REVIEW

Australian Energy Market Commission

FIRST INTERIM REPORT

Optional Firm Access, Design and Testing

24 July 2014

Submissions due 4 September 2014. Reference: EPR0039

First Interim Report

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Reference: EPR0039

Citation

AEMC 2014, Optional Firm Access, Design and Testing, First Interim Report, 24 July 2014, Sydney.

About the AEMC

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

Executive Summary

In February 2014 the COAG Energy Council (formerly the Standing Council on Energy and Resources) directed the Australian Energy Market Commission (AEMC or Commission) to develop, test and assess the optional firm access model that was initially proposed as part of the AEMC's Transmission Frameworks Review.

Optional firm access allows generators, if they choose, to pay to manage the financial effects of network congestion. This would require them to make payments, which would be used to fund and guide the way that transmission is developed, with more transmission investment being driven by commercial decision making on the part of the generation business. This should benefit consumers by minimising overall system costs, resulting in less cost being passed through to consumers.

This First Interim Report is the first report that has been published as part of this review. It sets out the work that we have done to date, and is accompanied by an Overview Paper, which provides a summary of this project.

The purpose of this review

As set out in our Terms of Reference, the objectives of this review are to:[1]

- confirm or modify the design of the optional firm access model as a result of testing and evaluation;
- assess whether implementing optional firm access is likely to contribute to the National Electricity Objective;
- engage with industry participants and governments to build understanding of the model and the potential impacts of its implementation; and
- recommend to the COAG Energy Council whether to implement optional firm access, and if so, how it could be implemented.

Significantly, the terms of reference referred to the model of optional firm access as set out in the Transmission Frameworks Review final report (Table 10.1) and directed us to build on this.

The Australian Energy Market Operator (AEMO) also received a terms of reference to undertake its own review, which complements that received by the AEMC. AEMO's work focuses on the "access settlements" component of optional firm access, and what variations to the access settlement mechanism would be necessary for a staged implementation of the optional firm access model.

1 See: http://www.aemc.gov.au/getattachment/32d53fe7-17b1-4eb4-88ae-ce110bb2a65c/Terms-of-reference.aspx.

The purpose of this paper

The First Interim Report presents an update on the work we have done since receiving the Terms of Reference. The focus at this stage has been on further developing certain "core" elements of the design of the optional firm access model. We have also included our initial work on how we will approach the assessment of the impacts of optional firm access. The core elements discussed in this paper include:

- The firm access standard, which defines the minimum level of firm access service quality to which a firm generator is entitled. The firm access standard which is proposed has evolved from what was proposed in the Transmission Frameworks Review. The proposal is for both a planning standard (which would require the Transmission Network Service Provider (TNSP) to plan to provide a specified level of capacity); and an operating standard (which would require the TNSP to operate their network to meet a target level of access).

- The TNSP incentive scheme, which would underpin the firm access operating standard. This incentive scheme would be designed to encourage to TNSPs to trade-off rewards and penalties against the risks that they face, and so make efficient decisions when operating their network.

- Inter-regional access, which would provide a firm inter-regional access product from one regional reference node to another. This would be firmer than the current inter-regional products offered, since it would not depend on flows across the interconnector in order for the product to pay out.

- Short-term access, which would be differentiated from long-term access by the assumed transmission expansion lead time: short-term firm access would only be issued for earlier periods than this, and long-term firm access would only be issued for later periods.

- Access settlement, and associated parameters, which would be the process under which dispatched non-firm generators would compensate firm generators that have not been dispatched due to a binding constraint.

- Initial transitional access allocation and sculpting, which would apply in the early years following implementation of the optional firm access model. The proposal is for a design to prevent sudden and significant changes in the market, while at the same time not delaying or diluting the benefits that the optional firm access model is intended to promote.

We have focussed on these core elements as they are central to assessing the implementation of optional firm access.

As required by our Terms of Reference, we have also set out implementation options for optional firm access. Implementation in this context refers to the order and timing by which the various elements of the optional firm access can be introduced, including whether it is implemented in all regions or just some.

We have also undertaken some further work on "recommended" elements on the optional firm access model. This includes a mechanism to incorporate market-led investment signals into TNSP investment decisions that are undertaken to meet reliability standards. At this stage, we do not consider that this is a "core" element of the regime that would need to be put in place at the commencement of the model. This element could be put in place at a later stage. This is discussed further in Appendix A of the First Interim Report, and we welcome stakeholder feedback on whether our allocation of elements to "core" and "recommended" is correct.

Next steps

We are seeking stakeholder comment on the work that we have outlined in this report.

Submissions on the First Interim Report are requested **by no later than 5pm, Thursday 4 September 2014**. Stakeholders are encouraged to include any relevant information and comments in their submissions.

We are planning to publish a supplementary report on pricing in early September 2014. This will provide a progress update on our work on pricing of firm access since the Transmission Frameworks Review. We will also publish a pricing model prototype for participants to consider.

We are aiming to publish a Second Interim Report in late November 2014. This will set out:

- a detailed design of the optional firm access model;
- our draft assessment of the benefits and costs of optional firm access; and
- our draft recommendation as to whether or not optional firm access should be implemented.

We will publish our final recommendation to the COAG Energy Council by mid-2015.

Contents

1 Introduction

1.1 Background to the review

In April 2013, the Australian Energy Market Commission (AEMC or Commission) completed a comprehensive review of the transmission arrangements that underpin the National Electricity Market (NEM), known as the Transmission Frameworks Review (TFR).

This review was requested by the COAG Energy Council (formerly called the Standing Council on Energy and Resources). Specifically, the AEMC was asked to:[2]

- review the arrangements for the provision and utilisation of electricity transmission services and the implications for the market frameworks governing transmission investment in the NEM; and
- 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.

The focus of the Transmission Frameworks Review was on the arrangements that govern the interface between transmission and generation. These include how generators could gain access to the wholesale market via the transmission system, the way in which network congestion is managed, what charges generators could face in relation to transmission, how the transmission network is planned, and how generators can connect to the transmission network. At the end of the review, we made a number of recommendations.[3]

To address issues raised in the Transmission Frameworks Review, the Commission developed an integrated package of market arrangements for the provision and utilisation of the transmission system, known as optional firm access (OFA).

Under the optional firm access model, a generator would have the ability (but not an obligation) to purchase financial access to the transmission system. If, in the event of congestion, a generator without such access was dispatched ahead of the generator with the access, the "non-firm" generator would pay the "firm" generator the difference between the local price[4] and the regional price[5]. The access would be underpinned by transmission capacity, that is, the transmission business may have to augment its network to accommodate the access purchased.

The Commission considered that this model has the potential to deliver better long term outcomes by introducing more commercial drivers into transmission

2 MCE direction, p. 3. The full MCE direction is available on our website at www.aemc.gov.au.

3 See: AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013, Sydney.

4 The local price is the price of supply a marginal unit of electricity at a point in the network.

5 The regional reference price, or the regional price, is the spot price at the regional reference node.

development, and to enable better trade-offs to be made between the cost of transmission and the cost of generation.

The Commission considered it reasonable and prudent to progress the optional firm access model, but also noted that implementing it would be a fundamental change to the market and would not be without risk. The Commission therefore recommended further work on the detailed design and testing of the optional firm access model. This would allow for the better assessment of the costs and benefits associated with the model.

1.2 Terms of Reference

The AEMC received Terms of Reference from the COAG Energy Council to develop, test and assess the optional firm access model that was initially proposed as part of the Transmission Frameworks Review.[6] The objectives of the Terms of Reference are:[7]

- confirm or modify the design of the optional firm access model as a result of testing and evaluation;
- assess whether implementing optional firm access is likely to contribute to the National Electricity Objective;
- engage with industry participants and governments to build understanding of the model and the potential impacts of its implementation; and
- recommend to the COAG Energy Council whether to implement optional firm access, and if so, how it could be implemented.

Significantly, the Terms of Reference referred to the model of optional firm access as set out in the Transmission Frameworks Review Final Report (Table 10.1) and directed us to build on this. Table 10.1 is reproduced in its entirety in Appendix C.

The Australian Energy Market Operator (AEMO) also received a Terms of Reference which complements that received by the AEMC to undertake its own review. AEMO's work focuses on the "access settlements" component of optional firm access, and what variations to the access settlement mechanism would be necessary for a staged implementation of the optional firm access model.[8]

The COAG Energy Council requires the AEMC, in conjunction with AEMO, to provide to them, and subsequently publish, a final coordinated package of work on the design, testing and assessment of the optional firm access framework by mid-2015.

6 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Transmission-Frameworks-Review.

7 SCER, Transmission Frameworks - Detailed Design and Testing of an Optional Firm Access Framework, 25 February 2014.

8 Further details on AEMO's work on optional firm access can be found here: http://www.aemo.com.au/Electricity/Market-Operations/Optional-Firm-Access.

1.3 Our approach to addressing the Terms of Reference

The National Electricity Objective (NEO) provides overall direction for the work we do as part of this project. In particular, and as required by the Terms of Reference, we have developed an assessment framework based on the NEO which guides our work on both the design of optional firm access and also our recommendation as to whether optional firm access should be implemented. This assessment framework is discussed further in chapter 3.

We have considered whether it would be more appropriate to commence our work by focussing exclusively on either developing the design of the model or assessing the impacts of optional firm access. Our conclusion has been that the inter-relationships between the design and the assessment aspects of the project are such that it is necessary to consider both aspects concurrently. Among other things, the impact of optional firm access on the NEM will depend on the design that is chosen.

For the most part, we have left our consideration of the path to implementation until later in the project, until we are clearer on whether implementation is justified. However, we have done some initial work by scoping the possible options for implementation (further, some implementation options are specifically referred to in the Terms of Reference). We acknowledge that implementation issues are significant, and so should be taken into account when deciding whether to proceed.

The Terms of Reference cite table 10.1 in the Transmission Frameworks Review final report a number of times. This is the starting point for our work on the design of the optional firm access model. We have taken the view that the Terms of Reference does not allow us to fundamentally redesign the optional firm access model.

Equally, however, the Terms of Reference mention "modifications to the optional firm access design", which indicates that some movement away from the core elements of table 10.1 is permitted where further analysis and testing reveals improvements can be made. Where we do consider modifying a core element of table 10.1 we will test this with stakeholders and explain why we consider the change would be beneficial.

We are not considering significant changes to the optional firm access model as set out in the Transmission Frameworks Review. Therefore, we are not seeking stakeholder comments on the core elements of the Transmission Frameworks Review that we provide as background in this report, except where we have specifically proposed amendments or developments to such core elements.

Any recommendation that we potentially could make must be agreed to by the COAG Energy Council before the model proceeds further.

1.4 Our process

1.4.1 Updating the COAG Energy Council

We are updating the COAG Energy Council regularly during this project, including at COAG Energy Council meetings and in the event that there are significant changes in the project.

We also update the Energy Market Reform Working Group regularly.

1.4.2 Reports to be published

To explain the progress with our work and to seek stakeholders' views on our analysis and conclusions, we will publish a series of reports as part of this project. This is the first such report to be published. The timing of key publications is set out below.

Table 1.1 Review process

Document	Purpose	Date
First Interim Report	To present the assessment framework, and provide a progress update on our work.	24 July 2014
Supplementary Report: Pricing	To provide a progress update on the work we have done to date on pricing[9] since the Transmission Frameworks Review. We will also publish a pricing model prototype for participants to consider.	Late August 2014
Second Interim Report	To set out: • a detailed design of the optional firm access model; • our draft assessment of the benefits and costs of optional firm access; and • our draft recommendation as to whether or not optional firm access should be implemented.	November 2014
Final Report	To set out: • a detailed design of the optional firm access model; • our final assessment of the benefits and costs of optional firm access; • our final recommendation as to whether or not optional firm access should be implemented, and if so, in what form; and • draft implementation plans (if required) for optional firm access should be introduced.	By Mid-2015

9 Under optional firm access, access prices would be calculated using a long-run incremental costing method.

Depending on our draft recommendation, we may publish subsequent report(s) in early 2015 (prior to the final report) that deal with potential implementation matters. Such implementation matters may include the preparation of draft rules.

Our Final Report will represent our complete response to the COAG Energy Council Terms of Reference.

1.4.3 Stakeholder engagement

We have been engaging with jurisdictions and key stakeholders - which include market participants, Transmission Network Service Providers (TNSPs), Australian Energy Regulator (AER), consumer representatives and the COAG Energy Council - in collaboration with AEMO. This engagement has been through our Advisory Panel and Working Group, as well as bilateral meetings.[10]

The interim reports we publish as part of this project allow all stakeholders to understand how our work on optional firm access is progressing and to make comments and submissions on this. We will take these submissions into account in preparing subsequent reports as part of the process.

While this is a critical component of the stakeholder engagement we will undertake on this project, there are other opportunities for stakeholders to engage with us. We are planning to hold a public forum on the First Interim Report for this project on 14 August 2014, in Sydney.[11] We may also hold another public forum later in 2014.

1.5 Role of First Interim Report

1.5.1 Role of report

This Report is a “progress update” to obtain stakeholder input on the work we have done since receiving the Terms of Reference. The focus has been on further developing certain "core" elements of the design of the optional firm access model. We have also included initial work on how we will approach the assessment of the impacts of optional firm access.

The body of this report focuses on the assessment framework, and the development of the "core" elements of the optional firm access model. This includes setting out issues for further consideration.

We have also undertaken some further work on "recommended" elements on the optional firm access model. These are elements of the model that could be beneficial but which are not critical to the model's operation and could be put in place at a later stage. One recommended element is discussed further in Appendix A, and we

10 Further details on these matters is available on our project page: http://www.aemc.gov.au/Markets-Reviews-Advice/Optional-Firm-Access,-Design-and-Testing.

11 Further details on this are available on our website.

welcome stakeholder feedback on whether our allocation of elements to "core" and "recommended" is appropriate.

An issue we have yet to explore in detail is governance. Governance refers to the institutional arrangements for the administration of the optional firm access model. For example, an organisation will be required to run any auctions that form part of optional firm access. Similarly, an organisation will administer the pricing model. There will be a range of considerations in identifying the most appropriate governance arrangements for optional firm access, including any interactions with existing governance arrangements in the NEM. Governance can only be finalised once the design of each element of the model is settled and it is clear what will be required from the organisation that is responsible for it. Our work on governance will be included in the Second Interim Report.

1.5.2 AEMO's First Interim Report

As noted above, AEMO and the AEMC are working collaboratively on this project. Technical matters that arise are being dealt with jointly. However, for this project there are separate governance and reporting structures for each institution. AEMO has produced a First Interim Report that responds to its separate Terms of Reference it has received. AEMO's report sets out: how it is approaching its work program, and a summary of some early findings and observations.

To the extent practicable, we have coordinated our reports so that they can be read as an integrated package.

1.5.3 Submissions

Written submissions from interested stakeholders in response to this First Interim Report must be lodged with the AEMC **by no later than 5pm, Thursday 4 September 2014.**

Submissions should refer to AEMC project number "EPR0039" and be sent electronically through the AEMC's online lodgement facility at www.aemc.gov.au.

All submissions received during the course of this review will be published on the AEMC's website, subject to any claims for confidentiality.

1.6 Structure of this report

The structure of this report is as follows:

- chapter 2 provides a summary of the optional firm access model;
- chapter 3 sets out our proposed assessment framework, along with our initial thoughts on the benefits and costs of the optional firm access model;

- chapter 4 discusses the firm access standard, which defines the minimum level of firm access service quality to which a firm generator is entitled;
- chapter 5 discusses the TNSP incentive scheme, which incentivises the TNSP to operate and maintain its network in such a manner to provide the firm access service to generators;
- chapter 6 discusses issuance of inter-regional access, which would be sold through an auction and allow generators to purchase firm access from one region to another;
- chapter 7 discusses short-term access, which would be available to generators for the period up to three years;
- chapter 8 discusses access settlement parameters, which are defined in the access settlement process through which financial compensation would be provided to firm generators;
- chapter 9 discusses the transition processes that would apply in the early years of the optional firm access model ("transition");
- chapter 10 discusses options for how optional firm access could be introduced into the NEM ("implementation");
- Appendix A discusses reliability access (a "recommended" element of the model, as opposed to a "core" element), which is where TNSPs provide some access to non-firm generators in order to meet reliability standards;
- Appendix B discusses the method for determining the initial transitional access allocation, which would be allocated to generators at the commencement of the optional firm access regime, building on the discussion in chapter 9;
- Appendix C reproduces Table 10.1 from the Transmission Frameworks Review final report; and
- Appendix D provides a glossary of commonly used terms in this report.

2 Summary of Optional Firm Access

2.1 Introduction

The Transmission Frameworks Review developed an alternative transmission model for the NEM, called optional firm access, which provides generators with the option of obtaining financially firm access to their regional reference price. In the final report and the accompanying Technical Report of that review we laid out the design of the optional firm access model. In Table 10.1 of the Transmission Frameworks Review final report we set out the “core”, “recommended” and “optional” elements of this model.

The purpose of this current project is to develop further detail of the model as well as assessing its potential benefits and costs. The following chapters set out our progress in developing various elements on the model since the publication of the final report of the Transmission Frameworks Review.

In order to provide background to the remainder of this report, we first present a high level overview of the key features of the optional firm access model.

2.2 Overview

2.2.1 Objectives

The implementation of optional firm access is intended to strengthen the level of integration between the transmission system and the energy market. It would provide a range of improvements in market outcomes, such as improved coordination between the transmission sector and the energy market. This has the potential to minimise prices for electricity consumers in the longer term by minimising the total system cost of building and operating both generation and transmission over time. In the Transmission Frameworks Review we identified that the key objectives to be achieved through the implementation of optional firm access would be to:

- provide a more commercial framework for the planning of the transmission network, including the ability for generators to signal for the necessary transmission augmentation to provide their access and connection requirements;
- provide locational signals, based on the shared transmission costs, for the siting of new generators;
- provide incentives for the TNSPs to manage the congestion on the networks, including those resulting from transmission outages to minimise the impacts on market participants;
- provide a basis to encourage inter-regional trade and identify the value of upgrading interconnector capability; and

- facilitate economic bids from generators, by removing incentives in the current market for non-cost reflective bidding behaviour under constrained conditions.

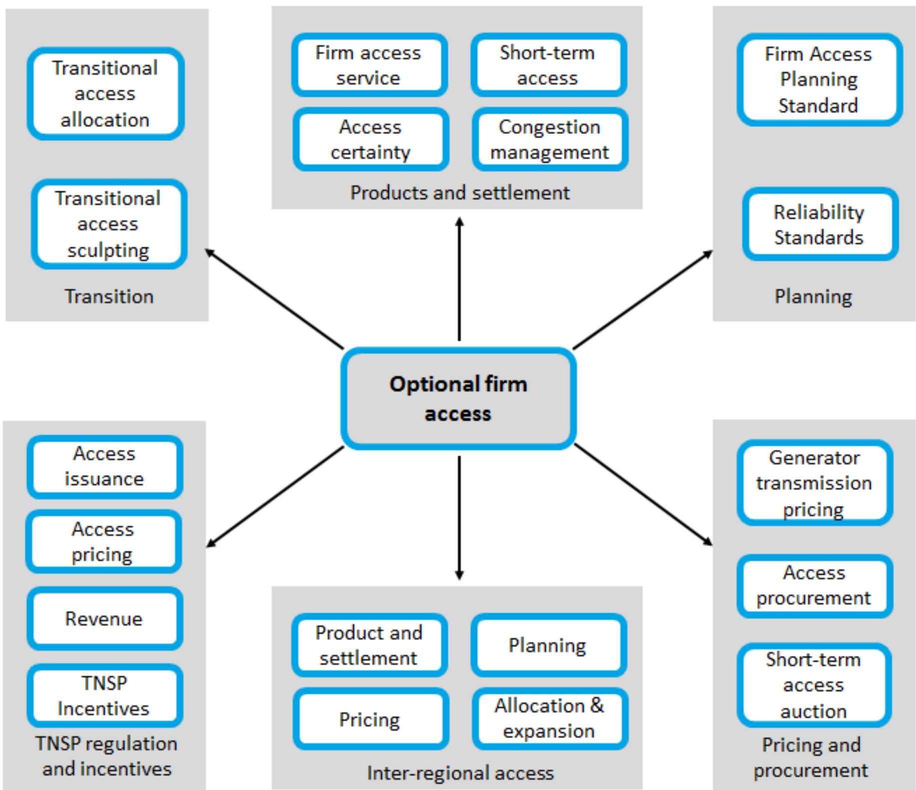
In this context, the optional firm access model potentially addresses several difficult and longstanding transmission issues in the NEM.

2.2.2 Features

Under the current arrangements for transmission, generators face a lack of certainty of access. In the present NEM design, the market provides access to generators by allowing them to be dispatched and so sell their output at the regional reference price. During periods of intra-regional congestion, a generator's level of access is uncertain, dependent on the level of congestion and the dispatch offers of other nearby generators. It may be constrained off – unable to obtain the access it desires.

The optional firm access model gives generators the option of obtaining firm access to their regional reference price. Even when they were not dispatched because of congestion, firm generators[12] would still be paid. The key features of the model that was proposed in the Transmission Frameworks Review are illustrated in Figure 2.1, and are summarised as below.

Figure 2.1 Key features of optional firm access



12 A firm generator is a generator with a firm access arrangement, and so the generator has some level of purchased firm access. This level could be the same as its capacity, below its capacity, or above its capacity A.

Access product and settlement

Each TNSP would offer the firm access service to generators in its region.

The firm access product provides the firm generator with the right to sell its output up to its access amount at the regional price, either by being dispatched, or by earning compensation at least equal to the difference between its offer and the regional price if congestion prevented it from being dispatched. This compensation would be provided at certain times.[13]

Generators would have the option of purchasing a quantity of long-term firm access from the TNSP, which may be for all or part of their output. The generator would seek the combination of firm access amount, location and duration that best met its needs and for which it was prepared to pay the associated firm access charge.

Generators that do not procure firm access would receive non-firm access. When dispatch of non-firm generators contributed to congestion they would compensate firm generators for any loss of dispatch.[14] The aim would be to allow firm generators to be in the financial position they would have enjoyed had they not been constrained off – that is, financial certainty would be enhanced.

Generators could also purchase short-term firm access (firm access up to 3 years out). Short-term access would provide the same level of access as long-term access. Short-term access would comprise any spare capacity on the network, as well as any capacity created through the TNSP undertaking activities to release more capacity. Short term access may also be supplied by generators engaging in secondary trading.

Access settlement would occur automatically through the market's settlement process. The processes for dispatch and the setting of the regional reference price would not be changed.

Access settlement would occur around congested flowgates: bottlenecks in the transmission network which are represented by binding transmission constraints in NEMDE.

Two factors would need to be calculated in order to determine settlement payments: a generator's usage of a flowgate and its entitlement to that flowgate. Its usage would depend on its output and how much it contributed to the constraint. Its entitlement would be based on the lesser of its agreed access level and its capacity, and would also depend upon the prevailing network conditions.

A generator may require entitlements on several flowgates in order to achieve its agreed level of access. Access settlement would automatically translate the generator's agreed access amount at its node into an entitlement on each relevant flowgate, which would depend on how energy flows on the network.

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13 This is discussed in more detail in chapter 4.

14 Although generators would have the option of being firm or non-firm, participation in the model would be mandatory.

The generator would not be required to determine its entitlement or participation at each flowgate.

The allocation of entitlements would aim to give firm generators a target entitlement corresponding to their agreed access amount on each flowgate. However, when flowgate capacity was less than was required to meet aggregate agreed access levels, this may not be possible. Consequently, entitlements might be scaled back, resulting in a shortfall in access settlements payments.

In summary, access settlement undertakes two main tasks. Firstly, it rations access to congested flowgates, giving preferential financial access to firm generators. Secondly, it provides some financial compensation to generators dispatched below their (scaled) access levels and recovers the cost of this from generators dispatched above their (scaled) access levels.

Planning

TNSPs would be required to plan and operate their networks to provide the level of capacity necessary to meet the agreed quantities of firm access (ie, the Firm Access Standard).

The firm access standard defines the minimum level of firm access service quality to which a firm generator is entitled. It translates the level of access that generators are entitled to, through their access arrangements, into the level of transmission capacity that TNSPs are obliged to provide. It therefore drives TNSP network planning and operation.

The firm access standard recognises that the actual network capacity reflects both TNSP planning (what capacity it has built) and operational decisions (how much of that capacity is delivered in a moment of time).

TNSPs would not be required to plan or operate their networks to provide non-firm access.

TNSPs would still be required to meet their jurisdictional reliability standards for load. Thus TNSPs would be required to meet both standards (ie, reliability and the firm access standard) simultaneously.

Key aspects of the planning process would be the same as currently, with TNSPs being required to produce both an Annual Planning Report (APR) and undertake Regulatory Investment Test for Transmission (RIT-Ts) for qualifying investments. TNSPs would be required to plan to meet both the firm access and reliability standards. However, there would be changes to the RIT-T analysis resulting from the implementation of optional firm access – benefits to generators would no longer be considered since generators would be able to directly indicate their preferred access levels.

Access pricing

Generators would pay TNSPs to obtain firm access. There would be no charge for non-firm access, although non-firm generators would be required to compensate firm generators they constrained off through access settlement.[15]

A request for additional firm access by a generator would increase the network capacity that the TNSP is required to provide over time, imposing new costs on the TNSP. The firm generator would pay an amount to the TNSP that covered an estimate of these incremental costs. Access pricing would estimate what these costs would be.

The price paid by generators for firm access would be regulated. The price paid by the generators would be the long run incremental cost (LRIC) of the TNSP providing the access, over the length of the access arrangement.

The long run incremental cost is the difference between two costs:

- The baseline cost, which is the net present value of a baseline transmission expansion plan (including investment, operating and maintenance) that is in place before the access request is received; and
- The higher adjusted cost, which is the net present value of the adjusted expansion plan – that is an amendment to the baseline expansion plan to accommodate the new access request.

The long run incremental cost is determined at the time a generator makes an access request and specifies what the generator would pay over the course of the specified length of the access arrangement.

The stylised expansion plans on which access prices are predicated are not the actual plans that the TNSP would follow in developing the network (ie, access prices are different to project costs). There would not be a one-to-one mapping between an access request and a transmission expansion project.

Access procurement

Generators could obtain new or additional firm access from the TNSP through the procurement process. Here, generators would enter into an access arrangement with the local TNSP.

The procurement process would typically be iterative, with the generator submitting a request, the request being priced and the generator then amending its request in response. However, the role of the TNSP would not simply be to provide a price for each request made, but also to advise the generator on possible service parameters that might best meet the generator's needs. For instance, TNSPs should advise generators

15 Although non-firm generators would still receive the local price, even if they must pay compensation.

how different access locations or firm access amounts would affect the access charge, and where small changes in the firm access amount triggered a large incremental cost.

Short-term firm access would be obtained through an auction, which participants would bid into. As well as TNSPs offering short-term access in such an auction, other generators could also offer in some of their long-term access to be sold as short-term.

Alternatively, rather than procuring additional firm access from a TNSP, generators may wish to purchase firm access from another generating company, or to transfer all or part of their agreed access to another power station within their own portfolio. Such secondary trading could either occur through: bilateral agreements between generators (subject to approval by the relevant TNSP)[16]; or the short-term access auction, that was described above.

Inter-regional access

Generators and retailers would be able to procure firm interconnector rights. These would entitle the purchaser to access the price difference between two regions on their access amount. The purchase of firm inter-regional access would guide and fund the expansion of interconnectors. This product would be firmer than the current settlement residue auction units that are available for purchase, and so the optional firm access would give generators and retailers greater confidence to trade across regional boundaries.

Inter-regional access settlement, and the firm access standard, would work the same as the intra-regional processes, which were described earlier.

Inter-regional access would be issued through an auction process. The auction drives the expansion for future inter-regional capacity. Market participants (generators and retailers) bid for this future capacity, revealing the benefits that would accrue to them.

TNSP regulation

TNSPs would be monopoly providers of the firm access service, which would be treated as a prescribed service under the Rules.

Revenue regulation would aim to ensure that the combined revenue from load and firm access services was just sufficient to cover the efficient cost, including a risk adjusted rate of return, of delivering these services.

A TNSP's revenue allowance would reflect its expenditure required to meet both the firm access and reliability standards.

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16 Approval by the relevant TNSP would be necessary since a transfer of access to a different node may be complex. The power stations could require different access to constrained parts of the network, with the transfer potentially increasing the capacity the TNSP was required to provide on some flowgates, or potentially reduce it on others. Mechanisms would need to be designed to protect the TNSP from an increase in its obligations without corresponding compensation.

In order to calculate TUOS following the introduction of the optional firm access model, each TNSP would estimate the amount of revenue expected to be received from providing firm access and, by subtracting back revenue from the allowed annual revenue requirement, a cap on the TUOS revenue to users of load services would be derived.

There may be increased revenue uncertainty for the TNSP under the optional firm access model (eg where an access request was made that was not foreseen at the start of the regulatory period) and so a mechanism should be introduced to address this.

Incentive regulation is an important component of the optional firm access model since it influences the uptake of firm access by generators. Generally, this would be a low-powered incentive scheme, since we consider that low-powered schemes can result in large changes to TNSP behaviour. Also, we consider that a low-powered incentive scheme is necessary at first in order to avoid exposing the TNSP to too much risk to which they have limited ability to be compensated for. The scheme would focus on exposing TNSPs to a share of any settlement shortfalls that may occur - incentivising TNSPs to provide a level of firm access that would be valued by the market.

Transitional access allocation

Transition processes would aim to mitigate any sudden changes that might arise from the introduction of a new access model. Affected parties should have time to develop their capabilities for operating in the new regime without being exposed to undue risks. On the other hand, transitional processes should be designed so that they do not unduly dilute or delay the benefits that optional firm access is intended to promote.

The main transition mechanism would be the allocation of transitional access to existing generators. These generators should receive a level of firm access that takes into account historical levels of effective access. After access is allocated to generators, the residual component, if there is any, should be allocated to initial firm interconnector rights. No access charges would apply to transitional access.

The initially allocated transitional firm access would remain constant for a period of some years. The initially allocated access would be sculpted back over time.

2.2.3 Design details in this report

This report expands on details of the design of the optional firm access model presented in table 10.1 of the Transmission Frameworks Review final report. That table provided the elements of the model which were categorised as:

- core – the term “core element ” is used to describe those elements of the model that, in our opinion, are central to the operation of the model;
- recommended – the term “recommended element” is used to describe those elements of the model that, in our opinion, would require further work to

establish whether or not they are workable and so may require some modification; and

- optional – the term “optional” is used to describe the additional elements outlined in the technical report that have been identified as being potentially beneficial: they would require further work to establish whether they are workable.

The following chapters set out the relevant elements of the model, and discuss whether our proposed changes are consistent with the categorisation or not. However, before we discuss elements of the model, we first discuss our proposed assessment framework for this project.

3 Assessment framework

Summary of this chapter

As set out in our terms of reference, one of the key questions that we are seeking to answer in this review is whether the implementation of optional firm access would contribute to the achievement of the National Electricity Objective.

In the Transmission Frameworks Review we set out our preliminary assessment of the optional firm access model. However, the Commission recognised that it was not possible to carry out the detailed analysis that would be required to fully capture the costs and risks of implementation and resultant benefits. We therefore recommended further detailed design and testing (ie, this project) in order to better assess the costs and benefits.

As part of this project we are seeking to assess the benefits of optional firm access to see if this model meets the long-term interests of consumers. Accordingly, we have developed a series of categories for assessment that would be impacted by the introduction of optional firm access. These are described in this chapter - including our initial thoughts on the positive and negative impacts that optional firm access would have on each of these categories. This will form the basis of our draft assessment that will be presented in our 2nd Interim Report to be published in November.

Our assessment of the optional firm access model will be conducted against the counterfactual of the current arrangements for transmission and generation continuing.

3.1 Introduction

One of the key components of this review is to determine whether the implementation of optional firm access is likely to contribute to the achievement of the National Electricity Objective (the NEO). As set out in the terms of reference,[17] this includes assessing potential areas of impact (for example, improvements in efficiency in the longer term driven by the signals on generation and transmission investment, and outcomes on contracting behaviour, risk allocation and commercial outcomes); as well as identifying any one-off, and ongoing costs and risks.

This chapter first discusses the assessment that we undertook in the Transmission Frameworks Review (section 3.2). It then discusses the overarching objective that will guide the detailed design, testing and assessment of the optional firm access model - the NEO (section 3.3). This is followed by a brief overview of our assessment process (3.4). It then discusses the range of categories of impact that we propose to use in assessing whether the optional firm access arrangements would promote the NEO

17 SCER, Transmission Frameworks - Detailed Design and Testing of an Optional Firm Access Framework, 25 February 2014, p. 1.

(section 3.5). This range of categories includes the potential areas of impact that were set out in the terms of reference, and that were referred to above. Finally, we set out areas that we wish to seek stakeholder feedback on (section 3.6).

3.2 Assessment in the Transmission Frameworks Review

In the Transmission Frameworks Review we set out our assessment of the optional firm access model, and the current arrangements for transmission, against the objectives of that review. The objective of the Transmission Frameworks Review was to "propose arrangements for transmission that are likely to optimise investment and operational decisions across generation and transmission to minimise the expected total system costs borne by electricity consumers".[18] However, this assessment was largely qualitative.

The Commission recognised that while work was undertaken to understand the costs and benefits associated with optional firm access, it was not possible to carry out the detailed analysis that would be required to fully capture the costs and risks of implementation and resultant benefits. Further, many of the potential benefits are not readily amenable to quantification, and the level of these may, in many cases, depend on wider changes in the market.

We therefore recommended that further detailed design and testing should be undertaken to develop the optional firm access model (ie, this project). This would result in a more detailed design of the model in order to better assess the costs and benefits.

Therefore, given this, and building on the assessment framework that was set out in the Transmission Frameworks Review, this chapter sets out the AEMC's proposed assessment framework for this review.

3.3 National Electricity Objective

The overarching objective guiding our approach is the National Electricity Objective (the NEO). The NEO is set out in section 7 of the National Electricity Law (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.”

18 See: AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013, p. 96.

By way of background, the three fundamental limbs of efficiency are:

- allocative efficiency (efficient use of);[19]
- productive efficiency (efficient operation);[20] and
- dynamic efficiency (efficient investment and innovation).[21]

The impacts on efficiency, and so the long-term interests of consumers, are considered further throughout the remainder of this chapter.

3.4 Our assessment process

In order to conduct our assessment for this project, we have identified the potential categories of impact that optional firm access would likely have on investment in, and operation and use of, transmission and generation. These are discussed in more detail below. We welcome stakeholder feedback on the categories of impact that we have set out below, and whether there are any categories that we have missed.

When conducting our assessment of the optional firm access model we will seek to assess the impacts - both positive and negative - within these categories. Our assessment of the optional firm access model will be conducted against the counterfactual of the current arrangements for transmission and generation continuing.

We will attempt to quantify such impacts - but we recognise in some cases that this may not be possible, and so a more qualitative assessment will be done. Further, even where some quantification is possible, such quantification may exhibit a large range of uncertainty. Also, in some instances, the qualitative issues may be more important than the quantitative issues. When we discuss the categories below we set out our initial thoughts on issues that we may investigate to identify the impacts of optional firm access on the category.

We will also assess the impacts across a range of scenarios, which include considering different future views of the NEM (for example, different levels of congestion in the network, different types of generation that connect to the network, or, indeed, whether

19 Allocative efficiency is achieved when resources used to produce a given set of goods and services are allocated to their highest value uses. This requires that goods and services are provided, and that consumption decisions are made, on the basis of prices that reflect as closely as possible the opportunity (or marginal) cost of supplying those goods and services.

20 Productive efficiency is achieved when only the minimum resource inputs are used to produce a given set of goods and services. Achieving productive efficiency is important because it avoids wasting resources which could have been used for producing something else.

21 Dynamic efficiency is efficiency in the discovery and use of new, economically valuable information ("value discovery"), which is of particular importance in relation to innovation and investment.

generation becomes more off-grid).[22] This will help to assess whether the model is likely to promote the National Electricity Objective across a range of scenarios.

The level of benefits derived from the implementation of optional firm access would depend on the extent to which wider changes in the market eventuate. However, the Commission recognises that it is difficult to envisage a highly likely view of the likely future change in the market. Accordingly, the Commission wishes to assess the optional firm access model across a number of different futures.

Ideally, the optional firm access arrangements would be robust in the face of future changes: the arrangements should be able to cope with a range of circumstances that might eventuate. The assessment across a range of scenarios will help to test that proposition - would the optional firm access arrangements deliver better outcomes in the face of an uncertain future.

Such an assessment will help assist stakeholders in understanding the potential costs and benefits of the model. For example, we understand that some stakeholders consider that the case for the introduction of optional firm access has not yet been made. This assessment will seek to determine whether the benefits of introducing optional firm access outweigh the costs.

We will recommend the implementation of the optional firm access if we find that the model promotes the National Electricity Objective. Our impact assessment helps inform this decision, ie, if we find that the positive impacts on efficiency from introducing optional firm access are likely to outweigh the negative impacts across a range of future scenarios, this would likely promote the National Electricity Objective.

Our draft assessment and draft recommendation will be contained within our 2nd Interim Report, to be published in November 2014.

