REVIEW

Australian Energy Market Commission

FIRST INTERIM REPORT

Transmission Frameworks Review

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First Interim Report

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

Executive summary

Transmission of electrical energy from generators to end use customers is central to the existence and efficient functioning of the National Electricity Market (NEM).

Dispersed generation from a range of sources and a market spread over such a large geographic area mean that planning, investment in and operation of the transmission network is pivotal to the efficient operation of the market and delivering efficient prices to customers.

The arrangements for transmission in the market have been progressively refined since it started, but still substantially reflect the jurisdictionally based arrangements that preceded the national market. One of the purposes of this Transmission Frameworks Review is to test whether these arrangements remain the most workably efficient and effective for taking the NEM forward into future decades. This is a particularly important question now with significant but uncertain changes in generation fuel mix and location highly likely, in part as a result of climate change policies.

This First Interim Report of the review does not make recommendations for reform but sets out for stakeholder consideration a series of potential alternate paths forward for development of transmission arrangements in the NEM.

The review

The Transmission Frameworks Review has been characterised by a very high level of stakeholder engagement, as well as a marked diversity of views about the effectiveness and efficiency of current frameworks, the need for change, and alternate reform paths. The Commission's thinking in conducting the review has been informed by the National Electricity Objective, together with some specific principles for transmission set out by the Council of Australian Governments in 2007.

The Commission will ultimately be recommending transmission frameworks that it considers are most likely to optimise investment and operational decisions across generation and transmission in a manner that minimises the overall long term costs to consumers, while facilitating continued security and reliability of supply. Long term costs will be influenced by how much and where transmission is built and the effectiveness of incentives for its efficient planning, operation and utilisation. They will also be influenced by the type and location of generation and loads that connect and the incentives for doing so efficiently.

This report

This First Interim Report sets out for stakeholder consideration and feedback some alternate paths to reform of transmission arrangements in the NEM in two broad streams.

First it outlines five alternate, future development pathways comprised of five internally consistent "packages" of policy reform, some of which are very different to current NEM arrangements. Each of these reflects a different approach to the future long term development of transmission frameworks. Central to each package is the nature of generator network access that it provides for, which in turn shapes the nature of charging, planning and in some cases institutional arrangements proposed in the package. The Commission stresses that at this stage it has not identified any preferred package.

At a second level this report also sets out for feedback some proposals for improving current arrangements for NEM transmission planning and connections to the transmission network. In the case of planning these are proposals that could be progressed to enhance current frameworks which, in most cases, would be consistent with each of the broader policy packages. Additionally, a number of more substantial options for the reform of planning arrangements are discussed, based on stakeholder submissions to the review.

In relation to the connection of generators and load, this report sets out for consultation some analysis, conclusions and questions with a view to clarifying and improving current arrangements. This focuses on clarifying ambiguity in the National Electricity Rules (the Rules) but also raises more fundamental questions about the nature of economic regulation of and access to connections and extensions. As with some of the options for changing planning arrangements, the connections proposals are somewhat separable and could apply to any of the packages.

The case for reform

Whether substantial reform of the NEM transmission frameworks is required remains an open question at this stage of the review. Stakeholders, including generators, have expressed widely varying views on the workability and efficiency of current arrangements. However to date limited evidence has been provided which demonstrates the materiality of any current or anticipated inefficiencies associated with the existing arrangements. Any significant framework change will carry implementation costs and risks which need to be proportionate to and tested against any risks of retaining current frameworks.

Pathways to reform

The five alternate policy packages outlined in this report represent a range of approaches to structuring the law, the Rules, financial obligations and institutions that provide the framework within which transmission in the NEM operates. They are not the only approaches or alternate pathways that could be considered. They draw on input from stakeholders, experience in other markets and the Commission's own analysis.

As this review has progressed it has become increasingly clear that key elements of transmission frameworks, such as the nature of generator access rights, charging for use of the transmission system, planning and the incidence of and responses to congestion are highly inter-related. Change to any of these key elements will need to take account of the impacts on the others. So, for example, the nature of access rights (if any) that a generator has to use the transmission network needs to be considered concurrently with the nature of charges that generators might pay for use of the network.

This report, therefore, outlines policy packages each of which addresses these key elements of transmission frameworks and, in the Commission's view, does so in an internally consistent manner. There are variations that might be proposed by stakeholders to some or all of the policy packages. However, the Commission urges stakeholders responding to this paper to avoid picking preferred elements out of several packages and attempting to combine them unless they can demonstrate that the internal consistency of a package is maintained.

Briefly summarised the five alternate paths for NEM transmission frameworks outlined in this paper are:

1. **Open access** – which substantially maintains current arrangements but clarifies that there would be no avenue for generators to seek firmer transmission access rights. No generator charges would be imposed for using the transmission network.

2. **Congestion pricing** – an open access arrangement as with package 1, but with the addition of a mechanism in the market to better maintain incentives for economically efficient generator bidding when the transmission network is constrained.

3. **Generator transmission standards** – transmission businesses would have to meet minimum reliability standards for generators' use of the transmission network, in a similar way to load reliability standards. This would give generators increased certainty and transparency about their level of access to transmission, for which they would pay a charge. The standards would be independently set and enforced through financial incentives on transmission businesses.

4. **Regional optional firm access** – would allow generators to elect to pay for firm access for part or all of their output. If transmission constraints prevent dispatch of the firm output, when it would otherwise be dispatched, the generator would be eligible for financial compensation. Transmission planners would need to account for the level of firm access but would make no planning allowance for non-firm generation capacity. Depending on the detail of the model, either new firm generators, or all generation electing for firm access would pay for use of the transmission system. Compensation would be funded by non-firm generation which is dispatched ahead of firm generation when a transmission constraint bound.

5. **Locational marginal pricing for generators** – all generators would purchase firm transmission rights at auction from a single, NEM wide transmission business.

The transmission business would then be obliged to ensure that generators obtained physical access for their output or pay financial compensation. The transmission business would be exposed to some risk because of the obligation to compensate generators unable to access the market. Whilst a transmission planning standard would be imposed, under this model the role for central planning of transmission would be reduced.

Planning

Central to efficient and effective transmission in the longer term are sound planning arrangements. These have been the focus of some attention by stakeholders and by broader commentators on the market, particularly in relation to inter-regional planning arrangements. Ensuring the ongoing effectiveness of these planning arrangements will be particularly important should the basic transmission frameworks remain substantially unchanged, and remain reliant on effective planning rather than stronger market signals such as would be delivered under some of the paths outlined above.

This report outlines a range of options for enhancing the current planning arrangements reflecting, in some cases, stakeholder proposals. These range through improving transparency of the Regulatory Investment Test for Transmission, improving the consistency of transmission annual planning reports, and aligning TNSP regulatory revenue determinations.

Also outlined are four options for more substantial reform of current planning arrangements. One of these is a stakeholder proposal to extend AEMO's Victorian planning and procurement role on a market-wide basis. Alternative options include a more harmonised approach to NEM planning broadly based on the arrangements that currently apply in South Australia and a proposal for a single, national "co-ordinating TNSP" with ownership of networks retained by jurisdictional TNSPs.

Connections

Stakeholder feedback to the earlier stages of this review indicated significant concern about the current market arrangements for the connection of new generators to the transmission network. Although an inherently complex process, the regulation and negotiation of such connections is claimed to be more difficult than it should be, in part exacerbated by a Rules framework that lacks consistency and clarity. This extends to uncertainty about the boundaries of contestability of service provision and connection asset ownership, operation and rights of access.

A fundamental concern has been expressed about the imbalance of bargaining power that connecting parties face in dealing with transmission businesses in negotiating a connection. Proposals for changing the economic regulation of connections have been outlined in this paper. The Commission is seeking evidence about the materiality of any impacts the imbalance of bargaining power is having on costs and efficiency in order to better assess whether the proposals for reform are proportionate to the problem.

Responding to this report

The Commission welcomes the very high level of stakeholder engagement with this review that has been demonstrated to date. As noted above, this report sets out a wide range of options for reform to current transmission arrangements, some of which are clearly alternative pathways and some of which represent options for more incremental changes to aspects of current frameworks.

We look forward to stakeholder responses to these proposals which will assist the Commission in refining and framing its draft and final recommendations to the Ministerial Council on Energy. We stress again that, wherever possible, feedback should endeavour to assist us to continue to assess the most appropriate pathways to future frameworks by providing evidence of the materiality of issues raised from a whole of market perspective.

Contents

1 Introduction and background

1.1 Introduction

The Transmission Frameworks Review is a key project for the Australian Energy Market Commission (AEMC or Commission) in progressing its strategic priority of ensuring the delivery of timely investment and efficient outcomes in transmission and distribution through economic regulation. The transmission networks and their future augmentation will be critical to enable continued security and reliability of supply and promote efficient outcomes following the introduction of any policy initiatives that seek to influence behaviour in the energy sector.

A framework that promotes the efficient provision of transmission services to competitive and other regulated sectors of the National Electricity Market (NEM) should have the effect of minimising expected total system costs across transmission and generation, leading to lower prices for end consumers. This will occur where:

- TNSPs have incentives to efficiently invest in and operate their networks to meet load requirements at least cost and support a competitive generation sector;
- generators have incentives to offer their energy at an efficient price and invest in new plant where and when it is efficient to do so;
- the policies, incentives and signals that govern transmission and generation decisions are coordinated to promote consistent decision making between the regulated and competitive sectors of the NEM; and
- the safety, reliability and security of the transmission system is maintained.[1]

This review is testing whether current transmission arrangements have promoted, and will continue to promote, outcomes that are consistent with these features of an efficient regulatory regime, despite the uncertainty of future developments impacting the electricity industry.

Transmission arrangements govern the interface between generation and transmission, and between transmission and load. This review is particularly concerned with how the arrangements will minimise costs across transmission and generation. These arrangements include how generators can gain access to the wholesale market via the transmission system, the way in which congestion is managed, what charges generators face in relation to transmission, how the transmission network is planned, and how generators can connect to the transmission network.

The way in which the transmission network will be used in the future is uncertain. Patterns of network use are changing, affected by changes in the location, scale and operational characteristics of generation investment. For example, generators may locate further away from the existing network and there has been an increase in the

1 The assessment framework for this review is explained in detail in chapter 3.

amount of intermittent generation. These changes are likely to have significant effects on transmission investment in the long term, as well as leading to changes in network flows in the shorter term. Transmission arrangements will need to be sufficiently flexible to adjust to these uncertainties while continuing to minimise expected total system costs.

While the desirable features listed above are a useful goal in designing transmission arrangements, they represent a theoretical optimum which is unlikely to be achievable in practice. Attaining the right balance between maintaining the safety, security and reliability of the national electricity system and the various competing objectives involved in minimising total system costs is a difficult task that has challenged regulators in the NEM and internationally.

Further, constant changes that strive to perfect already workable arrangements can lead to significant uncertainty. Regulatory uncertainty can have a detrimental impact on investment through increased investment risk. This may distort investment decisions and lead to inefficiencies over time.

This review is seeking to undertake a comprehensive assessment of existing frameworks and, if required, make recommendations on a suite of arrangements that will promote effective outcomes in terms of generation and transmission operation and investment both now and in the future. The Commission expects that any changes to transmission arrangements that result from our recommendations will be workably efficient and will remain in place for a period of time to promote a stable and predictable environment in which efficient transmission and generation investments can be supported.

1.2 MCE Terms of Reference

The Ministerial Council on Energy (MCE) directed the Commission to conduct a review of the arrangements for the provision and utilisation of electricity transmission services and the implications of the market arrangements governing transmission investment in the NEM on 20 April 2010.

The Terms of Reference specifies that the review should focus on identifying any inefficiencies or weaknesses in the inter-relationship between transmission and generation investment and operational decisions under the current market arrangements, particularly in light of the anticipated impacts of climate change policies and the potential impacts of extreme weather events.

The MCE noted that:[2]

> "Where appropriate, the AEMC should recommend changes which would better align incentives for efficient generation and network investment and operation with a view to promoting more efficient and reliable service delivery across the integrated electricity supply chain."

2 MCE, *Terms of Reference - AEMC transmission Frameworks Review*, April 2010, p. 3.

In conducting the review, we are to consider the following key areas together in a holistic manner:

- transmission investment;
- network charging, access and connection;
- network operation; and
- management of network congestion.

This requirement to undertake a comprehensive review reflects the integrated nature of transmission arrangements, which is particularly important given the inter-related nature of the issues involved and changes that may be developed.

The full MCE direction is available on our website at www.aemc.gov.au.

1.3 National Electricity Objective and the MCE direction

The AEMC is required to have regard to the National Electricity Objective (NEO) in every review it undertakes under the National Electricity Law (NEL). The NEO will therefore form the overarching principle for the assessment framework used to evaluate potential transmission reforms.

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."

The AEMC has been directed to undertake this review by the MCE under section 41 of the NEL. This provides, amongst other things, for the AEMC to conduct a review into any matter relating to the NEM.

In reviewing the existing arrangements for transmission in the NEM and identifying any options for reform, the MCE Terms of Reference specifies that the AEMC should have regard to the NEO and to certain principles previously agreed by the Council of Australian Governments (COAG) in relation to earlier reforms. These principles are:

- accountability for jurisdictional investment, operation and performance will remain with transmission network service providers;
- where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment; and

- the new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place.

The Terms of Reference also provide that the AEMC is to have regard to the implications for trading and contracting risks and for investment and regulatory uncertainty, as well as the need for transitional and other arrangements to mitigate or manage such risks.

1.4 Submissions to the Directions Paper

The Directions Paper for the review was published on 14 April 2011. The Commission sought comment from stakeholders on the way it had framed the issues and whether we presented an appropriate structure for the review going forward.

The Commission received 22 responses from a range of market participants, consumer and large end-user groups, governments and market institutions. A full list of submissions can be found at www.aemc.gov.au.

Stakeholders broadly agreed that the review was structured appropriately. However, a number of stakeholders believed that the review should also consider economic regulation of TNSPs.[3] The Commission remains of the view that economic regulation will be best considered as part of the Rule change requests submitted by the Australian Energy Regulator (AER) on 29 September 2011, and therefore should not be addressed within the scope of this review.[4]

Stakeholders held a diverse range of views on the appropriateness of current transmission arrangements and their interaction with the generation sector. While a number of stakeholders considered that existing arrangements are robust and have resulted in reasonably effective outcomes to date, others, particularly a number of generators, considered that the nature of transmission services should be reformed, primarily to provide greater certainty of network access. Generators' views on the need for reform were typically dependent on the region within which they operated and their ownership structure. Generally large, government-owned generators from New South Wales (NSW) and Queensland considered that the existing arrangements are broadly appropriate, in contrast to Victorian-based privately owned generators who considered that substantial reform is required.

There was greater consensus amongst generators on the need to amend the connection arrangements. Generators generally considered that there is a lack of clarity around the existing arrangements, particularly regarding the obligations of TNSPs to facilitate

3 AEMO, Directions Paper submission, p. 3; Alinta, Directions Paper submission, p. 4; Energy Users Association of Australia (EUAA), Directions Paper submission, p. 2; Major Energy Users (MEU), Directions Paper submission, p. 3. AusGrid considered that economic regulation should be taken into account when considering changes to other frameworks (AusGrid, Directions Paper submission, pp. 1-2).

4 Note, however, that the economic regulation of connections is not covered by these Rule change requests and will be considered as part of this review.

connections to their networks. Generators were also concerned about the market power that TNSPs hold in providing different types of connection services.

Stakeholder views are discussed more generally in chapter 5.

The Commission has considered the views put forward by stakeholders and developed a number of policy packages for potential reform that respond to this range of views.

1.5 The purpose of this report

Recognising the lack of consensus about whether changes are required to the transmission arrangements and the mixed evidence about the magnitude of any inefficiencies in the current arrangements, the Commission has focused on two main issues in this report. First, the Commission continues to seek evidence and analysis about the effectiveness of the current arrangements. Second, to further test whether alternative arrangements may better meet the NEO, the Commission has developed five models for coherent transmission arrangements. These range from almost no change to proposals that reflect aspects of models adopted in other countries based around more well-defined access rights. The Commission is seeking views on whether these five packages represent the appropriate range of options to test and the relative merits of each option.

We are also seeking comments on specific options and proposals for enhancements or reform to the planning and connection arrangements.

1.6 Responding to this report

Chapter 2 sets out a list of questions that stakeholders may consider in the context of each of the packages, possible enhancements to planning and reforms to the connection arrangements.

How to make a submission

The closing date for submissions to this First Interim Report is **27 January 2012**.

Submissions should quote project number "EPR0019" and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

1.7 The review process

The table below sets out the process for this review.

Table 1.1 Review process

Document	Purpose
Issues Paper	To present the key issues identified by the Commission and set out the process for the review.
Directions Paper	To address some of the key issues raised in submissions to the Issues Paper and to identify key themes that the Commission proposes to take forward and how the Commission intends to do this.
First Interim Report	**To identify and discuss a short list of potential internally consistent policy packages, explain the framework for the assessment of these and continue testing the materiality of the problems identified.**
Second Interim Report	To assess the packages identified in the First Interim Report and narrow these packages down to one or two preferred options.
Final Report	To set out the Commission's policy conclusions and recommendations to the MCE, and to note any high-level implementation and transitional issues for further consideration.

1.8 Consultative committee

In accordance with the MCE direction, the AEMC has, by invitation, established a stakeholder Consultative Committee to help inform the review, including providing advice and views on our consultation documents. The membership of the Consultative Committee is comprised of representatives of the Australian Energy Market Operator (AEMO), the AER, industry participants and energy end-users.

Meetings of the Consultative Committee have been held on:

- 26 July 2010;
- 10 December 2010;
- 7 March 2011; and
- 28 September 2011.

Outcomes of the meetings can be found at www.aemc.gov.au.

1.9 Structure of this report

The remainder of this First Interim Report is structured as follows:

- Chapter 2 sets out the purpose and structure of this report. It also includes a number of questions for stakeholders to consider.
- Chapter 3 sets out our assessment framework. It describes the outcomes that well-structured and targeted transmission arrangements should promote.
- Chapter 4 provides a high level summary of the existing transmission arrangements.
- Chapter 5 discusses stakeholders' concerns regarding the performance of the existing transmission arrangements. It also provides the Commission's current views on the issues that have been raised during this review.
- Chapters 6 to 10 outline a series of five proposed policy packages for stakeholder comment. These policy packages represent holistic, internally consistent options for refining or reforming the existing arrangements.
- Chapter 11 discusses options for enhancing or more significantly reforming existing transmission planning arrangements.
- Chapter 12 provides an overview of existing connection arrangements and explains the areas of uncertainty that exist in relation to the interpretation and application of the National Electricity Rules.
- Chapter 13 addresses the economic regulation of services that are required to connect generators and other network users to transmission networks.
- Chapter 14 considers issues related to extensions that are required to establish a connection to the network.
- Appendix A provides simplified numerical examples of how aspects of the packages would operate.
- Appendix B discusses why a temporary, localised congestion management mechanism is not being further considered.
- Appendix C sets out various methodologies for calculating a transmission charge for generators that reflects long run marginal cost; and
- Appendix D discusses the application of deep connection charges.

2 This report

The purpose of this chapter is to explain how the proposals set out in this report were derived and how they fit together. The chapter explains where this phase of work fits in the context of the review. It provides a summary of the proposed packages and options for reforming planning and connection arrangements and also sets out the key questions on which the Commission is seeking stakeholder views.

2.1 Introduction

It has proven challenging to find broad consensus on the effectiveness of the current transmission arrangements and the case for change during the review. We are continuing our analysis and we continue to encourage stakeholders to provide analysis and evidence to inform this assessment.

This First Interim Report sets out five internally consistent policy packages for possible reform to the existing transmission arrangements. The proposed packages are described at a conceptual level and are accompanied by a relatively high level qualitative assessment of their relative strengths and weaknesses. This report seeks views on the merits of these packages.

The report also sets out a number of options for enhancing or reforming the transmission planning arrangements. Three of the proposed packages have direct implications for how the transmission network will be planned and the institutions that are required to support these arrangements, which are discussed as part of those packages. In contrast, the remaining two packages could be implemented without changes to the planning or institutional arrangements. However, there may be some enhancements that could be made to improve certain aspects of the existing arrangements. These options are presented separately to clarify that they are not required to maintain the consistency of any package, but could be implemented with a number of the proposed packages.

Finally, the report provides a number of proposals for changing the arrangements for connecting generators, load and other network service providers to the transmission network. These connection arrangements are somewhat separable and could apply to any of the packages.

The next phase of the review will consider which of the packages and options are most likely to contribute to the achievement of the NEO, informed by stakeholder submissions to this review and by comparing the packages against our assessment framework, as set out in chapter 3. We intend to set out one or two preferred packages and our preferred options for the planning and connection arrangements in more detail in the Second Interim Report.

The remainder of this chapter is structured as follows:

- section 2.2 describes how we derived each of the five policy packages and provides a high level summary of the packages. It also sets out questions for stakeholders to consider in reading and responding to this paper;
- section 2.3 sets out some issues that are specific to planning arrangements and provides a set of questions for stakeholders to consider in their submissions; and
- section 2.4 explains our approach to considering the connection arrangements and summarises the proposals for improving these, if required.

2.2 Five proposed policy packages for reform

Chapters 6 to 10 describe five proposed policy packages for reform. The packages provide a number of possible approaches to reforming the existing transmission arrangements, informed by stakeholder submissions. They take account of the interactions and interdependencies between access, congestion, charging, planning and, to some extent, connections.

Each of these packages is intended to represent an internally consistent approach to transmission arrangements that balances the set of policies and incentives that govern transmission decisions and the market signals which influence generation decisions. It is important that these signals work together to provide a coordinated and consistent approach to transmission.

The issue of access certainty for generators is a key consideration in this review. The implementation of climate change policies[5] and other changes that have impacted the energy market have and are expected to continue to change the generation mix and so the way in which the transmission network is used. Some stakeholders were concerned that this will lead to greater levels of congestion and so greater uncertainty of network access for generators. This uncertainty may impact on generator investment.

Our analysis of these issues has led us to conclude that access to the shared transmission network is central to understanding the role of transmission in the NEM. In this context "access" refers to access *across* the transmission network.[6] We have therefore considered what access models might apply in the NEM, and then assessed implications for congestion management, charging and planning and institutional arrangements that flow from the identified access model.

While the Commission notes that there are some concerns regarding weaknesses in the existing arrangements, as discussed in chapter 5, it is not yet clear how material these weaknesses are. The five packages provide for varying degrees of reform, which would reflect conclusions on the materiality of the issues that have been raised. These issues

5 In this context we are using the term "climate change policies" to encompass the range of Government policies that are intended to help mitigate climate change, including the Renewable Energy Target and a price on carbon emissions.

6 Access *to* the network is considered under connections.

include the impact of congestion and generators' need for certainty to promote efficient investment.

2.2.1 Summary of the packages

This report presents five proposed policy packages which are derived from existing approaches in the NEM, stakeholder submissions and international approaches to access.

The first two packages are based on the existing open access arrangements and therefore represent the least change:

- package 1 substantially maintains the status quo, but clarifies that there would be no avenue for generators to seek firmer access across the network; and
- package 2 clarifies the open access arrangements as in package 1, but also introduces a congestion pricing mechanism to better maintain incentives for economically efficient generator bidding when the transmission network is constrained.

The remaining three packages introduce varying degrees of firmer access rights for generators:[7]

- package 3 would introduce a model for applying transmission reliability standards to generation, similar to the arrangements that already exist for load;
- package 4 would introduce the option of firm financial access for generators, supported by a mandatory compensation scheme; and
- package 5 would introduce "firm transmission rights" that are auctioned by a single, NEM-wide TNSP (although it could be implemented with existing TNSPs with increased complexity). This approach is similar to those that are currently used in gas and electricity in parts of the United Kingdom (UK) and United States (US).

The following table sets out a high level summary of each of the proposed packages.

7 Note that access can be achieved either financially or through physical access. A generator is said to have financial access if it is compensated for the opportunity cost of being constrained off such that it is financially indifferent between being dispatched or being constrained off.

Table 2.1 Summary of the proposed packages

Package:	1: Open access	2: Open access with congestion pricing	3: Generator transmission standards	4: Regional optional firm access	5: National locational marginal pricing
Access/congestion	Generators have no firm level of access, no congestion pricing	Generators have no firm level of access, congestion is priced. All generators receive a proportion of congestion rents	Access defined by reliability standard for generators, no congestion pricing	Generators choose a quantity of firm access to the regional reference node	Generators are able to purchase fully firm rights to a national hub; non-firm generators exposed to congestion cost
Charging	No generator charge for use of the shared network	No generator charge for use of the shared network	All generators face a charge to reflect the cost of maintaining the standard	Firm generators pay a charge; no charge for non-firm generators but they are potentially liable for compensation	Rights purchased at auction, no charge for non-firm generators
Planning/institutions	No changes required (but enhancements possible)	No changes required (but enhancements possible)	TNSPs plan to new generator standard. Additional incentives required on TNSPs. Institutional arrangements to be considered e.g. who sets the standard. Further enhancements also possible	TNSPs plan to new standard for firm generators. Additional incentives required on TNSPs. Institutional arrangements need to be considered e.g. who sets the standard. Further enhancements also possible	Single (NEM-wide) TNSP plans to new standard for firm generators, investment funded by auction proceeds. Additional incentives required on TNSP

2.2.2 Key questions for stakeholders

The Commission is yet to determine whether it considers there is sufficient evidence to warrant substantial reforms to the existing arrangements. The Commission encourages stakeholders to provide additional evidence to support their views on whether substantial change is warranted.

However, we accept that many of the issues that have been raised reflect concerns about how transmission arrangements will respond in the future and therefore it is difficult to provide unambiguous evidence to support anticipated outcomes. For this reason, as outlined in chapter 3, we propose to consider which package is most likely to promote outcomes consistent with what we would expect to see in an efficient market, while recognising that any change may lead to short term transition costs.

The Commission is also interested in stakeholders' views on each of the packages that have been developed. Because each of these packages is intended to represent an internally consistent approach to transmission arrangements, care needs to be taken in "mixing and matching" between the core features of the packages to ensure they remain internally consistent.

The Commission is particularly interested in stakeholders' views on the following questions:

- Which package do you consider would best contribute to the achievement of the NEO and, more specifically, the objective of this review to minimise the expected total system costs faced by electricity consumers?
- What evidence or anticipated outcomes are there to support this view? Stakeholders should consider both:
  - why this package is more likely to contribute to the achievement of the NEO than the other packages presented; and
  - what evidence exists to suggest that the materiality of the problems identified would support adopting that package.
- In terms of your preferred package, are there any modifications that you would make, while maintaining the consistency of the package?
- Do any of the other packages presented merit further analysis and assessment?
- Are there any other packages for reform that we should consider and, if so, how would they better promote the NEO?

2.3 Planning

While transmission network planning arrangements are an essential component of any package of reforms, the Commission considers that there are a number of possibilities for enhancing planning arrangements that are an optional component of a number of the proposed packages, but are not required to achieve internal consistency. For clarity we have separated out the discussion of the essential elements of each package from the optional planning reforms.

The discussion of the planning arrangements in relation to each of the packages in chapters 6 to 10 is therefore confined to those elements of the planning arrangements that are integral to each package. Chapter 11 then sets out a number of other potential changes to the planning arrangements, any of which could be adopted with packages 1 to 4. The options proposed predominantly stem from inter-regional planning considerations, but recognise the large over-lap between inter- and intra-regional planning (and the difficulty in making such a distinction). They comprise:

- Options for enhancing existing planning arrangements. These options would be appropriate where the existing planning arrangements are considered broadly effective, but could benefit from enhancements in certain areas. Options include:
  - implementing a national framework for transmission network reliability standards for load;
  - improving the consistency of TNSPs' Annual Planning Reports;
  - improving the transparency of the Regulatory Investment Test for Transmission;
  - aligning the revenue resets of TNSPs; and
  - introducing reliability standards for interconnectors
- Options for more significant reform. These options may be appropriate if there is evidence to support the concerns raised by some stakeholders that existing arrangements are leading to an inefficient level of inter-regional investment, and include consideration of options proposed by some stakeholders. These potential options include:
  - option 1: enhanced coordination of the National Transmission Network Development Plan and Annual Planning Reports;
  - option 2: harmonised regime based on current South Australian arrangements;
  - option 3: a single NEM-wide not-for-profit transmission planner and procurer; and
  - option 4: joint-venture planning body established by TNSPs.

Chapter 11 also sets out a number of questions that stakeholders should consider in their response. These include:

- Is there a case for changing the existing planning arrangements?

- If so, is there a case for enhancements to existing arrangements or more significant reform?
- Of the options presented, which do you consider merit further assessment?
- Are there other options that should be considered?

2.4 Connections

While the approach to connections may change to some extent with each of the packages, the connections arrangements are largely separable from the other options for reform discussed in this report. Therefore the efficiency of the existing connections arrangements and our response to those issues are discussed separately in chapters 12 to 14.

Chapter 12 establishes that the existing connection arrangements lack clarity and therefore there is a case, as a minimum, for changes to improve certainty. The chapter provides an overview of the current provisions regulating the connection of generators, Network Service Providers (NSPs) and other transmission users to the national grid and explains the cause of uncertainty regarding the application of those provisions.

Chapter 13 then considers what form of economic regulation could apply to those services that require regulation. The strength of regulation will depend on the degree to which TNSPs are considered to have market power and the degree to which network users are considered to have countervailing buyer power. The chapter proposes three options for reforming the connections arrangements which represent increasing degrees of regulatory intervention:

- improving the dispute resolution framework that applies to negotiated transmission services;
- strengthening the negotiating framework that applies to negotiated transmission services, such as increasing the level of transparency associated with the negotiating process; and
- shifting all transmission services required for connection from negotiated to prescribed transmission services.

The Commission is particularly interested in stakeholders' views on the following questions:

- Which options, if any, do you consider would best contribute to the achievement of the NEO and, more specifically, the objective of this review to minimise the expected total system costs faced by electricity consumers?
- What evidence is there to support this view?
- Are there any other options for improving connection arrangements that we should consider and, if so, how would they better promote the NEO?

Finally, chapter 14 considers the obligations on TNSPs to facilitate connections and, in particular, whether TNSPs' obligations extend to providing extensions that are required in order to facilitate a connection. The chapter then considers what entities could own, operate and control extensions and whether it may be appropriate to provide for third party access to extensions.

Chapter 14 concludes with a series of high level policy questions for stakeholders' consideration, including:

- Is the provision of network extensions subject to workable competition?
- Are there any compelling reasons why competition in the provision of extensions should be limited to registered or incumbent TNSPs?
- Should third parties have the right to access extensions that are paid for by incumbent network users?

2.5 Summary

The Commission recognises that this report covers a lot of new material that stakeholders have not previously had the opportunity to comment on. Nevertheless, this report is at a crucial stage in the Review, and the Commission strongly encourages all stakeholders to provide evidence-based responses to the packages and analysis presented in this report. For the next report the Commission will narrow down the options for assessment and consider them in greater depth.

3 Assessment Framework

Box 3.1: Summary of this chapter

This chapter sets out the outcomes we are seeking to achieve through well-structured and targeted transmission arrangements, which will form the basis for comparing alternative packages against the existing arrangements. Consistent with promoting the NEO, the objective for this review is to provide arrangements that are likely to optimise investment and operational decisions across generation and transmission to minimise the expected total system costs borne by electricity consumers. Minimising total system costs implies that:

- TNSPs have incentives to efficiently operate and invest in their networks. This means that TNSPs should ensure that existing capacity is used efficiently and that the network is expanded in an efficient and timely manner.
- Generators have incentives to offer their energy at an efficient price and invest in new plant where and when efficient. This should occur when generators have access to a deep and liquid contract market and the transmission network supports a competitive generation sector.
- The set of policies or incentives that govern transmission decisions, and the market signals which influence generation decisions, should work together to provide a consistent overall framework.

Any implementation and transitional costs should not outweigh the benefits of moving to a new framework. As such, these costs will be taken into account in considering the relative merits of any proposed reforms.

3.1 Introduction

The purpose of this chapter is to set out a framework for testing the proposed options for reform against the existing transmission arrangements in the NEM. We discuss the outcomes that we consider would demonstrate a well-functioning market, consistent with promoting efficient decision making by individual market participants.

The NEO is at the core of every review and Rule change assessment that we undertake. The NEO is to promote efficient investment in, and operation and use of, electricity services for the long term interests of consumers.

Consistent with the NEO, the Commission's objective for transmission frameworks is to incentivise investment and operational decisions across transmission and generation to minimise the expected total system costs faced by consumers.

In a well-functioning market, total system costs across the whole supply chain, including distribution and retail, will be minimised. However, the focus of this review is on the inter-relationship between transmission and generation operational and investment decisions.[8] Therefore, in the context of this review, references to minimising total system costs refer to minimising the combined cost of investment in, and operation of, transmission and generation. This implies:

- TNSPs have incentives to:
  - operate efficiently, so as to maximise network availability in the short run; and
  - invest efficiently, such that load requirements can be met at least cost while maintaining quality, safety, reliability and security of supply; and
- generators have incentives to:
  - offer their energy at an efficient price; and
  - invest in new plant where and when it is efficient to do so.

While we consider these issues separately, in practice assessing whether transmission frameworks promote efficient outcomes across the supply chain, and particularly in generation, is a complex task. There are significant linkages between decisions regarding transmission investment and operation and those regarding other aspects of the supply chain, including generation and load. For example, a generator's decision on where to locate will influence the need for and cost of additional network capacity. Similarly, spare network capacity will influence the locational decisions of generators.

The framework and incentives governing transmission investment and operation therefore need to be co-optimised to promote efficient market outcomes overall.

There is also a complex inter-relationship between investment decisions and operational decisions, particularly for transmission. That is, transmission operational decisions can to some extent be a substitute for transmission network investment decisions. For example, TNSPs could extend the life of an asset through ongoing maintenance instead of investing in new equipment.

We are cognisant that a significant change in approach is likely to involve associated costs. Therefore our assessment framework also includes implementation and transitional costs.

COAG principles

In addition to the NEO, the Commission is required to have regard to principles agreed by the Council of Australian Governments (COAG). These primarily relate to issues regarding accountability and timing of transmission investment.

8 We note that in practice there are a number of factors that will influence both transmission and generation investment that sit outside the scope of energy market frameworks.

The COAG principles form another set of factors that the Commission will need to consider in assessing any potential options for reform. However, while these principles will be a factor in our assessment, we do not consider the principles to limit consideration of options. If the benefits of a preferred option are considered to outweigh the costs, the Commission may recommend that option to the MCE despite any inconsistency with the principles. It would then become a matter for the MCE to determine whether the recommendation was worthy of consideration despite any inconsistencies.

The remainder of this chapter discusses the outcomes we are seeking to achieve by ensuring that individual market participants have appropriate incentives to invest in, operate and use the network efficiently. This framework will guide our assessment of the five packages and the options for changes to the planning and connections arrangements.

3.2 Efficient decision making by TNSPs

3.2.1 Efficient investment in transmission networks

Transmission investment decisions play an important role in delivering efficient outcomes in the NEM. Transmission investment, combined with efficient operation of the network, should allow load requirements (i.e. meeting reliability standards) to be met at least cost. Transmission investment should also support a competitive generation sector through the timely and efficient construction of additional network capacity (although demand side options may be an efficient alternative to transmission investment). In the longer term, a slow response to building new transmission infrastructure can inhibit generators' ability to compete by limiting the available network capacity.

A failure to invest can also have shorter term consequences, such as increasing uncertainty for generators as to whether network capacity will be available to allow for their dispatch and potentially requiring higher cost generation to be dispatched. While building out all network constraints would be inefficient, there is a "tipping point" at which the inefficiencies associated with a network constraint would be greater than the cost of building out the constraint.

Constraints cause inefficiencies not only because higher cost generation must be dispatched so as to meet demand (resulting in productive inefficiencies) but also because generators have less certainty of dispatch. As discussed further below, this makes it difficult and more risky for them to enter into contracts, reducing the liquidity of the contract market and therefore increasing risk premiums and so costs. Generators may also find it difficult to obtain financing where the risk and cost of constraints is perceived to be high, resulting in allocative and dynamic inefficiencies.

TNSPs should therefore have incentives to invest in projects that will deliver the most value to the market.

Box 3.2: Regulated planning versus a market-based approach to transmission planning

Broadly, there are two approaches to transmission network planning:

- a regulated planning approach; or
- a market-led approach.

A regulated planning approach relies on regulatory obligations and rules to govern network investment decisions. A rule maker must work within the confines of defined obligations and rules in constructing frameworks that attempt to deliver efficient investment decisions by TNSPs. Such regulation cannot be comprehensive in practice and so TNSPs are still required to exercise their judgement when assessing the value of options to expand capacity.

Within the regulated planning approach, TNSPs could either be proactive or reactive in the way that they plan the network. Both approaches have their advantages and drawbacks. Proactive network planning requires TNSPs to forecast the likely future generation investment (and load) outcomes. This is unlikely to be perfect, and some consider that a proactive approach may distort otherwise competitive market outcomes in terms of generation investment. However, it may assist in overcoming the problem that transmission typically has a much longer lead time than generation.

A market-led approach requires a TNSP to respond to market signals through, for example, the purchase of access rights by generators. Instead of being governed by regulatory obligations and rules, decisions to expand the transmission network are guided by decisions in the generation sector. Similar to the reactive regulated planning approach, TNSPs respond to generators' decisions. However, under this approach TNSPs would likely have better information flowing from generators' decisions to purchase access rights.

In addition, while not an essential feature, financial incentives could be linked to a TNSP's obligations in respect of the access rights that it has sold. In theory this approach should promote efficient decision-making by requiring the TNSP to make a trade-off between building new capacity or facing the financial consequences of not meeting its contractual obligations. Whether this approach leads to efficient investment decisions will depend on the TNSP's willingness to take on risk and be exposed to market price signals.

In practice, regulated planning and market-led approaches are at two ends of a spectrum and network planning is likely to contain elements of both. The current arrangements in the NEM may be characterised as being more akin to regulated planning. Among other things, this review will test whether there may be benefits in moving further down the spectrum towards providing market-based signals for transmission investment.

As discussed in Box 3.2 above, there are two approaches to transmission planning: regulated planning or a market-based approach. Under a regulated planning approach, TNSPs are required to assess the need for new investment based on rules, regulations and assumptions about what value consumers place on reliability and quality, and what value generators place on access certainty. It is very difficult to perfectly capture these values.

However, there are a number of mechanisms that can be used to assist in achieving efficient outcomes. These include providing rules and requirements that seek to achieve least-cost outcomes, supported by a transparent planning process that is subject to stakeholder consultation. Under a market-based approach, decisions regarding the need for additional transmission capacity would be made in an informed manner by generators, who are better placed to make such decisions when presented with the correct signals. This would be likely to reveal the value that generators placed on firm access more effectively than could be facilitated by any regulated planning approach. However, this approach would also require TNSPs to have an appetite for risk-taking. In contrast, the provision of transmission services is traditionally a low risk business.

Under either approach, TNSPs should have incentives to implement their network development plans at least cost. Under a regulated planning approach this could be achieved by providing rules and regulations around how projects are evaluated and compared with alternatives. Under a market-led approach, TNSP revenues may be more closely tied to the cost of augmenting the network to provide stronger financial incentives for achieving the greatest value projects at least cost.

Efficient transmission arrangements will include checks and balances such that monopoly network businesses are held accountable for their decisions. This can be achieved in a range of ways, including consultations with stakeholders when developing planning documents.

3.2.2 Efficient operation of transmission networks

TNSPs should have incentives to deliver an efficient level of capacity at times when it is of most value to the market. A combination of financial incentives and obligations should encourage TNSPs to operate and maintain their networks efficiently and in a safe and reliable way.

In particular, incentives should be placed on TNSPs that encourage them to:

- manage their networks in real time to maximise capacity when it is most valued by the market;
- schedule planned outages at times when the value of network capacity is relatively low; and
- achieve an appropriate level of general maintenance across the network.

These incentives should complement and strengthen broader obligations on TNSPs to maintain an efficient level of reliability and security of supply on the network, as well as provide a minimum level of service quality for load customers.

There are a number of different ways to structure financial incentives on TNSPs to operate their network efficiently. To date in the NEM, such incentives have been linked to a TNSP's regulated revenue, representing a small percentage of the value of their asset base and so providing a relatively weak incentive.

Alternatively, incentives could be directly linked to the economic consequences of TNSPs' decisions, for example by requiring them to compensate network users for any losses where capacity is unavailable. This approach would provide a strong signal to manage the network consistently with the way in which capacity is valued by the market at any point in time. However, we are mindful that the provision of transmission services is traditionally a low risk business and exposing TNSPs to movements in the spot market price may not be an appropriate approach in the immediate future.

3.3 Efficient decision making by generation

3.3.1 Efficient investment in generation

Market price signals (spot and contract prices[9]) provide financial incentives for investment in new generation. These market signals should provide generators with appropriate incentives such that their investment decisions, including capacity and type of plant, location and timing, will be consistent with providing efficient prices for customers over time.[10]

The decision to invest in generation will be influenced by, among other things, the ability to underwrite contracts to manage the trading risks that generators face. There are two ways to do this (although a generator portfolio may contain elements of both):

- contract with retailers for part of a generator's capacity at an agreed price; or
- vertically integrate with a retailer.

These hedging mechanisms underpin investment by providing greater certainty over a future stream of predictable and stable revenues. Without such mechanisms, generation investment becomes more difficult as financing may not be forthcoming or the cost of financing may become prohibitively expensive as the risk premium must reflect the higher risks associated with less predictable revenues. Where a generator chooses to rely on contracting, a deep and liquid contract market is required to support generation investment. Vertical integration could arguably reduce the need for a deep

9 Contract prices include both longer term foundation contracts and shorter term (2 to 3 year) contracts such as those available on the futures exchange.

10 We note that demand side participation may represent an efficient alternative to generation investment.

and liquid contract market. However, this would also require there to be a sufficient number of integrated generator/retailers to maintain competitive pressures in both the generation and retail sectors so as to drive low cost outcomes for consumers. Further, liquidity of shorter term contracts may still be important.

A generator's willingness to invest will also depend upon its expected level of dispatch. Generators will be less willing to enter the market if they are uncertain about whether they will be dispatched, for example because future congestion is expected to be unmanageable and unpredictable. In part this is because they face the risk that where they cannot be dispatched, they will have to fulfil their contractual obligation by, in effect, paying for the purchase of electricity on the wholesale spot market, potentially at a very high cost. Therefore stable and predictable congestion, or an ability to hedge against uncertain levels of congestion, is important for promoting efficient levels of contracting as well as investment. This in turn flows through to efficient pricing for contracts and therefore efficient prices for consumers.

A generator's locational decision will influence the cost of future transmission network investment. It is desirable for generators to locate in areas where there is existing spare network capacity to minimise transmission costs. However, this must be balanced against other factors that influence locational decisions including access to fuel and water and the ability to obtain planning approvals. Overall, market signals should provide an incentive for generators to take into account the costs that they impose on the transmission network such that a balance is maintained between these potentially competing factors, minimising total costs to electricity customers.

3.3.2 Efficient operation of generation

The short term spot price for electricity is the key market signal that informs generators' short term operational decisions. Thus, if the short term marginal price signals that generators receive are efficient, then short run operational decisions should also be efficient, providing there is sufficient competition to drive efficient pricing outcomes.

Efficiency in this instance implies that generators should offer their energy at a price that reflects the cost of supplying one more unit of electricity to load from a generator's connection point.[11] This marginal cost will depend on a number of factors and will differ between generators depending on whether they contribute to or relieve constraints on the network, as well as their fuel costs and network losses. It will also depend on the level of demand and whether electricity can be sourced from a competing generator.

Where price signals result in efficient short run operational decisions by generators, demand should be met at least cost (assuming that transmission investment and

11 In the absence of network constraints and generation scarcity, this value is likely to equal the operating and maintenance costs (including network losses) of providing an additional unit of electricity.

operational decisions are also efficient). This should lead to efficient prices in the long run, consistent with promoting the long term interests of consumers of electricity.

Where generators receive a price that differs from the marginal cost of their energy, they may have an incentive to offer their energy as though they were a higher or lower cost generator to either avoid or increase their chance of dispatch. Misrepresenting the true value of their energy may result in higher cost generation being dispatched in place of lower cost generation, leading to productive inefficiencies. Therefore market signals should provide an incentive for generators to offer their energy at an efficient price.

3.4 Co-optimising generation and transmission decisions

Generation and transmission are both complements and substitutes. This implies that investment and operational decisions by generators and transmission should work together to achieve overall efficient outcomes. Expansion of the transmission network needs to support generation investment decisions, and generator decisions on where to locate need to take into account any requirement to construct additional transmission network. Similarly, operational decisions should be co-optimised such that least cost generation can be dispatched, taking into account network constraints and losses.

Therefore, the incentives and regulatory obligations that inform generator and transmission behaviour need to be considered together as a consistent package in order to deliver efficient outcomes. The policies that guide transmission investment must be consistent with both the policies that guide transmission operational decisions and the type and structure of market signals that govern generator investment and operational decisions. For this reason we have emphasised the need to develop internally consistent policy packages.

Given the inter-related nature of transmission frameworks, the number of factors that must be considered and the long term nature of investments, there will necessarily be some subjectivity about how much weight is given to each individual component. Consequently, it is the overall outcomes that are likely to arise from an internally consistent group of policies that must be evaluated against the outcomes from alternative approaches.

In the next stage of the review we propose to quantify the likely costs and benefits of individual components of the alternative policy packages where we consider the results are likely to be robust and informative. However, it is important to note that some costs and benefits are more suited to quantification than others. The ability of a model to accurately capture the combined effects of a complete policy package is limited, and modelling long term dynamic decisions is particularly challenging. Therefore qualitative assessment will be a necessary component of our evaluation of the policy packages.

3.5 Implementation and transitional issues

We note that there are an existing set of frameworks that were implemented at the inception of the NEM and refined over time. Therefore any significant changes to those frameworks will result in implementation and transitional costs. For this reason, our baseline for assessing alternative options is the ability of the existing set of transmission frameworks to promote the outcomes described above. Any proposed changes must be considered to result in materially more efficient outcomes to overcome the implementation and transitional costs associated with moving away from existing frameworks.

An additional factor to consider in assessing any proposed changes is the complexity involved. While increasing complexity may provide more refined and improved outcomes, the majority of the gains may be achieved from a simpler framework. Consequently the additional complexity associated with striving for a "first best" outcome may outweigh any incremental gains in efficiency. On the other hand, increasing complexity may be an appropriate and proportionate response to the identified issues that any proposed reforms seek to resolve, which is why private commercial arrangements are often complex.

Since NEM-start there have been a number of changes to the pattern of transmission network use. The increase in renewable generation and the implementation of climate change policies, among other developments, will continue to change investment decisions and therefore affect network operation over time. For this reason, we will seek to provide transmission frameworks that are robust and sufficiently flexible to promote efficient outcomes in the light of a changing investment environment. While we do not seek to second guess what those changes may be, we will assess any options for reform from a long-term perspective.

While the desirable outcomes described above are a useful goal in considering any changes to the current transmission arrangements, they represent a theoretical optimum that is unlikely to ever be achieved in practice. In addition, constant changes that strive to perfect already workable arrangements can lead to significant uncertainty. Regulatory uncertainty may distort investment decisions and lead to inefficiencies over time as a result of increased investment risk.

For these reasons, the Commission is mindful that any changes that result from this review should remain in place for a period of time to promote a stable and predictable environment in which efficient transmission and generation investments can be supported.

4 Summary of existing transmission arrangements

Box 4.1: Summary of this chapter

This chapter provides a brief overview of how the existing transmission arrangements operate, including an explanation of some key terms.

There are a number of mechanisms that, together, support the planning, investment and operational functions of transmission businesses. These arrangements are intended to ensure that TNSPs will invest in, maintain and operate their networks in an efficient and transparent manner. Many of these arrangements have only recently been implemented.

The way in which transmission arrangements are constructed will also influence generator behaviour, both in the long term through their investment decisions, and in the shorter term through the price and volume offers that they make. The way that generators respond to an absence of transmission network availability in the short and long run will influence the operational efficiency of the energy market and, ultimately, the price that consumers pay.

4.1 Introduction

This chapter summarises how transmission arrangements are currently designed. It is not intended to be a comprehensive discussion, but is intended to convey some of the key components of the existing arrangements that are being tested as part of this review. The following chapters provide further details on the current arrangements as required. Further detail on the existing transmission arrangements was provided in the Directions Paper for this review.[12]

This chapter is structured as follows:

- the remainder of this section discusses the characteristics of transmission that make it a particularly difficult industry to regulate;
- section 4.2 sets out the existing arrangements that govern investment in, and operation of, transmission networks;
- section 4.3 provides an overview of the arrangements that govern investment in generation; and
- section 4.4 sets out issues related to operational incentives for generators.

12 AEMC, *Transmission Frameworks Review*, Directions Paper, 14 April 2010.

4.1.1 The characteristics of transmission

Electricity transmission is the bulk transportation of electricity between generators and major load centres. Electricity flows along multiple paths across the whole network, consistent with certain laws of physics and according to network capability. The inability to store electricity implies that demand and supply must be constantly balanced in real time, taking account of these network flows.

Network capability depends on a complex range of factors and varies from one moment to the next, dynamically responding to changing conditions. Factors that influence transfer capability include, for example, security and reliability parameters, patterns of generation and demand, ambient weather conditions, the availability of transmission elements and the technical design limitations of individual network elements.

Transmission service providers are natural monopolies[13] and so are economically regulated to strive for more efficient outcomes than would occur in the absence of regulation. The way in which the regulatory framework is designed is crucial for promoting efficient investment in, and operation of, transmission networks. Over-investment in transmission capacity can lead to inefficiently high costs for consumers. On the other hand, under-investment in transmission can result in higher wholesale prices (as more expensive generation may need to be dispatched), a risk of supply interruptions and, ultimately, a risk of system failure.

These characteristics of transmission make it particularly challenging to economically regulate transmission network service providers.

4.2 Transmission investment and operational arrangements

In recent years there have been substantial reforms to the arrangements that govern transmission investment decisions. The intention of these reforms is twofold: to support timely and efficient network investment to deliver reliable supply for customers at an efficient cost; and to provide additional capacity where there is a net market benefit. TNSPs also face incentives to improve and maintain the reliability of their networks, particularly at times when network capacity is most valued by network users. This section discusses some of the core elements of these arrangements.

4.2.1 Transmission reliability standards

Under Chapter 5 of the Rules and various jurisdictional instruments, TNSPs are required to meet power quality and reliability standards through the planning and development of their transmission networks. The existing reliability standards for load differ between jurisdictions and in some cases lack transparency. The Commission has

13 Natural monopolies occur where it is only possible, or only makes sense, for a single entity to provide a service. This tends to occur where there are significant capital costs associated with the service provision. For example, in electricity transmission, it is more efficient for a single entity to invest in the necessary transmission equipment.

recommended a national framework for transmission reliability standards that is intended to promote consistency and transparency in the way in which standards are set and expressed across jurisdictions.[14]

Planning standards can be derived and expressed in a number of ways. The majority of states currently employ "*deterministic*" planning standards. This approach requires the transmission network to withstand a defined number of credible contingencies modelled under a variety of expected future baseline conditions. For example, an "N–1" standard requires the network to be able to withstand the failure of one component, "N–2" requires the network to be able to withstand the failure of two components, and so on.

"*Probabilistic*" planning, which is employed in Victoria, follows a two-step process. First, a "screening test" is applied to identify areas of potential network concern. This screening test checks the performance of the network against a range of deterministic criteria and performance requirements. Second, each potential weakness in the network highlighted by this screening test is subjected to more detailed probabilistic analysis, to determine the likelihood of non-supply. A cost-benefit analysis is then undertaken to compare the cost of non-supply with the cost of network augmentation.

Finally, a "*hybrid*" standard as used in South Australia employs elements of both probabilistic and deterministic approaches. Appropriate levels of reliability are economically derived using cost-benefit analysis for each connection point. These standards are then expressed in a deterministic manner and fixed for a defined period of time (currently five years in South Australia).

4.2.2 National planning and inter-regional augmentation

A number of different mechanisms assist the regionally-based TNSPs to identify possible investments to improve inter-regional transmission where it is efficient to do so.

The National Transmission Planner (NTP), which commenced as a role of AEMO on 1 July 2009, has responsibility for identifying investments that may achieve the efficient development of the grid through the publication of the annual National Transmission Network Development Plan (NTNDP). The NTNDP reports on the long term efficient development of the power system, including current and future network capability. The NTNDP has a focus on National Transmission Flow Paths (NTFP), which connect NEM jurisdictions. The first NTNDP was published in December 2010.

The Last Resort Planning Power (LRPP), which resides with the AEMC, is a mechanism for triggering cost-benefit assessments of potential projects if TNSPs are not responding to a material problem in a timely manner. The LRPP is intended to provide transparency and to encourage TNSPs to identify areas of the network which may need reinforcement or augmentation and test potential new transmission projects.

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14 AEMC, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, Sydney.

These functions assist TNSPs in identifying potential development options and can trigger action[15] if TNSPs are not responding to a material problem in a timely manner.

4.2.3 The Regulatory Investment Test for Transmission

The Regulatory Investment Test for Transmission (RIT-T) establishes the process and criteria to be applied by a TNSP for considering investment in its transmission network. The RIT-T became effective on 1 August 2010 and typically must be applied to assess augmentations and other new transmission investment.[16] The purpose of the RIT-T is to:[17]

> "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 RIT-T, as set out in the Rules, comprises two elements:

- a process element, which includes the procedural consultation requirements[18] and a dispute resolution mechanism[19]; and
- the test itself, which examines the costs and benefits of each credible option to establish the option that maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

The test requires TNSPs to examine the costs and benefits of credible options to establish the one that maximises net market benefits. Where investment is being undertaken to meet reliability standards, the preferred option may have a negative net economic benefit in which case the RIT-T should identify the option which minimises these costs.

In applying the RIT-T, TNSPs are required to consider a range of credible options to meet an identified need, including non-network solutions.

4.2.4 Revenue cap regulation

Incentives for TNSPs to minimise costs in undertaking investment and operational decisions are provided through revenue cap regulation under Chapter 6A of the Rules. TNSPs are provided with fixed annual revenue allowances, typically for a period of five years. The revenue cap is set using a building blocks cost of service approach. This framework is intended to provide TNSPs with incentives to minimise expenditure over

15 Note that the LRPP can force a RIT-T assessment but it cannot force the investment itself.

16 There are several exceptions to this requirement, which are set out under clause 5.6.5C of the Rules.

17 National Electricity Rules (NER or the Rules) clause 5.6.5B(b).

18 NER clause 5.6.6.

19 NER clauses 5.6.6A and 5.6.6AA.

the five year regulatory period because they retain (or are exposed to) differences between actual and allowed revenues for the duration of the revenue period.

In Victoria, the transmission network is planned and procured by AEMO. As AEMO is a not-for-profit organisation it is not subject to these financial incentives, and is not required to have a revenue determination approved by the AER[20] (although it is required to submit other components of a transmission determination for approval, including a pricing methodology). SP AusNet, which owns and operates the bulk of the transmission network in Victoria, is subject to a revenue cap. The revenue cap applies to those transmission services that have not been procured by AEMO through a competitive tender.

At the end of each revenue reset period the revenue allowances are rolled forward based on the value of actual capital expenditure. TNSPs are therefore only partially exposed to the costs of any inefficient over- or under-investment (they are exposed to initial financing costs and depreciation loss incurred up to the end of the regulatory period).

The incentives framework is designed to balance the need for investment in new capacity by minimising regulatory risk faced by TNSPs when investing, and ensuring that TNSPs undertake such investment efficiently so that customers do not pay more than necessary for transmission services.

4.2.5 The Service Target Performance Incentive Scheme

Incentives for TNSPs to operate their networks efficiently so as to maximise network capability are currently provided by the AER's TNSP Service Target Performance Incentive Scheme (STPIS). This scheme is intended to encourage TNSPs to improve reliability and provide transmission capability at those times when it is most valued by the market by rewarding (or penalising) TNSPs for performance against specified targets.

The scheme is comprised of two components:

- the Service Component provides incentives for TNSPs to minimise the number and duration of loss of supply events, and to maximise circuit availability; and
- the Market Impact Component provides incentives for TNSPs to minimise the market impact of transmission outages, based on the number of dispatch intervals where an outage on a TNSP’s network results in a network outage constraint with a marginal cost that exceeds $10 per megawatt hour (MWh).

Currently TNSPs face a financial incentive in the range of plus or minus 1 per cent of regulated revenue for the Service Component, and between zero and plus 2 per cent for the Market Impact Component.

20 AEMO is, however, required to have, and comply with, a revenue methodology (which does not need to be approved by the AER). See NER S6A.4.2 for further details.

4.3 Current generator investment incentives

Under the current arrangements there are a number of energy market and other signals that influence a generator's decision on when and where to invest, as well as decisions on fuel type, capacity and other variables. As discussed in chapter 3, the efficiency of transmission investment and operation is also critical to supporting a competitive and efficient generation sector. In the longer term persistent and material congestion can impact the efficiency of generator investment and operational decisions.

This section explains what factors generators consider when investing, including the impact of congestion. Section 4.4 then explains how congestion can influence generators' short term operational decisions to cause inefficient outcomes.

What governs generation investment decisions?

Building a business case for investment in generation requires assumptions about the potential revenue the generator will attain over its lifetime. Generator revenue is primarily obtained by selling energy to the wholesale market pool at the Regional Reference Node (RRN) for which they receive the Regional Reference Price (RRP).[21] Generators may enter into contracts with retailers or large users for at least part of their capacity. This allows generators to negotiate a fixed price for their energy. In either case, this requires that the generator is able to access the RRN whenever the generator is dispatched by AEMO.

In order to be dispatched, generators submit offers to AEMO which, in addition to certain operational parameters, detail the volume they are willing to generate at each of up to ten different prices. These offers are then used to dispatch generators in the most cost-effective way to meet the prevailing demand and frequency control requirements. Offers to generate are stacked in a "merit" order of rising price, and are then scheduled and dispatched, least cost first. However, at times there may be reasons why lower cost generation cannot be dispatched, which may result in more expensive generators being dispatched in its place to satisfy demand in a particular area.[22] These generators that would not have been dispatched but for the technical reasons are said to be dispatched "out of merit".

In the NEM, supply and demand are instantaneously matched in real-time through a centrally-coordinated AEMO dispatch process. A generator's "right" to use the transmission network depends on whether it is dispatched by AEMO's NEM Dispatch Engine (NEMDE) and the availability of network capacity. If the network is congested, generators face a risk of not being dispatched. Congestion is defined in Box 4.2.

21 Note that generators may also obtain revenue from selling ancillary services.

22 For example, the technical capacity of the transmission network, restrictions on how fast a generator can increase production, or it being optimal to withhold otherwise cheaper generation to access the generator's cheaper frequency control offers.

Box 4.2: What is congestion?

The carrying capacity of transmission networks is limited. Congestion occurs when the flow of electricity reaches the physical limits of the transmission network (or a particular part of it). At these times transmission capacity becomes scarce. The primary consequence of congestion on the transmission network is that it can cause some generators to be “constrained off” and some generators to be “constrained on” to ensure demand continues to be met.

A generator is said to be constrained off when it is dispatched for a quantity less than the amount it desired to produce at the market price. Conversely, a generator is said to be constrained on when it is dispatched for a quantity greater than the amount it desired to produce at the market price.

Uncertain and unpredictable network congestion leads to "dispatch risk" for generators, whereby they face a risk of not being dispatched even when they are in merit due to network congestion. Generators have limited ability to manage their exposure to dispatch risk as there is no functioning mechanism for TNSPs to provide access rights over the deeper network to the RRN, only a requirement to negotiate "in good faith". In this paper, this level of service is referred to as "non-firm" or "open" access.

Generators may choose to fund augmentations to the shared transmission network in order to reduce congestion and the risk of network constraints. However, generators receive no exclusive "right" to the use of such augmentations, and the benefits of the reinforcement may accrue to other generators.

Congestion is therefore only likely to be built out if a proposed augmentation passes the RIT-T or if it is required to meet load reliability standards.

What locational signals exist in the NEM?

Generators face a number of electricity market signals that may influence their locational decision. These include:

- **the cost of connecting to the network**. Currently in the NEM, generators pay charges relating only to the cost of their shallow connection to the shared transmission network, although any requirement to construct an extension from the generator's facilities to the network can have a significant cost impact;

- **the presence of congestion**. The frequency and materiality of congestion will influence a generator's ability to access the RRN, as discussed above, and so may provide a signal of where not to locate;

- **marginal loss factors**. Energy losses on the transmission network between a generator's facilities and the RRN will influence the outturn price it receives for its energy;[23] and

- **inter-regional price differences**. Price separation between regions can be an indicator of which regions require additional generation capacity.

In addition, generators will take into account other non-energy market signals such as access to fuel and cooling water and planning requirements. These non-electricity market factors can have a significant impact on overall costs, particularly the proximity of a preferred location to a fuel source.

However, generators are not currently exposed to any costs associated with additional transmission investment in the shared network that may be caused by their locational decisions. All costs involved in providing the shared transmission network are recovered solely from load. Further, although generators receive some signals associated with the short term costs of congestion through the risk of not being dispatched, they receive no direct congestion price signal within regions, as discussed below.

4.4 Current generator operational incentives

This section outlines the issues related to operational incentives for generators, in particular the impact of network congestion on generator bidding behaviour.

Price setting

Prices that generators receive in the NEM are derived for each trading interval[24] on a regional basis. These are known as regional reference prices (RRPs) and reflect the cost to supply the RRN. Congestion within a region ("intra-regional" congestion) can lead to "mispricing", which occurs because the price that is used for settlement (the RRP) is different to the price that would reflect local demand and supply conditions at the generator's connection point.

This means that differences in the cost of supply within a region are not reflected in the outturn price that a generator receives. Consequently, generators are not exposed to the short term costs of congestion that they impose on the network, although they are exposed to dispatch risk.

In addition to energy, the cost of supplying the RRN includes the short run marginal costs of transmission.[25] These costs include congestion and losses. Economic efficiency suggests that generators and loads should be exposed to these short run costs of using

23 Loss factors in the NEM are determined on an average basis and set annually. Therefore they will not always provide an efficient signal.

24 Dispatch occurs over a 5 minute interval. Prices are calculated for each 5 minute dispatch interval and averaged over the 30 minute trading interval to obtain the RRP.

25 The short run marginal costs of transmission are those costs that vary with transmission utilisation.

the network so that they utilise it in an efficient manner. However, unlike losses, congestion is not currently taken into account in the price that a generator receives.

Disorderly bidding

As discussed above, generators do not currently face a price that signals their impact on network congestion. However, they do implicitly face congestion costs in the form of dispatch risk. There is currently no mechanism that allows generators to hedge this dispatch risk. Instead, generators engage in behaviour, termed "disorderly bidding", to reduce the extent of being constrained off.[26]

Disorderly bidding occurs because generators located behind constraints know that the price they receive will be set by higher-cost generation elsewhere and therefore can make non-cost reflective offers. Such generators will instead offer capacity at a price which maximises their dispatch. At the extreme, this could be at the market floor price of -$1,000/MWh. When this occurs, the NEMDE is unable to distinguish high cost generators (such as peaking units) from low cost generators (such as baseload coal units), as it only observes the price floor offers from a range of generators affected by the constraint.

When all constrained generators price their offers at the price floor, dispatch is pro-rated among those generators based on the capacity they have made available in dispatch. This prevents demand from being met from the lowest cost generation options and represents a productive inefficiency. The most efficient generators are not fully dispatched as they have no mechanism to signal the value they place on this access. Reduced certainty of dispatch outcomes will impact financial markets, increasing costs and potentially discouraging investment in new generation plant.

26 Note that generators can also be constrained on. However generators are less likely to be constrained on as they can bid unavailable. Alternatively, generators may be directed to generate by AEMO for security purposes (NER clause 4.8.9), in which case the affected generator is entitled to compensation (NER clause 3.12.2).

5 Performance of existing transmission arrangements

Box 5.1: Summary of this chapter

This chapter provides an assessment of the strengths and weaknesses of the existing frameworks, drawing from stakeholders' submissions. The chapter also presents the Commission's current views on the issues that have been raised.

