefits test only considers those costs/benefits that accrue to consumers; and so treats customers differently to other participants in the electricity sector such as generators. Therefore, they are not being considered on a level playing field.

On a pragmatic point, while estimating expected changes in retail prices or affordability is an intuitively appealing concept, it is difficult to understand how practical or informative this would be in practice. An efficient net present value positive investment (i.e. where the benefits outweigh the costs to those who consume, produce and generate electricity) should reduce prices overall, all other things being equal.

However, since any costs or negative price impacts of an investment will likely flow to consumers at different times to when the benefits or positive price impacts will, the net price impact of any investment should vary over time.

A logical way to measure whether the investment will have a net beneficial price impact over its life would be to discount the costs and benefits over time. While, with additional assumptions, one might attempt to transform this into expected differences in price weighted over the life of the investment, this would only be a by-product of the market-wide cost benefit analysis rather than providing any different or better insights.

While other jurisdictions may have consumer benefits tests, this is typically either a supplement to a net market benefits test; or is used in jurisdictions where the network and retail sectors are not vertically disaggregated (like in Australia).

4.1.2 How does the RIT-T fit into the broader regulatory framework?

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

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

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

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

TNSP revenue proposals can also include significant network projects that may be reasonably required to be undertaken, but which are excluded from the ex-ante capital expenditure allowance in a revenue determination because of uncertainty about their requirement, timing or costs. These have the effect of enabling network revenue to be adjusted within a business's regulatory determination period. These are known as contingent projects.

Contingent projects are large discrete projects that are somewhat uncertain in terms of their need or timing at the start of the regulatory period.

In TNSPs' revenue determinations, the AER can approve proposed contingent projects and associated trigger events that would satisfy a contingent project application to the AER. Should the trigger event occur, a TNSP may apply to the AER during the regulatory period to amend the revenue determination to increase the business's allowed revenue to take account of forecast capital expenditure and incremental operating expenditure for the project.

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

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

4.2 Overview of stakeholder submissions to the options paper

The options paper sought stakeholder views on a number of elements associated with the RIT-T, including what benefits should be considered in the RIT-T; timing of the RIT-T; and the role of a dispute process in the RIT-T.

Stakeholders had mixed views on the RIT-T. Those stakeholders that sat towards the left of the spectrum of options for making the ISP actionable described in section 3.2 typically were in favour of recognising the benefits associated with the existing RIT-T arrangements:

- Some stakeholders pointed to the COAG Energy Council's recent review of the RIT-T, which found that the RIT-T in its current form remains the appropriate mechanism to ensure that new transmission infrastructure in the NEM is built in the long-term interests of consumers, and is appropriate to facilitate strategic interconnection investment decisions.[45]
- Nearly all stakeholders recognised that it is an important tool for protecting consumers from inefficient investments. The cost-benefit assessment process that TNSPs are required to undertake when examining credible options to address identified needs on their networks is designed to determine the project that is going to provide the best net

45 For a more comprehensive summary of the review see Box 4 in the AEMC's options paper for this review. EUAA, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.2; AEC, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.304; Consumer Challenge Panel - Sub-Panel No. 20, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.4.

market benefit. Indeed, the EUAA noted that a "lengthy timetable is an indication of a thorough process... faster is not always better."[46]

In contrast, and not surprisingly, those stakeholders that sat towards the right of the spectrum for options for making the ISP actionable did typically not consider that the existing RIT-T arrangements were suited to the energy transformation that is occurring:

- Some considered that the RIT-T process drives incremental investments. The concern from these stakeholders is that the current RIT-T is not designed to assess and facilitate investment in strategic projects that are required to connect new renewable generators across the NEM in a coordinated way.[47]
- Stakeholders also considered that the RIT-T is not appropriate for considering strategic investments. The concern around this issue is that the RIT-T is not able to assess the strategic benefits that a particular project, such as one that provides benefits across multiple NEM regions, is able to deliver to the market. Another aspect of this concern is that the RIT-T is not able to take into account the benefits that would flow from over-sizing transmission augmentations, to allow for the connection of renewable generators into the future, for example.[48]

More specific stakeholder views on the RIT-T are summarised in each of the sections below.

4.3 RIT-T benefits

4.3.1 Background

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

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

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

To assist TNSPs in completing a RIT-T, regulatory investment test application guidelines are required to be developed, published and reviewed by the AER. These guidelines provide guidance and worked examples on the use of the regulatory investment tests. The AER

46 EUAA, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.11.

47 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: Snowy Hydro pp.1-16; RES Australia pp.8-9; TransGrid p.8.

48 Ibid.

recently reviewed these guidelines to ensure they are useful to TNSPs and other stakeholders in understanding how to apply the RIT-T.

4.3.2 Overview of stakeholder views on this matter

The majority of stakeholders considered that the current benefit categories in the RIT-T are appropriate, with some recognising that the current RIT-T framework provides significant flexibility as to what benefits may be approved by the AER to be considered in the RIT-T provided they relate to the benefits for those who consume, produce and transport electricity in the NEM.

Some stakeholders suggested additional categories that could be incorporated into the RIT-T:

- environmental or facilitating a reduction in carbon emissions should be factored in
- generator investor risk should be included
- strategic benefits outside the electricity sector should be included
- system strength benefits should be included.

In addition, TNSPs noted that high impact, low probability events are not adequately captured in the RIT-T analysis.

Many stakeholders considered that the RIT-T does not adequately consider in which regions the benefits of an investment fall, and therefore which regions should pay for the investment. This is considered further in Chapter 7.

4.3.3 Commission's conclusions and recommendations

Environmental benefits

Some stakeholders noted that the RIT-T should be able to facilitate a reduction in carbon emissions. The RIT-T already captures the economic value of environmental policy. For example, Australian has an international commitment to 26-28 per cent emissions reduction by 2030, even though there is no current government policy to achieve this. However, when planning for transmission, parties can assume that NEM emissions will reduce pro-rata to this legislated level to 2030, and that post 2030 international targets will decline at a similar gradient. This assumption can then be operated within the model as a fixed carbon constraint over the period.[49]

Similarly, the effect of the Renewable Energy Target can also be incorporated in the RIT-T analysis. Where a state government has also introduced a renewable target and has a legislated mechanism to bring it to fruition, such as the Victorian Renewable Energy Target, it is similarly possible to incorporate this into the test, by effectively adding it to the national RET target.

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

49 Similarly, if the National Energy Guarantee was to be implemented then the wholesale costs of electricity would incorporate the costs of this policy through market modelling conducted consistent with this policy.

considered would be useful. Providing clarity on this was a key area of focus for the AER in its review of the RIT-T application guidelines.

Generator investor risk

As described in Chapter 6, currently the NEM does not provide a mechanism for parties to enhance the shared grid and manage congestion. Therefore, generators only pay the costs of the assets necessary to facilitate their connection, and nothing else. Generators bear the risk of being constrained off, or generators connecting in alongside them. The extent to which generators are constrained off should be incorporated in the fuel costs estimated in wholesale market modelling for the RIT-T. However, in return, they do not pay for anything on the shared network. Therefore, these risks are already factored into the RIT-T, consistent with the open access regime under the current framework.

Strategic benefits outside the electricity sector

The Commission does not consider it is appropriate for the cost-benefit test to consider broader societal benefits, such as jobs and growth, since:

- 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. Governments can provide capital contributions consistent with those benefits towards projects to increase their net economic benefits. This effectively allows non-NEM benefits to be captured in the analysis, whilst ensuring that electricity customers only pay for efficient expenditure associated with their electricity supply.
- It avoids the measurement problems associated with casting the benefit too widely, including with the need to identify and estimate indirect benefits.

The second point was recognised by the Finkel Review, and was a driver behind recommendation 5.2 of that review, which considered:

> there may be a future role for governments in facilitating considered and targeted investments in network infrastructure to enable the efficient development of renewable energy resources. The AEMC should develop a rigorous framework to enable the evaluation of these projects, including guidance for governments regarding the circumstances that would warrant government intervention to facilitate specific transmission investments. This should minimise the risk of consumers bearing the cost of unnecessary transmission infrastructure.

This will be considered in detail in our *Coordination of generation and transmission investment* 2019 review.

System strength benefits

System strength in some parts of the power system has been decreasing as conventional synchronous generators are operating less or being decommissioned. This can mean that system strength is not sufficiently high to keep the remaining generators stable and connected to the power system following a major disturbance. The relative stability of the power system can also reduce when additional non-synchronous generators connect to the network.

In 2017, the Commission recently made a rule that requires:

- AEMO to develop a system strength requirements procedure from which it can determine the required fault level at key locations in each transmission network necessary for the power system to be maintained in a secure operating state
- where a system strength shortfall exists, an obligation on TNSPs to procure system strength services needed to provide the fault levels determined by AEMO, which AEMO then enables as needed
- AEMO to develop system strength impact assessment guidelines that set out a methodology to be used by network service providers and generators when assessing the impact of a new generator connection on system strength
- new connecting generators to 'do no harm' to the security of the power system, in relation to any adverse impact on the ability to maintain system stability or on a nearby generating system to maintain stable operation.

Some stakeholders have queried whether benefits associated with system strength can be estimated under the RIT-T. System strength benefits can be estimated under the RIT-T. For example, if there is a constraint in a region due to system strength, then this would be included in the base case. The impact of credible options on the existence of the constraint or limit could be modelled through the RIT-T. In this way, the market benefits associated with system strength can be modelled. Such an approach was taken by ElectraNet in their South Australia Energy Transformation project assessment draft report, where they estimated how options could alleviate the cap on the level of non-synchronous generation that may be on-line in South Australia to ensure adequate system strength.

Therefore, the Commission does not consider the RIT-T needs to be changed in order to address this concern.

High impact, low probability events

This is a matter that was recently reviewed by the AER in their RIT-T Application Guidelines review. In its draft guidelines, the AER provided more guidance as to how the RIT-T can account for high impact, low probability events via its scenario analysis. In summary, RIT-Ts should capture these events by:

- Including a reasonable scenario where the high impact, low probability event occurs.
- Costing the impact of that high impact, low probability event occurring. In costing this event, we would expect the RIT proponent to include in the market benefit category changes in involuntary load shedding using a reasonable forecast of the value of electricity to customers. As a practice, the RIT proponent would use a measure of the value of customer reliability to reflect this value.

- Weighting the economic impact of the event by a reasonable estimate of its probability of occurring.

Therefore, the RIT-T should already adequately capture these events.

4.4 Length of the RIT-T process

While the length of the RIT-T process is often focussed on getting transmission infrastructure constructed, getting projects built requires more than just the RIT-T or other regulatory processes to be completed. There are post RIT-T processes, which are often confused with the RIT-T process. These are also discussed in this section.

4.4.1 Background

The RIT-T process is centred on stakeholder engagement and consultation, providing multiple opportunities for stakeholders to be involved and provide input. The three stage consultation process involves:

1. A project specification consultation report: the RIT–T proponent must make the consultation report available to all registered participants, AEMO and interested parties and invite submissions.
2. A project assessment draft report: if a RIT–T proponent decides to proceed with the proposed transmission investment, it must prepare a draft report within 12 months after the consultation period on the consultation report (or a longer period agreed to by the AER in writing). This draft report can be included as part of a TNSP’s annual planning report. As with the consultation report, the RIT–T proponent must make the project assessment draft report available to all registered participants, AEMO and interested parties and invite submissions. While the NER provides a time-frame within which the project assessment draft report must be published, TNSPs can complete this stage in less time if they wish to.
3. A project assessment conclusions report: the conclusions report must be published as soon as practicable after the consultation period for the draft report. The RIT–T proponent must make available its conclusions report to all registered participants, AEMO and interested parties. A RIT-T proponent can include the conclusions report as part of its annual planning report.

The table below shows the time-frames of the RIT-Ts that have been completed to date.

Table 4.1: Timing of RIT-T process

PROJECT	TIME TAKEN TO COMPLETE RIT (CONSULTATION REPORT TO FINAL REPORT, MONTHS)	TIME TAKEN FOR APPROVAL OF NETWORK REVENUES (FINAL RIT-T REPORT TO AER REVENUE APPROVAL DATE, MONTHS)	TIME TAKEN TO COMPLETE PROJECT WHERE COMMISSIONED
Projects with capital cost in excess of $41m			
AEMO - Regional Victoria Thermal Capacity – Ballarat and Bendigo	14	n/a AEMO project, so no economic efficiency test or approval of revenues	commissioned
AEMO/ElectraNet - Heywood interconnector	15	14	27
Powerlink, TransGrid - Qld to NSW interconnector	29	did not proceed after RIT-T final report	
TransGrid - Powering Sydney's Future	13	6	not yet commissioned
ElectraNet - Eyre Peninsula Electricity Supply Options	18	not yet approved	not yet commissioned
Projects with capital cost less than $41m (projects with a value of more than $41m, can skip the project assessment draft report stage)			
AEMO - Victorian Reliability Support (deferred after final report)	4	did not proceed after RIT-T final report	
ElectraNet: Dalrymple substation upgrade	7	6	42
Powerlink - Addressing the secondary systems condition risks at Baralaba Substation	6	not yet approved	not yet commissioned

4.4.2 Overview of stakeholder views on the length of time

Typically, most stakeholders that commented on this saw the length of the RIT-T process as appropriate. For example, Origin Energy noted that the RIT-T has an important role to play in assessing projects, and managing risks for consumers that pay for investment. Origin does not support any move to arbitrarily shorten the test given the complexities of the issues under consideration and the time needed to complete a robust and transparent process.[50]

In contrast, the South Australian (SA) Government considered that the RIT-T process can take far longer than can be considered reasonable.[51] It went on to say that the maximum time frames provided under the NER for the RIT-T process are too long and should be considered by the AEMC in this review as an opportunity to help accelerate investment in infrastructure. Further, the SA Government stated that the AEMC should consider opportunities to improve time frames for projects where the AER assesses the analysis undertaken through the RIT-T, the project is the preferred option under the RIT-T, and the AER then undertakes a further process to assess the capital expenditure to be added to the business' revenue.

Stakeholders also recognised there are other non-NER factors driving time-frames. For example, AGL noted that other sectoral laws and regulations, and closer engagement with responsible jurisdictional planning infrastructure and environmental authorities in NEM states and territories, may alleviate some of the delay and perceived risks.[52]

4.4.3 Commissions conclusions and recommendations

RIT-T analysis

On the one hand, the time taken to complete the RIT-T process is a function of the analysis that must be undertaken. Working up options for investment - including non-network options - to meet the identified need takes some time. In addition, market modelling must be undertaken to compare the market benefits of each option by looking at market outcomes. Assumptions must be finalised, options worked through, and running the actual model takes time. The recommendations to action the ISP will speed up these parts of the cost-benefit process by removing duplication, and streamlining the process.

The incorporation of the identification of credible options (currently done through the RIT-T project specification consultation report) into the ISP results in a streamlined RIT-T process. Allowing TNSPs to use ISP scenarios, inputs, assumptions and credible options for the streamlined RIT-T removes duplication from TNSPs having to formulate all of these again. Under the Commission's recommended model, robust and transparent consultation is conducted at every planning and investment decision step. This can be expected to increase confidence in transmission investment decisions, and minimise the chances of a dispute at the end of the process.

50 Origin Energy, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.4.

51 SA Government, submission to the options paper, *Coordination of generation and transmission investment*, 4 December, p. 2.

52 AGL Energy, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.3.

In addition, the Commission notes that clause 5.16.4(j) of the NER sets out that a TNSP has to publish the project assessment draft report for the RIT-T within 12 months of the end date of the consultation period on the project specification consultation report. However, given the current state of the market where new generation such as solar or wind can be built with very short lead times, the Commission queries whether this time-frame is still appropriate.

A similar issue was recognised by Energy Networks Australia commenting on the draft rule for the *Generation three year notice of closure* rule change, where they recognised the disconnect between the time-frame for new generation build and the time-frame for new transmission investment build.[53]

Therefore, the Commission recommends that the AER should submit a rule change request to the Commission that will change this time-frame from twelve months to nine months. This will speed up the time taken to complete the RIT-T.

Stakeholder consultation

Significant time is included in the process for stakeholder consultation. A key function of the RIT is that it creates transparency and confidence in the regulatory process by seeking stakeholder input. However, as discussed in the ISP chapter, trust and confidence in the process is achieved through having robust stakeholder consultation. Therefore, we do not consider that the time-frames associated with consultation for the RIT-T should be shortened.

We expect however, given it is part of our recommended approach, TNSPs will use the scenarios, needs, inputs and assumptions developed in the ISP as a basis for the RIT-T. This should minimise the disagreement that stakeholders and TNSPs may have over these things when the RIT-T is undertaken. This should also address the concern that the current uncertainty in the NEM creates challenges for the RIT-T process.

Post RIT-T revenue approval

The economic regulatory regime allows for limited circumstances in which network revenue can be adjusted during the five-year revenue determination process.

One way in which this can happen is through the contingent projects mechanism. This is applied to large discrete projects that are uncertain in terms of their need or timing at the start of the regulatory period. If they are considered necessary during the regulatory period (on the basis of a pre-determined trigger, which is specified in the TNSP's determination), the AER must then make a decision as to whether the trigger events for the contingent project have occurred. The AER must also determine the amount of capital and operating expenditure reasonably required to undertake the project and the impact of allowing such expenditure as revenue.

Most of the projects identified in the ISP have been identified in TNSP's revenue determinations as contingent projects. One way in which the time associated with this would be sped up is for businesses to involve the AER through the process of undertaking the RIT-T.

53 ENA, submission to the draft rule determination, *Generation three year notice of closure*, 27 September 2018, pp.1-2.

For the contingent project trigger event to be satisfied for most contingent projects that the AER has approved in recent revenue determinations, the AER will need to be satisfied that the RIT-T has been successfully completed before a TNSP submits a contingent project application. The AER determines this through undertaking a 5.16.6 determination.

BOX 2: OVERVIEW OF A 5.16.6 DETERMINATION

After the expiry of the period that parties have to dispute the RIT-T, and where a preferred option is not for reliability corrective action, the RIT-T proponent may request, in writing to the AER, that the AER make a determination as to whether the preferred option satisfies the regulatory investment test for transmission.

If this occurs then the AER:

- must, within 120 business days of receipt of the request from the applicant, make a determination, and specify reasons for its determination
- must use the findings and recommendations in the project assessment conclusions report in making its determination
- may request further information from the RIT-T proponent
- may have regard to any other matter the AER considers relevant.

Therefore, the completion of these determinations typically take around six months to complete.

Therefore, in practice, if this is undertaken it adds another six months to the process, before the TNSP can submit a contingent project application. TNSPs are unlikely to start stage 10 in section 3.4.2 (implementing the investment) until they receive revenue certainty, which is obtained by the successful completion of the contingent project process. The AER has 40 business days (two months) to complete the contingent project assessment. This can be extended by an additional 60 business days (three months) in complex cases.

The contingent project assessment sets the capital expenditure that is to be included in the existing revenue determination, and adjusts the business's revenues accordingly.

The Commission considers that the existence of the 5.16.6 determination adds unnecessary time to the RIT-T process, and can inhibit the timely building of transmission infrastructure. Therefore, the Commission recommends that criteria should be removed from the NER in order to remove six months of the transmission planning and investment decision-making process. The AER should submit a rule change request to give effect to this.

It is also worth mentioning that a similar determination does not exist in the RIT-D, and so this will align and promote consistency across the transmission and distribution planning and investment decision-making frameworks.

Post NER processes

Many stakeholders recognised that the non-NER processes, such as jurisdictional planning and environmental approvals also add time to the investment decision-making process. These are clearly outside the scope of the regulatory framework administered under the NER, but can be significant in the time taken to build transmission infrastructure since these often take around two years to complete.

Some jurisdictional governments have sought to address these non-NER processes. For example, the NSW Government will ensure that the state's planning and licensing frameworks support efficient and timely investment.[54]

In addition, there are a number of processes that exist that can be used by governments to speed up planning and environmental approvals. For example, all jurisdictions have variants on the project of state significance mechanism. This mechanism deems some developments to have state significance due to the size, economic value or potential impacts that the developments may have. Large, strategic investments that are identified in the ISP could be considered to utilise these processes. For example, Snowy 2.0 and the associated transmission project is designated by NSW legislation as critical state significant infrastructure.

In addition, TNSPs are reluctant to start to undertake some of these processes until they have revenue certainty from the AER. Some of our other recommendations will result in that revenue certainty being provided sooner. However, we also recognise that some jurisdictional governments are addressing this challenge themselves. For example, the NSW Government will provide a funding guarantee that will allow TransGrid to bring forward important preliminary planning work, including best placement of line routes, geo-technical studies and environmental, heritage and biodiversity assessments for the state's four priority transmission infrastructure projects.[55] This will:

- improve cost estimates used in regulatory approvals and reduce cost impacts on consumers
- bring forward the final delivery of priority projects by up to nine months.

4.5 Disputes for the RIT-T

4.5.1 Background

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

54 *NSW Transmission Infrastructure Strategy: Supporting a modern energy system*, November 2018.

55 Ibid.

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

There have only been two disputes to the RIT (both for distribution rather than transmission) process so far. In one of these disputes, the AER found that the network business had applied the RIT-D in accordance with the NER, and in the other the AER determined no amendment to the RIT-D final report was necessary.

4.5.2 Overview of stakeholder views on disputes

The majority of stakeholders that commented on this issue noted that disputes would be minimised if:

- Communities and stakeholders are more involved in the RIT-T throughout the process, recognising that this takes time. Engaging stakeholders from early on in the RIT-T process and undertaking robust and meaningful consultation should mean that their perspectives are addressed as a part of the process. Projects can be expected to be more successful when the local community has an opportunity to participate in key decisions. Ideally, participants should not feel pressured with a sense of urgency or that the decision has already been made and they have no real influence.[56]
- There was a more transparent consultation process, including the publication of stakeholder submissions, as well as responses to the issues that are raised in them.[57]

Stakeholders strongly supported a robust dispute process, and were opposed to removing it. However, some noted that transmission investment always has winners and losers, and this gets expressed through the dispute process.

4.5.3 Commission's conclusions and recommendations

The Commission considers that the existence of a dispute mechanism is an important component for an effective functioning regulatory regime. Indeed, the existence of a dispute mechanism provides a strong incentive for parties to undertake an effective process, with robust stakeholder consultation. The Commission agrees with stakeholders that the risks of a dispute are minimised the more involved stakeholders are earlier in the process.

The Commission also accepts the views put forward by some stakeholders that there are winners and losers associated with transmission infrastructure, and these parties can dispute outcomes, delaying the process. However, the Commission would observe that no RIT-Ts have been disputed to date, and so this does not seem a real concern.

Therefore, we do not recommend any changes to the dispute mechanism process.

56 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: Monash University p.17; RES Australia pp.9-10; Consumer Challenge Panel: Sub-Panel 20 pp.11-12.

57 These are measures that were proposed in the AER's draft RIT-T application guidelines. Energy Australia, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.2-3.

5 CONNECTION: RENEWABLE ENERGY ZONES

RECOMMENDATION 3: RENEWABLE ENERGY ZONES

The Finkel Review addressed the challenge of coordinating transmission network planning and renewable generation by focussing on the option of the development of REZs.

Measures to action the ISP, as explained in Chapter 3, will facilitate the development of REZs along nationally strategic transmission flow paths, i.e. AEMO's identification of when and where they are needed will be actioned. Furthermore, the RIT-T process (suitably improved through the recommendations made in Chapter 4) provides a mechanism for some other shared transmission projects. This chapter therefore focuses on those REZs that would not otherwise be developed as shared transmission projects following RIT-T or ISP processes.

The Commission has considered a number of options for implementing REZs throughout this review, including options stakeholders have suggested. Ultimately, the Commission has concluded that REZs should be implemented in the NEM through the Commission's recommendations with regard to making the ISP actionable (Chapter 3) and improving access and congestion (Chapter 6).