3.5 Categories of impact for assessing the optional firm access model

We propose to use the following categories of impact for assessing the efficiency of the optional firm access model (in no particular order):

- financial certainty for generation;
- effective inter-regional hedging;
- incentives on TNSPs to operate the network more efficiently;
- efficient dispatch of generation;

22 These may consider scenarios that were developed as part of CSIRO's Future Grid work (amongst others). See: http://www.csiro.au/en/Organisation-Structure/Flagships/Energy-Flagship/Future-Grid-Forum-brochure/Exploring-future-scenarios.aspx.

- efficient incentives on TNSPs to manage trade-offs between operation and investment;
- efficient investment in new network capacity;
- efficient investment in new generation capacity, including locational signals on where to build plants;
- efficient allocation of risk; and
- the level of transaction costs.

In addition to informing our recommendation as to whether or not to implement optional firm access, these categories of impact are also being used to assist the Commission in making decisions on the form of the model that will be assessed. For example, the policy developments that are discussed in the following chapters consider such impacts.

There are significant linkages between these different categories. For example, the incentives that govern transmission investment and operation will impact on the costs of generation investment: if generators face the full costs of transmission, they will factor these costs into their decision on where to locate. Similarly, generation investment decisions will impact on the costs of operating the transmission system: generation locations influence the amount of congestion in the network, which in turn influences how the TNSP may operate the network.

An extension of this is that the overall impact of optional firm access (which is achieved by bringing together the impacts across all of the above identified categories of impact) may be greater than the sum of these individual impacts. That is, while it may be possible to address some of the individual points using alternative approaches, the optional firm access model may deal with them in a more integrated fashion, and so provide a greater overall benefit.

We discuss each of these categories in further detail below. First, we discuss the desired characteristics of each category. We then set out how the current arrangements either exhibit, or do not exhibit, these characteristics. Finally, we set out our preliminary thoughts on how the optional firm access model, may, or may not, exhibit such characteristics. We are also aiming to investigate further the impacts of optional firm access, and we set out the tasks we are planning to undertake to do this at the end of each section.

3.5.1 Financial certainty for generation

The decision to invest in generation is influenced by, amongst other things, the ability of generators to enter into contracts to manage the trading risks that they face.[23] Where generators rely on contracting to manage trading risk, a deep and liquid contact

23 A generator might also vertically integrate with a retailer to manage trading risk, securing an agreed price for some or part of its generating capacity.

market is required to support generation investment. Investors may rely on a long-term contract, such as a power purchase agreement, or if they are confident that the contract market is sufficiently deep and liquid, can instead rely on a series of short-term contracts.

The ability of generators to sell forward (derivative) contracts against their output allows them to manage (or hedge against) the risk of spot price volatility. In the example of a basic swap, where a generator sells a volume of forward contracts, and is dispatched for an equal quantity, it receives the contract price on that volume through the receipt (or payment) of contract for different payments where the spot price is lower (or higher) than the contract price.[24] An investment product that works in this way, offsetting the price movement in the spot market, is referred to as a hedge.

The ability of generators to hedge against price volatility is important since it provides greater financial certainty to investors: they can be more assured of receiving a future stream of predictable and stable revenues.

Increased financial certainty should be reflected in a lower risk-adjusted cost of capital, ie, in lower financing costs for investors. This may result in lower prices for consumers, with generators able to offer electricity (both spot and contract) at lower prices than they otherwise would. The higher level of certainty should also make investment in the electricity sector more attractive than it otherwise would be.

A well-functioning contract market is also important to retail competition. Improving the ability of retailers to hedge against wholesale price volatility, by increasing the willingness of generators to offer contracts, would be expected to improve retail competition. In particular, it could improve the ability of non-vertically integrated retailers to compete against vertically integrated participants that are able to match generation to their retail portfolio in order to hedge against wholesale price risk.

Under current arrangements

Currently, dispatch risk may affect the ability of generators to sell forward contracts against their output.[25] Congestion may prevent generators from selling their desired amount of their offered output at the regional reference price. Whenever a generator has contracted for a higher amount than it is dispatched for, it is not perfectly hedged: it is exposed to the cost of making contract for difference payments but does not earn revenue by selling into the spot market to back those contracts.[26] Potentially, the cost is very high.

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24 We note that more complex derivative products also exist in the wholesale electricity market.

25 Other risks, such as outages of power station generating units, may also deter generators from contracting for all of their output.

26 Generators might deliberately sell a higher volume of contracts than their expected level of dispatch in the expectation of the contract price exceeding the spot price. Their motivation in this case is speculative - deliberately taking a risk, rather than offsetting of risk which is achieved by hedging, ie contracting up to expected dispatch volume.

Generators' uncertainty as to whether they will be able to generate and receive the regional reference price - at exactly those times when prices are likely to be particularly high - can decrease their willingness to contract with retailers, or increase the price at which they are willing to do so.

Where congestion was stable and predictable, generators might contract forward for the quantity of output for which they could be confident of being dispatched, although that may not be for 100 per cent of their generating capacity. However, congestion tends to be volatile and unpredictable (due to the uncontrollable nature of the network, due to factors such as weather conditions, and unplanned transmission outages) and the willingness of a generator to contract at a given price may be correspondingly lower.

Congestion may also affect the ability of a vertically integrated participant to cover its retail exposure.

As far as we are aware, there are no insurance products available to generators to protect against this kind of risk. Therefore, such financial uncertainty currently exists.

Under optional firm access

Positive impacts

Under the optional firm access model, by decoupling access from dispatch, generators would be able to "insure" (or hedge) against congestion risk. A constrained-off firm generator would earn the difference between its local price and the regional reference price on its access amount, which should at least equal the margin it would have earned by being dispatched. Therefore, financial certainty may be increased (particularly if the price of access is less than the financial benefit to the generator). We note that the extent to this would occur would depend on how the firm access standard is defined. This is discussed further in chapter 4.

Firm access may therefore provide greater financial certainty for generators to offer forward contracts on a volume reflective of their access amount.[27]

The higher expected level of hedging, or lower contract prices that may result under optional firm access,[28] should promote the benefits described above - higher levels of financial certainty for investors in the electricity sector, lower financing costs, possible improvements in wholesale competition and lower prices for consumers.

27 Generators may be expected to contract for a volume somewhat less than their nominal access amount to reflect the situations where access is scaled back.

28 Although contract prices would need to account for the cost of purchasing firm access.

Negative impacts

Optional firm access may negatively affect some generators in relation to financial certainty. Non-firm generators would face a higher degree of basis risk - earning a local price (after payment of compensation to firm generators) that is less than the regional reference price (but at least equal to their offer price). This basis risk may require complex bid adjustments, and monitoring of constraints for non-firm generators, depending on the dynamics of pricing around local prices. However, we note that this risk does replace the current risk of being constrained-off for some, or part, of their output. That is, under optional firm access generators are trading (existing) volume risk for basis risk. Further, the optional firm access model provides a product to mitigate against these risks, if these risks were deemed significant.

We also note that some stakeholders consider that optional firm access is not really optional - that they would be forced to buy access. We are considering optimal generator behaviour in relation to purchases of firm access.

Further, previous commercial decisions made by generators may not have anticipated the optional firm access model (however, we note that changes of this type have been discussed for a long time and so businesses may have anticipated similar changes); such generation may incur increased costs to allow them to access the market as planned. However, our proposed transitional arrangements should take these effects into account. These are considered further in chapters 10 and 11.

Issues to investigate

Issues to investigate - financial certainty for generation

- The extent to which volume risk is being exchanged for basis risk.
- The day-to-day effects of optional firm access on generators, including how generators contract.
- Whether there are changes in price volatility within the NEM.
- The flow-on impact of optional firm access on retail prices within the NEM.
- The strategies that generators may take in response to the introduction of optional firm access.

3.5.2 Effective inter-regional hedging

The NEM is an interconnected system, which facilitates inter-regional trade. By inter-regional trade, we generally mean a generator selling forward contracts to a retailer in another region of the NEM. However, the same kinds of issues arise for a vertically integrated participant that is attempting to serve its retail customers with generation assets that are located in another region. In both cases, the generator must sell its power at the spot price in one region, and – in effect - buy it back at the spot price in another region, exposing it to possible price differences between the regions.

An inter-regional product is a form of financial contract that hedges the risk from volatile inter-regional price differences. The availability of inter-regional products should give generators and retailers greater confidence to supply retail load using remotely-located generation. This should enable generators in lower priced regions to contract with retailers in higher priced regions, with resulting benefits to those consumers in higher priced regions.

An effective inter-regional hedging product also facilitates increased retail competition. By hedging risks from inter-regional price differences, retailers in one region, who may have contracts with generators (or their own generation assets) in that region, may be encouraged to enter into other regional markets. Therefore, effective inter-regional products allow the benefits of the existing interconnector capacity to be realised in promoting inter-regional trade – without any additional investment in capacity.

Under current arrangements

Currently, generators can partially hedge against inter-regional price risk, by purchasing the right to a share of the inter-regional settlements residue (IRSR) that accrues when prices between regions separate. The value of the IRSR is equal to the difference between the price paid by retailers in an importing region and the price received by generators in an exporting region, multiplied by the amount of flow across the relevant interconnector. Such rights are known as settlements residue auction (SRA) units, after the auction that AEMO holds every quarter.

SRA units provide an effective inter-regional hedge only when the interconnector is able to flow at a capacity and in the direction equal to the volume of settlement residue auction units sold. Unfortunately, interconnector flow may be sometime constrained well below its capacity, and this reduces the effectiveness of inter-regional hedging.

There are a number of problems with the existing arrangements:

- If generators who compete with the interconnector in dispatch bid -$1,000 they will be dispatched ahead of the interconnector – since the interconnector cannot rebid in this fashion. This reduces interconnector flows and so residues.
- If counter-price flows occur, where power flows from a high to a low-priced region, the value of the settlements residue will be negative. In this case, the payout on the SRA units is zero.
- If the interconnector's available capacity is reduced (eg due to outages) then flows, and therefore residues, will be reduced.
- Generators have an incentive to locate on parts of the network that are not used by other generators. Therefore, some new generators may seek to locate on interconnector flowpaths in order to take advantage of the large capacity

available. The effect may be to diminish flows across the interconnector, in which case fewer residues will accrue.

Such problems are evidenced in our initial transitional access allocation. The interconnector allocations (ie, the residual amount of access left, after generators have been allocated transitional access) were very close to zero in the base case. This may be considered to potentially illustrate some of the existing problems with the interconnectors, where generators may have an incentive to locate on interconnector flowpaths in order to take advantage of the large capacity available. This is discussed in further detail in appendix B.

Under optional firm access

Positive impacts

The optional firm access model introduces a firmer inter-regional access product.

The firmness of the new inter-regional access product would be (largely) independent of interconnector flow. Access settlement payments would be provided by generators dispatched above their firm access amount that caused the interconnector to be constrained off, so the payout on the inter-regional access product would not be reduced when it is constrained. While counter-price flows may still arise, access settlement would ensure that the holders of the product were not affected.

Further, new generators locating on interconnector flowpaths would no longer degrade the firmness of inter-regional access. This effect would change the current contributing factor in locational decisions for generators to use up interconnector capacity since generators would factor into their locational decision the value to them of locating on the interconnector. A new generator might locate on the interconnector flowpath, but the TNSP would be required to maintain the flowpath at a level to meet the agreed access amounts.

Indeed, a number of the benefits discussed above in improving financial certainty for generators will also occur inter-regionally. This includes: higher levels of financial certainty for investors in the electricity sector, lower financing costs, possibly improvements in wholesale competition and lower prices for consumers. For example, generators located in lower-priced regions should be better able to contract with retailers in higher-priced regions, with resulting benefits to consumers in higher-priced regions.

A further benefit may be increased retail competition. By decreasing the risk of inter-regional price differences, firm inter-regional access may encourage retailers in one region, who have contracts with generators (or their own generation assets) in that region, to enter into other regional markets.

Therefore, we consider that the introduction of access settlement would significantly change behaviour, and incentives, related to interconnectors. The creation of a firm inter-regional access product therefore allows the benefits of the existing interconnector capacity - without any additional investment in capacity - to be realised in promoting inter-regional trade.

Negative impacts

We recognise that one potential negative is that if we were to allocate transitional access today, based on our proposed allocation method, there would be no initial allocation to interconnectors. That is, any firm interconnector rights would need to be underpinned by new interconnector capacity. This is not a negative per se, but could suggest that it may take some time for sufficient demand for interconnector rights to develop in order to offset the costs. However, the optional firm access model reveals the value of interconnector rights to market participants. Therefore, any release of firm interconnector rights should be consistent with what is demanded, or valued, by market participants. This is discussed further in chapter 6.

Issues to investigate

Issues to investigate - effective inter-regional hedging

- The extent to which counterprice flows may be reduced, and so the extent to which the accumulation of negative inter-regional settlement residues may be reduced.
- The demand for inter-regional access products.
- The difference in total system costs between regionally matched load and generation, versus optimised inter-regionally load and generation.

3.5.3 Efficient incentives on TNSPs to operate the network

TNSPs should provide an efficient level of network capacity: ie, spend money to increase the availability of network capacity where the value to the market exceeds the cost. This value varies with time, so the TNSP should aim to maximise availability when the value of network capacity is at its highest (such times may occur when congestion occurs).

TNSPs need to be provided with a financial incentive to do this: such incentives are likely to provide the most robust and transparent driver for efficient decision making. This view that financial incentives are likely to lead to more efficient outcomes is widely held (and practised) by regulators internationally, as well as in Australia. Further, a simple obligation is ineffective, and no incentive means that TNSPs would provide network capacity in the way that minimises its *own* costs, and takes no account of market value.

For example, TNSPs should schedule planned outages at times when the market does not value the capacity of the network highly because wholesale prices are low (for example, such times may occur when congestion is not expected). Conversely, TNSPs should not schedule planned outages at times when the market values the capacity of the network highly (for example, where congestion is expected).

In order to achieve such incentives on TNSPs to operate their network efficiently, TNSPs need to have clear responsibility and accountability for the operation and performance of the transmission network.

Under current arrangements

Currently, TNSPs have a number of incentives to efficiently operate the network. One of these is the market impact component of the STPIS. This is a low-powered incentive to minimise outages when constraints are binding and the estimated market impact is above a defined threshold (where the outage on a TNSP's network results in a network outage constraint that has a value greater than $10/MWh).

We understand, through discussions with stakeholders, that this scheme has been considered successful at changing TNSP behaviour. However, this does not strongly take into account the prevailing wholesale spot market price at the time of a constraint and only incentivises the TNSP to minimise how often outages occur.

Under optional firm access

Positive impacts

The incentives to efficiently operate the network would be improved under optional firm access. The operational incentive scheme under optional firm access is intended to measure the value of network capacity through its impact on access settlement (as opposed to just being a count, as is the current market impact component scheme). This value would be signalled to the TNSP, which would encourage it to create a direct link between its operations and the value of capacity provided.

A failure to meet the firm access standard would result in a measurable cost to firm generators: the shortfall in access to the regional reference price. The optional firm access model would expose TNSPs to a share of this cost, which might increase over time, and would therefore create financial incentives on TNSPs to increase network availability when it is most valuable.

This approach would provide a signal to TNSPs to manage the network consistently with the way in which capacity is valued by the market at any point in time. Increased network capacity at times when the market values it would result in better outcomes for consumers.

Negative impacts

We note that there may be the ability for a TNSP to "game" the incentive scheme. This could involve deliberately "tanking" historical performance in order for a lenient target to be set. However, we consider that it would be difficult for TNSPs to game the scheme given the regulatory oversight. Appropriate governance arrangements should mitigate this.

There may also be regulatory challenges with successfully calibrating the incentive scheme that is proposed under optional firm access. Such schemes also assume that TNSPs are responsive to incentives. However, we note that historical information typically shows that they are.

Issues to investigate

> **Issues to investigate - efficient incentives on TNSPs to operate the network**
>
> - The likely optional firm access incentive scheme parameters, and so TNSP payments under the incentive scheme.
> - TNSP behaviour under the incentive scheme.
> - The factors on the network that a TNSP has control over, and, for those factors that it does not have control over whether there are any mechanisms that could be put in place to help the TNSP operate the network more efficiently.

3.5.4 Efficient dispatch of generation

Generators should have incentives to offer their energy into the wholesale market at an efficient price. While generators have an incentive to profit maximise, competition should drive efficiency in the market. This should result in productive efficiency – the least cost generation (in terms of operating costs) should be dispatched ahead of more expensive generation.[29]

The most profitable bidding strategy for a generator at any point in time will depend on factors such as its costs, demand, forward contracts and availability of other generators. However, we would expect an effective market design to deliver dispatch efficiency (ie, the least cost generators being dispatched first and so on) when the market is workably competitive. This is consistent with productive efficiency.

Efficient dispatch of generation should result in wholesale market outcomes being explained in terms of the underlying supply and demand conditions. Such outcomes promote the effective provision of electricity supply, including of both generation and parties providing demand side response. Transparency in the drivers of spot prices helps facilitate participants to make an economic decision that is based on the potential value of providing resources.

29 This is also true for inter-regional trade. If there is effective inter-regional trade, this would encourage generators to bid at cost.

Under current arrangements

The Commission recognises that there are a number of generator bidding behaviours that can potentially cause efficiency concerns, including:[30]

- bidding behaviour that relates to managing or exploiting network congestion, for example, generator's offering in prices of -$1,000 to maximise dispatch; and
- late strategic rebidding, for example generators rebidding very close to the relevant dispatch interval in order to limit the time available for other supply or demand side participants to respond.

Such behaviour creates efficiency concerns:

- more expensive generation (in terms of operating costs) being dispatched ahead of cheaper generation;
- since interconnectors cannot rebid at -$1,000, they may not be dispatched, even when they are cheaper than a generator or where their dispatch (instead of a generator's) can help to relieve congestion;
- unpredictable and volatile market outcomes may result; and
- the firmness of the current SRA instrument is reduced, diminishing the ability of generators and retailers to trade across regional boundaries.

We note that during the Transmission Frameworks Review we engaged ROAM to undertake modelling of the productive efficiency effects of bidding behaviour that relates to managing or exploiting network congestion (ie, those related to the first bullet point above - more expensive generation being dispatched ahead of cheaper generation).[31] This found that the cost has not been that material: it ranged from $3 million to $15 million a year.

We note that this did not, however, attempt to estimate other benefits that would result from removing the incentives for such bidding behaviour (the last three efficiency concerns discussed above):

- Potential reductions in market volatility and increased financial certainty for generators – with the benefits that could result from the increased willingness of generators to contract at a given price, and the greater attractiveness of investment in the electricity sector at a given cost of capital.

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30 The Commission notes that many (if not all) of the above practices can be exacerbated by structural issues. In addition, other forms of behaviour (such as economic withholding) may become a concern if structural issues lead to barriers to entry. However, the Commission considers that such matters are matters for the Australian Competition and Consumer Commission (ACCC) and jurisdictional governments.

31 ROAM Consulting, *Modelling Transmission Frameworks Review*, February 2013.

- Increased interconnector flows, and therefore IRSRs. An improved return on SRAs would enhance the ability of generators and retailers to engage in inter-regional trade.

- Reduction in the unhedgeable costs associated with counter-price flows, and therefore the accumulation of negative IRSRs.

As noted throughout this chapter, we are seeking to understand the potential magnitude of such benefits throughout our current assessment work.

Under optional firm access

Positive impacts

Under optional firm access, the incentive for bidding behaviour associated with managing or exploiting network congestion would be reduced. This would have a corresponding reduction in the volatility of wholesale prices and interconnector flows.

The dispatch process would be unchanged, but by decoupling access to the regional reference price from an individual generator's dispatch level, optional firm access would remove the current incentive on a generator with costs less than the regional reference price to maximise its dispatch irrespective of the severity of congestion.

Access settlement would expose generators to their local price, for any output above their access level. This should give generators the incentive to offer their energy in a manner that reflects its value. If a generator offers electricity at a price less than its cost, it risks being dispatched at a loss when the local price is below its costs.

These impacts should have flow on positive benefits to customers, to the extent that wholesale prices are passed through into retail electricity costs.

Negative impacts

Where local pricing influence is strong under optional firm access, a generator will tend to operate closer to its access level. This may lead to a firm generator displacing a lower-cost non-firm generator in dispatch. This would be a loss in productive efficiency.

A new form of pricing power may be introduced around local prices. This is discussed further in chapter 5. The potential for this, and the impacts of this, will be considered in the next stage of our work.

Issues to investigate

> **Issues to investigate - efficient dispatch of generation**
>
> - The impact of optional firm access on productive efficiency of dispatch, including:
>   - changes in generation dispatch outcomes, including inter-regional effects;
>   - changes to market volatility in wholesale prices; and
>   - impacts on the unhedgeable costs associated with counter-price flows.
> - Generator bidding behaviour under optional firm access, for example, whether a new form of pricing power is introduced.

3.5.5 Efficient incentives on TNSPs to manage trade-offs between operation and investment

Transmission services can be provided either through investment in networks or through the use of operational (non-network) measures. Sometimes operational measures and investment are substitutes for each other. Therefore, TNSPs should also have incentives to make efficient trade-offs between operation and investment, and between network and non-network solutions.

Such trade-offs become more difficult when established patterns of demand and generation are changing. TNSPs will have to balance competing views of the future, and probabilities of these futures occurring, when making such trade-offs.

Under current arrangements

There are currently some incentives on TNSPs for them to manage the trade-offs between operational and investment decisions. For example, the RIT-T process should allow TNSPs to investigate whether a operational investment may be more cost effective than a capital investment. Further, the regulatory arrangements do allow for some trade-off between operation and investment.

However, historically, there have been few incentives for TNSPs to take operational measures that could increase the capability of the network. We understand that this was partly the driver for the AER introducing the network impact capability component of the STPIS. This encourages TNSPs to identify limitations on each network element or connection point, and nominate either operating or minor capital expenditure projects that would meet the capability. These projects are expected to be small in value (in total be around one per cent of a TNSP's annual maximum allowed revenue).

This scheme is bonus only (with the TNSP potentially receiving a bonus of an additional 1.5 per cent of annual maximum allowed revenue).

This scheme has only been in place for a year or so, and there is limited evidence as to its success.

Under optional firm access

Positive impact

Under optional firm access, TNSPs would likely have stronger incentives to manage the trade-offs between operational and investment decisions. This is since:

- the firm access standard requires TNSPs to trade-off operational and investment decisions;
- the arrangements would result in a measurable outcome from a TNSPs' operation of the network; and
- incentives would be placed on TNSPs for them to increase the availability of their network when it is most valuable to the market, including through the offering of short-term access.

Issues to investigate

Issues to investigate - efficient incentives on TNSPs to manage trade-offs between operation and investment

- The day-to-day impacts of optional firm access on TNSPs.

3.5.6 Efficient investment in new network capacity

A key issue is how efficient development of the network occurs. In particular, how scarcity of transmission capacity is managed and how transmission investment decisions are made.

TNSPs should be able to trade-off the cost of augmenting the network with the costs of managing congestion, noting that building out all constraints is unlikely to be efficient (ie, the optimal level of congestion is not zero).

However, under-investment in the network will prevent generators accessing the wholesale market and lead to a more expensive mix of generation being dispatched to meet demand than would have occurred with more investment. There is therefore a efficient level of congestion where the cost of undertaking any more investment would be greater than the benefit provided, in terms of reducing the productive cost of reliably serving demand. Overinvestment ultimately imposes costs to customers.

Monopoly transmission businesses should have appropriate regulatory incentives and obligations to ensure efficient and timely investment in response to changing demand for transmission services over the medium to long-term. The Commission considers they should have signals, and access to information, for them to invest in their networks to meet the needs of generation and load customers. Such signals ensure that the network is expanded in an efficient and timely manner.

Under current arrangements

Currently, there is a regulated planning approach to transmission investment. TNSPs are required to assess the need for new investments based on rules and regulatory obligations. They make assumptions about the benefits that would result for market participants and consumers, and compare these to the associated costs. We note that such assumptions may be based on the value of customer reliability, and other information about market participant requirements. Accordingly, such assumptions may be informed by what market participants and customers value.

However, TNSPs have limited understanding of market participants' businesses and so, without market signals, it is difficult to estimate and capture these values. Nevertheless, there are incentives and planning approaches - such as the RIT-T, transparent planning and stakeholder consultation requirements - which encourage the implementation of transmission development plans at least cost.

However, the regulated planning approach has the potential to distort competitive market outcomes in terms of generation investment. Network planning generally involves TNSPs predicting the least-cost combination of generation and transmission to meet forecast load, and to plan the network accordingly. It can potentially result in imperfect co-optimisation. A TNSP knows the costs of transmission, but has imperfect information regarding the costs of generation, and has little incentive to forecast accurately the benefits accruing to generators.

Further, currently consumers bear all the risk of a TNSP making a "bad" decision. Currently, all investments are paid for consumers, and so they bear the risk. This is discussed further below in section 3.5.8.

Under optional firm access

Positive impacts

The optional firm access model would provide a basis for market-led development of the transmission network. The purchase of firm access by generators would fund and guide network expansion, with TNSPs required by the firm access standard to plan the network to meet all firm access concurrently, while continuing to meet load reliability planning requirements.

In making the decision whether to be firm or not, generators would trade-off the cost of transmission (in the form of the firm access charge) against the cost of congestion (which they would avoid by being firm). This trade-off would be made by generators, rather than TNSPs - the market would signal the need for new transmission investment, just as it does for generation. Optional firm access would place the investment decision in the hands of commercial entities, subject to competition, who therefore have a natural incentive to invest in transmission (through the purchase of firm access) at an efficient level.

It is worth noting that the introduction of an access product also encourages value discovery. Generators and TNSPs will have to assess what the value of the product is to them, and such assessment can lead to the discovery of new, economically valuable information – information that was not known to either party at the outset. Therefore, the parties involved can be expected to learn and discover new things, with such information about “value” leading to more efficient decisions about investment in the network.

Negative impacts

We understand that some stakeholders have previously argued that optional firm access may lead to inefficient outcomes in the network, for example, through underbuilding (ie, private interests do not equal public interests).

Other stakeholders are concerned that optional firm access could lead to overbuild in the network. However, we consider that if generators signal that such build is efficient for them, and they are paying for the costs of this build, then such a situation would not be inefficient. This is consistent with aligning risks with the party best able to manage them - it is better for the generator to signal such an investment is valued, than the TNSP to "guess" whether investments would be valued.

To the extent there are risks of overbuilding or underbuilding under optional firm access, these should be compared to the possibility of inefficient transmission development under the current arrangements. That is, even if there are risks under optional firm access they may be less significant than at present.

Issues to investigate

Issues to investigate - efficient investment in new network capacity

- The inter-relationships between firm access and the reliability standards - and what this means for investment in transmission.
- The benefits to be quantified under the RIT-T - does this promote efficient outcomes in the network.

3.5.7 Efficient investment in new generation capacity

Generators should have incentives to invest in new plant where and when it is efficient to do so. Information and price signals should provide financial incentives for generators and load to make efficient location decisions by trading off the costs they impose on the shared transmission network with other relevant decision factors such as proximity to fuel source.

Price signals should also encourage generators to invest in the appropriate fuel type (such as wind-powered or gas-fired plant) and technology (such as baseload or fast-start plants).

Under current arrangements

Certain locational signals do currently exist, such as transmission losses, congestion and inter-regional price variation. These provide a degree of incentive for efficient generator location. However, these signals are incomplete, as they do not signal the transmission investment costs required to mitigate the effects of long-term congestion.

For example, as discussed above, generators currently have an incentive to locate on interconnector flowpaths in order to take advantage of the large capacity available. This has the effect of diminishing flows across the interconnector as discussed above in section 3.5.2 .

Further, generators will be influenced by the development path that is predicted by the TNSP (and which was discussed above). The TNSP's transmission investment decisions may have an effect on generators' investment decisions by reducing congestion in certain parts of the network, and therefore encouraging generator investment in those areas. This creates a bias towards the generation and transmission development path that the TNSP predicts, even where a lower cost combination exists.

If the regulated planning approach delivers a transmission path that is significantly different from that required by competitive investment in generation, then a different generation pattern could emerge despite the locational signals provided by congestion. There is therefore a risk that the transmission assets that the TNSP has invested in would be underutilised and that alternative transmission assets would need to be built.

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

Under optional firm access

Positive impacts

The optional firm access model would create a clear and cost-reflective locational signal for the costs imposed on the transmission network for new generation investment that is currently missing in the NEM. Locational signals would therefore be provided to both firm and non-firm generators:

- firm, in the form of access pricing; and
- non-firm, in the form of compensation payments through access settlement and the risk of being constrained off.

The access pricing method aims to capture the incremental network costs of a generator's decision to locate in a particular part of the network. Firm access would be cheaper where there is existing spare network capacity than where there is not. Firm access would be cheaper where a generator located closer to load in more meshed parts of the network than where it located further from load in less meshed parts of the network.

Negative impacts

We understand that some stakeholders have previously argued that there are existing locational signals within the NEM, and that generators are indifferent to locational signals from transmission costs (or that these have lower prominence than other signals). If this was true, then introducing locational signals for the costs imposed on the transmission network through optional firm access would likely not have a large impact.

Issues to investigate

Issues to investigate - efficient investment in new generation capacity

- Those elements that are important in influencing location of generation (eg, fuel costs, transmission costs, congestion costs).
- The extent to which those elements are currently present in the NEM.

3.5.8 Efficient allocation of risk

There should be an appropriate allocation of risk between the different parties involved in the transmission and generation sectors: transmission businesses, generators and consumers. Risks should be allocated to those parties that are best placed to manage them. Further, the method for managing the risks should reflect, and be commensurate, with the level of risk that the relevant party faces.

Effective incentives usually arise where risks are appropriately allocated. As a general rule, if risks are allocated to those parties best placed to manage them, this should result in lower system costs over time. Further, if the environment in which businesses operate becomes less risky (in terms of unmanageable risk) then businesses' incentives to invest and/or innovate over time increases. This supports dynamic efficiency.

Under current arrangements

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

Under optional firm access

Positive impacts

In an appropriate alignment of decision-making and risk, under the optional firm access model, where generators make inefficient investment decisions, they would bear the cost of any expansion of the transmission network that was undertaken to give them firm access. Competition is likely to limit their ability to pass through the costs of inefficient decisions to consumers. This would represent an improvement over the current arrangements, where consumers bear the risk of inefficient transmission decisions. Generators have better knowledge of the risks than consumers.

Negative impacts

We understand that some stakeholders have concerns about the estimated prices that are produced through the long run incremental cost pricing model. The extent to which these estimates are wrong (both being over estimated, and under estimated) these costs would be passed on to consumers. We are producing a pricing prototype model to assess the accuracy of the estimated prices, compared to what project costs would be incurred. This will also allow us to assess the sensitivity of the prices to assumptions that are made. However, at this stage we do not consider that the pricing model should be systematically biased one way or the other. Therefore, the costs passed on to consumers should be "neutral" over time.

Issues to investigate

Issues to investigate - efficient allocation of risk

- The risk impact of optional firm access on TNSPs and generators.
- The accuracy of estimated prices under the LRIC method, and sensitivity to assumptions.

3.5.9 Transaction costs

We are also required under the terms of reference to consider the level of costs that are imposed on parties if this model is to be implemented. These include both:

- the one-off costs of implementing such a model; and
- the incremental on-going costs of operating, and investing, under such a model.

It is worth noting that where arrangements are complex to administer, difficult to understand, or impose unnecessary risks, they are less likely to achieve their intended ends, or will do so at a higher cost.

Issues to investigate - transaction costs

- The implementation costs associated with optional firm access for stakeholders that would be affected, including: AEMO; TNSPs; generators.
- The (incremental) on-going costs associated with optional firm access for stakeholders that would be affected, including: AEMO; TNSPs; generators.

3.6 Consultation questions

The AEMC would be interested in receiving feedback on the assessment framework contained in this chapter. Participants are encouraged to assess this against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative assessment criteria that should be considered.

We are particularly interested in hearing stakeholders' views on:

- whether there are any additional categories of impact to those that we have identified;
- whether there are any other impacts than those that we have identified;
- whether there are any particular scenarios that we should consider in undertaking the assessment; and
- whether there are any additional issues that we should be investigating.

4 Firm access standard

Summary of this chapter

This chapter sets out the proposed firm access standard that would apply under optional firm access. The firm access standard represents the level of access that TNSPs would be required to make available for firm generators. The firm access standard proposed in this chapter is an alteration from the specification in the Transmission Frameworks Review.

In the Transmission Frameworks Review we recommended that the firm access standard be a combined planning and operating standard. We also recommended that the standard only apply in defined normal operating conditions. During abnormal operating conditions, we recommended that the standard not apply.

We now consider that having a distinction between normal and abnormal operating conditions may create difficulties as well as potentially causing risks for generators. Therefore, we propose the firm access standard operate at all times.

The proposed firm access standard would have two components: a firm access planning standard and a firm access operating standard.

The firm access planning standard would be a requirement on TNSPs to plan the networks so that all firm generators would receive the full amount of access under specified conditions. TNSPs would be required to report on the planning activities that they are undertaking to meet this standard.

The firm access operating standard would set a target level of access for the TNSP to meet under all market conditions. This would be underpinned by an incentive scheme, which would motivate TNSPs to operate their networks to provide the appropriate level of flowgate capacity at all times through the incentive scheme.

4.1 Introduction

The firm access standard (FAS) defines the minimum level of firm access service quality to which a firm generator would be entitled. It translates the level of access that generators are entitled to (through their access arrangements) into the level of transmission capacity that TNSPs are obliged to provide. The specification of the firm access standard is an integral part of the optional firm access model since it provides generators with confidence in the effective provision of the firm access product, as well as driving efficient network planning and operation by the TNSPs.[32]

In this chapter, we examine the proposed structure of the firm access standard. This has been refined since the publication of the Transmission Frameworks Review. First, we explain what was recommended in the Transmission Frameworks Review and the issues that have subsequently arisen with this approach following further analysis (section 4.2). We then describe the revised firm access standard which includes both a planning (section 4.3) and operating (section 4.4) standard. We then describe how the two standards would work together to promote efficient behaviour from the TNSP (section 4.5) and some of the implications of the revised definition of firm access standard (section 4.6). Finally, we set out areas that we seek stakeholder feedback on (section 4.7).

4.2 Background

4.2.1 Firm access standard in the Transmission Frameworks Review

The firm access standard as recommended in the Transmission Frameworks Review was an operating standard which encompassed both TNSP planning and operations: actual network capacity would reflect both TNSP planning (what capacity it has built) and operational decisions (how much of that capacity is delivered in a moment of time).[33]

The firm access standard was to apply in a defined set of conditions - normal operating conditions. Normal operating conditions would include system normal (where all transmission elements are in service), and planned outages (where the TNSPs plan for some transmission elements to be out of service). The firm access standard would therefore require TNSPs to provide the agreed access amount specified in each access agreement under normal operating conditions only.

However, even for firm generators, access would be firm, but not fixed. Under specified conditions the firm generators' access would be allowed to be below target. Therefore, no minimum level of access would be required under abnormal operating conditions (where unplanned outages would occur).

The firm access standard would not take account of non-firm generators.

32 We note that TNSPs could choose to provide firm access by contracting with a non-network solution, rather than augmenting the network. There would need to be some parameters governing this process, allowing that the firmness of the product is protected.

33 AEMC, *Transmission Frameworks Review*, Final Report, AEMC, 11 April 2013, p. 27.

It would have been the responsibility of an organisation, most likely the system operator, to "tag" whether a particular congested flowgate was due to a normal or an abnormal operating condition.[34]

Under optional firm access, TNSPs would be required to meet both the firm access standard and the relevant jurisdictional reliability standard. While there would be two standards, neither would dominate the other, ie maintaining the firm access standard would be neither sufficient nor necessary for maintaining the reliability standard (and vice versa).

The key features of the firm access standard, as set out in Table 10.1 of the Transmission Frameworks Review's final report are extracted below.

Table 4.1 Table 10.1: Firm access standard

Core Elements	Recommended Elements	Optional Elements
• Firm access standard is an operational standard that applies in real-time dispatch, as opposed to a planning standard • Target capacity on each flowgate based on access and participation of firm generators only • Firm access standard does not place any obligation on TNSPs in relation to non-firm generators • Normal operating conditions includes system normal • Target flowgate capacity not required to be provided on uncongested flowgates • RIT-T assessments no longer include benefits and costs that accrue to generators	• Firm access standard is a single-tier standard • Firm access standard is uniform across the NEM (alternative is for it to vary between regions) • Normal operating conditions includes planned outages • Normal operating conditions criteria are flowgate specific • Firm access standard does not place any obligation on TNSPs outside normal operating conditions • No change in reliability standards for optional firm access implementation (but a parallel change to reliability standards is not ruled out by this)	• Firm access standard target flowgate capacity should include target super-firm entitlements. (The alternative is that it does not include super-firm entitlements)

34 In the optional firm access model, the locations in the shared network where congestion can occur are known as flowgates.

4.2.2 Developments since the Transmission Frameworks Review

Since the conclusion of the Transmission Frameworks Review we have undertaken further work on the design of the firm access standard. We consider that the proposed split between normal operating conditions and abnormal operating conditions may not in practice be workable since:

- the nature of the incentives it places on the TNSP may be sub-optimal for a generator's needs;
- it is not always possible to practically distinguish between normal and abnormal operating condition flowgates; and
- practical complexity arises in access pricing, transitional access allocation and access settlement.

These points are discussed in more detail below.