There are a wide range of views on the efficacy of existing arrangements. While some stakeholders consider the frameworks are broadly appropriate, others consider that there is a need for substantial reform to promote efficient investment and operational decisions by TNSPs and generators.

It is clear that there is some level of dissatisfaction with current frameworks, however it is difficult to identify the precise cause of the problems. The divergence of views amongst generators appears to be linked to in part to location and ownership structure, with large generators in Queensland and NSW generally viewing existing arrangements as largely appropriate compared to those in Victoria. Stakeholders' views are more consistent on the need for reform to the connection frameworks.

5.1 Introduction

5.1.1 Use of the transmission network is changing

The NEM is currently facing a period of significant change,[27] stemming in part from government policies responding to climate change. These policies are intended to influence the behaviour of market participants by changing the underlying economics of generation to promote less carbon-intensive technologies. However, continued debate around the most appropriate response to climate change has resulted in a period of uncertainty, particularly for generation investment.[28]

Further, there is significant uncertainty in the long term regarding the type and location of the large amount of generation investment that is expected to enter the market, including new baseload plant. This, in turn, creates uncertainty around the changing patterns of network flows and so the likely occurrence and materiality of congestion. Transmission frameworks will therefore need to accommodate a broad range of potential outcomes.

27 See: AEMC, *Transmission Frameworks Review*, Issues Paper, 18 August 2010, Sydney; and AEMC, *Transmission Frameworks Review*, Directions Paper, 14 April 2011, Sydney for further discussion on the changes that are likely to occur.

28 For further commentary on the impact of uncertainty around the introduction of a carbon price on investment in electricity generation see: Investment Reference Group Report, *A Report to the Commonwealth Minister for Resources and Energy*, April 2011.

5.1.2 Stakeholder views are mixed on the need for change

While the existing transmission arrangements have delivered investment in network infrastructure and reliable supply to date, the arrangements must allow TNSPs to respond in a timely way to these future challenges and uncertainties.

Stakeholders' responses to both the Issues Paper and Directions Paper for this review delivered no clear consensus on whether existing frameworks are sufficiently robust to meet these future challenges. Some stakeholders considered that existing frameworks generally result in effective outcomes for transmission and generation investment and operation. These stakeholders considered that only incremental changes are required, if any. Others considered there is a need for substantial reform.

The views expressed by generators appear to diverge according to jurisdiction and ownership structure. Large government-owned generators in Queensland and NSW considered current arrangements are broadly appropriate, compared to privately-owned generators in Victoria who raised a number of concerns. Since there are a number of regional differences in the way in which existing arrangements are applied it is difficult to identify the drivers of concern and, in particular, to isolate cause and effect. For example, it is not clear whether the concern of generators in Victoria is due to a lack of firm access rights, the use of probabilistic planning for load reliability standards or other factors.

Of all the issues raised, only the need to improve the connections arrangements has elicited a degree of consensus amongst generators. As discussed in the Directions Paper, a clearer view emerged from generators that there is a need to revisit the current connections arrangements, irrespective of any reforms that may be considered to other aspects of the transmission frameworks.[29] Issues regarding connections are discussed in chapters 12 to 14.

Given the range of views expressed, uncertainty around likely future developments and the infancy of some of the transmission frameworks, we are considering whether there is sufficient evidence to demonstrate that alternative arrangements would clearly deliver better outcomes, both now and in the future. A key consideration will be the likely implementation costs of any changes. This approach can supplement analysis of the efficiency of the existing arrangements.

The remainder of this chapter is structured as follows:

- section 5.2 presents an analysis of the existing arrangements that govern investment in, and operation of, transmission networks;
- section 5.3 discusses views that have been raised regarding the arrangements that govern investment in and operation of generation; and
- section 5.4 sets out a summary of the Commission's current views and the different approaches to reform that have been identified for consultation.

29 AEMC, *Transmission Frameworks Review*, Directions Paper, 14 April 2011, Sydney, p. 77.

5.2 Efficient investment in, and operation of, transmission networks

As discussed in chapter 3, transmission investment should support a competitive generation sector through the timely and efficient construction of additional network capacity. This section considers the ability of existing frameworks to achieve this outcome, drawing from stakeholder submissions.

Transmission planning arrangements are a key area of jurisdictional differences. This section therefore commences by examining the impact of these differences, followed by a discussion on institutional arrangements, national planning and inter-regional augmentation and issues raised by stakeholders regarding the RIT-T.

This section also includes a summary of stakeholder views in relation to the efficient operation of transmission networks and the importance of providing incentives for TNSPs to operate their networks to maximise network capability.

5.2.1 Jurisdictional differences in planning arrangements

Broadly, large generators in Queensland and NSW considered that the existing transmission planning and investment arrangements have delivered reasonably effective outcomes to date. In contrast, generators operating in Victoria expressed concerns with the efficiency of existing frameworks. This section examines some of the differences between jurisdictions that may influence these different views

Probabilistic versus deterministic planning

As discussed in section 4.2.1, different jurisdictions have different approaches to the way in which transmission reliability standards for load are set, which influence the way that the network is planned. Stakeholders hold divergent views on the relative efficacy of probabilistic and deterministic approaches to network planning. As discussed further in chapter 11:

- The Victorian Department of Primary Industries (DPI) and SP AusNet considered probabilistic planning would result in more efficient outcomes and that a higher level of transmission capacity in other states may be a result of inefficient over-investment.[30] The Victorian DPI also cited the Independent Pricing and Regulatory Tribunal's concerns that the reliability standards in NSW may not reflect customers' value of reliability or their willingness to pay for increased reliability.[31]

- Other stakeholders, including the National Generators Forum (NGF) and the Northern Group of generators (the Northern Group)[32], considered deterministic

30 Victorian DPI, Directions Paper submission, p. 9; SP AusNet, Directions Paper submission, p. 4.

31 Victorian DPI, Directions Paper submission, p. 9.

32 For the Directions Paper this group included Snowy Hydro, Delta Electricity and Macquarie Generation. The Northern Group submission to the Issues Paper also included CS Energy, Eraring Energy, Stanwell Corporation and Tarong Energy.

planning to be more appropriate.[33] The NGF was concerned that a probabilistic standard can make transmission investment difficult to justify. It also considered that probabilistic standards are unresponsive to participants' and customers' needs and could ultimately result in more blackouts.[34]

Where deterministic standards result in a greater level of network capacity being built, generators that locate in jurisdictions that employ a deterministic planning approach may enjoy greater network availability than those that locate in a region with probabilistic planning. This is a key difference between jurisdictions that may influence stakeholder views on the need to reform existing arrangements.

Not-for-profit versus economic regulation

Transmission planning and investment in most jurisdictions is undertaken by an economically regulated TNSP. Those TNSPs are subject to financial penalties or rewards as a consequence of their decisions. In contrast, AEMO undertakes transmission planning in Victoria and runs tenders for transmission projects where the project meets certain criteria. AEMO is a not-for-profit entity and so is not subject to financial incentives.

The Victorian DPI considered that having a not-for-profit business responsible for planning and procurement of transmission would be more efficient as it would be less likely to lead to non-transparent planning decisions which could be distorted by the financial incentives of monopoly network businesses.[35] It considered that these efficiency benefits would increase over time as a consequence of the expected need to transport electricity from generators located long distances from load centres.

In contrast, Grid Australia considered that the party responsible for transmission service delivery should also be responsible for transmission investment decision making.[36] It further suggested that, if it is accepted that incentive regulation promotes superior outcomes to regulatory planning process, then it is logical to conclude that the current arrangements in Victoria are sub-optimal.[37] This is because, as a not-for-profit entity, AEMO would not be responsive to financial incentives. Grid Australia therefore contended that the current regime in Victoria removes any scope for incentive regulation to encourage innovation, optimise trade-offs and undertake small investments to improve capacity of existing network assets.

Government owned versus privately owned generation and transmission

In NSW and Queensland, transmission and the majority of generation are government owned. In contrast, the incumbent Victorian transmission operator, SP AusNet, is privately owned, as are all the Victorian generators. AEMO, as transmission planner

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33 NGF, Directions Paper submission, p. 6; Northern Group, Directions Paper submission, p. 10.

34 NGF, Directions Paper submission, p. 6.

35 Victorian DPI, Directions Paper submission, p. 2.

36 Grid Australia, Issues Paper submission, p. 19.

37 Grid Australia, Issues Paper supplementary submission, p. 13.

and procurer in Victoria, is comprised of sixty per cent government members, with the balance of the company owned by industry members.

International Power noted the correlation between government-owned generation and support for existing transmission arrangements.[38] It suggested that common ownership of transmission and generation may mute the effect of any wealth transfers between the two entities.[39]

International Power also suggested that since generation and transmission in NSW and Queensland are both government-owned, there is an incentive on these parties to maximise overall profits.[40] International Power further considered that:[41]

> "government owned generation is a legacy issue that, while requiring due attention while it persists, is most unlikely to play any material part in further development of electricity supply. Thus the arrangements should be designed to promote the NEO in the context of private investment in generation, and hence in the absence of common ownership covering both transmission and generation."

The Commission's current views

The different approaches to transmission planning and investment between regions and differences in ownership arrangements makes it difficult to identify the source of concern with existing planning arrangements. We do note that the combination of deterministic planning by for-profit, and often government-owned TNSPs has apparently led to a greater level of satisfaction with planning arrangements amongst large generators in NSW and Queensland, compared to generators in Victoria.

Insufficient evidence has been provided to allow us to determine whether this is a result of inefficient overbuilding or an efficient response to market requirements.

In terms of the relative strengths and weaknesses of probabilistic and deterministic standards, the Commission has recommended to the MCE that a national framework for transmission reliability standards for load be implemented that requires standards to be economically derived and deterministically expressed (i.e. a hybrid standard).[42] The Commission considers that this approach provides an appropriate balance between ensuring the standards will promote efficient investment outcomes and maintain transparency in the way in which they are applied.

The relative strengths and weaknesses of these various approaches to planning are discussed further in chapter 11.

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38 International Power, Directions Paper submission, p. 3.

39 International Power, Directions Paper submission, p. 8.

40 International Power, Issues Paper submission, p. 23.

41 International Power, Directions Paper submission, p. 3.

42 See: AEMC, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, Sydney.

5.2.2 Institutional arrangements

The Commission has received a number of comments regarding the institutional arrangements in the NEM, primarily in relation to consideration of a single national TNSP and the potential to extend AEMO's independent planning and procurement role.

While not necessarily expressing support for a single transmission owner and operator, a number of respondents did indicate that consideration of a more consistent approach to planning is warranted across the NEM.[43]

Single national TNSP

In the Directions Paper, the Commission noted that having a single transmission owner and operator across the NEM could produce scale economies and promote national consistency. However it also noted the associated challenges with such a significant institutional change.[44] There was some stakeholder support for the concept of a single transmission owner being addressed further in this review[45] or being proposed to the MCE for assessment.[46]

A single national TNSP is discussed further in chapter 10 in the context of the fifth policy package.

Extending AEMO's independent planning and procurement role

The MEU considered that, as an alternative to a single TNSP, the "Victorian model" could be rolled out across the NEM such that AEMO identifies augmentations and expansions which are implemented under contract with TNSPs, who then hold the assets.[47]

The Victorian DPI was a proponent of extending AEMO's planning and procurement role for transmission across the NEM.[48] The EUAA also supported this model, stating that the outcomes in Victoria have been relatively favourable compared to other jurisdictions.[49]

The possibility of extending AEMO’s Victorian planner/procurer role across the NEM is discussed in section 11.3.3.

43 SP AusNet, Directions Paper submission, p. 4; DPI Victoria, Directions Paper submission, p. 2; MEU, Directions Paper submission, p. 34; Northern Group, Directions Paper submission, p. 10.

44 AEMC, *Transmission Frameworks Review*, Directions Paper, 14 April 2011, Sydney, p. 76.

45 Alinta Energy, Directions Paper submission, pp. 4 & 10.

46 MEU, Directions Paper submission, p. 33.

47 MEU, Directions Paper submission, p. 34.

48 Victorian DPI, Directions Paper submission, p. 2 .

49 EUAA, Issues Paper submission, p. 8.

5.2.3 National planning and inter-regional augmentation

As discussed in section 4.2, the Regulatory Investment Test for Transmission (RIT-T), National Transmission Planner (NTP) and Last Resort Planning Power (LRPP) are important components of the transmission planning arrangements. While the RIT-T is intended to ensure that any investments that are undertaken are the most efficient option to address the identified need, the remaining functions are intended to provide a greater focus on national planning and inter-regional augmentation.

A number of stakeholders provided wide-ranging commentary on the relative effectiveness of these mechanisms. Those that considered the existing arrangements to be broadly effective pointed to the relative newness of these frameworks and considered that there had been insufficient time to determine the effectiveness of the frameworks, particularly the NTP, RIT-T and LRPP.[50]

Those stakeholders that considered existing frameworks required strengthening highlighted the following concerns:

- multiple network planners not adopting a national focus;
- a failure to deliver sufficient interconnector capacity; and
- the value of the LRPP.

These concerns are briefly summarised below and are discussed further in chapter 11.

Multiple national planners do not adopt a national focus

Despite the establishment of the NTP, some stakeholders remain concerned that accountability for inter-regional planning remains unclear. This is because no single entity has the responsibility to adopt a national focus to identify and invest to meet the inter-regional needs of the NEM.[51] These stakeholders considered that the regulatory regime does not allow the AER, when reviewing the revenue allowance for a TNSP, to consider whether investments should instead be made on another TNSP's network.[52]

A failure to deliver sufficient interconnector capacity

Some stakeholders and industry commentators considered that the NEM has failed to deliver a sufficient level of interconnector capacity in the past decade.[53] Others suggested that inter-regional developments based on market benefits have not

50 AER, Directions Paper submission, p. 5; Alinta, Directions Paper submission, p. 10; Clean Energy Council (CEC), Issues Paper submission, p. 6; Electricity Networks Association (ENA), Directions Paper submission, p. 1; EnergyAustralia, Issues Paper submission, p. 6; ENA, Issues Paper submission, p. 1; Grid Australia, Issues Paper submission, pp. 6-7.

51 International Power, Issues Paper submission, pp. 11-13; MEU, Issues Paper submission, p. 27.

52 AEMO, Issues Paper submission, p. 12; Victorian DPI, Issues Paper submission, pp. 6-7.

53 Garnaut, Ross, *Climate Change Review - Update 2011*, Update Paper eight: Transforming the electricity sector, pp. 29-30; Infigen, Directions Paper submission, p. 3.

occurred because of similar fuel costs in adjacent regions[54] and the difficulty in quantifying competition benefits under the regulatory test.[55] The South Australian Department of Transport, Energy and Infrastructure (SA DTEI), while noting that AEMO and ElectraNet are investigating this issue further, was concerned that there was no incentive for these entities to proactively undertake a review of the Heywood interconnector. SA DTEI was further concerned that the feasibility study undertaken gave questionable results due to some of the fundamental assumptions used.[56]

International Power commented that the NTP focuses on major transmission paths whereas limitations on interconnector flows are commonly due to limitations of plant embedded deep within one of the interconnected regions.[57] Therefore International Power considered that the NTP should indicate the desirable level of reliable interconnector capability for each interconnector and flow direction as a means to maintain interconnector capability over time. This is discussed further in section 11.2.5.

In contrast Grid Australia noted that there are a combination of measures that exist which are designed to ensure that projects with net market benefits will be identified, evaluated, and constructed. Grid Australia also highlighted that all interconnectors are currently undergoing some form of assessment.[58]

The value of the LRPP

The small number of stakeholders that commented on the LRPP expressed divergent views. Infigen supported the use of the LRPP as a mechanism for triggering cost-benefit assessments of potential projects when TNSPs are not responding to a material problem in a timely manner.[59] In contrast, AEMO questioned the value of the LRPP given that the NTP arrangements are now in place.[60]

The Commission's current views

The Commission considers that an efficiently planned transmission network will have the following characteristics:

- delivery of efficient investment to meet load reliability standards (or recognise the value of customer reliability);
- provision of a level of network capacity that reflects the value to generators of being dispatched in the energy market; and

54 This implies that there are fewer efficiencies to be gained by increasing interconnector capacity as cheaper generation would not be replacing more expensive generation.

55 EUAA, Issues Paper submission, p. 10; Infigen, Issues Paper submission, p. 5; Northern Group, Issues Paper submission, p. 17.

56 SA DTEI, Directions Paper submission, p.4.

57 International Power, Directions Paper submission, p. 11.

58 Grid Australia, Directions Paper submission, p. 8.

59 Infigen, Issues Paper submission, p. 5.

60 AEMO, Issues Paper submission, p. 11.

- arrangements that provide confidence that effective co-ordination between generation and transmission investment, as well as between TNSPs in different regions, will be achieved.

In this context, the Commission broadly considers that the current planning arrangements are delivering outcomes that are consistent with these characteristics. There is no evidence to suggest that TNSPs are failing to meet load reliability standards. Scoping studies and a RIT-T have been undertaken or commenced to assess the need for more inter-regional transmission capacity. The NTNDP and TNSPs' Annual Planning Reports (APRs), in combination with the LRPP, promote transparency and accountability.

However, it is not clear whether the RIT-T is being applied to identify efficient investment to relieve congestion faced by generators, or whether the RIT-T appropriately captures the value that generators place on certainty of access.

Many of these arrangements are new, and so it is too early to undertake a comprehensive evaluation. However, stakeholders have raised a number of concerns with the existing arrangements. Given the scope of this review, it is timely to consider whether these arrangements can be further enhanced. A number of possible enhancements to transmission planning and investment arrangements have therefore been set out for consideration in chapter 11.

5.2.4 Effectiveness of the RIT-T

As discussed above, a number of stakeholders considered that recent reforms to the transmission planning arrangements, including the RIT-T, have not been in operation for long enough for their performance and adequacy to be able to be assessed at this stage.[61] Indeed, most TNSPs are in the early stages of applying the RIT-T for the first time. Grid Australia has recently published a draft RIT-T Handbook[62] to provide guidance on the way in which those TNSPs will apply the RIT-T, including the calculation of option value and competition benefits where applicable.

Despite its relative infancy, a number of stakeholders have identified several potential issues with the RIT-T.

Some stakeholders considered the RIT-T is unlikely to provide efficient and timely investment in the shared network.[63] Many of these stakeholders suggested that quantifying market benefits (especially competition benefits and option values) is inherently difficult under the RIT-T, meaning that fewer projects may pass the test than

61 AER, Directions Paper submission, p. 5; Alinta Energy, Directions Paper submission, p. 10; ENA, Directions Paper submission, p. 1.

62 Grid Australia, *RIT-T Cost Benefit Analysis*, Grid Australia Handbook, July 2011.

63 Brookfield, Issues Paper submission, p. 5; CEC, Issues Paper submission, p. 6; Victorian DPI, Issues Paper submission, p. 8; Infigen, Issues Paper submission, p. 6; International Power, Issues Paper submission, p. 19; Loy Yang Marketing Management Company (LYMMCo), Issues Paper submission, p. 23; Origin, Issues Paper submission, p. 6; TRUenergy, Issues Paper submission, p. 2; Infigen, Directions Paper submission, p. 3.

should.[64] This might lead to an inefficiently high level of congestion, which has a number of consequences as discussed in sections 4.3 and 4.4.

More broadly, some stakeholders argued that the RIT-T process does not ensure that TNSPs construct all economic projects; rather, it only prevents TNSPs from constructing projects that are uneconomic.[65] Further, AEMO and Alinta considered that TNSPs could apply discretion in applying a RIT-T. They considered that this discretion, combined with the existing information asymmetries between TNSPs and others results in parties being unable to provide checks and balances on TNSP investment plans.[66]

The MEU[67] considered the RIT-T objective should be modified to benefit consumers and not those who produce, consume and transport electricity as specified in the Rules.[68] The MEU considered the goal of "net market benefit" is not consistent with the NEO as it ignores wealth transfers that result in a least cost result for consumers.

Grid Australia considered that greater guidance on aspects of the RIT-T would be useful, particularly on when generator or other investment costs should be considered sunk.[69]

The NGF suggested that market revenue is a primary concern for generators and that the impact of augmentations on generator contractual positions is not considered in the RIT-T.[70]

Finally, the AER has recently published a compliance bulletin noting its concern that some TNSPs have misapplied the criteria for identifying credible[71] options to address an identified need under past regulatory test processes.[72]

The Commission's current views

The Commission agrees that there has not been sufficient opportunity to assess the operation of the RIT-T to date. We therefore consider that there is insufficient evidence to warrant significant changes to the RIT-T at this stage. However, there may be some value in improving the transparency of the application of the RIT-T. This is discussed further in section 11.2.3.

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64 EUAA, Issues Paper submission, p. 12; Infigen, Issues Paper submission, p. 5; LYMMCo, Issues Paper submission, p. 21; NGF, Issues Paper submission, p. 8; Origin, Issues Paper submission, p. 6; TRUenergy, Issues Paper submission, p. 2.

65 AEMO, Issues Paper submission, p. 9; International Power, Issues Paper submission, p. 19.

66 AEMO, Issues Paper submission, pp. 9-11; Alinta, Issues Paper submission, p. 17.

67 MEU, Directions Paper submission, p. 31.

68 NER clause 5.6.5B(b).

69 Grid Australia, Directions Paper submission, p. 10.

70 NGF, Issues Paper submission, p. 8.

71 Note that under the former regulatory test these were called "alternative" options.

72 AER, *Compliance Bulletin No. 5*, Criteria for determining credible options under the RIT-T, September 2011.

The Commission notes some stakeholders' views that calculation of market benefits is a complex exercise, particularly in respect of options value and competition benefits. This is largely a matter of the implementation of the RIT-T. The Commission welcomes the guidance provided in Grid Australia's draft RIT-T Handbook[73] and considers that there may be an ongoing role to support TNSPs in the application of the RIT-T such as through ongoing refinements to the AER's RIT-T guidelines.[74]

Contrary to the MEU's view that the purpose of the RIT-T is inconsistent with the NEO, the Commission considers that they are complementary. The NEO is primarily an efficiency test, similar to the RIT-T, that is intended to ensure that the Rules under which the market operates will drive efficient outcomes and so efficient costs for consumers. We note that "efficient cost" does not necessarily equate to "least cost" as the application of the NEO requires trade-offs between price and reliability and security of supply.

5.2.5 Efficient operation of transmission networks

In submissions to the Issues Paper[75] and Directions Paper, a number of stakeholders supported enhanced incentives to maximise network capability.[76]

Several stakeholders considered that the biggest driver of high volatility market events is network outages.[77] These stakeholders considered that:

- TNSPs should have greater incentives to minimise network outages;[78] and
- AEMO's network outage advice system should be upgraded to provide more timely and accurate information on network outages.[79]

The Northern Group stated that it is during non "system normal" events that the spot price tends to be more volatile and therefore less predictable. It considered that it is important to address the source of these problems, not the symptoms, and that one way to do this would be through better coordination between AEMO and TNSPs.

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73 Grid Australia, *RIT-T Cost Benefit Analysis*, Grid Australia Handbook, July 2011.

74 AER, *Regulatory investment test for transmission application guidelines*, June 2010. This is available from the AER website at aer.gov.au.

75 See: AEMC Directions Paper pp. 55-56 for further discussion on the views held by stakeholders.

76 AEMO, Issues Paper submission, p. 29; AER, Issues Paper submission, p. 5, Direction Papers submission, p. 6; AGL, Issues Paper submission, p. 29; International Power, Issues Paper submission, pp. 31-32; LYMMCo, Issues Paper submission, p. 30, Directions Paper submission, p. 8; NGF, Issues Paper submission, p. 12, Directions Paper submission, p. 5; Origin, Issues Paper submission, p. 3; TRUenergy, Issues Paper submission, p. 5; SP Ausnet, Directions Paper submission, p. 2; SA DTEI, Directions paper submission, pp. 3-4; Infigen, Directions Paper submission, pp. 2-3.

77 NGF, Directions Paper submission p. 5; Northern Group, Directions Paper submission, p. 5.

78 NGF, Directions Paper submission p. 5.

79 Northern Group, Directions Paper submission, p. 5.

Alinta Energy considered that one way to achieve better coordination may be to transfer the real time operation of the transmission system to AEMO.[80] Alinta Energy considered that this would provide a clear line of communication and would clarify governance issues over the operation of the network.

Grid Australia welcomed further consideration of how the current incentive arrangements on TNSPs may be enhanced but considered it important to note that there are limits to the extent that incentives can be placed on TNSPs.[81]

The AER has recently published an Issues Paper for a review of the Service Target Performance Incentive Scheme (STPIS).[82] As part of that review the AER has indicated that it will consider, among other things, the methods for setting targets, caps and collars, the amount of revenue at risk and the methods for establishing the financial incentives for both the service component and the market impact component.

TNSPs are required to report annually on their performance against the STPIS.[83] The table below sets out the results for the 2010 calendar year. Three of the five TNSPs were rewarded for their performance against the service component measures. Both TNSPs that were subject to the market impact component were rewarded for their performance, with Powerlink achieving close to the cap of an additional 2 per cent of their maximum allowable revenue.

Table 5.1 Compliance with the STPIS

TNSP	Service component	Market impact component
ElectraNet	0%	n/a
Powerlink	0.65%	1.97%
SP AusNet	0.58%	n/a
Transend	0.35%	n/a
TransGrid	-0.24%	1.45%

Note that not all TNSPs were yet subject to the Market Impact Component in that calendar year. Also note that the financial incentives for the Service Component are currently plus or minus 1 per cent of maximum allowable revenue, while the Market Impact Component has a range of zero to 2 per cent.

80 Alinta Energy, Directions Paper submission, p. 9.

81 Grid Australia, Directions Paper submission, p. 7.

82 AER, *Issues Paper - Electricity transmission Service Target Performance Incentive Scheme*, October 2011.

83 These reports are available at www.aer.gov.au.

The Commission's current views

The Commission has previously set out the importance of TNSPs operating their networks to maximise network capability at time when it is highly valued.[84] This is likely to become critical as patterns of generation change and new generation enters the market, increasing the risk of congestion. While congestion should eventually be built out where it is efficient to do so, in the interim appropriate incentives should be present such that the network is managed so as to minimise the costs of congestion.

The Commission noted in the Directions Paper that it intends only to give consideration to the incentives around network operation to the extent that they affect the other work streams under the review.[85] Therefore, the Commission has considered network operation in more detail in the context of the policy packages.

5.3 Efficient investment in and operation of generation

This section outlines the issues related to a generator's incentives to invest and operate efficiently, particularly in the presence of congestion on the transmission network. The section first considers whether existing arrangements signal efficient locational decisions. It then sets out stakeholders' and the Commission's views on the impact and materiality of congestion on generation investment and operation.

5.3.1 Locational signals

The absence of price signals to generators of the impact of their locational decisions on transmission network costs may result in inefficient locational decisions that increase overall transmission and generation costs.[86]

Stakeholders have expressed divergent views on the appropriateness of exposing generators to a price that signals the cost of transmission investment. Many stakeholders also commented on how a generator charge, if deemed appropriate, should be constructed.

Appropriateness of exposing generators to a price signal

Those stakeholders that supported the introduction of a signal for transmission costs in the form of a generator charge highlighted one or more of the following issues:

- Charging arrangements for generators are currently non-cost reflective, creating a distortion in the market[87] and not necessarily encouraging efficient

84 AEMC Issues Paper, pp. 33-34; AEMC Directions Paper, p. 54.

85 AEMC Directions Paper, p.11.

86 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies*, Final Report, September 2009, Sydney, p. 28.

87 ActewAGL, Directions Paper submission, p. 2.

investment.[88] Particular concern was raised regarding the charges that incumbent generators should face, with the Victorian DPI arguing that incumbents should not be exempt from charges.[89]

- Generation investment is often likely to be where the network is not well supported[90] and can result in significant levels of congestion.[91]

- In most markets businesses pay a cost to transport their product to market and therefore it is not necessary for generators to receive a firmer level of access in response to being charged.[92]

- Consideration should be given to pricing mechanisms which ration capacity such as auctions.[93] This would allow incumbents and new entrants to be treated equally.

Those stakeholders that provided conditional support for the introduction of a signal in the form of a generator charge noted one or more of the following:

- the construction of the generator charge is critical (this is discussed further below);

- consideration should be given to the nature of services provided to generators such that appropriate signals are provided.[94] Some stakeholders felt that any generator charge should be accompanied by some level of enhanced or firm access or generator reliability standard;[95]

- consideration should be given to the adequacy of existing signals;[96]

- excess network capacity provided by TNSPs (due to scale economies in investments) should not be charged to generators;[97] and

- levying charges on generators provides incentive for planners to overbuild transmission at generators' expense and this would need careful management.

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88 AEMO, Directions Paper submission p. 2; AER, Directions Paper submission, p. 3; MEU, Directions Paper submission, p. 10; Victorian DPI, Directions Paper submission, p. 6.

89 Victorian DPI, Directions Paper submission, p. 7; ActewAGL, Directions Paper submission, p. 2.

90 AEMO, Directions Paper submission, p. 1.

91 SA DTEI, Directions Paper submission, p. 1.

92 MEU, Directions Paper submission, p. 5.

93 Victorian DPI, Directions Paper submission, p. 7.

94 Ausgrid, Directions Paper submission, p. 3; ENA, Directions Paper submission, p. 1; Grid Australia, Directions Paper submission, p. 2; SP AusNet, Directions Paper submission, p. 5.

95 Alinta Energy, Directions Paper submission, p. 7; NGF, Directions Paper submission, p. 3; TRUenergy, Directions Paper submission, p. 3.

96 Alinta Energy, Directions Paper submission, p. 7.

97 International Power, Directions Paper submission, p. 7.

Additionally, applying charges for a level of reliability not required by some generators would be inefficient.[98]

Those stakeholders that did not support a locational signal in the form of a generator charge stated one or more of the following reasons:

- sufficient locational signals already exist, in particular from transmission losses and the risk of constraints;[99] and
- a forward looking network charge signalling the incremental cost of network capacity would be unstable and would therefore not be a credible long term signal. As it would require scaling it is not clear it would have any material effect on locational decisions.[100]

Construction of a generator charge

As noted above, some stakeholders considered that, were a generator charge to be introduced, then the construction of the generator charge would be crucial. However, there was not a common view on how a generator charge should be structured.

Grid Australia considered that generator charges should be transparent and provide certain and stable prices to ensure that the cost of managing the additional risk does not cause excessive additional cost for businesses.[101]

A number of stakeholders commented that a generator charge should reflect the long run incremental network costs associated with a given location.[102] For example, some stakeholders considered that an appropriate methodology for reflecting network costs would be a deep connection charge.[103] Consistent with a deep connection charge, some stakeholders commented that there would be no efficiency gains by imposing a generator charge on incumbents whose investment costs are sunk and who cannot react to a new signal.[104]

Conversely, the Victorian DPI considered that deep connections could discriminate against new entrants and lead to over-investment.[105] Similarly, the MEU stated that in

98 LYMMCo, Directions Paper submission, p. 7.

99 Infigen, Directions Paper submission, p. 2; Northern Group, Directions Paper submission, p. 1.

100 Northern Group, Directions Paper submission, p. 2; NGF, Directions Paper submission, p. 4.

101 Grid Australia, Directions Paper submission, p. 6.

102 AER, Directions Paper submission, p. 4; AGL, Directions Paper submission, pp. 11-12; Victorian DPI, Directions Paper submission, p. 6.

103 AGL, Directions Paper submission, p. 12; SA DTEI, Directions Paper submission p. 3; SP AusNet, Directions Paper submission, p. 5; LYMMCo, Directions Paper submission, p. 8.

104 Alinta Energy, Directions Paper submission, p. 7; International Power, Directions Paper submission, p. 7; TRUenergy, Directions Paper submission, p. 3.

105 Victorian DPI, Directions Paper submission, p. 1.

most markets businesses pay a cost to transport their product to market and therefore imposing a transportation cost on generators would not be inappropriate.[106]

International Power also commented that costs should be predictable prior to investment.[107]

Finally, LYMMCo considered there to be a risk that a generator charge could be reflective of a central planner's perspective of the best use of the system rather than reflective of actual costs. This could lead to the risk that transmission leads generation investment, distorting the competitive generation sector.[108]

The Commission's current views

The Commission notes that certain locational signals such as transmission losses, congestion and inter-regional price variation do provide a degree of incentive for efficient generator locational decisions. However, they do not signal the long term costs of transmission. Therefore, it is likely that there would be unrealised efficiency gains without the introduction of a generator charge in an open access regime because the existing locational signals are incomplete. However, as discussed further in the next chapter, the challenges of identifying the costs that individual generators impose on the network in an open access regime are likely to outweigh any benefits from doing so. For this reason, the open access policy packages (policy package 1 and 2) do not include a generator transmission charge.

In contrast, policy packages 3, 4 and 5, which include an enhanced level of service to a generator, should attract a generator charge commensurate with the service provided. There are a number of ways to construct a charge either in the form of a deep connection or Transmission Use of System (TUoS) charge, each with various advantages and drawbacks. These are discussed further in appendices C and D.

In the fifth policy package, which incorporates locational marginal prices and financial transmission rights, transmission costs are signalled through exposure to local marginal prices and the auctioning of transmission rights.

5.3.2 Investment certainty

A number of stakeholders considered improvements could be made to the way in which generators can access the transmission network and hedge dispatch risk.[109] Some stakeholders considered that, due to the interaction of the issues covered in this

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106 MEU, Directions Paper submission, p. 5.

107 International Power, Directions Paper submission, p. 3.

108 LYMMCo, Directions Paper submission, p. 4.

109 Ausgrid, Directions Paper submission, p. 2; Alinta Energy, Directions Paper submission, p.5; ENA, Directions Paper submission, p. 2; International Power, Directions Paper submission, p. 4; AER, Directions Paper submission, p. 3.

review, providing access rights could have a positive flow on effect on other areas that are being considered, such as congestion.[110]

In particular, AGL considered that the absence of a defined level of service to provide access to the RRN can materially impact a generator's trading risks.[111] Similarly, LYMMCo considered that generators who are not guaranteed access to the RRN may have to discount expected future revenue streams to account for the risk of congestion. This in turn makes it difficult to access competitively priced financing as this is more difficult to obtain for projects exposed to variable, uncertain revenue streams.[112] Financiers may include a risk premium, increasing the cost of new investments or, potentially, deterring entry.[113]

Generators may reduce the volume of contracts offered so as to minimise exposure to congestion, reducing liquidity in the contract market. Alternatively generators may require a higher price to account for this risk.[114]

The MEU considered that generators in one region will not provide firm offers to retailers in an adjacent region because of the risk of congestion at the boundary.[115]

However, other stakeholders considered that the current open access regime does not present any need for change. For example, the Northern Group considered that open access, tempered by dispatch risk and the NEM's regional pricing model has simultaneously encouraged investment in generation without causing inefficient levels of transmission cost.[116] The Northern Group further considered that the risk of a unit failure has a greater influence on a generator's contracting position than the risk of intra-regional constraints.[117]

Infigen believed that access issues are very difficult, complex and time consuming to resolve, and there are other transmission issues that are easier to define and more straightforward to resolve.[118] SP AusNet was concerned that providing firm access could increase the risk faced by TNSPs, for which they would need to be compensated.[119]

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110 AGL, Directions Paper submission, p. 2; MEU, Directions Paper submission, p. 27; LYMMCo, Directions Paper submission, p. 14

111 AGL, Directions Paper submission, p. 14.

112 LYMMCo, Directions Paper submission, p. 8.

113 AEMO, Issues Paper submission, p. 18; AGL, Issues Paper submission, p. 11, Directions Paper submission, pp. 5-7; Victorian DPI, Issues Paper submission, pp. 2-3; LYMMCo, Issues Paper submission, p. 10.

114 AGL, Issues Paper submission, p. 11; SA DTEI, Directions Paper submission, p. 2.

115 MEU, Directions Paper submission, p. 20.

116 Northern Group, Directions Paper submission, pp. 3-4.

117 Ibid.

118 Infigen, Directions Paper submission, p. 1.

119 SP AusNet, Directions Paper submission, p. 2.

NGF considered that all market participants rely on an implicit level of access to the network and that there is an expectation that the NEM frameworks will ensure that congestion does not materially increase.[120] In contrast, LYMMCo expressed less confidence that an implicit level of access exists and indicated this is why some generators place a higher value on resolving congestion than others.[121]

5.3.3 Materiality of congestion

Views on whether congestion is, or is likely to be, material have typically differed between stakeholders, and submissions to the Issues Paper[122] and Directions Paper for this review continued to diverge on this issue.

A number of stakeholders considered that congestion can have serious impacts for the NEM, particularly on investment certainty. These concerns were described above.[123]

A number of examples were provided where stakeholders considered that inefficient outcomes had occurred due to transmission constraints[124], including:

- AEMO outlined an example of a planned outage on a transmission line between Wallerawang and Mount Piper triggering a constraint on 7 December 2009. It calculated that if a set of bids that had existed before the market was aware of the constraint had remained in place, this would have reduced pool settlement by $300m;[125] and
- TRUenergy indicated that on 29 January 2009 it had faced the prospect of being constrained-off the system for a period of 7 hours at the market price cap.[126]

In contrast, a number of stakeholders contended that the level of materiality is low. Snowy Hydro believed congestion to date has been immaterial and transitory and that there is no evidence that existing arrangements would not deal with future congestion.[127] It considered that mispricing that results from the regional market

120 NGF, Directions Paper submission, p. 2.

121 LYMMCo, Directions Paper submission, p. 3.

122 See: AEMC Directions Paper pp. 52-54 for further discussion on the views presented by stakeholders in response to the Issues Paper.

123 SA DTEI, Directions Paper submission, p. 1; LYMMCo, Issues Paper submission, p. 12; AGL, Issues Paper submission, pp. 10-12; International Power, Issues Paper submission, p. 14; TRUenergy, Issues Paper submission, p. 19; AEMO, Issues Paper submission, p. 20.

124 AGL, Issues Paper submission, pp. 12-14, AER, Issues Paper submission, pp. 12-14, SA DTEI, Directions Paper submission, pp. 1-4; International Power, Issues Paper submission, p. 14; AEMO, Issues Paper submission, Appendices B to E; TRUenergy, Issues Paper submission, pp. 11-19.

125 AEMO, Issues Paper submission, Appendix B. Note that the Northern Group considered the total cost of this constraint for the 70 hours which it bound during 2009-10 as being in the order of $6.4m. It also suggested that the constraint was transitory in nature and could not credibly be described as being a "system normal" constraint. Northern Group, Issues Paper submission, p. 33.

126 TRUenergy, Issues Paper submission, p. 19.

127 Snowy Hydro, Directions Paper submission p. 4.

design is an acknowledged trade-off between the granularity of locational pricing signals and the efficient functioning of the contracts market.[128]

Similarly, the Northern Group considered that current evidence does not support a view that NEM congestion is on an upward trend or that mispricing has been a material issue to date. It considered that increased network investment by TNSPs will continue to limit network congestion in the NEM.[129] It considered that outage risk has a far greater influence on limiting a generator's willingness to enter into derivatives contracts than any measurable level of dispatch risk created by congestion in the NEM.[130]

Grid Australia contended that it is not clear that congestion could be considered material as estimates of competition benefits are highly contingent on a range of assumptions including generator bidding behaviour, customer demand response, and how prices to final customers compare to marginal cost.[131]

Producing conclusive evidence or obtaining agreement across the industry of what the costs of congestion to the market are, or would be in future, was considered to be difficult by a number of stakeholders.[132] The AER outlined that there is a risk that underlying issues would remain unresolved if there is a preoccupation with identifying congestion costs.[133]

As noted in section 5.3.2 above, some stakeholders believed that the issues related to congestion could be predominantly resolved by addressing access issues and by obtaining efficient and effective long term transmission price signals.[134] The Northern Group and TRUenergy considered that congestion issues can be addressed by efficient operation of the transmission system where non-"system normal" events and outages are better managed by and between AEMO and TNSPs.[135] This is discussed in section 5.2.5 above.

5.3.4 Efficient operation of generation

A number of stakeholders considered that the presence of congestion on the transmission network can lead to inefficiencies in the way in which generators operate, in particular how they construct their volume and price offers where constraints occur.

128 Snowy Hydro Limited, Directions Paper submission, p. 6.

129 Northern Group, Directions Paper submission, p. 1.

130 Ibid, p. 4.

131 Grid Australia, Directions Paper submission, p. 7.

132 Alinta Energy, Directions Paper submission, p. 8; AER, Directions Paper submission, p. 4; TRUenergy, Directions Paper submission, p. 8; NGF, Directions Paper submission, p. 5; LYMMCo, Directions Paper submission, p. 8; AGL, Directions Paper submission, p. 14.

133 AER, Directions Paper submission, p. 4.

134 AGL, Directions Paper submission, p. 2; MEU, Directions Paper submission, p. 27; LYMMCo, Directions Paper submission, p. 14.

135 Northern Group, Directions Paper submission, p. 5, TRUenergy, Directions Paper submission, p. 4.

For example, the MEU contended that congestion reduces competition in islanded regions and can result in the exercise of market power to raise prices.[136]

AEMO and the AER considered that generators may engage in forms of behaviour other than revising offers in response to mispricing. This included: reducing availability below true capability when there is an undesired risk of being constrained on;[137] reducing the maximum rate of change of a unit such that it cannot be ramped up or ramped down as quickly;[138] and disorderly bidding.[139]

Finally, a number of submitters considered that, where the access regime is ineffective at resolving congestion issues, congestion management mechanisms should be considered.[140] However, TRUenergy also noted that such mechanisms could have potential drawbacks on contracting.[141]

5.4 The Commission's current views

The Commission considers that there is some merit in examining models that would provide a greater degree of certainty to generators seeking to invest in the NEM. Congestion imposes a number of adverse consequences. First, it requires dispatch of more expensive generation capacity. Second, it can encourage disorderly bidding, further exacerbating dispatch inefficiencies. Third, it restricts competition, because fewer generators can compete in the price setting process. Finally, it creates uncertainty for generators over their degree of access to market, which may affect the liquidity of contract markets and incentives for investment in generation capacity. The Commission believes that a deep and liquid contract market, supported by greater certainty of investment, will assist in achieving efficient outcomes in the NEM.

While the theoretical inefficiencies of congestion are clear, the materiality of the impact of congestion on efficient investment and operational outcomes is less clear. Estimating the economic costs of congestion is extremely difficult to do with any precision, particularly when attempting to estimate future congestion. This is because the quantum and pattern of congestion depends on dispatch and locational decisions by generators. Dispatch decisions themselves will rely in part on strategic interactions between generators which are complex to model. Further, congestion could be found to be low simply because there has been excessive investment in transmission to date.

Given this lack of certainty of the materiality of the issue, the Commission has identified a number of different possible approaches to reform that reflect different

136 MEU, Directions Paper submission, p. 12.

137 AEMO, Issues Paper submission, p. 22; AER, Issues Paper submission, p. 3.

138 Ibid.

139 AER, Issues Paper submission, p. 3.

140 TRUenergy, Directions Paper submission, p. 5; AER, Directions Paper submission, p. 4; International Power, Directions Paper submission, p. 5; LYMMCo, Directions Paper submission, p. 9; AGL, Directions Paper submission, pp. 13-15; Alinta, Directions Paper submission, p. 9; MEU, Directions Paper submission, p. 30.

141 TRUenergy, Directions Paper submission, p. 5.

views on the materiality of congestion and its impact on the signals for efficient generation investment and operational decisions. Each "package" proposed represents an internally consistent approach to transmission arrangements that considers the interaction between policies and obligations that guide regulated transmission decisions and the energy market signals that generators respond to in their investment and operational decisions.

These packages are summarised in the table below and described in detail in the following five chapters. Each of the packages is described according to six key features:

- the definition of the access product or service level to be provided by TNSPs to generators;
- the way in which any access rights are assigned;
- the way in which the access product influences dispatch and congestion, and the way in which any compensation for being constrained off is allocated;
- the charge that applies to generators for use of the network (if at all);
- any changes to the planning, investment and operational decisions made by TNSPs; and
- any changes that are required to the institutional arrangements.

Table 5.2 Detailed summary of the proposed policy packages

Package:	Open access	Open access with congestion pricing	Generator transmission standards	Regional optional firm access	National locational marginal pricing
Access product	Generators have no firm level of access	No firm level of access, but all generators receive a proportion of congestion rents	Access defined by reliability standards for generators	Generators choose a quantity of firm access to the regional reference node	Generators are able to purchase fully firm rights to a national hub
Assigning rights	n/a	Congestion rents allocated according to proportional capacity	All generators within a zone receive the same standard	Generators choose to be firm by purchasing firm access	Rights are purchased at auction
Dispatch, congestion and compensation	Dispatch occurs as today. No compensation for being constrained off	Congestion is priced by exposing generators to the price at their local node. Dispatch process occurs as today	Dispatch occurs as today. No congestion price. No compensation for being constrained off	Dispatch occurs as today. Firm generators in merit but constrained off are compensated by non-firm generators, who are exposed to congestion costs	Dispatch occurs as today but all generators settled at the price at their local node, giving congestion price exposure. Firm generators have rights to hedge price risk
Charging	No generator charge for use of shared network	No generator charge for use of shared network	All generators face a charge to reflect the cost of maintaining the standard	Firm generators pay a charge, non-firm generators do not pay a network charge	Firm generators purchase rights, no charge for non-firm generators
TNSP planning, investment and operational decisions	No changes required (but enhancements possible)	No changes required (but enhancements possible)	TNSPs plan to new generator standard, with incentives attached. Further enhancements possible	TNSPs plan to new generator standard, with incentives attached. Further enhancements possible	TNSP plans to new standard. Incentives on TNSP to minimise cost of meeting rights, maximise capacity sales
Institutional arrangements	No changes required (but enhancements possible)	No changes required (but enhancements possible)	Need to be considered, including who sets standard	Need to be considered, including who sets standard	Single, national TNSP and other changes

6 Package 1: An open access regime

Box 6.1: Summary of this chapter

Access	Generators have no firm level of access, no congestion pricing
Charging	No generator charge for use of the shared network
Planning	No changes required. See chapter 11 for possible enhancements

This chapter sets out a proposed policy package that is based on the arrangements that exist in practice in the NEM today. Generators would have a right to connect to the network, however they are not able to obtain a firm right for use of the network to access the RRN. Instead, a generator's right to use the network will hinge upon whether it is scheduled in the merit order and the presence of congestion on the network. As is currently the case, generators would not pay a charge for using the network.

An open access model has a number of benefits, such as providing a disincentive to locate in congested parts of the network and maintaining competitive pressures on generators. Implementation costs would be minimal as this model broadly reflects the existing approach to access (in practice).

However, generators are exposed to uncertainty of dispatch, which can lead to dynamic efficiency costs such as a less liquid contract market and higher financing costs.

6.1 Introduction

This chapter sets out the first proposed package of reforms. The package is modelled on the status quo and therefore represents the least change from existing frameworks, as described in chapter 4. While this package does not introduce any new features to the existing arrangements it does provide clarity on the nature of access, which has been the source of some disagreement and confusion to date.

This chapter is structured as follows:

- the remainder of this section discusses the existing access arrangements in the NEM;
- section 6.2 sets out the key design features of an open access model. Since this package broadly reflects existing arrangements, which are set out in chapter 4, this section focuses on why a use of system charge is not being proposed and the importance of robust planning arrangements; and
- section 6.3 describes some of the issues, including advantages and disadvantages, of an open access model.

6.1.1 Current access arrangements

Currently the NEM operates under an open access regime. Generators have a right to connect to the transmission network,[142] but this right does not extend to a firm right of access across the network to the RRN. Generators instead are granted access when two conditions are met: they are scheduled in the merit order and there is no relevant congestion on the network. Generators do not have an inherent right to be dispatched, nor do they have a right to be compensated when constrained-off.

We note that several generators disagree with this interpretation of the Rules and instead consider that they have a right of access across the network, even if it is implicit.[143] These generators consider that clause 5.4A of the Rules gives them an opportunity to negotiate with TNSPs to obtain firm access to the RRN. However, we consider that the Rules as they are currently written cannot work in practice with an open access regime, as explained below. Package 4, as outlined in chapter 9 provides a workable model of firmer access that draws from the apparent intention of clause 5.4A.

Clause 5.4A

The existing Rules appear to contemplate generators negotiating firm transmission network user access with TNSPs. The Rules provide for generators to negotiate compensation from a TNSP in the event that they are constrained off or on the network, in return for an access charge.[144] However, this provision cannot work in practice because the scheme is not mandatory and all generators have open access to the network.

If a TNSP was to negotiate firm access with a generator in return for an access charge, it would have two options:

- augment the network to provide sufficient capacity for that generator to always be dispatched; or
- pay compensation to the generator in the event that it was constrained off.

Under an open access regime, the first of these is not practical. The TNSP could not prevent other generators from connecting to the network and using capacity. Assuming that the new entrant generators did not opt into the scheme, the TNSP would have no additional funding, other than the access charges paid by the firm

142 The Rules provide a connection applicant with an enforceable right to connect in accordance with the process under Chapter 5, rather than an absolute right to connect to the network. A TNSP has a corresponding obligation to connect the connection applicant in accordance with the Chapter 5 process.

143 AGL, Issues Paper submission, p. 2; International Power, Issues Paper submission, p. 27; LYMMCo, Directions Paper submission, p. 4.

144 NER clauses 5.4A(b), (f) and (h)(1). In addition to compensation arrangements, clause 5.4A contains a number of other provisions regarding access and connections. This includes use of system services charges to be paid by a connection application where network augmentations or extensions are required to facilitate a connection.

generator, in order to further augment the network.[145] Thus network augmentations to maintain access could not be funded unless such augmentations passed the RIT-T.[146]

The second option is also not practical. Paying compensation would require a counter-party to provide the necessary funding. However, the Rules do not provide clarity on where the funding for the compensation would come from.

The Rules appear to contemplate TNSPs recovering charges from another generator in the event that dispatch of that generator results in a firm generator being constrained off.[147] However there is no mechanism to compel generators to opt into this scheme and generators that cause others to be constrained off are unlikely to have incentives to join.[148]

Further, the Rules require TNSPs to negotiate in confidence and so TNSPs must negotiate compensation arrangements with one generator at a time. Thus if a TNSP agreed to pay compensation where a generator was constrained off, it could never be sure that it would be able to recover the funds from anyone other than the party with which it was negotiating. The TNSP would either have to risk reopening negotiations with incumbents or take the risk that arrangements could be negotiated with future generators.

In summary, the firm access provisions contemplated in the Rules cannot work in practice and, as far as we are aware, have not been applied to date. For this reason the Commission considers that either these compensation provisions should be removed to clarify that the NEM operates as a fully open access regime, or these provisions should be replaced with a workable form of access. Packages 1 and 2 provide options for implementing the former, while mechanisms for allowing for firmer access are considered in packages 3, 4 and 5.

6.2 Key features of an open access model

6.2.1 Product definition

By "access" we mean access across the network to the RRN. Unless defined otherwise, this is how access should be interpreted throughout the discussion of each of the packages. Access to the network is considered separately in the context of connections in chapters 12 to 14.

145 Assuming that the augmentation would not pass the RIT-T, either for the purpose of meeting load reliability standards or as a market benefit augmentation.

146 Unless investment falls within the exceptions in clause 5.6.5C(1) to (9).

147 NER clause 5.4A(h)(2).

148 Generators that cause others to be constrained off are, by definition, being dispatched themselves. This implies that they have no incentive to be part of a scheme that would require them to: (a) pay charges for access that they already have; and (b) pay compensation to those generators that they constrain off.

Under an open access model, all generators have a right to connect to the transmission network. However, that right does not extend into the network. Instead, the “right” to use the network is determined by whether a generator is scheduled in the merit order and therefore dispatched according to the NEM’s dispatch engine. In the absence of congestion and assuming that generators bid so as to reflect the marginal value of their energy, this approach achieves a least cost pattern of dispatch.

For clarity, generators have no entitlement to any level of access. This is the only “access product” available to generators.

6.2.2 Assigning rights

Unlike in packages 4 and 5, this package would not allow generators to negotiate a level of service for use of the network. Therefore this model would not need to consider how rights would be assigned.

6.2.3 Dispatch, congestion and compensation

Dispatch would be consistent with current arrangements i.e. generators are dispatched by the NEM dispatch engine based on their offers. Where constraints arise, generators may not be able to be dispatched in accordance with the merit order. In this instance, a generator may be constrained off (or on) the network. Generators would not be entitled to negotiate any form of compensation for the loss of profits arising from not being dispatched when they otherwise would have been, if not for the congestion.[149]

This process is consistent with what happens in practice in the NEM today. Similarly, this policy package does not include a price on congestion.

6.2.4 Charging

This package does not include a new charge for generators for use of the transmission network. Some inefficiencies may arise through the absence of a charge that signals the cost that generators impose on the transmission network through their locational decisions. However, these inefficiencies are likely to be outweighed by the difficulty in quantifying, and so charging for, a generator's impact on network costs under an open access regime.

Minimising transmission network and generation costs

Where generators are not exposed to the costs that they impose on the network, there is a risk that projects with relatively high transmission costs are built at the expense of projects where the costs to build the generator may be higher, but with significantly lower transmission costs.

149 Generators may still be entitled to compensation where they are affected as a result of an AEMO intervention. See clause 3.12.2 of the NER for further details.

There are a number of other signals in an open access regime that inform locational decisions. These signals include:[150]

- **Congestion**. A generator locating in an area with existing congestion risks being constrained off the network, providing a disincentive to locate in congested parts of the network. However, there is no means to differentiate between optimal locations in unconstrained areas.

- **Locational transmission losses**. Losses provide a signal of the short run marginal cost of transporting electricity, which will vary by location. While this signal facilitates efficient dispatch of existing generators, it is less useful as a longer term locational signal because it reflects the costs associated with energy lost as heat rather than the costs of transmission investment.

- **Inter-regional price differences**. Price differences between regions provide an efficient signal of the region in which a generator should locate. However, such price differences cannot inform the efficient locational decision within that region.

The cost of connecting to the transmission network, including any extensions or network augmentations, will also provide a locational signal.

Although these signals will provide generators with incentives to locate optimally from a private perspective, none of these signals reflect the shared transmission network costs that result from a generator's locational decision. Therefore these signals cannot ensure that overall network and generation costs will be minimised from a market-wide perspective.

Consequently, generators may still locate in congested areas where the expected returns are higher than the expected returns associated with locating in an uncongested part of the network. Such decisions will impact other generators' ability to reach the RRN. For example, a wind generator may be choosing between an uncongested location with a lower load factor or a congested area with a higher load factor. Depending on the expected prices, a generator may make higher returns locating in the congested area if its expected output is higher, despite being constrained off for part of its capability on occasion. This is demonstrated in appendix A.

The AER,[151] AGL[152] and the SA DTEI[153] have provided several examples of generators locating in areas which contribute to existing and ongoing congestion, constraining off existing generators and interconnectors. These examples include:

- the Kogan Creek coal plant in Queensland;

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150 We note that there are a number of other signals outside of the energy market that inform locational decisions, such as access to fuel and water and ability to acquire land.

151 AER, Issues Paper submission, pp. 12-14.

152 AGL, Issues Paper submission, pp. 12-14.

153 SA DTEI, Directions Paper submission, p.1.

- Uranquinty in NSW;
- Daadine and Oakey in Queensland; and
- intermittent generation such as wind in the South Eastern and mid-North regions of South Australia.

The SA DTEI cite a number of announced wind projects in areas of South Australia that are already congested, arguing that the existing framework is not providing sufficient locational signals to address congestion.[154]

We note that, contrary to the AER and SA DTEI views, the Northern Group considered:[155]

> "There is little or no evidence to suggest that the existing framework is encouraging systematically poor locational, operational or investment outcomes."

Attributing network costs to individual generators

The above discussion suggests that there may be some efficiencies to be gained from introducing a use of system charge for generators. However, it is not clear to what extent generators, under existing arrangements, actually trigger transmission investment.

Under this proposed package, as under today's arrangements, there is no generator reliability standard or a requirement for firm access to the RRN. Therefore there is no automatic trigger of network augmentations when a generator connects to the transmission network. Instead, the transmission network is reinforced to meet reliability standards for load or where such construction satisfies a RIT-T. Demand growth is likely to trigger transmission network investment either to allow those reliability standards to be met or where such growth would result in an investment providing net market benefits.

There are limited means by which a new generator connecting to the network can trigger shared transmission costs. An example is where the generator's connection would increase congestion such that the benefit to the market from relieving that congestion exceeds the cost of augmentation. Further, since all generators contribute to some extent to congestion, it is difficult to assign the costs of congestion to individual generators.

Thus, while all generators contribute to some extent to network costs, it is only indirectly as those costs are only triggered where an investment to relieve congestion passes the RIT-T. It is difficult to apportion the costs of congestion between incumbents

154 SA DTEI, Directions Paper submission, p. 1.

155 Northern Group, Directions Paper submission, p.1.

and new generators. Consequently it is very difficult to design a charge that would provide an appropriate signal of the network costs imposed by individual generators.

The Commission considers that the challenges in designing a charge that appropriately and accurately assigns transmission costs to individual generators would outweigh any efficiency gains from seeking to influence a generator's locational decision in respect of transmission network costs.

6.2.5 TNSP planning, investment and operation

The feasibility of an open access model is predicated on the assumption that congestion will be built out in a timely fashion where it is efficient to do so. While there is an efficient level of congestion, there is a "tipping point" at which the inefficiencies associated with the constraint would be greater than the cost of building out the constraint.

Constraints cause inefficiencies not only because higher cost generation must be dispatched in order to meet demand (resulting in productive inefficiencies), but also because generators have less certainty of dispatch. This makes it difficult and risky for them to enter into contracts, reducing the liquidity of the contract market and increasing risk premiums and so costs. Generators may also find it difficult to obtain financing where the risk and cost of constraints is perceived to be high.

The transmission planning and investment frameworks will therefore need to support the efficient and timely build-out of congestion. It is important not only that productive inefficiencies are minimised, but also that generators have confidence that any additional costs they face as a result of congestion will be for a limited period. However, the regulatory planning approach to transmission makes it difficult to achieve this result. Further, the RIT-T does not currently include a benefit to represent the value to generators of increased certainty. Even if the RIT-T was amended to include this, it would be very difficult to measure.

To the extent that existing planning, investment and operational frameworks are considered sufficient to support an open access regime, then no significant reforms are required to these arrangements. However, there may be a number of incremental changes that could be undertaken to strengthen elements of the frameworks. The need to strengthen existing frameworks and what options could be considered to do so are explored in chapter 11. As discussed in that chapter, the Commission's initial view is that existing frameworks have provided reasonably effective outcomes to date and that significant changes are unlikely to be warranted. However, if evidence was provided to suggest otherwise, then any of the options proposed in chapter 11 could be adopted (either individually or, in most cases, in combination) in this model.

6.2.6 Institutions

Unlike policy packages 3, 4 and 5, there are no specific changes that would be required to implement this package.

6.3 Advantages and disadvantages of the open access model

The advantages and disadvantages of the open access model, and stakeholders' views on the operation of transmission frameworks to date, are set out in some detail in the previous chapter. In summary:

- There is some debate on the efficiency of transmission investment and operational outcomes, however the Commission has yet to be persuaded that existing arrangements are not providing reasonably effective outcomes compared to the characteristics of an efficient regime.
- Open access provides generators with a disincentive to locate on constrained parts of the network to minimise the likelihood that they are constrained off. Where effective, this can facilitate the reduction in transmission costs and inefficiencies associated with congestion (although there have been instances where this signal has not been effective, as discussed in section 6.2.4).
- Inefficiencies may occur as a result of uncertainty of dispatch faced by generators, including illiquid contract markets and difficulty in obtaining financing for new projects (or refinancing existing generation). This could impact generation investment.
- Where congestion does arise, dispatch may not be efficient due to disorderly bidding, although the materiality of the associated inefficiencies are yet to be established.

The only change between this package and existing frameworks is the removal of any avenue for generators to seek to negotiate firm access to the RRN. For reasons set out above, the existing provisions that require TNSPs to negotiate firm access arrangements in good faith with a connection applicant that requests such arrangements have not been effective. Despite the evidence to suggest that these provisions cannot work in practice, we have been informed that the continued presence of these provisions in the Rules has led to protracted debates between generators seeking access and TNSPs who are required to negotiate in "good faith".[156]

Removing these existing provisions and clarifying that the transmission network is based on a principle of open access where no generator is able to negotiate firm access to the RRN could be considered to contribute to achievement of the NEO and reduce total system costs compared to the status quo. This approach would remove ambiguity in the Rules and remove the requirement for TNSPs and generators to spend time and resources negotiating in good faith on an issue that is unlikely to be resolved, if left as it is under the current arrangements.

156 NER clause 5.4A(b).

Table 6.1 Summary of advantages and disadvantages of package 1

Advantages	Disadvantages
Generators have a locational signal in the form of congestion in the network	Congestion may lead to productive inefficiencies associated with disorderly bidding
Current arrangements have delivered investment in transmission to meet load reliability standards	Dynamic inefficiencies may result from generator uncertainty regarding access to the regional reference node
This model is similar to the status quo and so incurs minimal implementation costs	

7 Package 2: Open access with congestion pricing

Box 7.1: Summary of this chapter

Access	Generators have no firm level of access, congestion is priced. All generators receive a proportion of congestion rents
Charging	No generator charge for use of the shared network
Planning	No changes required. See chapter 11 for possible enhancements

This chapter sets out a proposed policy package that, like the first package, is based on the existing open access arrangements. It differs from the first package only by introducing a price on congestion. The purpose of pricing congestion is to introduce a signal to generators that reflects the short run costs of using the network. This is intended to remove the current incentives for disorderly bidding by generators when there is congestion.

The Shared Access Congestion Pricing (SACP) model has two components. First, it exposes generators to congestion costs. Second, it provides a hedging element that partially protects generators against the pricing risks that arise as a result of no longer being settled at the regional reference price. The SACP model would be implemented across the NEM as a permanent change to the market design. The hedges are not explicitly allocated, but are determined automatically in real time.

The key advantage of the SACP is that it should encourage more cost reflective bidding and thereby improve dispatch efficiency in the NEM. This could represent a significant benefit to the market, which could be achieved without fundamental reform to the NEM arrangements. However, due to the way in which the hedges are allocated, the SACP model on its own does not strengthen locational signals relative to current arrangements. Consequently, concerns over the longer term impacts of congestion, such as the predictability of access for generators, are not addressed by this approach.

7.1 Introduction

This chapter sets out the second proposed package of reforms. Most of the features of this model are the same as those proposed for package 1. However, unlike package 1, this package introduces a congestion management mechanism that is designed to price congestion and so signal to generators the costs of their short term operational decisions. The model would be applied on a NEM-wide and permanent basis.

The particular model that has been included as part of this package was put forward by Ken Secomb on behalf of a group of generators (the "Southern Generators")[157] during the AEMC's Congestion Management Review. The need for a congestion price

157 International Power, AGL, TRUenergy, Flinders Power, LYMMCo, *A congestion management regime without allocating rights*, 4 April 2008.

was the subject of much debate during that review. A number of different approaches based on CSP/CSC arrangements were put forward at that time.[158] These proposals sought to expose generators to the marginal value of congestion through a pricing element (the Constraint Support Price (CSP)), while providing a measure of protection against the resulting risks through a contracting element (the Constraint Support Contract (CSC)).[159]

The options differed on features such as whether the mechanism was permanent or temporary, localised or NEM-wide, and how the contracting elements were allocated. At that time the Commission considered that the materiality of congestion was not sufficient to warrant the implementation of a congestion pricing mechanism.

However, as part of the Review of Energy Market Frameworks in light of Climate Change Policies, the Commission revisited the case for introducing a congestion management mechanism. This was because of concerns held by stakeholders that the materiality and unpredictability of congestion was likely to increase as a result of anticipated changes in the way in which the transmission network would be used in the future. While a congestion management scheme was recommended as a potentially proportionate response to managing levels of congestion in the NEM, the Commission also noted that this would, in itself, present a number of complexities.[160]

For reasons that are detailed in appendix B the Commission has decided against the use of a temporary localised congestion management mechanism, as contemplated in the Review of Energy Market Frameworks in light of Climate Change Policies. In summary, this is because such a mechanism would introduce a significant amount of additional complexity due to the need to:

- define a trigger for when the mechanism would be implemented (and removed);
- decide which part of the NEM to apply the mechanism to; and
- allow sufficient lead-time for the scheme to be incorporated in generators' contracts.