The Commission considers that the coordination of generation and transmission investment in general, including with regard to REZs, is best achieved by changing the access regime to one which would introduce more commercial drivers into transmission development. Changes to the access regime would enable better trade-offs to be made between the cost of transmission and the cost of generation in the development of REZs, and would align more of the risk of investment decisions with those who make them, and away from consumers.

Under these changes, REZs will emerge as a consequence of generators' and prospective generators' commercial locational investment decisions.

5.1 Background to REZs

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment through the development of REZs. It was envisaged that these REZs would facilitate the connection of new renewable generators to the transmission network in a scale- and cost-effective manner.

5.1.1 Current framework for REZs

While a "REZ" is not a defined term in the existing regulatory framework, the framework does have mechanisms to allow for the development of transmission infrastructure between areas with abundant renewable resources and the existing network. Indeed, the NEM currently has clusters of renewable generation around particular parts of the network, which could be considered REZs.

In considering what a REZ is, it is useful to consider the existing distinction between the shared transmission network and connection assets in the context of the existing open access regime.

Open access regime

Currently in the NEM, generators have a right to negotiate a **connection** to the transmission network, but no right to be dispatched to the **shared network** and so earn revenue in the wholesale market (this is otherwise known as "open access").[58] The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point, not the ongoing use of the shared transmission network to access the market.

Given this framework, a generator's access to the market price is intrinsically linked to its physical dispatch. Physical dispatch is determined by the NEM dispatch engine which takes account of, among other things, generators' bids and, importantly in the context of this discussion, the physical capacity of the transmission network.

When there are constraints (also known as congestion) on the transmission system, generators that would otherwise be dispatched are not dispatched ("constrained off"). As they are not dispatched, they do not receive access to the market price.

Reforms to access and congestion management are the subject of Chapter 6 of this report.

Connection assets

Under the existing framework, connecting parties are directly responsible for the payment of costs associated with any new apparatus, equipment, plant and buildings, or upgrades to existing apparatus, equipment, plant and buildings, to enable their connection to the transmission network and to meet their performance standards. For the purpose of this paper, these assets are defined as "connection assets".

Connection assets, which are used solely by one or more connecting parties, are paid for by that connecting party or parties.

There are already mechanisms in place in the existing regime to facilitate the coordination of connection assets, including from prospective REZs to the shared network. These mechanisms are:

- information provision, for example through the ISP and TAPR (discussed in more detail in section 5.2)
- the scale efficient network extensions (SENE) process and recent *Transmission connection and planning arrangements* (TCAPA) rule, which allow for generators to coordinate with

58 The Commission recently made a rule that establishes a transparent and efficient framework for the management of power system fault levels, also known as 'system strength', in the NEM. This has effectively started to move away from the open access arrangements. As part of this framework a new requirement was introduced on new connecting generators to "do no harm" to the security of the power system, in relation to any adverse impact on the ability of the power system to maintain system stability or on a nearby generating system to maintain stable operation, in accordance with AEMO's system strength impact assessment guidelines. For example, this could involve them paying costs to remediate the network for the impact they cause. For further information see: AEMC, *National Electricity Amendment (Managing power system fault levels) Rule 2017*, Rule Determination, 19 September 2017.

one another in the development of connection assets (discussed in more detail in section 5.3).

However, as discussed above, stakeholders have suggested, and the Commission agrees, that there may be barriers to the effective use of these mechanisms for the development of REZs, particularly those not identified through the ISP.

Shared network assets

In contrast to connection assets, generators are not responsible for the payment of costs associated with any augmentations to the shared transmission network for reasons other than to facilitate their connection.

While generators are able to fund the construction of shared network assets, they have substantial incentives not to do so due to the existing open access regime. Under the open access regime, no individual generator has preferential access to a shared network asset, even if the generator underwrote the transmission asset's construction, because access is determined by AEMO's dispatch engine. This creates a free-rider problem: each individual generator would prefer for other generators to underwrite transmission investment, to avoid the cost of doing so while enjoying the benefits that the transmission infrastructure provides to all generators.

As a consequence of this free-rider problem, shared network assets are typically funded directly by consumers through TUOS charges. To minimise the risk of inefficient expenditure, RIT-Ts are used to assess the appropriateness of investments, and consumers only pay TUOS consistent with the AER's regulatory determination process.

While connection of some REZs to the existing grid may be able to be justified through these processes as required for the provision of shared transmission services to customers, others may not as the benefits of incremental investment to the existing system may be more readily justified than investment to prospective areas of generation.

5.1.2 What is a REZ?

There are various possible definitions of what a REZ is. As such, the Commission has explored a number of options throughout this review for defining and implementing REZs. Options 1 to 4 in particular were outlined in the discussion and options papers:

- Under options 1 (enhanced information provision) and 2 (coordination of generators), REZs are given effect by generators collaborating together to create shared dedicated connection assets. This is already possible in the existing regime, although the Commission appreciates there may be barriers to their effective use given commercial sensitivities and incentives.
- A variation of options 1 and 2, Engie's proposed "transmission bond model", would define REZs in relation to bonds sold by TNSPs which would both require and entitle the bondholder to connect to the REZ.
- Option 3 defines REZs with reference to speculative expenditure undertaken by TNSPs to augment transmission capacity to a REZ. The speculative expenditure would be placed in a separate account to the regulatory asset base and only be recovered from consumers if

and when the expenditure is deemed by the AER to meet certain criteria (for example, it determines the expenditure is consistent with the capital expenditure objectives). TNSPs would receive a higher return on investment than applied to the regulatory asset base if and when the expenditure is recovered from consumers.

- Option 4 defines REZs with reference to prescribed transmission services that a TNSP must deliver. A TNSP would be required to provide transmission capacity to REZs.
- The clustering option would require or allow TNSPs to coordinate the connection of generation to REZs using an open season approach. At the end of the open season period, the TNSP would assess all applications received up to that point, and then plan the system and provide connection offers on a jointly optimised basis.

A summary of options 1 to 4 is provided in Table 5.1.

Table 5.1: **Summary of the range of options for REZs**

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

OPTION	OPTION 1: ENHANCED INFORMATION PROVISION	OPTION 2: GENERATOR COORDINATION	OPTION 3: TNSP SPECULATION	OPTION 4: TNSP PRESCRIBED SERVICE
the existing framework		significant commercial issues impede		

A more detailed explanation of these options, and analysis of their suitability, is provided in sections 5.2 to 5.7.

A number of other options were also suggested by stakeholders. These are briefly summarised and analysed in section 5.8.

5.2 Option 1: Enhanced information provision

5.2.1 Overview of option

The first option presented in the options paper is characterised by enhanced AEMO and TNSP coordinated planning to provide information to market participants on potential REZs for development by the market.

The Commission considers that this option can already be accommodated under the current regulatory framework as it applies to connections, which has a number of existing processes to provide better information to generators about where to connect:

- The ISP has provided information on optimal REZ development areas, which are supported by existing transmission capacity and system strength. The ISP sets out information to prospective connecting parties about where a good location to connect is (i.e. favourable resources, available land, and spare network capacity).
- The ISP is supported by TNSPs' TAPRs, which also provide information on good connection locations. The AER is currently developing a TAPR guideline, which aims to support the consistent provision of information by transmission businesses across the NEM. The TAPR guideline will provide generators and large transmission customers usable and consistent information that they need to make informed connection decisions.
- The Australian renewable energy mapping industry tool is a spatial data platform for the Australian energy industry that provides information to generators about capacity on transmission networks, provided by the Australian Renewable Energy Agency.

5.2.2 Stakeholder views on this option

The Commission's view that option 1 can already been accommodated by the existing connection framework was supported by several stakeholder submissions throughout this review. Submissions supporting REZs acknowledged that some degree of coordinated planning or information provision will be required in order to facilitate them, identifying the ISP as a suitable tool in this process.

However, a number of stakeholders also noted limitations with these existing processes. The Commission agrees that the provision of additional information through option 1 alone may not be sufficient to facilitate the necessary scaling of assets and coordination of parties. Furthermore, confidentiality provisions prevent TNSPs sharing information with multiple generators, which could be a barrier to coordination.

5.2.3 Commission's analysis and conclusions

Given this, our view is that this option alone will not sufficiently facilitate REZs consistent with the recommendation of the Finkel Review, without being combined with another option or model. This leads us to consider a model of generator coordination (option 2).

Some stakeholders have raised with us that in US systems, prospective generators are required to reveal information to the market about where and when they are connecting and locating. Stakeholders have suggested that this could assist in increasing information provision in the NEM. However, these arrangements are substantially different from the NEM. In the NEM, generators are concerned about revealing information due to the current open access framework, where a competitor could use this information to its advantage. In the US, there are typically generator queues, which process connection applications in the order that they are received. In this sense, a generator is less concerned about revealing information to the market, since it knows it has a guaranteed "slot" in the queuing, meaning that its connection application will be progressed before those submitted later.

In addition, AEMO is considering submitting a rule change request to the Commission that would allow AEMO to provide people with access to the information they need to develop or build grid-scale resources (such as a generating system, energy storage system or hybrid system) if they satisfy AEMO that this is their intent. This may also help address concerns around information provision.[59]

5.3 Option 2: generator coordination

5.3.1 Background

The second option for developing REZs presented by the Commission in the options paper involved generators coordinating to construct and build REZs.

As with option 1, the development of REZs under this option is possible under the current NER connection framework.

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

59 AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM*, November 2018.

In addition, the recent TCAPA rule further facilitates this option. The TCAPA rule is described in Box 3.

BOX 3: *TRANSMISSION CONNECTION AND PLANNING ARRANGEMENTS* RULE CHANGE

In 2017, the Commission made the TCAPA rule change to improve transmission connection and planning arrangements.

Transmission connection

The rule introduced greater contestability for the design, construction and ownership of transmission system assets used for connection, while at the same time making it clear that the incumbent TNSPs are accountable for providing a safe, reliable and secure transmission network. Specifically, the rule:

- better defines the assets and services required to facilitate a connection to the transmission network
- improves the clarity of the transmission connection process
- makes it clear and unambiguous that incumbent TNSPs have responsibility for the operation, maintenance and control of the shared transmission network, which promotes a safe, reliable and secure network for consumers
- introduces competition for the provision of services required to facilitate a connection to the transmission network, where this does not distort the accountability of the incumbent TNSP
- requires TNSPs to publish more and better information about how to connect to their network, and provide certain information to connecting parties on request
- strengthens the principles that underpin negotiations between connecting parties and incumbent TNSPs
- introduces a formal ability for either party to engage an independent engineer to provide advice on the technical aspects of a connection
- clarifies the process that applies to disputes about transmission connections
- provides a mechanism for third party generators to access the connection infrastructure
- provides a mechanism to transition the connection infrastructure to the shared network.

Allowing parties other than the TNSP to construct connection assets would more easily allow generators to coordinate through either themselves, or a third party. It also introduced the concept of a dedicated connection assets, and clarified that the services for new dedicated connection assets, including design, construction, ownership, operation and maintenance, can be provided on a contestable basis. This should therefore make it easier for generators to collaborate to share use of these assets.

Transmission planning arrangements

The rule also enhances the efficiency of the transmission planning arrangements and promotes a more coordinated approach to transmission planning. Specifically, it:

- requires TNSPs to include certain additional information in their annual planning reports, including about network constraints, load forecasting methodologies and changes since the last report
- requires the AER to develop a guideline to support consistency across transmission annual planning reports
- requires TNSPs to undertake joint planning on investments in other transmission networks to deliver market and reliability benefits in their own network.

5.3.2 Stakeholder views on this option

A number of stakeholders agreed with the Commission that generators can already coordinate connection through the SENE and TCAPA frameworks. However, stakeholders were overwhelmingly of the view that competitive tensions and commercial challenges act as a disincentive for generators to facilitate coordinated connections to the transmission network.

A number of stakeholders also noted that the coordination of generation can only be effective for connection assets. Access to assets within the shared network are subject to the existing open access regime, meaning that generators are unlikely to fund shared network assets (individually or in coordination with one another).

5.3.3 Commission's analysis and conclusions

Although the current NER allow the development of connection assets for REZs by generators coordinating, this will only occur if generators actually cooperate by sharing information in order to enable coordination of connections and investment in connection assets. The Commission shares the views of stakeholders that non-regulatory barriers may be impeding the practical use of this option in the current arrangements. Importantly, these issues cannot be addressed by the regulatory framework.

Furthermore, as noted by stakeholders, this option is unlikely to work for shared network assets because of the existing access regime. Under the existing regime, generators are provided insufficiently firm access rights to justify them making an investment in transmission augmentation, because the benefits of such investment can be enjoyed by other generators.

Consistent with most stakeholders' view, the Commission has concluded that while this option (alone, or in conjunction with better information provision through option 1) can theoretically lead to connection assets for REZs being built, non-regulatory issues, and the existing access regime, appear to preclude this option from practically facilitating REZs consistent with the recommendations of the Finkel Review.

5.4 Variation of options 1 and 2: transmission bonds

5.4.1 Background

In its May 2018 submission to the discussion paper, Engie outlined a possible mechanism for determining transmission investment for REZs, which it called "transmission bonds".[60]

Key features of Engie's model include:

- potential REZs would be identified through, for example, the ISP or TNSPs' own planning processes
- a TNSP would estimate costs for a potential transmission augmentation to a REZ
- the TNSP would issue transmission "bonds" of sufficient value to cover the estimated cost of the transmission augmentation - Engie's proposal notes that the bonds should be denominated as $/MW (notional capacity not firm capacity)
- prospective generators could purchase the bonds
- if sufficient bonds to cover the value of the transmission augmentation were sold, the augmentation would proceed. If the bondholder:
  - connects to the transmission augmentation, the value of the bond would be returned to it
  - does not connect, they would forfeit the value of the bond, which would be used to offset TUOS charges.
- if insufficient bonds were sold to cover the cost of the augmentation, the project would not proceed and bond holders would get the value of the bonds returned to them
- generators which are not bondholders would be unable to connect to the augmentation for a set number of years (say, three)
  - This attempts to avoid a potential "free-rider" problem whereby an individual prospective generator would prefer to wait for other prospective generators to purchase bonds so that the transmission augmentation proceeds, while avoiding risks associated with purchasing bonds. Were each individual generator to take this approach, no bonds would be sold and the augmentation would not proceed.

A more fulsome description of Engie's model can be found in its submission.

Engie envisaged that this mechanism would promote the optimal location and sizing of transmission augmentation because:

- only REZ areas with sufficient interest from generation projects would go ahead
- prospective generators would make an assessment of a range of factors and seek the best projects across the REZ areas available to proceed
- it would avoid inefficiencies of incremental transmission development to facilitate a REZ.

Furthermore, Engie noted that:

- customers will not bear the risk of speculative transmission development and stranded investments

60 Engie, submission to the discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, pp. 3-5.

- minimal regulatory changes would be required to implement the mechanism
- governments could explicitly subsidise transmission investment by purchasing bonds.

5.4.2 Stakeholder views on this option

The Commission summarised the transmission bonds mechanism in its September 2018 options paper.[61] This idea received some support from stakeholders, with a number of submissions to the options paper suggesting that the mechanism should be explored further, although little specific detail was provided on the mechanism itself.[62]

5.4.3 Commission's analysis and conclusions

We have considered the model further, given the stakeholder interest.

Building upon the benefits identified by Engie, the Commission also notes that unlike for option 2, the transmission bond mechanism does not depend on generators, who are in competition with one another, coordinating their actions. Instead, the decision to secure bonds for a given investment is made by each generator individually.

However, despite these potential benefits, the Commission has concluded that the model has some implementation challenges and so is not appropriate.

It is instructive to consider the nature of the "bond" product being bought, sold and owned.

In effect, the instrument is a guarantee on the part of the bondholder that if the TNSP does X, the bondholder will do Y or pay a "penalty" of $Z. Precisely defining X and Y may be practically and legally challenging, but simplistically:

- X approximates "build a transmission asset to the REZ"
- Y approximates "connect a generation asset (of certain size, characteristics, etc) to the aforementioned transmission asset/REZ".

In return, by buying the instrument, the generator is:

1. able to influence whether and where a transmission asset is built
2. given privileged ability to connect to the transmission asset/REZ.

Thinking about the instrument in this manner reveals two issues for the mechanism.

Can only complement, rather than replace, RIT-T

Because the instrument being bought and sold is not being used to pay for the transmission asset (other than in the case that the bondholder fails to connect to the transmission asset) it is not possible to rely on the sale of bonds to determine whether a transmission investment is efficient. Instead, transmission customers pay for the transmission asset through TUOS charges, meaning that a RIT-T process is:

- still required if the asset is treated as a shared network asset

61 AEMC, *Coordination of generation and transmission investment*, options paper, 21 September 2018, pp. 78-79.

62 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: Business SA p. 3; TransGrid p. 12; UPC Renewables p. 4; ERM Power p. 5; RES Australia p. 12; Clean Energy Council p. 4; PIAC p. 17.

- newly required, if the asset is treated as a connection asset (unlike for other connection assets, the asset is being paid for by consumers).

The model appears to assume that investment in a fully (or highly) utilised transmission asset is economically efficient. That is, the model assumes that provided the transmission asset is used because there is a commensurate amount of generation connected to the transmission asset, then investment in the transmission asset is in the interest of consumers.

However, this assumption does not appear to be correct. It is possible that a high cost transmission asset could be highly utilised but the total system cost to consumers would be inefficiently high.

For example, consider a possible REZ that is very remote from the existing transmission network and which has excellent renewable resources. Despite the high cost of the transmission asset because of the remote nature of the REZ, many prospective generators are likely to purchase bonds related to the REZ, because the transmission augmentation would provide them access from the excellent renewable resources to the market. Of course, the generators are not paying for the transmission augmentation itself — only promising to pay for the transmission asset if they fail to connect, which they are relatively unlikely to do given the strength of the renewable resources in the REZ. Instead, the cost of the transmission asset is likely borne by consumers through TUOS. It is therefore possible that the transmission augmentation is inefficient overall because of the high cost of the transmission asset despite being highly valued by prospective generators.

The sale of instruments could instead inform a RIT-T, rather than replace it. The TNSP and AER in undertaking and assessing a RIT-T could be confident that either:

- an instrument-holding prospective generator would connect, or
- it would forfeit the value of the instrument.

This may be better than the existing process, whereby forecasts of future generation connections are based on committed generators and estimates of non-committed generators undertaken by the TNSP and assessed by the AER. The mechanism would provide an additional avenue by which prospective generators could signal their intention to connect in a manner which the TNSP and AER could be confident.

Nevertheless, some benefits of the model as suggested by Engie appear based on it replacing, rather than informing, the RIT-T, and hence the benefits of the model may be somewhat diminished.

Outcome of model better achieved by changes to the access regime

More substantially, the Commission considers that the mechanism is a departure from the open access regime.

As outlined in section 5.1.1, the current open access regime can be simplistically defined as: “generators have a right to negotiate a connection to the shared transmission network but no right to be dispatched.”

Under Engie's model, the holder of the instrument would, in return for acquiring the instrument, be granted privileged connection rights to the REZ for a set period. This contradicts the existing open access regime. In effect, the instruments are a form of (non-firm) access rights:

- time-limited connection rights (and by extension, time-limited denial of connection rights to non-instrument holders)
- firmer (but not firm) access rights than current open access rights: if others are not able to connect for a period, this improves the likelihood of dispatch for existing connected parties through the dispatch engine, improving their access.

The nature of the non-firm access rights created by the Engie model do not appear preferable to either the existing open access regime or alternative changes to the access regime recommended in Chapter 6. For example, a prohibition of connections could result in connections that would otherwise be efficient from being delayed. This does not appear to be in the interest of consumers.

In order to address this issue, the prohibition on connections for non-instrument holders could be removed from the model, and so the open access regime remain unchanged. By buying the instrument the generator would still be able to influence whether a transmission asset is built.

However, this appears to create the very free-rider problem that Engie was trying to address through the prohibition of connections in its design of the mechanism. It seems unlikely that prospective generators would purchase the instrument (and take on a liability related to either invest in generation infrastructure or pay a "penalty") when it provides such little value to the prospective generator. It also seems likely that prospective generators would hold-off in the hope that another generator will take the risk, and then benefit from the transmission augmentation once constructed.

Indeed, this free-rider problem lies at the heart of why generator-funded transmission investment in the shared transmission network is practically implausible under the existing open access regime. Under the existing regime, generators are provided insufficiently firm access rights to justify them making an investment in transmission augmentation, because the benefits of such investment can be enjoyed by other generators.

The Commission understands that Engie put forward the transmission bond model as an alternative to changes to the access regime and the options put forward by the Commission for REZs in the options paper. The Commission welcomes Engie's innovative thinking, but on this occasion considers changes to the access regime discussed in Chapter 6 to be more appropriate than those contained in the transmission bond model.

5.5 Option 3: TNSP speculative investment

5.5.1 Background

The third option for developing REZs presented by the Commission in the options paper suggested that TNSPs make speculative investments to facilitate a REZ. That is, shareholders of TNSPs would bear some of the risks associated with transmission investment to a REZ.

Under current arrangements

Under current arrangements TNSPs can make speculative investments (that is, investments which have not been provided for in the allowed revenue as part of the AER's regulatory determination, or otherwise provided for through, for example, the contingent project process). However, in doing so, they would be exposed to risks and costs:

- If treated as providing connection services, the assets would not be rolled into the regulatory asset base and so the costs would not be recovered from consumers through TUOS charges. If the costs are also not recovered from connecting generators, the TNSP would not recover its costs.
- If treated as providing shared network services, under certain circumstances, incurred capital expenditure that does not meet the capital expenditure criteria may be excluded from the regulatory asset base and so not recovered from consumers through TUOS charges. [63] The capital expenditure criteria relate to the whether the expenditure is efficient, would have been incurred by a prudent operator, and based on realistic expectation of demand and cost inputs.[64]
- Even if the shared network investment is rolled into the RAB at the next regulatory reset, financing costs associated with the speculative investment would not be recovered by the TNSP, consistent with the capital expenditure sharing scheme.[65]

The effect of these mechanisms is to reduce the incentives for TNSPs to undertake speculative investments.

Potential change to the framework

As noted in the options paper, changes to the framework could be made similar to the mechanism for speculative investment set out in the National Gas Rules (NGR). This would provide stronger incentives for TNSPs to undertake speculative investments in shared transmission.

In the NGR, there is a mechanism that allows full regulation pipelines to undertake speculative investments and to include this expenditure in the capital base when circumstances change.[66] The NGR allow full regulation gas pipelines to create speculative capital expenditure accounts. This speculative expenditure is expenditure that does not conform to the regulator's assessment of what is appropriate at a given point in time but that can subsequently be approved due to changes in volumes or service charges. If, as a result of changes to volumes or service charges, the expenditure becomes approved by the regulator, the relevant portion of the speculative capital expenditure account (including a return that is approved by the regulator) can be rolled into the capital base at the commencement of the next access arrangement period. This would then allow the capital cost to be recovered through reference tariffs in the future.

63 NER, clause S6A.2.2A.
64 NER, clause 6A.6.7(c).
65 NER, clause 6A.5A.
66 NGR, rule 84.

5.5.2 Stakeholder views on this option

A number of stakeholders supported further investigation of this option. Others commented that there are likely to be practical difficulties in determining the appropriate rate of return to provide TNSPs for undertaking speculative investment.

5.5.3 Commission's analysis and conclusions

The intention of this option is that:

- TNSPs would be incentivised to bear more of the risk associated with REZ development, by receiving a higher return on investments that are ultimately (with the benefit of hindsight) in the interest of consumers, while
- consumers would be protected from the risk of stranded assets because they do not pay for the asset if an investment is ultimately (with the benefit of hindsight) not in their interest.

However, there appear to be a number of substantial drawbacks to this option.

On 27 November 2018 a Bill (the Bill) containing legislative amendments on binding rates of return was assented by the Governor of South Australian after being passed by the South Australian parliament.[67] The legislative amendments remove heads of power for the Commission to make rules regarding the determination of a rate of return. The amendments implement a binding instrument that sets out a single approach to the calculation of rate of return parameters for all regulated electricity service providers and all full regulation pipelines; and which is developed through a single, industry-wide process every four years.[68]

On 28 September 2018, the COAG Energy Council published proposed rule changes to support the introduction of the binding rate of return legislation. As a consequence of the passage of the Bill, the Commission has formed the view that it will be unable to implement option 3, because it would require a different rate of return to be applied to the speculative capital expenditure than for other capital expenditure recovered through the regulatory asset base.