Service Coverage

The model, as recommended in the Transmission Frameworks Review, obliged the TNSP to provide access only during normal operating conditions.

There was no incentive on the TNSP to maintain an adequate level of service during abnormal operating conditions. There was also no incentive on the TNSP for timely restoration of a forced outage, regardless of the prevailing market conditions. In abnormal outage conditions, market prices are typically high and so there may be significant impacts on participants at such time.

Therefore, given the potential for significant impacts on participants, the TNSP should have an incentive to restore the market in a timely manner (even if the *cause* of the abnormal outage condition was out of its control), and so move to lower price outcomes in the market.

Such incentives would likely be more attractive from a generator's point of view.

Flowgate Tagging

Under the Transmission Frameworks Review recommendations, an organisation would have been required to tag flowgates in real-time as either occurring in normal or abnormal operating conditions for access settlement. To a large extent, AEMO does this already, through the creation and application of “constraint libraries”, each of which relates to a particular transmission condition. However, this current process does not impact on participants' financial flows in settlement and so is not typically contentious.

A transmission outage would affect flowgates across a large part of the network, potentially even across multiple regions, although the impact diminishes as the electrical distance from the outage increases. We understand that when an outage occurs, AEMO only replaces the system normal constraints with outage-related constraints in a "zone of materiality" close to the outage, where the impact of the outage is material. For AEMO, "materiality" currently relates to the impact on dispatch efficiency and security. This definition would likely not be appropriate if optional firm access was in place.

The recommended firm access standard required the creation of a somewhat subjective division between situations where the TNSP would be subject to the firm access standard (normal operating conditions), and where it would not (abnormal operating conditions). Developing the process and then implementing individual decisions could have been difficult and contentious.

Complexity

There are several practical implications of a firm access standard that only applied during normal operating conditions. These are not insurmountable, yet contribute to making the model more complex to design, implement and operate. For example, the pricing model would have been required to only include the specification of normal operating conditions as an input.

Summary

For the above reasons we consider it appropriate to remove the distinction between normal operating conditions where the firm access standard applies, and abnormal operating conditions where the firm access standard does not apply. We propose that the revised firm access standard apply at all times (ie, both normal and abnormal operating conditions) and include a separate planning and operating standard. These two standards are expanded upon below. The implications of this revised firm access standard are explored below in section 4.6.

These developments are different to some of the core elements of Table 10.1 as discussed above. However, the Commission considers that the revised firm access standard has a number of benefits over the firm access standard as specified in the Transmission Frameworks Review. These are also discussed further in section 4.6 below.

4.3 Firm Access Planning Standard

4.3.1 Definition of the Firm Access Planning Standard

We propose that the Firm Access Planning Standard would be defined as a mandatory standard that requires a TNSP plan its network so as to be able to provide agreed access levels for firm generators under a set of specified conditions. This would specify the level of redundancy that TNSPs must build into their network.[35]

We note that the firm access planning standard would take into account the generator's economic assessment of the value of access. A generator, in deciding how much firm access to procure, would undertake its *own* economic assessment of the value of that firmness. The firm access planning standard - by incorporating that procurement decision - would therefore be established as an inherently economic standard. However, in order to allow TNSPs to plan to this level it would be expressed in a way that specifies how much redundancy the TNSP must build into their network (as opposed to an output-based approach). Indeed, expressing the firm access planning standard in a way other than in this manner would mean requiring the TNSP to second-guess a generator's assessment.

The firm access planning standard would be defined by the capacity that would be needed in order for all firm generators in the network to receive their full access amount during the specified set of conditions. TNSPs would have no firm access planning standard obligation in relation to non-firm generators.

We expect that the conditions used in specifying the firm access planning standard would be determined with reference to the expected occurrences of material constraints in a region.

4.3.2 Process for setting the Firm Access Planning Standard

The exact specification of the firm access planning standard would be undertaken by the TNSP, and approved by the AER. Specifically, we consider that the steps in the development of firm access planning standard may be as follows:

- the Rules would set out principles for the development of the firm access planning standard. These would provide principles for how the TNSP must plan to meet firm access requests at the specified conditions, for example, it would set out the level of redundancy that TNSPs must assume when planning their network. It may also recognise that forced outages may occur during the specified conditions and so these should be accounted for in planning;[36]
- the AER would develop detailed firm access planning standard guidelines that comply with the firm access planning standard principles, in consultation with market participants;
- each TNSP would develop a detailed firm access planning standard methodology (which could incorporate any jurisdictional variations);

35 This would involve the TNSP planning to evaluate the outcomes of a predetermined set of contingencies, without reference to the probability of the contingencies occurring.

36 The firm access planning standard would not provide 100 per cent guaranteed firmness at all times. However, the firm access operating standard would apply at all times, and so would help to facilitate the firmness of the access product at times outside the specified conditions. This is discussed further in section 4.4.

- the AER would review this methodology and approve it as being consistent with the firm access planning standard guidelines; and
- the TNSP would be required to demonstrate to the AER, and to stakeholders, that any firm access planning standard calculations have correctly followed the firm access planning standard method.

4.3.3 Planning for the Firm Access Planning Standard

TNSPs’ planning processes would be required to identify impending firm access planning standard breaches and appropriate options to remedy these.

Consistent with the Transmission Frameworks Review, TNSPs would be required to meet both the firm access planning standard and the reliability standard concurrently. In order to plan its network, the TNSP would first consider what capacity it has to provide to meet both standards concurrently. To do this the TNSP would need to consider every flowgate on its network, and the way each flowgate can impact different uses of the network. For example, the TNSP should facilitate the defined level of service to every firm generator at the same time, as well as meeting the reliability standard. The TNSP would then consider the limitations on its network in providing this capacity (ie, the current condition of the network). This includes factors such as demand (eg, the distribution of local load), capacity of lines (eg, line rating assumptions), and areas of congestion.

This planning would be set out in the TNSPs' Annual Planning Report (APR), which is a detailed short-term plan for the network. TNSPs are currently obliged to produce these documents. They set out the current capacity, and emerging limitations of the network under a range of different scenarios. The reports cover potential upcoming issues and future projects the TNSP may need to undertake to meet the jurisdictional reliability standards. With the introduction of optional firm access, we consider TNSPs would be required to evaluate their firm access planning standard obligations in these APRs. This may include setting out:

- a quantification of the firm access planning standard requirement the TNSP has in relation to total purchased firm access;
- a description of the current and potential flowgates that may impact on dispatch of generators during the specified conditions in the firm access planning standard; and
- an outline of the planning actions that are being undertaken to ensure the TNSP would continue to meet its firm access planning standard obligation.

The firm access planning standard must be met in an ongoing sense for the life of the access arrangement.

Generators would not need to be mindful of the need for potential flowgate augmentations, since this would be the TNSP's responsibility under the firm access planning standard. A generator would only be required to specify and purchase a level of access at a particular point. The TNSP would be responsible for determining where constraints on the network may bind under firm access planning standard conditions, and so allow the FAPS to be met.

Following this planning, TNSPs may need to undertake augmentations to meet their firm access requirements. As currently, TNSPs would then be required to apply a RIT-T to identify and select an augmentation option with the highest net benefit to resolve any potential firm access planning standard breaches.[37]

4.3.4 Flowgates outside specified conditions

The development of a planning standard requires a specified network condition for the TNSP to plan towards (ie, in the manner set out above). This helps generators to gain confidence that the access would be provided if it is purchased. We expect that the conditions used in specifying the firm access planning standard would be determined with reference to the expected occurrences of material constraints in a region.

However, some generators may value firm access at all times and not just at the specified condition.

There may be some constraints that bind with reasonable regularity, but that do not bind during the specified condition. For example, there may be a local load that consumes generation at some times. When the local load is not present, constraints may result. In these situations, augmenting the network to resolve the flowgate would be unnecessary to meet the firm access planning standard, even though such actions may be valued by the affected generators.

If the firm access planning standard applied at all times, and not just during specified conditions, this could result in additional augmentations being necessary. This would likely result in a higher price for the purchase of firm access, for a product that not all generators may value.[38]

We are currently considering this issue further. Some of the work that we are undertaking includes:

- evaluating the frequency, and materiality, of binding flowgates under different network conditions;
- examining historical flowgates to determine the extent and impact of constraints that would have bound on a firm access planning standard-compliant network; and

37 Consistent with NER clause 5.16.3(d), for those augmentations to meet the firm access planning standard that are estimated to cost less than $5 million, these would also have to be planned, and built, at least cost.

38 We note that a generator that was particularly concerned about access outside the specified conditions could decide to purchase a super-firm level of access, which could result in higher levels of access at all times.

- considering potential mechanisms that would allow TNSPs to resolve flowgates outside of the specified conditions if their impact is material, for example, allowing augmentations of the network to occur to provide capacity if such investments were favourable to generators.

4.3.5 Enforcement

As noted above, the firm access planning standard would be met concurrently with reliability access, and neither would have precedence over the other.

In terms of enforcement, we propose that a failure to comply with the firm access planning standard by a TNSP would be a breach of the Rules.[39]

However, we note that difficulties exist in proving whether TNSPs have planned towards a certain target. Planning typically has an "advisory" nature so that TNSPs only need to *take into account* relevant plans in making investment decisions (as opposed to being "bound" by their plans). Therefore, it would be difficult for a single generator to prove that a TNSP failed to plan its network to meet the firm access planning standard, and this failure consequently caused a loss to the generator (ie, by not receiving payments associated with their full access amount).

In addition, TNSPs in planning their networks are required to take into account a number of issues including firm access requests and reliability standards as discussed above. This would also create difficulties in proving that a TNSP did not meet the firm access planning standard requirement of a single generator. A number of factors feed into planning decisions - separating out a single factor, and the effect that it had on the plan, may be difficult.

Therefore, we consider that the AER may be the most appropriate body to assess compliance of a TNSP with the firm access planning standard across the entire network. This is due to its status as a NEM-wide regulatory body.

We are also considering whether a breach of the firm access planning standard could be considered a conduct provision in the Rules. A conduct provision allows a "person other than the AER" to seek action against another party based on a breach of a particular "conduct provision" clause of the Rules.[40] It also allows the person to recover the amount of loss or damage that was suffered as a result of any breach of that conduct provision. This would potentially allow a firm generator that considered that the TNSP did not provide sufficient capacity to underpin its access arrangement, to take an action against the TNSP.

39 Typically, compliance with transmission reliability standards is captured through conditions set out in jurisdictional instruments.

40 National Electricity Law, Part 1, clause 2AA(a).

4.4 Firm Access Operating Standard

The firm access operating standard sets a target operating condition for the TNSP to meet. The firm access operating standard would always apply regardless of prevailing market conditions, ie it would apply in both normal and abnormal operating conditions. The incentive scheme described in chapter 5 would motivate the TNSP to meet the firm access operating standard.

We recognise that it would be impossible for a TNSP to provide firm access at all times (ie, a TNSP cannot provide 100 per cent firm access to generators under all conditions). This is since there may be circumstances that influence capacity on the network that are caused by events outside the TNSP's control. However, the Commission considers that risk should be allocated to the party best able to bear the risk. In this instance, even though some events are outside the TNSP's control, the TNSP should have the best knowledge, and understanding of such events. Accordingly, the TNSP is in the best position to manage such events.

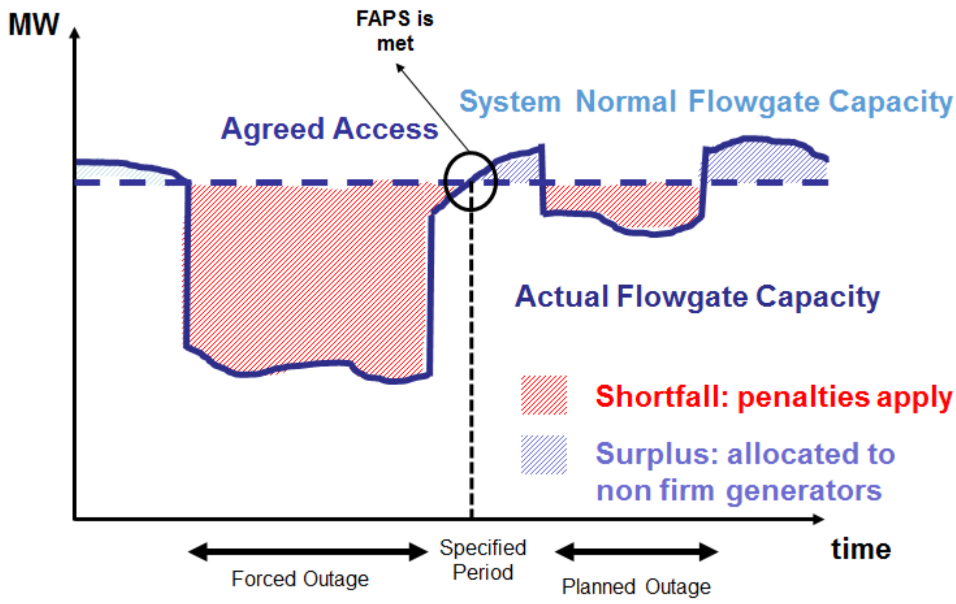
Through the incentive scheme, the firm access operating standard would allow the TNSP to make its decisions to operate and maintain the network, while considering the costs it may bear. For example, the TNSP may decide to incur access shortfalls where the cost of these shortfalls (to the TNSP) would be less than the cost of the operational remedy.

The incentive scheme is discussed in more detail in chapter 5.

4.5 Combined operation of firm access planning standard and firm access operating standard

The firm access planning standard and firm access operating standard are designed to work together to encourage a TNSP to plan and operate its network efficiently so as to provide the firm access service. Figure 4.1 shows a simplified example of how the firm access planning standard and firm access operating standard would interact. This diagram shows the flowgate capacity that would be available for the generator over the course of time as the blue solid line. The horizontal dotted blue line represents the purchased level of firm access, while the vertical dotted line represents the demand during the specified conditions.

Figure 4.1 Operation of the Firm Access Standard



In this example, the TNSP just meets the firm access planning standard as the level of access matches the purchased level of access at the specified period. Additionally, we can see that the TNSP has dropped below the firm access level agreed at two points, once because of a planned outage and the other due to a forced outage. In both of these periods, due to the firm access operating standard, the TNSP would face penalties as part of the incentive scheme. Consequently, the TNSP would have an incentive to minimise the market impacts (and so duration) of these outages.

We note that the forced outage could occur during the specified conditions. Typically, TNSPs should factor in the probability of forced outages occurring at such times when they plan the network to meet the firm access planning standard. If an extremely large outage on the network occurred (eg during a force majeure event), it could be the case that the capacity on the network during the specified condition may be lower than that required under the firm access planning standard. However, this should be rare. Regardless, the firm access operating standard would continue to apply and so would incentivise the TNSP to restore the outage as quickly as possible.

4.6 Implications

This chapter has laid out amendments to the firm access standard from what was specified in the Transmission Frameworks Review. The firm access standard as presented in this chapter does not rely on the specification of normal and abnormal operating conditions. We consider that removing this requirement makes the process simpler to implement while improving the certainty of the product to both generators and TNSPs.

This revised firm access standard addresses the three concerns as set out in section 4.2.2:

- the firm access standard applies at all times;
- there would be no need to separate out normal, and abnormal operating conditions; and
- the consequence of the above means that it would be more straightforward to implement.

These changes would promote the national electricity objective, consistent with the categories of impact that were set out in chapter 3. The revised firm access standard should provide increased financial certainty to generators (discussed below), as well as reducing transaction costs associated with the implementation of the model.

Box 4.1 sets out the implications of this proposal for the firm access product definition. We consider this definition appropriate since we consider that the specified conditions would be defined so the access product would be most valuable for generators (ie, correlated times of high congestion, with high market impacts, on the network). It is also worth noting that we are currently examining the significance of the variability in network capacity.

Box 4.1: Firm access product definition

The firm access product provides the firm generator with the right to sell its output up to its access amount at the regional price, either by being dispatched, or by earning compensation at least equal to the difference between its offer and the regional price if congestion prevents it from being dispatched.

This compensation would be provided at certain times:

- under the firm access planning standard, generators should be confident of being provided with fully firm access during the specified conditions; and
- under the firm access operating standard, TNSPs would be incentivised to provide a level of access that maximises the value of the access.

4.7 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- the implications of the firm access standard applying at all times;
- the implications of the firm access planning standard being based on specified conditions, and how these specified conditions should be defined; and
- the nature of enforcement of the firm access planning standard.

5 TNSP incentive scheme

Summary of this chapter

As set out in the previous chapter, the firm access operating standard is a key component of the firm access regime. Underpinning the firm access operating standard is the TNSP incentive scheme. This incentive scheme is designed to encourage the TNSP to trade-off rewards and penalties against the risks that it faces.

The incentive scheme that was recommended in the Transmission Frameworks Review only applied during normal operating conditions, ie, when the firm access standard applied. However, as discussed in the previous chapter, under our proposed firm access standard it would now apply at all times. Therefore, there needs to be corresponding changes to the incentive scheme to align it with the proposed firm access standard.

The incentive scheme aims to filter out - as far as possible - the unmanageable risks (for example, the timing of forced outages), while leaving a TNSP exposed to manageable risks (for example, the timing of planned outages). The incentive scheme would provide a continuous incentive on TNSPs to provide transmission capacity to underpin access agreements.

Such an incentive scheme also benefits consumers since TNSPs are encouraged to operate their network more effectively. This would have flow on consequences to consumers, since transmission costs are passed through to consumers through TUOS.

5.1 Introduction

Chapter 4 discussed the firm access standard. The revised firm access standard consists of both a planning standard (FAPS) and an operating standard (FAOS). The firm access operating standard is given effect through the TNSP incentive scheme, which is the subject of this chapter. The firm access operating standard, and so the incentive scheme, apply under all conditions (unlike the firm access planning standard, which only applies during specified peak conditions).

Designing an incentive scheme to effectively trade-off incentives and risks is complex. Accordingly, we have proposed two alternative TNSP incentive schemes, which are presented in this chapter. First, we explain what was recommended in the Transmission Frameworks Review and the issues that have subsequently arisen with this approach following further analysis (section 5.2). We then set out our two potential options for incentive schemes (section 5.3): Option 1, involving a *target* shortfall factor (section 5.4); and Option 2, involving an *annual* shortfall target (section 5.5). We then discuss impacts of the proposed incentive schemes on TNSPs (section 5.6), and some further considerations (section 5.7). Finally, we set out areas that we wish to seek stakeholder feedback on (section 5.8).

5.2 Background

5.2.1 TNSP incentives in the Transmission Frameworks Review

The Transmission Framework Review's final report proposed an operational incentive scheme. This incentive scheme applied *only* during normal operating conditions. That is, there were no obligations, or incentives, on the TNSP to provide access outside of these times. The distinction between these two conditions was intended to make the firm access standard attainable for the TNSP, and provide reasonable certainty around firm access firmness for the generator.

The incentive was based on - and would not exceed - the cost to firm generators of shortfalls of transmission capacity that resulted in entitlements, and so compensation, being scaled back beyond what should be delivered under the firm access standard. This would allow a TNSP to fall short of the firm access standard, and pay the shortfall costs instead, where this was economic to the TNSP (ie, the costs to the TNSP of doing something to help meet the firm access standard were less than the shortfall costs that it would have been exposed to). The shortfall cost is proportional to both the amount of shortfall and the flowgate price.[41]

The shortfall cost can be defined as the flowgate price multiplied by the difference between the target flowgate capacity (that which is required to provide the target firm entitlements to all firm generators participating in the flowgate) and the effective flowgate capacity (the actual flowgate capacity plus any flowgate support). By incorporating the flowgate price, the value of the shortfall to generators is reflected.

Through access settlement, payments by the TNSP would be allocated directly to the generators affected.[42]

The TNSP payment would be equal to some proportion of the costs to firm generators resulting from the breach, which would be achieved through the application of a sharing factor:

TNSP payment = incentive sharing factor (X per cent) x shortfall value

The AER would set the sharing factor (ie "X") between zero and 100 per cent based on a process and principles set out in the rules. We envisaged that a relatively low sharing factor would be set, resulting in a low-powered incentive. The sharing factor represented a practical recognition that TNSPs would be unable to take on all of the shortfall risks.

The fixed sharing factor would apply until the aggregate penalties reached a predetermined limit (or "cap") after which the sharing factor would be set to zero so that no further penalties would apply to the TNSP. The cap would also be set by the AER, and would be defined relative to a period of time - an annual basis was

41 This is indicative of the severity of the congestion and its impact on constrained-off generators.

42 See: AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013, p. 88.

considered appropriate. A cap was necessary since wholesale spot prices in the NEM can be very high. It would only take a small number of shortfall periods at the market price cap for a TNSP to be facing, and responsible for, a large settlement shortfall.

This TNSP incentive scheme was one-sided, ie, provided only downside for the TNSP. This was driven by a number of factors including that access should only be provided in response to firm generators' willingness to pay. Therefore, the TNSP should not be incentivised to provide capacity over and above the level of agreed access. Any surplus network capacity above the firm access standard level can be offered as short-term firm access or is, effectively, allocated to non-firm generators, who have indicated that they do not want to pay for access. Neither firm generators, nor customers gain any benefit from surplus capacity (and so should not pay the TNSP for providing this), and non-firm generators do not want to pay for the benefit that they may get.

Another factor driving the recommendation for a one-sided scheme was that TNSPs would be able to earn additional revenue through the sales of short-term firm access. This would have provided them with some upside. This is discussed in more detail in chapter 7.

The key features of the TNSP incentive scheme, as set out in Table 10.1 of the Transmission Framework Review's final report, are extracted below.

Table 5.1 Table 10.1: TNSP incentive scheme

Core elements	Recommended elements	Optional elements
• TNSPs would face an incentive scheme and pay a penalty equal to some proportion of the settlement shortfall due to firm access standard breach • TNSP penalties paid into access settlement to offset settlement shortfall and mitigate the scaling back of firm access	• Short-term access incentive scheme - TNSPs would be subject to 100 per cent of any settlement shortfalls • TNSPs face incentives outside the firm access standard to move back within normal operating conditions	• TNSPs face a high-powered long-term incremental access incentive scheme for new access (alternative is that TNSPs are only exposed to some share of the shortfalls) • TNSPs face incentives outside the firm access standard to encourage TNSPs to provide an efficient level of access

5.2.2 Developments since the Transmission Frameworks Review

We have developed a potential design of the TNSP incentive scheme since the Transmission Frameworks Review.

The developments adapt the TNSP incentive scheme to support the firm access operating standard, under which there is no distinction between normal and operating conditions (as discussed in section 4.4). In the Transmission Frameworks Review TNSPs were only required to maintain the firm access standard during normal operating conditions, and so TNSPs were incentivised to provide the agreed level of access during these periods (and nothing more). The proposed changes to the firm access standard result in the firm access operating standard applying at all times, and so we should consider how TNSPs should be provided with a continuing incentive to provide agreed access levels at all times.

The developments we have considered to address this concern are described in the remainder of this chapter. Option 1 discussed below is consistent with the core and recommended elements in the table above. Option 2 is largely consistent; however, in this option the TNSP penalties are not paid into access settlement.

5.3 Developing a TNSP incentive scheme

Currently, TNSPs are incentivised by the STPIS to minimise the market impact of reductions in capacity of their network. Part of the STPIS is a market impact component, which is a low-powered (ie, does not necessarily reflect the full market impacts of the outage) incentive to minimise outages when constraints are binding and the estimated market impact is above a defined threshold (a $10 flowgate price). We understand that market participants consider that this scheme has been successful in changing TNSP behaviour. Therefore, we consider that an incentive scheme, even where low-powered, may also be successful in driving a TNSP to operate its network to meet the firm access operating standard.

On the other hand, the market impact component of the STPIS does not strongly take into account the prevailing wholesale spot market price at the time of a constraint and only incentivises the TNSP to minimise how often outages occur (although it does have a $10 flowgate price materiality threshold). In contrast, the optional firm access incentive scheme aims to provide the TNSP with a cost signal that relates to flowgate prices at the time of a binding constraint.

The flowgate price, as set out in the Transmission Frameworks Review, is a measure of the value that is gained by relaxing the underlying constraint by a small amount. It is measured by the reduction in the total cost of generation dispatch when 1MW of additional power is able to pass through the flowgate. Where a constraint prevents cheaper generation from being dispatched, such that demand must be met by substantially more expensive generation from elsewhere in the region, then the flowgate price would be high.

Therefore, our proposed incentive schemes focus on exposing the TNSP to such flowgate prices, as did the scheme recommended in the Transmission Frameworks Review. Further, our scheme also takes account the shortfall volume of congestion (the

MW amount by which access for firm generators is reduced), as well as the flowgate price.[43]

We have developed two alternative options for an incentive scheme. Option 1 creates a "Target Shortfall Factor", while Option 2 has an "Annual Target Shortfall Amount". These options are discussed in more detail below.

It is also worth noting that we propose that this new incentive scheme could replace the current market impact component incentive scheme if optional firm access was to be introduced.

5.4 Option 1: Target Shortfall Factor

The proposed incentive scheme could have the following characteristics:

- TNSP rewards and penalties would be based on shortfall costs;
- nested caps and collars would be included in the scheme to limit TNSP risks and rewards, while aiming to ensure that incentives continue over the full year;
- the scheme would be made symmetrical by specifying a Target Shortfall Factor;
- incentive scheme parameters would be set by the Australian Energy Regulator; and
- the TNSP payments would be calculated and settled through access settlement.

These elements are described in turn below.

5.4.1 Shortfall costs

TNSPs would be exposed under the incentive scheme to the shortfall cost. The shortfall cost is defined the same as that presented in the Transmission Frameworks Review, and which was presented above.

As set out in chapter 4, under the revised FAS, the concept of normal and abnormal operating conditions is removed. Therefore, a TNSP would be potentially be exposed to shortfall costs during all trading intervals.

5.4.2 Nested caps

Given that a TNSP would be exposed to shortfall costs during all trading intervals, there is potential for extreme shortfall costs to arise under “abnormal” operating conditions. Therefore, any single cap (such as what was proposed under the

[43] It is worth noting that the scheme proposed here ignores congestion that imposes costs only on non-firm generators.

Transmission Frameworks Review) that may be applied to limit a TNSP's aggregate exposure could be reached very quickly.

If this were to occur, then the TNSP would have no further exposure to the scheme – and so no further incentive to manage access shortfalls – for the remainder of the year.

Therefore, we now propose that some additional "nested" caps would be included in the incentive scheme. "Nested" refers to the caps effectively being placed inside one another. So, within the annual cap, there may be monthly caps, and then daily caps within the monthly caps and so on.

For example, a possible scheme may include the following nested caps:

- no more than $10 million exposure in a year;
- no more than $200,000 exposure in a day (one 50th of the annual cap); and
- no more than $20,000 exposure in a trading interval (one 10th of the daily cap) on any flowgate.

The nested caps relate to net cumulative incentive amounts, so all incentive amounts – both positive and negative – are accumulated and netted.[44]

There would also be a series of nested "collars". These aim to limit the maximum cumulative (net) rewards that a TNSP is entitled to earn. How such rewards would arise is discussed further below (section 5.4.3). The collars could be symmetrical to the caps, although TNSP rewards would be limited by the target flowgate capacity. That is, a possible scheme may include the following nested collars:

- no more than $10 million rewards in a year;
- no more than $200,000 rewards in a day (one 50th of the annual collar); and
- no more than $20,000 rewards in a trading interval (one 10th of the daily collar) on any flowgate.

We discuss principles that could be used in setting these caps below in section 5.4.4.

These nested caps would be designed (and so set at a level) to avoid TNSP exposure to - as far as possible - the unmanageable risks (for example, the timing of forced outages), while leaving a TNSP exposed to manageable risks (for example, the timing of planned outages). The caps effectively share the risks between the TNSP and the firm generators. For example, they limit the share that is borne by the TNSP, but in doing so increases the share that is borne by generators (ie, increase their risk).

44 Once a TNSP hits one nested cap for a time period, it would no longer continue to accrue shortfalls during that time period against the next cap. For example, if the trading interval cap was $20,000, once the TNSP hit $20,000, only the $20,000 would contribute to the daily cap, even if more than $20,000 of shortfall was accrued in the trading interval. This stops the TNSP exhausting a number of caps in one short period.

5.4.3 Target Shortfall Factor

While the firm access operating standard applies at all times, we recognise that the TNSP is not expected to provide the target flowgate capacity (ie, the sum of all access requests) under all conditions. The TNSP should effectively manage the level of shortfall costs. Therefore, the TNSP should aim to meet a "target" level of shortfall costs.

The Commission recognises that this target level cannot be readily identified. It could be progressively discovered over time by TNSPs operating under an effective incentive scheme. In other incentive schemes (eg, the STPIS), the AER typically sets a target based on rolling performance, meaning that the target converges to the optimal level over time, tracking actual performance but with some lag, to allow a TNSP to be rewarded for performance improvements.

There would be a similar process for the optional firm access incentive scheme. The AER could specify a target that is expressed as a target shortfall factor, or T-factor. The shortfall factor is the ratio between actual and target flowgate capacities and is the amount by which firm access is scaled back in real time in access settlement due to flowgate shortfalls.

The T-factor can be thought of as relating the firm access operating standard level of average delivered firm access to the nominal firm access planning standard level of purchased firm access. So, for example, if the T-factor is 90 per cent, say, then a generator purchasing 100MW of firm access can expect to receive 90MW of access on average (ie, a generator is purchasing 100MW of 90 per cent firm access). Importantly, it is a weighted average, using the flowgate price as the weighting factor, since we understand that generators would be most concerned about their access when congestion is severe and flowgate price is high.

Under the incentive scheme, the TNSP would receive penalties if the shortfall factor is lower (ie worse) than the T-factor. It could receive rewards if the shortfall factor is higher than the T-factor, or if there is no shortfall.

However, there is no additional reward for the TNSP exceeding the target flowgate capacity, since this does not provide any additional benefit to firm generators and so the incentive reward is capped at this amount. This is consistent with the proposal as set out in the Transmission Frameworks Review – TNSPs should not be incentivised to provide capacity over and above what firm generators are willing to pay for.

The TNSP payment, or reward, would be calculated taking into account the nested caps and collars that were described above. That is, once a cap or collar is reached no further penalty or reward for the relevant time period would contribute to the overall assessment.

Given this, the incentive scheme parameters should be based on the target level of access, and so the symmetric nature of the scheme can be considered to be continuously incentivising TNSPs to provide a target level of access, where this level is uncertain.

We recognise that generators may value the surplus of access, and the shortfall of access differently. We welcome stakeholder views on how this may be valued.

5.4.4 AER sets the scheme parameters

The parameters of the incentive scheme could be set by the AER. It is expected that this could be done at either each TNSP regulatory reset similar to existing incentive schemes, or on an annual basis.[45] How often the parameters are set also influences uncertainty regarding the scheme - for example, setting the scheme on an annual basis may increase uncertainty.

The scheme parameters could define nested caps and collars and the T-factor. The AER may be given flexibility to include other structures: for example, sharing factors (these are discussed further in section 5.7.4). The AER's proposals must comply with principles and objectives that would be included in the Rules.

The AER could be required to consider historical performance when setting the incentive scheme parameters, as discussed above. One approach it may take could be to backcast the scheme using historical data: working out what aggregate penalty or reward the TNSP would have earned if the proposed scheme had applied over the history. The T-factor can then be adjusted – and the backcast recalculated – until the aggregate penalty/reward equals zero. So, the TNSP should break even if future performance matches the historical performance. If performance improves (or worsens), the TNSP would earn an aggregate reward (or penalty).

The AER should also consider a number of principles when setting the T-factor, and the nested caps, including:[46]

- the ability of the TNSP to "game" the incentive scheme - the TNSP may be able to "tank" historical performance in order to obtain a more favourable T-factor;
- providing some certainty to generators around access firmness - if the T-factor was able to change rapidly or become volatile this may undermine a generator's confidence in procuring long-term access;
- the financial position of a benchmark-efficient TNSP;
- the impact of the risk on a benchmark-efficient TNSP - ideally this could be incorporated in the cash flow-modelling underpinning the determination of

45 Setting the parameters on an annual basis would involve the AER consider these parameters from "scratch" each year. That is, it would not just adjust the parameters to current information using a formulaic approach.

46 These were similar principles to those proposed in the Transmission Frameworks Review for the AER to consider when setting the cap.

regulated revenues and prices, but alternatively it could be reflected through the return on equity; and

- creating sufficiently strong incentives for the TNSP to deliver firm access as efficiently as possible.

The AER could be required to take into account these (potentially competing) objectives when setting the T-factor.

5.4.5 Access settlement

The incentive penalty (or reward) could be paid into (or out of) access settlement in real-time. Access settlement is the process through which financial compensation would be provided to firm generators that were constrained off, and so not dispatched.

If the incentive amount is a penalty then the amount the TNSP pays is positive, and increases the entitlements to generators, partially offsetting the flowgate shortfall. In this situation, firm generators effectively receive partial compensation from the TNSP for the flowgate shortfall.

If the incentive amount is above the "target" level, then firm generators would effectively compensate the TNSP for the flowgate surplus. This provides a continuing incentive to the TNSP.

Therefore, the effect of the incentive scheme is to stabilise effective flowgate capacity around an amount equal to T times the target flowgate capacity (ie, the effective flowgate capacity that the TNSP needs to provide to allow all firm generators to be dispatched simultaneously at their agreed access level). This effect is limited by the caps applying under the scheme.

Rewards and penalties need to be allocated to the TNSP that has responsibility for the congested flowgate. Allocation of responsibility may not always be straightforward or intuitive: for example, consider a stability constraint on an interconnector. In difficult cases, where responsibility cannot be allocated within the normal settlement timeframe, there may need to be an ex-post readjustment of settlement. This would normally be between just the two TNSPs, but could also involve generators where one of the TNSPs involved has a binding cap applying but the other does not.

5.4.6 Summary of Option 1

This option for the incentive scheme addresses the limitations with the incentive scheme as specified in the Transmission Frameworks Review (discussed in section 5.2.2). This option adapts the incentive scheme to apply at all times, and also provides TNSPs with a continuing incentive to provide the generator's purchased levels of firm access.

A continuing incentive is now necessary since the firm access operating standard now covers all time periods, and so the target level of shortfall is imprecise. However, the economic level of firmness would be somewhere below 100 per cent. That is, in some instances it may be more cost-effective for the TNSP to pay the shortfall costs to generators, rather than incurring operational expenditure.

If the TNSP beats the firm access operating standard, the benefit goes to firm generators (not non-firm generators). The access that the firm generator has signalled it values is, in a sense, made more firm. Therefore, it is logical for firm generators to pay some rewards to the TNSP to beat the firm access operating standard. The scheme has become symmetric: firm generators may either receive penalty payments from the TNSP, or fund reward payments to the TNSP. However, there is still no additional reward for the TNSP beating 100 per cent firmness, for the same reasons as set out in the Transmission Frameworks Review. This is discussed further in section 5.7.1.

Another benefit of the scheme is that it incentivises TNSPs to operate its network to its most effective use. This incentive scheme should encourage TNSPs to operate their network to meet both the firm access and reliability standards; and to maintain the transmission infrastructure and maximise the availability of capacity.

A weakness of the scheme recommended in the Transmission Frameworks Review was that it only applied incentives during normal operating conditions. To address this, a separate "beyond firm access standard" scheme was suggested at the time, which would apply shortfall penalties during abnormal operating conditions, but levy a fixed "tariff" for these penalties, rather than the flowgate price. Here, the incentive applies in all periods and so provides TNSPs with an incentive to more quickly restore the network to system normal following any unforseen outages. It also avoids the problem of having to distinguish normal from abnormal operating conditions, the boundary for which is never likely to be clear.

Stakeholders, through our Working Group, have noted some limitations with this option. In particular, they are concerned that this incentive scheme may be perceived to create a lack of firmness. This is discussed further in section 5.7.3.

Stakeholders have also raised that since the settlement of the incentive scheme is occurring in real-time the payments (both to and from firm generators) may be considered to be uncertain. It would be hard to predict at the start of the year what generators would be expected to pay and what they would expect to receive through this scheme because these amounts would be calculated on a real-time basis. For example, if a generator suffers a shortfall when a cumulative cap has already been hit, then it would receive no compensation. But, if no cumulative caps are reached, then it may receive full compensation. This issue is addressed in part by Option 2 below.

However, such uncertainty for generators in the presence of congestion, should be less for generators under optional firm access, than it is currently. This is discussed further in section 3.5.1.

5.5 Option 2: Annual Shortfall Target

Given that some stakeholders consider a limitation of the above option to be that the scheme is settled in real-time, and so uncertainty is created, we have developed an alternative option. Here, the incentive payments and rewards are settled annually, on an ex post basis. This aims to provide generators with more certainty about what they would pay or receive compensation for.

In Option 2, some of the elements could apply the same as they did in Option 1, that is:

- the TNSP rewards and penalties would be based on shortfall costs, which are proportional to both the amount of shortfall and the flowgate price;
- "nested" caps would apply, limiting a TNSP's exposure to extreme shortfall costs in "abnormal" operating conditions; and
- the incentive scheme parameters would be set by the Australian Energy Regulator at each revenue reset, which would be based on (amongst other things) historical performance by the TNSP.

However, several elements differ, specifically:

- the scheme is made symmetrical by specifying an *annual* dollar target of shortfall costs (as opposed to a T-factor) for the TNSP to meet (or beat); and
- the TNSP payments are calculated ex post at the end of the year, and recovered from or paid to firm generators over the following year.