Instead, the Commission is putting forward for comment the permanent, NEM-wide mechanism proposed by the Southern Generators. We note that this was initially proposed as part of a suite of complementary measures. However, the Commission considers that this mechanism may have merit in its own right.

This chapter is structured as follows:

- the remainder of this section discusses the current arrangements;

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158 The CSP/CSC mechanism was first developed by CRA International for the MCE. See: CRA International, *NEM-Transmission Region Boundary Structure*, Final report to the Ministerial Council on Energy, April 2005.

159 See appendix A for an explanation of how the CSP and CSC are calculated.

160 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies*, Final Report, September 2009, p. 38.

- section 7.2 describes the key features of this model of open access with congestion pricing; and
- section 7.3 discusses of some of the potential efficiency benefits and costs associated with introducing a congestion price.

This chapter introduces the model at a conceptual level. Additional details on how the mechanism works in practice, including some numerical examples, are included in appendix A.

7.1.1 The current arrangements

Currently there is no price signal at an intra-regional level to reflect the cost of congestion. Only congestion between regions is priced.[161] There are some non-price signals, such as the exposure for generators of being constrained off. However, as discussed in the previous chapter, this signal 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.

It is this absence of intra-regional price signals that gives rise to disorderly bidding. As discussed in section 4.4, 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 regional reference node (RRN). The NEM dispatch engine cannot distinguish between low and high cost generation, and therefore does not dispatch the lowest cost generation. This results in productive inefficiencies.

Disorderly bidding also contributes to counter-price flows, as generators in a constrained region can bid at the price floor knowing that they will receive the regional reference price (RRP) (which is likely to be high). Some of this generation may then be dispatched to meet load in a neighbouring, unconstrained (and therefore lower priced) region, potentially displacing lower-cost generation in that region.[162] This results in energy flowing from a high price region into a low price region (i.e. counter-price flows), implying that higher cost generation is being dispatched to meet demand.

In addition to causing productive inefficiencies, counter-price flows reduce the "firmness" of the inter-regional settlements residue, which is used as a hedge to manage price risk between regions.

When counter-price flows occur, AEMO has a mandate to intervene in the market by "clamping" flows. It does this through intervening in the dispatch process to limit the accumulation of negative settlements residue beyond $100,000.[163] It is difficult for

161 Ignoring losses, price separation should only occur where there is congestion on the network. Therefore the difference in the RRPs between regions can be considered to represent the price of congestion.

162 Because generators' offers in the neighbouring region will affect their settlement price, they are unable to bid at the price floor.

163 See: AEMO, *Power system operating procedure - dispatch*, SO_OP3705, 25 July 2011, pp. 23-24.

market participants to anticipate when flow clamping will occur, creating uncertainty for generators which is likely to be reflected in higher contract prices.

Box 7.2: Inter-regional settlements residue

Under existing arrangements, generators do not face any risk associated with settlement prices when trading intra-regionally because a single price is determined at the RRN and applied across that region. However, price (or "basis") risk may arise when generators trade between regions. One way to reduce (or "hedge") this risk is to purchase units to the inter-regional settlements residue (IRSR) that accrues when prices between regions separate.

The value of the IRSR is equal to the price difference between the regions multiplied by the flow between the regions. IRSR units are sold at settlements residue auctions (SRAs), which are held every quarter.

When generators trade between regions, their revenue may therefore comprise two elements:

- a "pricing element", which is the volume they are dispatched for multiplied by their RRP; and
- a "hedging element", which is derived from any IRSR units the generator has purchased at auction.

The IRSR does not, however, provide a perfect hedge for inter-regional basis risk. A key reason for this is because if counter-price flows occur, the value of the settlements residue will be negative (as a result of power flowing from a high price region to a low price region). In this event, generators would continue to be exposed to a level of basis risk. However, they would not face the cost of the negative settlements residue, which is recovered from the importing TNSP.[164]

7.2 Key features of the congestion pricing model

7.2.1 Product definition

As under package 1, all generators would have a right to connect to the transmission network[165] but would have no entitlement to any level of access across the network to the RRN. A generator's right to physical access across the network would depend on whether the generator is scheduled in the merit order and the availability of network capacity.

164 NER clause 3.6.5(a)(4).

165 The Rules provide a connection applicant with an enforceable right to connect in accordance with the process under Chapter 5, rather than an absolute right to connect to the network.

However, the SACP model presented in this package seeks to ensure that generators scheduled in the merit order are always the lowest cost generators. It does this by changing the way in which generators are settled for their output.

Currently, within a region, all generators receive (and loads pay) the same price, so there is no price separation within a region as a result of congestion. However, each local node[166] has an implicit price. In many electricity markets around the world, including in parts of the US, this price - the price associated with supplying an additional unit of electricity at that particular node - is made explicit and is referred to as the Locational Marginal Price (LMP).

In the NEM, congestion may cause the implicit LMP[167] at the generator's node to diverge from the RRP.[168] Therefore, conceptually, settlements residue arises from intra-regional price separation between the local node and the RRP.

Consequently, a generator's revenue can be considered to comprise two elements (in exactly the same manner as in the inter-regional example given in Box 7.2):

- a pricing element, equal to the volume it is dispatched for multiplied by the implicit LMP; and
- a hedging element, equal to the volume it is dispatched for multiplied by the difference between the implicit LMP and the RRP.

Currently both elements are allocated to generators based on the amount for which they are dispatched. The implicit intra-regional settlements residue allocated to generators in dispatch therefore provide a perfect hedge.

Package 2 makes this intra-regional price separation explicit. In the presence of congestion, generators would be settled for their output at the implicit LMP, rather than the RRP. The allocation of the intra-regional settlements residue would be de-linked from the volume of energy for which generators are dispatched and instead allocated on the basis of capacity, as discussed below. The purpose of this would be to expose generators to the marginal cost of the transmission network at their local node.

7.2.2 Assigning rights

Under package 1, a generator's right to access across the network is determined solely by whether it is dispatched. This is dependent on the generator being scheduled in the merit order and there being sufficient network capacity. Being dispatched, and therefore gaining access to the RRN, enables the generator to be remunerated for its

166 A local node is equivalent to the connection point.

167 More accurately, the implicit LMP is called the Pseudo Nodal Price (PNP). This is because it is not established directly, but is solved for using the regional reference price. This chapter continues to use the terminology "implicit LMP". Appendix A, which provides an example of how the SACP mechanism works, provides further clarification on this issue.

168 The RRP is the LMP applying at the RRN.

output. As discussed above, this remuneration can be thought of as including intra-regional settlements residue.

Similarly, under package 2, a generator's right to physically use the network would again be determined by dispatch. However, at times of congestion, access to the intra-regional settlements residue would no longer be determined by dispatch. Instead, this hedging element would be allocated based on a generator's proportion of the total generation capacity behind a given constraint. This is described further in the following section.

7.2.3 Dispatch, congestion and compensation

The SACP model is intended to change dispatch outcomes relative to today's arrangements so as to resolve disorderly bidding and improve dispatch efficiency. The model exposes generators to the implicit price at their local node and provides a hedging instrument that varies in real time depending on network conditions and the generators behind the constraint. However, the model does not provide a long term solution to congestion or the certainty of compensation associated with fixed rights.

The SACP mechanism comprises two components:

- the pricing element exposes generators to their implicit LMP and therefore the marginal costs of the network; and
- the hedging element which, as discussed, is equivalent to a share of the intra-regional settlements residue.

This therefore results in two potential sources of revenue for generators:

- payments for their energy which, in the presence of congestion, is settled at the implicit LMP; and
- a share of the intra-regional settlements residue that accrue when intra-regional congestion occurs.

Each of these components is described in further detail below.

Exposing generators to the implicit price at their local node

Settling generators at their implicit LMP (the CSP element of the mechanism) exposes them to the short run operational costs that they impose on the network. This approach is intended to resolve disorderly bidding by changing the incentives that generators face when they make their pricing and volume offers.

Where congestion occurs, the SACP mechanism changes the price that generators receive depending on the extent to which they contribute to or help relieve network congestion. Those generators whose dispatch contributes to congestion would receive a price (their implicit LMP) lower than that received by generators whose dispatch does not contribute to congestion or alleviates it. (This is illustrated in appendix A.) In this way the pricing aspect of the scheme is intended to encourage generators to take the costs of congestion into account in submitting their offers. In the absence of congestion the implicit LMP for a generator would equal the RRP (ignoring network losses).

Allocating the settlements residue

The CSC represents a share of the settlements residue that accrues between the RRP and a generator's implicit LMP when congestion occurs. Under existing arrangements, the allocation of the settlements residue based on dispatch volumes provides a perfect hedge against basis risk.

Under the proposed SACP model, CSCs would not be allocated in line with dispatch volume, nor allocated as explicit rights (i.e. a fixed right that is allocated through auctioning or grand-fathering). Instead, they would be determined in real time based on three key variables:

- available transmission capacity;
- a generator's available capacity as a proportion of total available generation capacity impacted by the constraint; and
- the degree to which dispatch of the generator contributes to the constraint.

Thus the level of the CSC would not be fixed for each generator but would change subject to these variables. Note that this implies that a new entrant generator would automatically be entitled to a share of the total value of the CSC, based on its proportional share of total available generation capacity. Thus the congestion pricing mechanism and associated CSCs would not explicitly protect incumbent generators from the threat of entry.

Further, since the CSC would not be dependent on the volume for which a generator is dispatched, generators would receive any revenue accruing from the settlements residue irrespective of the volume that they are dispatched for.

The pro-rata sharing approach to determining CSCs for individual generators broadly attempts to replicate the existing way in which congestion risk is shared between generators (as occurs under disorderly bidding), while at the same time attempting to create efficient dispatch incentives at the margin. Under disorderly bidding, generators bid at the price floor. Their dispatch is pro-rated based on capacity, so in effect they receive a share of the intra-regional settlements residue based on their relative capacity, as well as a pricing element for their energy.

Under the SACP model it would be made explicit that the settlements residue would be allocated based on relative capacity. This means that generators would receive the same share of the settlements residue as would be expected under disorderly bidding, but they would no longer have to compete to secure these. This separate allocation of settlements residue also means that generators would, in effect, receive the implicit

LMP for their energy. This would provide efficient signals at the margin, meaning that generators would have incentives to bid cost-reflectively. This is discussed further in section 7.3.3.

7.2.4 Charging

Under this model, there would be no transmission charge 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.

7.2.5 TNSP planning, investment and operation

No changes to the TNSP planning, investment or operational arrangements would be required to give effect to this model. Some changes to AEMO's dispatch and settlement processes and systems would be required, but we understand that these would not be significantly material.

However, as discussed further in chapter 11, a number of options could potentially be implemented to improve the transmission planning arrangements under this model.

7.2.6 Institutions

As with TNSP planning, investment and operational arrangements there are no changes that are specifically required to institutional arrangements to implement this model. However, there may be a number of enhancements that could be made to improve these arrangements which are discussed in chapter 11.

7.3 Advantages and disadvantages of congestion pricing

7.3.1 Impact on transmission investment and operation

The SACP model is unlikely to have any impact on transmission planning or investment. The model does not target the source of congestion: it simply manages the effects. Therefore, the mechanism is unlikely to lead to a transmission response or more efficient long term investment in the network. However, there may be some impact on network operation.

As discussed in section 7.1.1, disorderly bidding contributes to counter-price flows. To the extent that pricing congestion removes incentives to disorderly bid, then counter-price flows will also be reduced. This implies that there would be less need under the SACP model for AEMO to intervene in the market and clamp counter-price flows, compared to the current arrangements, which would reduce contracting risk for generators. This is demonstrated in appendix A, which also raises the prospect of including interconnectors within the SACP scheme.

7.3.2 Impact on generator investment decisions

Locational decisions

The SACP does not strengthen locational signals relative to existing arrangements in the NEM. This is primarily because new generators automatically receive a CSC for a significant proportion of their capacity (reducing the CSCs that would be received by existing generators), providing them a level of protection against congestion regardless of when and where they locate. As a consequence, the SACP model provides few incentives for minimising long term congestion.

Investment certainty

To the extent that disorderly bidding is resolved and therefore the firmness of IRSR units across interconnectors is improved, the risk of contracting between regions will be reduced. Firmer IRSR units should also promote increased competition between regions, improving dynamic efficiency and lowering costs to consumers over time.

However, the SACP does not significantly strengthen investment certainty compared to the existing arrangements. The automatic CSC allocation under the SACP model means that existing generators should face broadly the same level of congestion risk as they do now (assuming that disorderly bidding is the usual response to congestion arising). Arguably, however, more efficient price signals might reduce market risks by increasing the predictability of dispatch and price outcomes.

7.3.3 Impact on generator operational decisions

The key strength of the SACP model is that, in sharpening congestion price signals, it should improve the efficiency of dispatch. This is achieved by exposing generators to their implicit LMP rather than settling them at the RRP, and therefore de-linking the receipt of the settlements residue from the volume of a generator's dispatch.

Under this model, a generator behind a constraint has no incentive to offer its energy below its short run marginal cost. This is because it risks being settled at that price (through the CSP), and making a loss if its offer is accepted. Therefore, a generator behind a constraint has an incentive to offer its energy at a price that at least equals its marginal cost of production. Irrespective of whether it is dispatched it will receive its share of the settlements residue and, in general, this should ensure that no generator is worse off than it would have been if it had engaged in disorderly bidding under current arrangements.

As the numerical examples in appendix A demonstrate, this model provides incentives for cost reflective bidding, and therefore is likely to lower the overall costs of dispatch compared with existing arrangements. By encouraging more cost reflective pricing the SACP model should lead to increases in productive and allocative efficiency of energy production in the NEM.

We are not aware that the SACP mechanism (or similar) has been rigorously tested in terms of its operation and outcomes. If we were to progress this option further, we would be likely to undertake modelling to verify how it would operate in practice.

7.3.4 Impact on co-optimising generation and transmission decisions

This model continues to rely on a regulated planning process to identify the need for transmission investment. The components of this process, including the Annual Planning Reports, National Transmission Network Development Plan, Last Resort Planning Power and particularly the Regulatory Investment Test for Transmission, will continue to be central to promoting efficient transmission decisions that meet the load reliability standards while accounting for generation decisions. The model also relies on TNSPs being responsive to changes in generation investment, particularly in terms of their locational decisions, and the way in which the network is used in the short term. Compared to the status quo, the introduction of a congestion price should provide additional information on the cost of congestion.

7.3.5 Implementation

While the Commission has not yet undertaken a detailed assessment of the cost of implementing a permanent, NEM-wide congestion price, it is likely the SACP model would be relatively straightforward to implement. The CSP/CSC approach was originally designed to be integrated with the NEM's regional pricing model. Relevant information needed for calculating the various components of the SACP model are already available to AEMO (such as coefficients that represent the impact generators have on network flows and the marginal value of constraints, among other variables).

Importantly, the SACP model does not require changes to any constraint formulation or orientation, which greatly reduces complexity compared to the changes required under a regional boundary change.[169] However it would require a change to the existing settlement methodology.

Table 7.1 Summary of advantages and disadvantage of package 2

Advantages	Disadvantages
Generators have a locational signal in the form of congestion on the network	Does not resolve unpredictability of congestion
Addresses disorderly bidding and so improves dispatch efficiency	Dynamic inefficiencies may result from uncertainty regarding generator access
This model is similar to the status quo and so incurs fewer implementation costs than later models	

169 For example, changes were required to many hundreds of constraints as a result of the abolition of the Snowy region.

8 Package 3: Generator reliability standards

Box 8.1: Summary of this chapter

Access	Access defined by reliability standard for generators, no congestion price
Charging	All generators face a charge to reflect the cost of maintaining the standard
Planning	TNSPs plan to new generator standard. Additional incentives required on TNSPs. Institutional arrangements to be considered e.g. who sets the standard. Further enhancements also possible

This chapter sets out the third proposed policy package, which would introduce transmission reliability standards for generators. The proposed model adopts a hybrid standard that is economically derived but expressed deterministically. This proposal seeks to align the arrangements for transmission services for generation with those that apply to load.

Introducing a generator reliability standard is intended to increase certainty for generators by defining a level of access to the transmission network that TNSPs are mandated to provide. The level of the standard would be common within geographic zones. A generator transmission use of system charge would be introduced to reflect the costs to TNSPs of maintaining the standard and the cost differences of doing so at different points on the network. TNSPs would also be provided with incentives to meet the standard.

Introducing a standard should improve access certainty compared to the status quo, although generators would not be able to choose their level of access. The economic analysis that underpins the standard would reflect the value that generators place on certainty. The standard would also be transparent so that each generator would have a specified level of access under a set of demand and transmission conditions. However, the "one size fits all" approach is unlikely to lead to a standard that is appropriate for all generation types and there would be a number of implementation issues to address, such as how to value access certainty, how to set the boundary of the zones and derive a methodology for setting charges.

8.1 Introduction

This chapter describes the third proposed package of reforms. This is the first of the packages that introduces a level of firmer access for generators. This model stems from the existing arrangements for load, whereby TNSPs are required to plan their networks to meet defined transmission network reliability standards. This arrangement is extended to generators through the application of access standards that apply to all generators.

The package draws from work commissioned by the AEMC from Hill Michael to develop a model to express transmission reliability standards for generators. Hill Michael's Final Report is available on the AEMC website.

This chapter is structured as follows:

- the remainder of this section highlights key reasons why the current arrangements may not provide sufficient transmission capacity from a generator's perspective and lists the principles that may guide the development of a standard;
- section 8.2 sets out the key features of this model of transmission reliability standards for generators; and
- section 8.3 discusses some of the issues associated with implementing generator reliability standards, including the advantages and disadvantages.

8.1.1 The current arrangements

The Regulatory Investment Test for Transmission (RIT-T) currently provides a process and test under which new investment in transmission capacity is assessed. New investment is primarily undertaken to meet load reliability standards. Consequently much of the transmission service that generators receive is driven by a need to meet load standards. Transmission investment to resolve congestion that does not impact load standards may also occur where the benefits of additional capacity exceed the costs. This can be thought of as an economic planning standard for generation. However, there may be a number of reasons why the RIT-T may not support investment in efficient levels of capacity when the combined costs of transmission and generation investment are considered.

Transparent and economic access

Under the existing frameworks there is a risk that TNSPs may not undertake all investments that are economic because there is no enforcement mechanism that requires TNSPs to invest in projects that are not required for reliability purposes. The RIT-T prevents inefficient transmission investment, however it does not ensure that efficient projects are built.

There is no obvious system for methodically identifying every plausible project for testing. A TNSP cannot be expected to run a RIT-T on every possible transmission investment project to ensure that every economic project is progressed. TNSPs must therefore be relied upon to identify all potential economic projects, supported by stakeholder consultation, the TNSP's own annual planning review and Annual Planning Report (APR), the National Transmission Network Development Plan (NTNDP) and the Last Resort Planning Power (LRPP).

Further, the testing process relies on market projections that are inevitably subjective to some extent, so the TNSP and its stakeholders could reasonably have different views about whether a project was economic.

Together, these challenges with the RIT-T process imply that the existing arrangements do not provide certainty or transparency for generators in understanding the level of access that they are likely to have going forward.

Valuing certainty

Access certainty for individual generators does not appear to be properly valued in applying the RIT-T. The focus of the RIT-T is to examine the expected NEM-wide costs of congestion, not the incidence of these costs on individual generators. However, generators may value certainty of access more highly than is recognised by the RIT-T.

Excluding the value of access certainty to generators may be appropriate under current arrangements whereby generators do not face a charge for use of the network. Instead, generators are subject to the risk of congestion and the associated opportunity cost of not being able to access the Regional Reference Price (RRP), which provides a locational signal. If a certainty premium was factored into the RIT-T resulting in less frequent or material congestion, then this locational signal would be dampened.

However, without placing an explicit value on generator access certainty, even if an enforceable standard was introduced the resulting level of transmission capacity may not meet generators' needs. This would have consequential impacts on the efficiency of generator investment, as discussed in section 3.3.

8.1.2 Principles to guide the development of a standard

There are a number of principles that may guide the development of a reliability standard for generators. These principles were previously used by the Commission to inform its recommendation to the MCE on transmission reliability standard for load, and include:

- *Economic efficiency*: the standards should be derived from economic analysis that relates transmission costs to the value generators place on access reliability.
- *Transparency*: there should be transparent and consistent processes for setting, applying and enforcing standards.
- *Specificity of standards*: the standards must specify the planning scenarios and the access outcomes that are required under those scenarios.
- *Fit for purpose*: the standards may differ geographically to reflect the underlying economics e.g. remote generation may have a lower reliability standard due to the higher cost of maintaining reliability.
- *Governance*: the standards should be set by a body separate from the planning body responsible for applying the standard.
- *Amendable*: a process should be established for amending the standards from time to time to reflect any changing economics.

- *Accountability*: transmission planners should be accountable to the AER for ensuring that the standards are met.
- *Technology neutral*: the standards should not require a particular form of technology (e.g. network rather than non-network) to be used.
- *Effectiveness*: the standards should deliver broadly the level of access reliability that generators require and are willing to pay for.

8.2 Key features of generator reliability standards

8.2.1 Product definition

Form of standard

Under this model, mandatory, hybrid transmission reliability standards for generation would be introduced. These terms are defined and discussed below.

The generator reliability standards[170] would be mandatory and so TNSPs would be required to plan and expand their networks so as to maintain the standards. The AER would be responsible for monitoring and enforcement.

The standards would be of a hybrid form.[171] As discussed in section 4.2.1, this means that the standard would be economically derived then expressed in a deterministic form and fixed for a defined period of time. Such standards are intended to give rise to a broadly economic level of transmission capacity, while maximising transparency.

The economic analysis, and the resulting specification of the deterministic standard, would be undertaken by a body independent of TNSPs. Importantly, that analysis would include a "certainty premium" that captures the value that generators place on access certainty. Conceptually, the certainty premium is similar to the value of customer reliability that is used in Victoria as a measure of the cost of unserved load to assist in planning the transmission system.

Since the standards would be expressed deterministically, the demand and transmission conditions under which a specified level of generation access would be met would need to be defined.

The standard would therefore need to define three dimensions:

- *Demand* - the demand conditions under which the standard must be achieved (such as peak or off-peak).

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170 Note that the terms "reliability standard" (in the context of generation) and "access level" are used interchangeably throughout this chapter.

171 The hybrid approach has previously been proposed by the AEMC in the context of developing a national framework for demand-side reliability standards.

- *Transmission* - the transmission conditions under which the standard must be achieved (such as N, N–1 or N–2).[172]

- *Access* - the access standard that must be met under all of the specified demand and transmission conditions (for example, the access standard could require that there be a defined limit on transmission congestion under a cost-based merit order dispatch).

The demand and access conditions would be fixed for all generators. However, the transmission conditions may vary between geographic areas, as discussed further below. More generally, it is likely that these dimensions would be set for a period of time, such as five years, then subject to review to ensure the standards continued to broadly reflect the underlying economics.

Zonal definition and monitoring of the standard

The standards would be set and monitored on a "zonal" basis, which would be smaller than a region but greater than the nodal level. For example, an "N–1" standard might apply (on average) in zone A and an "N–2" standard might apply (on average) in zone B. This contrasts with a "nodal" approach to setting and monitoring standards whereby an access requirement would be set and monitored at each generator node or connection point.[173]

A uniform regional standard, that is the same at all connection points within a region, would be easier to apply and monitor than a more granular zonal approach. However, the regional approach is unlikely to be economic. This is because the benefits of the standard are likely to be similar across locations,[174] but the costs will be higher in more remote locations. Consequently a TNSP may achieve the standard for a zone by providing some generators in that zone with a very high standard and others, who are in a location where it is more expensive to provide transmission capacity, a relatively lower standard.

Conversely, a different level of standard could be applied at each node. A nodal approach may give individual generators a level of access that is closer to their desired level. However, a standard that is nodally-differentiated is likely to be significantly more complex to derive and apply as there would be a greater number of standards to monitor, test and plan to. Further, a version of the nodal approach is contemplated as a separate model in the next chapter.

172 This refers to the number of transmission elements that can be out of service while still maintaining network security. For example, a power system comprising N elements that is resistant to a single component being out of service is said to be reliable to N–1. This means that all customer load would continue to be supplied even with one bulk power system element out of service. A higher level of reliability is provided when the transmission system is planned to be reliable to N–2 where no customer's load will be affected even if two elements are out of service.

173 A third option would be to set a common standard across a zone, but monitor it at each node. For example, all generators at each node in zone A would be guaranteed an N–1 standard.

174 The benefits may differ between technologies and entities with different risk profiles. However, it is likely that a given generator would receive similar benefits from a specified level of service, irrespective of where they were located.

As discussed in section 8.3.5 below, quantitative analysis would be required to determine the geographic boundaries of the zones, which will depend on the geographical and historical idiosyncrasies of the existing grid. However, it is likely that these zones would be based on groups of connection points that reflect similar costs to maintain a common standard. There may be a number of other criteria that could be applied, for example requiring that significantly different access levels do not arise within a zone. A useful starting point might be the NTNDP zones,[175] which would then be refined based on the criteria established.

As an example, in regions where demand is primarily concentrated in a small sub-region (such as in Victoria), zones could be specified in relation to the distance from this demand centre. Zones furthest from the demand centre would likely have lower average access levels and/or higher charges[176] since the cost of providing access is likely to be greater than for zones closer to the demand centre. The deterministic standard would be designed to reflect this variation. However, note that a zone may not be geographically contiguous, but could instead be formed from a number of non-adjacent areas.

The zonal approach could leave some generators with an access level below (or above) the standard average and so the precise access level that would apply to individual generators may be uncertain. We note that there may be alternative approaches that provide greater certainty. However, this approach has been chosen for two key reasons:

- The premise of this option is to align the arrangements for transmission services for generation with those that apply to load. Typically, there are a number of load customers at any given connection point. Therefore, while on average they will receive a defined level of service, the actual level that customers receive will vary around this average. Thus, a zonal approach is closer to existing arrangements for load.

- The zonal approach provides for a greater distinction between packages 3 and 4, and to some extent package 5. The standard could be applied on a nodal basis, which would naturally lead to providing generators with different levels of access according to their preferences. However, this is the focus of packages 4 and 5.

8.2.2 Assigning rights

Unlike packages 4 and 5 discussed in chapters 9 and 10, the standard would not provide generators with a property right that guarantees access. Further, generators would not be able to negotiate the level of the reliability standard that would apply at their individual connection point so there is no need to assign rights. However,

175 For the purposes of the NTNDP, AEMO divides the transmission system in the NEM into 16 zones.

176 As discussed in section 8.2.4, care would need to be taken to ensure that these two locational signals, the level of standard and the associated charge, did not double count locational differences.

generators would have greater certainty than under packages 1 or 2 about the level of access that they could expect.

8.2.3 Dispatch, congestion and compensation

There is no change to dispatch under this model. There may continue to be congestion from time to time, although the introduction of a certainty premium into the planning process may lead to a lower level of congestion than under the current arrangements.

No congestion management mechanism is proposed under this model since congestion may be expected to be less with a reliability standard in place. However, the model is not inconsistent with introducing a price on congestion, as discussed in the previous chapter. Further consideration could be given to introducing a mechanism to manage disorderly bidding if it proved persistent and material even with a generator reliability standard.

Generators would not be entitled to compensation if the standards were not met. Therefore, although this model would provide greater certainty of access, it would not guarantee firm access. However, TNSPs may be given financial incentives to encourage them to meet the standards. This is discussed further below.

8.2.4 Charging

Establishing generator charges

In return for receiving a defined level of access standard, all generators would be required to pay an ongoing charge that reflects the relative cost of meeting and maintaining the standard. This is necessary to provide an appropriate locational signal for generators such that they internalise the network costs associated with maintaining the standard at their chosen location. The charge would be common across a zone, since the zones would be constructed around connection points with similar costs associated with providing a given standard.

The standards proposed under this model may change from time to time, are common across zones and will provide a defined level of supply to both incumbents and new entrants. Further, this approach is consistent with the charges that apply to load. For these reasons, a generator Transmission Use of System (TUoS) charge is likely to be the most appropriate form of charge (compared to a deep connection charge). This charge should provide an appropriate signal to new entrants such that they internalise the network costs associated with their locational decision and so promote efficient locational decisions.

Some stakeholders have previously raised concerns with the use of TUoS charging for generators, particularly regarding the potential volatility of the charges.[177] The Commission notes that such charges have been used for over 20 years in Great Britain

177 LYMMCo, Issues Paper submission, p. 47; NGF, Directions Paper submission, p. 4; TRUenergy, Directions Paper submission, p. 3.

and have been relatively stable. However, if we were to seek to progress such an option further, we would be likely to undertake modelling to assess the stability of the charges in a NEM context. If the resulting charges were likely to be unacceptably volatile, a number of mechanisms could be employed to manage these effects, such as fixing charges for periods of more than a year, or introducing constraints on the amount by which charges could change.[178]

The variation in the standard between zones will in itself provide some locational signals for connecting generators, in addition to the variations in the generator TUoS charge. Therefore, care would need to be taken to prevent these separate mechanisms from double counting the locational differences.

Appendix C provides further details of the basis on which a generator TUoS charge might be developed. Appendix D sets out challenges associated with a deep connection charge approach and for these reasons it is not being proposed for this model.

TNSP revenue recovery

Consideration would need to be given to what proportion of TNSP revenue would be recovered from generators. Both generators and load benefit from the transmission network and so it is difficult to precisely assign costs between them. Therefore the split of revenue recovery between generators and load customers is somewhat subjective. The most straightforward method of allocating costs may therefore be a fixed proportion of TUoS revenue (i.e. those costs that it is possible to allocate on a locational basis), such as a 50/50 division. Common services charges would continue to be recovered from load.

In most regions of the NEM, 50 per cent of load TUoS charges are currently recovered locationally, with the remainder recovered on a postage stamp basis. Consequently the 50 per cent that is currently recovered on a postage stamp basis could instead be recovered through locational generator TUoS charges. However, further consideration would need to be given to the appropriate division of costs.[179]

Alternatively, load could continue to pay TUoS charges for all of the network capacity that is required to meet load reliability standards. Generators could then pay the incremental costs of any additional capacity that was required to meet the generator reliability standards, above and beyond what is required for load. However, this is likely to be a significantly more complex process.

In either case, consideration would also need to be given to the appropriateness and form of any transitional provisions to apply to existing generators.

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178 Under clause 6A.23.4(f) of the Rules, locational TUoS charges for load must not change by more than 2 per cent per annum compared to the average for the region.

179 In Great Britain, the split is based around an initial allocation of 75 per cent to load and 25 per cent to generation. It is understood that this essentially represented a compromise between 50/50 and load paying 100 per cent. In Western Australia's Wholesale Electricity Market (WEM), generation pays 20 per cent locationally, with load paying 50 per cent locationally and 30 per cent on a postage stamp basis.

TNSP revenue allowance

If generator reliability standards were introduced, the arrangements through which transmission investments were funded would need to be reviewed. Typically, anticipated investments are forecast as part of a TNSP's five-yearly revenue determination and funding is provided as part of a TNSP's maximum allowed revenue each year. However, load growth is more straightforward to forecast than generators' entry decisions. Two possible options for ensuring TNSPs have sufficient revenue to undertake uncertain capital expenditure are:

- the existing contingent projects mechanism; or
- providing TNSPs with unit cost allowances (UCAs).

Currently, projects that are too uncertain to be included in a TNSP's revenue allowance at the time of its revenue determination may be classified as a "contingent project".[180] TNSPs are able to identify contingent projects at each regulatory reset, subject to a number of criteria.[181] The TNSP must also identify an appropriate trigger under which it may commence construction of that project. When a contingent project is triggered, a TNSP may apply to the AER for an amendment to its revenue determination to include a forecast profile of expenditure for that project.[182] This expenditure is then included in the maximum allowed revenue (MAR) going forward.

Alternatively, TNSPs could be provided with a set of UCAs used to fund additional investment to meet generator reliability standards. The UCAs would reflect the average cost in different zones of network investment on a dollars per megawatt basis for each TNSP. Similar to contingent projects, a trigger would be established to determine the point at which a TNSP may commence construction. Once triggered, a TNSP's annual MAR would be adjusted to reflect the UCAs, providing the necessary funding to carry out the investment.

The UCA would apply to the construction, establishment and operation of the relevant assets over the regulatory control period in which the expenditure is incurred. At the beginning of the next regulatory control period the assets would be rolled into the regulated asset base of the TNSP.

The UCAs would be determined as part of the model that currently applies to the transmission revenue determination process. Under this model, TNSPs would propose an average unit cost, per megawatt per year for the construction of various assets. The UCA would be determined according to the typical costs associated with construction and establishment of various transmission assets, and through forecasts of operating and maintenance costs. The AER would have final approval of the UCA as part of the revenue determination process.

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180 Contingent projects are provided for under NER clause 6A.8.

181 For example, contingent projects are only permitted to be included in the revenue determination if the proposed capital expenditure exceeds the greater of $10m or five per cent of the maximum allowed revenue of the first year of the regulatory control period. See NER clause 6A.8.1(b).

182 NER clause 6A.8.2(a).

The contingent projects approach is likely to be appropriate for providing the necessary funding to meet generator reliability standards. This mechanism is typically used for high value projects of which there are likely to be few triggered over a regulatory period. However, the UCA approach may be appropriate if the need for investment within a regulatory control period is sufficiently uncertain that contingent projects cannot be identified during the revenue determination process, or if there are likely to be many, lower value projects. The UCA approach is discussed further in chapters 9 and 13.

8.2.5 TNSP planning, investment and operation

TNSPs would be required to plan their networks so as to meet and maintain the new generator reliability standard, together with the existing load reliability standards. Since the standards would be expressed deterministically, planning will be driven by studies of the demand and transmission conditions specified in the standards. Where the studies reveal that generator or load levels standards will not be achieved, the TNSP would identify and assess potential investment projects that would restore the required level of access or demand supply.

The preferred projects would be considered under the RIT-T (unless exempted)[183] and then progressed through to commissioning. The RIT-T would be amended to refer specifically to the generator reliability standards as a reason for transmission investment and, as for load, TNSPs would be able to progress with the investment option that minimises costs.

Ideally, the specified demand and transmission conditions would be the same for both the generator and load standards, simplifying the planning process through fewer planning studies and more certainty of consistency of application of the two standards. However, this is not essential and may not be practical given the different fundamental objectives of the two standards.

Since the generator reliability standard would be mandatory, the AER would need the tools to monitor and enforce the standard. These tools would include financial incentives to reward (or penalise) TNSPs for meeting (or not meeting) the standards. Given that the standards would be deterministically expressed, some consideration would be required in the design of the financial incentives since deterministic standards are either met or not - it is a binary outcome.

One option to grade the incentives would be to base any reward on the number of zones in which the TNSP met the standard. Alternatively, TNSPs could be penalised based on how far away they were from meeting the standard. Under this approach consideration would need to be given to the appropriate financial incentive to apply if a TNSP exceeded the required standard. This is because the standard should incorporate a generator's willingness to pay for access. If a TNSP exceeds this standard,

183 There are some instances where a TNSP is not required to apply the RIT-T to proposed transmission investments. These exclusions are set out in NER clause 5.6.5C(a).

this would imply that the generator was receiving a higher standard than it was willing to pay for.

Consideration will also need to be given to how a TNSP's performance would be assessed. The Commission's preference is to measure performance based on observed outcomes. Compared to using modelling outcomes this approach has the advantage that it is less open to dispute. However, there may be some difficulties in accurately defining the transmission operating conditions in which the standard is to be met sufficiently tightly to facilitate this approach.

8.2.6 Institutions

An institution would need to be tasked with setting the generator reliability standards, including undertaking the economic analysis that would underpin the standard.

In the Updated Final Report on transmission reliability standards for load[184] the Commission proposed that standards would be determined on a jurisdictional basis by a body that was independent of the transmission network owner. It was proposed that each jurisdiction would also have the option of appointing the AEMC to set that jurisdiction's transmission reliability standard for load.

Further consideration would need to be given to whether this approach would be applicable for generation reliability standards. Alternatively, it may be appropriate to nominate a single, national standard setter. For load reliability standards the Commission recommended that the AEMC undertake this role where requested, supported by advice and analysis from another party to inform this decision.

This will be an area for further consideration should the Commission progress this model, following stakeholder feedback.

8.3 Advantages and disadvantages of generator reliability standards

8.3.1 Impact on transmission investment and operation

A generator reliability standard would change the way in which TNSPs plan and invest in their networks. In addition to meeting reliability standards for load, TNSPs would be required to meet reliability standards for generators. As discussed further below, whether or not this leads to an increase in transmission network capacity will depend on the level at which the standard is set and the existing capacity of networks.

The RIT-T would continue to be used to identify efficient investment solutions. However, investments to meet generator requirements would be treated consistently with those required to meet load reliability standards. Therefore TNSPs could proceed with least cost investments to meet the generator reliability standard, as currently occurs for load, even where there is a net cost.

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184 AEMC, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, Sydney.

Provided the economic analysis that underpins the generator reliability standard is reasonably accurate, then broadly efficient transmission investment outcomes should result. However, while the economic analysis will be undertaken by an independent entity, achieving an accurate standard is likely to be very difficult in practice. The economic analysis would necessarily need to make assumptions about future outcomes, including generator behaviour, that are inherently uncertain and difficult to predict.

Similarly, the certainty premium that is key to providing generators with an appropriate level of transmission capacity will be challenging to estimate and will necessarily be a very broad measure that attempts to find an average level of preferred access across different technology types. Therefore over or under-investment in the network could result compared to efficient levels, with consequential cost impacts for both generators and customers. However, the likely efficiency impacts must be considered against the status quo and an attempt to value the certainty premium may improve outcomes against this baseline.

The standard could also impact transmission operational decisions to the extent that investment in new capacity could be delayed by changing operational or maintenance practices. However, it is unlikely that there would be a direct impact on the day to day operation of the network.

8.3.2 Impact on generator investment decisions

Locational decisions

Implementing a reliability standard for generators would introduce two new locational signals for new entrants:

- the charge associated with the new reliability standard which, like the standard, would be likely to differ between zones; and
- the reliability standard itself, which would be likely to differ between zones and so influence the zone within which a new entrant generator will locate.

These two locational signals will allow generators to appropriately balance a higher access standard against the cost of that standard. The extent to which these signals influence a generator's locational decision will depend on the strength of the signal relative to other factors that influence such decisions, including access to fuel and cooling water, site-specific land use planning requirements and so forth.

The generator TUoS charge can be considered to provide a signal of the value of network capacity and therefore the trade-off between the construction of new transmission capacity and delaying generator entry. Thus, over the longer term, the charge should promote the efficient use of the network through the efficient timing of entry (and exit) decisions.

Common application of standard versus technological discrimination

The proposed standard is common across defined zones and therefore does not vary with generation type, such as baseload, peak and intermittent generation. However, different generation types are likely to value access certainty differently. Clearly, a peaking plant will value access at peak times, but will not need or seek access at off-peak times. An intermittent generator, on the other hand, is unlikely to be selling firm forward contracts and so is likely to be concerned more with the average level of access than volatility around this average.

Clearly this issue also exists on the demand-side, where the planning standards will deliver reliability that is too high for some consumers and too low for others. However, it is arguably more pertinent on the generation side, where a single generator may be connected at a point and might therefore expect an access level that suits it specifically, rather than one that suits an average generator.

While it would be technically possible to provide different levels of reliability to different connection points, this would significantly increase the complexity of the model. Further, it would not be possible to provide different levels of reliability to multiple generators located at the same connection point. While this area could be given further consideration if the model was progressed, it is for these reasons that we have decided to consult on a model which has a common standard.

Investment certainty

Transmission reliability standards for generators could improve access certainty, and so investment certainty, in three ways compared to the status quo:

1. The new standard would be mandatory, and so current uncertainty as to whether a TNSP will undertake economic projects is removed.
2. The economic analysis underlying the reliability standards would assign a specific economic value to access certainty, which is not currently factored into the RIT-T.
3. The new standard would be deterministically expressed, so each generator would know that it would have a specified level of access under specified demand and transmission conditions.

Providing a mandatory transmission standard for generators will improve generator certainty regarding the likelihood of transmission investment being undertaken. As discussed in section 8.1.1, transmission capacity is currently primarily driven by a need to meet reliability standards for load. The proposed model counteracts uncertainty under the status quo regarding whether or not transmission investment will be undertaken to allow for generators to access the market on an ongoing basis.

Placing an explicit economic value on access certainty is intended to promote a level of transmission network capacity that appropriately reflects the efficiencies gained from increasing certainty of accessing the RRN. This approach is intended to strike an appropriate balance between any additional costs associated with transmission investment and the dynamic efficiency gains that should flow from improving the certainty of generators' revenue streams. As discussed in section 3.3, certain revenue streams are likely to promote more efficient generator investment decisions through access to financing at an appropriate cost and a deeper and more liquid contract market.

While the level of the deterministically expressed standard would be certain, the extent to which this promotes investment certainty for generators will depend on what that level is. The level of the standard would need to be sufficiently high to give meaningful investment certainty. Of course, since the standard would be based on economic analysis, if the standard was relatively low then this would imply that the costs associated with building additional transmission capacity outweighed the benefits associated with greater access certainty.

8.3.3 Impact on generator operational decisions

Implementation of a generator reliability standard would be unlikely to change the way in which generators would make their operational decisions. In particular, where congestion arises, generators would still have an incentive to make their offers to reduce the extent of being constrained off. However, depending on the level at which the standard is set, the instances of congestion and so disorderly bidding may reduce.

Consequently, while this package may improve efficiency of dispatch compared to the status quo due to fewer instances of congestion, it would not entirely eliminate disorderly bidding. As discussed above, this package is not inconsistent with the introduction of a price on congestion. Therefore, if disorderly bidding was found to result in inefficient outcomes, there may still be a case for implementing a congestion management mechanism.

8.3.4 Impact on co-optimising generation and transmission decisions

Like the status quo, the model proposed in this chapter still relies on a regulated planning process with limited market signals. However, the proposed process has been revised to incorporate an explicit value on access certainty for generators. Further, we would expect that generators would contribute more to the planning process given its additional importance in meeting reliability standards specifically for generators. Further, compared to the status quo, this approach is likely to provide improved investment certainty, derived from greater certainty about transmission investment, and improved locational signals as network costs will be signalled directly to generators through a TUoS charge.

8.3.5 Implementation and feasibility

While there would be a number of implementation issues to consider under this model, these changes are likely to be less fundamental than under models that assign property rights and allow generators to choose their level of firmness. The challenges discussed below include:

- deriving and applying reliability standards for generators;
- defining the boundaries of the zones within which a common standard would apply;
- establishing a methodology for calculating the charge;
- the cost of any new infrastructure that may be required to meet and maintain the standards; and
- the treatment of new entrants.

Deriving and applying the standards

Deriving and applying generator reliability standards is likely to be a challenging task for a number of reasons. The economic analysis that underpins the standard is likely to be particularly challenging and contentious to undertake. This is because market modelling would be required, which would require assumptions about generators' locational decisions and bidding behaviour.

A further challenge in deriving the standards would be establishing an appropriate "certainty premium" to account for the value that generators place on certainty of network access. This premium is likely to differ between generator types as well as between businesses that have different risk profiles. Further, it is unlikely that generators would reveal such information. Therefore further consideration would need to be given to how this premium could be defined and measured.

Defining boundaries for zones

A methodology would be required to identify the zones over which a common access standard and charge would apply. This would require quantitative analysis to group proximate connection points that would cause similar costs to meet and maintain a common standard.

Alternatively, the zone over which the common access standard applied could be derived on some other basis. In such instances the charge may need to vary between connection points that receive the same level of service so as to reflect any material cost differences.

Under either approach, a number of boundary issues will arise, such as:

- establishing transparent and unambiguous zonal definitions; and
- managing future changes to the zonal boundaries to reflect corresponding changes to the underlying economics of access provision.

Establishing a methodology for calculating generator TUoS

A methodology would also be required to calculate the appropriate charge to be faced by generators to promote efficient locational decisions. As discussed in section 8.2.4, the generator TUoS charge at a connection point should reflect the relative cost to the TNSP of meeting and maintaining the standard.

Appendix C sets out a number of approaches for reflecting the long run marginal costs associated with network investment and discusses some of the complexities associated with the process. Two contrasting approaches that may warrant further consideration are the Cost Reflective Network Pricing (CRNP) and the MW Mile approaches.

CRNP is already used in the NEM to calculate TUoS charges for load. CRNP is capable of being used in networks with varying levels of reliability. This is because it reflects the costs of the assets actually employed to supply load (or accommodate generation) at each connection point. If a higher level of reliability means that a greater amount of (or more costly) assets are required, this will be reflected through a higher charge. However, this is also the methodology's weakness. Charges are based around recovering the costs of existing assets and do not explicitly reflect the incremental costs of expanding the network.

In contrast, the MW Mile approach does estimate the costs associated with accommodating an additional MW of load (or generation) at a connection point. However, it is not clear that a MW Mile methodology could be developed that would be well suited to network pricing where connection points receive differing levels of reliability.

The way in which generator charges would be calculated is an area that would require further consideration should this package be selected for further development.

Potential need for additional infrastructure

The most significant costs involved in implementing generator reliability standards would be any additional infrastructure required, and the time involved in its construction, so as to meet the new standard for generation. Clearly the need for new investment will depend upon the level at which the standard is set and the degree to which that standard is already being met. Quantitative modelling of these variables would therefore be required to determine the costs involved in implementing generator reliability standards.

Assuming that new investment is required, possibly the most straightforward way to achieve the transition would be to initially set the standard based on currently available capacity. The standard could then be gradually ramped up to the economically determined capacity over a period of time.

As an option to assist in the transition, TNSPs could initially simply be required to measure and report on the level of service provided to generators, without any obligations for TNSPs to deliver a particular standard. This would provide information and value to generators through increased transparency and measurement of service delivery, prior to designing, setting and enforcing the reliability standard.

Treatment of new entrants

The way in which generator entry that triggers new investment is treated may impact the timing and potentially the location of new investment. There are three options for considering new generator entry:[185]

- not connect new entrants until the network has been reinforced to meet the new capacity requirements;
- allow the new entrant to connect and the standard to be temporarily breached until the required transmission reinforcements can be undertaken; or
- allow the new entrant to connect, but where congestion arises these new plants are constrained off before the access of incumbents is affected (noting that this would change the way in which generators are dispatched). Once the required transmission augmentation is completed, the higher access level would become available to the new entrant.

Table 8.1 Summary of advantages and disadvantages of package 3

Advantages	Disadvantages
Provides a transparent and enforceable reliability standard for generation access	Complexity of deriving and applying standards
Provides greater certainty for generators, improving liquidity in the contract market, offsetting potentially increased transmission costs	Uncertainty if standards are changed over time
Approximates an economic planning standard, given the hybrid approach	No opportunity to opt for a different access standard to other generators in the same zone
Non-discriminatory between technologies and incumbents/new entrants	Does not address disorderly dispatch

185 See: AEMC, *Transmission Frameworks Review*, Directions Paper, 14 April 2011, Sydney, pp. 29-30 for further discussion of these options.

9 Package 4: Regional optional firm access model

Box 9.1: Summary of this chapter

Access	Generators choose a quantity of firm access to the Regional Reference Node
Charging	Firm generators pay a charge, no charge for non-firm generators but they are potentially liable for compensation
Planning	TNSPs plan to new standard for firm generators. Additional incentives required on TNSP. Institutional arrangements to be considered e.g. who sets the standard. Further enhancements possible

This chapter sets out the fourth proposed policy package, which would apply the existing principles of clause 5.4A of the Rules to generators on a mandatory basis. This would give generators the option of obtaining firm financial access rights for any quantity of their capacity. The mechanism to deliver this access would be a combination of: physical network augmentation, as specified by a generator planning standard; and settlement payments between non-firm and firm generators, where the former prevent the latter from being dispatched.

This model would provide firm access to generators who are prepared to pay the associated charge. As generators would be making the economic trade-off between the benefits and costs of firm access, there would be no need for TNSPs or the regulatory planning process to estimate the value that generators place on the firm access. The model would also address the problem of disorderly bidding.

Although the model is based on concepts contemplated under the existing Rules, it would still represent a substantial change to the NEM arrangements. The development and use of generator planning standards and transmission charging methodologies would add complexity. Generators not opting to purchase firm access rights would be liable to pay compensation to firm generators in the event of congestion. This might also lead to gaming issues, the materiality of which would need to be considered.

9.1 Introduction

This chapter sets out the fourth possible model for consideration, which would introduce firm financial access rights. While this model would result in significant changes to the current NEM arrangements that exist in practice, it has been developed from the current provisions of clause 5.4A of the Rules. Before discussing the model in more detail, this chapter therefore briefly explains its genesis.

For ease of discussion this chapter refers to "firm" or "non-firm" generators to distinguish between generators that opt to purchase firm access rights and those that do not. However, as discussed further below, in practice generators would be able to choose a quantity of access for which they are firm, ranging from zero to their full capacity.

This chapter is structured as follows:

- the remainder of this section discusses the catalyst for this model;
- section 9.2 describes the key features of this regional optional firm access model; and
- section 9.3 discusses some of the potential efficiency benefits and costs associated with introducing this model.

Appendix A provides a simple numerical example of this model.

9.1.1 Catalyst for this model

Clause 5.4A of the Rules contains provisions that appear to offer generators the option of obtaining firm access through a *transmission network user access* arrangement.[186] As discussed in chapter 6, we have concluded that these elements of the Rules cannot work in practice, principally because participation in the mechanism that would provide firm access is optional. The regional Optional Firm Access (OFA) model resolves this issue by making participation in the scheme mandatory.

It is unclear whether the current clause 5.4A is seeking to offer generators physical access or financial access - or both. The relevant provisions include:

- 5.4A(e)(2), which refers to network *augmentations* and *extensions* being undertaken under a *transmission network user access* arrangement;
- 5.4A(f)(3)(i), which requires that *use of system services* charges should be paid by the generator to the TNSP in relation to any required *augmentations* and *extensions*;
- 5.4A(f)(4), which provides for *access charges*. These include:
  - an amount to be paid by the generator to the TNSP in relation to the costs incurred in providing *transmission network user access*;
  - compensation to be provided by the TNSP to the generator in the event of the generator being constrained off or on; and
  - compensation to be provided by the generator to the TNSP in the event that the generator's dispatch causes another generator to be constrained off or on.

186 Where terms are italicised in this section, they refer to defined terms in Chapter 10 of the Rules.

In practice, providing firm access requires elements of both physical and financial access. This package attempts to achieve this in an integrated manner through:

- requiring generators without firm access ("non-firm" generators) to pay compensation to generators with firm access ("firm" generators) when they cause them to be constrained off; and
- introducing a planning standard to specify the network augmentations required (if any) to support the required level of network capacity and release firm access rights.

In addition, the proposed model would provide greater clarity regarding the charges to be paid by generators in return for receiving firm access rights.

The model would generally introduce a clearer and more robust process than the existing arrangements provide. However, as indicated below, this would result in substantial changes to the arrangements which currently exist in practice.

We note that a number of stakeholders have suggested that a mechanism based on the principles envisaged in clause 5.4A might be workable if mandatory. For instance, LYMMCo suggested a model that it believed was how "5.4A could have worked if it was implemented and managed from market start". LYMMCo suggested that incumbent generators should be clearly allocated rights. New entrants would then have the following options if they did not locate where there was spare capacity: fund transmission augmentations (to release new rights); buy existing rights off an incumbent; or agree to pay compensation.[187]

The regional OFA model presented here is also quite similar to a model put forward for consideration by AGL.[188] However, the primary focus of that model was the provision of physical access. It included a different mechanism for the payment of compensation by non-firm generators and placed less emphasis on this - with the expectation being that, in most cases, generators with non-firm access would restrict their output in the presence of congestion.

9.2 Key features of the regional optional firm access model

9.2.1 Product definition

The regional OFA model would provide generators with the option of obtaining financial access to the regional reference node (RRN). This would allow generators that took up this option to manage the risks associated with being constrained off.

A constrained off generator will lose out on spot revenue on its constrained output but make savings on short run operating costs, such as fuel costs compared to its preferred output under the prevailing regional reference price (RRP) . Therefore, the opportunity

187 LYMMCo, Directions Paper submission, pp. 5-6.

188 AGL, Directions Paper submission, Appendix 1.

cost of being constrained off is the difference between the RRP and the generator's short run marginal cost (SRMC), multiplied by the constrained off amount.

The regional OFA model is intended to compensate constrained off firm generators for this opportunity cost such that the generator would be financially indifferent to being constrained off.

However, firm generators might not be fully compensated outside of defined "normal operating conditions". Therefore, access would only be truly "firm" under such conditions.

The model, as presented here, also does not provide any compensation for generators that are constrained on, although it could potentially be further developed to do so. It is assumed that the current arrangements for compensation under direction by AEMO[189] would be maintained.

9.2.2 Assigning rights

The regional OFA model would allow generators to choose their quantity of firm access (i.e. they could choose to have firm access for all, part or none of their capacity).

Firm access rights would be assigned by TNSPs in response to generators' applications. The transmission investment required to provide any requested firm access rights would be assessed through use of a generation planning standard, which is similar in principle to the standard discussed in chapter 8. This investment would need to be completed before the access rights would be released to the relevant generator. Note that this does not imply generators could not connect before the relevant capacity was built. Rather, the generator would remain non-firm until such time as firm access could be provided.

There are two broad approaches that could be adopted to release firm rights:

- A one-off release of firm rights for each power station (noting that the rights may not cover the full capacity of a power station). If a newly connecting (or previously non-firm) generator decided to request firm access rights for all or part of its capacity, it would pay a deep connection charge to fund the transmission investment required. It would then have firm rights on an enduring basis. There would, however, be no mechanism and no incentive for firm generators to become non-firm.

- The ability to switch between firm and non-firm products. Under this approach, generators would receive rights for a defined period of time in return for a generator Transmission Use of System (TUoS) charge. The charge would reflect the costs associated with transmission investment required to release additional rights. Generators could subsequently opt to become non-firm, in which case they would no longer pay the TUoS charge.

189 NER clause 3.15.7.

These options are discussed in more detail in section 9.2.4 below.

9.2.3 Dispatch, congestion and compensation

Under the regional OFA model, dispatch would be undertaken as under the current arrangements, with all generation - firm and non-firm - dispatched economically based on offer prices. There would be no distinction between firm and non-firm generation in the dispatch process.

The transmission network would be planned to accommodate firm generation through use of the generator planning standard. This planning standard would not extend to non-firm generators, and therefore the inclusion of some non-firm generation in dispatch could lead to firm generation being constrained off.

In the event of congestion, non-firm generators would be required to pay compensation to the firm generators that had been constrained. As noted previously, the model aims to compensate such generators for the opportunity cost of being constrained off. The way in which this compensation is calculated is described below.

Compensation payable

A firm generator would be eligible to receive compensation if it would have been in merit in an unconstrained system but, in reality, was constrained off (i.e. it was not dispatched but would have been in the absence of congestion).

The compensation payable to the firm generator would be the difference between the RRP and the relevant locational marginal price (LMP), multiplied by the amount by which the generator is constrained off.[190] The LMP reflects the cost associated with providing an additional unit of generation at the generator's local node, and would be used as a proxy for the generator's SRMC.

These compensation payments are, in effect, the intra-regional settlement residues that arise when congestion occurs and causes local prices to diverge from the RRP. As discussed in chapter 7, these intra-regional settlement residues are currently implicit and are linked to dispatch volumes. In this regional OFA model, the residues are instead linked to firm access rights (and the amount of compensation that a non-firm generator is required to pay, as discussed below). Therefore when a firm generator is not dispatched, it still receives a payment derived from the intra-regional settlement residues.

Since a constrained off generator is (by definition) not dispatched, the generator's offer price must be at least as high or higher than the LMP. Therefore, compensation based on the difference between the RRP and the LMP would be at least enough to compensate a constrained off generator for its lost profit.

Using the generator’s offer price to determine the compensation would, in theory, be more accurate than using LMP. However, this assumes that offer prices were set cost reflectively. In practice, constrained off generators would have an incentive to misrepresent offer prices (which by definition would be above LMP) downwards towards LMP in order to maximise the amount of compensation paid. However, there would then be a risk of generators being dispatched inefficiently if they failed to correctly estimate the LMP or if the congestion was removed. Using LMP removes these incentives to misrepresent offers and the consequent possibility of disorderly dispatch.

Compensation contributions

The compensation paid to constrained firm generators would be funded through contributions from dispatched non-firm generators, which the network would not have been planned to accommodate. Given that constrained off firm generators would receive implicit intra-regional settlements residues as compensation, non-firm generators, in the presence of congestion, would be required to relinquish these residues in order to fund the compensation requirement. Conceptually therefore, non-firm generators can be considered to be settled at their local LMP (which will, ignoring losses, equal the RRP in the absence of congestion).

In order to be dispatched, the non-firm generator's offer price must be lower than (or equal to) its local LMP. The most compensation that a non-firm generator would be required to pay would be the difference between the RRP and its local LMP (per MW). Therefore a non-firm generator would always receive a settlement price at least equal to that at which it would be prepared to generate. Consequently it would still be better off being dispatched than not (or at least indifferent).

Matching of compensation amounts

The regional OFA model is designed to be self-funding to ensure that it does not create settlement deficits (or surpluses) that would need to be funded from (or disposed of) elsewhere in the market (unlike the national LMP model, as discussed in the next chapter).

This means that the compensation paid out and the compensation contributions levied would need to match. However, in general this is unlikely to automatically be the case, and so some scaling would be required.

It is proposed in the model that the larger amount of compensation payable or compensation contributions is scaled back. If the compensation funding available exceeded the compensation requirement, the contributions levied on non-firm generators would be scaled back.[191] Conversely, if the compensation payable exceeded the funding available, the compensation paid to constrained off firm generators would be scaled back. As a result, firm access rights in the regional OFA model would not be fully firm.

190 Appendix A provides a worked example of this model.

191 This would mean, in effect, that non-firm generators were being settled at a price in excess of LMP.

As an alternative, fully firm rights could be provided by increasing the contributions paid by non-firm generators (assuming the self-funding nature of the model is to be maintained). However, this could lead to such generators being settled at a price that is less than their offer price. This approach would introduce significant risk for such generators and is likely to result in less efficient outcomes as non-firm generators may game their offer price in order to avoid being dispatched.

Given that the model provides access within each region, matching of revenue amounts would be undertaken on a region by region basis. However, further consideration would need to be given as to whether matching would be undertaken for each trading interval, or whether any surpluses or deficits could be netted off over longer periods.

9.2.4 Charging

Under the regional OFA model, non-firm generators would face a locational signal through their exposure to the intra-regional cost of congestion since they may be required to fund compensation payments. Alternatively, generators could choose to hedge this exposure by paying a transmission charge in return for firm access rights.[192] These access rights would be underpinned by a defined level of physical network capacity. The transmission charge would vary by location to reflect the costs associated with the provision of this network capacity.

Section 9.2.2 identified two approaches to allocating, and charging for, firm access rights. These are explored in more detail below.

Deep connection charging

A deep connection charging approach might represent a relatively simple way to implement the regional OFA model. If a new (or existing non-firm) generator opted to purchase firm access rights, the TNSP would use the generation planning standard to identify the incremental transmission investment required to provide these rights. The generator would be charged for the costs of this investment directly. This could potentially be provided by the TNSP as a negotiated transmission service.[193]

However, under a deep connection charging approach, there would then be no flexibility (or incentive) for a firm generator to opt to become non-firm. Additionally, the Commission holds a number of concerns regarding the use of deep connection charging more generally. These are discussed in greater detail in appendix D, but, in summary, they relate to:

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192 To be precise, all generators with an element of firm capacity would pay a transmission charge based on the level of that firm capacity.

193 Negotiated transmission services are explained in chapter 12. Briefly, the assets that provide negotiated transmission services are not included in a TNSP's Regulatory Asset Base (RAB) and the charges are negotiated with the TNSP under a framework set out in Chapters 5 and 6A of the Rules. However, as discussed in chapter 13, generators have raised a number of concerns regarding the efficacy of negotiating with monopoly TNSPs.

- potential discrimination between incumbents and new entrants. While a new entrant must face a transmission charge, for incumbents this cost is sunk (or, if rights have been grandfathered, may never have been paid). This may lead to inefficient network usage;

- the "lumpiness" of transmission assets. Under deep connection charging, new entrants are required to pay for the whole cost of new transmission assets, even if they will not make full use of them. This can often be the case as such assets are usually large and are supplied in discrete sizes or "lumps". This can effectively result in a new entrant being charged for capacity that they do not use. This might also then mean that a subsequent entrant would not be required to fund any additional investment, as it can make use of the over-provision of network capacity to the first entrant. This can lead to "first mover disadvantages", where generator proponents delay their entry in to avoid incurring the costs of additional transmission capacity that will benefit all entrants. Again, this is likely to lead to an inefficient level of competition in the wholesale market; and

- the difficulty in accurately calculating deep connection charges. Establishing a charge that reflects the impact a generator will have on network flows requires a number of assumptions, such as defining a counterfactual that does not include the generator and predicting network flows that are dependent on generator bidding behaviour. This is likely to be a contentious and difficult process.

Generator TUoS

Under a generator TUoS approach, firm generators would not directly pay for the actual, additional new assets required to provide them with firm access. Rather, all generators with firm access would pay an ongoing charge reflective of the costs of providing this service. This would require the development of a methodology to allow for the calculation of such TUoS prices.

For example, the TUoS charge would need to reflect the extent to which costs varied by location. Consideration would be required as to whether these locational differences would be best achieved by nodal or zonal charging (and, if so, how zones were defined). Appendix C provides further discussion on the way in which a generator TUoS charge might be constructed.

Incumbents would pay the same charges that new entrants would be faced with, meaning that they would have no cost advantage. Since charges would be levied on a per unit basis (i.e. $/MW), generators would only pay for the amount of the capacity that they have rights for. Therefore there would be no issues with first mover disadvantages.

As discussed in section 8.2.4, the Commission notes the concerns that have previously been raised by some stakeholders regarding the potential volatility of generator TUoS charges, and that we would likely undertake further analysis to assess the likely stability of such charges, should they be recommended.

Generator firm access would be provided by TNSPs as a prescribed transmission service,[194] reflecting the fact that the service was provided by the totality of the network, not just the incremental assets constructed. However, consideration would need to be given to the proportion of the TNSP's allowed revenue for prescribed services that should be recovered from generators through TUoS charges.[195]

It might also be necessary to adjust the TNSP's allowed revenue within a regulatory control period in order to ensure that it had sufficient revenue to fund transmission investment associated with releasing firm access rights. As discussed in the previous chapter, this could potentially be achieved through use of the existing contingent projects mechanism or through the introduction of locationally varying unit cost allowances (UCAs). Given that it might not be clear whether new generators were likely to be firm or non-firm, there would be additional uncertainty under the regional OFA model which might suggest that a UCA approach was more appropriate.

The use of TUoS charging would add a greater degree of flexibility, in that generators with firm access rights could subsequently opt to become non-firm, and would no longer be liable for TUoS charges. However, this would tend to increase the complexity of the model, as generators would be required to "book" rights for defined periods, rather than making a one-off decision under a deep connection charging methodology. In particular, the need to avoid asset stranding might lead to a minimum booking period being required for firm access rights where additional transmission investment was necessary.

Note that new generators would continue to pay a shallow connection charge, as they do under the status quo, under either the deep connection or the generator TUoS charging arrangements. Similarly, new generators would pay the shallow connection charge whether they were firm or non-firm.

9.2.5 TNSP planning, investment and operation

The main change to planning arrangements under the regional OFA model would be the introduction of a generation network planning standard. TNSPs would be required to plan their networks in accordance with this new standard, in conjunction with existing reliability standards for load. The standard would be similar, in principle, to the proposed generator reliability standard that is discussed in some detail in the previous chapter.

The firm access planning standard would require that, under defined transmission operating conditions and assuming away all non-firm generation, all firm generators would be able to access the RRN. As described in chapter 8, a TNSP would undertake planning studies to identify potential future breaches of its planning standards, and

194 Prescribed transmission services are explained in chapter 12. Briefly, the assets that are used to provide prescribed transmission services are included in the TNSP's RAB and the revenues that a TNSP can recover for those services are regulated by the AER.

195 Given that not all generators would be paying TUoS charges, it would not necessarily be as logical for generation to pay 50 per cent of TUoS revenue as under package 3.

would explore potential investment projects to remedy any breaches. Such studies would be undertaken when a generator requested the release of firm access rights, in order to assess what, if any, transmission investment was required in order to facilitate this.