These legal challenges could conceivably be addressed, for example through further changes to the NEL. However, even if these challenges were addressed, the Commission does not consider that the mechanism is likely to deliver significant benefits.

Consistent with submissions from a number of stakeholders, a key difficulty for this mechanism is how to determine the appropriate higher rate of return for the investing TNSP.

In deciding whether to incur speculative capital expenditure, the TNSP would have to weigh up:

- the risk that going into the future, the regulator does not deem that the capital expenditure should be recovered from consumers (on the basis that, in the fullness of time and with the benefit of hindsight, the investment was not appropriate)

67 *Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Bill 2018*.

68 COAG Energy Council Senior Committee of Officials, Bulletin — Binding rate of return guideline: Senior Committee of Officials response to submissions on binding rate of return legislation, June 2018, p. 1.

- the prospect of the capital expenditure receiving a higher return if the regulator deems the capital expenditure should be recovered from consumers.

If the TNSP deems that the likelihood of the speculative capital expenditure being recovered is low (i.e. a relatively highly speculative investment) then it will require a higher return, reflective of the higher risk. Conversely, a relatively high probability of the speculative capital expenditure being recovered (i.e. a relatively low level of speculation) then it will require a lower return.

The TNSP may also be less likely to make speculative capital investment if the higher rate of return (or the premium over the rate of return applied to the regulatory asset base, e.g. the regulated cost of capital plus one percentage point) is not specified in advance. Not knowing higher rate of return in advance creates further risk for the TNSP and lessens the chances of it speculatively investing.

Assuming the AER determines the higher rate of return ex ante (i.e. before the investment is made), it would have to weigh up the prospective benefits to consumers if the investment is beneficial in the fullness of time against the likelihood that the benefits arise.

For example, an investment that has a low chance of being beneficial, and is highly valuable to consumers if it is beneficial, may be provided a relatively high rate of return. This reflects that:

- consumers would be willing to pay the relatively high cost of capital given the high benefits should they materialise
- TNSPs need to be provided a relatively high rate of return to incentivise them to invest, given the relatively high prospect that the TNSP will not recover its capital.

Conversely, an investment that is relatively likely to be beneficial (but not likely enough to justify its inclusion in the RAB from the outset) but which has relatively low prospective benefits would receive a relatively lower premium to the rate of return.

It is likely to be challenging for the AER to make this trade off, given it would be required to assess a plethora of likely future scenarios, for which the benefits and costs are difficult to predict.

Were the AER to set the return on capital too high, this would provide an inefficiently large incentive for TNSPs to invest and would mean that the costs recovered from consumers would be too high. Were the AER to set the return too low, TNSP’s would have a diminished incentive to undertake the speculative capital expenditure.

Given the practical difficulties associated with this option, as well as the current legal barriers to the determination by the AER of a rate of return different to that calculated under a rate of return instrument, the Commission is not recommending this option be implemented. In forming this view, the Commission also notes that despite this mechanism’s inclusion in version 1 of the NGR, it has not been exercised since the NGR has come into effect. While this may be related to the specific design of the mechanism in the NGR (for example, there is no requirement for the regulator to specify what the rate of return will be ex ante), the Commission nevertheless considers that the lack of use in the gas regime may be indicative of its effectiveness in electricity.

5.6 Option 4: TNSP prescribed service

5.6.1 Background

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

5.6.2 Stakeholder views on this option

While there was some support provided for the TNSP prescribed service option in stakeholder submissions, the majority of feedback cautioned against using this model for REZ development due to the significant risk that consumers would be exposed to from the potential for underutilised transmission assets. In implementing an option that involved TNSPs undertaking speculative investment on behalf of consumers, stakeholders warned that significant mitigation measures would be required to protect consumers from inefficient investment and stranded assets.

As the Commission outlined in the discussion paper for this review, a REZ approach that involves the development of the transmission network to influence where new generators should locate is significantly different to the current practice where a new generator connection request drives incremental augmentation of the transmission network. If a transmission investment that will deliver a prescribed transmission service is made on the basis of an expectation that new generation will locate in a particular area of the NEM, consumers will bear the risk that this expectation is wrong and the asset becomes stranded.

5.6.3 Commission's analysis and conclusions

Given this significant drawback, in the options paper the Commission stated that did not propose to consider this model. The Commission continues to consider that option 4 is not in the long-term interest of consumers.

The Commission also notes that option 4 is a change to the existing access arrangements. Some generators would be receiving subsidised connection assets, granting some generators with a "free" access right.

5.7 Clustering approach

5.7.1 Background

The options paper also raised a clustering option.

A clustering or group consideration of connections approach would allow TNSPs to coordinate generator connections based on what delivers the most efficient outcome. Rather than individual connection applications being approved on a sequential basis, the TNSP would establish a time window or 'season,' during which connection applications would be accepted, but not processed. At the end of the period, the TNSP would then assess all applications received up to that point as a group, planning the system and providing connection offers on a jointly optimised basis. Groups of generators could alternatively be clustered based on their geographic location, rather than through a connection season. To reap the benefits of the clustering approach, the season must be sufficiently long so that an appropriate number of connection requests accumulate but not so long as to unduly delay connection applications.

The intended objective of a REZ is to enable the coordination of the development of transmission and generation at the lowest cost. A clustering approach aims to achieve this objective by requiring the incumbent TNSP to assess the transmission augmentations needed, to connect generation projects and coordinate these based on what is most efficient. The main benefits of a clustering approach appear to be that the risk of not being selected by the TNSP to connect as part of a cluster, and presumably be charged lower connection costs than they would be subject to if they were to connect separately, would incentivise proponents to:

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

It is important to clarify that a clustering approach does not have to mean that a generator is refused the ability to negotiate access to the transmission network altogether because the TNSP determined that the proposed connection was not part of the group of connection projects that would deliver the most efficient augmentation outcome. The clustering approach just means that the TNSP would not connect the generator as part of a cluster, but would negotiate it outside the cluster, as is the current process (at presumably a higher connection cost).

5.7.2 Stakeholder views on this option

Stakeholders had mixed views on this option.

Some stakeholders considered there may be merit in the option as it would incentivise and facilitate collaboration between relevant parties.

However, stakeholders also identified drawbacks, including:

- the proposed 'season' for connections may prevent otherwise efficient generation connections proceeding, or inappropriately delay such connections
- it may be inconsistent with the existing access regime
- it may inappropriately favour the incumbent TNSP, and hence be inconsistent with the existing competitive provision of connection services.

5.7.3 Commission's analysis and conclusions

While the Commission recognises some possible benefits of this approach, on balance it does not recommend it, primarily because of concerns that the seasons will inappropriately delay connections. To work effectively, the seasons may have to be sufficiently long to allow for prospective generators to accumulate. However, in doing so, there is the risk that generation connections are not processed in a timely fashion.

5.8 Other options

A number of other options have been suggested by stakeholders throughout this review. It should be noted that these options were not necessarily supported by the stakeholders which suggested them, and at times were a "second-best" alternative to the stakeholder's preferred option.

Many of these options are described in greater detail in appendix B.5 of the options paper.

Changes to the access regime to facilitate REZs

A number of stakeholders suggested a variety of models for implementing REZs which involve changes to the access regime. In addition to Engie's transmission bond model discussed above, examples include:

- "trade-able" financial access rights or a form of access pricing (AEMO)
- co-contribution to deep augmentation costs (EUAA)
- a change to the access regime be implemented for REZs while retaining the existing open access regime for the rest of the network.

In general, the Commission considers the changes to the access regime recommended in Chapter 6 would more effectively facilitate REZs.

With specific regard to the idea of implementing changes to the access regime for REZs while retaining the existing open access regime for the rest of the network, the Commission considers that this option is unlikely to be feasible. Electricity flows on transmission lines consistent with Kirchhoff's laws.[69] As a consequence, on a meshed network (like the NEM), the dispatch of any particular generator can be influenced by the dispatch of all other generators on the network. That is, the physical effect of a particular generator's dispatch cannot be isolated to a particular part of the network. As a consequence, it may be that the dispatch of a generator outside of a REZ, operating under the existing open access regime, constrains off a generator with firm access within the REZ. Because the generator outside of the REZ is operating under the open access regime, there is no compensation available to pay the firm generator. In effect, there is no way to make access from the REZ firm without altering the access regime of the whole NEM.

EUAA's reverse contingency process[70]

69 Kirchhoff's laws are two laws of physics concerning electric networks in which steady currents are flowing. They were first described in 1845 by German physicist Gustav Kirchhoff.

70 Energy Users Association of Australia, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.7.

Under this model, as generators connect to transmission assets they would be required to make contributions to the cost of the transmission assets. The contributions would then be removed from the regulatory asset base, so consumers would no longer pay for that proportion of capital costs.

This model is:

- already possible under the TCAPA rule change for transmission connection assets
- inconsistent with the open access regime for shared transmission assets. The outcomes sought from this model with regard to shared transmission assets is better achieved through a change to the access regime.

For these reasons, the Commission does not recommend this approach.

TransGrid's proposed regulatory arrangements to facilitate REZs[71]

Under TransGrid's model, transmission connection assets to REZs could be funded as prescribed transmission services until generators pay to connect. At this time, generators would then pay for the connection assets.

The Commission does not consider this idea to be in the long-term interest of consumers. As with option 4, prescribing services means that the risk of asset stranding lies with consumers.

Ausgrid's contestable augmentations idea[72]

This option suggests applying elements of the transmission planning arrangements in Victoria to the REZ locations throughout the NEM. Through a robust, transparent and consultative process, AEMO would identify REZs and then competitively tender for transmission augmentation to support the REZ.

Ausgrid envisaged that, ideally, it may be possible for "foundational" generators to underwrite the transmission asset.

The need for contestability, and some of the considerations associated with this, is discussed at the end of Chapter 3. In summary, there already exist frameworks for contestable connection assets in the NEM. These could be used as envisaged by Ausgrid. However, under the current access regime it is highly unlikely that generators will underwrite shared transmission infrastructure, because they have no firm access to that infrastructure once built. Instead, under the current access regime, consumers would pay for the transmission infrastructure, and then bear the risk of stranded transmission assets developed through the REZ identification process.

Augrid's 70:30 stranded asset risk sharing mechanism idea[73]

As an alternative to options 3 and 4, Ausgrid suggested that consumers and TNSPs could share the risk of investments made consistent with delivering the prescribed transmission service to a REZ. This would be achieved by only a proportion (e.g. 70 per cent) of the

71 TransGrid, submission to discussion paper, *Coordination of Generation and Transmission Investment*, 18 May 2018, p.4.

72 Ausgrid, submission to discussion paper, *Coordination of generation and transmission investment*, 23 May 2018; AEMO, Victorian Electricity Planning Approach, June 2016.

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

capital costs being placed into the RAB. Like with option 3, the remaining proportion would only enter the RAB if and when the investment was deemed efficient by the regulator, through an ex post review.

The Commission does not consider this option to be appropriate. Under the suggested model, the TNSP may never recover a proportion of the costs incurred, despite the fact that it may have been necessary to make the investment in order to deliver the prescribed service. The model places an undue amount of risk on a TNSP that were capacity to a REZ to be prescribed (by a central authority) but ultimately not required, the TNSP would not recover its capital. This is unlikely to be in the long-term interest of consumers. It is likely to increase the cost of capital required by TNSPs to invest in the sector given the heightened risk. In turn, this is likely to result in higher TUOS charges if the AER permits a higher regulated cost of capital to be used in revenue determinations, and/or stifling transmission investment.

AEMO's non-financial incentives idea

AEMO suggested that non-financial incentives could be used to promote generation investment at favourable sites. For example, generators choosing to locate in the REZ (perhaps identified through the REZ) would result in the approvals process for necessary augmentations being streamlined – consequently fast-tracking the connections process. This could reduce costs and risks for generators.

The Commission does not recommend this approach. In general, the Commission prefers the use of financial incentives because it is more difficult to tailor the non-financial incentives to the appropriate level. If too weak, the desired investment is not delivered, and if too strong then an inefficient amount of generation investment may occur. Furthermore, caution would need to be exercised in streamlining the approvals process to avoid diminishing the benefits associated with these processes. Finally, in providing non-financial incentives to invest in certain locations, consumers will still bear the risk that transmission investment to support generation at that location is inefficient, and that a more preferable location would have been a better choice.

Ausgrid's pioneer scheme idea[74]

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

This type of framework is possible under the changes introduced by the TCAPA rule.

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

Government funding of transmission for REZs

Some stakeholders suggested that governments could financially support transmission for REZs, either through direct financial contributions or discounted debt financing.

Of course, governments are currently free to make investments or otherwise support particular transmission projects. However, in general, the Commission favours models which allow for risk to be borne by parties which are best placed to manage them. Government funding of transmission for REZs transfers the risk of transmission asset stranding from consumers to taxpayers, who also do not appear well-placed to manage the risk associated with asset stranding.

Consequently, while acknowledging that governments are able to financially support transmission investments, the Commission does not recommend embedding this approach into the regulatory framework through law or rule changes.

5.9 Other connection related matters

Throughout this review, the stakeholders have raised a number of other matters relating to connections:

- The unprecedented volumes of connection in the NEM at the moment, creating resourcing issues for AEMO and TNSPs, as well as developers and prospective generators experiencing costs and delays. Some of these are being exacerbated by developers who are new to the Australian system trying to progress connection applications.
- A lack of clear and consistent documentation, including time frames and check lists, to guide new connecting parties on TNSPs websites.
- The operation of marginal loss factors, given the large number of generators connecting at the moment. Generators note that since these are static numbers for a year, given the significant number of generators connecting, this is resulting in significant year on year fluctuations. In addition, there is not a lot of transparency about how these factors are calculated. This is discussed further in chapter 6.
- The recent changes to the connections framework including the: TCAPA rule , *Managing power system fault levels* rule change, and *Generator technical performance standards* rule, are all relatively new. While these are beneficial, and do represent improvements to the arrangements these changes have caused challenges in getting up to speed with what has been implemented, and so take time to understand.
- Issues being created around multiple generators seeking to connect at the same time, and same location, but ultimately moving along different time frames. This creates complications with assessing technical requirements for example, if Generator X sought to connect in early 2018 then its performance standards would have been started to be assessed on this basis; however, Generator Y may progress along the connection journey more quickly and so actually connects in mid 2018, and so the performance standard studies for Generator X would need to change accordingly. The NER framework for connections envisages the process is linear, whereas in practice, the process is more iterative.

The Commission proposes to consider these issues through the *Coordination of generation and transmission investment* 2019 review. It is considering the implementation of the managing power system fault levels rule change through the Commission's work on South Australian issues, whereby a paper on this will be published early 2019.

5.10 Conclusions on REZs

The Commission has not been able to identify any options that facilitate the development of REZs which do not also involve a change to the access regime and which also represent an improvement on the status quo.

This is because any option which involves:

- generators contributing to the cost of shared transmission assets (or otherwise taking some of the risk of developing shared transmission assets) requires that the generator receive some form of firmer access right than currently available under the open access regime. Otherwise, generators will have an incentive to free-ride on investments contributed to by other generators, enjoying the benefits of access without having contributed to the costs. Given that each generator will have an incentive to free-ride, each individual generator will be reluctant to contribute to the cost of the shared transmission assets.
- TNSPs undertaking speculative investment in either shared network infrastructure or connection infrastructure either requires:
  - consumers to bear the risk of this investment, which the Commission does not consider to be appropriate or in their long-term interest
  - TNSPs to bear the risk, and be compensated accordingly. However, establishing how to appropriately compensate TNSPs is both practically and legally challenging.
- the facilitation of REZs through enhanced information or cooperation between parties is already accommodated within the existing regime, which does not appear to sufficiently facilitate REZs consistent with the recommendations of the Finkel Review.

Consequently, the Commission recommends the changes to the access regime outlined in Chapter 6. Among other benefits outlined in that chapter, changes to the access regime will facilitate REZs as a consequence of generators and prospective generators' commercial locational investment decisions.

6 ACCESS: NETWORK CONGESTION AND ACCESS

RECOMMENDATION 4: NETWORK CONGESTION AND ACCESS

How generators access the transmission network, and how congestion of the transmission network is managed, underpins the transmission framework. Currently, the NEM does not provide a mechanism for parties to enhance the shared grid in a way that enables them to manage congestion: connections do not price deep connection costs, and market pricing does not reflect locational pricing.

The Commission has heard from renewable providers that the current arrangements for generator access and congestion management are no longer sustainable. In the absence of any arrangements that deal with this in the NEM, parties are looking to the ISP to address and resolve these issues. However, given the ISP is a centralised plan, it will be unable to address these concerns, given that the generation, load and retail sectors of the industry are disaggregated and it will be nearly impossible for one party to correctly predict and guide decisions of each sector. Markets, and decentralised decisions, have been shown to be more efficient and more innovative - delivering cheaper outcomes for consumers.

There is a significant amount of capacity that is seeking to connect to the network. Private sector investors are planning generation where transmission has limited or no capacity to connect it. In addition, interconnectors are frequently constrained, meaning that consumers cannot access lower cost energy from generation in neighbouring states.

Therefore, the Commission considers that there needs to be changes to the access regime in order to facilitate this transition. The Commission has recommended a phased reform approach to make generator access to the transmission network and congestion management fit-for-purpose for the energy transformation. Access reform is needed now in order to be put in place for the future. The approach will provide the necessary tools for those who are best placed to bear the risk of resource investment to do so, facilitating the coordination of generation and transmission investment.

Access reform also helps to facilitate our other recommendations for actioning the ISP, integrating large-scale storage facilitates, facilitating REZs and improving transmission charging.

6.1 Background

As discussed in Chapter 2, a foundational principle of the NEM is that decisions to invest in generation capacity are made by businesses operating in a competitive environment, rather than by vertically integrated monopolies. Investment in generation assets is market-driven and takes account of expectations of future demand, the location of energy sources, access to land and water and access to transmission. The result is that risks associated with generation investment rest with those businesses.

In contrast, transmission investment decisions remain the province of regional, transmission network businesses.[75] Transmission businesses are subject to incentive-based economic regulation of their revenues for the provision of transmission services, as well as various other obligations relating to reliability, safety and investment decision-making processes.

Generation and transmission are both complements and substitutes. They are part of an integrated system and are difficult to separate. This implies that investment and operational decisions by generators and TNSPs should work together to achieve overall efficient outcomes. The way that transmission and generation investment decision-making processes interact, and in particular, their operational consequences, have been the subject of ongoing discussion since before the establishment of the NEM in 1998. Since NEM start, there have been at least twelve major reports and reviews dealing with various aspects of congestion management and generator access, including five reviews by the Commission in addition to this COGATI review, stretching back to 2005 when the Commission was created.

A key objective of the COGATI terms of reference is to consider, on a biennial basis, whether the timing is right for access reform, in light of likely emerging and future changes to the patterns and quantities of generation and transmission investment. Based on the body of experience gained by the Commission in undertaking its various reviews, we consider that reform is now required to address issues in the existing regime given changes being witnessed in the market.

6.1.1 Current arrangements for access and congestion

As noted in section 5.1.1, the NEM has an open access regime. Simplistically, generators have a right to negotiate a connection to the transmission network, but no right to be dispatched in the wholesale market and so earn revenue at the region-wide market price.

The connection regime requires generators to pay for assets which enable them to connect to the shared network.

There are some locational signals (i.e. to guide where generators decide to locate) that are provided to connecting parties under the current regime:

- Marginal loss factors - these provide an indication of present flows on the network, but they are not a good indicator of future flows. Indeed, stakeholders have raised concerns about the operation of marginal loss factors given the large number of generators connecting at the moment, and marginal loss factors inherently change after a new generator connects to the network. Generators note that since these are static numbers for a year, given the significant number of generators connecting, this is resulting in significant year on year fluctuations in the marginal loss factor. Generators have also raised the concern that there is not a lot of transparency about how these factors are calculated. The Commission also notes that these are not a good indicator of future flows, and so should not be relied on by developers to underpin their investment cases. Further, they do not signal current or future congestion, or the likely cost of congestion.

75 The exception is Victoria where decisions to augment the transmission network are made by AEMO.

- Level of capacity on networks - as discussed in Chapter 4, there is information provided to connecting parties about where there is spare capacity in the network, including what the current system strength parameters are in a particular region. However, current congestion patterns are not necessarily a meaningful indicator of future congestion. A generator will not be able to predict AEMO or TNSP behaviour, nor the behaviour of other generators, and so future congestion, over the life of its investment.

Therefore, both of the above indicators are static representations of the current network, as opposed to considering the implications over time.

Once connected, generators' access to the shared network is determined dynamically through the dispatch process. This is consistent with a framework designed to deliver the efficient level of transmission for customers where constraints will arise on the network - reflecting that the cost of alleviating a constraint by building shared network transmission assets may exceed the value of alleviating the constraint. As a result:

- some generators can be constrained off, despite having bid at a price less than the market price, and hence receive no revenue
- other generators are dispatched despite bidding at a price above that which would have been the market price were it not for the constraint. As a consequence, the market price is likely to be higher than it would otherwise have been.

Generators are unlikely to underwrite transmission assets to alleviate constraints, as this improves access for all generators through the dispatch process, not just the generator which underwrote the investment. Consequently, as a market-based approach does not create incentives for generators to invest, planning transmission to alleviate constraints (or open up entire new regions to the transmission network) is undertaken through centralised processes. AEMO, through the ISP, TNSPs through their TAPR and RIT-T processes, and the AER in its revenue determination and related processes, make assumptions regarding future generation location and quantity in order to determine the appropriate level of access required by current and prospective generators - attempting to balance the cost of transmission investment with the cost of congestion.

6.1.2 Issues arising from open access

The inherent disconnect between market-based, decentralised generation investment decision-making and centralised, regulated transmission investment decision-making has wide-ranging consequences, and has been the source of multiple reviews on this topic.

Some of the issues arising from the open access framework identified throughout previous reviews include:

- **limited intra-regional locational signals reflecting congestion:** all generators which are dispatched receive the market price, which is a region-wide price. Consequently, there are only limited intra-regional price signals reflecting congestion. As discussed above, there are some non-price signals, such as the exposure for generators of being constrained off,[76]and marginal loss factors. However, these signals may not always provide a strong incentive to generators to locate or offer generation efficiently and does not take account of the impact on other generators.

- **risk allocation for transmission investment:** While there are regulatory processes in place designed to limit the risk of poor transmission investment decisions being made through the centralised processes described above (such as the RIT-T and the AER's revenue determination process), end consumers are ultimately exposed to this risk, which includes:
  - inefficiently located, sized or timed transmission investment, including too much or too little transmission capacity (resulting in higher than necessary TUOS charges or higher than necessary market prices as a result of higher cost dispatch and reliability issues respectively)
  - inefficient signals provided to generators for their locational decision, as discussed above.
- **disorderly bidding:** The absence of intra-regional price signals also can give rise to disorderly bidding. Disorderly bidding arises when generators know that the offers they make will not affect the settlement price they receive as a result of congestion between them and the rest of the market. Each generator behind a constraint bids at the market floor price to maximise its dispatch quantity. This can result in inefficient dispatch - higher cost generation resources being dispatched instead of lower cost resources.

Insufficient locational signals for generation investment, and the risk of poor transmission investment decisions being borne by consumers, are less likely to result in material issues for consumers in an environment where:

- there is little investment in transmission and/or generation, or
- the required pattern, location and timing of transmission and/or generation investment is clear, and so centralised decision-making is likely to be relatively efficient.

Conversely, these problems are more likely to be material where there is likely to be a major transformation of the generation and transmission capital stock, and where the nature of that transformation is uncertain. This is the situation in which the NEM currently finds itself.