These elements are discussed in more detail below.

5.5.1 Annual Shortfall Target

An annual target could be set by the AER, which would represent the target amount of shortfall costs that would occur in a year. This could be set with similar considerations as to how the T-factor would be set (ie, if a TNSP maintained its historical performance it would be expected to incur the target shortfall costs). However, it is likely to be relatively more straightforward to set an annual target, since no T-factor is involved. For example, the AER may set a target shortfall amount for 2015 of $10 million.

In each trading interval, the shortfall costs could be calculated, with these subject to the nested caps.[47] This is the same as what was proposed in the Transmission Frameworks Review incentive scheme. The shortfall costs that were calculated through access settlement would always be penalties (or zero), in the sense that they are "using up" the target shortfall amount. This would result in access settlement payments to firm generators being scaled back in real-time.

47 Note that in access settlement there is now no TNSP support MW, and the effective flowgate capacity is simply allocated amongst generators in the normal way.

At the end of the year, the actual aggregate capped shortfall costs would be calculated. Although the shortfall costs are calculated for each trading interval, the aggregate calculation can be done ex-post. This would be calculated as simply adding the shortfall costs (subject to the caps) up over the year.

Under this specification of the incentive scheme, the TNSP would pay penalties if the actual shortfall costs are higher (ie worse) than the target shortfall costs. It could receive rewards if the actual shortfall costs are lower (ie better) than the target shortfall costs, or if there is no shortfall.

Any difference between the target and actual aggregate shortfall costs would then be payable by/to the TNSP. This would be done through payments to, or from, firm generators over the following year.

Here, the calculation of such penalty outcomes is much simpler since no T-factor is involved. Continuing on the above example, the target for 2015 is $10 million. The aggregate capped shortfall cost is calculated at $14 million, so the TNSP owes $4m to be payable to firm generators over 2016. Alternatively, if the aggregate capped shortfall cost is $8 million, the TNSP is owed $2 million, to be paid by the firm generators in 2016.

5.5.2 Allocation and payment mechanisms

Allocation mechanisms would need to be defined for the payments and receipts. Generators would have to fund any rewards for the TNSP themselves. This would define, for each generator, the aggregate amount payable or receivable in relation to the annual TNSP payment. Allocation could be simple or complex:

- allocated pro rata to the generator's firm access MW (ie, simple); or
- allocated by reference to the actual shortfall costs borne by the generator (ie, complex).[48]

Continuing on the example from above, the total $4m that the TNSP must pay the firm generators, may be allocated as $1 million to generator A, and $3 million to generator B.

A payment mechanism would also need to be defined in order to facilitate payments and receipts. There are a number of possible alternatives for this, including:

- one-off or monthly invoices directly between the generator and TNSP; or

48 Such an allocation would imply the continuing need for a T-factor to determine whether the actual shortfall costs for a generator were higher or lower than a "target". An allocation cannot be made solely based on aggregate shortfall costs since, in the event of the TNSP being rewarded, this would mean the generator with the highest shortfall costs would also contribute most to rewarding the TNSP. This may seem inconsistent.

- through settlement statements, between AEMO and the generator, and between AEMO and the TNSP.

5.5.3 Summary of Option 2

Similar to Option 1, this incentive scheme adapts the incentive scheme to the revised firm access standard described in chapter 4.

Option 2 should also mitigate the uncertainty of payments to firm generators. The payments under this scheme could be worked out on an ex post basis at the end of the year. The payments would then be recovered from, or paid to, firm generators over the course of the next year. Firm generators should therefore be able to plan at the start of the year what payments they would be expected to make, or receive. This would avoid generators having to consider how such incentive payments would affect their trading position.

Option 2 has a number of additional benefits, including:

- it avoids the need to set an arbitrary T-factor;

- it avoids the need to apply an annual cap during the year (ie, would promote efficient incentives for TNSPs): for example, a TNSP may perform very poorly in the first six months of the year, but very well in the next six months (ideally, the caps would be set to avoid this happening). Under Option 1, the annual cap might be hit within the first six months; whereas in Option 2, when the year is taken as a whole, the annual cap may not have been hit; and

- it allows time to resolve errors and disputes in the calculation of incentive payments without having to reopen settlements (ie, would minimise transaction costs associated with the regime).

Option 2 would represent a movement away from Table 10.1 in that Table 10.1 requires penalties to be paid into access settlement. This option is based on an ex post settlement of payments or rewards.

5.6 Impacts of the incentive scheme on the TNSP

As with the Transmission Frameworks Review incentive scheme, the two options for the revised incentive scheme aim to filter out - as far as possible - the unmanageable risks (for example, the timing of forced outages) while leaving a TNSP exposed to manageable risks (for example, the timing of planned outages). However, whilst the original firm access standard incentive scheme requires the actual condition of the network to be explicitly identified – and classed as normal operating conditions or abnormal operating conditions – in the revised incentive scheme this automatically occurs. Differently structured penalties apply to the different conditions, because the shortfalls during these different conditions have different intrinsic characteristics which interact with the scheme in different ways.

This difference in philosophy and approach is best explained through illustrative examples. Three example conditions are considered in turn below: a planned outage, a forced outage and system normal. TNSP penalty (and reward) outcomes are derived, based on the example of nested caps specified above:

- no more than $10 million in a year;
- no more than $200,000 in a day (one 50th of the annual cap); and
- no more than $20,000 in a trading interval (one 10th of the daily cap) on any flowgate.

For simplicity, the examples illustrate outcomes under Option 1 where there is no T-factor.[49]

5.6.1 Planned outage scheduling incentives and behaviour

The characteristics of, and objectives for, planned outages are understood to be as follows:

- They typically have an extended duration, from one day to several weeks.
- Advance notice of planned outages to market participants is generally possible and desirable.
- They should be scheduled for periods when congestion costs are likely to be low.
- They should be cancelled, where practical, if conditions change adversely from those expected.

Consider a planned outage with the following characteristics:

- It is of six weeks' duration.
- It reduces the flowgate capacity by 1000MW below the target flowgate capacity on a particular flowgate.
- It gives rise to an expected flowgate price of $5/MWh on that flowgate for ten hours (ie, 20 trading intervals) per business day.

Maximum penalties under the incentive scheme would then be:

- $2,500 (1000MW x $5/MWh x 0.5) per trading interval: this does not hit the trading interval cap.[50]
- $50,000/day (20 x trading interval penalty), which does not hit the daily cap.

49 This corresponds with assuming that the T-factor is 100 per cent (ie, the TNSP is fully exposed - other than the caps or collars - in this example).

50 This is multiplied by 0.5 since a trading interval is half an hour, and MWh has an hourly basis.

- $250,000/week (5 x daily penalty) and so $1.5m for the 6-week duration.

No incentive scheme caps are hit and so shortfall costs are charged to the TNSP in full. The TNSP is fully responsible for, and exposed to, congestion costs. Leaving aside system normal and forced outage penalties, a TNSP could have six such outages in a year before hitting the annual cap.

Therefore, a TNSP has a strong incentive to reduce its exposure to penalties by:

- Rescheduling the outage to a period with a lower expected flowgate price.
- Shortening the outage duration: eg by overnight or weekend working.
- Reducing the flowgate capacity impact: eg through live line working.
- Giving generators advance notice: possibly encouraging (potentially by paying them) them to align their own outage plans or otherwise to change operating or trading plans to reduce congestion costs. (Note that firm generators are not exposed to congestion costs in this example, but non-firm generators might be.).

In summary, the typical characteristic of the planned outage – and the design of the caps – means that a TNSP is likely to have a high exposure to the consequential shortfall costs.

5.6.2 Forced outage incentives and behaviour

Next, a forced outage is considered. It is assumed to occur in a peak period on a major flow path and so create severe congestion. Its assumed characteristics are as follows:

- It reduces the flowgate capacity by 1000MW below the target flowgate capacity on a particular flowgate.
- It creates a flowgate price of $1000/MWh on that flowgate, which remains high until the failed element is restored.

Penalties under the incentive scheme are then:

- The shortfall cost is $500,000 per trading interval: the TNSP penalty is therefore capped at $20k per trading interval.
- This continues until the daily cap of $200,000 is hit (after five hours, ie, 10 trading intervals) or the element is restored.
- This repeats the following day, and so on, until the element is restored.
- The annual cap would only be hit if the forced outage continues for 50 days.

A TNSP has an incentive to ensure the element is returned within five hours. If it does not achieve this, the incentive is then to return the element before the next day. And this incentive keeps repeating, day after day, for a maximum of 50 days.

The TNSP also has an incentive to reduce the frequency of forced outages. It is recognised that in the above example, the TNSP is exposed to only a small percentage (four per cent) of the estimated shortfall cost. However, there would be other forced outages during less stressful conditions when the percentage exposure would be higher.

Because any severe congestion caused by a forced outage would cause the trading interval cap to be hit, the incentive scheme penalty is similar to a tariff: $20,000 for each trading interval in which a major forced outage occurs and then $200,000 for each day it continues. This is not dissimilar – in structure – to the existing STPIS incentive on forced outages and to any beyond-FAS scheme that would have been introduced under the Transmission Frameworks Review approach.

5.6.3 System normal incentive and behaviour

A third possible example is of a flowgate shortfalls occurring during system normal periods. This may be due to a planning failure: for example due to a TNSP deliberately delaying a planned expansion in order to reduce capital expenditure.[51] Alternatively, it might be because flowgate capacity is below the specified firm access planning standard level.

The assumed characteristics are:

- A relatively low flowgate capacity shortfall of 100MW on a flowgate.
- A modest average flowgate price of $2/MWh on that flowgate.

On these assumptions, penalties are then:

- $100 shortfall cost per trading interval, which does not hit the trading interval cap.
- $4,800 shortfall cost per day, which does not hit the daily cap.
- $1.7m per year, which does not hit the annual cap.

In this case, the TNSP could be fully exposed to the shortfall costs (depending upon what other incentive penalties accumulate during the year) and would have an incentive to undertake the necessary capital expenditure or otherwise ameliorate the situation. Of course, under more severe assumptions, the annual cap would be hit and the degree of incentive reduced.

This raises the question as to whether anticipated shortfall costs should be included within the RIT-T, allowing a TNSP to deliver flowgate capacity in excess of the target flowgate capacity under firm access planning standard conditions so as to reduce the cost of shortfalls at times that are not the specified conditions for the planning standard. This issue is being considered separately and so is not discussed further here.

51 In such instances, the AER could also take enforcement action for breaching the planning standard.

5.6.4 Summary

The above examples illustrate how the incentives on a TNSP under the incentive scheme may vary depending upon the underlying conditions causing flowgate shortfall costs. For a planned outage, a TNSP would be very sensitive to the expected flowgate price and would either seek outage periods where the flowgate price is likely to be low or aim to minimise duration and flowgate capacity impact. For a forced outage, a TNSP instead aims to reduce average forced outage frequency and duration, and it can perhaps respond to severe outages in order to reduce the duration of that particular outage. For a system normal shortfall, a TNSP may be incentivised to undertake capital expenditure.

The assumptions presented above are illustrative only. In practice, typical outage characteristics may vary substantially from those presented. The parameters of the real scheme would be tuned to actual outage characteristics, based on quantitative and historical analysis.

It should also be noted that the examples above involve only a single congested flowgate. In practice, multiple flowgates would bind over a period. The trading interval cap would apply to each individual flowgate, but the other caps would apply in aggregate across all flowgates.

We also note that the incentive scheme also impacts on generator behaviour. We are undertaking further work on understanding any interactions between the incentive schemes proposed here, and generator bidding incentives.

Our proposed incentive schemes are both consistent with the promotion of the national electricity objective, and the assessment framework that we set out in chapter 3. The schemes provide a continuing incentive on the TNSP to operate, and maintain, the network to meet firm access requests. It also promotes the TNSP making appropriate trade-offs between operating, and investment, decisions.

With the assistance of AEMO, we are currently seeking to calculate what payments would have been for TNSPs if the incentive regime had been in place historically. This will inform our future analysis.

5.7 Further considerations

5.7.1 Should the TNSP be rewarded for delivering below target network capacity?

Under either option, the TNSP would be rewarded for providing flowgate capacity in some instances. This may appear somewhat inconsistent with the Transmission Frameworks Review rationale, that a TNSP should not provide more capacity than what a generator is willing to pay for.

Under the revised firm access standard, the TNSP is only required to deliver 100 per cent access during the peak conditions specified in the firm access planning standard.

However, the firm access operating standard applies across all periods, and so the target shortfall that is set (either through a T-factor, or through an annual amount) should represent a weighted-average of the delivery expectations across all conditions. Under system normal conditions we would expect the TNSP to deliver close to the 100 per cent level, whereas under forced outage conditions it is accepted that capacity is likely to be substantially below this level.

Such a target can be compared to the effective target under the incentive scheme, recommended in the Transmission Frameworks Review scheme, which would be 100 per cent under normal operating conditions but, formally, 0 per cent during abnormal operating conditions. An earlier version of the firm access standard even proposed different target factors under different tiers of normal operating conditions. The weighted-average T-factor, or the annual target, effectively distils all of these targets into a single target covering all network conditions.

TNSPs are not rewarded for beating 100 per cent firmness, for the same reasons as discussed in the Transmission Frameworks Review, ie, a TNSP should not provide more capacity that a generator is willing to pay for. At the same time, a reward is appropriate for achieving more than the target (but less than 100 per cent) since the TNSP is improving the firmness of the access for the firm generator, consistent with signal that the generator has provided the TNSP. Therefore, these options are still consistent with the rationale in the Transmission Frameworks Review that a TNSP should not provide more capacity than what a generator is willing to pay for.

In relation to Option 1, the likely level of the T-factor is unclear at this point. We are planning to consider likely T-factor values by modelling historical data. Clearly, some congestion occurs during system normal conditions and some occurs under outage conditions. The weighting of the average between the two sets of conditions would depend upon the relative frequency and degree of shortfalls and on the relative flowgate prices. The latter may be difficult to estimate using historical data, since the bidding behaviour of generators in the presence of congestion would often have led to extreme flowgate prices which are unlikely to be repeated under the optional firm access regime.

5.7.2 TNSP is hedged against the overall level of congestion prices

An interesting characteristic of the schemes discussed here is that a TNSP should not be adversely affected by an overall increase in the level of congestion prices. The targets should be set so that, if the TNSP maintains its historical level of performance, its rewards and penalties under the scheme would net to zero (although the overall level of risk for the TNSP may increase). If congestion prices double, say, but performance is maintained, rewards would double but so would penalties, meaning that they still net out to zero. In contrast, under the previous, asymmetric scheme, penalties would double and there are no offsetting increases in rewards.

Notwithstanding this, under higher congestion prices the incentives on a TNSP to improve performance would correspondingly increase. Scheme payments increase at the margin but not in aggregate.

5.7.3 Uncertainty about access firmness

As discussed above, where the scheme caps are not hit, the incentive scheme acts to stabilise effective flowgate capacity (as allocated to generators). However, some generators perceive that such schemes would result in uncertainty about access firmness. We note that a generator should be certain about the level of access (ie, 100 per cent) it would receive during peak conditions (ie, where the FAPS applies). A generator may factor this uncertainty into its procurement decision.

However, under Option 1, with a T-factor, this is likely to be harder to factor in. If T is 0.9 and the generator requires 900MW of access, it may decide to procure 1000MW of agreed access so, after the effect of the incentive scheme, it receives 900MW. But, to the extent that T is based on historical performance, it may vary as TNSP performance changes, albeit possibly only at each regulatory reset. A generator procuring long-term firm access may be unable to forecast how the T-factor is liable to change. Similar concerns may arise with Option 2, with generators may be unable to forecast how the annual target would change over time.

As noted above, this uncertainty can be mitigated to some extent by the objectives provided to the AER in setting the scheme parameters. However, the uncertainty is also inherent in the proposed firm access standard – indeed, in any firm access standard.[52] A firm generator is, in effect, paying for some agreed level of peak flowgate capacity but cannot be certain how much of this capacity would be available away from peak.

Stakeholders may consider that this proposal is more uncertain than the model proposed in the Transmission Frameworks Review, where firm access should have been provided all of the time where normal operating conditions applied. However, this firm access operating standard applies over all conditions. Therefore, it may be considered that this model is firmer. We are currently investigating some empirical examples of how "firm" such a product would be.

5.7.4 Scaling of shortfall costs

In the Transmission Frameworks Review, we recommended that TNSP penalties should be based on shortfall costs that are scaled by an X per cent factor. In contrast, the current proposal incorporates nested capping rather than scaling. In fact, the two are not mutually exclusive, and the AER could design a scheme which incorporates both mechanisms.

However, as illustrated in the above examples, the potential advantage of unscaled penalties is that, for modest but extended congestion, a TNSP can be exposed to the full shortfall cost and is able to make decisions on that basis. Scaling would dilute this incentive.

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52 For example, in the firm access standard proposed in the Transmission Frameworks Review, there is uncertainty over the duration and severity of shortfalls during abnormal operating conditions.

5.8 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- whether the proposed definition of the incentive schemes where TNSPs are subject to both rewards and penalties is appropriate. This differs from the penalty only regime that was recommended in the Transmission Frameworks Review;
- whether generators would value firm access when there is a surplus and a shortfall differently;
- how should the nested caps and collars be structured, for example, is it necessary to define these caps all the way down to trading intervals;
- whether stakeholders consider that the better structure for the incentive scheme is around a T-factor (ie, Option 1) or through an annual target (ie, Option 2), along with supporting arguments for the preferred incentive scheme; and
- whether stakeholders consider that the options for the incentive scheme provide certainty (or not) for generators in terms of both the product and also payments they would be expected to make.

6 Issuance of the long-term inter-regional access product

Summary of this chapter

The optional firm access model proposed here includes both a long-term and short-term inter-regional access product. These represent firmer inter-regional access products than are currently available (ie, the inter-regional settlement residues). The reason for the increased firmness is that the access product under optional firm access does not depend on flows across the interconnector.

The offering of such products resolves existing potential issues with the operation of interconnectors.

Long-term inter-regional firm access would be offered, and issued, through an auction. This is considered appropriate since it is seeking to bring together a large number of interested parties - any market participant can purchase inter-regional access.

Short-term inter-regional firm access could be offered, along with short-term intra-regional access, in a separate auction. This is discussed further in chapter 7.

6.1 Introduction

The previous chapters discussed aspects of the optional firm access model that relate to intra-regional firm access. However, the optional firm access model also includes an inter-regional firm access product. Generators and retailers would be able to procure firm inter-regional access rights, which would entitle them to the price difference between two regions. This product would be firmer than the current Settlement Residue Auction units that are available for purchase since the payments would not be dependent on interconnector flow, and so the optional firm access product would give generators and retailers greater confidence to trade across regional boundaries.

This chapter discusses the latest work that has been undertaken on the process for the issuance of this long-term inter-regional access product. First, we explain what was recommended in the Transmission Frameworks Review (section 6.2). We then set out the objectives of inter-regional access (section 6.3), before setting out our proposed approach (section 6.4). We also set out some further considerations with the issuance of the inter-regional access product (section 6.5). Finally, we set out areas that we seek stakeholder feedback on (section 6.6).

6.2 Background

6.2.1 Inter-regional access in the Transmission Frameworks Review

Inter-regional access product

The Transmission Frameworks Review recommended an inter-regional firm access product.[53] Inter-regional firm access differs from intra-regional firm access in two ways:

- it provides access from one regional reference node to another; as opposed to intra-regional access which provides access from a generator's node to the regional reference node; and
- it can be purchased by any market participant, as opposed to intra-regional access which is only available to generators.

We termed the inter-regional access product in the optional firm access model a "firm interconnector right". The holder of a firm interconnector right is entitled to the price difference between two regions based on its access amount (similar to the current settlement residue auction units, but a firmer hedge). Therefore, aside from the two differences mentioned above, the inter-regional and intra-regional access products operate in the same manner:

- both provide a hedge against congestion;
- both require TNSPs to provide the network capacity to underpin the agreed access; and
- both would have a fixed charge, which is set at the time of purchase.

Inter-regional access settlement would work by allocating a pool of funds to holders of firm interconnector rights. The pool of funds available would be equal to:

- the price difference between two regions, multiplied by the interconnector flow; plus
- payments from generators whose dispatch caused the interconnector flow to be diminished; plus
- payments from TNSPs whose actions were responsible for the interconnector flow to be diminished (in accordance with the operational incentive scheme as discussed in chapter 5).

These amounts, and so the pool of funds, would be worked out through access settlement. The model used for inter-regional settlement would be the same as that

53 See: AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013, p. 75.

used for intra-regional settlement. This can be facilitated since intra-regional settlement needs to recognise inter-regional entitlement on flowgates where the underlying constraint has an interconnector term.

TNSPs would be required to maintain capacity on hybrid flowgates[54] in accordance with the firm access standard. Hybrid flowgates include interconnector entitlements. The issuance of inter-regional firm access means that inter-regional transmission capacity must be maintained and could not be degraded through TNSPs using the capacity to provide new intra-regional firm access to generators connecting on inter-regional transmission paths.

Prices for inter-regional access would be produced based on the long run incremental cost pricing methodology that is used in intra-regional access. This method is based on a long-run incremental cost, which calculates both present and future incremental costs associated with expansion.

Inter-regional access issuance

In the Transmission Frameworks Review, a possible issuance mechanism for the inter-regional product was recommended.[55] This consisted of two stages:

- The first stage involved the system operator running an auction for inter-regional access on interconnectors, offering access in quarterly blocks.
- Where a potential expansion signal was received in the auction, the second stage involved the relevant TNSPs undertaking a joint investment test (which would be similar to the RIT-T) on the upgrade of the interconnector in question.

An auction process allowed multiple parties to reveal their demand for inter-regional access at the same time. It also allowed for a limited amount of access to be allocated to those parties who would value it most highly. Bidders would be encouraged to reveal the value that they placed on access - assuming there was sufficient bidding competition. This would maximise the likelihood that an interconnector would be expanded. Such expansions would occur where the inter-regional access that would be created would be valued by participants.

The second stage was considered necessary since the auction was only designed to reveal demand for inter-regional access. The investment test would consider the benefits associated with a particular project that would be undertaken to provide the inter-regional access. This test would consider the potential investment options available to the TNSPs, which would result in the requested capacity being released.

54 Underlying hybrid flowgates are hybrid transmission constraints that include both generator and interconnector terms. Transmission constraints are formulated by AEMO to reflect the limits of the network, and therefore place limits on the combination of generation and interconnector flows that can be dispatched.

55 See: AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013, p. 79.

Also, we considered that the amount of benefits that would accrue to parties other than generators (eg, benefits for the TNSP being more easily able to meet its reliability standards) would likely be higher for inter-regional investments than for intra-regional investments. Therefore, it may be that benefits would exceed the bids from these investments - potentially justifying higher cost projects. Accordingly, we proposed a "filtering" process to identify those projects warranting further assessment.

Key features of both the inter-regional access product and issuance mechanism

The key features of the inter-regional access product, and issuance mechanism, as set out in Table 10.1 of the Transmission Frameworks Review's final report, are extracted below.

Table 6.1 Table 10.1: Inter-regional

Core elements	Recommended elements	Optional elements
• Inter-regional access provides access from a neighbouring regional reference node (cf intra-regional access is from a generator node) to the regional reference node • Access settlement for inter-regional access is the same as for intra-regional access • Firm access standard for inter-regional access is the same as for intra-regional access • Any market participant can purchase inter-regional access and the access level is not limited in access settlement (cf intra-regional access limited by generator capacity) • Inter-regional access is sold in an AEMO-run auction (cf intra-regional access, which is sold bilaterally by TNSP)	• Inter-regional access is sold in quarterly blocks • Auction sales are subject to TNSP verification that any associated capacity expansion is economic • Auction prices would be based on the LRIC pricing methodology	• Short-term and long-term inter-regional access is sold at the same auction, and short-term intra-regional access at a separate auction (alternative is that short-term intra- and inter-regional access being sold at the same auction and long-term inter-regional access at a separate auction)

6.2.2 Developments since the Transmission Frameworks Review

The inter-regional access product specification is the same as it was set out above, and as it was in the Transmission Frameworks Review.

We have refined the design of the issuance mechanism for the inter-regional product since the Transmission Frameworks Review. The refinements aim to address:

1. That it was recognised in the Transmission Frameworks Review that many of the details of the issuance process still needed to be worked through; and

2. Given the changes to the proposed firm access standard (detailed in chapter 4), and the short-term firm access processes (detailed in chapter 7), there is a need to revisit the issuance of inter-regional access.

Further, chapter 7 proposes that the issuance of inter-regional short-term firm access could be combined with intra-regional short-term firm access. Therefore, this chapter focusses on the issuance of long-term inter-regional firm access (not the product itself).

The developments that we have made to address these concerns are described in the remainder of this chapter. All of the developments are consistent with the core elements in the table above.

6.3 Objectives of the inter-regional firm access issuance mechanism

As explained in the Transmission Frameworks Review there are a number of objectives that we consider should apply to the inter-regional firm access issuance mechanism:

- The issuance mechanism should accommodate multiple parties, with competing demands for new inter-regional firm access.

- The revenue from the sale of firm interconnector rights should cover the estimated price (through the long run incremental cost) associated with creating new firm interconnector rights.

- There should be consistency of pricing and issuance between inter- and intra-regional firm access in order to ensure that one is not unduly favoured over the other.

- The issuance mechanism should be consistent with the latest proposals for the firm access standard and short-term firm access issuance.

It is worth noting that these objectives are quite similar to those that apply in relation to intra-regional firm access issuance. The main difference is around the first objective, given that it is assumed that generators would typically purchase long-term intra-regional firm access at the time of entry, and that generally there would not be multiple generators entering at the same time and location.

These objectives frame the discussion throughout the remainder of this chapter.

6.4 Proposed approach

In order to meet the above objectives, we propose that the inter-regional access issuance would have the following characteristics:

- Inter-regional firm access is sold through an auction process, run by the system operator.
- The auction would have a reserve price set at long run incremental cost.
- Restrictions would be placed on how long the inter-regional firm access sold at the auction would be available for, and the shape of the inter-regional firm access available.

Unlike the Transmission Frameworks Review there is no need for the second step of the issuance process (the joint investment test). The reasons for this, and the elements as currently proposed, are discussed in more detail below.

6.4.1 Inter-regional firm access auction

Just as was set out in the Transmission Frameworks Review, firm interconnector rights would be sold through an auction. The system operator would run an auction for inter-regional access on interconnectors, offering access.[56] The auction would be designed to reveal demand for firm interconnector rights. Market participants (generators, retailers or speculators) would bid for these future inter-regional rights, revealing the benefits that would accrue to them through their bids.

As described above, the firm interconnector rights that were purchased in the auction would provide firm access from one regional reference node to another regional reference node.

Similar to that proposed in the Transmission Frameworks Review, the reserve price in the auction would be based on the long run incremental cost price – this is discussed further below in section 6.4.2.

We consider that auctions for inter-regional firm access would be relatively straightforward compared to auctions for short-term access given that the number of products that participants are bidding for are relatively limited. While participants may bid for firm interconnector rights between different regions, and in different directions, there are a finite number of options.[57] Compare this with the short-term

56 We consider that this is appropriate since the system operator has the expertise in running and setting auctions, eg, the current Settlement Residue Auctions. Further, it can play the role of an independent third party in a process that necessarily involves multiple TNSPs.

57 Where interconnectors are relatively isolated – for example, QNI – it is possible that the associated inter-regional firm access could be sold at a standalone auction, separately from the other interconnectors.

firm access auction where bidders could be located at myriad nodes, and so the auction would have to simultaneously solve multiple constraints.

6.4.2 LRIC reserve price

We consider that the reserve price for the auction should be the long run incremental cost. This would be derived from the same pricing model that would be used for intra-regional LRIC.

The auction would operate as follows:

- If the auction price was at, or above, the long run incremental cost, the auction would clear, and so the inter-regional firm access would be sold at the auction price.[58]
- If the auction price was below long run incremental cost, the auction would not clear, and so the access would not be issued.

This aligns the inter-regional regime with the intra-regional regime - the long run incremental cost becomes the price for new inter-regional firm access on a take-it-or-leave-it basis.

The long run incremental cost method is designed to provide smooth, transparent and robust prices that guide efficient generator behaviour, while at the same time covering the cost to TNSPs of providing firm access services. These benefits can also be realised for inter-regional access as well.

The price paid for inter-regional access would reflect the incremental transmission costs (comprising capital and operating and maintenance costs) that are created by the decision to seek inter-regional access. These signals would promote efficient use of the existing network. We consider that the pricing model could be easily adapted to be used for this purpose. This is since the pricing model needs to recognise inter-regional entitlements on flowgates where the underlying constraint has an interconnector term.

The long run incremental cost should factor in any additional benefits associated with providing future intra-regional firm access. This is since the pricing model includes both intra- and inter-regional elements on the network, and so if providing inter-regional access helps the TNSP to meet its intra-regional firm access obligations, this would be picked up through the pricing method.[59]

However, there are some challenges with using long run incremental cost as a reserve price in such an auction. These challenges are discussed below in section 6.5.1.

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58 This is discussed further in section 9.5.4.

59 Further, any reliability benefits should already be captured through the reliability access auction process, which is discussed in appendix A. The auction clearing logic is designed to ensure that auction payments cover the long run incremental cost reserve price. This is one reason why we do not need a second assessment stage.

6.4.3 Shape restrictions

The auction relies on a long run incremental cost reserve price to ensure that the auction revenue covers the transmission costs associated with backing the newly issued firm interconnector rights. The long run incremental cost model is designed to price correctly a long-term "strip" (constant annual MW over several consecutive years) of firm access. It may not perform well on short-term strips, or on unusual shapes (varying annual MW). These limitations will be understood better once the long run incremental cost prototype has been developed and calibrated.

If, say, the auction was restricted to issuing long-term strips, this would not necessarily mean that individual participants must bid in this way, only that aggregate cleared MW was a long-term strip. However, there may be other bidding restrictions, depending upon the technical details of the auction design.

Shape restrictions, if these are necessary, are likely to apply equally to intra-regional firm access issuance, so this is not a problem specific to inter-regional. However, given that inter-regional firm access issuance would be the aggregate of multiple independent bids, difficult shapes are more probable. The planned development and calibration of a prototype long run incremental cost pricing model will provide an indication of what shape restrictions are necessary to ensure pricing integrity and accuracy.

6.5 Further considerations

There are a number of further considerations that we are currently working through in relation to inter-regional firm access. These are outlined below.

6.5.1 Long run incremental cost issues

Stability constraints

First, calculating long run incremental cost on an interconnector may raise some issues that do not arise – or are not so material – intra-regionally. Most significantly, interconnector limits often relate to power system stability[60] rather than (or as well as) thermal limitations.[61]

Much expansion of interconnector capacity would be associated with relieving stability constraints rather than thermal constraints. There are many different types of stability constraints, and accordingly many different ways of relieving them. Typically, the different solutions would deliver quite different "lumps" of capacity increase, at a variety of $/MW costs.

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60 The capacity of the network is limited by the potential that a certain contingency could take place.

61 A thermal limit is the maximum capacity at which a transmission element can securely or safely operate without physical damage or risks caused by overheating.

The long run incremental cost model proposed in the Transmission Frameworks Review only considered thermal limitations. The model functionality needs to be expanded to cover stability limitations.

The challenge in setting long run incremental cost for stability "elements" is to choose the appropriate expansion projects to model. For example, if a relatively small increase in inter-regional firm access is demanded, and baseline growth is expected to be slow, a project with a small lump would be most economic. Therefore, the estimated demand from the demand assessment process described above should be used to select the appropriate expansion projects for the "stability elements" in the long run incremental cost model.

In the Transmission Frameworks Review we considered that the assessment stage would be required to factor in stability elements. But, we are now aiming to incorporate these into the long run incremental cost calculation. This is one reason why we no longer need a second stage in the issuance process.

This will be considered further in the supplementary report on pricing, to be published in late-August.

Non-convexity of long run incremental cost

Second, the long run incremental cost curve may in practice be a variety of shapes. For example the long run incremental cost does not necessarily produce monotonically increasing prices (ie, the curve is non-convex). This has implications for how the auction would "solve" - there may be multiple local maxima that it needs to identify.

Non-convexity also means that a clearing price based on the long run incremental cost (ie, the incremental costs) may not necessarily cover average costs. New firm access that prompts an immediate expansion would have a high cost but - given the lumpy nature of an expansion - the marginal cost of additional firm access is lower once that expansion is "committed". This would have implications for how the auction is designed, and how the prices are set (eg, whether they are pay as bid or not).

We are considering both of these issues further.

6.5.2 Auction timing process

The firm access planning standard definition means that firm access is essentially an annual product. Therefore, the auctions would not be held more often than on an annual basis. Shorter-term products could be available through the short-term firm access auction, discussed in chapter 7.

Significant, long-term firm access issuance may require a substantial expansion of interconnector capacity. Accordingly, there would need to be substantial demand for additional inter-regional firm access - from multiple generators - to support an expansion of an interconnector. There would also be a lot of effort involved in setting up a full auction, such as the TNSP preparing long run incremental cost calculations and market participants preparing bids. Therefore, we consider that there may be some form of pre-testing, or expression of interests, before the full auction would be run.

6.5.3 Integration with intra-regional

At the same time as there is demand for inter-regional access, there may be some demand for intra-regional firm access that uses part of an interconnector path. For example, intra-regional access from the Hunter Valley shares part of the network path used by QNI South. Intra-regional and inter-regional demand could potentially compete (for existing spare capacity) or complement (by supporting lumpy expansion). There is therefore a need to integrate these two sources of demand for these two products.

Integration would be achieved to some extent through the setting of the long run incremental cost baseline. For example, if future increases in Hunter Valley intra-regional firm access are forecast, this would raise the price of spare capacity on the associated flowpath and this would cause the long run incremental cost for inter-regional firm access on QNI South to increase. Conversely, if future demand for QNI South inter-regional firm access is anticipated (eg, through the assessment process described above in section 6.5.2), this would be factored into the baseline and may increase the long run incremental cost for Hunter Valley intra-regional firm access.

We are considering further how such integration could occur.

6.5.4 Allocating surplus auction proceeds

Depending how the auction is structured, it may be the case that the auction proceeds exceed long run incremental cost (which, as discussed above, is only a reserve price). If such a situation occurs, there is a question of who should receive any surplus of auction revenue.

We propose to follow a similar process that is used currently for the passing-through of settlement residue auction proceeds. That is, the surplus would be allocated entirely to the importing region, and so the surplus component would be passed through to TUOS users.

6.5.5 Interaction of short-term and long-term firm access issuance

Short-term firm access issuance was discussed in chapter 7. Although the emphasis of that chapter is on intra-regional short-term firm access, the process is likely to be used for the combined issuance of intra- and inter-regional firm access. The process is similar to the one proposed here for long-term inter-regional firm access: using an auction with an long run incremental cost-based reserve price. However, in the short-term - within which no transmission expansion is possible - the long run incremental cost is zero, by definition.

Therefore, any spare inter-regional capacity that is not sold under the process described in this chapter - because bids do not cover the reserve price - may be sold eventually as short-term firm access. Recall that, under long run incremental cost, existing spare capacity is not generally treated as having zero value because - even if there are no current bidders for that capacity - there may be bidders in the future. These anticipated future bidders are effectively incorporated into the "baseline" assumptions for future demand for firm access. So, in the inter-regional context, if demand for inter-regional firm access[62] is anticipated to grow over time, the current long run incremental cost of that inter-regional firm access would be priced to reflect that expectation.

For the short-term firm access auction, all bidders are assumed to be present, and so there is no need to include a baseline demand. The reserve price is therefore set to zero. Demand for the short-term firm access would be reflected in the auction clearing price.

6.6 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- the extent to which stakeholders would be interested in purchasing inter-regional access; and
- whether the proposed process for the issuance of long-term inter-regional access is considered appropriate.

62 Or, demand for intra-regional access, which uses some of the same transmission elements as inter-regional firm access.

7 Short-term firm access

Summary of this chapter

In addition to the long-term firm access product, the optional firm access model also includes a short-term firm access product. We understand that such a product is attractive to some existing generators - both intra-regionally and inter-regionally. It also encourages TNSPs to think about the most efficient use of their network.

The means of issuing and procuring short-term access differs from those for long-term firm access. Apart from that, short-term and long-term access function in the same way - they entitle the holder to be paid through access settlement when the generator is not dispatched because of congestion.

Under our proposed approach to short-term access we consider that:

- short-term firm access and long-term firm access issuance timescales could be differentiated by the assumed transmission expansion lead time: short-term firm access could only be issued for earlier periods than this, and long-term firm access could only be issued for later periods;
- short-term firm access could be issued through regular auctions;
- short-term access could have equal firmness to long-term firm access; and
- to the extent possible, intra-regional and inter-regional short-term firm access could be integrated within a single auction.

The offering of short-term access would not require a TNSP to undertake network augmentation in order to support the access. We envisage that the TNSP could undertake operational activities to release short-term access.

This proposal has aimed to simplify the recommendations relating to short-term firm access that were discussed in the Transmission Frameworks Review.

7.1 Introduction

In addition to the long-term firm access product, the optional firm access model includes a short-term firm access product. The means of issuing and procuring short-term access differs from those for long-term firm access. Apart from that, short-term and long-term firm access function in the same way – they entitle the holder to be paid through access settlement when the generator is not dispatched because of congestion.