The Regulatory Investment Test for Transmission (RIT-T) would be adapted to reflect the new planning standards and, intra-regionally, would become focused on ensuring that load and firm access planning standards were maintained at least cost. However, inter-regional transmission investment would continue to be made on the basis of net market benefits.

A firm access operating standard associated with the planning standard would also be introduced. This would require that the network capacity provided through the investment process was made available during "normal operating conditions" sufficient to allow firm generators access to the RRN (assuming the absence of non-firm generation). Finally, financial incentives would be placed on TNSPs to maintain the planning and operating standards.[196]

9.2.6 Institutions

Few changes to institutional arrangements would be required to implement the regional OFA model. Investment necessary to underpin access rights would be undertaken by TNSPs, and AEMO would adjust settlement cash flows to give effect to the collection and payment of compensation.

The main issue would be establishing the governance arrangements for the generation-side planning standard. This was discussed in the previous chapter.

Similarly, there would be some governance issues to be considered with regards to the introduction of generator transmission charges. If these were deep connection charges or intra-regional TUoS charges, it is likely that these charges would be levied by TNSPs using existing governance arrangements. However, any requirement for inter-regional generator TUoS charges, or generator TUoS charges levied on a national basis, might require the development of national methodologies and the use of a central agency to collect and distribute funds.

9.3 Advantages and disadvantages of a regional optional firm access model

9.3.1 Impact on transmission investment and operation

A key advantage of the regional OFA model is that generators would decide whether or not the provision of firm access was economic. They would make the trade-off between the benefits of having firm access and the costs associated with this. These decisions would reveal the value that generators placed on firm access.

196 See section 8.2.5 for further discussion on how financial incentives may be applied to TNSPs.

Under the current planning approach using the RIT-T, it is TNSPs who assess the economics of network augmentations by estimating the expected benefits and comparing these to the anticipated costs. However, this evaluation does not consider the benefits to generators associated with firm access. Further, it would be difficult for TNSPs to estimate this value.

In contrast, under the regional OFA model, the TNSP's role (intra-regionally) would only be to assess what network expansion was required to provide the access requested and how to achieve this at least cost. Decisions regarding whether firm access is economic and, if so, how this should be provided would therefore be made by the most informed party in each case.

There would also be benefits from the package in terms of the increased transparency associated with transmission planning. Under current frameworks, and despite a number of checks and balances designed to encourage TNSPs to undertake RIT-T assessments (such as the NTP and the LRPP), it is very difficult to know whether there are unrealised benefits associated with potential transmission projects that have not been assessed.

Under the regional OFA model, there would be a much greater degree of certainty as to when augmentations should be made, as these decisions would be made by generators. Any potential breaches of the planning standard would also be more transparent. For example, a scaling back of compensation during normal operating conditions would signal a possible breach of the firm access standard and could be investigated further. Generators who were denied fully firm financial access as a result of the scaling back would be empowered and motivated to promote such investigations.

9.3.2 Impact on generator investment decisions

Locational decisions

Generators purchasing firm access rights would pay a transmission charge giving a signal of the investment costs associated with the provision of the transmission capacity. Generators would make the trade-off between the costs associated with different locations.

Generators without firm access would also be exposed to locational signals, since they would be liable for compensation. The compensation contribution would reflect the costs of congestion associated with each node. Again, generators would make trade-offs between these anticipated costs, and between the costs of being non-firm and firm.

Investment certainty

Generators would have the option of obtaining a product giving financial certainty of dispatch during normal operating conditions. Purchasing firm access would provide a generator with the confidence to issue forward contracts, knowing that it would have the revenue stream to back them, even during periods of congestion. This would provide more revenue stability for generators and would be likely to commensurately reduce their cost of capital.

This option would extend to allowing for partially firm access, such that a generator could opt for an access level greater than zero but less than the power station capacity. This might particularly appeal to intermittent generators, which might only be able to generate towards the upper end of their capacity very infrequently.

However, firm access rights would not be 100 per cent firm, in that financial compensation would be likely to be scaled back outside of normal operating conditions. This would leave firm generators with some residual level of risk.

9.3.3 Impact on generator operational decisions

The regional OFA model would not introduce any changes to the dispatch process. However, the introduction of a compensation and contribution regime would change the incentives on generator bidding during periods of congestion, and so would address the existing problems of disorderly bidding.

Currently, generators will reduce their offer prices (potentially down to -$1,000/MWh) to avoid being constrained off by intra-regional congestion. Under the regional OFA model, a firm generator would be compensated for being constrained off and so would have no reason to disorderly bid to ensure dispatch.

Similarly, non-firm generators would effectively be settled at LMP and, given that their offers would potentially determine the LMP, they would have no incentive to submit offers below costs.

However, the regional OFA model might create new incentives for the gaming of offers:

- by firm generators, in order to become eligible for compensation. Firm generators that were out of merit might lower their offers such that they were still not dispatched but became eligible to receive compensation. However, they would risk being dispatched and settled at less than cost; and
- by non-firm generators, in order to minimise their contributions. Non-firm generators might increase their offers with the aim of increasing the LMP and therefore reducing compensation contributions payable. Again, there would be risk involved - in this case, of not being dispatched.

Further consideration would need to be given to the likely materiality of these potential behaviours, and whether any measures were required to mitigate them. This would to require modelling to test the likely extent of gaming.

9.3.4 Impact on co-optimising generation and transmission decisions

The regional OFA model moves away from a regulated planning process undertaken by TNSPs and instead introduces market signals that influence the planning process. In doing so this approach allocates a greater degree of the decision making process to generators, allowing them to appropriately balance the cost of additional transmission with their investment decisions. This approach therefore provides for a more market-based approach to co-optimising generation and transmission decisions.

9.3.5 Feasibility and ease of implementation

Although the regional OFA model would not require significant institutional changes and is based on concepts contemplated under the existing Rules, there would still be a number of significant implementation issues to be considered. The challenges discussed below include:

- development of the firm access planning and operating standards;
- establishing a methodology for calculating transmission charges; and
- the interaction with demand-side reliability standards.

Development of firm access planning and operating standards

Many of the challenges involved in developing a firm access planning standard would be the same as previously discussed in respect of a generator reliability standard in chapter 8. However, a particular issue would be defining the "normal operating conditions", on which the firmness of firm access is predicated. The definition would have to be practical, unambiguous and economic. If the firmness definition was too stringent, transmission charges would consequently be higher and contracted access might become uneconomic for many generators. On the other hand, if the definition was too loose, then dispatch uncertainty would remain even for firm generators.

Establishing a methodology for calculating transmission charges

As discussed, further consideration would need to be given to the most appropriate form of transmission charge, and a detailed methodology then developed. The interactions between charging, economic regulation and the processes for assigning rights would also need to be considered.

Appendix C discusses and assesses potential methodologies that could be used as the basis of generator TUoS charges. Appendix D discusses deep connection charging, and evaluates this concept against the same assessment criteria used in Appendix C.

Interaction with demand-side reliability standards

As with package 3, the general interaction between the generation standard and the existing load standards (including the extent to which these vary across jurisdictions) would need to be given further consideration.

Under the regional OFA model there would be a further issue. If there was insufficient firm generation capacity to meet peak demand, then a TNSP would need to plan to provide peak access to some non-firm generation in order that demand-side reliability standards could be met. This might lead to some non-firm generators getting firm or firmer access for free. However, this is an issue which already exists - currently, all generator access is received free, as a by-product of demand-side reliability standards. The problem should be substantially mitigated under the regional OFA model, although not necessarily removed.

Table 9.1 Summary of advantages and disadvantages of package 4

Advantages	Disadvantages
Provides financially firm access under normal operating conditions	Only one "firmness" standard, set by defined operating conditions
Firm access leads to greater certainty for generators, improving contract liquidity	Complex to determine cost-reflective transmission charges
Generators make economic decisions regarding the value of "firmness" and, consequently, transmission investment	Risk of generators gaming offers to maximise compensation (and minimise contributions)
Option of firm access only applying to a portion of generation capacity	
Addresses disorderly bidding issues	

10 Package 5: National locational marginal pricing

Box 10.1: Summary of this chapter

Access	Generators are able to purchase fully firm access to a national hub; non-firm generators exposed to congestion cost
Charging	Rights purchased at auction, no charge for non-firm generators
Planning	Single (NEM-wide) TNSP plans to new standard for firm generators, investment funded by auction proceeds. Additional incentives required on TNSP

This chapter sets out the final proposed policy package, which represents the most significant departure from the existing NEM arrangements. Generators would, by default, be settled using their Locational Marginal Price (LMP), but would have the ability to obtain fully firm financial transmission rights through auction-based allocation mechanisms. These rights would provide firm and basis risk free access to a single (notional) national trading hub. This hub would be given effect through use of a single "system marginal price", and is intended to promote a deeper and more liquid market in energy trading than arises under the existing regional approach. Load would be settled using this single price, not using LMP.

While this model could be implemented with existing TNSPs, in terms of consistency with the model's underlying principles it would be more appropriate to introduce a single, NEM-wide TNSP. Because generator access is provided across the whole network, a single TNSP would allow for these rights to be provided most efficiently, and for incentives to be put in place to drive this. A single TNSP would also have other benefits, including eliminating the need to coordinate planning between TNSPs and promoting consistency of approach across the NEM in matters such as the connection of transmission users.

A fundamental change to the existing NEM would clearly come with significant costs. These costs would include requirements for changed and additional systems, and the introduction of complex methodologies, particularly in relation to the auctioning of rights. In particular, it is not clear whether the option of a single TNSP is feasible. Introducing the model with multiple TNSPs, while possible, would further increase the complexity of the required regulatory arrangements, if efficient outcomes were to be promoted.

10.1 Introduction

This chapter sets out the final suggested model for introducing firm access rights. It also provides the "firmest" level of access to generators. While this model represents a fundamental change from the existing NEM arrangements, it is not without precedent. The model of firm financial access rights has been adapted to the Australian market from existing approaches employed in the US and UK. Before introducing the proposed model, this chapter therefore briefly sets out the way in which such rights operate in some US and British energy markets.

This chapter is structured as follows:

- the remainder of this section provides a summary of relevant aspects of certain US and British energy markets;
- section 10.2 describes the key features of the national LMP model; and
- section 10.3 discusses some of the potential efficiency benefits and costs associated with a model of national locational marginal pricing.

Appendix A provides a numerical example of this model.

10.1.1 International approaches to providing firm access

Access in US electricity markets

Many US electricity markets make use of locational marginal pricing combined with Financial Transmission Rights (FTRs). This approach was first introduced into PJM[197] in 1998 and has gradually been introduced in other US markets (such as New York, New England, California and Texas).

LMPs are designed to reflect the short run marginal costs of delivering electricity to customers at a specific location and at a specific point in time. As such, LMPs reflect the costs of generating electricity, and of network congestion and losses, while incorporating the complexities of energy flows in electricity networks. The aim of LMPs (because they reflect the short run marginal costs of the network) is to send price signals to market participants that will encourage efficient consumption and generation decisions.

However, LMP markets create price volatility between every individual network location, as prices will differ between each network location. This creates risks for market participants whose supply contracts with customers are struck on the basis of a price that does not vary by location. FTRs therefore allow participants to hedge locational risks between two specific nodes, or between the price at a node and the price at which load is settled (which might be an averaged price, rather than that applying at a specific node). Trading hubs are often formed to help manage volatility and to promote trading liquidity (for example, there are 20 trading hubs in PJM). FTRs also effectively provide firm access in that the FTR holder will receive the associated revenue stream irrespective of any dispatch consideration.

In most cases, FTRs are allocated through auctions. Auctions are usually performed centrally by the relevant Independent System Operator (ISO) or Regional Trading

197 The PJM market has evolved from an initial Pennsylvania, New Jersey and Maryland base to encompass 13 US states as well as the District of Columbia.

Organisation and occur a number of times a year (monthly, quarterly or every six months). Each auction contains multiple rounds (a proportion of the overall volume of FTRs is released each round) with FTRs of different durations being available. For example, most US markets provide for FTRs with monthly, quarterly, yearly and 3 yearly durations. Recent Federal Energy Regulatory Commission legislation requires that FTRs are made available with durations of at least 10 years.[198]

An important property of FTRs is that they are self-financing. This will occur provided the FTRs released are simultaneously feasible – that is, if the power flows represented by the FTRs can be simultaneously dispatched without exceeding network limits. If this holds, then the revenue paid to FTR holders will not exceed the total settlement residues arising from the differences between the prices at which demand and generation are settled.[199] In simple terms, this requires the network to have a capacity at least as great as that assumed in the definition of the set of FTRs. Due to changing network conditions, and the many variables which can affect it, determining a feasible set of FTRs is not straightforward, which means that FTRs will often be defined relatively conservatively by the ISO (i.e. less than the full capacity of the network is allocated). Further, FTRs tend not to be fully firm, but are usually scaled to reflect any under- or over-allocation of FTRs relative to the settlement residues available.

The national LMP model set out here draws on the approach of settling generators using locational marginal pricing and auctioning access rights that provide a hedge against the resulting basis risk. However, in the national LMP model, load is settled at a single national price and not using the relevant LMP.

Access in British electricity and gas markets

As a net pool market, the British electricity market does not employ LMP. Under this net pool approach, generators are self-dispatched, which is to say that they have a right to generate at their desired level. Generators also submit bids and offers (to decrease and increase their output, respectively) into a "Balancing Mechanism". This allows the System Operator (SO) to ensure that the system is balanced and to manage congestion. The acceptance of bids in the Balancing Mechanism by the SO provides compensation to generators where there is a need to constrain plant off the system.

The market therefore provides all generators with fully firm financial access. In order to participate in the market, generators are required to purchase an access right through payment of a locational Transmission Use of System (TUoS) charge. New access rights apply indefinitely, and are backed by the construction of additional physical network capacity (if required under the relevant planning standard).[200] Generators have the ability to terminate their rights at the end of each financial year.

198 FERC Order 681.

199 The concept of settlement residues was introduced in chapter 7. Further, the use of settlement residues to provide financially firm access has already been discussed in chapter 9.

200 Recently, the requirement for any necessary transmission reinforcements to be completed before the generator is able to participate in the market has been relaxed. This will tend to increase the costs of congestion.

This gives considerable certainty for generators, who are effectively able to renew their access each year by continuing to pay the associated TUoS charge,[201] but little certainty for transmission planners.

The access regime in the British gas market is considerably more sophisticated than in the electricity market. Gas "shippers" are able to obtain firm access to a notional "National Balancing Point", which the wholesale price of gas on a spot and contract basis is set by reference to. These entry rights are allocated through a system of long and short term auctions, with shippers able to purchase rights up to 16 years ahead. Unlike the access rights applying in the electricity market, the rights are for a defined period (a quarter, a month or a day). Auctioning the rights ensures that they are allocated to the shippers that value them most highly. Additionally, the long term time-limited nature of these rights gives certainty to both shippers and network planners. However, purchasing rights over such a long period of time represents a significant commitment on the part of shippers, and the risk of shippers defaulting on such payments needs to be managed.

Where congestion is present on the gas network, the SO is required to "buy-back" capacity, effectively providing a constrained off payment to those with firm rights. Shippers may also purchase interruptible capacity, but this attracts no compensation in the event of congestion.

The national LMP model set out here draws on these approaches to providing access rights, particularly from the British gas market.

10.2 Key features of the national LMP model

10.2.1 Product definition

The access rights available to generators under this model would provide fully firm access to a notional national trading hub. The model would remove the concept of regions from the market arrangements.

All load would be settled at a single system marginal price (SMP), which would be calculated on an unconstrained basis (i.e. it would be the national marginal price assuming that all plant offering into the market could be dispatched).[202]

An access right would essentially provide a generator with two benefits:

- a hedge against basis risk; and

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201 There is uncertainty as to the level of TUoS charge that will be levied each year but, as previously noted, these charges have generally been quite stable in the British context.

202 Note that alternative approaches for settling load could be adopted, for instance a weighted average price. It might also be possible to use prices calculated at a more granular level, for instance state-based averages. However, the national SMP has been used here to best illustrate the national basis of the model and to most simply provide a national trading hub.

- compensation for being constrained off or on.

A hedge against basis risk

All generators would be remunerated for their output at the LMP applying at their local node. However, purchasing an access right would provide an additional revenue stream equal to the SMP less the LMP, when the SMP was greater than the LMP. This opportunity for generators to effectively be settled at SMP can be thought of as providing access to a national trading hub where all energy would be traded on the same basis. It is one premise of this model that this arrangement would encourage greater liquidity in energy trading than is currently the case.[203]

Compensation for being constrained off or on

The financial payments would also effectively provide firm financial access to generators, as a payment would be received even if the generator was constrained off. This would compensate the generator for the opportunity costs associated with not generating. Assuming the LMP was a satisfactory proxy for a generator's SRMC, the generator would be indifferent to running if it received the difference between the LMP and the SMP in any event.[204] However, receipt of compensation would be dependent on the generator being in merit. That is to say that a generator would not receive a payment if it would not have been dispatched in an unconstrained system.

Under the national LMP model, and unlike the regional OFA model (package 4), access rights would be fully firm. Generators holding rights would receive the full amount of compensation for being constrained off even outside of what would be considered to be "normal operating conditions".[205]

The model would also ensure that constrained on generation was appropriately compensated (replacing the current arrangements[206] for compensation under direction). This means that non-firm generators would always receive the LMP, even if it exceeded the SMP. However, consideration would need to be given as to whether firm generators would continue to receive the SMP or whether they should receive the LMP in such circumstances (i.e. whether firm generators would be liable for negative compensation if the LMP exceeded the SMP).

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203 This might represent a particularly beneficial change for regions with a low level of trading liquidity, such as Tasmania or South Australia.

204 As discussed in chapter 9, since a constrained off generator is by definition not dispatched, the generator's offer price must be at least as high or higher than the LMP. This means that compensation based on the difference between the LMP and the SMP would be at least enough to compensate a constrained off generator for its lost profit.

205 Some force majeure type provisions might be needed for very extreme situations.

206 NER clause 3.15.7.

10.2.2 Assigning rights

The national LMP model would give generators the option of being firm or non-firm and, further, would allow them to choose their level of firm access (i.e. they could choose to have firm access for all or just part of their capacity).

A key feature of the model is that rights would primarily be allocated through a system of auctions. These auctions would be for an amount of rights defined by a "baseline" level of capacity, which would be the simultaneously feasible amount of rights available given the existing network and given assumptions consistent with those used in the planning process. Additional mechanisms would be provided to release "incremental" rights over and above the baseline capacity.

The discussion below assumes that the counter-party to the rights is a single national TNSP although, as noted later, it might be possible to implement the model with multiple TNSPs.

Allocation of baseline capacity

Access rights available under the baseline capacity would be auctioned in a mix of long term products (potentially quarterly or annual blocks of capacity released over a 10-20 year period) and shorter term options (monthly, daily or even half-hourly products). Clearly, careful consideration would need to be given to the design and frequency of the auctions, as well as to the periodicity of the products.

The TNSP would be obliged to release all baseline capacity, with the revenues allowed under the TNSP's regulated revenue cap funding the provision of this capacity.[207] Unlike existing arrangements, generators would contribute to the TNSP's revenue allowance through the proceeds received from the auctions. This is discussed further in section 10.2.4, below.

Release of short term incremental capacity

The TNSP could release additional firm access rights on a short term basis over and above the baseline capacity if feasible given likely operating conditions (i.e. if the TNSP considered that the conditions would be more benign than those assumed in the planning assessment). This would allow non-firm generators to secure firm capacity when it was available and it was valued by them.[208]

Such capacity could be released through the same short term auctions used for baseline capacity. However, in order to provide an incentive for the TNSP to release this additional capacity, it would need to be allowed to retain some or all of the extra revenue received from the auction (i.e. this would be separate from the amounts

207 The baseline could not be determined by the TNSP without independent oversight as it would have an incentive to minimise the baseline amount.

208 For example, a wind farm which only had firm rights for part of its generation capacity might wish to obtain additional rights if it expected meteorological conditions to allow it to generate closer to its generation capacity than would normally be the case.

allowed under the revenue cap). The TNSP would also be exposed to any additional costs that might arise if the incremental capacity was not available in real time and generators with firm access rights were constrained off. This would encourage the TNSP to make efficient trade-offs between the benefits and costs associated with releasing additional capacity.

Release of long term incremental capacity

A mechanism would also be required to facilitate the release of incremental access rights on a long term basis. This would most likely apply to newly connecting generators in a situation when baseline rights had been exhausted for the majority of the period in which the generator desired firm access.

The additional rights would be provided by the TNSP investing to increase the capacity of the network. While the generator might not be required to fund the investment in full, it would be required to demonstrate a strong commitment to avoid the risk of asset stranding (which would occur if the TNSP invested in new assets, and these were not subsequently used).[209] This might be achieved by requiring the generator to book rights at a defined reserve price for a defined minimum period (perhaps 10 years).[210]

Once the generator had demonstrated this commitment, the TNSP would undertake the investment required to provide the additional network capacity. Within the existing regulatory control period the TNSP would be provided with additional revenue to cover these costs through use of a locationally specified Unit Cost Allowance (UCA).[211] The new assets would then be rolled into the TNSP's Regulatory Asset Base (RAB) at the subsequent revenue determination, and the additional network capacity would become part of the defined baseline capacity.

10.2.3 Dispatch, congestion and compensation

Under the national LMP model, dispatch would be undertaken as now, with all generation - firm and non-firm - dispatched economically based on offer prices. There would be no distinction between firm and non-firm generation in the dispatch process.

As in the regional OFA model, the network would be planned and operated only to accommodate firm generation, and the inclusion of some non-firm generation in dispatch might lead to firm generation being constrained. Again, as in that model, the access rights provided would not guarantee *physical* access but rather *financial* access, in that compensation is paid for being constrained off.

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209 If the generator was not required to fund the investment in full, this would imply that some level of stranding risk would be borne by consumers. Further consideration would need to be given to the exact level of risk sharing that would be appropriate.

210 Generators would not be required to make such commitments when purchasing baseline capacity, as the assets providing this would already be sunk.

211 The concept of locationally specified UCAs was introduced in chapter 8.

This financial compensation would be largely funded from settlement residues. This means, in effect, that where a generator with firm access rights was constrained off by a non-firm generator, the settlement residue (the amount by which the SMP exceeds the LMP) would be paid to the generator with the access rights.

However, a key difference between this model and the regional OFA model is that compensation would be fully firm. This means that even if the pool of settlement residues was insufficient to cover the required constrained off payments (which might result in the event of network outages, for instance), these payments would still be made in full. This requires the identification of an additional source of funding, as discussed below.

The national LMP model would not introduce a specific congestion management mechanism. However, the exposure of all generators to their LMP would remove the existing problems of disorderly bidding for much the same reasons as packages 2 and 4 (in that generators would no longer be competing to secure the settlement residues).

The exposure of generators to LMP would extend to those with firm access rights. The access payment (SMP less LMP) would be linked to the volume that the generator would have been dispatched for on an unconstrained basis, not to actual output. Therefore, even firm generators would be incentivised to bid at a price that reflected the value of their energy, as the price at which constrained generation would be settled would be directly reflective of the relevant generators' offers.

10.2.4 Charging

Under this model, locational signals would be provided to all generators as a result of the use of LMP for generation. Generators with non-firm access would be directly exposed to the LMP. Generators purchasing firm access rights at auction would see a locational signal through the payment made at auction to hedge the risk arising from the LMP. Generators purchasing firm access rights released on a long term incremental basis would be presented with a signal linked to the costs associated with the provision of the additional transmission capacity.

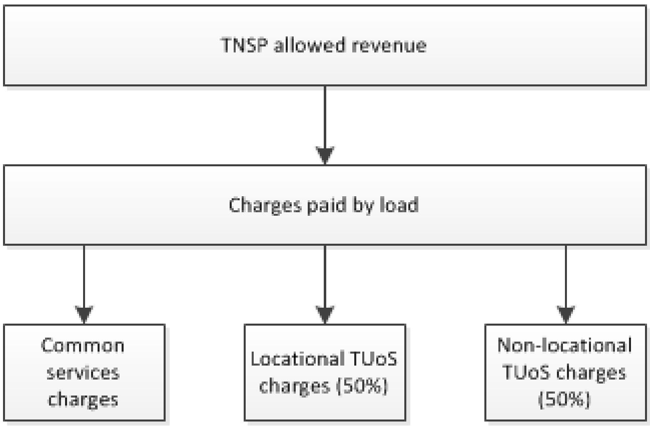
In effect, therefore, non-firm generators would see a short term locational signal, and generators with firm access would be exposed to longer term signals.

Load would not be exposed to a short term locational signal through energy pricing, as all load across the market would be settled at SMP. However, load would see a long term signal through TUoS charging, similar to the current approach.

The diagram below summarises the current transmission charges paid by load. Note that, for simplicity, connection charges are ignored, and it is assumed that 50 per cent of TUoS is recovered from load on a locational basis.[212]

212 This may not be the case in jurisdictions using the modified Cost Reflective Network Pricing methodology.

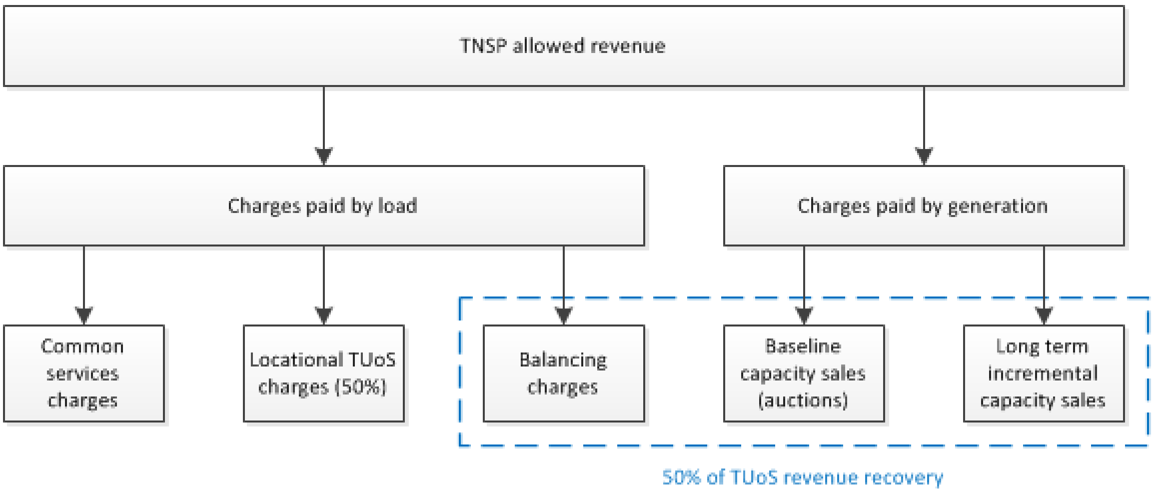
Figure 10.1 Current transmission charging arrangements



Under the national LMP model there would be no regions in the NEM, and so there would be a single transmission pricing methodology applied by the TNSP on a national basis. A percentage of the revenue that it was possible to apportion on a locational basis would continue to be recovered from load through locational TUoS charges (again, for simplicity, this is assumed to be 50 per cent). This would provide a nationally consistent locational signal for load across the market.

However, unlike the current arrangements, generators would fund part of the TNSP's allowed revenue. Therefore, as shown in the diagram below, a proportion of TUoS revenue would be assumed to be recovered through the sale of baseline and long term incremental access rights. As discussed in chapter 8, determining an appropriate proportion is arguably a somewhat subjective matter, to which further consideration would need to be given. However, in the interests of simplicity, the diagram assumes that 50 per cent would be appropriate. (Connection charges are again also ignored.)

Figure 10.2 Transmission charging under the national LMP model



Much of the TUoS revenue to be recovered from generators would be done so through auctions, and the outcome of these would be uncertain. To ensure that actual revenue recovery matched the allowed revenue, as shown in the diagram, a TUoS balancing charge would be required (which could be either positive or negative). This could be levied on generators, load or both, although the above diagram assumes that this would be levied solely on load. This charge would ensure that total TUoS revenue recovered matched the TNSP's allowed TUoS revenue.

Funding for access payments

In addition to the transmission charges set out above, there would be a requirement for an uplift charge. Given that the residues available in settlement would not always match the compensation payments required to provide fully firm access, the uplift charge would provide a mechanism for the recovery of any deficits (and the distribution of any surpluses, although this would be less likely). The concept of the uplift charge is very similar to the balancing charge discussed above, but they would play two distinct roles: the former would reconcile settlement residues against the compensation funding required, whereas the latter would balance transmission charges recovered from generators against 50 per cent of the required TUoS revenue recovery.

The uplift charge would be levied on load, although the TNSP would be exposed to a portion of this through an incentive scheme. Proceeds from the sale of short term incremental access rights would also go to meeting this funding requirement. These arrangements are discussed in more detail below.

10.2.5 TNSP planning, investment and operation

As noted, one of the main features of this model is the national trading hub, which is intended to promote a deeper and more liquid contract market. Therefore, in order to for access rights to this hub to be provided most efficiently - and in order to be able to put incentives in place to drive this - it would be preferable to have a single entity with full control of all planning and operational responsibilities for the whole system. This is why the model has, so far, been presented using a single TNSP. However, the establishment of a single TNSP - and the absence of regions - might also have other benefits, for instance removing any perceived biases between intra- and inter-regional planning.

The following subsections consider some of the other features of the national LMP model with regard to TNSP planning, investment and operation.

Planning standards

Under the national LMP model, there would be a single, national set of integrated planning standards for generation and load. Given the absence of regions, there would no longer be any differentiation between intra- and inter-regional investments, or between regions.

Of particular importance for this model would be the generation element of the standards that would, in effect, determine the network investments required to provide additional firm capacity. The most appropriate form of such a standard has already been discussed in chapter 8, together with some considerations relating to the governance arrangements that would apply.

The planning standard would operate in a very similar manner to that outlined in package 4, although access for firm generators would be on a national basis, rather than regionally under package 4. The planning standard would be used to define the baseline capacity in that it be used to understand how much firm generation could be accommodated without breaching the standard. Similarly, planning studies would be undertaken when a generator requested the release of long term incremental access rights in order to assess what transmission investment was required in order to facilitate this.

Regulatory Investment Test for Transmission, National Transmission Network Development Plan and Last Resort Planning Power

The Regulatory Investment Test for Transmission (RIT-T) would be adapted to reflect the new planning standard, being used to identify network investments consistent with maintaining the load and firm generation access planning standards at least cost.

There would be no role for the RIT-T in identifying market benefit investments. The decision as to whether or not an upgrade was warranted would be taken by generators, with the planning standard used to determine the resulting augmentations based on economic considerations. There would be no need to attempt to identify projects that delivered economic benefits over and above this. Additionally, since there would be no regions, there would be no need to test potential inter-regional upgrades.

Given that there would be no need to ensure that RIT-T assessments were undertaken on projects associated with inter-regional flows, there would be no need for the AEMC to hold a Last Resort Planning Power. Similarly, the existing processes for developing a National Transmission Network Development Plan and multiple Annual Planning Reports would be reduced to a single, NEM-wide transmission plan developed by the TNSP.

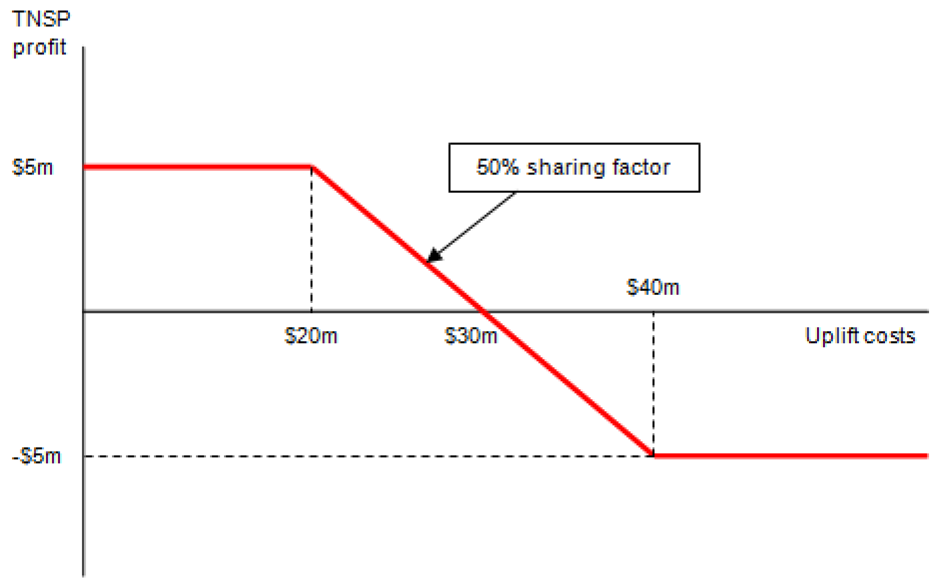
Incentives to provide firm access

As previously noted, access rights under this model would be fully firm, and it is proposed that any additional revenue required to fund this would be recovered from load through an uplift charge.

However, it would be important to place incentives on the TNSP to minimise the amount of the uplift charge. The TNSP would be able to influence this, for instance by ensuring that network availability was maximised at the times when it is valued most.

The incentive would be provided by allowing the TNSP to retain a share of any savings made in relation to a target level of uplift costs and to be exposed to a share of any overrun of the target. This is illustrated in the below example.

Figure 10.3 Example incentive scheme



The example incentive scheme above has a target uplift cost of $30m, a symmetric 50% sharing factor (i.e. both above and below the target cost), a $5m cap on profits and a $5m collar on losses. That is to say that the TNSP would retain 50% of any savings below the $30m uplift cost target to a maximum of $5m and would be exposed to 50% of any overrun beyond the target, again to a maximum of $5m. Below a cost of $20m, consumers would gain 100% of any further savings, but would be exposed to 100% of any losses above $40m.

The target and the parameters for the incentives would be defined ex-ante on a periodic basis by the AER. Initially, it is probable that these would need to be reviewed and reset on a more frequent basis than full revenue resets are undertaken - most likely annually.

It should also be noted that the costs and benefits resulting from the sales of short term incremental access rights would need to be reflected in the incentive scheme. One approach might to include revenues from such sales directly in the mechanism, using these to offset costs.

10.2.6 Institutions

As already indicated, the major change to institutional arrangements required to implement the model presented above would be the creation of single, NEM-wide TNSP.

One approach to establishing a single TNSP could be to merge the existing TNSPs, with the owners of each these entities becoming shareholders in the new merged organisation. However, as discussed in section 10.3.5, there would likely be a number of significant challenges involved in the implementation of such an initiative.

It is not inconceivable that the model could be introduced without making this change. However, doing so would make the efficient provision of national generator access rights - and the implementation of associated incentive schemes - significantly more complex. It is likely that very involved contractual arrangements would be required between TNSPs to coordinate the investments required to release additional access rights and to allocate the costs and benefits associated with the incentives.

Additional risk

A key element of this model is that the TNSP would be exposed to a greater level of risk as compared to any of the other models being considered in this review, including existing arrangements. This would be as a result of the incentive put in place to minimise the costs resulting from the provision of fully firm access, as well as the potentially associated arrangements for the release of short term incremental capacity.

AEMO

In the model as presented with a single TNSP, AEMO's role in regards to electricity would become focused on market operation. Given the national coverage of the TNSP, there would be no need for a National Transmission Planner or any requirement for AEMO to have a network planning and procurement role in Victoria.

If the model was implemented without the establishment of a single national TNSP, consideration would need to be given as to the appropriateness of AEMO acting as planner and procurer in Victoria given the inconsistency of these arrangements with the use of financial incentives. This matter is discussed further in chapter 11.

10.3 Advantages and disadvantages of the national LMP model

In that this model is consciously less constrained by existing arrangements and other practical considerations, it has many theoretical efficiency advantages over the other models that we are considering. Equally, however, this means that there would be significant implementation costs, and some ongoing level of additional cost and complexity, involved in adopting the model. In particular, it is not clear if the establishment of a single TNSP is feasible.

10.3.1 Impact on transmission investment and operation

Informed decision making

In common with the regional OFA model, it would be generators that make the economic trade-off between obtaining firm access and the costs associated with doing so. The TNSP's role would be confined to assessing what expansion would be required to deliver firm access and how this could be done at least cost. Decisions regarding the impacts of transmission capacity on generators would be made in an informed manner by generators themselves, who are better placed to make such decisions when presented with the correct signals. This would be likely to reveal the value that generators placed on firm access more effectively than could be facilitated by any centrally planned approach.

Efficient use of network capacity

By selling access rights transparently in a time-limited manner, it would be clear to generators (including prospective generators) and to the TNSP when unused network capacity would be available. It is likely, therefore, that network capacity would be used in the most efficient manner possible, whether this was through new entrants booking capacity on a long term basis when it became available or through opportunistic (previously non-firm) generators purchasing access rights in the short term.

Equally, this process would provide the TNSP with robust information with which to plan the future expansion of the system, as it would have firm knowledge of generators' requirements many years in advance. This would give increased certainty to transmission planners, increasing the efficiency with which the system could be planned and provided.

Transparent generator-side planning standard

As discussed in previous chapters, the current planning approach using the RIT-T can be characterised as providing an "economic" planning standard for generators. That is, network augmentations will be constructed if an estimation of the expected benefits exceeds the anticipated associated costs. The benefits of "firmness" of access are not captured by the RIT-T. Further, despite the checks and balances in place, it is difficult to know whether there are unrealised benefits associated with potential transmission projects that have not been assessed.

Under the national LMP model, the transmission planning standard would continue to be economically-derived but there would be a much greater degree of certainty as to when it should be applied (in that this decision would be made by the generator, as discussed above).

Further benefits of a single TNSP and no regions

In a market with no regions, there would clearly be no inter-regional flows to be planned for. Equally, if a single TNSP could be established, there would be no need to coordinate planning between TNSPs. This approach would therefore eliminate a number of perceived or potential issues associated with inter-regional transmission planning, including the need for TNSPs to cooperate and for the benefits resulting from an inter-regional augmentation to be assessed through a RIT-T. The TNSP would instead undertake transmission planning on a consistent basis across the market.

Although planning would be consistent across the market, that is not to say that only a single level of reliability would be provided - the actual level might vary between connection points. However, the driver for this would solely be economic, and this would be determined and specified in a transparent manner.

There may be other benefits associated with having a single NEM-wide TNSP in terms of the consistent approach it would bring. One example would be consistency of approach to connecting new generators and load.

Incentive on the TNSP to maximise available network capacity

The fully firm nature of access rights under the national LMP model would reveal the costs associated with the unavailability in real time of network capacity that had been provided through the planning process.

By exposing the TNSP to a portion of these costs, the model would place a powerful incentive on the TNSP to minimise them by taking actions to maximise available network capacity at times when it was most valued. Even partial exposure to costs would be likely to represent a significant amount of money in absolute terms, and it is anticipated that it would provide a strong incentive to adjust TNSP behaviour. Such incentive schemes are used in the British regulatory arrangements, and are generally considered to have been relatively successful.

The proposed scheme would represent a more market-based approach than the existing service target performance incentive scheme, and might therefore wholly or partly replace this.

10.3.2 Impact on generator investment decisions

Locational decisions

As previously noted, all generators would be exposed to some form of transmission locational signal. Non-firm generators would be directly exposed to any costs of congestion, and generators purchasing firm access rights at auction would see a locational signal through the payment made to hedge this risk. Generators purchasing firm access rights released on a long term incremental basis would be presented with a signal linked to the investment costs associated with the provision of the additional transmission capacity. It would be generators which would make the trade-off between each of these costs, and between these costs and the other locationally varying costs facing them.

Investment certainty

Generators would have the option to obtain a product giving absolute financial certainty of dispatch. This would give generators complete confidence in contracting, providing a certain revenue stream in all circumstances.[213] This would give revenue stability for generators, which should have associated benefits in terms of reducing generators' cost of capital.

213 Assuming that the generator was in merit i.e. would be dispatched given no constraints.

Unlike package 4, access rights would be fully firm in all but the most extreme of circumstances. This would remove the risk present in the regional OFA model that constrained-off payments would be "scaled back" outside of "normal" operating conditions.

The options available to generators would include a partially firm access product, such that a generator could opt for an access level greater than zero but less than the power station capacity. As with package 4, this option might particularly appeal to intermittent generators.

Auctioning access rights would make firm access available to all parties, including new entrants, on a non-discriminatory basis. If "baseline" capacity was unavailable, there would be a process to release incremental capacity, again on a non-discriminatory basis.

Offering access rights for sale on a long term basis, as contemplated under this model, would offer certainty to generators who could potentially secure firm access for a significant portion of the life of their generating plant, if they wished.

10.3.3 Impact on generator operational decisions

The implementation of the national LMP model would remove the incentives that lead to disorderly bidding and the productive inefficiencies in dispatch that result when higher cost plant is dispatched despite the availability of unused lower cost generation.

This is because all generators, including those with firm access, would be incentivised to make offers into the dispatch process based on the value of their energy to the market, as the price at which constrained generation would be settled would be directly reflective of the relevant generators' offers. Consequently, if a generator was to submit an offer to generate below cost, there would be a risk that it would be settled at this price.

An additional major advantage of the national LMP model is the single national trading hub, to which all generators would be able to secure firm access which was basis risk free through obtaining a single right. In contrast, to trade nationally:

- under the existing arrangements, participants use their non-firm access to the region, and can, through inter-regional settlements residue (IRSR) auctions, obtain a semi-firm product to manage inter-regional basis risk; and
- under the regional OFA model, participants would be able to secure firm access to the region and, again, would need to obtain the semi-firm IRSR product to manage inter-regional basis risk.

The national LMP model might therefore better facilitate national energy trading and should consequently increase liquidity in energy trading and competition in generation, with likely resultant benefits for consumers.

10.3.4 Impact on co-optimising generation and transmission decisions

Compared to the status quo, the national LMP model relies primarily on market signals rather than the regulatory planning process to identify requirements for transmission investment. For this reason, similar to package 4, generators have a greater role in driving the addition of transmission capacity. Exposing generators to network costs allows them to better trade-off these costs with the costs of generation investment.

10.3.5 Feasibility and ease of implementation

The major changes to the market and transmission arrangements that would be required to implement the national LMP model would have significant implementation costs. There would also be some level of ongoing additional cost and complexity that would result from adoption of the model.

Establishing a single, national TNSP

Establishing a single, NEM-wide TNSP at this stage in the evolution of the market is likely to be difficult to the point that it is not clear that it is feasible. A wide range of private and government shareholders would need to agree to a merger of TNSPs. There would also be numerous other issues to be resolved, such as:

- rights allocation (shareholding levels);
- board selection;
- asset valuation;
- financing arrangements;
- liability allocations; and
- industrial relations issues.

As discussed in section 10.2.6, introducing the model with multiple TNSPs, while possible, would further increase the complexity of the required regulatory arrangements, if efficient outcomes were to be promoted.

Another option would be for TNSPs to establish a joint-venture company to take transmission investment decisions centrally, while the ownership of the networks was retained by individual TNSPs. However, to the extent that TNSPs continued to be responsible for the operation and maintenance of the network and the delivery of investments, this would still require any incentives put in place to recognise the division in responsibilities between TNSPs and the joint-venture company. This option is discussed further in the next chapter.

Access allocation processes

The other main implementation costs associated with introducing the model would be the requirements for changed and additional systems, particularly in relation to the auctioning of access rights. This would also result in some degree of additional ongoing cost and complexity. Managing these issues might represent a challenge for smaller generating companies in particular.

As already discussed, consideration would need to be given to many aspects of the allocation process, including the products offered, the frequency of the auctions and detailed issues associated with the design of the auction itself. The detailed arrangements for the mechanism to release long term incremental access rights would also need to be developed, including the methodology for setting a reserve price that reflected the costs associated with providing the additional transmission investment. Finally, consideration would need to be given to prudential requirements, as generators could potentially be making financial commitments to the purchase of rights over a long period of time.

Potential additional direct costs to consumers

Finally, the model may result in some additional direct costs to consumers, both through the uplift charge levied to make up any compensation shortfalls and through changes to energy price paid by load (i.e. the SMP). Before recommending adoption of this model, the Commission would therefore need to be satisfied that the productive and dynamic efficiencies that would result from proving access rights would be likely to outweigh these potential costs.

Table 10.1 Summary of advantages and disadvantages of package 5

Advantages	Disadvantages
Provides fully firm access, leading to greater certainty for generators	Complex process of long-term and short-term auctions
Generators choose an economic level of access	Complex process for release of long-term incremental capacity
Addresses disorderly bidding	May result in additional direct costs to consumers through uplift charges
National hub promotes trading liquidity	Not clear that a single national TNSP is feasible (and further complexity if not feasible)
Long-term access products provide certainty for generators and transmission planners	
Resolves any perceived inter-regional planning issues	

11 Options for reforming planning arrangements

Box 11.1: Summary of this chapter

This chapter sets out for consultation a number of options for potentially enhancing or reforming existing transmission network planning and institutional arrangements. These are intended to help ensure that efficient outcomes are promoted following any future changes in the use of the network.

The chapter discusses the characteristics that an efficiently planned network is likely to exhibit, and sets out our views that the current arrangements are delivering many of the outcomes that would be expected under a well-functioning transmission planning regime. Further, in some cases, such as the Regulatory Investment Test for Transmission (RIT-T), these arrangements have only recently been introduced and it is too early to comprehensively evaluate their effectiveness. However, we note that there are a number of stakeholders who continue to hold concerns regarding the efficiency of existing planning arrangements, particularly in respect of inter-regional investment.

We are also mindful that effective planning and institutional arrangements would be particularly critical under policy packages 1 and 2. Without market signals of the demand for network services to inform transmission network planning and investment decisions, greater reliance would be placed on regulatory mechanisms to ensure that TNSPs make efficient decisions. It is in this context that we are considering whether improvements can be made to the current arrangements.

The options discussed in this chapter range from enhancements to the current arrangements to more substantial reform, including a model advocated by the Victorian DPI for a single NEM-wide planner/procurer. The Commission is seeking stakeholder views on the merits of these options and whether there is evidence to suggest that changes to the existing arrangements are required.

In considering any potential options for reform, the Commission is required to have regard to certain policy principles previously agreed by the Council of Australian Governments (COAG). These are discussed further in section 11.3.

11.1 Introduction

The purpose of this chapter is to set out a series of options for potentially enhancing or reforming the existing transmission network planning and institutional arrangements. As discussed below, the Commission considers that the current arrangements are delivering many of the outcomes that would be expected under a well-functioning transmission planning regime. However, we note some stakeholders' views, as outlined in section 5.2, that there are some concerns, particularly with the transparency of the investment process and the level of inter-regional investment.

The Commission also recognises the added importance that would be placed on planning arrangements under certain of the policy packages presented in this report. In particular, under policy packages 1 and 2, generators would have no role in assessing the economics of network augmentations (unlike packages 4 and 5, where this information would be provided to TNSPs through market signals of the demand for network services). It would consequently be imperative that transmission planning arrangements support the efficient and timely development of the network to meet load reliability standards and build-out of congestion to the extent that this is valued by consumers. In the event that existing arrangements are considered sufficient, then no significant reforms would be required. However, there may be a number of enhancements that could be undertaken to strengthen elements of the planning arrangements, and it is in this context that we consider that options for enhancing these arrangements should be evaluated.

However, stakeholders have also proposed a number of more substantial options for reform. These include a proposal by the Victorian DPI for a single body to be responsible for transmission planning, investment decision-making and procurement across the NEM, similar to the current Victorian regime,[214] with another option reflecting countervailing views that the existing arrangements in Victoria might be inappropriate.[215]

Several stakeholders also expressed support for the consideration of a single TNSP that would own and operate transmission across the NEM.[216] The desirability of a single, national TNSP has already been discussed in chapter 10 in the context of policy package 5. In that chapter, we noted that a more feasible approach at this stage of the evolution of the NEM might be for TNSPs to establish a joint-venture body, and this option is also explored further in this chapter.

This chapter is structured as follows:

- the remainder of this section discusses the features of an efficiently planned transmission network and the current transmission planning arrangements in the NEM;
- section 11.2 discusses potential enhancements to the existing regime; and
- section 11.3 considers more substantial reforms to transmission planning arrangements.

11.1.1 Assessing the performance of transmission planning arrangements

Designing appropriate arrangements and incentives for efficient transmission planning and investment is among one of the most difficult challenges in electricity market regulation. It requires coordinating the decisions of a number of different individual

214 Victorian DPI, Directions Paper submission, p. 7.

215 Grid Australia, Issues Paper supplementary submission, p. 13.

216 Alinta Energy, Directions Paper submission, pp. 4 & 10; MEU, Directions Paper submission, p. 33.

entities from both regulated businesses and the competitive sector. This is an issue that regulators around the world have grappled with.

It is also challenging to assess the performance of transmission businesses and whether they have achieved efficient outcomes through a regulated planning process. This is because there is a lack of measurable outputs associated with transmission investment. For example, it is difficult to assess whether an alternative investment would have been more efficient in terms of the outcomes that would have resulted.

Further, given the uncertainty surrounding demand patterns, generator investment locations and generator production levels, it is difficult to accurately plan a transmission network. There are therefore risks and uncertainties associated with the planning process, and the challenge is to design the regulatory and institutional arrangements that best allow for the management of these.

In general, we consider that an efficiently planned transmission network is likely to exhibit the following characteristics:

- efficient investment is delivered to meet load reliability standards (or recognising the value of customer reliability);
- generators are provided with a level of access that reflects the value of being dispatched in the energy market; and
- there is confidence that the arrangements promote effective coordination between generation and transmission investment, and between TNSPs in different regions. This is important in ensuring that total system cost is minimised.

Against this background, we consider that the existing arrangements have generally performed well to date. In particular, we observe that they are delivering:

- compliance with load reliability standards;
- scoping studies and RIT-T evaluations to assess the need for more inter-regional transmission capacity; and
- a high degree of transparency through the Annual Planning Reports (APRs), National Transmission Network Development Plan (NTNDP) and Last Resort Planning Power (LRPP).

Despite this transparency, it is difficult to know whether the RIT-T process will always identify every opportunity for efficient investment, and whether this appropriately captures the value that generators place on certainty of access. More generally, assurance is required that the transmission network that has transpired under the existing arrangements is equally as efficient as that which would have developed in the absence of jurisdictional, regional and TNSP boundaries, and this is difficult to assess.

Further, many of the planning arrangements are relatively new - the RIT-T, for example, only came into effect in July 2010 - and we note the views expressed by some stakeholders that these new frameworks should be given the opportunity to work before further reforms are contemplated.

However, particular concern has been expressed by some stakeholders that the current arrangements may not be leading to sufficient inter-regional transmission investment. This concern was set out in Professor Garnaut's Electricity Update Paper for the Government as part of his review of climate change issues.[217] As we discuss below, it is not clear to the Commission that the current arrangements are failing to deliver an efficient level of inter-regional investment or that options for additional inter-regional investment are not being considered by TNSPs. However, we recognise that there may be scope for greater transparency as to how TNSPs are assessing these options.

11.1.2 Current transmission planning arrangements

There are a number of mechanisms that work together to promote an efficient and transparent planning process under the existing arrangements.

AEMO as the National Transmission Planner (NTP) publishes the NTNDP. This document provides a strategic, twenty year outlook for potential development of the transmission network in the NEM.

Detailed planning of transmission networks in the NEM is undertaken by regionally-based TNSPs, except in Victoria where this planning is undertaken by AEMO (in its role as a TNSP in Victoria). These TNSPs publish APRs each year that present a detailed analysis of their plans for the transmission network in their region over a five year planning horizon. The TNSPs are required to have regard to the NTNDP when developing their APRs. TNSPs then undertake RIT-T assessments of specific projects, except in certain circumstances (for instance, if the capital cost of the project is likely to be less than $5 million).[218]

As a further measure to ensure timely and efficient inter-regional transmission investment, the LRPP is vested in the AEMC. The LRPP allows the AEMC to direct registered participants to apply the RIT-T to potential transmission projects if they are likely to relieve forecast constraints in respect of NTFPs.

Most of these arrangements have only recently come into effect. AEMO published the first comprehensive NTNDP at the end of 2010,[219] so the APRs that have recently been published by TNSPs are the first to take account of the NTNDP. The RIT-T is also relatively new, having come into effect on 1 July 2010.

217 Garnaut, Ross, *Climate Change Review - Update 2011*, Update Paper eight: Transforming the electricity sector, pp. 29-30.

218 NER clause 5.6.5C.

219 An interim National Transmission Statement was published at the end of 2009.

Box 11.2: The National Transmission Network Development Plan and Annual Planning Reports

AEMO is required to publish the NTNDP each December.[220] The NTNDP must consider the efficient development of the national transmission grid over a twenty year horizon.[221] In developing this strategic plan, AEMO is required to identify a range of credible scenarios for demand growth and generation investment. The focus is on elements of the national transmission grid that affect the transmission capability of national transmission flow paths. AEMO is also required to have regard to TNSPs' APRs in developing the NTNDP.

The NTNDP must, among other things:[222]

- contain the location of current and potential National Transmission Flow Paths (NTFPs) under each of the scenarios identified;
- specify a development strategy for each current and potential NTFP;
- provide information on the pattern of congestion on current NTFPs; and
- summarise the augmentations proposed by TNSPs in their most recent APRs and compare them to the current and previous NTNDPs.

In comparison, the APRs that are published each June by TNSPs contain a more detailed, medium-term plan for the development of their networks. The information that APRs must contain includes:[223]

- demand forecasts;
- potential network constraints;
- proposed network augmentations; and
- proposed replacement of transmission assets.

The APRs must also set out the way in which the proposed augmentations relate to the most recent NTNDP and the development strategies for NTFPs that are specified in the NTNDP.[224]

Despite the fact that most TNSPs are in the early stages of applying these arrangements, we note that some stakeholders have raised initial concerns about the

220 NER clause 5.6A.2(a).

221 See NER clause 5.6A.2(b) for a full list of matters that AEMO must consider in preparing the NTNDP. NER clause 5.6A.2(c) lists matters that the NTNDP must contain or consider.

222 NER clause 5.6A.2(c).

223 NER clause 5.6.2 and 5.6.2A set out the matters that TNSPs must consider and publish in their APRs in planning their network.

224 NER clause 5.6.2A(5).

application of the RIT-T by TNSPs. The AER has recently issued a compliance bulletin identifying an apparent misapplication by TNSPs of the criteria for developing alternative options in past undertakings of the regulatory test, and highlighting a concern that some TNSPs may also misapply the "credible option" definition under the RIT-T.[225] We further note that Grid Australia has recently published a draft handbook to provide guidance on how those TNSPs will undertake the cost benefit analysis under the RIT-T.[226]

The Commission would be interested in stakeholder views on the effectiveness of the planning arrangements now that one cycle of the NTNDP and APRs is complete. In particular, the Commission is interested in whether stakeholders consider the intention of the NTNDP to provide a national strategic framework within which TNSPs apply their local knowledge to develop detailed projects has been achieved.

Box 11.3: Inter-regional transmission charging

The final element of the transmission planning framework considered by the Commission in its 2008 report on National Transmission Planning Arrangements (which included the NTP and RIT-T) was inter-regional transmission charging.[227]

Under current transmission charging arrangements, customers do not contribute to the costs of transmission assets in other regions that support electricity flows to their region, even if they benefit from those flows. Instead, TNSPs recover their revenues solely from customers within their own regions.

As a result, positive net inter-regional transfers of electricity will lead to implicit cross-subsidies between customers in different regions. The absence of a mechanism to resolve this cross-subsidisation could represent a potential barrier to the coordinated planning of transmission investment across different regions, and this will become increasingly important to the extent that climate change policies or other factors increase the level of inter-regional flows.

In light of the Commission's assessment of the issue, the MCE has proposed a Rule change to implement an inter-regional transmission charging scheme.[228] This request has revealed a number of complex design issues, on which the Commission has recently consulted.[229] However, once implemented, we consider that an inter-regional transmission charging scheme might mitigate some stakeholders' concerns regarding the efficacy of the current inter-regional transmission planning process.

225 AER, *Compliance Bulletin No. 5*, Criteria for determining credible options under the RIT-T, September 2011.

226 Grid Australia, *RIT-T Cost Benefit Analysis*, Grid Australia Handbook, July 2011.

227 AEMC, *National Transmission Planning Arrangements*, Final Report to MCE, 30 June 2008, Sydney.

228 MCE, *Rule Change Request - Inter-regional Transmission Charging*, February 2010.

229 AEMC, *Inter-regional Transmission Charging*, Discussion Paper, 25 August 2011, Sydney.

Arrangements for inter-regional planning

A number of stakeholders raised concerns that the current arrangements for transmission network development would not deliver sufficient new augmentations between regions.[230] Stakeholders' specific claims included:

- TNSPs are focused on meeting their obligations within a region and place a lower priority on inter-regional augmentations;[231]
- the framework does not facilitate a national market, and there are strong biases against inter-state flows;[232] and
- TNSPs do not have sufficient incentives to cooperate in a coordinated manner to optimally design the NEM transmission network.[233]

Inter-regional transmission capacity is important as it supports greater competition in the generation and retail sectors by allowing participants to access the market in other regions. However, as described in Box 7.2, where there is congestion between regions, basis risk will arise. Participants can reduce this risk by purchasing Inter-Regional Settlements Residue (IRSR) units. IRSR units do not, however, provide a perfect hedge for inter-regional basis risk, for instance if there are network outages or if counter-price flows occur. International Power, in particular, considered that the predictability of inter-regional access is currently poor, limiting the ability of generators to compete between regions.[234]

We also understand that some stakeholders consider that the RIT-T sets a higher hurdle for inter-regional augmentations when compared to intra-regional augmentations that are often required to meet a transmission reliability standard. This is because the assessment of market benefits, including competition benefits and options value, is relatively difficult.

Grid Australia's response

In contrast to these views, Grid Australia submitted that, as a consequence of recent reforms, transmission frameworks now incorporate an effective "whole of grid" approach to network planning. It suggested that efficient national planning of transmission investment is facilitated as the strategic, national context for projects

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230 The South Australian Government, Directions Paper submission, p. 4; International Power, Directions Paper submission, p. 11.

231 International Power, Directions Paper submission, p. 11.

232 Garnaut, Ross, *Climate Change Review - Update 2011*, Update Paper eight: Transforming the electricity sector, pp. 29-30.

233 Alinta Energy, Directions Paper submission, p. 10; Victorian DPI, Directions Paper submission, p. 7.

234 International Power, Issues Paper submission, p. 14.

provided by the NTNDP is effectively integrated with the practical, local knowledge provided by TNSPs.[235]

Grid Australia also noted in particular that all the interconnectors in the NEM are currently under some degree of active review, including:[236]

- a feasibility study being conducted by ElectraNet and AEMO on the South Australian interconnector;[237]
- a further round of upgrade studies on QNI being undertaken by Powerlink and TransGrid; and
- preparatory work being undertaken by AEMO and TransGrid to investigate the benefits of upgrading the Victoria to NSW interconnector.

The Commission recognises the work being undertaken by TNSPs to assess inter-regional upgrade options. The Commission has also previously recognised that it is not immediately obvious that the level of price separation between regions within the NEM would suggest that there is a clearly insufficient level of inter-regional transmission capacity between the regions.[238]While the absence of significant and sustained price separation between regions is not necessarily determinative of sufficient inter-regional investment, we consider that it provides a useful indicator.

Options for reform

At this stage it is not clear whether the different perspectives raised by Grid Australia compared to some other stakeholders reflects a lack of transparency in the planning process or more fundamental concerns. For this reason we are consulting on a spectrum of options, from enhancement of the existing arrangements to more substantial reform. The Commission is seeking comments from stakeholders on these options, as well as additional evidence to support or contest our initial view on these issues.

11.2 Potential enhancements to existing arrangements for transmission planning

While section 11.3 discusses potentially significant reforms to the transmission planning arrangements, the Commission's current view is that retention of the current

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235 Grid Australia, *Garnaut Climate Change Review Update 2011*, Response to Transforming the Electricity Sector (Update Paper 8), April 2011, p. 11, attached to Directions Paper submission.

236 Grid Australia, Directions Paper submission, p. 9.

237 Subsequently, Electranet and AEMO have announced an intention to assess an incremental upgrade of this interconnector through a joint RIT-T process in 2011/12. Electranet, *South Australian Annual Planning Report 2011*, June 2011, p. 33.

238 AEMC, Advice for MCE on Garnaut paper, 2 June 2011, pp.13-19. Available at: http://www.aemc.gov.au/News/Whats-New/AEMC-consideration-of-the-Garnaut-Update-Paper-of-29-March-2011.html

regime (which itself is the product of a number of recent reforms) is an equally valid option for consideration.

However, in the context of policy packages 1 and 2 and the central importance of efficient planning to the effectiveness of these options, we have identified a number of possible measures that could be undertaken to enhance the efficiency of the existing arrangements. In particular, these modifications would aim to improve transparency in the planning process, most notably for inter-regional planning, and allow opportunities to be identified for a more coordinated approach. They include:

- implementing a national framework for transmission network reliability standards for load;
- improving the consistency of the APRs;
- improving the transparency of the RIT-T;
- aligning the revenue resets of TNSPs; and
- introducing reliability standards for interconnectors.

11.2.1 A national framework for transmission network reliability standards

The Commission has previously made a recommendation to the MCE to introduce a national framework for transmission reliability standards for load. The Commission remains of the view that a national framework for transmission reliability standards that are economically derived but deterministically expressed (a "hybrid" form of standards) will provide efficiency and competition benefits. Implementation of the framework would ensure that standards in all regions would be based on economic considerations and would provide greater certainty and transparency for network users, allowing them to better optimise investments across the NEM.

All TNSPs in the NEM have obligations governing the service provided to load. These standards generally ensure a level of redundancy on the system, implying that the supply of power to total load will be maintained in the event of a certain level of contingencies. Load as a whole can therefore be considered to receive a defined level of transmission service.

However, transmission reliability standards are largely defined in jurisdictional instruments and therefore differ between jurisdictions, sometimes significantly.[239] At the request of the MCE, the Commission undertook a review of transmission reliability

239 For example, as discussed in chapter 4, Victoria is the only state to adopt a probabilistic planning standard. South Australia has adopted a hybrid standard and the other NEM states use deterministic planning standards.

standards in the NEM, with a view to developing a national framework for network reliability. The MCE has yet to respond to the Commission's recommendations.[240]

In its final report, the Commission made recommendations for a national framework to promote consistency in transmission reliability standards and for the implementation of this framework. The key elements of the proposed framework are:

- transmission reliability standards that are economically derived using a customer value of reliability or similar measure, and capable of being expressed in a deterministic format; and
- standards are to be determined on a jurisdictional basis, by a body independent of the transmission asset owner. There would also be the option for a jurisdiction to allow a national body to set its reliability standards.

This approach allows states to continue to set the most appropriate standards for their jurisdiction, while allowing for greater transparency and comparability of outcomes between jurisdictions.

A number of stakeholders expressed their support for the Commission's proposals in submissions to the Directions Paper for this review.[241]

11.2.2 Improving the consistency of the APRs

Recent analysis undertaken for the Commission as part of our assessment of whether or not to exercise the Last Resort Planning Power has suggested that improving the consistency in the way in which TNSPs' APRs are presented might usefully increase transparency in planning processes.[242] In particular, requiring TNSPs to approach their APRs with a uniform format would improve the ease with which APRs could be compared, particularly to the NTNDP.

The APRs are an important part of the NEM's planning arrangements. They provide stakeholders with valuable information on the future development of the transmission network in each jurisdiction. The APRs include information on load forecasts, projections of where the transmission network will be congested and options to address this congestion. In addition, the APRs are required to set out the manner in which their proposed augmentations relate to the development strategies that are contained in the most recent NTNDP.

However, each TNSP adopts a different approach to presenting the outcomes of its annual planning. This can make it difficult to compare outcomes between the TNSPs and with the NTNDP. For example, not all the APRs map the network limitations

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240 AEMC, *Transmission Reliability Standards Review*, Final Report to MCE, 30 September 2008, Sydney; and AEMC, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, Sydney.

241 LYMMCo, Directions Paper submission, p. 9; NGF, Directions Paper submission, p. 6.

242 Intelligent Energy Systems, *Assessment of inter-regional congestion: report to the AEMC*, 3 November 2011, section 4.2.6. This report is available on the AEMC website at www.aemc.gov.au

identified in the NTNDP to development work considered by the TNSP in a transparent manner. Ensuring that all issues identified within the NTNDP have been captured by TNSPs would be an easier and more transparent process if TNSPs adopted a uniform approach to their APRs.