It seems clear to the Commission that the NEM is currently undergoing a significant change in the generation fleet and associated transmission infrastructure. As outlined in section 6.3 below, it is for this reason that the Commission considers the timing is right for access reform.

6.2 Stakeholder views

In the options paper, we asked for stakeholder views on whether we should look at the access regime:

76 As discussed in Chapter 4, there is limited information provided to connecting parties about where there is spare capacity in the network including what the current system strength parameters are in a particular region. However, current congestion patterns are not necessarily a meaningful indicator of future congestion. A generator will not be able to predict AEMO or TNSP behaviour, nor the behaviour of other generators, and so future congestion, over the life of its investment.

- consumers typically supported some change to congestion and access arrangements *immediately*[77]
- existing generation did not typically favour any change to the status quo;[78] while renewable generation typically wanted change, but did not want to pay for transmission[79]
- networks generally agreed that congestion is an issue, but most consider that actioning the ISP should be a priority.[80]

Renewable generators provided examples of how the risks of congestion are an impediment for renewable investments, and that the large amount of generation seeking to connect to the network is creating difficulties in forecasting congestion risks. In contrast, consumers also noted there were risks, but risks associated with consumers in providing "spare capacity" (either by directly overbuilding or indirectly by including potential market benefits of an augmentation) in the network, which might never be used.

Stakeholders had mixed views on when congestion and access issues should be addressed:

- Origin Energy considered no significant changes to the current congestion management regime were required.[81]
- The Clean Energy Council, TransGrid and Energy Networks Australia consider that the priority should be actioning the ISP, and that while congestion is important, it should be considered further once actioning the ISP is addressed.[82]
- Similarly, TasNetworks agreed that network utilisation, operability and resilience planning must be prioritised to support the ISP. However, it also commented that some consideration should be given to this now. For example, although a REZ is identified in north-west Tasmania to be maximally utilised within 10 years, the volume and nature of connection enquiries received to date necessitates action now so access and congestion can be managed appropriately.[83]
- RES Australia considered issues with congestion will be exacerbated in the near-term unless this is addressed.[84]
- The Consumer Challenge Panel stated that the message they have received from consumers and their advocates is that congestion and access should be addressed as part of this review, and not relegated to a later stage – progress needs to be made now before the impending wave of investment. They consider that developers are "obviously hopeful of regulated funding for as much as of their network needs as possible, but a

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77 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: SACOSS p. 2; EUAA p. 8; Consumer Challenge Panel - Sub-Panel No. 20 p. 14.

78 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: Snowy Hydro p. 2; Delta Electricity p. 1.

79 Palisade Pty Ltd, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.12.

80 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: TransGrid p. 12; Energy Networks Australia p. 10; TasNetworks p. 7.

81 Origin Energy, submission to the options paper, p. 10.

82 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: TransGrid p. 12; Energy Networks Australia p. 10; Clean Energy Council p. 4.

83 TasNetworks, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p. 7.

84 RES Australia, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p. 15.

clear framework that allows the developers to signal their locational preferences and have some "skin in the game" has to be preferable to proceeding based on 'hope'".[85]

- The South Australian Government stated that "access and congestion management issues need to be addressed in the near term and the AEMC should commence consideration of these issues as soon as practicable."[86]

6.3 Commission's analysis and recommendations

6.3.1 Issues arising from current arrangements

How generators access the network, and how congestion of the transmission network is managed, is a fundamental underpinning principle of the transmission framework. Currently, the NEM does not provide a mechanism for parties to enhance the shared grid in a way that enables them to manage congestion - connecting parties only pay the direct costs associated with facilitating their connection, the price that generators face does not reflect locational signals, and generators do not receive any guaranteed level of access to the transmission network.

The NEM is currently undergoing a significant transformation, with an unforeseen level of generators seeking to connect to the network. Proposed generation roughly equal to the current size of the NEM (50GW) is foreshadowed for connection to the grid over the next 10 years.[87] Private sector investors are planning generation where transmission has limited or no capacity to accommodate it. In addition, interconnectors are sometimes constrained, meaning that consumers cannot always access lower cost energy from generation in neighbouring states. For example, in NSW, as at November 2018 more than 20,000 MW of large-scale projects were progressing through the NSW planning system. The NSW Government's Transmission Infrastructure Strategy published in November 2018 stated that "for every 20 projects looking to connect to the grid only one can. Companies simply will not invest if they can't connect."[88]

The existence of congestion risk is a major impediment to new generation connecting.[89] Congestion can result in very unpredictable and volatile market outcomes, and so can contribute to a lack of certainty for generators about financial outcomes. For example, Palisade commented in its submission to the options paper that congestion creates curtailment for generators to reduce temporary congestion, increased costs and losses to generators.[90] Generators recognise that some level of congestion is inevitable, but the existing and projected levels of congestion are unlikely to be efficient, resulting in cost-effective generation being constrained off or being forced to locate in less desirable locations.

85 Consumer Challenge Panel - Sub-Panel No.20, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p. 14.

86 Government of South Australia, submission to the options paper, *Coordination of generation and transmission investment*, 4 December 2018, p.3.

87 AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

88 NSW Transmission Infrastructure Strategy: Supporting a modern energy system, November 2018, p.3.

89 UPS Renewables, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.5.

90 Palisade Pty Ltd, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.11.

Indeed, connecting generators are demanding more information on where to connect. For example, generators are calling for more accurate data on where there is spare capacity on the network. However, given the scale of generation connecting, at some point even more information is unlikely to be helpful given the locations where there is spare capacity will be changing so significantly in a short space of time. This is further creating difficulties for parties wishing to connect. For example, RES Australia commented that while a congestion risk assessment is typically undertaken by consultants when renewable projects are financed - this is becoming more difficult to forecast due to difficulties in predicting future generation developments and not having perfect foresight of technical issues.

Because generators' access to the market is determined through the dispatch process, generators are unlikely to underwrite shared transmission network investment to secure better access. Were they to do so, other generators would also enjoy the benefits of improved access without having contributed to the cost of the shared network. This creates a free-rider problem - each individual generator waiting for another generator to underwrite transmission investment. As a result, in practice generators do not underwrite shared network transmission investment, with transmission investment in the shared network being directly recovered from consumers through TUOS charges.

However, consumers are facing rising energy prices, and so are concerned about the risks of congestion but are thinking about this from the other perspective - in relation to affordability. For example, both the Australian Aluminium Council and Energy Users Association of Australia consider that consumers under the current access framework bear a disproportionate amount of risk (and costs) of transmission - which is at odds with other industries where the owner of any asset bears the risk that technology or consumption patterns may reduce the asset's value.[91]

The Commission has heard from prospective generators that the current arrangements for generator access and congestion management are no longer sustainable. In the absence of any arrangements that deal with this in the NEM, parties are looking to the ISP to address and resolve these issues. Indeed, the ISP noted that there is a need to increase the capability of the transmission system to reduce congestion and provide generators, existing and new, with cost-effective access to market. It highlighted the importance of coordinating generation and transmission investment.

However, given the ISP is a centralised plan, it is unlikely that it will be able to address these concerns given that the generation, load and retail sectors of the industry are disaggregated and it will be nearly impossible for one party to correctly predict and guide decisions of each sector. Markets, and decentralised decisions, have been shown to be more efficient and more innovative - delivering lower and cheaper outcomes for consumers.

Therefore, the Commission considers that there needs to be changes to the access regime in order to facilitate this transition. The Commission has recommended a phased reform approach to make generator access to the transmission network and congestion

91 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: Australian Aluminium Council p.1; Energy Users Association of Australia p.5.

management fit-for-purpose for the energy transformation. The approach will provide the necessary tools for those who are best placed to bear the risk of resource investment to do so, facilitating the coordination of generation and transmission investment.

The phased approach is as follows:

1. The access arrangements would be changed to implement dynamic regions for determining the price payable to generation.
2. The information that is produced from dynamic regional pricing, including where congestion occurs and the costs of congestion, would be used to supplement the planning arrangements for transmission. For example, the current patterns, timing and cost of congestion could be used as inputs to the ISP and RIT-Ts, in order to assist in determining the appropriateness of future transmission investments.
3. In response to the information on congestion, connecting parties (e.g. generators) would be able to purchase firm transmission rights or firm access to the network, which in turn would be used to underwrite the necessary network investment needed to physically provide that access. Generators' collective decisions to purchase transmission rights would guide TNSPs' planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity consistent with the rights purchased by generators. In this phase, the two investment decision-making processes will be aligned.

The Commission favours a phased approach because it allows some of the issues outlined above to be addressed in an expedited fashion, while providing a pathway to address the remaining issues of the open access regime.

6.3.2 Dynamic regions for pricing generation

As noted above, under the current arrangements, dispatched generators receive the market price, which is the same throughout the region.

The regions of the NEM are, in operational time-scales, fixed.[92] While the regions of the NEM currently broadly coincide with state boundaries, the underlying rationale is to reflect likely transmission constraints on the shared transmission network (which have tended to be greater between the states due to the historic pattern of transmission infrastructure development). Where constraints are too great, the distortion to price signals are too high, and so different pricing regions are appropriate.

Overview

Where congestion arises and transmission constraints occur, pricing regions will be dynamically created which will reflect transmission constraints that are actually occurring at that particular time.

In any individual dispatch interval, dispatched generators will be paid the new, dynamic regional price that applies where they are connected, rather than the existing regional reference price. Where there are no constraints on the transmission network, the new,

92 The regions of the NEM can be changed through a rule change. One such change has been made to abolish the Snowy region, made in 2007.

dynamic region will include the regional reference node, and so the price generators receive will be the existing regional reference price.

Creating dynamic regions has the effect of putting a price on congestion and hence addresses a number of the concerns raised in section 6.3.1. Dynamic regions introduce a signal to generators that reflects the short-run costs of using the network. This will provide better information to generators about where congestion occurs, which they can consider when making their locational decisions, as well as removing the current incentives for disorderly bidding by generators when there is congestion.

Market customers (e.g. retailers) would continue to be settled at the regional reference price.

A consequence of this change is to introduce a new risk to generators arising from generators not being settled at the regional reference price. This risk is addressed, in part, by providing financial compensation to generators on the difference between the regional reference price and the dynamic regional price of the generator. The money to back this compensation arises from the difference between the price market customers are being settled at (the existing regional reference price) and the price some generators are being settled at (the new, dynamically determined regional price of the generator). This is analogous to inter-regional settlement residue in the current NEM, but would occur intra-regionally under the method described above.

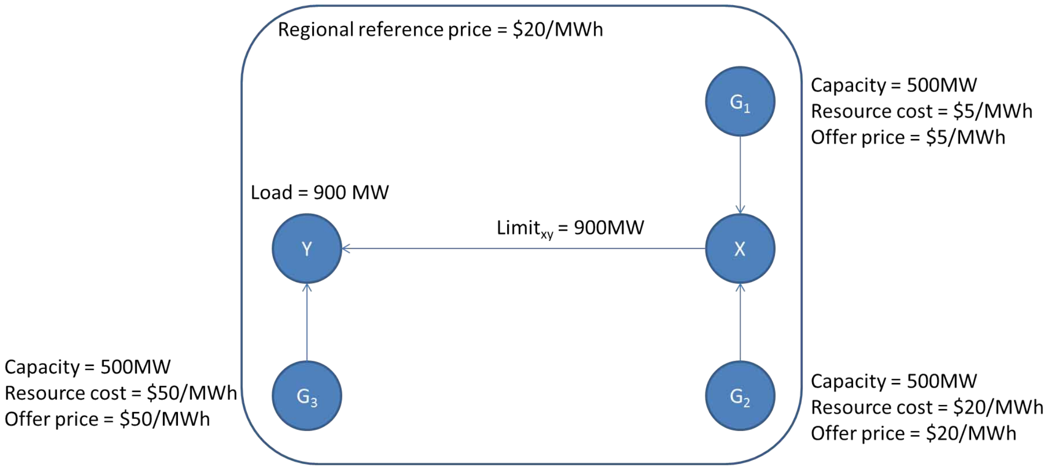
This financial compensation will be dynamically allocated to generators on the basis of their capacity. As a result, generators will not always be fully compensated on the price difference between the dynamic region they are in and the existing regional reference price. While this risk is not fully addressed here, the Commission notes that the risk may not be any greater than the risk that generators currently face. Currently, generators face the risk that they are not dispatched as a result of a transmission constraint and hence receive zero revenue regardless of the market price. Following these changes, generators will instead be exposed to a different risk: that despite being dispatched, they receive the dynamic regional price rather than the region-wide price, and are not fully compensated the difference between these prices.

Examples of the dispatch outcomes

An example of the mechanism is shown in figures 6.1, 6.2 and 6.3.

Figure 6.1 shows the arrangements under both the status quo and in dynamic regional pricing when there are no transmission constraints.

Figure 6.1: No congestion



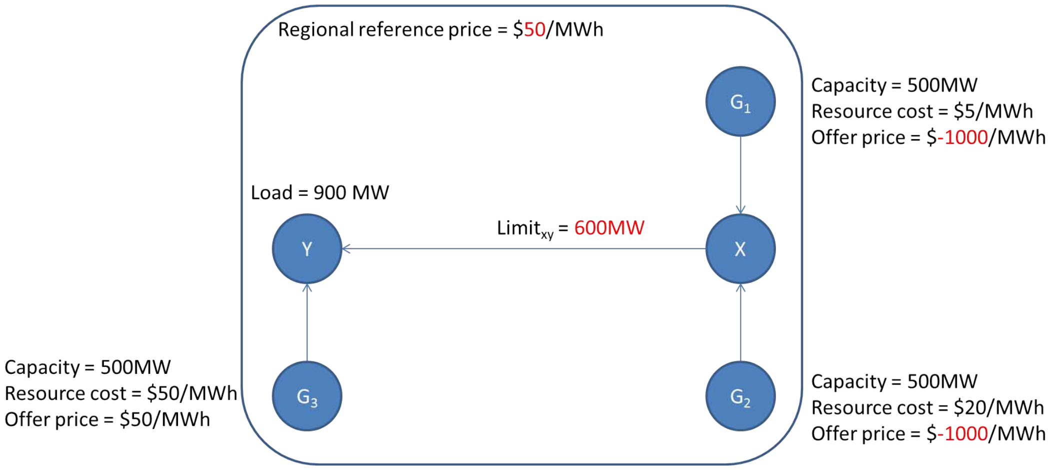
Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	0	5	500	10,000	2,500	7,500
G2	500	0	20	400	8,000	8,000	0
G3	500	0	50	0	0	0	0
Total	**1,500**	**0**		**900**	**18,000**	**10,500**	**7,500**

Source: AEMC analysis

In this simple example, all of the 900MW load in the region (encircled in blue) is at point Y. Generator 3 is at point Y, and generators 1 and 2 are at point X. There is a transmission limit of 900MW between X and Y. G1 and G2 have lower resource costs than G3 so bid at lower prices. The transmission limit is not violated because all the load (900MW) at Y can be accommodated across the transmission network from generators 1 and 2 at X. Generator G2 is the marginal generator and so set the regional price of $20/MWh. Generator 3 is not dispatched.

Compare this to the example in Figure 6.2 below, where the transmission constraint is now 600MW under the status quo open access approach. Here, all generators dispatched receive the market price, which is a region-wide price. Consequently, there are only limited intra-regional price signals reflecting congestion.

Figure 6.2: Open access, transmission constraint binds



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	0	-1000	300	15,000	1,500	13,500
G2	500	0	-1000	300	15,000	6,000	9,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**0**		**900**	**45,000**	**22,500**	**22,500**

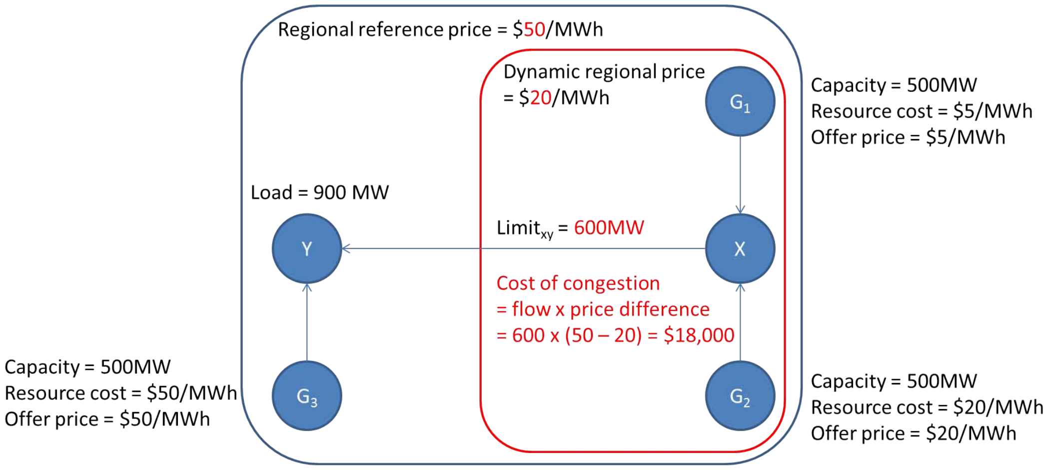
Source: AEMC analysis

In this example, generators 1 and 2 are constrained down due to the transmission constraint, and generator 3 is dispatched in addition to generators 1 and 2 to serve the load at Y now not served in full by generators 1 and 2. Generator 3 sets the regional price of $50/MWh. Here, the generators behind the constraint know that if they bid according to their resource costs, then they would not be dispatched. However, they know that the offers that they make will not affect the settlement price they receive as a result of congestion between them and the regional reference price. Therefore, each generator behind a constraint will bid at the market floor price to maximise its dispatch quantity.

This will result in inefficient dispatch - higher cost generation resources being dispatched instead of lower cost resources. Generator 1 has lower resource costs, so the optimal dispatch is generator 1 to be dispatched at its full capacity (500MW) and generator 2 to then make up the remainder to the transmission limit (a further 100MW). But because the market dispatch engine dispatches on the basis of bids, not underlying costs, this does not occur.

Now compare this to the example in figure 6.3, where the transmission constraint is again 600MW but dynamic regional pricing is in place.

Figure 6.3: Dynamic regional pricing, transmission constraint binds



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	9,000	5	500	10,000	2,500	16,500
G2	500	9,000	20	100	2,000	2,000	9,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**18,000**		**900**	**27,000**	**19,500**	**25,500**

Source: AEMC analysis

Due to the transmission constraint, generators 1 and 2 are in a different dynamic region (circled in red) to the regional reference node.

There is no longer an incentive for generator 1 or 2 to disorderly bid. Doing so would expose the disorderly bidding generator to a low dynamic regional price.

In the example, generators 1 and 2 bid reflective of their resource costs.[93] Generator 2's dispatch is constrained down to 100MW, so it remains the marginal generator in the dynamic region, setting the price in the dynamic region at $20/MWh. Generator 3 is dispatched to meet demand at Y, and so it sets the regional reference price of $50/MWh.

The cost of congestion is calculated as the flow on the line between X and Y (600MW) multiplied by the price difference between the dynamic regional price ($20/MWh) and the regional reference price ($50/MWh): 600 x (50 - 20) = $18,000. This is the difference between what consumers are paying for electricity (at the regional reference price) and what generators are being paid for electricity (at the dynamic region price), directly analogous to settlement residue that arises from inter-regional settlement currently. This $18,000 of settlement residue is divided between generators 1 and 2 in proportion to their capacity as a compensation payment (in the example, half each as they have the same capacity, so $9,000 each).

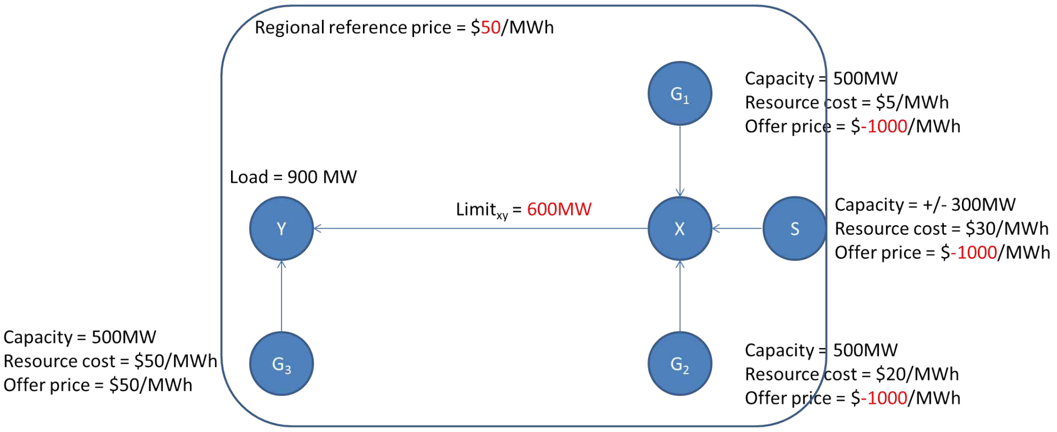
93 In this example, generator 2 would have an incentive to bid just above the bid of generator 1, in order to increase the compensation payment. This would allocate more of the margin to generator 2 and less to generator 1. However, physical dispatch outcomes are unaffected by this bidding behaviour and dispatch is optimal.

Exposing generators to the dynamic regional price removes the incentives to disorderly bid when transmission constraints arise. This means that at times of transmission congestion, the lowest cost combination of generation should be dispatched. The resource cost of dispatch is lower than under the status quo.

The key advantage of these changes is that it should encourage most cost reflective bidding, and so improve dispatch efficiency in the NEM.

These benefits may become particularly prevalent if storage plays an increasingly large role in the NEM. Figure 6.4 shows this in practice for the status quo open access arrangements.

Figure 6.4: Open access, transmission constraint, storage



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	0	-1000	200	10,000	1,000	9,000
G2	500	0	-1000	200	10,000	4,000	6,000
S	300	0	-1000	200	10,000	6,000	4,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**0**		**900**	**45,000**	**26,000**	**19,000**

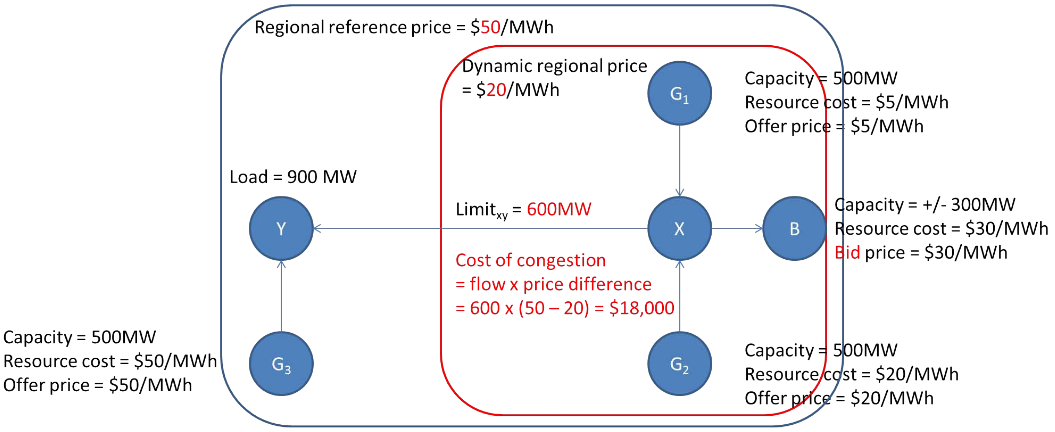
Source: AEMC analysis

In this example, storage (S) behind a constraint has an incentive to disorderly bid (as seller of electricity, i.e. analogous to a generator) in order to receive the region wide market price.

Not only is this more inefficient than were the storage not there (because the resource cost of the storage device is in the example higher than generators 1 and 2, which the storage device partially replaces in dispatch) it's even more inefficient than were the storage facility to charge instead of generating.

What might happen under dynamic regional pricing is shown in figure 6.5 below, were storage to be charged the dynamic regional price when acting as load.