In this chapter, we discuss the latest work that we have undertaken on short-term firm access. First, we explain what was recommended in the Transmission Frameworks Review and the issues that have subsequently arisen with this approach following further analysis (section 7.2). We then set out the objectives for the short-term access product (section 7.3) and our proposed approach to short-term access (section 7.4). Finally, we set out areas that we seek stakeholder feedback on (section 7.5).

7.2 Background

7.2.1 Short-term firm access in the Transmission Frameworks Review

The Transmission Frameworks Review recommended a short-term firm access product with the following characteristics:

- The product would be issued on a quarterly basis.[63]
- The product would be issued through an open auction.
- The product would be backed by TNSPs releasing additional capacity on their networks, probably through operational activities.[64]
- Neither the issuance, revenue nor the expenditure associated with the sale of short-term firm access would be regulated.
- A strong incentive, exposing TNSPs to 100 per cent of any settlement shortfalls, would apply where sales of short-term firm access caused a breach of the firm access standard.

Allowing TNSPs to retain the revenue from the sales of short-term firm access was intended to:

1. Encourage TNSPs to undertake operational activities to promote the most efficient use of their networks. TNSPs would have an incentive to release short-term access if the costs of doing so were less than the revenue they received.
2. Provide some upside to TNSPs, in recognition that the proposed operational incentive scheme for long-term firm access held downside risk only. TNSPs were only incentivised to provide access to generators that signalled that they valued such access.

We noted that TNSPs would also be able to back short-term access using spare capacity on the network – capacity which exceeds the capacity required to back existing long-term firm access. Spare capacity might exist due to:

63 We did not preclude the offering of the product on a shorter or a longer timeframe.

64 TNSPs could also undertake capital activities to release short-term access. We thought it unlikely that they would do so as the expenditure would not be rolled into the regulatory asset base. It seemed unlikely that TNSPs could sell sufficient short-term access on an ongoing basis to cover the cost of long-lived assets that would never earn a regulated rate of return.

- legacy transmission capacity, developed prior to the commencement of optional firm access;
- "lumpy" network expansion, where expansion of the network to meet firm access requests creates spare capacity;
- reliability standards requiring that some network access be provided to non-firm generators; or
- TNSPs undertaking discretionary operational decisions to release capacity on the network.

We left open the question of how much of the revenue TNSPs should retain from sales of short-term firm access backed by existing spare capacity, given that this would have been previously paid for by consumers and/or generators.

Short-term firm access entitles the holder to be paid through access settlement. In order to avoid access settlement payments to the holders of long-term firm access being diluted, we recommended that short-term access would have equal firmness to long-term access in access settlement.[65] TNSPs would have a strong incentive regime to give effect to this.

The key features of the short-term firm access product, as set out in Table 10.1 of the Transmission Framework Review's final report, are extracted below.

Table 7.1 Table 10.1: Short-term firm access

Core elements	Recommended elements	Optional elements
• Actual project cost of the investments to meet firm access standard (excluding short-term access) and/or reliability standards would be rolled into the RAB	• TNSPs can offer short-term access through auction process • Generators can sell short-term access through the TNSP auction • Short-term access incentive scheme – TNSPs would be subject to 100% of any settlement shortfalls	• Short-term access has equal firmness to long-term access in access settlement (alternative is that short-term access is treated as mezzanine)

7.2.2 Developments since the Transmission Frameworks Review

We recognised that the short-term access product was not as well-defined as the long-term access product. It required further investigation in order to design a product that would be useful to generators while providing efficient incentives to TNSPs. Most

65 We also considered a possible alternative: treating short-term firm access as having “mezzanine” firmness in access settlements, meaning that entitlements would only be allocated to short-term firm access holders once long-term firm access holders had received their full target entitlement.

of its elements were therefore recommended rather than being treated as core elements of the optional firm access model.

We have therefore further developed the design of the short-term firm access since the Transmission Frameworks Review.

The developments we have made to address these concerns are described in the remainder of this chapter. All the developments are consistent with the core and recommended elements in Table 7.1 above.

7.3 Objectives of short-term firm access

The objectives of the revised short-term firm access issuance and trading processes are as follows:

1. The processes are consistent with the firm access standard, so that long-term firm access firmness is not unduly diluted.

2. The processes promote efficient and transparent allocation and pricing of existing network capacity.

These objectives are discussed in turn below.

7.3.1 Consistency with the firm access standard

When a generator purchases long-term firm access, the TNSP is required – through the firm access planning standard – to plan the network so as to be able to provide that access under specified peak conditions. Subsequent purchases of firm access by other generators are not permitted to dilute a firm generator's access below that standard. Network capacity must therefore be continually sufficient to accommodate all long-term firm access in aggregate.

Short-term firm access is most easily issued where there is spare network capacity: ie, the amount of existing network capacity exceeds the firm access planning standard requirement. This avoids problems of the long-term firm access being diluted - it does not entirely prevent dilution occurring, but it does mean that any dilution does not cause the quality of the service to fall below the level specified by the firm access planning standard.[66]

Spare capacity may arise for a number of reasons:

- a decline in the issued amount of long-term firm access, eg, due to the sculpting back of transitional access;

- lumpy expansions, where more network capacity is added than is required to meet the firm access standard; and

- TNSP discretionary activity, where a TNSP chooses to provide network capacity over and above the firm access planning standard requirement.

We also consider that short-term firm access should be covered by the TNSP incentive scheme in order for the quality of the firm access service to not fall below the firm access operating standard.

7.3.2 Efficient and transparent allocation and pricing

The demand for short-term firm access might exceed what can be provided by spare network capacity. The most efficient and transparent way to ration the demand to the level of spare network capacity is through an auction process.

7.4 Proposed approach

In order to meet the objectives set out above, we propose the following characteristics for the short-term firm access product and associated processes:

1. Short-term firm access and long-term firm access issuance timescales could be differentiated by the assumed transmission expansion lead time: short-term firm access would only be issued for earlier periods than this and long-term firm access would only be issued for later periods.

2. Short-term firm access could be issued through regular auctions.

3. Auction products and timings could be structured according to the preferences of the market, but short-term firm access should have equal firmness to long-term firm access.

4. Secondary trading could be permitted in the short-term firm access auction (although secondary trading could still occur through bilateral negotiations).

5. To the extent possible, intra-regional and inter-regional short-term firm access could be integrated within a single auction.

6. The TNSP incentive scheme (see chapter 5) could include short-term firm access.

7. In the auction, TNSPs could be required to make short-term access available.

The sales revenue from short-term firm access could flow to a number of parties, including offsetting TUOS charges or flowing to the TNSP. We are seeking stakeholder views on which of these is more preferable. We discuss this further in section 7.4.8 below.

These elements are discussed in more detail below.

66 The short-term firm access would "soak up" flowgate capacity that might otherwise provide access settlement entitlements to firm generators in excess of what the firm access standard requires.

7.4.1 Division of short-term and long-term firm access

The division between short-term and long-term for firm access issuance would be fixed, based on a deemed transmission expansion lead time, referred to here as the short-term horizon.[67] Obviously, in practice, the expansion lead time varies from project to project. However, it is not feasible for the short-term horizon to vary. We anticipate that the short-term horizon would be set at some value between three and five years (inclusive).

Thus, a generator would not be able to obtain long-term firm access within the short-term horizon. This is not considered a problem. A generator can purchase short-term firm access in the interim, and the short-term and long-term firm access products should be equivalent with regard to the level of firmness they provide to the generator (see section 7.4.3 below). Both new and existing generators should be able to plan their long-term firm access purchases ahead of time.

The division of short-term and long-term firm access is needed to prevent either issuance process pre-empting the other. We consider that there are strong incentives for TNSPs and generators to view the products very differently. Short-term firm access auction prices might often be below the typical long-run incremental cost of transmission but above zero, so:

- long-term firm access should not be sold within the short-term period at a price (zero) that undercuts the short-term firm access auction price;[68] and
- short-term firm access should not be sold within the long-term period at a price which potentially undercuts the long-term firm access price.

7.4.2 Auction design

The Transmission Frameworks Review Technical Report contains a description of the design for firm access auctions.[69] This remains our working assumption as to how the short-term auction would be defined. The auction clearing process is analogous to generation dispatch:

- The auction bids are analogous to dispatch offers, although inverted: the higher the auction bid, the lower the analogous dispatch offer.
- The auction constraints are expressed in the same way as NEMDE transmission constraints. These would represent the firm access planning standard capacity of

67 This is the time it would take the TNSP to augment its network to meet long-term access requests by generators.

68 The price of long-term firm access is set at the long run incremental cost of transmission. Within the short-term horizon, the long run incremental cost must be zero, since there is no possibility of – or requirement for – network expansion.

69 Section 12.6.3.

the existing network: ie, the capacity under the conditions specified in the standard.[70]

Short-term access to the regional reference price would depend on the generator obtaining access to the regional reference node through multiple flowgates.

Although we are still working through the details of the auction, we consider that the auction would have a reserve price of zero. This represents the zero long run incremental cost of transmission during the short-term horizon.

7.4.3 Attractive short-term firm access products

The structure of the short-term firm access product should be attractive for generators. We therefore consider that the short-term firm access is treated identically to long-term firm access in access settlements. This ensures that the issuance of short-term firm access does not unduly dilute the firmness of any long-term firm access that has been issued.

7.4.4 Secondary trading through the short-term firm access auction

Efficient allocation requires efficient secondary trading mechanisms as well as efficient processes for TNSPs to issue short-term firm access. It may be the case that holders of existing firm access (whether short-term or long-term) value their holdings less highly than others who are seeking additional firm access. Therefore, short-term firm access trading mechanisms could also allow the secondary trading of firm access: the purchase of firm access from an existing holder rather than from the TNSP.

Generators could sell access through bilateral agreements (subject to approval by the TNSP). However, we consider that it may generally be more effective and efficient for generators to offer secondary trades of access through an auction. First, because the one auction process can be used both for existing holders of firm access to secondary trade their firm access and for TNSPs to issue short-term firm access. Second, because an auction is able to clear bids and offers at different nodes whereas this is difficult to do bilaterally.

We note that secondary trades would only clear if a buyer and seller share a binding constraint in the auction dispatch.[71]

7.4.5 Integration of inter-regional short-term firm access

Integrating inter-regional access into the short-term firm access auction allows network capacity to be allocated from intra-regional to inter-regional firm access, or vice versa.

70 These are analogous constraints to those used in the transitional access allocation (see chapter B), which would be updated to be current at the time of the auction.

71 For further discussion on this please refer to sections 12.6.4 to 12.6.6 of the Transmission Frameworks Review Technical Report.

This would help facilitate the most efficient overall use of the network. For example, the QNI North interconnector participates in many Queensland constraints, along with Queensland generators. Some of the Queensland generators who hold firm access may sell some of their firm access into the auction. This potentially could be converted into firm interconnector rights (provided the interconnector is not constrained within New South Wales).

For inter-regional access to be included in the short-term firm access auction, some entity would have to be responsible for making "bids" on behalf of an interconnector in order for them to be represented in the auction.

Any market participant (generators, retailers, or speculators) can purchase inter-regional firm access. There may therefore be bids and offers for inter-regional firm access from multiple participants and these would need to be aggregated into a consolidated interconnector bid or offer. Any inter-regional firm access cleared in the auction would then be allocated between the appropriate buyers or sellers.

7.4.6 Incentive scheme implications

Chapter 5 describes the TNSP incentive scheme that would apply to firm access. The amount and cost of access settlement shortfalls that occur – where actual network capacity is insufficient to deliver agreed access to all firm generators – would depend on the amount of firm access that is issued. Since the short-term firm access auction would likely have a zero, or a low reserve price, all short-term access would likely be "sold".

If the TNSP is obligated to sell all spare capacity as short-term access, then the AER can safely assume when it sets targets for the incentive scheme there is no spare network capacity. This is efficient since it allows the network to be fully, and most efficiently, used. While the AER may not know the exact levels of network capacity and firm access, the AER would know that firm access issuance is maximised with respect to network capacity. Therefore, it should set targets based on this assumption. In a sense, this makes the AER’s task easier, since one potential uncertainty – the level of spare capacity – is removed.

7.4.7 Obligation to sell into the short-term auction

An obligation could be placed on the TNSP to sell short-term firm access into the auction. This is different to the short-term access proposal in the Transmission Frameworks Review, where the TNSPs offered short-term access at their discretion.

We consider that the obligation on TNSPs could be appropriate, since in the absence of such an obligation, the TNSP may choose to withhold some network capacity from the auction since this would reduce its exposure to the incentive scheme. Therefore, the obligation promotes efficient and transparent allocation and pricing of existing network capacity.

However, there is a question as to how the network capacity that is released as short-term access should be determined. If the TNSP makes the calculation, it may be conservative. On the other hand, it is more familiar with its network and so how much short-term access can be offered.

We are currently considering the governance arrangements for the determination of spare capacity. We note that if all the auction revenue flows to the TNSP, then there is unlikely to be a need for strong governance of the release of short-term access.

7.4.8 Sales revenue

We are also currently considering how the auction revenue from the short-term access revenue would be allocated.

There are several possibilities, including:

- auction revenue from existing capacity to be passed through to TUOS users, in an analogous way to that currently used for settlement residue auction revenue, while auction revenue relating to the additional capacity that can be released through the TNSP undertaking discretionary expenditure flowing through to the TNSP as an incentive for the TNSP to offer it;[72]
- the auction revenue to be allocated in full to TUOS users, which would likely result in the minimum offering of short-term access by the TNSP;
- the auction revenue to be allocated in full to the TNSP, which would likely promote the offering of short-term access by the TNSP; or
- the auction revenue to be split between TUOS users, and the TNSP. This should provide an incentive on TNSPs to offer short-term access, while at the same time allowing customers to benefit from the offering of short-term access.

We welcome stakeholder views on how the auction revenue may be allocated, and reasons for this allocation.

7.5 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the assessment framework, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on our proposals for:

- whether the proposed short-term product is attractive, including:

- whether it is appropriate that it only covers timescales less than the transmission expansion lead time (which we consider at this stage to be three years); and
  - whether it is appropriate that short-term access is treated identically to long-term firm access;
- whether an auction with no reserve price is the most efficient means of allocating short-term firm access based on existing spare capacity;
- whether the proposed process provides the right incentives and obligations on TNSPs, including:
  - the allocation of sales revenue from the auction; and
  - whether the TNSP should be obligated, or heavily incentivised, to release short-term access.

72 This would raise questions as to how existing and additional network capacity are to be defined and distinguished.

8 Access settlement parameters

Summary of this chapter

This chapter sets out the proposed arrangements for access settlement within the optional firm access model. Access settlement is the mechanism under which dispatched non-firm generators would compensate firm generators that have not been dispatched due to a binding constraint.

The development of the access settlement regime has presented technical issues that were not examined during the Transmission Frameworks Review. This chapter specifies our proposed solution to these issues.

Generating stations are composed of multiple dispatchable units, which are dispatched independently of each other. Furthermore, a generator consumes load which is not included in determining each generating unit's dispatch. Settlement is currently undertaken with the data from revenue meters which may measure multiple dispatchable units and loads. For access settlement to operate, information from dispatch flowgate entitlements and payments would be necessary.

Access settlement would be undertaken on the basis of a new concept called a revenue meter identifier. A revenue meter identifier will be a combination of the metered dispatch of one or more dispatchable units with the associated loads. All the associated elements (dispatchable units and loads) must be connected to the same location on the transmission network.

We propose that access settlement would operate under a principle that load can only be classed as auxiliary load if it is operationally, commercially and temporally associated with, and electrically close to the dispatch unit identifier(s) associated with a revenue meter identifier(s). We propose grandfathering arrangements for existing loads of incumbent generators that do not meet the operationally, commercially and temporally association conditions.

The capacity of a generator while determining flowgate entitlements would be the maximum generation from each revenue meter identifier over the last two years. If the generator is less than two years old, nameplate capacity could be used.

8.1 Introduction

Optional firm access introduces a process called access settlement, which would be the process through which financial compensation would be provided to firm generators that were constrained off and so not dispatched. Access settlement would occur around congested flowgates: bottlenecks in the transmission network which are represented by binding transmission constraints in the NEM dispatch engine (NEMDE). These are locations where congestion actually occurs.

Currently, dispatch and settlement occur through the same process, while under the optional firm access proposal these two elements would need to be separated. To do this, a number of variables such as generator capacity would need to be specified.

This chapter gives background to the issue of access settlement (section 8.2), and then describes how a number of technical issues that relate to access settlement in the optional firm access model can be resolved. These include:

- how to reconcile the metered generation used for settlement and dispatch (section 8.3);
- the treatment of auxiliary load (section 8.4);
- the grandfathering of metering arrangements for existing generation (section 8.5);
- the treatment of different generation types (section 8.6);
- how generator capacity is to be defined (section 8.7); and
- additional issues that will need to be considered for access settlement (section 8.8).

We are seeking stakeholder feedback on the first five of these technical issues. However, the additional issues that will need to be considered for access settlement are provided for stakeholder information.

We understand that AEMO is also considering the operation of access settlement under optional firm access. The First Interim Report covering this work is available from the AEMO website.

8.2 Background

8.2.1 Access settlement in the Transmission Frameworks Review

Access settlement was set out in the Transmission Frameworks Review final report.[73]

As noted above, access settlement is the process through which financial compensation would be provided to firm generators. We considered that access settlement would be undertaken as part of the wholesale market settlement process with data supplied from NEMDE.

Two factors are needed in order to determine settlement payments: a generator’s *usage* of a flowgate and its *entitlement* to that flowgate. The generator's usage was to depend

73 Australian Energy Market Commission, *Transmission Frameworks Review*, Final Report, AEMC, April 2013, Sydney, p. 30.

on its output and how much it contributed to the constraint. Its entitlement was to be based on the lesser of its agreed access level and its rated generating capacity, and would also depend upon the prevailing network conditions.[74]

A generator may require entitlements on several flowgates in order to achieve its agreed level of access to the regional reference price. Access settlement would automatically translate the generator's agreed access amount at its node[75] into an entitlement on each relevant flowgate, which would depend on how energy flows on the network.

The features of the access settlement model as described in the Transmission Frameworks Review are presented in Table 8.1.

Table 8.1 Table 10.1: Access settlement

Core Elements	Recommended Elements	Optional Elements
• Flowgates created on every transmission constraint • Flowgate parameters (participation factor and capacity) taken from NEMDE • Target entitlements based on access amount multiplied by participation factor • Non-firm entitlements not provided unless firm target entitlements are met	• Transmission constraint defined as "any NEMDE constraint arising from a limitation on a TNSP network for which a constrained generator is not currently compensated" • Firm access amount limited by capacity • Non-firm access amount is the shortfall between availability and firm access • Super-firm entitlements provided, subject to firm entitlement scaling factor and as needed to top-up firm entitlements • Flowgate support generators provided with negative entitlements (to ensure paid regional reference price) which adds to effective flowgate capacity • The settlement period for access settlement is a trading interval (30 minutes)	

74 These would not be fixed entitlements to each flowgate, but would vary dynamically with the capacity of the network. The sum of entitlements on each congested flowgate would always be set equal to that flowgate's capacity.

75 Australian Energy Market Commission, *Transmission Frameworks Review*, Final Report, AEMC, April 2013, Sydney, p. 30.

8.2.2 Developments since the Transmission Frameworks Review

The optional firm access model set out in the Transmission Frameworks Review assumed each generator was connected to a single point on the transmission network.

However, in reality, a generator plant may be composed of several units, potentially with different connection points.

The Commission has therefore proposed a number of clarifications on how access settlement would operate to accommodate the physical realities of the network. The clarifications proposed in this chapter are consistent with the policy position of the AEMC as laid out in Table 10.1 of the Transmission Frameworks Review.

8.3 Metering of generation

8.3.1 Current arrangements

The current AEMO dispatch process determines targets for dispatch units, which AEMO refers to by their DUID (we term this a "dispatchable unit identifier" for the remainder of this chapter). Typically, these are individual physical generating units. However, in some cases they are logical “aggregated units” which represent the aggregate output of a number of specified physical units. An example of this would be the situation in many wind farms.

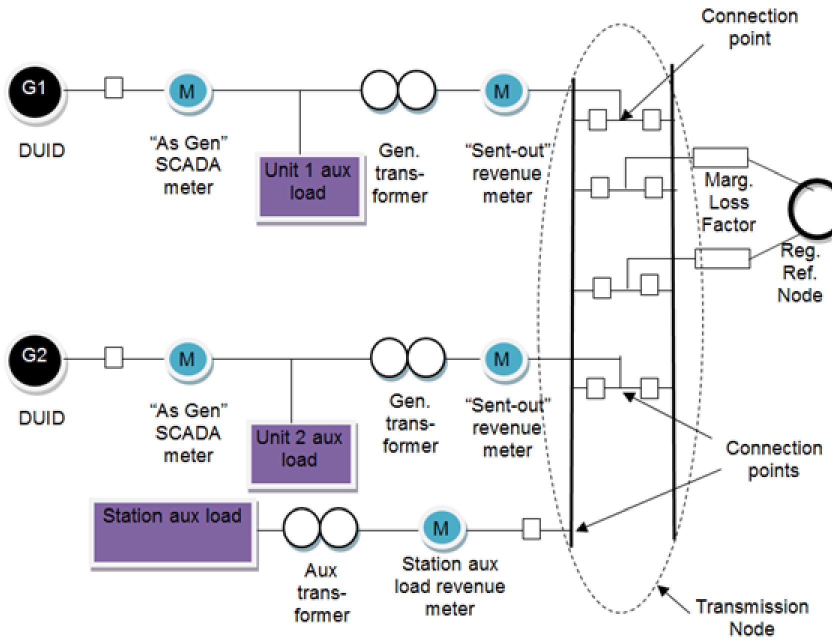
Since dispatchable unit identifiers are dispatched, it is these entities which appear on the left hand side of the constraint equations, with participation factors applied. Consequently it is these terms that would be used in access settlement to determine a generator's compensation from its participation in a flowgate.

Dispatch is predicated on SCADA meters[76] which are attached to the terminals of a physical generating unit. These meters are sufficiently accurate for use in dispatch, but not for settlement. Instead, settlement for generators is based on revenue meters, which are more accurate meters placed somewhere between generating unit terminals and the connection to the shared network. The information from these settlement meters is not real time and thus cannot be used in dispatch.

Figure 8.1 shows the possible metering arrangement of a power station with two generating units. In this example it can be seen that each of the two separate generating units have their own SCADA and revenue meters.

76 Supervisory Control and Data Acquisition (SCADA) meters provide real time information which can be remotely accessed.

Figure 8.1 Metering of a standard power station



Generating units consume electricity while operating, known as auxiliary load. These auxiliary loads are currently connected in a number of different ways. This includes the load being:

- connected between the generating unit and the revenue meter and thus only implicitly metered; and
- separately metered and thus deducted out explicitly during settlement. The connection of these auxiliary loads to the transmission network may be electrically remote from their associated generating unit (eg some mines are considered auxiliary load while being remote from their associated generators).[77]

In Figure 8.1 the generator has an explicitly metered load for supplying the station. In addition, there is a separate load that is implicitly metered from the output of the dispatchable units.

In the dispatch process, auxiliary load is an implied part of the total load calculations that AEMO uses to determine the right hand side of constraint equations.

Load pays the regional reference price regardless of whether the load results in either an offset in generation or a purchase from the wholesale market. This means that there is a modest incentive, from a settlement perspective, to class load as auxiliary to generation compared to being a separately metered load. There are benefits in having loads netted off before market settlements because of reduced exposure to participant fees and ancillary services charges as well as not being responsible for losses.

77 If an auxiliary load and generating unit are located on different parts of the network an increase of the auxiliary load may not have the same impact on flowgate capacity as a decrease of generation by the same amount.

8.3.2 Proposed arrangements

Under optional firm access, settlement can be resolved through the concept of a revenue meter identifier (or RMID). The revenue meter identifier would be created by allocating each generating station's auxiliary load across associated dispatchable units. All access settlement would therefore be undertaken on the difference between generation and consumption at each revenue meter identifier.

In the same way that a generating station can be composed of multiple dispatch unit identifiers, it would be capable of being composed of multiple revenue meter identifiers. A revenue meter identifier may measure the output of one or many dispatchable units, net of one or more auxiliary loads.

By virtue of dispatch unit identifiers and auxiliary loads being connected via a single metering point, they all must have the same participation factors in constraints. Thus, the participation factor for a physical RMID can be defined as being the (single) participation factor of its associated dispatch unit identifiers and auxiliary loads. This makes it suitable for use in access settlement, which requires participation factors to be well defined.

Refer back to the example seen in Figure 8.1. In this situation, each of the revenue meters would become a revenue meter identifier with a single associated dispatchable unit. The generating unit loads would be implicitly netted out in dispatch while the station load would be logically mapped between the two revenue meter identifiers.

8.4 Treatment of auxiliary load

Depending on the prevailing nature of constraints at a location, there may be stronger incentives under optional firm access for load to be classified as auxiliary load for the purposes of access settlement. This would mean that the load pays the local price rather than the regional reference price. To minimise this occurrence, we propose the creation of guidelines of what can be new auxiliary load. So that auxiliary load is matched to an appropriate revenue meter identifier we propose the following principle.

Box 8.1: Principle for the treatment of auxiliary load

Load can only be classed as auxiliary load if it is operationally, commercially and temporally associated with, and electrically close to, the dispatch unit identifier(s) associated with a revenue meter identifier(s).

We consider that this principle can be applied to new auxiliary load: whether associated with new or existing generation. The principle is defined below:

- A load is *operationally associated* with a dispatch unit if the load is required for the generating unit to operate. It is also operationally associated if the load and generation are part of the same industrial process so that the generation cannot operate without the load being present. This is the case with many co-generation systems.

- A load is *commercially associated* with a dispatch unit if the same party is financially responsible for both the generating unit and the load. If two or more companies have generators at the same physical site, all load and generating units of the different companies would be required to be separately metered.

- A load is *temporally associated* with a dispatch unit if, under normal circumstances, the load consumes electricity at the same time as the generating unit is operating.

- A load is *electrically close* to a dispatch unit if the load is connected to the same location of the transmission network. This results in the load and generation having the same participation on flowgates.

Some party would be responsible for undertaking the case-by-case assessment of what load could be classed as auxiliary load – this would likely be the system operator. Some party (potentially the same party) would also be responsible for mapping the auxiliary loads to the appropriate revenue meter identifiers across generating stations.

In trading intervals where the net output of a revenue meter identifier is negative, the generator would pay the regional reference price as if it were a load.

8.5 Grandfathering

The Commission notes that some existing generators have metering and auxiliary load arrangements that would not comply with the principle laid out in section 8.4. However, changes to the existing metering and network arrangements may be costly. Therefore the Commission propose that grandfathering arrangements are developed for existing generators.

In situations where an existing auxiliary load is electrically close to an associated dispatch unit identifier even if it is not operationally, commercially or temporally associated with that dispatch unit identifier, it would be authorised as an auxiliary load. In this situation AEMO would be required to develop a mapping of auxiliary loads to revenue meter identifiers that may operate as an exemption to the above principle. These arrangements would continue for the remaining life of the generator.

However, it would be inappropriate to similarly grandfather existing auxiliary load that is not electrically close to the associated dispatch unit identifiers. This is since the auxiliary load and the generating unit may have different participant factors in the flowgates. In this situation the load may be required to change its connection point if it wishes to be authorised as an auxiliary load.

These principles and process only apply in relation to access settlement. From our analysis we consider that around five generating stations in the NEM would not be able to continue their current metering arrangements under this proposal.

8.6 Scheduling of generation

Currently scheduled and semi-scheduled generators feature on the left hand side of AEMO's constraint equations[78] while non-scheduled generators are on the right hand side of the equations. The result of this is that when a constraint binds, scheduled and semi-scheduled generators may have their dispatch reduced while this risk is not faced by non-scheduled generators. Attempting to integrate non-scheduled generation into the optional firm access model would raise significant practical implementation problems as non-scheduled generators do not appear in constraint equations.

So, with the implementation of optional firm access a non-firm scheduled or semi-scheduled generator would receive the local price, which may be different from the regional reference price. A non-scheduled generator would continue to receive the regional reference price for all of its generation, regardless of the constraints in the network. We are considering whether the introduction of optional firm access would change the incentives on generators in determining whether to be scheduled or non-scheduled.

Box 8.2: Embedded Generation

The optional firm access model is focussed on generators' interaction with the transmission network. Access settlement would be undertaken in relation to each generator's participation in a flowgate. Similarly, the firm access planning standard and firm access operating standard would provide obligations on TNSPs to provide efficient levels of access for firm generators.

Embedded generators are those generators that are connected to a distribution network. The optional firm access model would not create obligations on distributors in relation to the provision of network capacity for the export of embedded generation.

Any scheduled generator becomes part of the optional firm access model. Therefore, embedded generators that are scheduled would be part of the optional firm access regime. However, embedded generators would not be able to procure firm access on the distribution network.

Embedded generators would be able to purchase firm access from where the distributor connects onto the transmission network to the regional reference node. If they were non-firm (and were scheduled), they would still be subject to compensation payments where they constrained off other generators through the firm access regime.

8.7 Capacity of generators

The Transmission Frameworks Review stated that firm access entitlements of a generator would be capped at its rated capacity. The intent of this decision was so that

78 As long as the generator's participation factor in the particular constraint is larger than 0.07.

firm access acts as a hedge against constraint risk, and not a purely financial transmission right. However, rated capacity is not currently defined in the Rules.

It is proposed that this be defined in the following way:

- For new generators, or generators that have been operating for less than two years, it would be based on nameplate specifications for the associated generating plant, allowing for acceptable auxiliary load.
- For generators that have been operating for more than two years, rated capacity would be based on maximum historical output as measured by the revenue meter identifier over a two year period.
- Beyond the first two years, capacity would be recalculated annually. If a generator's circumstances were to change within a year (eg, it returns from being mothballed) and it were to consider that its registered capacity should be increased, it would be able to request an ad hoc recalculation of its rated capacity using the above method.

Through discussions with our Working Group we understand that the above approach is considered appropriate.

We consider that the use of nameplate information is appropriate for new generating plant as it represents the best estimate of the generating plant's capacity. For plant that has been operating for an extended time, the maximum dispatch over a period would demonstrate with better accuracy what the actual capacity is. We consider a two year window to be a long enough period of time for most intermittent or peaking generators to be able demonstrate their full capacity.

We note that it would be possible for a generator to have its capacity determined to be less than its previously purchased level of firm access. In this situation the generator could choose to:

- request a reassessment of its capacity;
- sell some of its long-term firm access in the short term auction as described in chapter 7; or
- retain the access and thus hold a super-firm level of access.

8.8 Additional issues

As noted in chapter 1, the COAG Energy Council has also requested that AEMO undertake an associated work program, which is largely focussed on access settlement. The AEMC is also considering a number of other policy questions relating to access settlement, which would need to be resolved in order for AEMO to develop the settlement algebra.

Some of the additional issues that we are in the process of examining include:

- The determination and use of flowgate prices in certain situations outside the standard pricing regime (eg during an administrative price period, where the administrative price cap applies). Application of access settlement pricing in these conditions will require adjustment to avoid an unintended outcome.

- Whether it is more appropriate to use half-hourly, or five minute data to determine access settlement values.[79] During the Transmission Frameworks Review we recommended that half-hourly data be used. AEMO notes that this creates anomalies, but also notes that shifting to five minute data would create different anomalies.

- Whether the access quantities of each generator during settlement would be adjusted for their marginal loss factors (ie, as the dispatch figures are currently adjusted to take into account marginal loss factors). As each of the generators and interconnectors within a constraint will have different loss factors, AEMO considers it necessary to scale access quantities by the relevant loss factors to the relevant Regional Reference Node. Doing so may require respecification of the settlement algebra.

- Whether inter-regional settlement residues are created through the application of marginal loss factors to settlement amounts, and if they are created who would the funds associated with this be allocated to.

- Where an interconnector provides flowgate support (ie, if flow across the interconnector relieves a constraint) whether there is the potential for negative settlement residues, and if these do arise, who should pay for these.

We are currently developing our position on all of the above issues. We have mentioned these here to provide information to stakeholders on issues that we are currently considering.

AEMO are undertaking tests of their access settlement systems. For these tests, AEMO have made some working assumptions on the above issues. This allowed the settlement algebra to be progressed, and for AEMO to undertake tests of the prototype access settlement system. We note that the working assumptions made by AEMO may change, following further consideration of these issues by the AEMC.

8.9 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on our proposals for:

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79 We note that we are considering this issue for *access settlement* only. That is, we are not considering whether the whole market (including for dispatch) should shift to five minute determination.

- how to reconcile the metered generation used for settlement and dispatch;
- the treatment of auxiliary load;
- the grandfathering of metering arrangements for existing generation, including whether this treatment is cost effective (ie, would it better to require all generators to comply with the proposals, rather than introducing grandfathering arrangements);
- the treatment of different generation types; and
- how generator capacity is to be defined.

We are not seeking stakeholder comments on the aspects of the Transmission Frameworks Review that we have provided as background in this chapter, since these proposals do not change the core elements of the optional firm access model.

9 Transitional access

Summary of this chapter

Providing for a transition to optional firm access is intended to allow participants to adjust to a significant regulatory change in the market. At the same time, it should not unnecessarily delay or dilute the benefits that the optional firm access model is intended to promote.

An initial grant of transitional access to existing generators would aim to reflect the expectation that generators' current levels of access will continue for some time. This grant of access should therefore approximate the implicit access a generator currently receives.

Sculpting back the transitional access would encourage generators to purchase the level of firm access that they value, and signal to transmission businesses the level of network capacity that is efficient. In order to develop a sculpting profile, this benefit must be traded off against the need to manage the commercial and financial impacts on existing investors of introducing optional firm access.

9.1 Introduction

A transition period would apply in the early years following implementation of the optional firm access model.[80] It is intended to provide a learning period and other assistance for participants to adjust to a significant regulatory change in the market while at the same time not unnecessarily delaying or diluting the benefits that the optional firm access model is intended to promote.

The main transition mechanism is the allocation of transitional access to existing generators. Transitional access would act identically to the firm access service except that access (to the extent allocated) would not need to be procured from a TNSP. Such generators would therefore receive a potentially substantial benefit for no direct payment.

The other main transition mechanism is how the initial allocation of transitional access should be "sculpted" over time.

This chapter sets out our rationale for transitional access as well as our preferred approach to the sculpting of transitional access.

80 It is important to distinguish transition from the implementation process. In this report, "implementation" refers to the order and timing by which the various elements of the optional firm access model can be introduced, including whether it is implemented in all regions or just some. The transitional process is a component of the overall implementation design.

9.2 Background

9.2.1 Transition in the Transmission Frameworks Review

In the Transmission Frameworks Review, we set out four objectives for the transition to optional firm access:

1. to mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the optional firm access regime;

2. to encourage and permit generators – existing and new – to acquire and hold the levels of firm access that they would choose to pay for;

3. to give time for generators, TNSPs and other market participants to develop their internal capabilities to operate new or changed processes in the optional firm access regime without incurring undue operational or financial risks during the learning period; and

4. to prevent abrupt changes in aggregate levels of agreed access that could create dysfunctional behaviour or outcomes in access procurement or pricing.

We recommended transitional access allocation and sculpting that aim to act as a proxy for the access that generators could expect under the status quo:

- At the beginning, transitional access should approximate the implicit access that generators currently enjoy, based on how they use the network.

- Recognising the risk that generators' implicit access is always at risk of being degraded over time (for example by the location of new generators nearby), transitional access should be sculpted back over time.

- Recognising that existing generators should expect some level of implicit access over the life of their assets, transitional access should be sculpted back to a residual level.

We recommended a four-stage transition process, as summarised below.

Stage 1: Access requirements

Generators' access requirements – the level of firm access they would need to have unfettered access to the regional reference node – were to be calculated, based on historical generation patterns.[81]

81 MNSPs would be treated as generators for the purpose of allocating transitional firm access.

Stage 2: Access scaling

These access requirements were to be scaled back to the extent necessary to ensure that all transitional access could be accommodated by the shared network. Scaling would aim to maximise the allocation of access while being robust to constraint formulations. In particular, small changes in access for one generator should not cause large changes in access for others.

Stage 3: Access sculpting

Each power station's scaled access level was to be sculpted back over time, so that transitional access reduced over a number of years and then expired. Sculpting would follow the profile illustrated in Figure 9.1. The following sculpting parameters would determine the shape of the profile:

- X, the "learning period" over which initially allocated transitional access would not be sculpted back;
- Y, the period of time over which initially allocated transitional access would be sculpted back to provide a gradual transition;
- K, the proportion of a generator's capacity to which transitional access would be sculpted back over the Y period and then retained until Z years elapse; and
- Z, which is a proxy for the residual power station life.

All power stations were to be provided with a minimum X+Y years of access. Younger power stations could be provided with longer terms, Z years, where Z was a proxy for residual power station life.[82]

The values of X, Y, Z and K were to be determined during optional firm access implementation.