The Commission is therefore seeking views from stakeholders, particularly TNSPs, as to the possible costs and benefits of requiring TNSPs to adopt a uniform approach to their APRs.

11.2.3 Improving transparency when applying the RIT-T

As previously discussed, the RIT-T has only recently been implemented, taking effect from 1 August 2010. TNSPs have therefore been developing the exact approach they should take when conducting RIT-T assessments, and we note that Grid Australia has recently published a draft handbook to provide guidance on this matter.[243] This option seeks to further enhance the process to be followed, with the aim of promoting a high level of transparency in RIT-T assessments.

The RIT-T establishes the processes and criteria to be applied by a TNSP in considering investment in its transmission network.[244] The purpose of the RIT-T is to identify the investment option which maximises net economic benefits and, where applicable, meets deterministic reliability standards (in which case, if there are net costs, the RIT-T should identify the option which minimises those costs). The RIT-T is intended to maximise the net economic benefit to all those who produce, consume and transport electricity in the market.[245]

The RIT-T does not include any wealth transfers between market participants in determining the outcome of the test. Wealth transfers on their own do not improve or reduce overall efficiency in the electricity market. However, they could have significant impacts on affected participants, including in the wider economy.

Therefore, an option to increase transparency in the application of the RIT-T would be to require TNSPs to estimate the economic impacts on market participants and customers that would be affected by a proposed investment, including wealth transfers. In many cases the impact would be limited to the level of Transmission Use of System (TUoS) charges to be incurred by customers. In other cases there may be impacts on generators through changes in the level of congestion (and so access) and on consumers through price impacts. The scope of the analysis required to identify the impacts would be proportionate to their likely materiality.

We consider that greater transparency of these aspects of the analysis might help stakeholders to better understand why some investment options are not taken forward, despite having potentially significant benefits for some stakeholders, because of

243 Grid Australia, *RIT-T Cost Benefit Analysis*, Grid Australia Handbook, July 2011.

244 For more information on the RIT-T see: AER 2010, *Regulatory Investment Test for Transmission*, June 2010 and AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010.

245 NER clause 5.6.5B(b).

offsetting costs for other stakeholders. We also consider that requiring greater transparency for this analysis would provide further encouragement for TNSPs to focus on high quality analysis of market impacts as part of the RIT-T analysis.

11.2.4 Aligning TNSPs' regulatory resets

Every five years TNSPs are required to submit to the AER a proposal that sets out their capital and operating expenditure requirements for the following five years. The AER is tasked with approving a revenue cap for the five year regulatory period. This process is known as the "regulatory reset" process. At present the regulatory resets for the TNSPs in the five relevant NEM regions are staggered over a period of several years.

Aligning the regulatory resets of all TNSPs might better allow for the development of an optimal system-wide transmission investment program. For example:

- the AER and its consultants would be better able to compare and align the various TNSP augmentation plans and raise questions if TNSPs had significantly different plans for investments in NTFPs;
- the AER would also be able to assess the NEM-wide implications of intra-regional investments;
- TNSPs would be prompted to clearly coordinate the investment proposals they submit to the AER; and
- the AER would be able to apply a more consistent approach to the economic regulation of TNSPs, rather than adopting any improvements on a staggered basis as at present.

In addition, aligning the regulatory resets may also be important if, as discussed in section 11.2.5, some form of interconnector reliability standard is adopted.

In 2007 the Energy Reform Implementation Group (ERIG) found that:[246]

> "the sequential nature of revenue cap determinations limits the development of nationally coordinated investment plans. This is because the regulator and the individual TNSP are conducting determinations in isolation and in the absence of certainty over the investment proposals of other TNSPs, thereby minimising the ability of each to identify mutually supporting projects. Furthermore, the current sequential arrangements limit the regulator's ability to compare costs and assess a nationally efficient level of expenditure."

246 Energy Reform: The way forward for Australia, A report to the Council of Australian Governments by the Energy Reform Implementation Group, 12 January 2007, p. 175.

As part of the Commission's review of National Transmission Planning Arrangements, the MCE directed the Commission to give "consideration of alignment of regulatory periods to further reinforce the national character of the planning arrangements".[247]

In that review, the Commission did not recommend alignment as it considered that the costs of implementation were likely to be substantial, while many of the benefits identified by ERIG would instead be achieved through the annual NTNDP and the application of the Chapter 6A revenue Rules,[248] including the new contingent project mechanism.[249] The Commission further considered that aligning each region's transmission and distribution revenue determinations might be more beneficial.[250]

While we note that the NTNDP has significantly improved the quality of planning information available, it is still the case that the revenue determinations that influence investment decisions are made in isolation of each other. Further, the contingent project mechanism under the Chapter 6A arrangements does not appear to have been used as much in practice as the Commission had envisaged.

We also note the difficulty of considering intra-regional investments in isolation, since a very large proportion of all transmission investment with a mitigating impact on network constraints will have some inter-regional effect. This is illustrated by recent analysis performed for the Commission, which found that approximately two-thirds of all constraint equations contain an inter-regional term.[251] In addition, it is possible that patterns of generation will change significantly in the medium term, and that this will further increase the importance of coordinated inter-regional transmission planning. These factors suggest a need to ensure that planning is optimised across the NEM.

We consider that it is prudent to re-consult with stakeholders on the likely benefits and costs of aligning TNSPs' regulatory revenue resets. We note that there would likely be material implementation costs, including through the need for interim revenue controls to bring all the reset dates into line. Further, the existing provisions that allow TNSPs to propose the length of their regulatory control period would need to be revisited.[252] However, it is not clear that there would be any enduring costs, provided that electricity and gas distribution resets were also retimed in order to smooth the AER's resourcing requirements.

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247 MCE, *Terms of Reference - National Transmission Planning Arrangements*, July 2007, p. 7.

248 AEMC, *National Transmission Planning Arrangements*, Final Report to MCE, 30 June 2008, Sydney, p. 73.

249 Contingent projects provide a mechanism for capturing identified capital projects that are sufficiently uncertain such that they cannot be included in the maximum allowed revenue at the time of the regulatory reset. TNSPs may propose a forecast expenditure outside of the revenue reset process where an identified trigger is met. See NER clause 6A.8.

250 AEMC, *National Transmission Planning Arrangements*, Final Report to MCE, 30 June 2008, Sydney, p. 74.

251 Intelligent Energy Systems, *Assessment of inter-regional congestion: report to the AEMC*, 3 November 2011, p. 18.

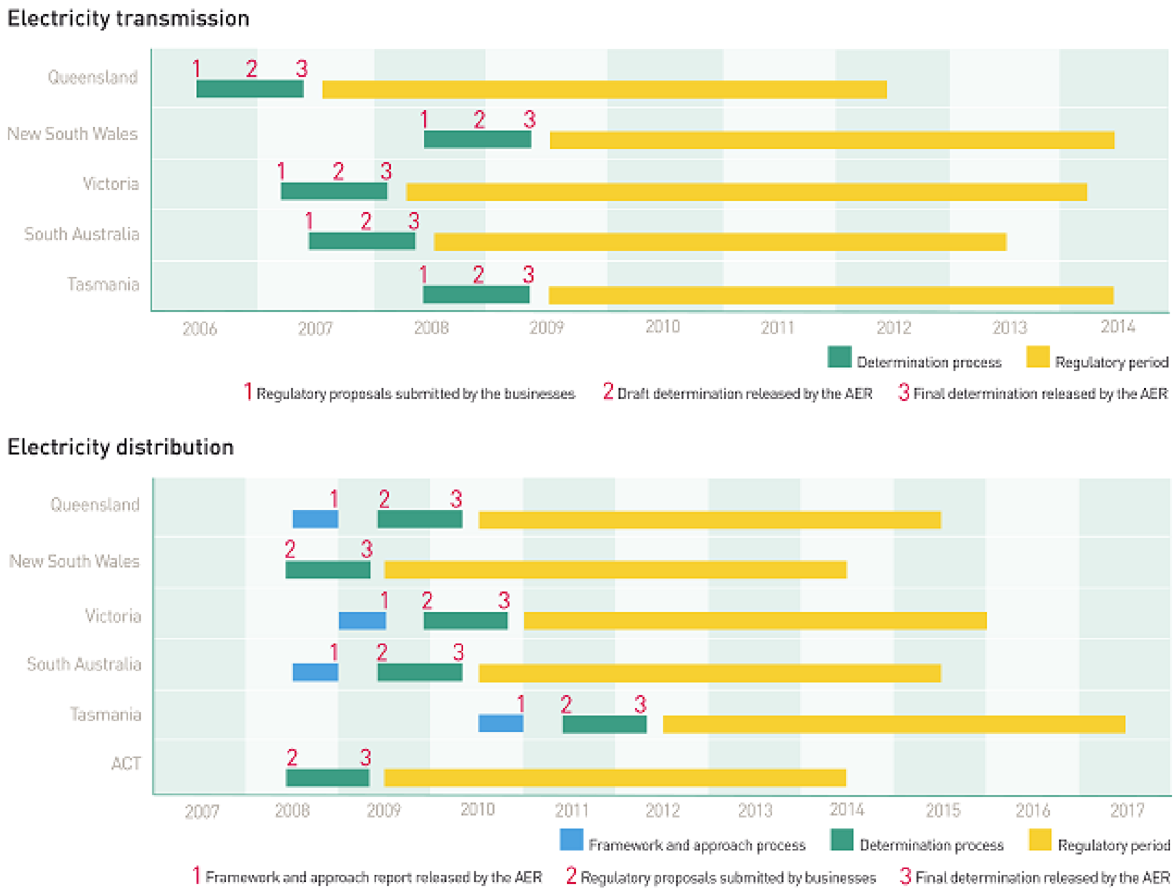
252 See NER clause 6A.14.3(e) and the definition of *regulatory control period* in Chapter 10. At present, all regulatory periods are five years but TNSPs may propose any period not less than five years.

We are therefore particularly interested in stakeholders' views as to the implementation costs associated with adjusting TNSPs' revenue resets. We note from Figure 11.1 below that it appears that by extending the current regulatory control period in South Australia by one year, transmission determinations for four states could be aligned by 2014.

Figure 11.1 also shows that transmission and distribution determinations are not currently aligned in the majority of jurisdictions, and we note the Commission's earlier view that doing so could be beneficial to the market and would reflect the joint planning framework set out in Chapter 5 of the Rules. However, to align transmission and distribution determinations within jurisdictions would represent a mutually exclusive alternative to aligning all transmission regulatory periods.

The Commission therefore also seeks stakeholders' views as to the relative merits of aligning all TNSP revenue resets as compared to aligning jurisdictional transmission and distribution determinations.

Figure 11.1 Indicative timelines for AER determinations on electricity networks



Note: The New South Wales and ACT distribution determinations were developed under transitional Electricity Rules, which did not provide for a framework and approach process.

Source: AER State of the Energy Market 2010, Figure 2.2, p. 53.

11.2.5 Reliability standards for interconnectors

There is no existing requirement on TNSPs to consider interconnector capacity when undertaking other network augmentations. TNSPs may separately keep the capacity of interconnectors under review, and would be likely to conduct a RIT-T assessment if there was a good indication that there was likely to be an economic case for a interconnector capacity upgrade. However, some stakeholders are concerned that this process is less likely to result in augmentations being undertaken as compared to work required to meet reliability obligations within a region.[253]

The capability of the NEM's interconnectors varies over the long term as system conditions change with load growth, new network augmentations and new generator connections. Interconnector capability can also increase (or decrease) when transmission lines are re-rated to a higher (or lower) thermal limit, or TNSPs change their operating practices. In general, any reductions of interconnector capability are not automatically corrected by the associated TNSPs. The exception is where a generator negotiates the connection of a new generating unit, where the impact on the transfer capability of the network must be considered as part of the performance standard.[254]

The capability of the interconnectors is assessed in the NTNDP, which attempts to project when and where the NTFPs will be constrained. However, International Power considered that the NTNDP (of necessity) deals with the transmission network in a "broad-brush" manner, focusing on the major transmission paths.[255] International Power raised concerns that reductions in interconnector capabilities are often due not to limitations within these major transmission paths, but rather to limitations that result from generation plant embedded deep within one of the connected regions.

In response to this perceived problem, International Power proposed that, rather than the NTP seeking to indicate where investment is needed to give desirable interconnector capability, the NTP should rather indicate the level of reliable interconnector capability it considers desirable for each interconnector and flow direction. TNSPs would then be given the responsibility to ensure that the capability was maintained as part of their planning process. International Power saw this as giving the need for interconnector capacity and reliability an equal status with jurisdictional reliability planning standards.[256]

International Power suggested that this proposed approach would offer the following advantages over the current arrangements:

- augmentations for inter-regional reliability would have the same importance as augmentations to meet intra-regional reliability issues, and might therefore be more likely to be included in the TNSPs' APRs;

253 International Power, Directions Paper submission, p. 11; Garnaut, Ross, *Climate Change Review - Update 2011*, Update Paper eight: Transforming the electricity sector, pp. 29-30.

254 NER schedule 5.2.5.12.

255 International Power, Directions Paper submission, p. 11.

256 International Power, Directions Paper submission, p. 12.

- market participants would have greater certainty that the capability of the interconnectors would be maintained over time; and

- TNSPs would need to collaborate when undertaking network planning to maintain the NEM's inter-regional capacity, improving coordination.

We note, however, that there may be some disadvantages in introducing reliability standards for interconnectors. For example, the requirement to maintain a certain level of capacity could mean that, in some circumstances, future investment to maintain capacity is more costly than other options that would meet load reliability standards and/or relieve congestion. Further, in determining the appropriate level of capacity to be maintained, the NTP would undertake a cost benefit analysis. The assumptions made as part of the analysis would be locked in for a period of time, irrespective of the actual costs of meeting the resulting standard.

To ensure that such an approach operated efficiently, the NTP would need to obtain adequate information from TNSPs on the costs of maintaining the capability of the interconnectors so that it could set the level of capacity efficiently.

11.3 Options for more significant reform

In addition to the potential enhancements to existing frameworks set out in the previous section, we are seeking stakeholders' views on options for more substantial reforms. This will help us to understand whether there is evidence that such reforms could have material benefits for efficient investment in, and operation and use of, transmission networks. These potential more significant reforms reflect concerns noted by some stakeholders and comprise:

- Option 1: Enhanced coordination of the NTNDP and APRs.

- Option 2: Harmonised regime based on the South Australian arrangements.

- Option 3: A single NEM-wide transmission planner and procurer.

- Option 4: Joint-venture planning body established by TNSPs.

The first two of these options are potentially complementary, with option 1 concentrating on improving coordination between regions and the focus of option 2 being the harmonisation of arrangements within regions. Any or all of the enhancements to existing frameworks described in the previous section could also be implemented in combination with these options.

In contrast, options 3 and 4 are mutually exclusive, stand-alone options which, if implemented, would be inconsistent with the adoption of the majority of the other options and enhancements presented in this chapter.

We recognise that these options could be designed in a range of different ways, and we seek to explain these options below. The Commission encourages stakeholders to indicate if they believe that the options could be more effective if designed in different ways.

11.3.1 Option 1: Enhanced coordination of the NTNDP and APRs

While TNSPs and AEMO in its role as NTP are currently required to consider the latest NTNDP and APRs respectively, the requirements to do so could be tightened so as to improve the coordinated planning of NTFPs.[257] This option might achieve some of the efficiency benefits that could result from a single transmission network planner, without the need to devolve planning responsibilities from existing jurisdictional bodies while retaining the potential benefits of having a number of different perspectives provided as inputs into the planning process.

Currently each year:

- the NTP, in consultation with TNSPs and having regard to the most recent APRs, prepares the NTNDP that provides a twenty year outlook for the NEM under a range of scenarios;[258] and
- each TNSP prepares an APR with a detailed plan for their respective region, having regard to the most recent NTNDP.[259]

The coordination of planning in the NEM could be further integrated by requiring the NTP to endorse the APRs and the TNSPs to endorse the NTNDP. This would ensure that:

- the NTP is satisfied that the APRs fully take account of the scenarios presented in the NTNDP;
- individual TNSPs are satisfied that the NTP has taken into account their APRs and any other advice they have provided in the NTNDP; and
- the NTP and TNSPs are satisfied that the APRs reflect joint planning where the proposed augmentations impact on NTFPs.

The desired outcome would be a national plan for investment in NTFPs, encapsulated in the NTNDP and individual APRs, that reflected local circumstances, was coordinated between regions and considered the longer term outlook contained in the NTNDP. The detailed knowledge of TNSPs would be better combined with the strategic nature of the NTNDP. It would give stakeholders, including the AER, greater confidence that an efficient level of investment was being undertaken.

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257 Reflecting the large over-lap between intra- and inter-regional planning discussed in section 11.2.4, the NTNDP considers National Transmission Flow Paths. These are defined as the portions of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres.

258 NER clause 5.6A.2(c)(1).

259 NER clause 5.6.2A(5).

However, it would be necessary to develop a process to be followed in the event that the various TNSPs and the NTP could not agree on a coordinated plan. At a minimum, TNSPs and the NTP would be required to publish any areas of disagreement and the reasons for their position. Ultimately, the AER would be required to decide whether or not to provide allowances for investments as part of TNSP revenue determinations.

Also of potential relevance is the approach that the Commission has recently taken in considering whether to exercise the LRPP. This has included essentially undertaking a reconciliation of the APRs and NTNDP. Therefore, this process, or an evolution of it, could play a role in identifying any inconsistencies and potentially resolving them.

Box 11.4: Allocation of planning roles in Victoria

The process described in this section 11.3.1 seeks to achieve a national plan for transmission investment, while capturing the benefits associated with the involvement of multiple parties. It is based on the premise that a plan developed by and agreed to by TNSPs and the NTP is likely to result in more efficient outcomes than a plan determined by either in isolation.

In most jurisdictions, the NTP provides an important check of TNSPs' investment programs in order to ensure that an efficient, strategic and coordinated approach is taken to the long term development of the national transmission grid. In Victoria, however, there is no such independent review, as the jurisdictional planning function and the NTP function are undertaken by the same entity.

Further, it is our understanding that there is no ring-fencing in place within AEMO between these functions. While the synergies between the two functions might mean that this is an efficient use of highly specialised resources, it places a great deal of reliance on AEMO's public consultation and internal decision-making processes. This is particularly the case given that the Victorian arrangements do not, by design, provide for any AER oversight of transmission investment decisions made by AEMO.[260]

11.3.2 Option 2: Harmonised regime based on current South Australian arrangements

As a potential complement to option 1, the Commission is considering whether there is a case for recommending the implementation of a harmonised set of transmission planning arrangements across all jurisdictions. This would allow for the identification and promotion of best practice in transmission planning, and would remove the transaction costs associated with multiple sets of arrangements in the NEM (for instance, the impacts on market participants operating in multiple regions). Importantly, and particularly in the context of the adoption of option 1, it would provide for consistency in the relationships between the NTP and jurisdictional planners.

260 AEMO is required to apply the RIT-T in identifying efficient investments and, as such, is subject to some oversight by the AER. However, AEMO is not subject to a revenue determination.

Use of financial incentives

As identified in section 4.2.4, and in Box 11.4 above, the transmission planning arrangements in Victoria differ significantly from those in other jurisdictions. In Victoria, it is AEMO that is responsible for the planning and procurement of the transmission network. As a not-for-profit organisation, AEMO is not subject to the financial incentives that are provided to TNSPs in other states. The use, or otherwise, of financial incentives in the regulation of transmission has already triggered some debate in this review.

In its response to the Directions Paper, the Victorian DPI suggested that incentives distort the behaviour of profit-making monopoly network businesses, as privately owned TNSPs:[261]

- have incentives to cut back on investment or to invest late in the regulatory period in order to maximise profits;
- have incentives to over-forecast capital expenditure requirements through pricing determination processes to secure larger revenue allowances; and
- have few incentives to make optimal trade-offs between network and non-network options, as investment-based augmentations are automatically rolled into the asset base.

In contrast, Grid Australia considered that the incentive properties of the arrangements used outside of Victoria are appropriate and that they lead to efficient outcomes. This is achieved through the way in which the revenue cap is determined, the fixed nature of the revenue cap between reviews, and service obligations placed on TNSPs. Grid Australia stated:[262]

> "The combination of the financial incentives on TNSPs to minimise cost with the measures to ensure appropriate service delivery imply that:
>
> - TNSPs have an incentive to meet their service obligations at the lowest cost...; and
> - TNSPs have an incentive to spend efficiently (both operating and capital) and improve their service levels where this generates a reward under the service target performance incentive scheme that exceeds the cost of that initiative."

261 Victorian DPI, Directions Paper submission, p. 8.

262 Grid Australia, *Garnaut Climate Change Review Update 2011*, Response to Transforming the Electricity Sector (Update Paper 8), April 2011, p. 25, appended to Directions paper submission.

Grid Australia has further contended that if it "is accepted that incentive regulation promotes superior outcomes to central planning, then it is logical to conclude that the currently limited role for incentive regulation in Victoria is sub-optimal".[263]

The Commission notes that, as AEMO is not structured to respond to financial incentives, a great deal of reliance is placed on the decision making of the AEMO board. While its decisions will not be motivated directly by financial considerations, they could be informed by other perspectives, for instance operational considerations resulting from AEMO's additional role as market operator. If AEMO failed to adopt least cost solutions to ensure that new investments were undertaken efficiently, there might be a reputational impact, but it is not clear that AEMO would face any other consequences.

We therefore consider that financial incentives are likely to provide the most robust and transparent driver for efficient decision making. While this requires the relevant incentives to be appropriately structured, the use and refinement of such arrangements in the NEM and in other markets around the world suggest that this can be achieved.

The Commission is also mindful that all of the firmer access models that have been proposed in chapters 8 to 10 contemplate an increased role for such incentives to ensure efficient outcomes will be achieved. For example:

- the models of transmission reliability standards for generation and regional optional firm access consider the application of regulatory incentives to reward or penalise TNSPs for the achievement of the standards. Under the regional optional firm access model, regulatory incentives may also be placed on TNSPs to meet the associated operating standards; and
- under the national locational marginal pricing model, the TNSP (or TNSPs) would be incentivised to minimise the amount of uplift charges required to provide fully firm access by maximising the availability of the network at the times when this is valued most highly.

Additional complexity could arise in Victoria from the separate roles undertaken by SP AusNet and AEMO. SP AusNet is a for-profit entity, responsible for the operation of the vast majority of the transmission network in Victoria. It would therefore be desirable to expose SP AusNet to all financial incentives present in the market arrangements relating to transmission operation. However, since AEMO makes the planning and investment decisions in Victoria, it would not be appropriate for SP AusNet to bear any risk associated with these activities. This would make the use of incentives encompassing both operational and planning elements particularly challenging.

263 Grid Australia, Issues Paper supplementary submission, p. 13.

A potential harmonised regime

In the context of these issues, we would be interested in stakeholders' views as to whether there is a case for harmonising the transmission planning arrangements across all jurisdictions. Given our current views highlighted above, the Commission considers that such a regime would need to allow for the use of financial incentives to influence the making of investment decisions. This implies that AEMO would not make such decisions in Victoria.

There would, however, be a very significant role for AEMO in such a harmonised regime. In particular, through its NTP function, AEMO would play a key role in driving the strategic development of the national grid and would provide an independent check on transmission investment decisions made in all jurisdictions (including Victoria).

Additionally, AEMO could be tasked with providing demand and supply forecasts for use in transmission planning by TNSPs. As highlighted in Box 11.5, the transmission planning arrangements in South Australia provide for Electranet to be supplied with demand and energy forecasts by AEMO. This would address any concerns that, as for-profit bodies, TNSPs might have an incentive to overstate demand and therefore over-invest.

The Commission also notes that the South Australian transmission planning arrangements employs reliability standards that are economically derived but deterministically expressed. As discussed in section 11.2.1, this approach to setting standards formed the basis for the national framework for reliability standards that we have previously proposed to the MCE. A harmonised transmission planning regime based on the South Australian arrangements would therefore be consistent with this earlier recommendation. We further note that AEMO plays an important role in conducting the economic analysis underpinning the South Australian reliability standards, and this could logically be extended on a national basis under a harmonised set of arrangements.

The Commission would be interested in stakeholders' views as to whether transmission planning arrangements based on those currently used in South Australia would represent an appropriate basis for a national approach to transmission planning and investment decision making.

Box 11.5: Provision of independent demand forecasts

As part of the annual planning review process, TNSPs use demand and energy forecasts which are published in their APRs. These forecasts are used to verify and modify connection point forecasts supplied to TNSPs by DNSPs.

In Queensland, New South Wales and Tasmania, the forecasts are produced by TNSPs themselves. In Victoria and South Australia the forecasts are derived by AEMO, with AEMO supplying forecasts to Electranet in South Australia for use in that region's APR. In Victoria, the APR is prepared by AEMO. The forecasts from around the NEM are also reproduced by AEMO in the Electricity Statement of Opportunities (ESOO).

The accuracy of the demand forecasts used in planning is key to ensuring an efficient level of investment. If demand forecasts are too high or too low it is likely that inefficient over- or under-investment in transmission will result.

The Commission understands that the accuracy of demand forecasts has tended to decrease in recent years. Historical relationships between electricity demand and economic growth have changed for reasons that are not fully understood, but are likely to include factors such as economic uncertainty, natural disasters and increased energy efficiency.[264]

However, concern has been expressed by some stakeholders that there are systemic inaccuracies in TNSPs' forecasting. The Northern Group considers that forecasts have consistently over-stated actual demand since the NEM commenced. While the Northern Group noted that TNSPs might have an incentive to overstate demand in order to justify more transmission investment, it suggested that AEMO, which as a not-for-profit body would not have the same incentive, has also over-forecast.[265]

AEMO has expressed particular concern with the forecasts produced in Queensland. In its most recent ESOO, AEMO took the step of preparing alternative forecasts for Queensland, and these project energy and demand to be lower than anticipated by Powerlink.[266]

11.3.3 Option 3: A single NEM-wide transmission planner and procurer

The Victorian DPI has submitted a proposal to this review that seeks to extend AEMO's Victorian planning and procurement role on a national basis.[267] Under this proposal AEMO would:

264 AEMO, *Electricity Statement of Opportunities*, 2011, section 3.11.1.

265 Northern Group, Issues Paper submission, pp. 17-18.

266 AEMO, *Electricity Statement of Opportunities*, 2011, section 3.11.3.

267 Victorian DPI, Directions Paper submission, pp. 7-10.

- perform all transmission network planning across the NEM;
- make all transmission investment decisions in the NEM as a not-for-profit entity;
- procure most new transmission services, including non-network services, through a competitive tender process; and
- apply the probabilistic planning methodology that is currently applied in Victoria to assess the need for new investment.

This section considers the implications of these aspects of the proposal.

Unlike options 1 and 2, which are potentially complementary with each other and with all the potential enhancements set out in section 11.2, the introduction of a single NEM-wide transmission planner and procurer essentially represents a stand-alone option. In particular, introducing a single network planner is an alternative to seeking to improve coordination between TNSPs in terms of inter-regional planning. Therefore, many of the options discussed earlier in this chapter would not be considered further if this proposal was progressed.

Box 11.6: Transmission planning and investment decision making

In considering the proposal from the Victorian DPI, it is important to be able to distinguish between transmission planning and investment decision making.

Transmission planning involves identifying drivers of future transmission needs on both a strategic, market-wide, long term basis and to address more localised requirements in order to ensure objectives and standards imposed on TNSPs will be met.

In contrast, investment decision making involves identifying the optimum project to address an identified need, and making a commitment to proceed with this.

NEM-wide not-for-profit transmission planner and investment decision maker

In making its proposal, the Victorian DPI considered that a single, not-for-profit national planner and procurer would provide efficiency benefits compared to the existing approach of multiple, regional planners subject to financial incentives. Given the changes facing the electricity sector, the Victorian DPI considered that transmission planning is likely to have a more national dimension than previously the case, with more inter-regional augmentations potentially becoming necessary to transport electricity from generators located long distances from load centres. It therefore considered that a move away from the "current fragmented and regionalised planning structure to a national planner procurer model" should be assessed.[268]

268 Victorian DPI, Directions Paper submission, pp. 7-8.

The Victorian DPI's views regarding the use of financial incentives in transmission planning and investment decision making by a not-for-profit entity have already been discussed in the previous section of this chapter.

The Commission agrees with the Victorian DPI regarding the importance of a national perspective being captured in transmission planning, and notes that the way in which this option differs from the existing NTP arrangements is that investment decisions would also be made by AEMO on a national basis. However, while giving a more national dimension to investment decisions might be beneficial, it does not necessarily follow that extending the Victorian institutional arrangements to the full NEM is the only or most effective means of achieving this.

We are also mindful that a single national transmission investment decision maker would require a process for capturing detailed local knowledge. Currently, regional TNSPs have significant information and knowledge with respect to their individual networks and the geography of their regions. There is a risk that some of this detail could be lost if planning functions were shifted to a single national planner/procurer. Further, as has already been set out, the Commission considers that financial incentives are likely to provide the most robust and transparent driver for efficient decision making.

The Commission does not consider that a compelling case has yet been made that there are likely to be significant efficiencies to be gained from moving to a model of NEM-wide planning and procurement undertaken by a not-for-profit body. However, the Commission seeks views from stakeholders and evidence that may suggest otherwise.

Competitive procurement of transmission services

Once the investment decision had been made in the model proposed by the Victorian DPI, AEMO would procure the required transmission services through a competitive tender process. In principle, such a process should lead to efficient outcomes, encouraging innovative solutions which should drive costs down over time, providing benefits to end consumers through lower prices and potentially improved services.

However, as discussed in Box 11.7, augmentations are only subject to competitive tendering if they meet certain criteria. It is not clear how many projects would meet these criteria (assuming the same criteria would be applied if the process was adopted nationally) and therefore how many network services could be tendered in practice.

We note that AEMO has recently conducted a tender for a terminal station at Tarrone.[269] The Commission understands that six competitive tenders have been held in Victoria by AEMO (and previously VENCorp) in the last decade.

269 AEMO, Invitation to Tender: Tarrone Terminal Station, 2 July 2010.

Box 11.7: Economic regulation of network augmentations in Victoria

In Victoria, the transmission network is planned and procured by AEMO, which is not required to have a revenue determination approved by the AER. There are two processes by which augmentations are facilitated. First, a project may be constructed through competitive tendering if:[270]

- the capital cost of the augmentation is reasonably expected to exceed $10 million; and
- it can be provided as a distinct and definable service and will not have a material adverse effect on an incumbent network asset owner.

The cost of a competitively tendered augmentation is charged to AEMO (and ultimately to consumers) for the remainder of the asset's life under a contract entered into with AEMO. The AER has no involvement in this process.

If the above criteria are not met, the augmentation may be classified as non-contestable. Further, AEMO may classify an augmentation as non-contestable if the consequent delay in implementation would unduly prejudice system security or if it does not consider it economical or practicable to treat an augmentation as contestable.[271]

Where augmentations are non-contestable, AEMO "directs" an augmentation to be made. AEMO must negotiate with the incumbent provider (usually SP AusNet) on the terms and conditions of the augmentation. The Commission understands that if the incumbent provider is subject to a transmission determination, and the service in question would be covered by this, then the augmentation would usually be rolled in the RAB at the start of the next regulatory control period.[272] It would be subject to AER oversight at this stage. Otherwise, the negotiated terms and conditions would continue to apply.

Where tenders have been undertaken, there appears to have been a relatively low level of success by new entrants into the Victorian market for the provision of transmission network services. We are only aware of two companies other than SP AusNet who are registered TNSPs for a limited number of transmission assets in Victoria, namely TransGrid and Rowville Transmission Facility (RTF).[273] However, it might be that the *threat of entry* is sufficient to maintain a competitive discipline on SP AusNet. Further, it is unclear whether the application of these arrangements on a NEM-wide basis might drive more competition, for instance between incumbent TNSPs on a cross-border basis.

270 NER clause 8.11.6(a).

271 NER clause 8.11.6(b).

272 We note that under NER clause S6A.4.2(d), the network asset owner may instead apply to the AER to reopen its revenue determination to take account of the directed augmentation within the current regulatory control period.

273 We understand that RTF was the result of a tender held in 1998.

Finally, we note that the procurement process appears to introduce additional complexity for network users who are seeking to negotiate a connection to the transmission network. In its submission to the Issues Paper for this review, the NGF noted a number of concerns in negotiating connection agreements with AEMO. These included:[274]

- the complexity of multiple connection agreements. The NGF noted that up to sixteen connection agreements could be required for a single connection point;
- a limited scope to influence the agreement content. The NGF provided an example whereby AEMO procures shared transmission services and subsequently negotiates and enters into a project agreement and network services agreement with the successful tenderer. The connection applicant has little ability to influence this process.

We note that the level of complexity impacting on network users could be reduced, and that AEMO's current connection initiatives seek to develop ways of achieving this. However, a tendering approach will always have an inherently greater level of complexity and transactions costs as compared to arrangements involving a single incumbent TNSP.

The Commission has not been provided with quantitative evidence to demonstrate that the procurement of transmission services is resulting in more efficient outcomes. As such, the Commission is currently unconvinced that this process should be adopted more broadly across the NEM. We would, however, welcome stakeholder views on how well AEMO's procurement approach has worked in practice and whether it is delivering better outcomes than the economic regulation framework.

The wider economic regulation frameworks that apply to transmission networks in regions other than Victoria are being considered under a Rule change request proposed by the AER.[275] Therefore, and without prejudice to future Commission decisions on this Rule change request, we would also encourage stakeholders to consider whether potential enhancements to the network regulation regime would affect their views on the relative benefits of adopting the procurer model.

Probabilistic planning

At present, TNSPs predominantly use deterministic reliability standards when planning transmission networks (although, as previously discussed, the deterministically expressed standards applying in South Australia are derived from economic considerations). In contrast, AEMO uses a probabilistic methodology to plan the Victorian transmission network.[276]

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274 NGF, Issues Paper submission, pp. 18-19.

275 AER, *Economic regulation of transmission and distribution network service providers, AER's proposed changes to the National Electricity Rules*, September 2011.

276 For further information, see 4.2.1.

Under the Victorian DPI’s proposal, AEMO would use probabilistic planning throughout the NEM. We note that the approach to setting planning standards is an issue that can be considered separately from the identity of the planning body. Therefore, the introduction of more economically based planning approaches in jurisdictions other than Victoria and South Australia is not, in our view, dependent on changes to the wider transmission planning framework.

Nevertheless, the Victorian DPI considered that it would be appropriate for a national planner/procurer to make use of probabilistic planning, contending that this leads to more efficient investment, including undertaking augmentations at the most efficient time, resulting in lower costs to end consumers.[277] The Victorian DPI's support for probabilistic planning has already been discussed in more detail in section 5.2.1, together with the divergent views held by other stakeholders regarding the use of and subsequent outcomes resulting from probabilistic planning.

As noted in section 11.2.1, the Commission has previously recommended that transmission reliability standards for load should be economically derived using a customer value of reliability or similar measure, and capable of being expressed in a deterministic format. Similarly, this "hybrid" approach has been recommended as the most appropriate methodology for implementing a transmission reliability standard for generation in chapter 8. As discussed in that chapter, the Commission considers that this approach is likely to provide the most appropriate balance between transparency and efficiency.

Consistency with COAG policy principles

The MCE’s Terms of Reference for this review specifies that the Commission should have regard to principles previously agreed by COAG, including that "accountability for jurisdictional investment, operation and performance will remain with transmission network service providers.”[278]

The Victorian DPI noted this COAG principle but considered that it would not prevent or restrict the AEMC from considering a national planner and procurer model. The Victorian DPI considered that "TNSPs which currently plan, own and operate the transmission networks in other jurisdictions would remain accountable for delivery of investments and the operation of transmission networks under an extended AEMO planning role". On this basis, the Victorian DPI proposed that we examine the potential extension of AEMO's role in planning Victoria's transmission network on a national basis as part of this review.[279]

277 Victorian DPI, Directions Paper submission, p. 9.

278 MCE, *Terms of Reference - AEMC Transmission Frameworks Review*, April 2010, p. 3.

279 Victorian DPI, Directions Paper submission, p. 9.

In contrast, Grid Australia considers that, given this principle and other statements made by the MCE, "policy makers are clear in their intention for transmission network investment decisions to remain with TNSPs".[280]

Ultimately, it would be a matter for the MCE to determine whether any recommendations were inconsistent with the COAG principles and whether it supported such recommendations despite any inconsistencies.

11.3.4 Option 4: Joint-venture planning body established by TNSPs

In chapter 10 we noted that a potentially more pragmatic alternative to creating a single national TNSP might be for existing TNSPs to establish a joint-venture body. This entity would assume all the rights and obligations associated with being a TNSP across the NEM, although the physical ownership of the networks themselves would be retained by individual TNSPs. This means that it would be the joint-venture body that would have the contractual relationship with Distribution Network Service Providers (DNSPs), generators and customers for the provision of transmission services. The individual TNSPs would in effect be agents of the joint-venture body.

The intention of creating this entity would be to better allow for the coordination of transmission planning across regions and the NEM as a whole. All decisions related to network investment would be made by the joint-venture body, which would direct individual TNSPs to make the required augmentations.

As a result, the joint-venture body's responsibilities would include a national planning role to identify the strategic direction for the national network.

However, the joint-venture body would also have full responsibility for the making of investment decisions. This would be possible as it would have access to detailed knowledge of costs and local conditions through its members. This would additionally allow for asset replacement and refurbishment programs to be coordinated with augmentations. Annual planning reviews for each jurisdiction would be undertaken by the joint-venture body, and it would therefore produce a single planning document covering both national and local considerations.

Individual TNSPs would be responsible for the detailed design of network augmentations and for the delivery of investments in line with the national plan. TNSPs would also individually continue to be responsible for the operation and maintenance of the network.

Use of financial incentives

This option 4 represents a mutually exclusive alternative to option 3 (as well as to options 1 and 2). Essentially, it would create a for-profit national planner and investment decision maker, as opposed to a not-for-profit entity undertaking these roles as under option 3. This would allow the national planner and investment decision

280 Grid Australia, Issues Paper supplementary submission, p. 8.

maker to be exposed to financial incentives which, as noted previously, the Commission considers to provide a robust and transparent basis for decision making.

Unlike option 3, the national entity would be subject to a revenue restriction determined by the AER. It would be the joint-venture body that recovered revenue from transmission users and was responsible for ensuring that all obligations, including reliability standards, were met.

Individual TNSPs would provide network services to the joint-venture body, and would make augmentations as directed. It would be for the joint-venture body and its member TNSPs to determine appropriate levels of remuneration for the delivery of network services based on the overall revenue allowance permitted by the AER. These arrangements would need to recognise the division in responsibilities between TNSPs and the joint-venture body in order to ensure that any financial incentives were appropriately targeted.

The AER's assessment of the joint-venture's capital expenditure forecasts (made on behalf of all TNSPs) would be a crucial check on any potential drivers for over-investment in transmission. We envisage that AEMO could play a role in providing advice to the AER in this regard.

The Commission would be interested in stakeholders' views as to the likely advantages and disadvantages of this option, and whether there would be merit in developing this concept further.

Consistency with COAG policy principles

As with option 3, in assessing option 4 it would be necessary to consider the extent to which the option is consistent with the COAG policy principle that "accountability for jurisdictional investment, operation and performance will remain with transmission network service providers."[281] Under option 4, all decisions regarding network investment would be taken by the joint-venture organisation comprised of TNSPs, but TNSPs would not individually be responsible for the making of all investment decisions relating to their own service areas.

As under option 3, in the event that this option was pursued, this would ultimately be a matter for the MCE to determine.

281 MCE, *Terms of Reference - AEMC Transmission Frameworks Review*, April 2010, p. 3.

Box 11.8: Transmission arrangements in Ireland

The transmission arrangements in the Republic of Ireland demonstrate how responsibilities could be divided between two types of body involved in the provision of transmission in a manner similar to that envisaged under option 4.

Under these arrangements, EirGrid acts as the Transmission System Operator (TSO) and its responsibilities include the operation, maintenance and development of the transmission system in a safe, secure, reliable, economical and efficient manner. ESB Networks is the Transmission Asset Owner (TAO), and it is required to maintain the transmission system and carry out construction work for its development in accordance with the TSO's Transmission Development Plan.[282]

Every five years the Commission for Energy Regulation (CER) puts in place a revenue control that sets the transmission revenue that can be collected from customers. This revenue is collected by the TSO through TUoS charges, and is distributed between the TSO and TAO in accordance with the Infrastructure Agreement between the two bodies.[283] This agreement also provides for other responsibilities to be divided between the two bodies as follows:[284]

Table 11.1 Breakdown of TSO and TAO responsibility in Ireland

Activity	TSO Responsibility	TAO Responsibility
Identification of Need	X	
Provision of Standard Costs		X
Selection of Optimal Solution	X	
Obtaining Planning Permission	X	
Obtaining Wayleaves (easements)	X	
Outage Planning	X	
Detailed Design		X
Procurement of Materials		X
Procurement of Resources		X
Management of Site Works		X
Commissioning		X

282 Commission for Energy Regulation, *Decision on TSO and TAO transmission revenue for 2011 to 2015, Decision Paper*, 19 November 2010, Dublin, p. 22.

283 Ibid, p. 3.

284 Ibid, p. 23.

11.4 Summary

The Commission notes the challenges involved in designing appropriate arrangements and incentives for efficient transmission planning and investment. Against this background, we observe that the existing arrangements are delivering many of the outcomes that would be expected under a well-functioning transmission planning regime. Further, a number of the transmission planning arrangements are new, and it is therefore difficult to comprehensively evaluate their performance.

However, there are a number of stakeholders who continue to hold concerns regarding the efficiency of existing frameworks, particularly in respect of inter-regional investment. We are also mindful that robust planning frameworks are an essential component of packages 1 and 2.

We have therefore presented in this chapter a number of options for reforming the existing planning frameworks, ranging from enhancements to the current arrangements to more substantial options. These reflect the different views on the need for change. However, the Commission considers it important that, following the conclusion of this process, planning arrangements then remain stable in order to give certainty to those making commercial investment decisions.

As part of our process for considering which, if any, of the options should be further considered, the Commission is seeking stakeholder responses to the following questions:

- Is there a case for change?
- If so, is there a case for enhancements to current arrangements or for more substantial reform?
- Of the options presented, which do stakeholders consider merit further analysis and assessment?
- Are there any other options that should be considered?

12 Issues related to current connection arrangements

Box 12.1: Summary of this chapter

Stakeholders, in particular generators, have raised a number of concerns regarding the way in which the connection process operates and the extent to which issues related to connections lead to inefficient outcomes.

Stakeholder submissions have also demonstrated that there is a lack of clarity regarding how connections are currently regulated. The Rules are not clear in relation to what services TNSPs are required to provide to facilitate a connection to the national grid and how those services are regulated. This uncertainty has resulted in a degree of discretion on the part of TNSPs in relation to what services they provide, how those services are regulated, and consequently what rights generators, other Network Service Providers (NSPs) and other transmission users have when negotiating a connection to the national grid.

This chapter provides an overview of the current provisions regulating the connection of generators, NSPs and other transmission users to the national grid. It explains the causes of uncertainty regarding the application of those provisions in terms of what services related to connections are regulated under the Rules, how those services are regulated and what obligations TNSPs have in relation to connections.

The Commission considers that the current connections provisions should be amended to clarify their application and address the current causes of uncertainty.

12.1 Introduction

Several generators' submissions in response to the Directions Paper stated that the current connections provisions are unclear about the services that TNSPs are obliged to provide, the scope of those services and how those services are treated for regulatory purposes. For example, Origin Energy's concerns regarding the current connections provisions included that:[285]

> "Across jurisdictions, there is a lack of clarity and consistency around the classification of transmission services. The current NER definitions for transmission services can be confusing. The NER can greatly benefit from further guidance and clarification on both the definitions of various transmission services as well as the process for classifying them."

Concerns regarding the interpretation and application of the connections provisions were also raised by the NGF and TRUenergy.[286]

285 Origin Energy, Directions Paper submission, pp. 6-7.

286 NGF, Directions Paper submission, pp. 10-11; TRUenergy, Directions Paper submission, pp. 7-10.

The purpose of this chapter is to:

- provide an overview of the current provisions regulating the connection of generators, NSPs and other transmission users to the national grid; and
- explain several areas of uncertainty that currently exist in relation to the interpretation and application of those provisions and which may prevent efficient connection outcomes.

This chapter focuses on connections of new generators, as most of the issues that were raised in submissions related to generator connections. However, several of these issues are also relevant to connections of NSPs and other transmission users (i.e. large load).

The remainder of this chapter is set out as follows:

- section 12.2 describes the range of services that are required to connect a generator, NSP or other transmission user to the national grid;
- section 12.3 provides an overview of the current connections provisions and explains the key causes of uncertainty in the interpretation and application of those provisions; and
- section 12.4 provides a summary of these issues and sets out several questions for consideration by stakeholders.

This chapter is the first of three chapters in this report that address issues related to connections. Chapter 13 addresses the economic regulation of services that are required to connect generators and other users to the national grid, and sets out options for the economic regulation of those services. Chapter 14 deals specifically with issues related to "extensions" to the shared network that are required to facilitate a connection.

12.2 What services are required to connect to the national grid?

When seeking to interpret the current Rules provisions related to connections, it is important to understand that in order to connect to the national grid, a generator or other connecting party usually requires the relevant TNSP to provide several different services. As explained in section 12.3.1 below, those services go beyond what the Rules currently define as a *connection service*[287].

To connect to the national grid, a generator may require the TNSP to provide some or all of the following services, which are illustrated in Box 12.2 below:

[287] Where terms are italicised in chapters 12 to 14 of this report, they should be given their definition in Chapter 10 of the Rules. Any terms that are not italicised should be interpreted according to their common usage, unless otherwise defined in these chapters.

- the provision of a physical connection between the generator's facilities and the shared transmission network, and the construction, operation and maintenance of any assets that are required to provide that physical connection;
- the construction, operation and maintenance of a new substation to allow the generator to connect to the existing shared transmission network, and/or any other upgrades to the shared transmission network (such as communication or protection systems) that are necessary to meet the requirements of the Rules as a result of that connection;
- the construction, operation and maintenance of an extension from the generator's facilities to the TNSP's assets that provide the connection referred to above.

In addition, transmission users may fund augmentations to increase the capacity of the deeper network. However, such augmentations are optional and are not **required** to connect, and accordingly are not addressed in this chapter.

The treatment of each of these services (and the underlying assets) under the Rules is currently unclear. Section 12.3.1 explains that the Rules refer to several services that are relevant to connections, but the boundaries of what is included in each service and the regulatory treatment of each service is unclear. That section also notes certain areas where TNSPs' practices as to how these services are classified appears to vary between jurisdictions.

12.3 Causes of uncertainty regarding how services are currently regulated

There is a lack of clarity in the Rules regarding a number of elements of the regulation of services required for connections.

This uncertainty stems in part from definitions in Chapter 10 of the Rules that provide limited guidance and contain some ambiguity. The uncertainty is also contributed to by a degree of disconnect between the provisions in Chapter 5 that specify the connection process and those in Chapter 6A that govern the economic regulation of services.

As a result, a degree of interpretation is required on the part of both TNSPs and connecting parties in establishing their respective obligations and rights with regards to connections. This section explains the key causes of that uncertainty.

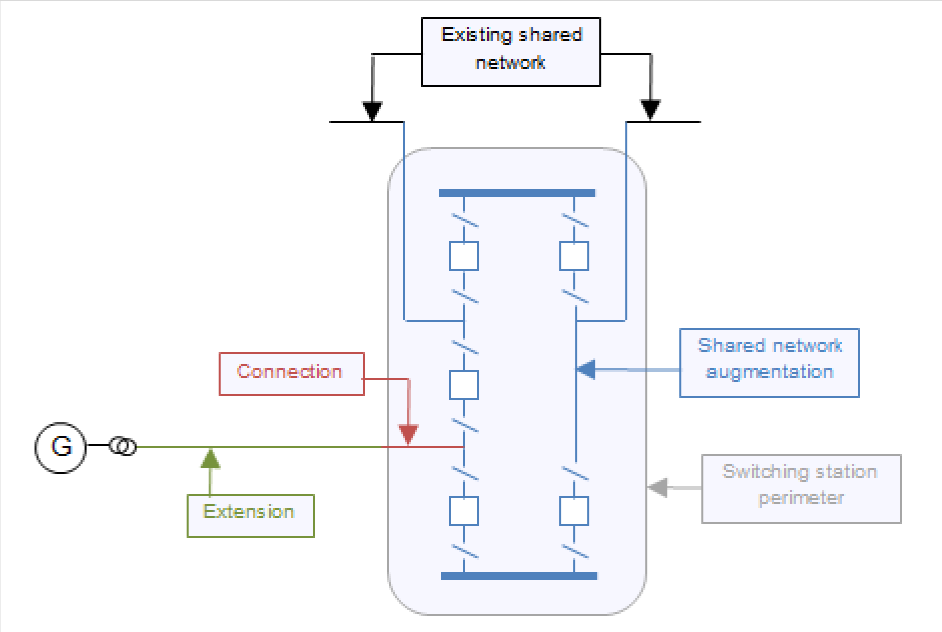
12.3.1 Categorisation of services related to connections under the Rules

As noted in section 12.2, several services are required to connect to the national grid. Box 12.2 provides a simplified illustration of the services that may be required to connect a new generator.[288] It is based on our understanding of the practices of most

288 The diagram is an example only. In particular, the layout of the switching station is based on an example and it is acknowledged that this layout may not be appropriate for all connections. In

TNSPs (noting that there are some divergences). It is intended to illustrate the key concepts and terms that are used in the connections provisions of the Rules.[289]

Box 12.2: Simplified example of a generator connection



This connection requires the construction of a new switching station[290] to allow the generator to connect to the existing shared transmission network. Prior to the connection, the transmission line at the top of the diagram was joined up and formed part of the shared transmission network. The existing line is shown in black. Other than this black line, everything else in the diagram is new and is constructed to allow the generator to connect.

In order to connect the generator, the existing transmission line is cut into and a new substation is connected to it. After the new substation is operational, all electricity in that part of the network flows through that substation and the substation is therefore considered to form part of the shared transmission network. The new substation is shown in blue. As explained below, most TNSPs classify this new substation as providing a *shared transmission service*.

In order to connect the generator to the new substation, a physical link or "connection" is required. This connection is shown in red. TNSPs' practices vary in relation to what they consider is part of the *connection service* under the Rules. For illustration, this diagram uses the practice of several TNSPs that the

particular, a switching station of this size may not be necessary for a single generator connection. The switching station layout is not critical and does not affect any of the categorisation issues discussed below.

289 The Commission's understanding of TNSPs' practices in relation to connections has been informed by TNSPs.

290 For the remainder of this example, and elsewhere in this report, the term "substation" has been used as a more generic reference to the infrastructure required to connect generators to the transmission network. We also note that the term "terminal station" is used in Victoria.

connection service involves the physical connection plus any assets that are exclusively used by the generator and are located between the shared transmission network and the substation fence. Most TNSPs consider that the *connection point* is located at the boundary between the red and blue lines.

The generator also requires a new transmission line to be constructed from its facilities to the boundary of the assets that are used to provide the *connection service*. In this diagram, this new line is referred to as an "extension" which is consistent with the practice of most (but not all) TNSPs, who treat this line as an *extension* under the Rules. This extension runs from the generator's transformer to the substation fence, which is consistent with the practice of several (but not all) TNSPs. Depending on how close the generator's facilities are to the substation, this extension could be anywhere from only a few metres long to hundreds of kilometres long. The current practice of TNSPs is that the generator may elect to construct and operate this extension itself, engage a third party to do so, or request the TNSP to do so.

Regardless of uncertainties about how these services are classified, the practice of all TNSPs is that the connecting generator is required to pay for all of the services that are required for it to connect to the national grid. The classification of these services affects important matters such as how charges and other terms are determined and whether TNSPs are required to provide them, but not who pays for them.[291]

"Connection services"

Every connection to the national grid requires the TNSP to provide a *connection service*. However, the exact scope of a *connection service* as defined in the Rules is unclear.

A *connection service* is defined in the Rules as:[292]

> "An *entry service* (being a service provided to serve a *Generator* or a group of *Generators*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*) or an *exit service* (being a service provided to serve a *Transmission Customer* or *Distribution Customer* or a group of *Transmission Customers* or *Distribution Customers*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*)."

This definition does not make it clear what the service involves - i.e. what is required "to serve a Generator ... at a single connection point".

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291 The only assets in Box 12.2 that are not paid for by the connecting generator are the black line that represents the existing shared network. There may be some circumstances where a new substation to connect a new generator could be classified as a *prescribed transmission service* and therefore paid for by all users rather than by the connecting generator, for example if it passed the RIT-T, but those circumstances are rare and are outside of the scope of this chapter. It is noted that different rules apply to generators in existence at the start of the NEM, who do not pay for the construction, operation or maintenance of substations to which they are connected.

292 NER Chapter 10.

The boundaries of the service are also unclear, due to uncertainties as to the location of the "connection point". A *connection point* is simply defined as "the agreed point of supply" established between the TNSP and the generator.

The definition of a *negotiated transmission service* (which is discussed in section 12.3.2 below) includes *connection services* that are provided to a generator at a single *transmission network connection point*. A *transmission network connection point* is defined as a *connection point* on a *transmission network*. The Commission understands that some TNSPs use the transmission network connection point and the connection point to define the two ends of the connection service (and therefore the connection assets that are used to provide that service). In particular, one TNSP considers that:

- the *connection point* marks the boundary between the assets that are used to provide the *connection service* and the assets that are used to provide the *extension* - i.e. the boundary between the green and red lines in Box 12.2;[293] and
- the *transmission network connection point* marks the boundary between the assets that are used to provide the *connection service* and the assets that form part of the shared transmission network - i.e. the boundary between the red and blue lines in Box 12.2.

However, because the relevant definitions do not provide certainty as to the location of either of these points, the extent of the connection service and the demarcation between the various services remains unclear.

These definitions could be considered to support a minimalist approach in respect of TNSPs' obligations to provide a physical connection to the network. In particular, it could be interpreted that the *connection service* only involves the physical connection at the connection point, and does not include any obligation to construct any assets between that point on the shared transmission network and the generator's facilities, including any extension.

The definition of *connection assets* does not help resolve this issue, essentially defining them as assets that are used to provide *connection services*. Accordingly, neither the definition of *connection assets* nor the definition of *connection services* provides certainty as to what comprises a *connection service*.

"Shared transmission services"

The Rules define a *shared transmission service* as:[294]

> "a service provided to a *Transmission Network User* for use of a *transmission network* for the conveyance of electricity (including a service that ensures the integrity of the related *transmission system*."

293 This interpretation appears to differ from most TNSPs, who consider that the *connection point* is located at the boundary between the red and blue lines in Box 12.2.

294 NER Chapter 10.

This definition provides little guidance as to the types of services that it covers and whether it covers any services related to connections.

The Commission understands that TNSPs consider that the construction, operation and maintenance of any augmentations to the existing shared transmission network that are required to connect a generator, NSP or other transmission user to the national grid are a *shared transmission service*. This approach is adopted in Grid Australia's Categorisation of Transmission Services Guidelines.[295] These augmentations would include a new substation, or other augmentations that are necessary to allow a connection (such as an upgrade to communications or protection systems).

The Commission understands that the practice of most TNSPs is to distinguish between *connection services* and *shared transmission services* based on either: whether the service relates to assets that, once operational, will form part of the shared transmission network (in which case the service is treated as a *shared transmission service*); or whether the relevant assets will be used exclusively by the connecting party (in which case the service is treated as a *connection service*). However, this distinction is not set out in Chapter 6A of the Rules or the relevant definitions.[296]

As noted above, the distinction between *connection services* and *shared transmission services* does not affect who pays for those services. Grid Australia's Guidelines state that any works that are required to the shared transmission network in order to effect a generator connection are funded by the relevant generator in accordance with the "causer pays" principle.[297] However, the Commission notes that a "causer pays" principle is not expressly set out anywhere in the Rules.

"Extensions"

The classification of extensions, and the boundary between extensions and connection services, is particularly important because the Rules provide that TNSPs are obliged to provide *connection services* but TNSPs consider that they have no obligation to provide *extensions* except in limited circumstances.[298]

The Rules define an *extension* as:[299]

> "an *augmentation* that requires the *connection* of a power line or *facility* outside the present boundaries of the *transmission* or *distribution network* owned, controlled or operated by a *Network Service Provider*"

295 Grid Australia, *Categorisation of Transmission Services Guideline Version 1.0, August 2010*, pp. 8-10.

296 TNSPs may base this distinction on the approach taken in the transitional provisions in clause 11.6.11 of the Rules.

297 Grid Australia, *Categorisation of Transmission Services Guideline Version 1.0, August 2010*, p. 9. Under Grid Australia's approach, generators are required to pay for all such services, provided that they are classified as *negotiated transmission services*.

298 See NER clause 5.3.6(k), which is discussed in section 12.3.4 below.

299 NER Chapter 10.

An extension is therefore a specific type of *augmentation*, which is defined in the NEL as work to enlarge a transmission system or increase its capacity.

These definitions do not clarify whether, or in what circumstances, works that are required for a connection to the national grid are classified as an extension.

TNSPs' practices regarding the classification of extensions appear to vary. The Commission understands that many TNSPs effectively treat an *extension* as covering anything that is required for a connection but which is not a *connection service* or a *shared transmission service*. In practice, many TNSPs use the substation fence as the boundary between the assets that are used to provide a *connection service* and the assets that are used to provide an *extension*, although there is nothing in the Rules to suggest that this is the appropriate demarcation.[300] This approach is shown in Box 12.2, where the *extension* involves the construction, operation and maintenance of the new transmission line shown in green.

However, one TNSP appears to consider that an *extension* as defined in the Rules is part of the *connection service* and only relates to assets that are within the substation fence. That TNSP considers that the transmission line outside the substation fence does not provide a service that is regulated under the Rules.

Distinction between assets and services

In relation to each of the above categories of service under the Rules, it is not clear whether the relevant service includes the construction of the assets that are required to provide the service.

Origin Energy raised this concern in its submission:[301]

> "In addition, we see further benefits in clarifying the treatment of construction assets required to provide connection or shared network services. Origin understands there is a distinction between the provision of a transmission service and the transmission assets that deliver that service; the construction of assets is not a transmission service in and of itself. This is not necessarily a consistently held view across the market. As such, the treatment of construction assets and transmission services is not uniform across the NEM. Investigating and clarifying this distinction in the NER can improve the operational efficiency of these Rules."

This lack of clarity arises in part because construction of the assets is not clearly part of any of the defined services under the current Rules provisions. For example, the definition of a *connection service* does not provide any guidance as to whether a *connection service* also includes constructing the underlying *connection assets*.

300 The use of the substation fence as the demarcation point appears linked to TNSPs' views that contestability is the key factor in determining whether a service should be economically regulated (see section 12.3.3 below) and the view of several TNSPs that works within the substation fence are not contestable.

This issue is important because, if the construction of the assets is part of a *prescribed transmission service* or *negotiated transmission service*, then:

- TNSPs are required to undertake that construction if requested by a connecting party; and
- the recovery of the capital costs of construction will form part of the charge for that service and will be regulated by the Rules.

This uncertainty is also related to a difference in approach between Chapters 5 and 6A of the Rules. Chapter 5 relates to the connection process and is primarily focused on asset provision. In contrast, Chapter 6A, which sets out a framework for the economic regulation of services, focuses on the provision of services and implicitly assumes that the assets that provide those services have already been constructed.[302]

Since the construction of an asset is not clearly part of the services referred to in Chapter 6A, there is no express link between the regulation of a service and the construction of the asset that provides that service. The NGF raised this concern in its submission to the Directions Paper where it noted that the related provisions of Chapters 5 and 6A "do not work together in a clear coherent manner".[303]

This issue is relevant to all assets necessary to facilitate a connection, including connection assets, substations and extensions.

Origin Energy considered that this distinction between assets and services was particularly important if contestability is used as the test for whether services should be economically regulated (which is discussed in section 12.3.3 below). Origin Energy submitted that the construction of the underlying assets may be contestable, but that does not mean that the transmission service delivered using those assets is also contestable and should not be economically regulated.[304]

The Commission understands that the current practice of most or all TNSPs is to treat the construction of the underlying assets as part of the relevant services referred to in the Rules. For example, the charges for a connection service will generally include recovery of the capital costs for constructing any connection assets.

12.3.2 Categories of services for economic regulation purposes

For the purposes of the economic regulation of services - i.e. how charges are determined - the Rules divide transmission services into the following three categories:

301 Origin Energy, Directions Paper submission, p. 6.

302 As discussed in chapter 13, prior to the introduction of Chapter 6A of the Rules, the system for classifying transmission services was primarily based on the function of the underlying assets. When Chapter 6A was introduced, transmission services became classified by the characteristics of the service without reference to the underlying assets.

303 NGF, Directions Paper submission, p. 10.

304 Origin Energy, Directions Paper submission, p. 6.

- *Prescribed transmission services*: Charges for *prescribed transmission services* are recovered from transmission customers in accordance with the Rules, not directly from the connecting party under a Connection Agreement. The assets that are used to provide *prescribed transmission services* are included in a TNSP's Regulatory Asset Base (RAB) and the revenues that a TNSP can recover for those services are regulated by the AER pursuant to the TNSP's transmission determination under Chapter 6A. Several specific types of transmission services are defined in the Rules as *prescribed transmission services*.

- *Negotiated transmission services*: Charges for negotiated services are not directly regulated by the AER and the assets that are used to provide *negotiated transmission services* are not included in a TNSP's RAB. Instead, the connecting party negotiates with the TNSP under a framework set out in Chapters 5 and 6A, with certain high-level requirements set out in the Rules (for example, obligations on the TNSP to offer fair and reasonable connection terms and to negotiate in good faith[305]) and recourse to arbitration if agreement cannot be reached. Several specific types of transmission services are defined in the Rules as *negotiated transmission services*.

- *Non-regulated transmission services*: The charges and other terms applying to non-regulated transmission services are commercially negotiated outside of the Rules. A *non-regulated transmission service* is simply defined as any service that is not a *prescribed transmission service* or a *negotiated transmission service*. This definition potentially leaves significant scope for services to be assigned to *non-regulated transmission services* due to the uncertainties regarding what services fall within the above two definitions. A TNSP is required to provide prescribed and *negotiated transmission services*,[306] but the Rules do not impose any obligation on a TNSP to provide non-regulated transmission services.

Each of these three categories are relevant to the services that are required to connect a generator, NSP or other transmission user to the national grid. Chapter 13 of this report explains which services fall into each category, and uncertainties about the classification of some services related to connections.

12.3.3 The role of contestability

There is currently uncertainty as to whether contestability is a relevant factor in determining whether a service is subject to economic regulation under the Rules. The appropriate test is for determining whether a service is contestable is also unclear.

Several submitters raised issues related to the role of contestability. Origin Energy stated:[307]

305 NER clauses 5.3.6(c) and 5.3.7(a).

306 NER clause 6A.1.3(2).

307 Origin Energy, Directions Paper submission, p. 6.

"We agree with the AEMC's position that contestability is not a criterion for determining whether a transmission service is prescribed, negotiated or non-regulated. However, this principle is not applied consistently in the market place. For example, Grid Australia presents a different interpretation in its Categorisation of Transmission Service Guidelines. Paragraph 3.2 states that:

Extensions to connect a Transmission Customer or Generator would generally be offered as non-regulated transmission services, as these works are usually fully contestable."

The NGF made similar comments in its submission.[308]

The Grid Australia Guidelines, and the practices of most TNSPs, treat contestability as the key factor in determining whether a service should be classified as a negotiated transmission service or a non-regulated transmission service.[309] If a service is contestable, Grid Australia considers that there is no reason why TNSPs should have an obligation to provide it or why it should be economically regulated.

There is no formal linkage in the Rules between a service being non-regulated and it being contestable.[310] However, the Draft Determination and Final Determination for the Rule change that introduced Chapter 6A indicated that a link may have been intended. For example:

- The Final Determination stated that "contestable services are outside the scope of regulation".[311]
- The Draft Determination stated that "The Commission has...clarified in the Draft Rule that services that are capable of competitive supply will not be subject to the commercial negotiation/arbitration requirements".[312]

However, neither the Draft nor Final Determination provided clarity on whether extensions were considered to be "capable of competitive supply". The definition of "contestable" in Chapter 10 of the Rules provides only limited guidance, stating that a transmission service is contestable if the laws of the relevant jurisdiction permit it to be provided by more than one TNSP "as a contestable service or on a competitive basis".