Figure 6.5: Dynamic regional pricing, transmission constraint, storage



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	9,000	5	500	10,000	2,500	16,500
G2	500	9,000	20	400	8,000	8,000	9,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**18,000**		**1,200**	**33,000**	**15,500**	**25,500**

Source: AEMC analysis

Compared to Figure 6.4, generator 2's output is increased in order to service this local load. This allows the storage facility to charge at a price less than its assumed resource cost ($30/MWh): an efficient dispatch outcome.

Other features

Here, there would be no transmission charges levied on generators - all network charges would continue to be paid for by load. However, as discussed, the distribution of revenues between generators would change when congestion arose.

No changes to the TNSP planning, investment or operational arrangements would be required to give effect to this. Some changes to AEMO's dispatch and settlement processes and systems would be required, but we understand that these would be relatively small. Therefore, we consider that this would be relatively straightforward to implement from the perspective of market systems.

These changes do not target the source of congestion: it simply manages the effects. It also continues to rely on the regulated planning process to identify the need for transmission investment. Our recommendations to action the ISP will continue to be a centralised approach to promote efficient transmission decisions that meet the jurisdictional reliability standards, while accounting for generation decisions.

While this strengthens locational signals somewhat by exposing generators to the local price, while also providing them compensation against it, the fact that this changes in each dispatch interval does not provide generators predictability of access. Therefore, there is a need to progress to the latter stages of reform.

6.3.3 Better information

Currently, transmission investment decisions are made by transmission businesses. The ISP, and then TNSPs through their TAPRs, assess the need for new investments based on rules and regulatory obligations. These parties make assumptions about the benefits that would result for market participants and consumers, and compare these to the associated costs.

However, these parties may not have a complete understanding of market participants' businesses and so, without market signals, it is difficult to estimate and capture these values. Nevertheless, there are incentives and planning approaches - such as transparent planning and robust stakeholder consultation requirements - which encourage the implementation of transmission development plans at least cost to the best of their abilities.

These planning processes will be supplemented by the provision of additional information that will be made available in this stage. This information would include information revealed by the introduction of dynamic regional pricing, including:

- patterns of congestion and the dynamic location of regions
- costs associated with congestion, including the costs of congestion on a particular transmission element.

Dynamic regional pricing, and the better information that flows from that, will assist with actioning the ISP by providing a greater level of information to AEMO and the wider market about transmission constraints and their cost. This will better enable:

- AEMO, informed by stakeholder views, to develop future ISPs
- TNSPs to make efficient transmission investments informed by the ISP and the information provided by dynamic regional pricing and
- the AER to assess the efficiency of transmission investments, again informed by an improved ISP as well as the information provided by dynamic regional pricing.

6.3.4 Generators contribute towards transmission

Despite the benefits of the above changes, Commission has substantial concerns that alone they will not result in optimal outcomes. While better information improves the likelihood of good transmission investment decision-making by TNSPs, the planning of transmission in phases 1 and 2 is still a fundamentally centralised approach undertaken by a combination of AEMO (in developing the ISP), TNSPs (in developing RIT-Ts) and the AER (in determining revenue allowances to TNSPs).

The final stage introduces the notion of firm transmission rights. Generators are able to buy firm transmission rights from a TNSP in return for either being physically dispatched or paid for the lost revenue from not being dispatched.

Here, generators will use the ISP, along with other sources of information, as an important guide to their generation and transmission investment decision-making, and be able to compel TNSPs to provide transmission services consistent with the level of firm transmission rights procured by generators. The advantages of the final phase are that:

- generators will have strong financial incentives to make efficient and coordinated investment decisions in both transmission and generation infrastructure, and
- if, despite these incentives, inefficient decisions are made, it is primarily generators, and not consumers, who bear the risk of this.

Issues with central planning approach to transmission investment

Generally, markets are more efficient than central planners in coordinating resource allocation decisions. Indeed, it was this foundational view that resulted in the development of a competitive generation sector for electricity: the NEM.

While there are currently regulatory safeguards to reduce the risk of inefficient investment decision-making by TNSPs (such as the RIT-T and the AER's revenue reset process), these safeguards are inevitably imperfect. The prospect of a TNSP making inefficient transmission investment decisions arises because the TNSP:

- can relatively accurately forecast the cost of transmission, but has substantially imperfect information regarding both the costs and benefits of generation (as accruing to generators or consumers)
- has only limited financial incentive to get the investment "right," because consumers are primarily exposed to the risk of poor transmission investment decisions, rather than the TNSP.

To be clear, this is not intended to be a criticism of TNSPs or the AER, but merely recognises the inevitable limitations of planning and regulation as compared to markets.

There are potential consequences associated with a TNSP making the wrong investment decisions – it could either *not invest* and so the costs of congestion would be increased, or it could inefficiently *invest,* increasing the cost of transmission. Transmission investment decisions impact on generators' investment decisions. Once an investment decision is made, congestion in a part of the network will be alleviated or spare capacity created, encouraging generators to connect in those areas. This creates a bias towards the transmission and generation development path that is predicted by transmission businesses, even where a lower cost combination existed.

Whenever the regulated planning approach delivers a transmission path that is not co-optimised with generation investment, the result is the potential for higher combined cost of generation and transmission than could otherwise be achieved. These costs are borne largely by electricity consumers, who have only limited influence on these investment decisions. This does not represent an ideal alignment of risk and decision-making.

The AEMC's proposal for this access reform introduces commercial drivers into the transmission planning process, by having generators make decisions about what transmission infrastructure to fund, receiving firm transmission rights in return. The Commission considers that generators, acting on the basis of financial incentives, are better placed to make efficient and coordinated transmission and generation investment decisions. Furthermore, to the extent that generators do not make efficient decisions despite these incentives, it is they, and not consumers, who wear the majority of the associated risk.

This reflects that well-functioning markets tend to deliver better outcomes for consumers than centralised approaches (whether undertaken by TNSPs, the AER or AEMO). Indeed, the desire to introduce market-based decision-making into the generation sector, and to put the risk of those decisions onto commercial entities and not consumers, was one of the key original rationale for the disaggregation of the vertically integrated electricity sector and the creation of the NEM. The AEMC's approach to decentralise some transmission investment decision-making is internally consistent with the fundamental design of the NEM, reduces risks for consumers and improves the likelihood of efficient coordination of transmission and generation investment. In contrast, those US markets that have central planning typically have more meshed networks and denser populations, which means that the practical ramifications of risks associated with building the "wrong" transmission infrastructure are less.

Once all three stages of access reform are completed, generators will be provided with a price signal about the costs associated with locating in a particular place of the grid. Generators will then be able to make a *choice* about whether or not to pay to receive firm access to the transmission network. This market driven approach aligns the disaggregated, commercial decisions of the generation sector, with that of the transmission sector. It provides the necessary tools for those who are best placed to bear the risk of resource investment to do so, facilitating the coordination of generation and transmission investment and avoiding unnecessary risks being placed on consumers.

Design

This final stage addresses, to a large degree, the limitation of transmission and generation investment decisions being made through different processes, by sharing the transmission investment decision-making with generators.

This would be achieved by generators being able to buy firm transmission rights in order to manage the risk of congestion. Instead of generators' compensation for being constrained off being a function of the capacity of generators (as under dynamic regional pricing), the compensation would be a function of the quantity of firm transmission rights they hold. Generators would, in effect, be able to hedge against the price difference of their dynamically determined regional price and the existing region-wide price.

TNSPs would be obliged and financially incentivised to provide a level of access consistent with the firm transmission rights collectively held by generators, meaning that the purchase of firm transmission rights by generators would underwrite transmission investment.

Because the transmission rights are a firm hedge between the dynamically determined regional price and the existing region-wide price, generators receive the full benefit of the transmission upgrade they underwrite - avoiding the free-rider problem in the current open access regime, and allowing a greater reliance to be placed on commercial transmission investment rather than the existing, centralised and regulated processes.[94]

Generators that do not hold firm rights would be exposed to more of the cost of congestion (because they have not contributed to alleviating the congestion through the purchase of transmission rights), while generators that hold transmission rights would be hedged against the cost of congestion. This provides an incentive for generators to underwrite the appropriate amount, location and timing of transmission investment, balancing the costs of transmission investment against the costs of congestion, as well as other locational decision factors such as fuel resources. In effect, generators would be incentivised to contribute towards the cost of transmission, allowing them to factor this into their locational decision.

Allowing generators to contribute funds towards transmission infrastructure would introduce more commercial drivers on transmission businesses and more commercial financing of transmission infrastructure.

The approach should result in a closer alignment of generation and transmission investment and should have substantial benefits because:

- by better aligning the processes of generation and transmission investment it should reduce the prospect of poor coordination, reducing costs to consumers, and
- if, despite this better alignment, poor coordination does occur, it is generators, rather than consumers, that bear more of the risk and cost of this.

As such, it has the potential to minimise prices for electricity consumers in the longer-term by minimising the total system cost of building and operating both generation and transmission over time.

6.3.5 Timing and interaction with other recommendations

Reform to the access regime should occur through a phased approach to address generator connection and access to the transmission network, and to make congestion management fit for purpose for the transformation of the generation fleet.

A phased approach strengthens the benefits that will be realised by actioning the ISP, as well as addressing the pressing issue of integrating large-scale storage into the NEM, while providing a pathway to address the remaining issues of the open access regime. Coordinating investment in generation and transmission in this way will reduce the risk of both over investment (stranded assets) and underinvestment (congestion) in transmission infrastructure.

In order to progress this phased approach to access reform, the Commission will develop the necessary rule changes, and any NEL changes that are required, through our 2019 biennial review of the coordination of generation and transmission investment. It is expected that the

94 An alternative, as suggested by some stakeholders, would be the introduction of deep connection charges imposing costs on connecting generators related to those that they impose on the network. Palisade disagreed with deep connection charging, as it may ultimately deter new generation investments that are vital for the sustainable management of the grid. Palisade Pty Ltd, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.12. This final stage resolves this problem by giving connecting generators something (firm transmission rights) in return for making a financial contribution that underpins transmission investment.

COAG Energy Council will submit rule changes for all stages of the phased approach to the AEMC in early 2020. Our consideration of the phased reform in 2019, including whether changes to the NEL are required, and the subsequent rule changes, will involve extensive stakeholder consultation. This will allow consideration as to whether the proposed implementation dates, sequencing of staging and proposed implementation program is appropriate.

Consultation within the processes described above will allow for further stakeholder feedback on the design of the stages and their timing.

7 CHARGING: CHARGING FOR USE OF THE TRANSMISSION SYSTEM

RECOMMENDATION 5: CHARGING FOR THE USE OF THE TRANSMISSION SYSTEM

Given the need for greater interconnection identified in the ISP, concerns have been raised about whether the current inter-regional transmission charging regime adequately attributes the cost of interconnectors to those who benefit from them. The current inter-regional transmission charging arrangements provide a mechanism for TNSPs to recover some costs associated with interconnector investments from TNSPs in other regions. However, these arrangements can be considered to be crude.

Transmission pricing is always complicated and contentious, because it involves multiple objectives which are almost certain to conflict with each other. Developing a pricing method involves understanding the relative priorities of these objectives and finding suitable trade-offs between them.

In considering charging arrangements, it is important to recognise that there will never be perfection; and therefore, there is likely to be a trade-off between improved accuracy and administrative complexity and costs. Indeed, in relation to upgrading interconnectors it is not immediately clear or simple to work out who benefits, given that interconnectors:

- are looped, with flows affecting multiple regions
- are tidal, with interconnector flows reversing direction at different types of the day, in different seasons and so on.

The Commission recognises that calculating inter-regional TUOS (IR-TUOS) is complicated. However, the Commission considers that the existing IR-TUOS arrangements should, over time, adequately ensure that those who benefit from the interconnector pay for the interconnector.

Having said this, the Commission considers that there are a number of aspects of the existing IR-TUOS arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment. These should be considered in more depth through reviewing the IR-TUOS arrangements through CoGATI 2019.

In addition, part of the access reforms discussed in the previous chapter involves generators paying for transmission. This raises broader questions about the rest of the TUOS framework. In order to allow a holistic consideration of TUOS issues, alongside the implementation of access reform, CoGATI 2019 should scope components of TUOS that need to be revisited, with the intention for rule changes on these aspects to be submitted by the COAG Energy Council by the end of 2019, to be progressed alongside the implementation of access reform.

7.1 Background

Transmission charging arrangements determines *who* pays for the services provided by the transmission network, and *how* the costs of the transmission network are recovered.

7.1.1 Who pays for the transmission network?

As discussed in Appendix B, the focus of TNSPs, under the current framework, is to deliver a reliable supply of electricity to consumers, as well as to make offers to connect to generators and loads that wish to connect to the network. Because there is an obligation on TNSPs to reliably supply consumers, it is *consumers* who fund investments in the transmission network that enable export of energy from generators, and relieve congestion where necessary. The costs of the service (i.e. TUOS charges) associated with providing this reliable supply are therefore recovered solely from load (i.e. consumers, either directly or indirectly through their retailer).

Under the current regime, generators have the right to negotiate a connection to the transmission network and in doing so pay a connection charge that relates to the cost of their immediate connection to the shared transmission network. But, because the development of transmission infrastructure to enable the export of energy from generators only occurs to the extent that it is necessary to make sure there is a reliable electricity supply to consumers, generators do not pay any form of TUOS charge.

7.1.2 How are the costs calculated?

TNSPs are subject to economic regulatory oversight by the AER in relation to their augmentation, replacement, operating and maintenance costs for the provision of prescribed transmission services. TNSPs must apply to the AER, for the AER to assess their revenue requirements. The AER sets a maximum allowed revenue that a network can recover from consumers during a regulatory period. The TNSP's maximum allowed revenue is recovered through TUOS charges to consumers. TNSPs recover their allowed revenue from consumers in their region.[95] This also applies for interconnector assets, meaning that consumers pay for the assets that are geographically in their region.[96]

Under Chapter 6A of the NER there is a set of pricing provisions, which set out how TNSPs are to recover their allowed revenue through TUOS charges. These are based on a set of pricing principles and require TNSPs to develop separate prices for each category of prescribed transmission service.[97] Each TNSP must also publish a pricing methodology which, in part, sets out how the revenue to be recovered has been allocated to each category of prescribed transmission service.

The majority of the TUOS services component of prescribed transmission services are recovered in the form of either a locational or non-locational charge. The split between the

95 Possibly via a coordinating TNSP and/or a DNSP.

96 It is unclear, where regions are not neighbouring,i.e. for a Victorian - Tasmanian interconnector - who should pay for the assets.

97 Clause 3.6.5(a)(5) of the NER provides for jurisdictions to establish inter-regional charges through inter-governmental agreement. However, in practice, inter-regional transmission service payments have been negotiated only between South Australia and Victoria.

locational and non-locational components of TUOS services can be either on a 50:50 basis (standard cost reflective network pricing), or based on a reasonable estimate of future network utilisation and the likely need for future transmission investment (modified cost reflective network pricing), which has the objective of providing more efficient locational signals.[98]

In addition to charging customers within their region for use of the transmission system, the NER includes inter-regional transmission charging arrangements. An inter-regional charge is levied by TNSPs in the electricity exporting region on the TNSP in the importing region of the NEM. The charge is recovered from the customers in the importing region. The amounts recovered from the inter-regional transmission charge are then passed onto consumers in the exporting region in the form of lower transmission charges. This charge improves the cost-reflectivity of transmission charges and the allocation of costs across regions.

Given inter-regional transmission charging has been a focus of stakeholder comment in this review, we explore this in further detail in the below section.

7.1.3 Inter-regional transmission charging

The current inter-regional transmission charging arrangements were introduced in 2013, when a mechanism was introduced for TNSPs to recover some costs associated with interconnector investments from TNSPs in other regions. The Commission's final determination to introduce these arrangements recognised that this was needed given the interconnected nature of the NEM, and to provide efficient price signals for TNSPs to undertake investments where the benefits may extend to other regions.[99]

TNSPs in each region levy a charge - a modified load export charge - on TNSPs in neighbouring inter-connected regions. Customers pay a share of the costs of transmission used to import electricity into their region from neighbouring regions. Given all regions import and export electricity, it results in a net payment between TNSPs of neighbouring regions.

The modified load charge, as calculated under the current arrangements, only recovers the locational component of TUOS charges. The locational component only covers half of the revenue required to recover the costs of prescribed TUOS charges.

BOX 4: OPERATION OF THE MODIFIED LOAD EXPORT CHARGE

This box provides additional detail on how the modified export charge is calculated for the purposes of inter-regional transmission charging. Assume that region "A" TNSP's system has only one interconnector with region "B" TNSP's system, the modified load export charge operates as follows:

98 NER clause 6A.23.3(d)(1)-(2).

99 The new rules were introduced in 2013 and introduced a new inter-regional transmission charge for consumers. The inter-regional transmission charge commenced on 1 July 2015 and is levied between transmission businesses in neighbouring regions. Transmission businesses will recover this charge from individual consumers through the locational component of their regulated (prescribed) TUOS charges.

1. **Determine the aggregate annual revenue requirement** - The aggregate annual revenue requirement is determined being the revenue requirement for the provision of prescribed transmission services.[1]
2. **Split the aggregate annual revenue requirement into the annual service revenue requirement** - The aggregate annual revenue requirement is split among four categories of prescribed transmission services – entry services, exit services, prescribed common services and prescribed TUOS services. The amount to be recovered for each category is called the annual service revenue requirement. The IR-TUOS arrangements only apply to the prescribed TUOS service category.
3. **Split the annual service revenue requirement for prescribed TUOS services** - The region A TNSP splits the annual service revenue requirement for prescribed TUOS services on a 50/50 basis into a non-locational and locational component.[2]
4. **Recovery of non-locational component** - The non-locational component is recovered on a postage stamp basis, being a charge that does not vary by location of the transmission customer or their level of utilisation of transmission assets.
5. **Allocating the locational component to determine the modified load export charge -** The locational component is then allocated to the connection points of transmission customers within the A region TNSP's transmission system plus the connection point between the B TNSP and A's system using the prescribed cost reflective network pricing methodology. The prescribed cost reflective network pricing methodology attributes the cost of transmission assets to the connection points based on their proportionate use of the investing TNSP's system.[3] This is done based on the non-coincident level of peak utilisation of those assets by the transmission customers and TNSP B over the past regulatory year.
6. **Modified load export charge -** The modified load export charge is the locational charge from step 5 for the B region connection point. The modified load export charge is trued up in subsequent years to reflect actual utilisation in the regulatory year.
7. **Billing -** The region B TNSP will undertake the same process to determine the modified load export charge payable by TNSP A. Each TNSP will bill each other the modified load export charge and ultimately there will be a net amount payable by one of the TNSPs. Receipt of the net payment flows through as a reduction to the intra-regional pricing for the transmission customers in the receiving region and vice versa.

Note: [1] The aggregate annual revenue requirement is the maximum allowed revenue adjusted in accordance with clause 6A.22.1.

Note: [2] The AER may approve an alternative method that better reflects future investment.

Note: [3] There are actually two allocations done by TNSP A. The first allocation is done using a cost reflective network pricing methodology (which does not need to be the prescribed methodology) but only for intra-regional customer connection points, i.e. excluding the region B connection point. This allocation is used to determine prices for intra-regional customers. The second allocation which the Commission described is only for the purposes of determining the modified load export charge for the region B connection point. For simplicity, the Commission did not consider the impact of settlement residues arising from regulated interconnectors.

7.2 Stakeholder submissions

A number of stakeholders have commented to the Commission on the existing IR-TUOS arrangements, particularly how these operate in relation to interconnectors. A number of stakeholders consider that the existing approach is "crude" and should be reconsidered:

- UPC consider that costs should be proportioned on a benefit basis, with the NER not currently allowing this and so distorting the cost allocation.[100]
- Energy Networks Australia considers that alternative pricing arrangements, particularly for interconnectors, may be appropriate.[101]
- Hydro Tasmania notes that the historical approach of allocating interconnectors to customers is likely to require rethinking.[102]

PIAC considered this in more detail and noted that the RIT-T is designed as a NEM-wide cost benefit analysis and so as a result the modelling is insensitive to where in the NEM these costs or benefits occur - it only considers the total costs and total expected benefits across all customers throughout the NEM. For projects which are incremental expansions or reinforcements of the existing network, PIAC considers that this misalignment would not pose a significant issue as the expected benefits from the investment accrue exclusively to consumers within the network's jurisdiction. However, PIAC considers that this is not necessarily the case for more strategic or nationally significant investments such as those on interconnectors, national transmission flow paths and projects closer to the borders between meshed network jurisdictions. In these cases, a significant proportion (even the majority) of benefits may accrue to another jurisdiction. PIAC considers that this misalignment effectively means that one set of consumers may be paying for the benefits received by a different set of consumers.[103]

7.3 Commission's analysis and conclusions

Given these concerns raised by stakeholders, the Commission has considered whether the existing IR-TUOS arrangements sufficiently align costs and benefits of transmission investment between the regions.

7.3.1 Expansion of interconnectors and benefits

Given the arguments made by stakeholders about who *benefits* from interconnector capacity, it is first useful to consider who benefits from interconnectors.

At its simplest, interconnectors are constructed to increase trade of electricity between regions. Taking the example of an interconnector built between regions X and Y, then:

- For the region that is exporting (region X), the price will increase due to more generation being dispatched. Therefore, generators in region X will benefit since the increased

100 UPC, submission to the options paper, *Coordination of generation and transmission investment,* 19 October 2018.

101 Energy Networks Australia, submission to the options paper, *Coordination of generation and transmission investment,* 19 October 2018.

102 Hydro Tasmania, submission to the options paper, *Coordination of generation and transmission investment,* 19 October 2018.

103 PIAC, submission to the options paper, *Coordination of generation and transmission investment,* 19 October 2018.

capacity on the interconnector allows more generators to be dispatched, and so earn money in the wholesale market.

- However, the prices between the two regions will converge. Typically, the prices in the exporting region will increase; while the prices in the importing region will decrease. Therefore, while generators in the exporting region will benefit from increased dispatch and higher prices, some of this will be at the cost of consumers in the exporting region paying higher prices (typically called a "wealth transfer").
- For the region that is importing (region Y), the price will decrease due to having an increased supply of generation from region X generators exporting to region Y. Therefore, consumers in region Y will benefit from having access to more and cheaper generation.
- Similarly, given the prices converge, the generators in region Y will receive lower prices.
- In addition, in the NEM, when prices between regions separate congestion rents are created. In the NEM, this is called the inter-regional settlements residue. The value of the inter-regional settlements residue is equal to the difference between the price paid by retailers in an importing region and the price received by generators in an exporting region, multiplied by the amount of flow across the regional interconnector.[104]Therefore, given the capacity of the interconnector has increased, there will be the creation of new inter-regional settlement residues. These residues are auctioned off by AEMO, with parties able to purchase these to help hedge the risks of trading across multiple regions. The proceeds of these auctions go to offset TUOS fees TNSPs charge end users in the importing region. Therefore, the benefits associated with this component of the interconnector expansion will flow through to the consumers in the importing region.

However, the consideration is not this simple in practice:

- There is the possibility of looped regions. For example, if the SA-NSW interconnector is built, the interconnectors between NSW, Victoria and South Australia will form a loop. The expansion of the SA-NSW interconnector (from zero) is likely to impact Victoria, as well as NSW and South Australia.
- Further, interconnectors in the NEM are tidal with interconnector flows reversing direction at different types of the day, in different seasons and so on. Therefore, it is very difficult to determine what is the "importing" or "exporting" region, since which region is the importing region will change depending on a number of factors.
- The above analysis is static. A large interconnector expansion is likely to create an initial step-change in the prices between the two regions, creating short-run gains or losses for generators in the region with the price increase, or decrease, respectively. However, in the long-run these will be eroded by investment or retirement decisions being made by generators and potentially changing consumption patterns for consumers.
- In addition, there are likely to be other benefits associated with interconnectors that relate to aspects other than increasing trade. For example, construction of an interconnector enables sharing of frequency control ancillary service resources, reducing overall frequency control ancillary services requirements for a particular region, but also

104 It also includes a reduction due to losses in the two associated regions interconnectors.

increasing competition for provision of these services. In addition, interconnectors assist with sharing diversity between the loads and generation between the regions, as well as the ability to share reserves. All of these factors are harder to quantify.