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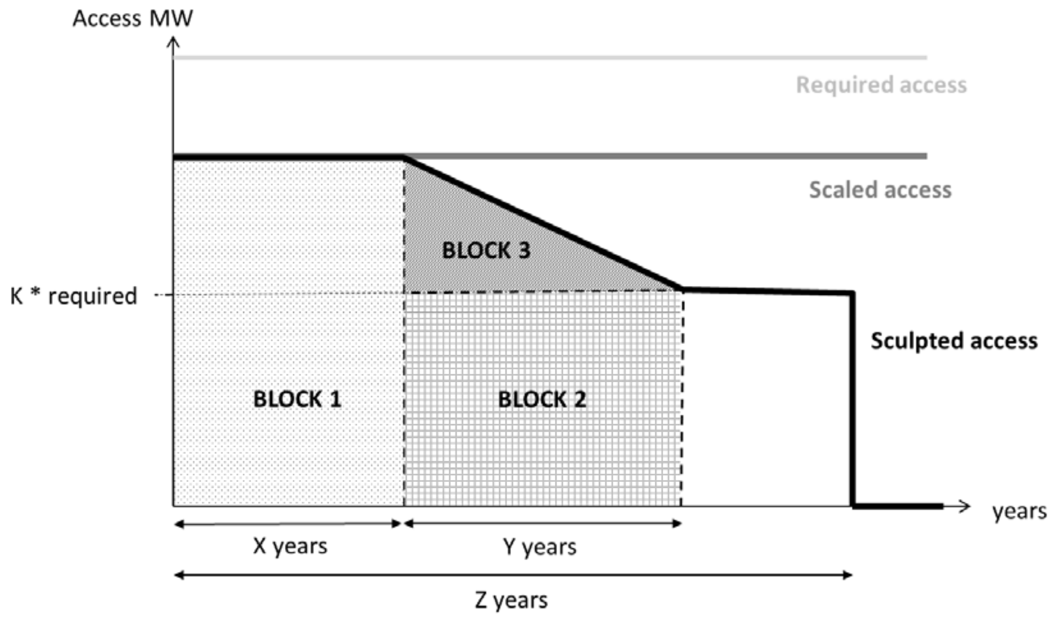
82 Although for generators for whom the likelihood of optional firm access is a *foreseeable* regulatory change, ie those that have invested since the Transmission Frameworks Review, we noted that a shorter transitional period might be justified.

Figure 9.1 Sculpting of transitional access for a power station



Stage 4: Access auction

A one-off auction was to be established to allow generators to sell some of their transitional access or buy additional transitional access from other generators.[83] It would allow for more efficient reallocation of access than could be achieved through a series of bilateral trades. The auction was to be similar to the short-term access auction, although auction clearing and settlement was to be conducted by the system operator, not TNSPs.

The auctioned products were to be based on the three blocks illustrated in Figure 9.1. Constraints were to be placed on the clearing of bids and offers such that the post-auction holdings of access complied with the firm access standard; that is, the TNSP would not have to undertake any network expansion in order to accommodate the new holdings.

Summary

The transition processes were intended to help existing generators, from the commencement of the optional firm access regime, to hold access amounts that would provide them with firmness of access to the regional reference node similar to the de facto access they enjoy currently. Aggregate access holdings would initially be commensurate with transmission capacity, but as these were sculpted back over time, transmission capacity would be freed up to support new access issuance to existing or new entrant generators, charged for in accordance with access pricing.

83 Generators would also be allowed to bilaterally trade access outside the one-off auction.

The key features of the transitional processes, as set out in Table 10.1 of the Transmission Framework Review's final report, are extracted below.

Table 9.1 Table 10.1: Transitional access

Core elements	Recommended elements	Optional elements
• Existing generators are allocated some transitional access, at no charge • Transitional access allocation is firm access compliant on existing network • Transitional access is sculpted back over time	• Transitional access auction established for one-off reallocation of transitional access • Transitional access allocation based on generator capacity and pre-optional firm access operating regime • Inter-regional transitional access would only be allocated to the extent that it would not cause any additional scaling back of generators' transitional access	• Sculpting profile based on 3 parameters X, Y, Z and K to be determined in implementation (other profiles are possible)

9.2.2 Developments since the Transmission Frameworks Review

We have developed and tested an initial transitional access allocation method, consistent with stages 1 and 2 above. A summary of the method is provided in 9.4.1 below. Detail on the initial transitional access allocation method and indicative results are provided in appendix B. The allocation methodology is consistent with the recommendations of the Transmission Frameworks Review.

We have developed the transitional access sculpting methodology that would form stage 3 of the four-stage process described above. We have considered three different options, taking into account the objectives of the transitional arrangements, the relevant economic principles and the factors relevant to the decisions on the individual sculpting parameters. All options are consistent with the recommendations of the Transmission Frameworks Review.

We have not done any further work explicitly on the transitional access auction (stage 4 above). However, the mechanics of this auction would be similar to those of the short-term firm access auction that is described in chapter 7.

9.3 Rationale for transitional access

Set out below are our further considerations on the rationale for allocating and then sculpting transitional access.

9.3.1 Why have a transition?

Alternative approaches to transition

As described above, in the Transmission Frameworks Review we set out a possible approach to a transition to optional firm access, in the event it was introduced. However, in order to best understand the advantages and disadvantages of transitional access, it is useful to consider other ways in which optional firm access could be introduced. In particular, one alternative to granting existing generators transitional access would be to require all generators to purchase the amount of firm access that they wish to hold, rather than them being allocated an amount of firm access free of charge. That is, there would be no transitional access.

Several reasons could be raised for not granting transitional access. Most significantly, no generator is formally guaranteed access to the market at present, and both the entry of new generators and changes in load can degrade the access a generator currently enjoys. Conversely, allocating transitional access would fix a level of access for existing generators for a period of time.

In addition, given the significant period of time that is likely to elapse between the proposals to introduce optional firm access in the Transmission Frameworks Review and any actual introduction of optional firm access, existing participants would have had a significant period to prepare for optional firm access. This should mitigate the effect of the regulatory changes.

We note that other access schemes have been introduced without the provision of transitional access to existing participants. For example, new gas trading arrangements in the United Kingdom commenced in 1999 with an auction for gas entry capacity.[84]

Arguments in favour of transitional access

While there are arguments in favour of an approach in which existing generators are not granted transitional access, we continue to favour granting some access to such generators.

In particular, granting transitional access would better reflect the current arrangements in the wholesale market. Although as described above generators currently have no formal guarantee of access to the network, based on their experience of the network they will have some expectation of future access. Indeed, the investment that was made by an existing generator is likely to have been based on expectations of transfer capability from a particular location, for which the generator would not pay a charge. This is not to say it is impossible that a generator’s access could be degraded over time, but that for many generators they could expect that their current levels of access will continue for some time. As set out in section 9.4.1 below, the initial allocation of access we propose aims to reflect the implicit access a generator currently experiences.

84 See: http://www.iea.org.uk/publications/research/new-gas-trading-arrangements.

We also consider it is in the long-term interests of consumers that there is an appropriate transition for investors in the electricity sector where there are significant regulatory changes. That transition should include adequate notice of regulatory change, time and - where necessary - assistance to adjust. Exposing generation investors to large and unforeseeable regulatory risk can deter - or increase the costs of - future investment. This would run counter to the National Electricity Objective. Optional firm access represents a significant change to the market framework on the basis of which previous generation investment has occurred.

Sufficient transitional access should therefore be allocated to existing generators for a long enough period that they do not suffer significant commercial or financial impacts. Doing so also gives time for generators to develop their internal capabilities to operate new or changed processes in the optional firm access regime without incurring undue operational or financial risks, consistent with the fourth objective in section 9.2.1. It may also be difficult for generators, with no operational experience of optional firm access, to appropriately value firm access at the time of the model's commencement.

On balance, transitional access will contribute to the overall sustainability of any optional firm access reform. This sustainability can only be achieved if there is a perception that existing generators and investors have been appropriately provided for through transitional arrangements.

9.3.2 Why have sculpting back of transitional access?

We have set out above why existing generators should be granted some form of transitional access, and why this would contribute to the National Electricity Objective. At the same time, however we consider that all generators should be encouraged to acquire and hold the levels of firm access they value.

Granting transitional access to existing generators in perpetuity would not achieve the function of signalling the value that generators place on access to the network. If existing generators are granted access for free they may hold access that they do not value.

Instead, by requiring all generators to *purchase* access they wish to hold, they would be encouraged to consider how much they value firm access. This would send a signal to the TNSP as to where capacity is most valuable. This can drive both replacements to and augmentations of networks.

To take replacements as an example, under current market arrangements TNSPs will replace assets over time, such as when they age. In many cases a TNSP will replace an asset with another asset of a similar size. There may be circumstances however, particularly in the event of falling demand, where a TNSP might, in order to reduce expenditure, choose a replacement that is of a smaller size. This can be an efficient choice to make.

On the other hand, where there has been an allocation of transitional access the TNSP would be required to maintain its network to meet the levels of firm access allocated.

Even though a generator would not have signalled it values capacity at a certain location (and plant could even have been withdrawn from service), the TNSP would be required to undertake replacements to maintain the existing level of capacity at that location. It would be more efficient for generators to elect to maintain the network capacity if they valued it highly enough to pay for firm access.

Separately, if generators hold firm access they do not value it may appear to the TNSP that there is less spare capacity on the network than is in fact the case – that it is "full". In these circumstances if additional firm access is sought, such as by a new generator, an augmentation could be triggered that may, in the absence of transitional access, be unnecessary and result in an increase of the total cost of the system.

Therefore, in deciding on the transitional access sculpting profile that best serves the long-term interests of consumers, an inherent trade-off needs to be made between:

- managing the commercial and financial impacts of optional firm access on existing investors, along with providing a learning period; and
- encouraging generators to purchase the level of firm access that they value.

The transitional arrangements should not unduly dilute or delay the benefits that the optional firm access model is intended to promote. Consumers will benefit if optional firm access promotes the most efficient combination of transmission and generation costs. While in the short to medium term it is desirable to protect existing investments from balance sheet effects, in the medium to long term it is desirable that all generators - existing and new - pay for firm access if they wish to hold it.

There are a number of other reasons why we consider transitional access should be sculpted back. It may be justifiable for transitional access to expire prior to some reasonable expectation of a power station's life because:

- some regulatory change is an accepted feature of the NEM; and
- discounting effects over the medium to long term reduce the present value of the impacts of regulatory change within that time scale.

Finally, we have referred above to the importance of any optional firm access reform being sustainable. A perception that the transitional arrangements are reasonable is likely to enhance the sustainability of the optional firm access reform. It is important that the level of transitional access granted to existing generators be reasonable. Where access must be purchased consumers would benefit since revenue from the sales would offset the charges passed through to consumers. Where access is granted for free consumers miss out on these benefits. We should not set out to unnecessarily create windfall gains for generators that are paid for by consumers.[85]

85 It is argued by Riesz et al that windfall gains for incumbents could raise regulatory risk and financing costs for new entrants by creating the perception that market arrangements favour incumbent emissions-intensive plans. See Dr J Riesz, Dr J Gilmore, Assoc. Prof I MacGill, *Working*

9.3.3 Additional considerations

Some stakeholders, including as part of our Technical Working Group, have raised issues relating to transitional access and, more specifically, the need for sculpting. We have responded to some of these comments below.

Barriers to entry

Some stakeholders have raised concerns that transitional processes - by giving existing generators a significant proportion of their required firm access free of charge - may create a barrier to entry or significant competitive disadvantage for new entrants.[86]

We do not consider the allocation of transitional access to existing generators to create a barrier to entry. The new entrant generator would have two possible means of acquiring firm access (even before the sculpting period has started):

- from another generator through secondary trading; or
- from its local TNSP at the regulated access price.[87]

The new entrant may have a different cost basis than an existing generator as a result of having to purchase firm access. However, new entry should occur where investors have a reasonable expectation over time of making a risk adjusted rate of return sufficient to support an investment case. The allocation of transitional access to existing generators is not likely to affect this.

Secondary trading

Stakeholders have also commented that transitional access sculpting - which releases firm access based on existing network capacity for either existing or new entrant generators to buy – is unnecessary because secondary trading will provide new entrants with the opportunity to acquire firm access.

The efficient allocation of existing capacity - in the absence of sculpting of transitional access - would depend on the effectiveness of secondary trading. In theory, secondary trading of firm access should occur if:

- the new entrant values firm access based on existing capacity more than another generator that is located in a similar part of the network; and

Paper on the proposed Optional Firm Access model for the Australian National Electricity Market, UNSW Centre for Energy and Environmental Markets Working Paper, May 2014, p. 5.

86 For example, see Dr J Riesz, Dr J Gilmore, Assoc. Prof I MacGill, *Working Paper on the proposed Optional Firm Access model for the Australian National Electricity Market*, UNSW Centre for Energy and Environmental Markets Working Paper, May 2014, p. 3.

87 Whether a new entrant is able to purchase firm access from the TNSP during the transitional period will depend on the approach we propose for implementing optional firm access, including by stages. This is discussed further in chapter 10.

- secondary trading mechanisms are effective.

However, the effectiveness of secondary trading mechanisms will depend on the feasibility and the willingness of parties to trade. It may be difficult to establish a secondary trading platform that could achieve:

- the conversion of transitional access to the long-term firm access sought by a new entrant generator;
- transfer of access between locations; and
- sufficient liquidity, in the absence of transitional access sculpting.

If there is significant strategic value in holding transitional access then existing generators may be unwilling to trade their transitional access to a new entrant.

If there are significant doubts about the effectiveness of secondary trading mechanisms then transitional access sculpting will be more likely to promote long-term consumer interests.

9.4 Proposed approach to Transitional Access

The previous section set out the rationale for providing transitional access and then sculpting it back. This section describes how we propose that initial allocations of transitional access should occur and our preferred approach to sculpting.

We have not set out below what the values for the sculpting parameters should be. Once we have come to a final view on the approach to sculpting we will form a view on the sculpting parameters.

9.4.1 Initial allocation

The initial allocation of transitional access would allocate existing network capacity among existing generators. It would aim to provide the existing generators with firm access that replicates the implicit access level that they currently receive. It would also be set so the network would be compliant with the firm access standard at the time optional firm access is introduced.

In the technical report of the Transmission Frameworks Review we laid out a method for allocating initial transitional access to existing generators. This method was based on a model that attempts to simultaneously dispatch all generators at their historical capacity.

We have worked with AEMO to undertake a series of tests based on the method outlined in Transmission Frameworks Review. AEMO used the NEMDE Queue for the tests. These tests were to examine how the method operates, and to examine the variations of results from different inputs. A report by AEMO on the work it undertook is available on our website.

It is important to note that the tests that have been run were not for the purpose of determining the actual initial transitional access allocations for generators. If optional firm access is introduced, it will be necessary to undertake the initial allocations at this point by running the method at that time.

A more detailed analysis of the method and results can be found in appendix B.

Some stakeholders have questioned our use of the above method. Appendix B also discusses alternative methods to perform this initial allocation of access.

9.4.2 Sculpting

Below we describe three options for sculpting transitional access. They set out different frameworks and the relevant considerations for determining the sculpting parameters X, Y, K and Z that we proposed in the Transmission Frameworks Review (as described in section 9.2.1 above). The options are:

- Option 1 – high degree of sculpting, such that firm access must be procured from the TNSP after a short period.
- Option 2 – no sculpting, such that initially allocated transitional access is "grandfathered" over the long term, with a reliance on secondary trading to achieve an efficient allocation.
- Option 3 – an intermediate option, with sculpting to a residual level that would potentially differ by generator.

Advice we received from Houston Kemp Economists identifies the relevant economic principles in determining a sculpting methodology to be:[88]

- The methodology should achieve an efficient allocation of existing network capacity, ie, firm access based on this capacity should be allocated to the parties that value it most highly. For this to occur, all generators, existing and new, should face a price signal that reflects the costs caused by their use of the transmission network to allow for consistent valuation.
- Transaction costs should be minimised to the extent possible while still meeting the first principle.

The Houston Kemp advice considers that either procurement of all access from the TNSP (option 1) or grandfathering all access with secondary trading (option 2) could achieve an efficient allocation of firm access based on existing network capacity. In choosing between the two options, the relevant considerations would be their relative transaction costs and the expected efficiency of secondary trading mechanisms. All else being equal, the approach with the overall lower cost to implement and administer should be preferred.

88 Houston Kemp Economists, *Optional Firm Access to Electricity Transmission Infrastructure: Sculpting Transitional Access*, 4 June 2014.

The advice recognises that if option 1 is preferred, then K would need to be set greater than zero if the Commission believes that the revenue outcomes of existing generators are likely to be substantially affected by the introduction of optional firm access. Concerns about revenue implications and so risks for existing generators are likely to depend on the extent of long-term contractual arrangements.

The third option is our preferred option. We consider that there are additional considerations beyond the efficient allocation of existing network capacity. In particular, option 3 recognises our concern about the balance sheet implications for existing generators in the context of the objectives discussed in section 9.3.1. At the same time it encourages generators to purchase the level of firm access that they value.

We have considered an alternative option where new entrant generators would receive transitional access on the same basis as existing generators, requiring the transitional access allocation to be recalculated and existing holdings to be diluted to accommodate a new entry.[89] We do not consider that this option would promote efficient outcomes because:

- It would dilute the locational signals for new entrant generators that the optional firm access model is intended to provide.
- It could lead to significant uncertainty for generators about their transitional access holding over time, affecting their contracting behaviour and therefore diluting the financial certainty that the optional firm access is intended to promote.

We therefore do not propose this option for further consideration.

9.4.3 Option 1

Option 1 is consistent with a preference that both new and existing generators procure firm access from the TNSP rather than through secondary trading.

Initially, transitional access would be allocated to existing generators in accordance with the methodology described in section 9.4.1. This would provide a learning period for existing generators, helping them to prepare for the introduction of optional firm access and to assess the value of holding firm access. After a relatively short period X, the initially allocated transitional access would be sculpted back to zero (K = 0).

X would need to be long enough for existing generators to procure new long-term firm access to replace their transitional access once it is sculpted back, ie, at least as long as the short-term horizon that is discussed in chapter 7. It would also need to be long enough for regulatory arrangements relating to TNSP revenue and incentives to be adjusted, assuming that these would not pertain until X has expired.

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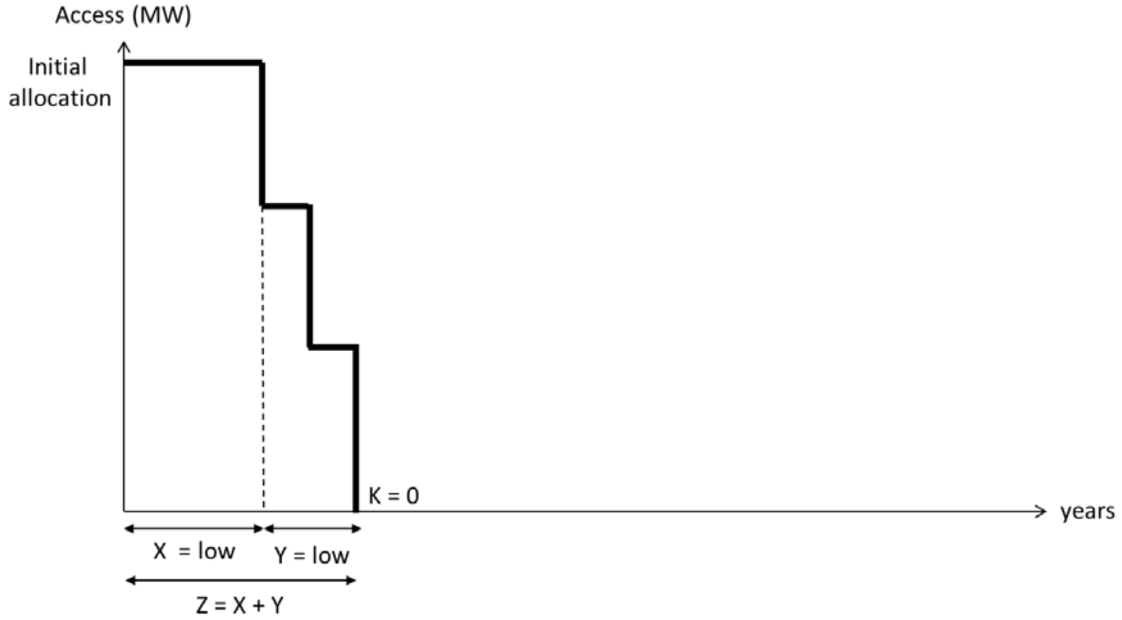
89 This is similar to the second alternative transition mechanism described by Reisz at al. See Dr J Riesz, Dr J Gilmore, Assoc. Prof I MacGill, *Working Paper on the proposed Optional Firm Access model for the Australian National Electricity Market*, UNSW Centre for Energy and Environmental Markets Working Paper, May 2014, pp. 11-13.

Y would be a short period: only so long as is necessary to provide for stable access pricing, procurement and planning processes as the network moves from appearing full to appearing empty.

A possible sculpting profile consistent with this methodology is illustrated in Figure 9.2.

Figure 9.2 Option 1: sculpting of transitional access for a generating unit



Under option 1, generators would need to procure long-term firm access through the TNSP. As that procurement process would have reference to the long run incremental cost of transmission, both existing and new generators would face an efficient price signal which helps to achieve an efficient allocation of access between generators.[90]

The Houston Kemp advice recommends that this option be preferred where there are concerns about the efficiency of secondary trading mechanisms. For secondary trading to be efficient there is a need for market participants to be aware of the value of existing capacity amongst holders of the firm access based on that capacity. In the absence of frequent trading of firm access and transparency about the associated traded price, firm access would not be transferred to those users that value it most highly.

The advice also notes that this approach is likely to have higher initial costs, related to existing generators having to procure firm access through the regulated procurement processes. These costs should fall as market participants become familiar with the processes.

90 See chapter 2 for a summary of access pricing and procurement.

9.4.4 Option 2

Option 2 relies fully on secondary trading to achieve an efficient allocation of firm access based on existing capacity to the generators that value it most highly.

Initially, transitional access would be allocated to existing generators in accordance with the methodology in the previous chapter.

After X years, a one-off sculpting back of transitional access would occur. K should be high but less than one. The sculpting back of transitional access after X years to a more conservative allocation would allow for unanticipated changes in loads or the network that may affect the TNSP's ability to meet the FAPS.

Existing generators would then retain their sculpted level of transitional access for Z years, unless they chose to sell it through secondary trading mechanisms.

As in the first option, X would be relatively short but would need to be at least as long as the short-term horizon that is discussed in chapter 7 and for TNSP regulatory arrangements to be adjusted.

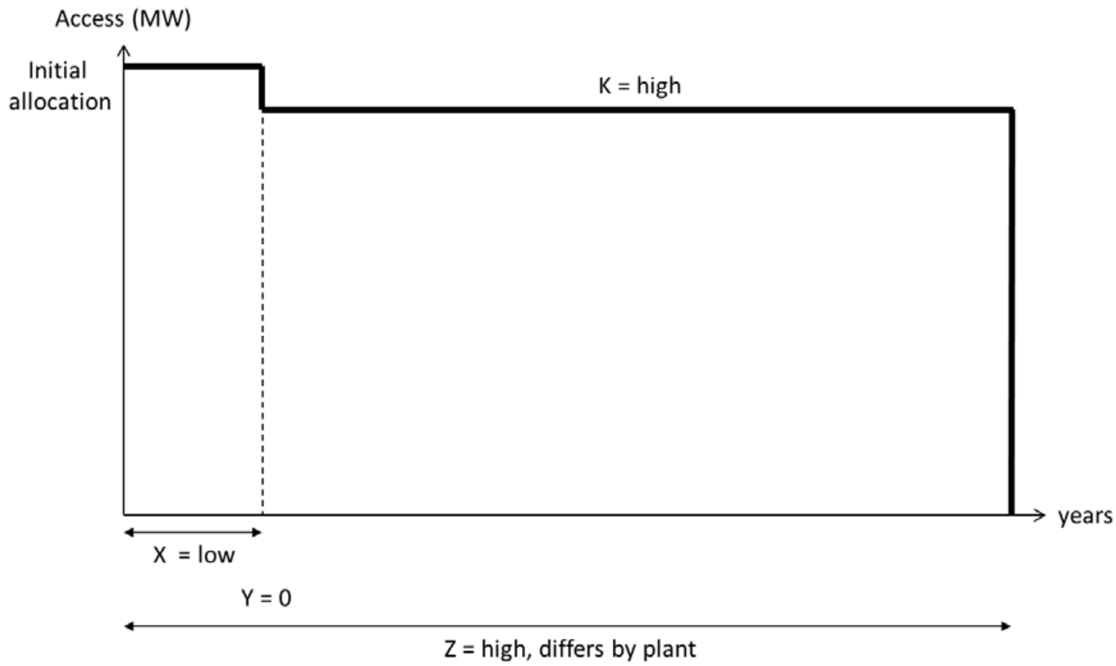
Y would be zero; the small step in allocated transitional access that occurs after X years should not cause issues for the access procurement, pricing and planning processes.

Z would be high and would differ by plant. The advice cautions that independently assessing the remaining asset life for each power station, in order to determine Z, would be extremely difficult. The remaining asset life would depend on both physical and economic factors. The economic factors would in turn be influenced by the decisions of other generators to enter or exit the market.

The Houston Kemp advice recommends that the best approach to choosing Z would be for each power station to nominate a proposed remaining asset life, to be objectively assessed by an independent agency (eg, the Australian Energy Market Operator). The assessment should be principally focussed on ensuring that the remaining asset life for each power station is consistent with other power stations within the NEM.

A possible sculpting profile consistent with this methodology is illustrated in Figure 9.3.

Figure 9.3 Option 2: sculpting of transitional access for a generating unit



The Houston Kemp advice recommends that this option should be preferred only where there is confidence that the secondary trading mechanisms would achieve an efficient allocation of access.[91] For this to occur, there needs to be sufficient certainty about the value of firm access based on existing capacity. As described above, this is only likely to occur where there is frequent trading with transparency of prices.

The advice notes that this option is likely to have lower initial implementation costs, but that ongoing costs are likely to be higher because it would involve additional costs associated with secondary trading.

9.4.5 Option 3

As discussed in section 9.3 above we seek to manage the commercial and financial impacts on existing investors while not unduly diluting or delaying the benefits that the optional firm access model is intended to promote.

Our preferred option recognises that existing generators may be affected by the introduction of optional firm access, in particular if:

- competitive dynamics require them to hold firm access in order to achieve similar outcomes to what they expect to achieve currently; and
- they are in long-term contractual positions that did not factor in the cost of purchasing firm access; or

91 It is worth noting that secondary trading of access between generators would only be possible with generators that share the same flowgates.

- the cost to a particular generator of purchasing firm access is significantly higher than the average cost of doing so.

We propose that initially transitional access would be allocated to existing generators in accordance with the methodology described in section 9.4.1. It would be retained for a medium X period, sculpted back over a low-medium Y period to a K level that would differ by plant. Z would also differ by plant.

X should be long enough to allow for the adjustment of current contract positions and for the balance sheet impacts - if any - of sculpting back to K to appear small, given discounting effects. It is assumed that this would be longer than the short-term horizon referred to above and the period of time necessary for regulatory arrangements to adjust, although these are also relevant considerations in this option.

Ideally X should not be so long that the holdings of transitional access affect TNSPs' network augmentation or replacement decisions. This is discussed further below.

Y would be a period only as long as is necessary to provide for stable access pricing, procurement and planning processes as the network moves from appearing full to appearing empty. This would be used to transition from the X period to the period where generators have K level of access.

K could differ for each generator. It would require an assessment of whether an existing generator is likely to suffer ongoing balance sheet effects as a result of optional firm access. Relevant considerations might include:

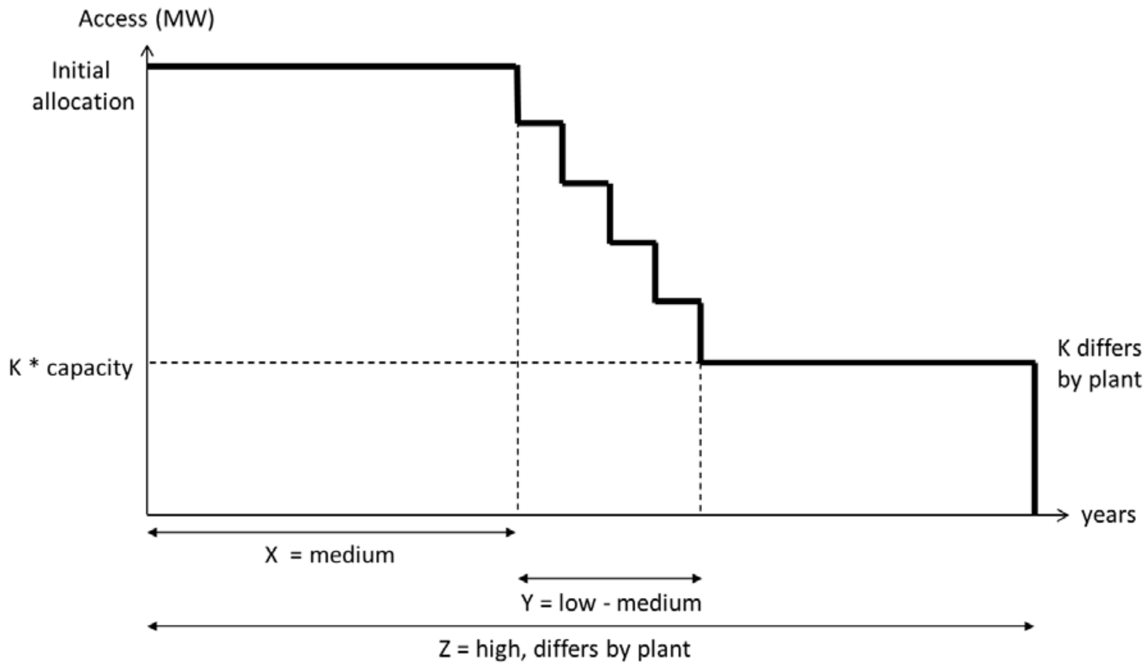
- the existing contractual positions of the generator; and
- the extent to which the generator's access price differs from other generators.

As proposed in the Transmission Frameworks Review, Z would be a proxy for remaining plant life and assessed on an individual basis. The end-of-life of a generator might possibly be benchmarked against closure decisions of similar generators.[92]

A possible sculpting profile consistent with this methodology is illustrated in Figure 9.4.

92 Riesz et al note the potential for the treatment of existing generator exit to create rent-seeking behaviour. See Dr J Riesz, Dr J Gilmore, Assoc. Prof I MacGill, *Working Paper on the proposed Optional Firm Access model for the Australian National Electricity Market*, UNSW Centre for Energy and Environmental Markets Working Paper, May 2014, p. 4.

Figure 9.4 Option 3: sculpting of transitional access for a generating unit



There is another advantage of the proposed methodology. It releases capacity that can be used to back the purchase of Firm Interconnector Rights.[93] The initial transitional access allocations, that are discussed in appendix B, allocated little access to the interconnectors to be available for firm interconnector rights. Sculpting back of transitional access allows more firm interconnector rights to be become available, and be released. Even with efficient secondary trading, parties wishing to purchase firm interconnector rights would not be able to buy transitional access and convert this into firm interconnector rights.

Finally, we have referred above in section 9.3.2 to the fact that transitional access may drive the extent to which TNSPs need to maintain/replace their networks. For example, where demand is falling, a TNSP may in the absence of transitional access choose to replace aging assets with smaller assets. On the other hand, where transitional access has been granted the TNSP would have to replace an old asset with a similarly sized asset to meet the firm access standard. We will attempt to investigate when the different TNSPs are likely to have to undertake replacements of parts of their networks. If we can identify a point when significant replacements are going to have to occur, more sculpting before this point could be beneficial. This would then require generators to signal, through purchasing firm access, how much they value access at the relevant point and what sized asset the TNSP should undertake the replacement with.

93 See chapter 6 for the description of inter-regional firm access.

9.5 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the assessment framework, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- our proposed approach for the initial allocation of transitional access;
- whether stakeholders agree that transitional processes should seek to protect existing investments from significant commercial/financial effects due to regulatory change, but that they should not unduly dilute or delay the benefits that the optional firm access model is intended to promote;
- whether stakeholders agree that option three is the preferred method for sculpting;
- whether X should be related to the time period after which TNSP augmentation of the network is likely, and if so what this time period is likely to be; and
- whether it is feasible to calculate individual K and Z values for each power station, and if so, what factors should be taken into account when calculating these. If it is not feasible to calculate individual K and Z values for each power station, what approach should be taken to calculate these values.

We are not seeking stakeholder comments on the aspects of the Transmission Frameworks Review that we have provided as background in this chapter, except where our proposals would change core elements of the optional firm access model.

10 Staged implementation

Summary of this chapter

Under the terms of reference we are required to develop a set of options for how optional firm access could be implemented. There are many elements of optional firm access, which can be introduced at different times, and in different regions to others.

An implementation approach would only be needed where there is a positive assessment of the impacts of optional firm access.

We consider there are three high-level implementation options, which are discussed further in this chapter:

- *simultaneous implementation* of all core elements of optional firm access;
- *temporal staging* of all core elements of optional firm access; and
- *geographic staging* of all core elements of optional firm access.

The way optional firm access is implemented impacts on how successful it will be, and how soon the benefits would be realised. The sooner such benefits are realised, the quicker customers will benefit. We consider that the full benefits of optional firm access can only be realised when all core elements have been implemented in all jurisdictions.

10.1 Introduction

There are many elements to the optional firm access model, which may be able to be introduced at different times, and in different regions to others. Implementation in this context refers to the order and timing by which the various elements of the optional firm access model can be introduced, including whether it is implemented in all regions or just some.[94] If optional firm access is recommended, the manner in which it is implemented can determine how successful it is for the NEM. We note that the need for an implementation approach depends on a positive assessment of the impacts of optional firm access.

The best approach to implementation of optional firm access was only considered at a high-level in the Transmission Frameworks Review.[95] This focussed mainly on setting

94 It is important to distinguish implementation from the transitional process. In this report, "transition" refers to the mechanism of allocating an initial level of firm access and then reducing this over time, so that the introduction of optional firm access does not create sudden changes in the market and to provide for a learning period. The transitional process is a component of the overall implementation design.

95 See: AEMC, *Transmission Frameworks Review*, Final Report, 11 April 2013, p. 140.

out an implementation plan to carry out the detailed design, testing and assessment of optional firm access (that is, this project).

The terms of reference for the current project, however, specifically require the AEMC to consider the most efficient approach to implement optional firm access. We are required to do three things:

- develop a feasible set of implementation options;
- assess these to identify the most efficient option; and
- recommend an implementation plan.

This chapter deals with the first of these by setting out possible options for implementing optional firm access. These include staging temporally and also geographically, both of which are identified for consideration in the terms of reference. These options are not intended to be exhaustive at this stage, and additional options may be developed and consulted on at later stages in the project. We also welcome stakeholder feedback on any other potential options for implementation.

These options only consider the implementation of "core" elements. We note that there are some elements that are not "core" to the model, and that may be introduced at a later stage (for example, reliability access). However, this chapter focuses on the elements that are necessary to commence the optional firm access model.

The chapter first considers the different restrictions on implementing parts of the optional firm access model (section 10.2). On the basis of these restrictions, a number of options for implementation are then proposed - sections 10.3 through 10.5. Finally, we set out areas that we wish to seek stakeholder feedback on (section 10.6).

10.2 Restrictions on the implementation of optional firm access elements

The optional firm access model is comprised of a number of different elements. While all of these elements would need to be introduced to achieve the full benefits of optional firm access, it is useful to start the analysis of implementation options by analysing each element in turn to identify what timing restrictions exist on its implementation. This then allows consideration of what restrictions there are on implementation of the full model.

We note that these restrictions relate to putting the element of optional firm access into place after the rule changes have occurred (ie, they do not include the rule change process and associated consultation).[96]

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96 We understand that it has previously been AEMO's practice to begin building IT and market systems following a draft rule determination by the Commission. If this approach were taken, then this could also accelerate the implementation of several elements in terms of a few months.

10.2.1 Access settlement

Access settlement is the mechanism, operated by AEMO, through which compensation is made in real time to firm generators that were constrained off and so not dispatched. This is adapted from the current AEMO settlement mechanism.

While proposals for adapting AEMO's systems would be identified as part of the current project, they would need to be built, reviewed, and trailed. We understand from our discussions with AEMO, that this would require at least twelve months.

We also consider it necessary that generators would need to have time to adapt their trading mechanisms, and so contract positions, to the new model. We understand that such learning times may be in the range of two to three years.

What happens with existing allocations from settlement residue auctions would also need to be considered. The existing allocations under settlement residue auctions are sold out to three years ahead, but include a termination mechanism where material changes to settlement occur. Such clauses should limit timing restrictions associated with this element.

10.2.2 Planning

Planning refers to the introduction of the firm access planning standard, and associated changes to the Annual Planning Reports and RIT-Ts that TNSPs must undertake.

First, the AER would need to make changes to the RIT-T, including relevant guidelines. We consider that up to twelve months should be allowed for this. This is consistent with the length of the time that the AER took to develop the existing RIT-T, and associated guidelines.

Second, TNSPs would need to make associated system and process changes in response to such changes. We consider that twelve months should be sufficient for this - this is also consistent with the lead time that was allowed for in the transition from the Regulatory Test to the current RIT-T.

10.2.3 Pricing

Pricing and procurement processes for the firm access product would need to be put in place. This would include development of the pricing model, and associated processes.

If the National Transmission Network Development Plan[97] (NTNDP) is to provide the inputs for the pricing model (as was recommended in the Transmission Frameworks Review), then there may need to be changes to the data and assumptions that are contained within this document. These inputs would likely need to be consulted on, as

97 See: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.

are the current assumptions used in the NTNDP. We consider that such consultation, and the production of outputs, may take twelve months. This is consistent with current timeframes for the production of the NTNDP.