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308 NGF Directions Paper submission, p. 10.

309 Under TNSP's current practices, contestability does not appear to have any role in determining whether a service is classified as a prescribed transmission service.

310 There are specific provisions in Chapter 8 of the Rules that relate to the Victorian connections arrangements and allow certain augmentations to the shared network to be provided on a contestable basis. However, those provisions are not relevant to the more general issue of whether services are classified as negotiated or non-regulated.

311 AEMC, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Rule Determination, 16 November 2006, Sydney, p. 37.

312 AEMC, *Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Draft Rule Determination, 26 July 2006, Sydney, p. 24.

Contestability of construction versus operation and maintenance

If contestability is an appropriate test for determining whether a service should be subject to economic regulation, then a question arises as to whether a distinction should be drawn between the construction, operation and maintenance parts of the service and the level of contestability of each part of the service.

For example, if a generator connection requires the construction, maintenance and operation of a new substation, it is likely that only a registered and licensed TNSP can operate and maintain the substation once it is built. Accordingly, these aspects of the service are unlikely to be contestable. However, it appears to be possible for someone other than a TNSP (either the connecting generator itself or a third party) to construct the substation. That party could potentially then either gift or lease the substation to the TNSP. If such an arrangement is possible, then it may be appropriate to treat the construction aspect of the service as contestable and not regulated but treat the operation and maintenance as non-contestable and subject to economic regulation.

The Commission is aware of generators undertaking the construction of substations themselves (or through their own sub-contractors) in at least two instances, with the substation subsequently being gifted or leased to the TNSP. However, we understand that these TNSPs have some concerns about this arrangement and may be reluctant to adopt it in future. Any such arrangement would need to be agreed to by the TNSP, as it would not be appropriate to compel a TNSP to accept a gift or lease of an asset that has been constructed by someone else where the TNSP would then take on the liability for the maintenance and operation of that asset.[313]

This issue also applies to extensions, which are discussed in more detail in chapter 14.

12.3.4 What are TNSPs' obligations in relation to connections?

There is also uncertainty in the Rules as to the extent of TNSPs' obligations in relation to connections. Several provisions of Chapters 5 and 6A set out specific obligations of TNSPs. However, these provisions are unclear and there is no single provision that exhaustively sets out the extent of a TNSP's connection obligations and clarifies exactly which services they are required to provide.

The key obligations on TNSPs in relation to connections are as follows:

- Under clause 5.3.6(a) of the Rules, a TNSP is obliged to make an offer to *connect* a prospective user to its *network* (where to *connect* means to form a physical link to the TNSP's *network*). This obligation leaves doubt as to the extent of a TNSP's obligations. For example, it is unclear whether the TNSP is only required to form a physical link at the *connection point*, or whether the TNSP is also required to

313 The Commission also understands that the gifting or leasing of such an asset may have significant taxation consequences for the TNSP, which may make the TNSP reluctant to enter into such an arrangement.

construct, operate and maintain any assets that are required to facilitate the connection.

- Under clause 5.3.6(b), a TNSP's offer to connect must be fair and reasonable and must be capable of acceptance to constitute a *connection agreement*. Under clause 5.3.7(a), a connection applicant must negotiate and enter into a *connection agreement* with a TNSP if it wishes to accept the TNSP's offer to connect. A *connection agreement* is defined as an agreement by which a person "is *connected* to the *Network Service Provider's transmission* and/or *distribution network* and/or receives *transmission services* or *distribution services*".[314] TNSPs therefore have a clear obligation to make a fair and reasonable offer to connect a generator, but it is unclear what transmission services, if any, must be offered to the generator and provided under the resulting connection agreement. The wording "and/or receives transmission services" leaves uncertainty as to whether the TNSP is required to provide any transmission services under a connection agreement, or whether the provision of any such services is optional. It is also unclear what "transmission services" are intended to be provided under a *connection agreement*, for example whether the only services that must be provided under that agreement are *connection services* or whether the agreement should also cover *shared transmission services* and/or *extensions*.

- Under clause 6A.1.3, a TNSP must provide *prescribed transmission services* or *negotiated transmission services*. As explained above, there is some uncertainty as to what services are prescribed or negotiated, and what services are non-regulated.

In relation to extensions, clause 5.3.6(k) provides that:

> “Nothing in the *Rules* is to be read or construed as imposing an obligation on a *Network Service Provider* to effect an extension of a *network* unless that extension is required to effect or facilitate the *connection* of a *Connection Applicant* and the *connection* is the subject of a *connection agreement*.”

The interpretation of this provision, in particular the exception regarding connections, is unclear. This issue is discussed in more detail in Chapter 14.

12.4 Summary and questions for stakeholders

As described above, there is currently considerable uncertainty in the Rules regarding how services that are required for a connection are regulated, and the rights of TNSPs and connecting parties in relation to those services.

The connections provisions rely to a large extent on TNSPs and generators (or other connecting parties) negotiating the terms of the connection. However, it is difficult for parties to negotiate efficient outcomes if they do not know their underlying rights and obligations and what rules apply to their negotiations.

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314 NER Chapter 10.

The Commission agrees with the following comment made by the NGF in its submission on the Directions Paper:[315]

> "The current provisions give rise to confusion, which makes negotiating a connection more challenging than it needs to be. Improvements to drafting can make the connection process more efficient for all counter-parties."

Accordingly, the Commission considers that amendments should be made to clarify the interpretation and application of the relevant provisions of Chapters 5 and 6A of the Rules and the relevant definitions in Chapter 10 in relation to:

- what each transmission service required to connect to the national grid involves, including the boundaries of the current categories of *shared transmission services*, *connection services* and services provided by means of *extensions*, and whether each service includes the construction of the underlying assets;
- how each such service is regulated under the Rules, including which services are *prescribed transmission services*, *negotiated transmission services* and *non-regulated transmission services*; and
- what TNSPs' obligations are in relation to connections and the provision of each of these services.

These provisions should be clarified regardless of whether the Commission also adopts some of the more significant reforms related to connections that are discussed in chapters 13 and 14 of this report.

The Commission seeks stakeholders' views on the issues discussed in this chapter, including the following specific questions:

- Does the description in this chapter of the current connections provisions and TNSPs' practices correspond with stakeholders' experiences in practice?
- Are the current categories of services in the Rules - e.g. *shared transmission services* and *connection services* - the appropriate categories for classifying services related to connections, or should one or more new categories be created for services related to connections?
- Should the construction of the underlying assets be part of the relevant services that a TNSP is required to provide under the Rules?
- Is contestability an appropriate test for determining whether a service related to connections should be economically regulated under the Rules? If so:
  - What is an appropriate definition of contestability?

315 NGF Directions Paper submission, p. 11.

- — Should contestability be considered separately in relation to the construction aspects of the service and the ongoing operation and maintenance aspects of the service?
- — Which services required to connect a generator, NSP or other transmission user to the national grid are contestable?

- What obligations should TNSPs have in relation to connections?

13 Economic regulation of connection-related services

Box 13.1: Summary of this chapter

The purpose of this chapter is to outline proposals for reforming the economic regulation of transmission services that are required to connect a generator or transmission user to the national grid. Some stakeholders have raised concerns regarding the current connection arrangements, particularly in relation to the imbalance in bargaining power between network users and TNSPs.

Three proposals have been developed in response to these concerns that represent varying degrees of change to the current arrangements:

- enhancements to the dispute resolution provisions that currently apply to negotiated transmission services;
- strengthening the negotiating framework that applies to negotiated transmission services, including measures to increase transparency and potentially specifying the return that TNSPs are entitled to for providing these services; and
- migrating transmission services that are required for the connection of generators and other transmission users to the national grid from negotiated transmission services to prescribed transmission services.

Generators, or other transmission users, would continue to pay for all services required for their connection to the transmission network.

The assessment of the proposals will be primarily based on consideration of the degree of imbalance in bargaining power that generators and other transmission users face when negotiating with a TNSP. The Commission seeks further evidence on the materiality of any impacts of this imbalance.

13.1 Introduction

This chapter addresses how transmission services that are required to connect a generator or other transmission user to the national grid should be regulated. It sets out three possible proposals for the economic regulation of those services.

In this chapter, the Commission is not proposing that consumers pay for connection-related services that are provided to a generator. The potential forms of economic regulation discussed in this chapter only impact on how the charges for these services (and other terms and conditions related to their provision) are determined, not who pays for them.

This chapter focuses on the connection of generators and other transmission users (i.e. non-DNSP large load), which was the focus of submissions. However, the connection of Network Service Providers (NSPs) is also discussed where relevant.

This chapter is structured as follows:

- the remainder of this section describes the range of services that are required to connect a generator, NSP or other transmission user to the national grid, how those services are currently regulated and stakeholders’ concerns regarding imbalances in bargaining power;
- section 13.2 outlines the principles that were used to develop the proposals that are presented in this chapter;
- section 13.3 provides a high level outline of the proposals for economic regulation; and
- sections 13.4 to 13.6 describe each of the three proposals and the advantages and disadvantages of each proposal.

13.1.1 What connection-related services should be subject to economic regulation?

The Commission considers that transmission services should be subject to economic regulation if they cannot be provided on a genuinely contestable basis. This includes situations where, for reasons of system security or reliability, it is appropriate that the incumbent TNSP should provide the service.

The Commission considers that the following services **required** to connect a generator, transmission user or NSP to the national grid cannot be provided on a genuinely contestable basis and should be subject to some form of economic regulation:[316]

- the operation and maintenance of a new substation to enable a generator, transmission user or NSP to connect to the national grid; and
- the connection of a generator, transmission user or NSP to a substation.

As discussed in chapter 12, the Commission is seeking stakeholders' views on whether it is possible to separate the construction of a new substation from the subsequent operation and maintenance of that substation, and whether the construction aspect of this service is contestable. If the construction of these assets is not a separate service that is genuinely contestable, then the construction, operation and maintenance should be treated as a single service and subject to economic regulation.

The connection of a new generator or transmission user may also require other upgrades to the existing transmission network such as communication and protection systems to meet the requirements of the Rules. If those services are required for a

316 The extent to which a transmission service can be provided for on a genuinely contestable basis is considered in more detail in chapter 12, and in chapter 14 with specific reference to "extensions" from a generator's facility to the transmission network. Where a view is formed that certain transmission services can be provided for on a contestable basis, these should not be subject to economic regulation under the Rules. As noted in chapter 12, the link between "contestable" and non-regulated transmission services is not clear.

connection, then these services should also be subject to economic regulation under the Rules.

Augmentations to the transmission network for the purpose of providing a generator with better conditions of access to the regional reference node are not required to connect a generator. It is possible for the generator to connect without such an augmentation. Those augmentations are not directly related to connection and accordingly are not the subject of this chapter.

In the remainder of this chapter, services that are required to connect a generator, other transmission user or NSP to the national grid, are referred to as "connection-related services". As explained below, these services are generally broader than the services that are currently defined as *connection services* in the Rules.

13.1.2 Current economic regulation of connection-related services

The purpose of this chapter is to consider how connection-related services should be economically regulated, and the costs and benefits of various potential forms of economic regulation.

The Rules are currently not clear on the economic regulation of connection-related services. Under the Rules:

- All transmission services, including *shared transmission services* and *connection services* required to connect NSPs[317] to the transmission network, are categorised as *prescribed transmission services*. *Prescribed transmission services* are subject to a revenue cap that is determined by the AER during transmission revenue determinations.

- *Connection services* provided to generators and other transmission users are characterised as *negotiated transmission services*. However, as explained in chapter 12, the scope of *connection services* is unclear and appears to be very narrowly applied in practice.

- Apart from *connection services*, the Rules are unclear in relation to the categorisation of other connection-related services. In particular, it is unclear how the services associated with the construction, operation and maintenance of a new substation to enable a generator to connect to the national grid are economically regulated. For example, it is unclear whether these services meet the requirements of a *prescribed transmission service* or a *negotiated transmission services*.

The Commission understands that it is the practice of TNSPs to treat all connection-related services that are provided to generators (other than extensions to connect a generator's facility to a substation) as *negotiated transmission service*. The Commission understands that TNSPs consider that services associated with the

317 Except Market Network Service Providers.

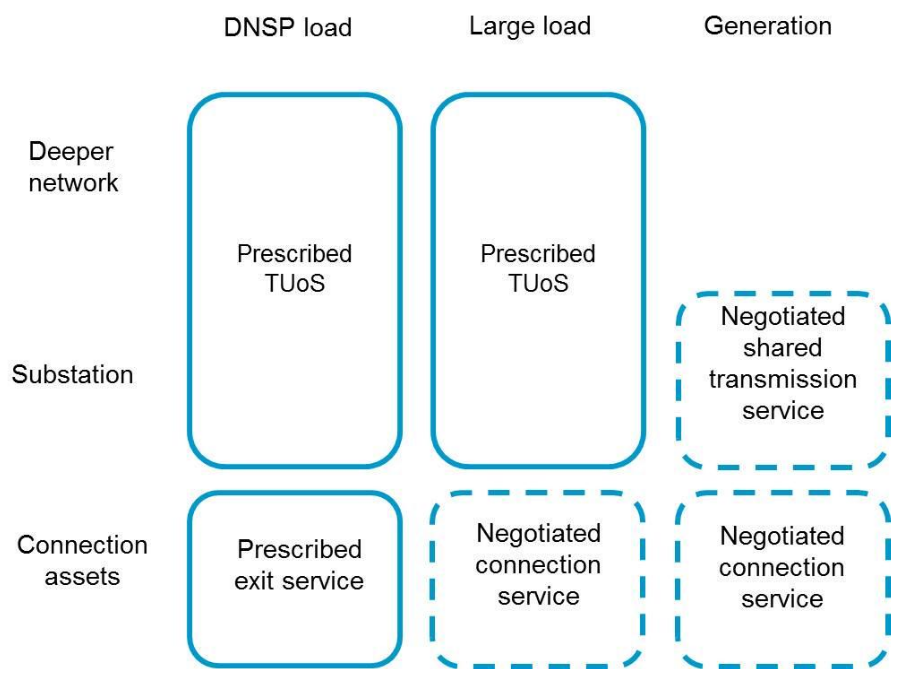
construction, operation and maintenance of a new substation to enable a generator to connect to the national grid are classified as a *shared transmission service* that is a *negotiated transmission service*. However, there is some uncertainty as to whether this service comes within the strict wording of the relevant definitions, which are not clearly worded.

In contrast, the Commission understands that TNSPs' practice is to classify the construction, operation and maintenance of a new substation to enable a DNSP or other transmission user (such as a large load) to connect to the national grid as a *shared transmission service* that is a *prescribed transmission service*.

This issue is further complicated by the varying regulatory treatment between incumbent and new generators. The Commission understands that incumbent generators connected prior to the start of the NEM are not required to pay any share of the costs of the existing substation to which they are connected, or contribute to the ongoing maintenance of those substations.

Figure 13.1 illustrates the Commission's understanding of TNSPs' practices regarding the classification of connection-related services.

Figure 13.1 Illustration of current arrangements



As noted in chapter 12, regardless of the uncertainties about how these services are classified, the practice of all TNSPs is that new connecting generators are required to pay for all connection-related services.

13.1.3 Imbalances in bargaining power

Imbalances in bargaining power between a TNSP and a generator or other transmission user arise when there is only a single provider of a transmission service in the market. This means that a generator or other transmission user cannot seek alternative offers for a transmission service and is bound to negotiate with a single service provider for price and non-price conditions of supply. When this situation arises, a TNSP is not disciplined by competitive markets forces in setting or influencing the price for connection-related services.

In practice, all transmission services required by a generator to connect to the national grid (excluding extensions and other services that may be classified as non-regulated transmission services) are supplied according to the "negotiate/arbitrate model" of economic regulation. The negotiate/arbitrate model is predicated on generators, and other transmission users, having sufficient countervailing market power such that they can negotiate technically and economically efficient outcomes. Transmission services provided for under this model of economic regulation are characterised as *negotiated transmission services*.

To safeguard generators' and other transmission users' countervailing market power, the Rules specify a number of criteria that a TNSP must satisfy in supplying *negotiated transmission services* to a generator or other transmission user. These criteria are outlined in the Rules, and must be reflected in the negotiating framework developed by a TNSP which is subject to AER approval during transmission revenue determinations. The intention of the negotiating framework is to ensure that the price and non-price terms and conditions of supply are reasonable.

However, generators and other transmission users that responded to our Issues Paper and Directions Paper consistently argued that they experienced significant imbalances in bargaining power when negotiating for transmission services with a TNSP and that the negotiate/arbitrate model provided inadequate safeguards against TNSP monopoly power.[318] The assumption that generators, and other transmission users, had some degree of countervailing market power was challenged by these stakeholders in submissions.

Infigen noted that the imbalance in negotiating power was "probably the single largest issue with regards to new connections...generators have no effective means to force NSPs to follow existing Rules".[319]

TRUenergy argued that the prevailing imbalance in negotiating power has led to inefficient connection agreements:[320]

> "...there has always been an imbalance in the bargaining power when negotiating with a monopoly during the connection process. Therefore, in negotiating a connection contract with a monopoly, it has always proved difficult to get concessions from that monopoly when finalising the

318 Infigen, Issues Paper submission, p. 8; AGL, Issues Paper submission, p. 28; EUAA, Issues Paper submission, p. 8; MEU, Issues Paper submission, p. 37; Northern Group of Generators, Issues Paper submission, p. 30.

319 Infigen, Directions Paper submission, p. 6.

320 TRUenergy, Directions Paper submission, p. 6.

> connection contract. Thus, in negotiating any connection agreement, we have always felt that we absorbed an unnecessary allocation of liability in the connection contract. Perhaps this is not surprising given the lack of bargaining power a generator has when negotiating with a monopoly."

Origin noted a similar concern with regard to negotiating with TNSPs:[321]

> "Once a connection process commences, the balance of power shifts towards the NSP. There is limited opportunity for the connection proponent to contest delays and hold the NSP accountable. The existing NER do not sufficiently recognise the increased negotiating position held by the NSPs once the process commences. A connecting party is unable to switch 'connection providers' in the middle of the process, either because there are no alternative service providers or, if there are, it is not commercially viable to do so. The NER require improved incentives and structure to account for this inherent imbalance in the negotiating positions of NSPs and connection proponents."

While generators and other transmission users who provided submissions were uniform in their views that there was an imbalance in bargaining power, each had different views as to the extent and materiality of the issue. The Commission therefore considers that there is insufficient evidence to allow for an informed judgement to be made at this stage as to the extent of the imbalance in bargaining power, the materiality of the inefficiencies that might result, and the scope of reform that may therefore be appropriate.

13.2 Guiding economic principles for the development of proposals

The guiding principle for developing and assessing the proposals for the economic regulation of transmission services in this chapter is that the extent and form of economic regulation applied to each type of transmission service should be based on the degree of market power exhibited in the provision of that transmission service. This is based on the assessment framework used for the 2006 Review of Electricity Transmission Revenue and Pricing Rules and formulated by the Expert Panel on Energy Access Pricing (the Panel), which reported to the MCE on the issue in April 2006.

The Panel reasoned that:[322]

> "the general principle to be applied is that more intrusive and potentially costly forms of regulation...will only be warranted where substantial market power is involved. Where the market conditions involve the reality of, or potential for, a measure of contestability or the prospect of

321 Origin, Directions Paper submission, p. 2; NGF, Directions Paper submission, p. 2.

322 Expert Panel on Energy Access Pricing Report to the Ministerial Council on Energy, April 2006, p. 47.

meaningful commercial negotiation, less intrusive and costly forms of regulation are likely to be warranted. "

Box 13.2: Summary of the 2006 Review of Electricity Transmission Revenue and Pricing Rules

The AEMC's 2006 review of the electricity transmission revenue and pricing Rules considered the economic conditions of supply for transmission services. It led to a number of changes to the arrangements that guide generator and other transmission user connections to the national grid. Notably, these changes included:

- The system for categorising transmission services was changed from asset based to service based provision. Prior to the adoption of Chapter 6A in the Rules, services were characterised according to the function of the asset and the service that asset provided. The current arrangement is now based on the provision of services, without reference to the underlying assets.
- Connection services provided to generators and other transmission users were migrated from the prescribed transmission service category to the negotiated transmission service category.

The 2006 review resulted in a continuation of the three-tiered approach to the economic regulation of transmission services by maintaining the categories of *prescribed transmission services*, *negotiated transmission services* (previously referred to as "negotiable" services) and non-regulated transmission service (previously referred to as "contestable" services).[323]

The Panel considered there were a number of consistent criteria for assessing market power that may be applied in the decision making process on whether more or less intrusive forms of regulation were appropriate including:

- **barriers to entry:** the presence and extent of barriers to entry in the market in which the services to be subject to regulation are provided;
- **network externalities:** the presence and extent of interdependencies (or "network externalities") between the services to be provided by TNSPs;
- **countervailing market power:** the extent of market power possessed by TNSPs;
- **substitution possibilities:** the presence and extent of substitutes, and the elasticity of demand in the market for the services to be subject to regulation;

323 Prior to the 2006 review, transmission services that did not meet the criteria for either prescribed transmission services or negotiated transmission services were not subject to regulation under the Rules. These were considered a "contestable" transmission service. The Rules currently provide for a similar type of transmission service that is not subject to regulation under the Rules, and is termed a "non-regulated transmission service".

- **information asymmetry:** the extent to which users and prospective users of the services are likely to have adequate information as a basis for negotiation with the owners, operators or controllers of the facilities.

The Panel cautioned that more intrusive forms of economic regulation should be limited to those services where there is likely to be substantial cost savings. Further, regulations should provide sufficient incentive for efficient investment and operation whilst minimising the scope for monopoly behaviour. Less intrusive forms of regulation, such as a negotiate/arbitrate model, or price monitoring regimes, incur lower administrative costs. These forms of economic regulation are more appropriate where market power is less substantial and there is potential for contestability to emerge.

The Commission considers that the assessment framework developed by the Panel is broadly appropriate for developing and assessing the proposals outlined in this chapter. The assessment framework duly considers issues associated with the imbalance in bargaining power that can arise where services are not contestable, as well as information asymmetries that can impact on achieving economically efficient outcomes.

It may be the case that imbalances in bargaining power become more problematic as the pattern of consumption and production of energy changes in response to climate change policies. In particular, the entry into the generator market of smaller renewable energy generation means that generators may have fewer resources and be greater in number than was assumed when the Rules for Chapter 6A were drafted. Such smaller generators may be less well-resourced and less familiar with connection negotiations, and therefore potentially less able to negotiate commercially and technically efficient connection arrangements with TNSPs.

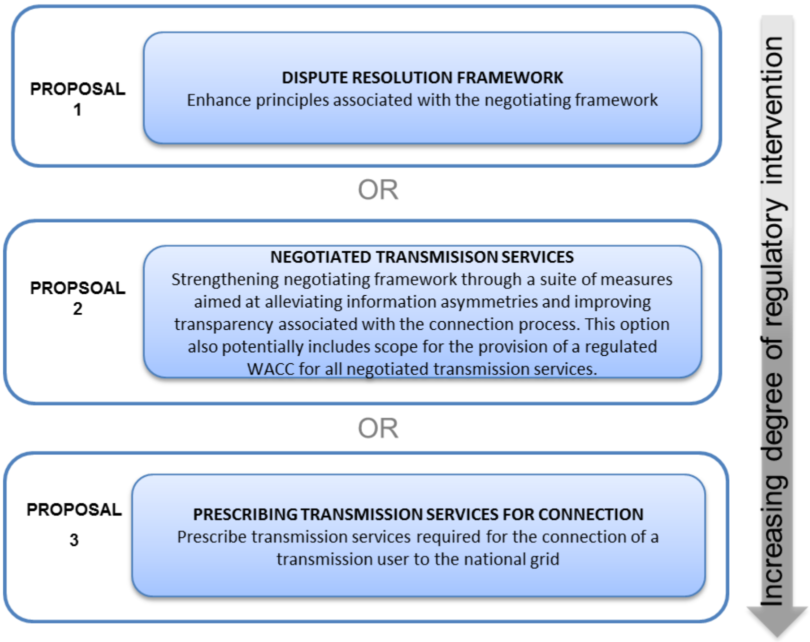
Therefore in applying the assessment framework described above, the Commission will consider the potential changes to the generation sector, as well as new information that has come to light through submissions on the effectiveness of the current arrangements in place.

13.3 High level outline of proposals

This section provides a high-level overview of the three proposals we have developed for potentially amending the economic regulation of connection-related services. The proposals have been developed on the basis of varying degrees of imbalance in bargaining power when generators and other transmission users negotiate with a TNSP for the provision of connection-related services.

It is instructive to view each of these proposals as being located along a continuum of decreasing bargaining power. As illustrated in Figure 13.2, the degree of regulatory intervention that is justified should be based on the extent of the imbalance in bargaining power and the materiality of the economic inefficiencies that arise when negotiating with the monopoly service provider for transmission services.

Figure 13.2 Proposals for the economic regulation of connection-related services



Proposal 1 may be appropriate where any imbalance in bargaining power is considered to be minimal, but sufficient to warrant some enhancement of the existing arrangements. The intended effect of this proposal is to reduce the barriers to arbitration by establishing a dispute resolution framework that is predictable and consistent in the quality of decision-making.

Proposals 2 and 3 may be appropriate if there is a material imbalance in bargaining power that is preventing generators or other transmission users from negotiating efficient arrangements with TNSPs.

Proposal 2 includes a package of complementary measures aimed at alleviating information asymmetries and increasing the level of transparency associated with the negotiation process. These measures could be implemented through the negotiating framework and potentially include:

- mandated transparency in the breakdown of costs associated with a connection;
- evidence of costs and any changes in costs;
- a requirement for TNSPs to publish standard contract templates; and/or
- publication of a standard price schedule and/or a range of estimated connection costs.

The Commission considers that this proposal could also accommodate greater specification in the weighted average cost of capital (WACC) that is applied to connection-related services.

Proposal 3 represents the greatest change to the current arrangements. All connection-related services would be migrated from the category of negotiated transmissions services to prescribed transmission services.

Under this proposal, the assets used to provide these services would be rolled into the Regulatory Asset Base (RAB) of a TNSP and charges would be allocated to the connecting party, such as the generator or other transmission user.

13.4 Proposal 1: Enhancements to dispute resolution

Box 13.3: Summary of Proposal 1

This proposal involves:

- establishment of an independent arbitrator, potentially within the AER; and
- changes to the arrangements for cost-recovery for dispute resolution.

13.4.1 Rationale for approach and description of proposal

While stakeholders have raised concern in relation to the difficulties they experience when negotiating with TNSPs for connection-related services, we understand that the dispute resolution process has not been invoked under the current arrangements, or prior to the adoption of Chapter 6A.[324]This may be because there are barriers to dispute resolution which prevent generators and other transmission users from using the process, or it may be that the materiality of concerns in the negotiating process has not been significant enough to incentivise a party to seek recourse.

This proposal would seek to make the dispute resolution process for generators and other transmission users more accessible should disputes arise in relation to the price and non-price terms of connection-related services. The changes outlined under this proposal would apply to disputes regarding both *negotiated transmission services* and *prescribed transmission services*.

A dispute resolution process should provide an efficient and effective pathway for resolving disputes between TNSPs and generators or other transmission users. Once invoked, the dispute resolution process should not be costly or protracted, nor should it pose an unnecessary risk to the generator or other transmission user achieving project outcomes. This means that where an applicant (i.e. a generator or transmission user) has assessed that they have a legitimate claim that requires arbitration, they should not be unduly penalised for taking action because of a cumbersome or time-consuming dispute resolution process.

324 The dispute resolution process is outlined in Part K of Chapter 6A of the Rules. It describes the process for commercial arbitration in relation to both *prescribed transmission services* and *negotiated transmission services*.

Conversely, a dispute resolution process should establish some threshold requirement to ensure that inappropriate claims are not made against either an applicant or provider (i.e. the TNSP). Parties should be encouraged to make a genuine attempt to resolve the matter as part of negotiations before resorting to dispute resolution.

Therefore, this proposal is intended to achieve two key outcomes for generators and other transmission users:

- to lower the barriers to dispute resolution in order to make this proposal more accessible where genuine attempts between the parties to resolve matters have failed; and
- to provide predictability and consistency in the quality of decision making in the dispute resolution process, which should also reduce potential barriers to invoking the process.

Under this proposal, the current provisions that require the appointment of a commercial arbitrator would be replaced by the establishment of a permanent arbitration body, potentially within the AER. Establishing a permanent arbitration body may increase the confidence of potential users of the dispute resolution process, such as generators and other transmission users. This is because over time generators and other transmission users may gain a better understanding of the quality of decision-making from the arbitration body.

Currently, at the initiation of a dispute resolution process, the applicant and provider are required to nominate two commercial arbitrators, with the final selection resting with the AER. This process of selection means that it is highly unlikely that the same commercial arbitrator is selected to hear a number of disputes.

An alternative option to establishing an arbitration body within the AER would be to establish an independent standing panel that would hear arbitration matters on an ongoing basis. Panel members could potentially be nominated through a combination of the AER, other market institutions and peak bodies.

Should an independent standing panel be established, we propose that the method of cost-recovery for the arbitration process be amended. There are two possible cost-recovery options:

- levying a fee on market participants to fund the arbitration body; or
- requiring that both parties equally contribute to the costs of arbitration.

Currently under the Rules, the commercial arbitrator has the power to set the terms of cost-recovery for the dispute resolution process, and may order for a single party to pay for the costs of arbitration.

Lowering the barriers to dispute resolution would necessitate the introduction of a threshold requirement. Before arbitration could proceed, both the applicant and the provider should be required to demonstrate that they have engaged in genuine attempts to resolve the matter at hand. The independent arbitrator would retain the power to determine whether the claims made by either party were either misconceived, lacking in substance or vexatious, and terminate proceedings.

The standard 30 day period for arbitration set out in the Rules[325] would remain unchanged under this proposal. This is a reasonably tight time-frame and shortening the time-frame for resolving disputes is not considered feasible, and may diminish the ability of the independent body to deliver decisions of a robust and high quality.

13.4.2 Advantages and disadvantages of proposal 1

Advantages

The proposed changes to the dispute resolution process may provide an effective means of lowering the barriers to arbitration and, more generally, may enhance the quality of decision making over the longer-term.

Centralising arbitration into a single independent body can potentially build and sustain the body of knowledge within the arbitrator. Over the longer term, this could potentially lead to greater consistency in the predictability and the quality of the decisions made by the independent body.

This proposal is also likely to provide clarity of information on the dispute resolution process. By providing clarity of information, generators and transmission users are likely to be better informed of the risks attached to arbitration, which may assist applicants in determining whether to invoke the dispute resolution process.

The method for cost recovery can also potentially play an important role in lowering the barriers to arbitration. Where the costs of arbitration are recovered as a general charge levied on market participants, generators and transmission users may be more inclined to take action as the cost of arbitration is limited to the time it takes to resolve the matter under dispute and their own costs.

Similarly, requiring both the applicant and provider to equally contribute to the costs of arbitration, irrespective of the outcome, may act as an incentive to only enter into arbitration where a genuine attempt has been made to resolve the matter under dispute.

The key advantage of establishing an independent body, separate to the AER, is that it would maintain a clear separation between the body which approves the service criteria and negotiating frameworks of each TNSP, and the body responsible for interpreting compliance with it. If the AER was responsible for both the approval and interpretation of service criteria and negotiating frameworks, then these functions might need to be separated within the organisation.

325 Clause 6A.30.5(a) allows for the period of arbitration to be extended with the consent of both parties.

Disadvantages

It is expected that if an arbitration body was established within the AER, that this would be overall less costly than commercial arbitration. However, funding for the arbitration body is likely to be sourced through the Commonwealth, which would represent an additional cost to taxpayers.

In addition, establishing an arbitrator within the AER may substantially increase its workload.

The key disadvantage of establishing an independent body, separate to the AER, is that it potentially increases the cost to industry participants, and therefore consumers. This disadvantage does not apply to the cost recovery method that requires the applicant and provider to equally share the costs of arbitration but that approach may impose a barrier to invoking dispute resolution.

Given that we are unable to precisely determine the reasons for generators and other transmission users not invoking the dispute resolution process, it is unclear whether lowering barriers to dispute resolution would result in its increased use or efficient connection outcomes as there may be other reasons for generators and other transmission users not invoking the dispute resolution process.

13.5 Proposal 2: Enhancements to the negotiating framework

Box 13.4: Summary of Proposal 2

This proposal involves strengthening the negotiation framework through a suite of complementary measures, potentially requiring TNSPs to:

- provide the connecting party a full breakdown of services and costs associated with the connection;
- provide the connecting party evidence of costs and any changes in costs;
- publish standard contract templates; and/or
- publish a range of indicative or average connection costs and standard designs that these indicative or average costs are based on.

This proposal could also include greater specification in a WACC that would apply to all *negotiated transmission services*.

13.5.1 Rationale for approach and description of proposal

Proposal 2 remains grounded in the negotiate/arbitrate model, and introduces a suite of complementary measures intended to improve transparency associated with the connection process and alleviate information asymmetries. This proposal is predicated on generators and transmission users having some degree of countervailing market power, and seeks to enhance existing countervailing market power by strengthening the negotiating framework.

This proposal introduces a suite of complementary measures that would be included under the existing negotiating framework. The measures are aimed at improving the transparency of the connection process, especially in relation to the derivation of prices for connection-related services. These measures are also intended to alleviate information asymmetries which may limit a generator or transmission user's ability to negotiate commercially efficient outcomes, as well as accurately forecast the costs associated with connecting to the national grid.

Mandated transparency of transmission services and costs

Under this proposal, TNSPs would be required to disclose at an early stage in the connection process the various costs associated with each type of transmission service, such as *shared transmission services* and *connection services*, that will be required to connect a generator or transmission user to the national grid. For example, a TNSP would be required to provide clear information regarding whether any augmentations to the deeper transmission network are required (such as communication and protection systems), what capital works and assets are required for those augmentations, how they will be classified, and how much they are estimated to cost.

Some TNSPs may already include such detailed information prior to finalising an Offer to Connect; this measure would simply formalise the process for some TNSPs. However, the Commission understands that some TNSPs do not provide a breakdown of costs, or even clearly allocate costs between negotiated and non-regulated transmission services.

In terms of the costing information, the negotiating framework would require that TNSPs provide a breakdown of information that describes information such as:

- the WACC applied to each transmission service;
- a depreciation allowance;
- operating and maintenance costs, and how those costs are calculated;
- terms and charges for asset replacement, if relevant;
- a Consumer Price Index (CPI) escalator or any other relevant cost adjustment provisions over the life of the contract, if relevant; and
- project management and insurance costs during the construction stage, if relevant.

Throughout the connection process a TNSP would be required to establish evidence of the costs associated with the provision of each type of transmission service being provided. This evidence would need to be sufficient to demonstrate that the TNSPs charges are cost-reflective. If the estimated cost initially provided by a TNSP for services changes during the connection process, as further information becomes available, then the TNSP would be required to explain the reasons for the change to the generator or other transmission user applying for connection.

Box 13.5: AEMO Victorian Connections Initiative

It is the Commission's understanding that AEMO, as a Victorian TNSP, is in the process of implementing a suite of measures that are similar to those outlined under proposal 2 through its Connections Initiative. In particular, AEMO is seeking to provide greater clarity and quality of information and resources to potential Connection Applicants seeking to connect to the declared shared transmission network in Victoria.

This includes information and resources such as:

- a suite of standard contract templates that AEMO uses for connections to be introduced early in 2012;
- indicative augmentation costs for connections to the transmission network;
- a schedule of hourly rates that apply to connection projects and indicative cost estimates for AEMO's processing of connection applications;
- indicative timelines for the completion of a connection process and milestones that need to be achieved in order to progress a connection application to finalisation; and
- AEMO's policy on managing multiple connections to the transmission network and its system for prioritising and coordinating competing connection applications.

AEMO makes a distinction between small and large projects according to whether augmentations will be required to the transmission network:

- small projects are considered to be projects that do not require an augmentation to the shared transmission network; and
- large projects are projects that require augmentation to the shared transmission network, such as the construction of a substation, or interface works

This information will be provided by AEMO through a specific connection-related portal on its website. On the website, AEMO will also outline its role more generally in the connection process including in Victoria and other NEM jurisdictions.

The Commission welcomes this initiative by AEMO and considers that it has the potential to significantly improve the efficiency of the connection process.

Indicative or average costs of connection and standard contract template

Every year TNSPs would be required to publish indicative or average costs of connection and a standard contract template. Both the indicative or average costs of connection and contract template and the schedule of prices would ***not*** be subject to the approval of the AER. A TNSP would not be bound to provide any transmission service according to its indicative or average costs of connection, as they are only intended to make indicative cost information available to potential connection parties.

The indicative or average costs of connection could outline:

- the estimated cost for construction, operation and maintenance of specified connection assets;
- the estimated cost of capital works for the construction, operation and maintenance of a new substation;
- the estimated cost of connecting a generator or other transmission user to an existing substation;
- the typical cost of a range of assets generally required to connect a generator or other transmission user to the national grid; and
- the extent to which the costs and technical requirements may vary according to the voltage of the transmission network.

TNSPs would also be required to publish a standard contract template which outlines the general terms and conditions of a Connection Agreement. Publishing a standard contract should provide generators or other transmission users with clear information on their liabilities for the life of the Connection Agreement. Each TNSP would be required to publish a single Connection Agreement, or a suite of agreements if relevant, covering all connection-related services provided by the TNSP. TNSPs would not be bound to provide connection-related services on the terms published in the Connection Agreement, as this would be subject to negotiation between the TNSP and connecting party during the connection process.

Greater specification in the application of the WACC

There is scope under this proposal to also adopt a regulated WACC to be applied to all transmission services that are categorised as negotiated transmission services.

The regulated WACC would be the same as that approved by the AER during the TNSPs transmission revenue determination and would remain unchanged over the regulatory control period. This measure could also include some flexibility in its application to specific transmission services as it may not be appropriate for the regulated WACC to be the same for all transmission services, as the risks in providing some transmission services may differ. For example, it is reasonable to argue that the provision of some transmission services may attract a premium above the regulated

WACC where the counter-party cannot secure payment with a bank guarantee or suitable parent company guarantee.

To ensure that TNSPs are not unduly attaching a premium to some transmission services, the AER would be required to develop supporting guidelines to determine circumstances when cost of capital for assets providing *negotiated transmission services* may be higher than the regulated WACC. A TNSP would be required to demonstrate to a generator or other transmission user during negotiation that it has considered and met the guidelines for applying a premium to the WACC.

13.5.2 Advantages and disadvantages of proposal 2

Advantages

Generally, proposal 2 maintains flexibility in arrangements between TNSPs and generators such that there remains scope for the two parties to negotiate innovative connection outcomes, or seek cost saving measures elsewhere in the connection process, thereby supporting commercially efficient outcomes.

This proposal allows generators and other transmission users to negotiate connection outcomes on a more informed basis, and alleviate typical information asymmetries that may persist during a connection process. This is achieved by mandating a number of transparency measures that require TNSPs to reveal the specific costs of connection much earlier in the connection process. It also requires TNSPs to demonstrate that the charges derived throughout the connection process are cost-reflective, and that the services are no more than the stand-alone costs of connecting a generator or transmission user to the national grid. For example, a TNSP would be required to provide a breakdown of the relevant costs associated with each transmission service, not a single annual charge for all services, as the basis of negotiations.

Mandating for transparency and evidence of changes in costs could give further confidence to generators and other transmission users that the prices charged by a TNSP are cost-reflective and economically efficient.

The measures relating to indicative or average connection costs and publication of a TNSP's standard contract are expected to support a generator or transmission user's countervailing market power in two ways.

Firstly, it should increase a generator or other transmission user's ability to forecast the potential costs of connection to the national grid more accurately. The ability to forecast the costs of connection is important for generators and other transmission users as they will be better positioned to determine the feasibility of specific projects earlier in the design stage. This is especially important for generators who are located at a substantial distance from the transmission network and may require significant capital works to give effect to their connection.[326]

Secondly, by requiring TNSPs to publish their standard contract templates, generators and other transmission users would be able to develop a clearer understanding, prior to the negotiation process, of the terms and conditions of connection. This is important, as it heightens generator and other transmission users' awareness as to some of the liabilities that they may be expected to bear when connecting to the national grid. This measure also provides a vehicle for TNSPs to communicate their expectations regarding the connection of a generator or other transmission user to the national grid.

More broadly, the combination of a requirement to publish indicative augmentation costs and TNSPs' standard contract templates may serve to highlight differences amongst TNSPs in the NEM. This may be a driver in converging standard terms and conditions across the NEM, which may have benefits for generators or other transmission users that operate in a number of NEM jurisdictions.

The specification of a rate of return on the value of assets used to provide transmission services required for connection would support generators and transmission users' countervailing market power by constraining a TNSP's ability to charge for services above an efficient rate or return. It is important to note that the inclusion of greater specification of the WACC does not mean that assets would eventually form part of the TNSP's RAB.

The measures outlined under this proposal are generally complementary to the adoption of greater specification in the WACC. To ensure that TNSPs do not attempt to compensate for a potentially lower WACC by increasing other charges, it would be necessary to mandate transparency measures. This is to avoid the possibility of TNSPs potentially "loading" another of the charges to achieve the same result as a higher WACC.

Disadvantages

A disadvantage for generators and transmission users under this proposal is the regulatory risk associated with a changing WACC over the life of a Connection Agreement. If the WACC that is determined during transmission determinations was applied to connection and substation assets this would mean that, at each transmission revenue determination, the WACC applied to those assets would change. It is unclear to what extent generators and other transmission users may be able absorb and pass through any potential changes in transmission charges caused by a different WACC determined through a new revenue determination.

An alternative to reduce uncertainty on the behalf of generators and other transmission users would be to consider locking in the WACC over the life of the Connection Agreement.

326 This, however, may depend on the economic treatment of an "extension" that connects a generator's facility to the transmission network.

There are a number of potential disadvantages faced by TNSPs under this proposal. The TNSP still faces some risk in providing transmission services because the provision of substation and connection assets are not rolled into a TNSP's RAB. The level of this risk will depend on the creditworthiness of the counter-party. If the counter-party becomes insolvent before a TNSP can recover the costs of providing the transmission service and the counter-party has not provided sufficient prudential support, then the TNSP is required to absorb the remaining costs which cannot be rolled into its RAB. However, this risk could be mitigated by allowing a premium to the regulated WACC.

This proposal also places a number of additional requirements on a TNSP which may increase the overall administrative costs imposed on a TNSP through the Rules.

13.6 Proposal 3: Prescribing transmission services

> **Box 13.6: Summary of Proposal 3**
>
> This proposal would migrate all connection-related services from the category of *negotiated transmission services* to *prescribed transmission services*.

13.6.1 Rationale for approach and description of proposal

Proposal 3 involves migrating transmission services required for the connection of a generator or other transmission user to the national grid from the category of *negotiated transmission service* to the category of *prescribed transmission services*. This proposal is predicated on generators and other transmission users possessing insufficient countervailing market power in negotiating commercially efficient outcomes with a TNSP, such that the negotiate/arbitrate model provides insufficient protection to a generator or other transmission users. This may be the case going forward, as the pattern of consumption and production of energy changes in the NEM in response to climate change policies. In particular, entry into the market of smaller renewable energy generation means that generators may have fewer resources and be greater in number than was initially contemplated when Chapter 6A was developed.

Under this proposal, all connection-related services would be re-categorised as *prescribed transmission services*. Specifically, those transmission services to be migrated would include *connection services* for generators and other transmission users, and *shared transmission services* for generators that exceed relevant network performance requirements in the Rules or jurisdictional legislation.[327]

327 Although all connection-related services would become a *prescribed transmission service*, certain transmission services would remain in the category of *negotiated transmission services*. These would include transmission services such as augmentation to the deeper network to improve access to the regional reference node and Use of System services relating to Rule 5.4A. However, it should be noted that we are separately recommending the removal of the relevant provisions of Rule 5.4A (see chapter 6). Additionally, the option of funding augmentations to the deeper network would become redundant under access models providing generators with firm access.

Under this proposal, the assets that provide the *shared transmission services* and *connection services* would become part of a TNSP's RAB. The charges levied on generators and other transmission users would be equivalent to a portion of the TNSPs' allowable revenue derived from the ratio between the value of the connection assets and the total value of the TNSP's RAB. Effectively, therefore, consumers would not bear the cost of providing connection-related services for generators and other transmission users.

Implementation issues

A key issue with the implementation of this model is that it would require the identification of all assets providing a connection-related service, and the inclusion of these in a category or categories of prescribed service.

This could be achieved in two ways:

1. the definition of *connection asset* and *connection service* could be broadened to expressly include all substation assets and other assets required for connection. These definitions would also apply to load and transmission customers; or

2. the category of "Prescribed Entry Services" used in the previous arrangements prior to the adoption of Chapter 6A in the Rules could be restored to cover the connection entry service, together with a new category of transmission service created to capture those assets and services specific to generators' connections which fall outside of this new Prescribed Entry Service (which would primarily be substation assets). This new transmission service could be characterised as a "Substation Entry Service", and would be a prescribed transmission service.

Options for TNSP revenue drivers

Under proposal 3, the assets required for the connection would be rolled into the RAB of a TNSP at the next regulatory reset subsequent to their construction, and the transmission revenue determination process would therefore allow sufficient revenue to fund these assets from that point onwards.

Therefore, an important consideration under this proposal is how TNSPs would fund investments for the connection of transmission users to the national grid during the period between when the assets are constructed and when they are rolled into the RAB at the start of the next regulatory control period. This could represent a significant challenge, as forecasting generator entry into the NEM is likely to be a far more difficult proposition than forecasting load growth. Two options are presented below. These have previously been introduced in chapter 8 in the context of providing funding for augmentations to the shared network to allow for the meeting of generator reliability standards.

Contingent projects

Under clause 6A.8 of the Rules, projects that are too uncertain to be included in a TNSP's revenue allowance at the time of its revenue determination can be classified as a "contingent project", and appropriate triggers associated with each project identified. When a contingent project is triggered, the TNSP may apply to the AER for an amendment to its revenue determination such that funding for the project is included in its allowed revenue going forward.

This option, however, might not be well suited to the construction of connection and transmission assets such as substations, which might be relatively high in number but relatively low in value. For instance, clause 6A.8.1(b)(2) of the Rules specifies that contingent projects must exceed the larger of $10 million or 5 per cent of the maximum allowable revenue for the relevant TNSP. Using the contingent projects mechanism would also require all potential connections to be known in advance of a revenue determination, although it would not be necessary to forecast the likelihood of each progressing.

Unit cost allowance

It would alternatively be possible to provide TNSPs with revenue to fund investment for new connections during a regulatory control period through a "unit cost allowance" (UCA or "revenue driver"). A UCA would be set for each TNSP at a level intended to reflect the costs of connecting new generators or other transmission users to the national grid on a dollars per megawatt basis.[328]

Under this mechanism, a TNSP would be required to propose an average unit cost, per megawatt, per year of connecting a generator or other transmission user to the national grid, to the AER as part of the transmission revenue determination process. The UCA would be determined according to the typical costs associated with construction and establishment of substation or connection assets, as well as through forecasts of operating and maintenance costs. The process for deriving the UCA would broadly follow the propose/respond model currently in place for transmission revenue determinations, and final approval of the UCA would rest with the AER.

The UCA would only apply to the construction, establishment and operation of the relevant assets over a single regulatory control period (in which the assets were constructed). At the beginning of the next regulatory control period, those assets constructed in the previous period would be rolled into the regulated asset base of the TNSP. A new UCA would be determined for use in the subsequent regulatory control period, which would apply to connections formed in that subsequent period.

In order to make certain that TNSPs did not construct substation assets or connection assets in anticipation of forecasts or likely connections to the national grid, it may be

328 Unlike the UCAs discussed in chapters 8 to 10, which would be defined on a zonal basis to reflect the varying costs of augmenting the shared network, it is proposed that a single UCA could be set per TNSP in respect of connection-related assets. However, further consideration could be given as to the extent to which costs would vary, for instance between metropolitan and regional areas.

necessary to identify a trigger point in the connection process at which point a TNSP is authorised to commence capital expenditure. A suitable trigger point may be the finalisation of a Connection Agreement between the TNSP and the Connection Applicant.

Using the UCA approach would only require a representative sample of potential connections to be known in advance of a revenue determination, such that a cost-reflective UCA could be determined. For this reason, and given the drawbacks associated with use of the contingent projects mechanism, the Commission's current view is that proposal 3 would best be implemented with a UCA approach. Importantly, this would also give strong incentives to the TNSP, as discussed in the next section.

13.6.2 Advantages and disadvantages of proposal 3

Advantages

The key advantage of this proposal is that it alleviates any imbalances in bargaining power between TNSPs and generators or other transmission users in the provision of connection-related services.

Through use of the UCA revenue driver approach, this proposal would give TNSPs a strong incentive to minimise the costs of connecting a generator or other transmission user to the national grid. This is because the UCA is calculated per megawatt that is connected to the transmission network. For example, where a TNSP connects a 500 MW generator to the network, the UCA released will be a set amount reflecting the estimated cost of a 500 MW connection and there is therefore an incentive for the TNSP to minimise the actual cost of that connection in order to maximise its benefits. The TNSP will obtain a benefit if actual costs are less than the UCA or bear the risks if actual costs exceed the UCA.

These incentive properties would therefore replace the ability of connecting parties to negotiate effectively with TNSPs as the discipline to promote efficient outcomes. The proposal is therefore likely to be particularly well suited for smaller, less well-resourced generators which may increasingly seek to enter the generation market in response to climate change policies. It is likely that imbalances in bargaining power and information asymmetries will be of greater consequence for smaller and less well-resourced renewable generation, who may be less able to negotiate efficient charges.

By increasing the level of prescription associated with the provision of connection-related services, this proposal also more generally provides greater certainty and transparency for generators and other transmission users seeking connection to the national grid.

Finally, the use of the UCA as a form of revenue driver should also minimise transaction costs incurred by typical direct revenue controls. The extent of economic regulation is limited to determining the per megawatt cost of connecting a generator or other transmission user. This means that the ability to negotiate technically and economically efficient connections that suit the individual generator or transmission user's circumstances should be maintained.

Disadvantages

Under this model, generators and other transmission users would face some degree of risk. Because TNSP revenue is subject to regulatory controls, the charges that are levied on a generator or other transmission user for use of connection-related assets may change between regulatory control periods or, potentially, year on year. However, the degree to which charges may change, and the extent to which generators and other transmission users are able to absorb changes to the charges levied on them, is unclear.

The proposal is likely to reduce the extent of information asymmetries as compared to current arrangements, as the AER has greater powers to reveal costs than a generator or other transmission users. However, information asymmetries may persist under the UCA revenue driver, causing the UCA to be incorrectly calculated. Where the UCA is set too low, a TNSP may not be able to construct a connection to the national grid within the technical parameters it considers appropriate for the type of generator or other transmission user without incurring a loss. Where the UCA is set too high, a TNSP is likely to recover more than the efficient costs of connecting a generator or other transmission user to the national grid.

There is also a risk that TNSPs may seek to construct generation assets and connection assets that do not meet the requirements of the generator or other transmission user. This is because the UCA incentivises a TNSP to minimise the cost to the TNSP of connecting of generator or other transmission user to the national grid. This incentive, and the greater level of prescription inherent in this proposal, might also more generally reduce the scope for flexible or innovative solutions that best meet the needs of connecting parties.

This proposal might mean that TNSPs face fewer risks in the provision of connection-related services. This is because, subsequent to the construction and establishment of such assets, a TNSP is able to roll them into its RAB at each new transmission revenue determination. Consequently, if a generator or other transmission user were then to become insolvent, the assets constructed to connect that party to the national grid would remain in the TNSP's asset base. This outcome would be likely to result in higher costs to consumers. Therefore, the prudential arrangements that would be put in place if this proposal was adopted require further consideration in order to ensure that any additional risk to consumers is avoided or, at least, minimised.

14 Providing and accessing extensions to the shared network

Box 14.1: Summary of this chapter

As discussed in chapter 12, there is considerable uncertainty in the Rules regarding how services that are required for a connection are regulated and what TNSPs' and connecting parties' rights are in relation to those services. This chapter considers these issues in the context of the provision of extensions that are required so as to establish a connection to the transmission system.

Currently, TNSPs generally treat extensions as a non-regulated transmission service on the basis that extensions are contestable. As such, TNSPs consider that they are not obliged to provide extensions, nor are TNSPs subject to the negotiating framework when negotiating the terms and conditions for the provision of extensions. Some stakeholders, particularly generators, have raised concerns that there is a lack of clarity around the definition of contestability and obligations on TNSPs to provide extensions.

Given the lack of clarity in the existing Rules, this chapter poses a number of high level questions for consideration by stakeholders regarding the appropriate treatment of extensions. The first of these relate to the feasibility of contestability in the provision of extensions to the existing network to facilitate a connection. The effectiveness of contestability in both the construction and subsequent ownership, operation and control of extensions will inform questions around who should be able to provide such services. This chapter also raises questions regarding the appropriateness of allowing third party access to extensions and the subsequent ownership implications.

14.1 Introduction

The purpose of this chapter is to raise a number of high level questions for consideration by stakeholders on the nature of providing and accessing extensions between users' facilities and the shared transmission network. The Commission is particularly interested in stakeholders' views on the questions and issues raised in sections 14.2 to 14.4.

As discussed in chapter 12, there is some confusion about what obligations TNSPs have in respect of connections, particularly in regards to constructing the assets required for connection purposes, such as extensions. Similarly, there is some ambiguity surrounding how extensions are regulated, both for economic purposes and in terms of providing for third party access. Questions about the treatment of extensions were also raised recently in the context of a Rule change on Scale Efficient Network Extensions.[329]

The lack of clarity in the Rules regarding TNSPs' obligations to provide extensions and uncertainty regarding the policy position that the Rules are intended to reflect has led us to consider more broadly the appropriate framework to guide the provision of extensions.

The following sections therefore set out a discussion of three fundamental questions relating to the provision of extensions for the purpose of connecting to the network:

- section 14.2 questions whether the provision of extensions is contestable. If there are barriers in the construction and/or operation of extensions, generators and other transmission users may have limited ability to negotiate efficient outcomes with monopoly TNSPs;
- section 14.3 questions who should be able to own, operate and control extensions; and
- section 14.4 questions whether third parties have the right to access extensions.

The remainder of this section sets out issues that have been raised in submissions to this review regarding the provision of extensions. Section 14.5 provides a summary of the issues discussed in this chapter.

14.1.1 Stakeholder views on the provision of extensions

Grid Australia's Categorisation of Transmission Services Guideline outlines how that group of TNSPs resolves the ambiguity in the Rules by providing guidance on how they approach extensions. In the guideline, Grid Australia states that:[330]

> "The TNSP may agree to extend its *transmission network* to a *Transmission Customer* or *Generator's facility*, but under clause 5.3.6(k) of the Rules is not obliged to do so."

The guideline further states that:[331]

> "*Extensions* to *connect* a *Transmission Customer* or *Generator* would generally be offered as *non-regulated transmission services*, as these works are usually fully *contestable*."

It therefore appears that Grid Australia considers that the key factor in determining whether an extension should be treated as a negotiated or a non-regulated transmission service is whether the service is contestable. If a service is contestable,

329 See, in particular, AEMC, *Scale Efficient Network Extensions*, Options Paper, 30 September 2010, Sydney.

330 Grid Australia, *Categorisation of Transmission Services Guideline Version 1.0*, August 2010, p. 7.

331 Ibid.

there is therefore, in their view, no reason why TNSPs should have an obligation to provide it. Further, because provision of an extension is contestable, if a third party or the transmission user owned the extension it would not be economically regulated. Therefore, even if it is owned by the TNSP, it should be non-regulated for consistency.

This approach arguably represents a minimalist view of what TNSPs are obliged to provide. Transmission users have a limited ability to challenge this approach, partly because of the lack of clarity around the definitions that may or may not support this approach (as discussed in chapter 12) and partly because of their limited negotiating power (as discussed in chapter 13).

Some stakeholders disagree with Grid Australia's interpretation of their obligations. Origin Energy, for example, considers that there is an alternative interpretation of clause 5.3.6(k), stating:[332]

> "NER clause 5.3.6(k) could confirm that an NSP will be obliged to extend its network if a Connection Agreement is in place. This clause can be interpreted to merely confirm that there must be a Connection Agreement in place before a connection can be effected, e.g. an NSP cannot be forced to augment the network without a Connection Agreement."

TRUenergy and the NGF raised similar concerns.[333]

14.2 Contestability in providing extension services

14.2.1 Is the provision of extensions genuinely contestable?

TNSPs in the Grid Australia group consider extensions to be contestable in general, as stated in Grid Australia's Categorisation of Transmission Services Guideline. We can infer from this that TNSPs consider that there is no requirement for the provision of extensions to be confined to TNSPs for the purpose of maintaining reliability or security of their network.

However, there may be other barriers to third parties undertaking such services in practice. These could include, for example:

- any requirement to be a registered TNSP in order to own, operate and control the extension;
- any state-based licensing requirements to operate part of a transmission network; and
- the desirability of possessing land acquisition powers to obtain the necessary easements for the land over which the extension will be constructed.

332 Origin Energy, Directions Paper submission, p. 7.

333 NGF, Directions Paper submission, pp. 10-11; TRUenergy, Directions Paper submission, pp. 7-10.

Under clause 2.5.1(a) of the Rules, only registered TNSPs can own, operate and control a transmission system. The transmission system is defined by the voltage at which the network operates.[334] Therefore, under the current Rules, if an extension meets the definition of transmission then only a TNSP could own, operate and control that extension, unless an exemption was obtained from the AER.[335] However, the Rules are not clear on whether extensions form part of the transmission system.

Aside from the potential regulatory barriers listed above, third party infrastructure builders may also have difficulty competing with TNSPs for other reasons. For example:

- TNSPs, as providers of network services, may have a significant competitive advantage in terms of economies of scale, experience and capability in providing network infrastructure services. Further, it is not clear how TNSPs allocate costs between different parts of their business and whether this provides scope for further advantages; and
- third party providers may be hesitant to bid against TNSPs if they are concerned about maintaining their relationship with those TNSPs for future contracts.

It is therefore not clear in practice how many parties could undertake the construction and subsequent ownership, operation and control of an extension. To the extent that there is not effective competition in the provision of such services, there may be a need to consider the appropriateness of extensions being classified as a *non-regulated transmission service* and so not covered by the economic regulation framework within the Rules.

14.2.2 Contestability in construction versus ownership, operation and control

The Grid Australia Categorisation of Transmission Services Guideline implicitly assumes that the transmission service classification relates to both the <u>construction</u> of an asset and the subsequent <u>ownership, operation and control</u> of that asset. Thus TNSPs apply the same transmission service classification to each of these elements. However, it may be possible to separate out these two parts of the extension service, in which case the appropriate service classification, and so the way in which each part of the service is regulated, may differ.

Our understanding is that transmission users, particularly generators, are primarily concerned with being able to control the construction of an asset. It is important for them to have the ability to oversee, and therefore have greater control over, project costs and timings. Further, the construction of extensions would appear to lend itself more to contestability, or for generators to construct such assets themselves. Carving

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334 The transmission network typically operates at voltages of 220kV and above. Network operating at lower voltages may be deemed to be transmission by the AER, or if it supports the higher voltage transmission network.

out the construction of assets would therefore seem to address what we understand are the key concerns held by generators.[336]

However, as discussed above, there may be barriers to contestability in the subsequent ownership, operation and control of such assets. Similarly generators, whose core business does not extend to owning and operating transmission assets, may be reluctant to undertake these functions themselves. The next section therefore considers who should be able to own, operate and control extensions.

14.3 Who should be able to own, operate and control extensions?

Given the lack of clarity with respect to the nature of extensions, whether they form part of the transmission system and the degree to which they may be considered contestable, this section considers which entities should be able to own, operate and control extensions that are required to facilitate a connection. The Commission considers there are a number of complex issues regarding the provision of extension services, as discussed below, and is seeking feedback from stakeholders on this point.

In theory, there are a number of entities who may be able to own, operate and control an extension from a transmission network to a generator's facility. These include:

- the "incumbent TNSP" to whose network the extension is connected;
- any registered TNSP;
- any third party infrastructure owner; and/or
- the connecting party.

There are a number of implications of allowing each of these entities to own, operate and control extensions, particularly in respect of the economic regulation of the service and the third party access provisions that apply. The discussion that follows broadly assumes that the pool of competitors for providing extension services is expanded as each of the ownership possibilities is discussed. Third party access is discussed separately in section 14.4.

14.3.1 Incumbent TNSPs

As discussed in section 14.2.1 it is not clear to what extent the provision of extensions is genuinely contestable. If there are factors that constrain effective competition in the provision of extension services, then this would suggest that only the incumbent TNSP within a region is reasonably able to provide them in practice.

335 The AER may exempt a party from the requirement to register as an NSP under clause 2.5.1(d) of the Rules and section 11(2)(b) of the NEL. The AER has issued a guideline setting out the requirements to gain an exemption, which is available on the AER's website.

336 As discussed in section 12.3.3, the same approach could, in principle, apply to other aspects of connection services. However, there are a number of reasons why, in practice, TNSPs are reluctant to allow third parties to construct assets that form part of the shared network.

Even if the provision of extensions is genuinely contestable, an incumbent TNSP may be better-placed to own, operate and control all assets that could conceivably form part of the transmission system and could be used to connect third parties to the transmission system in the future. Confining the ownership, operation and control of extensions to incumbent TNSPs would arguably simplify arrangements by ensuring that all transmission-related assets were covered by a consistent set of Rules that are applied in a consistent manner by a single TNSP within a region. This approach could potentially maximise the efficient use of transmission-related assets.[337]

However, limiting the ownership, operation and control of an extension, if not its construction, to incumbent TNSPs implies that some form of economic regulation would need to apply. Consistency with existing economic frameworks would imply that this would likely fall into the category of *negotiated transmission services* and so more clearly be subject to economic regulation. The appropriate form of economic regulation to apply in such instances was considered in chapter 13.

Further, there may be detrimental impacts from limiting the provision of extensions to incumbent TNSPs. A lack of competitive pressure could lead to a loss of innovation and few incentives for the incumbent TNSP to seek out and undertake measures to reduce costs. Despite imposing economic regulation, generators (and so consumers of electricity) may face higher costs in the long run.

14.3.2 Any registered TNSP

Alternatively, any registered TNSP could own, operate and control extensions. This would allow existing TNSPs in all regions to compete for the provision of the extension service, to the extent that such competition was considered viable and subject to any jurisdictional licensing requirements.[338] Similarly, any third party infrastructure provider that was able and willing to become a registered TNSP would be able to provide extension services. The purpose of only allowing registered TNSPs to provide such services would be to ensure that certain frameworks within the Rules still applied, in particular the clauses governing access. This is discussed further in section 14.4.

Under this scenario, the provision of extension services may be considered contestable, at least amongst TNSPs. This would imply that extension services would not need to be economically regulated, as competition in the provision of those services would be considered to be effective and would therefore lead to efficient prices.

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337 It may be possible to achieve most of these benefits if a third party owns the extension but enters into a suitable long term lease with the TNSP to operate it, which we understand has occurred at least once in the past.

338 At present the ability for registered TNSPs to compete in the provision of extensions may be limited as some of the potential barriers outlined in section 14.2.1 may still apply to TNSPs in other jurisdictions, such as licensing requirements.

14.3.3 Any third party infrastructure owner

To the extent that there are no barriers to offering extension services, including ownership, operation and control, then competition could be opened up to any third party infrastructure owner. In this instance, the third party provider would not be required to register as a TNSP. Extensions would not be subject to economic regulation, nor would they be subject to third party access provisions. Competition would be assumed to be sufficiently workable such that efficient prices would result. However, this would also assume that there are very limited benefits from allowing an incumbent TNSP full control over transmission assets in its region, including the coordination of investment and operation of its system.

For consistency, the same regulatory arrangements would apply to both third party providers and TNSPs. In other words, if TNSPs provided extension services then those services would be outside of the scope of the Rules. TNSPs would not be required to negotiate in good faith under the negotiating framework, nor would they be required to provide access to third party access seekers.