Because of these various conflicting factors, it cannot be said with certainty - even for very simple scenarios for interconnector expansion - who the benefits of the interconnector will flow to.

BOX 5: EXAMPLE: SA-NSW INTERCONNECTOR

There has been substantial modelling done on the benefits and impacts of the proposed new SA-NSW interconnector to illustrate some of the concepts discussed above with real numbers. Aside from undertaking a RIT-T to estimate the total market benefits from the SA-NSW interconnector, ElectraNet has commissioned consultant (Acil Allen) to develop forecasts of regional price impacts.

Consulting firm, The Energy Project, in its submission to the project assessment draft report for the SA Energy Transformation RIT-T where this new interconnection is being considered, has used these price forecasts to estimate the benefits accruing to consumers in NSW and SA, based on a simple calculation: multiplying the annual average price change by the annual regional load and then discounting these annual amounts to establish a net present value of estimated benefits that can be compared to the allocation of interconnector costs.

This is a reasonable approach for estimating wealth transfers. However, this analysis does not include some other aspects that affect who the benefits fall to, in particular, the congestion rents on existing interconnectors (i.e. the inter-regional settlements residue that accrues when prices between regions separate. The value of the inter-regional settlements residue is equal to the difference between the price paid by retailers in an importing region, and the price received by generators in an exporting region, multiplied by the amount of flow across the regional interconnector). These amounts are quite high, which further underpins the argument that the interconnector investment is needed.

Table 7.1 shows some back-of-the-envelope adjustments to The Energy Project figures, based on the following assumed (and admittedly speculative) changes to inter-regional settlements residue proceeds:

1. In the "without SA-NSW interconnector" scenario, inter-regional settlements residue levels remain indefinitely at the settlement residue auction clearing prices seen in the last twelve months.
2. In the "with SA-NSW interconnector" scenario, all inter-regional congestion is removed, leading to zero inter-regional settlements residue.

These assumptions apply to all of the relevant interconnectors: SA-NSW, NSW-Vic and SA-Vic.

Table 7.1: Back-of-the-envelope benefits calculation

	SA BENEFITS ($M NPV)	NSW BENEFITS ($M NPV)
RRP Benefits (The Energy Project Analysis)	1006	854
Loss of existing inter-regional settlements residue	(1308)	(480)
Net Benefit	(302)	374

Source: Create Energy Consulting analysis for the AEMC.

The inclusion of possible inter-regional settlements residue impacts substantially changes the picture. In The Energy Project analysis, the majority of benefits go to SA. In contrast, after allowing for the inter-regional settlements residue impact, it is possible that SA actually incurs a cost, with NSW continuing to receive a benefit. While this could be argued to be because the assumptions around the inter-regional settlements residue are unrealistic and inconsistent with the regional reference price projections, it nevertheless serves to demonstrate the importance of modelling and incorporating inter-regional settlements residue impacts. The analysis also fails to consider possible benefits or costs flowing to other regions (e.g. Victoria). This demonstrates that the Commission considers that the impact of other regions, and congestion rents, must be considered in order to get a useful estimate of the allocation of interconnector benefits.

Source: Creative Energy Consulting analysis for the AEMC.

7.3.2 Existing arrangements

Allocation of costs

Regulated interconnectors are funded through the regulated revenue for the TNSP from consumers in the adjoining regions to cover the costs of the investment. Under the current arrangements, regulated interconnectors must demonstrate that they are efficient by passing the RIT-T. This requires not just *positive* net benefit, but *maximum* net benefit, so only the best regulated interconnector projects should get funded and built.

The costs of a TNSP's assets are recovered from consumers in the region in which the assets are located - although this is relatively arbitrary. For example, in the case of the SA-NSW interconnector, almost two-thirds of the cost relates to new transmission assets in NSW and so would be paid for by NSW consumers.

In addition, the transmission network is interconnected, and changes over time. This means that some parts of an interconnector could become important for sustaining or maintaining intra-regional flows over time. This could help jurisdictional reliability standards to be met. It is possible that some of these components of an interconnector could therefore have been built anyway as part of an intra-regional investment. If this is the case, then the costs of the interconnector should reflect the bring forward cost of the asset, not the full cost.

In the RIT-T, the cost of these future int*ra*connectors – in the event that the interconnector is not built first – are commonly referred to as *deferred transmission benefits*. For example, in the SA-NSW interconnector RIT-T, the deferred transmission benefits are estimated to be $300m, compared to the full interconnector cost of $1500m. So we can think of this as the new interconnector costing $1200m.

The RIT-T does not specify in which region these benefits were predicted to arise. Assume, for example, that these arose entirely within NSW. Now NSW's geographic contribution of $1100m can be considered to be composed of two components: $800m for the interconnector and $300m for the future intraconnector. So, in summary, we have a $1200m interconnector cost, split 400:800 between SA and NSW. Alternatively, we can put the future intraconnector on the *benefits* sides of the ledger. So, whilst the interconnector cost is still $1500m, split 1100:400 between NSW and SA, NSW obtains $300m of benefits over and above the market benefits discussed in the previous section.

Pricing of transmission

In addition, since the proceeds of the inter-regional settlements residue flow through to TUOS, consumers also bear the benefits of price separation between regions through the congestion rent.

As described above, inter-regional transmission charging was introduced in 2013. This provides for some (net) payment from the TNSP in one region to the TNSP in the other, with corresponding flow on effects for the respective consumers. However, the inter-regional transmission charging only allocates the *locational component* of an asset's cost, which is typically around 50 per cent of the full cost.[105] The remaining costs are recovered through simple, postage-stamped, non-locational TUOS prices, which apply within each region and so does *not apply* inter-regionally.

7.3.3 Appropriateness of inter-regional pricing arrangements

A key design feature of the modified load export charge (i.e. the IR-TUOS arrangements) is that it uses the transmission pricing method, cost reflective network pricing, that was originally designed and implemented for intra-regional TUOS.

Transmission pricing is always complicated and contentious, because it involves multiple objectives which are almost certain to conflict with each other. However, the philosophy that is being articulated by PIAC is that the IR-TUOS arrangements should reflect a beneficiary pays approach. A beneficiary pays approach is based on the idea that the most efficient allocation of resources occurs when consumers pay the full cost of the goods that they consume.

An alternative approach would be to use long-run marginal cost pricing. A long run marginal cost approach aims to send a suitable price signal to consumers to encourage them to modify

105 Which approximates a long run marginal cost component.

their consumption in a way that maximises the net value (service value minus cost-to-serve) of the transmission system: current and future. This is where prices reflect marginal cost. The intra-regional pricing methodology seems to be inline with a long-run marginal cost approach to pricing. For example, the locational component is only applied to 50 per cent of the value of each asset. This is consistent with the rule-of-thumb that the long run marginal cost of transmission is around 50 per cent of the average transmission cost. This is consistent with the fact that in the intra-regional context, it would be expected that the alignment of costs and benefits on an individual project is of lower concern, given this is likely to be averaged over multiple projects.

There are similarities in price outcomes between the two approaches, but also some important differences:

- Similarities - Both outcomes are likely to reflect historical or predicted transmission flows. A consumer clearly benefits from upstream assets: if they didn't exist, the consumer's supply would be less reliable. Any increase in their consumption would increase flows on these assets, bringing forward the need for future investment. Both philosophies use flow-based analysis to allocate the historical or future costs of a transmission asset to downstream consumers.
- Differences - The beneficiary pays model does not reflect spare capacity, whereas in a long run marginal cost model if capacity is tight, increased consumption is more likely to prompt new investment, implying a higher long run marginal cost (and vice versa).

In terms of introducing IR-TUOS, the Commission considered a beneficiary pays pricing option. However, the final decision was not to adopt this, but instead to use the existing method for calculating the locational component of intra-regional TUOS.

The Commission's key concern with the particular beneficiary pays option that it considered in 2013 was that it locked in for perpetuity an initial estimate of benefit allocations. These predictions might well turn out to be wrong - and even perverse - from the viewpoint of future customers (given that transmission assets are paid off over 30 or 40 years). Indeed, the examples discussed above about the complexities of considering who benefits from interconnectors illustrates this point.

In order to avoid these inefficiencies, the Commission considered instead that inter-regional charges should be updated regularly to reflect the current use of the interconnector assets. While this could potentially be done by periodically revisiting the benefit predictions, it is likely that this would be problematic and contentious - driven by the winners or losers at that particular point in time. So, the AEMC decided that adapting IR-TUOS charges to new and varying circumstances was best done annually, using the locational method for intra-regional charging. In effect, this adopted a beneficiary type approach.[106]

106 Indeed, long run marginal cost price signals do not make sense in the context of interconnector investments since: regional price differences across the interconnector already reflect short run marginal cost, by incorporating marginal losses and congestion costs; and interconnector usage is driven by dispatch outcomes, which in turn primarily reflect generator bidding decisions. So, if the aim were to influence interconnector usage, the price signals would need to sent to *generators*, not *consumers* who pay for interconnectors.

7.3.4 Conclusions

Inter-regional TUOS could be modified

The Commission recognises that calculating IR-TUOS is complicated. Further, the Commission does not think that some of the recent suggestions or applying a static beneficiary pays principle to the calculation of IR-TUOS would be efficient. Broadly, the existing IR-TUOS arrangements should, over time, adequately ensure that those who benefit from the interconnector pay for the interconnector.

Having said this, the Commission considers that there are a number of aspects of the existing IR-TUOS arrangements that could potentially be refined to better reflect who benefits from interconnection, and who should pay. For example, the Commission considers the following aspects should be considered further:

- **Should the pricing methodology be modified to allocate costs based on average load, as opposed to peak load?** Transmission costs are currently allocated to load points based on their non-coincident peak demand. However, as per the above, it is clear that benefits vary depending on a number of factors. While generally a region is more likely to be importing when its demand level is high, there can be other factors that affect this. For example, the SA-NSW interconnector is likely to be towards NSW when it is windy in SA; and towards SA when it is calm, regardless of the underlying demand levels. It may be worth the IR-TUOS reflecting this. One way to do this could be to consider whether costs should be allocated based on average load, rather than non-coincident peak load.
- **Should the non-locational components of the inter-regional investment be included in the inter-regional transmission charge, rather than smearing it across the customers in the region?** The locational component of TUOS only allocates 50 per cent or so of the value of each asset. The remaining value is recovered through a non-locational "postage-stamp" charge where there is a single $/MW or $/MWh price applied to every load in the region. For the inter-regional charging arrangements, the locational 50 per cent of asset value is added to the charges. However, the non-locational charge is not added. Therefore, if we are considering aligning the costs and benefits of a new interconnector, we should consider whether the non-locational charges should also be included. We should also recognise that pricing of transmission is different to cost allocation.[107]
- **Should the TNSP be able to discount the non-locational elements of the inter-regional transmission charge?** There are prudent discounting arrangements that a TNSP can apply to intra-regional transmission charges. Under these arrangements, a TNSP is permitted to discount the non-locational charges - possibly down to zero - applying to a particular customer if it considers that this is in the interest of consumers as

107 The Commission did consider levying non-locational prices on the interconnector in 2013, but did not proceed with this for two reasons: there is a risk of inconsistencies between regions given TNSPs use different methods to calculate cost reflective network pricing; and there was a concern amongst stakeholders that this would amount to transferring, unjustifiably, some of the "sunk costs" of the network in one region to consumers in the neighbouring region. The first concern could be addressed by applying a standardised method to calculate the non-locational tariff, which is done for the locational component. In response to the second point, this is consistent with the principle described above that interconnector costs should be allocated on a beneficiary-pays philosophy.

a whole. This benefit could arise because of the price sensitivity of the customer, in which the full non-locational charge would cause it to close or relocate its business or find a means to bypass the transmission system. Prudent discounting arrangements allow a TNSP to take some factors into account, i.e. the customers willingness or ability to pay – which could not feasibly be incorporated into the transmission pricing method. This additional flexibility could lead to better outcomes for consumers as a whole. This flexibility may be useful in the inter-regional context.

Therefore, there may be some elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment. We will consider these questions further - and any other suggestions that may arise through the consultation process - in reviewing the IR-TUOS arrangements through CoGaTI 2019.

Broader review of TUOS should be undertaken

As discussed in Chapter 6, the final stage of the access reforms involve generators having the option to pay for transmission in return for firm access rights. This raises broader questions about the rest of the TUOS framework.

AEMO also considers that there is a broader issue with the pricing arrangements for distribution and transmission networks that needs to holistically review how network costs are recovered from whom.[108]

In order to allow a broad consideration of TUOS issues, alongside the implementation of access reform, CoGaTI 2019 should scope components of TUOS that need to be revisited.

Consideration of TUOS would involve:

- identifying pricing principles for TUOS and testing and agreeing on these with stakeholders, e.g. some principles may include **transparency** around the pricing methodology
- considering the **impact of recent trends and market outcomes** and how these may change the dynamics and use of the principles, e.g. entry of variable renewable generation, which has a variable output that depends upon local weather conditions, may create more variability about how the transmission network is used, which could impact on how it is priced
- considering the **impact of market design changes** and how this could impact on transmission pricing - this could include the introduction of five minute settlement, as well as the proposed access reforms
- developing sequencing for TUOS reform, by categorising:
  - discrete elements of the TUOS pricing method that can be tackled separately
  - the types of interdependence between the market issues and these discrete elements
  - the predictability of the various market changes.

108 AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM,* November 2018.

8 CONNECTION: TREATMENT OF ELECTRICITY STORAGE

RECOMMENDATION 6: CREATE A NEW REGISTRATION CATEGORY FOR ENERGY STORAGE SYSTEMS

The ISP identified that storage will have a large role to play in the future NEM. Electricity storage technologies have the potential to provide benefits to both the operators of those assets and the electricity grid more broadly.

Several large-scale energy storage systems have recently connected to the grid. AEMO is receiving an increasing number of enquiries and registration applications from storage proponents and expects this growth to continue.

This has raised some questions about the applicability and appropriateness of the existing regulatory framework for large-scale energy storage technologies, including hybrid systems. The appropriate NEM registration category that should apply to energy storage systems, and consequently how they should be treated within the regulatory framework, are issues that require long-term solutions.

To improve clarity for energy storage system proponents and remove operational inefficiencies for registered participants and AEMO, the Commission recommends that:

- AEMO submit a rule change request to create a new NEM registration category to accommodate energy storage systems.
- Whether or not it is appropriate for energy storage systems to pay TUOS be considered in the context of the rule change. The Commission's preliminary position aligns with that of AEMO's, i.e. if an energy storage system is a scheduled resource and can be constrained off the network, it should not be required to pay TUOS charges.
- Apart from TUOS, the rule change request should consider what other regulatory obligations should be placed on participants registered under the new category for energy storage systems.

8.1 Background

As set out in the discussion paper and options paper for this review, electricity storage technologies have the potential to provide benefits to both the operators of those assets and the electricity grid more broadly. AEMO is receiving an increasing number of enquiries and registration applications from proponents with "non-traditional" business models, and expects this growth to continue.[109] These include requests to register and connect energy storage

109 AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM*, 2018, p.3.

systems as stand-alone systems or in a "hybrid" system (coupled with new or existing generating systems and industrial loads).[110]

Four large-scale energy storage facilities have recently connected to the NEM:

- A 100 MW, 129 MWh lithium-ion battery storage system at Neoen's Hornsdale wind farm near Jamestown in South Australia. The Hornsdale Power Reserve utilises Tesla's technology and commenced operation in December 2017.
- A 30 MW, 8 MWh lithium-ion battery storage system at the Dalrymple substation on the Yorke Peninsula in South Australia. The Energy Storage for Commercial Renewable Integration, South Australia (ESCRI-SA) project is owned by ElectraNet and will be operated by AGL, and is due to be commissioned in the coming months.
- A 30 MW, 30 MWh lithium-ion battery storage system at the junction of four major transmission lines at AusNet Services's substation near Ballarat in Victoria. The Ballarat Energy Storage System is owned by AusNet Services and operated by Energy Australia. The battery is now registered and operating.
- A 25 MW, 50 MWh lithium-ion battery co-located with the 60 MW Gannawarra solar farm near Kerang in northern Victoria. The Gannawarra Energy Storage System will be jointly owned by Edify and Wirsol, and operated by Energy Australia. It is now complete and in the process of being fully commissioned.

AEMO noted in its stakeholder paper, *Emerging generation and energy storage in the NEM*, released in November 2018:[111]

> (New registration application) requests raise concerns about the appropriate registered participant categories to apply to an energy storage system, and more broadly around participation of energy storage systems under the regulatory framework. AEMO has also become aware that its systems and processes were not designed for energy storage systems or the types of new grid-scale business models that are being proposed now or may be proposed in the future.

Table 8.1 lists some of the energy storage facilities that are expected to connect to the transmission network in the near future.

Table 8.1: Energy storage projects in construction and planning

Northern Territory
• 5 MW/3.3 MWh chemical battery at Alice Springs
Queensland
• 2 MW/4 MWh lithium-ion battery being constructed alongside a solar and wind farm at Kennedy Energy Park
• 250MW pumped storage hydro project at Kidston Gold Mine

110 Ibid.

111 AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM*, November 2018, p.3.

• 20 MW/80 MWh chemical battery storage at Cape York Solar Storage project (battery and solar farm) • 100 MW chemical battery at Kaban Green Power Hub (combined with a wind farm) • Gympie Regional Energy Hub - Stage 2 - solar farm and chemical battery storage
New South Wales • Feasibility study recently completed into the potential expansion of the Snowy Hydro Scheme - Snowy Hydro 2.0
Victoria • 20 MW/34 MWh chemical battery to power glasshouse at Stawell planned (battery and wind farm) • 20 MW/34 MWh chemical battery at Bulgana Green Power Hub (battery and wind farm) • 80MW/320MWh chemical battery storage at Nowingi Solar Storage project (battery and solar farm)
Tasmania • Feasibility study for expansion of Tasmanian hydro
South Australia • 100 MW/400 MWh chemical battery storage at Kingfisher Solar Storage project (battery and solar farm) • 100MW/400MWh chemical battery storage at Riverland Solar Storage project (battery and solar farm) • 10 MW chemical battery at Lincoln Gap Wind Farm • 21 MW chemical battery at Snowtown North Solar Farm • 6 hydrogen fuel cell buses to be built near Adelaide • Australia's biggest solar thermal storage plant scheduled to open in 2020 near Port Augusta • Planning is under way on the Eyre Peninsula for the largest salt water pumped hydro facility in the world

Source: The Climate Council and https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

Note: These expected projects will add to the storage facilities already in operation not listed at the beginning of this chapter: 240 MW Shoalhaven Scheme pumped hydro storage facility, built in 1977 (NSW); Snowy Mountains pumped hydro scheme, built in 1973 (NSW); Pumped Hydro at Lake Wivenhoe (QLD's first pumped hydro facility, built in 1984); Alinta's 30 MW chemical battery at the Newman power station in the Pilbara (WA); 6 MW/1.6 MWh chemical battery at the Degrussa copper and gold mine (WA).

As can be seen in Table 8.1, energy storage technologies are not limited to batteries. However, the experiences of the battery storage systems at Hornsdale wind farm, the Dalrymple substation, the Ballarat substation, the Gannawarra solar farm and the increasing registration applications and interest from energy storage proponents have raised some questions about the applicability and appropriateness of the existing regulatory framework for energy storage technologies. Specifically, since storage facilities both "generate" and "consume", these lead to questions of:

1. Under what participant category (or categories) energy storage technologies should be registered? This includes consideration of the appropriate registration category for hybrid facilities e.g where an energy storage facility and a wind farm are co-located behind a connection point.
2. Whether transmission-connected energy storage technologies should pay TUOS charges?

These questions have been explored by the Commission as part of this review. Stakeholders provided feedback on the Commission's discussion of these issues.

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

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

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

8.2 Registration of energy storage and hybrid systems

8.2.1 Background

For the four grid-scale energy storage systems that have connected in the NEM to date, AEMO and the AER have put in place interim measures and agreed certain arrangements with the proponents of the projects, to get them connected. In 2017, AEMO published its views on how to apply the existing NER to the connection of utility-scale battery storage facilities.[112] The document explains that, under the existing NER, such facilities should be required to register as both market generators and market customers (if they have an aggregate nameplate rating over 5MW), and should discuss the process for negotiating TUOS charges with the relevant TNSP consistent with principles set out in the NER. This is consistent with the Commission's conclusions in our 2015 report on the integration of storage, which set out our views on how storage facilities could connect under the existing arrangements.

However, in its 2017 advice, AEMO concluded that there may be scope to improve the NER as they apply to batteries and other forms of storage to develop "comprehensive and robust long term arrangements." These improvements include changes that could be made to the way hybrid generation facilities – that is, those that combine an energy storage system with a form of generation, such as wind or solar – are treated. These facilities again raise questions about the appropriate way to register them for participation in the NEM.

To progress this work and seek stakeholder feedback on its developing views, AEMO launched a project on reviewing *Emerging generation and energy storage in the NEM.*[113]

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

113 AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM*, November 2018.

In the Commission's options paper, we expressed the view that a more holistic look at the registration framework in the NER may be needed to make sure that the participant categories sufficiently accommodate and support the participation of existing and emerging technologies and business models into the future, and to reduce operational complexity and administrative burden for AEMO and participants. The Commission noted that such a review could consider whether the existing approach to registering participants is appropriate, or whether an alternative approach should be pursued. For example, we noted that the framework could be amended to categorise participants based on:

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

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

Any significant change to the registration framework in the NER would need to be reflected throughout the rest of the NER framework. The Commission stated that any change to the approach to registering energy storage and hybrid facilities would need to include consideration of many issues, not just TUOS charging. For example, the introduction of a registration category specifically for storage would need to consider, among other things:

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

8.2.2 Summary of submissions

In submissions to the options paper, there was strong stakeholder support for the development of a new NEM registration category for energy storage systems. In its submission, Tesla stated that "(battery) energy storage does not fit well within any of the classifications for traditional types of participants in the energy market. While storage assets most closely resemble a generator in the services they provide to the market, they...are not, technically, a generator. The controllable nature of the load side of a storage asset, as well as the services that it can provide whilst charging, including both frequency and voltage support – also means that it's more than a traditional market load."[114]

Adani Renewables and the Clean Energy Council stated that the creation of a registration category for storage would be an acknowledgement of the emerging capability to provide services beyond traditional generation and load services.[115]

The Australian Energy Council suggested in its submission that this new participant category should be sufficiently flexible to allow the proponent to participate in the markets it chooses, for example, energy and ancillary services, and the manner in which it chooses, such as scheduled or non-scheduled.[116] Similarly, AGL stated in its submission that it may be necessary to introduce sub-categories of registration to remove unnecessary technical barriers to entry, whilst supporting a variety of technologies and their operational use. These sub-categories could reflect variations among energy storage systems such as battery storage versus pumped hydro, scheduled versus non-scheduled, and hybrid assets classified as semi-scheduled. AGL considered that these additional registration categories may also simplify administrative functions undertaken by AEMO by reducing complexities in the application and review process.[117]

In relation to the potential for establishing specific definitions and registration requirements for large scale storage facilities, Aurizon cautioned in its submission that care should be taken to avoid capturing demand customers with bi-directional energy flows from energy recovery systems, such as ports, railways and mines.[118]

In its submission, the Public Interest Advocacy Centre (PIAC) stated that a new registration category should be technology neutral and based on whether the facility both injects and draws material quantities of energy through its connection point. PIAC's view is that a separate registration category would encourage a more holistic integration of grid-connected storage into the regulatory and operations system of the NEM, rather than potentially having to compromise between the generation and load categories.[119]

PIAC also stated that the definition of the new storage-specific category must be based on the potential impact from the point of view of the wholesale market and network, such as whether the particular facility both draws and injects material quantities of energy through its connection point.[120]

Specifically on the issue of hybrid systems, Enel Green Power strongly encouraged the introduction of a separate registration category for hybrid systems as soon as possible to

114 Tesla, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.1.

115 Australian Energy Market Commission, *Coordination of generation and transmission investment*, Adani Renewables p.5; Clean Energy Council p.5.