10.2.4 TNSP incentives

An operating incentive scheme would apply to TNSPs in order to encourage them to operate, and maintain, their network to provide the firm access product.

We consider that there may be two restrictions associated with the introduction of an incentive scheme:

- ideally, there would be sufficient historical information on the parameters that the incentive scheme is measuring. Such historical information can help to make the initial incentive scheme stronger; and
- it may be considered that the incentive scheme should be put in place prior to a TNSP submitting a revenue proposal for a particular reset, so that the TNSP could consider the scheme in its proposal.

We note that there may be ways around these restrictions - a very low-powered incentive scheme could apply to address the first issue; and if the incentive scheme provided only upside there should be limited concerns about introducing this after a TNSP has submitted a revenue proposal.[98]

10.2.5 Transitional access

The transitional process should allow generators enough time to adapt their processes and strategies to optional firm access, without imposing undue risks.[99] This implies that the initial transitional allocation should occur with sufficient time to enable generators to adjust their contracting positions.

However, we also recognise that the actual allocation of initial access should occur as late as possible (even if the method was set earlier). This would allow the initial allocation to most closely resemble the current state of the network.

Therefore, this creates some tensions. The time periods for transitional access are discussed further in chapter 9.

10.2.6 Revenue regulation

Under optional firm access, revenue regulation would aim to ensure that the combined revenue for a TNSP from load and firm access services was just sufficient to cover the efficient cost, including a risk adjusted rate of return, of delivering these services.

98 Indeed, TNSPs have historically applied for early adaption of incentive schemes.

99 Other objectives were discussed in chapter 9.

Therefore, optional firm access affects the revenue determination of a TNSP. For example, augmentations that occur in response to firm access requests would form part of the regulatory asset base. Ideally, changes associated with the introduction of the firm access service would be introduced at a revenue reset. As described above, changes should aim to be introduced in enough time for a TNSP revenue proposal to take them into account. This could include the AER including the provision of the firm access service into their Framework & Approach documents.

TNSP regulatory control periods are currently staggered. Therefore, if we wait until each TNSP's current regulatory control period ends, optional firm access cannot be applied NEM-wide until all TNSPs have gone through a reset following the relevant optional firm access rule changes. This would take a number of years

However, we note that if, as recommended in the Transmission Frameworks Review final report, adjustments are made to the timing of the TNSP regulatory control periods in order to align these, then it may be possible for optional firm access to be introduced slightly earlier than this.

It would be possible for changes to the Rules to impose the elements of the optional firm access model on TNSPs during a regulatory control period that had already started at the time the rules were changed. This would require the revenue of the TNSP to be redetermined by the AER on the basis of the new rules. While this may detract from the regulatory certainty, such effects may not be significant if no new access had been purchased at this time.

There may be other ways to get around the challenges posed by the timing of TNSP resets. We are investigating this further, and welcome any comments from stakeholders on this.

10.2.7 Inter-regional access

The optional firm access model also offers an inter-regional access product.

The restrictions in respect of this element are similar to the restrictions described above for intra-regional access, specifically in terms of:

- pricing and procurement processes;
- inputs to the pricing model;
- revenue regulation; and
- transition from the existing settlements residue auction regime.

10.2.8 Summary

Given all of the restrictions described above, the most limitation restriction is the revenue reset timetable. This would be the driver of when full optional firm access could be introduced NEM-wide. All of the other restrictions could be addressed in this time.

There are some elements of optional firm access which could be introduced in respect of a TNSP prior to its next revenue reset. These are discussed further in the temporal staging section below.

10.3 Option 1 - Simultaneous implementation of all core elements

10.3.1 Description

Under this model, optional firm access would apply NEM-wide on a set date and all elements of optional firm access would commence in all jurisdictions on that date. This is illustrated in Figure 10.1, below.

Figure 10.1 Simultaneous implementation Approach

10.3.2 Timing

The timing is dictated by the issues described in section 10.2 above. If the rule changes to introduce optional firm access were made in mid-2016 then, assuming there were no changes to the timing of TNSP regulatory control periods, optional firm access could only be introduced once all TNSPs had been through a revenue reset (under this timeframe, this would imply a commencement date of 1 July 2022).

One option to implement such an approach would be to introduce via the NER a mandatory reopener, or adjustment provision for each revenue determination that occurs prior to the optional firm access commencement date. This could be triggered once certain conditions are in place, which may be as simple as the revenue determination for the final TNSP occurring.

For example, if Powerlink were the last revenue determination before the optional firm access commencement date, the NER could require either:

- At the time of the Powerlink determination, the AER to reopen the determinations of the other TNSPs to adjust the revenue in line with the optional firm access model to take effect from the optional firm access commencement date – this would allow flexibility in the timing of the optional firm access commencement date and new revenue; or

- In the last revenue determinations for the other TNSPs immediately prior to optional firm access commencement date the AER could provide for a change in the revenue determination from the optional firm access commencement date – presumably this would only work if the optional firm access commencement date was fixed in advance, and it would also require the AER to be able to set the new revenue some time in advance.

10.3.3 Transitional access

Access settlement would require an initial transitional allocation of access to existing generators. The initial allocation of access would be granted on the commencement date of optional firm access. This initial allocation would then be sculpted back over time according to the sculpting parameters. However, from this commencement date, purchases of firm access (by both existing and new entrant generators) from the TNSP could occur.

10.4 Option 2 - Temporal staging

10.4.1 Description

Under this option, different core elements of the optional firm access model would be introduced progressively. There is some flexibility in terms of the order in which this can be done, but in all cases access settlement would need to be introduced first.

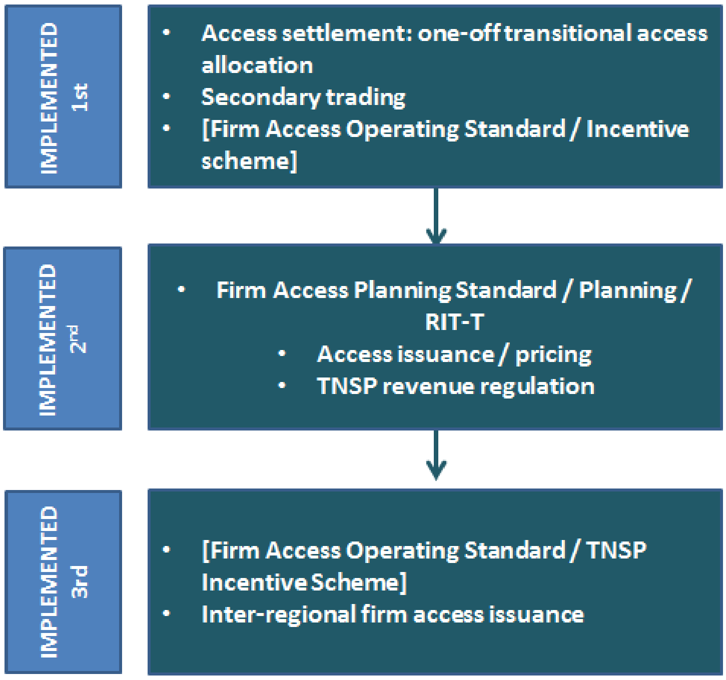
There could also be an element of geographic staging to this option, in that subsequent elements of the model would only be introduced in regions for which the TNSP reset had occurred (the alternative to this would be the introduction of some mandatory reopeners allowing introduction of revenue regulation and incentive elements at the same time in all regions).

There are several options for how temporal staging could occur. The general approach is that access settlement would be introduced first, then the ability to purchase firm access from TNSPs, and then inter-regional access. Differences arise as to when the incentive scheme is introduced.

We note that there would be no decision points in temporal staging. That is, the decision would be made at the beginning that all of the elements of optional firm access would be implemented in that particular way according to a particular timing.

This is illustrated in Figure 10.2, below. Here, the operating standard and so incentive scheme could either be introduced first; or introduced last.

Figure 10.2 Temporal staging options



10.4.2 Implemented first – Settlement and transition

The first stage of temporal staging must be access settlement.[100] Without this firm generators that were constrained off and so not dispatched cannot be compensated. There is no impact on TNSPs through access settlement alone (ie, without the incentive scheme applying) so it can be put in place for all regions even before revenue regulation arrangements are in place. Secondary auctions, or some other mechanism to trade access between generators, should also be put in place in this stage in order to encourage efficient holdings of access.

This initial transitional allocation would be based on the allocation method set out in chapter B and the sculpting parameters discussed in chapter 9.

We consider that in most cases there should be no need to adjust this initial allocation of access to incumbent generators over time. Any adjustment is likely to result in less certainty for the market. However, this may depend on how long this stage remains in place for. Where it is in place for a longer period, regular adjustments could be considered to reflect changes in usage of the network, including the entry of new generators. Either way, a mechanism for trading access should be in place. We would be interested in stakeholder views on this issue.

100 While we have not formed a view on what benefits there would be from just implementing access settlements, we consider that the full model is needed in order to reveal all of the benefits that optional firm access could likely offer.

10.4.3 Implemented second – Planning and revenue regulation

It would now be possible to purchase intra-regional firm access from TNSPs. As described above, planning and revenue regulation can most easily be introduced through a TNSP's revenue reset. However, there are potential mechanisms where such elements could be introduced at other times (ie, not solely on a revenue reset). It need not happen for all TNSPs at the same time however and can come in TNSP-by-TNSP.

We note that if some TNSPs offer access before others, there may be a risk of introducing distorting locational decisions for new generators (ie, a new generator may favour a region with firm access, over a region that does not have firm access available).

This stage would include changes to revenue regulation, and new planning requirements.

10.4.4 Implemented third - Inter-regional access

Here, it would now be possible to purchase inter-regional access rights. The procurement of inter-regional access rights would require multiple TNSPs to be subject to optional firm access planning and revenue regulation. This would be necessary in order for any potential upgrades to the interconnector that were necessary to provide inter-regional access rights to occur.

We note that it may be possible for inter-regional access to be introduced at the same time as planning and revenue regulation, provided neighbouring TNSPs were both subject to optional firm access planning and revenue regulation.

10.4.5 Incentives

Ideally, as discussed above, revenue regulation should be introduced before incentives so that TNSPs have an opportunity to adjust to the new arrangements before being exposed to financial rewards and penalties.

However, there may be ways in which an incentive scheme could be implemented earlier, including a "learning period" paper trial incentive scheme at an earlier stage, which would not be linked to a TNSP's revenue. The data from this could be used to set the initial incentive scheme parameters. Alternatively, it may be possible to introduce a low-powered incentive scheme at an early stage in the process.

10.5 Option 3 - Geographic staging

10.5.1 Description

Under this model, jurisdictions could choose when to take part in optional firm access. Optional firm access would apply only in those jurisdictions that were part of the optional firm access scheme. In those jurisdictions that did choose to take part, optional firm access could be introduced according to either of Options 1 and 2 above.

Here, elements could be introduced into different jurisdictions at different times, but the decision would be made at the beginning to introduce all the elements in this manner.

10.5.2 Settlement

Settlement would be introduced only for those jurisdictions that were part of the optional firm access scheme. Generators that were in jurisdictions that were part of the scheme and that had sought firm access would only receive compensation:

- from generators (and potentially the TNSP) that were also in jurisdictions that were part of optional firm access; and
- in respect of flowgates that were part of jurisdictions that were part of optional firm access.

This may reduce the firmness of the product. It may also create problems of flowgate tagging across borders and, in the longer term, send distorted locational signals to generators. From an initial high-level inspection it appears that the effect of constraints that cross borders is not significant. Such constraints appear more likely between NSW and Victoria, and we are investigating these regions further.

10.5.3 Transitional access

Transitional access would be allocated to generators within a jurisdiction from the time that the jurisdiction joins the optional firm access scheme. In practice this could mean that transitional access in one region could be fully sculpted back before it is initially allocated in another region. This does not seem to be a problem since it would still all be the same product and settled through the settlements mechanism. However, it could potentially create signals for a new entrant generator to locate in one region over the other.

10.5.4 Inter-regional access

There could only be an inter-regional product between neighbouring regions that joined the optional firm access scheme. For example, if Queensland did not opt to join the scheme, there could not be an inter-regional access product between NSW and Queensland.

10.5.5 Other challenges for geographic staging

The Commission considers there are a number of challenges associated with geographic staging.

First, any locational signals for transmission costs that would influence how generators would locate may be distorted. For example, a generator may decide inefficiently to locate in one region or the other based on the existence, or the absence, of optional firm access.

Second, geographic staging would be more difficult for the AER to implement in terms of revenue regulation. It would have to apply different regulatory regimes in different jurisdictions. Examples include the incentives that apply, determining the annual revenue amount (to meet both the firm access standard and reliability standards), and determining the regulatory asset bases. It may also potentially create problems in benchmarking across regions.

Third, a number of elements of the optional firm access model may need to be adapted. For example, the pricing model would need to contain only elements from those regions that had adopted optional firm access. Where there were a lot of elements that crossed borders, this would potentially reduce the firmness of the access product, and also the benefits that could arise (as discussed above).

Finally, we note that the inter-regional aspect of optional firm access could not be introduced with geographic staging.

Therefore, while we are considering geographic staging further, the Commission considers that, upon initial review, such a means of implementing optional firm access looks to have many challenges and downsides.

10.6 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- whether are there any implementation issues that we have missed;
- whether the restrictions that we have set out on implementation issues are consistent with stakeholder views;
- whether there are any other options for implementation that we should consider; and
- any initial thoughts on benefits or costs associated with the different implementation options.

A Reliability Access

A.1 Introduction

Under the optional firm access model TNSPs would have to simultaneously meet:

- the firm access standard, which was outlined in chapter 4 of this report; and
- the relevant jurisdictional reliability standard.

Therefore, both generators (through the firm access standard) and consumers (through reliability standards) would drive network investment decisions by TNSPs.

This chapter lays out a proposal to provide generators an opportunity to signal preferred investment decision when a TNSP considers an augmentation to meet the reliability standard. Generators could potentially use this process to receive discounted firm access.

We consider that this proposal lies outside the core model of optional firm access. That is, optional firm access can be implemented without the proposal outlined in this appendix.

However, this proposal could be beneficial to the operation of the model overall as it provides for market-led investment in those situations where the TNSP is augmenting its network to meet reliability standards. Therefore, we consider that this is a recommended element and so could be introduced at a later time.

We welcome stakeholder comment on whether our categorisation of this element as recommended is appropriate.

This appendix is structured as follows. First, we explain what was recommended in the Transmission Frameworks Review (section A.2). We then described the revised process for how reliability access would be dealt with (section A.3), including showing a worked hypothetical example of this process (section A.4). Finally, we set out areas that we wish to seek stakeholder feedback on (section A.5).

A.2 Background

A.2.1 Current planning and investment decision arrangements

Each TNSP is responsible for meeting jurisdictional reliability standards for the supply of electricity to consumers. These require that there is enough transmission capacity to transport sufficient generation to meet demand, and so is based on peak demand. Each jurisdictional government retains control over how the level of transmission reliability is set, monitored and enforced.

TNSPs undertake planning in order for their network to meet the relevant standard. TNSPs produce several planning documents, including APRs and RIT-Ts. The changes to APRs under optional firm access were discussed in section 4.3.

The RIT-T assessment is a process for individual investment decisions, which examines the costs and benefits of various options and establishes the one that maximises net market benefits. We note that for reliability investments, such net benefits may be negative, ie, at least cost. A TNSP is required to undertake a RIT-T assessment for any augmentations that cost over $5 million, including those augmentations necessary to meet reliability standards.

In assessing net benefits, the RIT-T requires that the TNSP consider the costs and benefits accruing to all NEM participants, not just the TNSP itself. For example, network augmentations may provide benefits to some generators by relieving congestion and so providing improved access to the regional reference node, potentially leading to lower-cost generation being dispatched. A TNSP, in undertaking a RIT-T currently, estimates the total costs of generation dispatch as a proxy for congestion costs: higher congestion costs would lead to a higher total cost of dispatch.

Any upgrades to meet reliability standards are funded by consumers, through TUOS charges.

We note that the Commission has recently made recommendations on a framework for setting and regulating transmission reliability in the NEM.[101] The focus of the framework was on implementing an effective framework for setting, delivering, and reporting on transmission reliability standards that includes greater consideration of the value customers place on reliability. The implementation of these recommendations would not make any difference to the issues that are considered in this chapter.

A.2.2 Reliability access in the Transmission Frameworks Review

The Transmission Frameworks Review recommended changes to the RIT-T process. We recommended that the RIT-T should be amended to no longer take into account benefits to generators.

The reasoning given for this approach was that, under the optional firm access model, generators (rather than TNSPs) decide on the economic benefits associated with transmission expansion. TNSPs then expand as necessary purely to maintain the firm access standard, not (explicitly) because of the economic benefits associated with the firm access service.

We also considered in the Transmission Frameworks Review what would happen if total firm access fell short of peak demand (which reliability standards are based

101 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-national-framework-for-transmission.

on).[102] In this situation, TNSPs would be required to provide access to non-firm generators to meet the reliability standard. In doing so, the TNSP would provide benefits to non-firm generators, effectively providing them with some access that they do not pay for. This is referred to as "reliability access".

The more firm access there was, the less reliability access TNSPs would generally have to provide. This therefore creates direct savings for consumers - generators would be paying for more of the transmission network through their firm access charges, and so less would need to be recovered from customers through TUOS. That is, if the network was not providing firm access, then it would likely need to be upgraded for reliability reasons, which would be paid for by customers.

The pricing method did not attempt to estimate and include the saving to the TNSP in the access price. We noted that some stakeholders considered access prices would be too high as a result. At the extreme, if no generators procured firm access, TNSPs might provide generators with the same amount of access they would pay for, but at no charge to those generators.

The theoretical ideal of the optional firm access model is that access should only be provided in response to firm generators' willingness to pay, leading to market-led network development. Providing reliability access is a necessary distortion of this ideal: it would not be acceptable to let the lights go out if insufficient generators sought firm access. However, where the ideal is unobtainable, we considered that the least distortionary outcome should be sought.

We recognised that the existence of such reliability access may affect generators' incentives to purchase firm access and/or mean that firm access is available at a lower price than would otherwise be the case.

We proposed a possible mechanism that could be considered at a later stage of the model to extend the philosophy of market-led development to the reliability side of the network. This was the reliability access safety net, where TNSPs would be responsible for "topping up" reliability access over and above that demanded by generators. In this process, if a TNSP identified a need for a reliability augmentation, it would have undertake a reserve auction of access to the generators. The TNSP would have been required to choose the auction bid from the generator that resulted in the least cost option.

We also set out that two mechanisms exist in the model that allow generators to obtain the reliability access. These were:

- The first mechanism takes place automatically in the determination of the price paid by generators wishing to buy firm access. The presence of reliability standards – and the extra transmission capacity associated with them – would automatically lead to higher levels of spare capacity, and so lower prices for firm access.

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102 AEMC, *Transmission Frameworks Review*, Final Report, AEMC, April 2013, p. 67.

- The second mechanism may arise out of short-term access issuance. Reliability access would create spare capacity in the network, which would facilitate additional short-term access issuance. Short-term access, sold through an auction, is likely to be sold at a lower price than long-term firm access.

The key features of Table 10.1 of the Transmission Frameworks Review relating to the analysis of projects to meet reliability standards are extracted below.

Table A.1 Table 10.1: Reliability Access

Core Elements	Recommended Elements	Optional Elements
• RIT-T assessments no longer include benefits and costs that accrue to generators	• No change in reliability standards for optional firm access implementation (but a parallel change to reliability standards is not ruled out by this) • Access charge excludes the effects of reliability standards and reliability access	

A.2.3 Developments since the Transmission Frameworks Review

Since the conclusion of the Transmission Frameworks Review, we have considered further how reliability augmentations may interact with the optional firm access process. In particular, we have considered how the RIT-T may be adapted to interact with optional firm access.

The issue that we have considered is the question of: since reliability access provides benefits to non-firm generators, should these benefits be incorporated in the RIT-T, and if so, how?

We propose an additional mechanism to allow reliability augmentations to be undertaken as cheaply as possible, without undue distortions to the offering of long-term access.

The option that we propose has some similarities with the reliability safety net proposal from the Transmission Frameworks Review (which was described above). However, under our proposed changes to the RIT-T, the TNSP is not reliant on generator bids for access. Rather the TNSP would take into account the generator bids as part of the wider RIT-T assessment process.

The option that we consider in the remainder of this chapter is consistent with the core and recommended elements of Table 10.1.

As noted in the Transmission Frameworks Review, we recognise that the provision of reliability access may result in a potential impact on access pricing for generators that subsequently apply for firm access. This will be considered further in our supplementary report on pricing.

A.3 Reliability costs and RIT-T

A.3.1 RIT-T process for reliability investments

In the Transmission Frameworks Review, as set out above, we recommended that generator benefits should no longer be included in the RIT-T. The reasoning applied primarily in the context of a FAPS-related RIT-T. Since it may not always be meaningful or practical to distinguish between FAPS-related and reliability standard-related RIT-Ts, a common set of RIT-T rules should ideally apply to all expansion decisions, irrespective of their cause.

We now propose that TNSPs would be required to include a generator's willingness to pay for any reliability access that is provided from reliability-driven expansions in the RIT-T assessment.

One way to discover the value of a reliability upgrade to a generator is to ask the generator if it would buy it, and at what price. The generator may potentially be willing to partially fund augmentation if it values the created access. However, reliability access is not specific to a generator and so selling the reliability access in this way (ie, asking the generator for how much it is willing to pay) is not meaningful.

Therefore a generator's willingness to pay is more easily revealed through a contingent auction process, in which generators are invited to bid for firm access which would be underpinned by one of the RIT-T options. When one of the options is selected for development, firm access would be sold to the highest bidder whose bid is associated with that option.

It should be noted that a generator's willingness to pay for reliability access would be less than the price of expansion as determined by LRIC. If this were not the case, the generator would just purchase the firm access through the standard procurement process, and pay the LRIC.

A.3.2 Contingent Auction

Given the discussion above, some form of competitive auction would be needed to encourage each generator to reveal the value it places on firm access.

In undertaking the auction, the TNSP would invite all generators potentially affected by the RIT-T decision to submit bids for the associated reliability access.[103] The TNSP would use these bids to inform its RIT-T decision. The TNSP's offer of firm access would clearly be contingent on the RIT-T decision; the winning bidder would be

103 We note that only generators could participate, and so bid, in the auction.

chosen from those generators whose firm access was associated with the preferred RIT-T option. Equally, the RIT-T decision would be contingent on the bids received.

We realise that in selling some firm access to a generator, the TNSP may be required to augment in addition to what would have been done for reliability purposes only. Therefore, when assessing the contingent benefit of a generator bid, the TNSP should deduct any necessary additional expenditure from the generator's willingness to pay. This expenditure should be determined using the LRIC price with the relevant RIT-T option included in the baseline.

To illustrate this, consider a simple example. Suppose that a TNSP has two reliability expansion options under a RIT-T. Option 1 costs $100m and permits some firm access to be issued to generator A; Option 2 costs $150m and permits some firm access to be issued to generator B.

Now suppose that the auction reveals how much generators are willing to pay: the values are $30m for generator A in option 1 and $90m for generator B in option 2. Assuming that there are no other material costs and benefits, option 2 has a lower net cost ($60m = $150m - $90m) than option 1 ($70m = $100m - $30m) and should be the preferred option.

The benefits of such a process are twofold:

- As dispatch cost estimates are not to be considered in a RIT-T under optional firm access, the contingent auction would provide the TNSP with the necessary alternative for estimating reliability access-related benefits.
- Generators are able to signal, through their bids, for a preference for a specific expansion. This maintains the optional firm access model's goal for encouraging market led planning, through generator choices and competition.

The Commission notes that such an auction would only be effective where there is sufficient competition between generators to encourage them to reveal their valuations of the access. Competition between generators in the auction can arise in two ways:

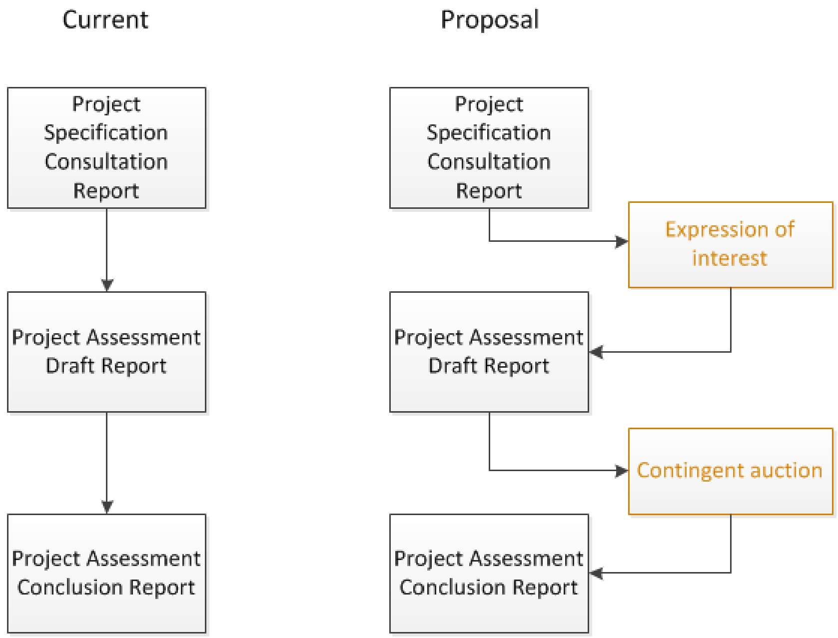
- There is competition between generators associated with different expansion options that the TNSP may consider in the RIT-T. That is, a generator cannot receive the firm access unless its expansion option is selected under the RIT-T and making a higher bid for firm access makes this more likely.
- There may be multiple generators to whom firm access might be allocated for each particular expansion option. If a particular augmentation option improves access for two (or more) generators, the one with the highest contingent bid would be allocated the created firm access.

However, the Commission considers that, even if competition is weak, any contribution by a generator to an upgrade that would be necessary for reliability access is better than none. That is, even one bid by a generator is better than the status quo where customers would pay the full cost of the augmentation.

A.3.3 RIT-T process

The addition of the contingent auction would require the RIT-T process to be amended. A high level flowchart of the current RIT-T process can be seen on the left hand side of Figure A.1. On the right hand side is the proposed process with the steps required for the contingent auction in orange.

Figure A.1 RIT-T process



At a high-level, we consider the modified process would be as follows:

- First, the Project Specification Consultation Report would be published (as it is currently). This contains information (amongst other things) on the need for the investment, the potential augmentation options being considered, and the parameters for any potential non-network solutions that could meet the investment need.
- Before any auction or expression of interest, we consider that all interested generators would have complete and up-to-date information on the potential augmentations that may be undertaken. Therefore, since the majority of this information would likely be contained in the Project Specification Consultation Report, there would be an initial expression of interest from generators after this point. This stage is necessary since, given the time taken to complete a RIT-T, it is unlikely that a generator's bid could be considered binding at this stage of the process. The results of this expression of interest could potentially lead the TNSP to consider other upgrade options.

- Next, the Project Assessment Draft Report would be completed. This would contain draft cost-benefit assessments, including generator's (unbinding) willingness to pay sourced from the expression of interest stage.

- The auction round would then occur. This would seek to reveal the generator's actual willingness to pay. The results from the auction would be used in the final cost-benefit assessment, and so would likely be binding on the generator. Since the auction round would be binding this would provide an accurate signal of how much a generator would favour a particular option.

- Finally, the Project Assessment Conclusions Report would be completed. This would contain the final results of the RIT-T, incorporating the results from the auction.

The specifics of the requirements in the expression of interest and contingent auction stages are yet to be fully developed. We are in the process of considering what information would be required to be supplied at each point by both the TNSPs and the generators. We are also examining how best to integrate these contingent auction steps into the current RIT-T timelines.

In addition, the process would require a threshold where the commitment from generators applying for firm access is "locked in".[104] This would be necessary to remove any incentive on generators to place high prices into the contingent auction, and then remove the bid after their preferred option is chosen, requiring consumers to completely fund the augmentation.

Once the threshold in the process has been passed and the TNSP has committed to an augmentation option, the generator would not be able to remove themselves from the obligation to purchase the agreed access at the agreed price. In the above indicative process, we have proposed that the threshold would be at some point after the publication of the Project Assessment Draft Report, ie at the contingent auction stage.

We recognise that the contingent auction adds a step to the current RIT-T process. However, we note that the current RIT-T has similar stages, such as where TNSPs are required to solicit non-transmission alternatives to network expansion.

A.3.4 Summary

The benefits to generators associated with reliability access should be in the RIT-T assessment. Whilst this has conventionally been done by a TNSP estimating changes in dispatch costs, this may be a poor proxy for the reliability access value and is in any case difficult for a TNSP to undertake since they may not have all the necessary information.

104 We recognise that since generators can bid into the auction, it could be the case that a committed generator bids into the process. Given that a committed generator may then delay, or potentially even withdraw its commitment to the plant, there would need to be appropriate financial commitments in place so that consumers would not be left bearing any funding associated with such a circumstance.

A contingent auction process provides a mechanism for the reliability access value to be better revealed by generators, assuming that there is sufficient competition between generators to encourage them to reveal their valuations. Furthermore, the auction process creates value by effectively converting the reliability access into firm access, which provides greater access certainty and firmness.

Relieving TNSPs of the need to estimate dispatch costs aligns the RIT-T process for reliability expansions with the approach proposed for FAS-related RIT-Ts.

By allowing generators to pay for some of the augmentations needed for reliability investment, customers benefit. In the absence of the generator paying for some of the augmentation, customers would have to fund the full costs of the investment. Under this proposal, consumers would not pay for all of the augmentation, and so benefit through lower TUOS charges. Also, since the investments would be signalled by generators, it is more likely that the investment would be efficient, and so consumers would bear less risk.

We note that this element of the model may not be frequently used - it depends how many generators are located in the part of the network which is being augmented. However, this would likely be a useful addition to the optional firm access model.

A.4 Example of the reliability access process

To demonstrate how this process would operate we have prepared a hypothetical simplified example.

In this example the TNSP considers that an expansion is necessary to ensure reliability at the regional reference node. The TNSP has outlined two potential augmentations, expansion of the capacity towards Generator A (estimated cost $100m) or an expansion towards Generator B (estimated cost $150m). These can be seen in Table A.2.

The TNSP would announce the intention to undertake augmentation and allow the generators to place their bids into the contingent auction. The cost of providing firm access for the two generators and the bid that the generators have placed into the contingent auction can also be seen in Table A.2.

Table A.2 Pricing of Firm Access

	Option 1 (Generator A costs)	Option 2 (Generator B costs)
Cost to TNSP of providing reliability expansion alone	$100m	$150m
Additional cost of providing firm access	$90m	$130m
Generator bid	$120m	$220m

Both generators have bid more than the cost of providing firm access, assuming the associated reliability expansion is undertaken, indicating that accepting the generator bid and providing firm access to the generators alongside the reliability improvements would be beneficial for the TNSP.[105]

The total net cost for consumers would be the total cost of the augmentation minus the payment from the generator. For Option 1 this would be $70m ($70m = $190m - $120m). For Option 2 this would be $60m ($60m = $280m - $220m).

In this situation the TNSP, through the RIT-T, process would choose augmentation Option 2 to meet the reliability standard at a cost of $280m. Generator B would pay $220m and receive allocated firm access. The remaining $60 million would be recovered though TUOS. Under the status quo arrangements, Option 1 would have been built with a cost to consumers of $100m.

A.5 Consultation questions

The AEMC would be interested in receiving feedback on the proposals contained in this chapter. Participants are encouraged to assess these proposals against the national electricity objective, and to discuss what they see as the main costs and benefits of this proposal, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- whether such a mechanism should be a "core" or "recommended" element of optional firm access;
- whether such a mechanism would be of interest to stakeholders, ie, would generators purchase reliability access;
- what commitments should be associated with bids, in order to minimise the risk of generators failing to meet their bids associated with the auction; and
- how the current RIT-T process could be modified to take this process into account.

105 The two options represent different methods of meeting the one reliability need. Only one of these options would be selected by the TNSP for the augmentation.

B Initial Transitional Access Allocation

B.1 Introduction

The allocation of transitional access to generators is intended to prevent sudden and significant changes in the market while at the same time not delaying or diluting the benefits that the optional firm access model is intended to promote. It also provides a learning period for market participants.

We propose that at the commencement of optional firm access that transitional access be allocated to existing generators. Transitional access would be the same as the firm access service except that it would not need to be procured from a TNSP and generators would not pay access charges for it. Also, as discussed in chapter 9, allocated transitional access would be sculpted back over time.

In this appendix we examine the AEMC's proposed method for allocating the initial transitional access to generators (section B.3) and an overview of the results (section B.4) of our first tests on doing so. We then examine some potential alterations to the method we used to allocate transitional access (section B.5) and alternate methods (section B.6) of doing so.

After the initial allocation of transitional access we propose it be "sculpted" over time. This is examined in detail in chapter 9.

B.2 Background

B.2.1 Transitional access in the Transmission Frameworks Review

In chapter 9 of the Transmission Frameworks Review we specified a four stage process for the allocation and operation of transitional access.[106]

Stage 1: Access requirements

Generators' access requirements – the level of firm access they would need to have unfettered access to the regional reference node – were to be calculated, based on historical generation patterns.[107]

Stage 2: Access scaling

These access requirements were to be scaled back to the extent necessary to ensure that all transitional access could be accommodated by the shared network. Scaling would aim to maximise the allocation of access while being robust to constraint formulations

106 AEMC, *Transmission Frameworks Review*, Final Report, AEMC, April 2013, p. 121.

107 Market network service providers would be treated as generators for the purpose of allocating transitional firm access.

(small changes in access for one generator should not cause large changes in access for other generators).

The access scaling would result in the initial transitional access allocations being consistent with the firm access standard. TNSPs would be able to meet the firm access standard obligations for generators with transitional access with the existing network.

The remaining stages were discussed in chapter 9.

The key features of the initial transitional access allocation, as set out in Table 10.1 of the Transmission Framework Review's final report, are extracted below.

Table B.1 Table 10.1: Transitional access

Core elements	Recommended elements	Optional elements
• Existing generators are allocated some transitional access, at no charge • Transitional access allocation is firm access compliant on existing network • Transitional access is sculpted back over time	• Transitional access auction established for one-off reallocation of transitional access • Transitional access allocation based on generator capacity and pre -optional firm access operating regime • Inter-regional transitional access would only be allocated to the extent that it would not cause any additional scaling back of generators' transitional access	• Sculpting profile based on 3 parameters X, Y, Z and K to be determined in implementation (other profiles are possible)

B.2.2 Developments since the Transmission Frameworks Review

Since the publication of the Transmission Frameworks Review, we have further developed our method to examine how it would operate in practice. To this end, we proposed to AEMO that it undertake a series of test runs of the method that we recommended would be used for stages 1 and 2 of the process. The main purpose of this was to examine the design and practicality of the process.

The method described in sections B.3 and B.4 is consistent with that laid out in the Transmission Frameworks Review.

B.3 Method

For our test of the method described in the Transmission Frameworks Review, we have been working with AEMO. We requested that AEMO undertake a series of transitional access tests based on the method outlined below. AEMO prepared a report summarising their work: *Transitional access allocation project*. This report is available from our website.

We note that we have yet to determine the governance arrangements for the initial allocation of transitional access at the commencement of optional firm access. A body, as yet undetermined, would be responsible for the allocation of transitional access.

B.3.1 Base case method

In the Transmission Frameworks Review we stated that the development of each generator's access requirement and the scaled initial transitional access allocation would be a two stage process. In practice, both the first and second stages of allocating transitional access were undertaken simultaneously.

The key components of the method of determining the initial allocation of transitional access are set out below:

- Each generator's access requirement is the maximum dispatch of each generating unit at any point over the previous two years.[108]
- Use the NEMDE Queue to model the simultaneous dispatch of all the generators in the NEM at each generator’s maximum capacity:
  - This is based on a peak historical NEMDE dispatch run which minimises the risk that the solution is not technically feasible.
  - The historical dispatch interval NEMDE file chosen for usage as our base case was from a peak period on a hot day in summer. This represents a situation where the network would be close to capacity.
  - All constraint equations are those that were in the constraint library at the dispatch interval used in the modelling.
  - The simulation changes the offers from the generators as described below.
- Transitional access allocation is calculated to each generating unit on an "as generated basis".[109]
- Extra load is added at the regional reference nodes so that the system balances. It is also assumed that the regional reference price is $1000/MW.
- Interconnectors are assumed not to flow in the first instance (ie interconnectors are clamped at zero).[110] Then, after access is allocated to the generators, dispatch

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108 This is in line with the proposed method of determining a generator's rated capacity as described in section 8.7 of this report.

109 We propose that the method that is used for the actual allocation would be done on the basis of a Revenue Meter Identifier to be consistent with access settlement (see section 8.3.2). This was not used for these runs as it would have been time consuming and would minimally alter the result at the aggregate level.

110 In the modelling, Basslink is treated as a generator in Victoria, consistent with our position that MNSPs are to be treated as generators.

is run again with the interconnectors flowing, but with the generators clamped at transitional levels.

- Each generator is assumed to place ten equal offers with each at one tenth of their capacity, with these offers increasing in $10/MWh increments with the lowest offer being $10/MWh.