As discussed above, third party providers may have some hesitation in bidding against TNSPs, from whom they may receive much of their work. If this was considered to be the primary explanation for a lack of competition in extension services, an alternative option may be to explicitly prevent TNSPs from providing such services. This would allow third party providers to compete freely in the market for extension services, although clearly consideration would need to be given to other issues that this might raise.

14.3.4 Transmission users

We understand that currently generators and other transmission users may own and operate extensions, often as part of their facilities. However, there are some restrictions. In Victoria, cross-ownership restrictions prevent entities from holding both a generation and a transmission or distribution licence.[339]

We also note that the Ministerial Council on Energy Standing Committee of Officials recently released a Regulation Impact Statement that considered the future possibility of co-ownership between generation and transmission.[340] MCE-SCO considered that there is a risk that any future co-ownership could reduce competition in generation.

In contrast to load, generators are in direct competition with each other and would benefit from preventing another generator from accessing an extension, even if there

339 Section 16 of the Electricity Industry Act 2000 (Vic) provides that a person must not engage in the transmission of electricity unless it holds a licence or has been exempted from the licence requirement. Part 3 of the Act sets out the cross-ownership restrictions. While there are a number of potential exemptions, none of these appear to cover a situation where an existing generator wishes to engage in the transmission of electricity.

340 Ministerial Council on Energy Standing Committee of Officials, *Consultation Regulation Impact Statement: Separation of generation and transmission*, 11 August 2011.

was spare capacity. There may therefore be a strong argument for preventing generators from owning, operating and controlling network extensions so as to promote competition in generation as well as to ensure that any economies of scale may arise from the use of that extension by more than one generator are captured.

However, we note that facilitating third party access to an extension that has been fully paid for by a generator for the purpose of its connection may not be an appropriate outcome in all situations. While it seems reasonable for the purpose of efficiency to facilitate additional connections to an extension of some length, where the extension has been sized specifically to connect a single generator a short distance from the network any efficiency gains are likely to be negligible.

Further, the absence of any property right to extensions is likely to curtail generators' appetites to invest in such extensions. If third party access to extensions was generally considered to promote efficiency, consideration would therefore need to be given to the appropriate application of that policy. This issue of third party access is considered further below.

14.4 Third party access to extensions

14.4.1 Background

The issue of which party or parties should provide extensions is directly linked to a question as to the rights that users have over such extensions.

It is our understanding that users have typically had sole use of the assets that they have funded in order to facilitate their connection. This is partly due to the fact that connection assets (i.e. the few assets forming the physical connection to the shared network) by definition are normally designed for a single user.

However, as discussed above, users often also fund new assets on the shared network. Technically, such assets could be used by multiple connecting parties, however patterns of generator entry (and large load connections) since the start of the NEM mean that such situations have not commonly arisen.

Similarly, the generators that have entered the market have typically located close to the existing network. However, patterns of generation investment are changing. For example, generators may locate further away from the existing shared network, and renewable generators such as wind-powered generation are locating around common fuel resources. Such connections are likely to require longer extensions and are consequently more likely to raise questions as to the rights of users of such extensions.

While there may be a view that the historic sole use of assets paid for by generators to facilitate a connection constitutes a right to the exclusive use of those assets, this is not provided for in the Rules.

Rights under current frameworks

As previously noted, clause 5.3.6(a) of the Rules obliges a TNSP to make an offer to connect a prospective user to the transmission network. The definition of *transmission network* specifically excludes *connection assets*. This might be taken as suggesting that subsequent users have no right to connect to existing *connection assets*.

However, the Rules can be interpreted as obliging TNSPs to facilitate connections and access to their entire transmission system, i.e. connection assets as well as the transmission network. For example:

- a TNSP is obliged to review and process applications to connect in relation to its part of the *national grid*, which includes connection assets;[341] and
- the principles which underpin Chapter 5 provide a framework for access to the *national grid* as well as for connection to a transmission or distribution network.[342]

Further, as noted above, a larger portion of the works undertaken to connect a user are likely to be on the shared network (such as the construction of a substation), with TNSPs clearly being obliged to facilitate a connection to such assets.

However, as discussed in section 14.1.1, most TNSPs appear to treat the provision of extensions as a non-regulated transmission service, rather than as connection assets or part of the shared transmission network.

Non-regulated transmission services, by definition, sit outside the framework for economic regulation of services under the Rules. Consequently, it is not clear to what extent network extensions treated in this manner would form part of the *national grid*.

There is therefore a lack of clarity about the access arrangements (if any) that apply to assets that provide non-regulated transmission services, and the extent to which non-regulated extensions are subject to the connection and access regime set out in the Rules.

Need for increased clarity

We are not aware of any examples to date of a transmission user seeking access to another independently owned user's network extension. However, as patterns of generation investment change this could become an increasing possibility.

Given the uncertainty around the rights of existing users and prospective new entrants with regards to extensions (and other assets used for connection more generally), we consider that the current frameworks would benefit from clarification.

341 NER clause 5.2.3(d).

342 NER clause 5.1.2(a)(1).

The following sections set out the relevant issues for consideration. We are seeking stakeholder views on these matters.

14.4.2 New entrant generators

Regardless of the extent to which an extension is contestable for the first connecting generator, neither the construction nor the provision of the extension is contestable for any subsequent generators that wish to connect. It is therefore necessary to consider the options for providing extensions that were set out in the previous section from this perspective.

Incumbent TNSPs

If an extension is owned by an incumbent TNSP but treated by that TNSP as being a non-regulated service, it is not clear to what extent the connection and access regime set out in the Rules applies, and therefore whether subsequent generators would have any rights to connect to the extension. This issue depends on the interpretation and application of several defined terms in the Rules.

If, instead, the incumbent TNSP treats the extension as being provided by *connection assets*, it is clear that the extension forms part of the *transmission system*. However, it is still unclear to what extent the TNSP has an obligation to offer to connect a subsequent generator to the extension (because *connection assets* form part of the *national grid* but are not part of the *transmission network*).

However, if the TNSP treats the extension as providing a *shared transmission service*, the extension would become part of the *transmission network*, and the TNSP would have a clear obligation to offer to connect a subsequent generator.

In such a case, the existing generator's ability to access the market might be reduced due to constraints caused by the new generator's connection. The incumbent may face further adverse consequences as a result of the new generator, such as through changes to its marginal loss factor.

However, the existing generator may receive some compensation for this (potentially) reduced level of service. The Rules specify that the price charged for provision of a negotiated transmission service should be adjusted to the extent to which the cost of the assets is recovered from the subsequent generators.[343] Such an approach would work best if the TNSP was levying ongoing charges on the existing generator. If the incumbent generator had funded the extension upfront, the Rules are less clear on how any refund of the capital contribution would be treated. In any case, this issue is likely to be addressed contractually between the TNSP and generator.

In terms of providing certainty for generators regarding third party access, restricting the provision of extensions to incumbent TNSPs would need to be accompanied by greater clarity in the Rules. As outlined in this section, there are a number of ways in

343 NER clause 6A.9.1(6).

which the provision of extensions could be undertaken under the current Rules which have different implications for third party access. Further, if third party access to extensions is permitted, the Rules would benefit from greater clarity regarding the rights of incumbent generators, particularly in respect of any capital contributions they have made towards the cost of the extension.

Any registered TNSP

It seems likely, under current frameworks, that if a registered TNSP other than the "incumbent" TNSP provided an extension, it would be on a non-regulated basis.

Therefore, while this would sit outside the framework for economic regulation of services under the Rules, it would again raise the question under current frameworks as to whether the connection and access regime set out in the Rules applied.

One reason for limiting the contestability of the provision of extension services to registered TNSPs rather than any third party infrastructure owner would be to ensure that the existing access provisions within the Rules are applicable. If it was considered that access provisions should apply to extension assets for efficiency reasons, the most straightforward way to do this would be to amend the existing access provisions to include extensions (or expand the definition of the transmission network to include extensions). This would place the same obligations on registered TNSPs in respect of access to extensions that currently exist for the shared network.

We note that third party infrastructure providers could still provide extensions services, however they would need to register as a TNSP.

Any third party infrastructure owner

If an extension was provided by a third party infrastructure provider other than a registered TNSP, the Rules would not apply. If another generator wished to access the extension it may be able to approach the infrastructure provider, but negotiations would be on an unregulated basis. Further, the third party provider may be restricted in its ability to negotiate access depending on the nature of its contract with the incumbent generator.

However, assuming that the third party provider is able to connect a new entrant, then there do not appear to be significant barriers to negotiation. While third party providers may have some degree of pricing power, this is limited to the extension. Access seekers are therefore likely to have greater substitution possibilities than when negotiating with the incumbent TNSP, since they could also connect to the incumbent TNSP's network.

For consistency, under this scenario registered TNSPs that provided extensions would also be exempt from facilitating access by new entrants.

If a new entrant is denied access to a non-regulated extension by either a third party provider or a TNSP, they may be able to seek declaration under Part IIIA of the

Competition and Consumer Act 2010 (Cth). However, a decision to "declare" infrastructure is dependent on a number of criteria, including that the facility is of national significance.[344] While an extension that is hundreds of kilometres long may potentially be considered of national significance, a line of tens of kilometres long (or less) might be less likely to be considered nationally significant. However, the general anti-competitive conduct provisions of the *Competition and Consumer Act* may also be applicable to any refusal to provide access.

Generators

Allowing generators to own, operate and control extensions as part of their generation facilities is likely to have similar issues as above regarding the applicability of the Rules and the possibility of declaration (noting that these issues exist today, as extensions may currently form part of a generator's facilities provided that the extension is not considered to be part of the transmission system). However, unlike with a third party access provider, generators may be less likely to enter into negotiations to connect a new entrant. This is because they would be assisting a competitor to enter the market, potentially reducing their competitor's costs.

14.4.3 DNSP load and network loops

The discussion above considers the possibility of another generator connecting to an extension.

However, more complex scenarios can be envisaged, for instance if subsequently using the extension represented the most efficient way:

- to serve additional DNSP load; or
- to achieve a required expansion in the capacity of the shared transmission network (i.e. by linking two points on the existing transmission network).

If the extension was subsequently used for either of the above purposes, the assets forming the extension would then be providing a *prescribed transmission service*. The Rules do contemplate the transfer of pre-existing assets into a TNSP’s asset base for purpose of subsequently being used to provide *prescribed transmission services*.[345]

However, such a process would clearly be complicated if the extension was owned by a party other than the incumbent TNSP. If it seemed that such situations were likely to be commonplace, this might be a driver to restrict the ownership of extensions to incumbent TNSPs or, alternatively, to allow incumbent TNSPs to be able to compulsorily acquire extensions owned by other parties.

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344 Competition and Consumer Act 2010, s.44G(2)(c).

345 NER clause 6A.19.2(8) and S6A.2.1(f)(8)(I).

14.5 Summary

The Commission considers that, in principle, it is appropriate to promote competition where it is feasible to do so. A workably competitive market allows regulatory intervention to be minimised, increasing opportunities and incentives via competitive pressures for innovation and cost reducing measures. Market-based approaches also typically lead to efficient risk-sharing outcomes, promoting efficient investment decisions. Together, these benefits of competition tend to reduce costs and lead to higher quality and improved services over time, resulting in more efficient outcomes for consumers.

However, as discussed above, there may be some uncertainty around whether the provision of extensions is workably competitive. Further, even if competition is feasible, there may be benefits in allowing TNSPs to maintain control over all transmission network assets in their region. For example, such an approach may better allow TNSPs to optimise transmission investment and operational decisions, and potentially allow for more efficient expansion of the network.

The Commission is therefore seeking stakeholder views on the discussion presented above and, in particular:

- Is there any evidence to suggest that competition in the provision of extensions is (or is not) workable?
- Are there any compelling reasons why competition in the provision of extensions should be limited to registered or incumbent TNSPs?
- Should third parties have the right to access extensions that are paid for by incumbent transmission users?

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AER	Australian Energy Regulator
APR	Annual Planning Report
CEC	Clean Energy Council
CMR	Congestion Management Review
COAG	Council of Australian Governments
CPI	Consumer Price Index
CRNP	Cost Reflective Network Pricing
DNSP	Distribution Network Service Provider
ENA	Electricity Networks Association
ERIG	Energy Reform Implementation Group
EUAA	Energy Users Association of Australia
FCP	Forward Cost Pricing
FTR	Financial Transmission Rights
ICRP	Incremental Cost Reflective Pricing
IRSR	inter-regional settlements residue
ISO	Independent System Operator
LMP	Locational Marginal Price
LRIC	Long Run Incremental Cost
LRMC	long run marginal cost
LRPP	Last Resort Planning Power
LYMMCo	Loy Yang Marketing Management Company
MAR	maximum allowed revenue

MCE	Ministerial Council on Energy
MEU	Major Energy Users
MWh	megawatt hour
NEL	National Electricity Law
NEMDE	NEM Dispatch Engine
NEO	National Electricity Objective
NER or the Rules	National Electricity Rules
NGF	National Generators Forum
NSP	Network Service Provider
NSW	New South Wales
NTFP	National Transmission Flow Paths
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
OFA	Optional Firm Access
PNP	Pseudo Nodal Price
RAB	Regulatory Asset Base
RRN	Regional Reference Node
RRP	Regional Reference Price
SA DTEI	South Australian Department of Transport, Energy and Infrastructure
SMP	system marginal price
SRA	Settlements Residue Auction
SRMC	short run marginal cost
STPIS	Service Target Performance Incentive Scheme
TUoS	Transmission Use of System

UCA	unit cost allowance
UK	United Kingdom
US	United States
Victorian DPI	Victorian Department of Primary Industries
WACC	weighted average cost of capital

A Examples of outcomes under different policy packages

This appendix sets out a series of examples to illustrate how a number of the access models proposed in this report would operate.

These examples are for illustration only. They significantly simplify what is, in practice, a very complex meshed network. Therefore while they provide a useful guide to explain how the various proposed mechanisms work and allow us to consider the likely outcomes under different approaches, significantly more complex modelling would be required to more accurately evaluate the different outcomes.

In addition to simplifying the examples by considering a two node network, a number of assumptions are made to keep the examples tractable, including:

- The coefficients of all generators in the constraint equations are assumed to be 1. The output of different generators will have different impacts on energy flows across the network, depending on factors such as where they are located. Consequently, generators will contribute to, or alleviate, congestion in different proportions. The coefficient is a measure of this effect. Assuming a coefficient of 1 implies that output from each generator will have the same impact on congestion.
- All generators are price takers. This implies that perfectly competitive market conditions hold such that no single generator is able to influence the outturn price in the spot market through their bidding behaviour. As a consequence, generators are assumed to bid at their short run marginal cost (SRMC) in the absence of incentives to disorderly bid.
- With the exception of the discussion on interconnectors in section A.5, the examples focus on intra-regional congestion and therefore ignore any power flows to or from other regions.
- The settlement period is 1 hour and there are no transmission losses.

The remainder of this appendix is set out as follows:

- section A.1 explains why disorderly bidding occurs;
- section A.2 shows how the Shared Access Congestion Pricing (SACP) mechanism that is central to package 2 operates;
- section A.3 shows how the regional Optional Firm Access (OFA) model under package 4 operates;
- section A.4 shows how the national Locational Marginal Pricing (LMP) model that forms package 5 would work; and
- section A.5 demonstrates why disorderly bidding can adversely impact interconnector flows and how the SACP mechanism can resolve this.

A.1 Why disorderly bidding occurs

As discussed in chapter 4, generators do not currently face a price that signals their impact on network congestion. This can lead to disorderly bidding, which results in more expensive generation being dispatched ahead of cheaper generation and so causes productive inefficiencies. This example explains why generators have an incentive to engage in disorderly bidding and the consequences for resource costs.

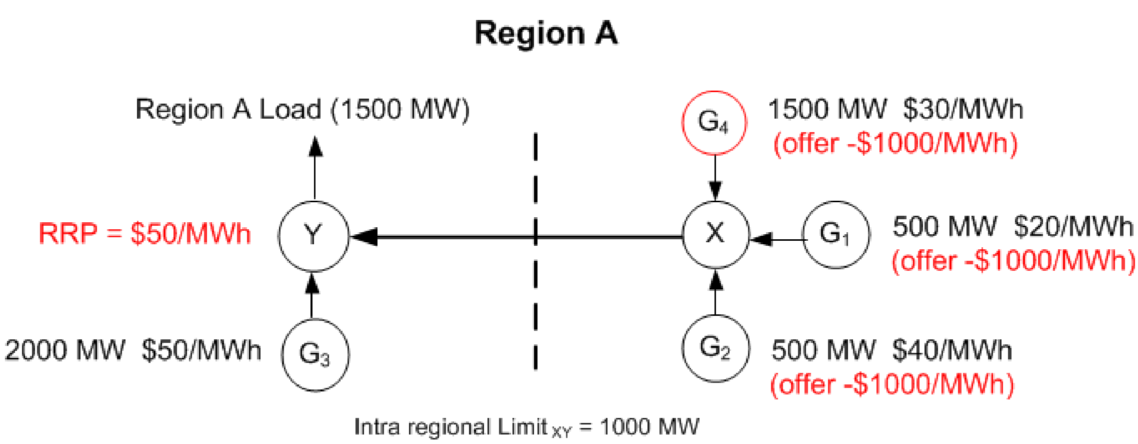
Figure A.1 below shows a region with two nodes: X and Y. The regional demand of 1,500 MW is located at node Y. There are three incumbent generators: G_1 and G_2 are located at node X and G_3 is located at node Y. The incumbent generators have the following characteristics:

Generator	Capacity (MW)	SRMC ($/MWh)
G_1	500	20
G_2	500	40
G_3	2000	50

The network limit between nodes X and Y is 1000 MW. The dashed line indicates a constraint.

Prior to the entry of G_4, each generator offers its full capacity at its SRMC. As G_1 and G_2 are lower cost relative to G_3 they are fully dispatched to meet demand at node Y. G_3 is then dispatched for 500 MW to meet the remaining load. The regional reference price (RRP) is set at Y by the marginal unit G_3 and is equal to $50/MWh. The intra-regional limit is met but not exceeded.

Figure A.1 Disorderly bidding



A large new generator, G_4, enters the market with a capacity of 1,500 MW and a SRMC of $30/MWh. This changes the dispatch outcomes.

There is now 2,500 MW of generator capacity seeking access to only 1,000 MW of transmission capacity in order to meet the load at Y. Assume that the incumbent generators continue to offer their energy at their SRMC. G_4, knowing that G_3 must be dispatched to meet demand and therefore will be the marginal generator, can undercut G_1 and G_2 by offering its energy at, say $0/MWh. In this instance, G_4 would be dispatched for 1,000 MW and receive the RRP of $50/MWh. G_1 and G_2 would not be dispatched as they would appear to be higher cost generators.

Knowing this will occur, G_1 and G_2 also have incentives to bid lower than their SRMC. Ultimately, all the generators located behind the constraint will offer all of their energy at the price floor (-$1,000/MWh) to ensure their level of access to market is maximised. The NEM dispatch engine subsequently allocates the available transmission capability between generators on a pro-rata basis. Dispatch outcomes, generator profits (revenues less SRMC) and resource costs are set out in Table A.1 below. Note that customers would face a total cost of $75,000 (RRP multiplied by demand of 1,500 MW).

Table A.1 Dispatch outcomes, resource costs and profits

Generator	Capacity (MW)	SRMC ($/MWh)	Offer price ($/MWh)	Dispatch volume (MW)	Resource cost ($)	Profit ($)
G_1	500	20	-1,000	200	4,000	6,000
G_2	500	40	-1,000	200	8,000	2,000
G_3	2,000	50	50	500	25,000	0
G_4	1,500	30	-1,000	600	18,000	12,000
Total				**1,500**	**55,000**	**20,000**

The dispatch outcomes for constrained generators reflect a proportionate sharing of the available transmission capability between nodes X and Y. For example, G_1 makes up 500/2500 = 20 per cent of generation capacity on the export side of the constraint and therefore secures 20 per cent of the constrained transmission capacity under the NEM's tied-bids rule. A similar calculation is performed for all other generators affected by the constraint.

Resource costs present the summed variable costs of dispatch for each generator, and profits the difference between revenues and variable costs for each generator. These measures will be important for illustrating how incentives change and productive efficiencies arise with the introduction of intra-regional congestion pricing (to be illustrated shortly). Note also that the profits of the marginal generator G_3 are zero, which reflects the assumption of competitive market conditions.

There are two key implications of disorderly bidding. First, it leads to inefficient dispatch. The efficient solution would have been for G_1 to be dispatched for 500 MW and G_4 dispatched for 500 MW. G_2, as the most expensive generator behind the constraint, should not be dispatched at all. This dispatch pattern would have led to a total resource cost of \$50,000. Instead, both G_2 and G_4 were dispatched for more than is efficient, leading to total resource costs of \$55,000.

Second, it weakens efficient locational incentives. Under existing frameworks, provided the new entrant's SRMC is lower than the RRP, it will still obtain a share of the network capacity in the presence of congestion because of the tied-bid rules. Thus a higher cost generator may have incentives to locate in a congested area, since it has the same chance of being dispatched as low cost generators when congestion occurs. This distortion in investment incentives arises because a new entrant will know that congestion costs will be shared by all existing generators impacted by the constraint.

In the particular example shown above, it would be more efficient from a market perspective, all other things equal, for G_4 to locate at node Y. However, from a private perspective G_4 does better by locating at node X. This can be seen from the table below, which shows the outcomes if G_4 were to locate at node Y. Note that G_4 would then become the marginal generator and so would set the RRP at \$30/MWh (and therefore not make any economic profit). Note that, since the RRP has reduced, costs to customers would also reduce from \$75,000 to \$45,000. Further, the constraint would no longer bind and therefore disorderly bidding would not occur.

Table A.2 Dispatch outcomes, resource costs and profits

Generator	Capacity (MW)	SRMC (\$/MWh)	Offer price (\$/MWh)	Dispatch volume (MW)	Resource cost (\$)	Profit (\$)
G_1	500	20	20	500	10,000	5,000
G_2	500	40	40	0	0	0
G_3	2,000	50	50	0	0	0
G_4	1,500	30	30	1,000	30,000	0
Total					**40,000**	**5,000**

A.2 Package 2: How does the SACP mechanism work?

As discussed in chapter 7, the SACP mechanism has two key features. First it establishes a local marginal price for generators affected by a constraint. This price reflects the marginal cost of supply at a particular connection point in the network, inclusive of the impacts of congestion and losses. It also explicitly places a value on the constraint, which is the Constraint Support Price (CSP).

To hedge against the basis risk that results from exposing generators to their local price, the SACP also provides a risk management tool through the allocation of Constraint Support Contracts (CSC). The CSC provides generators with access to the settlements residue. Box A.1 below sets out the basic operation of the SACP.

Box A.1: What is Constraint Support Pricing and Contracting?

The CSP/CSC approach seeks to expose generators to the marginal cost of congestion (the CSP) while introducing a supporting hedging instrument (the CSC), to offer a level of protection against such costs. It has the following key components:

- Establish the equivalent of a local marginal price for each generator impacted by a constraint (the Pseudo Nodal Price or PNP), which is derived as follows:

$$PNP_G = RRP_G - \sum_{k \in K} (Coefficient_{Gk} \times CSP_{Gk})$$

  where PNP_G is the local marginal price applying to a particular generator G, RRP_G is the regional reference price of the region in which G is located, k is a particular constraint of interest, K is the set of constraints in the NEM, $Coefficient_{Gk}$ is a measure of the impact of G's dispatch on energy flows across the constraint k and CSP_{Gk} is the marginal value of a particular constraint k to which G is exposed (in other words, the reduction in total dispatch costs achieved by relieving the constraint k by 1 MW).

- Allocate CSCs for each generator involved in the arrangement. The CSC is determined as follows:

$$CSC_G = Q_G \times (Coefficient_{Gk}(RRP_G - PNP_G))$$

  where CSC_G is the CSC applying to a generator G and Q_G is the relevant CSC quantity or volume allocated to G. In essence a CSC represents a right to a proportion of the residue that collects between two pricing nodes. Under the SACP mechanism, Q_G will be allocated based on the generator's proportion of total available capacity behind the constraint.

- Any generation output over and above CSC_G is settled at the PNP.

- The net settlement for G is therefore a weighted average of RRP_G and PNP_G.

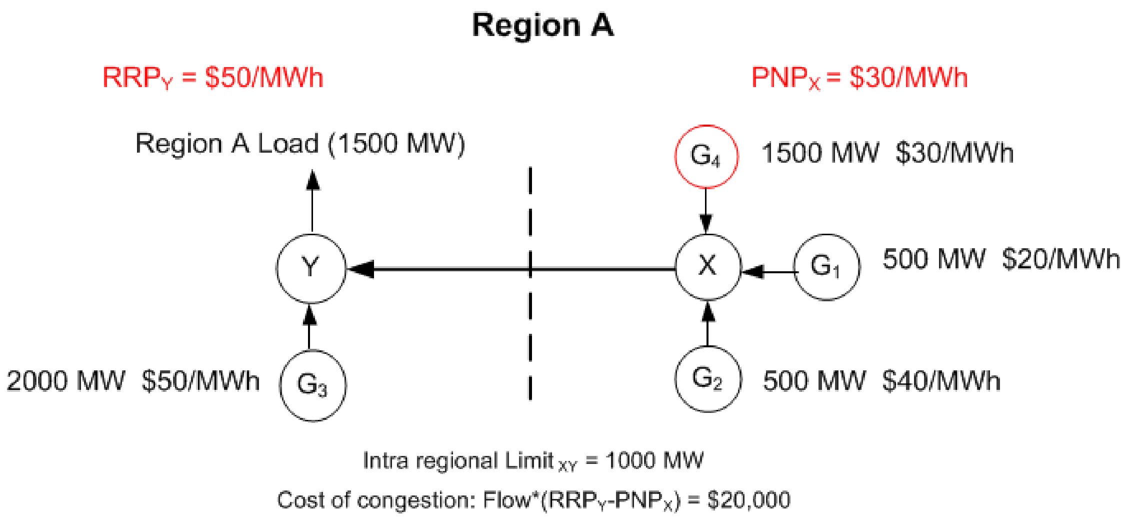
- Interconnectors may also be included in the arrangement and allocated a CSC, which entitles the interconnector the price difference between the two regions multiplied by a pre-specified volume of its flow (Q_I).

Note that a number of different terms have been used to describe various prices and values at a generator's local node. The relationship between the CSP and the Pseudo Nodal Price (PNP) is demonstrated in the first equation in Box A.1. In summary, the PNP is the price to which generators are exposed. This is comprised of a number of elements one of which is the CSP. The PNP is solved for using the relevant outturn price at the regional reference node. The PNP is equivalent to the LMP but is the term used when derived using the RRP and the CSP rather than calculating the LMP directly.

Figure A.2 below provides an example of how the SACP would be applied. This example uses the same assumptions regarding generator capacities and SRMCs and the network limit as in the previous example.

Assume that generators all bid at their SRMC. Their incentive to do so will be demonstrated later in the example. The following discussion then sets out how the PNP is calculated and how the CSC is allocated.

Figure A.2 Resolving disorderly bidding with a SACP mechanism



The first step is to calculate the PNP, which requires identifying the RRP and the CSP. The relevant RRP at node Y is $50/MWh, as in the first example, since G_3 must be dispatched to meet demand and so is the marginal generator. The CSP, or the marginal value of the constraint, is $20/MWh. This is because if the constraint was relieved by 1 MW, dispatch of G_3 would reduce by 1 MW and be replaced with 1 MW from the next most expensive generator, G_4. Marginally lifting the constraint therefore reduces the cost of meeting regional demand by $20/MWh ($50-$30). Consequently, as per the equation in Box A.1, all generators at node X would have the same PNP of $30/MWh (recall that all generators are assumed to have a coefficient of 1).

By creating a PNP at X there is now an explicit settlements residue between PNP_X and RRP_Y, measured by the line flow multiplied by the price difference between the RRP and PNP ($20,000 in this example). The general formulation of a CSC for a particular generator is set out in Box A.1. Under the SACP mechanism, the volume allocated to each generator is based on a pro-rata share of the available transmission capability, which is based on the capacity each generator has made available for dispatch. This volume is then multiplied by the difference between the RRP and the PNP, adjusted for the extent to which the generator contributes to (or helps alleviate) a constraint.

Dispatch outcomes, resource costs and profits with respect to the application of the SACP in Figure A.3 above are shown in Table A.3. Note that since customers are always settled at the RRP which has not changed, they would pay exactly the same amount under both disorderly bidding and in the SACP model ($75,000).

Table A.3 Dispatch outcomes, resource costs and profits

Generator	Capacity (MW)	CSC ($)	Offer price ($/MWh)	Dispatch (MW)	Resource costs ($)	Profit ($)
G_1	500	4,000	20	500	10,000	9,000
G_2	500	4,000	40	0	0	4,000
G_3	2,000	0	50	500	25,000	0
G_4	1,500	12,000	30	500	15,000	12,000
Total		**20,000**		**1,500**	**50,000**	**25,000**

The effect of the SACP mechanism is firstly to settle all constrained generators at their (implicit) local marginal price. For example, generator G_1 is dispatched for 500 MW and therefore receives 500*30 = $15,000. G_1 then receives an additional CSC payment (as do all generators affected by constraint). G_1's share of capacity is 200 MW. Thus its CSC payment is $4,000 (i.e. 200*1*(50-30)). G_1's total revenue for the dispatch period in question is therefore $15,000 + $4,000 = $19,000. Its profit is its revenue less its resource costs, or $9,000. The same calculation applies for all generators in the example, with outcomes set out in the table.

Note that CSC payments total $20,000, which is equal to the total settlements residue between X and Y. Another way of looking at the CSC allocation is that it represents a proportionate sharing of settlements residue caused by constrained network capacity between two nodes. G_1 makes up 20 per cent of total generation capacity affected by constraint between X and Y, and therefore is compensated 20 per cent of the settlements residue ($4,000).

A key outcome of the SACP mechanism is that by improving incentives at the margin this leads to more efficient (lower cost) dispatch. Table A.3 illustrates that total resource costs are $50,000 as compared to $55,000 under disorderly bidding. Note that, compared to the disorderly bidding scenario, G_1 now achieves a greater level of dispatch and higher profits ($9,000 compared with $6,000 under disorderly bidding). This outcome arises because under the SACP approach generators face the costs of their dispatch decisions at the margin, and therefore have incentives to bid more cost reflectively. For example, G_4 has no incentive to bid below its SRMC to achieve access to scarce transmission capability, since the level of access achieved under disorderly bidding is guaranteed through its CSC allocation. Rather, by bidding below cost G_4

risks receiving a local marginal price below its costs. The incentive for G_4 is therefore to offer its energy at or above SRMC.[346]

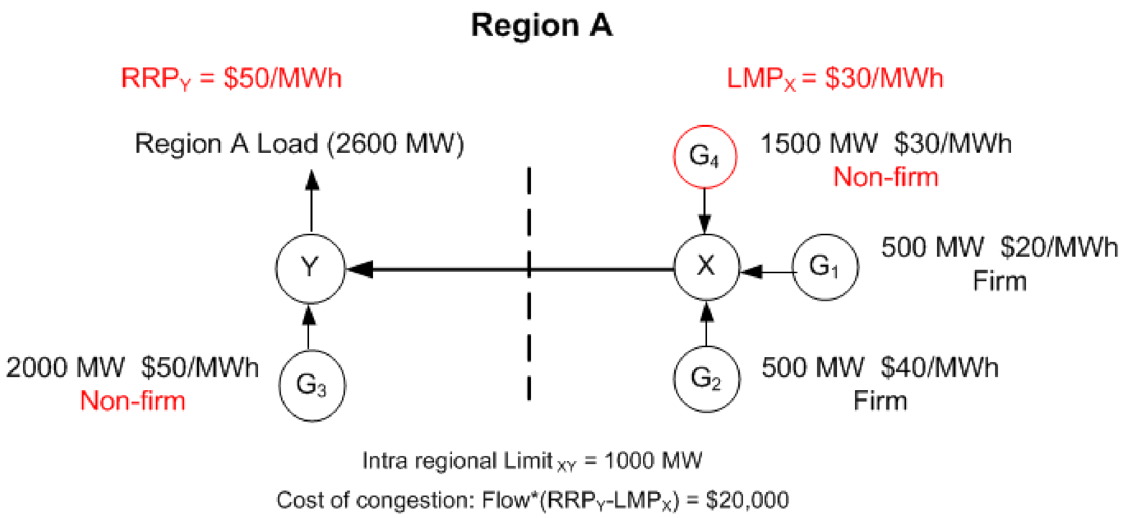
Although the SACP mechanism resolves some of the symptoms of congestion, it does not address its underlying causes. The locational signals remain the same as under the disorderly bidding case, with G_4 still having an incentive to locate at a congested part of the system.

A.3 Package 4: the regional OFA model

As set out in chapter 9, the regional OFA model would introduce a system of financial access rights, underpinned by physical transmission capacity. Generators without such rights would be required to fund compensation payments to generators with access rights if they caused those firm generators to be constrained off.

To illustrate this mechanism it is necessary to slightly modify the conditions in the example used in the previous sections of this appendix. In particular, load at node X has increased to 2,600 MW.[347]

Figure A.3 Providing firm access under the regional OFA model



As before, there is a limit of 1,000 MW on flows between nodes X and Y. Assume that the two incumbent generators at node X, G_1 and G_2, hold access rights to this capacity. G_4 enters at node X as a non-firm generator. This means that no additional transmission capacity is provided as a result of G_4's entry.

346 More precisely, the incentive of any generator is to offer its energy for a price as far above its SRMC as possible in order to maximise its profits, but risks not being dispatched in doing so. Consequently in a highly competitive market a generator's offer will be close to SRMC.

347 The increased load at node Y in this example ensures that generator G_2 is still "in-merit" following the entry of G_4, and is therefore eligible for compensation payments.

Dispatch outcomes, resource costs and profits under the regional OFA model are shown in the table below. Note that customers would pay $130,000 due to the increase in demand (although the RRP remains the same).

Table A.4 Dispatch outcomes, resource costs and profits

Generator	Access rights (MW)	Dispatch (MW)	Resource costs ($)	Revenue from dispatch	Compensation received (paid)	Profit
G_1	500	500	10,000	25,000	0	15,000
G_2	500	0	0	0	10,000	10,000
G_3	0	1,600	80,000	80,000	0	0
G_4	0	500	15,000	25,000	(10,000)	0
Total	**1,000**	**2,600**	**105,000**	**130,000**	**0**	**25,000**

As the cheapest generator, G_1 is dispatched for its full generation capacity (500 MW) and is settled at the RRP of $50/MWh. The new entrant, G_4, is the next cheapest generator and so is dispatched for 500 MW, which is the remainder of the capacity on line XY. It too is settled at the RRP of $50/MWh.

As a result of G_4 generating, G_2 has been constrained off. In an unconstrained system, G_2 would have been dispatched for 500 MW. Consequently G_2 will receive compensation. This is determined by the difference between the RRP ($50/MWh) and the LMP that would apply at node X ($30/MWh), multiplied by the constrained off amount. G_2 therefore receives 500*20 = $10,000.

This compensation is funded by the non-firm generator(s) causing the congestion, in this case G_4.[348] It can be seen that $10,000 exactly matches the amount by which G_4's revenue exceeds its costs. It is a key feature of the model that a non-firm generator should never make a loss by being dispatched i.e. any compensation contributions will never exceed the difference between RRP and the generator's offer.[349]

A key outcome, similar to the SACP mechanism, is more efficient dispatch than under disorderly bidding. Total resource costs are minimised, given the constraint.

The main difference from the outcomes under the SACP approach is the profitability of each generator. This result is linked to the allocation of the access rights. By having an access right, G_2 is protected against the costs of being constrained off and makes the

348 G_4 itself will have been constrained off by 1,000 MW but, being non-firm, is ineligible for any compensation.

349 As explained in chapter 9, this is because, in order to be dispatched, the non-firm generator's offer can be no higher than the LMP.

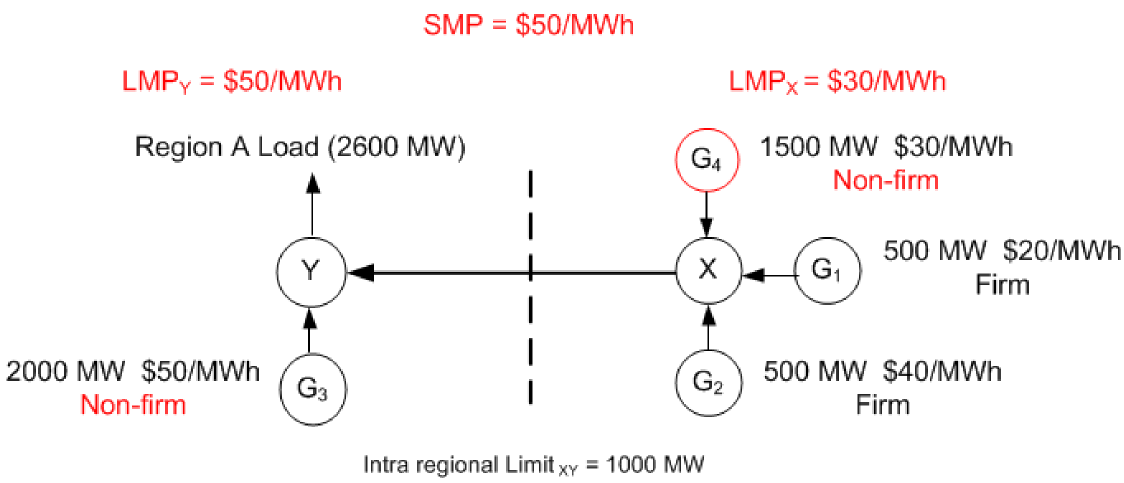
same amount of profit ($10,000) as it would have done had it been fully dispatched. (It would have received $25,000 of revenue and would have costs of $15,000.)

In contrast, the new entrant, G_4, makes no profit. This provides a strong signal to new entrants not to locate at node X.

A.4 Package 5: the national LMP model

Although there are a number of important differences between the regional OFA model and the national LMP model, if the same example is used and the same assumptions are made, then the outcomes in this instance will be identical.

Figure A.4 Providing firm access under the national LMP model



It is again assumed that the 1,000 MW of available transmission capacity has been allocated as access rights to the two incumbent generators at node X, G_1 and G_2, and that G_4 enters at node X as a non-firm generator. Dispatch outcomes, resource costs and profits under the national LMP model are shown in the table below.

Note that customers now pay a System Marginal Price (SMP) rather than a RRP. The SMP is the marginal price in an unconstrained dispatch and in this example is $50/MWh. This is the same value as the RRP in the previous example, so customers continue to pay the same total amount ($130,000).

Table A.5 Dispatch outcomes, resource costs and profits

Generator	Offer price ($/MWh)	LMP ($/MWh)	FTR (MW)	Dispatch (MW)	Resource costs ($)	Profit ($)
G_1	20	30	500	500	10,000	15,000
G_2	40	30	500	0	0	10,000
G_3	50	50	0	1,600	80,000	0
G_4	30	30	0	500	15,000	0
Total			**1,000**	**2,600**	**105,000**	**25,000**

Under the national LMP model, all generators are explicitly settled using LMP. Therefore, the non-firm G4 receives $15,000 of revenue, covering its costs but not allowing for any profit to be made.

Generators with firm transmission rights receive additional revenue if in-merit but constrained off. Since there are no regions and therefore no RRPs in this model, these payments are based on the difference between LMP and SMP ($20/MWh).

Generators G_1 and G_2 both receive payments (of $10,000) as a result of holding access rights (500MW*20/MWh). In the case of G_2 this payment provides compensation for the opportunity cost of not being dispatched.

As with the regional OFA model, outcomes under the national LMP model mean that efficient dispatch is promoted and locational signals are provided.

Access rights are fully firm

One key difference between the regional OFA model and the national LMP model is that, under the latter, access rights are fully firm. This can be shown by assuming that, for operational reasons, the transmission capacity on line XY was reduced to 800 MW.

Under the regional OFA model, the compensation paid to G_2 under these circumstances would be reduced from $10,000 to $6,000. This is because $6,000 would be the maximum amount that could be recovered from the non-firm generator G_4 responsible for the congestion without causing it to make a loss. As a result, G_2 would no longer be fully compensated for the opportunity cost of being constrained off.

Under the national LMP model, G_2 would continue to be fully compensated to the amount of $10,000. As a result there would be a revenue shortfall in settlements of $4,000. As discussed in chapter 10, this deficit would largely be recovered from consumers, with the TNSP having some exposure in order to provide an incentive to minimise such reductions in transmission capacity.

A.5 Interconnectors

This section considers the introduction of interconnectors, in particular:

- the impact of disorderly bidding on interconnector flows; and
- how the SACP mechanism in package 2 can alleviate inefficient counter-price flows between regions.

A.5.1 Disorderly bidding and interconnector flows

As shown in section A.1 above, disorderly bidding can result in inefficient dispatch outcomes within a region. Disorderly bidding may have particularly pernicious effects when it occurs near interconnectors, because it can cause counter-price flows which devalue Settlements Residue Auction (SRA) units. As discussed in Box 7.2, SRAs are the key hedging tool used for managing the risks of trading across regions. Figure A.5 and the discussion below illustrates why counter-price flows occur and how it can result in inefficient outcomes.

Figure A.5 Disorderly bidding and interconnector flows

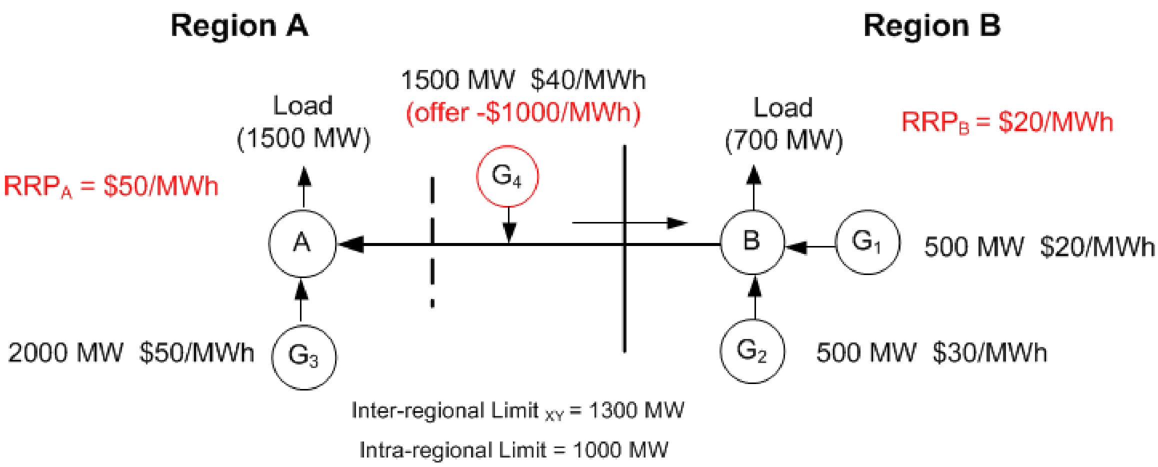


Figure A.5 introduces an additional region and load centre (Region B). Load in Region A is 1,500 MW. Load in Region B is 700 MW. The incumbent generator G_3 remains in Region A. The incumbent generators G_1 and G_2 are now in Region B. The new entrant, G_4, enters in Region A near the region boundary. The generators have the follow characteristics (noting that the SRMC of G_2 and G_4 have changed from the previous examples but all the capacities remain the same):

Generator	Capacity (MW)	SRMC ($/MWh)
G_1	500	20
G_2	500	30
G_3	2,000	50
G_4	1,500	40

The interconnector limit, shown by the dark vertical line, is 1,300 MW. The intra-regional limit (the dashed line) remains at 1,000 MW.

Generators in Region B have the lowest SRMC across both regions. However, when the intra-regional constraint binds, the more expensive generator in Region B is not dispatched. This is because of G_4's ability to bid at -$1,000/MWh when constrained off from its own RRN, as seen in section A.1 above. Generators in Region B are not constrained off from their RRN at B, however, and consequently will offer their energy at SRMC or above. There is no incentive for generators in region B to compete with G_4 on price since they will receive a market price below their SRMC if they do so.

Consequently, the dispatch engine observes that G_4's offer of -$1000/MWh is cheaper than G_2's offer of $30/MWh and therefore fully dispatches G_4 to meet demand in Region B as well as Region A. Thus G_1 becomes the marginal generator in Region B (and sets a RRP of $20/MWh at node B). The results are shown in Table A.6 below.

Table A.6 Dispatch outcomes, resource costs and profits with counter-price flows

Generator	Capacity (MW)	SRMC ($/MWh)	Offer price ($/MWh)	Dispatch (MW)	Resource costs ($)	Profit ($)
G_1	500	20	20	200	4,000	0
G_2	500	30	30	0	0	0
G_3	2,000	50	50	500	25,000	0
G_4	1,500	40	-1,000	1,500	60,000	15,000
Total				**2,200**	**89,000**	**15,000**

In the absence of clamping (discussed below), the effect is to create a counter-price flow from the higher priced region (Region A) to the lower priced region (Region B) of 500 MW. Recall that the settlements residue is the difference between the price in the export region and the price in the import region, multiplied by the flow between regions. Counter-price flows therefore result in a negative settlements residue. Where this occurs, the value of the SRA units is scaled back, implying that they are not firm. In this instance, the "settlement deficit" is $10,000.

Clamping

AEMO currently attempts to "clamp" these counter-price flows when they are projected to be very large to contain the settlement deficit (for example by reducing interconnector flows and thus, in the above example, reducing G_4 dispatch). However in many cases this is not entirely successful due to technical reasons.[350] A negative settlements residue may therefore accumulate.[351] Dispatch outcomes, resource costs and profits (generator revenues - marginal costs) following clamping are shown in Table A.7 below.

Note that with clamping the spot price in Region B will be $30/MWh rather than $20/MWh, as G_2 is now dispatched and so becomes the marginal generator. This leads to an increase in profits for G_1 if the clamping procedure is implemented.

Table A.7 Dispatch outcomes, resource costs and profits with clamping

Generator	Capacity (MW)	SRMC ($/MWh)	Offer price ($/MWh)	Dispatch (MW)	Resource costs ($)	Profit ($)
G_1	500	20	20	500	10,000	5,000
G_2	500	30	30	200	6,000	0
G_3	2000	50	50	500	25,000	0
G_4	1500	40	-1,000	1000	40,000	10,000
Total				**2,200**	**81,000**	**15,000**

Disorderly bidding near interconnectors can create a number of adverse impacts. For example, there is a reduction in competition. Generation capacity in Region B is at a competitive disadvantage relative to constrained generation capacity in Region A. This is because the offers of the unconstrained generators in Region B are not de-linked from the market price they receive for their output. Clamping mitigates this outcome to a degree.

Another key issue is the impact of disorderly bidding on inter-regional SRA units. While holders of SRA units are not required to fund negative residues, the SRA pay-out will nonetheless be zero at times of counter-price flows. The unpredictability of counter-price flows, and the potential for these to occur when price differences between regions are high, subsequently limits the effectiveness of SRA units as an inter-regional price hedging tool.

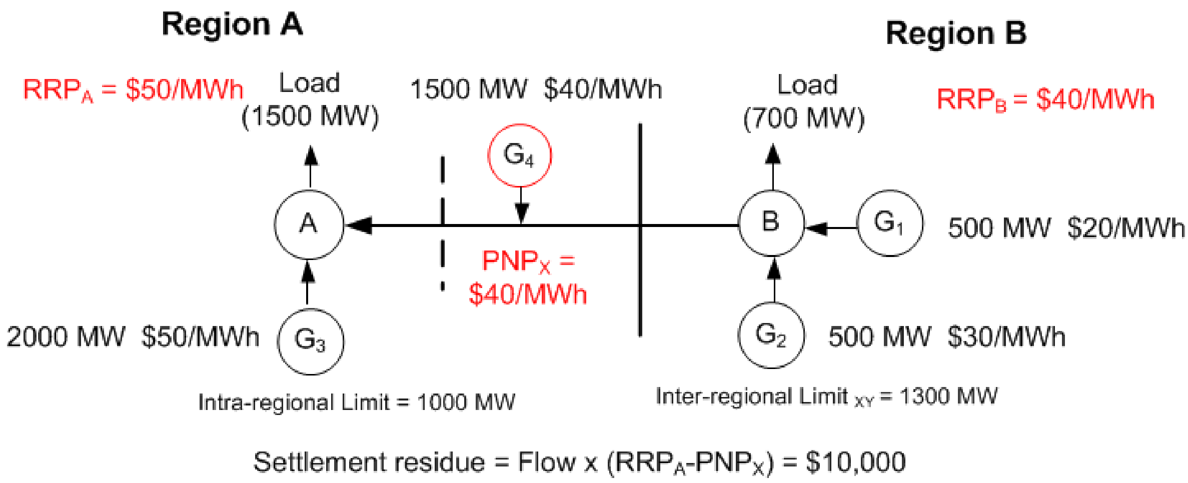
350 These technical reasons include, for example, technical rates of change of certain generators, security issues, and potential breach of Frequency Control and Ancillary Services constraints.

351 See: AEMO, Issues Paper submission for examples of this.

A.5.2 SACP and interconnector flows

As discussed in section A.2, the SACP mechanism removes incentives on generators to disorderly bid. In turn, this also prevents counter-price flows that arise as a consequence of disorderly bidding. This is briefly illustrated in Figure A.6 below.

Figure A.6 SACP and counter-price flows



Recall that in the scenario above counter-price flows occurred because generation in Region B could not match the below cost bidding of G_4, which subsequently led to an inefficient counter-price flow. The counter-price flow is removed with the introduction of a local marginal price at $G_{4,}$'s connection point. $G_{4,}$ now has an incentive to bid at its SRMC of $40/MWh. Less expensive generation in Region B is now dispatched ahead of constrained generation in Region A to meet load in Region B and some load in Region A. Power now flows from the lower priced region to the higher priced region and so no intervention from AEMO is required.

Dispatch outcomes, resource costs and profits are illustrated in Table A.8 below. Note that because there is only one constrained generator in Region A in this example, G_4, this generator under the SACP receives the full settlements residue between its PNP and RRP_Y. The relevant CSC quantity is 1,000 MW.

A change in incentives means that rather than a 500 MW counter-price flow across the interconnector (or zero with clamping), there is now a 300 MW flow consistent with the power flowing from the low priced region to the higher priced region.

Table A.8 Dispatch outcomes, resource costs and profits

Generator	Capacity (MW)	CSC ($)	Offer price ($/MWh)	Dispatch (MW)	Resource costs ($)	Profit ($)
G_1	500	0	20	500	10,000	10,000
G_2	500	0	30	500	15,000	5,000
G_3	2,000	0	50	500	25,000	0
G_4	1,500	10,000	40	700	28,000	10,000
Total		**10,000**		**2,200**	**78,000**	**25,000**

Efficient counter-price flows

The need for AEMO to clamp flows would not be removed entirely as efficient counter-price flows may still occur. For example, referring back to Figure A.6, if G_4 was in fact lower cost relative to generation capacity in Region B then G_4 would be fully dispatched and be utilised to meet demand in Region B. This would be the most efficient way to meet demand but would still devalue the SRA units between Regions A and B.

One way this could be addressed is through an automatic CSC allocation to the interconnector. This would entitle the interconnector to a portion of the "intra-regional" settlements residue with respect to the constraint in Region A. For example, if the interconnector received a CSC allocation of 500 MW, then the interconnector would be entitled to half the intra-regional settlements residue currently allocated to G_4 ($5,000). This could be used to top up the inter-regional settlements residue fund and thereby improve the firmness of the SRA units (this residue could be purchased by generators in region B to hedge their exposure into Region A).

B A time-limited localised congestion management mechanism

This appendix explains the Commission's conclusion that the use of Constraint Support Pricing and Contacting (CSP/CSC) schemes on a time-limited and localised basis should not form part of any of the integrated policy packages to be considered in this review.

We have reached this view because we consider that any productive efficiency benefits delivered through the application of temporary, localised CSP/CSC schemes are likely to be more than offset by a number of major drawbacks, which would significantly add to risk and uncertainty for market participants. In summary, these are as follows:

- Congestion tends to be transient and unpredictable, and shifts between one location and another across the network, particularly given forced and planned outages. This means that establishing an appropriate threshold trigger for introduction of a such a scheme, or determining when it should be removed, would be complex. While locations can be identified easily with the benefit of hindsight, it is not clear that they can be forecast accurately. Thus, dispatch efficiencies and congestion risks would be likely to remain for participants.

- The practical application of the mechanism would require numerous constraint equations to be included in the scheme. This might be challenging to manage over time, particularly in the context of constraint equations that are constantly being developed and altered.

- Numerous constraint equations may be used to manage any one particular constraint, with each constraint variant implying a different impact on generators. This means that in practice it may be difficult for generators to determine their financial exposure to congestion, as they would need to forecast which constraint variant was likely to bind at any particular time.

- Allocating congestion rights (the CSCs) across multiple generators would be likely to be complex and contentious, potentially resulting in disputes.

These issues are discussed in detail below.

B.1 Introduction

In a December 2003 report to COAG, the MCE recommended that a new process should be developed for assessing wholesale market regional boundaries, and that an independent economic study should be commissioned to develop the criteria and process for boundary changes.[352] CRA International was engaged to undertake this study and developed an intra-regional congestion pricing mechanism tailored

352 Ministerial Council on Energy, *Report to Council of Australian Governments on Reform of Energy Markets*, 11 December 2003.

specifically to the NEM to operate as either a substitute or complement to regional boundary change.

In the latter case, it was intended that schemes implemented using this CSC/CSP mechanism would have functioned as time-limited, interim arrangements applied flexibly in selected areas of the NEM to operate between region boundary reviews. In this context, these CSP/CSC arrangements would have differed from the Shared Access Congestion Pricing (SACP) proposal being considered in this review as part of package 2 in two significant ways:

- The CSP/CSC arrangements would only apply to certain areas of the NEM and only on a temporary basis. Therefore, triggers would need to be put in place to define when (and where) the arrangements should be introduced and removed. This is unlike the SACP mechanism which would form a permanent feature of the NEM arrangements.

- Under the CSP/CSC arrangements there would be a need to explicitly allocate CSCs (which, as discussed in chapter 8, are equivalent to a share of the intra-regional settlement residues). Under the SACP proposal the CSC allocation would be determined automatically in dispatch based on pro-rata generation capacity.

CRA International recommended that a CSP/CSC scheme should be implemented on a trial basis to manage an enduring constraint in the Snowy Region, and this occurred in 2005. Key aspects of this trial are discussed in section B.2.

As noted in chapter 8, the potential for the more widespread use of time-limited, localised CSP/CSC schemes in the NEM was considered in some depth during the Congestion Management Review (CMR).[353] In that review, the Commission concluded that the use of such arrangements was undesirable because they would likely raise significant implementation issues and competition concerns, with significant wealth transfer implications. In the context of the low level of materiality of congestion identified in the CMR, the Commission recommended that CSP/CSC schemes should not become a permanent fixture of the regulatory framework for the NEM.[354]

However, time-limited, localised CSP/CSC arrangements were reconsidered by the Commission in 2009 as part of the Review of Energy Market Frameworks in light of Climate Change Policies. The Commission concluded that the use of such schemes might be a proportionate response to managing potentially increasing levels of congestion in the NEM. However, the Commission also noted that the practicalities and costs of introducing and using location-specific and time-limited arrangements were pivotal to this finding. The Commission therefore recommended that further consideration be given to these matters.[355]

353 AEMC, *Congestion Management Review*, Final Report, June 2008.

354 Ibid, p. 198.

355 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies*, Final Report, September 2009, pp. 37-38.

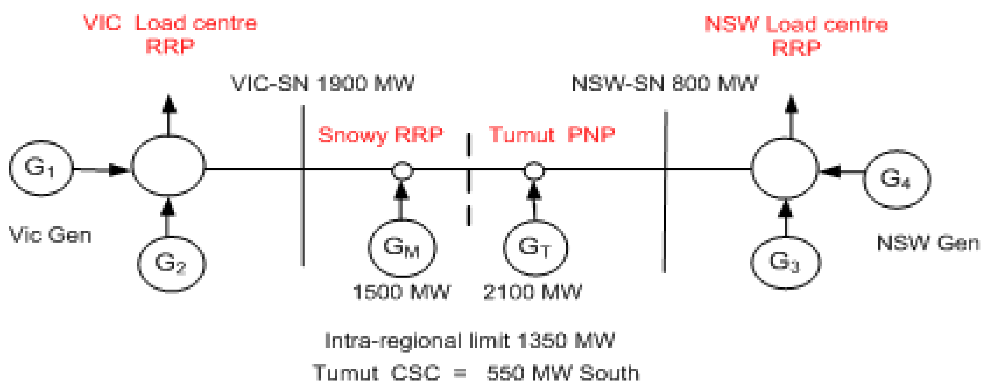
The Transmission Frameworks Review has allowed for this further assessment of the CSP/CSC approach, both in its time-limited, location-specific form, and in other variations.

B.2 Application to the Snowy region

A location-specific, time-limited CSP/CSC mechanism was introduced into the Snowy region in October 2005 to manage an enduring constraint between Murray and Tumut. This constraint bound in both a northerly and a southerly direction. The rationale for the implementation of the scheme was to improve price signals in the region until a broader review of regional boundaries could take place. Transmission augmentation was not considered a viable alternative due to environmental considerations (since the transmission lines traverse the Snowy Mountains national park).

A basic network diagram representing the arrangement in the Snowy region is set out in Figure B.1 below:

Figure B.1 CSP/CSC applied in Snowy region



The vertical dashed line in the diagram represents the line limit (binding at 1350 MW depending on network conditions and direction of flow). G_M is Snowy Hydro's Murray power station and G_T is Snowy Hydro's Tumut power station.

The application of a CSP/CSC scheme was quite straightforward in this instance, as only Snowy Hydro generation was involved in the application. Both the local marginal price (as discussed in appendix A, technically this was implemented as a Pseudo-Nodal Price or PNP) and CSC were applied to Tumut generation only. Note that the RRP for the Snowy region was at Murray connection point (G_M), and as a consequence both Murray and Tumut were effectively exposed to their local marginal price after the arrangement was implemented. The PNP applied regardless of whether the constraint bound in a northerly or southerly direction, while CSC applied only for flows in a southerly direction. The PNP was generally equivalent to the NSW RRP, provided there were no constraints between Tumut power station and NSW.

The rationale for introducing a CSP/CSC arrangement was primarily to encourage more efficient dispatch of Tumut generation capacity. The key element of the arrangement was to establish a local marginal price at the Tumut connection point. The lack of intra-regional pricing meant that previously Snowy Hydro would have incentives to engage in disorderly bidding if the constraint bound in either direction.

If the constraint bound in a southerly direction, Snowy Hydro could achieve full access to constrained transmission capability (at the expense of NSW generation) by bidding Tumut at -$1000/MWh. NSW generation would not match these bids because unlike Tumut, their bids would influence the price they received for their output. At the same time Snowy Hydro could offer Murray's generation capacity at very high prices in order to set a high Snowy RRP (and thereby receive a high price for their output).

These dispatch outcomes were inefficient from the perspective of congestion in the Snowy region. Ideally, Snowy Hydro should have incentives to reduce, not increase, Tumut's output in circumstances, where due to high demand in Victoria for example, flows are moving in a southerly direction. Applying a local marginal price to Tumut restored incentives for Snowy Hydro to bid Tumut in a way that reduces its impact on the constraint.

Snowy Hydro received a 550 MW CSC for Tumut capacity, to help offset some of the price risk (the difference between the Snowy RRP and Tumut PNP) associated with being exposed to the PNP (entitling Snowy Hydro to receive the Snowy Region RRP for the entire 550MW regardless of its dispatch). This returned some of the value of access Snowy Hydro had lost from not being able to bid Tumut generation in a disorderly fashion. For the remaining 800 MW of transmission capacity, with flows going south, Tumut would compete with NSW and Queensland generation on an equal footing.

If the constraint bound in a northerly direction Snowy Hydro would, under prior arrangements, be faced with the opposite incentive, to reduce rather than increase the dispatch of Tumut. This is because Tumut would receive a low Snowy RRP for its dispatch, even though electrically it was on the import side of the constraint (i.e. it was effectively in the NSW region). In these circumstances it would be more efficient for Tumut to be dispatched for more rather than less volume (because its dispatch would have reduced the loading on the constraint). Snowy Hydro was in effect at a competitive disadvantage relative to NSW and Queensland generation under northerly flows, with the effect that over 2000 MW of generation capacity was removed from competitive supply in NSW at these times. The effect of the CSP was to provide Tumut with (effectively) the NSW RRP at these times, encouraging it to generate when the constraint bound in a northerly direction.

The Snowy CSP/CSC scheme was removed in 2008 with the abolishment of the Snowy region (which had the effect of placing Murray generation in Victoria and Tumut generation in NSW).

B.3 Assessment of localised time-limited CSP/CSC schemes

The CSP/CSC arrangement in the Snowy region was considered to have had a number of strengths, in that it was relatively easy to implement and was generally successful with regard to improving the efficiency of dispatch around the relevant constraint.

However, the Snowy example can, to some extent, be considered to represent a unique case. In particular, the constraint in question was material and enduring, and only one generating company was affected by the scheme. These conditions would be unlikely to hold in other applications. In general, congestion is likely to be transitory, difficult to predict and forecast, and tends to shift from one area to another with demand growth and new investment.

Building on the assessment undertaken during the CMR, the Commission has concluded that the benefits of adding localised, time-limited CSP/CSC schemes to the NEM regulatory arrangements are unlikely to outweigh the costs, and are therefore an option that should not be pursued further. Given the transitory nature of congestion, the introduction of a location-specific and time-limited CSP/CSC arrangement is likely to add to participant uncertainty, which may have consequential impacts on the liquidity of contract markets and investment. The following sections discuss these issues in more detail.

B.3.1 Predictability of congestion and triggers for implementation

As noted, the Snowy circumstances were unusual in that the underlying congestion problem was clearly identifiable, and was unlikely to change over the medium term. Analysis undertaken for the CMR on the incidence and materiality of congestion demonstrated that, apart from the Snowy region, congestion under system normal conditions was generally unpredictable and transitory (particularly given that almost half of all congestion was due to outages).[356]

For the more generalised application of interim, localised congestion management schemes in the NEM, establishing an appropriate threshold trigger for introduction of the arrangement would therefore be complex. While locations can be identified easily with the benefit of hindsight, it is not clear that they can be forecast accurately. There is therefore a significant risk that any criteria for the introduction of such a scheme may not be triggered to allow for material, transitory congestion to be addressed, as well as the opposing risk that a scheme may be introduced when there is no need for it. To the extent that congestion is not captured by a scheme, dispatch inefficiencies and congestion risks for participants will remain.

This issue is exacerbated by the importance of forward contracting in the NEM, which raises the question of the appropriate lead time for the implementation of a scheme. Given the unpredictability of congestion, if a mechanism was to be of value it would need to be implemented relatively quickly. However, this might mean introducing a scheme that significantly alters trading risks into an environment where most

356 AEMC, *Congestion Management Review*, Final Report, June 2008, pp. 14-15.

participants are already heavily contracted. Giving a longer notice period risks leaving the congestion unaddressed in the short term, and the congestion either ceasing or being built out in the longer term, rendering an interim measure redundant

In addition, threshold criteria and a process for removing the scheme would be required, given that it is intended to be an interim measure only.

B.3.2 Identification of constraints and participant risk

Congestion tends to occur across a collection of network paths, or a cutset, rather than at any single network asset. The practical application of the mechanism would require numerous constraint equations to be tagged as part of the scheme. It may subsequently be challenging to manage the list of what constraint equations are included in a scheme. This is particularly the case for complex network configurations and in the context of dynamic constraint equations that are constantly being developed and altered. Even in a relatively straightforward CSP/CSC application such as the Snowy region, there were over 120 different constraint variants which controlled flow over the relevant constraint, each with potentially different generator contribution coefficients. A different CSC could apply for each different constraint form (given the different generator constraint coefficients), and would change over time as prevailing network flows changed.