116 Australian Energy Council, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.4

117 AGL, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.3.

118 Aurizon, submission to options paper, *Coordination of generation and transmission investment*, 23 October 2018, p.5.

119 PIAC, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2019, pp.13-14.

120 PIAC argued that this impact-based categorisation allows for the many possible configurations of storage, including when it is part of a hybrid system. Ibid, p.14.

reduce duplication as well as current development and operating costs.[121] Tesla also supported an approach that allows for the co-location of multiple assets behind a single point of connection in order to realise greater utilisation of existing network infrastructure.[122]

In its submission, Palisade strongly supported the introduction of a framework where participants can define each service individually for registration, regardless if they are buying or selling into the market.[123] This would include that the participant can register to both sell and buy without restriction. Such a framework would allow for flexibility and reduce restrictions to fully access the revenue opportunities that storage facilities offer.[124]

8.2.3 AEMO's views

Building on what the Commission articulated would need to be considered when thinking about the registration of energy storage systems, and whether they should pay TUOS, AEMO's stakeholder paper proposes steps for how grid-scale energy storage systems could be better integrated into the NEM, enabling the NEM framework to incorporate new business models.[125] The AEMC agrees with AEMO that a more transparent and durable approach to addressing the questions of registration and TUOS charging is required.

As part of its consideration of how to better integrate energy storage systems into the NEM:[126]

> AEMO considers that there is a broader issue with the pricing arrangements for distribution and transmission networks that needs to more holistically review how network costs are recovered and from whom. A holistic review is the appropriate mechanism to identify whether it is appropriate to charge TUOS for energy storage systems, whether participating in the NEM as a stand-alone energy storage system or aggregated with other resources.

The issue of a holistic review of TUOS charges across the NEM is considered by the Commission in Chapter 7.

In its stakeholder paper, AEMO suggests a definition of energy storage system for use in the NER that is technology neutral and incorporates all storage types: "A resource capable of receiving imported energy from the national grid or other energy source and storing it for

121 Enel Green Power, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.4.

122 Tesla stated that due to the current interim classification of battery storage assets, project developers looking to combine their renewable assets with storage need to find ways to preserve the renewable generator's classification as semi-scheduled, whilst the battery is separately registered as both a scheduled generator and market customer. Tesla, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.10.

123 Palisade added that if the participant is only able to register either as a customer or a generator the participant would be constrained to only sell or buy electricity. This restriction will act as a barrier for the introduction of new technology and innovation because it limits market entrance opportunities. Palisade supports the proposal to allow participants to register for a range of different categories under the proposed framework. Palisade, submission to the options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.13-14.

124 Ibid, p.13.

125 AEMO, *Emerging generation and energy storage in the NEM*, 2018.

126 AEMO, stakeholder paper, *Emerging Generation and Energy Storage in the NEM*, November 2018, p.29.

later export of energy to the national grid or Customer located (or connected) at the same site."[127]

In proposing a pathway forward for integrating energy storage systems into the NEM, AEMO is seeking input on different options for registering these facilities. These include:

1. Create a new Registered Participant category for grid-scale energy storage systems.

2. Create a 'hybrid' Registered Participant category.

2a. Create a new Bi-directional Resource Provider Registered Participant category that allows a person to register to provide a 'hybrid' system including grid-scale energy storage systems, generation or load.

2b. Amend the Generator or Customer Registered Participant category to include energy storage systems as a classification.

AEMO's preferred option is to create a new bi-directional resource provider registered participant category, with the key benefit of this participation model being that a registered participant would provide and manage one offer and respond to a single dispatch instruction for each service.[128] AEMO considers that this model would allow proponents to register and operate more efficiently and ensure the NER's arrangements are clear for participation of bi-directional models.[129]

To integrate energy storage systems, AEMO has two parallel streams of work progressing:[130]

Stream 1 – This work stream will define energy storage systems and create a new category for bi-directional technologies to facilitate participation in the NEM. This new category would initially cover storage systems offered into the market and operated as a stand-alone resource. AEMO expects to submit a rule change to the AEMC by March 2019.

Stream 2 – This work stream involves further consultation with stakeholders and analysis of the appropriate participation model and requirements to facilitate aggregation of "hybrid systems." This new model and consequent facilitation requirements would cover situations where a proponent has an energy storage system and other on-site generation or load and wishes to offer it to the market as an aggregate resource, rather than separately participating in the market via the individual resources.

The work being undertaken by AEMO will continue to inform the Commission's consideration of these matters, and the two market bodies are collaborating on the integration of energy storage systems into the NEM.

127 Ibid, p.19.

128 Under this concept, the registered participant aggregates the physical capabilities and optimises between components of the hybrid system. AEMO market systems would treat the entire "hybrid" system as a single unit and would not be able to optimise the use of the individual resources. Ibid, p.24

129 Under this option, a proponent would register in one Registered Participant category and operate the entire facility as an aggregated hybrid system across both imports and exports. Ibid, p.27.

130 Ibid, pp.27-28.

8.2.4 Commission's analysis and recommendation

The Commission agrees with stakeholders that certainty on a long-term approach to registering electricity storage systems is needed. As stated in the options paper published as part of this review and earlier in this section, the AEMC and AEMO are working collaboratively to identify the challenges of the existing arrangements and potential solutions. Stakeholder input into this process has been very valuable.

The Commission considers that a new NEM registration category should be created to accommodate energy storage systems. As noted above, AEMO intends to submit a rule change to the AEMC by March 2019 to create a new category for bi-directional technologies to facilitate the participation of energy storage systems in the NEM. Implementation of a long-term solution for how energy storage systems are treated in the NER will reduce confusion about the appropriate registration categories for these technologies, and provide regulatory certainty for proponents of these systems. It will also support more efficient integration of energy storage systems into the NEM and reduce the operational burden for AEMO and current registered participants with regard to the participation of these systems in the market.

Currently, energy storage systems have to be registered as both a generator and a market customer, which imposes a double set of obligations on them. In this sense, creating a new registration category will reduce barriers to entry for these technology types, allowing them to be considered on equal footing as generators, and preserving the underlying NEM principle of technology neutrality.

Creating a new category for energy storage systems is also necessary in order to implement the recommendations outlined in Chapter 6 for access settlement. In order for energy storage systems to be able to be treated differently to load under these arrangements in terms of the price they pay to import electricity (the dynamic regional price rather than the existing regional reference price), they require a separate registration category that details these specific conditions and associated obligations.

As the Commission noted in the options paper, any significant change to the registration framework in the NER would need to be reflected throughout the rest of the NER framework. The many and varied NER obligations (e.g. technical performance standards) are tied to the existing registration categories. A new approach to registering storage participants would need to map regulatory obligations to the appropriate parties throughout the NER framework. Hydro Tasmania also noted that careful consideration would need to be applied in this context as registration obligations have a wide range of implications for market participants.[131]

The Commission considers that this process should be driven by an approach that is "technology neutral" and seeks to establish competitive neutrality. The assignment of regulatory obligations should be based on the access principles that apply in the NEM. Careful consideration would need to be given through a rule change to determine that the

131 Hydro Tasmania, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.8.

benefits of implementing new arrangements outweigh the potential costs of doing so. This is a view that was also expressed by TransGrid in its submission to the options paper.[132]

The Commission has a number of rule changes relating to registration categories under way, with several others expected shortly, and has previously flagged that a more holistic look at registration is required.[133] Creating clarity for storage proponents creates a pressing need for this rule change to be considered immediately. A rule change to create a new registration category for large-scale storage systems would inform any broader review of registration categories in the NEM.

8.3 TUOS charging

8.3.1 Background

What are TUOS charges?

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

1. prescribed entry services
2. prescribed exit services
3. prescribed common transmission services
4. prescribed TUOS services.[134]

While not explicit in the NER, TUOS charges (not a defined term) are used by TNSPs to recover the costs associated with their provision of prescribed TUOS services.

How are TUOS charges calculated?

Chapter 6A of the NER, among other things:

- regulates the revenues that may be earned by TNSPs from the provision of transmission services
- regulates the prices that may be charged by TNSPs for the provision of prescribed transmission services
- establishes principles to be applied by TNSPs in setting prices that allow them to earn the whole of the aggregate annual revenue requirement.[135]

The NER require a TNSP to submit to the AER a revenue proposal and a proposed pricing methodology relating to the prescribed transmission services that are provided by means of,

132 TransGrid, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.12.

133 The AEMC has received three rule change requests seeking to facilitate wholesale demand response in the NEM. These requests propose the creation of a new NEM registration category for third party demand response service providers/aggregators. In the final report for the AEMC's *Frequency controls frameworks review*, the Commission suggested that the appropriateness of the existing registration categories in light of new technologies and business models should be considered.

134 Prescribed TUOS services provide specific benefits to: (a) transmission customers who have a connection point with the relevant transmission network, based on the location of that connection point within the transmission system; and (b) TNSPs who have a direct or indirect connection or an interconnection with the relevant transmission network, based on the location of that connection or interconnection within the relevant transmission system. Chapter 10 of the NER.

135 The aggregate annual revenue requirement is the calculated total annual revenue to be earned by an entity for a defined class or classes of service. The aggregate annual revenue requirement for prescribed transmission services is the maximum allowed revenue that a TNSP may earn in any regulatory year of a regulatory control period from the provision of prescribed transmission services. See clause 6A.3.1 of the NER.

or in connection with, a transmission system that is owned, controlled or operated by that TNSP.[136]

The NER requires that:

- Prices for recovering the adjusted locational component of prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network by transmission customers and for which network investment is most likely to be contemplated.
- Prices for recovering the adjusted non-locational component of prescribed TUOS services must be on a postage stamp basis.

Who currently pays TUOS charges?

It is not explicitly stated in the NER that a TNSP must recover the costs of prescribed transmission services from transmission customers and other TNSPs (i.e. those that, by definition, receive the services). Rather, it is the definition of prescribed transmission service, the definitions of the categories of prescribed transmission services, the pricing principles and TNSPs' pricing methodologies that establish a basis by which the costs of prescribed TUOS services are recovered from those parties. So, in practice, the costs of prescribed TUOS services are recovered from transmission customers and other TNSPs through TUOS charges. As stated above, transmission customers include customers, non-registered customers and distribution network service providers (DNSPs) that have a connection point with the transmission network. TUOS charges are therefore not currently recovered from generators, consistent with the existing access regime for generators.

How do energy storage technologies fit into these arrangements?

As required by AEMO's interim arrangements for the registration of utility-scale storage,[137] the project proponents of energy storage systems greater than 5 MW are currently required to register as both a market generator and a market customer in relation to their connection points. Under the current arrangements, transmission customers (which includes market customers) pay TUOS charges.

ElectraNet sought an exemption from the AER from TUOS charges being payable for the ESCRI-SA battery on the basis that the transmission services being provided under the terms of the connection agreement between AGL and ElectraNet will comprise negotiated transmission services, not prescribed transmission services. The AER accepted this conclusion and agreed that TUOS charges would not be payable at the connection point under the NER. However, the AER did not consider that this approach should set a precedent for all future projects.[138] As the Commission noted in the options paper, under the current regulatory framework, it appears as if in the absence of any regulatory change, or bespoke

136 See: clause 6A.10.1(a) of the NER.

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

138 See: https://escri-sa.com.au/globalassets/reports/escri—-sa—-project-summary-report—-the-journey-to-financial-close—-may2018.pdf

arrangements agreed to by the AER, transmission-connected energy storage systems are liable to pay TUOS charges if they are a customer or a non-registered customer.

Implications of the current arrangements

Energy storage systems are both importers and exporters of energy. As explained above, AEMO has put in place interim arrangements requiring utility-scale storage facilities to register as both market generators and market customers to reflect this dual capability. As explained in Section 8.2, any changes to the existing approach, for example the creation of a new registration category specifically for energy storage systems, would require changes to the NER. Given the link between registration and TUOS charging, any such change would also require consideration of whether TUOS charges should be payable by transmission-connected energy storage facilities.

In the options paper published as part of this review, the Commission discussed the issue of energy storage systems and TUOS charging. The Commission outlined how this issue is currently managed, the principles underlying the TUOS framework in the NEM and considerations that would need to be a part of any analysis of whether or not energy storage systems should pay TUOS going forward.

8.3.2 Submission summary

Of those stakeholders who commented on energy storage systems and TUOS in their submissions to the options paper, the view was widely held that storage should not pay TUOS. The Australian Energy Council stated that any proposed rule to address this issue should attempt to treat storage consistent with the underlying economic principles that led to the current approach of charging customers rather than generators.[139]

Tesla expressed the view in its submission that until the question of registration is answered with regard to energy storage systems, these systems should not pay TUOS. Tesla explained that this position should "not be perceived as being counter to principles of technology neutrality, as an energy storage asset is not a traditional end-use customer (it does not "consume" electricity), nor is it a typical generator (it is not the source generation point). Storage assets also provide unique characteristics – being fully controllable, as well as providing tangible network benefits including system security, frequency and voltage support."[140]

A point made by the majority of stakeholders that commented on storage and TUOS was that TUOS would be double-charged if storage is required to pay for use of the transmission system – once when the electricity is imported by the energy storage system and again by the final end-user as the consumer of the electricity. The argument for this being a problem was that it would result in higher costs for consumers and be contrary to the NEO. In their submissions, TasNetworks and Engineers Australia argued that, aside from increasing costs to consumers, charging storage for use of the transmission system could disincentivise

139 Australian Energy Council, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.4.

140 Tesla, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2019, p. 1.

generation and storage investment as well as limit the market for auxiliary service provision.[141]

Further, a majority of stakeholders expressed the view that in cases where transmission connected energy storage is used for energy arbitrage and grid support (i.e. not driving grid augmentation), such energy storage should be treated only as a generator under the existing transmission charging regime. Monash University and Energy Networks Australia stated that if storage demand operates within transmission constraints and does not contribute to reliability indices, then it should not pay full TUoS charges. There may be some common charges that could be reasonably allocated to storage devices to support their charging operation.[142]

Infigen considered in its submission that it is appropriate for energy storage systems to be charged for the marginal cost of network use, and this is already captured by generation and load marginal loss factors. Not applying TUOS to storage would reduce complexity and uncertainty without materially impacting the efficiency of the system. Storage proponents could still negotiate with TNSPs in their connection applications and would incur shallow connection costs as necessary.[143]

A number of stakeholders identified circumstances in which, or reasons why, energy storage systems should pay TUOS charges. In its submission, S&C Electric Company stated that the electricity "retained" by electricity storage may attract TUOS, as it is properly consumed (this would mean metering both import and export to determine the consumption). It may also be deemed to be auxiliary load, as this loss is necessary to operate the electricity storage device.[144]

Going a step further, the Major Energy Users considered that, in comparison to other forms of storage, a battery should be considered as a consumer when accessing its "fuel" and as a generator when exporting the electricity at a later time. So as not to get preferential treatment compared to other forms of storage, the Major Energy Users argued that a battery should pay for the costs associated with its acquisition of the energy it will later release as electricity. For example, to be consistent, a battery should pay for its electricity network costs as an importer of electricity, just as a gas turbine pays pipeline network charges for importing its gas.[145]

UPC Renewables stated in its submission that where storage acts as a load on the system it should pay a suitable TUOS charge reflective of the loading it places on the system. A cost reflective approach makes sense as most storage facilities will act as a load during low demand/high generation times which should translate into low cost TUOS charges. The cost would serve as an incentive for load to utilise the transmission system at low cost times.[146]

141 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: TasNetworks p.8; Engineers Australia p.6.

142 Australian Energy Market Commission, *Coordination of generation and transmission investment*, options paper submissions: Monash University p.20; Energy Networks Australia p.4.

143 Infigen, submission to the options paper, *Coordination of generation and transmission investment*, 18 October 2018, p.4.

144 S&C Electric Company, submission to options paper, *Coordination of generation and transmission investment*, 18 October 2018, pp.11-12.

145 MEU, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.6.

146 UPC Renewables, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.5.

Building on this point, Monash University suggested in its submission that if storage were to pay TUOS it may drive relocation of storage to more favourable locations where TUOS charges can be offset by network support services. Furthermore, if the TUOS charges can be made efficient with sufficient granularity and dynamic response to system conditions, then the storage may operate without incurring significant TUOS charges and network costs. Monash University suggested that such improved TUOS would also stimulate more efficient demand-side response to system conditions.[147]

In its submission, Palisade suggested that TUOS charges may be applicable to storage facilities that do not export electricity into the grid. In this instance, there is no double charging. If the storage facility does not dispatch electricity into the grid, it acts ultimately as a customer.[148] Finally, the Clean Energy Council considered that it may be appropriate that behind the meter site specific loads should attract TUOS charges.[149]

8.3.3 AEMO's views

In its recent stakeholder paper on the integration of energy storage systems into the NEM, AEMO proposed that an energy storage system that is a scheduled resource and can be constrained off should not be required to pay TUOS charges. If a bi-directional resource participant - the new NEM registration category being proposed by AEMO - has a market load in a hybrid system, TUOS should be recovered based only on the electricity from that market load, which should be separately metered.[150]

AEMO's position for non-scheduled energy storage systems (i.e. systems with a nameplate rating less than 5 MW) on the other hand, is that they should incur TUOS charges. This is based on the fact that they will appear to the grid as uncontrolled load and will compete for capacity with end-use consumers.[151]

147 Monash University, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, pp.19-20.

148 Palisade, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.13.

149 Clean Energy Council, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.6.

150 AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM*, November 2018, p.29.

151 Ibid, p.30.

Figure 8.1: AEMO's position on how energy storage systems (ESS), including hybrid systems, align with recovery mechanisms and principles

	ESS non-energy recovery	Participant fees and charges	TUoS
Proposed approach	Non-energy services recovery based – ESS charged on the basis of electricity imports from and exports to the NEM.	NEM Participant fees and charges – ESS charged on the basis of electricity imports from and exports to the NEM.	Scheduled ESS should not pay TUoS. Where a 'hybrid system' includes market load, this needs to be separately metered.
Principles			
Technology neutrality – avoidance of special treatment of technologies	Yes, consistent with the treatment of Market Customers and Market Generators for the import and export of electricity, where exceptions are needed these will be considered.		Consistent with the treatment of generating systems.
Consistency with existing NEM recovery arrangements	Yes, consistent with the treatment of Market Customers and Market Generators for the import and export of electricity.		N/A since there is no consistent approach to TUoS charging.
Maximum level of transparency	Yes, ESS would be NER defined and clarified in Chapter 3.	Yes, ESS would be NER defined and clarified in AEMO's next fee determination.	Yes, ESS would be NER defined and TUoS in Chapter 6.

Source: AEMO, stakeholder paper, *Emerging generation and energy storage in the NEM*, November 2018, p.30.

Like the Commission, AEMO considers that there is a broader issue with the pricing arrangements for distribution and transmission networks that needs to be more holistically reviewed to determine how network costs should be recovered and from whom.[152] As recommended in Chapter 7, the Commission views that changes are required to the way TUOS is calculated and charged in the NEM.

8.3.4 Commission analysis and recommendation

The question of whether storage should pay TUOS is closely tied to the way in which the energy storage system is registered - TUOS and other implications for how storage operates in the market flow from this. Tesla also expressed this position in its submission to the options paper, stating that "settling the process for registering utility scale storage assets within the national framework is a necessary precursor to determining what charges these assets should be subject to."[153]

The Commission considers that whether or not, or to what extent, it is appropriate for energy storage systems to pay TUOS should ultimately be considered as part of a rule change that seeks to create a new NEM registration category to accommodate energy storage systems. The Commission's position on this issue is reflected in Recommendation 6. In this context, an

152 AEMO is of the view that a holistic review is the appropriate mechanism to identify whether it is appropriate to charge energy storage systems TUOS, whether participating in the NEM as a stand-alone system or aggregated with other resources. Ibid, p.29.

153 Tesla, submission to options paper, *Coordination of generation and transmission investment*, 19 October 2018, p.1.

assessment of storage and TUOS charging should adopt a "technology neutral" approach, be based on the current principles applied in the NEM and should not seek to pick winners in determining a TUOS charging arrangement.

The fundamental principles that underpin the existing transmission framework are that the purpose of the network is to supply electricity to consumers, and that consumers of electricity pay for the costs incurred by the TNSP in providing the shared transmission services from which they benefit. Because energy storage systems withdraw electricity from the grid like other consumers, careful consideration would need to be given to the implications for other participants if energy storage systems were to be exempt from TUOS charges. Such an approach may require a change to these fundamental principles, which would have broader impacts across the regulatory framework than just the consideration of TUOS charging. However, several aspects of the existing regulatory framework (including reliability standards) appear to be based on the assumption that transmission customers "end consume" the electricity supplied by means of the transmission network, or represent consumers who "end consume." As stated in the options paper, a re-definition of what it means to "consume" energy could be explored to create a distinction between "end-consumers" and energy storage systems who consume for the purposes of generating later.

Energy storage systems also export electricity. Given the Commission's conclusions on access in Chapter 6 where storage does not get access rights to the regional reference price, this would suggest that energy storage systems should not pay TUOS. In this context, the Commission considers that energy storage should also not benefit from jurisdictional reliability standards, i.e. transmission should not be built for the storage to receive a reliable supply. Consideration would also need to be given to whether and how storage would:

- be assigned congestion compensation under first stage of the recommended changes to the access regime
- be able to procure firm transmission rights to import or export electricity, consistent with the final stage of the recommended changes to the access regime.

It is possible that the TUOS charging outcome of a new storage registration category rule change may need to be revisited in the context of recommendations made in Chapter 6 for a framework of dynamic regions, pricing congestion and financial access rights for generators. The Commission considers that the prospect of new access arrangements should not prevent a solution being developed for storage in the mean-time as part of a rule change to create a new NEM registration category to accommodate energy storage systems.

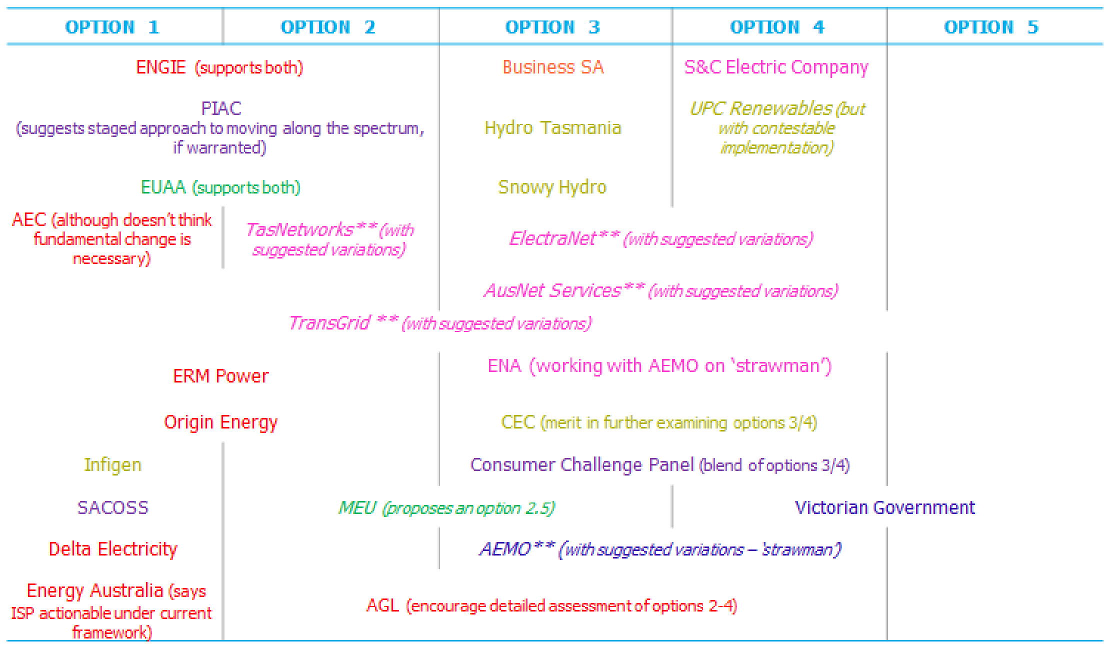
ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COAG	Council of Australian Governments
Coordination of generation and transmission investment review	CoGaTI
Commission	See AEMC
DNSP	Distribution Network Service Provider
ESCRI-SA	Energy storage for commercial renewable integration, South Australia
ESB	Energy Security Board
IR-TUOS	Inter-regional TUOS
ISP	Integrated system plan
LRPP	Last resort planning power
NEL	National Electricity Law
NEM	National electricity market
NEO	National electricity objective
NER	National Electricity Rules
NSW	New South Wales
NGR	National Gas Rules
NTNDP	National Transmission Network Development Plan
QLD	Queensland
REZ	Renewable energy zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SCO	COAG Energy Council Senior Committee of Officials
SENE	Scale efficient network extensions rule
TAPR	Transmission annual planning report
TCAPA	Transmission connection and planning arrangements rule
TNSP	Transmission Network Service Provider
TUOS	Transmission use of system

A SUMMARY OF OTHER ISSUES RAISED IN SUBMISSIONS

A.1 Summary of stakeholder views on options for making the ISP actionable

Figure A.1: Which options did stakeholders support in their submissions to the options paper?