If each generator was to put in a single offer, a small deviation in a participation factor in a binding constraint could lead to large changes in allocated transitional access. By having multiple offers, a constrained generator would be dispatched for all their output below the local price. Note that the usage of $10/MWh as an offer step is an arbitrary value. The larger the offer step, the less the impact from any difference in constraint participation factors. Thus a larger offer step results in a more equitable allocation among generators but the total amount of generation access would decrease.

It is a requirement that TNSPs would be able to meet their firm access planning standard requirements for allocated transitional access with the existing network. As described in section 4.3 the firm access planning standard would be a requirement for TNSPs to plan to provide capacity to firm generators during specified conditions. We consider that if optional firm access is implemented then the conditions used for the transitional access allocations should match those used to define the firm access planning standard.

In the method outlined above, a peak demand scenario was used as we have assumed that peak demand would be correlated with high network utilisation. However, the specification of the firm access planning standard would determine the input data that would be used to allocate transitional access at the commencement of optional firm access.

B.3.2 Scenario testing

In addition to the specific base case method as set out above, we have tested a variety of other scenarios, to evaluate elements of the method. These are set out below:

- Steep offers profile – the same trading interval is used as in the base case, but the tapering of the offers is changed: offers are increased in increments of $100 rather than $10 to examine the impact of changing the simulated offer structure;

- Off-peak – a historical trading interval from a non-peak demand time in summer was chosen in order to see the impact on the method of changing network utilisation in the source file;

- Windy – a historic trading interval from a hot windy day was chosen, in order to see the impact of line ratings and non-scheduled generation under such conditions;[111]

- Winter – a historic trading interval from a winter period was chosen, in order to see the impact on the network capabilities;

- Mothball – the same historical trading interval is used as in the base case, but this scenario includes mothballed generation that is returned to service (eg Playford B, which has not run over the last two years is given its registered capacity) in order to determine if transitional allocations alter significantly if such generators were included; and

- No Flowgate Support – the same historical trading interval is used as in the base case, but this scenario removed flowgate support impacts from generators that had negative participation factors in any binding constraints. This was to examine if the level of flowgate support is an important consideration in setting transitional access.

The historic dispatch intervals that were used as the basis for each of these runs can be seen in Table B.2.

Table B.2 Test runs undertaken by AEMO[112]

Scenario	Date	Dispatch Interval
Base case	15 January 2014	15:00
Steep offers	15 January 2014	15:00
Off-peak	12 January 2014	04:05
Windy	20 December 2013	11:30
Winter	6 June 2013	19:30
Mothballed generation	15 January 2014	15:00
No flowgate support	15 January 2014	15:00

B.4 Results

This section provides an overview of results based on the method outlined in section B.3. The purpose of presenting results in this report is to evaluate the method proposed.

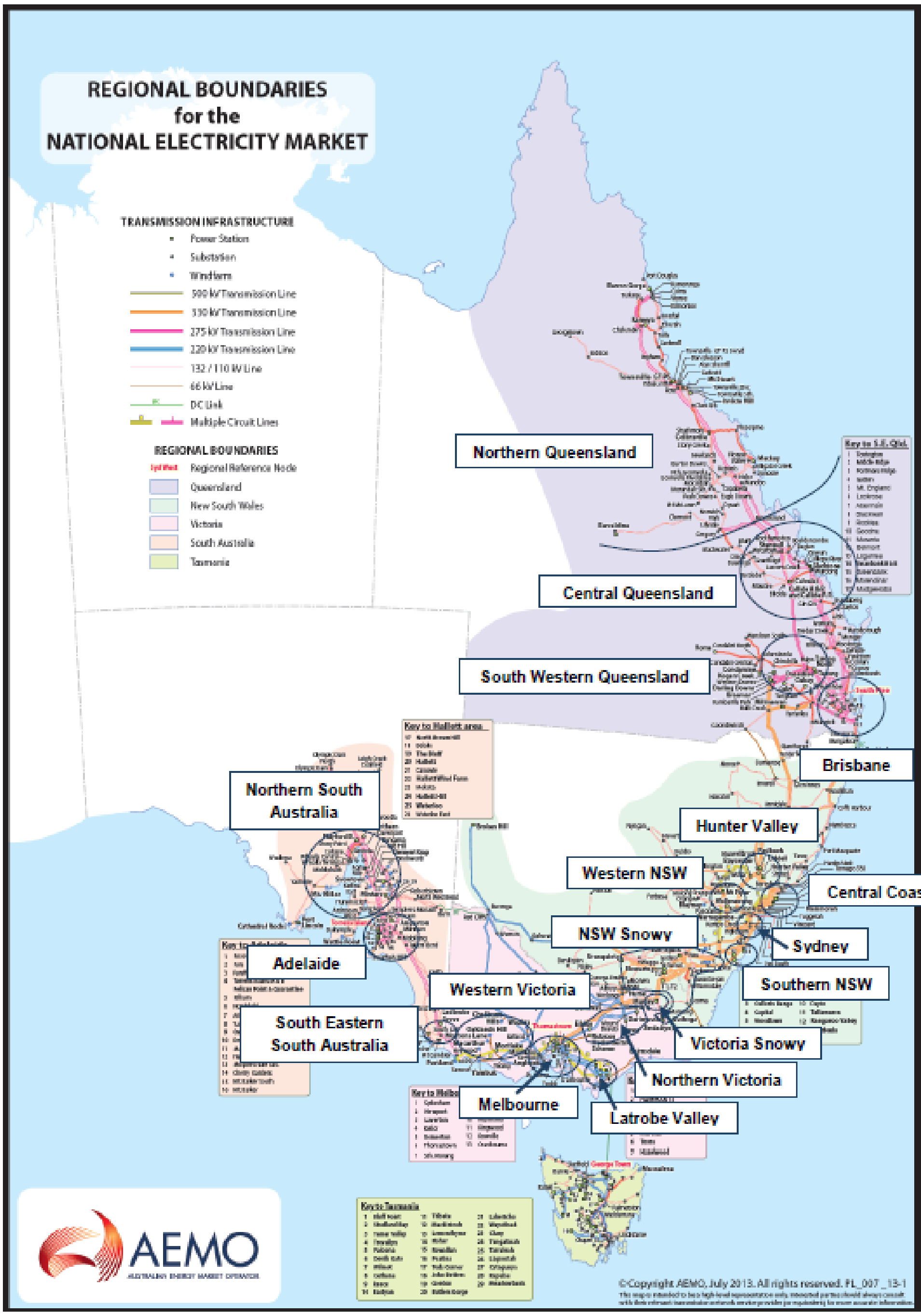
111 Note that as the allocations for semi-scheduled generation was based on maximum availability over the last two years, the wind conditions would not affect these generators' availability in the model.

112 Table sourced from AEMO, *Transitional access allocation project*, June 2014, p. 20.

The results presented in this report do not represent the allocations that would be used at the commencement of optional firm access. Any results from these initial runs will be different from the actual allocations if optional firm access is implemented, even if the method is unchanged. This is because any runs for the implementation of optional firm access will be undertaken with the network, load and generation profiles of the market at that time.

Figure B.1 shows the sub-regions used in analysing the results from the test runs. Figure B.2 shows within the sub-regions the average percentage of their capacity the generators would receive as initial transitional access under each scenario.

Figure B.1 **Sub-Regions used for analysis of transitional allocation results[113]**



113 AEMO, *Transitional access allocation project*, June 2014, p. 12. The sub-regions used are simple breakdowns to provide an indication of the geographic spread of transitional access allocations. These do not represent the sub regions of the NTNDP or any other report.

Figure B.2 Transitional access allocations[114]

Sub-Region	Base	Taper	Off-peak	Windy	Winter	Mothball	Flowgate
Northern Queensland	100%	100%	100%	100%	100%	100%	100%
Central Queensland	99%	99%	97%	97%	96%	99%	99%
Brisbane	100%	100%	100%	100%	100%	100%	100%
South Western Queensland	84%	84%	84%	85%	82%	84%	82%
Hunter Valley NSW	100%	97%	100%	100%	100%	100%	100%
Central Coast NSW	100%	100%	100%	100%	100%	100%	100%
Sydney	100%	100%	100%	100%	100%	100%	100%
Western NSW	100%	90%	100%	100%	100%	100%	100%
Southern NSW	100%	80%	99%	100%	100%	100%	100%
NSW Snowy	63%	73%	26%	48%	60%	63%	63%
Victoria Snowy	100%	100%	92%	96%	100%	100%	100%
Northern Victoria	87%	87%	100%	93%	100%	87%	87%
Latrobe Valley	95%	95%	91%	96%	95%	95%	95%
Melbourne	86%	86%	100%	100%	100%	86%	86%
Western Victoria	100%	100%	100%	100%	93%	100%	100%
South Eastern South Australia	90%	90%	88%	60%	74%	90%	90%
Adelaide	100%	100%	100%	100%	100%	100%	100%
Northern South Australia	97%	97%	90%	87%	86%	99%	97%

The method laid out in section B.3.1 uses the same constraint sets as were employed in the historical dispatch runs. However, the different generation and demand assumptions used in the simulation mean that the constraints that become binding may be different from those that have bound historically.

In the simulation all generators are simultaneously making offers at their full capacity, which we note has never historically occurred. However, allocating transitional access on the basis of the participation in the modelled constraints (ie, those constraints contained in NEMDE) would provide TNSPs with confidence that the firm access standard could be met in all situations with existing capacity. Attempting to remove constraints that have not bound historically would make the TNSPs reliant on historical network conditions and offer decisions by generators. Therefore, the initial allocation may not be firm access standard compliant at the commencement of the regime.

We note that while we refer to a single base case run, AEMO also undertook repeatability analysis by examining 80 peak periods from the summer 2013/14 using the same method. This showed that the results were repeatable and that there was a low deviation of transitional access allocations across the different runs.

B.4.1 Generator Allocations

In our test runs, in all the scenarios, most mainland generators received an allocation of about 100 per cent of their total capacity. The main exceptions were located in:

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114 AEMO, *Transitional access allocation project*, June 2014, p. 18.

- south west Queensland;
- New South Wales Snowy sub-region; and
- south eastern South Australia.

These are examined below.

South West Queensland

A number of generators between Tarong and NSW have an allocation of about 70 per cent of their capacity. The modelled access was bound by a constraint that we understand AEMO uprated in March 2014.

We expect that any run which were to use a historical NEMDE file with the network post-April 2014 would result in a significantly higher initial transitional access allocation for generators in south west Queensland.

New South Wales Snowy

The generators in the Snowy sub-region have allocations of 63 per cent of their capacity. These generators are affected by a constraint north of Bannaby, where the loop around Sydney intersects with the line coming from Victoria.[115] All NSW generators are affected by this constraint, but the southern NSW generators have higher participation factors in this constraint, and so are affected more significantly.

South Eastern South Australia

A number of South Australian generators located near the Victorian border receive allocations of approximately 90 per cent of their capacity. This represents generators that have located along the flowpath between the Heywood interconnector and Adelaide and thus have high participation factors on the interconnector.

B.4.2 Inter-regional flows

In the Transmission Frameworks Reviews we recommended that initial access be allocated to generators and then any residual capacity be allocated as firm interconnector rights. This was to replicate the current situation where local generation, through the ability to make offers, is generally able to be dispatched ahead of interconnector flows. Furthermore, we note that interconnectors feature with a low participation factor on many constraint equations meaning that any change on these may cause large movements in the flow across the interconnector.

115 Some stakeholders have noted that this constraint has not bound historically. We discuss the difference between our modelled results and historical results in section B.4.

In the initial tests that AEMO undertook, we saw that after transitional access was allocated to generators, there was no, or minimal, residual to be allocated to interconnectors.[116]

However, we note that the recently announced upgrade of Heywood was not included in any of the test runs. After the upgrade is complete inter-regional flow would be improved. Therefore, we expect undertaking runs after the upgrade has occurred would result in an increased transitional access allocation to firm interconnector rights between South Australia and Victoria.[117]

B.4.3 Tasmania

The average transitional access allocation for Tasmanian generators in the base case is 63 per cent. However, there are a number of problems in modelling transitional access for Tasmania and large variances in transitional access are observed across the individual generators.

As noted in section B.3.1, our approach involves adding extra load to the regional reference nodes so that the system balances. In Tasmania, this involves adding extra load to Georgetown (northern Tasmania). However, the Tasmanian network is not designed for a large load at Georgetown – demand is typically located on southern parts of Tasmania, such as Hobart. In addition, Tasmania has a higher ratio of generation capacity to load than the other states.

Furthermore, Tasmania's peak demand conditions are in winter – not in summer as we are modelling.

We are investigating potential solutions to these issues and welcome stakeholder views on potential methods of allocating transitional access in Tasmania.

B.4.4 Changes in offer structures

One of the scenarios examined involved a change in the offer structure, so that offers were in \$100/MWh steps rather than \$10/MWh steps. This was to test the effect of the offer structure on the transitional access allocations.

The result of this change is that transitional access is allocated in a less variable manner among generators than the base case. We note that increasing the size of the offer step leads to a transfer of access allocation from generators with low participation factors in constraints to generators with high participation factors in constraints. However, this is

116 If there are parties that value inter-regional access, it may still be possible to purchase it during the transitional period. Some generators on inter-regional flow paths may be willing to sell their allocated access through the short term auction process, which could become firm short term inter-regional access. This process may be available, depending on the structure of implementation and is elaborated in chapter 7.

117 Including network assets that currently do not exist in historical dispatch runs from NEMDE would be difficult and hence was not attempted.

not a one-to-one transfer and high participation generators would not gain as much access as low participation generators would lose. Consequently any increase in the offer step size would result in a total decrease in allocated transitional access across all generators.

Therefore the setting of the size of the offer step becomes a trade-off between equity among generators, and the total amount of firm access allocated across each region. We are yet to determine the appropriate size of the offer step and welcome stakeholder feedback on the appropriate values to use.

B.4.5 Seasonal distribution

For most of the sub-regions the results are consistent between the peak and other scenarios. However, in the NSW Snowy and southern NSW sub-regions, the allocation dropped significantly in the winter and off-peak scenarios compared to the base case. We consider that this was most likely driven by two effects:

- the distribution of local load; and
- contribution of non-scheduled generation.

As noted in section B.3.1, it is necessary to add load to the simulated NEMDE runs, so that the simulation balances. To ensure the feasibility of the transitional access allocation under all dispatch conditions, this simulated load must all be located at the regional reference node, rather than distributed across the region.[118] As more load must be added at the regional reference node in the winter and off-peak scenarios, a much higher proportion of the total simulated New South Wales load is in Sydney. Thus the simulated demand on transmission infrastructure could be higher in these scenarios than if the load were to be spread across the region. However, we do not consider that spreading the load to be appropriate as explained in section B.5.1.

Furthermore, the historical NEMDE dispatch intervals include the amount of non-scheduled generation at that time. We note that in the peak period, non-scheduled generation was not exporting to the level that was seen in the non peak and winter scenarios. The introduction of some of this non-scheduled generation may lead to scheduled and semi-scheduled generators being constrained off.

B.4.6 Flowgate support

In our transitional access allocations all generators are simulated as available at their maximum capacity. This includes generators that would be providing flowgate support.[119] Consequently, some generators may be allocated access that can only be met with the operation of the flowgate support generators at the same time. As a test,

118 As discussed in sectionB.5.1 adding distributed load would artificially increase capacity on some flowgates and so cause a TNSP to be in breach of FAPS should congestion occur on these flowgates

119 A flowgate support generator has a negative participation in constraints. When such a generator operates, more can be dispatched from other generators.

AEMO examined a scenario where flowgate support generators were removed from binding constraints.

The results of this test were a minimal change in transitional access allocations, with a slight decrease in transitional access allocations to generators in south west Queensland.

We consider the inclusion of flowgate support generators while determining transitional access allocation is appropriate. This situation represents the operation of AEMO's constraints which we understand include such generators. If the operation of a flowgate support generator was necessary for a TNSP to meet the firm access planning standard requirement, then that TNSP can enter into a network support agreement with the relevant generator.

B.5 Considerations on our method

We note that the method we have used includes a number of inputs where values that are different from those in our base case could be used. As examined below, these include how load is distributed across the region, usage of peak availability for initial access requirement and using historical trading intervals.

B.5.1 Distribution of additional load across region

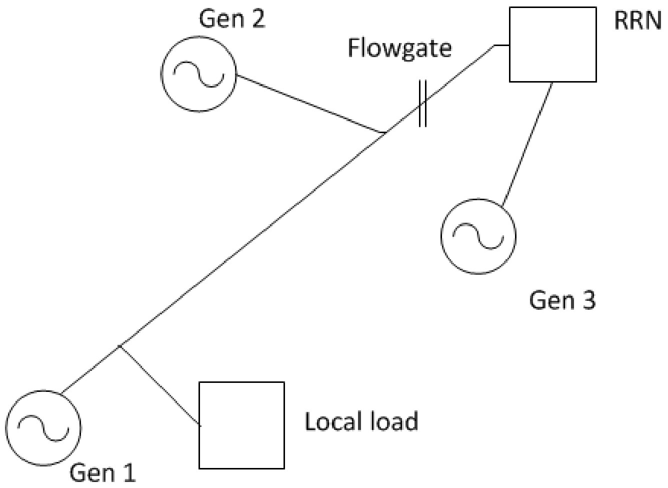
One potential amendment to the method would be to simulate an increase in demand across the network, rather than just at the regional reference node, to get the system to balance. For example, if a local load represents a quarter of the regional demand in the original NEMDE file, it would represent a quarter of the increased demand level used to ensure all generation is dispatched.

This change would result in simulated remote load (ie regional towns and transmission connected industrial plants) consuming more generation, and thus potentially relieving constraints that may appear between generators and the regional reference node. There are some stakeholders who consider that this represents a more accurate method of allocating transitional access as it maintains, as close as possible, the current geographic balance of load across the network.

However, we consider that there are issues with such an approach. The TNSP may require the additional remote load to be present to provide the allocated transitional access. If the increased load at a remote part of the network results in an increase above the maximum demand for load, this could result in the TNSP not being able to meet its obligations at the beginning of optional firm access.

An example of this can be seen in the simplified network in Figure B.3. Under our proposed method where the additional load is all at the regional reference node, the model shows a flowgate in which Generator 1 and Generator 2 participate. This would result in Generator 1 and 2 both receiving an initial allocation less than 100 per cent, depending on their participation factor.

Figure B.3 Treatment of local load



If we were to spread the additional load across the region, Generators 1 and 2 would both be allocated more transitional access as some of their generation would be absorbed by the increased local load near Generator 1. However, after the transitional period commences the TNSP would be responsible for ensuring that these transitional allocations are met within the firm access standard. In the situation where the increased local load is required for the dispatch of allocated transitional access to occur, the TNSP may not be within its firm access standard obligation, requiring additional augmentation of the network which may be at consumer's expense.

The additional load that is added in our method is not to represent network topography, but rather to allow the system to balance in the model and this is best located at the regional reference node.

B.5.2 Using peak availability to set the initial access requirement

The initial access requirement for generators has been specified as the maximum generation over the previous two years. We note that this may not accurately reflect the possible generation at peak demand periods. For example, this process would allocate access to intermittent generation at its highest generation point, which may not be correlated with the peak demand periods. Structuring the initial offers so they match generation during previous peak times may provide a more accurate picture of the requirements of generators at times where the network is closest to capacity.

However, we consider that determining transitional access allocations in such a manner is not appropriate for the following reasons:

- it may act as a market distortion in the periods leading up to the calculation of transitional access, as generators may place market offers in a manner to maximise their allocated transitional access;

- it will result in generators that are not operating at the measured peak (ie units out for maintenance) receiving little, or no, allocated access which could result in market shock; and
- it may result in some generator technologies being preferred over others.

B.5.3 Using historical dispatch intervals

Some stakeholders have suggested that transitional access allocations should be based on historical dispatch intervals further in the past (ie historical periods of high congestion). These participants noted that all of our tests have been based on data within the last year and consider that any testing run should use NEMDE files over a wide time period.

These participants also note that the current market may not be reflective of wider market trends due to the presence of the carbon price in the examples used.

However, it would be difficult to nominate a time period where there was not a particular circumstance that may affect allocations for one or more generators.

Furthermore, we consider that the test should be based on data that is sourced as recently as possible. If optional firm access is introduced, the transitional access allocations should be based on data from the period just before implementation. This is because the distribution of generators, loads and network assets is constantly changing as new assets enter and leave the market. Consequently, any transitional access allocations based on older data would be less meaningful.

B.6 Potential other methods

There are other potential methods of allocating transitional firm access amounts. These include undertaking a proportional allocation and a possible two-step process, and are elaborated below.

B.6.1 Proportional allocation

Some stakeholders have proposed a methodology based on allocating an equal proportion of access to all generators within a region. This proportion could be determined by dividing the regional peak demand by the total registered capacity of all generators within that region. The proponents of this methodology consider that it would be a simpler, more equitable and more transparent methodology than the one we recommended in the Transmission Frameworks Review.

However, we consider that the outcome of such a method would be inappropriate as the current network does not provide equal levels of access for all generators. Therefore, to ensure the network was compliant with the firm access standard, it would be necessary to determine the maximum proportion of capacity that could be dispatched from the generator least able to be dispatched in each region. This would be the maximum transitional access allowed for all generators. If this were not the case, consumers would be required to fund any augmentations to bring generators up to the equal proportion amount.

Therefore, proportional allocations would result in low but equal allocations of transitional access for all generators. It would also result in there being a high proportion of network capacity not allocated in flowgates remote from those where the generator with the worst dispatch participates. Such an outcome would be inefficient as it would not allocate transitional access in a manner that reflects existing network conditions.

B.6.2 Two stage allocation

We consider that one alternate method that could be feasible would be to undertake a two stage allocation of access. The two stages are as follows:

1. The method as described in section B.3.1 is undertaken but with no additional load added at the regional reference node; and

2. Modelled extra load is placed at the regional reference node. The generators' remaining capacity (beyond what was determined in step 1, which would be the minimum allocation) is then offered in the market using the process outlined in section B.3.1.

If there were no constraints binding in the first step then each generator would receive an equitable minimum allocation. We consider the usage of such a process could result in some generators receiving a higher access than using only the method as laid out in section B.3.1. However, any increase in transitional access allocations to one generator would result in reduced transitional access allocations for generators who participate in the same constraints.

We also note that such an approach may have issues if there are binding constraints observed in the first step. If congestion was present in the first step examined, then any generators participating in any binding constraint would likely have a maximum allocation of what was dispatched in that first step. It would be impossible to increase allocation to one generator in a binding constraint without removing allocation from one of the other participating generators, which the method does not allow to happen.

We welcome feedback on the appropriateness of this method and whether it should be further investigated.

B.7 Consultation questions

The AEMC would be interested in receiving feedback on the methodology and results contained in this appendix. Participants are encouraged to assess this methodology against the national electricity objective, and to discuss what they see as the main costs and benefits of this methodology, or whether there are some alternative proposals that should be considered.

We are particularly interested in hearing stakeholders' views on:

- the method we proposed to use in calculating transitional access;
- whether there are any variations in the input assumptions that could be considered;
- comments on the materiality of any issues with the proposed approach; and
- the proposed alternate methodologies.

C Table 10.1 of the Transmission Frameworks Review final report

Table C.1 Core and recommended elements of the optional firm access model

	Core Elements	Recommended Elements	Optional Elements
Access	• The firm access service is provided by TNSPs • Access entitlements are independent of dispatch • Access settlement balances in each settlement period • Access settlement occurs at congested flowgates • The amount of compensation paid or received would be the difference between a generator's usage and its entitlements, multiplied by the flowgate price • The sum of the entitlements must equal the flowgate capacity • TNSPs must maintain the firm access standard • The firm access standard is based on level of flowgate capacity required to provide access to firm	• Access charge is fixed - apart from specified indexation - for life of access agreement • Flowgate support generators paid regional reference price	

	Core Elements	Recommended Elements	Optional Elements
	generators • Access is firm but not fixed • Access charges paid to TNSPs		
Access settlement	• Flowgates created on every transmission constraint • Flowgate parameters (participation factor and capacity) taken from NEMDE • Target entitlements based on access amount multiplied by participation factor • Non-firm entitlements not provided unless firm target entitlements are met	• Transmission constraint defined as "any NEMDE constraint arising from a limitation on a TNSP network for which a constrained generator is not currently compensated" • Firm access amount limited by capacity • Non-firm access amount is the shortfall between availability and firm access • Super-firm entitlements provided, subject to firm entitlement scaling factor and as needed to top-up firm entitlements • Flowgate support generators provided with negative entitlements (to ensure paid regional reference price) which adds to effective flowgate capacity • The settlement period for access settlement is a trading interval (30	

	Core Elements	Recommended Elements	Optional Elements
		minutes)	
Firm access standard	• Firm access standard is an operational standard that applies in real-time dispatch, as opposed to a planning standard • Target capacity on each flowgate based on access and participation of firm generators only • Firm access standard does not place any obligation on TNSPs in relation to non-firm generators • Normal operating conditions includes system normal • Target flowgate capacity not required to be provided on uncongested flowgates • RIT-T assessments no longer include benefits and costs that accrue to generators	• Firm access standard is a single-tier standard (as opposed to the alternative of a multi-tier standard, as described in the Technical Report (August 2012)) • Firm access standard is uniform across the NEM (alternative is for it to vary between regions) • Normal operating conditions includes planned outages • Normal operating conditions criteria are flowgate specific • Firm access standard does not place any obligation on TNSPs outside normal operating conditions • No change in reliability standards for OFA implementation (but a parallel change to reliability standards is not ruled out by this)	• Firm access standard target flowgate capacity should include target super-firm entitlements. (The alternative is that it does not include super-firm entitlements)
Access pricing	• Access charge based on Long Run Incremental Cost (LRIC), defined as difference in NPV between baseline expansion costs and adjusted expansion cost	• Access charge excludes the effects of reliability standards and reliability access • LRIC calculated separately for	• Meshedness factor use to adjust the lumpiness of parallel lines (other alternative approaches may be possible) • Discount rate for NPV calculation

	Core Elements	Recommended Elements	Optional Elements
	• LRIC estimated based on stylised model rather than actual TNSP expansion plans • Access charge must take account of cross-regional impacts and provide for appropriate cross-regional payments between TNSPs • Access charge is payable through annualised payments over the access term • Non-firm generators do not pay an access charge	each transmission branch element • Element LRIC based on initial spare capacity, flow growth, lumpiness, incremental usage and access term • Element parameters based on a combination of detailed forecasts for shorter-term and stylised estimates for longer-term • Forecasts based on NTNDP or other information provided by NTP • Super-firm access charged the same way as firm access: ie generator capacity not taken into account • No negative access charge on elements where a negative LRIC is calculated (ie expansion can be deferred as the result of the new access) • Annual payment profiling specified in access charge methodology • Access pricing model and input parameters are maintained by NTP • Pending access requests included	based on TNSP regulated cost of capital (alternative discount rates are possible) • Pricing is undertaken by TNSP, using a copy of the model provided by the NTP (alternative is that NTP or another central agency undertakes pricing)

	Core Elements	Recommended Elements	Optional Elements
		in forecasts	
Access procurement	• Access agreement defined by: amount, power station, node, term, profile, payments • Access firmness standard and incentives not specified in access agreement, but through rules or regulations	• The access amount that a generator can procure is not limited by its capacity; however, its entitlement that it receives will be limited by capacity • Access customisation permitted, subject to no adverse impact on other users • Generator details will be confidential at early stage of procurement process, but will be published at a later stage • Access term not restricted • TNSP can offer short-term access through auction process • Generators can secondary trade access bilaterally with TNSP permission • Generators can sell short-term access through the TNSP auction • Prudential arrangements to ensure access payments made are specified in access agreement • TNSPs may delay access	• Procurement will follow a process described in the technical report (alternative processes are possible) • Pricing model may be available for generators to use • Access profiled by peak/off-peak following forward market conventions (other profiles are possible and even option structures) • TNSP approves bilateral secondary transfer, subject to no increase in net LRIC (other criteria are possible) • Short-term access has equal firmness to long-term access in access settlement (alternative is that short-term access is treated as mezzanine)

	Core Elements	Recommended Elements	Optional Elements
		commencement where expansion required • Grouped procurement permitted	
Inter-regional	• Inter-regional access provides access from a neighbouring regional reference node (cf intra-regional access is from a generator node) to the regional reference node • Access settlement for inter-regional access is the same as for intra-regional access • Firm access standard for inter-regional access is the same as for intra-regional access • Any market participant can purchase inter-regional access and the access level is not limited in access settlement (cf intra-regional access limited by generator capacity) • Inter-regional access is sold in a AEMO-run auction (cf intra-regional access, which is sold bilaterally by TNSP)	• Inter-regional access is sold in quarterly blocks • Auction sales are subject to TNSP verification that any associated capacity expansion is economic • Auction prices would be based on the LRIC pricing methodology	• Short-term and long-term inter-regional access is sold at the same auction, and short-term intra-regional access at a separate auction (alternative is that short-term intra- and inter-regional access being sold at the same auction and long-term inter-regional access at a separate auction)
Revenue regulation and incentives	• TNSPs have an ex ante allowed revenue allowance based on the	• An uncertainty mechanism would be introduced allowing the TUOS	• TNSPs face a high-powered long-term incremental access

	Core Elements	Recommended Elements	Optional Elements
	efficient costs of providing current levels of load and firm access services • Actual project cost of the investments to meet firm access standard (excluding short-term access) and/or reliability standards would be rolled into the RAB • A cap on the TUOS revenue – which would restrict charges that users of load services face – would apply • TNSPs would face an incentive scheme and pay a penalty equal to some proportion of the settlement shortfall due to firm access standard breach • TNSP penalties paid into access settlement to offset settlement shortfall and mitigate the scaling back of firm access	revenue cap to be adjusted upwards or downwards • Short-term access incentive scheme – TNSPs would be subject to 100% of any settlement shortfalls • TNSPs face incentives outside the firm access standard to move back within normal operating conditions	incentive scheme for new access (alternative is that TNSPs are only exposed to some share of the shortfalls) • TNSPs face incentives outside the firm access standard to encourage TNSPs to provide an efficient level of access
Transition	• Existing generators are allocated some transitional access, at no charge • Transitional access allocation is firm access compliant on existing	• Transitional access auction established for one-off reallocation of transitional access • Transitional access allocation based on generator capacity and	• Sculpting profile based on 3 parameters X, Y, Z and K to be determined in implementation (other profiles are possible)

	Core Elements	Recommended Elements	Optional Elements
	network • Transitional access is sculpted back over time	pre-OFA operating regime • Inter-regional transitional access would only be allocated to the extent that it would not cause any additional scaling back of generators' transitional access	

D Glossary

Table D.1 OFA Model Glossary

Defined Term	Meaning
access	network access
access charge	a charge payable by a generator to its local TNSP in return for receiving firm access
access settlement	a new settlement process in the model through which access-long generators receive payments and access-short generators make payments
agreed access (amount)	the nominal amount of access specified in an firm access agreement, which may vary between peak and off-peak periods
abnormal operating condition	when the transmission network is operating under a specified set of conditions outside of normal operating conditions
auxiliary load	load that is part of a generator's operation and is removed as removed as part of with a generating unit
availability	for a conventional generator, the offered availability; for an intermittent generator, the Unconstrained Intermittent Generation Forecast
capacity shortfall	the difference in a settlement period between target flowgate capacity and actual flowgate capacity when the latter is less than the former
congested flowgate	a flowgate whose capacity is fully utilised in dispatch and which is causing dispatch to be constrained
constrained off	(for a generator) dispatched below its preferred output; a firm, constrained-off generator will typically be access-long and so entitled to payment from access settlements
constrained on	(for a generator) dispatched above its preferred output
dispatch access	the right to be dispatched in NEM dispatch at a specified MW level in accordance with a dispatch offer and paid the local price on dispatched output
dispatchable unit	either an individual generating unit or logically grouped generating units that are connected to the same node
effective flowgate capacity	the amount of capacity that is allocated between generators in the entitlement scaling algorithm; equals the flowgate capacity plus the flowgate support plus the TNSP support
embedded generator	a generator connected to a distribution network
exporting region	the region from which a directed interconnector withdraws power
firm access (service)	a transmission service provided to generators that have a firm

Defined Term	Meaning
	access agreement with their local TNSP, up to the level of the agreed access amount
firm access arrangement	an arrangement between a TNSP and a generator which specifies the service parameters for the provision of firm access service
firm access level	(for a generator) the lower of the generator's agreed access and capacity
firm access operating standard	the agreed service standard that TNSPs supply firm generators in each trading interval
firm access planning standard	the required level of network capacity TNSPs would plan to provide
firm access standard	the service standard for firm access, which is the lowest level of service quality that the TNSP is permitted to provide
firm generator	a generator with a firm access arrangement, and so the generator has some level of purchased firm access (this level could potentially be the same as its capacity, below its capacity, or above its capacity)
firm interconnector	an interconnector for which AEMO holds some agreed access in trust
firm interconnector right	a right to receive a specified proportion of the IRSR proceeds of a firm interconnector
flowgate	a point of potential congestion on the transmission network; the notional location on a transmission network represented in NEMDE by a transmission constraint
flowgate capacity	the maximum aggregate usage of a flowgate allowed in dispatch and the RHS of the corresponding NEMDE transmission constraint
flowgate participation (factor)	the proportion of a generator's output that uses a flowgate; the coefficient applied to that generator's dispatch variable in the LHS of the corresponding NEMDE transmission constraint
flowgate price	the marginal value of flowgate capacity in dispatch: the amount by which the total cost of dispatch would increase if flowgate capacity were reduced by 1MW; calculated in NEMDE as the dual value of the corresponding transmission constraint
flowgate support	the aggregate, absolute flowgate usage of flowgate support generators
flowgate support generator	(with respect to a flowgate) a generator with a participation factor less than zero
flowgate usage	the amount of a generator's output notionally flowing through the flowgate; the product of the generator's output and its flowgate participation

Defined Term	Meaning
generator	a power station, or the generating company responsible for the power station, depending upon the context
generator node	the transmission node at which a generator, or the distribution network used by an embedded generator, connects to the shared transmission network
hybrid flowgate	a flowgate in which generators and interconnectors both participate
importing region	the region into which a directed interconnector injects power
interconnector	a notional entity that is dispatched by NEMDE to transfer power from one RRN to a neighbouring RRN across a regulated interconnector
inter-regional access	network access provided to a directed interconnector, from the RRN in the exporting region to the RRN in the importing region
inter-regional hedge	a security which pays out an amount proportional to the inter-regional price difference in a settlement period, used by market participants to hedge inter-regional price risk
inter-regional price difference	the difference in RRP between two neighbouring regions
inter-regional settlement residue	the fund, held in trust by AEMO, into which, or from which, settlement payments relating to directed interconnectors are paid
intra-regional access	network access provided to a generator, from its generator node to the RRN in its local region
local price	the marginal value that a generator at a node provides to economic dispatch; the locational marginal price
long-run incremental cost	the immediate and future incremental costs to a TNSP associated with providing additional firm access
NEMDE	National Electricity Market Dispatch Engine: The computer system through which AEMO dispatches scheduled plant in the NEM and sets market prices.
NEMDE Queue	An offline version of the NEMDE which can be used to simulate NEMDE outputs, using fixed power system inputs.
network access	the right to be paid in AEMO settlement the difference between the regional reference price and the local price for a specified MW level
node	a local region on the network where all connected participants have the same flowgate participation and local price
non-firm access	the access received by generators that do not have an firm access agreement and so do not receive a firm access service
non-firm access level	(for a generator) the difference between availability and agreed access amount, when the former takes a higher value

Defined Term	Meaning
non-firm generator	a generator without a firm access agreement
normal operating condition	the transmission operating condition where the specified abnormal operating conditions are not in effect
power system stability	the capacity of the network as limited by the potential that a certain contingency could take place
preferred output	the quantity of a generator's availability that is offered at or below the RRP
rated capacity	the maximum determined export capacity of a revenue meter identifier
reliability access	the access provided to a non-firm generator so a TNSP can meet its reliability standard
reliability standard	the minimum service requirement for TNSP supply to consumers
regional reference price (RRP)	the price paid to a dispatched generator in regional settlement
regional reference node (RRN)	the node where the regional reference price is set
remote region	a region other than the local region
revenue meter identifier	a grouping of one or more dispatchable units and auxiliary loads for use in access settlement
SCADA meter	a meter used for the real time measurement and dispatch of a dispatchable unit
settlement residue auction	the auction through which AEMO sells SRA rights
shortfall	capacity shortfall
shortfall cost	the capacity shortfall multiplied by the flowgate price
SRA right	the right to receive a specified proportion of the inter-regional settlement residue for a specified directed interconnector
target firm entitlement	(for a generator on a congested flowgate) the product of the firm access level and the participation factor
target flowgate capacity	the minimum amount of flowgate capacity that a TNSP must provide on a congested flowgate to comply with firm access standard
target non-firm entitlement	(for a generator on a congested flowgate) the product of the non-firm access level and the participation factor
thermal limit	the maximum capacity at which a transmission element can securely or safely operate without physical damage or risks caused by overheating

Defined Term	Meaning
TNSP support	(at a flowgate) the absolute value of the negative flowgate entitlement allocated to TNSPs pursuant to a financial quality incentive regime
transitional access	a level of firm access service that is allocated to existing generators at the commencement of the optional firm access regime and for which no access charge is payable