The implication of this is that the localised application of CSP/CSC schemes (and this feature applies to CSP/CSC arrangements more broadly) may cause uncertainty for generators since, in order for generators to determine their financial exposure, they would need to forecast which constraint variant was likely to bind at any particular time (and thus which CSC would be applicable) and how this would change over time. Consequently, choosing which constraint equations to include in a CSP/CSC arrangement is likely to be complex. Further, any constraint variant left out, but which subsequently binds, would mean that dispatch inefficiencies (disorderly bidding) would still occur.

The application of a CSP/CSC arrangement in the Snowy region represents a striking example of this latter issue. Once the CSP/CSC scheme was implemented in the Snowy region, it was found that the additional generation now being dispatched by Tumut (as a result of the PNP) was in fact contributing to increased binding of a constraint in NSW between Tumut and Sydney. This led to disorderly bidding by NSW generators in order to maximise their access to the Sydney RRP, but Snowy Hydro's Tumut generation could not compete effectively due to the low local PNP it was subject to as part of the CSP/CSC arrangement. In effect the implementation of the CSP/CSC scheme in the Snowy region caused the congestion to shift from the Snowy region to NSW in this instance. This had unintended consequences for Snowy Hydro's own exposure to congestion.

Shifting patterns of unpredictable and transitory congestion could therefore make a localised approach to implementing CSP/CSC arrangement problematic. The Snowy example demonstrates that implementing a PNP for a particular participant could expose that participant to price risk if the associated CSC does not cover all the constraints to which that participant may be exposed. A localised approach may therefore significantly add to risk and uncertainty for market participants.

B.3.3 Allocation of CSCs

The question of how to allocate explicit congestion rights (the CSCs) under a localised time-limited application of CSP/CSC is highly problematic, and has never been satisfactorily resolved during previous discussion of the proposal. The Snowy region represented a unique situation in that it was the only region in the NEM without load. Only one generation company (Snowy Hydro) and two of its generation plants were involved in the arrangement. And no interconnector was provided with a CSC. The issue of CSC allocation would therefore become considerably more difficult with involvement of more generators and interconnectors in the scheme.

A number of potential allocation methods have been previously proposed, most notably an allocation based on historical dispatch. However, this then creates implementation challenges – what historical dispatch should be used? There would be no simple way to get agreement from generators, and a potential risk of lengthy disputes, jeopardising the introduction of the scheme. In addition, an allocation method that provided existing generators with explicit rights in preference to prospective new entrants could be viewed as discriminatory and anti-competitive.

Alternatively, congestion rights could be allocated through an auction process. This should ensure that those participants who value the rights most would receive them, consistent with non-discrimination and economic efficiency. However, to implement such a framework of periodic auctions, for potentially a very large number of constraints, would add greatly to the complexity of the NEM trading environment. This would represent a very large change to implement a scheme applying to only parts of the market on a temporary basis.

Consequently, the allocation of CSCs raises important and complex questions which would represent a significant transaction costs for the implementation of localised and time-limited schemes.

B.3.4 Locational signals and investment decisions

Despite the additional complexity that would result from including provision for time-limited, localised congestion management schemes in the NEM regulatory arrangements, long term locational signals to resolve congestion on an enduring basis would not be improved. This is because such schemes would be uncertain and temporary in application. Hence, the pricing outcomes that might result from their implementation would also be uncertain. When prospective investors made decisions to invest, they would not generally know whether or not (or how) a particular project would be affected by a location-specific interim constraint management mechanism. This may also add to uncertainty, potentially compromising the ability of participants to access financing for investment purposes.

C Options for generator TUoS charging

As detailed in chapters 8 and 9, policy packages 3 and 4 provide generators with a defined level of service in return for a charge that is commensurate with the impact they have on the need to augment and maintain the transmission network. This charge could be in the form of an annual generator Transmission Use of System (TUoS) charge or a one-off deep connection charge.

The purpose of this appendix is to consider how a generator TUoS charge might be calculated based on methods that seek to reflect the long run marginal cost (LRMC) of the transmission network. Using an LRMC based generator TUoS charge would provide a means of allocating a forward looking efficient cost of transmission to generators based on their impact on the network. The options presented in this appendix cover a spectrum of alternatives but are not intended to be an exhaustive list of all potential methodology variations.

Appendix D then considers the use of deep connection charges for providing and maintaining a defined level of transmission network service.

This appendix is structured as follows:

- section C.1 outlines the assessment criteria that we are using to evaluate the various charging methodologies;
- section C.2 introduces the concept of LRMC in terms of transmission pricing and its practical application;
- section C.3 outlines a range of potential options for calculating a generator TUoS charge and provides an initial evaluation of those options against the assessment criteria; and
- section C.4 outlines a number of other considerations to take into account if introducing a generator TUoS charge in the NEM.

C.1 Assessment criteria for charging methodologies

As discussed in chapter 3, the overarching principle for assessing the relative merits of any potential changes to the transmission arrangements is the NEO. Stemming from the NEO, we consider that the design of a generator charging methodology should be assessed against the following key principles:

- **Efficiency** - incorporating the principle that costs to society should be minimised. This includes the likelihood of the methodology producing outcomes which promote efficient long term investment decisions in both transmission and generation;
- **Cost reflectivity** - the accurate allocation of transmission costs amongst generators according to cost causation principles;

- **Effectiveness** - any charge should be practical and proportional to implement and should, or should be likely to, influence generators' locational decisions as between locations that impose different costs for using the network;

- **Transparency** - any charge should be the simplest possible to meet its objectives with necessary visibility of the process provided to market participants;

- **Predictability and stability**[357] - to provide relative certainty over the long term, generators' charges should not be overly sensitive to small changes in the transmission system and its users; and

- **Competitive neutrality** - there should be no undue discrimination.

In those policy packages where a generator charge is included, the preferred charging method is likely to require trade-offs between these criteria.

C.2 What is LRMC?

C.2.1 Concept of LRMC

According to standard economic theory, prices should be set at marginal cost since, in the absence of externalities, this maximises economic welfare. This is because:

- such prices reflect the costs involved in providing an additional unit of output;

- where the user values an extra unit more than it would cost to produce it, it is economically efficient to produce that unit; and

- setting prices equal to marginal cost means that users will continue purchasing extra units until it is no longer economically efficient to produce them at that price.

In this context, LRMC is the measurement of change in the "investment and operation" cost of transporting an additional increment or decrement of electricity across the network when the level of transmission capacity can be altered.[358]

With electricity transmission, it is not practical to add capacity in very small increments. Economies of scale mean that it is efficient for capacity to be added in "lumps".[359] The effect of an increment of generation is therefore to bring forward (or delay) the time in which a planned future lump of network augmentation needs to occur.

357 While grouped together here and often used interchangeably, predictable and stable are two quite different criteria. If a charge is relatively predictable, then informed decisions (and cost pass through) can be made by a generator even if the charge is somewhat unstable. A "stable" charge may conflict with the first criterion to be cost reflective as the true cost may change over time.

358 By way of comparison, short run marginal cost, by its nature, would be the cost of meeting an incremental change of power supply or demand without allowing for capacity investments.

359 An explanation as to why investment "lumps" occur is provided in appendix D.

Box C.1: Example - Using the optimal transmission development path to determine LRMC

The example below describes the optimal transmission development path of a theoretical electricity system under two scenarios: a base case and the connection of a new 200MW generator. Comparing the net present values (NPVs) under the two scenarios provides the LRMC over the assumed time horizon of 5 years. This comparison determines the cost of bringing forward the network augmentations caused by the 200MW generator.

This example is demonstrated in Table C.1, assuming a constant cost of transmission of $500/kW and a discount rate of 7 per cent per annum.

Table C.1 NPV calculation

Year	Base case		Base case plus 200MW generator	
	Installed capacity (MW)	Augmentation cost	Installed capacity (MW)	Augmentation cost
1	5000	$0m	5200	$100m
2	5200	$100m	5200	$0m
3	5200	$0m	5500	$150m
4	5500	$150m	5500	$0m
5	5550	$25m	5550	$25m
NPV		**$220m**		**$234m**

As can be seen in Table C.1, the present value of all augmentation requirements over the 5 year period is $220m under the base case scenario. If the new 200MW generator connects in year 1, this revises the optimal transmission development path by bringing forward both the 200MW augmentation that was originally required in year 2, and the 300MW augmentation that was required in year 4, each by 1 year. The present value of this revised transmission development path is $234m.

Therefore, the long run cost of connecting the 200MW generator in year 1 is the present value of the cost of bringing forward the already planned augmentations. This is the $14m difference between the NPVs under each scenario.

In economic terms, LRMC should represent the present value of the additional cost of bringing forward an investment (or indeed, the additional saving from deferring an investment where this is the case). The LRMC is therefore the cost associated with undertaking expansion sooner (or later) than would otherwise be the case in response to an incremental change in demand or generation.[360]

The calculation of LRMC can be shown in a simple example in the box above. Note that this example is for illustrative purposes only and, as such, does not seek to represent actual investment decisions by generators or TNSPs.

C.2.2 Practically applying LRMC to transmission charges

While economic theory provides a useful starting point for calculating LRMCs to apply to transmission charges, in practice there are a number of challenges that must be considered. Of key importance is the source of information used to estimate LRMC. There are two options for sourcing the necessary information: historical data and forward looking data. Ideally in a competitive market charges should be set on a forward looking basis. However, as discussed in this section, there are strengths and weaknesses associated with this approach.

A precise calculation of LRMC as described in C.2.1 above is difficult as it must be based on a variety of assumptions about the future. It requires a complete set of forecast data regarding transmission investment costs, the factors that determine the location of new plants, and demand growth to enable an optimal transmission development path to be mapped. This is especially difficult the longer the investment horizon is.

All forecasts are subject to error, and as the future is unknown, any pricing methodology based on forward looking futures, across multiple scenarios, is at risk of charging assets to the wrong party or charging for assets that do not actually get built.

In practice, an approximate calculation of the LRMC of transmission is usually performed based on several simplifying assumptions concerning the optimum network. There are two general approaches for recovering long run network costs:

1. identify whether the actual network would need to be reinforced to accommodate a particular change at a particular location and determine what is the cost of that change and to allocate that to the causer; or

2. assume that the impact on transmission cost of extra generation or demand at a particular place can be represented by some notional or average reinforcement and then develop a mechanism to allocate the costs to users.

The first option, which can be characterised as a deep connection charge, presents a number of issues which are discussed separately in appendix D.

360 For the avoidance of doubt, it is not equal to the cost of the required expansion. For transmission, high fixed costs and economies of scale result in average cost usually being higher than marginal cost. Therefore marginal cost alone cannot adequately recover the revenue required to cover a return on a transmission investment. If it is desired that the generator TUoS charge, in combination with load TUoS, should achieve this then the calculated charge would need to be scaled up.

The second option, usually implemented through a generator TUoS charge, allows for a locational signal by calculating the relative variation in charges at different locations. This requires a method for determining how to assign the costs to a generator based on its location. This generally involves using a "load flow model" to model the flows on the network to determine a generator's use of the network.[361]

For a generator TUoS charge that uses a load flow model, there are a number of different ways in which flows can be determined, each giving different results (and therefore different charges). However, that is not to suggest that there is anything intrinsically flawed with any of them.

Load flow models can be broken into two main types – the incremental flow method or the flow tracing method. These are introduced in the next two sections prior to discussing the options for estimating LRMC which employ such load flow models.

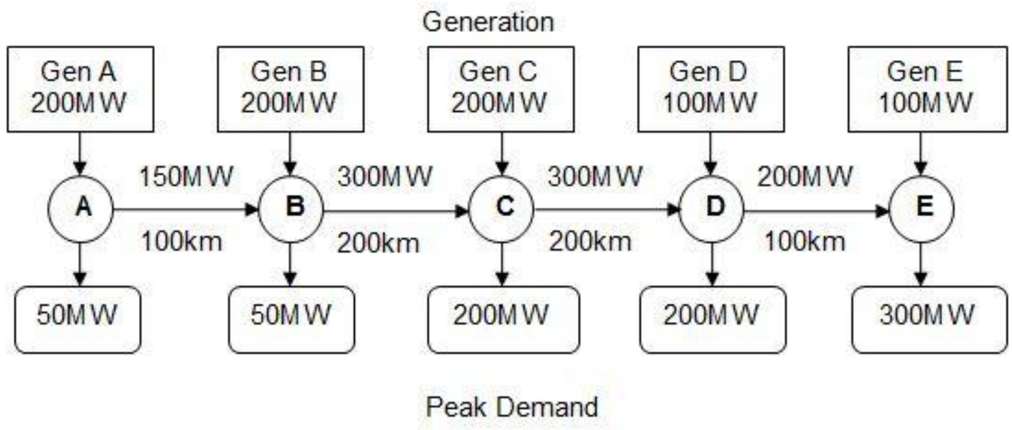
C.2.3 Incremental flow method

An incremental flow method examines the consequent impact on the transmission network of a unit increase or decrease in generation at each generator connection point in turn. Transmission network costs can then be allocated to generators based on how the incremental change in generation impacts the flow on the total network.

The incremental flow methodology looks at an increase in generation at a node and measures how much the flow increases or decreases as a consequence on all circuits in the network. This is used as a measure of the incremental use of those circuits by the incremental change in generation at the node.

Consider the simple example in Figure C.1, where power flows from Node A to Node E. For simplicity, transmission losses are ignored.

Figure C.1



361 A load flow model incorporates elements such as branch lengths and impedance levels. If generator TUoS charging was to be implemented, the complexity of the actual load flow model developed would need to be considered. This would include, for example, whether it should only account for real power or whether it should make some allowance for reactive power.

Under this methodology, the power flows and therefore the resulting marginal cost, would depend entirely upon how the increment at each node is compensated. An increase of 1MW generation at node A can be balanced by a decrease in generation (or increase in demand) of 1MW at any of A, B, C, D or E (whichever is chosen is referred to as the "slack node"). Which node is chosen as the slack node is likely to produce a different flow pattern.[362]

Similarly, the flow pattern would differ if, rather than choosing a slack node, all other generation is decreased by an equal share or, perhaps, in proportion to the generation at that node. Again, the flow pattern would differ if it is demand that increases by an equal share or in proportion to demand at the node. These features can impact the magnitude of the charge at each location.

The different flows apportioned to each line can be seen in Table C.2 where a 1MW increase is applied at node A. The increase is assumed to be balanced by a decrease in generation elsewhere.

Table C.2 Line flow patterns when an extra MW is injected at A

Compensation	AB (MW)	BC (MW)	CD (MW)	DE (MW)
A is the slack node (no change)	150	300	300	200
B is the slack node	151	300	300	200
C is the slack node	151	301	300	200
D is the slack node	151	301	301	200
E is the slack node	151	301	301	201
All remaining nodes generation uniformly decreased	151	300.75	300.50	200.25
All remaining nodes generation decreased by proportion of generation at node	151	300.67	300.34	200.17

Table C.2 shows that the flows on each line would change if a different method of compensation is used. Where Node A is the slack node, there are no incremental flows across the remainder of the system and therefore there would be no allocation of costs to Gen A. However, where node E is the slack node, the incremental flows from an injection at node A would be an extra 1MW across all lines. This would result in a high allocation of costs to Gen A.

Hence an incremental flow methodology can be shown to be sensitive to the selection of the slack node in terms of the absolute level of cost allocation. However, it can be shown that only the absolute allocations and not the relative allocations are impacted

362 However, it will not change the geographical differentiation of the charge at each node. That is, the relative charge remains unchanged.

by the choice of slack node. Hence an incremental flow methodology can be shown to be compatible with a causer pays approach as it is the relative differentials that it provides and it is these that would impact generator behaviour.

C.2.4 Flow tracing method

A flow tracing method examines what proportion (or "participation factor") each generator uses each transmission asset based on tracing the energy input by the generator across the transmission network to reach demand. Transmission network costs can then be allocated to each generator based on its participation factor.

Flow tracing enables assessment of the usage, by a particular generator, of the transmission network. It can be thought of as working out the responsibility for meeting the demand at a node, as well as the flows out of a node, by determining the generators' proportion of flow into the node. This assumes that the majority of generation is transported to meet local demand with smaller proportions used to meet remote demand.

It effectively distinguishes which generators supply, and which transmission assets are used to supply, each individual demand. Unlike the incremental flow method, which is based on the marginal effects of a change to demand/generation on the network, tracing is able to provide participation factors based on actual (historic) usage. This can then be used to approximate future use of the transmission system and inform future pricing options.

The method can be illustrated by continuing the same five node example from the incremental flow methodology in C.2.3 above.

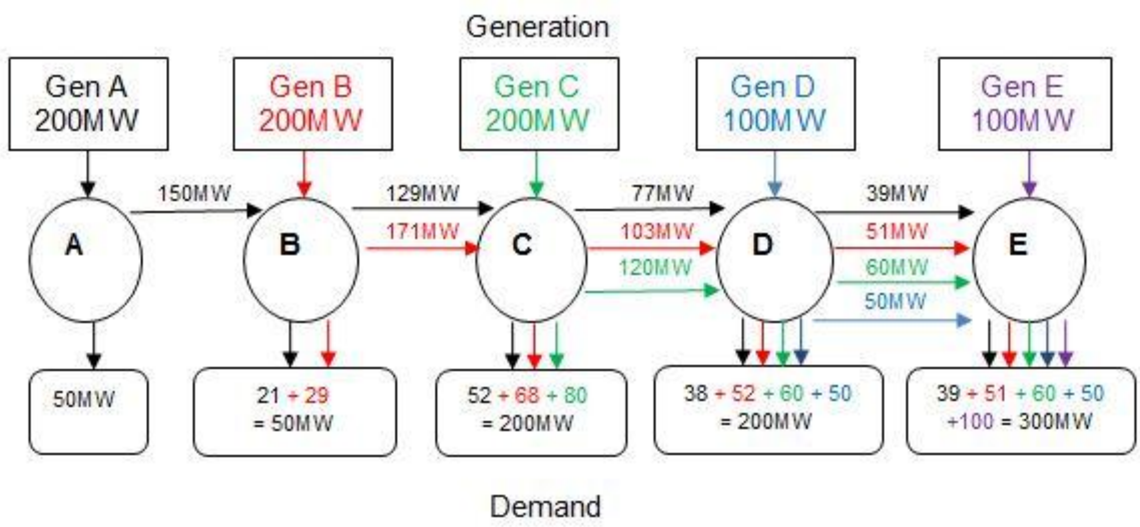
Table C.3 Determining load flow proportions

Node	Historic data (MW)		Proportion of demand met by generator				
	Flows out of node	Total input at node	Gen A	Gen B	Gen C	Gen D	Gen E
A	150	200	100%	0%	0%	0%	0%
B	300	350	43%	57%	0%	0%	0%
C	300	500	26%	34%	40%	0%	0%
D	200	400	19%	26%	30%	25%	0%
E	0	300	13%	17%	20%	17%	33%

Table C.3 shows the proportion of the demand at each node that each generator is deemed to be supplying. This is also shown in picture form in Figure C.2 where the flows on each line are allocated to the generators at each node. The flows attributable to each generator, as well as the demand at each node the generator is deemed to have met, are differentiated by colour.

For example, Table C.3 and Figure C.2 show that Gen A meets all of the load at node A and sends the remaining 150MW to node B, which is 43% of input at node B . Therefore Gen A is deemed to send 43% of electricity flow out of node B and into node C, which is 129MW.[363] 129MW is 26% of total input at node C and therefore Gen A is deemed to send 26% of electricity flow out of node C, which is 77MW. This is repeated across the lines and nodes for each generator. In this example, as Gen E causes no flow on transmission, its allocation of circuit costs would be zero.[364]

Figure C.2 Flow tracing



A flow tracing methodology does not have the sensitivity to the selection of a slack node, but it does assume future use can be estimated by historic use. To employ the flow tracing method as an estimate of the impact of an increment (and therefore giving a forward looking economic signal of the effect of incremental flows on future augmentation needs), it needs to be accepted that future flow patterns behave similarly to existing flow patterns.

C.3 Transmission pricing methodologies for generators

The previous section provided two load flow methods for determining and differentiating how each generator uses the transmission network. This section sets out four options for deriving transmission prices for generators. Each of these options uses the results of the load flow analysis as an input into the calculation.

363 It is also deemed to meet 43 per cent of load at node B, which is 21MW.

364 This contrasts with the incremental flow method where, depending on the position of the slack node, Gen E can be shown to decrease the flows across transmission lines resulting in a negative allocation of costs. For example, this is shown in the MW Mile example in section C.3.1.

The options considered for calculating transmission prices in order to determine transmission charges in this appendix are:[365]

- MW mile method;
- Forecast based long run network pricing;
- Apply Cost Reflective Network Pricing (CRNP) to generation; and
- The Irish Single Electricity Market (SEM) model.

Each method is described in turn below followed by an initial assessment against the assessment criteria provided in C.1 above.

C.3.1 MW mile method

The MW mile method builds on the incremental flow approach to determining relative use of the transmission network and factors in both the quantum and the distance of power transmitted. There are a number of potential variations including the Incremental Cost Reflective Pricing (ICRP) method[366] and the reverse MW mile method. These are discussed in turn below.

ICRP is sometimes characterised as an ultra-long run incremental pricing methodology based on the assumption that there is no spare capacity. This assumption implies that any increased flows above a base level would require incremental reinforcement of the affected circuits.

The ICRP method uses load flow analysis to determine how much (MW) and how far (km) power flows around the network.[367] This provides an estimate of the level of flow on the entire network in terms of MWkm. These results can then be used to calculate how much this flow changes as increments of generation are added at each location in turn to estimate the impact that each generator has on network flows in terms of MWkm.

A second step is then required to convert the MWkm attributed to each generator into a price in $/MW. This can be done by a simple mechanism such as deriving a cost in

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365 Note that an assessment of a postage stamp methodology is excluded (as this provides no estimate of LRMC and no locational signal). Similarly an assessment of deep connections is also excluded as this is dealt with in appendix D.

366 A version of incremental cost reflective pricing is the DC load flow (DCLF) ICRP pricing methodology currently used in Great Britain to set transmission use of system charges for both demand and generation.

367 Variations of the MW mile method can exist by using different assumptions for the load flow model. For example, assumptions can be made regarding whether to use existing routes on the current network without outages or whether to incorporate a security factor which allows for a secure outage. Similarly an assumption can be made about whether power can be routed at will on existing routes or whether all flows must satisfy Kirchhoff's laws.

dollars of an additional MWkm of transmission capacity.[368] An optional further step, used in Great Britain, is to average charges across connection points into zones in order to provide additional stability of prices.

MW mile method example

The MW mile methodology can be described by extending the incremental flow method example above.

In this example, all generators are assumed to be running to meet peak demand conditions by uniformly scaling their installed capacity down to meet load. This ensures that the assumption of no spare capacity holds.[369] Additionally, we assume that each line (AB, BC and so on) is of the length shown in Figure C.1 and that transmission losses are ignored.

The load flow model calculates the MW flow on each line and multiplies it by its length to get a MWkm figure under a base case. For example, the MWkm on line AB is 150MW * 100km = 15,000MWkm.

Table C.4 Base case total MWkm on each line

Base Case	AB	BC	CD	DE	Sum
MWkm	15,000	60,000	60,000	20,000	155,000

Generation is then increased by a single increment (usually 1MW) at each generator node on the network in turn. In this example, demand is correspondingly increased at the slack node which we assume to be node C.

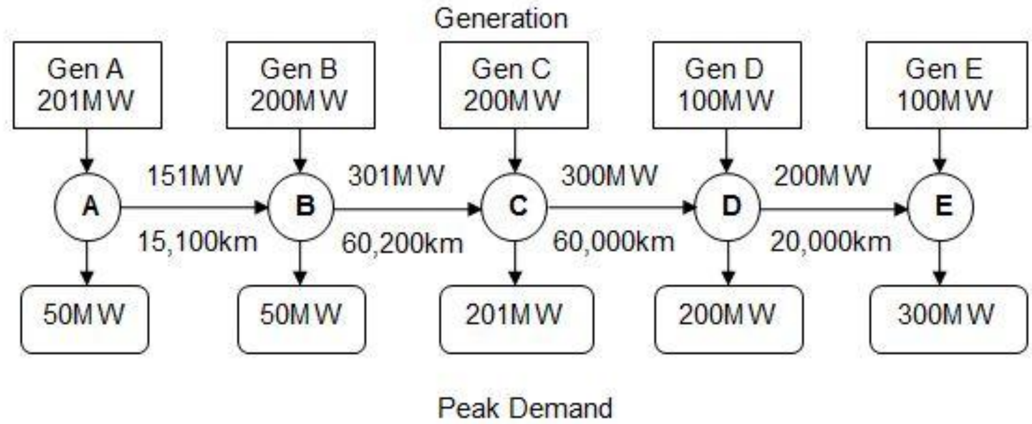
The model is re-run and the change in total system MWkm is found by summing all the change in flows on each branch. This is repeated for each generator node.

For example, injecting an extra 1MW at node A means 201MW is injected in total. This causes an electricity flow of 151MW on line AB which results in 15,100MWkm. The flow on BC also goes up by 1MW to 301MW. This provides 60,200MWkm. As C is the slack node, demand is 201MW at node C and no additional flows occur (over those that occur in the base case) on lines CD or DE. This is shown in Figure C.3.

368 In practice, even if such a generic approach were adopted, costs would likely be derived and applied taking into account factors such as voltage, line type (overhead line or underground cable) and topography.

369 As an exercise to illustrate the point of scaling generation to meet demand, we can see from Figure C.1 that total peak demand is assumed to be 800MW. If total installed capacity of the network was 1000MW, then we can determine that the installed capacity at Gen A, Gen B and Gen C would be 250MW and Gen D and Gen E would be 125MW. (i.e. in Figure C.1 they have already been uniformly scaled down from their capacity by a factor of 80 per cent to meet peak load).

Figure C.3 MW mile - MWkm flows attributable to Gen A



The full results for when a 1MW increment is added at each node and then compared to the base case is provided in Table C.5.

Table C.5 Total MWkm when adding an increment at each node in turn

	Branch (MWkm)				Sum (MWkm)	Change (MWkm)
Node	**AB**	**BC**	**CD**	**DE**		
A	15,100	60,200	60,000	20,000	155,300	300
B	15,000	60,200	60,000	20,000	155,200	200
C	15,000	60,000	60,000	20,000	155,000	0
D	15,000	60,000	59,800	20,000	154,800	-200
E	15,000	60,000	59,800	19,900	154,700	-300

Assume that the annual cost of providing an additional MWkm of transmission capacity is $20.

To calculate the charge for each generator in $/MW, the change in MWkm due to an incremental increase in generation is summed across each branch. This is shown in the last column of Table C.5 above. For example, an incremental increase in generation at node A leads to a total change in flows of 300MWkm. This change is then multiplied by the cost per MWkm of $20. The nodal tariffs applying at each node are calculated in Table C.6 below.

For example, Gen A's unadjusted tariff would be 300MWkm * $20/MWkm = $6,000/MW. Multiply this by its capacity of 250MW to get a total charge of $1,500,000.

The unadjusted nodal tariffs can then be scaled by a constant to achieve a given level of revenue recovery. In this example, the target is a net zero revenue recovery, and so all tariffs are scaled down by $1,250 as shown in Table C.6.

Table C.6 MW Mile tariffs

Node	Unadjusted nodal tariff	Unadjusted generator charge	Adjusted nodal tariff	Adjusted generator charge
A	$6,000/MW	$1,500,000	$4,750/MW	$1,187,500
B	$4,000/MW	$1,000,000	$2,750/MW	$687,500
C	$0/MW	$0	-$1,250/MW	-$312,500
D	-$4,000/MW	-$500,000	-$5,250/MW	-$656,250
E	-$6,000/MW	-$750,000	-$7,250/MW	-$906,250
Total		**$1,250,000**		**$0**

Reverse MW mile method

The reverse MW mile method can be broadly characterised as being comprised of the following steps:

1. run a base case load flow analysis which determines the direction of the dominant flow;

2. take each generator in turn and reduce all demand on a pro-rata basis to meet the dispatch of that generator in the load flow model;

3. re-run the load flow model to determine the generator's use of each line in the network;

4. compare the direction of flow in each individual generator scenario to that of the base case to identify if the generator is credited or charged for the line;

5. calculate the charge based on proportion of usage multiplied by the cost of the line. Note that usage can be negative to receive a credit; and

6. repeat steps 2 to 5 for every generator.

Table C.7 Assessment - MW Mile method

Criteria	Assessment/Rationale
Efficient	In general, generators that locate in areas where more transmission is needed would face a higher charge than those that locate where less capacity is required. This provides incentives in line with minimising total generation and transmission costs. However, no account is made for whether a line actually needs reinforcement, and if so, when that would be. Additionally, caution is needed when determining costs per MWkm as counterintuitive results are possible. This can occur, for example, when higher voltages have a lower cost per MWkm.
Cost reflective	Consistent with the points noted with regard to efficiency above, a MW Mile method would provide relative locational charges consistent with where an additional increment causes the greatest flows on the transmission network. However, ignoring spare capacity means that the resulting charges would not reflect how near to requiring reinforcement a transmission line is.
Effective	The MW mile methodology has been successfully implemented in Great Britain. The resulting charges provide incentive for the most economical projects to be developed first. While it has been suggested by some parties that in Britain that the use of the methodology has deterred generator entry, the many potential projects waiting for connection dates seem to provide evidence to the contrary.
Transparency	The simplicity of the modelling used means that the methodology is generally very transparent. However, certain elements such as how a cost per MW is calculated would need to be made available and consistently applied.
Predictable and stable	Because the MW mile method takes no account of spare capacity on lines, this smooths out the lumpiness of investment effect and ensures the charges are relatively stable. Charges will however be affected by the entry and exit of other generators. The option to average by zones allows for greater stability. However, any shift in zonal boundaries (if allowable) could cause a significant change in charge.
Competitive neutrality	The fact the MW mile method assumes no spare capacity means it does not distinguish between generators who use lowly loaded transmission lines and those which use lines which are highly loaded. This might not efficiently charge low load factor intermittent generation who may or may not use the transmission at peak times.

C.3.2 Forecast based long run network pricing

This model seeks to calculate charges based on the long run costs of the network and reflecting actual network limits (and spare capacity). The forecast based methods described here have most in common with the theoretical calculation of LRMC but, due to their complexity, have not been known to be applied to transmission charging. However, they have been used in some distribution networks outside of Australia. Long Run Incremental Cost (LRIC) and then Forward Cost Pricing (FCP) are two methods introduced below.

Long Run Incremental Cost (LRIC)

LRIC uses a forecast of expected future generation connections and takes into account how near circuits actually are to requiring reinforcement. It calculates how new generators (or an increase in capacity of an incumbent) affects network capacity and therefore causes network reinforcement. The calculations take into account the lumpiness of investments as well as when the reinforcement would need to occur. Resulting charges are annuitised costs of the network reinforcement decisions.

The LRIC methodology can be thought of as calculating how much a new increment of generation would advance or postpone reinforcement of network branches. For each node, the present value of that advancement or postponement is estimated. This approach can be summarised as follows:[370]

1. forecast expected demand and generator plans into the foreseeable future;

2. estimate the system reinforcements that would be required over time to meet the expected demand levels and generation plans. That is:

   (a) use load flow analysis to determine flows on each transmission branch; and

   (b) using load growth and existing transmission capacity and the modelled load flow on each line, determine the time it would take before reinforcement on each line is required;

3. as a base case, estimate the cost of these reinforcement requirements for each transmission line in present value terms;

4. in turn, adjust each generator's input by an increment and reconsider the system requirements and reinforcements that would be required on each transmission line to facilitate the additional injection;

5. estimate the costs of these reconsidered requirements for each transmission line in present value terms;

6. calculate the difference between the net present values of the investment program(s)[371] divided by the MW level of increment at that node; and

7. the charge is then the difference in the net present values multiplied by an annuity factor. The annuity factor could reflect the rate of return on the investment and incorporate an allowance for operation, repairs and maintenance of the transmission assets.

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370 For a more detailed and mathematical description, see for example, Li (2007): F Li and DL Tolley "Long Run Incremental Cost Pricing Based on Unused Capacity".

371 This requires summing the present values of the incremental cost to each branch (from the increment in generation). This is compared to the sum of present values of each branch of the base case.

Forward Cost Pricing (FCP)

The FCP model can be used to calculate annual charges for generators. This method provides cost signals relative to the available capacity, the expected cost of reinforcement, and the time before the reinforcement is expected to be necessary.

FCP effectively splits the network into groups of generators connecting at similar voltage levels, and for each group, looks at whether a test generator (of a typical size generator connecting at that voltage level), connected at a point would trigger the need for reinforcement. If it does, a charge is applied that is modified by the expected time to reinforcement and the probability of a generator of the test size actually connecting there. If there is no reinforcement then there would not be a charge. It is therefore driven by hypothetical rather than actual network investments.

Table C.8 Assessment - Forecast based long run network pricing methods

Criteria	Assessment/Rationale
Efficient	These methods most closely reflect the concept that charges should be set based on a forward looking basis and the actual need for reinforcement. The resulting charge would provide a stronger signal to those generators whose connection to, or use of, the system results in the actual need for reinforcement. This should promote the most efficient projects becoming economic first.
Cost reflective	The methods explicitly take into account spare capacity which ensures more weight (of signal) is given to increments which bring reinforcement nearer or where it is already imminent. It therefore is likely to be relatively cost reflective and promote efficiency. This positive impact is likely to be dampened by the required level of subjectivity and potential for forecast errors.
Effective	There are currently no known applications of forecast based long run network pricing for transmission, as it was developed for distribution networks (whose characteristics are not a direct match to transmission).
Transparency	The methods are highly complex and reliant on forecasting the future, which would likely be highly resource intensive.
Predictable and stable	The methods focus on when reinforcement would actually be triggered by a breach of branch capacity limits. This makes the method very sensitive to small changes when the branch limit is being approached. Averaging nodes into zones could mitigate some of this impact.
Competitive neutrality	Because it is concerned with remaining capacity and the timing of the investment, it can be thought of as approximating deep connection charging and therefore has the associated issues for entrants and managing investment lumps. However, it can allow for sharing of costs once subsequent generators connect.

C.3.3 Using CRNP for generation

In the NEM, locational TUoS charges for load are calculated via the CRNP methodology, or a modified version (modified CRNP). All TNSPs in the NEM use the TPrice load flow model to calculate the charges.

The CRNP methodology estimates the relative locational differences in transmission costs to be allocated between demand nodes. This is achieved by using TPrice to allocate a proportion of the optimal replacement cost of each transmission branch to individual demand nodes based on their proportional use of those shared network elements. The amount of revenue to be recovered is then applied to the demand nodes according to their proportional use of the network.

The CRNP method requires the revenue to be recovered to be determined administratively via the price control framework rather than using an estimate of LRMC to derive this. It therefore may only be considered a weak proxy for estimating LRMC. However, it does achieve locational differentials and therefore provides a signalling function of the relative efficiency of locating at different nodes.

The CRNP methodology could also be applied to generators in a similar manner to the way in which load is currently charged.[372]

Table C.9 Assessment - CRNP

Criteria	Assessment/Rationale
Efficient	As the methodology is based on recovering a level of revenue that is determined administratively, there is not a direct linkage to LRMC. Perverse incentives are possible, as more heavily utilised assets will attract a lower per unit charge. This can mean that the use of transmission elements with spare capacity attracts a higher charge than those with no available capacity. If modified CRNP is used, then this would, to a certain degree, take into account the level of spare capacity.
Cost reflective	The differentials would be reflective of the relative cost imposed by each generator compared to others. However, the actual charge would be directly related to the level of revenue to be recovered from generators which would need to be determined administratively.
Effective	CRNP is currently used in Western Australia to provide charges for generators. It has also proven to be effective for deriving load charges in the NEM.
Transparency	While T-price is currently in use in the NEM providing some familiarity for participants, it is unlikely to be currently well understood outside of TNSPs.

372 This could be either on a regional (as currently) or NEM-wide basis. The critical inputs to be determined would be the proportion of revenue to be recovered via the generator charge, whether to use CRNP or modified CRNP, and how to determine the times of greatest utilisation of the network by generators. A NEM-wide methodology with a positive revenue recovered from generators would need to be carefully implemented to minimise distortions to load.

Criteria	Assessment/Rationale
Predictable and stable	While dependent on input conditions, there is no direct link between triggering an investment lump, and being charged for it, CRNP would therefore be unlikely to be subject to significant volatility.
Competitive neutrality	The CRNP methodology would not allow for spare capacity which would mean that generators connected to lines with significant spare capacity would be charged based on an optimised replacement cost for the entire line. This is resolved by modified CRNP.

C.3.4 Irish SEM model

The electricity markets of Northern Ireland and the Republic of Ireland have combined into a single electricity market (SEM). The SEM has developed a model where both forward looking reinforcement needs and retrospective cost recovery are used to set generator charges.[373]

The key feature of the methodology is that locational differentials are determined by actual network reinforcement costs rather than hypothetical ones. However, actual costs associated with projected future transmission investment would not actually be recovered.

The generator tariffs are set to recover a given revenue amount set via the price controls, associated with the costs of building, operating and maintaining the transmission network. The resultant locational charges are capped such that a predetermined maximum percentage of the allowed transmission revenue that is to be recovered from generation can be recovered through locational charges.[374] Any allowed revenue to be recovered from generators that is not recovered via locational generator TUoS charges is instead recovered from generators via a common postage stamp charge.

In the SEM, a reverse MW mile load flow analysis is used to determine each generator's use of the network. However, it is the anticipated future network configuration five years ahead that is taken as the basis for the study.

Therefore, locational charges in each year are calculated with reference to expected flows over the anticipated transmission system configuration. This requires creating a future network snapshot which includes transmission reinforcement projects that are projected by the system operator to be in place in five years' time.[375]

373 For a more detailed explanation of the SEM G-TUoS methodology see: SEM 11-037, *All-Island Generator TUoS Methodology*, June 2011, and SEM 11-018 *Locational Signals Project: All Island Generator TUoS*, 11 April 2011. These are available at www.allislandproject.org.

374 In the SEM, 30 per cent has been chosen.

375 In the SEM these would be published in yearly statements of network requirements which outline the system operators' expectations for the upcoming seven year period. Each system operator has a database of all existing /planned assets in the network and a cost associated with each as well as including a date that the assets is due to be built or is built.

Locational charges would only be levied on new circuits, and only for a certain number of years after they have been built. For each new circuit, a locational charge is calculated for each generator in proportion to its use of the new circuit. Utilisation is based upon modelled generation dispatch in four network development scenarios.[376] In this context, use of new circuits can be by both new entrants and incumbents alike.

In the SEM model, new assets are defined as those to be built in the next five years or that have been built in the last seven years. This means that new assets are charged for on a locational basis for twelve years. After this point, assets would cease to be classed as new and would no longer be treated locationally. They would instead be treated as sunk assets and allowed revenue linked to them is recovered on a postage stamp basis.

Table C.10 Assessment - Irish SEM model

Criteria	Assessment/Rational
Efficient	This approach would result in a generator charge that was higher in areas where more transmission was needed than in areas where less transmission capacity was required. This would provide incentives in line with minimising total generation and transmission costs. Shifting charges for assets over seven years old into the postage stamp charge might add some distortions to efficient entry. For example an entrant might choose to wait until the seven years have passed before connecting so they avoid the locational element of the charge.
Cost reflective	This model ensures that entrants who connect see some cost implications of their actions even if they connect after a circuit has been commissioned. The charges would be related to actually implemented or planned reinforcement schemes (via the load flow modelling) but would still reflect an administratively determined level of revenue. Both new and existing generators would pay for the reinforcements they "use". Spare capacity would not be paid for by generators.
Effective	This model has only recently been developed for the Irish SEM and has therefore not been proven to be implementable or robust at providing meaningful signals.
Transparency	The methodology is likely to be highly complex and its design relatively subjective. However, once agreed, it should be mechanical to apply and therefore understandable.
Stable and predictable	There is the potential for significant variation of charges as reinforcements come into or drop out of the twelve year horizon for locational charging.
Competitive neutrality	This methodology appears to be competitively neutral.

376 In the SEM, these scenarios are "Winter Peak with zero wind generation assumed", "Summer Peak with zero wind generation assumed", "Summer Peak with wind generators dispatched at 80 per cent of their installed capacity" and "Summer Minimum with wind generators also dispatched at 80 per cent of installed capacity". A locational charge is calculated for each generator unit under each scenario, with the maximum derived tariff for each taken as the basis for its locational charge.

C.4 Further design considerations

There are a number of other issues that would need to be considered when selecting a preferred charging model. Some, such as the decision to implement charging regionally or NEM-wide may impact how feasible the preferred option is. Others, such as having zonal or nodal charges and for what period to fix charges, are policy decisions which might be influenced by the desire for stable charges.

These areas of design also interact. For example, if a positive amount of a TNSP's revenue is to be collected from generators, then a NEM wide generator TUoS would present a number of consistency issues due to load TUoS being collected regionally.

These further design considerations are discussed below.

C.4.1 Regional or market wide

A generator charging scheme based on LRMC could be regionally-based or cover the whole of the NEM.[377]

A market-wide generator charging scheme would provide a locational signal which would promote a more efficient spread of generation between, as well as within, regions. Additionally, schemes to implement inter-regional TUoS for load are currently being considered to fully reflect the locational signal for load between regions. The complications associated with designing an inter-regional TUoS charging scheme for load would indicate that there might be significant benefits associated with the implementation of a single NEM-wide generator TUoS methodology as opposed to inter-regional generation TUoS charging (provided any inconsistencies with the way in which load TUoS is recovered are not problematic).

However, regional generator charging is likely to be more consistent with the current design of the NEM and load TUoS, which is calculated on an intra-regional basis. If a positive amount of TNSP revenue is to be recovered from generators, a regional approach might lessen the impact of any unintended consequences from the imperfect level of harmonisation that currently exists between TNSPs' load charging methodologies.

C.4.2 Zonal or nodal

Generator charges can be calculated on a nodal or zonal basis.[378] A nodal charge is likely to be more cost reflective, but subject to greater volatility.

377 Note that a short run cost signal already exists between regions since regional reference prices diverge when there are constraints between jurisdictions. However, short run signals are not necessarily effective to inform long run decisions because: they are targeted at improving short run dispatch; they change often and sometimes significantly to reflect instantaneous network conditions; and they are unlikely to fully signal the cost of network investments.

378 Note that load charges in the NEM are currently calculated and charged on a nodal basis.

Where charges are calculated for zones, this can be done within the methodology based on areas that contain generation nodes with similar marginal costs and which are geographically proximate, or simply assigned administratively. It should be noted that volatility for individual nodes can exist where zone boundaries change and a generator may be assigned to a new zone.

C.4.3 Revenue recovery

Unadjusted generator TUoS charges based on the methodologies described in this appendix would each be likely to provide for a different level of revenue being recovered.[379]

It could be determined that an unadjusted charge provides the level of revenue to be recovered from generators, with the remainder recovered from demand. Another option is to administratively set the desired level of revenue to be recovered from generators (from 0 per cent to 100 per cent).[380] A downside is that it is difficult to provide a rationale for choosing any one level over another.

Where a predetermined level of revenue is desired to be recovered from generators, the raw charges calculated by the methodology could be scaled by a constant. This would retain the relative price differences for generators at different nodes and maintain the desired variation in relative signals.

C.4.4 Period to fix charges

It would be expected that generator TUoS charges would be calculated annually, although longer-term charges could be derived. In selecting the appropriate duration, there would be a trade-off between ensuring prices are stable (promoting investment) and producing an effective price signal (promoting efficiency). Locking-in charges can create market distortions due to the true cost changing over time. On the other hand, an unpredictable and volatile charge is likely to increase the risk premium associated with obtaining finance.

One option for managing volatility in charges is to employ a mechanism to limit the year on year variations in charges, such as the existing 2 per cent rule in NEM load TUoS charges.[381] However, this would decrease the cost reflectivity of the signal and could require large corrections at a point in the future to be able to reflect the true cost.

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379 In Britain for example, unadjusted G-TUoS charges provide approximately 15 per cent of total revenue.

380 A 0 per cent level would not necessarily mean that there would be no use of system charge for generators, but that the charges generated would be scaled to ensure there are negative and positive charges. The net revenue recovered would be zero.

381 Under clause 6A.23.4(f) of the Rules, locational TUOS charges for load must not change by more than 2 per cent per annum compared to the average change in locational charge for the region.

C.4.5 Inclusion of embedded generation

Flows on transmission networks can be caused by embedded generation as well as directly connected generation. Therefore, consideration needs to be given as to whether it would be efficient to expose some or all embedded generators to the same signals as generators connected to the transmission network.

C.4.6 Energy or capacity based charge (and renewable considerations)

Charges could be based on installed capacity[382], actual energy volumes generated, or a combination of both.

Capacity charges do not alter short run costs and therefore do not distort dispatch. They assume that the transmission network is required to be built to extract the full capability of the generator. In contrast, energy based charges would only charge generators based on how much they generate. The charges would therefore be a variable cost taken into account when a generator decides how to offer into the NEM, potentially distorting dispatch.

Certain technology types, such as intermittent generation, do not necessarily use the system at peak demand times, which is what drives transmission investment.[383] Intermittent generation is therefore likely to result in lower levels of transmission investment compared to other technology types. Low capacity factor/intermittent resources are likely to prefer charges based on energy used rather than capacity and/or potentially prefer models with optional access than a model with firm access for all (in that they might be likely to opt for a non-firm product that attracts no TUoS charges for at least part of their capacity).

Additionally, intermittent generation cannot be relied upon to delay transmission investment and it may therefore not be appropriate for them to be provided with a negative charge (should these form part of the charging scheme).

382 Note that where there are negative priced nodes, a mechanism to ensure capacity is not overstated would be required to ensure generators do not inefficiently benefit.

383 There is however, an argument that intermittent generators may use the system at minimum demand which requires investment in transmission to accommodate their peak generation.

D Deep connection charges

The purpose of this appendix is to evaluate the effectiveness of deep connection charges as a means of providing a locational signal to generators. As discussed in chapter 9, in policy package 4 generators that opt to become "firm" would face a charge commensurate with the cost of providing that firm access.[384] This charge could be either a transmission use of system charge, as discussed in appendix C, a deep connection charge, as set out in this appendix, or potentially a hybrid approach containing elements of both.[385] Deep connection charges have been advocated by some stakeholders as a means of providing a locational signal for new entrant generators.[386]

This appendix introduces the concept of deep connection charging and evaluates the impact of implementing deep connection charges against the set of assessment criteria identified in appendix C.

D.1 What is a deep connection charge?

This section explains the difference between "deep", "shallow" and "super-shallow" network assets. It then provides a high level overview of specific design features for a deep connection charge.

D.1.1 Differentiation between shallow, super-shallow and deep connection charges

When discussing transmission network costs caused by generator location decisions and considering how to allocate these costs, there is a need to distinguish between:

- **Dedicated transmission assets** - which are those assets installed solely for the purpose of the connecting user and are expected to remain dedicated to that user over the lifetime of the asset. For example, this could include a physical line between a generator and the shared transmission network, and the work required to connect that line;

- **Other connection-related assets** - which are those assets that are necessary to give effect to a connection but which are used by, and become part of, the shared network. They are required only to connect the generator to the shared

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384 As discussed in chapter 8, we consider that a generator TUoS charge is likely to be more appropriate for a model of generation reliability standards, although such standards could be introduced with a deep connection charge.

385 For example, the regulatory arrangements in the Wholesale Electricity Market in Western Australia include both generator TUoS charges and capital contributions for deep connections.

386 AER, Issues Paper submission, p. 13; TRUenergy, Issues Paper submission, p. 6; AGL, Directions Paper submission, pp. 11-12; SP AusNet, Directions Paper submission, p. 5; SA DTEI, Directions Paper submission, p. 3.

transmission network, and exclude any subsequent shared network augmentations required to meet performance or reliability standards; and

- **Shared transmission assets** - which are those assets that constitute the shared network and are necessary to meet performance and/or reliability standards.[387]

This distinction between transmission assets allows a better understanding of what is generally meant by deep and shallow connection charges:

- a **super-shallow connection charge** entails a generator who is connecting to the transmission system paying a connection charge which incorporates the dedicated assets only;
- a **shallow connection charge** entails a generator who is connecting to the transmission system paying a connection charge which incorporates dedicated and other connection-related assets;[388]
- a **deep connection charge** entails a generator who is connecting to the transmission system paying a connection charge which incorporates the dedicated assets, other connection related assets and the incremental cost of upgrading the shared transmission assets (if these are required as a result of that connection).

As discussed in chapter 12, new generators in the NEM pay a shallow connection charge, as TNSPs have in practice adopted a causer-pays approach to connection charging. However, the Commission understands that those generators connected prior to the start of the NEM pay only a super-shallow connection charge (i.e. they pay only for the dedicated assets, with the costs of the other connection-related assets that form part of the shared network being recovered from load).

The remainder of this appendix focuses on how a deep connection charge might be designed and the efficiency implications of implementing such a charge in the NEM in return for a firmer level of service than generators are currently able to obtain.

D.1.2 Deep connection charge design

Conceptually, the principle of a deep connection charge is relatively simple. If a new generator connects to the transmission network, and this leads to investment of $x, that generator pays $x to connect.

387 Some assets that are initially connection-related assets may accommodate more generation or load connections over time. In this case, there could be mechanisms to redistribute the charges between the parties who come to share the assets. In the NEM this is currently possible under negotiated charges although this process lacks transparency.

388 In the case of shallow or super-shallow connection charges, where it is the intended policy for a proportion of the costs of shared network assets to be recovered from generators, this would need to be recovered via a use of system charge.

Under a deep connection approach, when a generator connects to the transmission network its connection charges are determined individually and independently from other generators’ connection charges, based on the costs of its dedicated assets, other connection-related assets and the costs it imposes on the shared network. This provides a locational signal as generators face the costs that they impose on the network. The deep connection charges may be paid by the generator as a lump capital sum or an annual annuitised value of that lump sum.

Deep connection charges would be likely to require:

- the capacity of the existing shared transmission network being defined and allocated amongst the incumbent generators; and
- new generators who are connecting at a location which does not have adequate spare capacity to make a payment to the TNSP which would be used to upgrade the network.

In terms of policy package 4, the essence of the optional firm access is that a generator is able to contract with its TNSP for firm access. This could be implemented through a "deep connection" process. In response to the generator's request, the TNSP would assess the transmission investment required to deliver the connection requirements, calculate the cost and then would levy that cost on the generator.

The introduction of such an approach would represent an increased level of service for incumbents over that which currently exists in the NEM. This is because a deep connection charge would ensure that the network standards for incumbent generators would be maintained by allocating generator driven augmentation costs to new generators. This contrasts with the present arrangements where generators are exposed to the potential for a new generator to connect and this connection triggering no transmission augmentation. Under current arrangements, this could lead to constraints which reduce the incumbents' ability to access the regional reference node.

D.2 Impacts of a deep connection charging methodology

There are two main areas to consider when assessing the impact of a deep connection charge in relation to the assessment criteria identified in appendix C:

- the lumpy nature of transmission investment; and
- the impacts on new generator entrants.[389]

Note that this section first considers the concept of a mandatory deep connection charge. Where there are different impacts due to a deep connection charge under an optional firm access regime, these are highlighted in the discussion below.

389 This could be an incumbent generator with a new project or a new generator looking to enter the market.

D.2.1 The lumpy nature of transmission investment

In considering optimal charging arrangements, it is important to take into account that transmission network investment cannot normally be expanded in small increments of discrete investment. That is, transmission investment is "lumpy".

Why transmission investment lumps occur

The capacity of a circuit is generally limited by its electrical current carrying capacity. Costs to increase this current carrying capacity are often significant. For example, a higher voltage transmission line might be required to increase the current carrying capacity on a circuit. Often, due to "off the shelf" sizes of transmission assets (for instance, standardised voltages), it is not possible to increase transmission capacity in small increments. Therefore, a transmission upgrade might necessarily provide a greater increase in capacity than that which, at least initially, is required.

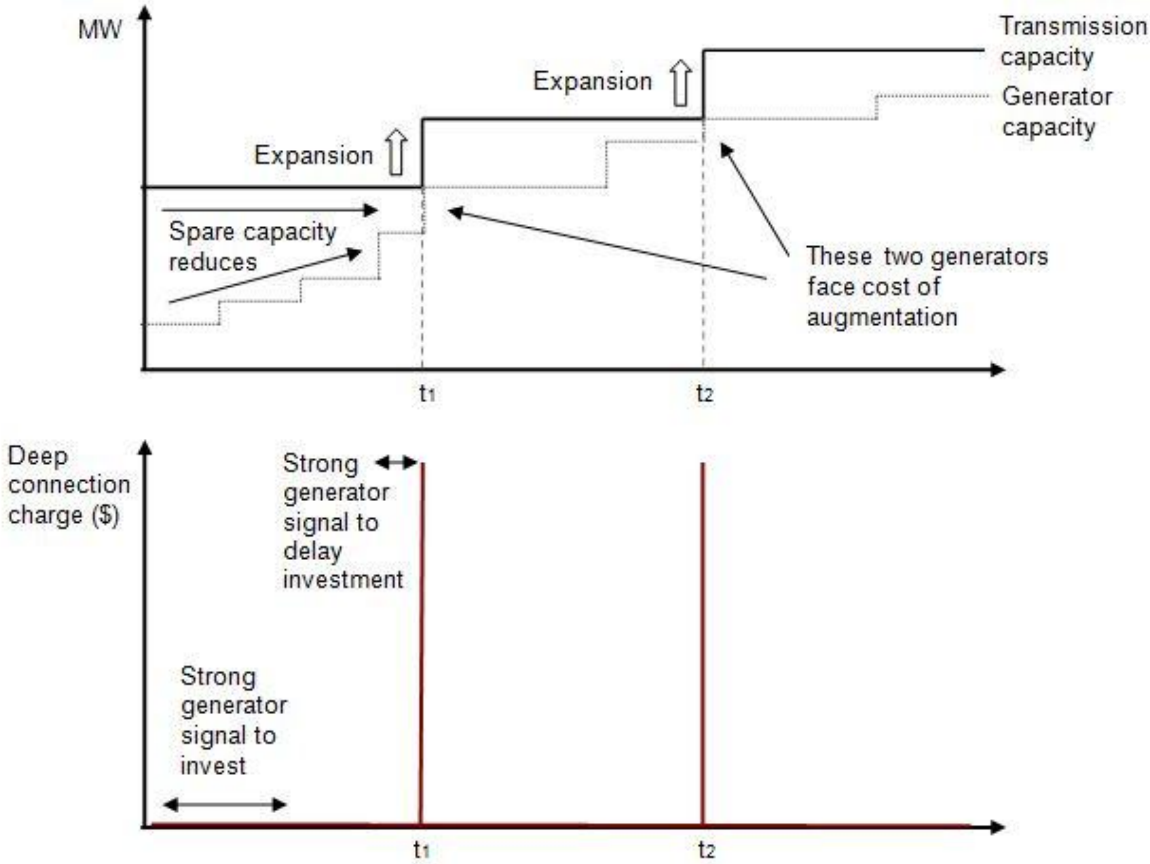
How transmission investment lumps impact generator investment

A "lump" of investment costs a discrete amount and provides a certain amount of capacity. Once a lump has been paid for, use of any spare capacity it provides by an additional entrant should, in an economic sense, attract no charges unless additional investment is required (as the marginal cost of providing the capacity is zero).

This means that a deep connection charge that reflects the costs to connect at a single location and at a single point in time would result in very high charges for an entrant immediately prior to new network investment. Where this new investment provides spare capacity then there would be close to zero charges immediately after the investment has occurred for subsequent entrants. This type of oscillating signal (shown in Figure D.1) is unlikely to promote efficient generator investment.

Figure D.1 shows that additional transmission capacity is triggered at t_1 and t_2. The cost of this transmission capacity is borne by the generator who triggers this, no matter how small and regardless of the fact that other generators have contributed to reducing the available spare capacity. An entrant who uses spare capacity to connect brings forward the time when the deeper reinforcement actually occurs.

Figure D.1 Generator investment signals due to a simple deep connection charge



Therefore, a significant drawback with the deep connection methodology is the fact that a relatively small addition in generator capacity may trigger a large network investment requirement. This imposition of the full cost of a transmission augmentation on a new generator is a significant first mover disadvantage, in that the first user is required to pay for some capacity it does not require. Additionally, when an augmentation funded by a new entrant's deep connection charge results in spare capacity, this would mean that a second entrant generator would be cross-subsidised by the first. These first mover disadvantages would create competitive distortions in generation investment as new entrants might have an incentive to delay entry.

There is consequently a risk that introducing a deep connection charge would not necessarily facilitate a transmission and generation combination which minimises costs to customers in the long run. Where there are a large number of potential generator investors who would all benefit from an increase in network capacity, but each one is too small to contemplate paying for the reinforcement by itself, this would result in an overall inefficient outcome.[390]

390 For example, cheap and plentiful generation could be sourced at a location which would prove to be difficult to extract due to the deep connection methodology requiring one generator to be the first mover and bear the transmission augmentation burden for its competitors.

Optional firm access regime

A deep connection charge under an optional firm access regime would be also impacted by the lumpy nature of investment. The same issue of first mover disadvantage would arise, in that there would be an incentive (to both new entrants and non-firm incumbents) to purchase firm access only when this does not trigger additional transmission investment. However, the additional availability of the non-firm service may allow for those generators who are willing to be non-firm to enter.

Potential for arrangements to reimburse first mover

To mitigate some of the first mover issues, some of the cost of the additional investment could be shared by future entrants or purchasers of firm capacity. A method to do this could include devising "second comer" arrangements. Under this approach, subsequent new generators would be required to rebate a proportion of the original cost to the first mover.

A mechanism for calculating the cost reflective proportions of the network investment would then need to be established. This would increase the complexity of the approach. Further, any second comer arrangements would not remove the requirement for, and potential burden to, the first mover to provide the initial capital investment.

D.2.2 Impact on generator entrants

While a deep connection charge has the benefits of being stable and providing a strong signal to locate in areas which avoid significant augmentation requirements, it is likely to also have some negative impacts on new generator entrants. These impacts are discussed below.

Stability

A desirable feature of any charge for those that face it is that it is stable and predictable. This promotes certainty. Where charges are variable and difficult to predict with any accuracy, a higher financing premium might be required to offset the increased risk. Deep connection charges provide certainty for generators and their financiers as the charge would be determined upfront and not subject to change.[391]

However, the level of a deep connection charge can be very uncertain until it has been calculated by the TNSP, and the process for doing this is likely to be complex with little transparency. For instance, establishing a charge that reflects the impact a generator will have on network flows will require a number of assumptions to be made, such as

391 This predictability would be reduced with second comer arrangements, however, these should only result in transmission costs decreasing for the generator as their original burden is subsequently being shared.

defining a counterfactual that does not include the generator and predicting network flows that are dependent on generator bidding behaviour

Additionally, locking in a charge can create distortions as the true cost that the charge is intended to reflect is likely to change over time. It is very difficult to attribute the need for actual network augmentation investment to each particular new network connection. It is particularly difficult to do this at the time of connection.

Locational signal

A deep connection charge could be effective in influencing the locational decision of a new generator entrant, as facing the full cost of investing in additional network capacity is likely to present a strong signal against locating in areas where augmentations would be required. Similarly, a signal would exist to connect where (or when) there is spare capacity due to corresponding low charges. This may promote more efficient use of the network.

However, as noted in section D.2.1 above, there is a risk that imposing a deep connection charge could be inefficient because the signal may result in the investment or purchase of firm access rights being inefficiently delayed or prevented.

Potential discrimination between incumbent and new entrant generators

A deep connection charge ensures that the network standards for incumbent generators are maintained by allocating all generator driven augmentation costs to new generators. However, incumbents' ongoing use of the network, as well as new generator entry and demand growth, contributes to constraints that may trigger transmission investment. Incumbents' use of the network will also create costs in terms of the maintenance and replacement of assets required to ensure that network standards continue to be met.

Charging new entrants for the deep connection costs associated with their investment decision raises the costs for new entrants relative to incumbents, affecting allocative efficiency. In order for a new generator facing a significant deep connection charge to enter the market it needs to have some other cost advantage to be able to compete with the incumbent.

This can be shown by considering the cost differentials between incumbent and new entrant generation. The replacement of an incumbent generator by a new entrant is justified where the forward looking cost of the new generator is less than the incumbent. This is when the total forward-looking cost of the new generator (adjusted for any difference in the value of service potential that new generator has over the incumbent) is less than the forward-looking cost of the incumbent:

$$Gen\_Cost^{New}_{Capex} + Gen\_Cost^{New}_{Opex} + Trans\_Cost^{New} - \Delta Service < Gen\_Cost^{Old}_{Opex} + Trans\_Cost^{Old}$$

Where:

Gen_Cost^{New} is a new entrant generator cost

Gen_Cost^{Old} is an incumbent generator cost

$Trans\_Cost^{New}$ is a transmission cost faced by the new entrant generator

$Trans\_Cost^{Old}$ is a transmission cost faced by the incumbent generator

ΔService is the value of service potential that new generator has over an incumbent

Capex is capital expenditure[392]

Opex is operational expenditure[393]

If, at the same location, $Trans\_Cost^{Old}$ is zero and $Trans\_Cost^{New}$ is large, as under a deep connection charge, then new entry may be inefficiently deferred. Any deep connection charge previously paid by an incumbent would be a sunk cost, in the same way that its original capital investment would be. In order to make entry economic, a new generator would require either a significant cost advantage in the other cost variables on the left hand side of the equation, or be able to provide a significant service value in excess of the incumbent.

Windfall gains to incumbents

A further concern related to promoting a competitive generation sector is that deep connection charges could lead to windfall gains over time for incumbent generators. Under the competitive market process, the spot price in the wholesale market must be sufficiently high to make entry financially viable. Under a deep connection charge approach, the spot price would have to rise even higher to offset the higher connection costs of the new entrant. This may reduce the level of competition in the generation sector.

Since incumbents do not pay transmission charges under a deep connection regime, the rise in prices would mean they receive a windfall gain for a period of time before new entrant generators are provided a sufficiently high price signal to connect.

Optional firm access regime

Following the implementation of an optional access regime with deep connection charging, incumbents would be able to purchase access rights to existing capacity (at zero or very little cost) which, if purchased, would no longer be available to new entrants. Therefore, new entrants would find firm access to be relatively more

392 This is sunk for incumbent generators.

393 This is used to refer to all forward looking (and hence avoidable) costs.

expensive and so be placed at a competitive disadvantage, with the result that entry might be inefficiently delayed. This would allow incumbents to make windfall gains in the energy market.

Although new entrant generators would have the option of being non-firm, incumbents would still stand to gain through the compensation transfers between non-firm and firm generators.

D.3 Summary evaluation against criteria

An assessment of deep connection charging against the assessment criteria detailed in appendix C indicates that there are some potentially significant issues that would need to be considered when assessing whether the introduction of deep connection charges would further the NEO. These are summarised in Table D.1 below.

Table D.1 Evaluating a deep connection charge

Criteria	Assessment/Rationale
Efficient	A first mover who triggers an augmentation would be subject to a high charge while subsequent generators can connect at a relatively low cost. This creates a gaming issue and could distort competition. Additionally, lack of efficient signals of the value of transmission capacity could result in a sub-optimal transmission and generation combination.
Cost reflective	The principle is for a deep connection charge to be reflective of the cost to connect a new generator. In practice incumbents would use assets paid for by new entrants. Second comer arrangements would ideally be required for generators who use spare capacity created by a first mover.
Effective	The signal to new generation would be to locate primarily where there is spare capacity if this is available, which could lead to more efficient network usage. However, the signal might be so strong to prevent a first mover ever coming forward in regions where it would be efficient to augment the network.
Transparency	The deep connection charging principle is simple, although estimating the costs caused by a new generator (or a generator seeking firm access) can be a subjective exercise lacking in transparency. Additionally, the need for second comer arrangements increases complexity.
Predictable and stable	A deep connection charge has the advantage that the charge would be known at the time of connecting and would be fixed.
Competitive neutrality	Traditionally designed deep connection charges would result in new entrant costs being raised relative to incumbents which could delay new entry and provide interim windfall gains for incumbents. Additionally, a potential cross subsidy exists without effective second comer arrangements where new entrants face the entire cost of new investment, but second comers can free ride.

While a stable charge would be likely to eventuate, the Commission has concerns with the degree to which the charge could be considered to be effective, efficient and to provide competitive neutrality where this was implemented in a mandatory regime. Under an optional firm access regime with a deep connection charge only for those who opted to purchase such access, the negative impact would be somewhat diluted but not totally removed.