Note: Generator (with thermal in portfolio); Renewable generator/developer; Network/supplier; Consumer Group; Energy User; Business Group; Market Body/jurisdiction

**Note that all TNSPs suggested different variations of different options.

A.2 Summary of issues identified by stakeholder in submissions to the options paper that have not yet been raised in the final report

This section sets out outstanding issues raised in submissions to the options paper and the AEMC's response to each issue. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

Table A.1: **Summary of (other) issues raised in submissions**

STAKEHOLDER	ISSUE	AEMC RESPONSE
Role of the ISP		
ENGIE, Palisade, Energy Australia, Delta Electricity, Powerlink, Adani Renewables, Energy Australia, Enel Green Power, Engineers Australia	Suggestions for AEMO's modelling for the ISP. (ENGIE, p.3; Palisade, p.1; Energy Australia, pp.3-4; Delta Electricity, pp.4-7; Powerlink, p.4; Adani Renewables, p.3; Energy Australia, pp.3-4; Enel Green Power, pp.2-3; Engineers Australia, pp.4-5)	This issue is outside the scope of the review and is a matter for AEMO.
Origin Energy	Policy makers should remain mindful of the limitations of any type of strategic planning. Given the 20-year time horizon, the ISP is based on inherently uncertain assumptions. Forecasting multiple decades into the future is likely to have a significant margin of error. This is not necessarily through any lack of skill or consultation, but rather due to the basic uncertainty regarding environmental targets, technology and fuel costs and a host of other variables. (p.3)	We agree with this position and have included measures in the design of our recommended model for actioning the ISP to create flexibility and the ability to respond to changes in the market.
SACOSS	(Finkel) clarifies that the integrated plan was not intended to override market outcomes. In balancing the trilemma, the Finkel Review provides adequate time for market responses to reliability and emissions goals. (p.2)	We consider that transmission planning and investment would benefit from stronger links to support the current transformation of the NEM.

STAKEHOLDER	ISSUE	AEMC RESPONSE
CCP20	In the context of ISP projects, CCP20 is of the view that future iterations of the ISP could and should provide the evidence base to advance these projects through the existing RIT-T process. (p.3)	We consider that there are some efficiencies that can be achieved through better linking the ISP and the RIT-T process, and have recommended that the RIT-T process be streamlined for ISP projects to reflect this.
RES Australia	COAG Energy Council needs to provide AEMO and the TNSPs with directions and mandated milestones in order to ensure that the ISP can be delivered in a timely manner. (p.7)	We consider that our recommended model for actioning the ISP achieves this objective. One component is that SCO should provide advice to AEMO as to what scenarios should be modelled in the ISP.
SACOSS	Strategic plans are different to implementation plans – the former is intended to provide direction. The action in the case of the ISP is the action of the market in responding to the signals it is receiving form the market operator. (pp.1-2)	We consider that "actionable" refers to the creation of stronger links between the ISP and the transmission investment decision process.
EUAA	The urgency being applied to make the ISP "actionable" seems to result in "actionable" being defined as "quickly build new assets." (p.3)	We consider that "actionable" refers to the creation of stronger links between the ISP and the transmission investment decision process.
PIAC	The ISP only identifies the transmission investment required. Under the current regulatory framework, it does not and cannot direct investment decisions in the other	We agree with this sentiment and considers that our

STAKEHOLDER	ISSUE	AEMC RESPONSE
	stages of the supply chain. In that regard, it requires the rest of the industry to respond to the signals set out in the ISP in order to achieve the optimal whole-of-system outcome. If this were not to happen, the expected benefits elsewhere in the supply chain enabled by the transmission investment may not eventuate. (p.6)	recommendations for actioning the ISP and reforming the access regime will address this concern.
Hydro Tasmania	Criteria for "strategic investments" could include: investments that clearly provide NEM-wide benefits; projects that require long lead times; projects that will be of value in the event of early power station retirement; projects that are robust to a range of future scenarios and policy outcomes; projects that provide optionality and can be developed sequentially in response to market needs and conditions (these can represent least regret investments). (pp.4-5)	These issues should be considered in the context of the NER changes required to implement the AEMC's recommended model for actioning the ISP.
RES Australia	A measure that quantifies the impact on the dispatch of the NEM could be used as a threshold criterion for investments being included in the ISP. (p.2)	This issue should be considered in the context of the NER changes required to implement the AEMC's recommended model for actioning the ISP.
Snowy Hydro	There is merit in looking closer at the US Federal Energy Regulatory Commission approach under Order 1000 suggested by AEMO. (p.5)	We considered this approach as part of the review, with some elements of this being incorporated into our recommended model for making the ISP actionable.
Snowy Hydro, Spark Infrastructure	Asset stranding is a risk worth taking for consumers due to the risk of underinvestment in transmission - the risk to consumers that the investment will not take place at all, resulting in higher energy bills, must also be taken in to account. (Snowy Hydro, p.10; Spark Infrastructure, p.38)	We disagree with the position that consumers should be subject to asset stranding risk since this would increase the costs that they pay for

STAKEHOLDER	ISSUE	AEMC RESPONSE
		transmission infrastructure. We consider that consumers should not be exposed to the risk of inefficient investment in transmission infrastructure, particularly given the current focus on affordability.
Powerlink, ENA	Further consideration should be given to reducing the current confidentiality provisions in the NER which prevent TNSPs from disclosing certain information in relation to proposed connections, given the broad benefits that information sharing could provide in the current context of transformational change. (Powerlink, p.4; ENA, p.9)	TNSPs should consider submitting a rule change request to the Commission on this matter.
EUAA, PIAC	Several stakeholders supported the current reliability standard (0.002% USE) serving as the basis for investment evaluation, also stating that rates of return should reflect efficient risk allocation. (EUAA, p.5; PIAC, p.25)	The issue of the appropriateness of the reliability standard is a matter squarely in scope of the Commission's assessment of the *Enhancement to the RERT* rule change request.
TasNetworks	Consideration should be given to how transitional arrangements from the status quo to a new model would be implemented. (p.3)	We agree that this is an important issue and should be a part of the development of rule changes to implement our recommended model to action the ISP.
PIAC	Develop a separate investment efficiency test for strategic investments (provide NEM-wide benefits) in the ISP. Alternative funding or cost-recovery models should be	As described in our recommended model for

STAKEHOLDER	ISSUE	AEMC RESPONSE
	used (determined project by project), including government funding of all or part of the investments. (p.11)	actioning the ISP, the Commission considers that ISP projects should be assessed using a streamlined RIT-T process. For cost recovery, our recommendations for access reform will change the way transmission investment is currently recovered.
ISP Group 1 and Group 2 projects		
EUAA	It is not reasonable to fast-track the Group 1 projects through the regulatory process. (p.9)	Progressing the Group 1 projects is a matter that will be reported on by the ESB to the COAG Energy Council in December 2018.
RES Australia	RIT-T processes currently under way for Group 1 projects should not be delayed until a determination is made regarding the linkage between the ISP and RIT-T. (p.9)	Progressing the Group 1 projects is a matter that will be reported on by the ESB to the COAG Energy Council in December 2018.
TransGrid	Group 1 and 2 projects could be expedited by allowing TNSPs to use ISP inputs for their RIT-Ts and through the AER streamlining its revenue determination process. Any significant change in responsibilities to make the ISP actionable will need to be balanced to ensure that it does not result in delays to the delivery of the Group 2 projects. (p.13)	Progressing the Group 1 projects is a matter that will be reported on by the ESB to the COAG Energy Council in December 2018. The Commission recommends that its model for

STAKEHOLDER	ISSUE	AEMC RESPONSE
		actioning the ISP be applied to Group 2 projects.
Monash University	Group 1 projects should be expedited through the RIT-T process for regulatory approval to proceed in conjunction with non-network options that enable optimal timing to be refined. Group 2 and 3 projects are subject to a great deal more market uncertainty. A different approach is needed to quantify their value in a form which could be regarded as a "conditional" or "interim" RIT-T process to approve the ISP project Groups as the basis for a "project final" RIT-T. (p.2)	Progressing the Group 1 projects is a matter that will be reported on by the ESB to the COAG Energy Council in December 2018. The Commission recommends that its model for actioning the ISP be applied to Group 2 projects.
Snowy Hydro	Group 2 projects should not be subject to the RIT-T, or an amended version of the RIT-T which is integrated into the ISP process. Instead, the regulatory framework should be amended so that these projects (which are nationally significant and strategic) are subject to an alternative approvals process, which simply requires the relevant TNSP to competitively source the most efficient means to deliver the project. (p.1)	We disagree; cost-benefit tests play an important part of checks and balances for transmission infrastructure. The Commission recommends that its model for actioning the ISP be applied to Group 2 projects.
The RIT-T		
UPC Renewables, CEC, TransGrid and Snowy Hydro	The RIT-T process does not deal with the "chicken and egg" problem of which comes first, generation or transmission investment? (UPC Renewables, p.3; CEC, p.3; TransGrid, p.8; Snowy Hydro, p.10)	The Commission's recommendations for access reform are being made to address broader congestion issues in the NEM, and will better coordinate investment in generation and transmission.
Delta Electricity	Disputes are only currently necessary since the RIT-T modelling is led by the project	We consider that the cost-

STAKEHOLDER	ISSUE	AEMC RESPONSE
	proponents, which reinforces information asymmetry between the project proponent and stakeholders. Modelling should be undertaken by an independent party, in which case there would be a reduced need for disputes. (p.6)	benefit analysis for transmission projects should be undertaken by the parties required to implement the project in order to achieve the most efficient outcome for consumers.
Origin Energy	There is a potential for a streamlined RIT-T for smaller, less risky projects. (p.8)	We consider that there are some efficiencies that can be achieved through better linking the ISP and the RIT-T process, and have recommended that the RIT-T process be streamlined for ISP projects to reflect this.
Origin Energy	Do not support any move to arbitrarily shorten the test given the complexities of the issues under consideration and time needed to complete a robust and transparent process given the RIT-T has an important role in assessing projects, and managing risks for consumers. (p.1)	We consider that there are some efficiencies that can be achieved through better linking the ISP and the RIT-T process, and have recommended that the RIT-T process be streamlined for ISP projects to reflect this.
Powerlink	The AEMC should reconsider whether the current $6 million cost threshold or exclusions applicable to the RIT-T remain appropriate in the current context, particularly given the vast amount of RIT-Ts being undertaken. (p.2)	We consider that the threshold and exclusions are fit for purpose. The AER has also recently reviewed the cost thresholds.
ERM Power	For staged projects, the benefits should be assessed on both the benefits of the	This is a matter for the RIT-T

STAKEHOLDER	ISSUE	AEMC RESPONSE
	project on a standalone basis, but also the benefits that would be derived if the other future projects eventuate. (p.4)	Guidelines.
CEC	The degree of change to the RIT-T process is potentially significant. Therefore, a consultative process beyond the time-frame for the AEMC's final report is warranted to fully canvass and assess potential improvements to the RIT-T framework. Any process should have a firm adherence to the RIT-T's fundamental priority to protect consumers from inefficient investment. (p.4)	We have recommended changes to improve the RIT-T process, while not altering its purpose of protecting consumers from inefficient investment.
Renewable Energy Zones		
Origin Energy	Providing for low-cost new entry connections, with minimal risk for consumers paying for stranded assets, should be the aim of REZ policy. Importantly, such assessments of REZs should not occur in a manner that crowds out efficient private sector generator or storage investment in favour of government backed proposals. (p.5)	The Commission's recommendations for access reform can be expected to support market development of REZs where this is efficient.
ENA; Infigen	REZs are not required to be connected in the immediate term, and specific changes are not currently needed to address the connection of REZs – this issue should be considered in the ongoing evolution of the ISP implementation framework. (ENA, p.3; Infigen, p.3)	The Commission's recommendations for access reform are being made to address broader congestion issues in the NEM. They can also be expected to facilitate the connection of REZs where this is efficient.
TasNetworks	Regardless of which option(s) are recommended, consideration of the practical REZ issues is needed, e.g. obligations arising from the new "do no harm" provisions and the "chicken and egg" problem. (p.7)	We agree that system security and timing considerations must be taken into account when thinking about the best way to facilitate REZs. The

STAKEHOLDER	ISSUE	AEMC RESPONSE
		Commission's recommendations for access reform can be expected to facilitate the connection of REZs where this is efficient.
TasNetworks	For the clustering option, it would require several other issues to be resolved, such as the geographical size of the cluster. (p.7)	We agree that this is an issue that would need to be considered in the context of the clustering option. However, to facilitate REZs, the Commission's recommendations for access reform can be expected to support their market development where it is efficient.
RES Australia	For option 1 - Enhanced information provision - described by the AEMC, the RIT-T would need to include the benefits associated with uncommitted projects, assuming they would be committed if the project goes ahead. (p.10)	This is something that the RIT-T can currently take into account.
TransGrid	There is cost associated with developing clustering proposals, including the engineering analysis and marketing required to get proposals to market. A mechanism or process to recoup these costs that are borne on TNSPs would be needed. (p.11)	Were the clustering option to be preferred, this consideration would be taken forward in its detailed design. However, the Commission's recommendations for access reform can be expected to support market development of REZs where this

STAKEHOLDER	ISSUE	AEMC RESPONSE
		is efficient.
RES Australia, CEC	For the ENGIE transmission bond proposal, caution the creation of a barrier to entry because generators would require large balance sheets to support the purchase of bonds. (RES Australia, p.12; CEC, p.4)	This is a practical consideration when thinking about the ENGIE bond model, however, as we concluded in Chapter 5, we do not consider this to be the most efficient way to facilitate the development of REZs.
Treatment of storage		
ERM Power	Where possible the rules should set clear outcomes to ensure any "barriers to entry" for investment in storage are minimised as much as possible. (p.6)	We agree.
Tesla	Any decisions that may inhibit the progress of storage projects should be avoided, and a requirement to pay both connection charges and TUOS charges is a clear example of an outcome that would perpetuate existing market distortions, provide a direct disincentive for storage assets, lead to further competitive disadvantage relative to other generators, and hinder the development of new storage required to meet the increasing demand for flexibility and provision of critical network services. (p.1)	We agree that the regulatory treatment of energy storage systems requires changing, and expect that the creation of a new NEM registration category and the rights and obligations that flow from it will address a lot of these issues.
AEC	Our reflection is that a "one size fits all" approach to TUOS charging is unlikely to be appropriate. Fortunately the existing rules provide the TNSPs a clear objective in seeking to apply network charging efficiently for each user and gives them considerable latitude for doing so, ultimately overseen by the regulator. For some business models zero TUOS charging will be correct, but in other cases TUOS charges equivalent to conventional transmission customers would be appropriate. (p.4)	We agree that TUOS charging needs to be further analysed, which will be done through the rule change request to create a new NEM registration category for storage.

STAKEHOLDER	ISSUE	AEMC RESPONSE
PIAC	An impact-based NEM registration categorisation allows for the many possible configurations of storage with and without co-located generation or load (both with respect to relative sizing and dispatch patterns). For example, a storage facility which is co-located with generation (or load) may display the same behaviour from the system-side as a pure generation (or load) facility and hence would not require being registered under the new storage-specific category. (p.3 & p.14)	These issues should be considered in the context of the recommended rule change request to create a new registration category for large-scale storage systems.

B CURRENT TRANSMISSION REGULATORY FRAMEWORK

The current transmission framework is made up of five key elements that are:

- planning
- access
- connection
- charging
- economic regulation.

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

B.1 Planning

Transmission planning occurs over a number of time horizons

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

Currently there are several different forms of planning:

- Long-term planning focusses on long-term expected generation and demand, and so on long-term investment and replacement needs. This long-term planning is typically strategic in nature and is undertaken by AEMO as national transmission planner through its preparation of the NTNDP (replaced this year by the ISP), which projects out 20 years.
- Short-term planning has a focus on the near term and specific investment and replacement needs. It takes into account the results of the national planning undertaken by AEMO. This short-term planning is currently undertaken by the jurisdictional planning bodies and focusses on more regionally specific needs, with a more immediate focus - TAPRs typically focus on the next 5-10 years.
- Project specific planning relates to a particular investment need and culminates in an investment or replacement decision being made by the TNSP. These project specific plans consider the benefits to generators, consumers and network businesses of a particular investment. This is currently undertaken by the jurisdictional planning bodies[154] and focusses on what is the best way to achieve a particular identified need, e.g. in building this transmission line, what exact specifications should it be built to, and what route should it take. In particular, this also includes considering whether a network investment

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

should be made, or whether the identified need could be addressed through a non-network option, e.g. demand management.[155] This approach assists in providing transparency on these planning activities to put forward non-network options as a credible alternative to network investment and assist network users to make decisions about where best to connect to the network.

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

In addition to these types of planning, the AEMC also has a last resort planning power.[156] This allows the Commission to direct registered participants to apply a project specific test (RIT-T) to potential transmission projects if they are likely to relieve projected constraints in respect of national transmission flow paths connecting NEM regions and the Commission considers that the project is unlikely to be addressed if the AEMC does not exercise the power.

Planning to standards

A key transmission planning question is what standards apply, i.e. what is a business planning too. Identifying a standard is important since this is one way that the costs and benefits associated with the transmission network can be quantified, and so costs constrained. The standard to which parties are planning the transmission framework also impacts on who pays for the transmission infrastructure, that is, the beneficiaries of the particular standard are the parties who bear the cost.

Transmission businesses have an obligation to reliably supply customers

The reliability standards that networks are required to meet are defined in terms of reliably supplying customer load.[157]

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

There is no reliability standard for generators

There is no set reliability standard for generators - there is no guarantee that the network will have the capacity to export the energy they generate to enable them to earn revenue in the wholesale market. This translates through to the planning of the network - transmission businesses do not plan to provide a particular generator with a specific amount of capacity across the transmission network.

However, the existing framework does allow AEMO and TNSPs to plan investments that could be considered "net beneficial." That is, if by building transmission infrastructure to allow

155 For investments over $6 million, this process is undertaken through the RIT-T.

156 Clause 5.22 of the NER.

157 These are different to the NEM reliability standard, which is the maximum expected unserved energy (0.002 per cent) in a region for a given financial year as a share of total energy demanded in that region.

increased output for generators, outcomes in the wholesale market will be improved for the benefit of consumers.

B.2 Access

Generators have no right to be dispatched in the wholesale market

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

Generators have no guarantee that they can export all of their output to the system at any given time. Instead, generators earn money by being dispatched through the wholesale market that is run by AEMO. AEMO's market dispatch engine seeks to maximise the value of trade given the physical limitations[158] of the power system. As a consequence, generators are not required to pay for the cost of transmitting the electricity they produce.

Each generator in a particular region receives revenue at the clearing price (known as the "regional reference price") for the electricity delivered - even when that clearing price is above the price it offered into the market. In this way, the spot market coordinates the physical dispatch of generation and all generators earn at least their offer for each unit of electricity delivered. If a generator is not dispatched they cannot earn revenue from the spot market. Since generators have no rights to earn revenue in the wholesale market, they also do not have a right to be compensated for not being dispatched.

BOX 6: WHOLESALE MARKET AND NODAL PRICING

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

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

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

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

particular point.

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

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

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

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

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

B.3 Connection

Generators and large load have a right to negotiate connection to the transmission network

Generators and large load have a right to negotiate connection to the transmission network. Generators and large load pay for the incremental costs of the infrastructure that is necessary to facilitate their connection.

Recent amendments have been made to the transmission connections framework to clarify and improve outcomes

The Commission recently completed the TCAPA rule that sought to provide connecting parties with certainty, clarity and control over their connections.

The final rule:

- Better defined the assets and services required to facilitate a connection to the transmission network.
- Improved the clarity of the transmission connection process.

- Made it clear and unambiguous that incumbent TNSPs have responsibility for the operation, maintenance and control of the shared transmission network, which promotes a safe, reliable and secure network for consumers.
- Introduced competition for the provision of services required to facilitate a connection to the transmission network, where this does not distort the accountability of the incumbent TNSP.
- Required TNSPs to publish better and more information about how to connect to their network, and provide certain information to connecting parties on request.
- Strengthened the principles that underpin negotiations between connecting parties and incumbent TNSPs.
- Introduced a formal ability for either party to engage an independent engineer to provide advice on the technical aspects of a connection.
- Clarified the process that applies to disputes about transmission connections.

Generators can fund augmentations in the deeper network

In addition to paying for costs associated with their connection, transmission users *may* fund augmentations to increase the capacity of the deeper network.[159] Currently, generators - or a coalition of generators - can fund a transmission expansion in order to gain the benefits of reduced congestion. Such expansions are called "funded augmentations." With these investments there is no guarantee that a future generator will not connect and cause renewed congestion. The Commission understands that these arrangements have been little used due to the free rider problem. Other generators will also benefit from the network capacity without having contributed to the costs of the network investment, and may even prevent the funding generator from using it.

B.4 Charging

Consumers pay for transmission services

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

Generators pay to facilitate their connection

In contrast, generators only pay for the costs of connection to the transmission network since they have no right to the regional reference price.[160] In other words, they do not pay for the broader costs of the transmission network.

159 NER, clause 5.18.

160 These costs may be paid to the TNSP but may be paid to other parties if the relevant connection service/assets are contestable.

The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point. A generator only pays the costs of connection.[161]

B.5 Economic regulation

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

The planning framework does not regulate or direct which investment decisions should be made, nor does it determine what investment costs TNSPs should be able to recover from customers as regulated revenue. Instead, the planning framework accompanies an incentive-based economic regulatory framework, with it providing opportunities for the AER and other stakeholders to be more fully informed on the efficiency of network investment decisions.[162]

This supports an outcome where consumers only pay for efficient expenditure. Given consumers pay for transmission, any proposed expenditure on the network must be shown to provide market benefits or be necessary to maintain a reliable supply of electricity to network customers, or security and safety on the network. Consumers should not bear the risk of speculative investments or investments that are for the sole benefit of generators (if such an investment would, for example, relieve congestion for generators but not to the extent that it provides an overall market benefit through a reduction in wholesale electricity costs).

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

- TNSPs are subject to economic regulatory oversight by the AER in relation to their augmentation, replacement, operating and maintenance costs for the provision of prescribed services. TNSPs must have the AER assess their revenue requirements.[163]
- Augmentation and replacement decisions relating to the network are subject to cost-benefit tests (RITs) to assess whether the investment or replacement will create a net market benefit for consumers. The RIT-T is an important part of the planning undertaken by TNSPs, influencing investment decisions and drawing on other planning outputs, such as their TAPRs. The role of the RIT-T is to seek cost effectiveness for the consumer by increasing the transparency of individual investment decisions. This transparency and accountability for investment decisions is what reconciles any differences between the economic interests of the TNSP conducting the RIT-T and what maximises the net economic benefits across the market.

Economic regulation is incentive based

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

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

163 The RIT-T applies to investments above $6 million.

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